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Canadian Income Funds

by Keith Martin and Heléna Klumpp, in Washington

US power companies are looking at Canadian income trusts as a source of financing for acquiring distressed assets and cashing out existing projects in the United States.

The trusts have seen phenomenal growth in Canada. At last count, there were more than 114 trusts with a market capitalization of C$57 billion, or roughly 7% of the aggregate capitalization of the Toronto Stock Exchange. Last year, 86% of new capital raised through initial public offerings in the Canadian market was through income trusts. The figure for the first half of 2003 was 80%.

The transactions are structured to produce higher returns for investors than from investing directly in operating companies. This means the trusts can afford to pay more than competing bidders for operating businesses.

Most trusts invest in assets in Canada. The first trust based on assets in the United States was formed in 2002. By August 2003, there were nine trusts centered on US businesses.

The trust structure has hit occasional turbulence. A decision by Pricewaterhouse Coopers in September not to take an assignment as auditor for Specialty Foods — the manufacturer of such products as Nathan's franks and Fischer's bacon — led other accounting firms to announce that they were reviewing the US tax risks in the Canadian income trusts in which they have been involved. US-based Specialty Foods sold 45% of the company to a Canadian income trust in March 2003. Lee Sheppard, a */ continued page 2*

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WIND DEVELOPERS would be helped in three ways by the final energy bill that is currently stalled in Congress.

The bill is a priority for the Bush administration. It passed the House in November, but fell two votes short in the Senate. The administration will try again when Congress returns in late January to find the remaining two votes. This will not be an easy task: the bill is a complicated jigsaw puzzle of provisions that help various constituencies and pit regional interests against one another.

The bill would extend a deadline for completing wind farms to qualify for a federal tax credit of 1.8¢ a kilowatt hour */ continued page 3*

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writer on tax subjects whose columns are read by policymakers in Washington, wrote in March that, "So troubled are some practitioners by these deals that your correspondent has received an unprecedented two separate packages of prospectuses for these deals."

However, the deal structures are continuously evolving. The first issue of "income depositary securities," or IDSs — a new structure not involving a trust for use with US businesses where a large share of the investors will also be in the US — started to trade on the American Stock Exchange the first week in December. Another purchase of interests by an existing Canadian income trust in two US power plants is scheduled to close in mid-December. The accounting firms appear to have been comfortable with these transactions.

US power companies are looking at Canadian income funds as a source of financing.

What?

A Canadian income trust is a trust formed in Canada that raises money in the capital markets and pools it for investment.

Most trust units are placed with retail investors. There has been less interest in them among institutional investors because of fears about potential liability. Persons with claims against a corporation cannot ordinarily sue the shareholders to recover on the company's debts. The fear is that the trustee might be sued as the manager of the business and, in turn, have a right of indemnification from the unitholders under Canadian case law or that the unitholders might be sued directly under the theory that the trustee is merely acting as their agent. Most Canadian counsel believe the risk of liability passing through to unitholders under either of these theories is remote. Nevertheless, fear of liability has acted as a deterrent to institutional investment. The Ontario finance minister said in her budget message in late March that the government would limit liability imposed on unitholders in trusts formed under Ontario law, but the measure to do this failed to pass before the legislature adjourned in June. Passage of such a law in Ontario is expected to lead to enactment of a similar law in Alberta. Most trusts are formed in one of the two provinces.

The typical trust has 20 to 30% Canadian institutional investors, 55 to 70% Canadian retail investors, and 10 to 20% foreign investors — mainly US.

Financing Device

The main attraction of the trusts as a source of financing is that the trust investors receive pre-tax dollars from businesses in which the trust invests. The trust is not subject to income tax in Canada. Rather, its earnings are taxed to the investors directly. About 40% of existing units are held through tax-deferred retirement funds with the result that the earnings are often not taxed immediately at the investor level either.

The investors focus on the cash return. The return may be expressed like a dividend yield. It is the cash distributed to unitholders in the latest period divided by the current price of one income trust unit.

Because of the tax advantage, the typical trust returns at least 27% more cash to Canadian investors than would a similar investment directly in corporate shares. The trust structures its investments in such a way that its share of cash flow from a power project or company in which it invests will have been largely untaxed in either the United States or Canada, and the trust itself is not subject to income tax.

Private equity firms have used this math to turn large profits. For example, Kohlberg Kravis Roberts & Co. and the Ontario Teachers Pension Plan Board together acquired 90% of the Yellow Pages business in Canada from Bell Canada in November 2002 for C$900 million, and then resold a 25% interest in the business in the summer 2003 through an income trust for C$935 million. American Industrial Partners achieved similar alchemy by acquiring Great Lakes Carbon — a US-based producer of calcined petroleum coke for making aluminum — in 1998 and then selling down the investment to a Canadian trust in 2003.

Canadian companies are moving to convert into income trusts from corporations. There were seven such conversions in 2002. Some US companies with appropriate business models have also converted. One US company that converted last spring had reduced its tax rate to 4% in the first quarter after converting.

Some market analysts in Canada have warned that the Canadian government may be forced eventually to respond to the erosion in the corporate tax base. Estimates of the current erosion range from C$500 million to $C1 billion a year. However, many countries have eliminated taxes at the shareholder level on earnings that were already taxed to a corporation (so it is not clear how much the erosion bothers the Canadian government apart from the need to make up tax revenue). The Bush administration pushed the United States in the same direction last spring with the reduction in the tax rate on dividends received by individuals to 15%.

A company wanting to sell part of its business should usually receive a higher valuation from a Canadian income trust than from another purchaser. The discounted cash flows that are projected from the business will have a higher value because the calculations are done using pre-tax dollars. Investment bankers have been peddling the structures as an exit strategy for private equity funds for their US portfolio companies.

The most suitable investments for income trusts are in companies or projects with a history of stable and predictable cash flow. The capital expenditures required to maintain the business should also be predictable and reasonable. Ideally, there should a moderate prospect for growth. Utilities and transmission lines with regulated rates of return and power projects with long-term offtake contracts fit this profile.

Standard & Poor's and Dominion Bond Rating Service both rate income trusts based on the sustainability of cash distributions. The Standard & Poor's rankings are from 1 to 7 from most stable to least stable. S&P has tended to give power funds its highest ranking. However, as of December 2002, only 25 income funds had asked for ratings.

The amount of cash that can be raised through a Canadian trust is a function of the certainty of the cash projections. The riskier the business model, the higher the yield required by the investors. Most operating companies have significant debt. The cash the trust investors will receive is what remains after payment of this debt. More debt adds to uncertainty about cash-flow projections. Short-term debt that */ continued page 4*

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for generating electricity from wind. The current deadline is December this year. The new deadline would be December 2006. The credits run for 10 years after a wind farm is put into service. The tax savings from the credit pay approximately a third of the capital cost of the typical project.

The energy bill would also give wind developers modest "AMT relief." One problem with the federal wind credit is it cannot be claimed by corporations on the "alternative minimum tax." The United States has essentially two separate income tax systems for corporations. Corporations must calculate their regular income taxes and also their taxes under an "alternative minimum tax" that is imposed on a broader tax base but at a lower rate and pay whichever amount is greater. A company that pays minimum taxes in a year cannot use its wind credits that year. The energy bill would allow wind credits to be used in the future to offset minimum taxes, but only for the first four years after a project is put into service and then only for new projects built after the energy bill is signed by President Bush.

The energy bill would also limit a "haircut" that wind developers suffer currently when a project benefits from certain state tax credits, tax-exempt financing, government grants or subsidized energy financing. In such cases, the amount of the federal wind credit is reduced by the amount of the other benefits the project receives. The energy bill would limit this "haircut" to — at most — half the amount of the federal wind credit.

The leasing industry has pushed hard in recent years to allow lease financing to be used for wind projects. It cannot be used today because it would result in loss of tax credits for projects that use such financing. Leasing companies failed to get this into the final bill.

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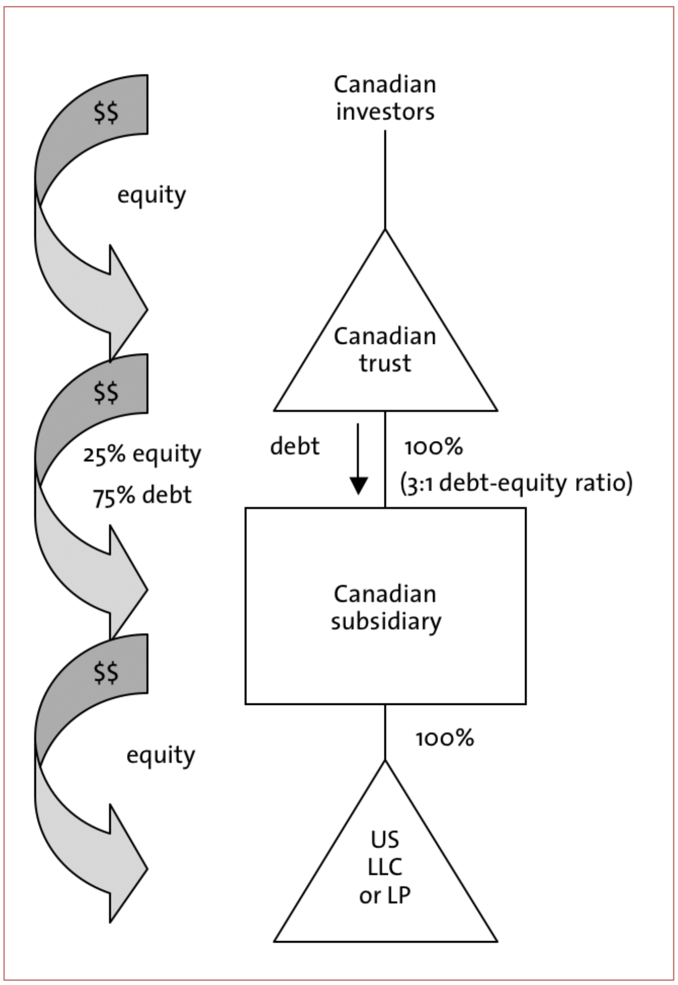
must be refinanced introduces risk that the interest rate will change.

Power plant and pipeline trusts might offer cash returns of 9 to 11%, according to a recent study by the Bank of Canada. The bank said returns for oil and gas trusts might exceed 20% reflecting the greater risk in a business that is based on depleting reserves and volatile commodity prices. There were eight trusts focused on the power industry by December 2002 with a value equal to 11% of total market capitalization of all income trusts.

Basic Structure

The structures for income trusts are varied and evolving.

However, the basic idea is a trust is formed in Canada and units are sold to the public and listed on a Canadian stock exchange.



It is important that the trust qualify as a "mutual fund trust" for Canadian tax purposes and distribute all of its earnings currently to avoid being taxed. This means that it cannot be "established or maintained primarily for the benefit of non-residents" of Canada. Thus, foreign ownership of the trust units must stop at 49%. However, there is an exception to the foreign ownership restriction for trusts that have never held more than 10% of their assets in "taxable Canadian property." Thus, a trust with all US assets would be free to raise capital in both the US and Canadian markets without worrying about breaching the limit on foreign ownership.

In cross-border deals, the trust forms a Canadian corporation as a subsidiary. A sizeable fraction of trust units are held in Canadian retirement savings plan accounts that are subject to a 30% limit on the amount of foreign content. The units in a trust whose only asset is a US business would be considered foreign property. Formation of a Canadian subsidiary ensures that the trust is considered invested in Canadian property, even if the ultimate assets are American. The Canadian subsidiary must have a "substantial Canadian presence."

The trust capitalizes the Canadian subsidiary with one-fourth equity and three-fourths debt. Thus, for example, if $100 million were to be invested in the Canadian subsidiary for it to use, in turn, to acquire US assets, $25 million would be contributed to the Canadian subsidiary in exchange for shares and the other $75 million would be lent.

The Canadian subsidiary then uses the money to acquire equity interests in a US partnership or limited liability company that owns a project or is an operating business.

Taxes

Canadian income trusts take the position that their earnings from US projects or businesses are largely free from US income taxes. The US partnership or LLC is not itself subject to tax. Tax is collected from the partners. Under US tax rules, the Canadian subsidiary that is a partner must file a US tax return and pay income taxes — just like any American partner — on its income that is "effectively connected" with a US business. However, the Canadian subsidiary takes the position that the income it earned as a partner is largely offset by the interest it pays on its debt to the trust. Interest payments are deductible by the Canadian corporation in computing its US income taxes.

The United States has "earnings stripping" rules that prevent foreign parent companies from capitalizing their US subsidiaries largely with debt and then "stripping" the earnings from the company by withdrawing them as interest payments to the parent. When the rules apply, interest deductions are disallowed. At least two things must be true for the rules to apply. The Canadian subsidiary must have a high debt-to-equity ratio — it does — and the interest must be paid to a related party. It is not in this case as long as the trust is ignored for US tax purposes so that the interest is considered paid to each unitholder individually.

The US normally also collects a withholding tax at the border on payments by a US taxpayer to someone outside the country. The payments by the Canadian subsidiary to the income trust would normally attract a US withholding tax. However, the trusts take the position that there is none in this case because the payments cross the border as interest and there is an exception in the US tax rules from withholding tax for "portfolio interest." The key to qualifying as "portfolio interest" is that the Canadian corporation cannot pay the interest to one of its shareholders that owns 10% or more of the shares. If the trust is ignored, then the interest is treated as if paid to the thousands of unitholders individually.

With US taxes offset, the trusts argue there is little tax below the investor level in Canada, either. The Canadian subsidiary is subject to income taxes in Canada in theory on its earnings. However, its earnings are largely offset by the same interest deductions that offset its income for American taxes. The trust is not taxed as long as it distributes all its earnings. The main Canadian tax is collected at the investor level.

There is a different structure for situations where an income trust is used to raise capital in Canada to acquire a US target company. The structure makes use of a Nova Scotia unlimited liability company that is a "hybrid" for tax purposes — it is taxed in Canada but ignored in the US — and there are more steps in how the capital moves from the trust to where it is used to make the US acquisition.

Air Pockets

The trusts have hit occasional turbulence.

Some critics charge that the debt on which earnings are paid out as interest is not really debt. The interest rates are high. The debt is subordinated — because of the tiered structure — to other creditors of the operating business. It is held by the same persons who hold the equity. / continued page 6

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CALIFORNIA utilities are pressing not only for large refunds from certain independent power projects, but are also asking the California Public Utilities Commission to alter the formula for calculating future payments to such projects for their electricity.

The dispute involves "QF" or "qualifying facility" projects. Examples of such projects are wind farms, and solar and geothermal power plants.

The legal proceedings could complicate refinancings of QF projects in California over the next 12 to 18 months, reports Bill Monsen with MRW & Associates in Oakland.

The refunds could run into the hundreds of millions of dollars. They cover the period December 2000 through March 27, 2001. For example, Pacific Gas & Electric claims it overpaid QFs by more than $200 million during this period.

The refunds became an issue after owners of QF projects complained to a California appeals court about a change the California Public Utilities Commission made in March 2001 in the formula for calculating energy payments the utilities are required by contract to make to QFs for their electricity. The appeals court not only rejected the QFs' appeal, but also sent the case back to the California Public Utilities Commission to consider whether QFs were overpaid for electricity during the four months before the formula was changed. An administrative law judge has set February 2 as the deadline for legal briefs to be filed in the case.

Meanwhile, the utilities are also pressing for a change in the formula for computing "short-run avoided cost," which is the measure for energy payments under most QF contracts after 2006. The change would reduce the amount utilities would have to pay QF projects for their electricity in the future.

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Specialty Foods — a US company that converted to a trust structure — said Pricewaterhouse Coopers declined to act as its auditor because of doubts about the interest deductions the company was taking. The announcement in September this year sent a chill through the income trust market. Deloitte, KPMG and BDO Dunwoody announced that they, too, were reviewing the trusts in which they were involved. In October, another PwC client, Heating Oil Partners — a US-based distributor of home heating oil that is owned 86% by a Canadian income trust — said it would continue to file US tax returns that claim interest deductions, but would take the "conservative" approach of excluding the interest from its tax calculations in financial reports to investors. PwC has remained its auditor.

Policy concerns make some Canadian fund managers nervous. One told *Forbes* in October that she refuses to buy income trusts based on US companies because she cannot understand why the US government would allow US business profits to be shifted to Canada and taxed there rather than in the US.

Securities regulators in Ontario are wrestling with reporting requirements. An income trust is an indirect offering of interests in an operating company, but the reporting entity for securities law purposes is the trust. The issue is whether investors are getting the disclosures they need to make informed investment decisions. This and other issues are expected to be addressed in an upcoming draft policy statement on income trusts. In June, Canadian securities regulators also proposed the equivalent of the Sarbanes-Oxley rules in the US that will require the chief executive officer and chief financial officer of companies to certify the financial statements and require annual disclosures about audit committees and services provided by outside auditors. Details about how the new rules apply to income trusts remain to be worked out.

The funds have a tax advantage that should let them pay at least 27% more than competing bidders for operating businesses.

IDS Structure

Two of the most recent cross-border deals have used a newer structure called "income depositary securities" that raises fewer tax issues. The first registration statements for IDS offerings were filed with US and Canadian securities regulators earlier this year. The first set of IDSs began trading on the American Stock Exchange in December.

