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PROJECT FINANCE
NewsWire

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Storm Over Argentina

by Keith Martin, in Washington

Chadbourne lawyers working on projects in Latin America reported a number of effects from the turmoil in Argentina. However, the situation remained fluid as the *NewsWire* was going to press in late January.

Debt Freeze

The Duhalde government moved quickly to try to bring order to the economy, but many of the new rules were hastily drafted and leave unanswered questions. Argentine lawyers are reluctant to express firm views because of the frequency of new decrees from the government.

Argentina declared a formal moratorium on repayment of government debt on December 23.

However, payment of private debts denominated in foreign currencies has also been blocked by inability to get approval from the central bank for transfers of foreign currency out of the country.

The Argentine Congress passed a set of emergency measures — called the devaluation law — the first week in January to give the government broad powers to manage the crisis. The new law ended the one-to-one peg between the Argentine peso and the dollar.

A new currency exchange regime took effect on January 11. It established a two-tier exchange regime. There is a "regulated market" in which exporters are required to sell the foreign currency they collect from export sales at the rate of one / *continued page 2*

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ENRON came under pressure to release tax returns and other details about its tax planning.

The Senate Finance Committee asked the company in late January to let it release information pulled from the company's tax returns. The committee already has authority to review the information, but not to make it public.

"It was a shock to read that Enron may have used nearly 900 tax-haven subsidiaries to avoid taxes and hide its financial debts," Senator Charles Grassley (R.-Iowa) said. Grassley is the top Republican on the committee. Congressman Charles Rangel (D.-New York), the / *continued page 3*

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dollar for 1.4 pesos, and importers of certain goods are permitted to buy dollars to pay for their imports at the same ratio.

The peso has been allowed to float for all other transactions. The peso dipped as low as 1:1.95 in late January, but had recovered by press time to 1:1.8. Some analysts are forecasting that it could drop to 1:2.70 by the end of this year.

The Argentine central bank announced a hierarchy of imports, tied to the tariff classifications of goods, in which purchasers of the most favored imports would be allowed to buy dollars within the next 90 days, the next most favored within 180 days and the next within 360 days. All requests for foreign currency must be made through commercial banks.

However, little if any currency is being dispensed in practice. US embassy officials in Buenos Aires reported on a conference call with American business representatives on January 25 that most exporters appear to be delaying collection of foreign currency receivables in the hope that by the time they receive payment, mandatory conversion into pesos at the 1:1.4 rate will have been dropped in favor of the floating rate. This puts a severe strain on the regulated market because the government is attempting to limit use of dollars for imports to the amount of foreign currency brought in by export sales.

The devaluation law had a number of other significant provisions.

It authorized the government to impose a 5-year tax on oil and gas exports. Tax rates of 20% to 30% are being discussed, but the government is under pressure from the oil and gas industry to look elsewhere for revenue.

It directed that all contracts denominated in foreign currency should be renegotiated within 180 days to apportion the effects of the peso devaluation between the parties. The central bank subsequently issued regulations directing that lenders of foreign currency loans of more than $100,000 would have to agree to extend payment terms and lower the interest rate. Loans with maturities of from one to five years must be extended by 20%. Longer-term loans must be extended by 10%. The regulations require a 33% reduction in interest rate.

The new law also declared unenforceable any sort of price indexing in contracts.

It also rescinded any provisions in contracts with the government that link payments to the value of foreign currency — for example, price escalation clauses intended to compensate the contractor if the peso loses value in relation to the dollar. It authorized the government to renegotiate such contracts, and said that suppliers could not use the new law as an excuse to suspend or vary performance. US power companies that bought Argentine utilities when they were privatized in the 1990's found themselves squeezed potentially by a mismatch between dollar obligations and the declining value of peso revenues. At least one said it would cooperate with the government to prevent spikes in electricity prices, but would resist giving up any contract protections against loss in value of the peso.

> Argentina directed that all contracts denominated in foreign currency should be renegotiated.

Argentine lawyers advise that whether these new rules apply to contracts that, by their own terms, are governed by New York or other foreign law must be determined on a case-by-case basis.

Creditors' Rights

In late January, the Argentine Congress commenced debate on a bill limiting creditors' rights and overhauling the bankruptcy laws. The measure quickly passed the Senate and was expected also to pass the House. International banks complained. The US ambassador met the third week in January with the ministers of economy, foreign affairs and production to voice US objections.

In its initial form, the bill would have given insolvent debtors an "exclusivity period" of 180 days — rather than the 60 days allowed currently — to present a reorganization plan. If the debtor could not get approval for its plan within the new longer time period, then there would be mandatory "capitalization" of creditors' claims in which creditors would be forced to accept nonvoting preferred shares in the debtor in place of their debts. The only preference the shares carried would be at liquidation.

This mandatory capitalization feature had been dropped from the bill by the time the NewsWire went to press.

However, the bill still proposed to overhaul existing bankruptcy laws in several other significant respects. All foreclosure proceedings against Argentine borrowers would be suspended for 180 days after the bill is enacted. The bill would eliminate any "cram-down proceedings" under which a debtor who cannot get approval for its plan of reorganization is essentially put up for sale to creditors and third parties under special bidding procedures. It would also allow a debtor to shed 100% of its debts in bankruptcy. Current law does not allow a debtor to seek release for more than 60% of each admitted claim.

Paul Weber, a project finance partner in London, said the bill is being watched closely by lenders because any material impairment in the collateral for a loan or in the ability of a lender to enforce its rights under the financing documents is a default under most loan agreements.

Effects

The most immediate effects of the Argentine government actions were on US power companies that bought Argentine assets and on banks.

Banks with commitments to lend into Argentina but whose loans are not yet fully disbursed looked for ways to avoid any further funding. Most loan agreements have "conditions precedent" that must be met before each draw on the loan. One common condition is that there must have been no "material adverse change" in the condition of the project or the borrower or in the validity or priority of the lien that the lenders have on the project assets. Another condition is that the loan cannot be in default.

Some loan agreements, particularly with multilateral lending agencies, make an "inconvertibility event" — defined as a change in the one-to-one peg of the peso with the dollar — automatically a default. In other loan agreements, it is a default if there is any "material adverse action" by a governmental authority or if the borrower goes more than a specified period of time without being able to gain access to dollars with which to make payments on the loan.

Lenders whose loans are already fully funded appear to have few good options other than to wait for the situation to stabilize. */ continued page 4*

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ranking Democrat on the tax-writing committee in the House, called for legislation to deny interest deductions on debt instruments that a corporation records as equity on its books.

Meanwhile, the Senate Finance Committee announced plans to launch an investigation into Enron's corporate tax structure and its use of tax products to shelter income, but seemed in no rush to set a date for hearings. The committee staff appears to be proceeding with caution. A lot of Enron tax planning is no different than that used by many other US multinationals.

The Enron situation has complicated the outlook this year for tax legislation. The Senate is scheduled to start debating the Bush energy plan — including tax incentives for some new power plant construction — in February, but the schedule could slip if members of Congress feel they need to understand better what went wrong with Enron before committing to a new energy policy. At the same time, there may be pressure to revisit some Clinton era tax proposals to crack down on hybrid debt and other sources of book and tax disparity.

GENERATORS who paid tax grossups in addition to the cost to connect their power plants to the grid are now asking utilities for their money back.

The Internal Revenue Service said in December that such payments do not have to be reported in most cases as income by utilities. The IRS notice applies to interconnection payments made after December 26, 2001. However, the same principles should apply to earlier payments. The agency said it would issue private letter rulings to anyone who wants confirmation about earlier payments.

One utility, Entergy, said it plans to send letters to generators on its system telling them how they can get their money back. The utility expects to */ continued page 5*

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Payments are continuing on many foreign currency loans on large infrastructure projects with the project sponsors using offshore accounts to make payments. Many of these loans were structured to take advantage of a special provision in Argentine law that waives withholding taxes on interest payments on foreign borrowing to finance projects that produce goods for the export market. Borrowers under such loans — called "negotiable obligations" — are allowed to keep the foreign currency earned from export sales in offshore accounts.

The International Finance Corporation said that 11% of its $10.9 billion in disbursed loan and equity portfolio is in Argentina. The director urged IFC staff to cut costs and concentrate on closing new financings so that the agency can add more good assets to its books. The IFC — an arm of the World Bank — provides financing for private projects in developing countries.

The freeze on repayment of government debt has led to claims against foreign banks on credit default swaps. Credit default swaps are financial instruments that holders of sovereign debt sometimes enter into with investment or commercial banks to protect against loss in value of the bonds in the event of a government default. The terms of the swaps vary and ability to collect depends on how such key terms as "restructuring," "repudiation" and "moratorium" are defined in the particular agreement, according to Robin Lahiri, a consultant with Chadbourne in London. Press reports varied about the amount of government debt affected by the moratorium. The estimates ranged from $141 billion to $155 billion. Government bonds had already been trading in the market at one quarter of face value before the moratorium, so there had already been a substantial loss in value before any "credit event" that triggered payment on the swaps.

The equivalent protection for private debt is political risk insurance. The standard political risk policy protects against "inconvertibility," or the inability at any exchange rate to convert local currency and transfer the converted proceeds overseas. A number of notices of potential claims have come in, according to Julie Martin, former head of the political risk program at the Overseas Private Investment Corporation and now with Marsh & McLennan, but these are not full-blown claims yet because the insurance policies have a waiting period before claims are paid. The purpose of the waiting period is not so much to verify the facts that justify a claim, Kenneth Hansen, a project finance partner in Washington explained, but rather "to limit the insurer's risk with respect to momentary crises that are quickly resolved." Hansen said there is always the potential for Argentine claims to "evaporate into uncovered devaluation prior to the expiration of required waiting periods," but no one is making predictions.

Insurance coverage for losses caused by devaluation — as opposed to inconvertibility — became available for the first time last year, but no policies were written on Argentine pesos.

According to Julie Martin, most political risk insurers have significant exposure in Argentina. Some political risk providers have suspended all coverage for the country — not just for inconvertibility, but also other traditional coverages for expropriation and political violence. As yet the market is not seeing a spillover effect to Brazil, but probably because the market is already at capacity on Brazilian exposure and not in a position to write more.

Spillover

Ironically, the spillover effects of the Argentine situation may be less significant in Latin America than in Spain. As much as 12% of the Spanish gross domestic product, or GDP, is tied to Argentine investments.

US embassy officials in Buenos Aires said there have been few effects on neighboring countries in Latin America apart from tourism. The number of Argentine tourists flocking to beaches in Uruguay is down significantly. Governments in neighboring countries have been watching, perhaps with greater interest, the potential for political instability to spread. Argentina is an exporter of gas to power plants across the border in Brazil.

A Chadbourne lawyer, David Schumacher, reported from São Paulo that he found no evidence of Argentine contagion during a trip across Latin America in late January. "People knew the devaluation was coming and planned on it occurring, so it has not been a surprise perhaps like it was in Asia. There are potential balance of trade issues, but as far as the ability of projects in other countries to borrow, it does not seem to have had an effect."

