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New Tax Incentives for Energy

by Keith Martin, in Washington

The massive Wall Street rescue package approved by the US Congress in early October included a series of tax incentives for energy projects. Some are merely extensions of existing incentives. Others are new.

Solar energy emerged as a big winner.

Congress extended a 30% tax credit for commercial and residential solar projects by another eight years through 2016. It made other changes that should make larger developers and tax equity investors more likely to be able to use the tax credit. It eliminated a barrier to utility ownership of solar projects. It also eliminated a cap on tax credits for homeowners who buy solar panels, which should lead to more direct sales of panels to homeowners in the future.

Wind farm developers were given another year through 2009 to complete projects to qualify for production tax credits on the electricity output. Developers of most other types of power plants that use renewable energy were given another two years through 2010.

The shorter extension for wind may reflect the shifting politics of wind in Congress. Congress gave the wind industry the choice of a one- or two-year extension, but the two-year extension would have come with a cap of 35% of project cost on the total benefit that each wind farm can receive from tax credits. The industry chose the shorter time period. It will try to extend the deadline again in 2009.

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PARTNERSHIPS should take the tax consequences into account before asking a lender or other creditor to convert debt into equity.

The Internal Revenue Service addressed the tax issues in proposed rules in late October. Such conversions are likely to become more common until the economy recovers.

In general, the partnership should determine the "liquidation value" of the partnership interest that the lender or other creditor will receive. The liquidation value is the share of cash the creditor would receive as a partner if the partnership liquidated and sold all of its assets at market value and then distributed the sales proceeds to the

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Most project developers cannot use the tax subsidies on their projects. Most barter them to institutional investors in exchange for capital to build projects, either by bringing the investors in as partners to own the projects and allocating them the tax benefits or, in the case of some solar projects, by selling and leasing back the projects. There has been a sharp contraction in the supply of available tax equity since mid-September. The collapse in the debt markets has led to a contraction in all types of capital available. There are discussions underway with Congress about interim measures that would allow developers to convert the subsidies more directly into cash, perhaps as part of an economic stimulus bill in a "lame-duck session" in November or early in the next Congress that takes office in late January. There is some sympathy from Congressional staff, but any such relief is considered a heavy lift politically.

The massive Wall Street bailout bill that passed Congress in October included many new tax benefits for energy projects. Solar energy was a big winner.

Coal was another big winner in the Wall Street bailout bill.

The bailout bill includes a long list of tax incentives to use coal. The House was adamantly opposed to any such incentives. However, it ended up with its back against a wall after the House first rejected the larger bank rescue measure, causing stock prices to plummet. The Senate then sent the bill back to the House for a second vote, but this time with a large package of energy tax incentives appended, including for coal. The House was in no position to say no.

Solar

The bailout bill made five changes in the current tax incentives for solar energy.

Companies that buy solar equipment for commercial use can claim 30% of the cost in the year the equipment is put into service. This is called an investment tax credit. The credit is a direct offset against taxes the company would otherwise have to pay. The deadline to put equipment in service to qualify had been December 2008. The bailout bill extended it eight years through 2016. After 2016, the credit will fall back to a "permanent" level of 10% unless the deadline is extended again by Congress.

The bill also made it easier for corporations to use the investment credit. The United States has essentially two corporate income tax systems. Corporations compute their regular income taxes and then their alternative minimum taxes using a broader definition of taxable income and a lower rate, and they pay essentially whichever amount is greater. The rule had been that the solar credit could be used to reduce regular taxes by as much as 75%, but not below the level at which minimum taxes kick in. The bailout bill eliminated the bar against using credits to offset minimum taxes. The 75% limit on how low regular taxes can be reduced will remain in place. The change applies to tax credits on equipment completed in tax years starting after October 3, 2008. Thus, for example, a corporation that pays taxes on a calendar-year basis would benefit from the rule change on solar equipment put into service starting in 2009.

The ability to use tax credits against minimum taxes mainly helps larger developers. They will be more likely to be able to use the tax credits directly rather than have to enter into complicated tax equity transactions. It may also make potential tax equity investors more likely to commit to solar projects that require future funding before the investor knows whether it will be on the minimum tax. Tax credits that cannot be used in the year equipment goes into service can be carried back one year and forward for as many as 20 years.

Regulated utilities will be able to claim tax credits on solar equipment put in service after February 13, 2008. In cases where work on a project started before February 13, the credit can be claimed only on the work after February 13. Tax credits could not be claimed in the past on "public utility property." A solar project fell into that category if the rates for sale of electricity from the project were set by a public utility commission on a rate-of-return basis.

The conventional wisdom is that letting utilities claim tax credits will mean fewer opportunities in the future for independent solar companies. Utility-scale solar projects exist today because of so-called solar set asides in a few states. There are 26 states with mandatory "renewable portfolio standards" that require electric utilities to supply a certain percentage of their electricity from renewable sources. Some of the states require that a share come specifically from solar energy. To the extent utilities choose to generate the electricity themselves, that will leave fewer opportunities for independent developers.

The truth is almost certainly more complicated. The solar industry did not fight the utilities on the change in law. Utility holding companies could already benefit from the 30% solar credit by owning projects through unregulated affiliates. What a utility could not do was claim a tax credit *and* put the project into the rate base on which the utility is allowed by its regulators to earn a return. Some industry experts have speculated that there will be a shift in the role played by independent developers from selling electricity to utilities to developing and selling projects to utilities — a so-called build-and-transfer model. Some utilities may also become more interested in solar as a form of distributed generation. Utilities grow by making new investments that add to rate base. Utilities may be more interested in owning solar panels on roofs of big-box stores, office buildings and homes in the future because they can now qualify for tax credits and put the panels into rate base.

The bailout bill should increase demand for solar panels from homeowners. Homeowners qualified in the past for a residential tax credit for 30% of the cost of photovoltaic panels and solar hot water heaters. The maximum credit that could be claimed on each type of equipment was $2,000. The bill eliminated the cap on solar panels but left it in place on solar hot water heaters. The cap has been eliminated only for solar panels installed after 2008. Congress also extended the deadline to claim residential tax credits on new solar panels and hot water heaters through 2016. The deadline had been December 2008.

Homeowners who pay minimum taxes */ continued page 4*

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partners, including the creditor in its new role as a partner.

If the liquidation value is less than the principal amount that the creditor was owed on the debt, then the partnership must report the difference as income. Anyone excused from a debt has income. The income in this case is reported by the persons who were partners immediately before the creditor became a partner.

Economically, the creditor has a loss. However, it cannot claim the loss immediately on its tax return. Rather, it takes a tax basis in its new partnership interest equal to the full principal amount of the debt that was converted. If the creditor later sells the partnership interest for less than its basis, then it will have a loss at that time.

This approach of using the liquidation value to determine how much of the debt a creditor recovered by converting the debt into equity in the partnership only works if the partnership maintains proper "capital accounts" for the partners. Each partner usually has a capital account that tracks what the partner put in and took out of the partnership. The balance a partner has at any given time is his claim on the assets if the partnership liquidates. The IRS has detailed rules for how capital accounts are supposed to be calculated. If the partnership does not keep proper capital accounts, then the IRS said the parties will have to fall back on other measures — what it calls a "facts and circumstances" approach — to determine what value the creditor received.

Most conversions of debt into equity in a partnership should be tax free for the creditor. However, the creditor will have income to the extent the debt being converted is money the partnership owes the creditor — and that the creditor has not reported yet as income — for rent, royalties, past services or unpaid interest, including "original issue discount," on a loan.

The new rules are in proposed regulations interpreting section 108(e)(8) of the US tax code. They were published in the Federal Register on October 31. */ continued page 5*

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had been able to use residential credits against such taxes, but not after 2007. The bailout bill restored the ability retroactively to the start of 2008.

Any homeowner who claims a residential credit must reduce the tax basis in his house by the amount of the credit.

Many roofers and installers focus on the residential market. Several large solar companies do as well, but with the intention of owning solar panels put on roofs of houses. They either lease the panels to the homeowners or sign contracts to sell them electricity. Lifting the cap on the tax credit a homeowner can claim may make some homeowners more likely to own panels, since it brings down the cost of panels to homeowners who choose to purchase the panels when they are new. However, there should still remain a healthy residential solar business since an independent solar company owning the panels can claim depreciation worth roughly another 26% of the cost of the panels and share the tax savings with the homeowner by charging a reduced rent or price for electricity.

Other Renewables

Companies that generate electricity from wind, geothermal steam or fluid, biomass, landfill gas, municipal solid waste or from incremental additions to existing hydroelectric facilities qualify for production tax credits on the electricity output. The credits are 1¢ or 2.1¢ a kilowatt hour, depending on the energy source. They are 2.1¢ a kilowatt hour for wind, geothermal steam or fluid and "closed-loop" biomass (plants grown exclusively to be used as fuel in power plants). They are 1¢ a kilowatt hour for other projects. Those are the tax credit figures for electricity generated during 2008. The credit amount is adjusted each year for inflation.

The deadline to place projects in service to qualify was December 2008.

The bailout bill extended it through 2009 for wind farms and through 2010 for other types of renewable energy facilities. Tax credits can be claimed on the electricity output for the first 10 years after a project is placed in service.

Congress also made the tax credit available for the first time at the 1¢ level to developers of projects that use "marine or hydrokinetic" energy to generate electricity. Such projects must be placed in service between October 3, 2008 and December 31, 2011 to qualify. "Marine or hydrokinetic" energy means waves, tides, currents or temperature differentials in oceans and free-flowing water in rivers, lakes, streams and irrigation canals. A project cannot involve a dam or other structure that impounds water. It must have a nameplate capacity of at least 150 kilowatts.

Municipal utilities, electric cooperatives and Indian tribes do not benefit from tax subsidies because they do not usually pay federal income taxes. The bailout bill authorized $800 million in "clean renewable energy bonds" as an alternative. These are bonds that can be issued to finance power plants that would qualify for production tax credits if they were privately owned. A project must be owned by a municipal utility, electric cooperative or Indian tribe. The borrower does not have to pay interest. The lender receives tax credits from the federal government instead. Since the tax credits are equivalent to interest, they must be reported as income by the lender.

Congress authorized $800 million in such bonds in 2006 and 2007. The limit was later increased to $1.2 billion. The first-round allocations of bond authority by the Internal Revenue Service were disappointing. The IRS received 701 applications to finance 786 projects. It approved bonds for 33 solar projects, 13 wind farms, 13 landfill gas facilities, 12 biomass facilities and six hydropower plants. The largest single bond allocation was $33 million. The average allocation was just a few million dollars.

Since the projects also qualify for depreciation deductions if privately owned, many municipal utilities, coops and Indian tribes would do better to put the projects in private hands, but take advantage of a "safe harbor" in the existing tax rules that lets them buy the electricity while coming close economically to the rights a lessee would have over the project.

Congress tinkered with the rules affecting various types of projects.

The tax code said anyone using municipal solid waste to generate electricity can claim production tax credits only if he "burns" the waste. The bailout bill changed the word to "uses." Developers who plan to gasify garbage and run the gas through gas turbines — rather than use direct incineration — had sought the change.

Some developers add additional generating capacity to existing biomass power plants. Tax credits could not be claimed in the past on the additional electricity output unless the original plant went into service after October 22, 2004 or the upgrades were so extensive as to turn the original plant into a new facility. The bailout bill makes clear that tax credits can be claimed on the electricity from any "new unit" added to an existing biomass plant after October 3, 2008.

The bill reworked the rules for when production tax credits can be claimed on the incremental electricity output from "efficiency improvements or additions to capacity" at existing dams. Anyone adding capacity at an existing dam that was not used previously to generate electricity had to show there would not be "any enlargement of a bypass channel, or the impoundment or any withholding of any additional water from the natural stream channel" as a consequence of installing turbines.

Developers struggled with this test. The bailout bill changed it. After 2008, a developer adding new equipment at an existing non-hydroelectric dam will have to show that the dam was operated for "flood control, navigation, or water supply" and was not being used on October 3, 2008 to generate electricity. The IRS must certify that the project will not increase the water surface elevation.

The bill lets investment tax credits on geothermal projects be claimed against alternative minimum taxes. Geothermal developers have a choice of claiming production tax credits of 2.1¢ a kilowatt hour on the first 10 years of electricity output from their projects or taking an investment tax credit for 10% of the project cost in the year the project is first placed in service. Almost all developers choose production tax credits. If the owner of the project pays minimum taxes, it may be unable to use production tax credits. They can be used against minimum taxes only for the first four years after the project is placed in service. The bailout bill lets the full investment credit be used against minimum taxes. The change is unlikely to cause a switch because of the large disparity in value between production tax credits and the investment credit.

Cogeneration, Fuel Cells and Small Gas Turbines

Cogeneration facilities are power plants that produce two useful forms of energy from a single fuel. An example is a power plant that burns coal under a boiler to produce steam. Some of the steam might be used as process heat at an adjacent factory and the rest is run through a turbine to generate electricity.

The bailout bill provides a 10% investment tax credit for new cogeneration units put in service / continued page 6

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US MULTINATIONAL CORPORATIONS with earnings parked in offshore holding companies have been given leave to bring the earnings back temporarily to the United States without triggering US income taxes.

The move is part of the US government effort to ease the credit crisis. However, the IRS is cracking down at the same time on other ways of repatriating earnings that companies insist do not trigger taxes.

The United States taxes US corporations and American citizens on worldwide income. It does not matter where the income is earned or whether it is brought back to the United States. However, US companies with active business operations in other countries can usually defer US taxes on the earnings by operating overseas through offshore holding companies. As long as the earnings remain outside the United States, tax is deferred until the earnings are repatriated. It is only possible to defer US taxes on income from an *active* business, like a factory in China or Brazil. Dividends, interest and other forms of *passive* income are taxed in the US without waiting for repatriation.

US companies must be careful not to make effective use of earnings in the United States before they are formally repatriated. An example of effective use is where a US parent corporation has its Bermuda holding company guarantee repayment of a bank loan to the parent in the United States.

IRS policy since 1988 has been to allow temporary loans of up to 30 days at a time by offshore subsidiaries to their US parents without triggering US taxes. However, a subsidiary cannot have loans outstanding for 60 or more days during a single tax year.

In early October, the IRS said it will allow loans of up to 60 days and no more than 180 days in total. The relief is temporary. It applies only during the 2008 and 2009 tax years. The relevant tax year is the tax year of the foreign subsidiary making the loan. The IRS announcement is in Notice 2008-91. / continued page 7

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after October 3, 2008. If work started before that date, then the credit can be claimed only on the work after October 3.

The full credit can be claimed on cogeneration units of up to 15 megawatts in capacity. The credit is reduced as the capacity approaches 50 megawatts. There is no credit for units over 50 megawatts. For units between 15 and 50 megawatts, the credit must be multiplied by a fraction. The numerator is 15 megawatts and the actual capacity is in the denominator. Thus, only a 3.75% investment credit can be claimed on a 40-megawatt unit (10% x 15/40). The owner must reduce his basis in the cogeneration unit for depreciation by half the tax credit.

To qualify for an investment credit, at least 20% of the energy output must be "useful" thermal energy, meaning steam put to use directly as steam and not used to generate electricity.

The unit must have an energy conversion ratio of more than 60%. There is always an energy loss when fuel is converted into electricity. The conversion efficiency requirement is waived for units that are designed to run on biomass. There is no minimum conversion ratio for such units, but only a fraction of the tax credit can be claimed if the conversion ratio is less than 60%. In such cases, the credit must be multiplied by the actual conversion ratio divided by 60.

Fuel cell power plants qualify currently for a 30% investment tax credit, but must be in service by December 2008. The bailout bill extended the deadline by another eight years through 2016. The fuel cell plant must have an electricity-only generation efficiency of more than 30%. The credit is capped, after the bailout bill, at $3,000 per kilowatt of generating capacity.

Small gas turbines of less than two megawatts in size qualify currently for a 10% investment credit. The credit can be claimed not only on the cost of the gas turbine, but also related equipment. The gas turbine must be "stationary." It must have a conversion efficiency of at least 26%. The deadline had been the end of this year to place such turbines in service. The bailout bill extended it another eight years through 2016. The credit is capped at $200,000 per megawatt of capacity.

Congress dropped a restriction that would have denied tax credits on cogeneration units, fuel cells and small gas turbines that are owned by regulated utilities. Companies will also be able to use the tax credits on projects completed after this year as an offset against minimum taxes.

Coal

Coal developers were not expecting much from Congress, but ended up with a maze of potential tax incentives for use of coal.

There is already an investment tax credit for investing in new IGCC (integrated gasification combined-cycle) power plants. The credit can only be claimed on equipment at the front end of such a plant that is "necessary for the gasification of coal, including any coal handling and gas separation equipment." The credit is 20% of cost. The total amount that can be claimed in credits nationwide is $800 million. Developers hoping to claim credits must apply to the IRS for an allocation. No credits remain for IGCC projects that use bituminous coal. Another $133.5 million in credits remain for IGCC projects that use sub-bituminous coal and $133 million for projects that use lignite. Applications for the remaining credits were due at the US Department of Energy by October 31. Part two of the application must be submitted to the IRS by March 2, 2009. The IRS relies heavily on the Department of Energy to select the winning bidders.

There are no additional credits for IGCC plants in the bailout bill.

Coal developers were not expecting much, but ended up with a maze of new tax incentives to use coal.

However, the bill increased a separate investment tax credit for other power projects that use "advanced" technologies to generate electricity from coal. The credit was 15%. It has been doubled to 30% for new projects after the original credits are exhausted. Congress authorized $500 million in credits originally in August 2005. Of that amount, $125 million in credits remain to be awarded by the IRS. Applications had to be at the Department of Energy by October 29.

The bailout bill authorized another $1.25 billion in tax credits for such projects. The IRS is expected to start taking applications for them next year.

Companies applying must be able to show that their projects will sequester at least 65% of carbon dioxide emissions. Congress directed the IRS to give the "highest priority," in making awards, to a ranking of applicants by percentage of CO_2 sequestered and to give a "high priority" to applicants who have a research partnership with a college or university.

A project can be a new power plant or a retrofit or repowering of an existing plant. To be considered an "advanced" technology, the project must have a design net heat rate of 8,350 Btus/kWh or better with at least 40% efficiency of energy conversion. The plant must also be designed to meet certain pollution standards, including 99% removal of sulfur dioxide and 90% removal of mercury. The tax code has a series of assumptions that must be made in calculating the heat rate. The fuel must be at least 75% coal. The plant must have a nameplate capacity of at least 400 megawatts.

The bailout bill also increased a separate existing investment tax credit for gasification projects. The credit can be claimed on new facilities that gasify any "solid or liquid product from coal, petroleum residue, biomass, or other materials which are recovered for their energy or feedstock value." The equipment must turn the material into a "synthesis gas" composed primarily of carbon monoxide and hydrogen. The credit was 20% of the equipment cost. The bailout bill increased it to 30%.

The credit can be claimed on the gasification train at a plant that converts coal or biomass into synthesis gas. (A separate train must then turn the gas into transportation fuel.) "Biomass" is defined narrowly for this purpose. It includes only agricultural or plant waste, byproducts from wood or paper mill operations, and forest trimmings.

The total gasification credits that can be claimed nationwide were originally capped at $350 / *continued page 8*

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Companies that renew loans too quickly after the initial term has run risk having the IRS treat the borrowings as a single loan. Some tax experts argue that a 13-day or shorter break between two 60-day loans will cause aggregation, while a wait of at least 52 days is safe. Whether the IRS will aggregate if the wait is 14 to 51 days is unclear.

A trade group representing corporate tax directors called on the Treasury in mid-October to extend the time periods because of the deteriorating financial situation. The group said 60 days is too short even to fund corporate operations through the end of 2008 and called on the government to allow loans of up to six months to a year. It is not clear the Treasury has authority on its own to extend the period that long without a vote by Congress.

Meanwhile, the IRS issued regulations in late June to crack down on an approach it said some US companies have been using to claim tax-free repatriation. In one example of the tactic, a US parent company has two US subsidiaries, A and B. A has a foreign subsidiary. Its foreign subsidiary makes a capital contribution of 10% its own shares and 90% cash to B in exchange for shares in B. Making a capital contribution to a corporation does not usually trigger taxes. The IRS put a halt to such in-bound capital contribution transactions as of June 24.

However, it took a more generous view of a transaction in a private ruling made public in August. Two affiliated companies — one US and one non-US — formed an offshore partnership with a third party. The three partners, 1, 2 and 3, each contributed cash to the partnership. The partnership then bought a US business from the US partner 1 and a foreign business from non-US partner 2. The non-US partner took back "tracking interests" that tracked the economic results just of the business it sold. The IRS said that none of its earnings would be considered "invested in United States property," meaning effectively repatriated.

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million. All $350 million has been allocated by the IRS. The bailout bill authorized $250 million more in credits.

It also tightened eligibility. Future gasification facilities must include equipment to separate and sequester at least 75% of the carbon dioxide emissions from the project. The credit may be recaptured if a project fails later to meet this sequestration threshold. Congress directed the IRS to give the "highest priority," when allocating tax credits, to rankings of projects based on the percentage of CO_2 sequestered and to give a "high priority" to any applicant who has entered into a research partnership with a college or university.

Projects that produce fuel from coal using the Fischer-Tropsch process qualify potentially for a separate "alternative fuels credit" of 50¢ a gallon, but only for fuel used in motor vehicles or motor boats. The bailout bill added aviation fuel to the list of eligible uses.

The alternative fuels credit is a credit against excise taxes on the fuel. The US government collects a "manufacturers" excise tax on some fuels when they leave the bulk transfer system. Fuels that escape manufacturers tax are subject to a retail excise tax when they are sold to the consumer. The alternative fuels credit is a credit against any retail tax. The IRS will refund the amount of the alternative fuels credit to the extent the credit exceeds the retail taxes the company has to pay.

The alternative fuels credit is available only through September 2009. The bailout bill extended it another three months to year end. Any coal-to-liquids plants must certify that at least 50% of CO_2 emitted during production in the last three months of 2009 was separated and sequestered. The percentage will increase to 75% after 2009 if Congress extends the tax credit.

Coal-to-liquids companies were also given more time to sign binding construction contracts to build new plants and deduct half of the capital cost immediately. Half the cost of any new "qualified refinery" can be deducted in the year it goes into service. The portion of any coal-to-liquids plant that converts synthetic gas made from coal into a liquid fuel is such a refinery. The refinery must be under a binding construction contract by the end of 2009 to be built. It must be put into service by 2013. Its primary purpose must be to produce liquid fuel. The federal tax savings from the 50% immediate writeoff are worth 2.6¢ or 3.6¢ per dollar of capital cost, depending on how rapidly the equipment would have been depreciated otherwise. The balance of the plant must be depreciated normally.

The US government will pay up to 10% of the cost of new cogeneration units through tax credits.

Separately, companies that convert coal or fly ash into fuel that is less polluting qualify potentially for "refined coal" credits today of $6.06 a ton. The credits can be claimed for 10 years after the facility that makes the refined coal is first put into service. The deadline to place such facilities in service had been December 2008. The bailout bill extended it by another year through 2009.

The bill also modified what is required to qualify as "refined coal." Until now, the producer had to show at least a 20% reduction in at least two types of emissions from burning the refined coal compared to the raw coal and at least a 50% increase in value of the refined coal compared to the raw coal. There had to be at least a 20% reduction in nitrogen oxide emissions and either sulfur dioxide or mercury.

The need to show at least a 50% increase in value robbed the tax credit of much of its utility as an inducement to coal companies to invest in refined coal equipment. Coal prices fluctuate. So does the cost of allowances that an electric utility might otherwise have to buy to cover its emissions as an alternative to burning refined coal. Thus, no one investing in a refined coal facility today would be able to tell whether it will qualify for a full 10 years of tax credits.