The idea behind the new structure is to replicate the economics of the Canadian income trust structure but broaden the market for the securities. The structure does not use a Canadian trust. Rather, a US corporation is formed to raise capital by issuing IDSs. Each IDS is a common share in the corporation and a fractional interest in a subordinated note. The IDS is traded on a US stock exchange and the shares — but not the note — are also listed on a Canadian exchange. The investor can separate the two pieces or combine them again as a single unit. The US corporation has the same high debt-to-equity ratio as in the basic trust structure.

With IDSs, there is again little tax except at the investor level. The US corporation that issues the IDSs is in theory subject to income taxes in the United States, but its income is offset by the high interest payments on the note portion of the IDS. Since the interest is paid directly to the investors, there is a stronger case for avoiding US earnings stripping rules that would disallow the interest deductions and for avoiding US withholding taxes on interest paid to Canadian investors on grounds that the interest is "portfolio interest." Because the debt and equity are separable, there is arguably a lower risk that the debt will be recharacterized as equity.

A drawback with the IDS structure is the IDSs are foreign property. They will attract less Canadian pension money. However, since the investor will be a shareholder in a corporation rather than a unitholder in a trust, the liability concerns disappear with the result that there may be more interest in them in the institutional market. There are also no limits on the percentage of the deal that can be sold to US investors.

Canadian counsels continue to tinker with the IDS model in the hope of achieving non-foreign property status to bring back the Canadian retirement savings plan investors. At the end of the day, the IDS structure is an attempt to do directly in the US market what the Canadian income trust permitted in Canada: allow US businesses to be both publicly-traded and have their earnings taxed only at the shareholder level.

The US project finance community has tried using US real estate investment trusts, or REITs, and master limited partnerships to get to the same place, but these entities — which the US tax laws expressly permit to operate as publicly-traded businesses with only one level of tax — are really only suited for investors in real estate and oil, gas and other natural resources businesses. Efforts to persuade Congress to allow master limited partnerships to be used in other energy businesses have failed to date.

Portfolio Financings of Wind Farms

by Chris Groobey, in Washington

Developers of wind projects in the US have been moving to portfolio financings this year as a way to recoup development costs and refinance construction and mini-perm loans. Such portfolio financings present interesting risk-allocation issues.

A portfolio financing starts with a group of wind projects, each of which has its own power sales agreement and is either currently operating or very close to completion. The projects are bundled under a special-purpose holding company owned by the developer. The holding company issues bonds that are repaid by the revenue streams generated by the projects. If the bonds are not repaid, then the bondholders have the right to assume ownership of the projects.

The first financing of a portfolio of wind projects, a $380 million bond offering, closed earlier this year. The transaction closed approximately five months after the underwriters were selected. Other offerings are in the pipeline from developers who have a critical mass of wind projects either nearing completion or already in operation.

Developers use portfolio financings to receive, in a lump sum, the approximate present value of the / *continued page 8*

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by federal law to buy electricity from two kinds of power plants — cogeneration facilities that supply both steam and electricity, and other power plants that use waste or renewable fuels. These are QF projects. The utility pays the "avoided cost" for the electricity, or the amount the utility would have had to spend to generate the electricity itself. Owners of such power plants enter into long-term contracts with the utilities to sell their electricity. They usually receive both "capacity" payments and "energy" payments. A capacity payment is a payment by the utility to be able to call on the plant. An energy payment is an amount per unit of electricity actually delivered.

The arguments the utilities are making threaten to reduce not only future energy payments to QF projects, but also capacity payments, according to Monsen. The commission is expected to hear arguments about the level of future payments in the second quarter of 2004.

INTERCONNECTION with a utility grid could be more expensive in the future for independent power producers.

Independent power producers must pay the cost to connect their power plants to the local grid. This is the only way to move the electricity to market. Interconnection with the grid usually requires not only a radial line from the independent power plant to the nearest utility substation, but also improvements to the grid itself to accommodate the additional electricity. The grid improvements are called "network upgrades."

The utility usually builds the intertie and network upgrades and has the independent generator reimburse it for the cost.

However, the Federal Energy Regulatory Commission has said it is inappropriate for utilities to make independent generators bear the cost of network upgrades. Independent generators / *continued page 9*

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revenues expected to be generated by the projects. The proceeds are used to recoup development costs or pay off project-level debt, thereby freeing up capital to develop still more projects. Often, portfolio bond proceeds come at a lower cost to the developer than if the developer borrowed money based on its corporate credit or against a single project. Bonds also typically have a longer tenor than bank loans and less restrictive covenant packages. Most importantly, portfolio bonds have a lower required debt service coverage ratio (as low as 1.3x) than project-specific debt (typically 1.5x to 1.75x), which significantly increases the amount that can be borrowed against a given revenue stream.

Structure

The structure of a portfolio financing is straightforward. Each of the projects included in the portfolio is owned by a limited liability company. The projects are self-contained, meaning that they have their own power sales, operations and maintenance and other contracts. It is helpful to the transaction if the projects are located in diverse geographic locations and the power sales agreements are with different purchasers.

The developer then creates a new limited liability holding company to own the individual project companies that own the wind farms. Each of the companies that owns a project guarantees the repayment of the bonds by the holding company, thereby ensuring that all of the projects' revenues are available for debt service.

The holding company issues the bonds and enters into various agreements that govern the relationship between the holding company and the bondholders and provide security for repayment of the bonds. It also contracts with another entity, usually another subsidiary of the developer, to provide administrative services to the holding company as it has no employees to prepare financials or otherwise comply with its obligations under the financing documents.

The bonds will typically mature roughly at the same time as the scheduled termination of the longest-lasting power sales agreement in the portfolio. The repayment schedule for the bonds is structured to match the expected revenues and scheduled expirations of the various power sales agreements, so payments on the bonds, and distributions of remaining amounts to the developer, will be somewhat uneven.

The security package consists of pledges of the equity interests in the holding company and the project companies and in all of the assets that comprise the projects, including physical assets, contracts, permits and revenues from power sales. Documenting the security package can be time consuming given the number and diversity of assets being pledged and is a long lead-time item affecting the timetable for the financing.

Some of the proceeds of the bonds are used to fund reserve accounts. These typically consist of a debt service reserve account with a required balance equal to the next payment or two of principal and interest on the bonds and one or more other accounts that have negotiated balances and would be tapped if major maintenance is required on the projects (for example, in the event of a design defect in a specific model of turbine) or if operations and maintenance costs exceed budgeted amounts.

The bonds are repaid out of revenues from electricity sales and ongoing capital contributions that the developer must make to the holding company. The ongoing capital contributions are a percentage of "section 45 tax credits" to which the developer is entitled. The US government allows a tax credit of 1.8¢ a kWh for generating electricity from wind. The credits may be claimed for 10 years after each project is placed in service. The present value of the tax savings from the credits is worth about a third of the capital cost of a wind farm. The capital contributions must be made, or guaranteed, by a creditworthy entity and are made on a "hell-or-high-water" basis, meaning that the developer is not excused from making them even if, for example, the tax credit is repealed by Congress or the credits cannot be used because the developer lacks the tax base to use them fully. Depending on the price at which the projects sell electricity, the capital contributions tied to tax credits might represent 20% to 40% of the revenue stream supporting the bonds.

The terms of the bonds are negotiated with the underwriter. Wind consultants and independent engineers prepare pro-forma financials and, based largely upon potential deviations from base-case financials, reserve accounts and coverage ratios are negotiated. Ratings are obtained, bondholders are identified and the bonds are issued and sold.

Allocating Risks

Any power project brings with it many risks. Financing a project, or a portfolio of projects, is an exercise in risk allocation. One must first identify all the risks and then assign them to various participants in the transaction. John Maynard Keynes said that a banker is someone who lends you his umbrella and, at the first sign of rain, asks for it back. Banks avoid taking any risks for themselves; this is doubly true for institutional investors participating in bond offerings.

The developer wants to maximize the amount it receives from the sale of the bonds. The amount the developer receives is a function of the price and interest rate at which the bonds are offered, the bonds' ratings, required coverage ratios and balances in reserve funds. All of these factors are influenced by risk allocation and, when the risks are allocated away from the bondholders, the factors swing in favor of more proceeds being paid to the developer.

Portfolios of wind projects have many of the same risks as more traditional power plants. For example, all power projects have risks associated with operations and maintenance procedures, the credit quality of offtakers, changing environmental and energy-related regulations and *force majeure* events. Wind portfolio financings address these risks in the same way as all other projects: proper operations and maintenance are assured by contracting with reputable companies and maintaining reserve funds; offtaker credit is reflected in the bond ratings and debt service coverage ratios; regulatory risks are analyzed and accepted, and insurance is purchased and contracts are written to protect against *force majeure* events.

However, wind projects also carry unique risks that are not present in other power projects. These risks include abnormal weather patterns, still-evolving turbine and blade technologies and potential changes to the tax code, renewable portfolio standards and other government programs. Also, with respect to portfolios in which some of the projects are not yet fully operational, a creditworthy entity must be ready to replace the lost revenues from power sales and payments associated with tax credits if the projects are not completed on schedule.

Weather Risks

Wind is what runs wind farms just as fossil fuels are what power more traditional power plants. The developer of a wind farm takes the wind risk just as the developer of a more traditional power plant takes the risk that he will not be able to obtain enough fuel.

The wind industry has a challenge to make the investor community comfortable that wind risks are as manageable as risks with fossil fuels. Wind developers do this mainly by offering very conservative economic terms that / continued page 10

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can be charged for the cost of the "direct intertie" — the radial line and related equipment that connects the plant to the grid. However, network upgrades are supposed to be paid for by all users of the grid. Current FERC policy is to require utilities to repay any amounts collected from generators for network upgrades within five years with interest.

The energy bill currently stalled in Congress would reverse this policy. The bill would give utilities the option of asking FERC to let them charge the generator for the cost of network upgrades or to pass through the cost to all grid users in transmission rates. However, FERC could not allow the cost to be passed through to all grid users in situations where the grid improvements are only needed because of the addition of the generator's power plant.

The bill would also bar FERC from requiring utilities to pay interest when returning amounts collected from generators for network upgrades.

Entergy and Southern Company asked for this language.

SYNFUEL projects received good news from the IRS in late October, but are not yet in the clear.

The IRS said that even though it does not believe "coal agglomeration plants" are making a synthetic fuel from coal — as required to qualify for a federal tax credit of $1.095 an mmBtu on their output — it nevertheless will not challenge project owners who claim the tax credits on grounds of failure to make synfuel. A coal agglomeration plant is a plant that adds chemical reagents to crushed coal. The IRS made the announcement in Announcement 2003-70. The agency has issued more than 80 private letter rulings to owners of the projects confirming that they are making synfuel. Senior IRS officials felt it / continued page 11

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ensure the bonds will be repaid even if the projects are afflicted with extraordinarily poor wind conditions.

A wind consultant projects long-term wind speeds, wind speed frequency distribution and seasonal variations. The data is then matched to the power sales agreements and incorporated into a model of the long-term energy output for each project and the portfolio as a whole. A financial base-case is developed based on conditions that the consultant opines are as likely as not to be experienced (the "P50" scenario). A worst-case scenario, which might have only a 5% chance of occurring (the "P95" scenario), is also modeled. The base case becomes the model that determines the aggregate amount of bonds that will be sold and the worst-case scenario guides the required balances for reserve funds and the conditions that must be met for distributions to be made out of the bond structure.

For example, the bonds might be structured so that they will still be paid if the projects operate at only 90% of projected levels, there is a 50% increase in operations and maintenance costs, or various low-wind scenarios occur in conjunction with, for example, increased major maintenance expenses. These considerations might require a relatively high average projected debt service coverage ratio — for example, 1.85x over the 20-year life of the bonds — compared to bonds supported by more traditional technologies. Coverage ratios can be expected to decrease over time as institutional investors become more experienced with such projects.

Technology Risks

Another risk that bondholders will require the developer to address is the risk of pervasive defective technology (as opposed to discrete individual breakdowns) in the turbines and blades that transform wind into electricity. Wind turbines have gone through two generations of technology in the last 10 years. Just as with any new technology, there may be some wariness about whether it will suffer from teething problems.

Technology risk is mitigated in various ways by the developer: by grouping many technologies into one portfolio so that a design defect does not affect the economics of the entire portfolio, by obtaining an independent engineer's assessment of the appropriateness of the various technologies to the corresponding sites and the adequacy of the developer's arrangements for operations and maintenance of the projects, and by pushing as much of the risk as possible on a creditworthy vendor for the turbines.

Portfolio financings of wind projects work best with projects that are already operating or close to being put into service.

A wind portfolio financing will be much more attractive to bondholders if the projects are spread across different geographic areas and there is a mix of equipment from different manufacturers. For example, the first successful windpower portfolio financing consisted of seven facilities in six states (in four wind "regions") using five models of turbines from four manufacturers. The diversity of technology was commented upon favorably by the rating agencies and contributed to the investment-grade ratings for the bonds, which, in turn, expanded the pool of potential bondholders. Simple demand and supply suggest the more institutions willing to lend, the lower the cost of the money.

Developers also mitigate technology risk with contractual arrangements and reserve accounts. Wind turbines have been through at least two generations in the past decade; a number of models have been recalled or reengineered. This unsettled history results in investors demanding substantial major maintenance reserve accounts and provisions in the bond documents requiring redemption of at least a portion of the bonds upon a recall or other indication that faulty technology will prevent a project from contributing its share of the portfolio's revenues.

Regulatory Risks

Somewhat counterintuitively given their reputation as environmentally benign sources of electricity, wind projects also face the risk of regulatory change, especially in the environmental area. For example, several currently operating wind projects faced opposition to renewals of their permits due to concerns over the number of bird strikes at the facilities. Investors who are more accustomed to worrying about changing clean air regulations now must become comfortable with the practices and procedures of the Fish and Wildlife Service. In other words, the same regulatory risks are present in windpower as with more traditional power plants, just with different regulators.

Tax Risks

Federal tax credits provide roughly a third of the capital cost of a wind project. Lenders are willing to take credit risks, but not tax risk. This means that a creditworthy user of the tax credits will have to agree to make ongoing capital contributions to the borrower so that the tax credits are part of the revenue stream that can be used to repay the bonds. These capital contributions must be made on a "hell-or-high-water" basis, meaning that if the wind blows, such contributions must be made. They must be made even if Congress changes the tax law to withdraw the credits, the projects do not qualify for credits because they failed to be placed in service by the deadline to qualify for credits, or the developer lacks the means to use the credits. They do not have to be made to the extent the wind fails. Wind risk is addressed in other ways. Tax credits are viewed in the same manner as revenues received from offtakers who buy the electricity. The credit rating of the developer is added to the mix with the credit ratings of the various offtakers. The bonds themselves will likely be rated at the lowest rating assigned to the developer and the offtakers.

Construction Risks

Construction risk is not as great in wind projects as in more traditional power projects because the typical wind farm takes only six months to construct. However, one wrinkle in wind projects is that incomplete projects not only fail to generate power sales revenues, they fail to trigger the availability of the associated tax credits. If any of the projects in the portfolio is not yet in operation at the time the bonds are sold, the developer must agree to replace both the lost power revenues and the lost income based on tax credits if the project is not completed on schedule. For example, in one portfolio financing this year, the bonds were sold a few months prior to scheduled completion of two of the seven projects. The developer entered into a construction completion agreement with the holding company that issued the bonds. The agree- / continued page 12

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was too late to change course. The tax credits only run through 2007.

However, many synfuel projects remain under IRS audit. The IRS commissioner promised several key members of Congress that the first audit will be concluded by December or January. An issue in the audits is whether the plants were placed in service in time to qualify for tax credits. Plants had to be operating by June 30, 1998 to qualify. The plant owners are waiting to see what position the IRS takes on this issue in the first audit.

The IRS tightened its rulings policy in late November. It will not issue rulings confirming that a plant qualifies for tax credits in the future unless an earlier ruling was issued with respect to that specific plant. It will not be enough to show that the plant is using a chemical reagent on which the IRS ruled earlier. A few exceptions may be made. However, even then, the plant owner will have to get a "determination letter" from the local IRS district director confirming that his plant was put into service by June 1998 before the IRS national office will issue a ruling that the plant is making synfuel.

Meanwhile, the IRS released an internal legal memorandum in late November that shot down a theory that IRS agents who are conducting the audits would like to use to deny tax credits to synfuel plants that have been moved to new locations. More than half the plants have been moved. The issue when a plant is moved is whether it is still the same plant that had to have been put into service by June 1998 to qualify for tax credits. The memorandum reaffirms that most plants that have been moved remain the same plants. It also addressed what equipment had to have been installed and have been operating at the original site. The "facility" that the tax law requires have been in service by June 1998 excludes feedstock "preparation equipment, / continued page 13

Wind Portfolios

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ment provided that the developer would make payments to the holding company that would replace the lost revenues and tax credit payments if the projects were not completed on schedule. In a worst-case scenario, meaning the projects failed key tests by certain dates, the developer was required to make lump-sum payments to the holding company that would then be used to redeem a portion of the bonds. ◎

Risk Allocation in UK Wind Projects

by Adrian Congdon, in London

The United Kingdom government has committed itself to meeting 10% of UK electricity supplies from renewable sources by 2010 and aspires to increase this to 20% by 2020. Given the low starting point, this means that some 8,000 additional megawatts and some £6 billion investment will be needed to meet the 2010 target. Windpower — both onshore and offshore — is seen as the best means of providing most of this capacity.