Some corporate debt issuers in other Latin countries have expressed concern about their ratings in cases where they have significant Argentine investments. There have been discussions, but no action taken, about whether currency exchange risk coverage should be obtained on transactions in places like Panama, where the dollar is legal tender.

Next Time?

Is there anything that developers or lenders should do differently after the experience in Argentina?

"Monday morning quarterbacking is hard," said Noam Ayali, a project finance partner in Washington. "Maybe look harder at whether to buy political risk cover; maybe look harder at country stability and the government situation. There have been complaints about political corruption and mismanagement in Argentina for years."

Multilateral lending agencies, like the IFC and Inter-American Development Bank, enjoy preferred creditor status, meaning that governments tend to ensure that scarce foreign currency is used to repay them first. Export credit agencies like the Overseas Private Investment Corporation and US Export-Import Bank do not enjoy the same protection. Ayali said that one of the lessons for lenders may be the cost of working with multilateral lending agencies is worth it, because lenders who lend alongside a multilateral as part of a "B loan" syndicate share in the preferred creditor status of the multilateral lender.

"It struck me that a lot that has happened here has happened before," Paul Weber said from London. Many Argentine deals, even though structured at the height of euphoria over Latin America and unprotected against currency devaluation risk, were still carefully designed to match expenses with revenues in the same currency.

Law firms revisit their standard contract clauses after large events like Argentina to see what can be learned from the experience. Paul Weber suggested broadening "material adverse change" clauses to make clear that they refer to changes that affect the economic prospects of the entire country and not necessarily just the project. Aruna Chandra, in New York, pointed to clauses in project agreements that allow offtakers to pay in the local currency in situations where they cannot convert into dollars. Developers are always careful in such situations to put mirror provisions in their contracts with suppliers, but there is the potential for a mismatch due to different interpretations of the contracts by the project counterparties. Rather than try to match language, the developer might be better off allowing the offtaker to pay in pesos only to the extent that it can get the supplier to accept pesos. ◎

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make prompt refunds of tax grossups collected during 2001, but said that refunds of earlier amounts will have to wait until the utility can get a refund itself from the IRS.

Several issues have come up since the IRS issued its notice. The IRS notice only applies where the generator has a "long-term" interconnection agreement with the utility. Some utilities have questioned whether this requirement is met if the generator has a right to terminate the interconnection agreement at any time after 30 days' notice. Such provisions are commonplace. Some utilities award generators a "transmission credit" for the cost of system upgrades that the generator can work off against future wheeling charges or assign to whomever the generator sells its electricity. Some utilities feel the tax treatment of interconnection payments in this circumstance is unclear.

Talks are underway with senior IRS and Treasury officials to resolve both issues.

Meanwhile, the Federal Energy Regulatory Commission is expected to release a standard form of interconnection agreement for comment that utilities and generators would be expected to use in the future. An industry group of both generators and utilities submitted a "consensus" document that they hope will be the document put out for comment. This document has language explaining when a tax grossup will be required in the future on intertie payments, but the tax language remains unsettled.

SYNFUEL PROJECTS receive attention from the IRS.

The agency had a backlog of 22 ruling requests when it reopened the rulings window last October after a hiatus of about a year and a half. It had worked through 20 of the requests by late January and hoped to finish the last two by February 1. No new ruling requests have come in since October.

In the meantime, at */ continued page 7*

Western Merchant Plant Outlook

by Dr. Robert B. Weisenmiller, Mark Fulmer and Heather Vierbicher, with MRW & Associates, Inc., in Oakland, California

If the events of the past few years — price spikes in the Midwest, the California electricity crisis and the Enron bankruptcy — demonstrate anything, it is that electricity industry restructuring and competitive wholesale markets have not solved the riddle of the industry's historical swings between undercapacity and overcapacity.

In the past, under cost-of-service regulation, the consequences of a utility's poor timing for resource additions were generally absorbed in rates, although a utility could face adverse financial consequences from imprudent investments or inadequate service reliability.

In today's market, merchant energy companies are worried that they will suffer a financial bust for building too much generating capacity. However, building too little capacity does not guarantee booms. Power shortages lead to price spikes, and price spikes produce volatile markets, which in turn lead to politicized power markets, regulatory uncertainty and turmoil in the financial markets. Thus, high prices are never sustainable because of the effects of politics and of market responses.

Despite the slowdown in power plant development, many analysts and industry watchers predict the US will have excess generating capacity for years to come.

However, a review of the historical ups and downs of power plant development, particularly in the western US, suggests that industry and market expectations rarely match the actual outcome. In fact, the current tightening in the financial markets may have provided the discipline power plant developers needed to sustain their financial health in the future.

This article explains the factors that contribute to the swings between under- and overcapacity in the power industry and discusses whether power markets in the western US are headed for a period of excess capacity.

Understanding the Variables

The cornerstone for electric resource planning is the assumption of economic rationality. That is, new power plants will be added only when costs are expected to be covered by revenues.

However, forecasting the need for power or future power prices is not easy. Even in the days when vertically-integrated utilities undertook sophisticated integrated resource planning processes and could count on recovering some costs through rates, reality seldom matched expectations. The Pacific Northwest provides a good example: over the past 25 years, this area has seen major shifts in expectations from under- to overcapacity every 5-7 years.

Certain characteristics of power markets make the industry prone to periods of under- and overcapacity. First, developing power projects requires long lead times. Project development activities for a 500 to 1,000 megawatt gas-fired, combined-cycle facility can easily require four to six years: one to two years to develop a viable site, about one year for permitting and another two to three years for construction. Controversial or difficult projects may require a decade or more. If major pipeline or transmission upgrades are required, the overall timing can again be eight to ten years.

Second, factors influencing either the demand- or supply-side of the load-resource equation can tip the capacity balance into an under- or overcapacity situation. These factors include the economy, policy decisions and the weather, among other things.

On the demand side, economic growth or recession will affect electricity demand. Yet, while long-term economic trends are difficult to forecast, it is even more difficult to forecast short-term variations in economic activity. This results in demand forecasts that either overstate or understate the actual demand for power. For example, in the early 1990s, electricity demand was projected to grow at about 2% per year. However, in the early 1990's, California suffered its greatest economic downturn since the Great Depression. The economic slump depressed electricity demand growth and resulted in an overcapacity situation. On the other hand, in the late 1990's, California's economy expanded and, as a result, electricity demand soared and the state suffered from a shortage of generation capacity. Although demand growth was about 2% over the ten-year period — matching expectations for the long term — the state still experienced periods of over- and undercapacity.

In early 2002, the question for California is whether Silicon Valley's high-tech firms will spark a new economic boom in northern California or relocate to states with more favorable business climates, leaving behind a new rust belt of yesterday's technologies and dot-com dreams.

Short-term variations in electric demand can lead planners and policy-makers to act in ways that can exacerbate the over- or under-supply of generation. In the early 1990s, as a result of the slowing of electricity demand growth, policy-makers made several decisions affecting future resource additions. They terminated a resource solicitation. They encouraged the buyouts and shutdowns of "qualifying facility" projects. They provided Southern California Edison with economic incentives to close a troubled unit at the San Onofre nuclear generating station. Dams were removed from service for environmental reasons. The state's power market was restructured with an exclusive orientation towards spot power (and without any capacity markets). Development of any significant new resources was delayed. Thus, once demand grew faster than expected in the late 1990s, the state was under-resourced.

As seen last year, policy decisions can have a substantial impact on electricity demand. One of the most important policy lessons to come out of California's recent crisis is that it is possible to achieve significant energy savings in a very short time frame. The California Energy Commission estimates that the various education programs and utility demand-side management efforts reduced California's peak demand by about 3,000 megawatts during the summer of 2001. The Pacific Northwest also achieved large savings in terms of its loads. The Bonneville Power Authority cut electricity demand by thousands of megawatts by buying back power from certain industrial customers such as aluminum smelters.

The impact of variations in the weather on loads is fairly obvious. Weather conditions vary around their expected values, but seldom precisely reflect average conditions. Mild weather reduces either summer cooling or winter heating loads, just as severe weather conditions strain the electricity system. Variations in annual rainfall also affect both hydroelectric generation and agricultural pumping loads. Milder weather and higher hydroelectric generation depressed power markets in 1999, while low hydro conditions in the Pacific Northwest in 2000 and 2001 contributed to supply shortages.

Third, the balance between supply and demand can be as readily influenced by shortfalls in supply as increases in loads. Along with natural variations in the level of potential hydroelectric generation, the expected level of supplies can be higher or lower than anticipated. Plant operators can increase the output or availability at existing power plants over time, while environmental restrictions, relative eco- */ continued page 8*

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least four projects are under audit. The IRS appears to be probing whether the projects were placed in service in time to qualify for tax credits. The deadline was June 1998. Audits of other projects are expected.

US TREASURY OFFICIALS gave a preview in late January of guidelines the government may propose later this year to settle controversies over writeoffs for costs of intangible assets.

Examples of intangibles are debt instruments, contracts and permits. Companies must usually "capitalize" amounts they spend on such assets. This means recover the cost for tax purposes ratably over the life of the assets. The US tax laws assign an arbitrary writeoff period of 15 years to many intangibles, but the actual life must be used for contracts and other assets that a company creates itself rather than buys from someone else.

However, there are many instances where US companies deduct amounts they spend on intangibles immediately in the year the money is spent, only to be challenged later on audit by the IRS.

Treasury officials said the new guidelines will let payments that do not produce a benefit beyond the end of the next tax year be deducted immediately. An example is where a company prepays its insurance premium in December for a one-year policy that runs from December to December. However, a prepayment in December for a policy that runs from February to February would have to be deducted proportionately in each of the next two years.

The new rules will also allow expensing — or immediate deductions — for small dollar amounts where the paperwork to capitalize is not worth the cost. Small may mean up to $5,000.

Transaction costs must be included in the cost of the intangi- */ continued page 9*

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nomics, or forced outages can reduce the availability of supplies. A portion of generation throughout the western US in the past two years has been unavailable because of emissions limitations and higher than expected forced outages following periods of higher than anticipated operations.

Fourth, power plant development can be adversely influenced by regulatory and market uncertainty. Throughout the West, project development has been dampened by both the tsunami of price shocks from California rolling through the interconnected, regional market and the resulting desire of other western states to erect firewalls around California rather than form a regional electricity market.

In California's case, uncertainty over who will buy the power from new plants has stalled new plant development. California's power problems left few creditworthy entities to pay for power supplies. The Pacific Gas & Electric Company filed for bankruptcy, while Southern California Edison spent almost one year on the precipice of bankruptcy. Utilities throughout the western US were financially weakened by the need to buy high-priced power in wholesale markets to cover their net short positions for their retail customers. It is impossible to use project financing for the construction of a new power plant without either an offtake agreement with a creditworthy entity or a functional wholesale market with a variety of creditworthy buyers.