The bailout bill dropped the market value test and increased the required reduction in nitrogen oxide emissions to 40%. A plant must still show at least a 20% reduction in either sulfur dioxide or mercury emissions. The change only applies to new refined coal facilities put into service in 2009. The IRS is working in the meantime on guidance. The guidance is expected to explain early next year how, and how often, the IRS expects companies to certify the pollution reductions.

The bailout bill authorized separate tax credits of 34.48¢ an mmBtu to be claimed for a year — and, in some cases, a little longer — by anyone producing "steel industry fuel." The facility that produces the steel industry fuel must either be a new facility or modified existing facility that was put into service during the period October 2008 through December 2009. "Steel industry fuel" is liquefied coal waste sludge that is used as a feedstock for producing coke at steel mills. The liquefied sludge must be "distributed on coal." Credits can be claimed for only a year or, if longer, through December 2009. Steel companies must be hoping the credit will be extended. As with so many tax benefits, the initial step is to get in the tax code and then try to expand the provision.

There was already a more generous tax credit for building a new facility to produce coke or coke gas. That credit was 56.55¢ an mmBtu for the output from such a plant in 2007. The amount is adjusted each year for inflation; the IRS will not announce the 2008 amount until next April. The coke or coke gas credit can be claimed for four years after a facility is first placed in service. The facility must go into service by December 2009 to qualify. However, the amount of credit is capped at an average output of 23,200 mmBtus a day. To the extent there is overlap, the new tax credit for producing steel industry fuel cannot be claimed on any fuel that also qualifies for the existing credit for producing coke or coke gas.

Finally, the US government collects an excise tax on coal mined in the United States. The tax is $1.10 a ton on coal from underground mines and 55¢ a ton on coal from surface mines. However, the tax cannot exceed 4.4% of the sales price of the coal. The tax had been scheduled to drop to 50¢ a ton on coal from underground mines and 25¢ a ton on coal from surface mines, and the cap had been scheduled to fall to 2% of the sales price for the coal, in 2014. The bailout bill pushed back the date the tax will drop to 2019. / continued page 10

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the two affiliated partners, 1 and 2, were improved because the partnership allowed the businesses to attract new capital. The ruling is Private Letter Ruling 200832024.

HOW BIOFUEL PLANTS should be depreciated for tax purposes remains unclear.

The IRS told its field teams in late August not to rely on a memo that it circulated late last year that said facilities that produce ethanol should be depreciated over seven years. Many ethanol producers depreciate their plants over five years. The proper depreciation depends on whether the plants are considered used to make chemicals, which would allow them to be depreciated over five years, or are "waste reduction and resource recovery plants" that convert "biomass" into a "solid, liquid, or gaseous fuel." The IRS has been challenging ethanol producers who used five-year depreciation on audit. A change in depreciation to seven years costs the typical ethanol producer about $3 million in extra taxes. In late August, the agency said it is still studying the issue. Its latest memo is Chief Counsel Advice 200835032.

BUSINESS METHODS AND TAX STRATEGIES may be harder to patent after a federal appeals court decision in late October.

Bernard Bilski applied to the US Patent Office to patent a "method of hedging risk in the field of commodities trading." Both the Patent Office and the court rejected the application on grounds that his proposed invention was purely a mental process of doing mathematical calculations to determine how best to hedge a particular risk and then identifying and executing a transaction that the calculations suggested would be a good hedge. Both suggested that the idea was unpatentable unless Bilski could show a connection to a mechanical device or a transformation of an article into a different state or thing.

Many tax lawyers are concerned that allowing patents on tax strategies lets someone essentially charge rent for use of the US tax code and turns transactions into / continued page 11

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Revenues from the tax are used to fund a trust that is short on money to pay "black lung" benefits to retired miners. The government calculated the expected present value of the shortfall as of October 5, 2008. If the shortfall is eliminated before 2019, then the tax rates will drop sooner.

Biofuels

Biofuels use in the United States is subsidized through tax credits. Farm-state Senators occupy senior positions on the Senate tax-writing committee, and the presidential campaign starts in Iowa where biofuels are important to voters.

The tax code distinguishes among five types of biofuels: ethanol and other alcohol fuels, biodiesel, renewable diesel, cellulosic biofuel and "liquid fuel derived from biomass."

The first four fuels benefit potentially from income tax credits. Income tax credits are given to small producers of ethanol or agri-biodiesel, to anyone blending any of the three fuels with gasoline or diesel fuel and to service station owners who sell the first three fuels at retail, and to producers of cellulosic biofuel. The income tax credits for biodiesel and renewable diesel were scheduled to expire at year end. The bailout bill extended them for another year through 2009. The tax credits for ethanol and other alcohol fuels already run through 2010. The tax credit for cellulosic biofuel was just enacted in a farm bill last May and runs through 2012.

The income tax credit used to be higher for blending agri-biodiesel — as opposed to other kinds of biodiesel — or for selling agri-biodiesel at retail. It was $1 rather than 50¢ a gallon. The bailout bill increased the credit for all biodiesel to $1 a gallon, effective for biodiesel blended or sold after 2008. The bill also added camelina to the list of plants whose oil can be used to make agri-biodiesel. The list is still important for small producers of agri-biodiesel, who qualify for an income tax credit on their output. A producer is considered small only if he has the capacity to produce no more than 60 million gallons a year. According to Wikipedia, farmers in Montana have been turning to camelina as a cash crop that can be sold for its oil. The chairman of the Senate tax-writing committee is from Montana.

A number of biodiesel plants in the United States import plant oil from overseas and then export the biodiesel they produce to Europe. The bailout bill bars any income or excise tax credits from being claimed in the United States on any ethanol or other alcohol fuel or biodiesel that is "produced outside the United States for use as a fuel outside the United States." The change is retroactive to May 15, 2008.

Congress waded into a controversy that the US Treasury Department tried to settle in April 2007 over what qualifies for tax credits of $1 a gallon as "renewable diesel." The term had been defined in the US tax code as diesel fuel made from "biomass" using a thermal depolymerization process described in one of two testing manuals published by the American Society for Testing and Materials — D975 and D396. Oil refiners urged the Treasury to define "renewable diesel" more expansively to include diesel fuel made by mixing poultry parts or other biomass with oil in existing refineries. The Treasury agreed.

Traditional biodiesel producers complained to Congress for fear of being muscled out of the still small biodiesel market by the oil majors. Congress responded in two ways. First, it broadened the definition. Renewable diesel will be defined after 2008 as any "liquid fuel" made using a process described in one of the two ASTM testing manuals "or any other equivalent standard" approved by the IRS. Congress said that aviation fuel can qualify as renewable diesel. However, renewable diesel will no longer include any fuel made by "co-processing" biomass with oil or other substances. The co-processing ban went into effect on October 4.

Congress added "compressed or liquefied gas derived from biomass" as another type of alternative fuel that will qualify in the future for an excise tax credit. "Biomass" for this purpose means any organic material other than oil, gas and coal or byproducts of those three. An example is wood or garbage. The federal government collects excise taxes of as much as 24.4¢ a gallon on gasoline, diesel and other fuels. Excise tax credits of 50¢ a gallon can be claimed currently by companies selling liquefied petroleum gas, P series fuels, compressed or liquefied natural gas, liquefied hydrogen, and liquid fuel made from coal using the Fischer-Tropsch process. The credits apply only to sales through 2009, with the exception that they run through 2014 for liquefied hydrogen. The credits are refundable to the extent they exceed the amount the company owes in excise taxes.

The bailout bill should make pipelines more willing to carry biofuels. Many oil and gas pipelines are owned by master limited partnerships or MLPs. These are large partnerships whose units are traded on a stock exchange. The partnerships enjoy an advantage over corporations competing in the same line of business since the partnerships are not subject to income taxes. Their incomes are taxed to the partners directly. The key to qualifying as an MLP is to make sure that at least 90% of the gross income the MLP earns each year is considered eligible income.

The types of eligible income are mostly various forms of passive income. Examples are interest, dividends, rents from leasing out "real property" (as opposed to equipment), and gains from the sale of capital assets and real property.

Pipelines will be able to count fees from transporting and storing ethanol, biodiesel and other alternative fuels as good income in the future.

Finally, the bill gives companies producing cellulosic biofuel or other alternative fuels more time to put new production facilities in service and qualify for an immediate tax deduction for half the cost. Such a deduction can already be claimed under section 168(l) of the US tax code on any new plant for making "cellulosic biomass ethanol." The balance of the plant cost is depreciated normally. The accelerated deduction applies only to new plants put into service by 2012. The bailout bill broadened section 168(l) to apply to all cellulosic *biofuel* facilities — not just those that produce ethanol.

There is a separate right in section 179C of the tax code to deduct 50% of the cost of any new "qualified refinery" that is put into service by 2013. A production facility qualifies as such a refinery if it has a primary purpose of making liquid fuel using gas from biomass, among other permitted feedstocks. An example of gas from biomass is landfill gas. If a company cannot make the 2012 deadline for completing a cellulosic biofuel plant, then it might still qualify for an immediate deduction for 50% of the plant cost by treating the plant as a qualified refinery. However, to qualify, the plant must be under a binding construction contract by December 2009 to be built, and it must be completed by December 2013.

Carbon Sequestration

The bailout bill authorized tax credits of $10 and $20 a ton for sequestering carbon dioxide. It also let CO_2 pipeline businesses be organized as master limited partnerships, which should make it cheaper to raise equity.

The new tax credits are $10 a ton for CO_2 captured and used as a tertiary injectant for enhanced oil recovery. They are $20 a ton for CO_2 disposed in under- / continued page 12

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potential minefields because royalties could have to be paid, retroactively to the date of the patent application, to any patent holder who manages to patent a strategy involved in the transaction. The Patent Office granted 65 patents on tax strategies through last April and had another 110 applications for such patents pending. Most applicants claim in their applications that a computer is needed to implement their ideas. The appeals court said, "We leave to future cases the elaboration of the precise contours of [the machinery part of the machinery-or-transformation test] . . . such as whether or when recitation of a computer suffices to tie a process claim to a particular machine."

The case is *In re Bilski*. The court released its decision on October 30.

Law firms and financial advisers have applied for at least two patents on structures for financing US wind farms and solar projects. One application by a law firm for a patent on a "prepaid service contract" structure used to finance at least two wind farms was rejected by the Patent Office and was withdrawn. Another application for a patent on a structure for guaranteeing tax equity investors in wind deals at least a minimum return was filed by a financial adviser in June.

REITS can own solar panels on roofs of buildings and supply electricity to tenants without jeopardizing their status as passthrough entities for tax purposes.

REITs are real estate investment trusts. They are a popular form of entity in the United States for owning buildings and other real estate because they are not subject to income taxes on their earnings. The investors are taxed directly. In order to qualify as a REIT, at least 95% of the gross income the entity earns each year must come from a list of certain types of eligible income and at least 75% must come from a separate and more narrowly-focused list. "Rents from real property" are eligible income for both tests.

The IRS told one REIT in / continued page 13

New Incentives

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ground salt formations or coal seams that are not capable of being mined.

The IRS will track how much CO_2 has been sequestered on account of the tax credits and announce when 75 million tons are reached. No more tax credits may be claimed after the year in which the 75-million-ton target is reached. Total US greenhouse gas emissions are about 7.2 billion tons a year, of which roughly a third comes from power plants.

The taxpayer claiming credits must own the industrial facility at which the CO_2 is captured. At least 500,000 tons of CO_2 must be captured at the facility per year. The owner can contract with someone else to use or dispose of the CO_2.

There are new tax credits of up to $20 a ton for sequestering carbon dioxide. Congress also made it cheaper to raise equity for new CO_2 pipelines.

However, if the CO_2 is not used or disposed properly, then the tax credits will have to be paid back to the IRS. The CO_2 must be both captured and used or disposed of in the United States or a US possession like Puerto Rico or the US Virgin Islands. The dollar amount of the credits will be adjusted for inflation after 2009.

One impediment to greater carbon sequestration in the United States is lack of a network of pipelines to carry CO_2. The bill will allow businesses that own CO_2 pipelines to be organized as MLPs, meaning that the businesses can list units on a stock exchange and will not be subject to income taxes on their earnings. MLPs can raise equity more cheaply because of the tax advantage and because the units can be resold more easily than normal partnership interests. The key to qualifying as an MLP is to make sure that at least 90% of the gross income the MLP earns each year is considered eligible income. Eligible income includes income from producing, processing, transporting or marketing minerals and natural resources. The bailout bill added "industrial source carbon dioxide." It was unclear in the past whether byproducts of producing, processing or transporting minerals or natural resources qualify.

Transmission

The bailout bill gives electric utilities another year to shed all or part of their transmission assets. One obstacle to doing this has been that the utilities face potentially large tax bills if they have little unrecovered "tax basis" in the assets. In such situations, virtually all the compensation they receive is taxable.

Congress voted in October 2004 to let any utility that sells transmission lines or related equipment spread the income taxes on its gain over eight years. The utility must reinvest the sales proceeds in other electric or gas utility property or another power or gas company in the United States.

The deadline to sell was originally 2006. It was later extended to 2007. The bailout bill extended it again through 2009.

The transmission assets must be sold to an "independent transmission company." An independent transmission company can be an ISO (independent system operator), RTO (regional transmission organization) or other independent transmission provider approved by the Federal Energy Regulatory Commission, or any company that is not a "market participant" as the Federal Energy Regulatory Commission defines that term and whose own transmission facilities are put under operational control of an ISO or RTO within four years after the end of the tax year in which it acquires transmission assets from a utility.

Other Changes

Projects on Indian reservations qualify for more rapid depreciation. There is also a wage credit tied to the number of Indians hired to work on the project. Both benefits expired at the end of 2007. They have been extended through 2009.

Property that would have been depreciated over five years if it was built elsewhere — for example, a wind farm or solar project — can usually be depreciated over three years if built on a reservation. Most gas- and coal-fired power plants are depreciated over 15 or 20 years today. They qualify for 9- or 12-year depreciation if built on a reservation. Buildings are normally depreciated over 39 years, but 22 years if built on a reservation.

There is a separate annual wage credit tied to the number of Indians the project employs on the reservation. The credit is 20% of wages and employee health insurance costs paid during the year to employees who are enrolled members of Indian tribes and their spouses. "Substantially all" the work each employee does must be on the reservation. The worker must also live on or near the reservation where the services are performed. There are other restrictions.

Battery makers received a boost. The bill authorizes tax credits of $3,700 to $15,000 for buying a plug-in vehicle, depending on battery capacity and vehicle weight. The credits will phase out over the next two quarters after 250,000 vehicles are sold. If there were ever a strong move to plug-in hybrids, it would increase electricity usage in the United States, since the cars must be recharged over night.

Finally, the bill authorizes another $3.5 billion in "new markets tax credits" to be allocated by the US Treasury in 2009. New market credits are tax credits that store-front lenders — called community development enterprises or CDEs — can hold out as a carrot to raise equity from investors to use, in turn, to lend or invest in businesses in low-income areas. Investors receive a tax credit for 39% of the equity they invest in a CDE. The tax credit is claimed over seven years. The tax credit not only helps the CDE raise money to lend, but also makes it possible to lend at low interest rates. Many large banks have set up CDEs through which they lend to projects in rural and other parts of the country that qualify as low income. Investors often use leverage to increase the amount of tax credits in relation to the actual equity invested.

The Treasury announced 2008 awards of new markets tax credits on October 20. The agency awarded $3.5 billion in credits for 2008 to 70 CDEs out of 239 who applied. ◎

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a private ruling made public in July that amounts received from its tenants in commercial office buildings for electricity and steam count as part of "rents from real property."

The REIT had been buying electricity and steam from local utilities and then sub-metering it to calculate how much to charge some tenants and charging other tenants a fixed cost per square foot. It planned to install generating equipment at each building and hire an outside contractor to operate it. Tenants would be charged for electricity and steam the same way as before. The IRS had to decide on which side of a line the charges fell. "Rent from real property" includes charges for services that are customarily furnished by landlords. An example is trash collection and cleaning of public spaces. However, it does not include "impermissible tenant service income." An example is maid service.

The IRS said the electricity and steam charges fall on the good side of the line. It does not matter whether they are broken out separately on bills for rent. The ruling is Private Letter Ruling 200828025.

A STRUCTURE for borrowing in the tax-exempt bond market against future property tax receipts to finance infrastructure projects has come under fire from a House subcommittee.

The subcommittee criticized use of the structure by the New York Yankees to help finance a new baseball stadium. Rep. Dennis Kucinich (D.-Ohio), the subcommittee chairman, charged at a hearing in September that the Yankees claimed an inflated property value in order to boost the amount of tax-exempt bonds that could be issued to finance the ballpark. He repeated the charges at a second hearing on October 24.

The same day, the Internal Revenue Service reissued regulations in final form that make the structure possible.

State and local governments can borrow at reduced interest rates in the tax-exempt bond market to finance schools, roads, hospitals and other public facilities. The */ continued page 15*

Heavy Demand for DOE Loan Guarantees

by Kenneth Hansen and Shunko Rojas, in Washington

Demand is expected to be heavy for the next round of federal loan guarantees for energy projects through the US Department of Energy.

The department is soliciting applications for up to $30.5 billion in guarantees in three targeted areas: up to $18.5 billion to support nuclear power facilities, up to $10 billion for renewable energy projects and up to $2 billion for nuclear fuel projects.

First round nuclear applications were due September 29. The department received 19 applications for 21 reactors seeking a total of $122 billion in financing — more than 10 times the amount of guarantees the department is currently authorized to award.

The deadline for renewables and transmission and distribution project applications was originally December, but has been postponed to February 26.

The renewables program contemplates supporting alternative fuel vehicles, biomass, efficient electricity transmission, distribution and storage, energy-efficient building technologies, geothermal, hydrogen and fuel cell technologies, energy efficiency projects and solar, wind and hydropower projects.

This latest round of solicitations has been launched in an environment of greater regulatory certainty than was the case for an earlier first round. The final rules for the loan guarantee program, issued October 23, 2007, introduced needed clarifications and useful changes that addressed some of the concerns raised in response to an earlier notice of proposed rulemaking. Nevertheless, some significant challenges to making effective use of the program remain.

DOE appears sympathetic to addressing the remaining impediments. Reports have emerged indicating that the department will issue a "notice of proposed rulemaking" as early as mid-November, hoping to have a revised set of rules in place for the program in January.

Key Features of the Current Round

The goal of the current round is to support projects that "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases" and "employ new or significantly improved technologies as compared [with] technologies in service in the United States."

A "new or significantly improved technology" is one that is

> concerned with the production, consumption or transmission of energy that is not a commercial technology, and that either (1) has only recently been developed, discovered or learned; or (2) involves or constitutes one or more meaningful and important improvements in productivity or value, in comparison to commercial technologies in the United States at the time the Term Sheet is issued.

A technology is already "in general use," and thus ineligible, "if it has been installed in and is being used in three or more commercial projects in the United States" and has been in operation for at least five years.

The Department of Energy is implementing the loan guarantee program through a series of solicitations, each targeting specific areas of technology. The submitted applications compete for the available financing authority. The evaluation process results in the applications being ranked, with the ones seen as better fulfilling the statutory and solicitation criteria receiving higher scores. DOE has declined to establish firm timelines for the processing of applications or the awarding of financing commitments.

The application process for the current round differs for each of the three technology areas covered.

For applicants hoping to share in the $10 billion allocated for "Energy Efficiency, Renewable Energy and Advanced Transmission and Distribution Technologies," the steps of the process are as follows. Pre-applications are now due February 26, 2009. The Department of Energy is then expected to "pre-select" some of the applicants for further review. If a project passes muster after a more formal review, then the government will issue a term sheet and sign a conditional commitment, pending negotiation and execution of the formal loan guarantee agreement.

In this area, DOE distinguishes among three types of projects and asks applicants to sort theirs according to whether it is a "manufacturing project" (in which the energy-saving technology is reflected in the manufacturing process or in use of the manufactured goods), a "stand-alone project" or a "large-scale integration project" (involving the staged development, financing, construction and operation in one project of more than one renewable energy, energy storage, energy efficiency and advanced transmission and distribution technology), the latter category being subject to some particular rules. A project sponsor may not submit an application for multiple projects using the same technology, other than in the case of large-scale integration projects. However, a sponsor may submit separate applications for each different technology or different project type. Loan guarantees for manufacturing projects or stand-alone projects will be limited to one project per applicant per technology.

Applications for guarantees for renewables and transmission projects will be evaluated based on a weighted average of multiple criteria. Technical and financial factors will each constitute 50% of the score. The technical factors include technical relevance and merit (10%), applicant capabilities, technical approach and work plan (20%), and environmental and energy security benefits (20%). Financial factors to be considered include creditworthiness (30%), construction factors (10%), and legal and regulatory factors (10%).

The process for nuclear power facilities is quite different, introducing an innovative, dynamic ranking mechanism. Applications will be evaluated on a continuous basis as they are received. DOE will review the initial submissions and assign an initial score providing a preliminary ranking of the projects. This ranking is expected to provide applicants information to assist them in making a self-selection decision as to how to improve their applications and their rankings and whether to proceed with the cost of completing a full application. Applicants who complete their applications but are not initially selected to enter into negotiations will be welcome to remain in queue, unless specifically excused.

Nuclear generation applications had to be submitted by September 29, and an initial ranking is expected shortly from DOE. Second round applications are due December 19, 2008.

The application process for nuclear fuel projects is broadly similar to that for nuclear generation projects, though without the dynamic ranking mechanism. Also, the deadline for the submission of part two of the application is earlier (December 2, 2008).

Financial Structure

Loan guarantees cannot exceed 80% of a project's costs. The project cost for this purpose includes spending on the design, engineering, financing, construction, startup, commissioning and shake down of a project. Initial research and development costs and operating costs are not included. Also, certain guarantee program-related costs, specifi- / continued page 16

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market is supposed to be off limits to private borrowing. There are exceptions for 15 types of private projects that Congress felt throw off public benefits. Sports stadiums are not on the list.

New York City used a combination of taxable and tax-exempt debt to finance new stadiums for its two baseball teams, the Yankees and Mets. The city owns the land under the two ballparks. It leased the land in each case to a local government agency called an industrial development authority, or IDA. The IDA subleased the land to the baseball team and issued a combination of tax-exempt and taxable debt to finance construction of the stadium. Each team built or is building its stadium as the "agent" for the IDA. The IDA holds legal title to the stadium. Each team signed an agreement promising to operate and maintain it.

Each team must make four kinds of payments to the IDA. It pays rent for use of the ballpark, unspecified installment sale payments, a percentage of net revenue from stadium parking and PILOT payments that are specially-negotiated property taxes. (The term PILOT stands for payments in lieu of taxes.) The parties are careful about which parts of the debt are secured by which payments. The PILOT payments are dedicated to the tax-exempt debt, and the rents and installment sale payments are each used to secure a different series of taxable debt. Under IRS rules, no more than 10% of payments used to repay tax-exempt bonds or of the security behind such bonds can come from private sources.

Cities can issue tax-exempt bonds that essentially borrow against future property tax collections. The taxes must be "generally applicable taxes." In this case, the taxes pledged to support each bond offering were specially-negotiated taxes from a single taxpayer. Are they still essentially general property tax collections? The IRS said yes in two private rulings issued to New York City in 2006. The city has another ruling request pending for an additional $360-plus million in bonds tied to Yankee / continued page 17

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cally the credit subsidy cost and administrative fees, that are assigned to applicants to defray the costs of administering the loan guarantee program are ineligible for DOE-guaranteed (or any federally-guaranteed) financing.

The terms of the DOE support vary according to the percentage of loan that is guaranteed. Up to 100% of any project debt may be guaranteed as long as the guarantee does not cover more than 80% of the total project cost. In cases where a 100% guarantee of the debt is chosen, the only permitted lender is the Federal Financing Bank, which is part of the US Treasury Department.

