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The Road Ahead

Two factors have great influence on winners and losers in the US energy market: oil prices and government policy. Private equity and hedge funds rushing to pour money into renewable energy and biofuels projects need look no farther than a chart that the American Wind Energy Association uses as part of its lobbying effort on Capitol Hill to see the role of government policy. The chart shows dizzying rates of growth in new wind farm construction during periods when production tax credits are available. Construction of such projects grinds to a halt when the credits expire. The same pattern emerges in other key sectors. Almost all segments of the US energy market are affected by government policy.

A new Congress takes office in January with the Democrats in charge of both houses for the first time in 12 years. With them may come a new energy agenda. The following is a transcript of a conversation in December among four veteran energy lobbyists in Washington about what to expect in 2007 from the new Congress. The panelists are Rich Glick, director of government affairs for PPM Energy, the number two US wind developer, and a former senior policy advisor to the US energy secretary during the Clinton administration, Jonathan Weisgall, vice president for legislative and regulatory affairs for MidAmerican Energy Holdings Company, the holding company that Warren Buffet uses to invest in the US power sector, Gene Peters, chief lobbyist for the Electric Power Supply Association, the trade association for the US independent power industry, and Joe Mikrut, a lobbyist with Capitol Tax Partners and a former lawyer with the Joint / continued page 2

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SEVERAL KEY TAX INCENTIVES were extended by Congress in December.

Congress gave developers of renewable energy projects another year to qualify for production tax credits. The credits in 2006 were 1.9¢ a kilowatt hour for generating electricity from wind and geothermal steam or fluid and 1¢ a kWh for generating electricity from biomass, landfill gas or municipal solid waste or from turbines added to an existing dam. They run for 10 years after a project is put in service. The amount is adjusted each year for inflation. The credits are worth about 33¢ per dollar of capital cost in a typical wind farm in present-value terms. / continued page 3

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Tax Committee staff in Congress and former senior Treasury official. The moderator is Keith Martin with Chadbourne in Washington.

Renewables

MR. MARTIN: We are talking about what the next Congress might do on energy and taxes related to energy in 2007. Let's start with renewables. In my mind, renewables and biofuels are different things. "Renewables" refers to power projects that run on renewable energy, like wind farms or solar installations. "Biofuels" are ethanol and biodiesel.

Rich Glick, Congress just extended the deadline by another year to December 2008 to place most renewable energy projects in service to qualify for production tax credits worth about 33¢ per dollar of capital cost in a typical wind farm and worth less in some other kinds of renewable energy projects. It also gave developers until December 2008 to put new solar projects in service and qualify for a 30% investment tax credit. Will Congress extend these deadlines again in 2007?

MR. GLICK: We hope so. One potential opportunity is the agenda that the new speaker of the House, Nancy Pelosi, will be trying to put through the House in the first 100 hours of the new session. She has already said that one of the items on the agenda will be elimination of a number of oil and gas tax incentives that were adopted in the Energy Policy Act of 2005, and with that comes some additional money that could be used potentially to extend the production tax credit further.

MR. MARTIN: Do you think the next extension will be for more than one year?

MR. GLICK: We hope that the credit will be extended on a longer-term basis because that would bring down the cost of wind, geothermal, biomass and other renewable energy projects. Unfortunately, we are living in a constrained budget environment that might be even more constrained if the new Democratic leaders put Congress back on the old pay-go system. If Congress returns to pay-go, it will be more difficult to get the production tax credit extended on a long-term basis.

MR. MARTIN: "Pay-go" means that Congress cannot enact new tax subsidies, or extend existing ones, unless it finds a way to pay for them either by raising other taxes or cutting spending?

MR. GLICK: Yes.

MR. MARTIN: Joe Mikrut, you are close to the tax committees. How likely is it that Congress will extend production tax credits again in 2007?

MR. MIKRUT: As Rich Glick said, the House will be trying in the first 100 hours to carve back some of the tax benefits provided to large oil companies. This could free up $3 billion in estimated revenue. A one-year extension of the production tax credits costs a little less than $3 billion. The revenues associated with the two items match up rather well. The production tax credits are popular items and are relatively easy to extend.

On the other hand, there are other segments of the energy industry that were given benefits in the Energy Policy Act of 2005, but were left out of the "extenders bill" in December. They will also be seeking extensions or additional funding for their tax provisions. There are other groups that want policy changes in the existing statute — such changes would absorb revenue — and there are always "new starters." In the end, there will be a pot of money, but it won't be there for long. I think Congress will be looking to dedicate whatever it saves from cutting back tax benefits for the large oil companies on some combination of tax incentives for energy efficiency, renewables and alternative fuels.

MR. MARTIN: What you both have been talking about is the first 100 hours in the House. A bill must pass both houses of Congress to become law. What is the timing in the Senate?

Green has become the new "red, white and blue" in Washington.

MR. MIKRUT: My understanding is that the 100-hour bills will not go through the House committees. Rather, the House leadership will assemble the bills, with input from the committee chairmen, and go directly to the House floor. It is relatively easy in the House to legislate quickly because of the restrictive rules on floor debate and amendments.

However, once the bills get to the Senate with its more open rules, they become magnets for amendments. Thus, the Senate will be on a much slower track. Whatever tax legislation that is ultimately enacted in 2007 may emerge from the budget reconciliation process. That process usually takes at least six to nine months to play out fully.

MR. MARTIN: So we are talking late summer or early fall before anything makes it all the way through Congress, at the earliest?

MR. MIKRUT: That's right. In the normal order of things, tax bills are taken up early in the year in the House and then sent over to the Senate, where they are debated later in the year.

MR. WEISGALL: I think one countervailing factor that may come into play is that the recently-enacted one-year extension of the production tax credit will make the extension question less urgent. That probably militates in favor of a longer-term extension, but that issue may move to a back burner because the credit has just now been extended through the end of 2008. The Democrats insist they are serious about promoting renewable energy. Renewable energy has become mainstream. You hear frequently in Washington that "green has become the new red, white and blue." The one-year extension was terrific, but it could have a backfire effect because it will reduce some of the urgency for Congress to act quickly on yet another extension.

MR. MARTIN: The solar credit — does anyone have a feel for whether the 30% solar credit is likely to be extended at the same time?

MR. MIKRUT: The production tax credit and the solar credit have been moving in lockstep, and I expect the staffs to keep them together. My understanding is that some of the larger, concentrating solar projects are not as nimble as other renewable projects and may have a more difficult time getting siting, financing and construction done within the extra year provided by the extenders bill. They may need something more, but it will be up to the proponents of those projects to press their case in the new Congress.

MR. MARTIN: Rich Glick, you and I / *continued page 4*

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The deadline had been December 2007 to place projects in service. The new deadline is December 2008.

Congress also pushed back the deadline to put commercial solar projects and fuel cells in service and qualify for a 30% investment tax credit. The investment credit is claimed entirely in the year the project is put in service. The deadline to qualify is now December 2008. Solar projects completed after that date still qualify for an investment credit, but the amount drops to 10%. The investment credit can be claimed not only on solar electricity projects, but also equipment that uses sunlight to supply hot water. The tax credit allowed on fuel cells is limited to $500 per kilowatt of capacity. There is no credit for fuel cells installed after 2008.

Congress authorized another $400 million in "clean renewable energy bonds." These are bonds that state and local governments, electric cooperatives and Indian tribes can use to borrow money for a wind farm, solar project, biomass or geothermal power plant or other project that, if it were privately owned, would qualify for production tax credits. The bonds do not require any interest payments. Rather, the lender can claim tax credits each year tied to the outstanding principal amount of the loan.

Congress authorized $800 million in such bonds in the Energy Policy Act in August 2005. Anyone wanting to use the bonds to finance a project had to apply to the Internal Revenue Service for an allocation by last April. The IRS allocated all the available bond authority in late November. The government received 709 applications asking for a total of $2.6 billion in bond authority. A total of 610 awards were made. Of the awards, 434 were for solar projects. The largest single award was $33 million to an electric cooperative. The largest amount awarded for a municipal project was $3.2 million. The latest Congressional action will open the door for another round of allocations in 2007.

E85 — a vehicle fuel that is 85% ethanol — is subject to federal excise / *continued page 5*

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participated in a panel discussion at a wind finance conference in October in New York. Elizabeth Paris and John Gimigliano from the Senate and House tax writing committees were a little less optimistic than the audience hoped that the production tax credit would be extended at full value. They said there is not the money to extend the credit indefinitely. Many members, particularly on the House side, thought the subsidies were supposed to be temporary, and they are frustrated that the industry keeps returning year after year to extend them.

None of the discussion so far has suggested there is any doubt the credits will be extended again; it is just a matter of timing. Are there questions about the amount or whether the credits will be extended at all given what these two key staff members said?

MR. GLICK: The production tax credit is more costly to the federal treasury each time it is extended. That's due primarily to the success of the program. As more renewable generation gets built, more tax credits are claimed. What Elizabeth and John were saying is the program is getting too costly to survive much longer, and that is a big concern. The renewables industry believes it needs a long-term extension to spur investment in things like new factories to make wind turbines. That is what will move us to a point where we no longer need the credit; scale brings down turbine costs to a level where these projects can compete with other power plants on a more equal footing. At the same time, as the credit gets more expensive, it becomes more difficult to get through Congress. We are essentially in a Catch-22 situation. We may see Congress at some point either phase out the tax credit or reduce the value.

MR. MARTIN: It sounds like you would bet that Congress will not phase out or cut back the production tax credit in the near term, and that the deadline to complete projects will be extended at least one more time.

MR. GLICK: I think we are confident of that, but we are not confident of a long-term extension because of the fiscal constraints.

> The production tax credit will probably be extended at least one more time. The extension may be coupled with a phase out.

MR. MARTIN: Joe Mikrut, in your rounds on Capitol Hill, are you hearing any complaints, perhaps related to the cost of another extension?

MR. MIKRUT: No more than any of the other extenders. I think the staff is going to examine everything. These provisions that expire periodically — and I am not talking just about the energy credits but also provisions like the research and employment tax credits — have been extended almost by rote in the past. Congress has always found a way to extend the entire package, sometimes while finding a way to pay for the extension and sometimes not. It was much more difficult to extend the entire package in the last Congress. Most of the non-energy extenders expired at the end of 2005, but were not extended until December 2006. The list of energy and non-energy extenders has also gotten longer and there is a one-year gap between some of their expiration dates. In general, the energy tax extenders expire at the end of 2008 while the non-energy extenders expire at the end of 2007.

In addition to the extenders, a top priority for the incoming Democratic Congress will be enactment of a "patch" to spare middle class taxpayers from having to pay additional alternative minimum taxes. When you start adding up the one-year cost of all the extenders including this AMT patch, you are getting close to $100 billion. That fiscal cost has gotten everyone's attention.

The cost will force the tax-writing committees to examine all the expiring provisions. The proponents will be asked to justify why their provisions should be extended once again.

The whole extenders package has become too large, too expensive, and too unwieldy, but my guess is Congress will find a way to renew most of them again.

National RPS?

MR. MARTIN: Switching gears, Gene Peters, do you think a national renewable portfolio standard will be enacted in 2007? In other words, will Congress require US utilities to supply a certain percentage of their electricity from renewable sources? Many states already do this.

MR. PETERS: The idea has tremendous support within the Democratic caucus. It has been a personal priority of the incoming chairman of the Senate Energy Committee, Jeff Bingaman (D.-New Mexico). A national RPS has had majority support in the Senate in recent years. There is an excellent alignment of the political stars on this one.

Whether the Bush administration will embrace it is another matter.

I don't see a ton of really hard-core opposition in the House or Senate. I think it is a question of finding the right vehicle and trying to see whether they can navigate it through the White House.

MR. MARTIN: Are the regulated utilities putting up much of a fight against a national RPS?

MR. PETERS: My members, to be honest, are split on this one. We have not taken a position as a trade association on whether Congress should adopt a national RPS. I don't think the utilities as a group are rolling over, but there are utilities that either are already operating in states that have very significant renewable portfolio standards and others that would rather have a common standard that applies nationally than have to grapple with different state rules.

MR. MARTIN: Jon Weisgall, what is your prediction about a national RPS?

MR. WEISGALL: I think it will be a top priority of the incoming Democrats. I don't see a lot of opposition to it. You have a situation in the west where renewables, particularly wind, are almost the only resource that is being embraced. One of the issues may be what type of RPS will capture the 60 votes that measures need today to pass in the Senate. Will it be a pure renewables RPS, meaning primarily wind, solar, geothermal and biomass, or will we see nuclear and possibly some kind of clean coal technologies defined as renewables?

MR. MARTIN: What about hydroelectricity?

MR. WEISGALL: Small incremental / continued page 6

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tax when sold at a reduced rate of 13.25¢ a gallon. The special rate was scheduled to expire on September 30, 2007. Congress extended it through December 2008. It also extended a special rate of 12.35¢ a gallon for vehicle fuel that is at least 85% methanol or alcohol made from coal.

Most ethanol in the United States is made currently from corn. Many people expect the next wave of ethanol plants to use cellulosic material like bagasse, corn stalks and switchgrass. The Energy Policy Act in 2005 let anyone investing in a "refinery" to make liquid transportation fuels deduct 50% of the cost immediately when the plant is put into service. (The other 50% of the cost is recovered over time as depreciation.) There had been some uncertainty about whether the 50% deduction could be claimed on ethanol plants that mash corn into alcohol. Congress suggested in December that it can only be claimed on ethanol and biodiesel plants that turn corn or other biomass "via gas" into liquid fuel. However, it let the 50% deduction be claimed on plants that make cellulosic ethanol, regardless of the process. A cellulosic plant must be put in service by 2012 to qualify.