California's Department of Water Resources, or DWR, is one of the few creditworthy power buyers in California today. At one time, it appeared that the DWR's portfolio of power purchase contracts might provide the credit support for the construction of new projects. However, this program is mired today in regulatory uncertainty as some California public officials attempt to renegotiate these contracts. Moreover, the bond sale needed to finance the DWR's power purchases is stalled by disputes among the governor's office, the DWR, California's new power authority, the California public utilities commission and the State treasurer's office, among others.

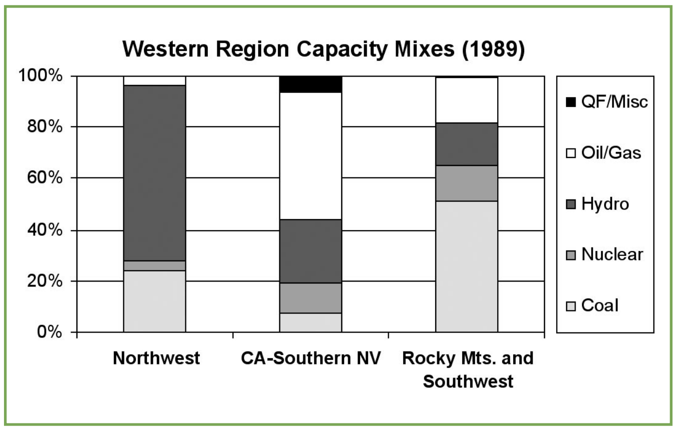
Finally, volatile fuel markets can dramatically change the nature of the optimal supply mix. In recent years, the conventional assumption was that low-cost gas combined with very efficient turbine technology would allow new combined-cycle power plants to displace the operation of many existing power plants. However, volatile gas markets have revived developers' interest in coal, nuclear and renewable technologies as resources to be built into diversified power portfolio.

Resource Diversity in the West

The electricity market in the western US is characterized by a diverse mix of coal, nuclear, hydroelectric and gas generation.

Particular subregions are dependent on specific resource types. The resource mix of the Pacific Northwest is dominated by hydroelectricity from the Columbia River system, which has limited long-term storage. The resource mix of the inland Southwest historically has been overly dependent upon baseload coal and nuclear generation. In 1989, baseload resources accounted for almost 70% of the Southwest's capacity. This fraction has decreased to under 50% today. California has been, and continues to be, particularly dependent on oil- and gas-fired generation.

Political boundaries obscure the natural, interrelated nature of the Western power market. Electricity demand peaks in the winter in the Pacific Northwest but peaks in the summer in California and the inland Southwest. Thus, seasonal exchanges — either through the market or through long-term agreements —allow one subregion to provide power in an off-peak season to another during a peak season. For example, hydroelectricity from the Pacific Northwest or coal and nuclear



power from the Southwest can displace gas-fired generation in California in the summer months, thus mitigating to some degree California's resource imbalance. This exchange of energy is then reversed when needed. Swings in hydroelectric availability or power plant outages also can be buffered more readily across the requirements of the region as a result of the complementary nature of the region's resource mix.

The region's resource mix has historical roots. In the Pacific Northwest, the Depression-era Works Progress Administration dams on the Columbia River dominated the region for the majority of a century. California's environmental requirements and regulatory climate led to its dependence on gas-fired generation. In the 1970s, high oil prices and expected load growth led to major coal and nuclear construction programs throughout the West, but particularly in the Rocky Mountain and Southwest desert states. Many of these coal and nuclear plants became operational in the mid-1980s just as oil and gas prices crashed.

Bust, Boom, Bust?

The coal and nuclear plant development programs, coupled with California's "qualifying facility" and demand-side management programs and a regional recession, led to an overhang of regional surpluses into the mid-1990's. Inland utilities that had added resources as a bet on power sales into the wholesale market faced financial ruin as a result of excessive reserve margins. One utility, Public Service of New Mexico, found itself with a reserve margin of over 80%.

By 2000, the regional surpluses were absorbed by load growth. California's story of supply shortages has been told many times in the past year. What is less well known is that the reserve margin for the Arizona-New Mexico-Southern Nevada region was just as bad as California's, if not worse. The North American Electric Reliability Council reported that this region had negative reserve margins in 2000 and 2001, with frequent rolling blackouts averted only by a combination of the absence of severe regional heat waves, plants remaining on line and imports from other regions. Even so, rolling blackouts occurred in the Las Vegas area on July 2, 2001.

These regional shortfalls rippled throughout the whole western US. California was rudely surprised when it assumed it could rely on imported surplus power during its peak periods, primarily from the Bonneville Power Authority's dams. In 2000 and 2001, the Pacific Northwest experienced one of its lowest hydro years on record. As a result, electricity imports into California dropped an average of 2,000 megawatts for the period from May through August in 2000 and almost 3,500 megawatts in August.

The shortfall in hydroelectric generation required significantly greater gas-fired generation, which in turn led to a congested gas transportation system, higher gas prices, greater air emissions and challenging */ continued page 10*

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ble. The Treasury said the IRS may stop insisting that transaction costs include an allocation of employee salaries and other overhead. However, bonuses and commissions tied directly to a transaction would still have to be treated as a cost of the intangible acquired.

The Treasury said it is weighing an alternative where *all* employee compensation — including tied bonuses and commissions — could be expensed if the transaction is considered "regular or recurring."

Outside legal fees that a lender pays to document a loan must be treated as a cost of the debt instrument. However, the government will no longer require lenders to capitalize reasonable amounts paid to secure a credit history and property appraisal or salaries and other internal overhead of the loan origination department.

Fees paid to outside counsel in acquisitions would still have to be capitalized, but the government will no longer require capitalization of a portion of the officers' salaries for the time spent on negotiating the deal. Also, capitalization will not be required for amounts spent after the acquisition on integrating the two companies or paying severance to employees who are let go.

These are guidelines the government may adopt. It will be interesting to see whether the IRS backs off in pending taxpayer audits before the guidelines are formally published.

TAX SHELTERS are starting to worry the Bush administration.

Bush Treasury officials have insisted in the past that Congress should allow more time for new regulations requiring corporations to report tax shelters to the IRS to work before trying to legislate.

One potentially worrisome development is that only 95 companies reported tax shelters to the government */ continued page 11*

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operating schedules for the state's aging fleet of existing gas-fired power plants. This should not have been a surprise. A well-circulated 1999 California Energy Commission study pointed out California's vulnerability to supply shortages during statewide or regional heat storms.

In 2000 and 2001, price spikes in the West caused a surge in potential project development. In an average year, the western region requires about 3,000 megawatts of net resource additions, not counting capacity that is needed to make up for the low existing reserve margin nor that needed to replace retirements. Thus, with a four to six year development cycle, at least 12,000 to 18,000 megawatts should be in permitting or construction at any given time. Along with the 41,000 megawatts of approved plants or those undergoing review prior to 2000, over 60,000 megawatts of additional potential projects were announced in 2000 to 2001. If all of these plants were to come on line by 2010 instead of 2005, the WSCC-wide reserve margin would balloon to 60%. For reference, region-wide only about 11,200 megawatts (net) came on line in the WSCC from 1997 through 2000.

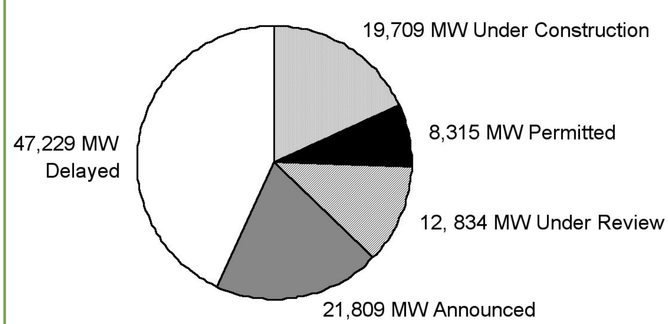
Analysts always knew there would be some attrition as project developers ran the gauntlet from press release to operating project. The higher the stack of press releases in the power plant gold rush era, the larger the number of canceled projects or deferral notices when forward price curves reflected the impacts of those potential projects. Thus, a boom of potential projects appears to have gone bust. *Power Markets Week* recently reported that developers have announced almost 85,000 megawatts of potential projects nationwide as either having been put on hold until markets look brighter or scrapped altogether. In California, nearly 5,000 megawatts of projects have been cancelled or postponed. In the West, nearly 60,000 megawatts of projects have been delayed, although not all for economic reasons. Calpine alone recently announced that it was placing 34 plants, totaling 15,100 megawatts, on hold. In December, Mirant said that it would defer or cancel any new plants beyond those that are under construction. Nonetheless, projects totaling over 30,000 megawatts have recently become operational or are already under construction, which will address near-term supply shortage concerns in the West. Furthermore, better hydro conditions, higher retail prices and continued conservation will reduce the need for thermal power plant output in 2002 relative to 2000 and 2001.

Even if only a fraction of the announced plants materialize, a strain will be put on the gas and electricity delivery infrastructure. A recent study by the Western Governors Association estimated that if most of the new demand is met through gas-fired generation, then $2.1 billion of pipeline expansions and upgrades would be needed. If the demand is met by using coal-fired generation located at the minemouth, an investment of at least $8 billion in high-voltage electric transmission infrastructure would be needed.

Conclusions

Historically, the timing of electricity generation capacity additions has never been particularly optimal. Long project

New Capacity Proposed for the WSCC



development lead times combined with uncertain supply, fuel price and demand forecasts often give rise to over- and undercapacity periods. The consequences are often felt most strongly at the local level.

Regional markets for electricity are needed to facilitate the flow of power between areas that have either too much or not enough generating capacity. Regional markets also will provide some benefits in terms of load and resource diversity. Capacity markets, such as an "available capacity" or "installed capacity" market, may smooth out the power plant development cycle while some form of capacity payment should dampen the volatility of energy markets. Demand-side management can fill the gap when regions face unexpected surges in electricity demand and insufficient capacity. Developers will be able to mitigate their own risks by building diverse, national portfolios to act as a hedge against regional fluctuations in capacity markets. The challenge for the industry is to develop a political consensus on these issues that will lead to regulatory certainty and a favorable long-term investment climate.

The financial community can also play a role in smoothing out the project development process by seeking out objective, independent assessments of market risks and mitigation strategies as part of the due diligence process.

Industry restructuring and the expansion of competitive markets has led to a race among merchant developers to translate competing development plans into operating projects, particularly in regions which are seen as having too little capacity or a suboptimal supply mix. Perhaps fortunately, the plans of merchant energy developers have been influenced by Wall Street's expectations as to emerging supply and demand trends. Each developer individually may have an incentive to build as much as it can. The financial community has a broader perspective and acts as a useful brake.