This article reviews recent progress in UK wind farm projects, how risks in such projects are being apportioned, and what some of the principal obstacles are ahead.

The rate of planning approval of UK wind farm projects has increased exponentially over the last year and is expected to improve further. Onshore, it is reported that some 1.4 gigawatts are in the planning stage with some 6.0 gigawatts being prepared for submission over the next 18 months. Offshore, 700 megawatts have reportedly been approved, a further 700 megawatts are in planning and 4.0 to 6.0 gigawatts of capacity will be applied for in round 2. Round 1 of this process was covered in the December 2002 issue of *NewsWire*: it contemplated relatively small projects within UK territorial waters (broadly within 12 nautical miles of the mainland). The first of the round 1 projects to achieve operation (in November 2003) is National Wind Power's 60 megawatt project off North Hoyle. Round 2 builds on the perceived success of its predecessor and envisages much larger projects beyond the territorial waters. The first round 2 projects are expected to be awarded shortly. However, there are problems with the planning process, and these are addressed below.

Risk Allocation

A pattern of financeable risk apportionment is emerging in wind farm projects.

Turbine manufacturers have assisted by offering robust warranties. Warranties of five years duration are typical and, while lesser periods may be acceptable for proven technology, 10-year warranties have been reported. Twenty thousand operating hours are needed to demonstrate that technology is proven. Offshore in particular, wind turbine manufacturers are keen to stake a position at the forefront of an industry in its first stages and to identify first hand the actual and potential problems. Wind turbines are growing larger in size, producing greater yields, with offshore providing more opportunity than onshore in this respect. GE is a market leader, employing its 3.6 megawatts offshore turbine at Airtricity's Arklow Bank project in Ireland: this is the world's first commercial use of offshore wind turbines more than 3.0 megawatts in capacity. GE Wind is also active in the UK market.

Contractors who are responsible for civil works and balance of plant have been reluctant to enter into EPC (engineering, procurement and construction) arrangements that would make them jointly and severally liable with the turbine manufacturers for risks for which the turbine manufacturers are responsible (design, supply and installation of the wind turbines). Instead, general contractors prefer that each should contract directly with the developer in respect of the scope of its own works: the various contractors then enter into an interface agreement among themselves, regulating their mutual liabilities.

The conventional EPC structure is still used by some consortia, together with back-to-back agreements apportioning liability among the consortium members. Conceptually, there is no great distinction between the ultimate liabilities under an EPC arrangement with a back-to-back agreement as compared to separate contracts with an interface arrangement: so long as the responsible party is financially sound (and there have been questions raised as to the creditworthiness of some manufacturers), a company incurring exposure through no fault of its own should ultimately have satisfactory recourse against the responsible party. Some argue that the EPC structure with its single point of responsibility is itself too rigid for the practicalities of offshore wind projects. Such concerns might be assuaged by introducing an element of partnering to address, for example, weather risk and cost overruns. At North Hoyle, a long lead time of 12 months was used to mitigate schedule risk.

Apportionment of weather risk is still an issue between developers and contractors. However, it is particularly noteworthy that non-recourse financing is not currently available for the construction phase of offshore wind projects: while this may lessen the demands for an EPC structure, it raises further questions of how developers should raise funding. There is room here for deep-pocket sponsors and, possibly, private equity.

While who takes weather risk may be an open question among the various parties, lenders appear increasingly comfortable with wind risk. Data are available to identify the wind risk in a particular area: if the area is assessed as "P99," for example, then that means that the wind is expected to be enough at the project site to enable debt service to be covered in 99 out of 100 years. Weather derivatives are also available if the generator chooses to hedge the risk: the downside is that, in so doing, the generator trades away any upside in price (unless it chooses to trade in the market by buying wind "puts").

Deal Terms

Financing is offered for terms of up to 15 years. Offshore leases range from terms of 22 years (in round 1) to 40 years (in round 2), so there is enough of a tail after the financing has been repaid for comfort, and lenders do not need to concern themselves with decommissioning issues.

Lenders are willing to accept contracted O&M (operation and maintenance) support for just the first five years of commercial operation of onshore projects, but a longer period will be required offshore. Maintenance reserve arrangements are open for discussion, but lenders will typically require six months of debt service reserve.

Debt service coverage ratios of 1.3 to 1.4 might be expected, although the market is fluid in this respect. Debt-equity ratios are in the region of 75-25.

A firm offtake contract is key: windpower is claimed to be unbankable in the UK on a merchant basis (although it has been banked in Ireland). As reported in the December 2002 issue of *NewsWire*, renewable obligations certificates, or "ROCs," are key to making a successful offtake contract. To recap briefly, ROCs constitute government support: renewable generators are awarded ROCs that can be sold on the open market. Electricity suppliers (as opposed to genera- / continued page 14

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feedstock and product conveyors, and storage tanks" for the chemical reagent, the IRS said. The memorandum is ILM 200334024.

A Senate subcommittee has launched an investigation into the synfuel industry. The subcommittee — called the Senate permanent subcommittee on investigations — has a broad mandate to shine a spotlight into dark recesses of the federal government. The subcommittee has subpoena power. It does not ordinarily legislate, but brings its findings to the attention of the public through public hearings. It is the same subcommittee that conducted the Army-McCarthy hearings in the 1950's and that forced executives of the major oil companies to testify about high gasoline prices under the glare of television cameras during the Arab oil embargo in the 1970's. The staff director said it is still too early in the investigation to predict in what direction it might be headed.

The energy bill currently stalled in Congress would allow new synfuel plants to be built in the future and qualify for tax credits. However, the tax credit would be only 51.7¢ an mmBtu and would be capped at $37,760 a year per project. In addition, the bill would define synfuel more narrowly for future projects. Output from a future plant could only qualify as synfuel if it has a market value at least 50% more than the value the raw coal used to produce it and if there is at least a 20% reduction in the amount of nitrogen oxide and either sulfur dioxide or mercury released from burning it.

STATE TAX CREDITS can be sold and the buyer can deduct the cost immediately, the IRS said.

An individual qualified for a tax credit against state income taxes for renovating an historic property. He could not use the tax credit, so he sold it to / continued page 15

Risk Allocation

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tors) and traders pay a penalty of £30/mWh (indexed) to the extent they fail to supply (or trade) 3% from renewable sources. The proceeds of this penalty are distributed among the ROC holders, thus creating a market dynamic. Under offtake contracts, generators will transfer their ROCs to their offtakers in return for a fixed price.

Perhaps unsurprisingly, most of the income of renewable generators comes from ROCs rather than electricity sales — some £47 a megawatt hour against £17 a megawatt hour in 2003. It can be seen from this how important ROCs are to the bankability of a project.

Conversely, actual and potential weaknesses in the ROC mechanism may serve to undermine the renewables market disproportionately. First, there is the commercial risk that parties will default on their penalty obligations, thus reducing the amount to be distributed and the value of ROCs themselves: TXU failed to pay £23.1 million owing in this respect when its UK operations collapsed. Second, the value will be diluted as more renewable generation comes on line. Third and most important is the political risk. The UK government states that it is committed to ROCs in the long term, but lenders and developers focus on the fact that, whereas 10% of all electricity supplies from renewable sources by 2010 is a target, 20% by 2020 is no more than an aspiration. On that basis, lenders and developers argue that all renewable projects are deemed merchant after 2010. Some might regard this argument as somewhat disingenuous: the implication is that such projects then become unbankable while, actually, terms of offtake contracts for renewable projects do extend beyond 2010 (even if the balance of contractual risk may change) as do the terms of the requisite loans. Therefore, there is presumably some confidence that ROCs will remain in place after 2010. Nevertheless, the government is committed to review the ROC mechanism in 2005 or 2006, and there are calls for it to boost the market by making 20% by 2020 a target rather than an aspiration as well as by increasing ROC prices.

Political and regulatory risk remain a material issue, both on a UK and a European Union level. The EU is expected to introduce an emissions trading scheme in 2005, and it is unclear how this will interact with the ROC mechanism, which is a different type of product. The UK government needs to maintain financial support for the renewables sector, particularly offshore wind while that market is nascent with the attendant high prices. Government support is seed corn money. As well as ROCs, it takes the form of capital grants. In October this year, the government announced it was giving £59 million in grants to six offshore wind farms in addition to £58 million previously allocated to another six.

A pattern of financeable risk allocation is emerging in UK wind projects.

Remaining Obstacles

While most risks can be managed between the parties to a project, there are some large-scale obstacles to the initial development of wind farms. These relate to planning and the grid network.

The planning approval process onshore and offshore has not been uniform throughout the UK. Onshore, the approval rate in Scotland is 90% while in Wales it is only 20%. This regional variability fuels further applications in Scotland, but it may lead to a Scottish backlash against wind farms on the basis that the Scots have to view what some regard as eyesores so that others elsewhere can feel environmentally virtuous. Reasons for delay in the planning stage include landowner and developer inexperience of "section 106 agreements." Section 106 agreements are contracts between developers and local authorities under which planning permission is granted in return for developers upgrading highways and other public works. Offshore, planning has been complicated by there being two alternative routes to obtain approval, one centered on section 36 of the "Electricity Act 1989" (also the route used onshore), the other centered on the "Transport and Works Act 1992."

The government is seeking to address problems both onshore and offshore. In October 2003, it issued a consultation paper seeking comments on the proposed Planning Policy Statement 22, or "PPS22." PPS22 is intended to set out the framework within which planning decisions on onshore renewable energy projects should be made by local planning authorities. The object is to assist in meeting the target of 10% by 2010 as well as in cutting CO_2 emissions by 60% by 2050. Among the government's proposals are that planning policies that rule out or place constraints on renewable energy technologies should be barred. In addition, planning authorities should seek to promote public knowledge and acceptance of renewable projects. The government wants regional targets to iron out disparities. It also wants to prevent local landscape from being used as a reason to prevent development. What form PPS22 finally takes remains to be seen, but it should be expected that onshore planning policy guidance will evolve in a more renewables-friendly direction.

PPS22 applies to England: equivalent documents are being issued by the Scottish Parliament and the Welsh Assembly. Regarding offshore wind farms, the government plans to assert jurisdiction in relevant areas outside territorial waters in a similar way to that used to exploit North Sea oil and gas and to rationalize the planning process so that section 36 becomes the lead consent in the way that it is onshore (although additional types of consent will be needed to address the fact that these projects are marine).

The obstacles relating to the grid network are regulatory and practical in nature. One concern is whether wind farm generation can be suited to the grid code (part of the regulatory regime). The grid's requirement for stability conflicts with the sporadic nature of wind farm generation.

Some in the industry take the positive view that it is up to manufacturers to carry out the requisite research and develop wind turbines that can cater to the grid's demands for stability, frequency response, reactive power and fault ride-through. However, all sides recognize that the grid system needs upgrading in any event. Even though the UK network does have an availability of 99.98%, much of the transmission network was constructed more than 40 years ago and is regarded as needing urgent replacement. The problem this raises is that the time required for the planning and construction phases of new grid infrastructure is / continued page 16

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another individual as allowed by state law. That individual claimed the credit and used it to reduce his taxes.

The IRS said in a private ruling that the individual who used the credit could not only use the credit to offset his state income taxes, but he could also deduct the amount he paid for the credit against his federal income taxes.

The IRS reasoned that section 164 of the US tax code allows individuals and corporations to deduct the state income taxes they pay. It might look like the buyer who used the credit ended up not paying any state income taxes. However, in fact, he bought an item of "property," the IRS said — the tax credit — and used the property to pay his taxes. Anyone using property to extinguish a debt is treated as if he sold the property for cash and then used the cash to pay the debt. The IRS said that is effectively what happened here.

The ruling is Private Letter Ruling 200348002. The agency made it public at the end of November.

MUNICIPAL LEASE DEALS are under investigation by the staff of the Senate Finance Committee.

The committee chairman, Senator Charles Grassley (R-Iowa), asked the US secretary of transportation in mid-November to supply the committee with copies of all "LILOs, SILOs, QTEs, and similar transactions" that the US Department of Transportation has reviewed since 1995. Grassley said the transactions are allowing US corporations to claim "billions of dollars" in "bogus depreciation deductions" on "bridges, water lines, sports stadiums, and subway systems constructed with taxpayer dollars."

Grassley said he will press for legislation to shut down municipal lease deals retroactively to November 18, / continued page 17

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historically some six to seven years, which means that, if the planning phase started now, the infrastructure would be unlikely to be available for transmission of the 8,000 additional megawatts needed from renewable sources in order to meet the government's 10% target for 2010. Even before the planning stage begins, a decision will have to be made how to fund the £1 to 1.5 billion anticipated costs of the infrastructure works. Ofgem — the industry regulator — has recently issued a consultation paper on this. The government will have limited scope to expedite this process since there will be numerous private land interests involved.

Planning thus appears the main outstanding issue facing those seeking to develop the UK renewable sector, particularly windpower, and this is in the context of both approval of specific schemes and the upgrade of grid infrastructure. There are other complications in the planning process relating, for example, to the Ministry of Defense and the protection of birds. Nevertheless, planning approval rates are accelerating, and the government is committed to facilitating the planning process and supporting the industry financially.

Meanwhile, there is the requisite will among lenders, developers and manufacturers to make wind projects commercially viable and to take advantage of offshore projects to develop technologies which produce greater yields. ◎

The Schwarzenegger Energy Policy?

by Robert Weisenmiller, Steve McClary and Heather Vierbicher, with MRW & Associates, Inc. in Oakland, California

Although Arnold Schwarzenegger only took office in California on November 17, it is not too early to speculate about the implications of the new regime for energy markets in general and the project finance community in particular.

This article has three parts. It looks first at the broad political landscape that Schwarzenegger must navigate because that landscape will limit his options when it comes to energy policy. Then it explains the state budget crisis that will have to be the new governor's first priority and that could force him to spend political capital that he could otherwise use to address energy issues. Finally, it discusses the governor's energy strategy as outlined during his campaign. Putting these pieces together, the article offers some insights into how the energy industry may develop in the new Schwarzenegger era.

Political Landscape

The political landscape facing the Schwarzenegger administration is complex and sets limits on any California governor's ability to govern.

California has a multicultural society that gives rise to wide-ranging political philosophies. Term limits have produced inexperienced legislators and strengthened lobbyists' role in the legislature. State budget passage requires a two-thirds majority, leading to recurring annual deadlock in Sacramento. Primaries favor each party's more extreme candidates, leaving moderate politicians locked out of the general elections. A progressive legacy inflates the role of the state's residents through initiative, referendum, and the recall process that brought Schwarzenegger into office.

Democrats currently control both houses of the California legislature, giving Republicans little or no meaningful voice in the legislature. Only on budget issues, taxes, and urgent legislation, all of which require a two-thirds vote to pass, do the Democrats need a few Republican votes to pass legislation. Not surprisingly, an initiative to reduce the number of votes required to pass a budget or raise taxes has qualified to be on the ballot in next spring's election.

The ballot initiative adds another layer of complexity. Under California's constitution, petition drives can place initiatives directly on the ballot. In fact, voter initiatives are quite common. Periodic "grass root" outbursts have resulted in major policy shifts such as the limitations on property taxes and the establishment of term limits. Now Californians can also point to their first successful recall of a governor. The legacy of voter initiatives includes an increasingly dysfunctional state government that responds to crises with inaction and photo opportunities.

Budget Mess

Key Democratic leaders realize that Schwarzenegger has received a strong mandate from California's electorate to shake up Sacramento and the political *status quo*. Nevertheless, they are likely to challenge this political neophyte. The budget crisis may present Democrats with their best hope for tripping up the new governor, just as it proved the undoing of Gray Davis. Unpopular spending cuts or tax increases could quickly eliminate the political capital with which Schwarzenegger entered office.

In the late 1990s, California received an unprecedented budget windfall as the dot-com boom brought new revenue into the state coffers. Rather than reduce taxes or establish an expanded reserve, Gray Davis and the legislature squandered most of this one-time windfall by increasing spending on politically popular programs. Expenditures in the 2000-2001 fiscal year rose 20% over the previous year. However, when the economy fell into recession the windfall was lost. In the summer of 2002, legislators had to overcome a $23 billion deficit to reach a balanced budget for fiscal year 2002-2003. The governor and the legislature used a series of accounting tricks, short-term loans, and raids on special funds to paper over the problem rather than cut programs or increase taxes — painful actions to take in an election year.

By the summer of 2003, Governor Davis and the legislature faced a two-year budget gap of $38 billion, an amount equivalent to one-third of general fund spending. One month after his re-election, Governor Davis claimed that it was time to address the budget deficit with a mixture of spending cuts and tax increases. A special session of the legislature generally ignored his proposals and adopted a budget that included a tripling of the vehicle license fee, a proposed $1.9 billion bond sale to pay on-going pension obligations, and another bond issue of $11 billion to finance the deficit.

Predictably, tax increases proved unpopular. Following through on a campaign pledge, Governor Schwarzenegger repealed the unpopular vehicle license fee on his first day in office. The deficit reduction bond measures are already being challenged in court on the grounds that the state constitution requires voter approval. Schwarzenegger says he will ask voters to approve a deficit finance bond measure of as much as $15 billion, but his proposal has already run into opposition in the legislature.