Owners of batteries that make coke or coke gas — for example, at steel mills — can claim tax credits of $1.17 an mmBtu on the coke or coke gas they sell to third parties. The credits can be claimed on four years of output. The coke battery must be put in service by 2009. (The credits used to be called "section 29 credits" by were renumbered section 45K in August 2005.) Credits of this sort are liable of being phased out if oil prices return to levels reached during the Arab oil embargo in the 1970's. In December, Congress voted to free coke and coke gas projects from any risk of a phase out. However, it also made clear that only steel coke qualifies for the credits — not petroleum coke. The credits are capped at $23,200 a day per coke facility.

Projects built on Indian reservations qualify for faster depreciation. For example, a wind farm can be depreciated over / continued page 7

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additions to existing hydroelectric dams are always there. The real controversy will be whether to try to buy votes from conservatives by adding nuclear and clean coal. A national RPS may also be seen by some players as a way possibly to stave off a carbon regime or other stiffer action to combat global warming. The fact is that with nearly half the states having already enacted renewable portfolio standards, the utility industry is getting comfortable dealing with them. That's another factor that might mitigate in favor of a federal RPS passing in 2007.

MR. MARTIN: Will this be something that is dealt within the first 100 hours in the House?

MR. PETERS: Not in the first 100 hours.

MR. GLICK: I agree with that. The Senate has voted for a national RPS on three separate occasions, only for it to die in the House where it has never actually been voted upon. The new House leaders are likely to support a national RPS. On the other hand, it is a complicated proposal. The House has not had a lot of experience with it. It is likely to have to go through the normal committee process.

There is still some uncertainty in the House about whether there are the votes to move it out of the House Energy and Commerce Committee. It think it has to survive a couple hurdles before we can say it will be enacted.

MR. WEISGALL: It is not a 100-hour measure. Forgetting clean coal and nuclear for a minute, how are you going to define "renewables"? If you look at the 20 or so states that have these standards, there are already varying definitions. Part and parcel of a federal RPS will be the development of a national renewable energy credit trading program. That's not something that you can do in 100 hours. I agree with the others: this will take time. It will go through the normal channels because of the complexity and some of the competing policy issues.

MR. MARTIN: Rich Glick, what percentage will the federal government adopt as the RPS target?

MR. GLICK: In the past, the Senate has adopted an escalating target that would require utilities eventually to supply 10% of all their retail electric sales from renewable energy. There have been other proposals for as much as 20% on a national basis. If I had to bet, I think Congress will lean more toward 10% than 20% by 2020.

A national renewable portfolio standard will probably be enacted in 2007.

MR. PETERS: The number will depend on how the word "renewables" is defined.

MR. MARTIN: If a national RPS is adopted, what happens to the state renewable energy credits that may have been purchased under long-term contracts? Are they swept away?

MR. GLICK: No, I don't think so. I am basing my comments mostly on the legislation that passed the Senate and was sponsored by Senator Jeff Bingaman (D.-New Mexico). That measure actually had a specific provision that notes that states can have their own programs and exceed the federal requirement. To the extent a state has already adopted a program with renewable energy credits, or decides in the future to adopt such a program, the federal legislation would not hamper or do anything to impair the state credits.

Bush Budget

MR. MARTIN: Okay, new topic. The Department of Energy has been surveying people in the renewable energy industry for ideas to include in the Bush budget at the end of January. Has anyone heard what might be in the budget to promote renewables?

MR. GLICK: PPM Energy has been working with MidAmerican and a large number of other companies to persuade the administration to include a long-term extension for the production tax credit in the budget. Fifty-four

Congressmen and 42 Senators recently sent letters to the President urging him to include a five-year extension in his budget. What I have heard, and this may turn out to be pure conjecture, is the administration is thinking of proposing a long-term extension for the production tax credit, but phasing out the credit over the same period. For instance, one might get full value in year one, but by the fifth year, the credit would be worth only half the value it had in the first year.

MR. WEISGALL: I think it is important to link our first two topics, because they are closely related: a production tax credit and a renewable portfolio standard. Let's face it; an RPS is a stick. A production tax credit is a carrot. Reasonable people can differ about which is the better policy prescription. I would argue that combining the two makes a whole lot of sense. Ultimately, a production tax credit without a renewable portfolio standard works. You have an incentive to put in renewable energy. However, to have a mandate without the tools to implement it is tough. We are seeing that in California. We are seeing it in the renewable field as a whole other than wind. Wind is nimble. Biomass, incremental hydro and geothermal are more or less baseload renewables. There is a lot to be said for combining the carrot with the stick.

As for what we are likely to see in the Bush budget, the production tax credit is a lot like location in real estate. It's the first, second and third priority if you want to achieve a goal of getting renewable megawatts on the ground in any reasonable time period.

MR. PETERS: The only thing that I would add is the Bush budgets haven't had that much impact on Capitol Hill for the last six years, and that was during a period when the Republicans were in control. This one will be even less meaningful than the ones in the past. What is more important is what signals go up to the administration from Congress. That's why the letters that Rich Glick mentioned may be more important than what shows up in the budget.

MR. WEISGALL: We are assuming the Democrats will stay disciplined on pay-go budget rules. No one has questioned that during this conversation.

MR. MIKRUT: It's not 100% clear. First, they have to put the pay-go rules in place, so it is a question of whether and where they sit within the first 100 hours. Congress may adopt some of its priorities before imposing a pay-go requirement. Another unknown is that even though pay-go traditionally has meant that there must be a dollar-for- / continued page 8

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three rather than five years. The deadline to place projects in service to qualify had been December 2005. It has now been extended to December 2007. A wage credit for hiring Indians to work in jobs on the reservation was also extended for wages paid or incurred through December 2007.

Finally, Congress authorized the US Treasury Department to allocate another $3.5 billion in "new markets tax credits" in 2008. The credits had been expected to be fully allocated with the 2007 round of credits. New markets credits are tax credits that are supposed to induce equity investors to invest money in storefront lenders — called community development entities, or CDEs — to businesses in low-income areas. Each investor receives a tax credit for 39% of his equity investment. The credit is spread over seven years. Some larger financial players have organized CDEs for making loans and applied to the Treasury for tax credit allocations. The government allocated $2 billion in credits in each of 2004 and 2005 and $3.5 billion in 2006.

Another $3.9 billion will be allocated in 2007 and $3.5 billion in 2008. (The $3.9 billion for 2007 includes $400 million in credits for projects in the Gulf states hit by Hurricane Katrina.) Applications for 2007 allocations must be submitted by February 28.

UTILITY RELOCATION PAYMENTS continue to cause trouble at the IRS.

A city worked with a private developer to build a mix of single-family homes, town houses, condominiums and rental units on a parcel of land. Two high-pressure gas pipelines ran across the land and had to be moved to make way for the construction. The city reimbursed the pipeline company for the cost of moving them.

The IRS ruled privately that the utility had to report the reimbursements as income.

The utility had insisted that the city pay a "tax gross up" in addition to reimbursing it for the cost of the move.

The city argued that the / continued page 9

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dollar match between tax expenditures and revenue raisers, Congress does not necessarily have to resurrect that rule, or may phase it in over time. For example, there is growing concern in Congress about the reach of the individual alternative minimum tax. Any significant fix could cost hundreds of billions of dollars over time. Congress may make an exception from the pay-go rules to fix the AMT problem. So although the new Congress may want to bring back some form of budget discipline, it is not clear exactly what form the new pay-go rules will take.

Congress is unlikely to adopt carbon controls in 2007, but the jockeying for position this year will shape what happens ultimately.

MR. WEISGALL: The key dilemma facing the Democrats on tax benefits for renewable energy projects is how to pay for them, and renewable energy is not the only priority on the Democratic agenda. The incoming House Ways and Means chairman, Charlie Rangell (D.-N.Y.), has said that his primary goal is some form of AMT relief. Those numbers are staggering. You are looking at something like $45 billion annually.

MR. PETERS: I could not agree more. The Democratic party as a whole strongly supports renewables, but if you look at key members of Congress, Charlie Rangel's number one, two and three priorities are AMT relief. The AMT is hitting his constituents hard right now.

There is another point: the more cynical among us might say that the Republicans were not the most fiscally-conservative or disciplined party while they were in the majority, but now that they are in the minority, look for Republicans to return to those roots. We could have a very interesting situation develop where a moderate, "blue-dog" coalition of southern Democrats teams with a newly-empowered fiscally-conservative and disciplined Republican minority. You could find it much more difficult than we have been suggesting to enact anything that costs money.

Global Warming

MR. MARTIN: That is a recipe for gridlock. Let me go to another big topic: carbon controls or global warming. Let me start with Jon Weisgall. Will anything happen on global warming this coming year, and if so, what?

MR. WEISGALL: The quick answer is no. I think that the Senate Environment Committee, chaired by Senator Barbara Boxer (D.-California), will start looking immediately into the possibility of some kind of mandatory carbon controls. There will be a lot of issues to address, including whether to adopt a carbon cap or a carbon-intensity form of legislation. I do not see anything being enacted in 2007.

Carbon controls are more controversial than a renewable portfolio standard and, even if a bill passes the Senate, I think it is going to run into some potentially serious roadblocks in the House. You have two new incoming House chairmen — John Dingell (D.-Michigan), the incoming chairman of the House Energy and Commerce Committee who is going to look out for the automobile industry, and Nick Rahall (D.-West Virginia), the incoming chairman of the House Resources Committee and a strong supporter of the coal industry. But the potential opposition in the House is a secondary issue. This legislation will have a tough time coming out of the Senate, notwithstanding the fact that even the frontrunners for the Republican presidential nomination in 2008 — not only John McCain, but also other folks who are not even in Congress — are all supporting some form of carbon legislation.

The power industry believes some form of carbon-constrained regime is coming, but I don't think it is coming next year.

MR. MARTIN: Rich Glick, do you agree?

MR. GLICK: I agree that a consensus about what to do will be very difficult to find, especially on the House side where the key committee chairman will be very concerned about the impact of climate legislation on the industry.

Having said all that, I think the irony is some utilities that burn coal, some car companies and other coal extracting companies may see this as their last best hope. If a president is elected in 2008 who is a strong supporter of stringent limits on greenhouse gas emissions and if the 2008 elections bring in another class of incoming freshmen to Congress who strongly support action on global warming — Senator Boxer, for instance, is looking for the California-type approach — it may be possible for those who oppose controls to do much worse. There is already talk within the utility industry of trying to get a deal done now when President Bush is in office.

MR. MARTIN: Rich Glick, some utilities that are planning to build new coal-fired power plants believe that it is best to rush those plants into service, figuring the plants will be exempted or "grandfathered" from any new carbon controls. Is that a reasonable bet?

MR. GLICK: It is a gamble. There is a very real possibility that when Congress does get around to adopting a greenhouse gas limit, it may not grandfather plants that were built in the last five or 10 years. Or Congress may adopt some sort of compromise approach. Utilities may see this as a slam dunk. They need to weigh the risk that they may not get everything they anticipate.

MR. MARTIN: Gene Peters, if Rich Glick and Jon Weisgall are correct, Congress is unlikely to act on global warming in 2007. Do you think such action is more likely in 2008?

MR. PETERS: In Washington we talk about each Congress as a two-year enterprise. My guess is that what Congress fails to do on this in 2007, it will also fail to do in 2008. I expect the new Congress to end up with a stalemate in a lot of areas, including a comprehensive carbon control regime.

That said, what fundamentally is changing is that the dialogue on global warming is moving into a new, more serious phase. The analysis, the hearings, the attempt to work out the very significant compromises and regulatory changes that will be required to take action in this area are beginning in earnest. The political consensus needed for action is not yet there, but we are getting a lot closer to it. My members are taking the debate that is just starting in the House and Senate very seriously. We are actively trying to create our own climate change policy statement. There is / continued page 10

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reimbursement was similar to government grants that are treated as nonshareholder "contributions to capital." Such grants are not taxable income. The IRS disagreed. It said a payment must have as its primary motivation "the benefit of the public as a whole" in order to fall in this category. It said this one did not because the motivation was to help a private developer.

The case is addressed in Private Letter Ruling 200647002. The IRS made the ruling public in late November.

The parties asked the wrong question of the IRS.

A utility can normally deduct its costs to move equipment. However, under a line of cases that the courts were describing as "well established" by the 1930's, moving costs cannot be deducted when the company will be reimbursed for them, but the reimbursement does not have to be reported as income, either. In addition, if the city could have used its power of eminent domain to force the utility to move the gas pipelines, then it is possible that the pipelines were "involuntarily converted." Compensation paid in such an involuntary conversion does not have to be reported as income, provided it is reinvested in similar property. Spending on the move would have been considered such a reinvestment.

CALIFORNIA said in December that it will appeal a state court decision that an annual fee on limited liability companies is unconstitutional.

The court said the "fee" is a tax. The fee is a maximum of $11,790 for LLCs with incomes of more than $5 million. The court said what makes the fee unconstitutional is the state makes no effort to determine how much of an LLC's income was earned in California. Taxes can only be imposed on income from a source in California. Governor Arnold Schwarzenegger vetoed a bill in September that would have fixed the fee retroactively by linking it to the amount of California income.

The state could be / continued page 11

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zero chance of action in the next two years in Congress, but the debate this year and next will shape what happens ultimately.