FERC Considers Tighter Regulation Of Independent Power Companies

by Lynn Hargis, in Washington

The Federal Energy Regulatory Commission proposed changes in late December, in the wake of the Enron bankruptcy, to the "uniform system of accounts" that investor-owned utilities must use to report their financial results each year to federal regulators. The revisions are aimed at collecting better information about the "fair value" of financial instruments, hedges and derivatives held by utilities.

FERC also asked for comments on whether to subject independent power producers and power marketers to two types of utility regulation in the future.

FERC asked whether independent power producers and power marketers that are authorized currently to sell electricity at market rates should nevertheless be required to file financial reports like the investor-owned utilities under the uniform system of accounts.

It also asked whether independent */ continued page 12*

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last year, despite stiffer new reporting requirements. The voluntary disclosures flagged 272 transactions, but 100 of them were "plain vanilla" equipment lease financings that lease advisers have been encouraging taxpayers to report, possibly in the hope of burying the government in paperwork. Treasury officials also said some companies sent their disclosures to IRS service centers rather than the special office in Washington set up to monitor tax shelter activity. They suspect bad faith may have been involved in at least some of these filings.

The government is now trying a carrot and stick approach.

The IRS announced on December 21 that it would waive accuracy-related penalties to anyone who voluntarily discloses by April 23 a tax shelter or other questionable item that he took on his return. What the IRS really wants is the name of the "promoter" so that it can go after the customer list. Controversy has arisen because the IRS wants all documents and memos related to a transaction from anyone taking advantage of the limited amnesty. Turning over some of them may breach confidentiality agreements.

The government also sent 28 letters to tax shelter promoters in late December whom it suspects failed to report transactions. The promoters include seven accounting firms and seven investment banks. Formal summonses are expected to follow.

Meanwhile, the government lost three high-profile tax shelter cases in the past few months on appeal that it had won in the lower courts, raising more concerns.

The Senate Finance Committee will probably vote out tax shelter legislation this year. The committee released two drafts of an anti-shelter bill in the last Congress. Committee staff say no more advance drafts will be circulated.

It is possible that the publicity given to Enron's tax planning */ continued page 13*

FERC Regulation

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power producers and power marketers should be required to get advance approval from FERC before issuing any stock, debt or other securities or assuming any liabilities.

In the past when the commission has issued orders to independent power producers and power marketers authorizing them to sell electricity at market rates, the orders have routinely waived any need to file uniform accounts and have given a blanket authorization to issue securities and assume liabilities without having to seek the commission's approval.

FERC is considering requiring independent power producers and power marketers to get advance approval before issuing stock, debt or other securities.

Persons holding these orders would be affected by the new rules. Any change would be prospective.

The actions are part of a "notice of proposed rulemaking" that the commission issued on December 20. Comments are due by March 9.

Congressional Pressure

One of the first Congressional hearings after the Enron bankruptcy focused on whether the Federal Energy Regulatory Commission was too lax in its oversight of Enron's power marketing activities. Section 204 of the Federal Power Act requires prior FERC approval before any "public utility" can issue securities and or assume liabilities. "Public utility" is broadly defined to include not just vertically-integrated, investor-owned utilities, but also power marketers and independent power producers. Enron's power marketer, like others that make wholesale sales of electricity at market-based rates, enjoyed a blanket prior authorization for such securities issuances and liability assumptions, and thus did not have to seek FERC approval for its specific debt obligations or security issuances. Congress is pressing FERC, the Securities and Exchange Commission and other US regulatory agencies to explain how Enron's securities went unregulated, even when the company was selling almost 20% of the nation's electricity.

The notice of proposed rulemaking that FERC issued on December 20 was perhaps partly in response to the hearings.

How Enron Escaped Regulation

When Enron Power Marketing, Inc., or "EPMI," sought approval from FERC in 1993 to sell electricity at market-based rates, it also asked the commission for waivers from various utility regulations that would ordinarily apply to the sale or purchase of electric transmission facilities, arguing that these rules should not be applied to bare contracts for the purchase and sale of electricity.

FERC refused to "waive" section 203 of the Federal Power Act for electricity contracts. That section requires prior FERC approval for any sales or consolidations of "facilities" — in this case electric contracts. The commission said that wholesale energy contracts are "facilities" and, in fact, this is what gives the commission jurisdiction over power marketers who might own nothing else. It is ownership of "facilities" that makes a power marketer a "public utility" subject to FERC regulation under the Federal Power Act.

However, FERC granted EPMI relief from section 204 of the Federal Power Act. That section requires prior FERC approval before any owner of "facilities" can issue stock or make loans. FERC had said in prior orders that a power marketer like Enron did not propose "to obligate itself to serve electric consumers" and, therefore, its financial health — and, apparently, that of every entity that sells at market-based rates — was not a concern under section 204. As a result, FERC granted blanket prior authorization for the security issuances and assumptions of liability by EPMI, provided no one protested within an initial comment period of 30 days or so. FERC reserved the right to modify this blanket authorization in the future to require a further showing that neither public nor private interests will be adversely affected by leaving the blanket authorization in place. FERC has given similar blanket authorizations to other power marketers and independent power producers whom it authorizes to sell at market-based rates.

FERC may have trouble defending the logic for blanket authorizations in the current Enron-crazed environment. The situation today bears an eerie resemblance to what led Congress to enact section 204 in the first place.

It was railroad financial scandals in the 1920s that led to enactment of a forerunner to section 204. Congress enacted section 20a of the Interstate Commerce Act in an effort to repair the damage done to railroad stocks and credit after several railroad bankruptcies. It then copied section 20a almost verbatim into the Federal Power Act in the 1930s after a series of public utility holding company financial crashes of the late 1920s and early 1930s. The Federal Power Commission, which FERC replaced, quoted an historian of section 20a in a 1962 order:

> While this extension of the [Interstate Commerce Commission's] authority was designed indirectly to protect the investing public against the dissipation of railroad resources through faulty or dishonest financing, its dominant purpose was to maintain a sound structure for the rehabilitation and support of railroad credit, and for the consequent development of the transportation system. *It aimed to render impossible the recurrence of the various financial scandals, with their destruction of confidence in railroad investment, which had become notorious, and to prevent the subordination of the carrier's stake as transportation agencies to the financial advantage of alien interests* . . . .

Impact on Independent Power Companies

Assuming that FERC itself, or Congress or the courts, decide to require power marketers and generators to seek prior approval before issuing any securities or assuming liabilities, what will it mean for the power supply industry?

The independent power industry requires huge sums of capital for building generation facilities.

Although full FERC regulation under section 204 may be burdensome and intrusive to power marketers and generators who have thus far avoided it, in fact FERC generally approves such applications, rejecting the rare protests to them if FERC believes such protests are not relevant to the securities issuances themselves. For example, FERC rejected protests to a section 204 approval request by the Midwest Independent Transmission System Operator, Inc. last year and to issuance of securities by a qualifying facility called Robbins Resource Recovery Partners, L.P. / continued page 14

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may have more of a dampening effect on tax shelters than anything Congress might do. Many corporate tax directors say they have not seen any change in their approaches to tax planning or that of outside advisers who are pitching ideas — at least for now.

MAURITIUS overhauled its companies act, effective on December 1.

Offshore business companies of the kind that US multinationals use to hold investments in India, Pakistan and Mauritius converted automatically into "category 1 global business license companies." At least one director of a category 1 company must be resident in Mauritius, according to Suzanne Gujadhur Bell, director of Mutual Trust Management Mauritius Limited in Port Louis.

Category 1 companies must prepare annual audited accounts and are subject to strict filing deadlines and penalties if they do not comply. The accounts are filed with a new Financial Services Commission that replaced the old Mauritius Offshore Business Activity Authority.

HOLLAND made it harder to use hybrid debt to strip earnings into Holland from another country.

The action is important because many US multinationals make offshore investments through Dutch holding companies.

Hybrid debt is an instrument that is treated as debt for tax purposes in one country but as equity in another. For example, suppose a Dutch holding company advances funds for a project in another country. The advance is drafted so that it looks like a loan for tax purposes in the country where the project is located. The project company deducts the earnings it pays out as interest on the loan. Meanwhile, the Dutch holding company avoids tax on the interest in Holland by reporting the / continued page 15

FERC Regulation

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in 1994. The commission usually approves section 204 applications by delegation to the staff and as quickly as the statutory hearing requirements permit, in order not to interfere unduly with financial transactions.

FERC does not have section 204 jurisdiction over a company if the state in which the company is both organized and operating already regulates the security issuances and assumptions of liability. In the past, this protected most franchised public utilities from the need for federal approval of securities issuances, but it does not provide relief for many independent generators since such generators tend to be organized outside the state or states in which they operate. On the other hand, increased federal regulation of such securities may reduce the opportunity for comparable state jurisdiction, such as that being sought to be reimposed in California over EWGs as "public utilities" under state law.

Such re-regulation of "public utility" securities may be an unavoidable consequence of the Enron bankruptcy. If FERC adopts this approach, it will be with the aim of repairing the damage done to the credit and securities of other power marketers and generation owners by Enron.

The industry should address in comments to FERC whether this is, or is not, a necessary price to pay to restore public confidence in the credit and stocks of power marketers and other sellers at market-based rates. Comments could also suggest ways to make the rules effective, while perhaps requiring less information from and regulation of non-traditional "public utilities" that sell at market-based rates. ◎

Utility Mergers Hit A Wall

by Lynn Hargis, in Washington

A US appeals court overruled US Securities and Exchange Commission approval for a consummated merger between two US utility holding companies in mid-January on grounds that the merger would have violated the Public Utility Holding Company Act, or "PUHCA."

The two utility holding companies are American Electric Power, a holding company headquartered in Ohio, and Central South West, a holding company with its headquarters in Texas.

PUHCA is a 1935 statute aimed at preventing utility holding companies from extending their reach beyond state borders in a manner that makes it difficult for states to regulate their public utility subsidiaries.

The court said the planned merger violated a restriction in PUHCA against owning more than a single integrated utility in a single region. The case is *National Rural Electric Cooperative Association et al. v. SEC*. The decision was announced January 18.

Congress has seemed on the verge for the past several years of repealing PUHCA, but the Enron bankruptcy has made the fate of the statute less certain. There have been suggestions that stricter enforcement of PUHCA by the US Securities and Exchange Commission might have prevented the Enron bankruptcy. (Enron's power marketing operation was exempted from PUHCA regulation under an SEC staff "no action letter.")

Interconnection Requirement

The court found that the SEC had failed adequately to explain its decision under two separate provisions of PUHCA: the "interconnection requirement" and the "region requirement."

The interconnection requirement reflects a policy that a registered public utility holding company must constitute a single "integrated public-utility system." There are currently 35 registered holding companies in the United States, including AEP. The US Securities and Exchange Commission has interpreted the statute to mean that such a utility system's assets must be "physically interconnected or capable of physical interconnection."