Schwarzenegger also has proposed mid-year budget cuts and state workforce reductions, although specific details are not yet available. He must propose a detailed budget for 2004-2005 to the legislature in January and convince the legislature to enact it. Given his expressed desire to limit cuts in social programs, he has a difficult balancing act ahead. Clearly, California's budget challenges dwarf the fictional foes faced by action hero Schwarzenegger.

So far it has been unwise to underesti- / continued page 18

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2003. Language to do this is included in a bill the Senate Finance Committee reported to the full Senate in October. The bill is "must-pass" legislation in 2004. Its main focus is to rescind a tax break for US exporters that the World Trade Organization has declared illegal. The European Union will start imposing punitive duties on imports of US goods starting on March 1 unless the export tax break is repealed. The bill would require companies leasing equipment to municipalities to treat any service contract under which the municipality agrees to continue operating the equipment after the lease ends as part of the "lease term." This would have the effect of reducing the value of the depreciation deductions that the lessor can claim on the leased equipment. The Senate is expected to take up the measure in early 2004. Grassley said he would seek to make it retroactive to leases entered into after November 18, 2003.

Meanwhile, the Democratic staff of the Senate permanent subcommittee on investigations — a separate subcommittee not normally involved in tax issues but with a wide mandate to investigate all government programs — issued an 86-page report in mid-November on the "tax shelter industry." The report focuses on several tax shelters marketed by KPMG. The subcommittee held two days of hearings on tax shelters on November 18 and 19.

Bob Roach, minority counsel to the subcommittee, said the investigation has not been completed. No further hearings are planned, but they remain possible.

INDONESIA jailed an oil company executive because his company failed to pay the proper amount of taxes.

The action is a warning to senior corporate executives in other countries.

This is the first detention under a regulation announced in July / continued page 19

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mate Schwarzenegger the politician. He ran a brilliant and unconventional recall campaign. He attracted a respected group of economic advisors, including Warren Buffet and George Schultz. Schwarzenegger has pledged to make direct appeals to the public and use the power of reform initiatives if blocked by the legislature. Given his unconventional route to the governor's office, that strategy may work, particularly since polls show the legislature and its career politicians are even less popular than ex-Governor Davis.

Schwarzenegger will probably resume the push for deregulation in California — if the state budget mess does not prove too large a distraction.

Energy Policy

Against this backdrop of fiscal crisis and political volatility, fixing California's energy policy and regulatory environment will be a cornerstone of Schwarzenegger's initiative to improve California's business climate. Schwarzenegger needs to get the right policies in place soon for several reasons. First, energy is likely to be a key campaign issue in the 2006 elections. Second, California appears to have a small window of opportunity to attract needed investment that can forestall an energy shortage predicted for the end of the decade.

Energy policy has been highly politicized in California since well before the energy crisis in late 2000 and early 2001. Indeed, California's energy morass stems from the restructuring framework enacted during the previous Republican administration. However, it was the combination of high prices and apparent market failure during 2000 and early 2001 that made electricity restructuring a public issue and branded the Davis administration as hesitant and indecisive.

Every politician with ambitions for higher office has his or her own energy policy agenda. State Senator Joseph Dunn, supported by California's trial lawyers and eyeing the attorney general job, would "end energy deregulation rather than mend it." State Treasurer Phil Angelides, a potential gubernatorial candidate in 2006, supports a resurgence in public power. Another likely candidate for governor, Attorney General Bill Lockyer, emphasizes the litigation his office led before the Federal Energy Regulatory Commission and in civil courts against the energy "market manipulators".

The best guess today is that California will need significant additional generating capacity by the end of this decade. Given project lead times in California, there is a limited window of opportunity to re-establish the necessary prerequisites for attracting investment in energy infrastructure.

Investment in California's energy infrastructure is hampered by a litany of woes: a lack of creditworthy buyers and sellers, unclear market rules, a flawed wholesale market design, and the operational and economic impacts of the portfolio of expensive and inflexible power contracts signed by the state Department of Water Resources, or "DWR," during the California power crisis in 2001. Topping off this list, key members of the legislature are hostile toward anything that could be characterized as deregulation.

Just as in many other parts of the US, a large number of efficient gas-fired power plants were built in California in the last few years, and the state now has adequate reserve margins. DWR's contract portfolio and California's successful demand-side-management programs have left California generally long on capacity. However, the state still faces a capacity shortfall during periods when demand peaks simultaneously in California and neighboring western states. In addition, some geographic areas, such as San Francisco and San Diego, have inadequate transmission capacity that has created a need for additional local generation or expanded transmission.

The legislature adopted an aggressive renewable portfolio standard to add diversity to California's generation mix. This requires the investor-owned utilities to enter into long-term contracts for renewable resources to meet the new standards. It increases pressure on merchant power plants that have not locked in buyers for their output. Particularly hard hit are older, inefficient power plants that were mostly divested by the investor-owned utilities in the late 1990's. Partially completed new projects without power purchase contracts have been put on hold, and less efficient power plants are being mothballed. A dry year that causes hydroelectric plants to reduce output, significant power plant shutdowns, or a resurgence of load growth could bring new power shortages. The chart above shows forecasts of demand in relation to supply by the California Energy Commission. Supply is expected to be adequate through 2007, but there is at least a one-in-ten chance that supply will fall short during this period.

To shape a new energy policy, Schwarzenegger will need to not only work with the Democratic legislature but also with Davis appointees. For example, no new seats on the California Public Utilities Commission will open up until early 2005 (unless a sitting commissioner steps down before the end of his or her term). Schwarzenegger will have an opportunity to appoint a new commissioner to the California Energy Commission in early 2004. The Senate must confirm appointments to either agency. Both agencies are governed by five commissioners, so it could take two or three years for Schwarzenegger to appoint a working majority. He may need to rely extensively on line-item budget vetoes to reshape these agencies. Or he may pursue a more aggressive agency consolidation approach, discussed below.

Predictions

Governor Schwarzenegger is expected to bring a needed infusion of fresh thought to the state's energy policy, which has been driven by reaction to the failures that led to the power crisis in late 2000 and early 2001.

Schwarzenegger's campaign stance was notable for reliance on market strategies rather than a continued railing against the problems of the state's deregulation to date. His administration also professes a willingness to learn from successful deregulation efforts elsewhere in the country (see sidebar). At the same time, he faces the constraints described earlier on his ability to act.

Some of Schwarzenegger's policies should be fairly uncontroversial with the legislature and the holdover Davis appointees. The following five policies fall into this category.

1. A strong commitment to the environment. One of the new governor's first appointments was Terry Tamminen, a longtime conservationist and a political independent, as secretary of the Environmental Protection Agency. Tamminen is expected to try to streamline California's permitting and regulatory review processes, allowing certain "green" objec- */ continued page 20*

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2003 that allows the jailing of delinquent taxpayers owing taxes of more than 100 million rupiah — or about $12,000 — for up to one year without trial, reports Hilton King with Makarim & Taira S. in Jakarta. The amount of taxes in this case is about $5 million. The executive — a British citizen — works for a Canadian company, Fortune Oil & Gas. "There are supposed to be dozens of other persons, including more expatriates, that will be made subject to a detention order if their taxes are not paid," King said. It is not unusual in developing countries for companies to fail to declare their incomes fully to preserve some bargaining room because of the habit of tax inspectors to "negotiate" over the amount of taxes payable.

ITALY is replacing its corporate income tax.

Starting on January 1, corporations will be subject to tax at a flat rate of 33%. Italy is adopting a "check-the-box" system that will allow taxpayers to elect to treat certain companies as transparent for tax purposes. Companies will have the option of filing consolidated returns with Italian affiliates or even filing a worldwide consolidated return that includes affiliated entities that are outside Italy. Unused foreign tax credits may be carried backward and forward for the first time. There are also new "thin capitalization" tests that will limit the ability of parent companies to "strip" earnings from Italian subsidiaries by injecting capital into the subsidiary heavily as debt so that earnings may be pulled out in the form of interest.

PERU will collect a 0.15% banking transaction tax starting January 1. However, banks will have until February 1 to comply. Details were published in the official gazette on December 5.

HUNGARY will impose a */ continued page 21*

Schwarzenegger Plan

Governor Schwarzenegger wants the various state energy agencies to follow a single energy policy. He favors better price signals at the retail level. Private investors in generation and natural gas infrastructure will be courted.

Schwarzenegger will renew the push for deregulation of power markets while providing insurance against a repeat of the price spikes and power shortages that plagued California in late 2000 and early 2001. His action items include real-time pricing and retail choice for large commercial and industrial customers point. He also wants to limit the ability of state regulators to review the prudency of utility power purchases. His plans to impose reserve requirements suggest an understanding that some safeguards must be put in place. A proceeding is underway at the California Public Utilities Commission to decide on an appropriate reserve requirement for the state's investor-owned utilities. A final decision may be issued before the end of this year.

Schwarzenegger favors private investment in power generation and natural gas infrastructure. The California Power Authority has a mandate currently to make public investments in the electricity sector. This is at odds with the Governors vision. Therefore, Schwarzenegger is expected to propose eliminating the CPA. He may also try to eliminate the Electricity Oversight Board.

California may find itself re-embracing electricity restructuring under Schwarzenegger. The governor has promised to look to the experiences of states in New England and the mid-Atlantic region and to Texas to understand how these states' successes can be replicated in California.

Finally, Schwarzenegger stated his intention to "explore options for renegotiating . . . overpriced electricity power purchase agreements" entered into in 2001 when electricity prices were at an all-time high. However, the state has already renegotiated 22 long-term contracts and is holding on-going negotiations with another seven energy firms over their contracts. ◎

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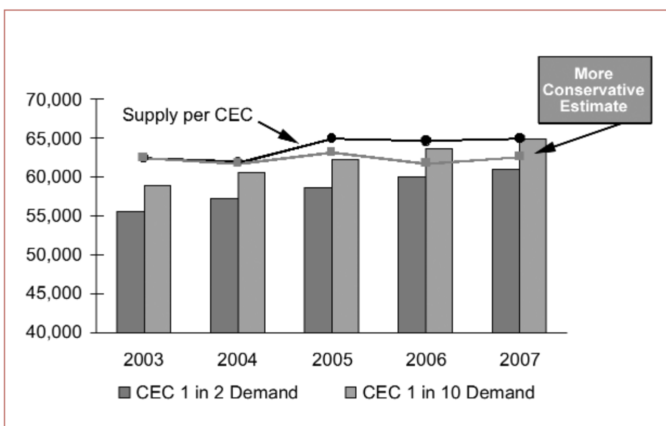
tives to be achieved more efficiently. Environmental issues are likely to continue to be a strong element of policy in this green-friendly state.

2. Support for demand-side management programs and renewable energy. Schwarzenegger wants an increase in the renewable portfolio standard to 30%, a very aggressive goal. This is good news for investors in such resources, but it may prove a constraint on other generation development.

3. Investment in California's energy infrastructure, in particular natural gas transmission projects and new generation, as a key to stabilizing the energy markets. The governor also wants advanced meters that would allow for better pricing signals through "real-time" pricing.

4. Consolidation and pruning of California's energy regulatory agencies. An early candidate for elimination is the California Power Authority, which was created in the middle of the energy crisis and has been searching for a role ever since (see sidebar). Rationalizing the state's energy regulatory structure could reduce the regulatory risk in generation and transmission development.

5. DWR contract restructuring. Schwarzenegger wants to rewrite some contracts that the DWR signed in 2001, but his options may be limited because many of these contracts were renegotiated in some fashion under Governor Davis. He may try to involve the utilities more directly, instead of relying primarily on DWR and its consultants and legal advisors. The utilities could consider a broader range of restructuring tools, such as contract buy-outs rather than



simply trying to shorten the contract terms.

In other areas the new administration will face greater opposition from the legislature and from Davis holdovers and separately elected constitutional officers in the executive branch. There are four policies where such opposition is expected.

a. Core/Non-core retail structure. Since the suspension of third-party options in 2001, large customers and their suppliers have supported a return, perhaps limited, to a retail market that offers choice to consumers. Recent proposals focus on core and non-core approaches that would afford choice to large, presumably more sophisticated customers. Opposition by key members of the legislature is fierce, and this may be one of the early energy battlegrounds for the Schwarzenegger administration.

b. CPUC revenue allocation and rate design have moved strongly in recent years toward protecting small consumers. A more pro-business Schwarzenegger policy orientation may push this pendulum back toward rate design that takes economic development and business retention concerns into account.

c. State-federal confrontation. Schwarzenegger would like to end the Davis administration's bitter confrontations with the federal government on all fronts. A return to the Republican fold would seem to point to a new *rapprochement* between Sacramento and Washington. However, the state attorney general is expected to pursue his energy litigation with the Federal Energy Regulatory Commission through every possible appeal. In the near term, Schwarzenegger will have limited influence on the California Independent System Operator, the California Public Utilities Commission and the California Energy Commission, each of which has its own differences with its federal counterparts.

d. Regional cooperation. Given how interconnected western power and gas markets are, it would be wise to work with the Federal Energy Regulatory Commission and the other western states to achieve a regional, competitive wholesale market. However, we expect other western states to harbor continued mistrust of California, attempting to erect a "firewall" around California, even though most politicians in neighboring states will be much more interested in working with Schwarzenegger than they were with Davis. The Pacific Northwest is vigorously opposed to the "standard market design" proposed by the Federal Energy Regulatory Commission. It could easily take five years or more to achieve any truly regional approaches.

To sum up, California was already taking / *continued page 22*

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new tax on electricity and gas sales starting January 1.

The tax is HUF 186 per megawatt hour of electricity and HUF 56 per gigajoule of natural gas. It must be paid by energy distributors and traders on sales to commercial and industrial customers who consume more than 6.5 gigawatts of electricity a year or more than 500 cubic meters per hour of gas. The tax is expected to raise HUF 11 billion in 2004, or a little under $49 million.

The Hungarian parliament also voted to cut the corporate tax rate from 16 to 14%.

GREECE said in October that it will cut the corporate tax rate from 35% to 25% on investments of more than 30 million Euros in an effort to attract foreign investors. An investor will benefit from the reduced rate for 10 years.

GOVERNMENT OPERATING SUBSIDIES must be reported as income, the IRS said.

The IRS made the statement in late October in a "coordinated issues paper," or memo sent to IRS agents in the field about how to handle an issue that is coming up frequently in audits of telephone companies.

When Congress further deregulated the US telephone industry in 1996, it worried that the quality of service would decline in urban ghettos and farm communities that offer less opportunity for profit. Therefore, it required by law that "all providers of telecommunications services should make an equivalent and non-discriminatory contribution to the preservation and advancement of universal service." Congress also set up a fund. Each telephone carrier must pay a percentage of its interstate end-user revenues into the fund. The carriers collect the amounts as a "USF surcharge" on phone bills. Disbursements are then made from the fund back to telephone carriers to help defray the cost of deliver- / *continued page 23*

California Energy Agencies

California has a patchwork on energy agencies. Together, they spend $314 million a year, with the bulk of it — $223 million — spent by the California Energy Commission. There are at least seven such agencies:

Electricity Oversight Board: Responsible for monitoring and investigating matters related to the electricity grid and electricity markets.

California Energy Commission: Has statutory authority to license thermal power plants over 50 megawatts in size. Responsible for forecasting California's energy needs and developing long-term energy policies. Promotes renewable energy and energy efficiency. Supports research and development of new energy technologies.

California Public Utilities Commission: Regulates privately owned telecommunications, electric, natural gas, water, railroad, rail transit and passenger transportation companies. Sets rates, standards and safety rules for the various regulated utilities under its jurisdiction.

California Independent System Operator: A not-for-profit corporation created by the state legislature but regulated by the Federal Energy Regulatory Commission. Manages the majority of California's transmission system.

California Power Authority: Ensures California has a sufficient surplus of generation capacity. Finances new electricity generation.

California Energy Resources Scheduling: A division within the Department of Water Resources. Manages the long-term electricity contracts signed by the state on behalf of the state's three largest investor-owned utilities.

Division of Oil, Gas and Geothermal Resources: Involved in various energy-related regulatory activities, including oil-drilling activities. ◎

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steps to restore confidence in the energy regulatory and investment climate before the election. Personnel changes at the CPUC and CEC were obvious examples of that movement. The Schwarzenegger administration will continue in this direction if it is not distracted or stymied by the state budget mess. The state was singed if not scorched by the inept way in which it deregulated electricity supply in the 1990's and then responded to the electricity crisis. Schwarzenegger appears to want to resume the push toward true deregulation. It could be at least two years and maybe longer before anyone can tell whether he will succeed. ◎

Russian Due Diligence

by Laura Brank, in Moscow

I have been working in Moscow for more than eight years, and I constantly have clients coming in, dropping a memorandum of understanding on the desk and saying, "Look, we have signed this great MOU with these guys. We have been dealing with them for six months, everything is great, can you just formalize everything?" I ask them, "Did you conduct due diligence?" They respond, "Well, no, because we have been working with them for six months, we have seen the licenses, we have looked at their charter and we are okay with everything."

Due diligence is extremely important in any transaction, but it is even more important in the Russian context.

There is an expression that came out of the negotiations between Ronald Reagan and Mikhail Gorbachev over disarmament, where Reagan turned with a smile to Gorbachev, and said "*doveryay no proveryay,*" which means "trust but verify." That is very much the case in all Russian deals. All information from Russian partners needs to be verified. This applies across the board, whether dealing with partners or a company in which one is investing, and even with suppliers. One really needs to know with whom one is dealing, especially in light of the changes in the world since September 11, 2001 and the Enron and WorldCom collapses in the US.

