CHADBOURNE
& PARKE LLP

PROJECT FINANCE
NewsWire

June 2004

The Next Frontier: Subsovereign Projects

by Kenneth Hansen, in Washington

Municipal project finance is presenting itself as a new frontier in emerging market project development.

Until the past decade or so, debt investment in emerging markets went largely to national governments. The 1990s saw a reallocation of debt investment toward private project financings and public-private partnerships of various forms as the challenge of developing and operating public infrastructure — power, roads, water, ports, airports and telecommunications — was moved in country after country from the relevant government ministry to the private sector.

With the Asian economic crisis, Argentine collapse and Enron bankruptcy, the decline in private capital available for emerging market infrastructure development was dramatic. For instance, with respect to the power sector, Jamil Sagkin, the director of the World Bank's energy department, notes:

> Private participation and investment has not paid off recently, and can no longer be relied on to fulfill expectations . . . . In the tax year between June 30, 2001 and July 1, 2002, private investment in energy projects throughout the developing world fell almost 50%,

/ continued page 2

IN OTHER NEWS

TAX-EXEMPT FINANCING will be harder to arrange for power plants under new regulations the Internal Revenue Service proposed in May.

Access to the tax-exempt bond markets in the United States is supposed to be restricted to financing for schools, roads, hospitals and other public facilities. However, the US tax laws make an exception for 13 types of "exempt facilities." One exception covers "solid waste disposal facilities." These produce public benefits even if they are privately owned.

Power companies have used this exception to issue tax-exempt debt in two situations. One is for power plants that

/ continued page 3

IN THIS ISSUE

Subsovereign Projects

continued from page 1

compared to a high of US$46 billion that was spent 1996-1997. And private investment in energy sector projects is showing further signs of decreasing.

The collapse in energy investment was paralleled to a greater or lesser extent in other sectors.

The retrenchment of private capital had reinforcing motivations from both the supply and demand sides. On the demand side, host governments had found the panacea of private capital to be less than advertised. The off-balance sheet image was clouded by comfort letters and government support undertakings that gave rise to claims, arbitrations and attempted recoveries from political risk insurers.

On the supply side, a number of developers, particularly in the power and telecom sectors, responded to weak economic environments, especially in the US and Europe, by "hunkering down," focusing on core activities and withdrawing from the business of developing public infrastructure in emerging markets.

This is a particular disappointment for those countries that continue to see private development of public infrastructure as the right way forward. But it is clear that public-private partnerships as they evolved in the 1990s are widely being rethought — by foreign investors as much as by their hosts.

However, it is also clear that infrastructure development and operation by national ministries is not likely to return as the dominant model in many countries. The convenience of private capital and the value of private sector development and operating expertise are too great, and the related efficiencies are too well demonstrated, for things to go full circle. But pure privatization has not worked out well in all contexts. The search is on for new models that help address both public needs and the risk management concerns of project sponsors and lenders. What that search is likely to find is a variety of public-private partnerships in which the relative advantages of each sector are tapped to enhance the prospects for success of particular projects

The search is on for new models for financing infrastructure projects in emerging markets.

New Paradigm

Part of that next phase of project structuring is beginning to percolate at the municipal level. In the United States, where municipal financings are supported by local taxes and user fees as well as by, in qualifying cases, a federal tax exemption on interest income, municipal bond finance has become a huge industry.

Similar financings in emerging markets have been relatively unusual. The principal clients of the dominant public lenders to emerging markets have been sovereigns — *i.e.*, national governments. The World Bank by its charter is only permitted to lend to national governments or under a sovereign guaranty. The regional multilateral development banks — with the possible exception of the newest member of the tribe, the European Bank for Reconstruction and Development — have also historically been primarily sovereign lenders, although they all now have important and growing private sector programs. Likewise, the export credit agencies were, until recently, dominantly sovereign lenders and, in the past 10 to 15 years, have expanded their focus to privately-developed infrastructure projects. Missing from all these, however, was a public sector window dedicated to municipal or other subsovereign lending.

A theme to emerge from the past decade of experiments in the private development of public infrastructure has been that full privatization is not necessarily the efficient answer. Some projects may belong in the public sector for some purposes — such as ownership — but provide an efficient private sector role — such as operator. Municipal water projects are a good example. So are toll roads.

The challenge for emerging market subsovereigns is how to persuade financiers to rely on their projects, their balance sheets and their tax bases as an adequate source of repayment. Subsovereigns are not just "little sovereigns." Depending on the nature of the entity, they may pose (unlike their national counterparts) the risk of bankruptcy or otherwise ceasing to exist. Their revenue flows may be subject to interruption by higher legislative authorities. Sovereign undertakings may, at least to some extent, be reinforced by international legal principles or treaties that may not apply to subsovereign entities.

While challenges in subsovereign or municipal lending are substantial, the opportunities posed are clear. Both host governments and agency lenders are recognizing that projects, like politics, are local. The benefits of a power project or a water project may well flow nationwide, but the immediate need is most likely to be felt most intensely locally. Increasingly, local governments have sought the necessary legal authority to develop such projects on their own. Once the legal authority is provided, the challenge is to convince the main players in the emerging market project finance market to take such projects — and the creditworthiness of their municipal partners — seriously.

In some cases, law has been a bigger issue than credit. While the US Export-Import Bank approved a project loan in favor of the city of Moscow, Russian municipal entities (other than Moscow and St. Petersburg) appear prohibited by Russian law from fresh borrowings of foreign currency. In many countries, municipal budgets are allocated by the central government, with local authorities lacking the power to tax or even to retain project-based revenues.

Progress

Still, great strides are being taken. For instance, the International Finance Corporation and the World Bank have jointly established a "Municipal Fund," a window of IFC lending specifically targeted to private investor partnerships with municipal entities. While the IFC has invested in a variety of municipal projects over the years, its traditional focus has been projects with majority */ continued page 4*

IN OTHER NEWS

burn waste fuels; taxpayers argue the plants dispose of waste by turning it into electricity. The other is for pollution control equipment that traps ash and other solid particles at the back end of power plants that burn regular coal and other solid fuels. Such equipment can account for as much as 25% of the total cost of a power project.

New regulations the IRS issued in May would rule out tax-exempt financing in at least one of these situations. The rules are merely proposed. They will not take effect until 60 days after final rules are published in the *Federal Register.*

Tax-exempt financing is only available for equipment that disposes of "solid waste." In the past, "solid waste" was defined as solid material with no value at the place where it is located. The IRS proposes to drop value as a factor in whether material is waste. In the future, one must show the material has been discarded. Fossil fuels used at power plants would never qualify.

The IRS said ash caught at the back end can only qualify if it is transformed into something else usable. The IRS has reserved on what "transformation processes" it is willing to accept; it is looking for suggestions from industry by August 4. It said an example of what it has in mind is shredding waste tires to harvest material that can be used for road paving.

The agency said it may publish a list of the specific "transformation processes" it will accept after reviewing whatever comments it receives.

SYNFUEL hearings have been postponed — and possibly shelved — by Congress.

The staff of the Senate permanent subcommittee on investigations has been looking into the use of section 29 tax credits by owners of roughly 53 "coal agglomeration plants" that add chemical reagents to crushed coal to turn the coal into synthetic fuel. Critics charge that the plants do little to transform */ continued page 5*

Subsovereign Projects

continued from page 3

private sector sponsorship. The World Bank, in contrast, has lent billions of dollars to municipalities, but always, per its charter, under sovereign guarantees. The World Bank and IFC thus identified that "a gap exists for investment in well run subsovereign operations without sovereign guarantees."

The Municipal Fund is designed to fill this gap by supporting emerging market subsovereign projects with debt and equity investment. According to the joint World Bank and IFC announcement, "The objective is to finance critical investments, promote commercialization and corporatization of services and help subsovereign development partners gain access to financial markets." The World Bank and IFC describe typical projects to include a partial credit guarantee for a bond issue by a municipal water company to finance the construction of a water treatment plant, a loan against local rates on an electricity distribution company to finance a portion of its medium-term capital expenditure program, and investments in municipal sanitation facilities to be managed by a private concessionaire.

Also, the United States Trade and Development Agency has recognized the challenges — and opportunities — in municipal project finance by providing technical assistance grants to explore municipal debt as a mechanism for financing water projects in China and India.

The Inter-American Development Bank has also supported municipal projects, including private concessions of water projects supported under its private sector lending program. However, it remains a cutting edge for the IDB, Dennis Flannery, the bank's executive vice president (and a past head of project finance at First Boston Corporation) asserted in a speech at the recent annual conference of the US Export-Import Bank. While the IDB does not yet have any particular program for municipal or other subsovereign lending, Flannery said that figuring out structures for supporting municipal projects — especially municipal public-private partnerships — is an important mission at the bank.

One viable model may be subsovereign lending. The benefits from many projects are felt more intensely locally than by the national government.

Flannery also noted when interviewed that project finance has more than just physical infrastructure to offer Latin American municipalities. Such entities too often lack responsible fiscal policy and discipline. A well-structured project financing, with rigorously designed terms and careful implementation, offers municipalities a valuable model of responsible project management whose positive demonstration effects could extend beyond the particular infrastructure project.

Likewise at the US Export-Import Bank, municipal finance is considered to be the cutting edge. The preferred approach of the US Export-Import Bank to subsovereign landing has been, if a sovereign guarantee is not available, then to make a loan to a creditworthy local bank to be onlent to the subsovereign borrower. However, in the case of its loan to Moscow, the bank made the loan directly to the city, though with its credit supported by a guarantee from a Russian bank. Ironically, if this transaction had been structured according to the traditional onlending approach, then the loan would have gone into default during the 1998 Russian financial crisis when local banks were prohibited from making payments on such loans. As it was, the direct loan to Moscow remained current notwithstanding the difficulties that befell its bank guarantor.

Notwithstanding the credit, legal and structuring challenges, the importance of municipal infrastructure, and the apparent increasing likelihood that in many countries, municipal authorities will step up to the responsibility of pursuing such projects, suggest that the opportunities for the export credit agencies and the development lenders will fill some of the void left by the retrenchment in national build-own-operate and related concessions.

If the public lenders step up to the plate, and if successful municipal project financings follow, presumably the commercial lenders will also be quick to see, and seize, the opportunity. ◎

The Route to a Financeable Toll Road

by Douglas M. Fried and Jonathan Finklestone, in New York

Toll road development on a public-private partnership basis is expected to increase in various regions of the world in the months and years ahead. This article discusses issues that toll road developers should address in order to have a financeable project.

