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PURPA and PUHCA Edge Closer To Repeal

by Lynn Hargis, in Washington

Electric utilities will no longer have to buy electricity from "qualifying facilities" under the national energy plan that the Senate passed in April. Existing contracts with QFs are not affected. However, if an existing contract is amended in the future, there is a danger that the utility will be freed from any obligation to buy power.

The Senate also voted to repeal the Public Utility Holding Company Act of 1935 — called "PUHCA." Repeal of PUHCA will have far-reaching effects on how the electric and gas utility industries are structured in the United States.

Changes to PURPA

The Senate voted in April to terminate any requirement under the "Public Utility Regulatory Policies Act," or "PURPA," for utilities to buy electricity from cogeneration facilities and small power plants that burn renewable fuels at the "avoided cost" the utility would pay to generate the electricity itself. However, the termination is conditioned on the Federal Energy Regulatory Commission finding that the power plant, or "qualifying facility," in question has "access to independently administered, auction-based day ahead and real-time wholesale markets for the sale of electric energy." Given FERC's open access rule, Order No. 888, requiring all public utilities to */ continued page 2*

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THE NEW DEPRECIATION BONUS that Congress enacted last March may undergo some "technical corrections."

Congressional staff are concerned about reports that some companies are taking the position assets that do not qualify for the bonus in the hands of the current owners — because the assets were already under construction or binding contract last September 11 — can be turned into "good" assets by selling and leasing them back.

The Joint Tax Committee staff is also recommending that Congress tighten the definition of "self-constructed property." This is important because assets that a company "acquires" do not */ continued page 3*

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transmit for other sellers, including QFs, many QFs should be viewed as already meeting the test of having access to such markets. For these QFs, the utility purchase obligation will in fact disappear. However, for those QFs that do not have access to such markets, the purchase obligation will remain.

Existing QF contracts should not be affected. A "grandfather" provision in the Senate bill says that the bill "shall not affect" the rights or remedies of any party under any QF contract in effect upon enactment, including the right to recover costs of purchasing electric energy or capacity.

In a move to help utilities that buy power from QFs, the Senate also made clear that utilities are allowed to recover all "prudently incurred" QF costs in the retail rates that the utilities charge their customers. Such recovery of QF charges in retail rates has already been recognized by the courts. For example, in *Freehold Cogeneration Associates v. BRC of New Jersey,* 44 F.3d 1178 (3d Cir. 1995), *cert. denied sub nom. Jersey Central Power & Light Co. v Freehold Cogeneration Associates,* 116 S.Ct. 68 (1995), a US appeals court made it clear that a utility must be allowed to pass through in retail rates the charges that it pays under a QF contract approved by a state commission. The court also noted that the QF charges were prudently incurred, since the one possible exception to the mandatory passthrough of federal rates under the supremacy clause of the US constitution has been the potential ability of state commissions to deny imprudently incurred costs. The Senate bill effectively codifies this case law and ensures that utilities can pass through QF charges in retail rates.

The Senate also voted to remove any restriction on utility ownership of QFs. Utility interests in QFs are limited currently to no more than 50%, because Congress in PURPA considered it unwise to have utilities on both sides of the bargaining table, both selling and purchasing from QFs, particularly if utilities are required to purchase QF power. The Senate bill allows utilities to own 100% of QFs.

In an interesting twist, a utility might conceivably be required to buy from itself (from its QF affiliates) in the future if the affiliates lack access to an independently-administered, auction-based day ahead and real-time wholesale market. Utilities that do not promote such access might benefit by being forced to buy from their own affiliated QFs and have the costs passed through to their retail ratepayers.

One of the aspects of PURPA that allowed QFs to succeed originally, in addition to the long-term contracts, was the limitation on utility ownership, which required "non utilities" or independent power producers to have a place in the developing industry. Without long-term contracts and with full utility ownership, it will remain to be seen whether anyone without the credit rating and resources of franchise utilities will be able to finance the building of new QFs.

Finally, the Senate voted to eliminate the obligation under current law for utilities to sell retail electric power to QFs, but only if competing retail electric suppliers are "able" to provide it. The assumption appears to be that, if there is retail competition, then suppliers who are able to supply energy will do so at competitive prices.

A potential problem with this language is that utilities were always "able" to provide retail power to QFs, but preferred not to, which is why PURPA required it and required that the rates for retail service not discriminate against QFs. The new language should probably require that retail suppliers be "able *and willing*" to provide retail service at a reasonable, non-discriminatory price.

Repeal of PUHCA

The Senate bill repeals the entire "Public Utility Holding Company Act of 1935," which, for better or worse, has dictated and controlled the structure and regulation of the electric industry in the US over the last seven decades. This broadsweeping statute has been replaced with a requirement that companies that are affiliated with utilities must open up their books and records to regulators.

Elimination of PUHCA, if it actually occurs, will have far-reaching effects. (There have been serious efforts to repeal PUHCA since at least the l980's.) The repeal will open up the electric and retail gas industries to many new players who have been constrained by the statute's limitation on the geographic spread of utility subsidiaries owned by the same holding company; PUHCA requires that all subsidiaries of a single utility holding company must be "physically integrated." It will also free these new players from existing restraints on non-utility businesses; PUHCA requires that holding companies divest their non-utility businesses. The elimination of the latter restraint will mean that non-utilities, like oil companies, can acquire public utility systems, and also that registered holding companies that currently own many traditional, monopoly utilities will be free to diversify into other non-utility businesses.

Here are some of the opportunities that repeal of PUHCA will open up:

- Utility systems, including transmission and distribution systems, can be acquired by a holding company even though they are not capable of physical integration with existing utility systems that the holding company owns or will acquire.
- There will be no limitations on the geographic separation and spread and, therefore, on the size of electric and retail gas holding company systems, and such companies will not be regulated as utility holding companies.
- There will be no need to avoid "registration" as a holding company by reincorporating in the state where an acquired utility operates. For example, Enron would not have had to reincorporate in Oregon to own Portland General Electric, thereby subjecting the holding company to Oregon regulation.
- There will no longer be any limitation on interstate utility holding companies owning both retail gas and electric companies.
- There will no longer be any limitation on non-utility businesses owning utilities.
- There will be no PUHCA requirement that interstate utility holding companies get approvals before acquiring new generating companies.
- There will no longer be any requirement that limits the number or uses of securities issued by a holding company based on subsidiary public utility gas and electric companies.
- There will no longer be a requirement that states must approve interstate holding company investments in foreign utilities.
- There will no longer be a federal requirement that interstate utility holding company investments in any business must be approved.
- There will no longer be a federal requirement that interstate holding companies must get approval to guarantee subsidiary or other loans.
- There will no longer be restrictions on foreign holding companies owning US public utilities.

There will undoubtedly be many / *continued page 4*

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qualify for the bonus if the company signed a binding contract before September 11 to acquire them. The rule for property that a company constructs itself is that construction cannot have begun before September 11. Most power plants and turbines are considered self constructed the way Congress wrote the law last March. The Joint Tax Committee staff thinks this was an error.

The Senate is expected at least to move against sale-leasebacks, according to Russ Sullivan, chief tax counsel to the Senate tax-writing committee. He is less sure whether the House will act this year. Sullivan said the Senate may wait to see whether the Internal Revenue Service takes action on its own before legislating.

The US Treasury is reportedly working on guidance, but any guidance is on a slower track than was thought earlier. IRS officials had said in March that guidance would be issued by "mid-year." Now the discussion is whether to commit to such guidance in the next business plan that the IRS will issue for the 12 months starting July 1.

Meanwhile, at last count, 20 states have "decoupled" from the depreciation bonus. Many states whose tax systems piggyback on the federal income tax have decided they cannot afford lower tax receipts. Another three states allow only a partial bonus. In another five states, the state revenue departments have said the bonus is available, but bills are pending in the state legislatures to decouple. Only five state legislatures have expressly adopted the depreciation bonus (Alabama, Delaware, Oregon, Utah and Kansas).

The depreciation bonus is a speeding up of tax depreciation for new assets that are placed in service during a window period of last September 11 through December 2004 or 2005, depending on the type of asset. Most gas- and coal-fired power plants have until 2005. The idea was to give a boost to the US economy in the wake of / *continued page 5*

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more intended and unintended impacts that will be discovered after PUHCA is repealed. The main effect of repeal is to open the gates to utility consolidation and to allow ownership of public utilities by oil companies and other large players who have not previously been active in the utility sector. At least initially, PUHCA repeal should lead to numerous opportunities for acquisition, merger and disposition of electric utility assets for all current and many new players in the electric, retail gas and independent power industries. Ultimately, the very largest players may again gain consolidated control over the retail gas and electric utility companies as they did in the 1920's before PUHCA was passed.

Outlook

A different version of the national energy plan passed the House of Representatives last July. Now that the Senate has acted, "conferees" — or senior members from the two houses of Congress — will meet to come up with a common bill to send to the president. The conference is expected to take until October to play out. There is no guarantee that House and Senate negotiators will be able to reach agreement before Congress adjourns for the year before the November elections.

The bill that passed the House last July did not terminate the purchase requirement in PURPA or repeal PUHCA.

However, the House is expected to use as its starting point for negotiations on electricity issues a bill that the chairman of the House energy and power subcommittee, Rep. Joe Barton (R.-Texas), introduced. The Barton bill is similar to the Senate bill on PURPA and PUHCA with one exception. It would not drop the current 50% limit on utility ownership of QFs.

Changes to FERC's Authority

The widest utility regulatory differences between the Senate bill and the Barton bill may lie in their treatment of FERC's authority over mergers.

The Barton bill would eliminate FERC's existing authority to approve certain utility mergers; the Senate bill increases FERC's authority over mergers.

FERC currently must approve mergers or dispositions of "jurisdictional assets," which include transmission facilities and wholesale contracts, books and records, but not generation or distribution facilities. If PUHCA is repealed, there will be no federal review of mergers of generation or distribution companies, and the extent of FERC's authority to approve mergers of utility holding companies is unclear. The Senate bill transfers some of the PUHCA review authority to FERC, although under different standards than PUHCA sets. The Barton bill would eliminate the review altogether, along with FERC's existing merger approval authority.

The Senate bill also adds a list of factors that FERC must consider before allowing generators to charge market rates. These include market power, the nature of the market and its response mechanisms, and reserve margins. The Senate bill requires FERC to change to a "just and reasonable" rate any market rate that it finds is unjust and unreasonable. The bill provides for refunds of unjust and or unreasonable rates effective from the date that the commission publishes notice of its intention to initiate a proceeding. The bill does not propose to make this refund authority retroactive to sales that occur before enactment.

More Energy Tax Incentives

by Keith Martin, in Washington

Developers planning new power projects in the United States should take into account the possibility that an array of new energy tax incentives will become law this fall.

The new incentives could affect the choice of fuel, equipment and plant design, and how projects are financed.

They are part of a national energy plan that passed the Senate in April. The same plan passed the House last July. The two houses must still iron out differences in content between the versions of the plan that each passed before sending the final measure to the president for signature. Most observers expect the process to take until October to play out.

Cogeneration

Both houses of Congress have now passed a nearly identical tax credit for new cogeneration facilities. Therefore, assuming the national energy plan makes it the final step to the president's desk, this credit is certain to become law.

A "cogeneration" facility is a plant that produces two useful forms of energy from a single fuel. One of the outputs must be steam or another form of thermal energy. The other can be electricity or mechanical shaft power. The tax credit is 10% of the capital cost of the project.

To qualify, the plant must produce at least 20% useful thermal output, and it must have an energy conversion ratio greater than 70%. That means that the energy content of the electricity or mechanical power must be more than 70% of the energy content of the fuel used to produce it. (The conversion ratio must exceed 60% for smaller projects of 50 megawatts or less in size.) The 20% thermal output test may be hard for many companies to meet. The test to be a qualifying cogeneration facility under the Public Utility Regulatory Policies Act used to be only 5% useful steam output, and this was often difficult to reach.

The Senate waived both these requirements for plants that "generate electricity or mechanical power using back-pressure steam turbines in place of existing pressure-reducing valves or which make use of waste heat from industrial processes such as by using organic Rankin, Stirling, or Kalina heat engine systems." The House did not provide for a similar waiver.