MR. WEISGALL: Let me add to what Gene just said. Even in the Senate, I think Gene is right. People are taking a serious look at this, but you need 60 votes to get legislation passed in the Senate. There are already a large number of very interesting proposals on climate change in the Senate, but there are so many different approaches that I wonder if the Senate can coalesce around one approach in a year. You have Senator Bingaman and the National Commission on Energy Policy. There is a McCain-Lieberman bill with an economy-wide carbon cap. Each has different target levels of reductions by different target years. Senators Boxer and Carper, Representative Waxman and some environmentalists have proposed different kinds of power-sector-only carbon caps. There are tax proposals, such as a straight Btu tax and a carbon tax on fossil-fuel plants. It will be hard to coalesce around one plan in one year.

The second point I want to make is this: don't discount the pressure from environmentalists, the nuclear industry, and possibly even technology vendors for mandatory action on carbon.

MR. MARTIN: Won't that pressure also come eventually from power companies who are under pressure from shareholders to disclose the expected cost of future carbon controls in their annual reports and from regulators to control other pollutants besides carbon? Power companies would like to know sooner rather than later what they are required to do about carbon so that they can address it at the same time as other emissions.

MR. PETERS: I agree. One more point is worth stressing: no one is discounting the California proposal or the regional greenhouse initiative in the northeast. These are real programs that are already in place. My members are investing in power plants in these parts of the country that already have carbon controls. The plants will run for the next 20, 30 or 40 years. Carbon controls at the state level are already an important part of the equation.

Opponents of carbon controls may push to adopt them while Bush is still president and congressmen from Michigan and West Virginia control the key House committees.

Biofuels

MR. MARTIN: Switching now to a series of short topics, let me start with Joe Mikrut on ethanol and biodiesel. The current tax credits and excise tax reductions run out at the end of 2008. There has been talk about extending them as part of a farm bill. Any idea what the timing would be and how long an extension is under discussion?

MR. MIKRUT: I am not sure the Senate Finance Committee has settled on a proposal yet, but I have heard that the farm bill may be a likely vehicle.

MR. MARTIN: The tax extenders bill that just cleared Congress allows 50% of the cost of any new plant to make cellulosic ethanol to be deducted immediately. The remaining cost would be recovered over the normal depreciation period. Joe Mikrut, any idea how that tax benefit made it into the extenders bill?

MR. MIKRUT: The Energy Policy Act of 2005 had a provision that allows a similar 50% write-off for the expansion or construction of oil refineries as an inducement to the oil companies to add to existing refinery capacity. This was a provision Congress enacted late in 2005 in response to high gasoline prices. Since cellulosic ethanol is viewed as a long-run substitute for gasoline, Congress decided to provide the same benefit to cellulosic ethanol plants.

Other Issues

MR. MARTIN: Next topic, tax credits for advanced coal and gasification projects. The Internal Revenue Service announced in November how $350 million in tax credits for gasification projects would be shared among a large number of competing applicants. The credits cover 20% of the cost of such projects. They were authorized in the Energy Policy Act in 2005. Almost all $350 million in credits went to just four projects, and no credits were allocated to coal-to-liquids projects.

Joe Mikrut, have you heard any talk on Capitol Hill about either authorizing additional credits or gripes about how the allocations were handled?

MR. MIKRUT: I have heard complaints about many of the allocations. I think the IRS and Treasury had a very difficult task in trying to allocate the all the new credits authorized by the Energy Policy Act. These credits generally deal with subject matters that are foreign to most tax professionals. The Department of Energy may be in a better position to evaluate the worthiness of competing projects and allocate the credits. There has been a bit of controversy in the way the IRS and Treasury allocated the 2005 credits. If Congress authorizes another round of credits, it may want to be clearer about how it wants the money allocated.

MR. MARTIN: Will there be a move to authorize another round of credits?

MR. MIKRUT: The proponents of these programs will try. As we have said throughout this conversion, the budget will be an issue. There will be many claimants competing for scarce dollars.

MR. MARTIN: Do you see the gripes about how the allocations were handled this last round playing out in any fashion on the Hill?

MR. MIKRUT: The fact that some projects were left behind is, in a way, a good story because it means that these credits are popular. They were successful. They are stimulating investment, as intended. If there were leftover credit allocations, that could be a problem. In terms of the politics of adding more money to the programs, the more people who were left out, the better the odds are that Congress will find a way to address these concerns.

MR. WEISGALL: The tax extenders bill in December made an interesting technical correction. The Energy Policy Act allowed a 15% investment credit for power projects that use advanced coal technologies. One of the criteria to qualify is there has to be 99% removal of sulfur from coal. This is almost impossible to do in the case of / continued page 12

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required to refund as much as $1 billion if it loses the appeal.

LLCs doing business in California should file protective refund claims in case the state has to pay refunds. The statute of limitations on refunds is four years. There is still time to file protective claims as far back as 2002.

SOURCE RULES for determining where income is earned are important.

The more income that a US company can report earning outside the United States, the more foreign taxes the company will be able to claim as a credit to reduce its US income taxes.

The IRS explained in regulations in late December how to determine where income is earned that a company receives from a project on or under the high seas, in outer space or involving cross-border communications. The regulations interpret sections 863(d) and (e) of the US tax code.

It will be hard for US companies to claim that ocean or space projects produce *any* foreign source income. Income received from such projects by US persons will be treated as earned *entirely* in the United States. The ocean is defined as the area outside territorial waters of any country, meaning more than 200 miles offshore. The rule makes sense since such income is unlikely to have been taxed by another country.

A US company cannot ordinarily convert ocean or space income into foreign source income by investing through an offshore subsidiary. That's because a subsidiary that is owned more than 50% by US shareholders will be treated like a US person for this purpose.

There is one possible out. The income will turn into foreign source income to the extent the company can show that the income was tied to tasks performed, resources employed or risks assumed in a foreign country. This rule is a trap for foreign companies involved in projects on the oceans or in outer space that have a US connection. Some of their income may end up being taxed in the United States as / continued page 13

Road Ahead

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western coal, which has such low sulfur content to begin with. The extenders bill let projects using subbituminous coal meet the sulfur test by showing they can achieve emissions of 0.04 pounds or less of sulfur dioxide per million Btus. None of the tax credit allocations for advanced coal projects in early December was for an advanced coal project that uses subbituminous coal. Such projects should now be able to compete in the next round.

The Bush budget in late January is likely to prove as meaningless as his budgets in each of the last six years when Republicans controlled Congress.

MR. MARTIN: One thing we have not mentioned is the transmission grid. The newspapers are full of stories about how additional capacity is needed on the grid. The Energy Policy Act in 2005 took modest steps to help, but they were truly modest. Rich Glick, do you see anything else happening on transmission this coming year in Congress?

MR. GLICK: I do, actually. Renewable energy is going to be very popular with the new Congress. Wind farms are located in rural areas, far away from where most people live and consume power, so wind developers are probably more likely than others to experience congestion on the grid. Many of the clean coal power projects that Congress wants to encourage are also far from the big cities where there is the greatest demand for electricity. I think Congress is going to have to look at opportunities to promote investments in new transmission capacity well beyond what was done in the Energy Policy Act in 2005.

MR. MARTIN: And what might Congress do?

MR. GLICK: One example is there has been a lot of discussion lately about using federal utilities, primarily the Power Marketing Administration in the US Department of Energy, to invest in new transmission capacity in areas that are primarily wind rich — the Dakotas, the Pacific northwest — but that don't have a lot of people to consume power where renewables projects would be located.

MR. MARTIN: Jon Weisgall, do you see any further action on nuclear power this coming year, especially with Harry Reid as the Senate majority leader? He has been fighting efforts to turn his state, Nevada, into a repository for nuclear waste.

MR. WEISGALL: Look, nuclear provides one of the great dilemmas for liberals. You want clean energy, you want renewables, but you really cannot have an honest discussion about climate change and global warming unless you are willing to entertain nuclear power. We have a so-called renaissance taking place in the nuclear industry, but I still think we are 15 years away from seeing a new plant come on line. I think the incoming Congress will have to pay homage to nuclear, but the Energy Policy Act in 2005 was loaded with every indemnification you can think of, and delay damages and tax credits for the first few nuclear plants, so a lot has been done already. Senator Pete Domenici (R.-New Mexico) was the real champion of nuclear plants in Congress. He will no longer be chairman of the Senate Energy Committee, and I don't expect to see major new steps on nuclear power in 2007. ◎

A New Structure for MLP Roll Ups?

by Keith Martin, in Washington

A structure that a manager of private equity and hedge funds plans to use to take the company public may open the door to "roll ups" of wind farms, ethanol plants, solar facilities and other projects that have had trouble using master limited partnership structures.

A master limited partnership is a limited liability company or partnership with units that are traded on a stock exchange or over-the-counter market.

A business structured as an MLP has several advantages over other forms of business.

First, its earnings are subject to only one level of income tax. In contrast, income earned by a corporation is taxed twice: once to the corporation and again to shareholders when the earnings are distributed as dividends. Second, unlike other partnerships, MLP units are liquid and can be sold more easily. This allows businesses organized as MLPs to raise equity more cheaply. Investors are willing to pay extra for the ability to exit the business freely. Third, an MLP has a currency — MLP units that can be sold on a stock exchange — that it can use to make acquisitions.

MLPs have been used to "roll up" or acquire multiple gas pipelines, coal reserves, propane distributors and other energy-related businesses.

However, the difficulty using an MLP is that partnerships whose interests are publicly traded are ordinarily taxed like corporations unless they can fit in one of several exceptions in the US tax code or IRS regulations. The term "MLP" refers to a publicly-traded partnership that fits in one of these exceptions.

Key to MLP Status

One exception is for partnerships that receive almost entirely eligible income. The types of eligible income are mostly various forms of passive income. Examples are dividends, interest, rents from leasing out real property and capital gains from the sale of income-producing capital assets and real property. At least 90% of the gross income that such a partnership earns each year must be from eligible sources.

Another type of eligible income — in addition to passive income — is income from natural resource businesses. This category is at the core of most energy MLPs. Eligible income includes:

> income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy and timber).

The key is an MLP must do something / continued page 14

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US source income based on the same principle.

A television company that has its programs broadcast by satellite into other countries does not earn income from an activity in outer space if it merely pays someone else to transmit the programming; the satellite operator does. However, it does have space income if it leases transponders or capacity on the satellite to make the broadcasts.

The IRS said it is still studying how to treat income earned from leasing shipping containers. This will be addressed separately in the future.

US telephone and internet companies that earn income from "international communications" must treat the income as earned 50% in the US and 50% abroad. However, communications are considered to take place entirely in the US if they are between two points in the United States or between a point in the US and the high seas or outer space. Foreign telecom and internet companies with offices in the United States will have US source income — and have to pay tax on it in the United States — to the extent their income is tied to the US office.

> *The IRS acknowledged that it may be hard in today's world to figure out where telephone calls or internet use starts and ends. It said it will accept any "consistently applied reasonable method."*

PAPER COMPANIES complain that the IRS policy of allowing production tax credits on only the net amount of electricity supplied to the grid will reduce credits for power plants at paper mills by half.

Many paper mills burn lignin from spent chemicals used in the papermaking process, bark and wood chips in boilers to produce steam. The steam is then run through a steam turbine to generate electricity. Electricity output at a typical mill can vary from 10 megawatts to more than 50 megawatts.

The US government allows production tax credits of 1¢ a kilowatt hour to be claimed as a reward for generating / continued page 15

MLPs

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to a "mineral or natural resource."

Geothermal energy, fertilizer and timber are considered natural resources, but Congress said that "fishing, farming . . . [and] hydroelectric, solar, wind, or nuclear power production" are not activities that deal in minerals or natural resources. Inexhaustible resources, even if natural resources, do not qualify. Examples of inexhaustible resources are soil, sod, turf, water, air and minerals from sea water.

Alternatively, a partnership can avoid being taxed like a corporation if it allows only limited trading in partnership interests. The interests could not be listed on a stock exchange or NASDAQ. Restricting trading may not be a satisfactory approach since the company will not benefit fully from the higher multiples for publicly-traded shares. In general, shares are considered publicly traded if they are listed on a stock exchange or are "readily tradable on a secondary market (or the substantial equivalent thereof)." Congress said shares are not considered "readily tradable" on a secondary market unless the share prices are regularly quoted by someone who is making a market in the shares. Also, the time frame to complete a trade must be comparable to trading on an established exchange. Thus, units are not readily tradable where one can find a quote on a computer system, but the interests cannot be sold within the same time frame as on an over-the-counter market.

Fortress Offering

Fortress Investment Group is a manager of 17 private equity and hedge funds and two other investment vehicles. The company has $29.7 billion under management. The management company is owned currently by five individuals. It earns three kinds of income: fees of 1% to 2% a year of the funds under management, incentive fees that are a percentage of the returns earned by the various investment funds, and a return as an investor on $500 million of its own money that it has either invested in or committed to the various funds.

Fortress plans to sell 13.5% of the management company to Nomura for $888 million in a private sale followed by a sale of another 10% to the public. The management company will be restructured as an MLP in connection with the transactions. Fortress filed a registration statement with the US Securities and Exchange Commission on November 8 and updated it on December 21. The sale of units is still pending. The company hopes to raise as much as $750 million from the public sale, which suggests the company is worth as much as $7.5 billion. Units will be listed on the New York Stock Exchange.

A new master limited partnership structure may open the door to roll ups of wind, solar and ethanol businesses.

The structure Fortress proposes to use suggests a way to use MLPs for roll ups of energy projects that do not fit neatly under MLPs because they generate active income and are not considered natural resource businesses.

Fortress manages the 19 funds and investment vehicles currently through 19 separate management companies, each of which is a limited partnership. Each of these limited partnerships is currently a partnership among the five principals who own the business.