In its order approving the AEP-CSW merger, the SEC said that a unidirectional transmission contract between the widely-separated AEP and CSW systems — over several hundred miles — was sufficient to "interconnect" the systems.

The court disagreed. It said this conclusion was inconsistent with prior SEC orders that a transmission contract is not enough by itself to integrate distant utility assets.

The SEC tried to rationalize this inconsistency by arguing that the length of an interconnection line is not relevant to whether two utilities are interconnected. It simply goes to whether the two utilities are within a "single area or region." The court remanded the merger — or sent it back — to the SEC to focus on the inconsistency of this new position with how the agency has applied PUHCA in the past.

Region Requirement

Probably more important is the court's finding that the SEC failed to support its conclusion that the AEP and CSW merged company meets the "single area or region" requirement of PUHCA. The court said the SEC appeared not to have given serious consideration to the question at all.

The court said that the SEC had listed a number of factors in past merger cases that might support a finding that even though two utility systems were distant geographically, they could still be located in "a common economic and geographic region." These factors include "industrial, marketing and general business activity, transportation facilities, and gas utility requirements."

The court chastised the SEC for apparently concluding that a proposed merger satisfies the "region requirement" if it satisfies all the other parts of PUHCA. The SEC "may not interpret the phrase 'single area or region' so flexibly as to read it out of the Act . . . ," the court said. If there is a legitimate basis for concluding that AEP's service territories (in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia) fall in the same "region" as CSW's service territories (in Arkansas, Louisiana, Oklahoma and Texas), the court said, "we cannot find it in the record before us."

The court indicated that the SEC may have gone about as far as it can go with its "flexible" interpretation of PUHCA's single system requirements and that any further flexibility would have to come from Congress.

The [SEC] may well be right that PUHCA's region requirement is outdated in light of recent technological advances. In view of the statute's plain language, however, only Congress can make that decision. In fact, a pending bill would repeal PUHCA, but it has not yet become law.

The decision may become another factor in the PUHCA repeal debate in Congress. In the meantime, mergers that meet the pre-AEP and CSW criteria should still be approved, but those that push the PUHCA envelope may have finally hit a wall. Until Congress acts on PUHCA, this decision will limit the scope for utility mergers. ◎

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transaction as an equity investment. Returns from many equity investments are not taxed in Holland under a "participation exemption."

Under new legislation that took effect on January 1, certain debt instruments with equity features will be classified as equity for Dutch tax purposes. This would have *helped* with earnings stripping into Holland if the legislation did not also deny the participation exemption on such instruments in cases where the interest is tax deductible by the borrower.

Under the new legislation, debt instruments will be classified as equity in three situations. One is where the loan has a term of more than 10 years and the interest is dependent on the profits of the borrower or a related party. Another is in the same circumstances, except the interest is only partly dependent on profits and the interest that will be paid in all events is less than half the market rate. The last situation is where the interest is a seemingly normal fixed or floating rate, but the interest is not paid unless there are profits, the loan is subordinated and it has a term of more than 50 years.

Dutch companies that borrow under these kinds of instruments will not be able to deduct the interest payments in Holland. Moreover, payments to an offshore lender will be subject to withholding taxes as dividends.

The new legislation applies to loans made after January 1, 2002, according to Waldo Kapoen with Loyens & Loeff in The Hague.

A US MULTINATIONAL lost its bid in court to treat its Japanese subsidiary as a "controlled foreign corporation," or CFC, for US tax purposes.

The case is important to US power companies investing in Latin America, where sometimes the only way to prevent the IRS from taxing earnings from the project before the earnings are repatri- / continued page 17

Mexican Tax Laws Change

by José Ibarra, with Chevez, Ruiz, Zamarripa & Cia in Mexico City, and Heléna Klumpp, in Washington

Mexican tax reforms that took effect on January 1 will have a direct effect on the overall tax cost of doing business in Mexico. The following is a discussion of the major provisions that will affect investors in Mexican projects.

Tax Rate

The corporate income tax rate remains 35% in 2002. However, that rate will drop 1% each year until it reaches 32% in 2005.

The reform bill eliminated a taxpayer's election to defer 5% of its income tax by retaining distributable profits. (The deferred portion was paid when such profits were eventually distributed.)

Dividends

Two changes will affect the tax cost of distributing earnings from Mexican corporations.

Mexican companies are required to maintain special "CUFIN" *(cuenta de utilidad fiscal neta)* accounts. Generally speaking, the balances in these accounts represent profits that have already been taxed at the regular corporate tax rate. Distributions from a CUFIN account to Mexican resident entities are not subject to further taxation. If a company makes a dividend to a Mexican resident entity but has no earnings in its CUFIN account from which to pay the dividend, then the dividend is subject to a 35% "equalization tax." The tax is computed on the amount of the dividend "grossed up" by a multiple of 1.5385 to account for income taxes that should have been paid at the corporate level on those profits.

Before the new tax reforms, a dividend paid to an individual or a nonresident shareholder out of a CUFIN account was subject to a 5% withholding tax, but one had first to "gross up" the dividend by 1.5385 before applying the withholding tax. The result was the withholding tax was effectively 7.69% of the actual dividend paid. (Critics charged that the gross-up violates tax treaties limiting dividend withholding taxes to 5%.) If a company made a dividend to a nonresident but had no earnings in its CUFIN account from which to pay the dividend, then the dividend was subject to the same 35% equalization tax as on dividends paid to residents, plus the 5% withholding tax.

The new tax reforms eliminated the withholding tax on distributions made out of CUFIN accounts.

They also changed the way CUFIN accounts are maintained. A company computes its CUFIN account balance by adding its taxable profits and subtracting its tax liability and non-deductible expenses. Prior to the reform bill, a company could never have a negative balance in its CUFIN account. Now, if a company's tax liability and non-deductible expenses exceed taxable profits, it will create a negative account balance. The negative amount (adjusted for inflation) must be used to offset any future positive earnings in the CUFIN account. Requiring taxpayers to make a reduction of future CUFIN balances could drastically reduce a company's ability to pay tax-free dividends. To somewhat counterbalance the effect of this provision, a company will now be permitted to carry forward for three years as a credit the amount of equalization tax that is paid on any distribution exceeding CUFIN earnings.

Expensing For Investments

New investments in certain fixed assets may now be recovered with a one-time, present-value deduction in the year immediately following the tax year in which the asset is first used. For the past three years, investments were required to be depreciated on a straight-line basis. For example, an investment in a building that was made in 2000 had to be recovered at the rate of 5% over 20 years. Now such an investment may be recovered through a one-time deduction at 57% of its total value in the year after the asset was placed in service. The 57% represents the present value of the depreciation deduction to which the owner would have otherwise been entitled, discounted at a 6% rate. The statute requires use of this discount rate. Assets located in Mexico's three largest cities — Mexico City, Guadalajara and Monterrey — must meet additional requirements to qualify for the immediate deduction.

Consolidation

Mexican tax laws allow related companies to consolidate their profits and losses on a limited basis for income tax purposes. Since 1999, members of a controlled group have only been permitted to report 60% of their tax items on a consolidated basis. The remaining 40% must be reported by each company individually. Until last month, special rules applied to companies considered "pure holding companies," which are companies that derive at least 80% of their gross income from transactions with their subsidiaries. These companies were permitted to consolidate 100% of their profits and losses with 60% of those of their subsidiaries.

The new tax reforms place pure holding companies on the same footing as regular consolidated groups: only 60% of their tax items may be consolidated with the rest of the group's 60%. The other 40% of the holding company's income must be reported separately. This change will hit hardest the group structures in which interest-bearing debt was incurred at the holding company level and income-producing assets were kept in lower-tier companies. Previously 100% of the interest could be used to offset 60% of the subsidiaries' income. Now 40% of the interest deduction must be taken at the holding company level, where there may be no income against which to use it.

A en P Interests

The reform bill affects the way a sale of an interest in an *asociacion en participacion* will be viewed for tax purposes. An *asociacion en participacion*, or "A en P," is similar to a US partnership in that it is considered transparent for Mexican tax purposes. Previously, upon the sale of an interest in an A en P, the purchaser was deemed to acquire directly the assets and liabilities of the A en P. The purchase price was allocated among the A en P's assets and it stepped up the buyer's basis in those assets for Mexican tax purposes. Now the sale of an interest in an A en P is treated exactly like the sale of shares in a corporation: the total value is assigned to the interest itself, with no possibility to increase the tax basis of the underlying assets. This means that the buyer of an interest will not see its purchase price reflected in larger depreciation deductions or smaller gains on sale of the underlying assets.

Other Changes

Three changes will affect the way companies account for and pay value-added taxes and income taxes.

First, value-added taxes, or "VAT," must now be computed on a cash method — not accrual. This means that the tax liability arises when sales of goods or services are actually paid. Correspondingly, VAT amounts may / continued page 18

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ated to the United States is to keep the earnings in the project country.

However, this strategy works only if any corporation formed to own the project in the project country is a CFC. Since that requires that US investors own more than 50% of the corporation by vote or value and this is not always the business deal, elaborate arrangements are sometimes worked out to give US investors slightly more than the appearance of control of the company.

Burndy Corp., a US manufacturer of electrical connectors, formed a joint venture company in Japan with two local manufacturers to make the same product for the Japanese market. Burndy owned exactly 50% of the shares in the Japanese company. Each of its Japanese partners owned 25%. Each shareholder appointed directors to the board of the company in this ratio. Burndy could also appoint the CEO of the company, but did not do so in fact. Many significant business decisions — like whether to pay dividends — required a consensus.

Burndy argued that it owned more than 50% of the company by value because it could get a "control premium" for its shares. It argued that it controlled the company because the chairman of the board was supposed to vote its way in the event of a tie.

The US tax court rejected both arguments. The court said the fact that many significant decisions required a consensus or supermajority vote meant that Burndy did not have control in fact, even though it may have looked that way without careful analysis.

The case is Framatome Connectors USA, Inc. v. Commissioner. *The US Tax Court released its decision in the case on January 16.*

CULM is not "biomass" for tax purposes, a federal district court in Pennsylvania said in late January.

Culm is dirt, wood, / continued page 19

Mexico

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only be credited when VAT has actually been paid to vendors and suppliers. Under prior law, the provision of goods or services (or the invoicing of either), as opposed to the payment for them, gave rise to VAT liability.

Second, all corporate taxpayers must now make advance payments for tax each month. Under prior law, taxpayers with gross receipts under a minimum threshold were permitted to make advance basis on a quarterly basis. Such distinctions were eliminated as of January 1.

Finally, inflationary gains or losses must now be computed once each year using the monthly average of liabilities and financial assets, instead of on a monthly basis and using daily averages as in prior years. ◎

Power Contract Securitizations

by Chris Groobey, in Washington

The Enron bankruptcy has made it more difficult — but not impossible — to "monetize" the revenues an electricity generator expects to receive over time from a long-term power sales contract by borrowing against the revenue stream in the capital markets.