Why?

Due diligence is critical in Russia for a number of reasons.

First, there is a lack of transparency in Russia, in terms of both ownership and financial statements. Although this is becoming better, it can still be very difficult to find out who owns a company because companies are hidden behind layers of offshore entities. Transparency is also a problem on corporate balance sheets. There are a number of hidden liabilities with which a western lender or investor may not be aware because they are not captured on the company's balance sheet. These often involve sureties, guarantees, barter relationships and other kinds of trades. Also, managers often keep two sets of books. They used to do this for tax evasion reasons. These days they do it to hide related-party transactions from authorities.

Another reason due diligence is so critical is that there is a lack of publicly-available information in Russia. It is very difficult to perform quick research on asset filings or to determine whether a company's stock has been properly issued. This research takes considerable expertise.

Bribery also makes due diligence important in the Russian context. Bribery may be a concern to a western investor, but it might not cross the radar screen of a Russian company — and thus may not be disclosed upon inquiry — because the company did not view it as a problem. Is there bribery in all Russian companies? Yes and no. There is a certain level of corruption in almost all Russian companies, but the scope and recurrence differ from one company to the next. The Yukos case, in which bribery is alleged at the highest levels of the Russian oil giant, is an extreme — but cautionary — tale. An investor or lender should find out if bribery is rampant and at what level. Money laundering is prevalent as well, and should be investigated.

Environmental problems may also sneak up on an investor or lender. Many Russian companies are violating environmental laws. They do not think it is any big deal because they pay small fines and penalties. Like bribery, environmental problems do not give much for concern to them and so they may not mention them to an investor.

Finally, any number of non-Russian laws may apply to a Russian company. One example is the US "Foreign Corrupt Practices Act." Many Russian companies now have to comply with it because they are listed on US exchanges. There are similar laws in England. The "USA Patriot Act" is another example. (See article on USA Patriot Act on page 28.)

What to Look For

Once the decision has been made to conduct due diligence on a Russian company, the question is what to */ continued page 24*

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ing mandated universal services. There are similar universal service funds at the state level to which phone companies can submit claims for reimbursement for lost revenues.

The phone companies argue they should not have to pay income taxes on the amounts they receive from these funds. Government subsidies often go untaxed — for example, where a local community reimburses a railroad for the cost of an overpass so that highway traffic will not be tied up by trains or a city reimburses an electric utility for the cost of burying power lines.

However, the IRS insists the subsidies in this case are income because the intention is to supplement the telephone company's income.

The telephone companies may end up in court. The IRS coordinated issues paper is UIL:61.40-01.

US MULTINATIONALS are at risk of losing US tax deferral after a change in ownership of offshore subsidiaries.

The risk is to offshore subsidiaries that have existed since at least May 1996.

American companies are subject to income tax in the United States on worldwide earnings. However, most adopt ownership structures that delay any US tax on profits earned in other countries until the profits are repatriated to the United States. This requires operating abroad through an offshore holding company — for example, in Holland or the Cayman Islands — and ensuring that all legal entities formed in other countries as subsidiaries of the offshore holding company are considered "transparent" for US tax purposes. Transparency is usually a matter of making an election on a tax form filed with the Internal Revenue Service. However, the IRS publishes a list of legal entities for which an election is not allowed. There is gener- */ continued page 25*

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look for. The following is a discussion of the major issues to keep in mind. All of this is very practical, not theoretical, advice. These are issues that Chadbourne has seen over the course of being involved in Russian transactions. For most of these items, Chadbourne has been involved in litigation or disputes arising subsequent to an investment by a foreign company.

The point of the due diligence is not to find problems that mean you cannot go forward. It is to find problems and resolve them before committing a lot of time, resources and money to the project only to find out about these problems later.

First, an investor or lender must verify that the Russian company has been properly established and its shares were validly issued.

Shares acquired in a privatization give particular cause for concern because almost no privatization in Russia went off without a hitch. It is very rare that a privatization was carried out in full compliance with the laws of the time. President Vladimir Putin recently said, in connection with the Yukos matter, "Oh no, we are not going to go after all privatizations. This is a unique situation because of the criminal element." Whether or not that statement is entirely accurate will become clear over time. However, even if the government does not go after an asset, a competitor might. This is something to look out for.

A due diligence inquiry should also look into whether the company's charter complies with Russian law. It may contain restrictions on foreign ownership. In most cases this is illegal, but nonetheless such restrictions are often found and could cause problems going forward.

Registration is extremely important. You cannot obtain shares in a Russian "closed" or "open" joint stock company unless those shares have been registered. This is not a theoretical or merely formalistic issue. For the last year and a half, Chadbourne has been working with a client that bought a majority interest in a mining company in the Far East. It had purchased its shares from another western company. Unbeknownst to this shareholder, the shares were not registered at the time the company was formed. The minority shareholders were having some financial problems and decided that a good way to extract money — both from the majority shareholder and the company — was to take advantage of the fact that the shares had never been validly issued. The minority shareholders had held the shares for six years at that point and had been receiving dividends from the company for the entire time. Nonetheless, they challenged the validity of the share issuance because the shares had been traded before they were registered.

Clever Russian businessmen use the fact that form frequently prevails over substance to help strip foreigners of their Russian investments.

A share purchaser should also make sure that previous transfers were valid and all required approvals were obtained. For joint stock companies, the only valid means of recognizing title is the transfer in the shareholders' register, not a share certificate. A purchase that drives a shareholder's ownership percentage above 20% of a joint stock company or a limited liability company requires the approval of the Anti-Monopoly Ministry. Also, there are pre-emptive rights for the existing shareholders to buy shares in joint stock and limited liability companies. If the seller is another shareholder, the other shareholders must have waived their rights to those shares.

Next, ownership of assets should be verified.

A lender or investor should make sure that the Russian company holds the proper title to its assets, and that the approvals required in connection with the purchase of those assets were properly obtained. The consequences of not receiving these approvals are that the Anti-Monopoly Ministry could unwind the transaction. There may also be fines.

A recent example illustrates why this is important. Chadbourne represented a lender that was providing a loan to Company A. Company A had purchased substantially all of its assets from Company B. As the transaction proceeded, it became clear that Company A had not obtained the major transaction approvals. It also had not complied with the interested party transaction rules in connection with those transfers. Amazingly, at the same time that we were doing our due diligence, the minority shareholders in Company B sued Company A for the return of those assets. They said that the assets were illegally transferred due to failure to comply with the interested party transaction rules and the major transaction rules. Luckily, in this case everything was resolved without going through the court system, but again it is just another example of how these things are not just theoretical. The cautionary tale here is that in Russia — as well as other CIS countries — form often prevails over substance. Issues that a westerner would consider to be non-substantive can have a huge impact on an investment in Russia. Very, very clever Russian businessmen use the fact that form frequently prevails over substance to help rid foreigners of their investments in Russia.

Next are real estate and land issues.

Any ownership or leasehold rights to property must be registered in Russia in order to be valid. This frequently comes up in the leasing context. Nine times out of the ten, the Russian lessor will say, "Well, we do not want to register. It is very bureaucratic. It takes too much time. It is expensive." What it usually means is, "We do not want anybody to know because we do not want to pay taxes in connection with the lease." A lease is not valid if it is not registered. (There are some exceptions for leases that are under one year in term.)

Tax issues always loom large in Russia.

An investor needs to make sure that the company in which it is investing — or with which it is doing business — is regularly making its tax filings and paying its taxes. A company should also be making regular social and pension fund contributions. Frequently Russian tax authorities, particularly in a company's first year of business, will investigate a company to try to find fault with its accounting methods.

The investigation should also verify the existence of any tax exemptions the company claims to have, or even those you, as an investor, may have. In another recent deal, a very large western investor started a big production facility in Russia about a year and a half ago. The investor was entitled to certain tax exemptions, but it mistakenly thought that those exemptions applied at the federal, regional and city levels when in fact they did not apply at the city level. The investor failed to pay city-level property taxes, and lo and behold, the authorities were all over it within a few days. */ continued page 26*

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ally one such entity in each country. An example of an entity that cannot be transparent is an S.A. or *sociedad anonima* in a Latin American country.

An offshore subsidiary that has existed since at least May 1996 may be "grandfathered." Thus, for example, an S.A. in Argentina that has existed since at least May 1996 might be allowed to be treated as transparent.

But beware: the IRS said in late October that such a subsidiary will lose its grandfather protection after a change of 50% or more in the ownership of the subsidiary. The IRS had proposed such a rule in November 1999. It formally adopted the rule in late October. The agency said any such change in ownership since November 29, 1999 will cause loss of grandfather protection. It does not matter if the change was incremental and spread over a period of years. Once the 50% threshold is reached, grandfather protection is lost. Loss of grandfather protection where too much change has already occurred will be effective as of October 22, 2003.

The agency also said that changes in indirect ownership can trigger this result — not just direct changes.

INDIA confirmed that foreign companies that invest into India through Mauritius are entitled to tax reductions under the India-Mauritius tax treaty.

The main benefit from the treaty is no capital gains taxes have to be paid when an investor exits from India by selling his shares in an Indian company. The sale of shares by a "tax resident" of Mauritius is exempted from tax under the treaty.

India has tried to deny treaty benefits in the past on grounds that the companies through which foreigners invest are merely shell companies with too little link to Mauritius to qualify as */ continued page 27*

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Other Pitfalls

Environmental liabilities need to be investigated. An environmental impact assessment should be prepared in connection with obtaining a license for any natural resource project. Licenses are also required with respect to the discharge of pollutants whether into the air, the water, the soil.

The penalties for violating Russian environmental laws are not very high, and thus some companies do not worry very much about these violations. But for financing reasons, it is very important that there is an environmental program in place and that it is monitored to ensure that there is no violation of environmental laws.

Contractual liabilities are another problem area for many Russian companies. Some companies are so desperate for financing in the early stages that they agree to outrageous terms to provide all of their output at a very "reasonable" price to a purchaser. Alternatively, they may have engaged in very long-term supply contracts in order to get the financing. The due diligence investigations should look into whether there is a way out of those types of contracts.

The Russian employment system is still very much a remnant of the Soviet system. There have been some changes since the market economy came along, but they are not dramatic.

The investigation should look to how the company terminated employees and how it has been paying employees. With respect to the latter, some Russian companies have developed tricks to get around social fund taxes, which are based on a percentage of what each individual employee is paid monthly. To lower that amount, Russian companies often engage in various schemes where they are paying insurance premiums or all sorts of other things. Recently one Chadbourne client refused to go forward with a deal because of this problem, which had gone back many years.

Bribery is a common problem in Russian companies. There are anti-bribery laws on the books in Russia. These laws not only catch payments to government officials, but also those made to commercial persons in order to win or retain business.

Currency issues are very important in Russia because there is a concerted effort to ensure that there is no capital flight out of Russia. The restrictions have lessened over the course of the last few years. They were especially tightened after the 1998 crisis.

Earlier this year the mandatory conversion requirement dropped to 25%. In other words, 25% of the hard currency that a Russian company receives for the export of its oil must be converted into rubles and cannot be converted back into dollars unless there is a specific purpose for doing so. Regulations govern what is an adequate purpose for these measures.

Oil and Gas Deals

There are issues that are specific to oil and gas deals.

The due diligence inquiry needs to look at whether the Russian company obtained all of the relevant licenses. This inquiry can be time-consuming; rumor has it that ExxonMobil needed 44 different licenses in connection with one of its projects. The benefit is worth the cost, though, as liability for failure to comply with licensing requirements can be severe. In the worst-case scenario a project could lose its license. Non-compliance includes not meeting the required levels that you need to in accordance with the law, not making timely payments of taxes, etc.

The license investigation must go deeper than simply asking whether all the required licenses were obtained. Was the licensing authority authorized to give that license? There is a lot of competition between the local and federal governments, and all the steps must have been followed. Some licenses may have restrictions on foreign ownership. These are almost always completely unconstitutional and do not accord with the law on foreign investment. It is something an investor can fight. Chadbourne represented a client who complained that, for whatever reason, the local government had imposed some crazy restriction on foreign ownership. It took us a while to get rid of the restriction, but finally the local government dropped it.

For any company that is a party to a production sharing agreement, the investigation needs to look at whether all the relevant government agencies have signed off on the production sharing agreement and whether it meets the requirements of the production sharing agreement law, which was amended this June.

Companies that export oil raise additional concerns. The company should not have substantial debts with the customs authorities for the export or import of its product. Any such arrears could prohibit it from exporting in the future. The company must have all relevant contracts in order if it is putting its product through a pipeline. Any tax indebtedness of a Russian company could prohibit it from putting its oil through the pipeline system. This happened to a major Russian oil company two years ago; Transneft suspended throughput of the company's oil as a result of the company's tax arrears to the Russian government (despite the fact that the Russian government was a shareholder in this company).

How the Patriot Act Affects Project Financings

by Samuel R. Kwon, in Washington

Lawyers in the Chadbourne offices outside the United States have been asking when and how the USA Patriot Act might come into play in project finance transactions.

The Patriot Act is a law enacted in the wake of the terrorist attacks in the United States on September 11, 2001 to give US law enforcement agencies more tools for tracking down terrorists. The statute has been criticized by civil libertarians in the United States. It has broad reach. There are three separate requirements that might come into play in project finance transactions. They relate to establishment of a private banking or correspondent account, banking with foreign shell banks, and "primary" money laundering.

One goal of the Patriot Act is to cut off the supply of funds to terrorist groups. It does this through comprehensive rules on money laundering and bank secrecy. Participants in project finance transactions should be aware in particular of three rules.

Opening Accounts

Any "financial institution" that establishes or maintains a "private banking account" or a "correspondent account" in the United States for a non-US person (including a foreign visitor or a representative of a non-US person) must establish internal due diligence procedures designed to detect and report instances of money laundering through these types of accounts.

Financial institutions subject to this requirement include all US banks whose deposits are insured by the Federal Deposit Insurance Corporation. The requirement also applies to trust companies, brokers and dealers / continued page 28

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"tax residents" of the country. However, the Indian Supreme Court put the issue to rest in a decision on October 10. The Supreme Court said it is up to Mauritius to decide who is a "tax resident" of the country and once Mauritius decides, its determination must be respected by the Indian authorities, even if the result is that income goes untaxed in both countries. Some treaties have "limitation of benefits" clauses that prevent treaty shopping where foreigners look for a third country with a favorable tax treaty through which to invest. However, the India-Mauritius treaty lacks such a clause. The Supreme Court declined to read one into it.

Roughly a third of foreign investment into India is run through Mauritius. Of the 20,000 offshore companies registered in Mauritius, nearly 6,000 invest into India. Many of the others invest into Pakistan and China, two other countries with which Mauritius has favorable tax treaties.

BRAZIL increased a social security tax called COFINS from 3% to 7.6% by presidential decree in October. At the same time, it decided to eliminate an 5% excise tax, called IPI, on purchases of machinery and equipment. The IPI tax will be gradually eliminated starting January 1 under a timetable still to be determined.

BULGARIA cut its corporate tax rate to 19.5%, effective January 1.

LUXEMBOURG is preparing to subject certain holding companies formed under Luxembourg law to corporate income taxes.

The change will apply to "1929 holding companies." These are often used by multinational corporations to own foreign operations. They had been exempted from tax in Luxembourg on income. The finance ministry released a draft bill in / continued page 29

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registered with the US Securities and Exchange Commission, investment bankers, investment companies within the meaning of the US securities laws, currency exchanges, insurance companies and loan or finance companies. This requirement also applies both to US branches of foreign banks and to foreign branches of US banks.

Any financial institution establishing or maintaining a private banking account or correspondent account must put in place procedures designed to collect two types of information: the identity of the nominal and beneficial owners of the account and the sources of funds deposited into the account "as needed to guard against money laundering."

If the account is maintained by or on behalf of a senior foreign political figure (or any immediate family member, including the spouse's parents) or by a close associate of such a figure whose association is publicly known, then the financial institution must take additional steps to detect and report any transactions that may involve the proceeds of foreign corruption. A senior political figure includes a current or former senior government official — a person with substantial authority over policy, operations or the use of government-owned resources — in the executive, legislative, judicial, administrative, or military branches of a government outside the United States, whether elected or not. It also includes a senior executive of a foreign political party or a foreign government-owned commercial enterprise.

A "private banking account" is an account (or a combination of accounts) requiring minimum aggregate deposits of $1 million or more in cash or other assets, and established on behalf of one or more individuals with direct or beneficial ownership interest in the account. A beneficial owner of an account is a person with a contractual or judicial authority to direct funds in and out of the account. It also includes a person entitled to all or any part of the assets in (or the income from) the account so long as the entitlement represents more than $1 million or 5% of the assets in (or the income from) the account, whichever is less.

A "correspondent account" is an account established to receive deposits from or make payments on behalf of a non-US bank. It also includes accounts designed to handle other financial transactions related to such a bank.

There are three requirements in the Patriot Act that might come into play in project finance transactions.