Fortress plans to form a master LLC that it intends to treat as a master limited partnership for tax purposes. The master LLC will have two subsidiaries: one is a Delaware corporation and the other is a Delaware LLC that will be treated as "disregarded," meaning that it will be treated for income tax purposes as if it does not exist.

The master LLC will have two classes of units. The A units will be sold to Nomura and the public. Unitholders will be entitled to all the economic returns, but only a 23.5% vote in master LLC affairs. The five principals will retain the B units. B units carry no economic rights, but have 76.5% of the votes. That will let the principals retain control over the business.

The principals will also retain 76.5% of the interests in the 19 existing management partnerships directly. The other 23.5% of the interests in the management partnerships will be put under the corporation or the disregarded entity depending on whether they produce eligible income for the 90% gross income test for MLP qualification. Entities that produce eligible income will go under the disregarded entity. Those that generate ineligible income will be put under the corporation. That way, the ineligible income will be converted into eligible income — by converting it into dividends — by the time it is received by the master LLC.

Fortress hopes to raise as much as $750 million in the public offering. The Fortress group has $600 million in outstanding debt currently. Roughly $250 million of the proceeds from the offering will be used to repay $250 million in debt that was borrowed in order to make distributions to the five principals. The remaining $500 million in proceeds from the public sale will be contributed by the master LLC to the corporation and disregarded entity in a ratio to be determined. However, the disregarded entity plans to lend at least part of the capital it is contributed to the corporation and take back a demand note that pays interest and can be called at any time. Some of the $888 million paid by Nomura may follow the same path.

The note is another way of converting ineligible income received by the corporation into eligible income — since some earnings will move from the corporation to the disregarded entity in the form of interest. However, it also reduces the amount of taxable income the corporation has to report. Fortress hopes that the corporation will be able to deduct the earnings it transfers to the disregarded entity as interest. The effect is to convert some portion of the ineligible income into eligible income while subjecting it to only one level of tax.

Connecting Dots

The same structure could be used to roll up businesses that do not qualify easily for MLPs. The part of the business that generates eligible income can be owned by the disregarded entity. The rest can be put under the corporation. All of the income would be converted into eligible income. Some of it would be taxed twice and some only once to the extent of the annual "earnings stripping" achieved / continued page 16

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electricity from "biomass." Credits can only be claimed on electricity a mill sells to a third party, but not on electricity the mill consumes itself.

The IRS said in October that such tax credits can only be claimed on the net amount of electricity that is supplied to the grid.

The American Forest & Paper Association complained in a memorandum sent to the US Treasury Department by email in late November that 110 paper mills it surveyed in 2004 sold four million megawatt hours of electricity to the grid and bought back 2.3 million.

The trade association estimates, production tax credits could not be claimed on slightly more than half the electricity the paper industry generates from biomass and sells to nearby utilities. The issue is certain to spill over to Congress.

A DEBT-EQUITY SWAP between a US company and the Mexican government produced income for the US company, but because the IRS guessed wildly at the amount, a US appeals court let the company off.

Kohler Co., a US maker of plumbing fixtures, planned in 1986 to build a plant to manufacture such fixtures in Mexico. Mexico was buckling under the weight of foreign debt. Mexican sovereign debt was trading at a steep discount to face value. The government put an enterprising program in place to reduce its debts without having to use scarce foreign currency reserves. If a foreign company planning to invest in Mexico would purchase existing Mexican debt, then the government would exchange the notes at a favorable rate for pesos; the pesos had to be invested in Mexico. Kohler bought Mexican sovereign debt with a face amount of $22.4 million from Bankers Trust Co. for $11.1 million. It then traded the notes with the government for pesos worth $19.5 million at the exchange rate in effect at the time.

The IRS said Kohler had to report the $8.4 million difference as taxable income.

A US appeals court said / continued page 17

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through the intercompany note and to the extent of income that is received by the disregarded entity from operating businesses directly.

Fortress is the first fund manager in the US to try to go public. Fortress said it hopes to gain a currency it can use to make acquisitions and reward other fund employees. It also wants a source of permanent capital. Its funds have only 650 investors in total. Institutional money in private equity and hedge funds can be nimble. It wants access to another source of capital through the public markets.

The five principals in Fortress retain ownership of 76.5% of the business directly with only one level of tax. They keep their 76.5% ownership in the operating partnerships directly.

They have the option of converting their B shares in the operating companies into A shares in the MLP in the future at a one-for-one exchange. However, there is a risk that such a future exchange would trigger a tax to each principal to the extent the A shares he receives are worth more than the "tax basis" that the principal has in the B shares he exchanges. If such a tax were triggered, the MLP could benefit from a step up in the value of the various fund assets. The corporation and disregarded entity will sign a "tax receivable agreement" with the principals promising to pay them 85% of the cash value of any such step up to the MLP (including any step up that occurs as a result of the private sale to Nomura). The cash value is the ability to recover the step up through depreciation deductions over time. ◎

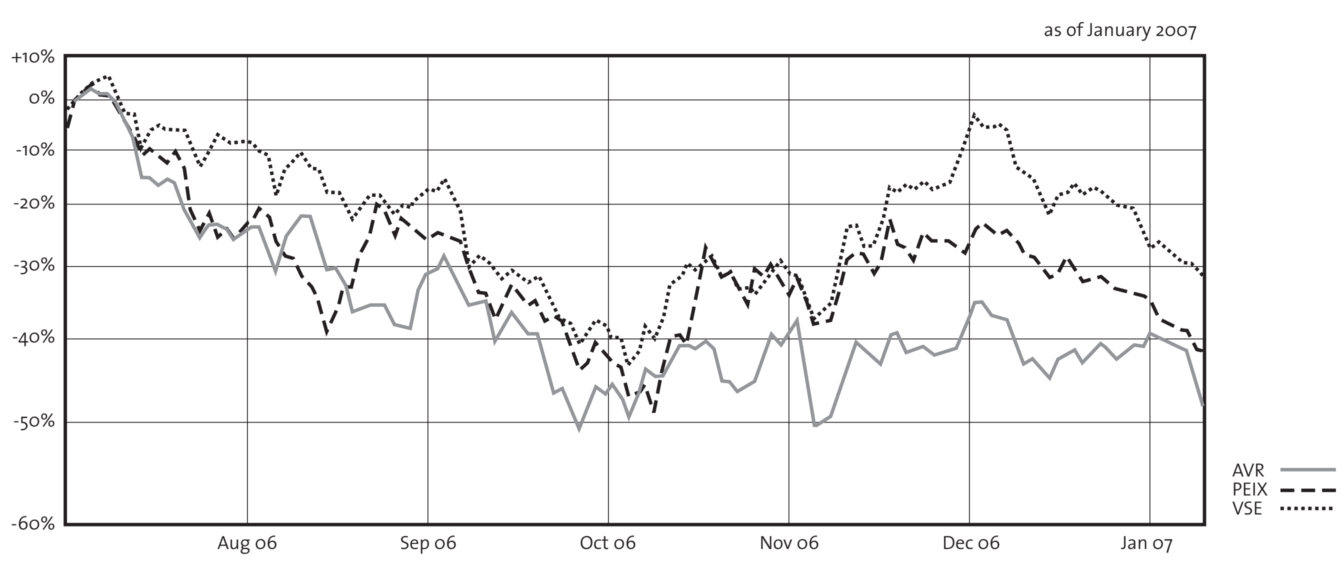
Funding Ethanol Deals in a Turbulent Market

by Todd Alexander, in New York

During the last six months, the appetite of private equity funds for investing in ethanol deals has gone from euphoric to cautious.

The change is understandable given the rapid reversal in the "crush spread," or the difference between the price of corn and ethanol. Corn prices rose during the past six months from the low \$2 range in June to the high \$3 range in December while ethanol prices fell from the \$4 range in June to just above \$2.

The effect of these commodity swings has also taken its toll on the public markets, as evidenced by the decision by Hawkeye Holdings to defer its initial public offering and the overall performance of the other publicly-traded ethanol companies, such as Aventine Renewable Energy, VeraSun Energy and Pacific Ethanol.



Given these conditions, developers who are still seeking funding for new plants have to ask themselves: what are the prospects for raising equity? And how should one approach the task? The short answer to these questions is that the prospects for raising equity have diminished at least for the moment, but money remains available for deals that are properly structured and able to differentiate themselves. The following is a discussion of ways many projects do just that.

Stand Apart

Many of the fundamentals that led the equity markets to embrace the ethanol industry early last year remain in place. First, there are more than 100 plants in commercial operation that continue to service their debt even with poor crush margins. Second, the market was receptive to an initial public offering by US BioEnergy of $140 million on December 14, 2006. Third, Congress recently extended a tariff of 54¢ a gallon on imported ethanol through 2008 that will continue to provide the industry with a buffer against low-cost imports from Brazil and elsewhere. Fourth, the Democratically-controlled Congress is likely to provide the industry with at least as much support as the current Congress.

Nonetheless, there is no disputing that the equity markets have become more selective. As a result, it is essential for developers to take to heart the importance of differentiating their business plans from those of their competitors in one or more of the ways discussed below.

Offtake Agreements

One of the more exciting trends in the ethanol industry during the past year has been the acceptance of ethanol as a fuel additive by the oil industry. Examples of this include a joint venture that Marathon Oil announced with the Andersons to own ethanol facilities jointly, as well as agreements by several oil companies to enter into long-term offtake agreements directly with ethanol producers.

Sponsors of ethanol facilities can benefit from this change in direction by entering into synthetic and actual tolling agreements that shift the price risk of corn and ethanol to the offtaker in exchange for offering a discounted product. For instance, we have seen synthetic tolling agreements signed in which the offtaker agrees to pay a price for ethanol equal to the price of corn plus price of natural gas plus a processing fee. We have also seen actual tolling agreements offered where a large agricultural concern has / continued page 18

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Kohler had some amount of income, but the IRS claim that Kohler had $8.4 million in income failed to take into account the restrictions on how the pesos could be used.

The court called the effort by the IRS to prove the pesos were worth the full $19.5 million "pathetically short of the mark." It called the claim by Kohler that it received no more value than the $11.1 million it paid for the notes from Bankers Trust "equally pathetic." It said the burden would normally be on Kohler to prove that it did not have the income the government said it did, but the government had to pick a number that was at least plausible on its face in order for the burden to shift. In this case, the court said, the government insisted on "all or nothing, lost all, so gets nothing."

The case is *Kohler Co. v United States*. The appeals court released its decision in late November.

Kohler and the IRS agreed that the swap was a taxable exchange, but they disagreed about the amount of income it produced. The court was not sure the swap was a taxable exchange. Another US appeals court said that a US company had no income in a 1997 case called *G.M. Trading* involving the same Mexican swap program. It said the value the US company received in the swap fell into the category of some government grants that are not taxable to the recipient because they serve a government purpose and leave the taxpayer no better off economically. An example is where a government reimburses a railroad for the cost of elevating its tracks above a highway. Such grants are called nonshareholder "contributions to capital."

The court in the Kohler case did not buy that analysis. It thought the better way to report the transaction would have been for Kohler to take a tax basis in its Mexican plant of only $11.1 million. That way, any additional value would be taxed as gain when Kohler makes a future sale of the plant.

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agreed to pay an owner a processing fee for the right to have its corn and natural gas processed by a plant.

Both of these options can be extremely attractive to private equity, provided that the returns afforded by the processing fee are adequate. First, this type of offtake agreement assures the owners that there will be a market for their product. Second, the agreement either eliminates or greatly reduces the risk that declining crush spreads will squeeze profits from a project below the internal hurdle rate if the supply of ethanol temporarily exceeds demand or corn prices remain at elevated levels. Third, the agreement may allow a project to increase the amount of debt thereby reducing the amount of equity required.

Sponsors entering into these types of contracts need to concern themselves not only with the tolling fee, but also with other essential terms and conditions. For instance, what liability do the owners have if the project is completed late? Who takes the risk of force majeure and other unplanned maintenance events? What recourse does each party have after a breach by the other, given the tremendous potential exposure that each party has to the other in these types of arrangements?

In addition to the use of offtake agreements, at least two plants took advantage in 2006 of the derivatives markets to lock in margins for corn, natural gas and ethanol, thereby using the financial markets to create a proxy for a tolling agreement. Of course, this strategy is much more difficult to implement under the current pricing environment, but may still be possible for plants that are nearing completion or that have sponsors willing to provide credit to support their obligations.

Construction Costs

Construction costs in the ethanol industry increased significantly in the past year. It is now common for owners to pay more than $1.75 a gallon for turnkey projects. In addition, the lead times for critical-path items like field-constructed tanks have increased dramatically and the liquidated damages offered to support the schedule and performance have also declined. As a result, owners have begun to explore cost- and time-saving alternatives.

The most common cost-saving device is the use of a limited notice to proceed. Under the terms of a limited notice proceed, the owner agrees to provide the contractor with enough money to begin the initial drawings for the site and to make equipment deposits on those items that have either long delivery times or are experiencing price escalation. The benefit of this approach is to shave off of the schedule the 45 to 60 days of engineering work commonly associated with the construction process before the contractor begins to break ground and to allow the contractor to lock in the prices of those pieces of equipment that have been driving construction prices toward $2 a gallon.

Sponsors using a limited notice to proceed should be careful to integrate the contractor's performance under the limited notice with its performance under the more general construction contract. For instance, the warranties, the performance guarantees and the schedule in the final construction contract need to be coordinated so as not to disadvantage the owner for having given the contractor an early start. In addition, the price escalation provisions should be designed in such a way as to minimize the owner's loss of leverage with the contractor.