Yields have increased, investor appetite has decreased and rating agency scrutiny has intensified. Even bonds that were intended to be carbon copies of previously successful offerings, which otherwise should have been relatively straightforward transactions, became both more complex and harder to close than the parent deal.

Investor demand for bonds backed by revenue streams from power sales and other energy service agreements is down. Investment banks have shared in some of the pain as their bond sales commissions have decreased, but the greatest impact is on the issuers who now must pay more over time to borrow less money.

Extended Sales Process

Road shows are more arduous than before. Questions from potential investors are more pointed, more cities and presentations must be included on itineraries and, in general, investors are signing up for fewer bonds than in more normal times. The practical impact of these developments is to make it more difficult to close parallel transactions (for example, paying down an existing financing with the proceeds of the new bonds) as it is now more difficult to predict the ultimate closing dates of offerings. In addition, the number of days that elapse between distribution of the final offering circular and actual receipt of funds — "T+x days" — has tended to increase in the aftermath of the Enron bankruptcy as the investment banks need more time to line up buyers for the bonds.

In a number of instances, material changes have been made to transaction terms after the red herring was printed in response to investor or rating agency concerns. Issuers then face the added expense and delay associated with "stickering" the offering circular to draw to investors' attention the differences between the preliminary and final offering circulars. Even if the structural changes are not so significant as to be "material" for disclosure purposes, offering circulars and the corresponding transaction documents often require reworking, adding to transaction costs and occasionally delaying the offering.

Rating agencies are also paying closer attention to debt offerings. For example, in the past, the rating agencies tended to rely primarily on the ratings of the offtaker and the sponsor when formulating ratings on receivables-backed securities. Since the Enron bankruptcy, the rating agencies have become more involved in the minutiae of transactions and have required more changes than ever to significant and ancillary deal terms. This increased scrutiny means longer review periods and sometimes extensive revisions of payment terms, collateral packages and operational covenants to achieve the targeted ratings, even when the offtaker and sponsor are themselves unaffected by Enron's collapse.

Outside accountants and other advisers have also become more careful — even skittish. Audited financials must be included in offering circulars and the reports of experts and consultants give comfort to investors that the issuer's revenue and cost projections are reasonable. All of these third parties are potential targets for investors seeking recourse if an issuer defaults on its bonds and all are now more careful in their analyses and precise in their written work products. The practical impact is that comfort letters and consents are not given as freely or quickly as they once may have been.

Diminished Proceeds

Issuers have been taking home fewer proceeds from offerings than originally projected — in some cases, the discrepancy can approach 20% of the pre-Enron expectation.

Even after aggressive road shows, fewer investors have been willing to purchase energy-oriented bonds and, when they do, they often do so in a reduced aggregate amount that effectively results in higher-than-required coverage ratios. For example, bonds might require, and be priced for, a 1.03-to-1 coverage ratio but the smaller offering amount results in an effective 1.07-to-1 coverage ratio.

The impact on issuers can extend to the closing process as documents and offering circulars are revised to take into account the gap between the bonds that will actually be sold at closing and the aggregate amount of bonds that could otherwise be issued based on the contractual revenues. In such cases, the parties either reduce the offering to match the amount of bonds sold or revise the transaction documents to enable the issuer to sell additional bonds when investor appetite recovers.

Many energy-oriented bonds issued recently have been sold at a discount from the face value (meaning that investors paid, for example, 97¢ for each dollar of principal amount). The discounted purchase price increases the effective yield of the bonds above the stated yield, which increases the attractiveness of the bonds to investors but reduces the proceeds to the issuer.

However, too much of a discount can be burdensome for holders of the bonds since the discount is treated as accruing over time for tax purposes and must be reported as taxable income even though no cash is paid to the holder until the bond reaches maturity. Issuers need to be aware, both for disclosure purposes and for general marketability of the bonds, of the impact of a significantly discounted purchase price.

"Market Out" Provisions

Each of the factors discussed so far is an impediment to closing a transaction on the terms initially proposed and at the time originally planned. However, the events of September 11 also precipitated a change in the traditional documentation between issuer and investment bank that, however unlikely, may prevent an offering from closing at all. / *continued page 20*

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rock and other debris from underground coal mining in the anthracite region of eastern Pennsylvania. Similar debris from bituminous mines is called "gob."

The US government offered an energy tax credit until 1987 as an inducement to power companies to build new power plants that use biomass for fuel. The owners of at least one power plant in Pennsylvania that uses culm claimed energy tax credits after an IRS official, who has since retired, said the agency had tentatively concluded that culm could qualify as biomass, at least in cases where the culm bank had been remined to remove anything that could be sold as coal. The IRS and a federal district court denied the credits. The taxpayers are deciding whether to appeal.

WIND DEVELOPERS got more good news from the IRS.

Wind projects qualify for section 45 tax credits in the US. This is a tax credit of 1.7¢ a kilowatt hour for electricity generated. The credits run for 10 years after a project is placed in service.

However, the credits are subject to a "haircut" in amount if the project also benefits from government grants, tax-exempt financing, other tax credits or subsidized energy financing.

The IRS said in a private ruling made public in mid-January that there was no haircut in a case where a wind developer received a grant from a nonprofit entity set up and funded by an investor-owned utility. The utility set up the organization to encourage renewable energy projects. It was part of a deal with state regulators in exchange for permission to let the utility restructure. The IRS said the fact that the organization was set up as part of a deal with state regulators did not transform it into a government program.

The ruling is PLR 200202048. It follows on the heels of another / *continued page 21*

Power Contract Securitizations

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Specifically, after the September 11 attacks, many investment banks revised the "market-out" provisions in their standard purchase agreements — the agreement entered into a few days before the closing of the offering pursuant to which the investment bank agrees to purchase the bonds from the issuer — to provide that the bank will have no obligation to purchase an issuer's bonds in the event of a terrorist attack against the United States.

Previously, "market-out" provisions were generally limited to declarations of war and other upheavals with which market participants were more familiar prior to the September attacks. Now, given their new familiarity with attacks that take place on US soil and may cause the financial markets to close for a period of time, the investment banks have expanded their ability to walk away from a transaction if they do not believe they will be able promptly to resell the bonds into the larger market. The capital markets remain open to securitization transactions involving power companies. However, issuers will need to remain flexible with respect to their timing, economic expectations and relations with third parties until the market as a whole regains its comfort with the energy sector. ◎

Venezuelan Oil And Gas Projects

by Noam Ayali, in Washington

The new "hydrocarbons law" that took effect in Venezuela on January 1 will make it very hard — if not impossible — for developers to finance oil and gas projects in the country on a project finance basis.

The new law was announced in a decree by President Hugo Chavez on November 2 under special powers granted to him by the National Assembly. Unfortunately, it fails to address serious concerns and criticisms raised by both the international oil and gas community and by business and legal experts in Venezuela about earlier drafts.

One key concern with the earlier drafts was the requirement that the state must take a majority interest in all new upstream exploration and production projects. Another criticism focused on the increase in royalty payments to the state by producers, from 16.6% to 30%, an increase that industry and other observers viewed as contrary to the trend in other hydrocarbon-producing countries of reducing royalties.

The new law fails to address either of these concerns. As a consequence, it continues to generate controversy and criticism to the point where the president of the National Assembly has committed the assembly to review it, notwithstanding the special decree powers granted to President Chavez.

Nationalization

Much of the controversy and criticism focuses on the requirement that "primary activities," defined as exploration, production, gathering, transportation and storage of hydrocarbons, must be conducted by the state. This effectively amounts to what many commentators view as a second nationalization of the oil and gas sector in Venezuela.

Under the new law, primary activities "shall be performed by the State, either directly by the National Executive or through exclusively owned companies. Likewise, these activities may be performed by companies in which the State has decision making control by holding over 50% of the capital stock, which for purposes [of the new law] shall be denominated joint venture companies."

While the new law does not explicitly refer to Petroleos de Venezuela SA, the state-owned petroleum company (PDVSA), most industry participants interpret this provision as effectively requiring PDVSA to have control of any joint venture companies.

Much has also been made of the fact that this provision will increase PDVSA's financial burden, saddling the company with significant additional costs of exploration and production activities.

Negative Pledge Problems

There has been little or no discussion of the implications of the World Bank negative pledge provisions on PDVSA's ability to access financing to fund such additional activities, or to structure project financings for such activities.

A brief primer on the World Bank negative pledge: The "general conditions" that apply to all World Bank loan and guarantee agreements include a negative pledge provision that limits the creation of security in favor of other external creditors over assets of member countries, including assets of subdivisions of member countries, entities owned or controlled by member countries and entities operating on member countries' account or for their benefit.

While the negative pledge clause — found in section 9.03 of the general conditions — does not prohibit the creation of security in favor of other creditors, it prevents the establishment of a priority for external debts owed to other external creditors over the debt due to the World Bank in the allocation, realization or distribution of foreign exchange, and it requires that the World Bank share *pari passu*, or ratably, in any security created in favor of any external creditors. The World Bank has taken the position that the clause clearly "catches" not only obvious assets such as gold and foreign exchange reserves, but also exportable assets, such as crops or minerals, to the extent they can be construed as "public."

This means the following for the new hydrocarbons law in Venezuela. PDVSA is a state-owned entity; Venezuela is a member country of the World Bank, and oil and gas are foreign exchange earning assets. Thus, under the terms of the negative pledge clause, PDVSA would arguably be prevented from granting security over its oil and gas assets, unless the World Bank shares *pari passu* in such security.

Anyone involved in project finance will immediately recognize the potential problem: if, as mandated under the new law, PDVSA is to have majority ownership and control over a joint venture project entity, how will the project entity be able to grant its lenders any form of security that is customary for a project finance transaction? In order to comply with the negative pledge, the project entity must grant the World Bank a *pari passu* security interest. Given the huge lending exposure of the World Bank in the many Venezuelan state projects in which it has participated compared to that of any potential project financiers to the particular new oil and gas project, this effectively renders the security meaningless from the perspective of project lenders. For example, if the World Bank's exposure in Venezuela as a whole — including the new project — is $12 billion, and the project financiers are being asked to lend $300 million toward the new project, the security claim the World Bank requires is in the ratio of $12 billion out of $12.3 billion. Alternatively, the project entity may seek a waiver from the World Bank of the negative pledge provisions. Unfortunately, the World Bank's waiver / continued page 22

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ruling late last year in which the IRS said the fact that a state awarded generators using renewable energy negotiable "credits" that could be sold to utilities for cash also did not require a haircut.

COAL transportation and handling costs of utilities cannot be deducted immediately, the IRS said.

The IRS released a series of rulings in December and January in which it rejected requests by power companies to deduct their transportation and handling costs for fuel immediately. The agency said the costs must be treated as a cost of the coal and deducted in the year the coal is burned.

An accounting firm had been urging power companies to apply en masse *for the rulings.*

A SALE-LEASEBACK transaction aimed at enabling a corporation to use expiring foreign tax credits was shot down by the IRS.