Where the guarantee sought is for less than 100% of the loan amount, DOE may guarantee loans from private lenders. However, if more than 90% of loan is guaranteed, then the non-guaranteed portion of the loan cannot be "stripped" (*i.e.*, traded separately) from the guaranteed portion. The guaranteed portion of the loan may be stripped if DOE guarantees 90% or less of the loan.

DOE will in all cases have a first priority lien on project assets pledged as collateral. If DOE guarantees less than 100% of the loan, DOE and the holders of the non-guaranteed portion of the guaranteed obligations may share the proceeds received from the sale of project assets pledged as collateral. Accordingly, while DOE retains the statutory requirement of having a first lien on all project assets, DOE will negotiate with parties about how the proceeds from the sale of collateral will be shared. However, the non-guaranteed holder cannot receive greater than a pro rata share of enforcement proceeds.

The required terms of these DOE loan guarantees present three major drawbacks.

First, where guarantees cover less than 100% of the loan, DOE currently requires project (and thus technology) risk-sharing from the private lenders as well as the equity. This radically reduces the range of potential sources of project debt and will likely increase the interest costs for those willing to accept the unguaranteed risks, undermining the economics of the projects that DOE was mandated to encourage.

Second, non-strippable instruments (loans that are more than 90% guaranteed) are excluded from the huge market for US government-guaranteed securities. Ironically, since the market would necessarily be investors who have achieved a degree of comfort, through expertise or pricing, with the project risk, the beneficiaries of the proposed guarantee will be the lenders who might, in fact, be least motivated by it. Clearly this scheme, while adding nothing to risk mitigation by DOE, will deprive the projects of much of the interest cost saving that might otherwise be available by virtue of support by US government guarantees. It would be surprising to find many projects adopting this financial structure.

Applications for DOE loan guarantees for renewable energy projects are due February 26. Demand could exceed the number of guarantees on offer.

In effect, the price of taking advantage of the large market for government-guarantee securities rather than the Federal Financing Bank is placement of a substantial piece of unguaranteed debt. Given the requirement that the loan, any portion of which is guaranteed, cannot exceed 80% of project costs, a typical structure might have the following elements: 72% of project costs financed with tradable, government-guaranteed paper, 8% covered by an unguaranteed portion of the loan that could share in project collateral *pro rata* with DOE, and the remaining 20% consisting of a combination of substantial equity and debt with no, or subordinated, recourse to project assets.

The third major drawback is the unfriendliness of the loan guarantee program for complementary project financing outside of the DOE-guaranteed loan. As the program is currently contemplated, any such financing not only would not be invited to share in liens on project assets, but it would also be subordinated with respect to the allocation of collateral enforcement proceeds in a default scenario. These terms are unlikely to be acceptable to the project lending programs of export credit agencies and will discourage or materially raise the interest costs of complementary commercial financing. Particularly for nuclear projects, with their immense financing requirements, a program design that discourages complementary export credit agency or tax exempt bond financing is particularly unfortunate.

Loan guarantees will be offered only to projects where the project sponsors make a "significant [cash] equity contribution" toward the project cost. Although DOE has not established a numerical minimum for the required cash equity contribution, a 10% target is under consideration. When evaluating projects, DOE will consider both the type and the degree of equity contribution proposed for each project. Applications for projects financed entirely through a combination of government-backed loans would be rejected.

DOE originally suggested that it would consider negatively that a project relies on other governmental assistance (*e.g.*, grants, tax credits or other loan guarantees) to support financing, construction or operation of a project. However, after receiving public comments, DOE recognized that, in certain circumstances, multiple forms of federal assistance could be beneficial. The dialog has ended up with no funds obtained from the federal government, or from a loan or other instrument guaranteed by the federal government, being permitted to pay for credit subsidy costs, administrative fees, or other fees charged by DOE for participating in the loan guarantee program.

Credit Subsidy Cost

If total project costs for an eligible project are projected to exceed $25 million, applicants must submit a credit assessment for the project. According to DOE, this will inform its evaluation of the project and estimation of the "credit subsidy cost."

The "credit subsidy cost" is, in effect, a required federal loan loss reserve. It refers to the cost of a loan guarantee, which is defined by the Federal Credit Reform Act of 1990 as the net present value of the estimated payments by the government to cover defaults and delinquencies and interest subsidies, less the amount the government expects to receive back in return as origination fees, penalties and recoveries.

The regulation of the credit subsidy / continued page 18

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stadium on top of the $950 million in bonds issued for the project in 2006.

The subcommittee charged that the city purposely overstated the value of the site for the new Yankee stadium as a way of labeling more of the payments from the club as payments in lieu of property taxes and, therefore, of increasing the amount of tax-exempt debt as a share of total borrowing. Kucinich charged at the hearing that city officials originally assessed the 17-acre stadium site in the Bronx at $26.8 million and, one day later with an eye on the bond offering, increased the assessment to $204 million. The city responds that the first assessment was based on the lot remaining vacant.

Meanwhile, the IRS has since revised its regulations on when PILOT payments will be considered "generally applicable taxes." The agency said it was concerned that the approach it was using in 2006 could be interpreted in an "overly broad manner."

Under the new rules, issued in final form on October 24, PILOT payments will be treated as generally applicable taxes as long as two things are true. First, they must be "commensurate with and not greater than" the regular tax for which they are a substitute. Second, the payments must be used for the same government or public purposes as general property tax collections and cannot be a "special charge."

The IRS said that, to be considered "commensurate," the payments must either be a fixed percentage or fixed adjustment to the regular tax. A fixed adjustment means a fixed dollar discount off the regular tax or a fixed reduction based on the characteristics of the property, such as the size of the business or number of employees. There can be adjustments in the "fixed" percentage or discount through the end of construction. In the case of property taxes, the payment must be tied to current property values; the property must be reassessed for PILOT purposes with the same frequency that other property is reassessed. The IRS said the PILOT payments cannot be tied to / continued page 19

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cost is a critical aspect that poses several questions and challenges to the success of the entire program. By law under the loan guarantee program statute, "[n]o guarantee shall be made unless: (1) an appropriation for the cost has been made; or (2) the [Treasury] Secretary has received from the borrower a payment in full for the cost of the obligation and deposited the payment into the Treasury."

Typically, credit subsidy costs for federal loan and guarantee programs have been largely covered by funds appropriated by Congress for that purpose. No such appropriation has been made for the DOE loan guarantees, and the DOE has indicated that it does not intend to seek one.

Fees for Renewables Projects

Loan Guarantee Amount	Application Fee	Facility Fee	Maintenance Fee
$0 — $150,000,000	$75,000 Part I: $18,750 Part II: $56,250	1% of the guaranteed amount	Between $50,000 and $100,000 per year
Above $150,000,000 — $500,000,000	$100,000 Part I: $25,000 Part II: $75,000	$375,000 + 0.75% of the guaranteed amount	Between $50,000 and $100,000 per year

DOE has decided to implement the loan guarantee program with "self-pay authority," which is to say the credit cost subsidy will be funded by up-front fee payments from users of the program. Applicants are not allowed to finance the credit subsidy cost with funds from a loan made or guaranteed by the federal government or with any other funds provided by the federal government.

Fees for Nuclear Generation and Fuels Projects

Loan Guarantee Amount	Application Fee	Facility Fee	Maintenance Fee
Any amount	$800,000 Part I: $200,000 Part II: $600,000	0.5% or 1% of guaranteed portion of guaranteed obligation	Between $200,000 and $400,000 per year

DOE is working on a methodology that can be used to calculate the credit subsidy cost for prospective loan guarantees, but no guidelines for estimating the credit subsidy cost have been announced yet.

The credit subsidy cost may be the Achilles' heel of the program. Different criteria can result in widely divergent cost estimates that could well affect a project's financial viability. Notwithstanding extensive inter-agency and intra-agency discussions, no agreement has been reached yet as to the appropriate levels of subsidy to require or even as to a precise procedure for determining it. Prospective borrowers may have an opportunity to provide their own estimate of an appropriate credit subsidy cost. However, inviting borrowers to propose the size of loan loss reserves, when they are betting their equity on the expectation that there will be no loss, would seem unlikely to lead to numbers that will satisfy government budgetary watchdogs. The subsidy numbers for other government guarantee programs are based on their respective track records. The closest proxy available to DOE might be its own financially-troubled foray into financing innovative energy technologies in the 1970s, which was not reassuring. That track record is unlikely to yield subsidy estimates that would be acceptable to prospective users of the DOE program.

DOE and the Office of Management and Budget will provide to project sponsors, at the same time a term sheet is provided, a preliminary credit subsidy cost estimate for the desired loan guarantee, immediately prior to payment of the facility fee and following payment in full of the application fees (about which more is below). However, the final credit subsidy cost determination will only be made at financial closing, when the credit subsidy cost is required to be paid.

Because of these uncertainties, applicants are free to withdraw their applications at any time if they find that the credit subsidy cost is more than they are willing to pay. However, this decision does not relieve the applicant of any obligations to DOE (for example, non-refundable application fees and the facility fee) that have already come due by the time of withdrawal.

Administrative Fees

The administrative fees, which are non-refundable, include any application fee, a facility fee and maintenance fees.

The application fee recovers costs associated with DOE's administrative costs incurred in connection with the pre-selection evaluation of an application. The application fee is paid in two installments: 25% with the initial application and the remaining 75% is due only from applicants who are pre-selected for formal review in renewables projects. In nuclear generation and fuels projects, the remaining fee must be submitted with the part II submission in December.

The facility fee recovers costs associated with documenting the deal, from issuance of a term sheet and conditional commitment letter to closing the final loan guarantee agreement. It is due prior to commencing negotiations on a draft term sheet.

DOE charges separate maintenance fees after the loan guarantee agreement is signed to cover its administrative expenses of servicing and monitoring the loan guarantee.

When estimating costs, applicants should also plan to cover costs in addition to the fees specified in the regulations. DOE has announced that it expects to use independent consultants and outside legal counsel in all aspects of the loan guarantee process. The applicant will be responsible for paying their fees.

In sum, DOE has made great strides toward functionality in implementing the loan guarantee program. A few inefficient quirks — such as the no-stripping requirement for guarantees between 90% and 100% of a loan and the mandatory use of the Federal Financing Bank to disburse a fully-guaranteed loan — survive in the program. The real potential show-stoppers, however, remain the credit subsidy cost payment and, for nuclear projects, the inhospitality of the program to unguaranteed co-financing. The requirement to pay stiff application fees and the fees of DOE's counsel and consultants, while remaining in the dark as to whether the subsidy cost could undermine the economics of going forward with the project, may well discourage participation in the program. ◎

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the amount of debt service, and they cannot be fixed amounts that do not vary with the assessed value of the property.

Tax increment bonds that are secured by tax payments from a particular project are already used in many states. New York law barred the state from using such bonds, so another structure had to be found.

EMPIRE ZONE tax credits in New York for wind farms and other renewable energy projects have federal tax consequences.

The IRS described them in an internal legal memorandum that was made public in late October. The memorandum is ILM 200842002.

The tax credits are credits against corporate income or franchise taxes in New York and can be claimed by businesses that bring new jobs to areas the state is trying to promote. Credits can be claimed for up to 14 years on older projects. Credits on new projects run for 10 years. The credit was tied in the past to the amount the project increased local employment. Under the current program, the credit is the greater of 25% of wages, health and retirement benefits paid to net new employees or 10% of the amount the company had to spend on "real property" the company owns in the zone. A company cannot claim a greater credit in any year than it paid in property taxes.

The credits are refundable to the extent the company does not pay enough in income or franchise taxes in a year to take full advantage of them. However, the company has an option of carrying the unused credits forward and using them the next year rather than asking for a refund.

The United States lets companies deduct the state income taxes they pay when calculating their incomes for federal tax purposes.

The IRS suggested the credits reduce the state income taxes a company is allowed to deduct. However, if the credit in a year exceeds the states taxes owed, then the company must report any refund as income. */ continued page 21*

Biofuels Strategies to Survive Loan Defaults

by Todd Alexander and N. Theodore Zink Jr., in New York

As the combination of closed credit markets, falling oil prices and reduced margins take a toll on biofuels producers, many companies are searching for the appropriate strategy to manage the expectations of their lenders.

Given that each producer faces a somewhat unique set of circumstances, unfortunately there is no universal strategy that can be employed. However, there are some lessons to be learned from the experiences of other companies in these situations. The lessons fall into three broad categories: understand which covenants in the debt agreements you are likely to breach, understand the mindset of the lenders, and use the tools available to offer the lenders a proposal that will be mutually beneficial.

Typical Debt Structures

There are two types of obligations that biofuels producers are most likely to breach in their loan documentation. The first type is financial covenants. The second is the obligations to repay interest, fees and principal.

Regional banks, which have financed the majority of the biofuels plants in operation today, tend to have more restrictive financial covenants than either the money-center banks or the capital markets. For instance, it is typical for regional banks to include tangible net worth tests and minimum debt-service coverage ratios in their documentation. It is quite possible that many ethanol producers who have borrowed from regional banks are, or will be, in breach of their financial covenants because of reduced crush spreads even if they are currently able to service their debt.

The good news is that banks are generally reluctant to accelerate a loan solely as a result of a breach of a financial covenant. Instead, lenders typically use these breaches as an advance warning mechanism to alert them that the loan requires additional attention, or to require borrowers to provide them with additional access to their financial information. However, they do usually take advantage of the opportunity to block further distributions to the owners until the breach has been cured.

On the other hand, lenders tend to take missed payments more seriously. Here again, the regional banks tend to have more aggressive principal amortization schedules than either the money-center banks or the capital markets and, accordingly, are more likely to find their borrowers unable to service their debt. The regional banks often adopt mortgage-style or straight-line amortization for their financings. In contrast, the money-center banks typically require only 6% of principal to be repaid in any year. Many of the capital markets transactions require only 1% of principal to be repaid.

Lenders' Mindset

If you are in breach or in potential breach of the loan covenants, take some comfort in the fact that, as a general rule, commercial banks turn to foreclosure only as a last resort. For several reasons, commercial banks are highly incentivized to work through any short-term liquidity issues that a producer may have. One reason is that they are required to reclassify the loan as non-performing if they decide to exercise remedies. Banks are required to increase their reserves once a loan is classified as non-conforming. This has a de-levering effect on its own business.

Another reason is that, unless a bank views the liquidity issue as having been caused by poor management, a foreclosure will not solve the underlying credit issue. As a result, if high corn prices or low oil prices, rather than poor management, are viewed as the culprit, lenders are likely to express a willingness to re-work the terms of their debt to accommodate the realities of the situation.

A third reason is that foreclosure can wind up being an expensive and time-consuming process for the banks. In a foreclosure, the banks will be required to devote substantial time and energy to a process that in many cases will not leave them in a significantly better position to recover the value of the outstanding loan. The foreclosure process requires the lenders to put in place a management team to preserve the value of the biofuels facility. It also forces the borrower's junior creditors to do their best to preserve their own rights to the collateral, which may involve taking legal actions that compel the participation of the senior lenders.

One exception to this rule is where an ethanol company's debt has been acquired by a hedge fund or others who specialize in buying distressed debt. These entities have been known to "loan to own." In other words, they may be seeking an opportunity to initiate a foreclosure with a view toward acquiring an operating facility at a fraction of its original cost.

Consensual Workout

Companies that find themselves in breach or on the cusp of a breach have many proven tools from which to choose as a means of finding a solution to their liquidity problems.

Usually the first step is to request that the lender agree to enter into a forbearance agreement. Under the terms of the forbearance agreement, the lender agrees, for a set period of time, not to exercise remedies to which it is entitled under the loan documentation. In exchange for this commitment from the lenders to "stand still," the borrower may agree to provide its lenders with additional reports and possibly restrict the use of operating cash flow. The borrower may also grant the lenders' consultants access to the facility and its personnel. It is generally important at this stage to increase the flow of information from the borrower to the lender to increase the level of trust between the parties.

During the standstill period, the lenders and borrower will attempt to modify the terms of their relationship in such a way as to allow the borrower to cure its defaults under the loan documents. The lenders will also likely try to assess whether the business has positive operating cash flow before debt service.

If the lenders conclude that the business is likely to have positive operating cash flow, then the lenders are usually willing to offer the borrower several types of relief from a fairly well-accepted menu of options. These include reducing the borrower's current principal payments, along with an extension of the term of the debt or by creating a bullet payment at the loan maturity date. The theory behind relying on a bullet payment at maturity is that the borrower will refinance the existing debt as soon as operating margins improve.

In addition to reducing the principal, the lenders may also agree to reduce the interest rate on the loan. This may be necessary to allow the borrower the breathing space necessary to recover, but is usually offered in conjunction with some form of compensation to the lenders, such as warrants in the company's equity. Such warrants may entitle the lenders to purchase equity in the company in the future if the company's financial condition recovers. This equity will often have the right to receive distributions on a preferential basis to the existing equity in the company.

Finally, the lenders often relax the financial covenants that may have been the cause of the default in the first place. The modification of the financial covenants / continued page 22

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It said that because the company has the *option* of receiving a refund, it must report the full excess credit as income, even the part that it chooses to carry forward, but, in that case, the full state income taxes owed in a future year would be deductible, ignoring any tax credits that are carried forward and used as an offset.

The IRS plans to address the same general issues in a published ruling — called a revenue ruling — by next June. The analysis should be considered tentative until the ruling is issued.

AN UNWIND of a transaction was respected by the IRS.

A US corporation sold part of its ownership stake in a foreign limited liability company to a foreign corporation, thereby turning the LLC into a partnership for US tax purposes.

The transaction was rescinded by the parties in the same year. The IRS said in a private ruling made public in late October that the rescission was valid. The key was that the parties put themselves back in the same position economically as if the transaction had never occurred and the transaction was unwound in the same tax year. The ruling is Private Letter Ruling 200843001.

US TOLL ROADS may have slightly less appeal for some foreign bidders after an IRS announcement in late October.

Several US states have sold sections of public highways to private companies who agree to maintain the roads in exchange for the right to collect tolls. Some states have also brought in private companies to build new lanes or new tollways that the states cannot afford to build on their own.

Many of the private companies interested in this business are non-US companies.

One consideration for them is whether they will have to pay US capital gains taxes if they later sell their interests in such projects at a profit.

An IRS announcement in late October makes it more likely the answer is yes.

In a toll road deal, a / continued page 23

Biofuels

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may be done in exchange for tighter reporting requirements, increased access to the company's records and, in some cases, an agreement to change existing management.

If the lenders conclude that the business is not likely to have positive operating cash flow before debt service, then the lenders are less likely to be lenient. In these cases, the borrower may be in a position where its owners are asked to contribute additional capital to the company or otherwise increase the lenders' collateral by contributing some other type of asset to the project, such as the right to receive delivery of feedstock at prices below the current market or a feedstock-handling facility owned by an affiliate of the borrower.

Filing for Bankruptcy

In cases where additional collateral is not available, borrowers may be forced to consider a voluntary bankruptcy. Bankruptcy offers the enticing feature of allowing owners to "reject" or terminate agreements, subject to court approval. This can be a nice tool for increasing the value of a business if a biofuels company has a particular set of contracts that have become unprofitable. For instance, if an ethanol facility agreed to pay a corn originator an above-market price for its services, the company could reject the agreement and then enter into an agreement with a new corn originator on more favorable terms.

Lenders dislike bankruptcy proceedings for many of the reasons stated earlier with respect to foreclosure. In addition, filing for bankruptcy introduces the concept of a bankruptcy judge with oversight over the debtor's business. It also invokes an automatic stay, which precludes any creditor from enforcing any of its remedies against the borrower without the court's approval.

While a bankruptcy may disadvantage the lenders, it often completely wipes out the value of any equity in the company. As a result, it is customarily used by owners only where they either see little or no value in the ownership under the current contractual arrangements and is often better used as the "stick" to persuade a group of lenders to accept the "carrot" offered as part of a consensual workout.

In conclusion, if the credit markets remain frozen and oil prices continue falling, many biofuels producers will be required to open a dialogue with their lenders regarding breaches and potential breaches of their loan documentation. If these discussions are well managed, they have the potential to increase the level of trust between lender and borrower, as well as create a more durable financial structure. ◎

State of the Tax Equity Market

The US government subsidizes wind farms through tax subsidies that pay a little more than half the capital cost of a typical wind farm. Most developers cannot use the tax subsidies directly and end up bartering them for capital to pay project costs. The developer finds a bank, finance company, investment bank or insurance company to own the project in a partnership with him. The investor is allocated 99% of the economic returns from the project, except possibly cash, until the investor reaches a target return, after which the investor's interest in the project drops to 5% and the developer has an option to buy out the remaining interest of the investor. Cash may be distributed 100% to the developer until he gets back the capital he invested, after which cash follows other partnership items and goes 99% to the investor.

The American Wind Energy Association hosts a fall finance conference each October in New York. The conference this year came at a time when US share prices were tumbling, the credit markets were frozen and Congress had just passed a massive Wall Street bailout bill. Six panelists talked about whether it is still possible to raise tax equity for wind farms and on what terms. They are David Berry, director of finance for Horizon Wind Energy, Jack Cargas, a managing director at Bank of America, Clay Coleman, director of corporate finance for Iberdrola Renewables, John Eber, managing director and head of energy investments for JPMorgan Capital Corporation, and two tax equity arrangers, Tim MacDonald, senior vice president of Meridian Clean Fuels, and Phil Mintun, managing director of Capstar Partners. The moderator is Keith Martin with Chadbourne.

MR. MARTIN: It is hard to avoid the elephant in the room. The credit markets are frozen. The headlines in the newspapers this morning are about the huge drop in US share prices. Jack Cargas, what is the current state of the tax equity market and is it still possible to get tax equity?

MR. CARGAS: Is it okay to give a Joe Bidenesque response? Yes. [Laughter]

MR. MARTIN: As long as you do a parody of both vice presidential candidates and wink coyly at the camera.

MR. CARGAS: I guess this is the part of the conversation where we were asked not to be glum, but it is quite difficult. There has been a sea change in the tax equity market, much like the sea change in the capital markets as a whole. The tax equity market remains open, but new deals have to be very, very clean.

MR. MARTIN: What is an example of something that is not clean?

MR. CARGAS: How about a wind farm that is highly levered in west Texas, a part of the country where projects run the risk of being curtailed or knocked off the grid because there is too little transmission capacity.

MR. MARTIN: Phil Mintun, you have been out in the market lately looking for tax equity investors to fill gaps in existing syndicates. How is it going?

MR. MINTUN: It is harder than it has ever been in my experience, which goes back in renewable energy projects five years and in tax equity in general 18 years. The closest parallel I can think of to what is happening today is the trouble the airline industry went through raising lease equity. The airlines ended up sheltering taxes the old-fashioned way by not making money. That was an industry-focused event. What we are seeing here is an impact on tax equity for wind that reflects a larger trend in the economy.

MR. MARTIN: David Berry, you are in the market today trying to raise tax equity for a portfolio of wind deals. How do you see the market?

MR. BERRY: Thanks for not calling on me first. It is definitely hard going. You have a limited number of players. Many of the players who did deals last year are not bidding on deals currently. As to whether we are experiencing a tsunami or a sea change, my gut is that this is a blip on the radar. I'm not saying things are going to be as easy as they were last year come this time next year, but I think these deals offer a very attractive risk-adjusted return to banks, so if you have temporary issues of adequate capital resources, liquidity and tax capacity, if you believe in the US economy and if you believe in the banking sector, then you have to believe those issues will resolve themselves and we will return to a pretty well-functioning market.