Another approach that is receiving increasing consideration is where the owner builds the project itself. Under this approach, rather than entering into a turnkey contract with a

The number of ethanol plants already under construction and the inversion of corn and ethanol prices is making it hard to raise equity for new projects.

contractor, the owner in effect agrees to act as its own general contractor. This has the benefit of avoiding much of the mark-up associated with hiring a general contractor, but it does leave the owner without a third party to absorb the risk of construction delays and cost overruns. Although these risks can be reduced by properly structuring the subcontracts to provide for a pass through of certain rights, such as schedule and warranty work, this approach is most practical where the owner has a combination of construction experience and the ability to finance cost overruns.

Energy Costs

Many in the investing community have accepted the idea that we have entered an era of higher natural gas prices. Accordingly, investors are now more receptive to financing the additional up-front capital costs needed for infrastructure to avoid use of natural gas.

We saw several approaches used in 2006. One is the use of coal as the direct energy source for steam requirements. This approach is now in use at several plants and is under consideration by several more. Another is to derive methane from manure as has been proposed by Panda for its plant currently under construction in Hereford, Texas, as well as for other plants that Panda has under development. A third approach is to burn the distiller's grains that are a co-product of the ethanol production process to create steam. This approach is under consideration by several plants as well and is claimed by some to have a payback period of less than four years under current pricing conditions.

Each of these alternatives holds out the allure of lowering steam costs. However, sponsors should be aware that each of these alternatives has yet to be fully accepted by the financial community and, as a result, requires either a contractor to guarantee their performance to a degree or another credit-worthy party to provide completion support.

Value Added Co-Products

Many plants in the future are likely to squeeze more value out of the corn they consume to make ethanol. For instance, VeraSun announced in 2006 that it would be producing biodiesel from oil extracted from its distiller's grains using a process developed by Crown Iron Works. Separately, GS CleanTech offers its own corn oil extraction technology from the syrup produced by ethanol facilities.

Another approach taken by Ethanex, / continued page 20

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A FORECLOSURE SALE of the Great Plains coal gasification project triggered more than $1 billion in income and some recapture of tax credits for the owners.

The owners were five interstate gas pipelines. The project was built in the early 1980's in North Dakota to turn lignite into gas of high enough quality that the gas can be put into interstate pipelines. It has been operating since 1984. A partnership of the pipeline companies built the plant using $550 million in equity contributed by the pipelines and another $1.45 billion borrowed from a US government entity called the Federal Financing Bank. The US Department of Energy guaranteed repayment of the loan.

Gas prices dropped precipitously just as the project was nearing completion. By August 1985, the project had defaulted on the loan, and the Department of Energy ended up two months later having to repay the Federal Financing Bank $1.57 billion in principal and unpaid interest. The Department of Energy bought the project in June 1986 in a foreclosure sale by exchanging $1 billion of its debt claim against the project partnership. It later wrote off the remaining debt in exchange for the shares of a separate company that managed the project. In 1988, the government resold the project to an electric cooperative in North Dakota called Basin Electric.

The pipeline companies argued that they made a sale of the project to the government for only $1 billion and not the full $1.57 billion in outstanding debt. The US Tax Court disagreed. The rule is that when a "recourse" debt is involved, the borrower realizes only the market value of his assets in a foreclosure sale. (A debt is recourse if the lender can pursue the partners personally for repayment of the loan.) However, with a "nonrecourse" debt — or debt where the lender is limited to foreclosing on specific collateral — the borrower realizes the *full* amount of the debt in the foreclosure sale. The debt in this case was not explicitly labeled. However, the court said it was nonrecourse in substance / continued page 21

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among others, is corn fractionation, which removes non-fermentable components of the corn from those that are fermentable. Although more capital-intensive, fractionation has the advertised benefits of allowing increased output of ethanol from the same plant, reduced enzyme requirements and higher-value distiller's grains, and it creates its own source of corn oil for sale.

Fractionation raises the same issues as use of innovative technologies to reduce natural gas consumption. Use of any non-traditional process to create value-added co-products can create structuring issues if sponsors are asking lenders to finance a portion of these costs.

Management Team

Until recently, most ethanol plants were built by farmer coops. In the last two years, there have been moves toward larger plants, multi-plant platforms and heightened merger activity. Private equity funds and the capital markets are increasingly focused on management structures. They want managers with flexibility and experience to achieve the highest risk-adjusted returns on investment.

Sponsors should address the management structure and offer a seasoned management team in their business plans to handle these concerns before seeking debt and equity. We have seen several well-structured transactions fail to gain traction in the equity markets because of their failures to propose a team that was perceived as responsive to these concerns.

In the current market, it is essential to distinguish a project from the competition. Successful projects have done this by adopting one or more of the techniques described in this article. ◎

Ethanol Opportunities in the Next Round

by Logan Caldwell, with Houston Biofuels Consultants LLC in Houston

The capacity to produce ethanol at US plants is expected to outstrip domestic demand for the fuel by the spring given the number of new plants that are under construction. Nevertheless, there may be a silver lining.

Demand for ethanol in the United States reached 5.9 billion gallons a year on an annualized basis in May 2006. Production capacity is expected to exceed six billion gallons a year by the spring and continue growing monthly. The volumes of ethanol that US fuel refiners are required by law to mix with gasoline under the Energy Policy Act of 2005 will never exceed domestic production capacity. For example, in 2010, demand must be at least 6.8 billion gallons a year by law. However, another two to four billion gallons of additional capacity are likely to be available by then, raising US production capacity to between eight and 10 billion gallons a year (even more if all announced projects proceed as scheduled). Even though we expect another increase in the so-called renewable fuels standard — or volume of ethanol that blenders are required by law to mix with gasoline — by Congress in 2007, it will take a year or more to modify terminals and develop ethanol and gasoline blend stock supply chains.

Developers who raised equity recently have been using five strategies.

If ethanol demand is to increase in any significant way in the next two years, it will be because ethanol producers have persuaded blenders to use additional ethanol on their own. It is a tough environment, but there are new opportunities for developers.

A Roller-Coaster Year

The market has reversed in the space of just a year. A year ago, Congress ordered blenders to use more and more ethanol each year for the next seven years, corn prices had fallen below the 40-year average, and President Bush was complaining that the United States had to wean itself from an addiction to oil. Gasoline refiners were scrambling to figure out how to retool their gasoline production, blending and distribution systems to stop using the fuel additive MTBE.

By June 2006, it looked as though the expectations of even the most enthusiastic ethanol producers and developers had been surpassed: oil prices had climbed above $70 a barrel and ethanol commanded a premium of up to several dollars a gallon over gasoline. A gallon produced was easily a gallon sold. It appeared to many in the ethanol industry that the mandates had met their intended purpose and created the additional ethanol demand the industry needed to reach a critical, sustainable mass.

Gasoline blenders also felt a sense of satisfaction after successfully establishing ethanol supply to terminals hastily adapted for ethanol blending. However, supply was tenuous, and many terminals in the eastern United States and in Texas were in a state of high alert to assure the supply of finished gasoline for the summer driving season. Participants realized that MTBE had disappeared from the US gasoline supply system in a sudden swoop and not gradually over the course of the year as many expected. Exchanges of finished gasoline, on which gasoline blenders rely to balance supplies, reduce costs and cut truck traffic continued much as before, but with reformulated gasoline using ethanol in place of MTBE. Mirroring this change in the physical markets, trading of gasoline blend stock specially formulated to be mixed with ethanol commenced on the NYMEX (symbol "RB") while the more traditional gasoline contract (symbol "HU") started to wind down. It will disappear entirely with expiration of the January 2007 contract.

Ethanol demand stepped up between April and May 2006 from 4.4 to 5.9 billion gallons per year on an annualized basis, an increase of 125 million gallons a month of additional demand.

Then last May, ethanol demand stagnated.

Aside from minor fluctuations in ethanol usage largely explainable by seasonal shifts in gasoline demand, the usual pulses in demand accompanying the major driving holidays from Memorial Day through Christmas, / continued page 22

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because the government was unable to pursue the partners individually for repayment.

The court sided with the pipeline companies on the question of when the plant was sold to the government. The pipelines claimed both a 10% investment tax credit and separate 10% energy tax credit in 1984 when the plant went into service. Such tax credits vest ratably over five years. Thus, for example, if the plant was sold one year after it went into service, then 80% of the tax credits would have been recaptured. The pipelines argued that the foreclosure sale was not completed until November 1987 when the US Supreme Court declined to hear an appeal of the foreclosure. A sale is not final while it is still being appealed (and the sale date does not relate back once the appeals are exhausted). The IRS argued that the appeal was a sham with no purpose other than to delay when tax credits would be recaptured. The court declined to be drawn into a debate over motives.

The case is Great Plains Gasification Associates v. Commissioner. *The court released its decision on December 27.*

INCOME FROM FOREIGN SUBSIDIARIES was an issue in two states.

The New Hampshire Supreme Court told General Electric that it could not deduct dividends the company received from foreign subsidiaries in arriving at its New Hampshire tax base.

New Hampshire collects a "business profits tax" from companies doing business in the state. First, it determines the scope of any "unitary business" like GE that has lots of subsidiaries. The income of the entire unitary business is calculated, and then a share of the group income is apportioned to New Hampshire based on the property, payroll and sales of the group in the state. Dividends and royalties paid by one domestic entity in the group to another group member are ignored. The group stops at the water's edge. Thus, income earned by offshore subsidiaries is not part of the group income that is apportioned. However, it appears / continued page 23

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ethanol demand has held steady at 5.9 billion gallons a year. Houston BioFuels Consultants LLC has methods to estimate ethanol demand reliably on a weekly basis, one week in arrears. The weekly low during the period since May was 5.5 billion gallons a year the first week of July and the high was 6.5 billion gallons a year the first week of December. Thus, even the extremes were no more than 10% higher or lower than the mean and variations have generally been much closer. When the weekly demand is averaged over a given month, the variation is even less. One might have expected that discretionary ethanol blending would have dipped as ethanol prices spiked in late June to more than $1.50 per gallon over gasoline or surged in late September as ethanol prices dipped 30¢ cents per gallon below gasoline prices.

There are several reasons why ethanol demand has not varied as much as one might expect from spot prices.

First, the ethanol spot market is thinly traded, meaning very small amounts of ethanol are actually purchased and sold at the reported spot prices as a percentage of total market volume. On some days, few if any trades take place in the major regional market hubs (Los Angeles, Chicago, Houston and New York harbor), and trades often involve only a few rail car loads of ethanol. (A rail car contains approximately 29,000 gallons or 690 barrels.)

Second, much of the ethanol that is used in the United States is purchased in short-term deals, often three to six months in advance of the first delivery period. Many of these gallons are purchased at either a fixed price or at floating prices tied to a gasoline index. (Some ethanol purchased on a floating price basis is indexed to one or more of the regional ethanol market prices, and prices on this basis will fluctuate with the ethanol spot market.) Thus, most of the ethanol gallons used by blenders are at prices that can differ significantly from the spot ethanol price, and blenders and sellers have volume commitments made months in advance. Examples of how these prices are less volatile than spot prices can be observed in the publicly-reported quarterly financial statements and press releases of the publicly-traded ethanol companies. Aventine, Pacific Ethanol and VeraSun reported average sales prices of $2.37, $2.45 and $2.38 a gallon, respectively, for the July-to-September quarter. By comparison, for the previous quarter (April-to-June) VeraSun reported average prices of $2.39 a gallon, or practically the same as in the third quarter.

Output from ethanol plants in the United States is expected to outstrip demand by this spring.

Another major reason for the flat demand for ethanol is the physical inability of gasoline blenders to use additional ethanol without major investments. Ethanol is blended into gasoline at the last terminal in the supply chain, literally into the truck that delivers the finished gasoline to the retail station. (It is unlike other gasoline components that are blended in the refinery.) These terminals are typically well within 200 miles of the markets they serve. Once a terminal is blending 10% ethanol into all the gasoline it sends out (making what is termed an "E10" blend), even if it has the capability to blend more ethanol, it is unable to blend greater than 10% because that is the limit the auto makers warrant for non-flex fuel vehicles and because any amounts greater would violate a "substantially similar" rule imposed by the US Environmental Protection Agency. An exception would be if they blend E85 (an 85% ethanol blend that can be used legally by flex fuel vehicles only), but E85 is limited currently by a host of issues. Longer term, E85 could play a significant role in balancing both the ethanol and the US transportation fuels market, but E85 is not expected to be a significant factor in ethanol demand during the next two years.

As a consequence, most terminals in the United States that are currently blending ethanol are not in position to use more ethanol.

Thus, for there to be a significant increase in ethanol demand, terminals that are not blending ethanol currently need to start blending ethanol. For terminals to blend ethanol, dedicated facilities are needed at the terminal to unload, store, pump and measure the ethanol blended into gasoline. In addition, to take economic advantage of the high octane properties of ethanol, the blender needs to use a sub-octane blend stock called "CBOB." Otherwise, the blender is merely "splash blending," or blending 10% ethanol into a conventional finished gasoline. Splash blending to make E10 without using a CBOB creates another potential problem for the blender during the summer when the vapor pressure of the gasoline is of particular concern. Adding ethanol typically increases the vapor pressure of the finished gasoline by one pound per square inch. Since conventional gasoline specifications are regulated at the state level, some states have enacted "one pound waivers" to allow 10% ethanol to be splash blended with finished gasoline rather than CBOB to produce E10. With or without a waiver, the blender must consider the impact of ethanol on the volatility of the finished gasoline blend.