Additional requirements are imposed if the correspondent account is requested or maintained on behalf of a foreign bank that operates under an "offshore banking license" or under a banking license issued by a foreign country that the US does not believe has embraced international anti-money laundering principles. An offshore banking license refers to a banking license that prohibits the bank from conducting banking activities with the citizens of the licensing country or in the currency of that country. As of November 2003, nine countries and territories have been designated as uncooperative with international efforts to curb money laundering. They are the Cook Islands, Egypt, Guatemala, Indonesia, Burma (Myanmar), Nauru, Nigeria, the Philippines and the Ukraine. Any financial institution that maintains a correspondent account for a foreign bank from one of these nine countries or territories must identify the nature and extent of the ownership of the account owners — not just the identity of the account owners and the sources of funds. If the foreign bank in one of these nine countries on whose behalf a financial institution is maintaining a correspondent account in turn provides correspondent accounts to other foreign banks, then the identity of those other foreign banks, as well as the identity, nature and extent of ownership of the correspondent accounts in those other foreign banks, must be learned.

Banks do not have to go through all this trouble for a one-off transaction with another bank. However, an account that is used to provide *regular* service requires a full inquiry. The Treasury Department said an account providing regular service means "an arrangement to provide ongoing services, and would generally exclude infrequent or occasional transactions." While this relieves those financial institutions engaged in a "one-off" transaction with another bank, the Treasury Department has not made clear how frequent a dealing is "infrequent" for purposes of avoiding this rule.

Shell Banks

A narrower class of financial institutions is barred from establishing any correspondent account in the US for or on behalf of a foreign "shell bank."

This rule applies to banks insured by the Federal Deposit Insurance Corporation, other commercial banks or trust companies, US branches of foreign banks, thrift institutions and brokers and dealers registered with the Securities and Exchange Commission. It does not apply to investment companies, investment bankers, currency exchanges, insurance companies or loan or finance companies.

Financial institutions subject to this rule must also take steps to ensure that any correspondent account it has with a foreign bank that is not itself a shell bank is not used "to indirectly provide banking services" to a shell bank.

A shell bank is a bank that does not have a physical presence in any country. A physical presence requires a fixed place of business with at least one full-time employee. There must be operating records at that office, and the bank must be subject to the oversight of a government agency whose mission is to supervise banks.

"Primary" Money Laundering

The Patriot Act requires that special measures be taken by any financial institution — broadly defined — or any US "financial agency" that does business with a "primary money laundering concern." The special measures are whatever the US Treasury Department decides to require. A "financial agency" is anyone acting as a "bailee, depository trustee, or agent" in connection with the handling of "money, credit, securities or gold." Multilateral agencies like the World Bank, International Finance Corporation, Asian Development Bank and Inter-American Development Bank are not subject to this requirement.

The Treasury Department has not issued guidance on how broadly one ought to interpret the term "financial agency." For instance, it is possible that a law firm acting as an escrow agent for the participants in a project finance transaction may be a "financial agency" since it is an */ continued page 30*

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early November that would subject such holding companies to tax in the future in situations where at least 5% of dividends received from their subsidiaries are taxed at less than an 11% effective rate in the country from which the dividends were paid.

The change will apply from January 1. However, existing 1929 holding companies will be exempted until January 2011.

A REFUND may be hard to tell apart from a future discount. There are important tax consequences for utilities.

Most utilities are allowed to pass through taxes to their customers as a cost of providing service. However, in cases where the utility reports taxes for ratemaking purposes before it actually pays them to the government, a "deferred tax account" is established to keep track.

Congress cut the corporate tax rate in the late 1980's from 46 to 34%. As a consequence, many utilities had collected money in rates to cover future taxes that they would not have to pay. State public utility commissions made them return the money to their customers.

Florida Progress Corporation was ordered to return the amounts in the form of bill credits over 12 months. Each customer's bill, under the heading "monthly rate reduction," listed a credit reflecting the amounts being returned. The utility had already paid federal income taxes on the amounts it collected from customers and was now having to return. It proposed to amend its earlier tax returns to reduce its taxable income in those years. The IRS and the US Tax Court said no. The utility lost in late October in a US appeals court.

The court said the utility had not made a "refund" of money to its customers. Rather, it reduced how much it charged customers for electricity during the 12-month period. Therefore, it was not */ continued page 31*

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entity acting on behalf of another entity as an agent for money. An attorney at the Treasury Department dealing with the anti-money laundering provisions of the Patriot Act said such a broad reading is possible. However, the attorney also said a law firm may not be a type of institution this rule is meant to govern — banks and other entities typically viewed as financial institutions.

The US Treasury Department has the power to designate "primary money laundering concerns." A primary money laundering concern can be a jurisdiction outside of the US, a financial institution operating outside the US, a transaction within or involving a jurisdiction outside the US, or any type of account.

To date, two jurisdictions have been designated as "primary money laundering concerns." They are Nauru and Burma. The Ukraine was designated as one in December 2002, but the designation was rescinded five months later after the Ukraine took steps to fix its anti-money laundering rules. In addition, two financial institutions have so far been identified as primary money laundering concerns. They are Myanmar Mayflower Bank and Asia Wealth Bank, both from Burma.

Once the Treasury Secretary identifies a primary money laundering concern, he can impose additional reporting requirements on financial institutions or agencies doing business with such a concern. The requirements can include maintaining records and filing reports when transactions involving the concern occur, and obtaining and retaining information concerning the beneficial owner of any account opened or maintained in the US by a foreign person (or a representative of a foreign person) involving the concern.

If a US financial institution or agency opens or maintains a "payable-through account" in the US for a foreign financial institution involving the money laundering concern, it has additional reporting requirements. It must take steps to report the identity of each customer (and representative of the customer) of the foreign financial institution who is permitted to use (or whose transactions are routed through) the payable-through account, and any other information that is "substantially comparable to that which the depository institution obtains in the ordinary course of business with respect to its customers residing in the US" with respect to that customer.

A "payable-through account" is an account opened at a depository institution by a foreign financial institution through which the foreign financial institution permits its customers to engage in normal banking activities in the US.

The US Treasury can also flatly prohibit opening any correspondent or payable-through account that involves a primary money laundering concern.

US banks (including US branches of foreign banks) should continually monitor the announcements from the Treasury Department for any additions to the list of primary money laundering concerns — a list likely to keep growing — as well as for the specific rules imposed on doing business with such concerns.

Compliance Resources

When first enacted, the Patriot Act's anti-money laundering provisions created some panic and an overflow of different forms among US and foreign banks as they attempted to comply with the various due diligence and reporting requirements. Fortunately, as the Treasury Department began issuing detailed regulations implementing these provisions, it also made available various forms that financial institutions can use to satisfy the requirements. It has also published model internal procedures that it suggests financial institutions should adopt to detect money laundering. They are available on a website at www.fincen.gov. ◎

New VAT Rules in Europe

by Feddo Betist, with NautaDutilh in Amsterdam

The European Council formally adopted new rules on October 7 for collecting value-added taxes on gas and electricity.

The new rules will take effect on January 1, 2005, by which time all member countries will be required to have brought into force the necessary national implementing legislation. The new VAT directive will also apply to the Eastern European countries that will become members of the European Union in May 2004. The new VAT directive is supposed to eliminate current issues of double taxation and non-taxation and distortion of competition between traders.

Background

The gas and electricity market in the member countries of the

European Union used to be dominated by major electricity generators, transmission system operators, and national and local distribution companies that were almost completely state-owned. The gas and electricity market was mainly a national market limited to trade within each member country's borders.

Following the establishment of an European-wide internal market, the electricity and gas market in the member countries has been gradually liberalized in order to increase efficiency in this sector. As a result of the liberalization, gas and energy markets are no longer purely national and have started to operate on an international basis. This has led to the arrival of new market players such as power exchanges, independent power producers, brokers and traders. The dominant position of the state-owned companies, such as the large generators, is changing through privatization and mergers.

As a result of new EU and national measures, a considerable change in the operation of these markets is taking place. The liberalization of the gas and electricity market with its increasing cross-border transactions has led to the introduction of specific VAT rules on the place of supply of such goods.

Place of Supply

The " place of supply" determines in which member state the supply is subject to value-added tax.

VAT rates for electricity and gas range from 15% to 25%, depending on the country.

Before the liberalization of the gas and electricity market, the determination of the place of supply of electricity was not much of a problem because cross-border transactions were incidental. Supplies of electricity were mainly restricted to the home member countries, and the electricity or gas was taxed in those member countries. Opening up the gas and electricity market has resulted in an increasing number of cross-border transactions. As a consequence of the nature of these goods, the current rules regarding the place of supply are not adequate.

The current rules in effect under the national VAT legislation in all EU countries establish the "place of supply" as the place where the goods are located at the time when dispatch or transport to the person to whom they are supplied begins. In case the goods are not dispatched or transported, the place of supply is the place where the goods are when the title is transferred.

The nature of gas and electricity makes */ continued page 32*

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entitled to any deduction on account of the bill credits to its customers. Rather, it simply had less income to report from electricity sales in the current year.

The decision has a present-value cost to the utility. It is no doubt frustrating for Florida Progress because Dominion Resources won a similar case in a different US appeals court. The case is *Florida Progress v. Commissioner*. The court issued its decision on October 21.

MINOR MEMOS. Nearly 98% of the 1.5 million businesses in Florida paid no corporate income taxes last year, according to the *St. Petersburg Times*. The corporate income tax rate is 5.5%, but companies have found ways to shelter their incomes . . . . The European Commission said on November 28 that it will demand the French government collect $1 billion in back taxes from Electricité de France. The French government will have one month to respond.

— contributed by Keith Martin, Heléna Klumpp, Samuel R. Kwon and Adam Wenner, in Washington, Bill Monsen with MRW & Associates in Oakland, and Hilton King with Makarim & Taira S. in Jakarta.

European VAT

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it difficult to determine the place of supply as the physical flows of these goods are hard to trace. For example, when electricity is generated in and supplied from member state A to member state B, this does not mean that the electricity will actually flow through the transmission grid from member state A to member state B. Furthermore, due to the method of transportation by transmission line or gas pipeline, such transportation cannot be demonstrated by traditional transport documentation that shows goods have departed or arrived.

New rules will take effect in Europe a year from now on the collection of value-added taxes on electricity and gas.

Under the current rules, cross-border supplies will in principle lead to VAT registration of foreign suppliers in the countries where the customers are located. The current rules are difficult to apply when the contractual relationship is not in line with the physical flow of the goods. This happens when the customer requests direct delivery of the goods to his buyer and the latter is located in a third country.

New Rules

The new rules abandon one of the main principles that VAT is due where the goods are physically located at the moment of title transfer.

The new rules make a distinction between supplies of gas and electricity before and at the final stage of consumption.

For sales before the final stage of consumption, the "place of supply" is determined where the customer has his business premises or has a "permanent establishment" to which the gas or electricity is supplied, or, in the absence of such a place of business or permanent establishment, the place where he has his permanent address or usually resides. For application of this rule, the customer must qualify as a taxable dealer. For this purpose, a "taxable dealer" means a taxable person whose principal activity in respect of purchases of gas or electricity is reselling such products and whose own consumption of these products is negligible.

For sales at the final stage of consumption, or basically when the supply does not qualify as a supply before that final stage, the "place of supply" is determined where the customer has effective use and enjoyment of the goods. Where all or part of the goods are not in fact consumed by this customer, then these non-consumed goods are treated as if used and consumed at the place where he has established his business or has a fixed establishment for which the goods are supplied. In the absence of such a place of business or fixed establishment, he is treated as having used and consumed the goods at the place where he has his permanent address or usually resides.

In addition to the introduction of new rules for the place of supply of electricity and gas, new rules have been introduced regarding liability to pay VAT and imports so that VAT registration of foreign suppliers and double taxation may be avoided.

Liability for VAT

If both the supplier and his customer are located in the same country and the place of supply is in that country, then the supplier will have to charge VAT to the customer. However, if the supplier is located in one country and the customer is identified for VAT purposes in another country, then an obligatory reverse charge mechanism will apply. This means that the foreign supplier will not have to charge VAT as the VAT liability will be shifted to the customer. If the customer is not identified for VAT purposes, then the foreign supplier will in principle have to register in the country of that customer and collect VAT.

Exemption for Imports

The importation of gas through natural gas pipelines, or of electricity from outside the European Union will be exempted from VAT. This way, double taxation is prevented on gas and electricity supplied from non-EU countries.

Example

The following example shows how the new rules will be applied.

A US company supplies electricity to a Dutch customer. If the Dutch customer is a taxable dealer or is identified for VAT purposes in The Netherlands, the supply by the US seller is subject to 19% Dutch VAT. Based on the obligatory reverse charge mechanism — the seller is located outside Holland — the Dutch customer will be liable for the Dutch VAT.

However, if the electricity is actually consumed in Belgium by a "permanent establishment" of the Dutch customer, then the supply is subject to Belgian VAT. VAT will have to be collected by the Belgian permanent establishment — again, because the seller is outside the country where the electricity is consumed.

If the Dutch customer is neither a taxable dealer nor identified for VAT purposes and consumes the goods in The Netherlands, then the place of supply will be treated as The Netherlands. In this situation, the obligatory reverse charge mechanism will not apply, which would mean that the US seller would have to register for VAT purposes in The Netherlands and collect Dutch VAT from the Dutch customer. However, in The Netherlands a general reverse charge mechanism applies whenever a foreign seller supplies goods to a legal person who does not qualify as a VAT taxable person. An example is a mere holding company or a public body. (This general reverse charge mechanism does not apply to natural persons.) However, most European countries have not introduced such broad application of the reverse charge mechanism as The Netherlands has done. Most countries merely apply the obligatory reverse charge mechanisms.

In any of these situations the importation of the electricity from outside the European Union will be exempted from VAT.

Comments

Under the introduced new rules, US suppliers of gas and electricity will not be confronted with VAT registration in the EU and will not have to charge EU VAT to buyers, provided two things are true: first, they do not have EU permanent establishments from which the electricity or gas is supplied and second, the buyers are "identified" for VAT purposes. VAT registration is required and VAT will have to be collected if the final consumers are not "identified" for VAT purposes, unless in that situation a general reverse charge mechanism applies.

Therefore, in order to avoid VAT liability, US suppliers should check with their European customers whether or not these customers qualify as taxable dealers and check their VAT identification numbers. If their European customers are not identified for VAT purposes, they should determine whether or not a reverse charge mechanism applies in the specific country where the electricity is being supplied. ◎

Financing Upstream Oil and Gas Projects in the CIS

by Nabil L. Khodadad, in London

There are many ways to raise financing for oil and gas projects in the CIS, the region that used to make up the Soviet Union. This article discusses five: pre-payment contracts, supplier financing, structured trade financing, project financing and bonds. Two case studies are presented to illustrate how these methods are used to finance a project, often in combination.

Key Issues

Before delving into the different types of financing and the case studies, it is important to spell out some issues that are common to all projects in the CIS and will affect the terms of whatever type of financing a project seeks.

The project may be subject to restrictions on whether it can assign rights in a license to a lender.

In Russia, one cannot take an assignment over a license. In Kazakhstan, one can take an assignment over a subsoil contract, but such assignment must be registered by the Ministry of Energy and Mineral Resources. There is uncertainty as to whether the assignee can take or transfer to a third party the subsoil use rights without the consent of the Ministry of Energy. In Azerbaijan, this is less of an issue because most projects are evidenced by a production sharing agreement and usually it permits assignment, but assignment is typically always subject to the consent of the State Oil Company of the Azerbaijan Republic, called SOCAR.

Foreign exchange and offshore banking restrictions affect all CIS projects.

Many lenders insist that their borrow- */ continued page 34*

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ers establish offshore bank accounts so that they can take an assignment or charge over such accounts. However, it is very difficult for a Russian company to get approval to open an offshore bank account. Often the companies resort to back-to-back arrangements as a way of getting around some of these issues. Under such an arrangement, an offshore affiliate of a Russian producer borrows from the lender and opens an offshore account which it assigns or charges to the lender. The offshore affiliate then enters into a contract with an offtaker (such as Glencore or Vitol) and instructs the offtaker to remit payment directly to the offshore account. In Kazakhstan, it is much easier to obtain approval to open offshore bank accounts. In Azerbaijan this issue is typically dealt with in the production sharing agreement.

Repatriation requirements may affect lending arrangements as well. For example, in Russia, all proceeds from exports must be repatriated. Plus, 25% of foreign currency proceeds must be converted into rubles.

Export restrictions are also very important to financing arrangements.

There are many practical restraints on the export of crude oil and gas because pipeline capacity is limited. Russia sets quotas on exports, and a Russian producer is unable to export more than 35% of its production of crude oil by pipeline. In Kazakhstan there are no formal restrictions, but informally there is a lot of pressure to sell in the domestic market. However, some of the domestically sold crude oil actually ends up being exported. In Azerbaijan this is really less of an issue; most production sharing agreements provide that production can be freely exported.

Taxes and duties can be another significant issue.

Throughout the CIS, withholding tax is imposed on interest and management fees paid offshore. The withholding rates for interest are 15%, 15% and 10% in Russia, Kazakhstan and Azerbaijan, respectively. Tax relief can often be obtained by taking advantage of a bilateral tax treaty. For example, Russia has very favorable tax treaties with the Netherlands and Cyprus.