Some projects will have to choose between tax credits and accelerated depreciation. Any taxpayer who claims a tax credit on his project cannot depreciate it faster than over 15 years using the 150% declining-balance method. Thus, there is no tradeoff for most gas- and coal-fired power plants, but there would be for projects that use waste fuels.

The credit can only be claimed on new plants that are put into service during a window period from 2003 through 2006. The credit is drafted currently in such a way that a plant placed in service during this window period qualifies for the full credit, notwithstanding that it may have been well under construction before 2003. Plants completed later this year would not qualify.

Developers with too little tax base to use the credit can transfer it to another company via a sale-leaseback. However, the sale must occur before the plant is put into service.

Section 45

The national energy plan will extend a section 45 credit for generating electricity from alternative fuels. The credit is currently 1.8¢ a kilowatt hour. It can be claimed currently by persons generating electricity from

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the terrorist attacks on US soil by giving companies an incentive to invest in new plant and equipment. A company can deduct 30% of the cost of qualifying assets immediately. The other 70% of the cost is depreciated normally.

The bonus reduces the cost of a new power plant by as much as 5.39% after the tax savings are taken into account.

AN OCTOBER 31 DEADLINE is looming.

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

The IRS said in late May that companies that have already elected to forego any carryback of losses — before realizing that a longer carryback is allowed — or that chose earlier to take advantage only of a two-year carryback — can still change their minds. However, they must act by October 31. The IRS announcement is Revenue Procedure 2002-40.

A STRATEGY FOR REPATRIATING FOREIGN EARNINGS was upheld.

The Limited, which owns a number of trendy clothing stores, used $175 million in earnings that were parked in a Hong Kong subsidiary to buy certificates of deposit, or CDs, from its US subsidiary that issues credits cards to customers of the company's stores. In effect, the Hong Kong company lent the money for use by the company in the US.

The Hong Kong company did not lend the money directly to its US affiliate. Rather, the Hong Kong company first set up a new subsidiary in the Netherlands Antilles and then made a capital contribution of the $175 million to this new Netherlands Antilles subsidiary, which lent the money back to the United States.

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wind, "closed-loop" biomass and poultry litter. The current deadline for placing projects in service to qualify for credits is December 2003. Credits run for 10 years after a project has been placed in service. The amount is adjusted each year for inflation. "Closed-loop" biomass refers to trees or other plants that are grown exclusively for use as fuel in power plants.

Both houses of Congress have now voted to extend the deadline for placing new alternative fuels projects in service to December 2006. (The House did not extend the deadline for poultry litter projects.)

Both houses also voted to add to the list of eligible fuels.

The House would allow credits for the first time to persons who use "open-loop" biomass or landfill gas to generate electricity. "Open-loop" biomass is defined as "solid, nonhazardous, cellulosic waste material which is segregated from other waste material" and that falls into one of three categories. The categories are certain forest wastes, "solid wood waste materials" (like crates and construction wood wastes), and waste from "agriculture sources." Municipal solid waste of the kind that is normally disposed in landfills, most old growth timber and paper that is commonly recycled are not "open-loop" biomass.

The Senate did not add landfill gas to the list of eligible fuels. However, it added a long list of other fuels: "open-loop" biomass, hog and cattle manure (and straw bedding), geothermal and solar energy, municipal biosolids, recycled sludge and small irrigation power projects of up to five megawatts in capacity that generate electricity "without any dam or impoundment of water through an irrigation system canal or ditch." The Senate also voted to let credits be claimed by owners of some existing power plants that use biomass and that are modified to co-fire with coal. Many of the Senate additions are not expected to remain in the final bill.

The Senate voted to let tax-exempt electric cooperatives, municipal utilities, state and local governments and Indian tribes sell the section 45 credits on projects they own to other taxpayers for cash. It also deleted a rule under current law that a project cannot benefit from section 45 credits to the extent it was financed with tax-exempt debt.

The Senate had to scale back the cost of its provision because it added so many new fuels. Some projects that use fuels that the Senate is adding to the list of eligible fuels would qualify for only three or five years of credits rather than the full 10 years under current law. For example, open-loop biomass facilities would receive only three years of credits under the Senate bill.

Clean Coal

The national energy plan provides new tax incentives for retrofitting or repowering existing coal-fired power plants — or for building brand new plants — with clean coal technologies. There are three incentives in the Senate bill. There are two in the House bill. The provisions are almost impossibly complicated; they make a mockery of claims by Congress that it wants to simplify the US tax code.

The Senate voted for a tax credit of 0.34¢ a kilowatt hour for generating electricity at existing coal-fired power plants that are retrofitted within the next 10 years to use clean coal technologies. Credits would be claimed on the electricity output for 10 years after a plant is returned to service. The plant cannot have a nameplate capacity greater than 300 megawatts. Only 4,000 megawatts of capacity can qualify for this "retrofit" credit. Projects would have to be certified in advance by the Internal Revenue Service. The list of clean coal technologies includes advanced pulverized coal or atmospheric fluidized-bed combustion, pressurized fluidized-bed combustion and integrated gasification combined cycle. The bill imposes other requirements, such as maximum heat rates and emissions tests. The project could not have received any clean coal technology money from the US Department of Energy.

The Senate also voted for an investment tax credit for 10% of the capital cost of new or retrofitted clean coal plants. (A company whose retrofitted plant qualifies for the production credit of 0.34¢ a kilowatt hour could not also claim this credit.) A project would have to jump through a series of hoops to qualify. The hoops vary depending on the technology. For example, a plant using pressurized fluidized-bed combustion must be placed in service by 2016, and its heat rate and carbon emissions must comply with standards set by statute. Only 500 megawatts of pressurized fluidized-bed combustion projects in total can qualify for the tax credit, and only 250 megawatts of such capacity put into service before 2009 qualifies. Projects would have to apply in advance to the IRS for confirmation they fit under the megawatt cap.

Finally, the Senate voted for a production tax credit for the same projects that qualify potentially for the investment credit. This credit would run for 10 years. The amount would vary from 0.1¢ to 1.4¢ a kilowatt hour depending on when the power plant is placed in service and on its design net heat rate. Plants that produce fuel or chemicals from coal — rather than electricity — could also qualify. The credit would be claimed on each 3,413 Btus of fuel or chemicals produced.

Section 29

The Senate voted to allow more time for taxpayers to place projects in service to qualify for section 29 credits.

Section 29 credits are tax credits for producing oil from tar sands or shale, gas from coal seams, tight sands, Devonian shale, geopressured brine and biomass, or synthetic fuel from coal. The tax credit was $1.083 an mmBtu for such fuels (other than tight sands gas) produced during calendar year 2001. The amount is adjusted each year for inflation. The credit was originally enacted in 1980 after the Arab oil embargo as an inducement to Americans to look in unusual places for fuel. Credits run currently through 2002 on most gas projects. However, the wells had to have been drilled by 1992 to qualify. Credits for most syncoal projects and many landfill gas projects run currently through 2007. Landfill gas and syncoal projects had to be in service by June 1998 to qualify.

The Senate voted to create a new window period during which new projects can be placed in service.

The new window period — for projects other than synfuel plants — would run from the day President Bush signs the national energy plan into law through December 2004 . Such projects would qualify for three years of tax credits on their output.

New synfuel plants would have through 2006 to be put into service and would qualify for five years of tax credits.

The credit for all new plants would be fixed at 51.7¢ an mmBtu. There would be no inflation adjustments.

The Senate voted to allow high carbon fly ash to be used as a feedstock in synfuel plants. Current law limits the feedstock to coal. The Senate also voted to tighten the definition of "synthetic fuel." Future plants would be viewed as producing synfuel only if two things are true about the output. Nitrogen oxide and sulfur dioxide emissions from burning the synfuel must be at least 20% less than emissions from burning the raw coal used as feedstock, and the output must have a "market value" at least 50% / continued page 8

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No US taxes had been paid on the $175 million; the Limited organizes its offshore operations that so that US taxes can be deferred as long as the earnings remain offshore. US taxes are supposed to be triggered when the money is brought back to the US in any form that gives the US group effective use of the money in the United States. US tax is also triggered if an offshore subsidiary with earnings invests the earnings in "United States property." However, there is an exception for "deposits with persons carrying on a banking business." Thus, money can be parked in a US bank account without triggering a US tax.

The US Tax Court wasted no time in declaring the arrangement triggered US income taxes on the earnings.

However, a US appeals court overturned the decision. The appeals court said taxes were not triggered because the Netherlands Antilles company did nothing more than make a bank deposit. It said the credit card company qualified as a "bank." The case is *The Limited v. Commissioner*. The appeals court announced its decision in April.

The decision is one of a series of losses for the US government in significant tax shelter cases in the past year. The government has tended to win such cases in the lower courts, where the judges seem more prone to set aside tax schemes that work technically but that arguably violate the law in spirit, only to lose on appeal.

AGGRESSIVE CORPORATE TAX PLANNING is coming under fire from Congress.

The US Senate is expected to pass a bipartisan bill — with support from the Bush administration — this summer that would require corporations to have at least a "more-likely-than-not" opinion that a tax position is justified in order to avoid steep penalties if the company is caught on audit. Under current law, such / continued page 9

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higher than the raw coal. The Senate made a last-minute change in the provision at the request of Senator Max Baucus (D.-Montana) to allow a 20% reduction in mercury emissions to substitute for a reduction in sulfur dioxide. Baucus is chairman of the Senate tax-writing committee.

In what looks like an effort to help a single project, the Senate voted to allow credits to be claimed for another two years through 2004 at a coal gasification project that uses lignite as feedstock and produces coke, coke gas and other products. The facility was originally placed in service before 1993. Credits at it expire under current law at the end of this year.

The House voted as part of its version of the energy plan to extend section 29 credits, but not for synfuel plants.

Indian Reservations

Projects on Indian reservations qualify currently for special rapid tax depreciation and wage credits tied to the number of Indians hired to work on the project. A project must be operating by December 2004 to qualify. Both houses voted to extend this deadline by another year through December 2005. The House extends the deadline only for power plants, gas pipelines and a few other assets. The Senate extends it for all projects.

Fuel Cells

The Senate energy plan includes a tax credit for investing in fuel cell power plants and microturbines. The credit applies to equipment put in service by December 2006.

The credit for fuel cells is 30% of the capital cost. However, the amount claimed as a credit cannot exceed $1,000 per kilowatt of generating capacity. The fuel cell power plant must have a capacity of at least 0.5 kilowatts and operate at least at a 30% generating efficiency.

The credit for microturbines is 10% of the capital cost. The amount claimed as a credit cannot exceed $200 per kilowatt of capacity, and the microturbine must have a generating efficiency of at least 26%.

Outlook

The energy plan the House passed last July has $32 billion in energy tax incentives. The Senate voted in April for $15 billion. Senator Charles Grassley (R.-Iowa), the ranking Republican on the Senate tax-writing committee, predicted soon after the Senate vote that the final compromise will be about $20 billion.

Enactment of the national energy plan is not assured. Gene Peters, vice president for legislative affairs for the Electric Power Supply Association, said in late May he gives it a 60% chance. Jonathan Weisgall, chief lobbyist for MidAmerican Energy Holdings Company, said he thinks the politics of the plan favor enactment this year. Farm-state Senators — including Tom Daschle (D.-S.Dakota), the Senate leader — like the ethanol provisions. President Bush has made enactment of the plan one of his goals for the year. And the Republicans who control the House see a benefit to passing a bill with strong incentives for renewable energy in an election year to counter charges that they are too closely aligned with big oil and too insensitive to the environment.

Nevertheless, the measure is on a slow track. The House and Senate passed different bills. The differences must be reconciled. The Senate moved quickly in early May to appoint 18 Senators as "conferees" to negotiate with the House. The House has moved more slowly, and could name more than 50 members of Congress as negotiators in early June. The process is expected to take until October to play out fully.

When Is Planning to Accelerate Earnings "Fraud"?

by Neil Golden, in Washington

For public companies, events of recent months have spotlighted the question of when financial transactions having the effect of boosting revenues or earnings or reducing taxes may cross the line to constitute a fraud on shareholders or creditors.