Costs for installing the facility modifications can vary significantly from terminal to terminal depending on the terminal throughput, availability of existing facilities that can be put into ethanol service and local labor, materials, engineering and permitting requirements. In 2004, before construction costs escalated to where they are today, it was reported that one oil company invested more than $2 million to modify a terminal to blend ethanol near Atlanta. It appears an existing tank was modified for ethanol storage; otherwise if a new tank were needed, the cost would have been greater. The cost of facility modifications can easily be around $5 million dollars if a new tank or extensive rail facilities are needed.

Blenders and gasoline marketers have many exchange programs in place to manage costs, reduce truck traffic and air emissions and provide reliable supply. This creates a cross linking between the terminals whereby, for example, one terminal will supply gasoline for another company at its terminal and at the second company's terminal will supply gasoline for the first company. If the retail stations of one of the companies does not want to sell E10 for whatever reason, that means the exchange will be / continued page 24

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that dividends any group member receives from a foreign subsidiary are counted as part of the unitary group's income that is then apportioned partly to New Hampshire. GE wanted to deduct foreign dividends from the group income. The court said no. It cited a US Supreme Court decision involving Mobil Oil Corporation in 1980 that it said confirms that a state has the right to tax foreign-source dividends that are received by a corporation doing business in the state.

The case is *General Electric Company v. Commissioner*. The court released its decision in early December.

The Minnesota Supreme Court grappled with a related issue. A US corporation doing business in Minnesota had a French subsidiary. It filed a "check-the-box" election with the IRS to treat the French subsidiary as transparent for US tax purposes. Minnesota follows a similar procedure as New Hampshire. It first determines the unitary business and then apportions part of the group's income to Minnesota based on the sales, payroll and property in the state. However, Minnesota law says that the income of any foreign entities that are part of the unitary group in theory are excluded from apportionment (and their sales, property and payroll are also ignored when doing the apportionment).

The issue was whether the income from the French entity had to be included when the company opted to treat the French company as transparent for US tax purposes. The court said no. It said the election to treat it as transparent had meaning only for federal income tax purposes. The case is *Manpower, Inc. v. Minnesota Commissioner of Revenue*. The decision was released in early December.

MINOR MEMOS. A group of power companies is pressing the IRS to relax technical restrictions that could limit their ability to claim tax benefits from "domestic manufacturing." US companies that manufacture at home are not taxed on 6% of income from such manufacturing through 2009 and 9% / continued page 25

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disrupted. Thus, in areas where ethanol blending is not already prevalent, the complexity of rearranging exchanges is another hurdle to overcome for additional ethanol blending to occur. In practical terms, it means several blenders in a given area need independently to decide to blend ethanol for ethanol blending to take place.

The capital cost of facility modifications, the effort and expense of arranging for suitable CBOB, and the complexity of realigning of product exchanges have singly or in combination acted as a strong braking mechanism to further ethanol blending in the United States. They explain why ethanol demand has not changed since May 2006.

Government mandates to use ethanol have not had much effect because the targets have been set too low.

What's Ahead?

At the end of 2006, US ethanol production capacity was approximately 5.6 billion gallons a year. New ethanol plants already under construction are scheduled to come on line every month for at least the next several years. Announced projects for additional plants will add further to capacity for several years after that. With the new capacity additions and completion of plant expansions, ethanol production capacity will exceed US ethanol demand sometime in the spring 2007 since, by March 2007, new plant additions will bring US production capacity to six billion gallons a year. Every month thereafter for the next two years, more new US ethanol capacity is expected such that by the end of 2008, somewhere between eight and 10 billion gallons of ethanol production capacity will be available. Total announced projects would double that amount by 2010, but we expect many will be delayed or canceled because of lack of demand.

Imports have slowed but, for a variety of reasons, imports are expected to continue to come into the US even with a 54¢-per-gallon tariff and 2.5% *ad valorem* import duty. We expect increases in ethanol production in Brazil to parallel capacity increases in the United States. Brazil has a strong interest in exporting ethanol. With the announcement by Canada of an ethanol mandate by 2010 of 5%, an additional demand of around 0.5 billion gallons a year north of the border would absorb only a small fraction of the US oversupply since ethanol capacity is being added in Canada, too. It is likely to be 2008 or later before the Canadian mandate is actually implemented since, for now, the rulemaking process has only just begun with an announcement in late December 2006 by the Canadian federal government.

Could the wet mills swing to high fructose corn syrup and balance the ethanol market? Even though the wet mills (ADM, Cargill, Tate & Lyle and Aventine) either have or could in principle install facilities to increase high fructose corn syrup production instead of ethanol, we doubt this will occur to any significant degree because the wet mills generally have around a 10¢-per-gallon or more margin advantage over dry mills; the higher value of the co-products more than offsets the higher operating costs.

In retrospect, it is clear that the mandated use of ethanol played only a minor role in the volume of ethanol used since May 2006. The increase in ethanol demand was due to the disappearance of MTBE from reformulated gasoline, and ethanol was the only economically viable replacement. The current renewable-fuel-standard volumes do not reach current ethanol demand levels until 2009 when 6.1 billion gallons a year will be required. Even if Congress increases the mandate early in 2007, due to the time required to modify facilities and establish supply chains (we estimate nine to 18 months), this will not have a significant impact on ethanol demand until 2009. In the meantime, for ethanol demand to increase, ethanol producers and marketers have only the mechanism of price incentives to spur potential blenders of additional ethanol to invest capital and resources to modify facilities and begin using ethanol. Potential blenders of ethanol need to perceive ethanol prices will be low enough relative to gasoline for a long enough time to recover their investments of capital and resources needed to bring about additional ethanol blending.

With the prospect of an oversupplied market, ethanol producers and marketers may be best served by focusing on the price of ethanol in relation to the price of gasoline. This will be key to encouraging greater use of ethanol.

It is clear that the price gap between ethanol and gasoline this past year was not sufficient to induce additional discretionary blending. (Ethanol was around 20¢ a gallon over gasoline on average during 2006 after taking into account the blenders tax credit.) As a guide to the relative price of ethanol to gasoline needed to spur discretionary blending, in the spring 2005, ethanol sold at a discount to gasoline (before taking into account the excise tax credit), and additional discretionary blending was installed and has been in service ever since.

If ethanol prices are tied to gasoline, the opportunity may be available to manage the commodity price risk, and if similar programs are put in place on the corn and natural gas components, the ethanol producer may see whether his variable cash margin is going to be positive or not. If not, the deal normally should not be consummated since it would be better to forego the addition to capacity if it is only going to increase the loss. (Ethanol producers whose stakeholders supply corn to the plant may be an exception.) However if the variable cash margin is positive, even though nowhere near the levels achieved in 2006, it should be better to increase output and use the positive margin to help offset fixed costs.

Opportunities

If problems are opportunities in disguise, then one may feel that the opportunities in the ethanol industry over the next two years are very well disguised indeed.

Since one of the major concerns of potential ethanol blenders is the cost to modify a terminal and each major blender may have multiple terminals needing modification, one opportunity may be to work with a blender to take on the capital risk in exchange for a portion of / *continued page 26*

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after. However, the annual deduction is capped at 50% of wages paid to employees engaged in such manufacturing. Generating electricity is considered manufacturing. Transmitting or distributing it is not. The power companies want the IRS to make clear that employees count as engaged in manufacturing if they are in a separate entity that operates and maintains a project under an O&M contract with the project company. They are asking that wages paid to employees of the contract operator should count as good wages in cases where all the income from both the power project and the contract operator gets folded into the same consolidated tax return .... Most large companies use the accrual method of accounting to determine their taxable income. That means they report income or deductions when they "accrue" rather than waiting for cash to change hands. The IRS ruled in late December that an accrual taxpayer who signs a contract in December 2006 for services that will be performed in January 2007 or for insurance that will run from January to December 2007 cannot deduct its payments until they are actually made in January 2007. Three things must have occurred before a deduction can be taken under the accrual method. The taxpayer must be legally obligated to make the payment, the amount must be at least reasonably ascertainable, and "economic performance" must have occurred. The IRS said economic performance occurs under the service contract when the services are performed in January 2007. It said economic performance occurs under the insurance contract when the premium is paid. The ruling is Revenue Ruling 2007-3.

— *contributed by Keith Martin and Laura Hegedus.*

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the value that will be realized by blending relatively low-priced ethanol into gasoline. It may be that the developer uses this mechanism as part of a multi-year offtake agreement that could then be used to improve financial terms on an existing project that does not already have a firm offtake agreement or be coupled with a new ethanol plant that would come on line in 2009 or later.

Another opportunity could be in the logistics for supplying ethanol to a new marketing area. An example is a destination terminal that could operate on a hub-and-spoke arrangement to supply multiple small terminals and would itself be supplied by rail car unit-trains or marine vessel. While perhaps not as glamorous as ethanol production, logistics are just as vital to growth of the industry and will be a limiting factor (in the form of cost) for many years to come. Similarly, from the supply end, a gathering terminal with a hub-and-spoke arrangement similar to the terminal being constructed in Manly, Iowa could be another opportunity.

If lower ethanol prices over the next two years put downward pressure on margins, then the expected higher corn prices will exert further pressure. With such a rapid increase in the number of ethanol plants and capacity, any number of investors may consider shifting their investments elsewhere. Developers may find opportunities in combining, or re-combining, individual ethanol plants so as to create additional value that was not available with single plant operation or the current combination. ◎

Plant owners should focus on persuading more terminal owners to blend ethanol with gasoline, perhaps by offering to help pay the capital cost to modify terminals in exchange for a share of the return.

Municipalities Turn Again to Prepaid Gas Contracts

by David Schumacher, in Houston

Municipal utilities are again using the proceeds from the sale of tax-exempt bonds to prepay for long-term supplies of natural gas. A significant number of these gas prepayment transactions closed in 2006. More are likely in the future.

A prepaid gas deal is a structured transaction in which one or more municipal utilities, through a special-purpose entity often called a "joint-action agency," use proceeds from the sale of tax-exempt bonds to prepay for a supply of gas that will be delivered over a long period, such as 15 years. The joint action agency that issues the bonds uses the proceeds to buy the prepaid gas and then resells it to the municipal utilities that participated in forming the joint action agency.

Structured finance transactions fell out of favor after Enron collapsed. Interest in prepaid gas deals cooled. However, since the Energy Policy Act passed in August 2005, the deals have been making a comeback. The Energy Policy Act provided standards for determining whether a prepaid gas transaction meets certain federal tax code requirements. More than $5 billion in such transactions closed in 2006.

Both the utilities and gas suppliers can benefit from such deals. The utilities benefit from a long-term gas supply with a creditworthy gas supplier. The structure usually enables the municipal utilities ultimately purchasing the gas to buy gas at a discount from the market price when the gas is actually delivered. The gas supplier benefits from a low-cost source of capital that is repaid through the long-term delivery of gas to what is viewed as a stable market.

The municipal bonds are nonrecourse obligations of the municipal issuer and its participating municipal utilities. For repayment, the bondholders look only to the collateral in which the municipal issuer grants a lien in favor of the bondholders. The collateral is usually limited to the transaction contracts, the revenues the municipal issuer will earn from resale of the gas to its member utilities, and various reserve accounts established under the bond indenture.

The tax-exempt nature of the bonds is key to the transaction. The Internal Revenue Service will tax interest payments on state or local bonds if the bond proceeds are considered a private loan or if proceeds are used to prepay for property or services the primary purpose of which is to receive an investment return. The IRS issued regulations in 2003 providing guidance on the type of gas prepayment transaction that would not run afoul of IRS rules. Congress provided more clarity in the Energy Policy Act of 2005. The criteria generally require at least 90% of the gas that a municipality purchases must be used to serve the retail load of the purchasing utility or of other government-owned gas utility systems.

Structure

The typical prepaid gas deal involves four main parties: a special-purpose municipal entity that issues the bonds and uses the proceeds to prepay for a long-term supply of gas, the gas supplier, the municipal utilities that take and pay for the gas, and one or more counterparties to a hedge that has the effect of shifting gas price risk.

The issuer of the bonds is often a joint action agency, formed by municipal utilities, whose primary purpose is to enter into and manage transactions of this sort on behalf of member municipal utilities. This type of issuer usually has no assets. The structure allows the municipal utilities that will use the gas to avoid incurring debt directly and allows more demand to be aggregated to support the transaction.

The gas supplier must have the means to deliver gas over a long time period and, because it also has certain payment obligations if a problem arises in the transaction, it must have good credit. The credit of the gas supplier, or its guarantor, plays a significant role in determining the rating given to the tax-exempt bonds.

The gas price risk inherent in these transactions is typically mitigated through the use of gas price hedges. Each of the gas supplier and the municipal issuer enters into a hedge with the same counterparty. The creditworthiness of the hedge counterparty or its guarantor is also important to the rating on the bonds.

The contracts used to implement the deal must address six main risks. The gas supplier could fail to deliver gas. The municipal issuer could fail to take delivery. The municipal utilities that are the ultimate users could fail to take and pay for gas. The counterparty to the hedge could fail to make payment on the hedge. A force majeure event could prevent delivery or receipt of gas. The bonds could fail to qualify as tax-exempt debt.

Contracts

The main transaction contracts are a gas supply agreement between the gas seller and the municipal issuer, gas purchase agreements between the municipal issuer and its members, at least two gas price hedge agreements, and any guarantees that are needed to support the obligations of the gas supplier, the hedge counterparties and municipal utilities. The reserve accounts usually include a debt service fund into which amounts are deposited periodically to pay debt service on the bonds and an operating reserve established at inception to guard against revenue shortfalls.