A project in the CIS will likely be affected by either excise taxes or customs duties, or both. In Russia there are no excise taxes; however, there are duties. As of October 1, 2003, the applicable duty is $33.80 per ton of crude oil. On January 1, 2004, the Kazakh government is scheduled to introduce a new oil export tax that would vary according to the price of oil, with higher oil prices attracting higher tax rates. Azerbaijan has no export taxes or duties, but it imposes a charge called a "mandatory payment to the budget" that operates just like a tax. Under this mandatory payment, a producer is required to pay 25% of the difference between the export price and the domestic price. The domestic price for crude oil in Azerbaijan is much lower than the export price, so this mandatory payment effectively operates like a tax. Fortunately, producers who entered into production sharing agreements before the mandatory payment was introduced should be exempted.

Sources of Financing

With these issues in mind, there are several sources of financing that may be attractive to an oil or gas project in the CIS.

One source of financing is the prepayment contract.

This arrangement essentially involves the prepayment for future deliveries of petroleum. This can be an attractive form of financing for a producing company that does not have much of a track record. Usually the offtaker will focus on the producer's current levels of production. There are some disadvantages, perhaps the biggest of which is the fact that that there is a high implicit rate of interest because the offtaker usually demands a steep pricing discount — and that is, effectively, a hidden form of interest.

Another problem is that this sort of financing is usually available for only very short periods of time. In certain transactions the offtaker will also try to obtain equity-type rights. Although there are some disadvantages, it can be useful for companies that do not have a lot of history or production, and for them it may be the only source of financing.

Another type of financing is supplier financing.

Essentially a field service supplier, like a Baker Hughes or a Schlumberger, provides field services in exchange for a share of production. It is similar to a production sharing arrangement.

There are not that many examples of this type of financing in the CIS. For certain producers it may be the only sort of financing that they can obtain. There are some disadvantages. One disadvantage is that this type of financing effectively dilutes the interest of the equity investors because they are parting with some of their upside. If oil prices go up, they are in effect getting less of the cash flow because they are paying the producer in kind instead of in cash. Also, it is very important to draft the mechanism by which the operator recovers costs carefully to make sure that the field service company has the right incentives to mitigate operating expenses and capital expenditures.

A third type of financing is structured trade financing.

Essentially this is financing that is secured by an offtake contract. Typically the proceeds from the offtake contract will be placed in an offshore bank account. The contract will be assigned to the lender; the offshore bank account will be charged and assigned to the lender as well. This can be a very attractive form of financing. Structured trade financings tend to have lower interest rates and longer maturities than the type of financing that domestic banks are willing to offer. While a structured trade financing tends to have a longer term than a prepayment contract, it usually has a shorter term than a project financing, which is discussed in the next section.

There have been a lot of interesting developments in the field of structured trade finance. A couple of banks have been able to arrange structured trade financings for long periods of time. Approximately a year ago, *Société Générale* arranged a structured trade financing that was secured by export receivables. It was broken up into several tranches and the longest tranche had a tenure of six years, which is quite long.

In the press, there have been reports that Citibank and ABN Amro are considering a $500 million loan to Lukoil backed by oil receivables. This apparently is going to be broken up into different tranches, one of five years and another of seven years. The terms of these tranches are quite long for a structured trade financing.

As one would expect, the lenders in a structured trade financing focus on reserves. They look very carefully at existing levels of production and at the creditworthiness of the offtaker, because they are relying on the offtake contract for the repayment of their loans.

The terms and conditions typically found in a structured trade financing include a life-of-loan coverage ratio, which looks at projected net cash flow from proven reserves over the life of the loan in relation to long-term debt, and a life-of-field coverage ratio, which looks at projected net cash flow from proven reserves over the life of the field (a longer period than the term of the loan) in relation to long-term debt. The deal may also include a "top-up" covenant. This is a requirement that if oil prices fall, the producer must pledge or assign more production to the lenders. Usually a lot of time is spent negotiating this covenant.

Hedging is another issue in structured trade financing arrangements. Sometimes lenders want their borrowers to hedge against the risk that oil prices will fall. Sometimes hedging is not required at the outset of the loan, but is required if subsequent decreases in oil prices trigger a fall in coverage ratios below a certain agreed level.

A lender may also ask its borrower to grant a "negative pledge." A producer may not be assigning all of its production to the lenders, but the lender may want to be comfortable that no other future lender has access to production, particularly if oil prices fall. The first lender will want to make sure that the borrower is not assigning production to other lenders. If the borrower does, then it may be hard for the borrower to comply with the top-up covenant.

A fourth type of financing is project financing.

It is limited-recourse financing that is predicated on the merits of the project. There are longer loan maturities for a project financing than there are for a structured trade financing. Lenders are more sensitive in a project financing to all the risks associated with the project — for example, reserve risk, completion risk, operating risk, market risk, price risk, political risk, legal risk, environmental risk and force majeure risk.

In a structured trade financing, the lenders focus more on the offtake contract. In a project financing, the lenders have to get a lot more comfortable with the entire project. That requires more due diligence. Also, lenders in a project financing will try to take security over everything. That is not true in a structured trade financing, where the lenders' security is typically limited to an assignment or charge over the receivables, the offtake contract and the offshore bank account.

In a project financing, the lenders typically receive a guarantee from the sponsor that covers completion risk. Usually the most heavily negotiated issue in the deal is how to define "completion." This is an important issue because prior to completion, the sponsor guarantees the debt of the borrower. When completion is achieved, the guarantee disappears and the lenders can only look to the borrower for repayment of their loans. Usually the borrower's only asset is the project. Thus if the project fails, the lenders will probably not be repaid in full.

Finally, another financing option to consider is Eurobonds.

There has been an improvement in the creditworthiness of Russian and Kazakh issuers. This has been mirrored by the fact that sovereign credits for both Russia and Kazakhstan have improved. Russia and Kazakhstan are now investment grade. That makes the capital markets a lot more */ continued page 36*

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attractive to local producers than they otherwise would be.

There are certain advantages to Eurobonds. They are unsecured — the issuer does not have to pledge any security. The covenants and events of default also tend to be a lot less onerous than a structured trade facility or a project finance facility.

A Eurobond also allows the issuer to increase the potential universe of investors. With a structured trade financing or a project financing, a project is basically looking to commercial banks and bilateral and multilateral credit agencies. With a Eurobond, an issuer can look to other investors as well. A Eurobond offering is also a public relations exercise. It is a way for a company to advertise itself and to bring its credit to the attention of a much larger group of investors.

Probably the main disadvantage to a Eurobond, and there are others, is that it is very difficult to amend or waive covenants or events of default once the bonds have been issued. This is much easier to do for a syndicated loan facility.

Spreads for energy bonds have fluctuated over the last couple of years, but the trend is down. There are some significant issuers in Central and Eastern Europe; for example, Gazprom has about $4.2 billion of bonds outstanding, Sibneft $900 million, TNK $00 million and Lukoil $50 million. Those are big numbers. But the Central and Eastern European energy bond market is really just a small fraction of the energy bond market in Western Europe. In Western Europe the energy bond market is about one-quarter of a trillion US dollars,and in Central and Eastern Europe it is only about $9.2 billion.

There are many restraints on the export of crude oil and gas from the former Soviet republics because pipeline capacity is limited.

Karazhanbasmunai

To put this all in perspective, it is helpful to look at a case study on the financing of Karazhanbasmunai. Karazhanbasmunai has rights to a field called Karazhanbas. It is in the western part of Kazakhstan, very close to the North Buzachi field.

Karazhanbasmunai is a company that was set up during Soviet times and privatized in 1997. A Canadian independent energy company called Nations Energy acquired all the equity in Karazhanbasmunai. Between 2000 and 2003, Karazhanbasmunai was able to raise about $148 million of debt from a variety of sources.

Karazhanbasmunai is the borrower and has all of the rights to the Karazhanbas oil field. It entered into an offtake contract under which it has agreed to deliver 15,000 barrels per day to Glencore International. The bank syndicate has taken an assignment over the contract. All of the proceeds from the offtake contract are deposited into an offshore bank account in London, and that account is pledged to KBC Bank and a syndicate of lenders. In addition, there are a couple of other key assets that are assigned or pledged to the lenders as security. KBC and the syndicate have lent $80 million to Karazhanbasmunai.

In addition to the structured trade financing, there are other layers of financing as well. Karazhanbasmunai has borrowed about $40 million from three different Kazakh banks. Generally the terms of those loans are not quite as favorable; the interest rates are higher on the domestic loans because the Kazakh banks have a higher cost of funding. Karazhanbasmunai has also issued about $20 million in bonds to a number of Kazakh pension funds.

It is interesting to note that as production has increased over time, more and different types of financing became available to Karazhanbasmunai. For example, initially the only type of finance that was available to Karazhanbasmunai was pre-export finance. Then after production increased to 20,000 barrels per day, it was able to access the local capital markets, the domestic bank market and the domestic bond market. As production increased further, Karazhanbasmunai was able to access funds under a structured trade financing from a syndicate of European banks.

Karachaganak Project

Karachaganak is a condensate, oil and gas field located in western Kazakhstan. This field has been producing since Soviet times (1984). The field covers a vast area of 200 square miles and benefits from a 40-year production sharing agreement with the Kazakh government. It is a large and important project.

There have been three very large projects in Kazakhstan to date — Kashagan, which is still being looked at, Tengiz and Karachaganak. Karachaganak is the largest project to obtain financing on a limited-recourse basis. There are immense recoverable reserves: liquids of about 2.53 billion barrels and gas of 18.4 trillion cubic feet.

There are various members in the project consortium — British Gas, Agip, ChevronTexaco and Lukoil. The financing just concerned Lukoil. It did not concern the financing of the other three companies' interests in the project.

The project included the financing of a pipeline from Karachaganak to Atyrau. At Atyrau this pipeline connects with the CPC pipeline. Before this pipeline was built, oil was actually going to Orenburg. The consortium was not receiving world prices for its oil. It is now able to access the international markets. Today, the first oil is being shipped through the CPC pipeline. It may not look like a very big pipeline, but the Karachaganak/Atyrau segment of the pipeline is 600 kilometers long.

Financing was extended by the International Finance Corporation and a group of commercial banks under the IFC's A/B loan program. Basically, IFC is the lender of record on the A and the B loans, but it participates out the B loans to a syndicate of commercial banks. The split of the $150 million loan was roughly $75 million A loan:$75 million B loan; in other words, the IFC held on to about $75 million and through the B loan program it participated out another $75 million. The borrower is Lukoil Karachaganak, which holds a 15% interest in the Karachaganak field, and the ultimate parent is Lukoil JSC.

There was a completion guarantee. Prior to completion, Lukoil JSC is on the hook. If the loan is not paid after project completion, the lenders can only look to Lukoil Karachaganak for repayment of their loan. ◎

FERC Bars Information Sharing with Affiliates

by Adam Wenner, in Washington

The Federal Energy Regulatory Commission issued final rules in late November that bar electricity and gas transmission companies from sharing inside information with affiliates.

Electric utilities and gas pipeline companies that are affected by the rules must put compliance programs in place by June 1, 2004.

The new "standards of conduct" were designed to close a perceived loophole in long-standing regulations governing the relationship between transmission providers and their wholesale electric or gas marketing affiliates. Two general principles underlie the rules. First, the employees of a transmission provider who are engaged in transmission system operations must function independently from employees of the transmission provider who are engaged in sales, marketing and other energy-related activities. Second, a transmission provider must treat all transmission customers in a non-discriminatory manner and may not operate its transmission system to benefit its affiliates.

The final rules bar information sharing with "energy affiliates." These are companies that control — or are controlled by — transmission providers and that engage in certain types of activities. The types of activities include buying, selling or trading natural gas or electricity in the US and engaging in financial transactions relating to gas and electricity markets. Also included on the list are marketing affiliates that purchase and sell natural gas or electricity for resale to customers. The rules do not apply to ISOs (independent system operators), RTOs (regional transmission organizations), or to holding or service companies that do not engage in energy transactions in the US. Companies that purchase gas or electricity solely for their own consumption are also exempted.

The final rules retain an existing exemption that permits an electric utility that provides transmission to use the same employees for its interstate transmission business and its bundled retail sales business. However, if the retail sales unit engages in any wholesale sales, then the bar of information sharing applies.

FERC said when it issued the final rules */ continued page 38*

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that transmission providers continue to have economic incentives to grant undue preference to their affiliates. Its earlier regulations on this subject did not cover affiliates of transmission providers that are not marketers or merchant affiliates. FERC said its office of market oversight and investigations has uncovered several violations of the earlier regulations and "affiliate abuse activity." Consequently, the new rules provide that a transmission provider cannot permit the employees of an energy affiliate to conduct transmission system operations or reliability functions or allow them access to the system control center or similar facilities used for transmission operations (except to the extent that unaffiliated companies have the same access). The rules require transmission providers to train all of their support employees, including accountants and attorneys, in the standards of conduct and prohibit them from acting as conduits for sharing information with energy affiliates.

Certain exceptions apply to the employee sharing rules, including one for senior officers and directors and another for field employees who do operation and maintenance. In response to concerns that risk management employees must understand the exposure of the entire corporation, including the activities of the transmission provider and any energy affiliates, the final rules also permit risk management employees to be shared. However, such shared employees are prohibited from being "operating employees" — that is, hands-on decision-makers — of either the transmission provider or the energy affiliates or from being conduits for improperly sharing information.

Posting Information

The new rules require that transmission providers post the names and addresses of their energy affiliates (including any sales and marketing units) on the Internet and on the company's "open access same-time information system" — known as "OASIS" — website. In addition, a company must post organizational charges showing the business units, job titles and descriptions and chain of command for all positions, including whether each employee is involved in transmission or sales. If an employee is transferred from the transmission provider to an energy affiliate, or vice-versa, notice of the transfer must be posted on the Internet website and on the company's OASIS website.

The final rules requires that a company ensure that its employees who are engaged in marketing or sales, as well as employees of any energy affiliates, only have access to information that is also available to non-affiliated transmission customers. The employees cannot have access to any information about the transmission system (such as information about available transmission capability, price, curtailments, storage, ancillary services, balancing, maintenance activity, capacity expansion plans) that is not publicly available on the Internet.

Electric utilities and gas pipeline companies must put programs in place by June 2004 to prevent inside information from being shared with affiliates.

Implementation

Electric utilities and gas pipeline companies must comply with the new standards by June 1, 2004 and must post on the Internet current written procedures implementing the standards of conduct. The procedures must be described in sufficient detail to enable customers and FERC to determine that the transmission provider is complying with the new rules. Transmission providers are required to have employees attend training sessions and sign affidavits certifying that they have been trained in this area. Also, each transmission provider must designate a chief compliance officer.

FERC's new standards of conduct reflect that agency's continued efforts to maintain the separation of corporate functions that it believes is necessary for competitive markets to function, as well as its recognition that some companies have been less than strict in their compliance with FERC's restrictions on conduct. ◎

Environmental Update

Mercury

The US Environmental Protection Agency is expected to propose new rules in December that would limit mercury and nickel emissions from coal- and oil-fired power plants. The rules could be costly for owners of existing plants to implement.

The US government is under a December 15 deadline to release the new proposals. The deadline is in an agreement reached in 1998 to settle a lawsuit by environmental groups. There will actually be two alternative proposals. Drafts were sent to the Office of Management and Budget in late November for internal review.

It is unusual for a government agency to release alternative proposals. There will be a period for public comment after they are released.

One of the two proposals is for a "cap and trade" rule to regulate mercury emissions from existing coal-fired power plants. There would be a 34-ton cap during first phase commencing in 2010 and a cap of 15 tons starting in 2018. EPA believes that mercury reductions would be achieved during the first phase through "co-benefit" reductions from existing and anticipated pollution controls to achieve NO_x and SO_2 reductions that are expected under existing law. In other words, no special effort is required to reduce mercury emissions before 2010. Mercury allowances would be issued to owners of coal-fired plants based on a unit's share of the total heat input from existing coal units multiplied by an adjustment factor depending on the type of coal: 1 for bituminous, 1.25 for sub-bituminous, and 3 for lignite coals. Mercury is generally more difficult to remove from lignite coals than from bituminous coals.

The first proposal has an interesting legal underpinning. EPA will have to backtrack from its conclusion in December 2000 that regulation of mercury and other hazardous air pollutants from coal and oil-fired utilities is "necessary and appropriate" under the air toxics section of the Clean Air Act. The agency still believes that regulation of mercury from coal-fired plants and nickel from oil-fired plants is "appropriate," but it does not believe that regulation under the section 112 air toxic provisions is "necessary." Instead, it is proposing to regulate mercury and nickel from coal and oil-fired plants under the section 111 new source performance standard provisions. Section 111 of the Clean Air Act is much less prescriptive than section 112, and it allows EPA more flexibility in setting mercury and nickel emission limits. Under section 112, EPA must set emission limits at a level representing maximum achievable control technology, or "MACT." For existing sources, the MACT level is based on the average emission limitation achieved by the best performing 12% of plants in a particular category or subcategory of sources. For new sources, the MACT level must be set at the level of control achieved by the best controlled similar source. EPA has concluded that a "cap and trade" program qualifies as a "standard of performance" under section 111.

The mercury emission limits for new sources will vary depending on the type of coal that is being burned. The EPA proposal would set the following output-based mercury standards: 6.5×10^{-6} lb/MWh for bituminous, 21×10^{-6} lb/MWh for sub-bituminous, 67×10^{-6} lb/MWh for lignite, and 0.53×10^{-6} lb/MWh for coal refuse. For integrated gasification combined-cycle, or "IGCC," units, EPA is recommending a separate emission limit of 16×10^{-6} lb/MWh.