Transactions designed to keep debt off a corporate balance sheet, accelerate the reporting of revenues or earnings, or generate losses for income tax purposes should be analyzed with extra care in light of the renewed attention being paid to certain of such arrangements by the Securities and Exchange Commission.

This article summarizes recent actions taken by the SEC in some of these matters.

Senior executives and general counsel of public companies should take particular care in evaluating proposed transactions whose primary effect may be viewed as revenue or earnings management without an independent business purpose or that may otherwise be viewed as potentially misleading to investors if not adequately disclosed.

Background

The collapse of Enron has served as a wake-up call for financial reporting in the energy industry.

In recent weeks, a number of major public energy companies have announced that they are restating their revenues and expenses to disregard so-called "wash" trades in which electricity was simultaneously sold and repurchased from a counterparty with essentially no financial risk or gain involved in the transactions. Other public energy companies have issued public statements as a result of the increased market scrutiny in this area denying that they engaged in such transactions.

The SEC has launched investigations into the use of certain financial arrangements, including in the case of Enron the alleged improper use of special purpose entities to keep large amounts of debt off the parent company's balance sheet and lack of public disclosure of such transactions. Some companies have restated their balance sheets to bring formerly off-balance sheet debt onto the balance sheet.

The dollar amounts involved in many of these arrangements are huge. Restatements of revenues for some companies have involved billions of dollars of adjustments.

The energy industry is only the latest industry to face questions over the validity of financial reporting for certain types of transactions. In what is clearly a trend crossing several industries, a number of publicly-traded telecommunications companies also are being scrutinized for accounting practices related to alleged improper recognition of revenues in connection with sales of capacity on newly-constructed fiber-optic lines and swap transactions. The SEC has opened investigations into the financial reporting practices of firms such as Qwest Communications and Global Crossing Ltd. as well as Enron in connection with such arrangements.

Lines Drawn by the Law

A number of provisions in the federal / continued page 10

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penalties can usually be avoided by showing there was "substantial authority" for a position. Substantial authority is a weaker standard than "more likely than not."

In addition, a company would not be able to rely in the future on an opinion where the tax adviser receives fees from a broker or investment bank, or the fees he is paid are contingent on a successful closing or the amount of the tax savings the adviser can generate.

The Senate bill distinguishes among three types of aggressive tax planning.

Corporations would have to flag for the IRS all "listed transactions" (transactions that the IRS has put the public on notice will be challenged). If the IRS then disallows the tax benefits, the company would face an automatic 20% penalty. There is no way to avoid the penalty by showing that the company thought it had good grounds to claim the tax benefits. The penalty would jump to 30% if the company failed to disclose the transaction to the IRS, and it would have to report the penalty to its shareholders in a filing with the US Securities and Exchange Commission.

The next level down of aggressive tax planning is "reportable transactions" that have tax avoidance as "a significant purpose." The Bush administration is still fine tuning a list of warning signs that make a transaction "reportable." The warning signs include the fact that the company is indemnified against loss of the tax benefits or the transaction was marketed under conditions of confidentiality. If such a transaction is not reported and the tax benefits are later disallowed, then the company would face an automatic 25% penalty and have to report the penalty to the SEC. The company could avoid the penalty only by flagging the transaction for the IRS and by having a credible "more-likely-than-not" opinion from an outside tax adviser.

Another level down is "reportable transactions" that do not have tax avoidance as "a significant purpose." / continued page 11

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securities laws and regulations address the accurate reporting of financial transactions.

Among them is section 13(a) of the Securities Exchange Act of 1934 — called the "Exchange Act" — and the related SEC rules that require issuers of securities registered with the SEC to file annual and quarterly reports with the SEC and to keep the reported information current. Courts have construed this requirement to mean that the reports must be true and correct.

Section 13(b)(2)(A) of the Exchange Act requires public companies to keep books and records that accurately and fairly reflect their transactions and dispositions of assets. SEC Rule 12b-20 requires the inclusion of any additional information that is necessary to make the required financial statements, in light of the circumstances in which they are made, not misleading. Courts have held that information regarding the financial condition of a public company is presumed to be material.

Section 13(b)(2)(B) of the Exchange Act requires public companies to maintain a system of internal accounting controls sufficient to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, or "GAAP," and to maintain accountability of assets. Financial statements included in SEC filings must comply with SEC Regulation S-X, which, in turn, requires that such statements be prepared in conformity with GAAP. The SEC's enforcement actions related to alleged improper accounting for financial transactions by publicly-reporting companies frequently arise under these provisions.

In addition, SEC Rule 10b-5 makes it unlawful for any person, in connection with the purchase or sale of any security, to employ any device or scheme or engage in any act to defraud, or to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in light of the circumstances, not misleading. Section 10b-5 may be used by private litigants as well as the SEC to bring actions against issuers of securities, as well as officers and directors of such issuers, in connection with alleged accounting irregularities.

Good Rule of Thumb

A proposed transaction affecting the timing or amount of revenues or earnings should meet a two-pronged test from a legal point of view.

First, does the manner in which the proposed transaction is to be reported on the company's financial statements comply with GAAP?

Transactions affecting the timing or amount of earnings should meet a two-pronged test.

Second, even if the transaction as proposed to be reported complies with GAAP as a technical matter, does the proposed manner of reporting ensure that the transaction is fairly and adequately disclosed to investors when viewed from the broader perspective of the company's overall business?

Recent enforcement actions by the SEC and other Commission pronouncements show the importance of both parts of this test in evaluating a potential transaction.

In April 2002, Xerox Corporation agreed to pay a $10 million fine and signed a consent order with the SEC in connection with its practices in booking certain lease revenues, to settle an SEC complaint alleging that Xerox used so-called "accounting actions" to manage its earnings improperly and disguise its true operating performance over a four-year period. According to the SEC's release, the use of the special "one-time actions" and other "accounting opportunities" were closely tracked by senior management and accounted for as much as 37% of Xerox's operating profit during at least part of the period in question. The release noted that without those special accounting arrangements, Xerox's earnings would have fallen short of market expectations, often by a wide margin, in almost every reporting period from 1997 through 1999.

Xerox's accounting actions related largely to its leasing arrangements, which typically involved a single monthly payment under a bundled contract with the customer that covered three components: the lease of the equipment itself, a servicing component and a financing component. Under GAAP, Xerox was required to book revenue from the equipment component at the beginning of the lease, but was required to book revenue from the servicing and financing components over the term of the lease. According to the SEC's complaint, Xerox used complex accounting actions to shift revenue that the company had historically allocated to the servicing and financing components of the leases to the equipment component, thereby increasing revenues and earnings in the near-term periods by material amounts.

The SEC alleged that "[i]n violation of GAAP, Xerox had failed to disclose these methodologies, and the numerous changes it made to them, to investors, creating the appearance that the company was earning much more from its sales of equipment than it actually was." The complaint "alleges that the failure to disclose the changes in accounting methods and estimates was fraudulent." Without admitting or denying the SEC's charges, Xerox agreed as part of the settlement to restate its financial statements for the years 1997 through 2000 to make appropriate adjustments in the timing and allocation of its lease revenue recognition. It was also granted a 90-day extension to file its Form 10-K for the year 2001 to make similar adjustments.

Edison Schools, Inc., which operates public schools on a for-profit basis, recently settled charges with the SEC regarding alleged improper recognition of revenues and other securities law violations. Edison receives management fees from school districts in a stated per-pupil amount. Management contracts between Edison and the school districts generally provide that Edison is responsible for operating the schools from these fees. However, teachers in schools operated by Edison often remain employees of local school districts and are paid by the districts directly from funds withheld from the per-pupil payment to Edison.

Under GAAP, if Edison was deemed the primary obligor for the teacher salaries, it would be appropriate for Edison to report its revenues on a gross basis — in other words, to book as its revenues the total-per pupil / continued page 12

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The company would avoid an extra tax-shelter penalty simply by flagging the transaction for the IRS. However, if it failed to report, it would need a credible "more-likely-than-not" opinion to avoid the extra penalty.

The bill not only requires companies to get stronger opinions in the future but, for the first time, it also will put directly into the US tax code standards for tax opinions. For example, the law or accounting firm giving the opinion will not be able simply to rely on representations from the company about material facts that turn out in retrospect to have been unreasonable. In a joint statement released by the Senate tax-writing committee, the committee chairman, Max Baucus (D.-Montana), and the senior Republican, Charles Grassley (R.-Iowa), said they "think a taxpayer should not claim a position on a tax return that the taxpayer does not believe is correct unless this fact is disclosed to the IRS."

Under the bill, each "material" adviser — meaning law firm, investment bank, broker — involved in structuring, selling or implementing any tax shelter would have to report details about the transaction, including the advice given, to the IRS. Advisers would have to forfeit as much as 75% of their fees or $200,000, whichever is greater, for failure to report a "listed transaction." The penalty for failing to report other transactions is $50,000.

AN AMNESTY for reporting aggressive tax schemes to the IRS to avoid penalties netted about 1,600 disclosures. The amnesty expired on April 23.

The government said about 1,000 disclosures involved "listed transactions" that the IRS has put the public on notice will be challenged. (An example of a listed transaction is a type of cross-border lease called a LILO, or "lease-in-lease-out.") By coming forward, the companies making disclosures avoid an accuracy- / continued page 13

Earnings Ploys

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amount including amounts paid directly by the school districts to the teachers. On the other hand, if Edison was not the primary obligor for the teacher salaries, Edison would have to report its revenues on a net basis, excluding the teacher payments from the per-pupil amounts.

In its SEC filings, Edison included as revenue all per-pupil fees that the districts were obligated to pay it under the management agreements, without disclosing that there was any set-off for teacher salary amounts that were paid directly by the school districts to teachers. Edison did report the offsetting expense for the teacher salaries, so there was no effect on Edison's net income from reporting revenues on a gross rather than a net basis.

The SEC charged that Edison violated federal securities laws by failing to disclose that the teacher salary component of its revenues was never actually received by Edison but was paid directly by the school districts to the teachers, with the effect that Edison's revenues were inflated by such amounts. The SEC determined that the school districts retained a level of control over the teachers' salaries such that Edison was not a "primary obligor" with respect to the amounts and that, accordingly, the amounts should not have been included in Edison's reported revenues — even though this practice did not affect reported earnings or income. The SEC noted, "technical compliance with GAAP in the financial statements will not insulate an issuer from enforcement action if it makes filings with the Commission that mischaracterize its business, or omit significant information."

The SEC recently opened an investigation into the accounting practices of Global Crossing and Qwest with respect to recognition of revenues on their financial statements. One issue is the manner in which "round-tripping" transactions were booked. In one such situation, according to published reports, Qwest sold capacity on its US fiber optic network to Global Crossing for $200 million while Global Crossing sold capacity on its international fiber optic network to Qwest for the same amount. As reported, Qwest recorded its US capacity sales as operating revenue and then offset that amount completely by expensing its cost of purchasing the international capacity, while Global Crossing also booked the sale of its international capacity to Qwest as operating revenue but did not offset that amount by the amount Global Crossing paid for the US capacity. Instead, Global Crossing recorded its purchase of US capacity from Qwest as a capital expenditure on its balance sheet, with no offsetting immediate effect on its income statement. As reported, both companies claim that the accounting treatment given to their respective transactions complies with GAAP.

An opinion that financial reporting complies with GAAP is not enough.

The head of accounting in the SEC's enforcement division is quoted as saying that even if the transactions were reported in compliance with GAAP, if there is no business purpose in the round-tripping transactions, then the recording of revenues from the transactions could be "materially misleading" and, if the purpose of the transactions was to mislead investors and the impact of the transactions was material, the SEC could consider the transactions to be fraudulent.

Enron is also alleged to have inflated its revenues — by counting as revenues the value of transactions in which the same quantity of electricity or gas was sold and repurchased in multiple transactions without any profit or loss. Some of the transactions were between Enron and the supposedly independent partnerships that have been subject to scrutiny. Again, such transactions raise the question of whether there was any proper business purpose for the transactions, even if the accounting treatment given the transactions was appropriate.