MR. MARTIN: John Eber, is it still possi- */ continued page 24*

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private developer or consortium of private companies usually enters into a concession and lease agreement with the state giving the developer or consortium control over the road and the right to collect tolls in exchange for an obligation to operate and maintain it. The consortium makes a large upfront payment. The state leases it the land underneath the road. The parties take the position that the consortium bought the road because of the length of the concession agreement. The consortium usually allocates part of what it paid up front to the road. The rest is allocated to the franchise or license to collect tolls.

As a general rule, the US does not tax foreigners on their capital gains lest it discourage them from investing in US stocks and bonds. However, gains from investments in US real estate are taxed. Congress made them subject to tax starting in the mid-1980's after farmers complained that growing Japanese interest in US real estate was making it hard for their children to be able to afford their own farms.

Non-US companies investing in toll road deals usually hold their interests through special-purpose US corporations. When they exit an investment, it may be through a sale of the US corporation. There is no capital gains tax to pay in the United States as long as less than 50% of the value of corporation is attributable to US real property. The lease of the land and the highway are real property. However, in some deals, more than half the amount paid to the state for the concession is viewed as a payment for the right to collect tolls.

There has been a debate among tax counsel about whether the right to collect tolls is also an interest in US real property.

The IRS said in an "advance notice of proposed rules" in late October that it believes it is in some transactions and intends to issue regulations to that effect.

The IRS asked for comments in the meantime on whether it should also address how to allocate the upfront */ continued page 25*

Tax Equity Market

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ble to raise tax equity?

MR. EBER: I love dealing with the developers because they are such eternal optimists. It is a tough market as Phil Mintun said. Having said that, though, it is also a market that has grown at an incredible pace over the last few years with a very limited number of investors supplying the equity. We need time to catch up with the growth in demand for tax equity. The global financial meltdown is contributing to the current difficulties.

MR. MARTIN: Tim MacDonald, do you have a different view?

MR. MacDONALD: Yes. At Meridian, we take a broader view of the tax equity market, since we are raising equity for more than just wind or even renewable energy projects. We see a lot of change. The banks who had been supplying much of the tax equity for wind may not be there in as large numbers going forward, but there are other players in the wings waiting to take the stage. They have not been in the market to date because they have not been able to compete at the yields the banks have been offering. We see tax equity increasing in price, but not drying up.

MR. MARTIN: Clay Coleman, your company, Iberdrola Renewables, had a deal in the market earlier in the year and pulled it back. Did the decision to pull the transaction have to do with the market or was it something unique to the deal?

MR. COLEMAN: It was the market. I think I am more pessimistic than others on the panel. We really see this market as ugly with a blood-red capital "U." I think the chances of getting a new deal done in the market in the fourth quarter are slim and, even looking into 2009, we are facing a severe supply-demand imbalance for tax equity, which is mainly driven by the ramp up in demand from developers. You are going to need a lot more tax equity in 2009 than we had even in 2007, which was the high water mark for tax equity investment in renewable energy. If anything, the amount of tax equity that will be available is shrinking. A lot of projects will not attract tax equity next year.

The US tax equity market remains open, but deals have to be very clean.

MR. MARTIN: Jack Cargas, if somebody brings you a deal for the first time next week, is it too late to close in 2008?

MR. CARGAS: It is very close to too late. I generally agree with what Clay had to say, although he may be categorizing me as one of the optimists. I think that you can get equity for the right transaction and there may be the opportunity to get a new deal closed, but some of the very large transactions that are in the market now will be very difficult to get done this year. I think transactions will get done in 2009. The direct answer to your question is if the transaction is very, very clean, there is a chance you can still get it closed by the end of the year.

MR. MARTIN: John Eber, I think you told me there were 12 to 14 institutions that invested in the wind market as tax equity in the last two years. Which is the right number, and how many institutions are still in the market today?

MR. EBER: Fourteen sounds right. If you mean this week, I count six. I had seven two days ago, but another equity investor dropped out. Nine institutions have put tax equity into wind deals so far in 2008.

MR. MARTIN: Phil Mintun, do the numbers sound right?

MR. MINTUN: Yes. When you project forward into 2009, there is a lot of uncertainty. Wachovia, which was one of the bigger investors, is being fought over by Citibank, which has been an investor, and Wells Fargo, which has been an investor. The suitors could step into net operating losses that take not only Wachovia but also the winning bidder out of the market. That said, I guess I am optimistic that the number will be larger than six next year. We have lost people in the credit crisis. The institutions don't exist anymore. I am an optimist because if I thought this trend of shrinking numbers of tax equity investors will continue well into 2009, then I would probably be thinking about another way to earn a living.

Current Yields

MR. MARTIN: Tim MacDonald, how much does tax equity cost today in the wind market?

MR. MacDONALD: It is hard to give you a price today with events moving so quickly. Also, every deal is different.

MR. MARTIN: David Berry, do you have any way of describing where rates are currently and where they are headed?

MR. BERRY: They are significantly higher than they were last year. I think you are looking at probably a minimum of 100 basis points higher than a year ago.

MR. MARTIN: Would any of you disagree that rates are 150 to 170 basis points higher today than they were a year ago, and that's for benchmark deals, which are portfolio deals with multiple projects that offer investors risk diversification because the projects are in more than one state and involve more than one turbine type.

MR. EBER: That's about right.

MR. MARTIN: Where do you see rates going? If interest rates are coming down because of the economic dislocation in the economy as a whole, will that pull tax equity yields down? John Eber?

MR. EBER: Short term interest rates don't have as significant an effect on yields in the tax equity market as you might think. Tax equity yields today are being driven more by the risk premiums that institutions are being charged for putting out capital for long periods of time. Interest rates in the broader economy are coming down, but the risk premiums institutions must pay to raise capital are going up. That is affecting yields. The imbalance of demand for tax equity to available supply is driving them up further.

MR. MARTIN: Phil Mintun, what happens after we get through this period where even large corporations with decent credit are unable to issue commercial paper. Suppose the Federal Reserve Bank starts lending and the credit markets unfreeze. Will tax equity yields come down?

MR. MINTUN: I think you have to decide first what you think are the long-term effects of the turmoil we are going through today. Will the markets be changed permanently by the experience? Beyond that, you need a / continued page 26

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payment among the different assets the consortium gets in a toll road project and whether how long the concession agreement runs should have any bearing on how the upfront payment is allocated. Comments are due by January 29.

MUNICIPAL UTILITIES can own interests in oil and gas wells alongside private parties who also own interests without the wells being considered put to "private business use," the IRS ruled privately.

The ruling is important because it lets municipal utilities buy fractional interests in private oil and gas wells to secure gas supplies and pay the cost by issuing tax-exempt debt. Tax-exempt debt can ordinarily be used only to finance public facilities. The IRS said it views the fraction of each well owned by the municipal utility as a separate property, as if it were a full well in its own right.

The ruling is consistent with transactions involving power plants where a municipal utility might own an "undivided interest" or fraction of the power plant and borrow in the tax-exempt bond market to pay its share of the project cost. The utility takes its share of the electricity from the project in kind. The public and private owners of the plant must own the plant directly and not through a partnership or other common legal entity.

The ruling involving gas wells is Private Letter Ruling 200829008. A joint action agency acting for a group of electric and gas utilities that are municipally owned acquired "working interests" in oil and gas wells as a way of securing gas for its members. The seller retained a working interest of its own in each well, and other private parties held various kinds of other ownership interests entitling them to royalties, a share in net profits or "production payments" that are fixed in time or amount. The IRS made the ruling public in late July.

LUXEMBOURG is expected to eliminate a capital duty that it collects currently / continued page 27

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healthy market where a number of participants are looking to do each deal to have any chance of bringing down yields.

Deal Flow

MR. MARTIN: John Eber, you are my keeper of statistics. How many deals do you expect this year, how many with project-level debt, and how many with back-levered debt at the sponsor level?

MR. EBER: We expect 15 to 16 deals to close this year. I am estimating that will be about $4 billion worth of tax equity that will get raised for wind farms. Most of those are the all-equity PAPS structure. Three of those 15 or 16 deals will have project-level debt. In terms of actual dollars raised, those three represent a much smaller amount, probably 6% or 7% of the dollars raised. I count six or seven deals that are using back leverage. A lot of people in the market raising tax equity are large companies with plenty of their own capital and they aren't using any back leverage. I haven't seen any deals this year using the pay-as-you-go structure.

MR. MARTIN: Jack Cargas, what is a PAPS structure?

MR. CARGAS: The acronym stands for pre-tax after-tax partnership structure, and it means that the tax equity investor puts in the entire purchase price in cash up front.

MR. MARTIN: Tim MacDonald, what is a PAYGO structure?

MR. MacDONALD: In a PAYGO structure, the tax equity investor pays some amount up front and then makes continuing payments over time that are a percentage of the production tax credits it receives.

MR. MARTIN: Clay Coleman, tax equity investors tend to prefer the PAPS structure. They tend to prefer putting all their cash in up front rather than over time as they receive tax benefits. Why?

MR. COLEMAN: We have bid out our transactions both ways and consistently found that tax equity money is 50 basis points cheaper under the PAPS structure compared to the PAYGO structure.

I think there are two reasons. First, the institutions we deal with like to put all their money up on day one. If they have to fund over time, then they have to work out how to source and price the additional funding. They would rather avoid the complexity. The other issue with PAYGO is some tax equity investors have had a hard time with their auditors figuring out the appropriate accounting for it. The PAPS structure is a more traditional structure in terms of accounting treatment. The auditors find it easy to address. A PAYGO structure reduces the number of potential investors.

MR. MARTIN: John Eber, do you see a renewed interest in PAYGO or is it pretty much a relic?

MR. EBER: I was thinking about that the other day. PAYGO was created because it is an investor-friendly structure. It is better for investors who cannot write a big check today but have a steady and predictable tax base and want to invest in renewable energy. These are generally not financial institutions. Reviving the PAYGO structure may be one of the many things we can do over the next year or two to expand the number of potential tax equity investors. It comes with a cost. Tax equity is more expensive under PAYGO than PAPS, and the question will be whether the economics of the underlying project still work with a higher cost of capital.

MR. MARTIN: Do you agree with Clay Coleman that tax equity tends to be 50 basis points more expensive if a PAYGO structure is used?

MR. EBER: You can't compare the yield in a PAPS deal to a PAYGO deal. Because the tax equity is investing over time, you need to discount back all the expected future payments to simulate an upfront investment today and then measure your benefit stream against that to get what we would call a deferred equity yield. On a deferred equity yield basis, the two structures should show an equivalent cost of money, but on a pure IRR basis, the investor yield in a PAYGO transaction will look higher.

MR. MARTIN: Phil Mintun, in a PAYGO structure, does the tax equity investor charge for keeping its capital committed for the 10-year period that the production tax credits are expected to run and over which the investor will have to make payments?

MR. MINTUN: I agree with John that the deferred equity yield concept is one investors use, but we have also seen that the developer ends up paying a premium on a nominal basis, and you could say that a commitment fee for the future use of money is effectively built into the yield.

Bailout Measures

MR. MARTIN: David Berry, what effect do you see the Wall Street bailout bill that passed Congress in early October having on the market, both because the bill may help unfreeze the credit markets and because it extended production tax credits for wind farms?

MR. BERRY: It can help the market if banks get some of these bad loans off their balance sheets. If funding costs come down, it will make it easier for banks to commit to long-term deals. The extension of the production tax credit obviously is key for deals next year. I'm not sure if banks are going to be ready to start looking at deals for next year yet, but the effort in the bailout bill to unfreeze the credit market is a step in the right direction. I think with the PTC extension, once the funding costs or the costs for capital from banks is a little clearer, then people can start working on their 2009 deals.

MR. MARTIN: John Eber, you said 15 or 16 deals will probably be done this year. That compares to 18 last year. How many of those 15 or 16 remain to be closed before year end?

MR. EBER: My guess is the bulk of them are in the process of closing now — at least half. We have seven deals in our shop alone that are in the process of closing.

MR. MARTIN: So you are going to spend Christmas in a conference room at some New York law firm?

MR. EBER: I have some poor folks working for me who will. [Laughter]

MR. MARTIN: Phil Mintun, do you agree there will be 15 or 16 wind tax equity deals this year?

MR. MINTUN: Yes. My numbers for tax equity deals this year are a little higher, but I am guessing the discrepancy in John's number is just wind energy. I agree that more than half of the 2008 transactions are still in the closing stage.

MR. MARTIN: Jack Cargas, what effect do you see the Wall Street bailout bill having on the market?

MR. CARGAS: The fact that the PTC was extended makes us more interested in projects that were not certain to get into service this year. If the PTC had not been extended, we would have been sitting on the sidelines early next year until Congress passed an extension.

MR. MARTIN: Clay Coleman, has Iberdrola been affected by the Wall Street bailout bill or is it a nonevent?

MR. COLEMAN: We have not seen lenders starting to lend again yet. Nothing has been implemented from the bailout plan as yet other than the extension of the PTC. Looking forward into 2009, our biggest issue is the size of the market in terms of overall dollars. In 2007, the amount of tax equity in the market peaked at about $5 billion for wind farms and, since then, we have had one of the big three investors leave for an indeterminate amount of time and another of the big three is in an uncertain position. The market will struggle in 2009 to get back to the level of tax equity */ continued page 28*

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on capital contributions to Luxembourg companies, effective on January 1, 2009.

The country is also expected to stop collecting withholding taxes on dividends paid by Luxembourg companies to foreign shareholders in countries that have tax treaties with Luxembourg. Luxembourg has an extensive treaty network. The two changes should make Luxembourg more attractive as a location for offshore holding companies.

To avoid withholding taxes, the shareholder must have held its shares for at least 12 months, either own at least 10% of the Luxembourg company or have paid at least €1.2 million for its shares, and be subject to corporate income taxes in its home country that are comparable to corporate income taxes in Luxembourg.

INDIA cannot tax a company that provides offshore supplies and services tied to a turnkey project in India, the Income Tax Appellate Tribunal said in August.

A Korean company agreed to install an onshore fiber optic system for the Power Grid Corporation of India. It also agreed separately to provide certain supplies and services offshore. The contract for the offshore supplies and services was signed in India, but the company had no office on the ground involved in performing the contract or arranging the sale. The tribunal said that since the "delivery of the goods, documents and [a] substantial part of the sale consideration took place outside of India," the income was not subject to tax in India. The case is *LG Cable Limited*.

MINOR MEMOS. The US Government Accountability Office — an arm of Congress – reported that 28% of large corporations operating in the United States paid no US income taxes in 2005, a year when the economy was still fairly strong. Overall, roughly two thirds of corporations paid no US income taxes. . . . . Some banks that have been acting as tax equity investors in US */ continued page 29*

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in 2007. The problem for developers is we need the market to double in size from where it was in 2007 and there are not nearly the number of players coming into the market to allow it to double. Transactions are going to have to be squeaky clean and even the clean ones are going to face some pretty severe pricing pressure.

MR. MARTIN: Your parent acquired a New England utility. Will that mean that you no longer need to go into the tax equity market — you can use the tax benefits yourselves?

MR. COLEMAN: We have spent a lot of time analyzing our own tax capacity because not only do we have a New England utility, but we also have a gas business that generates a fair amount of taxable income. We have been working on models to project the crossover point at which we would be able to use not only the production tax credits but also the 5-year depreciation from our future projects. The Energy East acquisition will add marginally to our ability to use the tax benefits ourselves. Our current thinking is it gives us the ability to use only 10% of the tax subsidies from projects ourselves.

Expanding the Investor Pool

MR. MARTIN: David Berry, we have heard from everybody on the panel — except you so far — that one of the biggest challenges next year will be to increase the pool of potential tax equity investors. What do you think will be the key to doing that?

MR. BERRY: I agree that it will be a challenge. Some of it will happen naturally as investors who have been out of the market are attracted back by slightly higher yields. A couple of insurance companies that have been in and out of the market are now more solidly in it because yields are increasing. We also need to reach out to new kinds of investors, like consumer goods companies, technology companies and smaller banks.

There are a couple of policy things we might do, too, that I suspect we may get to later in this discussion. The industry probably needs to lobby Congress or the Treasury Department for changes in the tax laws that help expand the investor pool — changes like how tax credits can be passed through to investors and how deal structures can be guaranteed to make them less risky for investors and more palatable to new kinds of investors. We need to have that conversation as an industry, agree on a coherent position and go try to make it happen.

Only six of 14 institutions that invested in wind deals in the last two years are still in the market.

MR. MARTIN: Tim MacDonald, Meridian is out calling on Fortune 200 companies constantly trying to gin up tax equity. What do you think is key to generating more interest in wind?

MR. MacDONALD: I think there is already a tremendous amount of unanswered interest. The bad news is the pricing. The guys that are not playing in the banking club need higher returns than the market is offering today.

MR. EBER: It is going to take more than just yield because the amount in dollars you need to be willing to put out the door to participate in these deals is huge. The average deal we are working on today is $300 million of tax equity, with the typical investor doing around a 25% or 30% share to participate in a syndicate.

You have to be willing to write checks for a couple hundred million dollars on the large deals and maybe a hundred million dollars on the small ones. So, in addition to yield, you have to have a lot of capital available, which is why the industry historically has fallen back on banks and insurance companies, places that have a lot of capital available and are used to moving out large dollar amounts, and that is one of the big challenges for nonfinancial institutions. There are a few people you can think of that fit the bill, but trying to get them into an energy project finance deal is quite challenging.

MR. MacDONALD: May I disagree?

MR. MARTIN: Go ahead.

MR. MacDONALD: At Meridian, we have been doing multi-investor funds in the affordable housing sector for more than 20 years. Until this year when the housing sector fell victim to the same problems that are pulling down the larger economy, we would do $250 million funds once a quarter and John is right that we would do them with smaller tickets, but there is a market that would like to be supporting renewable energy. There are alternatives to the large-ticket investors.

MR. EBER: Those multi-investor funds are finding the current market a very challenging place to operate. There are a lot of banks that are not willing to lend today to fund companies that are trying to aggregate assets or act as a bridge to when they can pull the investors in.

I agree with Tim that there are plenty of investors who can do smaller-ticket investments. The question is whether there is a way to bring them into a market where the capital requirements are huge and the capital must be delivered in fairly quick order.

MR. COLEMAN: GE put a billion dollars into the market last year. How many of these smaller investors do we need to score hits with in order to replace a single GE?

MR. MacDONALD: We routinely raise a billion dollars in the housing market using multi-investor funds, so I would argue that it is possible to do. There are prudent players who know how to participate in these partnership structures. They are just not as supportive of the industry on pricing as the banks have been.

MR. MARTIN: Phil Mintun, you have been searching for additional investors to fill gaps in existing syndicates. Why is it so hard to find an investor here or an investor there to fill such holes?

MR. MINTUN: One of the challenges is perhaps that we call the investment tax equity. When you tell a corporation you are looking for equity, the corporation has a certain return requirement in mind that is not met currently by this product and this industry. You get a lot of people who don't even get beyond the first question. They hear "equity" and then they hear 6% or 7% after-tax returns, and the two don't match.

MR. EBER: They want higher returns than even the developer is earning.

MR. MARTIN: Does it help that every- */ continued page 30*

IN OTHER NEWS

renewable energy projects may have less tax capacity after the latest round of bank mergers and an IRS decision in October. US tax rules make it hard for one corporation that acquires another to make efficient use of existing tax losses in the target corporation. However, in a move aimed at making troubled US banks more attractive to potential suitors, the IRS said it will treat certain tax losses in acquired banks as if they occurred after the acquisition. The announcement is in Notice 2008-83. The change could give Wells Fargo, for example, as much as $74 million in additional losses if it closes on its proposed acquisition of Wachovia Bank, according to published reports.

— contributed by Keith Martin, John Marciano, Jenny Kim and Brian Americus in Washington and Richard Leder and Eli Katz in New York.

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one with money in the stock market is seeing the value of his holdings going down? Therefore, any positive return is above market.

MR. MINTUN: I don't think that is going to be the selling point for this business. [Laughter]

Guaranteed Return Structures

MR. MARTIN: David Berry, what about guaranteed return structures? What are they and would they be a way to attract new investors?

MR. BERRY: In partnership flip transactions, just to step back a minute, the tax equity investors have a preferred yield, so the developer may get the initial cash but, after a certain point, all of the cash and tax benefits will go to the tax equity investors until they get their preferred yield. Thus, JPMorgan makes its yield before we as a developer make a profit on our investment. A guaranteed return would reduce the risk that the investors never hit their yield. If you get to year 10 when the deal is expected to flip and the investors have not reached their target yield, then an insurer would come out of pocket and pay the tax equity investors what they need to hit their flip yield and their interest would be reduced to 5% or whatever residual interest was negotiated.

I think such structures might open up the market to new investors. You need really three things to be a tax equity investor. You need a tax appetite. You need liquidity. You need project finance know-how. The guaranteed return structure would remove one of those barriers to entry, if you will. You don't really need project finance know-how if you have a credit-worthy entity guaranteeing the return.

The guidelines the Internal Revenue Service issued in October 2007 for partnership flip transactions said that guaranteed returns are okay, but the guarantor cannot be the developer, turbine vendor or electricity offtaker or anyone related to one of those three. It is a tough time for insurance companies, but if any of them can come up with a product whereby they are guaranteeing these yields, I think they can stand to make a decent amount of money doing it.

Another thing we should think about is whether allowing sponsors themselves to guarantee the returns on the deals might be one way to increase liquidity in the market. We would not be wild about doing that in a healthy capital market. It would require a lobbying effort and a change in position by the IRS.

The supply of tax equity across all renewables is expected to fall about $2 to $3 billion short of demand in 2008.

MR. CARGAS: With respect to insurance companies and the like offering guarantees on the returns in these transactions, a lot of investors who are currently in the market are going to be thinking about the guarantees that they have on their affordable housing portfolios and some old lease-to-service-contract structures from guarantors who seemed bulletproof a couple years ago and are today either being replaced or collateral is having to be posted.

MR. MINTUN: AIG is what Jack is trying to say.

MR. EBER: I agree with Jack. It is not a good time to be talking about guarantees to experienced investors because I don't think they will make a difference until we get through this disruption and we can figure out who is really credit-worthy enough to stand behind that guarantee for the next 10 years.

MR. CARGAS: I wonder if the sponsor guarantee, like David mentioned, is a good idea because you would not have had the same sort of experience with the sponsors. You think of the sponsors as being decent credits and having some financial wherewithal.

MR. BERRY: You are saying you would rather do business with utilities than other financial institutions?

MR. CARGAS: Banks don't trust each other. [Laughter]

MR. MARTIN: Tim MacDonald, Meridian has a lot of experience with guaranteed return structures in affordable housing. Many people have suggested there are companies who have invested in affordable housing deals and never put money into wind, but they might be interested in wind if they can use the same structure. Do you think that is true?

MR. MacDONALD: I think it is. In our experience, the guaranteed return structure not only reduces the risk to the investor of reaching his return, but it also produces more favorable accounting for the investment. However, you need a credit rating behind the guarantee that, as Jack mentioned, is evaporating on us. That's the immediate problem.

You need someone credit-worthy to take the intermittency risk and the performance risk. Guaranteeing a housing deal is pretty simple because the affordable housing tax credit is tied to the amount invested and, as long as the housing portfolio does not fail totally, there is not a lot of risk to be guaranteed. We struggle with how to get somebody to wrap the guarantee around the base case financial model in a wind deal.

MR. BERRY: Project finance banks have typically underwritten debt on these projects of a P99 performance level, which means that there is a 99% chance that there will be at least as much wind as forecasted in the base case model. In some of these partnership flip deals as the terms have become a little less favorable for developers, the deal will flip on schedule in a P95 case. What that tells me is the risk is not so enormous as to cause a rational insurance company to shy away from it. I agree there is an issue about what insurers have the reputation and balance sheet to stand behind guarantees, but the risk itself is not an unreasonable one for a financial institution to take.

MR. MARTIN: Clay Coleman, what are the main risks that would have to be covered by a guarantor if you wanted to go the route of guaranteeing just some of the risks in a deal?