Opportunities

Many countries in Europe, Latin America, Asia, the Middle East and Africa are exploring road development through the use of public-private partnerships. Just before the European Union expanded from 15 to 25 member states on May 1, the European Commission published a "green paper" discussing the compatibility of European Union law and public-private partnerships. The green paper observed that over the last decade, countries have resorted with increasing frequency to public-private partnerships, which, in "view of the budget constraints confronting Member States . . . meets a need for private funding for the public sector." The green paper noted that trans-European transport networks that have fallen behind schedule for lack of funding could benefit from recourse to public-private partnerships.

According to *Infra-News*, the Irish public-private partnership road sector "looks set to gather pace again in 2004 with several DBFO (design, build, finance and operate) pre-approved projects being prepared for tender and a few others expected to reach */ continued page 6*

IN OTHER NEWS

the coal. The US government offers tax credits of $1.1036 an mmBtu as an inducement to turn coal into synthetic fuel. The subsidies on the 53 plants run to more than $2 billion a year.

The subcommittee was expected to hold public hearings in June. Those hearings have now been postponed until the fall at the earliest. It is possible there will not be any hearings. The staff is also no longer sure that it will write a report.

Meanwhile, the tax credits will disappear by law if oil prices return to levels reached during the Arab oil embargo in the 1970's. Futures contracts for US light crude were trading at close to $41 a barrel as the *NewsWire* went to press in late May. However, oil prices would have to reach at least $50.14 a barrel before the credits would start to phase out. The phaseout would be complete if prices reach $62.94 a barrel. These are 2003 prices. The phaseout range for 2004 will be slightly higher. The key is the average domestic wellhead price for the entire year.

In another development, the Senate voted in May to allow tax credits to be claimed on *new* synfuel plants that are built in the future. The existing tax credit runs through 2007, but it can only be claimed on output from synfuel plants that went into service by June 1998. Under the Senate provision, new synfuel plants built during 2005 and 2006 would qualify for tax credits of 51.7¢ an mmBtu. Credits could be claimed on five years of output. The Senate tightened the definition of what will qualify as synfuel for plants built in the future. Output would only qualify as synfuel if it has a fair market value at least 50% higher than the raw coal used as feedstock and there is less pollution from burning it. Nitrogen oxide and either sulfur dioxide or mercury emissions would have to be reduced by at least 20%. The amount of credits that could be claimed on each "project" would be limited to $37,751 a year.

The Senate provision is part of an export tax bill that must also pass */ continued page 7*

Toll Roads

continued from page 5

financial close in the next few months." *Infra-News* noted that "the government reaffirmed its support for the role of PPPs in upgrading the Irish road network and did not rule out the possibility of procuring more privately financed roads projects which are not a part of the current national roads improvement program."

A recent article in *Project Finance International* noted that "the central government of Mexico laid out a new plan last year to attract nearly US$2bn in investment to an ambitious toll road construction program modeled on the European private-public partnership (PPP) scheme." According to the article, the Mexican government is planning to issue tenders for nine new toll road developments in the first instance and, overall, "the government has identified 30 individual projects that are appropriate for the concession regime."

The Brazilian Senate, according to the *Economist* magazine, is considering a public-private partnerships law to allow for the development of roads. The *Economist* explained that "Brazil has 1.5 million km of road, but just 11% of that is paved" and to keep the economy growing at a healthy pace, "Brazil needs to invest 15 billion *reais* ($5.1 billion) a year in transport."

The *Moscow Times* recently reported that the deputy prime minister, Vladimir Yakovlev, announced that the Russian government plans to enact a federal law on toll roads in 2004. He is reported to have told the European Investment Bank that Russia needs to build approximately 1.5 million kilometers of new roads in order to normalize the situation on Russian roads. He stressed that roads transport development requires huge financing and that the development of toll roads could be the solution.

The Treasury Department in South Africa recently announced that standardized PPP provisions, which govern public-private partnerships for toll roads and other projects, have been finalized. An article in the *Sunday Times* newspaper noted that the new "provisions aim to optimize private-sector investment in modernizing public services and infrastructure through a common approach to risk transfer, risk-sharing and reducing the time and cost of negotiating deals." The newspaper noted that one of the active steps the government has taken to address the infrastructure backlog is "strongly backing the development of public private partnerships."

Finally, the *Polish News Bulletin* reported recently that the transport industry in Poland faces an "historical opportunity, as entry barriers to the huge and lucrative EU market are about to be removed."

> The concession agreement is the central document in a toll road project. Its terms determine whether the project can be financed.

Financeable Project?

Recognizing that there may be an increase in development of toll road projects on the public-private partnership model is an important first step, but once the markets are identified, then the relevant question for the toll road developer is, " What key factors determine whether a particular project will be financeable?"

Strong government support at the national, regional and local levels is essential. Toll roads can become a "hot potato" in political campaigns with opposition parties vowing to cancel a project if elected. Lenders will be concerned about the risk that a project will be cancelled if there is a change in government. Since the development of a project can take many years and demand significant resources in order to achieve financial close, broad cross-party support is important. A developer might also consider asking the government to reimburse certain development costs in the event the project is cancelled.

One of the principal features of a public-private partnership is that the private sector enters into an area that was previously the exclusive domain of the public sector. The government might have to enact special legislation to support the toll road development. Legislation may be needed authorizing the private sector to charge, collect and enforce the payment of tolls or authorizing the government to enter into the necessary contractual arrangements with the private sector to provide financial support, tax incentives or other benefits to the project. If government support is required, potential lenders will make an evaluation of the ability of the government to provide such support and to pass the necessary legislative programs. A toll road needs a solid legal foundation. Problems have arisen. For example, in Hungary, soon after a new toll road opened, litigation ensued over the level of tolls that could be charged. The project ended up with a cap. The cap impaired the ability of the developer to repay its lenders.

One of the greatest risks in any toll road project is how sound the forecasts are of road use. A developer might try to mitigate this risk by arranging for government support or guarantees of minimum traffic levels or revenue. As a *quid pro quo*, the government might ask to share in upside revenues if use of the toll road or revenues are above those originally forecast.

An important factor that will affect traffic volume is whether the public enjoys easy access by use of connecting roads and interchanges. Another factor is what alternative routes are available to drivers who do not want to pay the tolls. The lenders will want to know what plans the highway department and other private developers have to build other roads that might siphon off traffic. If the road is a "greenfield" development project with little or no supporting transportation infrastructure, then a developer might need an undertaking from the government to build a network of connecting roads and interchanges within a certain time frame. Connecting roads have the potential to funnel traffic onto the new toll road from existing roads. The location of interchanges could determine whether a highway will serve local traffic as well as intercity traffic. For example, interchanges just a few miles apart will encourage more local use of a highway, whereas interchanges that are many miles apart could discourage local traffic. A pristine highway will be of little */ continued page 8*

IN OTHER NEWS

the House before it can become law. House Republicans have been unable to reach agreement on what to put in the bill. The measure is not expected to reach the House floor before July at the earliest.

A bill introduced by Congressman Lloyd Doggett (D-Texas) is creating a lot of buzz outside Washington. Doggett introduced a bill in May to deny section 29 credits for existing synfuel plants on their future output. The bill is not expected to pass.

POWER PLANTS in the United States are not "US real property," the IRS has decided.

Foreigners are sometimes reluctant to buy shares in American corporations for fear that they will have to pay US taxes on their capital gains when they resell the shares. The United States does not ordinarily collect taxes from foreigners on their capital gains. However, in the early 1980's, Congress changed the law to require that taxes must be paid on gains from the sale of "US real property." It did so under pressure from American farmers who complained that foreign investment in US farmland was driving up the prices of farms.

Taxes must be paid by anyone investing not only directly in US real property, but also indirectly. For example, a foreign shareholder in a corporation at least 50% of whose assets were US real property on any of several testing dates during a 5-year "lookback period" will be taxed on his capital gains.

Congress did not say whether it intended power plants to be treated as US real property for this purpose. IRS regulations in this area are unclear.

However, the IRS branch with responsibility for the issue said in May that it has tentatively concluded that US power plants are not US real property, at least not ones that burn fossil fuels. It is less sure about power generating equipment that is built into hydroelectric dams. No one has asked the IRS yet to put this in writing.

/ continued page 9

Toll Roads

continued from page 7

benefit if the public cannot gain access to it.

Conversely, a developer might want the government to impose restrictions on competing modes of transport such as parallel roads and railways. The consequences are obvious if, following completion of a new toll road, the government decides to build a new freeway running parallel to the toll road or if the government decides to develop a rapid transit network in close vicinity to the project. The natural instinct is for governments to resist such demands. However, if a government retains the right to build parallel roads or alternative modes of transport, then the developer should consider asking the government to provide some form of compensation or support if competing modes of transport are put in place. A government traffic or revenue guarantee will not only mitigate the "traffic" risk inherent in the toll road project, but also, by its nature, compensate a developer for the impact of a failure by a government to build connecting roads or the development by the government of competing modes of transport. A traffic or revenue guarantee will also act as an incentive to the government to build connecting roads to help increase traffic flow on the toll road.

The Concession Contract

The concession contract is a central feature of a privately-financed toll-road concession. The concession contract grants the developer, or the concessionaire, a concession to develop, construct (or improve), operate and maintain a road in exchange for the right to collect tolls during the concession period. The concession contract lists the respective rights and obligations of the government and the concessionaire. It might also address the rights of the lenders to receive termination payments and under what circumstances the lenders may step in to remedy defaults or replace the concessionaire.

The period of the concession should not be any shorter than the term of the debt. It is preferable for the concession period to be longer than the term of the debt in the event the concessionaire's debt is not repaid as originally anticipated. There may also be circumstances when the term of the concession will be extended automatically in order to preserve the revenue generating period of the road, such as in the case of events of *force majeure* and other events that are recognized to be beyond the control of the concessionaire.

An area of tension is the government may want the right to construct parallel roads and other forms of transport that can undermine the project.

The project lenders, among other things, will focus on the termination rights in the concession contract and ways to mitigate their risk in the event of early termination of the concession contract. Careful analysis of the circumstances requiring the government to make termination payments and the amount of such payments will be required. The amount of the termination payment will vary depending on whether the termination occurs as a result of a breach by the government or by the concessionaire or is due to no one's fault. In projects where a government termination payment is possible, the creditworthiness of the government will be an important factor in attracting project debt. Even if a government agrees to make termination payments, if the country's credit rating is not high enough, the project still may not be able to raise project debt without additional credit support. Lenders will also want the right to cure concessionaire defaults and, if necessary, to replace the concessionaire with a substitute entity.