Useful Reading

General counsel would be wise to read a US appeals court decision in a 1969 case called *US v. Simon*, 425 F.2d 796 (2d Cir. 1969), *cert. denied*, 90 S.Ct. 1235 (1970).

Simon involved an appeal of a criminal conviction of two partners and an associate of a major public accounting firm for preparing and certifying a false and misleading financial statement of a public company called Continental Vending. The issue before the lower court concerned the treatment in Continental's financial statements of a receivable from an affiliated entity whose collectability was doubtful and the collateral for which was determined to be inadequate. Continental's financial statements did not note these deficiencies in the quality of the receivable.

The accountants testified at trial that the treatment of the receivable was not inconsistent with GAAP. However, the trial judge instructed the jury that whether or not the accounting treatment of the receivable was permissible under GAAP was not dispositive; rather, the issue was whether the financial statements as a whole "fairly presented the financial position of Continental."

In upholding the trial court's determination, the US appeals court stated that "[g]enerally accepted accounting principles instruct an accountant what to do in the usual case where he has no reason to doubt that the affairs of the corporation are being honestly conducted. Once he has reason to believe that this basic assumption is false, an entirely different situation confronts him. . . . If . . . he finds his suspicions to be confirmed, full disclosure must be the rule, unless he has made sure the wrong has been righted and procedures to avoid a repetition have been established. At least this must be true when the dishonesty he has discovered is not some minor peccadillo but a diversion so large as to imperil if not destroy the very solvency of the enterprise."

The appeals court decision in *Simon* is important because it has been cited by SEC Chairman Harvey Pitt and other enforcement officials recently for the proposition that financial transactions, even if reported on a basis consistent with GAAP, may nonetheless be deemed misleading in violation of federal securities laws without adequate additional disclosures.

The SEC's position in the Edison Schools matter is illustrative. Whether or not the accounting treatment of the portion of the per-pupil amounts paid */ continued page 14*

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related penalty if the tax benefits from the transaction are later disallowed. At least another 300 disclosures cover other transactions. The IRS said in mid-May that the amnesty helped it identify at least 30 transactions of which it had no prior knowledge.

The government is issuing summonses to accounting and law firms and investment banks involved in "listed transactions" seeking names of the participants in the transactions. As of May 12, 147 such summonses had been issued.

CORPORATE INVERSIONS generate more heat.

Members of Congress were angered by the news in April that Pricewaterhouse Coopers Consulting is inverting and that no special risk disclosures are needed in securities filings about the pending bills in Congress that are supposed to halt inversions. PwCC said none of the bills would apply to its transaction.

A corporate inversion is a transaction where a US company with significant foreign subsidiaries turns itself upside down so that the foreign subsidiaries are owned by a new holding company — often in Bermuda — and what was formerly the US parent becomes just another subsidiary of the new Bermuda parent. An inversion is done to keep foreign earnings outside the US tax net.

The Connecticut attorney general filed suit in May against Stanley Works to block a plan by the company to move its tax domicile to Bermuda. The state charged that the shareholder vote approving the move had not been properly conducted. The company is in the process of repolling its shareholders.

Meanwhile, the US Senate is expected to vote as early as June on a bipartisan bill to stop inversions. The measure faces an uncertain future in the House. The chairman of the House tax-writing committee — Rep. Bill Thomas (R.-California) */ continued page 15*

Earnings Ploys

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by school districts directly to teachers was consistent with GAAP seems to have been considered less significant by the SEC than the fact that Edison did not disclose the existence of the arrangements in its public filings and the fact that the amounts were never actually received by Edison even if appropriately included in its revenues as an accounting matter.

The SEC noted that by including such amounts in its revenues, Edison was able to report significant gross revenues for providing educational services to school districts that in fact paid Edison relatively little cash. The SEC concluded that "the revenues reported as total Per Pupil Funding do not fully describe the realities of Edison's operations."

Similarly, the SEC's complaint against Xerox asserted that the failure to disclose the specific accounting techniques used to enhance revenues at the outset of the leases created the misleading appearance that Xerox was earning much more from the transactions than it actually was.

Tax strategies used to increase corporate earnings have also come under increased scrutiny in the wake of the Enron collapse. A recent press report suggested that tax-related transactions accounted for as much as 30% of Enron's earnings in the year 2000, based on information released by Enron's tax department. It is an open question whether public companies that use highly aggressive tax strategies run the risk of being accused of inadequate disclosures in their financial statements if such strategies are not adequately explained.

Conclusion

The recent SEC actions against a number of companies, both in the energy industry and in other industries, show that the US government is taking a more aggressive posture with respect to financial transactions that may present a misleading picture of a company's revenues or earnings without more detailed disclosures. The SEC is taking action even in situations where the accounting treatment for the transactions conforms to GAAP. Public companies must review proposed transactions to boost revenues or earnings from the broader perspective of the adequacy of the disclosures about such transactions to be made in the company's SEC filings. ◎

IRS Blesses Technique To Boost Interest Deductions

by Heléna Klumpp, in Washington

A ruling by the Internal Revenue Service in May suggests that companies would be wise to look into doing their future borrowing using convertible debt instruments and then structuring the debt so that the amount of interest to be paid is "contingent" on future events.

The IRS said borrowers under such instruments can deduct substantially more interest than the stated rate. The extra deductions reduce the cost of borrowing.

A "convertible" debt is one where the lender may end up with shares in the borrower rather than cash.

IRS Ruling

The IRS ruled in May that borrowers under certain contingent convertible debt instruments may take bigger interest deductions than some critics had previously thought possible.

The IRS made its position known in Revenue Ruling 2002-31. The IRS said in the ruling that an issuer of a contingent convertible bond can compute its interest deductions based on the rate at which it would issue straight debt, instead of the rate at which the borrower would issue the same convertible debt without contingencies.

This is important because the interest rates on straight debt are typically much higher than the interest rates on non-contingent convertible debt. The difference is as much as 300 to 400 basis points, even considering the relatively shorter term expected of convertible bonds. The IRS also said that the borrower can deduct interest calculated on any premium it would have to pay if it repaid the debt in shares. Thus, by adding a contingent feature to a convertible debt instrument, a company may be able to increase the rate of its interest deductions significantly, as well as increase the principal amount on which such deductions are calculated.

Convertible Debt

Starting with the basics, a convertible debt instrument is a bond that may be converted into stock of the borrower, generally at set times or under set conditions. In a basic convertible, the conversion ratio is set upon issuance at a fixed amount of shares per bond. The interest will be typically much lower than that of a straight debt instrument because the conversion right adds value.

A contingent convertible debt instrument adds an additional wrinkle: instead of paying fixed, stated interest, a contingent convertible debt instrument provides for payment of interest only if certain conditions are met.

There are many variations in how contingent convertibles are structured. The IRS described one such instrument in its ruling. The instrument in the ruling was issued on January 1, 2002 at a discount from the stated principal amount of $1,000. The borrower pays no current interest. The lender loaned $625 and expects to be repaid $1,000 in 20 years. However, interest will be paid semi-annually beginning in 2005 if the average market price for the instrument measured over a six-month period is greater than 120% of the bond's "accreted value" at the end of that period. The accreted value at the end of a period is the $625 originally lent plus the amount of the discount that has accrued to date. If interest is payable for any semi-annual period, then the amount of the interest will be the greater of two figures. One is the cash dividend that was paid on the borrower's stock (multiplied by the number of shares into which the debt instrument could be converted). The other is X% of the average market price of the debt instrument for the six-month period.

On the same date that contingent interest might first be paid (January 1, 2005), the borrower has an open-ended right to redeem the debt instrument for cash equal to its then-accreted value. The lender also has the right, exercisable on two dates — January 1, 2005 or January 1, 2012 — to "put" the debt instrument back to the issuer for an amount equal to the instrument's accreted value as of that date. If the lender exercises its put, then the borrower has the right to pay the lender in cash, stock, or a combination of the two.

Tax Benefits

The IRS ruling answered the question about the amount and timing of the interest the borrower is allowed to deduct.

The IRS said the borrower should compute its interest deductions using a 7% rate, which is roughly equivalent to the rate at which the issuer would have issued a straight debt instrument. It also said that interest could accrue on the premium the borrower would have to */ continued page 16*

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— said initially that he is not keen on legislating against inversions, but he scheduled a hearing on them for June 6.

The Bush administration released "preliminary" results of its own study into inversions in late May. The US Treasury secretary, Paul O'Neill, said, "When we have a tax code that allows companies to cut their taxes on their US business by nominally moving their headquarters offshore, then we need to do something to fix the tax code." The report was short on specifics. O'Neill called on Congress, at the same time, to fix the parts of the tax code that cause US companies to feel they must move offshore in order to compete effectively with companies from other countries that tax on a "territorial basis," unlike the United States, which taxes American companies on their worldwide earnings.

The bill the Senate is likely to pass as early as June distinguishes between "pure" inversions and "limited" inversions. A "pure" inversion is one where the new foreign parent company ends up with substantially all the assets of the inverted US company and former shareholders of the inverted US company own at least 80% of it. "Pure" inversions after March 20, 2002 will essentially be ignored: the US will treat the new foreign parent company as if it remained a US corporation.

A "limited" inversion is one where former shareholders end up with more than 50% of the new parent company. Limited inversions after March 20 will not be ignored, but the US will make sure a full "toll charge" is collected on the appreciation in value of the assets that are moved outside the US tax net, and the inverted US company will have to get advance approval from the IRS for all transactions with affiliates for the next 10 years after the inversion.

The requirement to get advance approval for transactions with affiliates would also apply to companies that inverted in the past. They would */ continued page 17*

Interest Deductions

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pay if it repaid the debt in shares, which could be significant. In other words, the agency said the borrower should deduct interest — and the lender should report it — at the same rate at which interest would have accrued on a straight debt instrument identical in all respects to the contingent convertible except that it contains no contingencies and is not convertible.

The key to getting larger interest deductions is to add contingencies.

The IRS said this follows from a complicated rule in its "contingent payment debt regulations."

In the case of a straight debt instrument with fixed interest, the parties accrue interest deductions and income at the stated interest rate, assuming that rate is a market rate. However, when a debt instrument provides for payments that are contingent in time or amount upon some future event, then the parties have a harder time figuring out how much interest to deduct (or, in the case of the lender, to report as income). The contingent payment debt regulations, adopted in 1996, address this issue.

They instruct taxpayers to accrue interest on debt instruments issued for cash using the "hypothetical noncontingent bond method." This means that the parties must account for interest at the same rate as the yield on a hypothetical bond that does not include any contingencies. The hypothetical bond is deemed to be issued by the same borrower as the contingent bond and is identical in all respects to the contingent bond (except that it contains no contingencies). This hypothetical yield is applied to a projected payment schedule for the actual bond to calculate the amount of each payment that should be considered interest.

A borrower cannot use the contingent debt regulations to determine the amount of interest the borrower can deduct on a plain convertible debt. Thus, the key to getting larger interest deductions is to add contingencies that bring the instrument under the contingent debt regulations. Standing alone, the chance of convertibility is not considered a contingency. The contingency should relate to interest payments.

By pulling a convertible bond into the contingent debt regulations, a borrower could be entitled to take interest deductions that are based on higher-yield fixed obligations.

There is an additional benefit to contingent convertibles: the IRS said that the stock the lender receives upon conversion can be treated as a contingent principal payment that accrues interest.

The convertible debt market is booming. More than $119 billion in convertible debt was issued in 2001, up from $74 million in 2000. Its popularity may be attributable in part to the volatility of the stock market and the pressure that many companies are under from rating agencies to improve their balance sheets. They may be hoping for partial equity treatment on their books.

Of course, where there exists potential for phantom deductions, there is potential for phantom income. The borrower's interest calculations must be disclosed to the lenders and are binding on any US lender unless the US lender can establish to the IRS that they are unreasonable. However, foreign lenders or certain US lenders who are not subject to US income taxation (tax-exempt organizations, for example) will not care about any phantom US income.

Reservations

The IRS issued a notice at the same time as the revenue ruling that suggests the agency is not entirely comfortable with its conclusions on contingent convertibles. The notice is Notice 2002-36. In it, the IRS expressed concern that "relatively insignificant changes in the investment economics of a convertible debt instrument can effect a dramatic change in the amount of interest accruals." The IRS "invite[d] comments and suggestions for changes in the relative tax treatment of straight convertible debt instruments and contingent convertible debt instruments to eliminate or reduce the disparity in treatment of these instruments."