MR. COLEMAN: There is very little wind risk in a traditional PAPS deal because, as David pointed out, if the investor does not reach his target yield on schedule, he just stays in the deal longer at a 99% level until he reaches his return. There is a slight reduction in the overall rate of return to the investor because the additional return expected out of the tail or residual is not reached as quickly as originally projected, but we are really only talking about a few basis points reduction in overall yield.

The big risk that the investors are taking is tax risk. They have to have tax capacity. They have to be in a position where they know they are going to be paying taxes for the next six years because that is the depreciation period. It is the period when these wind farms are generating enormous tax losses. If they don't have the tax capacity, then they must carry the losses forward or plan on selling out of the portfolio in order to pass the benefits on to someone else.

MR. MARTIN: Phil Mintun, guaranteed return structures are challenging to do because they increase the tax risk. What is the challenge?

MR. MINTUN: There has long been attention in tax-advantaged investing to what proportion of your return comes from the tax structure of the transaction rather than the underlying business. Many of you may have heard of LILO and SILO transactions that were done in the 1990's in which the IRS has argued that the transactions were pure tax plays. Those deals have ended up in litigation and, so far, the courts have been deciding them against the taxpayers. There is today a very significant reluctance for investors to take a lot of tax risks in these deals.

Investors have not had a good experience over the last 10 years, and anything that you do to these structures that increases the tax risk would be viewed unfavorably. The fact that the IRS came out late last year with a safe harbor for partnership flip deals was a very positive event because it took the tax structural risk, as distinct from the tax capacity risk, off the table.

The world is changing, but I would be very surprised to see people looking to add a lot of tax structural risk to these transactions.

Crossover Point

MR. MARTIN: David Berry, is it possible, if tax equity yields keep increasing, that they will reach a point where it just does not pay to raise tax equity because straight debt is cheaper? How do you determine where that point is?

MR. BERRY: Sure. We are not quite there yet, but it is absolutely possible. What we do is the analysis that Clay Coleman discussed earlier, which is you can carry both production tax credits and losses from accelerated depreciation forward. We would figure out at what point in time in the future we would be able to use them. There is a time value hit to our keeping them because a tax equity investor presumably would use the credits and / continued page 32

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losses immediately. Compare the tax value hit with the cost of doing the transaction. Tax equity is an expensive form of financing, particularly for companies like Iberdrola and Energias de Portugal, which owns Horizon, that can raise corporate debt on the balance sheets at quite attractive rates.

MR. MARTIN: Clay Coleman, do you think wind companies are even close to the point where they conclude tax equity is just not worth it?

Only 15 or 16 wind financings are expected to close in 2008, compared to 18 last year.

MR. COLEMAN: The most conservative forecast you can do of your tax capacity is a self-sheltering analysis on a project-by-project basis, which is each wind farm uses its tax benefits as it has EBITDA to utilize them. You can elect 12-year straight line depreciation on a wind farm and, given the EBITDA figures we are looking at for wind farms today, you more or less match your EBITDA line in the first 12 years with the depreciation deductions and then start to use the PTC at the end of that period.

For an average project, we are finding that the reduction in the internal rate of return from using that versus an efficient immediate monetization of the tax benefits is about 300 basis points. Therefore, even if you have nothing outside of wind and you have no tax capacity other than that, you can calculate how much of a premium you are prepared to pay for tax equity above a debt yield.

Our position is a little bit better than the numbers one gets on with this "self-sheltering" analysis since we have some tax capacity outside of wind. We can use the tax benefits ourselves today on a certain number of projects with some delay. Obviously, as we continue to build new projects, we will reach a crossover point. We have done the calculation and there is a ceiling on what we are prepared to pay for tax equity and the numbers today in the market are pretty close to the ceiling.

MR. MINTUN: There are two points. Our analysis is that the breakeven rate for tax equity yields where the sponsor says "I don't want to do this deal, I'm just going to keep this on my own books," is very high. The more relevant question perhaps is, with project IRRs where they are today and forgetting the financing, at what point does a poorly-functioning tax equity market make people say, as they look at their capital spending budgets, "Is this a sector where I should be investing a lot of money?"

MR. MARTIN: David Berry, how are increasing electricity prices likely to affect the tax equity market?

MR. BERRY: They make it more likely that developers will be able to absorb the tax benefits themselves.

In 2003 and 2004, we were doing deals with power prices in the \$20 to \$30 per megawatt hour range and, with the tax credits at \$20 a megawatt hour, there is no way a developer can even come close to using tax credits against the operating income of a project. Today, you are looking at power prices of \$70 a megawatt hour or north of that, and they go up every year. Unfortunately, turbine costs also go up every year, but we are essentially at a point where we can use the production tax credits against the operating income of a project or you can, as Clay put it, elect 12-year straight-line depreciation and use the depreciation against the operating income of the project.

The issue is that we cannot use both the accelerated depreciation and the PTCs against the operating income, and therein lies the need for tax equity.

MR. MARTIN: Just one more math question for Phil Mintun. If a developer who can use the tax benefits itself keeps 100¢ on the dollar in terms of value, how much does that developer keep if he monetizes the benefits — 80¢ on the dollar? Is it possible to quantify?

MR. MINTUN: It varies from project to project. If you look at the present value of the after-tax cash flows to somebody who can use all of the benefits currently compared to the present value of the after-tax cash flows to the sponsor after a tax equity deal, the number is about 85¢.

MR. COLEMAN: We don't agree with that.

MR. MARTIN: What's your number?

MR. COLEMAN: If you think in terms of the self-sheltering analysis that I talked about, our returns are dinged by about 300 basis points if we carry the tax benefits forward for our own future use compared to immediate use of the tax benefits. Assume the tax equity investor is giving us 50% of the total capital for a project. In a PAPS structure, if we have to pay the investor a premium of 300 basis above what we would pay on an after-tax basis to borrow the capital and you multiply the 300 basis points times 50%, you get to 150 basis point impairment, if you will, in your overall economics. It's really almost a 50-50 split on the monetization of the tax benefits.

MR. MARTIN: Any other views on the panel?

MR. EBER: What Phil described is a present-value analysis, and you can really skew these numbers depending on what discount rate you use and whether or not you can back lever the deal. Companies will have different views depending on their discount rates and what other assumptions they might layer into the structure.

MR. MARTIN: One good way for new tax equity investors to get into the market would be to buy small pieces of existing deals. They can see the paperwork and learn about the transaction. Is there a secondary market in this paper? Also, this paper is a little like a bond. As yields go up, the value of the bond goes down. How do you deal with that problem if you are a reseller?

MR. EBER: There is a secondary market, but it has not been very active until this year. We tried to get it going last year by selling new investors small pieces of existing deals in an effort to jump start a secondary market. Unfortunately, three of the four investors we picked are out of the market now because they lost their tax capacities. Currently there is a market from a few investors who overindulged in deals they did last year taking larger pieces of deals than they could absorb. They are now selling their positions at a loss because the positions are like bonds and so, if you wrote a deal in the low sixes and now the flip returns are in the sevens, the only way you can sell your position is to take a sizeable loss. Some people are doing that just to get paper off their books. It is paper that they never really intended to hold long term.

Underperformance?

MR. MARTIN: Jack Cargas, is it true that tax equity investors price based on a P50 case projection?

MR. CARGAS: They are asked to do so in most requests for bids issued by my friends at the other end of the table. We do, in fact, size transactions and price at P50, but also look at a range of other sensitivities to determine what we think is a more realistic view of how the project might perform. The P50 forecast is just not what it purports to be and so we have to look at other scenarios. We not only look at other P sensitivities, but we also look at other availability numbers, different from what is offered in the bid documents. For example, we are regularly asked to assume a 97% or 98% availability factor.

MR. MARTIN: John Eber, how have wind farms performed in practice? What does actual performance to date suggest is the appropriate P case on which to price?

MR. EBER: Our portfolio has been consistently about 10% below the P50 case. I think all the leading consultants have confirmed over the last year that the wind farms on which they have done projections have consistently underperformed by about the same percentage. They don't have a clear answer as to why. Availability is probably the biggest reason for underperformance, but a lot of it is still unaccounted for.

MR. MARTIN: Are things getting better or worse?

MR. EBER: It is hard to say. These numbers are a little deceptive because 2008 has turned out to be a very good wind year and so sites we have that had underperformed significantly due to wind for two or three years in a row are actually performing well this year. It depends where you are in the weather cycle, but I think we have seen a systemic and consistent underperformance. The engineers say that has not happened in Europe, but it has been true of American wind farms. Part of the problem is these projects are really big, far bigger than anything they've dealt with in Europe. The sites are complex, and the forecasting methodology they have been employing in Europe does not work as well for conditions in the United States.

MR. MARTIN: What does a 10% shortfall equate to in P terms? Is it P84?

MR. EBER: About P80. Every wind farm is a little different in terms of how large a standard deviation you give to get to P80, but roughly that.

MR. BERRY: Keith, you asked if things have gotten better. I think they have. One thing is the developers have gotten smarter and have been more open about / continued page 34

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potential performance issues. We run wind numbers about 4% lower than where we used to. We price our tax equity deals accordingly.

It is important not to get too excited about the wind numbers being wrong because a lot of the underperformance is attributable to availability issues that have been specific to manufacturers. You have also seen projects in Texas, for example, that cannot get their power out because of curtailment problems. Finally, look at the history of the US wind power in terms of the number of turbine years. There is a huge concentration in west Texas, and 2007 and 2008 were statistically low wind years there.

I agree with John that there was a correction needed, but we think 4% is closer to the mark.

MR. EBER: I think most of the debate right now is what is the right correction. We are finance guys and we don't really know the right correction. We just know what is going on within our portfolio. We started investing in 2003 and have wind farms from Maine to Hawaii and it is a large sample. We have enough of a sample to say that performance is consistently below what was originally projected, but we are not certain why.

It is highly inefficient for a sponsor to do a wind deal and overproject the wind because our equity is expensive and, if the sponsor is paying attention to maximizing and optimizing our equity, the sponsor should never want to go beyond the 10-year flip period and start paying us back entirely in cash. It is just not prudent for a developer to be in that position.

Therefore, I think we are both a lot better off to underestimate how the project will perform and, if every deal starts flipping in eight or nine years, then you can achieve your peak efficiency because the developer may be in a position at that point to use the remaining production tax credits itself or it can re-monetize the remaining credits by selling down another position in the project. The developer does not want to be in a position of having to help the investor reach its return by paying in cash. The currency he should use is PTCs.

MR. MARTIN: Jack Cargas, how does the choice of turbines affect the ability to finance a project in the tax equity market? Are each of the following brands financeable: Vestas, GE, Siemens, Gamesa, Clipper, Nordex, Suzlon/RePower?

MR. CARGAS: What turbine type is selected by the developer is important. We have only financed three of the turbine brands you mentioned: GE, Siemens and Gamesa. Vestas is obviously a well-established brand. We are prepared to look at other turbine types as well, but would have to give them a thorough scrubbing before deciding whether to participate in projects with those turbine types.

MR. MacDONALD: One of the problems that we see when people bring an unproven turbine to us is the manufacturers seem to think that they can offer warranties and other support to the turbine on a par with what a GE or Siemens offers, and that just isn't true. Manufacturers with unproven brands have to go back and offer the same kind of warranties that Vestas was offering when Vestas was a small vendor, and that's a big problem.

Yields are up 150 to 170 basis points over a year ago. Developers are looking for ways to expand the number of potential investors.

Absorption Issues

MR. MARTIN: Phil Mintun, we are running into more absorption issues in the tax equity market this year. IRS rules allow as much as 99% of the tax subsidies to be allocated to the tax equity investor in theory. However, in practice, it may be impossible to get him a 99% share. Why?

MR. MINTUN: It gets very technical, but the problem is that investors are running out of capital account or outside basis. These are measures of what an investor put into the deal and what he takes out. They usually cannot go negative. A deficit is a sign that the investor took out more than his fair share. Construction costs have been escalating, with the result that projects are less profitable and there is less of a cushion to absorb the tax benefits and make sure that the tax equity can get its return by the target date 10 years out.

MR. MARTIN: David Berry, you told me earlier that deals are getting less efficient in terms of the tax equity investors' ability to absorb the tax subsidies and that tax equity investors today absorb the full production tax credits but only 65% to 70% of the depreciation. Is that correct?

MR. BERRY: They absorb only that fraction of the accelerated nature of the depreciation. In the typical deal, we will attempt to pass through 99% of the depreciation deductions to the tax equity investor, but after the investor runs out of outside basis, the investor must carry the remaining depreciation forward in time. There is a time value loss in the investor being unable to use the depreciation immediately.

MR. MARTIN: One solution to having too little capital account is for the tax equity investor to step up to something called a deficit restoration obligation. The investor declares itself willing to put money into the tax equity partnership when the partnership liquidates if the investor still has a deficit in its capital account at that time. Jack Cargas, have you noticed a greater reticence this year by equity investors to step up to deficit restoration obligations?

MR. CARGAS: It's an interesting question. When we first got into this market, which was only 18 months ago, we were very concerned about DROs. We wanted to do a clean deal without a deficit restoration obligation. Over time, we have become more comfortable with the concept and have agreed to step up to DROs, so that might be slightly counter to the response you were expecting.

MR. MARTIN: Clay Coleman, are equity investors more reluctant this year to step up to deficit restoration obligations?

MR. COLEMAN: We have not had an active term sheet discussion regarding DROs or anything else for several months, so I don't know if the picture changed. However, the major players seem fine with DROs. They allow you to pass on only the production tax credits effectively. They do not do anything for depreciation.

MR. MARTIN: John Eber, are equity investors less willing this year to agree to deficit restoration obligations?

MR. EBER: I think so. The trend this year has not only been higher tax equity yields but also investors wanting to do safer deals. They can afford to pick only the best deals because there is an oversupply of opportunities. That means that DROs are less common. I don't think it is a go-or-no-go question with DROs. It is a question of how much an investor is willing to commit to put in as additional capital, if necessary, at the end if he has a deficit in his capital account.

We have benchmarks in our shop. Many of our partners also have benchmarks about how much of a DRO they will take. We usually cap the DRO at a level that the base case model suggests will reverse itself. The DRO is an off-balance-sheet liability that none of us expects to be called, but you want to be prudent and not build up too much of that kind of exposure.

MR. MARTIN: What is a typical percentage cap for you?

MR. EBER: It seems like a popular percentage is around 20%.

MR. MARTIN: One other solution to having too little ability to absorb tax benefits is to put debt at the project level, as that makes the depreciation easier to absorb. However, it also increases the yield the tax equity investors will require. By how much, Jack Cargas?

MR. CARGAS: We have not done a transaction with project-level debt and we are not likely to do so. I hear anecdotally that there is a delta of 200 to 250 basis points between a typical unlevered PAPS deal and a levered PAPS deal.

MR. MARTIN: Why will you not do leveraged deals?

MR. CARGAS: We think these transactions are complicated enough without having a third party at the table.

MR. MARTIN: John Eber, if the lender agrees to forbear from foreclosing until the tax equity reaches its yield or until the production tax credits run, does that mean that the tax equity yield does not bump up?

MR. EBER: No, I think the yield will always bump up because you are investing fewer dollars but absorbing the same amount of tax benefits. You need a larger return in a leveraged deal, even if the risk is the same, because you are being asked to absorb a lot more tax benefits in relation to the dollars invested and using up more tax base that could have been applied to another investment.

The biggest impediment to leveraged deals is you usually need a 20-year power purchase agreement to make a leveraged deal work and such long-term power contracts are becoming rare. Few banks will lend to a project unless there is a long-term fixed-price offtake contract. */ continued page 36*

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Merchant Plants

MR. MARTIN: John Eber, how much protection would a developer have to show for power prices in a merchant deal to get tax equity financing?

MR. EBER: The preference is to get at least 10 years. If you go back a few years, all the deals had long-term PPAs. In the last year and a half, everybody has wanted to go merchant and hedges have become commonplace. However, today, with the limited tax equity available, the remaining investors are keen to do only the best deals. In this market, you need a minimum of 10 years of price protection. A PPA is even better.

MR. MARTIN: What special issues are there with a hedge in the form of a swap of fixed for floating electricity prices? Does the tax equity investor view the swap as the equivalent of debt and ask for a higher yield?

MR. EBER: I think there is a higher yield requirement when you have a swap — yes — but not as much as if you had debt.

MR. MARTIN: So if real debt bumps up the tax equity yield by 200 or 250 basis points, what does a swap do?

MR. EBER: It is hard to say. It depends on the quality of the swap provider, his creditworthiness. It depends on the terms and conditions of the swap and whether the swap provider takes a security interest in the wind farm or whether something might happen in the swap to cause the project to have to post additional security. I have seen everything from not adding much cost at all to adding 50 to 75 basis points, depending on the quality of the swap.

Tax equity covered close to 65% of the cost of a typical wind farm in the past. The share is now down to just over 50%.

Next Year

MR. MARTIN: We are down to the last question. Phil Mintun, what do you think will be the main topic of conversation next year for this panel? What will we be discussing then?

MR. MINTUN: It will be what happened to the huge amount of investment that had been expected to go into the wind sector in 2009.

MR. MacDONALD: I think we will be talking about how multi-investor funds work and how — [Laughter].

MR. EBER: I agree with Phil Mintun. I think 2009 is going to be a very tough year because there is a lot of unmet demand from 2008 that will roll into 2009. When you layer on top of that the 2009 demand that appears to be coming, there will be a huge gap between demand for tax equity and the available supply, unless something changes significantly like people back off projects or some significant new sources of tax equity appear over the next few months.

MR. COLEMAN: I echo that. We could see the demand for wind tax equity next year being on the order of $10 billion and the supply peaked in 2007 at $5 billion. Obviously, if you keep on jacking up yields, you can bring other corporate investors into the market, but we will arrive quickly at a point where tax equity is demanding a higher yield than the wind farm itself earns and that's not a sustainable business model. The bottom line is I think we are going to be talking about the ongoing demand and supply imbalance for tax equity.

MR. CARGAS: In addition to that conversation, I think we will be having the same conversation we had for most of this year — the one that ended on October 3 with passage of the Wall Street bailout bill — and that is whether Congress will extend the production tax credit again.

MR. BERRY: Does the rise of energy, and renewable energy in particular, to one of the three or four most important topics in the presidential election translate into a coherent and favorable policy on the federal level for wind energy. ◎

Frozen Credit Markets and Falling Oil Prices Create Challenges for Renewables Projects

Chadbourne held a "green business summit" in New York on October 17. One of the panels discussed the state of the credit markets and what the inability of even large corporations to borrow money, combined with falling oil prices, means for renewable energy projects in the United States. The panelists are Brian Goldstein, managing director for syndications at BNP Paribas, Steve Cheng, a managing director in the global energy group at Credit Suisse, Paul Ho, a principal at Hudson Clean Energy Partners, a private equity fund, and Rahul Advani, a vice president and one of the founders of another private equity fund called Energy Capital Partners. The moderator is Todd Alexander with Chadbourne in New York.

MR. ALEXANDER: New York City cab drivers tell me there is no commercial bank money for renewable energy projects because of the general freezing of the credit markets. Brian Goldstein, true or false?

Bank Debt Market

MR. GOLDSTEIN: It is pretty cold out there. There is some money, but certainly the challenge is not just with renewable energy projects but with credit for the economy as a whole. Capital is limited and scarce. There are debates within banks that have money to lend about how to allocate the capital among sectors. In general, we will see a retraction toward much stronger credit profiles and higher pricing to allow recovery of costs of capital.

Speaking to the trends across all sectors, banks are having a tough time finding capital to lend. The nine largest banks lost a total of $323 billion over roughly the last 18 months.

MR. ALEXANDER: What are credit spreads for renewable energy projects today compared to six months ago, assuming you can even find someone to lend money?

MR. GOLDSTEIN: Our cost of funds was 64 basis points over LIBOR in September and is now 72 basis points over LIBOR. The credit spreads that are charged not only have to cover my LIBOR costs, which is what I must pay to get my money to lend to you, but I now also need at least another 75 basis points on top of that before I can start to charge you a credit spread for the credit risk. And because the perception is that the risk of lending to you has increased because of general economic conditions, I need to charge a larger credit spread to compensate for the perceived risk in the overall market, which has driven these spreads well above 200 basis points for investment grade transactions.

Just to show you the difference in our cost of funds and Treasuries, there is an index that tracks the difference between three-month US Treasury bills and three-month LIBOR. It jumped to over 450 basis points earlier this month. That means that, on average, banks incur 450 basis points more than the Treasury rate before they reach the point of starting to recover their bare costs of funding.

MR. ALEXANDER: How much of a secondary market are you seeing for debt instruments and how are yields in the secondary market affecting your ability to finance new projects?

MR. GOLDSTEIN: They are making it incredibly challenging. Most of us are trying to arrange loans on your behalf, underwrite those loans if we can, and then sell them to investors, whether they are banks or institutional investors. The distress in the market means that a lot of investors need to sell the paper they already hold. Supply and demand drive secondary pricing for people trying to offload assets. They are having to sell those assets at a loss. One of the real problems in our ability to underwrite paper is that the secondary markets generally trade 200 basis points higher than what we are trying to do on the primary issuance market. Therefore, either the primary issuances have to price higher to match the secondary issuances, or they have to wait until the market settles and secondary pricing comes back in line with where we believe the primary issuance should be.

MR. ALEXANDER: Does that have an effect on the size of deals that can be placed in the market? Does it favor larger deals? Renewables projects tend to be on the smaller end of the market.

MR. GOLDSTEIN: Smaller is better. We are seeing a limited appetite to underwrite and take the distribution risk. As a result, we are clubbing deals, and a smaller deal makes it significantly easier for us to arrange a lending syndicate to underwrite the full loan amount.

Institutional Debt Market

MR. ALEXANDER: Steve Cheng, Credit / continued page 38

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Suisse has been one of the leaders in the term B loan market and on other capital market raises. Does what Brian said also describe the state of the capital markets?

MR. CHENG: The difference is that the term B market is probably even more shut down than the bank market. There are a few institutions who still have the liquidity and appetite to do smaller deals, but the cost of funds is being driven by the spreads in the secondary market. A year and a half to two years ago, the sweet spot in the market was in the single B to single B plus-rated area. Deals were getting done at 200 basis points over LIBOR with those credit characteristics. Today, if you have a single B or single B plus credit, the number will start at 1,000 or 1,200 basis points over LIBOR. That implies yields of 16% to 18%.

MR. ALEXANDER: Those sounds like hedge fund returns rather than lending rates. Do you see an opportunity for new entrants to come into the market to compete with the traditional lenders because the spreads today are closer to equity yields?

MR. CHENG: There are still institutional investors with funds who need to put money to work. However, some investment funds are basically shutting down. They need to set aside cash to meet redemptions. Cash is a very valuable commodity today.

MR. ALEXANDER: Do you think some of these funds will be able to raise new capital with a seven- to 10-year life and put it to work earning these high returns? That would help with market liquidity.

MR. CHENG: The money is already there if borrowers are willing to pay such high yields.

MR. ALEXANDER: Let me ask about another trend. Credit Suisse has been at the forefront of creating financial structures that mimic either a physical output or a physical input. These structures are different forms of hedges. Are lenders willing to accept hedges in today's market as a way of managing risk?

MR. CHENG: Deals are still getting done. People are still taking counterparty risk, but they are a lot more careful about evaluating counterparty risk and are trying to offset it. One way to offset it is by charging a higher interest rate.

The problem in the credit markets is not that primary lenders refuse to lend, but that buyers are demanding huge risk premiums in the secondary market.

MR. ALEXANDER: Brian Goldstein, do you agree?