Another critical issue is whether drivers will be willing to pay tolls. In many countries, a privately-operated toll road could be a driver's first experience with the concept of paying tolls to use a road. Developers rely on outside experts for traffic forecasts. An expert will review the projected traffic trends in the country and the particular region of the country where the road is to be located, historical trends in road usage, economic expectations and forecasts and finally the impact of the level of the toll rate on the projected usage of the road. While traffic studies are necessary, it is important to keep in mind that they are only projections of future traffic flow and not guarantees of future traffic levels. Frequently, downside scenarios of varying levels of forecasted traffic are used to assess whether a project will be robust enough to repay its debt if some or all of the basic assumptions in a project's base case change. Due to a general unwillingness of drivers to pay for sharp increases in toll rates and political considerations to keep tolls low, if traffic levels drop, it may not be possible to keep increasing the toll rate to compensate for the loss of revenue caused by lower than projected traffic.

Since concession periods are often long term, the manner in which the toll is adjusted will be of great significance. The concession contract might provide for toll adjustments in several ways. One option is to tie the level of tolls to certain costs of the concessionaire. For example, if the concessionaire has a foreign currency debt facility, it may want the toll rate (which will be payable in local currency) linked to changes in the relevant foreign currency exchange rate. Another option is to adjust the toll for inflation. Other adjustments to the toll rate might be made to guarantee a pre-determined minimum return on equity to the sponsors. The government might prefer that the sponsor keep tolls low to increase traffic volume, especially if a traffic guarantee is provided by the government. Regardless of how tolls are adjusted, at some point, increases in the toll will deter people from using the road (if there are other options) and will cause a decrease in traffic, reducing overall toll revenues. The lenders will want to see an analysis of how sensitive demand is to the toll charged.

The method of charging the toll will also have an impact on overall revenues. The concessionaire should analyze whether different classes of vehicles should be charged different rates. Should the toll be a flat rate or should it be charged by distance traveled? Should there be different tolls depending on the day of the week, the */ continued page 10*

IN OTHER NEWS

EXPORTS of coal, electricity and other commodities cannot be taxed.

The US constitution forbids the federal government from imposing any "Tax or Duty . . . on Articles exported from any State." Another clause in the constitution bars state governments from collecting any "imposts or duties" on exports or imports, except for fees that are strictly limited to covering the cost of inspections.

The IRS released a ruling in late April to a coal company that objected to paying a federal excise tax on its coal that was destined for overseas markets. The United States collects an excise tax of $1.10 a ton on coal from underground mines and 55¢ a ton on coal from surface mines. The tax is collected from the mining company when it sells the coal.

The company in the ruling sold coal to a coal processing company that removed impurities and then resold the coal to its own customers. The coal company was able to show that the processor had contracts to supply its coal to foreign buyers. It applied for a refund of the excise taxes it paid on the coal. The IRS balked at first, but then relented in a "technical advice memorandum," or ruling that the national office issues to settle a dispute between a taxpayer and IRS agents in the field. A tax could not be collected in this case because coal entered the "stream of export" when it was sold to the processor. The ruling is Technical Advice Memorandum 200417005.

In a related development, a US appeals court in late May turned down a request by an Ontario power company for a refund of US excise taxes paid on coal the power company bought from US suppliers. Ontario Power Generation, Inc. said its suppliers passed through the taxes. The US government conceded the taxes should not have been collected on exported coal, but it said the power company had no right to a refund. The suppliers filed briefs arguing that if anyone was owed a refund, it was */ continued page 11*

Toll Roads

continued from page 9

time of day, or the time of year that a journey is made? Complicated toll structures might optimize revenues in theory, but may be too complicated for the public to understand and deter drivers from using the road.

At the end of the day, both the sponsor and the lenders have a similar goal of finding the right toll to ensure revenues will cover all of the concessionaire's obligations plus a reasonable return on equity that is not too high for the market to bear.

In order to make a concession more attractive and to further bolster revenues, the concession contract might also give the concessionaire the ability to receive revenues from other activities along the road, such as from service stations, fiber optic cables, real estate development (such as hotels and retail outlets), advertising and other rights. The concession contract should specify the additional activities the concessionaire will be able to engage in, in addition to developing and maintaining the toll road and collecting a toll. If the government reserves the right to grant third parties the right to undertake such activities, the concessionaire should make sure that the granting of such rights to third parties will not interfere with the toll road or depress revenues.

Site and Permits

Private toll roads are usually built pursuant to fixed-price, lump-sum, date-certain turnkey construction contracts. The construction schedule and related deadlines are linked to deadlines in the concession contract. The construction contracts provide for payment of liquidated damages by the contractor if the road is not completed on time. They may also give the contractor a bonus if the road is completed ahead of schedule. If the project site has not yet been delivered by the government, the government should have a deadline to deliver the right of way over the site to the concessionaire so that the construction can stay on schedule. The site may either be delivered on one occasion or in stages during the construction period. A concessionaire should be compensated for late delivery of the right of way by the government.

The concession contract should address environmental sensitivities and should also include provisions addressing country-specific issues that require special attention. For example, the consequences of discovering archaeological artifacts in countries like Italy, Greece and Israel may require specific treatment. The route of the road may be through environmentally-sensitive areas and there may be opposition from local communities, landowners or environmental groups. The government should be better equipped than the concessionaire to manage such opposition.

Some governments, recognizing the importance of a quick and efficient permitting process, may introduce a streamlined approval process just for this project. A quick and efficient system to obtain permits and approvals can help avoid unnecessary delays and costs.

Some concession agreements may require the developer to add more lanes and extend the road in the future, raising complicated intercreditor issues.

Design Modifications

A common problem in toll roads is time and cost are both of critical importance to a private developer while government officials might not be as focused on completing construction on schedule and might feel that they have the continual right to require the concessionaire to make changes in the design of the road. Design or operational modifications can have a "domino" effect on the construction schedule and add to future operating expenses.

A concessionaire should analyze the extent to which the government's engineers may be involved in the continuing design of the road and the basis for compensation payable by the government (including the timing of payment) in the event design or construction changes are made at the government's request. A concessionaire should protect itself against an unlimited obligation to implement design changes requested by the government. A concessionaire will also want to be satisfied that the construction specifications and operational criteria are clearly established. Ambiguous criteria could lead to frequent disputes between the concessionaire and the government. Governments and concessionaires frequently have different expectations. It is better to identify these at the start of a project by making the contract as detailed as possible.

Some concession contracts require the concessionaire to expand the toll road by increasing the number of lanes or lengthening the toll road. A concessionaire may take future expansions or extensions into account in its original design of the project. For example, to reduce the future expansion costs, it may build the highway "outside-in," meaning that minimal disruption of the highway will result from the addition of lanes on the median. If the concessionaire has an obligation to lengthen the highway, careful consideration should be given to how the extension will be financed. For example, will the revenues from the extra sections of road be enough to finance construction of these sections or, if new sources of income are introduced, what will be the intercreditor arrangements among the different tranches of lenders? This can get extremely complicated.

Conclusion

Ultimately, a successfully-structured toll road project can make a significant contribution to the development of a country and the overall welfare of its citizens. A careful balance must be struck among the competing interests of the developer, the government and the lenders. The challenge is to find an equitable balance where the risks and responsibilities are allocated to the party best able to handle them. A well-structured toll road project can be a rewarding enterprise for all concerned.

IN OTHER NEWS

them — rather than their customer in Canada. The appeals court agreed. The case is *Ontario Power Generation, Inc. v. United States*.

SOME USE TAXES are an unconstitutional burden on interstate commerce, an Indiana court suggested.

Simon Aviation leased two aircraft. It took delivery of one in Canada and the other in Connecticut. It stored both in Indiana and used them to fly around the US. Indiana collects a 5% sales tax on equipment purchased in the state or an equivalent "use" tax when equipment is bought out of state but brought into Indiana by an Indiana taxpayer for use there. The taxes are collected on lease rentals in cases where a company leases equipment rather than buys it. Indiana gives credit for sales taxes already paid to another state against the use tax, except when the sale involves "vehicles, watercraft, or aircraft that are required to be titled, registered, or licensed by Indiana."

Simon Aviation argued that Indiana is barred by the US constitution from collecting a use tax on its aircraft. The constitution bars states from interfering with interstate commerce. Simon argued that the use taxes in this case have the potential to subject goods bought in other states to two taxes — a sales tax in the other state where the goods were purchased and a use tax when the goods are brought to Indiana for use there. This makes it more expensive to buy goods out of state since there is no possibility of a double tax when goods are purchased in Indiana.

The Indiana tax court agreed. The case is *Simon Aviation v. Indiana Department of Revenue*. The court released its decision in April.

SALE OF AN OFFSHORE SUBSIDIARY did not trigger taxes in the United States, the US Tax Court said in a decision eagerly awaited by US industry.

Dover Corporation, an elevator manufacturer, sold a subsidiary in */ continued page 13*

When Will the Next Power Crisis Start in California?

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

California has not yet fixed the problems that led to the electricity crisis in 2000 and 2001, though there has been some progress in restoring a workable electricity market structure. Electricity shortages could hit again as early as this summer. They will start as a "squall" rather than the "perfect storm" that buffeted the state before.

Most observers of the California power market accept that a contributing factor to the crisis in 2000 and 2001 was an under-investment in new energy infrastructure. We have written in these pages in the past that three fundamental prerequisites for investment in energy infrastructure are creditworthy buyers and sellers, predictable market rules, and a stable regulatory environment.

California has made progress toward re-establishing those investment prerequisites. Creditworthy buyers are once again in the market. Pacific Gas & Electric emerged from bankruptcy on April 14, 2004 with an investment-grade credit rating. Southern California Edison was restored to investment-grade status in December 2003. Sempra Energy maintained its investment grade rating throughout the crisis. Although many sellers and project developers remain in or on the edge of bankruptcy, some of the power suppliers to California's investor-owned utilities — including many "qualifying facility," or "QF," projects — have also seen their credit ratings upgraded.

Despite this progress, considerable work on the policy front remains to be done. Consensus on the types of reforms needed has not been easy to reach. A surfeit of regulatory proceedings has sprouted in the past three years to consider and implement the needed reforms, taxing the resources of the California Public Utilities Commission and industry stakeholders alike.