The taxpayer was the parent company of a domestic, deconsolidated subsidiary corporation with foreign tax credits that were about to expire. After consulting with its lawyers and a bank about how best to take advantage of the credits, the taxpayer implemented a transaction in which the deconsolidated subsidiary and one of the taxpayer's consolidated subsidiaries entered into mirror sale-leaseback transactions with affiliates of a bank. The consolidated subsidiary sold some of its used computer equipment to one of the bank's affiliates, who immediately leased the equipment back to the subsidiary. Meanwhile, the deconsolidated subsidiary purchased used computer equipment that was located in another country and immediately leased it back to another affiliate of the bank.

Within a month of entering into the leases, both lessees prepaid all the rent due over the 3-year terms of their respective leases. The prepayment made / continued page 23

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process is complicated and cumbersome. Moreover, there is very little positive track record of the World Bank agreeing to such waivers in favor of project lenders.

Last year's Hamaca heavy oil project financing, and the Sincor heavy oil project financing before it, relied on complicated structuring approaches for some form of security to support the PDVSA portion of the borrowings. The debt facilities in the two projects were secured by the shares and primary offshore and onshore accounts, all rights, title and interest in key agreements and subordinated loans of the private sponsors. (The sponsors were Phillips and Texaco in Hamaca, and Total and Statoil in Sincor). No similar pledge was granted by PDVSA; instead, both projects used a mechanism whereby a certain amount of PDVSA revenues were recycled into the project in the form of subordinated loans to the private sponsors, which were then held in reserve accounts to obtain a form of collateral. Moreover, both projects included limited backstop guarantees from the private sponsors, backing PDVSA's lifting obligations.

It is hard to imagine that lenders will have the same degree of comfort with such an approach where PDVSA will be the majority owner of a joint venture project entity. It is also hard to imagine that private sponsors will continue to have the same degree of comfort in providing backstop support for PDVSA when they are in significant minority positions in a project.

If the National Assembly does indeed re-examine the new law, the issue of state ownership is clearly one that deserves more consideration. Unless this part of the law is changed, only time and the markets will tell if project finance will continue to be a viable tool for Venezuelan oil and gas projects. ◎

Brazil Overhauls Regulation Of Power Sector

by Tom Felsberg and Ricardo de Lima Assaf, with Felsberg e Assodiados, in São Paulo

The Brazilian government announced in early January that it plans to modify the regulatory scheme for the power sector in an effort to revitalize the domestic power industry.

A number of regulatory changes will be instituted in the next few weeks. Other measures are expected to be implemented over the next several months.

The measures were announced by the *Câmara de Gestão da Crise Energética,* or CGE, which was established last year in the wake of a severe power shortage nationwide. They follow recommendations by the *Comitê de Revitalização do Sector Elétrico* — a power industry restructuring committee that is composed of senior officers and technicians from BNDES, ANEEL, CGE and representatives of affected government ministries.

Immediate Changes

The CGE announced the following new measures on January 9.

First, there will be changes in the calculation of firm power provided by the system and the operation safety margin of the system, under rules established by the country's independent system operator, known as the ONS. ONS is a non-governmental organization in charge of managing the system's technical operations. These changes will also apply to new thermal and hydro plants that are to come into operation. In addition, the firm energy values of each hydroelectric plant will be recalculated, leading to the reconsideration of the power reallocation system — called the MRE or *Mecanismo de Realocação de Energia* — procedures, established in 1998.

Brazil expects to "deverticalize" its utilities by the end of May.

Second, the wholesale energy market — called the MAE or *Mercado Atacadista de Energia* — will be eliminated and be replaced by something called the Brazilian energy market

— a new entity called MBE or *Mercado Brasileiro de Energia*. Since it first came into force in September 2000, the MAE was never able to settle financial transactions, and it was always a major obstacle for companies operating in the industry. The main difference between MAE and the new MBE is that the new market will be entirely regulated by ANEEL, as opposed to the self-regulating model under the MAE. This change of control will lead to revised mechanisms for establishing prices in the spot market for energy.

Third, there will be a mandatory "deverticalization" of utilities by separating generation, transmission and distribution functions, with a fixed deadline for accomplishing this. The federal government has already started the process of reorganizing state-owned companies under its control (FURNAS, CHESF and ELETRONORTE), and is expected to have completed that process by the end of May this year.

Proposals Still Under Discussion

The other measures that the government intends to implement will require more discussion among consumers, private companies and public entities with an interest in the process.

These include a proposal for so-called "old energy," generated by older, state-owned hydroelectric plants at a very low cost under initial contracts with distribution companies, to be fully regulated as the generator of the energy is gradually released from its supply commitment under such a contract. The release from the supply commitments is at the rate of 25% a year from 2003 through 2005. The purpose of this measure is to prevent cheaper energy produced by state-owned companies from undercutting electricity from private suppliers and to avoid rate shock since there will be a large amount of uncontracted energy in the system by 2003. It is unclear whether this measure will affect only the federal companies or both federal and state companies (like COPEL, CESP and CEMIG).

Also under discussion is a proposal to end ratepayer cross-subsidies by reducing residential rates and raising tariffs to the industrial sector.

Electric distribution companies will have to increase from 85% to 95% the volume of energy contracted under long-term agreements. The goal is to lock in power supplies under bilateral contracts, thereby reducing the exposure to the new wholesale market.

Distribution companies will then be required to meet standard conditions for services ren- */ continued page 24*

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by the consolidated subsidiary perfectly offset the prepayment received by the deconsolidated subsidiary. Three months later, the lessors swapped titles to the computer equipment so that the taxpayer's original computer equipment wound up back in its own hands. Because the ability to use foreign tax credits is tied to the amount of foreign source income a company has — the more foreign source income, the more foreign tax credits it may use — the leases were designed to create foreign source income for the taxpayer's subsidiary without creating any meaningful gain or loss for any of the parties involved. The prepaid rents were foreign-source income to the deconsolidated subsidiary because the leased property was located overseas.

The IRS called the transaction a "sham." In addition to disallowing the credits, the national office also urged its field agents to pursue negligence penalties against the taxpayer.

The IRS released a "field service advice" about the transaction in December. The number is FSA 200203053.

BRAZIL confirmed that mandatory arbitration provisions in business contracts are enforceable. This will please foreign investors who prefer not to have disputes decided in the local courts.

The Brazilian Supreme Court confirmed on December 12 that a recent law that permits arbitration is consistent with the Brazilian constitution. The status of the law had been in doubt since it was enacted in 1996 after the Supreme Court suggested earlier that the law conflicted with a right under the Brazilian constitution to have one's day in court.

The case reached the Supreme Court after lower courts in Brazil refused to recognize an arbitration award granted by a Spanish tribunal on grounds that the decision was not ratified by */ continued page 24*

competent authority. The underlying dispute was between MBV Commercial and Export Management Establishment, a Swiss company, and Resil Industria e Comercia Ltda., a Brazilian company. The Supreme Court said the award would be recognized in Brazil.

MINOR MEMOS: Brazil will eliminate two transfer taxes on coal and gas used to generate electricity starting March 1. The taxes are a .65% "PIS" tax and a 3% social security, or COFINS, tax. The taxes will be eliminated for all coal destined for use in power plants, but only for gas for use by power producers participating in a "priority program of thermo-electricity" . . . . The Labour government in Britain may propose a tax increase in its next budget in March, a senior Treasury minister warned in late January . . . . Several utilities lost a case in the Missouri courts over whether transformers, voltage regulators and other equipment used to distribute electricity qualifies for exemption from sales and use taxes under an exemption for equipment used "directly in manufacturing." The state tax department agreed that the production of electricity is "manufacturing," but said the electricity is already manufactured by the time it reaches this equipment. The utilities argued that the equipment is part of an integrated manufacturing process. The court disagreed. The case is *Utilicorp United et al. v. Director of Revenue*. It was decided on December 18.

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

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dered for all customers, including services to rural and low-income consumers. There will be an increase in the number of consumers considered "free" because they have an option to bypass the local distribution company and buy their electricity from any generation company, other distributors or traders.

The government also proposes to establish guidelines under which the "system" will contract for thermal plant power. The thermal supply will operate as a type of safety net against energy shortages. All consumers will bear the cost of the safety margin in supply.

In addition, the government has proposed measures designed to increase investment in thermal generation. These include subsidies for natural gas transportation from the Bolivia-to-Brazil gas pipeline to the PPT group plants and changes in the "normative value amount," or the ceiling price below which a distributor can pass through the cost of its power purchases to retail customers. According to the new model, the normative value will vary by region and time of use of the power produced, but will no longer vary by energy source.

Alternative sources of energy and cogeneration projects will also receive incentives such as access to special credit facilities, higher purchase prices to cover their investments and reduced transmission and distribution tariffs.

Conclusion

The new framework points to a less competitive market with government participation and an increase in tariffs charged to end consumers in order to support the expansion of the system.

Since not all measures have been fully disclosed by the federal government and the formal regulations to implement the new scheme have not yet been issued, the full impact of the changes remains still to be seen. In the meantime, market participants have suggested that investor appetite for the upcoming privatizations will probably be less intense than the government hopes. On the other hand, some market participants may be able to foresee more accurately income and expenditures if there is a reduction in regulatory risk.

If thermal plants become a backup for the system and their capacity generation cost is actually recovered from all consumers, then they will become a good choice for developers. ◎

Environmental Update

With Congress back in session, consideration of multi-pollutant legislation to cap and reduce air emissions from power plants is expected to take center stage in US Congressional committees with jurisdiction over environmental issues.

The Bush Administration is planning to enter the fray with its own multi-pollutant legislative proposal that is anticipated to be unveiled by mid-February.

Meanwhile, the Senate Environment and Public Works Committee has commenced a full-scale investigation of the Environmental Protection Agency's deliberations that are expected to culminate in new changes to the "new source review," or NSR program. EPA is expected to announce its revisions to the NSR program soon, with the release of final and proposed standards for overhauling the program.

In related news, the US Department of Justice recently announced that it will continue to pursue NSR enforcement actions filed against several utilities in 1999 and 2000. The department concluded that EPA has a reasonable basis for its allegations that several coal-fired plants were modified without undergoing Clean Air Act-required NSR permitting reviews.

New Source Review

EPA's enforcement actions against several utilities operating coal-fired plants received a boost in mid-January. The Department of Justice announced on January 15 that EPA's interpretation of what constitutes a "major modification" versus "routine maintenance, repair, and replacement" of a power plant is defensible, and that the high-profile NSR lawsuits and administrative actions against owners of coal-fired power plants, oil refineries and other industrial facilities can continue.

The Department of Justice also said that EPA's long delay in filing NSR enforcement actions — the NSR provisions have been in place since the late 1970s — was not the result of a new substantive reinterpretation of the disputed NSR provisions that would have required notice and comment by the public before the agency could act.