MR. GOLDSTEIN: Yes. Banks recognize that there is counterparty risk in a hedge structure or synthetic power purchase agreement. If the counterparty is investment grade, we might have argued in the past that it was a 30 basis point risk while it is 200 basis points in the current market. We can either increase the spread to reflect the risk or we can reduce the loan tenor.

In wind deals, for example, with 10-year hedges and merchant risk on the back end, the argument internally is whether to push the credit structure back to where it was in the mid- to late 1990's where you had very short mini-perm loans and lending limited to technologies that have been proven commercially viable.

MR. ALEXANDER: Paul Ho, you are with a private equity fund that invests in renewables. How have you been affected by the freezing of the credit markets and the downturn in the economy?

MR. HO: We are definitely affected. Renewables projects have tended to be financed in the tax equity market. Some traditional tax equity players like Wachovia, AIG and Lehman are out of business. Tax equity yields are headed up. Last year, you could get tax equity for a wind deal, for example, at a 6% or 7% after-tax yield. Now it is probably pushing toward 8%, and that is if you can even get the money. The pool of potential tax equity capital has been shrinking. Solar, geothermal and biomass companies are facing the same problem.

There has been a lot of discussion about how to increase the amount of available tax equity. One proposal that received some attention in the past was to allow master limited partnerships to be used by wind and solar companies. MLPs can be used today for oil and gas pipelines, coal reserves and other fossil fuel-related businesses. We think that would help level the playing field. It would eliminate a preference that causes capital to be directed more heavily today toward fossil fuel instead of renewables. But it is only part of the solution, since the MLP market is limited in size when you compare it to the amount of capital that a GE or AIG could marshal.

Another proposal has been to make it easier for utilities to take the tax subsidies from these projects. The Wall Street bailout bill that cleared Congress in early October makes it easier for utilities to claim tax subsidies on solar projects.

In the near term, I expect a serious slowdown through at least the end of 2008 in financings for renewable energy projects.

MR. ALEXANDER: Rahul Advani, you are also at a private equity fund. Do you want to add to anything Paul Ho said?

MR. ADVANI: I agree with Paul on his assessment about the near term. The dissolution of some key players in the tax equity market will seriously reduce the supply of tax equity.

The fact that the bailout bill let regulated utilities claim a 30% investment tax credit on solar projects — they had been barred from claiming the credit before — has caused people to take notice. You take notice when your offtakers are going potentially to be supplying meaningful parts of your capital structure. That means they will be more deeply involved in the development and structuring and have more influence over the project than they had before.

General Repricing of Risk

MR. ALEXANDER: How does the higher cost of debt affect your fund? Does it create new opportunities?

MR. ADVANI: You could see what has happened lately in the markets as a wholesale repricing of risk. The focus at Energy Capital Partners is not just on the renewable energy sector but the energy market as whole. What we saw in the last few years was lenders started assigning more value than may have been warranted to asset values. You saw lenders willing to lend and write commitments for projects that were greater than what I thought some projects had in total enterprise value. The banks assumed ever increasing asset values. That got people excited about development pipelines, especially for renewables projects. We saw big payments being made for wind and even some biofuels projects.

Today, there is a wholesale repricing. There is a renewed focus on the credit quality of the offtake arrangements. Debt yields are going up because of the higher perceived risk. Maybe the world of 6%, 7% and 8% yields is gone. Maybe we are living in a world of more expensive debt. Maybe we are living in a world of more expensive tax equity.

You need to ask yourself on a relative basis, how should I look at my equity returns? Do I now need to earn more? Don't I need a higher yield than the lenders and tax equity investors given that, as the true equity, I am going to be taking the most risk in the capital structure?

I don't think there will be a convergence of risk premiums so that everybody will be looking at 15% or 20% returns. Delineation will remain.

MR. ALEXANDER: You paint a bleak picture for the developers.

MR. ADVANI: I don't mean to. At the end of the day, good projects will get financed. One of the reasons we are investing in renewable energy projects is because, relative to a lot of the other assets in the energy sector, they are better investments. You are usually dealing with proven technologies. You have the ability in many projects to build on a fixed price. You know what the project will cost to build. You may have the ability to enter into a 20- or 25-year offtake contract with a utility who needs the electricity from renewable sources to comply with state renewable portfolio standards. There are large tax subsidies.

Solar, Biofuels and Wind

MR. ALEXANDER: Steve Cheng, let's talk through the various renewables sectors starting with solar. We have seen such a run up in interest in solar. There is probably a solar conference every two weeks somewhere in the US. Is the huge interest in solar a classic sign of a bubble like the dot-com bubble or do the economic fundamentals make sense?

MR. CHENG: You have a lot of publicly-traded solar companies, particularly manufacturers of solar equipment, and their stocks are being battered in the market. However, it is hard to assess an industry based on how well stocks perform. What drives up or drives down stock prices may have nothing to do with the fundamentals of the industry. In the longer term, solar and wind are the two leading / continued page 40

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renewables technologies that have shown the greatest potential.

MR. ALEXANDER: Rahul Advani, do you think the great interest in solar is a sign of an overheated market?

MR. ADVANI: Solar is a great product, wind is a great product, and renewables are a great product because, once they are built, they draw on a free source of energy. I agree with Steve Cheng that stock prices can be a distraction and may mask the fundamentals. However, I did a quick check this morning about what evidence there is of a bubble. I don't mean to pick on just one company. First Solar is an industry leader. It has a market capitalization today that exceeds the combined market capitalizations of Dynegy, Mirant, NRG and Calpine. Sunpower has a smaller market capitalization, but it is still greater than the market capitalization of FPL Energy. There are still signs of euphoria in the solar market.

We are talking for the most part about proven technologies, but there is still a lot to be proven, like how the projects will perform on a utility scale. There are also emerging new solar technologies that hold out the promise of lower costs and greater efficiencies. You have a lot of people placing bets that their technologies will be the key to bringing down costs of solar power and will find acceptance in the market, but these are bets rather than sure things.

MR. ALEXANDER: Will the cost of capital for developers of utility-scale solar projects be low enough to allow them to generate their electricity for less than 18¢ a kilowatt hour?

MR. ADVANI: I think so. The really large utility-scale solar thermal projects are still off in the future. You won't see them begin to come on line until 2010, 2011 and 2012. The good projects that are using proven technologies will succeed.

MR. ALEXANDER: Let me shift to a sector where there was clearly a bubble — the biofuel sector. Stock prices for biofuels companies have fallen as much as 90%. What do you see as the future for this sector, Paul Ho?

MR. HO: Despite the doomsday sentiment around the table, I feel like a kid in a candy store because we have money to spend. There are a lot of distressed biofuels projects. Some are looking to private equity for interim capital solutions.

On the biofuel front, we have seen the bubble burst and the publicly-traded companies are trading at a dollar or two a share. There are many challenges in that space. It is a business that requires large amounts of working capital. Many of the projects are still earning positive margins, but it is the working capital needs that are putting the companies into trouble.

The companies need more than a financial solution. In the longer run, the strategic players will be looking at moving back into the sector. The question for private equity participants like our fund is whether it is worth diving into the sector. The debt is trading at a deep discount. The question is whether we should play on the equity or debt side of the market. Adding to the uncertainty is there is a fair amount of disagreement between the two presidential candidates about what US policy should be going forward. That leaves at least some near-term uncertainty about the future viability of the biofuels market. The European Union has recently scaled back its targets. Some of the uncertainty should start to lift in the next six months. I am guessing that will bring investors back into the sector.

Another thing that warrants attention is commodity prices are coming down dramatically. We are looking at $70 oil today as opposed to $145 oil only three months ago. Ethanol is selling for $1.60 compared to $2.50 a gallon. Natural gas is under $7 an mcf. All of this has a bearing on the equity return profile of energy investments as well as how lenders look at the sector. And commodity prices could move lower still.

MR. GOLDSTEIN: We all want to do deals. By "we," I mean lenders, equity investors and developers. What we need to do in the current market is make them clean and straightforward, and those projects that have scale and good risk mitigation will get done, because we all have an interest in finding a way to do them.

MR. ALEXANDER: Steve Cheng, wind has been the largest of the various renewables sectors in terms of scale. What effect do you see the current turmoil having on it and what is the outlook over the next six to 12 months?

MR. CHENG: Wind is capital intensive. The biggest cost is the turbines. Developers must make down payments on the turbines starting more than a year in advance. People will be scrambling to make their payment obligations over the next 12 months. Banks were willing to lend as much as 80% of the turbine cost six months to a year ago, but the advance rates on turbine loans have declined dramatically.

MR. ALEXANDER: Where are the advance rates today?

MR. CHENG: Probably less than 50%. The difference has to come out of equity. Wind developers who want to take advantage of the one-year extension in production tax credits for wind farms need to keep their places in the turbine queue and, to do that, they will be looking for other sources of capital to make turbine payments.

Impact of Falling Oil Prices

MR. ALEXANDER: Switching topics, oil prices are falling. The last time we saw a push to develop renewables was after the Arab oil embargo in the 1970's. Oil prices were falling by the early 1980's and interest in renewables waned. Will we see that same pattern again?

MR. HO: I'm not concerned. It is clear that the American public is as worried about energy policy as it is about the general economy. It was clear from the presidential debates that energy policy will be one of the top two or three policy priorities for whichever candidate wins the election. Renewable energy is a lot closer to competing on a purely economic footing with fossil fuel today than it was the last time around. I don't think the government will let the opportunity pass this time to convert the economy to one based on green jobs and to wean the US from reliance on unstable sources of energy supply. Will there be a slight delay in terms of implementation of certain policy goals? Maybe. In the long run, we will find prices rising again just like in any other commodity cycle.

MR. ADVANI: At the end of the day, the future of renewable energy in this country comes down to political will. It is easy to have that conviction when oil is above $100 a barrel or when the conventional wisdom is the price will head back up or we are involved in skirmishes in the Middle East. It is more of a challenge for the politicians to remain firmly behind renewables when the economy is weak. For example, it is challenging during such periods to implement a cap-and-trade system to control carbon emissions because of the additional financial burdens imposed on power companies and electricity consumers.

The good news about political will is the cat is already out of the bag. The federal government has been slow to implement carbon controls, but the states, particularly in New England, have instituted them, and once such a system is in place, it tends to remain in place. Tax credits for renewable energy have just been extended by Congress. There are mandatory renewable portfolio standards already in place in 26 states. The policies to push renewables farther along are already in place. ◎

Mexico Goes Verde

by J. Anthony Girolami, in Mexico City

Mexico adopted a new renewable energy law in late October that is the first step in creating a comprehensive legal framework for developing renewable energy projects in Mexico and that will open up new opportunities for renewable energy developers and technology suppliers. The new law is expected to take effect in November.

Potential Market

Mexico has the good fortune of possessing many renewable energy resources that remain largely untapped. A 2003 study by the US National Renewable Energy Laboratory concluded that Mexico has national wind resources sufficient to generate more than 40,000 megawatts of electricity. The wind conditions in the Tehuantepec Isthmus of Oaxaca are among the best in the world with the potential to generate 8,800 megawatts. Baja California, Yucatan and the Mayan Riviera of the State of Quintana Roo benefit from wind conditions that could potentially generate 274 megawatts, 352 megawatts and 157 megawatts, respectively.

With respect to solar resources, Mexico has one of the highest potentials in the world with an average solar insolation of 5 kWh/m^2. The areas with the most solar potential are mainly in the north of the country and include large portions of the states of Baja California, Sonora, Chihuahua, Zacatecas and Durango.

As a region with volcanic activity, Mexico also has considerable geothermal resources with the potential to generate approximately 2,400 megawatts. Primary geothermal sources are located in Baja California, Sonora, Michoacán and Puebla.

Mexico has a long tradition of converting its hydraulic resources into electricity through the implementation of large-scale hydroelectric plants. Currently, approximately 21% of the country's installed capacity comes from hydro power. While large-scale hydroelectric facilities are difficult to implement and are capital intensive, small scale hydroelectric plants producing 10 megawatts or less are a viable option given Mexico's numerous hydraulic resources. It is estimated that small hydro projects have the potential to generate approximately 3,250 megawatts.

Notwithstanding the existing resources available for renewable energy development, Mexico / continued page 42

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continues to rely heavily on conventional plants fueled by fossil fuels and coal. The total installed capacity from renewable sources today in Mexico is just 3%, not counting hydroelectricity.

Existing Legal Framework

The Mexican electricity sector is state controlled. The generation, transmission, distribution and sale of electricity to the general public are the responsibility of the Federal Electricity Commission or "CFE". In 1992, the national electricity law was modified to allow private parties to generate power. Private entities are allowed to participate in four types of activities related to the electricity sector. They are self-supply of electricity also known as inside-the-fence projects, projects that sell their output to the CFE under long-term power purchase agreements, cogeneration facilities and production of electricity for export to neighboring countries.

Three percent of electricity in Mexico comes from renewable sources. A new energy law should increase the percentage.

Most renewable energy projects developed to date have been either constructed and operated by the CFE or by private companies either as inside-the-fence facilities or with long-term output contracts with the CFE.

An independent generator may be able to enter into a 20-year power purchase agreement with the CFE. Such contracts are awarded through a competitive bidding process. The CFE is currently in the process of tendering for a 100-megawatt wind project in Oaxaca.

With respect to the self-supply or inside-the-fence regime, a project developer is permitted to build a power plant serving multiple offtakers who collectively own the power plant. Self suppliers must obtain a permit from the Energy Regulatory Commission, called the "CRE," prior to commencing construction. Each of the project owners listed in the self-supply permit is entitled to take the share of electricity specified in the permit. The developer must enter into a separate interconnection and transmission contract with the CFE to connect the project to the grid.

The New Law

The two main objectives of the new law are to establish a comprehensive plan to promote the generation of electricity from renewable sources and to create the instruments for financing the transition to renewable energy.

The new law only applies to electricity that is generated from renewable sources, including wind, sunlight, water, geothermal steam or fluid, ocean currents and waves and biomass, and sold to the state-owned electricity distribution companies, the CFE and *Compañia de Luz y Fueza del Centro* (LFC). Large hydroelectric projects (greater than 30 megawatts) and nuclear plants are neither helped nor affected by the new statute.

The Energy Ministry is required to develop a national renewable energy plan and to establish a trust fund to provide financial assistance during the transition to renewable energy. The idea behind the plan is to give the CFE advance warning of the additions to the transmission grid that will be needed to move renewable energy from remote locations where wind is best or geothermal reservoirs are located to urban population centers.

The government is expected to set a specific minimum national content requirement for renewable energy projects and to coordinate with the Treasury to establish appropriate tax incentives.

The Energy Regulatory Commission will set tariffs or the prices that may be charged for renewable energy. The tariffs will be fixed over the term of each power purchase agreement, subject to adjustments for inflation and indexation methods formulated by CRE, and may not exceed 10% of the maximum tariff paid by the CFE to independent power producers for electricity from fossil fuels. Owners of renewable energy facilities operating under a self-supply permit will be allowed to sell any excess electricity to the CFE at a tariff to be determined by the CRE.

The government is determined to involve communities in planning for projects. Project developers are supposed to leave room for public participation in the planning stages and to earmark any income earned from the projects for regular lease payments to local communities and for implementation of social development programs.

Financing the Transition

The transition to renewable energy is to be supported by a trust fund that will be administered by a technical committee appointed by the Energy Ministry. The Energy Ministry is required to deposit a portion of its annual budget into the trust. Other funding for the trust may come from any carbon taxes imposed by the federal government, contributions by state and municipal governments, donations from international agencies, voluntary donations from citizens and proceeds from selling renewable energy bonds.

The trust will be used to support generation projects, rural electrification projects, the construction of transmission and interconnection infrastructure and biofuels plants. The trust is expected to engage in direct lending on preferential terms and provide loan guarantees. It may make grants in extraordinary circumstances for projects with significant environmental or socioeconomic benefits.

The Mexican government also plans to fund the trust through the sale of carbon credits and perhaps other strategies that are part of a broader effect to reduce greenhouse gas emissions. Renewable energy projects in Mexico are eligible for benefits under the "clean development mechanism" of the Kyoto protocol. The projects qualify for carbon credits that can be sold in international markets. It is possible that some of the proceeds from such sales may be channeled into the trust.

Details of the tariff structure, potential subsidies for renewable energy projects, tax incentives and a model power purchase agreement are expected to take form in the next 12 months. The Energy Ministry must establish the trust fund immediately. It has six months to submit a renewable energy plan to the president. It has eight months to publish regulations implementing the new law.

For centuries, the sun, wind and earth have played an important role in the daily life of Mexico. Aztec mythology is filled with references to *Huitzilopochtli*, the god of the sun, *Ehecatl*, the god of the winds, and *Chantico*, the goddess of volcanos, who, along with other deities, were responsible for creating and maintaining the life force of the Aztec universe. Modern-day Mexico is looking once again to these resources to produce energy of a different sort with the assistance of modern technology. ◎

Potential Effects of the Move from US GAAP to IFRS

US companies have used a set of "generally accepted accounting principles" — called US GAAP — to determine their earnings and value their assets for the past 75 years. Many companies outside the US use a different set of global standards called the international financial reporting standards, or IFRS. The United States may be moving to adopt these global standards.

Sherif Sakr, a partner in the New York office of Deloitte, spoke to Chadbourne lawyers on a video conference call in late September about what the shift in accounting methods means for US companies and for project finance and corporate transactions. Mr. Sakr worked with Deloitte in Europe and the Middle East before moving to New York. His areas of expertise include financial instruments, structured transactions, fair value measurements and IFRS. He received an award from President Bush in 2007 for working with the US Agency for International Development on training local standard setters, exchange commissioners and central bankers in developing countries about IFRS. The Chadbourne lawyers asking questions are Keith Martin in Washington, Charles Hord, Edouard Markson and George Zeitlin in New York, Irina Skidan in St. Petersburg, Anthony Girolami in Mexico City and Noam Ayali in Washington.

MR. MARTIN: What is IFRS and how does it differ from US GAAP?

MR. SAKR: The international financial reporting standards are standards issued by the International / continued page 44

IFRS

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Accounting Standards Board in London. The board was established in 2001 to replace a predecessor committee called the International Accounting Standards Committee that was established in 1973. IFRS is the equivalent of GAAP here in the United States, but international standards differ from GAAP. US GAAP generally tends to be more form driven or rules based. IFRS relies more on concepts and broad principles. It generally focuses more on the underlying substance of the transaction than on its legal form.

IFRS really started gaining momentum in 2002 when the European Union required the use of IFRS by all European-listed companies. More than 7,000 companies went through a transition to IFRS between 2003 and 2005. Today, more than 100 countries use IFRS, and we are now thinking about moving to IFRS in the United States.

MR. MARTIN: So there is more room for argument about how to account for transactions under IFRS than under US GAAP because lines are not drawn as clearly under IFRS as under GAAP.

MR. SAKR: Generally, that is correct.

MR. MARTIN: The US Securities and Exchange Commission indicated in August that it intends to move the US to IFRS. What is the timetable?

MR. SAKR: The current timetable provides an option for early adoption by certain companies as early as fiscal years starting after December 15, 2009. There is a roadmap to be released and there are certain milestones that need to be met before all public companies are required to move to IFRS. Large accelerated filers will be expected to move by fiscal years ending on or after December 15, 2014, accelerated filers by fiscal years ending on or after December 15, 2015 and non-accelerated filers by fiscal years ending on or after December 15, 2016.

MR. MARTIN: What does "accelerated filer" mean?

MR. SAKR: An accelerated filer is basically a company with a global market capitalization of between $75 and $700 million, as further defined by SEC Rule 12b-2. Accelerated filers must file their periodic reports with the SEC faster than smaller public companies have to file.

Some US companies may convert to IFRS accounting as early as 2010. The rest are expected to follow in 2014 to 2016.

Let me spend a minute talking about which entities qualify for early adoption. The SEC wants to implement IFRS on a limited scale initially to see how it will fit in our existing environment. The SEC decided to provide for early adoption as early as next year for US companies that are among the 20 largest companies globally in their industries based on market capitalization, but only if IFRS is used more often than any other method of accounting by those 20 companies. These are generally multinational corporations. Examples are pharmaceutical and manufacturing companies and large financial institutions.

MR. MARTIN: So those early adopters are companies that may switch as early as next year if they choose. Can others switch before 2014?

MR. SAKR: Only if certain milestones are met. The window period of 2014 through 2016 for conversion of all US public companies is contingent on certain milestones being met. There are basically four such milestones. One is the International Accounting Standards Board in London must obtain sustainable financing. The IASB is funded currently through contributions from corporations and "big four" accounting firms. The second milestone is improvements to IFRS. That is ongoing. The third milestone is improvement in the ability to use interactive data for IFRS reporting. The SEC has adopted a new filing system called XBRL that replaces the current Edgar system. The last milestone is companies need to have been educated about what IFRS requires. The process of educating everyone is already underway. This session is an example. Universities will start to include IFRS in their curricula within the next year or so. The CPA exam will include IFRS questions within the next two years.

MR. MARTIN: Help me understand something. If a European utility owns a subsidiary in the US — let's say it owns a US utility — would that US utility already be reporting on IFRS?

MR. SAKR: Not necessarily. The US utility probably has to turn in accounts to its regulators using US GAAP, but it probably also has internal IFRS reporting to file with the parent in Europe. It is a good example of how the US move to IFRS would make things easier for companies that are part of groups operating in more than one country.

MR. MARTIN: So the largest impact of the switch is on companies that are purely domestic concerns. They will have the most work to do to change.

MR. SAKR: That is probably a fair characterization. I would agree with that.

Transition Issues

MR. MARTIN: What transition issues does the switch create?

MR. SAKR: There are a lot of transition issues. Companies will basically be changing how they calculate income and loss and other items on their balance sheets and income statements in more than one area. The shift in accounting systems will require some reprogramming of systems that collect data for preparing financial reports. Different data may have to be collected. Data that is already collected may have to be analyzed differently. This may lead, in turn, to organizational changes within and beyond corporate accounting departments.

Stock-based compensation plans may be affected and could have to be restructured. The change to IFRS is a very broad exercise that will touch upon every group or department within an organization.

MR. MARTIN: One change is that many companies in the US use something called last-in-first-out accounting. Companies that use this method tend to be in industries where costs increase over time. There is an advantage in such industries to treat the last goods added to inventory as the first ones sold. LIFO cannot be used under IFRS. These companies will have to switch to treating the first goods in as the first ones sold. That will tend to reduce their earnings in the future, correct? That's the first question. The second question is which industries are big users of LIFO?

MR. SAKR: LIFO is common among manufacturers and retailers.

MR. MARTIN: If a company switches from LIFO to FIFO, would you expect its earnings to go up or down?

MR. SAKR: It depends on the direction in prices of the particular inventory item. If the company is acquiring inventory at escalating prices, and the most recently-acquired inventory is considered sold first, then you would expect to see a higher cost associated with that from a cost-of-goods sold perspective versus what would occur if the trend was for falling costs-of-goods sold. I don't think one can make a simple statement about how the change will affect earnings. The most one can say is the change will definitely have an impact, and that impact is broader than just the accounting impact and the result on earnings.

MR. MARTIN: According to news reports, IFRS will allow US companies to report roughly 20% more income. Is this true across sectors or does the impact vary by sector? And I should tell you most of the lawyers in our project finance group work with power companies, so we are keenly interested in the potential effects on them.

MR. SAKR: I have seen the same news reports, but don't see any support for the numbers. We have been discussing IFRS with many clients across multiple industries. We are trying to look at their competitors in Europe who have been through the conversion to see the impact of the transition from local GAAP — whether it was UK, French, German, whatever it was — to IFRS and try to gauge how earnings changed. I don't think the effect was always in one direction.

Differences in rules between US GAAP and IFRS will have disparate effects on companies. Reversal of impairment charges is an example of something that is permitted under IFRS. Therefore, if a company must report an impairment charge and the asset later appreciates in value, the company can generally reverse the earlier impairment loss and report a gain. This is not the case under US GAAP.