Moreover, a confluence of adverse weather conditions and delays in infrastructure upgrades could jeopardize California's tenuous supply-demand balance. As Chairman Pat Wood of the Federal Energy Regulatory Commission said of California in early May, "There are very troublesome conditions out there," and the power market "looks a lot like the days of yore."

In short, California has some distance still to go to revamp the rules and regulatory policies underpinning its electricity market in order to re-establish a favorable investment climate. Lawmakers, regulators, the utilities and other stakeholders involved in the process may not have time on their side.

Supply and Demand Imbalance

The current conventional wisdom, endorsed by the California Energy Commission, the California ISO — known as "CAISO" — and state utilities is that under average weather conditions, California should have adequate supplies of electricity for the next five years. However, these same agencies and others also warn that with the wrong convergence of variables, weather being but one, trouble could occur much sooner. In February, Edison International CEO John Bryson warned that now is the "calm before the storm" when regulators need to "establish 'clarity' about how electricity will and should be provided, what obligations utilities will have and the role of competitive markets."

> Electricity shortages could hit again as early as this summer in California, but they will start as "squalls" rather than the "perfect storm."

Both the California Energy Commission and CAISO predict that under normal conditions the state should escape supply emergencies in 2004. However, California may not have the luxury of "normal" conditions. The CAISO has already declared two "stage 1 emergencies" this year due to unseasonably hot spring weather in southern California and a combination of scheduled and forced outages. The CAISO was also forced to curtail load due to a potential transmission overload. Even without widespread outages, forecasters all acknowledge the potential that interruptible customers will be curtailed this summer.

Aside from adverse weather, two factors are causing significant concern for California going into the summer. First is the increasing probability that hydroelectric production in the West will be below average. Second is the possibility that existing transmission bottlenecks could be aggravated by planned and unplanned transmission outages. A report from Fitch Ratings in late April noted:

The importance of variability in hydropower generation in the West cannot be overstated. Indeed, the 1999–2001 drought in the Pacific Northwest was a key factor driving shortages and price spikes and affecting natural gas and electricity in [the] WECC in 2000–2001. Hydroelectric power generation, a low-cost source of energy, represents approximately 34% of installed capacity and is expected to provide 31% of total delivered energy in 2004, assuming normal underlying water conditions."

Unfortunately, "normal underlying water conditions" are not panning out for 2004. The West is entering the fifth year of below-normal flows in the Columbia Basin. The Bonneville Power Administration's Paul Norman says the five-year drought is turning out to be the worst since the dust-bowl days of the mid-1930s. The Colorado River situation is just as grim, suffering from the driest five-year period on record. California hydro conditions, while not as severe as elsewhere in the West, are expected to remain below average in 2004.

Transmission bottlenecks contributed to at least one of the recent CAISO emergencies, and the situation is not expected to improve this summer. Upgrade work on the Pacific DC Intertie that connects the Pacific Northwest to southern California will reduce the transfer capabilities from 3,100 megawatts to 2,000 megawatts through August. In September, the DC Intertie will be completely removed from service until the end of / continued page 14

IN OTHER NEWS

the United Kingdom in July 1997 to German elevator manufacturer Thyssen. Dover owned the subsidiary through a UK holding company; it was the UK holding company that sold the shares. Ordinarily when shares are sold in a foreign corporation that is owned even indirectly by a US company, any gain is taxed immediately in the United States. The US will tax the US parent company on any "passive" income received by its offshore holding companies. Gain from the sale of stock is passive income. Tax lawyers call such income "subpart F income."

A sale of assets — rather than stock — would not have produced passive income.

Therefore, Dover asked the IRS in December 1998 — more than a year after the sale — for permission retroactively to make a "check-the-box" election to treat the subsidiary as a "disregarded entity" — in other words, to treat the company for US tax purposes as if it did not exist. The IRS initially said no. It later changed its mind in March 2000 after listening to further arguments from Dover, but warned Dover that no inference should be drawn that the company could avoid passive income by making the election.

Dover made the election and took the position that it had no passive income from the sale. The IRS assessed it almost $34 million in back taxes on audit.

In court, the judge said the problem was of the IRS's own making. The election meant that the UK subsidiary no longer existed. What looked like a sale of stock was an asset sale for tax purposes. If the IRS did not like this result, it could amend its own regulations.

The case is Dover Corporation v. Commissioner. *The court released its decision in May. The decision had been eagerly awaited by US power companies, a number of whom have been fighting the same issue on audit.*

TELEPHONE COMPANIES are considered manufacturers of "tangible / continued page 15

California

continued from page 13

2004. Meanwhile, a long-awaited upgrade to Path 15, the major transmission link between the northern and southern parts of the state, is not scheduled to come online until the end of the year. Path 46, connecting California to the capacity-glutted desert southwest, lacks the capacity to import that excess power without significant upgrades. Approvals for upgrades to the Mission-San Miguel line are stalled before the California Public Utilities Commission in its cumbersome permitting process, delaying access to new generation in northern Mexico.

Drought unfortunately can further increase the possibilities of service interruptions: droughts lead to wildfires, which can in turn remove key transmission assets from service. For example, the southern California fires that occurred in October 2003 tripped the southwest power link, cutting off delivery of more than 900 megawatts to the San Diego region.

Longer term, projecting the balance of supply and demand requires a different perspective than anticipating needs for the coming summer.

Long-term supply-demand forecasts use, out of necessity, average values for outage rates, hydroelectric production and load growth. Of these elements, load growth has generally been the source of greatest long-term uncertainty. This continues to be the case in California given widely swinging policies concerning demand-side management and the reality that major segments of the state's economy are subject to boom-bust cycles. Five-year forecasts of peak demand by the California Energy Commission can vary by plus or minus 1,200 megawatts depending upon economic conditions, and by over 1,700 megawatts with swings in the level and focus of demand-side-management investment.

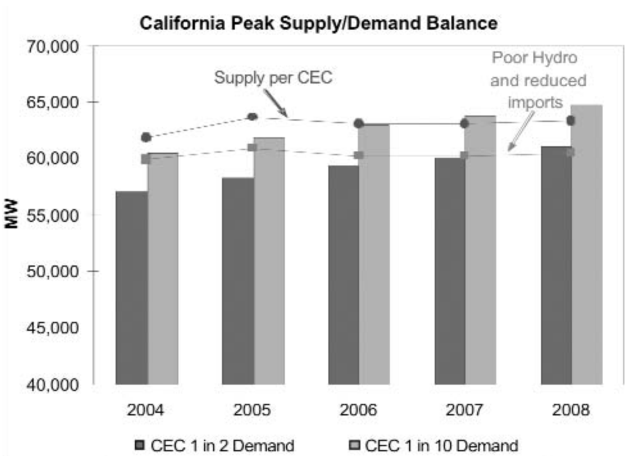
On the supply side, an issue coming under greater scrutiny in forecasting long-term resource balances is plant retirement. The CAISO notes that "more than 3,870 megawatts of thermal generation is potentially at risk of retiring over the next several years. These generating units are more than 40 years old, have high heat rates, and ran less than 40% of the time last year." While this 3,870-megawatt uncertainty makes the forecaster's life more difficult, much of that capacity has already undergone costly pollution retrofits, indicating some commitment to continued operation of those plants. A few units are being mothballed rather than permanently removed from service, at least as long as their owners see a potential for future profits.

The utilities are developing long-term plans for procuring electricity from wholesale generators that will be reviewed by the regulators later this year.

Introducing two additional variables — hydroelectric output and reduced imports — makes the story more interesting. The accompanying chart shows the most recent demand projections from the California Energy Commission along with the agency's supply forecast (released in January 2004). Under normal conditions — typical weather and base case supply forecast — supply is sufficient to meet demand. Concerns over supply adequacy in California appear justified if supply availability is decreased to account for drought conditions (normal peak hydro production reduced 15%) and imports are reduced (by 1,000 megawatts). The combination of a regional heat wave leading to high demand throughout the West, along with reduced imports due to transmission problems and limited hydro production during a drought year could cause supply problems as early as this summer.

Furthermore, in the long term both PG&E and Southern California Edison have proposed major maintenance projects (steam generator replacements) for the Diablo

Canyon and San Onofre nuclear plants, which could remove significant resources from the grid in the 2008-2010 timeframe. On the other hand, the California Energy Commission forecasts assume the retirement of Edison's Mohave coal plant; while likely, this is still being actively debated.



The bottom line is California is unlikely to enjoy an unbroken stretch of normal weather conditions over the next few years. But the "perfect storm" conditions of 2000-2001 are also unlikely to repeat. What does seem likely is a "squall": high regional temperatures coupled with poor hydro production or transmission failures. California has learned some lessons from the 2000-2001 crisis, such as better use of interruptible load and demand-response programs, use of backup generators during emergencies, and the huge conservation potential of California citizens and industries. However, to avoid relying on these emergency resources, infrastructure bottlenecks in both generation and transmission must be addressed.

A New Procurement Framework

The state legislature and the California Public Utilities Commission have made some positive moves to improve the California regulatory climate to support investment in new energy infrastructure.

In January 2004, regulators adopted a new procurement framework that embraces key provisions of legislation passed in 2002. The new procurement rules should correct some of the glaring flaws in the market design that contributed to the electricity crisis */ continued page 16*

IN OTHER NEWS

personal property," the Minnesota Supreme Court said.

Three phone companies in Minnesota that provide local telephone, wireless and long-distance service sued for refunds of state sales taxes they paid on equipment they purchased for use in their telephone businesses. Minnesota exempts from sales taxes equipment that will be used by the purchaser to manufacture "tangible personal property . . . to be sold ultimately at retail."

The Minnesota tax department turned down the refund claim. So did a lower court. However, the Supreme Court agreed in April with the phone companies. It said voice transmission through telephones involves turning a customer's voice into electronic form for transmission and then recovering the voice so that the caller on the other end can hear it. The voice heard in the telephone receiver is a "tangible" product because it can be felt by the senses — in this case, the human ear.

The case is Sprint Spectrum LP v. Minnesota Commissioner of Revenue. *The court likened the voice heard in the telephone receiver to electricity, which is also considered tangible.*

TWO HYBRID DEBT INSTRUMENTS survived separate IRS audits.

In one of the audits, a US company had injected capital into an offshore subsidiary both by making interest-bearing loans and by advancing other money under "subordinated loan agreements." The offshore subsidiary was not required to pay interest to its US parent on the subordinated loans. There was no fixed maturity date by when it had to repay the loans. The US company reported the loans as an equity investment in the subsidiary for US tax purposes, but it treated them as debt both for tax purposes in the country where the subsidiary was located and for financial statement purposes.