EPA is offering two approaches to mercury and nickel limits for comment. The second approach would set emissions limits for new sources at the same levels as in the first EPA proposal. However, the limits for existing sources would be different. They are as follows. Existing sources would have the option of complying either with an input-based pounds per trillion British thermal units or an output-based pounds per Megawatt hour standard: 2.0 lb/TBtu or 21×10^{-6} lb/MWh for bituminous, 5.8 lb/TBtu or 61 lb/MWh for sub-bituminous, 9.2 lb/TBtu or 98 lb/MWh for lignite, 0.52 lb/TBtu or 5.5 lb/MWh for coal refuse, and 15 lb/TBtu or 159 lb/MWh for IGCC units.

The proposals are sure to set off a fierce debate. They must be adopted in final form by December 15, 2004.

Kyoto Protocol

Rejection of the Kyoto protocol by Russia will send the international community back to the drawing board. The protocol cannot be implemented without at least one of the United States or Russia.

In early December, a senior aide to / *continued page 40*

Russian President Vladimir Putin said Russia will not ratify the protocol in its current form because it places significant limitations on the economic growth of Russia. President Putin had not formally rejected the treaty when the *NewsWire* went to press.

At last count, 120 countries had ratified the protocol. Russian rejection of the treaty would mean it will not go into effect even in those countries. The Kyoto protocol would have required approximately a 5.2% reduction in greenhouse gas emissions over the period 2008 to 2012. The reduction would be measured against 1990 emission levels.

It is unclear whether the United Nations will try again to forge a global agreement to reduce greenhouse gas emissions, or whether the individual countries will gravitate toward regional pacts. For example, the European Union might stay the course with the greenhouse gas reduction program that it already has well underway. The United States and Australia have both rejected the Kyoto protocol.

The Kyoto protocol provides that it will take effect after it has been ratified by 55 or more countries (including both industrialized "Annex I" nations and developing "Annex II" countries) whose combined emissions levels represent at least 55% of the carbon dioxide emissions from Annex I countries in 1990. As of the end of November, 120 nations had ratified the treaty. Those 120 nations accounted for 44.2% of the 1990 carbon dioxide emissions. Russia accounts for 17.4% of the emissions and thus its ratification of the protocol would have pushed the agreement over the 55% implementation threshold.

Transport Rule

A new air emission rule expected to be proposed by the EPA this month will require certain power plants to add or upgrade pollution controls to meet significant sulfur dioxide (or, "SO2") and nitrogen oxide (or, "NOx") reduction targets. EPA announced on December 4, 2003 that it will propose a new "Interstate Air Quality Rule" that is directed at reducing the interstate transport of fine particulate matter and NOx, an ozone precursor, emitted from power plants. The new rule will employ a two-phase approach that is similar to the Clear Skies Act bill currently being considered by Congress.

The press release announcing the new transport rule states that upwind sources significantly contribute to fine particulate and ozone pollution in downwind states. The rule is expected to call for a reduction in SO2 emissions from power plants by 3.7 million tons by 2010, approximately a 40% decrease from current levels, and a further cut of 2.3 million tons by 2015, for a total reduction of about 70% from current SO2 levels. The rule is expected to call for reductions in NOx emissions of 1.4 million tons by 2010, and an additional cut of 1.7 million tons by 2015, for a total NOx reduction of about 50%. EPA said that SO2 and NOx emissions will be permanently capped under the new rule and cannot increase. EPA is expected to propose a SO2 and NOx emissions trading program as part of the Interstate Air Quality Rule.

The proposed transport rule is expected to be very similar to the Bush administration's "clear skies initiative." It will attempt to obtain substantially the same results as the bill, but through an administrative rulemaking process. EPA affirmed its belief that the clear skies bill is the best approach to reducing multi-pollutant air emissions from power plants, but opted to exercise its existing authority to issue regulations in light of the legislation's uncertain future.

A final rule is expected to be issued in 2005.

Clear Skies

Two key Republican Senators introduced a bill in November that will probably serve as a vehicle for passing multi-pollutant legislation out of the Senate Environment and Public Works Committee next year. The two are James Inhofe (R-Oklahoma) and George Voinovich (R-Ohio). Inhofe is chairman of the committee.

Their revised "clear skies" bill adopts most of the Bush administration's original clear skies initiative, but with a few important changes. The changes should make complying with the measures less expensive for power companies. The Bush Administration has greeted the Inhofe-Voinovich clear skies proposal as a welcome development.

The bill would require substantial reductions in NO_x, SO_2 and mercury emissions from power plants by setting nationwide emission caps in a two-phase process. These caps would decline in 2018. Both bills propose a mandatory "cap and trade" emission allocation program for the three pollutants similar to the SO_2 allowance trading under the federal acid rain program. Neither bill calls for any cuts in

CO_2 emissions, a greenhouse gas, from power plants.

One of the most significant changes from the original Bush plan is the Inhofe-Voinovich bill would exempt qualifying cogenerators (as defined under the Public Utility Regulatory Policy Act, or "PURPA") from mercury, NO_X, and SO_2 requirements in the bill. Under the original Bush plan, all power plants with a capacity of more than 25 megawatts and selling more than one-third of their power to the grid would be regulated. Under the new bill, cogenerators would be able to opt into the clear skies program. If a cogenerator opts in, then it would be able to sell its excess emission reduction credits; however, it would be required to comply with the other applicable requirements of the measure.

The Inhofe-Voinovich bill would also make available a pool of mercury, NO_X and SO_2 allowances for new units. Instead of allocating 100% of the available allowances under the program, the new source set aside would hold back a number of allowances in reserve for new projects. The bill would create a 7% pool for SO_2 allowances and a 5% pool for NO_X and mercury allowances. Similar to the existing acid rain program, one NO_X allowance or one SO_2 allowance would be required for each ton of NO_X or SO_2 emitted, respectively. A mercury allowance would be required to generate one ounce of mercury. The creation of a new source allowance set aside is intended to encourage the development of new, cleaner generating facilities.

One other significant change from the Bush plan is the bill would increase the mercury emissions cap to be achieved by 2010 from 26 tons under the Bush plan to 34 tons. The 34-ton mercury cap is reportedly the level of mercury emission reductions that can be achieved through "co-benefit" reductions in NO_X and SO_2 emissions that would be required by 2010. This suggests that many regulated coal-fired plants would be able to avoid installing costly mercury control technologies until the second phase of the clear skies measure kicks in. The first phase of mercury reductions would have to be reached by 2010 and the second phase — reducing mercury to 15 tons — would not be required until 2018.

It is not clear the Inhofe-Voinovich bill will be able to make it out of committee. It remains controversial. Even if it does, it is doubtful that Congress will be willing to tackle such a politically charged issue during an election year.

In related news, the US Senate rejected a bill in late October that would have required electric generating facilities and other manufacturing plants to cut back their greenhouse gas emissions to 2000 levels by 2010. The vote for the bill was 43-55.

CO_2 Reductions

The US Department of Energy proposed changes in November for voluntary reporting of greenhouse gas emission reductions.

The department maintains a voluntary registry of greenhouse gas emission reductions that are submitted by various power generating and industrial companies. Since participation is not mandatory, the registry is primarily used as a tracking device to record voluntary efforts by companies to reduce greenhouse gases.

The proposed new reporting guidelines create a two-tier process of *reporting* of emissions reductions versus the registering of emissions reductions. Companies will continue to have flexibility in reporting greenhouse gas reductions on a plant-specific or project-related basis. The revised guidelines are also designed to encourage companies to register entity-wide data and demonstrate entity-wide reductions. The proposed guidelines provide that entities that are able to meet additional requirements established by DOE to *register* emission reductions achieved after 2002 would receive special recognition under the guidelines. In addition, third-party or independent verification of emissions reductions is "strongly encouraged," but is not required. While under no regulatory obligation to comply with the guidelines, participating companies may be able to derive important public relations benefits.

DOE will hold a public workshop on the proposed guidelines on January 14, 2004 in Washington, D.C., and will accept comments on the proposed guidelines until the end of January 2004.

In related news, the Chicago Climate Exchange (known as the "CCX") recently held its first auction of CO_2 emission allowances. The CCX has more than 20 members, including Amtrak, DuPont Co., American Electric Power, Motorola Inc., Ford Motor Co. and International Paper Co. Each member has voluntarily committed to reduce its greenhouse gas emissions by 4% in 2006 from baseline emission levels calculated based on CO_2 from 1998 to 2001.

The first auction was of 100,000 metric / continued page 42

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tons of 2003 vintage CO_2 allowances and 25,000 metric tons of 2005 vintage CO_2 allowances. The average successful bid was $0.98 per metric ton CO_2 for 2003 allowances and $0.84 per metric ton CO_2 for 2005 allowances.

RECs

The Federal Energy Regulatory Commission announced in early October that a power purchase agreement between a "qualifying facility" and a utility will not convey to the utility any renewable energy certificates that belong to the QF unless the contract specifically says that it does. Renewable energy certificates — called "RECs" — are a mechanism for selling the "environmental attributes" of power generated from renewable energy services such as wind, solar, biomass, and landfill gas power plants. FERC's ruling could mean increased costs for utilities in states where a renewable portfolio standard requires utilities to purchase a certain percentage of their power from renewable energy sources.

To date, 13 states have enacted some form of RPS and at least five other states are considering RPS-style legislation. For example, Texas requires each electric utility to obtain 1.65% of its power from renewable fuels by 2003, 2.15% by 2005, 2.75% by 2007, and 3% by 2009.

The issue is whether utilities that buy electricity from an independent generator also get the RECs associated with that electricity. If not, utilities in certain states will have to develop their own renewable generation projects to satisfy the RPS requirements or pay for RECs on the open market. The price of RECs ranges from approximately 1/2¢ to 2¢ per kilowatt hour, depending on the state.

The FERC ruling came in a case filed by several waste-to-energy plants who petitioned the commission for a determination that the QF power purchase agreements did not convey legal title to RECs. The utilities argued that since they are required under PURPA to buy power generated by QFs using renewable fuels, the environmental benefits associated with the electricity should also belong to the utilities. The QFs countered that most power purchase agreements do not inherently transfer RECs to utilities because the compensation paid to a QFs is based on a utility's avoided cost, which does not reflect the environmental costs of generating power.

Even though FERC ruled in favor of the petitioners, its order left the door open for individual states to determine that the sale of QF-generated power automatically transfers ownership of state-created RECs to a purchasing utility. It is unclear whether utilities will now seek legislative changes directly to the particular state RPS programs.

New rules limiting mercury and nickel emissions from coal- and oil-fired power plants could be costly for power companies to implement.

New Source Review

In late October, 14 states and 29 local jurisdictions filed a lawsuit challenging new rules issued by the US Environmental Protection Agency that draw a bright-line test for determining when replacing equipment at a power plant or other industrial facility requires an air permit. Included as plaintiffs in the suit are California, New York, Illinois, Washington, DC and most of the northeastern and mid-Atlantic states.

The new rule at the heart of the controversy was issued to settle conflicting EPA guidance and interpretations of the scope of the "routine maintenance, repair, and replacement" exemption. Under this exemption, a power plant owner does not need to apply for a modification of its existing "New Source Review," or "NSR," air permit if it replacing equipment at the plant in the course of routine maintenance, repair or replacement. If the replacement does not fit within this definition, a modified NSR permit must generally be obtained unless another exclusion applies. EPA's new rule creates a safe harbor for equipment replacement at a power plant or other industrial facility where three prerequisites are satisfied. First, the owner must be replacing an existing component of a process unit with identical components or components that serve the same purpose. Second, the fixed capital cost of the replaced component and any other costs associated with the replacement activity must not exceed 20% of the current replacement value of the process unit. Third, the equipment replacement must not alter the basic design of the process unit or cause the unit to exceed any emission limitations.

The petitioners allege that EPA's new rule, which was issued on October 27, 2003, violates the plain language of the Clean Air Act, is contrary to Congressional intent, and constitutes a radical departure from 25 years of prior agency and judicial interpretations regarding the applicability of the "routine maintenance, repair, and replacement" exemption. But the rule is not without supporters: a group of nine states, led by Virginia, as well as several industry trade associations have intervened in the case in support of the rule on behalf of EPA. The supporters assert that the new rule provides much needed clarity on the scope of the exemption and will help achieve energy efficiency and reliability objectives. A decision in the case is not expected until late 2004 or early 2005.

The rule is the second set of EPA reforms to the NSR program. The first rule was issued on December 31, 2002, and it revised the way industrial facilities calculate emission increases under the NSR program. It also incorporated other revisions to the NSR applicability provisions. The December 31, 2002 rule is currently being challenged by substantially the same coalition of states, local governments and environmental groups.

In a related development, EPA's assistant administrator for enforcement and compliance assurance announced that the agency will review on a "case-by-case basis" the ongoing investigations into more than 50 coal-fired power plants for alleged past violations associated with failing to obtain NSR permit modifications for certain equipment repair and replacement activities. EPA announced that it will review the cases under the new "routine maintenance, repair, and replacement" rule that was issued on October 27, 2003. The agency's decision to consider past actions of the utilities under the new "routine maintenance, repair, and replacement" rule is surprising in the wake of EPA's initial pronouncements that the past actions would continue to be pursued under the prior agency guidance. EPA clarified that it has not made a formal decision to drop all of the pending utility enforcement lawsuits that are based on the prior EPA guidance; however, it appears likely that only a handful of the more egregious cases will continue to be pursued by the agency.

The plants were part of a large-scale enforcement initiative launched in the late 1990's that culminated in a number of lawsuits against many of the major utilities with older coal-fired plants. Several of the utilities are engaged in ongoing litigation with EPA and the Department of Justice and a few of the utility enforcement cases have been settled. Utilities that settled are now reportedly pressing EPA to reevaluate the settlements in light of the new "routine maintenance, repair, and replacement" rule.

Chemical Security

In October, the Senate Environment and Public Works Committee approved a bill that would require tighter security at power plants and other facilities that use or manufacture potentially dangerous chemicals in the US. Compliance with the measure could be costly, particularly for plants located near population centers.

Under the bill, the Department of Homeland Security would take the lead in developing a list of "high priority" chemical sources based on a number of security-related factors, including the quantity of substances of concern at the site, the likelihood that the plant may be a target of terrorism, and the cost and feasibility of implementing enhanced security measures. The "high priority" plants would be required to prepare vulnerability assessments and develop site security plans. The bill also contains a toxic use reduction provision that would require the facilities to identify potentially safer chemical alternatives; however, the bill does not require the companies to use the safer alternatives.

The detailed vulnerability assessments and site security plans could lead to capital intensive upgrades to enhance plant security. The measure would apply to "chemical sources" that are required to complete a risk management plan in accordance with section 112(r) of the Clean Air Act. Section 112(r) applies to accidental releases of hazardous chemicals. Many power plants that store anhydrous ammonia in large amounts for use in selective catalytic reduction systems are typically subject to the 112(r) requirements.

The bill closely tracks legislative language proposed by the Bush Administration and intro- */ continued page 44*

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duced by Senator James Inhofe (R-Oklahoma), the committee chairman, earlier this year. The measure should come up for a vote in the full Senate in early 2004.

Brief Updates

California Governor Arnold Schwarzenegger has issued an executive order suspending all proposed state regulations for 180 days and ordering a review of all regulations adopted, amended or repealed since January 9, 1999. The order requires all state agencies to submit a report to the governor's office on such adopted, amended or repealed regulations within 90 days.

Several members of the "green power market development group" announced the largest single purchase of renewable energy credits to date. The group purchased approximately 36 megawatts of RECs generated from renewable energy sources such as wind, biomass, and landfill gas. The World Resources Institute said that the purchase means that 450 million pounds of CO_2 will be avoided because renewable sources will displace power plants using coal, oil, or gas. Members of the green market power development group include Alcoa Inc., DuPont, Delphi Corp., Dow Chemical Company, General Motors, IBM, Pitney Bowes and Staples.

The state of Washington released a draft of a proposed rule that would require new power plants over 350 megawatts to mitigate 20% of their projected CO_2 emissions. Under the draft proposed rule, plants could mitigate CO_2 emissions in any of three ways. They could pay a set fee per ton of CO_2 emissions, purchase forest land to offset emissions, or undertake efficiency projects. The draft proposed rule is part of an effort to standardize rules for siting new generation in Washington.

EPA is reportedly evaluating the widespread use of AP-42 emission factors by state permitting agencies to establish air permit emission limits. The AP-42 emission factors are based on industry averages, and originally were developed as a tool for preparing state-wide emission inventories and not as a source-specific method for projecting an individual source's emissions. The regulated community has criticized emission factors as being inaccurate and overestimating projected emissions. EPA may require states to use actual monitoring data and other methods to establish air permit limits instead of using AP-42 emission factors.

EPA recently released a proposed rule providing a conditional exclusion for regulating certain solvent-contaminated disposable industrial wipes as hazardous waste. To qualify for the exclusion, the industrial wipes must generally not contain free liquids, must be stored in leak-free containers, and must be combusted. Certain lightly contaminated industrial wipes — those containing not more than 5 grams of solvent — may be disposed in a regulated municipal or other non-hazardous landfill, provided that the solvents do not qualify as one of 11 listed solvents that are ineligible for landfill disposal under the proposed rule. Comments on the proposed rule must be submitted to EPA by February 18, 2004. ◎

— contributed by Roy Belden in New York

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