The questions on which the IRS invited comments suggest it is looking at three possible options. First, the IRS asked whether it should also let taxpayers accrue interest on straight convertible debt under the contingent debt regulations. Second, it asked whether the regulations should be modified to provide that the yield on contingent convertibles must be computed by reference to plain convertible debt instead of straight debt. Third, the IRS asked whether it should shore up a rule that says remote or incidental contingencies are not enough to bring an instrument under the contingent debt regulations.

The IRS also urged commentators to address the effects of two sections of the US tax code that apply to convertible debt: section 249, which denies any deduction for excessive conversion premiums where the premium reflects more than the cost of the borrowing, and section 163(l), which denies a borrower any interest deductions on debt instruments that are substantially likely to be repaid in issuer shares. The section 163(l) issue was largely assumed away in the fact section of the May ruling.

California Generation: Valuable Assets or Fool's Gold?

by Dr. Robert B. Weisenmiller, Steven C. McClary and Heather Vierbicher, with MRW & Associates, Inc., in Oakland, California

One hundred fifty years after the first miners struck gold at Sutter's Mill, companies rushed to cash in on California's newest source of riches: power markets.

In the first half of 2001, power prices routinely landed within a range of $200 to $400 per megawatt hour. Proposals for power plants, already at record levels, surged, supported by favorable perceptions of supply and demand fundamentals. In October 2001, more than 10,000 megawatts of baseload capacity awaited California Energy Commission approval or had recently been approved. Another 8,000 mws of capacity was under construction. Numerous entities claiming competence in the power area approached local governments, native / continued page 18

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need approval for 10 years measured from last January.

ARGENTINA moved in May to subject foreign shareholders of Argentine companies to personal assets taxes on their shares.

Shares issued by Argentine companies and owned by nonresident legal entities on December 31 each year will be subject to a 0.5% tax on the percentage they represent of the net equity of the company, according to Maximiliano Batista with Perez Alati, Grondona, Benites, Arnsten & Martinez de Hoz in Buenos Aires. Argentine companies will be responsible for collecting the taxes from shareholders. The new law is expected to have a significant effect on Argentine utilities that were sold to foreign investors in privatizations in the 1990's. The tax is not creditable against income taxes in the United States.

ELECTRIC AND GAS INTERTIES remain a hotbed of activity.

The Federal Energy Regulatory Commission released for comment in late April a draft model interconnection agreement that all utilities and independent power producers will be expected to use in the future. The commission is tired of having to act as an arbiter between independent generators and utilities. A majority of interconnection agreements today are filed with the commission unsigned because the parties cannot agree on terms.

Owners of independent power plants must pay the cost of power lines, breakers, meters and other equipment to connect their plants to the utility grid. The cost often covers upgrades to the grid itself to accommodate the additional power. The utility owns the intertie. Utilities have sometimes insisted they must report the value of the equipment as income and insist the generator pay a "grossup" to cover the income taxes. The IRS said in a notice last December that such payments do / continued page 19

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American Indian tribes, and businesses with offers for co-development of power plants that would provide cost containment or be a source of revenue in exchange for exclusive development rights or payment of risk capital.

By May 2002, the heady days of California's latest gold rush were already history. Current power prices have settled back down to a range of $20 to $40 per megawatt hour. Proposed new projects are being cancelled or delayed.

Financial markets are unlikely to provide substantial additional capital for power plant construction until power issues become less politicized, California's utilities regain investment grade credit ratings, a consensus develops around a coherent vision of a Western wholesale power market, and there is a return to stable and predictable regulatory ground rules.

These concerns haunt both investors with operating California power projects as well as those market players who only recently arrived. None of these ingredients is present now, although some progress is visible.

Given the magnitude of California's power debacle, it will take years to return to a stable, business-as-usual environment.

Election Year

California will hold elections for statewide offices this November, including the gubernatorial race and many legislative seats. The state must also address a staggering $24 billion budget deficit. (California's total annual budget is $99 billion.) Closing the budget deficit for this year will require the right political mixture of creative accounting and painful spending cuts and tax hikes. The budget woes do not end there and will likely return next year. Moreover, the projected shortfall assumes that California will be able to sell $11.1 billion in bonds to cover outlays by the Department of Water Resources, or "DWR," in 2001 to purchase power to keep the lights on. The state treasurer has struggled to align the Rubik's cube of competing interests and political agendas to achieve such a massive bond sale. Originally projected for last fall, the bonds may go to the market this coming fall or winter.

Given the November elections, most observers expect more creative accounting gimmicks than courageous leadership to come out of Sacramento this summer. The assignment of blame for the budget crisis and the state's electricity crisis last year will be a frequent refrain through the November elections. The patience of the California public and its politicians with energy issues appeared to have been exhausted by late 2001. However, Enron's financial meltdown, the release of "smoking gun" energy trading memos, and the plunging confidence in power market trading companies have reignited deep outrage among the California public. These financial and ethical meltdowns have handed a well-televised platform to Governor Davis and other California Democratic leaders to attempt to shift public attention away from other issues.

Little change in California's political leadership is expected to result from the November state elections.

Davis would like to run for president. Energy policy differences between President Bush and Governor Davis could resonate as campaign issues for the next two years through 2004. California energy policy issues could remain politicized for years as a result.

Lawsuits Abound

Since the electricity crisis erupted in California nearly two years ago, the search for a culprit — or culprits — has never ceased. California officials and regulators most frequently point fingers at the Federal Energy Regulatory Commission for inaction and at independent generators and electricity traders for manipulative behavior.

California has challenged FERC on numerous fronts. Lawmakers in California eliminated the independence of the governing board of the state's independent system operator, or "ISO," in a direct challenge to FERC policy on transmission operators. That policy calls for these entities to operate independently of any influence by state government and other "stakeholders." (The ISO's board of directors now serves at the pleasure of Governor Davis.)

California regulators and lawmakers are pursuing substantial refund claims through an aggressive political strategy. A year ago, the state demanded an $8.9 billion refund from electricity generators and power marketers. Governor Davis recently indicated state officials may ask for an even larger refund in light of "new evidence" of market manipulation, and some California officials have clamored for as much as $30 billion.

The state also has asked FERC to reopen for negotiation long-term power contracts executed last year during the power crisis, challenged FERC's policies on RTOs and standardized market redesign, and enacted legislation that challenges FERC's jurisdiction over exempt wholesale generators and the wholesale market.

Independent generators have not escaped the state's blame game. The state attorney general, a state Senate committee chaired by Senator Dunn, and the California Public Utilities Commission are all conducting multiple investigations to find support for lawsuits against generators.

For example, the attorney general has filed one lawsuit that challenges a number of short-term power transactions on grounds that power marketers violated federal law (section 205(c) of the Federal Power Act) by not filing rates in advance. In a separate lawsuit, the attorney general is seeking up to $2 billion from four companies for allegedly violating California's unfair business practices law by selling power at rates above levels FERC had previously established as reasonable. A third lawsuit alleges various power marketers "gamed" California's wholesale market. A number of class action suits have also been filed, including one by the city and county of San Francisco.

The unfortunate consequence of all the finger pointing is twofold. First, the investment climate may suffer a long-term loss of confidence and trust. Second, any efforts to move beyond the crisis are viewed as partisan maneuvering rather than valid policy positions.

A Muddled Future

While Governor Davis, the state attorney general, the legislature, and the CPUC are unanimous in their belief that California's energy woes are the result of market gaming by power generators and trading companies and inaction by FERC, these same parties (and others) are far from agreement on how to move beyond the electricity crisis and prevent another one from happening.

One vision for California's future electricity market is a greater role for public power, possibly by combining the newly established California Power Authority with local municipalization efforts. The California Power Authority was established in April 2001 with the passage of Senate Bill 6X as a sort of insurance policy against future crises. When the power authority began operations in August 2001, the state treasurer, Phil Angelides, characterized public power as "a birch rod" that should only be used when scolding no longer works, a reference to public power's */ continued page 20*

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not normally have to be reported as income.

Consequently, the FERC model agreement suggests that utilities should not ordinarily collect tax grossups, but it gives any utility the right to do so that believes "in good faith" that it has taxable income. The generator would be able to seek a ruling from the IRS on whether there is income in such cases. Utilities would be free when no grossup is collected to require the generator to post security. The security would be for the full amount of taxes that might have had to be paid in theory on the intertie (absent the IRS notice). The form of security is up to the utility. Any comments on the model agreement must be submitted to FERC by June 17.

Meanwhile, the IRS is making utilities who apply for private rulings confirming they have no income do more than simply show their cases are covered by the IRS notice last December. The IRS also wants them to make an affirmative case that they have no income. This makes for somewhat longer ruling requests than expected, but has not otherwise created difficulties. The power industry is talking to US Treasury officials in the meantime about whether the IRS is taking too narrow a view of the December notice.

Finally, discussions are also underway with the IRS about the tax treatment of gas interties. In general, an interstate pipeline must report payments from a power plant to connect to the pipeline as income. The reason is the power plant is usually a customer of the pipeline. Payments that a utility receives from a "customer or potential customer" must be reported as income. However, there may be situations where taxes on gas interties can be avoided.

CALIFORNIA said income from the sale of power by an out-of-state electricity supplier to a California purchaser is earned for tax purposes outside California.

California taxes any */ continued page 21*

Is the Storm Over, or Are We in the Eye of a Hurricane?

In the October 2001 *NewsWire*, we wrote an article called "California: Crisis Over?" We noted then that a number of factors combined to keep the doom and gloom predictions for the summer of 2001 at bay: unprecedented conservation efforts, the recession, some new generation coming on in the nick of time, falling gas prices, and cooperative weather throughout the West.

How much of this can be counted on for the summer of 2002? A fair amount of it. No one expects the conservation efforts to be as vigorous as last year when saving energy was on the news every night. However, electricity rates are still high, conservation and efficiency outreach is still taking place, and the efficient appliances purchased in 2001 will still be saving energy in 2002 and beyond, so some degree of savings can be expected. Furthermore, the state's economy is still lurching and is only slowly climbing out of the recession. A few thousand megawatts of new power plants are expected to come on line in the next few months and water conditions are at least back to normal in the Pacific Northwest (and much of California), where hydroelectric dams are a big part of the capacity mix. Gas prices are also back to normal levels. DWR's credit support assures sellers that they will be paid, and FERC market mitigation measures such as the must-sell requirement are still in place. Taken together, these factors suggest that the summer of 2002 should remain calm.

There is not a large margin for error. Savings will not match those during 2001. The public is oversaturated with calls to save energy, and will be much more inclined to tune out conservation */ continued page 22*

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role as a constraint on market excesses. The power authority can issue up to $5 billion in revenue bonds. However, in reality this additional tranche of bonds is in the queue behind the pending sale of DWR revenue bonds and the need to finance loans to cover at least part of the state budget deficit.

The power authority is on a public quest for a mission. Initially, the agency wanted to contract for peaking capacity for the summers of 2002 and 2003. However DWR, reeling from criticism of the long-term contracts it signed in early 2001, was unwilling to put state credit behind any power contracts negotiated by the power authority. In February 2002, the power authority submitted an investment plan to the legislature that focuses on renewable energy and demand-side management, but again neither DWR nor any of the regulated utilities was interested in assuming any obligations to support the power authority's activities.

A second vision for the future sees the CPUC resuming its historic regulatory role of overseeing vertically-integrated utilities. The regulatory agency is most aggressively pursuing this vision in the current examination of generation procurement policies for the state's three investor-owned utilities. (The IOUs were unable to procure power in the market after their credit ratings fell below investment grade during the recent electricity crisis.) The CPUC is seeking to return the utilities to the procurement — and possibly generation — role by January 1, 2003.