The reason for the subordinated loans was to avoid a capital tax in the */ continued page 17*

California

continued from page 15

before. Together the legislation and the regulatory framework represent significant steps toward improved regulatory stability in California.

PG&E's and Edison's financial problems arising from the electricity crisis stemmed from their inability to recover through frozen retail rates the runaway costs of procuring spot power from broken wholesale markets. Before the crisis, the utilities could have locked in reasonable prices for power through long-term contracts. But regulators encouraged (even required) an over-reliance on the volatile spot market. Although utilities were guaranteed full cost recovery for spot purchases, regulators could choose to penalize utility shareholders if, in hindsight, any long-term contracts were found to be "bad" deals. Regulators now acknowledge the important role of long-term procurement commitments. But the utilities are more convinced than ever of the need for up-front regulatory assurances for their procurement decisions. From the perspective of the utilities, high credit ratings and access to capital markets on reasonable terms and conditions depend upon the credibility of regulatory assurance that the utilities will be able to recover their costs.

The state legislature passed Assembly Bill 57 in 2002 giving utilities the freedom to enter into long-term power purchase agreements without fear of retroactive review. The legislation required California regulators to establish an upfront review and approval process for procurement plans. Utilities will be allowed full recovery of costs associated with these plans. In January 2004, the CPUC adopted a procurement framework based on AB 57 and another bill, Senate Bill 1976. The new procurement process establishes a regulatory framework that:

> (1) requires each utility to prepare and file a procurement plan that meets specified requirements; (2) provides the criteria by which the Commission should review and either adopt, modify, or reject each utility's plan; (3) eliminates the need for after-the-fact reasonableness reviews of utility actions in compliance with an approved plan; (4) ensures timely recovery of prospective procurement costs incurred pursuant to an approved plan; and (5) requires that an approved plan enable the utility to fulfill its obligation to serve its customers at just and reasonable rates, with such just and reasonable rates to include an appropriate balancing of price stability and price level.

The utilities are now developing long-term procurement plans that will be reviewed by regulators later this year.

Devil in the Details

Translating the new procurement framework into a workable process for securing future electricity supplies could prove the old axiom that "the devil is in the details."

A consensus about how to address problems that led to the last energy crisis remains elusive.

The California Public Utilities Commission has conducted at least eight workshops over the past three months trying to resolve the definitions and accounting questions associated with resource adequacy, just one issue to be addressed under the new procurement framework. The utilities have asked the Commission to resolve these issues expeditiously. With resource adequacy rules in place, Edison says it could complete its procurement plan by September 2004, and the commission could issue a decision on that plan by May 2005. On the other hand, PG&E has asked the commission to complete a review of both resource adequacy issues and its procurement plan by the end of 2004. Under either time frame, the utilities would conduct solicitations for new power supplies no sooner than 2005.

Meanwhile, other equally contentious issues are on similar tracks. For example, aggressive renewable resource requirements are required by law, but procurement rules, subsidies and schedules are under review in parallel sets of workshops. Community aggregation also is under discussion and, if widely adopted, could pose significant issues for the utilities' load expectations.

Procurement issues have proliferated to the point that they are being addressed in eight or more separate proceedings (see sidebar). The number of proceedings alone suggests a low likelihood of achieving a timely resolution of all these proceedings in a coherent fashion. To complicate matters, the current commissioners are chronically split and typically have resolved contentious issues on 3-2 votes. The terms of allied Commissioners Lynch and Wood will end early next year, creating vacancies for two new commissioners. Anticipating this change in the CPUC's makeup, difficult decisions could be held until a new commission is in place. Appointments of the new commissioners by the governor could be delayed. Even without delays in the appointment process, the new commissioners will require some time to get up to speed on the numerous and complex issues they will face.

At the same time, Southern California Edison has been lobbying in Sacramento for passage of AB 2006, which has the backing of the speaker in the state assembly. The bill would revise the AB 57 framework and redraw the boundaries of various California Public Utilities Commission proceedings in mid-case. Decisionmakers are being forced to balance the need to get the procurement process right with the need to get it done in a timely fashion.

Predictable Market Rules

The third prerequisite for a favorable investment climate is predictable market rules. Further clarification of the structure of the wholesale and retail markets must take place before the utilities make additional procurement commitments, whether through power purchase agreements or utility-built and -owned power plants. Like other states, California is debating the tradeoffs of utilities owning plants or contracting for power. (Edison's / continued page 18

IN OTHER NEWS

foreign country on capital contributions. No capital tax had to be paid on borrowed money.

IRS agents auditing the US company insisted that the US parent had to treat the subordinated loans as debt for US tax purposes. The US company had labeled them "subordinated loans." A US company cannot normally disavow the label it chooses for an instrument.

However, the IRS national office overruled the agent in a ruling made public in late April. The agency said the principle that a taxpayer cannot disavow his own form does not apply in this case because the US company consistently reported the instrument as equity on its US tax returns.

The IRS agent tried another argument. The foreign country where the subsidiary is located imputed interest on the loan. It treated the US parent company as if it received interest and then immediately made capital contributions back to the subsidiary in the same amount. Small amounts of capital tax had to be paid as a result. The IRS agent insisted that even if the US company is right that the instruments are equity investments, it must report the income that the foreign country imputes on the instruments. These payments should be reported as dividends on the company's US tax return.

The IRS national office said nonsense. The fact that a foreign country tax law imputes payments on an instrument does not mean there is income in the US. The ruling is Technical Advice Memorandum 200418008.

In a separate audit, a different US company faced its own challenge to a hybrid instrument. The company injected capital into an offshore subsidiary. It reported the investment for US tax purposes as equity. The offshore subsidiary treated it for local tax purposes as a loan. An IRS agent argued that the US tax code bars such inconsistent treatment. Section 385(c) forbids the holder of an instrument issued by a corporation from characterizing the instrument differently than the corporation did when the instrument was issued, / continued page 19

Too Many Proceedings?

There are nine significant proceedings underway before the California Public Utilities Commission to address issues stemming from the California energy crisis in 2000 and 2001. The sheer number makes for slow progress. Brief descriptions of the most significant ongoing proceedings are below.

- **R.04-04-003 – Referred to as the "umbrella proceeding," this proceeding is intended to ensure policy consistency and overall coordination for the review of the utilities' long-term procurement plans in conjunction with eight other proceedings.**
- **R.03-10-003 – "Community choice aggregation." This proceeding will establish the implementation rules allowing cities and counties to purchase and sell electricity on behalf of residents and businesses in their jurisdictions.**
- **R.02-06-001 – Demand response. This proceeding will implement policies and practices for advanced metering, demand response and dynamic pricing. An objective of the proceeding is to expand demand-response capabilities of large customers and assess the practical demand response potential of small customers.**
- **R.04-03-017 – Distributed generation. The scope of this proceeding is not yet completely defined, but a key priority will be to develop cost-benefit analysis methodologies to assist investor-owned utilities in the evaluation and interconnection of distributed generation projects.**
- **R.01-08-028 – Energy efficiency. This proceeding examines energy efficiency policies and programs, encourages utilities and non-utilities to propose energy efficiency programs and delineate specific program evaluation criteria, and determines who should administer commission-ordered energy efficiency programs.**

/ continued page 20

California

continued from page 17

plans for the Mountainview project and SDG&E's proposed acquisition of the Palomar plant are symptomatic of the current debate.)

The question of "debt equivalence" is another important factor that will play into utility decisions on power purchase agreements. The "debt equivalence" of long-term power procurement contracts is the imputation of debt-like characteristics to a portion of the revenue requirements of these contracts by rating agencies in their assessment of a utility's risk profile. For example, Standard & Poor's will add to a utility's reported debt a risk-adjusted portion of the revenue associated with power purchase contracts over the life of the contracts. This adjustment to the reported debt is considered in assessing financial ratios for a company (such as the ratio of funds from operations to debt) and could lead to a lower rating. Like most commissions, the CPUC does not consider debt equivalence when it sets a utility's authorized capital structure. The CPUC has committed to re-examine this factor as part of the pending 2005 cost-of-capital proceedings of PG&E and Southern California Edison.

There is universal agreement that wholesale market rules need reform, but limited progress on addressing these problems has been made. The CAISO still seeks approval for some variation of its MD02 proposal but is having limited success at the Federal Energy Regulatory Commission, which remains a convenient target for California politicians. For example, State Attorney General Bill Lockyer recently issued a white paper on wholesale market reform, attacking FERC for a failure to order refunds in the aftermath of the electricity crisis. The California Public Utilities Commission continues to challenge FERC's jurisdiction in wholesale markets by setting resource adequacy requirements for non-utility energy service providers, by adopting power plant operating standards for wholesale generators, and by seeking authority over siting of LNG terminals.

Long-term resource commitments are also threatened by uncertainty over the future structure of California's retail market. Utilities are reluctant to make long-term commitments without knowing what the customer base will be. But in California the retail market structure hangs in limbo awaiting decisions on two approaches to retail choice: direct access and community choice aggregation.

California suspended direct access (California's term for retail choice) in 2001 following the electricity crisis. Today, about 15% of the investor-owned utilities' combined load (primarily large commercial and industrial customers) is served under grandfathered contracts. State lawmakers are currently debating two pieces of legislation that would re-open the direct access market by creating a "core/non-core" market structure: large customers could either remain utility customers or could contract with energy service providers. The terms and conditions for such a core/non-core retail market structure have been the subject of vigorous debate in recent months. Legislators do not agree, for example, on the definition of a large customer, debating whether the cut off should be 200 kilowatts or 500 kilowatts of load.

In September 2002, the state legislature granted cities and counties the authority to establish community choice aggregation programs to procure power for their citizens. The City and County of San Francisco has already passed an ordinance to establish such a program, and a number of other cities have expressed interest in pursuing community choice aggregation as a means to lower electricity costs, pursue renewable energy and support economic development. The implementation rules and procedures for community choice aggregation programs are being considered in an ongoing California Public Utilities Commission proceeding.

The financial impact of the power crisis, particularly the legacy of high-cost contracts the state signed in 2001 to buy wholesale power, has resulted in high retail electricity rates. High electricity bills have in turn sparked interest in the core/non-core and community choice aggregation proposals. They have also spurred renewed interest in municipalization of power supply. Considering the undefined nature of their customer bases, California's utilities remain averse to entering into commitments that might ultimately lead to a replay of the debate over "stranded" costs.