The municipal issuer enters into a gas supply agreement with a creditworthy gas supplier. The gas supply agreement obligates the gas supplier to deliver a scheduled quantity of gas each day over the contract term. The municipal issuer uses the bond proceeds to make an upfront payment for all of the gas supply to be delivered over the term. The prepayment is calculated using a forward gas price curve. If the gas supplier itself is not creditworthy, then the obligation of the gas supplier to deliver the prepaid gas must be guaranteed by a creditworthy entity.

In some transactions, the municipal issuer enters into multiple gas supply agreements. This is done either to mitigate the risk of relying on one gas supplier or to create a structure where each gas supply agreement is dedicated to serving a particular municipal utility.

Risks associated with the failure of the gas supplier to deliver gas, or the municipal issuer to take gas (including due to the failure of a municipal utility to take gas from the municipal issuer or force majeure), are often mitigated by requiring the gas supplier to remarket the untaken gas. The gas supplier, in turn, earns a remarketing fee. The gas supplier will pay the municipal issuer from the proceeds of the remarketed gas an amount adequate to cover debt service on the bonds. If the gas supplier fails to deliver gas, then the gas supplier must compensate the municipal / continued page 28

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issuer for both the incremental cost of replacement gas and debt service. If a force majeure event prevents delivery or receipt of gas, the gas supplier usually must pay the municipal issuer an amount to cover its debt service. Finally, if the gas supply agreement is terminated early due to either a gas supplier default (including the gas supplier's persistent failure to deliver gas or a bankruptcy of either the gas supplier or its guarantor) or a municipal issuer default, the gas supplier must make a termination payment in an amount needed to redeem the bonds.

The municipal issuer also enters into gas purchase agreements with each of its members. The terms are substantially similar to the terms of the gas supply agreement between the gas supplier and the municipal issuer. The rating agencies will view a prepaid gas transaction more favorably if the gas that the municipal utilities intend to purchase is not a significant source of their daily gas supply requirements but merely a complement to their other supply sources.

The municipal utilities commit to take and pay for a fixed quantity of gas over the term of the transaction. They pay a price linked to the market price of gas at the time the gas is delivered, often less a discount. Each municipal utility covenants that payments for this gas will be treated as system operating expenses and thus will be paid before debt service on its outstanding debt.

The credit of the municipal utilities is often supported by a surety bond or other insurance product. The municipal issuer can call on this credit support in the case of a municipal utility default. The obligor on the credit support typically caps its exposure under the credit support instrument. For example, if the credit support obligor must make a payment based on the market price of gas at the time of the municipal utility default, then the market price of gas used in that calculation could not exceed a set price. Moreover, the credit support obligor's obligation to pay could continue for only a fixed period of time.

Both the gas supplier and the municipal issuer usually mitigate gas price risk by entering into hedges. The price risk arises from the difference between the fixed gas price that is used to determine the amount of the initial prepayment for the long-term supply and the market price for gas at the time the gas is delivered. Both the gas supplier and the municipal issuer face market-price risk. The gas supplier is exposed because it must purchase gas in the market periodically as each quantity of prepaid gas is delivered; the municipal issuer is exposed because it resells the gas to its members at the prevailing market price at the time of delivery (often with a further discount).

More than $5 billion in prepaid gas deals were done in 2006.

To mitigate the municipal issuer's gas price risk, the hedge counterparty pays each month to the municipal issuer a fixed price for a notional quantity of gas, while the municipal issuer pays an index price (less a discount) to the hedge counterparty on this notional quantity of gas. The fixed price is tied to the gas price used to determine the prepayment. The index price (less the discount) is the price that the municipal utilities pay to the municipal issuer for gas delivered during the relevant month. The notional gas quantity is equal to the quantity of gas scheduled to be delivered to the municipal issuer that month. Thus, if the market price of gas (less the discount) in the relevant month is higher than the fixed price payable by the hedge counterparty, then the municipal issuer must make a payment to the hedge counterparty. The municipal issuer has the revenues available to make this payment, without threatening its ability to pay debt service on the bonds, because the municipal utilities have paid for gas at the same index and discount. Conversely, if the fixed price is higher than the market price of gas (less a discount), then the hedge counterparty must make a payment to the municipal issuer. This payment helps the municipal issuer fill a revenue gap that would arise because the price at which it resells gas to the municipal utilities is less than the price used to determine the amount of the prepayment.

The hedge provider enters into a similar gas price hedge with the gas supplier. However, instead of paying a fixed price, the hedge counterparty pays the gas supplier the market price prevailing when the gas supplier delivers gas (less the same discount used to determine the municipal issuer's payment obligation under its hedge with the counterparty), and the gas supplier pays the hedge counterparty the same fixed price that was used to calculate the prepayment under the gas supply agreement between the gas supplier and the municipal issuer. The notional quantity of gas is the same under both hedge agreements.

The credit of the hedge counterparty is important in determining the rating given to the bonds. Thus, if the hedge counterparty is not adequately creditworthy, then its payment obligations under the hedge will have to be guaranteed by a creditworthy entity.

A mechanism is usually put in place to address a payment default by the hedge counterparty or its guarantor. This mechanism usually requires the gas supplier and the municipal issuer to find a replacement hedge counterparty within a given time period. If such a replacement counterparty cannot be found, then the gas prepayment transaction can be unwound. If this were to occur, then there may not be adequate funds to repay the bonds unless the gas supplier is obligated to make a termination payment for the full bond redemption price upon termination of the transaction. ◎

PIPEs Clogged

by Sey-Hyo Lee, Kevin Smith and Ruslan Koretski, in New York

PIPE offerings are a relatively fast way for public companies to raise capital in a private placement without the cost and delay of an underwritten public offering. "PIPE" stands for "private investment in public equity."

While sometimes perceived as a last resort for distressed companies, PIPEs have nonetheless become a popular financing alternative for small and mid-sized companies that have limited access to the capital markets or large companies that simply want quicker execution.

However, recent interpretations by the Securities and Exchange Commission of its Rule 415, which is the SEC rule governing so-called "shelf registrations" used in PIPE offerings, has chilled the PIPE market. These interpretations, issued through a series of SEC comment letters sent to participants in PIPE offerings, essentially state that PIPEs are primary offerings of the issuer and that PIPE investors are underwriters under the securities laws, which translates to increased liability exposure.

This article will provide an overview of PIPE offerings — how they are structured and why issuers are using PIPE offerings to raise capital — and then discuss Rule 415 and how recent SEC interpretations are affecting PIPEs.

Overview of PIPEs

A PIPE transaction is a private placement of equity or equity-linked securities by a public company to a limited group of individual or institutional accredited investors that is quickly followed by the registration with the SEC of those securities for resale into the public markets. Thus, PIPEs combine the speed of a private placement with some of the liquidity of a registered public offering. Many PIPEs are placed with hedge funds. Companies can offer a variety of securities in a PIPE transaction, including common stock and warrants to purchase common stock, convertible preferred stock or debt, or any combination of these securities.

In a typical PIPE offering, a company sells to accredited investors unregistered shares of common stock at discount to the current market price (often between 5% and 10%, but sometimes much steeper). The discount typically reflects the lack of immediate liquidity and the terms of the security offered. (The more illiquid a security, the higher the discount.) Issuers will often "sweeten" a PIPE offering by also issuing warrants that allow investors to purchase additional shares at a price equal to or at a premium to the current market price.

As the sale of the securities to PIPE investors is not registered with the SEC, the securities are "restricted" under the federal securities laws, which means they cannot be immediately resold by the investors into the public markets without registration or an exemption from registration. As result, PIPE investors receive trailing (or follow-on) */ continued page 30*

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registration rights under a registration rights agreement entered into with the company. These registration rights require the company to file a resale registration statement promptly following the closing of the private placement and to use its best efforts to have the registration statement declared effective by the SEC so that it can be used by PIPE investors to resell the purchased securities freely into the market. The deadlines for the company to take these actions are generally 10 to 30 days for filing and 60 to 120 days for effectiveness, with penalties for failure to meet these deadlines typically including liquidated damages paid to the investors (for example, 1% or 2% of the aggregate proceeds per month) to make them whole for the lack of liquidity. The company must keep the resale registration statement effective and up to date during the entire period when PIPE investors are reselling their securities (typically for two years).

Advantages

When compared to a registered underwritten public offering, a typical PIPE transaction offers significant advantages. PIPEs are generally completed on a much faster timetable. A PIPE transaction can be closed within a few days or several weeks, depending on the manner in which the PIPE is marketed. In contrast, an underwritten public offering for a smaller company can take several months to close.

The timing and scope of due diligence review by the investors is much more limited because there is no underwriter liability or the related need to establish a due diligence defense associated with a public underwritten offering.

The SEC review of the registration statement and the one- to two-month delay that may accompany it is avoided until after the sale of securities (and, importantly, after the issuer has received the proceeds from the sale).

The cost of a PIPE transaction is significantly lower than a public offering. Documentation necessary for a PIPE transaction has become fairly standardized, and disclosure documents typically consist of existing public information already on file with the SEC. The faster timetable and limited due diligence also contribute to lower transaction costs. Placement agent's fees are also typically lower than underwriting fees in a public offering.

The SEC is troubled by PIPEs offerings involving more than 30% of a company's public shares.

PIPE offerings do not involve extensive road shows, which are typical of registered underwritten offerings and can divert senior management's attention for significant periods of time.

Public disclosure of the PIPE transaction need not be made until definitive purchase commitments are received from the investors. As result, the transaction is less subject to market price volatility than a public offering.

PIPEs can accommodate more flexible deal structures and smaller offerings.

Disadvantages

However, PIPE transactions do have disadvantages.

The securities are often offered at a significant discount to the market price in order to compensate investors for a temporary lack of liquidity, and this often leads to a decline in the issuer's stock price after the deal is announced.

PIPEs may have significant dilutive effects, depending on the size of the offering, the discount and, for convertible securities, the conversion rate formulas.

The issuer may need to keep the resale registration statement effective for up to two years.

There is a danger of giving up control in the company if offered shares are concentrated in the hands of a small group of investors.

There is a risk (as evidenced by SEC enforcement actions) that potential investors who are contacted about the PIPE transaction will trade the company's securities based on the knowledge of the pending PIPE transaction before that information has been made available to the general public.

Some investors also engage in naked short selling in the issuer's shares before the PIPE offering is publicly announced. These investors sell shares of the company short without borrowing publicly-traded shares to cover their short positions and instead rely on the securities being acquired in the PIPE transaction, which often results in downward pressure on the price of the company's stock.

Rule 415

To provide investors in PIPE transactions with liquidity, issuers have relied on Rule 415 under the Securities Act, which allows issuers to register resales by investors in the privately-placed securities to the public at market prices. These resales by PIPE investors are referred to as "secondary offerings" under the securities laws because they are offered or sold by persons other than the issuer. Secondary offerings are distinguished from "primary offerings" which are offerings made directly by or on behalf of the issuer.

Secondary offerings in PIPEs can (and often are) registered on a short-form registration statement known as a "Form S-3" if the eligibility requirements to use this form are satisfied. Short-form registration statements are much easier to prepare because they permit an issuer to satisfy most disclosure requirements by simply incorporating past and future periodic reports filed with the SEC. In order to utilize Form S-3, the issuer must be a reporting company for at least one year and have timely filed all required SEC reports.

For secondary offerings, the principal additional eligibility requirement is that securities of the same class must be listed and registered on a national securities exchange (NYSE, AMEX or NASDAQ) or quoted on the automated quotation system of a national securities association. (Note: The OTC bulletin board and the "pink sheets" do not satisfy this requirement.) Importantly, secondary offerings do not need to satisfy the "public float" test — the aggregate market value of voting and non-voting securities held by non-affiliates must be $75 million or more — that primary offerings must satisfy in order to use Form S-3. This means that smaller companies with public floats less than $75 million that have been reporting with the SEC for at least a year can register a secondary offering in a PIPE on Form S-3, whereas they would not be able to use a Form S-3 for a primary offering. (OTC bulletin board and pink sheet companies generally rely on the secondary offering provision of Rule 415 to register the resales of restricted securities issued in a PIPE transaction on the long-form Form S-1 or Form SB-2 registration statements, which do not permit forward incorporation by reference.)

SEC Interpretation

The SEC has recently begun to express a revised interpretation of Rule 415 through its comment letter process (not through more formal rulemaking or interpretive processes) which has the potential severely to restrict the access of small and mid-cap companies to the PIPE market and also affect PIPE transactions for issuers of all sizes.

For many years, participants in the PIPE market have characterized the resales by PIPE investors as secondary offerings based on published SEC staff telephone interpretations. The SEC staff has listed several factors that are considered in determining whether an offering is a primary or secondary offering. These factors include how long selling shareholders hold the shares, the circumstances under which selling shareholders receive the shares, the relationship between the company and the selling shareholders, the amount of shares involved, and whether selling shareholders are in the business of underwriting securities or acting as a conduit for the company.

Prior to 2006, the SEC staff had not provided specific quantitative guidance — for example, on how big an offering can be before it starts to look more like a primary offering — or indicated how much weight each factor should be given in the analysis.

Since late spring, SEC staff have seemed unwilling to permit the shelf registration of PIPE resale transactions that would involve more than 30% of the "public float," or total number of shares in the company held by investors who are not affiliated with the company. The staff view is that such offerings are in fact primary offerings, not secondary offerings. Moreover, the SEC staff appears to be requiring issuers to identify the selling shareholders in the registration statement as underwriters in the primary offerings and to specify a fixed price at which the securities / continued page 32

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issued in the primary offerings will be sold in the market.

The potential consequences of the characterization of a PIPE resale offering as a primary offering rather than a secondary offering are extremely troubling to issuers and investors in PIPEs. They include inability to use Form S-3 unless the issuer is eligible to use Form S-3 for primary offerings (*i.e.*, the issuer can meet the $75 million public float test).