Effect on Transactions

MR. MARTIN: What should someone working on acquiring a US company do differently, if anything, in the deal documents given the expectation the US will be switching to IFRS?

MR. SAKR: At least one thing comes to / *continued page 46*

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mind immediately. There is often a reference in the legal document to US GAAP-based financial statements. Such references will need to change. To the extent there is an earnout or other form of purchase price to be paid over time tied to earnings, that may also be affected. One of the major differences from a deal perspective between US GAAP and IFRS used to be in the accounting for business combinations.

The switch to IFRS should be considered in setting debt-service coverage ratios. The coverage may look different after the conversion.

However, the standards have become fairly well aligned. The Financial Accounting Standards Board in the US issued FAS 141-R on business combinations. The IASB issued IFRS 3-R. The differences there are minor.

MR. MARTIN: What, if anything, should be done differently in corporate or project finance loan transactions? These are long-term borrowings or initial public offerings of stock.

MR. SAKR: Depending on which company you are talking about, the change to IFRS could potentially be as early as next year or as distant as eight years from today. You must first determine the time frame of the agreement to assess the potential relevance of IFRS.

The conversion to IFRS may have to be considered in setting debt coverage ratios. The numbers may look different after the conversion. A drop in debt coverage could trigger cash traps, cash sweeps or defaults. That possibility should be considered in drafting the loan agreement.

MR. MARTIN: What should be done differently, if anything, in risk factor disclosures in SEC filings?

MR. SAKR: Risk disclosures are another interesting area. The SEC requires disclosures in securities filing, but these are a matter of SEC rules. There is no US accounting rule requiring detailed risk disclosures in the notes to financial statements. However, IFRS requires detailed risk disclosures in financial statements. The required disclosures are described in IFRS 7. It focuses mainly on disclosures or risks related to financial instruments and provides a framework for quantitative disclosures relating to market risk, liquidity risk and credit risk and what steps the company has taken to manage the risks.

There will be a big shift. US companies will be required to make the same types of risk disclosures they make in the management discussions and analysis section of SEC filings and even provide more details in footnotes to the financial statements once IFRS is adopted.

Another point to emphasize here is that because IFRS generally focuses on the risks and rewards or substance of a transaction over its legal form, in many cases, you will see expanded disclosures supporting the company's accounting conclusions about complicated transactions that are not black and white. There are definitely more extended disclosures under IFRS than what you see under US GAAP.

MR. MARTIN: Is there a risk disclosure that is required just to put investors on notice that the change in accounting methods may have an effect on earnings?

MR. SAKR: Absolutely. Companies must disclose anticipated significant changes in accounting policies. Also, when a company first switches to reporting under IFRS, it must reconcile its equity and net income with the amounts that would have been reported under US GAAP. The company must also explain the adjustments it made to get to the new figures under IFRS.

MR. MARTIN: I have just a couple more questions briefly and then I will turn it over to others who may have questions. This change in accounting method only applies to public companies. Is that correct?

MR. SAKR: It only applies to public companies at this point, yes.

MR. MARTIN: And what do private companies do typically? Do they prepare US GAAP statements today? Would you expect them to switch?

MR. SAKR: I think it depends. There will definitely be an evaluation of the cost and benefit. Any move to IFRS will be a major exercise that will have relatively significant costs. If the company is planning to do an initial public offering some day, it will have to switch to IFRS as a practical matter. If the company is being acquired or is targeting another company, its new parent or the target may be on IFRS.

Other Issues

MR. HORD: Will the change to IFRS affect the SEC's XBRL process? I gather that the taglines for US GAAP are likely to be different from the taglines for IFRS.

MR. SAKR: The SEC is emphasizing the need to be able to expand the use of XBRL. One of the milestones that must be met before the SEC will implement full adoption of IFRS by US public companies is the need to make sure the new XBRL system can work with IFRS reporting.

MR. MARTIN: Charlie Hord, please explain what XBRL is for anyone who is unfamiliar with it.

MR. HORD: It is a new SEC initiative that essentially tags line items in financial statements and ultimately footnotes to financial statements, so that they can be accessed and analyzed in a variety of software programs. For example, if you wanted to compare the compensation of the chief financial officers of Microsoft, Google, GM, and any other public company, you could literally just type that into the SEC website, push a button, and it would produce a table or anything else you wanted by pulling the tagged financial information and making it readily comparable.

It means that there has to be greater comparability, among other things, in the line items and the entries in the financial statements, and that's part of what IFRS does.

MR. MARKSON: How do you expect the change in the national accounting standard would affect taxes?

MR. SAKR: Any changes in the composition and the values of the assets and liabilities of a company — and let's stay with US GAAP for a second without even moving to a different standard — could have potential tax implications from a deferred tax perspective, or even from an income tax perspective, based on the net income of the company.

Another potential effect is structured finance transactions that were tax driven may no longer achieve the same outcome after the accounting treatment changes or new forms of transactions may become possible. For example, a special-purpose entity used in a transaction might not have been consolidated under US GAAP but would have to be consolidated under IFRS. One of the goals of the transaction was to keep the transaction off balance sheet for certain accounting and tax reasons. The transaction may no longer work under IFRS.

MR. ZEITLIN: Unless the US tax laws change, it is hard to see how the switch from GAAP to IFRS will have any affect on the taxes US companies must pay, with the exception that if LIFO is eliminated as a method for determining book earnings, then companies will not be able to use it for taxes either, since use for book purposes is a prerequisite for using it for taxes.

MR. SAKR: I agree with you. The potential impact is on how transactions with tax consequences are structured. In some cases, a company may not be able to recognize the benefits from the transaction on its books.

Another potential impact is on companies with tax exposure in multiple countries. Take, for example, a company, headquartered in the US that has subsidiaries in other countries. In many cases, the tax reporting in overseas jurisdictions is based on the financial reports that the company files. As an example, if you change the statutory reporting from French GAAP to IFRS, now you have a different tax impact because you used to pay taxes based on your statutory French GAAP report and today you are filing your taxes based on the IFRS statutory report, and the numbers could be vastly different.

MS. SKIDAN: In view of the fact that the SEC is moving to an IFRS standard, do you expect that this will have any impact on private placements or so-called 144A offerings in terms of the types of financial information that must be included in offering memoranda?

MR. SAKR: That's a very interesting question, and I don't think there is a definitive answer to it yet. The SEC is expected to issue the IFRS roadmap laying out its current thinking about IFRS and how it will affect different areas, not just the financial reporting environment. Hopefully you will see some discussion around that in the roadmap.

MR. GIROLAMI: Can you comment about the implementation of IFRS in Latin America, particularly in Mexico, Brazil, Argentina, Chile?

MR. SAKR: There is a global shift to IFRS. Probably the two major capital markets that currently prohibit the use of IFRS for their domestic filers are the US and Japan.

So go to Latin America. Chile is / continued page 48

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converting to IFRS by 2009. Brazil is converting by 2010. Mexico has formalized a plan and is working to change national accounting standards to comply with IFRS.

MR. AYALI: What special issues does the conversion to IFRS raise for public companies that must comply with Sarbanes-Oxley?

MR. SAKR: That's definitely an interesting question, and companies need to think about the conversion more broadly than as a mere accounting exercise. Companies will have to make sure that any new controls and accounting procedures put in place during the conversion still comply with Sarbanes-Oxley. Also, documentation will need to be updated and processes must be put in place to mitigate new risks.

When the European Union moved from local GAAP to IFRS between 2003 and 2005, some companies may have underestimated the level of effort that conversion would require. Some started too late to work through the issues and ended up having to do certain adjustments manually because the accounting and data systems were not reprogrammed to collect or report data in the needed form. Some were thinking they could continue to track everything under local GAAP and basically do a top-level adjustment to reconcile to the new IFRS standards. That led to more use of Excel spreadsheets which is not a good controlled environment from a Sarbanes-Oxley standpoint.

Stock-based compensation plans will be affected and may have to be restructured.

Depending on the size of the company, it can take from one or two years up to five years to convert to IFRS. It is a massive exercise that will require careful planning and a well-managed process. It will probably require more effort than what was required to comply with Sarbanes-Oxley. ◎

US Supreme Court Affirms Sanctity of Power Contracts — Sort Of

by Bob Shapiro, in Washington

The United States Supreme Court upheld the application of the so-called "Mobile-Sierra doctrine" to certain long-term wholesale power contracts in a decision in late June. This was the first high court decision to address the Federal Power Act in more than 10 years.

The case involved power contracts that utilities in California and other western states signed during the California energy crisis in 2000 and 2001 during a period when electricity prices spiked. The utilities have been trying to get out of the contracts on grounds that the spot markets had become dysfunctional and noncompetitive due to market manipulation and for other reasons.

The Supreme Court held that power contracts signed by independent generators who had approval from the Federal Energy Regulatory Commission to sell at market rates are entitled to a presumption of validity, but it sent the case back to FERC for further consideration of two technical issues. In doing so, the court made clear the purchasing utilities have a high mountain to climb if they want to set aside the contracts.

The case is called *Morgan Stanley Capital Group, Inc v. Snohomish*.

Background

Under the Mobile-Sierra doctrine, there is a presumption of validity for power contracts against challenges that the rates in those contracts proved, in hindsight, to be too high or too low to be just and reasonable based on later events. Power contracts will not be modified by federal regulators unless they are found to violate the "public interest," a very high standard to meet. The doctrine was created by the Supreme Court 50 years ago in an era of cost-based ratemaking, not competitive market rates. Because of the Supreme Court's adherence to the doctrine in its latest decision, a power seller signing a long-term contract at prices that are consistent with the market-based rate tariff the seller has on file with the Federal Energy Regulatory Commission can feel confident that the contract cannot be overturned by FERC absent a finding of extreme public necessity.

The case before the Supreme Court concerned challenges to contracts signed during the California energy crisis in 2000 and 2001. Spot prices had exploded to levels that were several multiples of energy prices over the prior two or three years. In order to mitigate the impacts on ratepayers, purchasing utilities throughout the western United States signed hundreds of long-term contracts with dozens of suppliers during this period. After the spot prices moderated, many of the purchasing utilities, or state regulatory commissions or advocacy groups acting on their behalves, filed complaints at FERC seeking to have the contract prices reduced or the contracts abrogated.

The challengers offered a variety of arguments to support their claims. A number of the buying utilities claimed that the market was dysfunctional at the time of contract formation due to market manipulation by some of the sellers and, therefore, the historic Mobile-Sierra protection did not apply. Others contended that Mobile-Sierra protection should not apply to contracts signed under market-based rates because the contracts did not have to be filed and reviewed at FERC. Still others argued that Mobile-Sierra protection only applies in a so-called "low rate" case, where the selling utility is trying to increase the contract rate, but does not apply in a "high rate" case such as this one, where the purchasing utility is trying to lower the rate.

In general, all of the purchasing utilities wanted FERC to review the contract rates under the typical cost-based or "cost of service" standard of "just and reasonable" rates, rather than the more burdensome "public interest" standard of just and reasonable rates established by the court in Mobile and Sierra cases. Alternatively, even if the Mobile-Sierra doctrine applied, most of the utility buyers claimed that the "public interest" test was met because the contracts constituted an excessive burden on their ratepayers.

The Mobile-Sierra Doctrine

The Federal Power Act, among other things, approves wholesale rates between private sellers and either public or private buyers of electricity in the continental United States (except for most of Texas and Alaska). FERC establishes rates that are "just and reasonable" in the first instance, and if it later finds that rates have become unjust and unreasonable, it modifies the rates to a just and reasonable level. The statute also requires wholesale contracts to be filed at FERC, and the US Supreme Court, in two cases in 1956 — called *United Gas Pipeline v. Mobile Gas Service Corp* and *Federal Power Commission v. Sierra Pacific Power Co.* — held that "by requiring contracts to be filed with the Commission, the Act expressly recognizes that rates to particular customers may be set by individual contracts." Although the *Mobile* case involved the Natural Gas Act and the *Sierra* case involved the Federal Power Act, the relevant sections of the two statutes were substantially the same and were thus interpreted together.

In the *Sierra* case, the Supreme Court determined that if a contract did not permit unilateral changes to the price by its terms, then the contract could not be modified later unless the price caused a greater problem than merely whether the rate would produce a rate of return above a typical cost-of-service level. The court held that a utility "may agree by contract" to accept a low rate and, by accepting a low rate, it is not "entitled to be relieved of its improvident bargain" later. However, the court noted that federal regulators still have jurisdiction to modify the rate if the public interest would be adversely affected. According to the court, the public interest would be adversely affected in three situations. One is if the rate might impair the financial ability of the utility to continue service. Another is if the rate would place an excessive burden on the utility's other customers. The last is if the rate would be unduly discriminatory.

Since the *Mobile* and *Sierra* decisions, many United States courts of appeals have applied the *Mobile-Sierra* doctrine, but the Supreme Court did not have the opportunity to address the doctrine again, and never addressed the doctrine in today's climate where rates for wholesale power sales were not set by the regulators in the first instance, but rather are market rates that the parties to the contract negotiated themselves.

The Federal Energy Regulatory Commission in this case turned aside the challenges to the fixed-rate contracts, holding that the Mobile-Sierra doctrine applied and that the challengers did not meet the high, public */ continued page 50*

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interest burden of proof needed to overturn the contract rates. Those challengers that sought to meet the burden challenged the contract prices on ground that they created an "excessive burden" on ratepayers, one of the three grounds the Supreme Court said in the *Sierra* case might justify setting aside rates. They did not seek to challenge the rate on either of the other two grounds.

The US Supreme Court said utilities that want to set aside long-term contracts to buy electricity have a high mountain to climb.

On appeal of the FERC decision, a US appeals court invalidated the FERC order on a number of grounds, including that the Mobile-Sierra doctrine may not apply to contracts under market rate tariffs, rather than cost-of-service rates, since the contracts were not filed and reviewed by FERC and, even if the Mobile-Sierra doctrine applies, there is no higher "public interest" burden of proof to meet if the complaining party is the purchasing utility rather than the seller. In this case, the complaining parties were the purchasing utilities or their representatives. The appeals court sent the case back to FERC for further review.

What the Supreme Court Said

The Supreme Court rejected the reasoning by the appeals court and upheld the application of the Mobile-Sierra doctrine to long term contracts with market-based rates. The court said it does not matter whether FERC was asked to review the contract when the contract was signed. The Mobile-Sierra standard applies regardless of when FERC is asked to look at the contract.

The court also rejected the view that FERC must inquire whether the contract was formed in a dysfunctional market before deciding whether the Mobile-Sierra doctrine applies. The court noted that the ability of utilities to sign long-term contracts was a leading factor in eliminating volatility in the spot markets during the California energy crsis. The court said, "It would be a perverse rule that rendered contracts less likely to be enforced when there is volatility in the market . . . . Such a rule has no support in our case law . . . ." However, the court said FERC can set aside contracts if there is evidence of unfair dealing at the contract formation stage, or if the dysfunctional market conditions under which the contract was signed was caused by illegal action of one of the parties.

The court also rejected the view that in a "high rate" case, the buyer only has to show that the rate is outside of a "zone of reasonableness" to overturn the contract. Rather, a showing must be made that the contract prices are an excessive burden on the purchasing utility's ratepayers, which is a much higher burden to meet than a test that the prices to which the contracting parties agreed are high in relation to the generator's costs.

The Supreme Court sent the case back to FERC for further consideration of two issues.

The first issue dealt with the rule that a contract can be overturned if it places an "excessive burden" on other customers of the utility. FERC had concluded that the impact of the contract rates on the purchasing utilities and their customers was not excessive compared with existing rates to those customers at the time. The court said that this analysis was incomplete, because FERC should also have compared the contract rates with the rates that consumers would have paid once the markets were no longer dysfunctional.

The second issue related to the claim by some of the purchasing utilities that they were victims of market manipulation in the spot market. The court said that "if it is clear that one party to a contract engaged in such extensive market manipulation as to alter the playing field for contract negotiations, [then FERC] should not presume that the contract is just and reasonable." The court emphasized that "the mere fact of a party's engaging in unlawful activity in the spot market does not deprive its forward contracts of the benefit of the Mobile-Sierra presumption"; rather, the purchasing utility must show that market manipulation by the seller led directly to the high prices in its power contract. FERC failed in the case to address whether there was such a connection.

It is important to understand what the court did *not* say with respect to the second issue. For example, simply because a seller may have settled charges against it that it was involved in manipulating the California spot market does not mean, without more, that a long-term contract signed by that seller during this period can be abrogated. Nor would it be sufficient that there is evidence that some other seller engaged in unlawful spot market activity that affected the market during a period in which a purchasing utility signed a long-term contract with a different seller who was not so engaged.

What Happens Next

FERC had not yet issued an order concerning the two issues sent back to it by the Supreme Court as the NewsWire went to press in early November. It has a number of alternative paths to resolving the open issues.

If FERC believes the two issues were already fully addressed, then it could simply provide an analysis of each issue and decide the case again without reopening the proceeding for more evidence and briefing. This is unlikely to happen for all of the contracts at issue, although it is possible that the facts relating to one or more sellers would permit this result.

Most of the challenges to the long-term contracts entered into during the California energy crisis have been resolved through settlement agreements. FERC may try first to determine whether settlements are possible among the remaining parties.

If another hearing is required to gather additional evidence, then FERC could ask for a "paper hearing," with limited discovery and prepared affidavits and no cross-examination, or FERC could instead direct that a more formal, full evidentiary hearing be held on one or both of the issues. It is also possible that the sheer difficulty of meeting the Mobile-Sierra burden laid down by the Supreme Court in late June may cause some of the purchasing utilities to drop their challenges.

Unless the litigants decide to settle, the chances are high that whatever FERC decides in the next round will be appealed again to the US court of appeals. And the beat goes on. ◎

Solar Financing Strategies from an Investor Perspective

by Eli Katz, in New York

The market for financing solar energy equipment is still evolving as capital providers and solar developers search for cost effective ways to finance the equipment.

Most solar energy projects financed in the past few years have involved distributed energy. They have been solar energy systems that sell power to retail customers at a host location rather than directly to the grid. The next wave of solar systems coming to the market, both photovoltaic and solar thermal, are larger in scale and the electricity from many of them will be sold directly into the grid.

The lessons learned and techniques developed in financing smaller distributed solar energy projects will inform how, and to what extent the next generation of solar projects raises financing. Ultimately, the ability of solar to reach grid parity and claim its place as a viable cost-effective method of power generation will depend on whether these projects can attract financing on the scale enjoyed by wind, biomass and geothermal projects over the last few years.

Differences From Other Renewables

In the distributed energy market, the most typical arrangement is where the owner of a solar energy system retains the equipment and sells the power to a host offtaker under a power purchase agreement. These projects tend to be relatively small in scale when compared to utility-size power projects. Most of them are less than one megawatt of rated capacity. These projects are financed on an individual basis or aggregated together with a number of similar projects.

The financeable revenue streams from these projects are comprised of cash flow from the sale of power to the host offtaker, cash subsidy payments paid by / continued page 52

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state or municipal governments, renewable energy credits and federal income tax incentives in the form of tax credits and tax depreciation. The revenue stream associated with the tax incentives is worth 56% of the cost of the system.

The investment tax credit is 30% of the cost of the solar equipment. It "vests" over five years. If the equipment is sold or destroyed during this vesting period, then a portion of the credit previously taken must be paid back to the government. Solar equipment is depreciated largely over five years; 85% of the cost is deducted using the 200% declining-balance method, meaning that the deductions are front loaded into the early part of the five-year period. Tax benefits that cannot be used immediately can be carried forward for up to 20 years.

There are at least nine factors that drive the choice whether to use sale-leasebacks or "flip" partnerships to finance solar projects.

Solar tax subsidies are very different from those found in other forms of renewable energy projects, and the financing market is still refining structures that optimize these benefits in an efficient manner. Some of these differences create unique challenges as well as opportunities not available to other renewable energy projects. There are five key differences between the tax subsidies for solar and those in most other forms of renewable energy project financing.

First, the investment tax credit is claimed in the first year the system is placed in service for tax purposes. Other forms of renewable energy, such as wind and geothermal, qualify for a production tax credit that is claimed over a 10-year period.

Second, the amount of the investment tax credit is a function of the cost of the system. The tax credit can be viewed as a pure hedge against the future performance of the system; the credit is locked in regardless of how efficiently the system produces energy. Conversely, production tax credits for wind, geothermal and biomass projects have no correlation to the cost of the project; they are strictly a function of the amount of power generated by the project. The production tax credit for wind-generated power, for example, is currently set at $21 a megawatt hour of electricity output.

Third, the investment tax credit is available only to the first owner of the system. With very limited exceptions, the owner on the in-service date claims the entire investment tax credit. In a wind project, the 10 years of production tax credits are claimed by whoever owns the project when the qualifying power is produced.

Fourth, the investment tax credit may be claimed by an owner of a solar system even though the owner is not also the user or producer of the power. The production tax credit in a wind project, for example, may be claimed only by the owner of the project if he is also the producer of the electricity.

Fifth, in the distributed solar energy market, each individual project is far smaller then those that fall within the strike zone of most project financiers. The individual systems are typically aggregated together to form a more sizable investment and attract larger financing players. This has helped some, but variations between the individual projects and the resources needed to confirm that each individual project qualifies for the investment tax credit continue to challenge financing parties looking to minimize transaction costs and leanly staff these investment opportunities.

Monetizing the Tax Subsidies

Few solar developers have the tax base to use the tax subsidies themselves. To solve this problem, a developer might sell the equipment to someone who can use the tax subsidies and negotiate a sales price that reflects the tax subsidies. Alternatively, it can use one of two strategies to get value for the tax subsidies while retaining control over the project. The two most commonly used strategies are a flip partnership and a sale-leaseback.

In a flip partnership, the developer sells the solar equipment to a newly-created project company that it forms with an investor that has a large enough tax liability to make full use of the tax subsidies. The investor contributes cash to the project company to finance all or a portion of the equipment, or simply pays the cash directly to the developer to reimburse it for the cost of the system. The project company is a partnership for tax purposes. The partnership is the owner of the solar equipment and is entitled to all the revenue associated with the equipment, including the tax subsidies.

Partnerships themselves do not pay tax. Instead, the tax liabilities, tax credits and tax deductions pass through directly to the partners. The ratio in which a partnership divides its tax items among the partners is referred to as a partner's distributive share. A partner's distributive share of tax items does not have to correlate to its ownership percentage in the partnership. Also, the distributive share allocated to each partner may vary from year to year. Once the partnership is formed, the investor earns a preferred return on its cash investment equal to a return of its cash investment plus an agreed return on its capital (currently in the range of 7% to 8%, although returns are increasing). The investor's preferred return is measured on an after-tax basis and is paid through a combination of cash received by the partnership (from government rebates, sale of renewable energy credits and payments for electricity from the offtaker under the power purchase agreement) and the tax subsidies that are allocated by the partnership to the investor. The developer begins to share in the partnership profits once the investor has received its preferred return.

The partnership tax rules place a number of significant restrictions on this arrangement. First, during the preferred return period, the investor cannot receive more than a 99% share of partnership tax items. Second, even after the investor receives its preferred return, it must continue to receive at least 5% of the share it was getting during the preferred return period. For example, if the investor received 99% of the partnership profits in the first few years of the investment, it must keep 4.95% of the profits (5% of its interest in the earlier period) after it reaches its preferred return.

Third, while the developer can have the right to buy out the investor's interest in the partnership, the buyout price must be at fair market value. It cannot be set at a fixed price at the beginning of the investment.