Conclusion

California continues to make progress, albeit slowly, toward cleaning up the aftermath from the electricity crisis. Lawmakers, regulators and other industry stakeholders are keenly aware of the need for revamped */ continued page 20*

IN OTHER NEWS

unless the holder discloses the inconsistency on his US tax returns.

The IRS national office rebuffed the agent. It said there was no inconsistency in this case. The companies had reported the instrument all along for *US tax purposes* as equity.

The ruling is Technical Advice Memorandum 200419001. The text was made public in May.

A MEXICAN COURT said that companies cannot deduct profit-sharing payments to employees.

Most infrastructure projects in Mexico are owned by a project company with no employees. The employees are in a separate company that operates and maintains the project under a contract with the project company. The reason for this is Mexico requires that each company pay 10% of its profits to its workers in annual profit sharing. If most of the income is in the project company with no employees, this limits the amount of profit sharing that is required.

"The law has always said that the tax base on which corporate income taxes are computed may not be reduced by the profit-sharing amounts paid to employees," according to José Ibarra, a lawyer with Chevez, Ruiz, Zamarippa y Cia in Mexico City. "However, several companies and their litigation advisers considered the provision unconstitutional and, thus, some went to court while others simply deducted the profit-sharing payments." Such deductions were more common starting in 2002 because a change in Mexican law gave companies an opportunity to challenge the law in court.

The Mexican Supreme Court of Justice said on May 4 that the bar against deductions is not unconstitutional. The decision has two effects. It means higher income taxes for Mexican companies. It also means higher profit-sharing payments, since the payments are calculated as a percentage of the taxable income a company reports for income tax purposes.

/ continued page 21

Too Many Proceedings?

continued from page 12

- R.04-01-026 – Transmission assessment process. The CPUC is using this proceeding to attempt to streamline the transmission planning process and eliminate duplicative need assessments. Parties are also debating an economic methodology that would allow the CPUC to defer to the CAISO's assessment of need for new transmission projects.
- I.00-11-001 – Transmission planning. This proceeding preceded R.04-01-026 and has served as a forum to consider a wide range of transmission-related issues as well as specific transmission projects.
- R.04-04-025 – Avoided cost and QF pricing. The CPUC opened this proceeding to develop a common methodology to calculate avoided costs in a variety of regulatory applications. The short-run avoided cost methodology for prices paid to QFs will be an important and contentious component of this proceeding.
- R.04-04-026 – Renewable portfolio standards. This proceeding will establish baseline levels of renewable generation for each utility and set the annual procurement target each utility must meet in 2004. The CPUC will also adopt standardized contract terms and conditions for renewable electricity sales, finalize the "market price referent" methodology, and continue to develop a "least-cost and best-fit" evaluation process.

California

continued from page 19

policies and market rules. But consensus on critical issues remains elusive, and crafting detailed implementation rules is time-consuming. California may have precious little time before adverse weather, below-average hydro production, transmission bottlenecks or spikes in demand combine to upset the state's supply-demand balance and, perhaps, force a faster pace toward restoring a rational regulatory environment.

Libya Poised to be a Major Gas Exporter

by Dan Rogers in Houston, and Noam Ayali and Kimberly Heimert in Washington

The partial lifting of US trade sanctions against Libya, following the removal of UN sanctions last September, should help to propel Libya into the ranks of major league gas exporters. With most investment and trade barriers removed, Libya can now try to attract the nearly $30 billion in direct foreign investment that it claims to need in order to restore and upgrade its petroleum and petrochemical infrastructure over the next six to eight years. While much of this investment will probably be made in oil and petrochemicals, the impact of even a portion of this investment in the natural gas export sector will have a profound effect on key world gas markets.

Sanctions Disappear

US sanctions that were in place since 1986 were partially lifted on April 23 after the Libyan government pledged to dismantle its programs to produce weapons of mass destruction, destroy its existing chemical weapons stocks and immediately submit to UN inspections. The sanctions-lifting came on the heels of the UN's decision last September to discontinue its sanctions against Libya based on the Libyan government's decision to accept responsibility for the Pan Am Flight 103 bombing in Lockerbie, Scotland, pay compensation to the families of victims and cooperate in connection with the prosecution of the key terrorist players.

The US sanctions originally contained a ban on importing Libyan crude oil to the US and a ban on US investment in Libya. The sanctions were subsequently expanded to prohibit direct trade, commercial contracts and travel-related activities between US and Libyan interests. The US government then upped the ante in 1996 by enacting the "Iran-Libya Sanctions Act," or "ILSA," which extended the reach beyond US interests by imposing penalties on foreign persons that invested more than $40 million annually in activities that enhanced Libya's petroleum resources. Originally set to expire in five years, ILSA was extended in 2001 for an additional 5-year period. The collective set of sanctions effectively prevented the import into Libya of needed technology, spare parts and investment funds, substantially crippling Libya's ability to compete in the worldwide oil and gas sector. Interestingly, no penalties were ever imposed under ILSA, although an RWE-Dea led consortium was threatened with penalties in June 2003 when it signed a contract covering six new exploration blocks in Libya. RWE-Dea countered that under the terms of its deal, which involved the expenditure of $56 million on exploration costs over a period of five years, did not exceed the annual investment limits under ILSA.

Libya's New Position

The speed and effect of Libya's reversal of fortune is truly remarkable.

Only a few years ago, Libya's destiny to remain a pariah of the Western world seemed assured after the Bush administration labeled Libya as a member of the so-called "axis of evil." With most US and international investment and trading barriers now gone, Libya is today arguably one of the world's most promising energy sectors, with large amounts of already-proven oil and gas reserves and vast areas that remain unexplored. Several credible estimates place Libya's existing proven natural gas reserves at 40 to 46 trillion cubic feet. About 30% of these reserves are "associated gas," or gas produced in tandem with oil operations, with the remaining 70% being non-associated gas. Since only about 25% of Libya's surface area has been explored to date, mainly using older-generation equipment and techniques, most experts agree that Libya's actual gas reserves are significantly higher — perhaps at 70 to 100 trillion cubic feet or more. With such sizeable reserves located in relatively close proximity to */ continued page 22*

IN OTHER NEWS

ARGENTINA is considering refunding value added taxes paid on capital equipment and construction work at infrastructure projects during the next three years.

The government proposed the measure in late April. It must still pass Congress.

The program is aimed at spurring new investment. The value added tax is 21%. Refunds will be made within three months after taxes are paid. A total of 700 million pesos in refunds will be made on capital investments in areas other than infrastructure; there is no limit on refunds for infrastructure projects, according to Maximiliano Batista, a lawyer with Perez Alati, Grondona, Benites, Arntsen & Martinez de Hoz in Buenos Aires.

The economy minister said that the government will give top priority to investments in the energy sector. Argentina is coping with sudden shortages of electricity and gas. Refunds will not be available on projects that were already underway when the new program was announced on April 9 or that are required under existing contracts with the government, Batista said.

The economy minister also announced plans to allow investments in infrastructure projects to be depreciated more rapidly for tax purposes.

PERU is expected to impose a tax of up to 3% on mining companies on their gross revenue from mineral sales.

The tax must still pass Congress.

The government, in bid to soften the blow to the mining industry, has proposed that existing mining operations that are covered by tax-stability contracts with the government should be exempted from the tax. Roughly 70% of existing mines have such contracts. The contracts are promises by the government not to alter tax rates during the term of the contract as an inducement to the mining company to invest in Peru. The government also wants the tax rate to vary */ continued page 23*

Libya

continued from page 21

major European pipeline markets, and significantly reduced costs to produce and transport liquefied natural gas, Libya's removal from the international blacklist will allow it to become a major competitor in the European gas market, and a formidable competitor in the worldwide LNG trade — particularly in the Mediterranean and Atlantic basin markets.

Libya will be looking for $30 billion in direct foreign investment in the near term for oil, gas and petrochemical projects.

The steps that Libya needs to take in order to better capitalize on its new fortune are already underway. In an attempt to stimulate investment by those few oil companies that were not barred from activity in Libya (and perhaps in anticipation of eventual sanctions-lifting one day), Libya began to clear the ground for significant new foreign oil and gas investment by initiating important revisions to its 1955-era oil and gas laws. Post-sanctions lifting, the National Oil Company, the state-owned company that is responsible for overseeing oil and gas activities in Libya, has moved matters forward by recently issuing a new and improved exploration and production sharing agreement entitled EPSA-IV. One of the important features of ESPA-IV is an improved "gas clause" that provides more defined contractual terms and better fiscal incentives for the exploration and production of natural gas, liquefied petroleum gas and condensates, in addition to crude oil. With its new oil and gas legal structure and EPSA-IV as the foundation, the National Oil Company is now ready to make things happen. It has announced a tender for eight new exploration blocks (six onshore and two offshore) this summer and has said that more tenders will most certainly follow.

Gas Export Opportunities

Libya is a member of OPEC, and as such its ability significantly to increase its crude oil production and exports will be affected to a large degree by that organization's quota system. Since the export of natural gas and LNG are not subject to OPEC quotas, Libya should not face any artificial barriers to its ability to increase its production and export of natural gas and LNG at a rate far more quickly than for crude oil. In fact, a few OPEC members have already realized the benefits of being free to bring significant hydrocarbon revenues from LNG sales without any member interference. This benefit will no doubt play an important role in Libya's plans significantly to increase gas production and infrastructure and supplement existing gas pipeline infrastructure. Libya's decision in 2001 to join the Gas Exporting Countries Forum, which collectively controls over 75% of the world's natural gas reserves and 60% of its total gas exports, should not slow its growth plans since to date GECF has not adopted any form of member quota system.

Pipeline Exports

Gas production in Libya began in the 1960s in the form of associated gas. From the 1980s onward, Libya has consistently produced from 1.2 to 1.5 billion cubic feet per day of gas. Historically, about half of this gas has been marketed, 30% re-injected to enhance oil production, 15% flared and the remaining 5% used as fuel for field operations. Almost all Libyan gas has been consumed domestically under a policy that encouraged the use of gas for power generation in order to free its more valuable oil production for export, resulting in recent domestic gas demand growth at an annual rate of around 10%.

With the development by Agip/Eni of the $5+ billion Western Libya gas project, Libya is set to make its first pipeline exports of natural gas. The 595-kilometer subsea pipeline, named "green stream," is almost completed and will begin shipping eight billion cubic meters of gas per year across the Mediterranean Sea from Libya to Sicily, Italy and then onward to France in September of this year. The Western Libya gas project will also provide an additional two trillion cubic meters of gas per year for domestic Libyan consumption. Italian utility company Edison has committed to purchase four billion cubic meters of gas per year, mainly for power generation in Italy. Energia Gas and Gaz de France have each committed to purchase two billion cubic meters of gas for consumption in France.