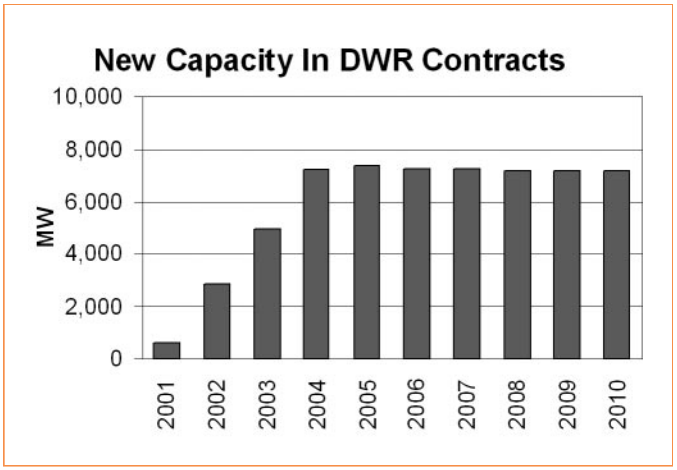
The utilities have asked the CPUC to establish some form of up-front reasonableness standards or a review process to remove any disincentive for entering into long-term contracts. When California restructured its electricity industry in the late 1990s, the utilities were encouraged to divest their generating assets and were required to procure power from a state-established spot market called the Power Exchange, or "PX." Utilities' purchases from the PX were deemed by the CPUC to be *per se* reasonable, while any other power procurement potentially faced a retrospective reasonableness review by the CPUC. The CPUC will consider the utilities' proposals for consistent reasonableness standards during the current procurement proceeding.

The CPUC has a number of difficult questions to answer during the procurement proceeding. They include the role of the new power authority in relation to California's regulated utilities. Procurement issues require a number of difficult decisions. How much additional power does California require in the next five to 10 years? What is the mix of required power among baseload, peaking and ancillary service contracts? How much of California's successful demand-side management activities last summer will persist over the next five to 10 years? How many of the DWR contracts will survive regulatory challenges? How much additional renewable power should California commit to buy? What is the future of direct access or local municipalization in California? What will the ISO's redesigned markets look like? What is the optimal portfolio strategy considering risks and price?

These questions will have to be answered against a backdrop of conflict. Political, jurisdictional and personal conflicts erode much of the potential for reestablishing a stable investment environment based on clear and predictable market rules.

Fight Over DWR Contracts

The story of how DWR became the only game in town has been recounted many times. On the positive side, the 57 long-term contracts DWR negotiated reduced credit risks for operating projects, reined in a runaway spot market, and potentially provided credit support for new projects (*see chart*). Governor Davis hailed the contracts on March 5, 2001,



as the "bedrock of a long-term energy solution" for California.

However, DWR negotiated most of these contracts at the height of the electricity crisis when power prices were soaring. As wholesale electricity prices / *continued page 22*

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company doing business in the state on the portion of its income that is considered from California sources. A three-factor formula determines how much of the company's income is attributable to California sources. The first two factors are the ratio of the company's California property to its overall property and California payroll to its overall payroll. The third factor is the ratio of the company's sales in California to its overall sales.

PacifiCorp — an out-of-state supplier of power — sold wholesale power to California utilities. It argued the electricity sold into California is "not tangible personal property" for purposes of calculating the sales factor and that it had no sales attributable to sources in California as a result. The State Board of Equalization agreed with PacifiCorp. A written opinion explaining the board's reasoning is expected this summer.

LOUISIANA confirmed that independent power plants are subject to property taxes at a lower rate than power plants that supply power directly to retail customers.

"Public service property," or property that is owned by a company that is "primarily engaged in the business of manufacturing, generating, supplying . . . electricity for light, heat, or power to consumers" is centrally assessed by the state for property tax purposes at a rate of 25% of the property's fair market value. Other property is assessed locally at 15% of fair market value.

The Louisiana Tax Commission told Cleco Corporation that its Evangeline power plant that supplies power to the wholesale market should be assessed at the higher rate. Cleco prevailed through three successive courts in challenging the tax commission. The state supreme court held ultimately in April that the Evangeline plant should be assessed locally at the lower rate. The court said this result does not violate a provision in the Louisiana constitution that requires / *continued page 23* *continued from page 20/* messages as "crying wolf." Both major nuclear plants in the state, San Onofre and Diablo Canyon, have major refueling outages scheduled. An unforeseen problem or two during the refueling cycles could keep a unit or two off line well into the summer. Nevada utilities are facing some of the same credit concerns that brought down the California utilities in 2001. Add to these factors a good heat wave, other major plant outages or transmission bottlenecks, and the result could be service interruptions, Stage 1 emergencies or even blackouts.

Always Look on the Bright Side: QFs

While the California power crisis took the state's qualifying facilities on a harrowing roller coaster ride, the ever-resilient QFs appear to have emerged in good shape. The ordeal began in November 2000, when Southern California Edison began defaulting on payments to QFs. In December 2000, Pacific Gas and Electric began paying only 15¢ on the dollar for QF power. This continued through March 2001, by which time the utilities had accumulated approximately $1.2 billion of combined debt to QFs.

The California Public Utilities Commission stepped in at this point with D.01-03-067, authored by CPUC Commissioner Carl Wood. The Wood decision was a mixed blessing. On one hand, it ordered the utilities to pay QFs in full on a going-forward basis, so the debt to QFs would not balloon any further. On the other hand, it did nothing about the back debt. Even worse, it changed the energy price formula for QFs in the Southern California Edison territory so they were tied to a gas price index at Malin (for */ continued page 24*

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dropped, the DWR contracts became extremely controversial. California is now saddled with contracts that will cost an estimated $43 billion over the next ten years.

California's state auditor performed a detailed review of the contracts and concluded that DWR had assembled a suboptimal power portfolio. The state auditor criticized the DWR portfolio for lacking sufficient peak-demand energy. In addition, many of the contracts are nondispatchable or required insufficient commitments and milestones for new construction. And the portfolio includes too many contracts where the power is delivered in southern California but cannot be sent north because of transmission bottlenecks. In the early months after signing the contracts, the agency frequently was forced to sell power at a loss during off-peak periods even while it remained obligated to purchase additional power on peak.

Concerns have also emerged that DWR may have used consultants who had conflicts of interest to negotiate the contracts. However, investigations have so far failed to turn up any evidence to corroborate these charges.

The Center for Energy Efficiency and Renewable Technologies , a nonprofit group advocating greater reliance on alternative energy, became concerned that the DWR contracts would foreclose for years to come the building of additional renewable energy projects in California. It began a broad-based campaign to force renegotiation of these contracts. The CPUC and the legislature agreed.

The CPUC is fighting the contracts before FERC. In February, the CPUC and Electricity Oversight Board filed a "section 206 complaint" at FERC against all the contracts. FERC has since decided to act as a referee for negotiations between DWR and suppliers who signed long-term contracts with the agency. In agreeing to oversee negotiations, FERC noted that neither the CPUC nor the Electricity Oversight Board has met the standard for FERC to vacate the contracts unilaterally. The negotiations began in mid-May; if they are unsuccessful, FERC will permit the adjudication of the California complaint.

California officials announced on April 22, 2002, that they have successfully renegotiated five long-term power purchase agreements entered into by DWR with Calpine, Constellation Energy, and three other developers. The restructured agreements will save the state $3.5 billion from the original $15 billion value of the contracts. As part of the deal, the CPUC voted to drop its complaint asking FERC to declare these particular contracts illegal on grounds that the companies manipulated the electricity market.

The long-term viability of the DWR contracts is based on the $11.1 billion bond issuance, which has been delayed by legal challenges and other issues. DWR is prohibited by law from contracting for electricity after December 31, 2002. DWR may continue to administer pre-existing contracts and sell electricity after that date. The new California Power Authority has volunteered to administer the contracts. Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric have said they do not want to assume the responsibility for administering these contracts.

PG&E Reorganization Plan

PG&E filed for bankruptcy in April 2001. On September 20, 2001, PG&E proposed a plan of reorganization that would enable PG&E to pay all valid creditor claims in full and to emerge from chapter 11 bankruptcy proceedings. The plan reorganizes Pacific Gas and Electric Company and PG&E Corporation into two separate, stand-alone companies that would no longer be affiliated with each other. The reorganized Pacific Gas and Electric Company would continue to own and operate the existing retail electric and gas distribution system, regulated by the CPUC. The electric generation, electric transmission and gas transmission operations will be reorganized as new businesses under PG&E Corporation and be regulated by FERC. The new entities will have the ability to issue debt. That debt, combined with new financing by Pacific Gas and Electric, $3.3 billion in cash on hand, and the restructuring of certain existing debt would be used to pay off PG&E's creditors. The creditors would receive a total of about $13.5 billion from cash and long-term notes.

The CPUC and the state attorney general oppose PG&E's plan. The bankruptcy court judge, Judge Montali, let the CPUC propose an alternative plan. Under the CPUC plan, PG&E would remain subject to all applicable state laws and CPUC regulation. PG&E's shareholders would be required to contribute $3.35 billion to the creditors, including $1.6 billion of the utility's return on equity for the years 2001, 2002 and 2003, plus $1.75 billion from the sale of additional stock. Additional cash would come / continued page 24

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uniform taxation of property in the same class because facilities that sell power to consumers and facilities that sell power at wholesale "are in two different classes."

NEW YORK is considering awarding local taxing districts broader authority to waive property taxes on power plants and to enter instead into so-called PILOT agreements.

"PILOT" stands for "payment in lieu of taxes." The power plant owner would negotiate how much to pay in place of normal property taxes. Bills granting this authority are awaiting committee action in both houses of the New York legislature. Property taxes would be waived not only on the power plant, but also on the site and intertie with the grid. However, the waiver would not extend to transmission lines. Under a PILOT agreement, the taxing district collects annually the amount specified in the agreement rather than the amount annually determined based on the market value of the facility. Advocates of the bills say this will reduce the volatility in property taxes collected from power plants whose values may fluctuate greatly from year to year.

SALE OF A POWER PURCHASE AGREEMENT produced capital gains.

The IRS said in a private ruling released in April that an independent power company that sold its above-market power contract to a third party could treat the sales proceeds as capital gain. Capital gains are taxed at lower rates for individuals, but not for corporations. The power company in question was an "S corporation," meaning that it is not subject to income taxes itself but rather its shareholders are taxed directly on their shares of any income.

The contract was for the sale of power from a "qualifying facility," or QF, under the Public Utility Regulatory Policies Act. It was signed at a time when / continued page 25 *continued from page 22/* Canadian gas delivered to the California-Oregon border) rather than the more appropriate but higher-priced Topock index (for southwestern gas delivered at the California-Arizona border), where the QFs actually buy their gas. This change was driven by the anomalous high gas prices at Topock seen during the winter and spring of 2001.

The switch from the Topock index was painful for QFs in southern California, but the gas price differential between Malin and Topock eventually returned to normal levels so that the QFs ended by being paid more under the new formula than they would have under the old. In the summer of 2001, many QFs, particularly those that use renewable fuels, entered into longer term agreements with the utilities for flat energy payments of 5.37¢ per kWh for five years. This was, and continues to be, substantially above the gas-indexed energy payment price. A few QFs tried to board the 5.37¢ boat after it left the dock, but the California Public Utilities Commission has held firm to its July 2001 cut-off date.

The $1.2 billion plus interest of back debt owed QFs is finally being paid down. As the result of an October 2001 settlement with the CPUC, Southern California Edison paid off all of its back debt in March, including that owed to QFs. QFs have also worked out a payment plan with PG&E for their outstanding receivables. With the back debts being paid off and stable prices guaranteed for five years for many QFs, the future is relatively good for the industry. ◎

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from the sale of $3.9 billion of new debt and the reinstatement of $4.3 billion of long-term debt.

Creditors will be provided the opportunity to vote on these two reorganization plans starting about mid-June. Lively confirmation hearings should follow this ballot. Judge Montali has rejected PG&E's plan for express pre-emption — a ruling that PG&E appealed — and ordered an unsuccessful mediation effort. While PG&E would like to emerge from bankruptcy by January 1, 2003, it is unlikely to do so unless there is a settlement between PG&E and the CPUC.