Lastly, the amount of tax benefits that the investor can absorb from the partnership is limited by its "capital account" balance and "outside basis" in the partnership. The capital account balances and outside basis account are used to track the economic value of the investor's interest in the partnership. Tax losses that exceed these balances cannot be used by the investor right away; they must be deferred until the investor's economic interest grows large enough to absorb them. The investor's economic interest in the partnership grows as the partnership earns income or as the investor contributes additional capital to the partnership. This last limitation usually comes into play when the investor makes a relatively small cash investment in the partnership. Its economic interest, as measured by its capital account and outside basis account might then be too small to take a 99% distributive share of the tax benefits.

The other way for the developer to get value for tax subsidies it cannot use is through a sale-leaseback transaction.

Such a transaction works like this. After the developer has signed the power purchase agreement and constructed the system, it sells the system to an investor and then immediately leases it back. The lease term will generally be coterminous with the power purchase agreement. The investor is now the owner of the equipment and receives the tax subsidies. The developer pays rent under the lease. The rent that the developer pays usually matches or is slightly less than the payments the developer expects to receive from selling power under the power purchase agreement. At the end of the lease term, the developer must return the system to the investor or buy it back from the investor.

Simply transferring title to the solar system is not enough to enable an investor to claim the tax benefits. The investor must be the "tax owner" of the system. To be the tax owner, the investor must generally have what the tax law calls the "benefits and burdens of ownership." The lease term must not run longer than 80% of the expected life and value of the solar system. The developer must not have a purchase option to repurchase the system at a bargain price.

Choosing Between Structures

There are at least nine factors that drive the choice of structure. / continued page 54

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First, the partnership model is preferable if the parties want flexibility in tailoring the size of the cash investment by the investor. In a partnership, the larger the cash investment, the greater percentage of the system the investor ends up purchasing. Where the investor is able to use the tax benefits more efficiently than the developer, then the parties will want the investor to contribute an amount at least large enough to absorb all the tax benefits in its preferred-return calculation. If the investor makes a larger cash investment than the minimum required to absorb all the tax benefits, then it will probably demand a larger residual interest after the preferred return has been achieved.

A sale-leaseback does not offer this flexibility. In a sale-leaseback, the investor purchases the entire system for its full fair value. Thus, the investor must pay 100% of the system cost. A developer that otherwise has a cheap source of capital will prefer to use the investor's capital only to monetize the tax subsidy portion of the system and might, therefore, prefer the more flexible partnership arrangement.

Second, the partnership model allows the developer to retain a portion of the system economics — both tax benefits and operating cash flow — during and following the period when the investor is earning a preferred return. If the developer expects to have at least some tax base, it might do better to use a partnership and retain a share of the tax benefits. The developer can also negotiate for a share of the residual value after the power purchase agreement expires.

The sale-leaseback arrangement is far less flexible in this regard. The investor receives 100% of the tax benefits. There is no residual value retained by the developer. The developer retains a portion of the economics during the lease term by earning a "spread," or the difference between the amount it receives from the power purchaser and the amount it remits to the investor as rent under the lease. There is no corollary in a lease to the "flip" in a partnership arrangements. At the end of the lease, the equipment belongs to the investor. If the developer wants the equipment back, it must pay full value for it at the end of the lease term.

A lease provides 100% financing. However, it is cheaper for a developer to get back the project in a partnership.

Third, it is easier to monetize the tax benefits through a lease. There are no complicated partnership tax accounting rules. In a partnership, 99% of the tax benefits at most can be transferred to the investor, but the investor may not be able to absorb a full 99% share depending on the cash investment he makes. He may not have enough capital account and outside basis to absorb them.

Fourth, a lease allows up to three months after a solar system is completed to bring in the investor. With a partnership flip, the investor must be a partner in the partnership that owns the system *before* it is placed in service. Determining the exact day that a solar system is placed in service is not an exact science. Placed in service is generally thought to coincide with the time that the system owner is authorized to sell power and actually begins to sell the power from the system. Many investors understandably want to hold off making their investments until they can be sure that the equipment works properly. This concern leads many investors to prefer the sale-leaseback structure where they wait up to three months to invest after the system becomes operable.

Fifth, a lease differs from a partnership in another very important respect. In a lease, the sponsor will be locked into making fixed rental payments for the entire term of the lease, regardless of the performance of the equipment. If electricity revenues fall short of what is required to pay rent, then the developer will have to top up these payments or risk defaulting and losing the system to the investor. The investor may also impose financial covenants and indemnity obligations on the developer. These restrictions can limit the flexibility of the developer during the lease term.

In the partnership structure, the developer has not contractually promised the investor a fixed revenue stream. While the investor is generally entitled to take almost all the profits until it reaches its preferred return, its profits are limited to the cash and tax subsidies that come from the project. If the system underperforms expectations, the investor does not have a contractual claim against the developer, and it must wait longer to reach its preferred return. There is a flip side to this as well: if the power purchase agreement produces more revenue than the rent required under the lease, the developer using a lease structure keeps the entire upside. In the partnership model, increased performance benefits the developer in that it shortens the time period until the investor reaches its preferred return and the developer can begin to share meaningfully in the profits, but the upside is shared with the investor.

Sixth, US GAAP accounting may also motivate an investor to pick one structure over the other. Lease accounting is governed by FAS 13, which generally allows the lessor in a "direct finance lease" to report income from the lease on a front-loaded basis using a constant yield method. Investors who are sensitive to the GAAP income profile of an investment may prefer a lease structure that enables book income to be front loaded into the early years of the investment. GAAP for partnership investments generally results in a more levelized income profile using the hypothetical liquidation book value method, which allows the investor to report income each period in the amount of money the investor would receive if the investor liquidated its partnership investment in that period.

Seventh, the partnership flip structure offers slightly less flexibility to the developer in the pricing of a buyout option, but generally will allow the buyout price to be set at a lower price. Internal Revenue Service guidelines for partnership flip deals prohibit a purchase option within the first five years of the investment and require the eventual buyout price to be the market value of the equipment at time of buyout. The inability of a developer to negotiate a fixed price for the eventual buyout at the onset of the transaction deprives the developer of the ability to solve to an all-in yield that it must pay the investor for the use of its capital. The effect of the no-fixed-price-buyout rule in the partnership structure is somewhat mitigated. After the preferred return period, the investor's interest can be reduced all the way down to 5% of its previous size. Although it cannot be fixed beforehand, the buyout price for the investor's diminished interest should be relatively low at that point.

When compared to the partnership on this score, the sale-leaseback has one advantage and one disadvantage. The IRS has not restricted the use of a fixed price buyout in a lease. Therefore, a developer can negotiate a buyout price with the investor at inception of the lease. The all-in cost of the financing can then be calculated as the discounted value of the rental payments plus the buyout price, assuming the developer is inclined to buy the system when the buyout is exercisable. The tax rules for leasing place a limit on this flexibility through the interaction of two rules: First, the purchase option must be a good faith estimate of what the value will be when the option is exercised. Second, the system must be projected to be worth at least 20% of its starting value when the lease ends. This means the purchase price at any time during the lease must be no less than 20% of the price the investor paid for the system. This price is likely to be significantly higher that the 5% required in the partnership structure.

Eighth, most states exempt solar equipment from sales taxes. However, not all do so. Sales taxes are normally collected on rents over the lease term rather than on the purchase price of the equipment at the start of the lease. Thus, in jurisdictions that collect sales taxes on solar equipment, the sale-leaseback structure may have the beneficial effect of deferring the sales tax liability.

Finally, often the decision about which structure to use comes down to the familiarity of the investor group with one structure over the other. Traditional leasing companies, now expanding their investment services to solar equipment, will gravitate towards the sale-leaseback structure. The lease structure is perceived to offer a fixed stream of cash payments and a set residual value that should provide the investor with its desired return. Partnership flip transactions are viewed as more esoteric and require an understanding of complex modeling and partnership tax rules, offer no fixed stream of payments, and give the investor less control over the system and the developer. ◎

Hydropower in Africa

by Alex Blomfeld, in London

A series of new hydroelectric projects in Africa are a reminder of the enormous unrealized potential for this source of electricity in the region.

This article assesses the advantages and disadvantages of hydropower in the African context and discusses some of the risks that a developer must address to have a financeable project. It also explores the potential for funding through the "clean development mechanism" of the Kyoto protocol on global warming.

Big Dams on the Continent

Big dams have long dominated Africa's electricity scene.

For example, Egypt's 2.1-gigawatt Aswan dam on the Nile and Ghana's 768-megawatt Akosombo dam on the Volta River began producing power in 1967 and 1965 respectively. Mozambique's 2,075-megawatt Cahora Bassa on the Zambezi River has supplied a large part of southern Africa's power for almost four decades. These projects and others like them have been a key feature in Africa's development.

Reliable figures are difficult to obtain but estimates for hydropower's share of Africa's power generation generally range between 18% and 32%. However, in many African countries, hydropower's share of total installed electric capacity is much higher, providing over 50% on-grid electricity generation in Cote d'Ivoire, the Democratic Republic of Congo, Ethiopia, Mozambique and Zambia.

In the context of rising fossil fuel prices and increasing concern about climate change, it is worth noting that hydroelectric power is the only significant grid-connected renewable energy source in Africa.

With seven major rivers — the Nile, Niger, Congo, Senegal, Orange, Limpopo and Zambezi — Africa is well endowed with hydropower potential. However, exploitation of this potential has historically been hampered by a mismatch between demand and supply that has not been able to be overcome by long-distance transmission line infrastructure.

It is estimated that only 7% of Africa's hydropower potential has been harnessed, compared to 33% for Europe and 65% globally. The hydropower potential of the Democratic Republic of Congo alone is reported to be sufficient to provide three times as much power as Africa presently consumes.

Given the very low energy-per-capita energy consumption in Africa, rising levels of economic growth and recognition that power is a crucial prerequisite to development, the demand for electricity in Africa is set to increase dramatically. As a tried and tested source of power with significant unexploited potential, it makes sense for Africa to look to hydropower to meet a large part of this demand. This is likely to include both new greenfield development and rehabilitation and operational improvement of existing hydro plants to restore and increase capacity.

Many new projects are planned or are under construction.

> Only 7% of potential hydropower has been harnessed in Africa, compared to 35% in Europe and 65% globally.

The financial closing in December 2007 of the 250-megawatt Bujagali project in Uganda on the Nile near Lake Victoria should inspire confidence in private sector investors, governments and development institutions that a hydropower project in Africa can be financed on a project finance basis. With construction of Bujagali ahead of schedule, Uganda's attention has now shifted to kick-starting construction of two proposed hydropower dams at Karuma and Isimba.

A large number of other African countries are currently planning or carrying out new hydropower projects in Africa including Angola, Cameroon, Democratic Republic of Congo, Ethiopia, Equatorial Guinea, Ghana, Guinea, Kenya, Liberia, Madagascar, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, Tanzania and Zambia.

Without doubt the most ambitious of these plans is for the Grand Inga project in the Democratic Republic of Congo, which at 39,500 megawatts could power all of Africa by itself. The World Energy Council convened talks in London earlier this year among potential investors in this mammoth project.

Advantages for Africa

As a well-established, proven and simple technology hydropower provides reliable power with low operations and maintenance costs (despite high upfront construction costs).

It also has a number of technical attributes which make it attractive. When stored in large quantities behind a dam, it is immediately available for use when required. This fast response time mean that it is flexible to react immediately to load demand changes and cover valuable peak demand allowing for the best use to be made of base load power from other less flexible electricity sources, notably wind and solar.

Furthermore, hydropower performs well at the so-called ancillary services, including spinning reserve, operating reserve, regulation and frequency response, voltage support and black start capability, which means it can interface well with transmission grids. This can assist in stabilizing transmission grid systems, which may often not be in optimal condition. Notwithstanding its unique ability to provide peak capacity, hydropower is most commonly used to provide baseload power in Africa.

When life-cycle costs are examined, hydropower consistently has the best performance among energy generation sources, with operating costs being low in comparison with the capital investment and average plant life being longer than for fossil fuel and other renewable power sources. With the increasing scarcity and cost of fossil fuel, this advantage can be expected to become even greater.

Hydropower is clean, climate-friendly and renewable power. It is probably not entirely emissions free as studies have shown that the decomposition of plant matter in reservoirs can emit methane that is a greenhouse gas even more harmful than carbon dioxide. However, notwithstanding these emissions, it has significantly less greenhouse gas emissions than fossil fuels, typically one fifth those of a typical coal plant.

These attributes make hydropower an attractive option for Africa in the context of climate change, particularly given its abundance in the continent. Carbon markets provide further incentives to develop such projects.

Finally, the benefits of hydropower are not limited to power generation but also include water supply, irrigation, navigation, fisheries and tourism. This is not the case for any other source of power.

Disadvantages

The high upfront capital costs of hydropower projects are a barrier to their development in Africa, where both government and private finance for large projects is usually scarce.

Moreover, the inadequate local capital markets and the lack of long-term financing in many African countries make financing hydropower plants difficult and the involvement of international development institutions or foreign government aid a frequent prerequisite.

Hydropower projects also tend to have lengthy lead times for planning, permitting and construction. These lead times can combine with hydrological, geological, geotechnical and siltation risks to make investment by private investors more risky and difficult than is the case for other power projects.

In addition, social and environmental issues are often sensitive and can lead to strong opposition by some non-governmental organizations and local communities to the approval of some projects.

Hydropower depends entirely on precipitation. Therefore, low rainfall and drought — both seasonal and longer–term cyclical in nature — can affect its reliability. Indeed, many African dams operate at below capacity due to variable rainfall, siltation or poorly-maintained infrastructure, including turbines and other equipment and transmission and distribution lines and facilities.

The exploitation of hydropower's potential in Africa also faces the same difficulties that other projects in developing economies face, including an uncertain regulatory environment, poor governance, a sub-optimal general investment climate and local conflicts and political instability.

Financing Hydropower in Africa

Hydropower projects require long construction periods and high capital costs. As a consequence, the viability of these projects relies critically on long debt tenors and a financing structure that is often not available from private lenders alone.

The financing structure will have a critical impact on the tariff. The tariff needs to balance return */ continued page 58*

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on investment against the offtaker's ability to pay for electricity and recover the cost from consumers.

These characteristics, combined with the old fashioned view of power as a public good, have meant that hydropower in Africa has traditionally been financed by public money. Such money has often supplemented by development assistance or concessional loans from development finance institutions. However, as evidenced by the successful closing of the Bujagali project in Uganda, there is a definite trend towards more private funding of huge dams as public finances are not up to the task of funding enough power generation to keep up with demand and future growth projections.

The financing of private power projects is generally through sponsor equity and debt raised on a non- or limited recourse basis on the strength of the project's revenue stream and securities provided by the project itself. If things go wrong, then the lenders have little or no recourse to the underlying balance sheet of the project sponsor.

Under such arrangements lenders naturally take a close interest in the viability of the project, particularly when (like hydro) it involves uncertain output and high construction risks. Lenders in Africa will look at risks typical of independent power projects in any emerging market, including the economics of the project, the potential to export power, demand growth for power, regulatory and political risk, payment risk based on the creditworthiness of the offtaker, currency risk and the availability of mitigants such as insurance to lessen the risk profile. Typical debt-equity ratios for hydro projects are in the region of 70:30.

In addition to the familiar emerging markets risks, hydropower presents unique risks that need to be mitigated, including negative public perception, project delay and cancellation arising out of social and environmental issues, hydrological uncertainties, geological and geotechnical risk, high upfront capital investments and the potential of water use conflicts within communities and with other countries.

Social and Environmental Issues

It is difficult to overstate the importance of dealing properly with the social and environmental issues that hydropower projects can present. These issues are often controversial and intensely political. They have the potential to delay progress on projects or even lead to their demise.

> New hydropower projects are under development in at least 18 African countries, including the gigantic 35,500-megawatt Grand Inga project in Congo.

Although, with the exception of emissions from reservoirs, hydropower projects do not emit significant airborne pollutants or gases that cause global warming, changes in the use of water resources can have negative implications on people, animals, plants and entire river ecosystems. Accordingly, "environmental assessment," when applied to hydropower projects, must include broader concern about environmental impacts and social impacts on people that may be displaced or whose water source and ecosystem may be changed by hydropower projects.

A failure to design or plan projects properly with such impacts in mind can mean the cancellation of projects. For example, a plan to build a large hydropower scheme east of the Epupa Falls in Namibia was finally abandoned this year largely due to its expected impact on the nomadic Ovahimba community, who live on both sides of the Kunene River, which was to have been dammed by the project.

Large hydropower projects in Africa often have a legacy of needing to resettle sizable numbers of people. Bodies such as the World Bank have now set standards for resettlement to mitigate some of the issues that such actions can pose. An important principle in those standards is that of compensation for those who need to resettle. There may also be relevant local law in respect of expropriation and compulsory acquisition of property.

The World Commission on Dams was established in 1998 as an independent, international, multi-stakeholder body to address the controversial issues associated with large dams.

In its November 2000 report entitled "Dams and Development — A New Framework for Decision-Making," the WCD made certain recommendations to ensure that the social and environmental aspects of large dams are addressed adequately in the planning, construction and operation of hydropower projects.

To follow WCD recommendations, a project must start with a needs assessment rather than starting with a proposed solution to an undefined problem. A needs assessment is followed by an options assessment that engages all stakeholders and utilises a transparent decision–making process. Decisions should value ecosystem, social and health issues as an integral part of project and river basin development, and the avoidance of impacts is given priority, in accordance with a precautionary approach.

Some countries, including South Africa and Uganda, are working to incorporate the WCD's recommendations into their national policies and laws.

Another way of mitigating environmental and social risk is by involving multilateral and bilateral development institutions in the financing. For example, the World Bank has adopted strict environmental standards that must be met by any project financed by the World Bank Group, including the International Finance Corporation, International Development Association and Multilateral Investment Guarantee Association.

World Bank or development institution involvement can ensure compliance with international best practices, which may not been obtained without the application of the such standards. These are generally much more detailed and prescriptive than the Equator Principles to which a number of commercial banks profess to adhere.

As a general matter, it is prudent to research and plan rigorously in respect of social and environmental issues. Studies should identify risks early so that they can be mitigated and a project's design amended as required. Once identified, these issues should be continuously assessed, including monitoring once the project is in operation.

A number of non-government organizations actively monitor plans to develop large dams in Africa and can be relied upon to expose issues. Governments and developers who do their homework will be better placed to avoid issues in the first place and navigate any controversies that may arise.

Lessons from past mistakes need to be learned so that projects can be better in the future. Project developers may find that host governments are best placed to mitigate environmental and social risks and would be well advised to involve host governments in these issues as early as possible.

Risks

Hydrological risk is the risk that a lack of rainfall or water conditions otherwise will not be sufficient to produce power at the designed capacity of a hydropower plant.

The unpredictable nature of Africa's weather means that this is a key concern for hydropower plants in the continent. For example, the output of hydroelectric facilities in East Africa was badly affected by droughts in 1999 and 2000, with Kenya in particular suffering from power shortages. Ghana's hydroelectric facilities were also adversely affected by droughts during the late 1990's, and Cameroon uses 30 diesel stations as back-up power during extended droughts.

These unpredictable conditions have meant that a number of African governments are changing their available mix of generation sources to be less dependent on hydroelectric power. Other countries are reviewing hydroelectric facilities, increasing dam storage capacities to allow for fluctuations in water supply.

Furthermore, the increasing prominence of the climate change issue and the likelihood that global warming will lead to increased prevalence of droughts has brought the issue of hydrological risk into sharper focus.

Siting and design of a hydropower project should be based on the best available reliable historical rainfall data. However, even the best planning and design cannot produce rainfall. Generators should take care to ensure that low water conditions arising out of prolonged drought afford them force majeure relief in their power purchase agreements. Offtakers could attempt to negotiate a termination right for prolonged low water conditions.

On a more macro level, since rainfall across the continent is not uniform and droughts rarely affect all countries simultaneously, perhaps the best mitigation of hydrological risk is better investment in regional transmission infrastructure. This would allow hydroelectric facilities in non-drought affected countries to make up any short- */ continued page 60*

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falls in generation during times of drought in another country.

The engineering properties of soil and rock often exhibit significant variability from one location to another. It is important to conduct a comprehensive site investigation, including adequate drilling and testing of these properties before project sponsors commit to a project. Geological and geotechnical expertise should also be available throughout the construction process.

In addition to the impact of drought, allocation and use of water resources for hydropower can be affected by domestic water law. This may give rights for irrigation and fisheries. There are also riparian states obligations under international water law, including the 1966 Helsinki Rules on the Uses of the Waters of International Rivers, the 1997 United Nations Convention on Non-Navigational Uses of International Watercourses and various regional treaties, which oblige certain African countries to share their water resources in an equitable manner. Due diligence on the applicability and effect of these water law obligations needs to be completed at an early stage of a project's planning.

Carbon Funding

Carbon credits under the "clean development mechanism" in the Kyoto protocol have been obtained by a large number of hydropower projects worldwide. There are over 1,000 hydropower projects in the CDM pipeline. Only a small number of these, such as the 3.5-megawatt West Nile electrification project in Uganda, are in Africa, and these often enjoy World Bank backing.

Indeed, it has been World Bank policy since 2003 to seek CDM funding for the hydropower projects it funds. This policy has not been without controversy for two main reasons. First, critics contend that many hydropower projects would occur without CDM funding thus do not meet the "additionality" requirement in the Kyoto protocol. Second, some have argued that many World Bank hydropower projects do not follow the World Commission on Dams recommendations. This view has found favor with buyers of carbon credits, and the so-called Linking Directive of the European Union on greenhouse gas emission trading (2004/101/EC) now mandates that hydro projects above 20 megawatts must "respect" the WCD to be eligible for credits under the European Emissions Trading Scheme.

There are signs that scrutiny of hydropower projects claiming CDM credits is set to increase even further. The executive board of the CDM recently noted that an auditor of a hydro project in China had refused to recommend the project for registration, raising questions about whether similar projects will fail to get international carbon credits used by companies and governments to meet binding emissions targets.

There are also reports that developers of large hydropower projects seeking to gain CDM credits for cutting emissions may soon have to gain independent verification from a third party that the projects comply with an European Union backed checklist on sustainability under new guidelines being drawn up by member states. ◎

Chadbourne & Parke LLP
30 Rockefeller Plaza
New York, NY 10112
+1 (212) 408-5100

1200 New Hampshire Ave., NW
Washington, DC 20036
+1 (202) 974-5600

1100 Louisiana, Suite 3500
Houston, TX 77002
+1 (713) 571-5900

350 South Grand Ave.
32nd Floor
Los Angeles, CA 90071
+1 (213) 892-1000

Paseo de Tamarindos, No. 400-B Piso 22
Col. Bosques de las Lomas
05120 México, D.F., México
+ 52 (55) 3000-0600

Beijing Representative Office
Room 902, Tower A, Beijing Fortune Centre
7 Dongsanhuan Zhonglu, Chaoyang District
Beijing 100020, China
+86 (10) 6530-8846

Dostyk Business Center
43 Dostyk Avenue, 4th floor
Almaty 050010, Republic of Kazakhstan
+7 (327) 258-5088

Riverside Towers
52/5 Kosmodamianskaya Nab.
Moscow 115054 Russian Federation
+7 (495) 974-2424
Direct line from outside C.I.S.:
+1 (212) 408-1190

Stroganovskiy Business Centre
19A Nevskiy Prospect
St. Petersburg 191186 Russian Federation
+7 (812) 332-9300

25B Sahaydachnoho Street
Kyiv 04070, Ukraine
+380 (44) 461-75-75

Chadbourne & Parke
Radzikowski, Szubielska and Partners LLP
ul. Emilii Plater 53
00-113 Warsaw, Poland
+48 (22) 520-5000

City Tower I, Sheikh Zayed Road
P.O. Box 23927, Dubai, United Arab Emirates
+971 (4) 331-6123

Chadbourne & Parke
a multinational partnership
Regis House
45 King William Street
London EC4R 9AN, UK
+44 (0)20 7337-8000