With the successful start-up of "green stream," attention will likely soon return to two other large-scale gas export projects that have been under intermittent development since 1997. The proposed 275-kilometer Libya-Tunisia gas pipeline project began with the signing of a joint venture agreement between the governments of Libya and Tunisia in May 1997. The pipeline was to transport two billion cubic meters of gas per year from Melitah, Libya to Gabès, Tunisia. A preliminary gas marketing agreement was executed in late 1997. Not much more was heard of the project until October 2003, when an agreement to form Jointgaz, a joint venture company, was formed to operate the proposed pipeline. To date, construction of the pipeline has not started.

In June 1997, the governments of Egypt and Libya signed an agreement in principle to link their respective gas pipeline grids. In November 2002, an agreement was reached to construct a $10 billion pipeline to transport gas from Egypt to Libya and link with the green stream pipeline to Italy, together with a parallel oil pipeline to bring Libyan oil to Egypt. The Libya-Tunisia pipeline project and the Egypt-Libya gas and oil pipeline projects are the only significant pipeline projects proposed for Libya to date, but when completed and put into operation, these pipelines will form the backbone of a master gas pipeline transportation system that Eni one day hopes will link the reserves of Libya, Egypt, Algeria and Tunisia for export to Spain. Increased access to and enhancement of Libya's natural gas reserves following the lifting of sanctions will only help to speed the development of the Libya-Tunisia pipeline project, as well as to fuel the desire to link Libya to other attractive European gas markets. Given Egypt's aggressive new plans to export its own substantial / continued page 24

IN OTHER NEWS

between 0.5% to 3% depending on the size of the mining company and to let mining companies claim a credit for any taxes paid against the income taxes the companies otherwise have to pay the government. This would turn the tax into a timing difference: companies would merely pay taxes earlier in time that they would have owed anyway.

The debate in Congress has been delayed several times. The mining industry remains strongly opposed.

Meanwhile, Chile is expected to impose a similar tax of up to 3% on gross sales of mining companies. Companies with operating margins of less than 5% will be exempted. Any tax paid can be offset against a company's income taxes. However, the income tax credit would have to be spread over three years.

VENEZUELA said it has found "massive evasion of income taxes" by the multinational oil companies. The minister of energy and mines said on April 7 that the government is taking action against the companies to collect back taxes. He declined to identify the companies involved. The tax commissioner promised to release more information this summer.

BRAZIL set off a controversy about its financial transactions tax.

Brazil collects a tax of 0.38% on financial transactions. The tax is called the CPMF and is levied on funds withdrawn from a bank account and transferred to a third party. A "provisional measure" issued on April 2 by the government has Brazilian banks up in arms because of two changes in the scope of the tax.

To date, Brazilian companies that export their products had been able to borrow against the expected export earnings without paying the CPMF tax on such borrowing. The loan is repaid to the banks directly by the importer, thereby avoiding the CPMF that would have been levied if the money / continued page 25

Libya

continued from page 23

gas reserves via at least two new LNG projects (one led by British Gas and one led by Union Fenosa/ENI) that are scheduled to come onstream between late 2004 and 2006, it is worth wondering whether the drivers behind the Egyptian government's support of the gas pipeline portion of the Egypt-Libya pipeline project are still there.

LNG Exports

Libya was the second entrant into the world LNG trade, beginning exports from the liquefaction facilities at Marsa El Brega in 1971. The LNG facilities, which were constructed and operated by Esso, are presently being operated at reduced capacity by Sirte Oil Company, a subsidiary of the National Oil Company. Spain's Enagas is the primary long-term customer, with other sales to nearby countries, such as Italy. The original plant was not designed to remove "heavier" gas liquids, such as propane, butane and ethane, from the feed gas stream before producing the final LNG product. Since these heavy gas liquids contain very high calorific heating values (measured by Btu content) relative to typical pipeline quality gas, Libyan LNG has historically been too "hot" for consumption without further treatment in downstream gas markets. The existence of UN and US sanctions effectively prevented the import of necessary technology and equipment to remove the heavy liquids before processing into LNG. As a result, the Marsa El Brega LNG facility has only been operated at a third of its design capacity of 3.5 billion cubic meters of gas per year, since its LNG product was only of interest to a limited number of buyers, such as Enagas, who possessed the necessary (and relatively expensive) liquids removal facilities at the LNG import terminal.

It has been estimated that 80% of Libya's natural gas reserves are located in the Sirte basin, with the remainder of known reserves located in the Ghadames basin and offshore under the Pelagian shelf. Libya's largest gas field to date, the Attahaddi field, began producing gas at the rate of 300 million cubic feet per day in 2002. This field alone contains 9-10 trillion cubic feet of proven gas reserves and is located near the Marsa El Braga LNG facilities. The Marsa El Brega plant's proximity to these considerable gas reserves, and the likelihood that these reserves will significantly increase with new exploration and production activity, make it an ideal candidate for upgrade and expansion in the near future. Shortly after the US sanctions were lifted, Shell was reported to have signed a contract with the Libyan National Oil Company to conduct new gas exploration activities and overhaul and possibly expand the existing LNG plant facilities. Numerous other oil and gas industry players will no doubt soon follow, particularly players such as Marathon Oil, ConocoPhillips, Occidental, and Amerada Hess, who will be negotiating the return to concessions they were awarded prior to being forced to leave following the imposition of sanctions.

> Libya's rebirth as a huge gas exporter will have consequences for neighboring countries that are hoping for a share of the lucrative LNG export market.

How all of this pipeline gas and LNG export activity ultimately plays out will make for interesting watching and plentiful opportunities for oil companies, service providers and financiers with the fortitude to venture quickly into this former "axis of evil" country.

Of particular interest will be the effect of this significantly transformed LNG player on the plans and prospects of Algeria, itself a longtime LNG exporter that recently announced its interest in licensing a new LNG export project later this year, and Egypt, which recently joined the world LNG ranks with the development and construction of at least two greenfield LNG export projects, one of which will begin operating in late 2004 and the other in 2005-2006. The cost to produce LNG from a greenfield project is usually higher than production from an expansion to an existing facility, so the Libyan LNG facility has at least a theoretical edge (although any expanded production from Libya is still a few years behind the first Egyptian LNG exports). The significance of this edge will depend on just how much new investment is required to overhaul and expand this 33 year-old facility.

Libya's proximity to Europe and the U.S. relative to West African and Middle Eastern LNG producers will also almost certainly foster greater competition for those LNG suppliers as well. For countries, such as the US, that are seeking to reduce their dependence on any one region for their critical energy supplies, this new LNG supply source is very welcome news. It is in some ways ironic that the country that now needs these energy supplies the most was the very country that for political reasons deprived itself (and much of the world) of access to these supplies for almost two decades. ◎

Libya Unveils Terms for Foreign Investors

by Nabil Khodadad, in London

Libya released the details in late April of the business deal it expects with foreign oil and gas companies that want to do business in the country. The terms are to be set out in a new model exploration production sharing agreement called "EPSA-4."

Two weeks later, it announced that eight exploratory blocks will be offered for oil and gas exploration to qualifying investors by the end of June.

Background

Fewer than 10 years after the first commercial oil discovery in Libya at Amal and Zelten (now Nasser) in 1959, Libya was producing 3.7 million barrels of oil a day. As a result of United Nations and United States sanctions and a lack of investment, Libyan production has slipped to only about a third of that amount. In a bid to reverse this decline and to double its output to three million barrels */ continued page 26*

IN OTHER NEWS

passed through the exporter's bank account, according to Ana Karina de Souza and Camila Silva with Machado, Meyer, Sendacz e Opice Advogados in São Paulo. The April 2 provisional measure requires exporters to repay such loans from their own bank accounts. Thus, a tax would have to be paid as the loan is repaid out of the export earnings.

Brazilian companies buying goods or services from suppliers often avoid CPMF tax currently by borrowing the money needed and instructing the bank to pay the loan proceeds directly to the supplier. This avoids an extra CPMF tax by bypassing the supplier's bank account. However, after the April 2 provisional measure, such loans must be deposited in the borrower's bank account, with the result that he will not be able to avoid CPMF while paying his suppliers.

The new rules are scheduled to take effect on August 1.

BOLIVIA is expected to start collecting a financial transactions tax on July 1. The tax will be 0.3% the first year and then drop to 0.25% the next year. It had originally been scheduled to go into effect two months earlier.

BULGARIA is expected to reduce the corporate tax rate from 19.5 to 15% starting in 2005.

The government called for the reduction in the latest budget in late April. The budget must still be approved by parliament, which is not expected to act until late in the year, according to Maria Dimitrova with the law firm Djingov, Gouginski, Kyutchukov & Velichkov in Sofia.

ITALY ruled out deductions for payments to tax havens.

Italy refused in April to let an Italian company deduct payments it made to a company in Lichtenstein for services. Payments to companies located in tax havens cannot be deducted unless the Italian taxpayer making the payments can show */ continued page 27*

Libya

continued from page 25

per day, Libya is seeking to attract $30 billion of foreign investment in its upstream and downstream sectors during the next decade and is lobbying OPEC for an increase in its export quota from 1.26 million barrels a day to at least two million barrels a day by 2007.

The state-owned National Oil Company has announced that all future exploration agreements will be awarded on the basis of public competitive bids.

Libya released details of the business deal it expects with foreign oil and gas companies that want to do business in the country.

There have already been three generations of EPSAs, or production sharing agreements. EPSA-4 is an attempt to introduce a more investor-friendly model agreement and to incorporate some clauses drafted into a new petroleum law expected to be approved by the General People's Congress for release this summer. The new hydrocarbons law will cover a variety of agreements, including joint ventures, production sharing agreements and service contracts. The existing hydrocarbons law was adopted in 1955 and covers only concession agreements.

Libya has remapped its landscape into about 250 blocks, each spanning one degree longitude and one degree latitude. The National Oil Company announced that a minimum exploration program will be pre-determined for each of the eight blocks and that bidding will be on a single bid basis per agreement. The blocks on offer are intended to be a representative sample of onshore and offshore blocks and include eight unexplored blocks scattered across five of Libya's seven oil and gas basins. The blocks being auctioned include one in the western Ghadames basin (a gas-prone basin), one in the northeast Cyreaica-Botnan basin, two in the western Murzuq basin, two in the Sirte basin (Libya's most prolific area) and two offshore in the Mediterranean.