The Justice Department's conclusions are not surprising given the limited case law and EPA guidance on the issue of what qualifies as "routine maintenance" and the deference given to agency interpretations of their own regulations. The report is careful to point out that it involves only a retrospective review and does not consider whether EPA's NSR enforcement actions were wise policy. The Justice Department review checks off one of the recommendations in the national energy plan that the Bush administration released last May.

The NSR permitting program has been criticized in the past as an overly burdensome, time-consuming and costly regime that hampers plant modifications and upgrades. EPA is in the midst of its own review of the NSR permitting program, and significant changes will reportedly be announced soon.

The anticipated NSR reforms are expected to include provisions for setting plant-wide applicability limits or "PALs" that would allow plants more flexibility in making changes under a facility emissions cap without obtaining an NSR permit for the modifications and providing an NSR permitting review exemption for "clean units" that have recently installed state-of-the-art emissions controls. The reforms are also expected to include a change in the emission accounting for calculating what constitutes an emissions increase — they are expected to use projected "actual" emissions instead of "potential" emissions in certain circumstances — and to allow the use of a cost threshold or investment test in the definition of what constitutes "routine maintenance."

Several of EPA's anticipated NSR reforms are expected to be proposed in a new rulemaking procedure that would require formal notice and comment prior to publication of a final rule. A final rule is also expected that will contain several other NSR regulatory changes that were previously proposed in 1996 — for example, the PAL concept and the exemption for clean units.

The Senate Environment Committee has launched an investigation into how EPA developed the NSR reform package. In mid-December, the committee sent a letter to EPA Administrator Christine Todd Whitman seeking full disclosure of the NSR reform efforts. The Senate Environment and Judiciary Committees expect to hold joint hearings in the next few weeks on this issue.

In a related development, in early January, New York State filed its own lawsuit in federal */ continued page 26*

district court alleging that two coal-fired plants near Buffalo, New York — formerly owned by Niagara Mohawk — were modified without undergoing an NSR review, obtaining the requisite permits and installing appropriate pollution controls. The New York enforcement action is an indication that certain states may continue aggressively to pursue coal-fired plants that were suspected of implementing past plant upgrades that were not subject to NSR scrutiny. The northeastern states, and particularly New York, have raised concerns about EPA's planned NSR administrative reforms alleging that such reforms will roll back the protections of the Clean Air Act. New York and eight other northeastern states have threatened to challenge whatever NSR reform package the Bush administration ultimately unveils.

The Bush administration is expected to call for significant reductions in NO_X, SO_2 and mercury emissions from power plants.

Multi-Pollutant Legislation

The Bush administration is expected to release its multi-pollutant proposal by early February — before scheduled deliberations in the Senate Environment Committee on a multi-pollutant bill introduced by the committee chairman, Senator James Jeffords (I.-Vermont). The Jeffords bill — called the Clean Power Act — would require significant reductions in nitrogen oxide or NO_X, sulfur dioxide or SO_2, mercury, and carbon dioxide or CO_2 from power plants to be achieved by January 1, 2007. The Jeffords bill would mandate 75% reductions in NO_X and SO_2 from 1997 and 2000 baselines, respectively; a 90% reduction in mercury levels from 1999 levels; and a reduction to 1990 CO_2 levels.

The Bush administration's proposal, which is being developed by EPA with substantial input from the US Department of Energy, is also expected to call for significant reductions in NO_X, SO_2 and mercury emissions from power plants. However, EPA staff confirmed that the agency's legislative proposal will not include provisions requiring reductions of CO_2, a greenhouse gas. The issue of requiring mandatory CO_2 reductions has generated a significant amount of controversy. Senator Jeffords has previously vowed to push forward with a multi-pollutant bill that specifically includes mandatory CO_2 requirements. The Bush administration has repeatedly stated that it opposes mandatory CO_2 reductions.

EPA is expected to ask for a reduction in the current SO_2 emissions cap and create new annual emission caps for NO_X and mercury emissions as well as call for a market-based trading approach to achieving the emission reductions. A market-based approach is generally viewed as more cost effective and as providing greater flexibility to achieve compliance. The EPA proposal is also expected to include the streamlining and replacement of certain existing air regulations that affect power plants, including the regional haze rule, the NO_X SIP call rule, the acid rain program requirements and the maximum achievable control technology standard for mercury.

The House Energy and Commerce Committee is also expected to hold hearings on the need for new multi-pollutant emission control levels for power plants in the coming months. Despite heightened interest by members of both houses of Congress in multi-pollutant legislation for power plants, the odds that such a measure will be enacted this year are low. House and Senate leaders are unlikely to agree on a multi-pollutant measure during an election year. Nevertheless, this year's debate could set the stage for passage of such a measure in the next Congress, particularly in light of the Bush administration's support for some level of coordinated reductions in NO_X, SO_2 and mercury emissions from power plants.

NO_X

EPA Administrator Christine Todd Whitman recently announced that the agency will delay implementation of the so-called "section 126 rule" that requires reductions in NO_X from specific power plants and industrial plants in 12 states in the eastern half of the United States where EPA has found that such sources contribute to air pollution in down-wind states. The section 126 rule is a parallel rule to the "NO_X SIP call rule" that requires similar NOx reductions from such facilities as power plants.

Administrator Whitman also confirmed that EPA will ultimately withdraw the requirement for states to implement the section 126 rule at least in cases where a state is on track to implement the NO_X SIP call provisions fully.

EPA plans to align the section 126 rule requirements with EPA's NO_X SIP call provisions. The section 126 compliance deadline will now be extended from May 1, 2003 to May 31, 2004 to coincide with a recent US appeals court extension of the NO_X SIP call compliance deadline. The delay of the start date for compliance from the 2003 ozone season (May to September) to the 2004 ozone season will give affected plants additional time to install pollution control equipment.

EPA's NO_X SIP call rule and section 126 rule are expected to force many existing power plants and industrial facilities to install costly pollution control technology, such as low NO_X combustion systems and selective catalytic reduction systems, to reduce NO_X emissions.

Brownfields

After several years of false starts, Congress recently enacted limited reforms to the federal Superfund law. Congress passed the reforms in late December and President Bush signed the legislation into law in early January. The reforms are intended to promote the redevelopment of "brownfield" properties that have existing contamination from past industrial operations.

The "Small Business Liability Relief and Brownfields Revitalization Act" includes three key components. The first is a "de micromis" liability exemption for businesses that sent less than 110 gallons of liquid materials or less than 200 pounds of solid materials to a Superfund site on the national priorities list — unless the materials have contributed significantly to the costs to remediate the site. The second major component includes an authorization of $250 million annually from 2002 through 2006 to provide grants to state and local governments to foster the site characterization and cleanup of brownfield properties.

Third, the new law also creates a new set of criteria to qualify for the "innocent landowners" defense from Superfund liability and adds two new defenses for contiguous properties and *bona fide* prospective purchasers who did not cause or contribute to a release of hazardous substances and who are not otherwise potentially liable or affiliated with an entity that is potentially liable for a release of hazardous substances. The "contiguous properties" defense would potentially apply to properties that are contaminated by releases from an adjacent property.

In order to qualify for the "innocent landowners" defense and the two new defenses, the entity acquiring the property must have conducted "all appropriate inquiry." The new law generally equates this level of inquiry to the current ASTM standards for conducting a Phase I environmental site assessment. For the next two years, the ASTM Phase I standards will satisfy the "all appropriate inquiry" requirement until EPA develops its own regulations. In addition to the "all appropriate inquiry" provisions, Congress also added new elements to clarify Superfund's "due care" requirements for asserting the defenses, including that the landowner must take reasonable steps to stop any continuing release and prevent or limit exposure to a previously released hazardous substance.

In order to qualify for the "innocent landowners" and "contiguous properties" defenses, the entity must not have known or had reason to know that the property was contaminated when it was purchased. This requirement, coupled with the "all appropriate inquiry" standard, has historically limited the utility of the "innocent landowners" defense and will probably restrict the application of the new "contiguous properties" defense as well. More promising is the "prospective purchaser" defense. While this defense also requires meeting essentially the same prerequisites as the other two defenses, a landowner can qualify for the "prospective purchaser" defense even if he knew the site was contaminated before it was purchased. The "prospective purchaser" defense is limited to purchases occurring after the date of enactment of the new statute.

Cooling Water

Environmental groups and a group of electric utilities have filed petitions challenging a final rule that EPA issued on December 18 that prescribes cooling water intake standards for new power plants and manufacturing facilities that withdraw water from rivers, streams, lakes and other waters of the United States for cooling purposes.

EPA's new rule creates a two-track approach, and facilities may choose either track. The first track describes default technology-based perform- / *continued page 28*

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ance standards based on a closed cycle, recirculating cooling system — that is, a "wet" cooling system — and the second track allows applicants to conduct site-specific studies to demonstrate that alternative approaches will achieve comparable intake flow reductions and meet similar aquatic organism protection standards. The environmental groups argue that EPA's rule should have been based on "dry" cooling towers that use less water but are more costly than "wet" cooling systems.

EPA's cooling water rule is expected to impose some significant costs on new plants. They will have to install intake structures that minimize the amount of water withdrawn for cooling purposes. EPA is expected to propose a similar cooling water intake system rule for existing utility and non-utility power producers by February 28, 2002. The cooling water intake standards for certain existing facilities must be finalized by August 28, 2003.

CO_2 legislation

Several new bills calling for the reporting of greenhouse gas emissions and the creation of a greenhouse gas registry have recently been introduced in the US Senate. The new proposals may signal renewed debate over whether to implement a program to track domestic greenhouse gas emissions and award early credits for voluntary reductions that may be later used in any new mandatory program adopted by the US to reduce greenhouse gas emissions.

The chairman of the Senate Environment Committee and two other senators introduced a bill on December 20 that would require companies to submit mandatory greenhouse gas emission reports to EPA. The measure is modeled on the national toxics release inventory or TRI program that requires mandatory reporting of releases of toxic chemicals. The TRI program is credited with generating significant reductions in chemical releases by US companies. Since the TRI report data is made public, many companies take steps to reduce such releases.

The bill would also create a greenhouse gas registry that would be available to record greenhouse gas reduction projects. Reductions reported to the registry would be subject to verification, and could include a number of activities including fuel switching, use of renewable energy, use of combined heat and power systems and methane recovery.

Senators John McCain (R.-Arizona) and Sam Brownback (R.-Kansas) also recently introduced a voluntary greenhouse gas registry measure. They propose to have the voluntary greenhouse gas registry be managed by the US Department of Commerce. Any reductions recorded on the registry would be eligible for credit against any future mandatory greenhouse gas reductions established by the federal government. Several other greenhouse gas reporting and registry bills are also pending in Congress.

A comprehensive energy bill that is advancing through Congress could serve as a possible vehicle this year to adopt new greenhouse gas emission reporting and registry requirements. ◎

— contributed by Roy Belden, in Washington.

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