While PG&E filed for bankruptcy, Southern California Edison struggled along the precipice. PG&E's filing for bankruptcy jolted the governor into negotiating a memorandum of understanding with SCE. Later, PG&E's bankruptcy plan motivated the CPUC to negotiate a settlement with SCE that resolved the financial crisis. The CPUC's agreement with SCE was negotiated as a settlement to pending litigation in federal court between the CPUC and SCE, and it has withstood the initial legal challenge. However, an appeal filed by an advocacy group in the US court of appeals is still pending. Despite these maneuvers, SCE is still rated below investment grade, and Standard & Poor's has indicated that it is awaiting "concrete evidence of supportive ratemaking decisions [by the CPUC] made independently of actions mandated by the [SCE] settlement agreement." Edison has proposed to the CPUC that it be allowed to negotiate additional long-term contracts that would rely on DWR's credit until it returns to investment grade.

Valuable Assets or Fool's Gold?

Just as the gold miners of years past sifted tons of dirt hoping to find nuggets of gold and most often found fool's gold, power developers and financiers must sort through many complex issues in the California power market that potentially hide worthwhile market opportunities. There are some niche opportunities where the balance of financial risks and returns is attractive.

California's dysfunctional power market costs Californians billions of dollars. This crisis quickly became a major public policy challenge, highlighting a dysfunctional regulatory system and forcing the bankruptcy of one of the nation's largest utilities. The billions of dollars in dispute have sparked costly litigation and investigations. As with the original gold rush, the benefactors are often not the miners but service providers. For example, bankruptcy attorneys have had a banner year.

Even though 2002 may be an election year, it is also the year when California must begin to reassure the financial markets that the state can return to political and regulatory stability. California faces a number of financial challenges. It hopes to issue the largest municipal debt sale in US history, organize a plan that resolves PG&E's bankruptcy, and return its major utilities to investment-grade ratings, all while addressing a massive state budget deficit. Moreover, it will need to reestablish a favorable climate for infrastructure investment. If it cannot, then it will have to choose between potential power shortages reemerging in the 2004 to 2005 period or the diversion of limited financing capability from other needs to power plants. While the worst of California's energy crisis is past, the state has a limited period of time to construct a workable energy future.

Argentina Allows Banks to Start Foreclosures

by Damiana Ponferrada and Jacques Wilson-Rae, with Perez Alati, Grondona, Benites, Arnsten & Martinez de Hoz in Buenos Aires

Argentina made further changes in its bankruptcy laws in mid-May. The changes repeal some of the more extreme protective measures — and amend others — that Argentina put in place last February for the protection of distressed debtors. The action follows an outcry from the international lending community to the February reforms. The new statute is Law 25,589.

Cram-down Proceedings

The new law reinstated and amended the "cram-down proceeding," a special process under which a debtor who cannot get approval for its plan of reorganization from creditors is essentially put up for sale under special bidding procedures. Thus, lack of approval of a */ continued page 26*

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electricity rates were higher than they are today. Utilities have looked for ways to get out of such contracts. In this case, the QF sold the contract to a third party, who then renegotiated it with the utility. The contract remained in place, but with reduced rates for electricity.

The QF wanted to pay tax on income from the sale at the 20% rate for long-term capital gains rather than the 39.6% rate for ordinary income. The IRS approved. The key for the IRS was that the contract was sold to a third party rather than back to the utility directly. A sale back to the utility would have been viewed as a cancellation of the contract rather than as a sale. Only a sale of property produces capital gains. The IRS also said it was important that the money to buy the contract came from borrowing from third parties and was not contributed by the utility. The ruling is Private Letter Ruling 200215037.

MINOR MEMOS: A farm bill that President Bush signed into law in mid-May authorizes federal loans at government borrowing rates, loan guarantees and grants to farmers, ranchers and rural small businesses to purchase renewable energy systems. Grants can cover up to 25% of the cost of such systems, and a combined grant and loan or loan guarantee can cover up to 50% of the cost . . . . Ken Kies, a heavyweight lobbyist and former staff director of the Joint Tax Committee in Congress, is urging the US Treasury to fix a problem that prevents many US multinational companies — including most power companies — from using foreign tax credits. Treasury officials are skeptical about whether they have the authority. Kies wants them to adopt administratively a proposal that passed Congress in 1999 for "worldwide fungibility" of interest. The proposal was part of a tax bill that President Clinton vetoed.

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

Argentina

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reorganization proposal will not be automatically followed by the debtor's bankruptcy.

The new law not only entitles the debtor's creditors and third parties to acquire the company by purchasing its common stock through a special bidding process, but also allows the debtor to reformulate reorganization proposals.

Another important amendment to the cram-down proceeding is the procedure for the appraisal of the company's value. The original bankruptcy law — before it was rewritten last February — provided that a court would determine the value of the company based on, but not necessarily equal to, its book value. The new law provides for the appointment of an appraiser who must submit a valuation to the court. The court then uses this valuation to determine the "market value" of the company.

If the appraisal is that the company has a negative value, then acquisition of the company by a creditor or third party does not require any payment to the shareholders.

If the appraisal is that the company has a positive value, then acquisition of the company by a creditor or third party requires payment of at least the "minimum price." That is the market value of the company, as determined by the court, but reduced by the same "haircut" that the creditors had to take on their debts. Thus, for example, if the present value of the debt release by creditors was 60%, then the "minimum price" for the company is 40% of its market value. Any bid below the minimum price requires the consent of two thirds of the equity capital of the company.

Exclusivity Period

The new law gives insolvent debtors an "exclusivity period" of 120 days to submit a reorganization plan. This is a reduction in the 180 days allowed last February. Argentine law used to allow only 60 days.

The new law also puts an end to the extension of the exclusivity period for existing Chapter 11-type reorganization proceedings.

Suspension of Foreclosures

All foreclosure proceedings against Argentine debtors had been suspended for 180 days from last February 14.

Under the new law, only auctions pursuant to foreclosure proceedings are suspended; foreclosure proceedings themselves can get underway. Therefore, foreclosure proceedings will continue until the auction is ordered by a court resolution. The new law also limits the suspension to those foreclosures that involve the home of the debtor or that involve goods and facilities that are put to commercial or productive use.

The new law also limits the scope of injunctions and attachments that had been suspended for 180 days from last February 14. Under the new law, enforcement of such injunctions and attachments is suspended only for actions to seize goods and facilities that are used by the debtor in commercial or productive activities.

The new law clarifies that the 180 days must be counted on the basis of calendar days and not business days.

Bankruptcy Proceedings

The new law puts an end to the suspension of bankruptcy proceedings and creditors are now again entitled to petition for the bankruptcy of debtors without restrictions.

Court Discretion

The bankruptcy law originally provided that if, at the end of the exclusivity period, the debtor has obtained the required majorities and no objections are made or any objections are disregarded by the court, then the court must approve the reorganization plan.

The new law gives the court discretion to impose a reorganization plan even if all classes of creditors have not agreed to it. However, in order to do this, three things would have to be true. First, the plan must have been approved by at least one class of unsecured creditors and by at least the holders of three quarters of the aggregate unsecured claims. Second, the plan must be fair and must not unreasonably discriminate against any nonconsenting class of creditors. Third, the payments to be made under the restructuring plan to creditors who did not accept it must be no lower than the ones that would be made to them if the company proceeded into bankruptcy.

Use of a Trustee

Under the new law, a trustee can now submit a proof of claim on behalf of a large group of noteholders or bondholders and be admitted by the court as a creditor with the right to speak for the entire group.

Under this procedure, each creditor in the group would vote for or against the reorganization plan and the group would be recorded as consisting of two blocks of votes — one percentage of votes for the plan and the other against — for computing the majorities in respect of admitted claims. However, for computing the majorities in respect of number of creditors, all noteholders and bondholders in the group who vote in favor of the plan will be treated as one creditor, and all who vote against will be treated as one creditor.

The new law also waives the need for the noteholders and bondholders actually to meet to cast their votes if the trustee and the creditors whom it speaks can agree on an alternative.

Prepackaged Bankruptcies

The new law introduces a concept similar to "prepackaged bankruptcies" under the US bankruptcy code. This is a procedure where the debtor and creditors can execute a restructuring agreement out of court and submit it to a court for its authorization. If the agreement is approved by a majority of unsecured creditors who also represent two thirds in principal amount of all unsecured claims, then the agreement can be officially approved and would be binding on all unsecured creditors.

Enforceability

Although the new law is enforceable as from its publication in the official gazette; any extensions already granted by courts under the February bankruptcy statute in pending reorganization proceedings would not be subject to revision. ◎

Sales of Gas Transportation Capacity

by David Schumacher, in Washington

A US court of appeals said in April that the Federal Energy Regulatory Commission can continue with an experiment to allow companies that hold rights to transport gas on interstate pipelines to sell, or "release," their rights at market prices to other companies that need the capacity.

Releases of capacity at market prices are allowed currently only in short-term increments of less than a year. The experiment had come under fire from a mix of pipelines, gas producers, consumers and state regulatory commissions, some of whom believe the FERC experiment goes too far and others of whom believe it does not go far enough.

The court ruling opens the door for FERC to allow such sales to become a permanent part of its capacity release program.

It could provide interesting opportunities for power projects to monetize their firm gas transportation rights.

Capacity Sales

FERC issued new regulations in 2000 as part of Order No. 637 that were supposed to enhance competition in the interstate gas transportation markets. The most significant rule change allows holders of firm transportation capacity to release firm capacity to a third party for a term of less than one year at any rate that the market will bear, even if the rate charged exceeds the maximum rate the pipeline can charge under cost-based rate regulation. Because the rule constitutes such a significant departure from FERC's usual cost-of-service ratemaking, FERC drafted the rule to expire on September 30, 2002. FERC said it would review the results of the experiment and decide whether or not to extend it.

The experiment with short-term capacity releases has been in effect, notwithstanding the litigation. Implementation of the program was not blocked while the courts heard the case.

In upholding the experiment, the appeals court said that the use of market rates in the short-term capacity release market is consistent with FERC's mandate under the "Natural Gas Act" to ensure just and reasonable rates. The court reasoned that competitive alternatives to released capacity would act to constrain rates such that, on an annual basis, rates for released capacity would roughly approximate cost-based rates. Even price spikes during peak periods are, in the court's view, the result of competitive forces and not monopoly power.

The court made these findings even though FERC did not undertake an extensive analysis of market forces in various product and geographic markets, as FERC has been required to do in other instances when it has */ continued page 28*

Gas Transportation

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approved the use of market-based rates for utility services (including the wholesale sale of energy).

The court also noted that FERC has in place certain procedural safeguards to protect consumers from the unlawful exercise of monopoly power. Specifically, FERC can monitor the prices in the capacity release market to ensure the market is working efficiently and can consider complaints brought by market participants.

The court rejected calls by certain pipelines that FERC should have extended the use of market prices to interruptible transportation service sold directly by the pipelines. The court said it was not unreasonable for FERC to take a gradualist approach to market prices for transportation service. The court also noted that the pipelines do have the option to seek market price authority from FERC by demonstrating that competition will preclude their unlawful use of market power.

The court's ruling opens the door for FERC either to extend its market-based rate experiment or to make it permanent. Because this experiment will end on September 30, 2002, FERC may make a decision as soon as this summer on whether to continue it.

If FERC does allow the continued use of market-based rates in the short-term capacity release market, power projects that hold firm pipeline transportation contract may be able to make better economic use of their firm transportation rights. For example, a project company that operates a "peaker" may be able to release short-term capacity during periods of peak gas usage at rates above what it is paying the pipeline, particularly when peak gas usage does not correspond to peak energy usage or when the project can economically rely on oil to operate.

A court ruling in April could provide opportunities for power projects to monetize their firm gas transportation rights.

Other Issues

The court also upheld two other important aspects of the FERC rule.

It agreed that FERC can require pipelines to revise their "imbalance penalty" mechanisms to provide shippers with more imbalance mitigation services and ensure that penalties more accurately reflect the harm imposed on the pipeline. Imbalance penalties are fees designed to deter pipeline users from taking out more or less gas than they put into the system. Additionally, with one technical exception, the court generally upheld FERC's requirement that holders of firm capacity must be permitted to subdivide, or "segment," their capacity to allow multiple uses of the capacity, so long as the pipeline can provide such segmentation rights in an operationally feasible manner.