Selling stockholders will be deemed to be underwriters in the offering and must be named as underwriters in the prospectus. As statutory underwriters, selling stockholders would be subject to "section 11" underwriter liability for the registration statement, which would invariably result in investors undertaking more extensive due diligence similar to that in an underwritten offering in order to take advantage of the underwriters' due diligence defense. As statutory underwriters, selling stockholders would be ineligible to use Rule 144 (the SEC safe harbor rule that, if complied with, allows investors to resell restricted securities in the public market subject to time and volume limitations without being considered an underwriter) to resell any of the securities issued in the private placement transactions. This could result in PIPE investors requiring registration statements to be maintained by issuers for longer than the two-year holding period under Rule 144.

Although the SEC has not articulated in writing its new position on Rule 415 in the context of PIPEs, based on the issues raised by the SEC in the comment letter process and informal discussions with the SEC staff members, the SEC staff appears to be focusing on the following characteristics of PIPE transactions in determining whether a primary offering is involved.

One issue is the size of the resale offering being registered — offerings of shares representing more than 30% of the issuer's public float would likely be considered a primary offering. For purposes of the 30% public float test, the numerator includes all fully-diluted securities held by the selling stockholder (including any shares issuable upon exercise of warrants or conversion of convertible securities, without regard to any "blocker" provisions), while the denominator would only include actual outstanding shares held by non-affiliates.

Another issue is indicia of control by the selling stockholders, including any board representation or other contractual provisions enabling control of the issuer; the more control, the more likely the SEC would view the resale offering as a primary offering.

Another issue is the extent to which selling stockholders have a view towards distribution of the securities; the sooner investors are able to resell their securities after the issuance in the PIPE transaction, the more likely the SEC would view the transaction as a primary offering. Although not specifically addressed by the SEC, lock-up agreements may be able to address this concern.

The SEC also appears to give weight to the following characteristics of PIPE transactions, which are indicative of investment intent of the investors, when deciding that an offering qualifies as a secondary offering: participation of individual investors as opposed to institutional investors (because institutions are more likely to engage in short sales and underwriter-like activities), smaller discounts to the market price, and a larger number of investors.

Impact on PIPE Market

A record $27.7 billion in PIPEs deals were closed through December 22, up 38% from the volume in 2005. However, the uncertainty and potential liability exposure created by the SEC's new interpretations of Rule 415 and the lack of clarity and formal guidance are having a noticeable effect on the market. By recasting secondary offerings as primary offerings, the SEC is eliminating most of the advantages offered by PIPEs to investors and issuers. The impact is even greater for smaller companies where a PIPE offering may be one of the only sources of capital available.

As an alternative to registration of resale of securities in a secondary offering, some practitioners are advising their clients that invest in PIPE transactions to rely solely on Rule 144 for resales and to price the private placement of securities accordingly.

The SEC is expected to issue more definitive guidance that both issuers and investors can rely on when structuring PIPE transactions; this guidance may be available shortly. Until there is further clarity from the SEC on how to structure PIPEs as secondary offerings, issuers and investors are likely to remain skittish. ◎

Environmental Update

Wetlands Permitting

The test for determining what wetlands in the United States are protected by the Clean Water Act remains unclear. Six months after the US Supreme Court profoundly muddied the water, the US Army Corps of Engineers has still failed to issue guidance.

A Supreme Court decision in June 2006 failed to endorse one test over another. Five justices decided to overturn two lower court decisions. At issue was what constitutes a "navigable water" so that the federal government can assert its constitutional power over interstate commerce to impose environmental protections. Four justices decided that "navigable waters" are "only those relatively permanent standing or continuously flowing bodies of water 'forming geographical features.'" Wetlands are also "navigable waters" if they have "a continuous surface connection" to such bodies of water with "no clean demarcation between" them. There are nine justices on the court. A fifth justice concurred in the result, but without endorsing the reasoning of the other four justices.

The test used by the four justices potentially excludes ephemeral and intermittent streams from "wetlands." An ephemeral stream has flowing water for only short periods after it rains. The US Environmental Protection Agency estimates that intermittent or ephemeral streams comprise about 59% of stream miles in the US (excluding Alaska).

The fifth justice, Anthony Kennedy, who concurred in the result reached by the other four, proposed his own test. He would treat as a "wetland" waters that have a "significant nexus" to traditionally navigable waters, meaning

> if the wetlands either alone or in combination with similarly situated lands in the region, significantly affect the chemical, physical, and biological integrity of other covered waters more readily understood as 'navigable.' When, in contrast, wetlands' effects on water quality are speculative or insubstantial, they fall outside the zone fairly encompassed by the statutory term 'navigable waters.'

The Kennedy test would require a deeper factual inquiry on a case-by-case basis. The Supreme Court case — there were actually two cases that were consolidated — was called *Rapanos* and *Carabell*.

Although there is precedent for applying just the test embraced by the four justices — the "plurality test" — some courts and observers suggest that Justice Kennedy's significant nexus test will be followed. Three US courts of appeal have decided cases involving wetlands since *Rapanos*. The US appeals court for the 1st circuit ruled in late October that the US Army Corps of Engineers can establish authority to regulate under either the significant nexus test or the plurality test. Two other US appeals courts — in the 7th and 9th circuits — applied the significant nexus test. In practice, an area will be subject to regulation as a wetland if it is considered a wetland under the plurality test. It may also be one if it is covered by the significant nexus test.

After the Supreme Court decision, the Army Corps seemed ready to draw clearer lines around what it considered wetlands. Now, more than six months have passed, courts are not using a common definition, and the Corps may be hesitating to provide some permits to build projects on potential wetlands.

The Corps made an internal announcement in early July to expect guidance. In the interim, the various Corps offices were told to delay making wetlands jurisdictional determinations for areas beyond the limits of traditional navigable waters. Permits involving traditional navigable waters have not been delayed, but Corps offices have been told to choose between two approaches for projects at other sites that may or may not be wetlands. An office can issue a permit with the strict Corps mitigation requirements for wetlands. Or it can delay a decision until headquarters issues guidelines on how to apply the *Rapanos* decision. Developers who accept permits that treat their sites as wetlands so as not to delay their projects will be able to ask that their permits be modified after the guidelines are issued.

The Corps is also in the process of reissuing all of its nationwide wetlands permits. Some of the nationwide permits are being modified to include jurisdiction over ephemeral streams. This may serve as an indication that the upcoming substantive guidance */ continued page 34*

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may be more reflective of Justice Kennedy's significant nexus test.

Clean Air Mercury Rule

US states had until November 17, 2006 to decide whether to regulate mercury emissions from coal-fired power plants on their own or participate in a federal "cap-and-trade" system. Twenty-one states submitted their own plans by the deadline. The 21 are Alabama, Arizona, Connecticut, Delaware, Idaho, Illinois, Iowa, Louisiana, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New York, North Dakota, Pennsylvania, Rhode Island, South Dakota, Texas, Vermont and West Virginia.

The federal government has proposed nationwide limits on mercury emissions from coal-fired power plants to reduce mercury emissions. The proposed rule applies to coal-fired steam generating units capable of generating more than 25 megawatts on an output basis and that sell more than 25 megawatts to the grid.

The proposed rule places a nationwide cap of 38 tons per year starting in 2010 and a cap of 15 tons per year starting in 2018. Each state and Indian tribe receives an annual budget to meet cap targets. States and covered tribes were supposed to submit plans to achieve reductions in their respective geographic areas. State and covered tribes were given the choice of participating in a cap-and-trade program managed by the US Environmental Protection Agency or adopting their own programs. Environmental groups advocated more stringent state rules to reduce mercury emissions. The deadline for state plans to achieve the required reductions was November 17, 2006.

For those states that missed the deadline, EPA has now proposed a federal program to be used as a surrogate to achieve the targeted reductions.

Although the proposed federal rule provides a method for unit-by-unit mercury allocations, the proposal notes that the preference is for participating states to issue the allocations. Thus, the proposed rule lets states submit a mercury allocation methodology while allowing the remaining trading program to be governed by the EPA cap-and-trade regulations.

States have until May 30, 2007 to submit their allocation methodologies. States have latitude to determine the frequency of allocations and whether allowances will be distributed for free. Allocations may be recorded in participating states by as early as December 1, 2007 for the 2010 control period. In the absence of a state plan or state allocation methodology in place by December 1, 2007, EPA will decide on allocations for the 2010 control period. Future years allocations could then be altered as state plans or state allocation methodologies are approved. The Environmental Protection Agency is collecting comments on the proposal by February 20, 2007.

Twenty-one states submitted plans in November to reduce mercury emissions from coal-fired power plants.

In mid-December, the New York State Environmental Board approved final regulations that will require coal-fired plants in New York to reduce their current mercury emissions by 50% by 2010 and by 90% by 2015. Under this state program, no emission credit trading is allowed. This is because of concerns over the creation of mercury "hot spots" in areas such as the Adirondack and Catskill mountains.

CO_2 Trading

The New York Department of Conservation reworked its proposed rules for the "Regional Greenhouse Gas Initiative" called "RGGI."

RGGI is a regional initiative to reduce greenhouse gas emissions. It now includes eight states: the original seven states of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont and now Maryland. Under the RGGI, the states will use a regional cap-and-trade system to limit CO2 emissions. Under the New York proposal, CO2 credits would be sold rather than allocated. Revenue from the program would be used by each state for energy efficiency and carbon abatement technologies.

Other RGGI states, such as Connecticut and New Jersey, are expected to issue their proposals early in 2007.

Opponents argue that in a deregulated electricity market like the one in effect in New England, utilities that receive free emissions credits will still pass the cost of allowances to consumers even though the utilities did not have to pay for them. Others complain about the potentially disproportionate impact on the coal industry. Although RGGI is limited largely to the northeast, it could be applied more broadly. California is exploring ways to join RGGI, but coordination of the programs may prove challenging. Public comments on the New York proposal will be accepted until January 12, 2007.

Miscellaneous

The US Supreme Court heard arguments on November 29 in a potentially landmark case over whether the federal government has authority to act on global warming without further legislation from Congress. A decision is expected in the case later this year.

The case is called *Massachusetts v. EPA*. At issue is section 202(a)(1) of the Clean Air Act. That section says that the Environmental Protection Agency "shall by regulation prescribe . . . standards applicable to the emission of any air pollutant from any class or classes of new motor vehicles or new motor vehicle engines, which in [its] judgment cause, or contribute to , air pollution which may be reasonably be anticipated to endanger public health or welfare." Based on this mandate, several environmental groups petitioned EPA in 1999 requesting motor vehicle standards for CO_2 and three other greenhouse gases. The EPA denied the petition and subsequent appeals made their way to the Supreme Court.

The justices were interested during oral argument in whether the environmental groups have "standing" to bring the case. To have standing, they must be able to show that they suffered an injury in fact. Some of the justices asked questions that suggested they are skeptical. For example, Justice Antonin Scalia asked whether harm posed by rising sea levels over time is enough to confer standing. The Supreme Court is also expected to rule this year in another Clean Air Act case called *Environmental Defense v. Duke Energy*. At the heart of the *Duke Energy* dispute is the term "major modification" as it is used in the prevention of significant deterioration program under the Clean Air Act. Duke made changes to some of its coal-fired power plants. It maintains that the changes were not "major modifications" requiring a permit. The alterations both extended life and increased the electricity output. EPA commenced an enforcement action The Court must decide what counts as an increase in emissions for purposes of a modification — an increase in annual emissions or an increase in hourly emissions. A decision is expected in early 2007.

In late December, the US appeals court in the District of Columbia invalidated an eight-hour air quality standard for ozone enforced by the Environmental Protection Agency. The case is *South Coast Air Quality Management District v. Environmental Protection Agency*. The decision means that EPA must rewrite its rules for ozone attainment.

In 2004, EPA issued an eight-hour air quality ozone standard. Nonattainment areas are classified as marginal, moderate, serious, severe or extreme, */ continued page 36*

The US Supreme Court is expected to decide a potentially landmark case on global warming as early as late spring.

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and deadlines are established for each of such area to clean up the air.

A number of areas were not considered in violation under an earlier one-hour ozone air quality rule, but they have been labeled nonattainment areas under the eight-hour ozone air quality rule. EPA gave these areas until June 2009 to achieve attainment. The US appeals court said the same stringent rules must apply in all areas of nonattainment, even areascounties that were reclassified as nonattainment areas when EPA moved to an eight-hour rule.

Both classification as attainment or nonattainment and status, such as severe or moderate, make a difference in permitting decisions. For example, under the current regulations, in a serious nonattainment area, 25 tons per year of nitrogen oxides (NO_X) or volatile organic compounds (VOCs) emissions trigger "new source review" procedures and the possible need for a permit. (NO_X and VOC emissions serve as a surrogate to control ozone because ozone is formed from the combination of NO_X, VOCs with heat and sunlight.) In contrast, in a moderate ozone nonattainment area, it takes 100 tons per year of NO_X or VOC emissions trigger new source review requirements.

Finally, a new technical standard, ASTM E 1527-05, took effect on November 1, 2006 for purchasers of property who want to limit possible Superfund liability if the property turns out to be contaminated. The Federal Deposit Insurance Corporation issued updated guidelines for lenders in mid-November. The FDIC guidelines — called "Guidelines for an Environmental Risk Program" — recognize that the value of real estate collateral may be significantly impaired by environmental contamination. The FDIC is recommending that banks implement environmental risk assessment programs focusing in particular on potential exposure of their borrowers for liability tied to contaminated sites. ◎

— contributed by Andrew Giaccia and Sue Cowell, in Washington

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