However, the court sent back to FERC for further work a rule that would give holders of firm transportation capacity who pay the maximum cost-based rate for the service certain "rights of first refusal" to maintain their rights to this capacity at the end of their contracts by matching the rate and term of any third-party bid for the capacity. The existing holder of the capacity could maintain its rights by bidding on service for as few as five years, regardless of the term bid by any third party. The court said the five-year period was arbitrarily selected. Responding to the court's decision, FERC said in a mid-May order that current pipeline tariffs would govern the term that existing shippers must bid when exercising their rights of first refusal until FERC can consider the issue further.

As a result of the court's ruling on this issue, if a project company is holding a firm transportation contract and wants to keep its contract at the end of the term, the project company may be required to match the bid of a third party seeking the capacity for a term that far exceeds the term of service for which the project company was hoping to contract. ◎

Environmental Update

Haze in National Parks

A US appeals court struck down a key section of a US Environmental Protection Agency rule aimed at reducing haze in national parks in late May. The section in question would have allowed states to impose pollution control requirements on power plants or other industrial facilities as a class instead of analyzing how much pollution each individual facility contributes.

The decision, in a case called *American Corn Growers Association v. EPA*, could spare owners of some older power plants from having to spend millions of dollars on pollution control.

The EPA rule is the "regional haze rule." It applies to facilities that contribute potentially to air pollution in "Class I areas," which include national parks and federal wilderness areas. Power plants covered by the rule might be many miles away from a park, but be close enough so that their emissions affect how clear the air is at the park.

The case was brought by several industry groups, including one representing electric utilities.

The regional haze rule, written in July 1999, requires states to review all major air emission sources built between 1962 and 1977 that emit over 250 tons a year of any of five visibility-impairing pollutants and that are located up-wind from Class I areas. The five pollutants are nitrogen oxide, or NO_X, sulfur dioxide, or SO_2, particulate matter, volatile organic compounds and ammonia. The rule provides that sources that are reasonably anticipated to cause or contribute to Class I visibility impairment must install best available retrofit technology, or "BART."

Last year, EPA issued proposed BART guidelines that appear to establish flue-gas desulfurization or scrubbers as the presumptive BART standard for utility boilers. Installing a scrubber on a large electric generating unit could cost from $50 million to $100 million. As proposed, the BART guidelines would set a presumptive SO_2 control level requiring emissions reductions of 90 to 95% compared to uncontrolled operations, which is significantly more stringent than the existing federal acid rain program requirements. The BART guidelines were expected to be finalized later this year; however, the court's decision could force EPA to re-propose certain portions of the guidelines. As a result, adoption of a final set of BART guidelines may be delayed.

Under the regional haze rule, states were required to identify BART-eligible sources based on a showing that a whole group of sources together emitted visibility-impairing pollutants within geographic areas that could affect a downwind Class I area. The court struck down EPA's "collective contribution" approach as being inconsistent with the plain language of the "Clean Air Act." The court said the regional haze rule impermissibly ties "states' hands and forces them to require BART controls at sources without any empirical evidence of the particular source's contribution to visibility impairment in a Class I area."

Although the court upheld other provisions of the rule, its rejection of the "group source" determination is a significant victory for the utility industry. EPA must now come up with a new way for states to identify BART-eligible sources. The court suggested it would accept a new version of the regional haze rule if it contains a mechanism to allow states to exempt BART-eligible sources on the basis of a particular source's emission contribution. It will be difficult in practice to demonstrate that an individual source affects visibility at a downwind Class I area, except for situations involving very large air emission sources. State rules implementing the regional haze rule program are due to be submitted to EPA in 2005. It is unclear whether this deadline will now slip in light of the appeals court decision. The EPA will have to put in place a new mechanism for identifying BART-eligible sources before the states can take any significant actions to implement the remaining requirements of the regional haze rule.

EPA has not indicated whether it will seek a rehearing by the appeals court go directly to the US Supreme Court.

Kyoto Protocol

Japan is expected to approve the Kyoto protocol in early June 2002, marking a significant step toward implementing the treaty. The Kyoto protocol will enter into effect after it is ratified by 55 or / continued page 30

more countries that represent at least 55% of total greenhouse gas emissions from all industrialized countries during 1990.

As of late May, more than 55 nations had ratified the Kyoto protocol, including all 15 European Union or EU member countries. Even though the number of countries that have ratified the treaty now exceeds 55, those 55+ countries do not yet fulfill the 55% requirement. The EU countries had hoped that the Kyoto protocol would be in effect by the upcoming world summit on development scheduled to start in late August in Johannesburg.

The Bush administration has already rejected the Kyoto protocol, and there is some doubt whether Canada and Australia will ratify the treaty. Assuming Japan's ratification, attention now turns to Russia as it becomes the key country that must adopt the treaty in order for it to enter into force.

Canada is conditioning its acceptance of the treaty on the acceptance of its request for a "clean energy export credit." Canada wants to receive credit for its "clean energy" exports of natural gas and hydroelectric power to the US. These credits would amount to almost one third of Canada's Kyoto protocol reduction targets. The EU countries are strongly opposed to the Canadian proposal.

Russia is expected to delay its consideration of the treaty until early 2003. It is negotiating with EU countries and Japan for reductions in foreign debt as a precondition to ratification of the Kyoto protocol. Russia is expected to benefit from the Kyoto protocol because it will be a net supplier of greenhouse gas emission reductions to EU countries; many Russian industrial plants have shut down since 1990, the year on which target levels are based. Russia will also benefit from the development of new foreign-financed projects using newer technologies, which may result in collateral greenhouse gas reductions.

Owners of older power plants near national parks may be spared from having to spend millions of dollars on new pollution control.

Greenhouse Gas Database

The national energy plan that passed the Senate on April 25 includes a requirement to establish a database of greenhouse gas emission reductions. The "National Greenhouse Gas Database" will be a comprehensive inventory of greenhouse gas emissions on a company-by-company basis, and it will give the government a means to track greenhouse gas emission reductions by each company.

Reporting greenhouse gas emissions for the database would be voluntary unless the database program fails to capture at least 60% of total US greenhouse gas emissions. Reporting would become mandatory if the 60% threshold is not achieved. If the program becomes mandatory, non-exempt companies failing to report could be subject to penalties of up to $25,000 a day.

Under the Senate bill, EPA would have the lead role in writing standards for measuring greenhouse gas emissions and verifying emission reductions. The Departments of Energy, Commerce, and Agriculture would also contribute.

The version of the national energy plan that the House passed last July does not provide for a greenhouse gas database, so the issue will have to be addressed by a joint House-Senate conference committee. In the meantime, the Department of Energy is revamping its existing voluntary registry of greenhouse gas reductions to ensure greater accuracy in the measurement and verification of such reductions.

Multi-Pollutant Legislation

The Senate Environment and Public Works Committee decided not to "mark up" a bill that calls for substantial reductions in emissions of NO_X, SO_2, mercury, and carbon dioxide, or CO_2, from power plants on May 23 as originally planned. The markup is now expected on June 20.

The bill imposes tighter implementation timeframes and more drastic emission reduction targets than the Bush administration's "clear skies initiative" that was unveiled in February.

Approval of the bill in committee appears doubtful because of an impasse over whether to include mandatory CO_2 emission reductions. Several Republicans on the committee are also strongly opposed to the timeframes for implementing the reductions and the stringency of the reductions. The bill would require 75% reductions in NO_x and SO_2 from 1997 and 2000 baselines, a 90% cut in mercury levels from 1999 levels, and a reduction to 1990 CO_2 levels. The reductions would have to be achieved by January 1, 2007.

The Bush administration is actively pushing its clear skies initiative, which calls for a two-phase approach to reducing air emissions from power plants. There would be a first phase of emissions reductions beginning in 2010, followed by an additional round of reductions starting in 2018. The cornerstone of the Bush plan is a new, nationwide "cap and trade," market-based approach that is patterned after the existing acid rain SO_2 emissions trading program.

The clear skies initiative has not yet been introduced in Congress, but Senator Bob Smith (R.-New Hampshire) is working on a draft bill. While for the idea of a multi-pollutant approach to address emissions from power plants enjoys broad support, there is a wide divergence of opinion on the best approach to achieve such reductions. Multi-pollutant legislation will remain a significant issue for the Congressional committees with jurisdiction over environmental matters, but meaningful progress this year is unlikely.

States Enact Multi-Pollutant Measures

Several northeastern states are taking steps to regulate multi-pollutant emissions from power plants. Connecticut and New Hampshire recently adopted new laws requiring reduced emissions from older power plants. In February, New York proposed new regulations designed to reduce NO_x and SO_2 emissions significantly from power plants in the state. Last year, Massachusetts adopted new regulations requiring NO_x, SO_2, and CO_2 emission reductions from the six oldest power plants in the state.

In early May, Connecticut Governor John Rowland signed a bill into law that will require the six oldest fossil fuel-fired power plants to meet lower SO_2 emission standards by January 1, 2005 without using emission trading credits. The six plants must meet an actual emission limit of 0.33 lbs/mmBtu starting January 1, 2005. In order to meet the stringent emission limit, the six plants will need to use lower sulfur coal or oil, switch to natural gas, or install costly pollution control equipment like flu gas desulfurization systems or scrubbers.

New Hampshire Governor Jeanne Shaheen signed the "Clean Power Act" into law on May 9. It requires the state's largest utility — the Public Service Company of New Hampshire — to reduce NO_x, SO_2, mercury, and CO_2 emissions from three of its plants built prior to 1977. Under the new law, NO_x and SO_2 emissions must be reduced by 70% and 75%, respectively, from current levels by the end of 2006. Mercury emissions will be capped at levels that will be driven by the results of a state study, and CO_2 must be reduced to 1990 levels by 2010. The Clean Power Act allows the Public Service Company to use allowances from in-state or upwind states in the region to comply with the new requirements.

State governments are acting on their own — without waiting for the US government — to require reductions in power plant emissions.

North Carolina Governor Mike Easley also recently unveiled a proposal to reduce NO_x and SO_2 by more than 70% from the state's 14 coal-fired / continued page 32

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utilities. Legislation similar to Governor Easley's proposal had passed the state Senate in April 2001; however, the measure died in the state House of Representatives.

Efforts by the northeastern states to achieve significant multi-pollutant emission reductions are proceeding at a much quicker pace than a proposed coordinated federal approach. The states' efforts are generally focused on the older power plants that were originally "grandfathered" out of the permitting requirements of the federal "new source review" program implemented in 1977. With federal multi-pollutant legislative efforts now stalled, additional states may follow the lead of Connecticut, Massachusetts, New Hampshire and New York in adopting comprehensive multi-pollutant measures.

Brief Updates

A US appeals court heard oral arguments in May 21 in the case *Tennessee Valley Authority v. EPA*, where the central issue is EPA's interpretation of what activities qualify as "routine maintenance" under the new source review permitting program. The TVA is challenging the federal government's assertion that it made significant modifications to its plants without the requisite new source permits. The decision in the case is expected to influence the outcome of other pending new source review cases filed by the federal government against several major utilities.

The Earth Justice Legal Defense Fund filed a challenge to EPA's final air toxics rule on April 25. The rule extends the deadline to May 15, 2004 for companies to file detailed applications to comply with case-by-case maximum achievable control technology, or "MACT," emission limits. The so-called "MACT hammer rule" was designed to give EPA more time to issue MACT standards for the remaining categories of major air toxic sources, including combustion turbines and industrial boilers. EPA and the Earth Justice Legal Defense Fund are currently in settlement discussions. They may agree on a shorter timetable for complying with the MACT hammer requirements.

EPA recently released guidelines on the types of air pollution that are exempted from reporting under the federal "Superfund" law. The Superfund law requires the reporting of releases of hazardous substances above certain threshold levels. EPA's guidance document classifies the type of releases that qualify as exempted "federally permitted releases." Under the guidance document, air emissions that are authorized under an air permit with federally enforceable requirements or any other federally-enforceable emission limit, operational requirement or work practice standard in a federal rule or an EPA-approved state rule would qualify as a "federally permitted release." Certain older power plants that are grandfathered from some federal emission reduction requirements may be subject to Superfund reporting if they emit certain hazardous air pollutants above a reportable threshold. ◎

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