As only 25% of Libya's oil and gas acreage is covered by exploration licences and as most of Libya has not been explored using modern techniques, Libya offers significant unexplored potential in the view of Wood McKenzie. According to the *Oil and Gas Journal*, Libya represents an "underexplored, underinvested, risk-filled, yet opportunity-laden country." Officials at the National Oil Company boast that Libya has experienced a 50% exploration success rate between 1993 and 2003 with 136 of the 270 wells drilled finding reserves.

With its proximity to Europe, high quality sweet crude oil and very low operating costs of on average $5 per barrel (and set to fall as foreign investment grows) and for some fields under $1 per barrel, Libya is attracting a lot of interest from the international oil and gas community.

Oil and gas companies such as Agip/ENI, Hellenic Petroleum, OMV, ONGC, PetroCanada, Repsol, Shell, Total, Turkish Petroleum, Wintershall, and Woodside Petroleum and are active in Libya. Agip/ENI is the most active foreign producer and accounts for about 16% of Libya's total output.

However, US oil companies are now poised to play a big role in Libya's oil and gas sector. As a result of the President Bush's recent decision to lift most economic sanctions against Libya, the National Oil Company anticipates keen interest in the exploration tender from US oil companies that for the first time in two decades will be allowed to do business in Libya. In addition, those US companies (such as Amerada Hess, ConocoPhillips, Marathon Oil Corporation and Occidental Petroleum Corporation) that have frozen assets in Libya are in the process of renegotiating their concessions. As evidence of the thaw in US-Libya relations, US oil companies are reopening their offices in Tripoli and the first shipment of Libyan crude oil to the US in 18 years is scheduled to load on June 3.

Business Deal

Under the new regime contemplated by EPSA-4, contracts will be awarded on the basis of competitive bidding instead of by way of closed negotiations. Under EPSA-4, foreign companies will be responsible for exploration and appraisal costs during a minimum exploration period of five years. However, any development expenditures and exploitation capital expenditures will be borne by the National Oil Company and the foreign contractor on an equal basis. Exploitation operating expenditures are also to be borne by the National Oil Company and the foreign contractor according to their primary production allocation. The development and production period will be 25 years for crude oil and associated gas and up to 30 years for non-associated gas.

Under EPSA-4, the National Oil Company will first take a predetermined share of any crude oil or gas produced. This differs from the practice of production sharing agreements used in most parts of the world where priority is given to cost recovery. The foreign contractor will then be allowed to recover its costs from the remaining balance. Any crude oil (or gas) remaining after cost recovery will be shared according to a set formula. The share of the remaining balance bidders offer to the National Oil Company will be the primary criteria for awarding contracts. In the event that two or more bidders offer the National Oil Company the same share, the bidder with the largest signing bonus will be awarded the contract.

Foreign companies will also be required to pay production bonuses upon making commercial discoveries and production bonuses upon reaching certain prescribed production levels. Bonuses are not recoverable by the foreign company from cost oil. Although foreign companies will be subject to income taxes and production royalties, such taxes and royalties will be taken out of the National Oil Company's share of crude oil (or gas), and the National Oil Company will be responsible for procuring an official receipt from the relevant authority confirming payment of such amounts.

During the exploration period, the foreign contractor will not be able to assign its interest in the agreement to a third party unless it has completed the minimum exploration program required by EPSA-4. After the making of a commercial discovery and during the exploitation period, all assignments will be subject to a pre-emption right in favour of the National Oil Company. / continued page 28

IN OTHER NEWS

that the recipient conducts a real business in the tax haven or that there was a business purpose for the arrangement. The taxpayer in this case claimed a business purpose: it argued that the Lichtenstein company helped it bring in another customer worth €1.2 million a year. The Italian authorities were not persuaded.

The ban against deductions only applies to payments to companies in tax havens outside the European Union. Thus, a payment to a company in Holland or Luxembourg would not be affected.

TURKEY is considering new tax holidays as an inducement to foreigners to invest in the country.

A committee with representatives from the Ministry of Finance and the Tax Council (which is an independent panel of tax experts) is working on a proposal to present to parliament. The proposal is that there should be a 10-year holiday from income taxes for investments of more than €150 million. In years 11 through 15, earnings from such investments would be taxed at only half the normal income tax rate. The corporate tax rate is currently 33%.

Investments of at least €100 would receive a 7-year tax holiday. The tax holiday for investments of at least €50 would be five years. Companies will be required to hire at least a minimum number of employees. Improvements to existing facilities will benefit from the new tax holidays on 40% of revenues.

Mustafa Uysal, head of the Tax Council, said the government hopes to put the new law through parliament this year, ideally before the parliament leaves on holiday in August.

INDIA cannot tax foreign companies doing business in the country at a higher rate than it taxes local companies, a tax tribunal ruled.

India taxes domestic companies at a 35% rate. Foreign companies are taxed at 40%. The decision by the tax tribunal only affects foreign companies that are in a / continued page 29

Libya

continued from page 27

Any disputes under EPSA-4 are subject to arbitration in Paris under the rules of the International Chamber of Commerce, with each party appointing one arbitrator and the third arbitrator being appointed by the International Chamber of Commerce.

EPSA-4 offers several improvements over its predecessor EPSA-3, which the National Oil Company credits with attracting over $1 billion dollars in foreign investment, primarily from European companies, since its launch in 1988. EPSA-4 includes a comprehensive gas clause that provides that natural gas discovered and produced by foreign contractors will be marketed jointly with the National Oil Company. Domestic gas sales will be indexed to international fuel prices, while gas sales to Europe will be tied to other fuels used for generating power in such region. If a market is not available, then foreign companies will not be required to appraise their gas discoveries. EPSA-4 also extends the development and production period for non-associated gas from 25 to 30 years.

An abandonment clause has been added to EPSA-4 that requires each of the foreign contractor and the National Oil Company to bear and finance 50% of all costs related to the abandonment of installations and site restoration and provides a mechanism whereby provisions for estimated abandonment and site restoration are deposited in an interest-bearing account.

EPSA-4 also gives foreign contractors more influence over decision making by the management committee. Under EPSA-3, the National Oil Company had the right to appoint two members to the management committee while the foreign contractor had the ability to appoint only one member. All decisions of the management committee were taken by simple majority. The management committee's powers are substantial and include the right to approve work programs and budgets. EPSA-4 calls for unanimous voting and thus gives the foreign contractor the power to block decisions of the management committee, a power that it did not have under EPSA-3. EPSA-4 also provides that as soon as a commercial discovery is declared, the operatorship shall be transferred from the foreign contractor to a company jointly owned by the foreign contractor and the National Oil Company. The management of the operator will be composed of four members, with two members appointed by each party. All decisions will be by simple majority of its members. ◎

A foreign investor will not be able to assign its interest in its concession to a third party until it has completed a minimum exploration program.

When to Restate Oil and Gas Reserves

by Joaquin M. Sena, in Washington

Oil and gas companies use outside consultants and internal advisory committees to verify their oil and gas reserve estimates. Internal disagreements are inevitable about the amount of estimated reserves and how to classify the reserves. When this happens, at least two questions are in the back of everyone's mind: What do we do, and will we have to restate the financials?

The answer to the first question is to determine whether an error has been made and whether it materially affects the company's financial statements.

If an error was made and it materially affects the company's financial statements, then the financials must be restated.

The author served for 12 years in the enforcement division of the US Securities and Exchange Commission, most recently as assistant chief litigation counsel in the division's trial unit.

To determine whether an error was made, begin by listing where the experts disagree. Determine whether the differences can be reconciled. Is the problem that the experts disagree about the quantity of reserves or how to classify them? As discussed below, discrepancies in quantity estimation may result from the use of different methods of estimation. Discrepancies in reserve classification may be attributed to different opinions about the reasonable certainty of recoverability.

A clear case for restatement is one where the financials contain a material misstatement due to an error in either quantity estimation or classification of oil reserves. A more complicated situation arises when none of the differing opinions is necessarily wrong. In this latter situation, the best approach would be to confer with the SEC staff or else err on the side of full disclosure and include a footnote in the financials that explains the difference in opinion and the magnitude of the difference. If the financials have already been filed, then the explanation can be included in an SEC Form 8-K.

Why Care?

The booking of oil and gas reserves has taken on increased significance as a result of both new legislation and new regulatory policies.

The new developments that are playing a role include the Sarbanes-Oxley Act in 2002, the decision by the SEC enforcement division to scrutinize the oil and gas industry, and the ambiguities in SEC Rule 4-10(a), which defines how oil and gas reserves should be classified. Both officers and directors of oil and gas companies are finding themselves under increasing regulatory and prosecutorial scrutiny and are potentially exposed to liability. This has led them, in turn, to seek the opinions of independent advisers and audit committees to confirm their estimates of reserves and the accounting for them. Unfortunately, the likelihood of disagreement rises along with the number of opinions sought.

Sections 302 and 404 of the Sarbanes–Oxley Act impose new responsibilities upon chief executives, chief financial officers and upper management. They require certification of the companies' periodic reports to the / continued page 30

IN OTHER NEWS

position to benefit from tax treaties between their home countries and India that bar discriminatory tax treatment. Such treaties usually require the foreign company to do business through an office or other "permanent establishment" in India.

The company whose case was heard by the tax tribunal was based in the United Kingdom. The decision was reported in late April in the Economic Times.

BANKRUPTCY did not discharge taxes owed to the United States.

The US government has the right in certain circumstances to go after anyone who is transferred assets by a company for income taxes that are owed by the company. This is called "transferee liability." It exists when a company liquidates and distributes all of its assets to its owners. It also exists when a company that is insolvent at the time distributes just some of its assets to its owners while the company remains in business. In such cases, the US government can pursue the owners for income taxes that the company should have paid.

The owners cannot escape this tax liability by filing for bankruptcy, a US appeals court said in May.

The US bankruptcy laws generally allow someone going through bankruptcy a fresh start; he gets to shed his debts and start over. However, this does not apply to income taxes. Such taxes are not discharged in a bankruptcy proceeding.

The case in May involved an individual who was the sole owner of a corporation. The corporation liquidated in 1987 and distributed all of its assets to its owner. The owner filed for bankruptcy in 1995 and was discharged from all of his debts. However, it later came out that the corporation had failed to file an income tax return for 1987, and it owed $481,180 in taxes that year. The IRS pursued the owner for the taxes. A bankruptcy court said the IRS was out of luck, since its claim / continued page 31

Restating Reserves

continued from page 29

SEC and the filing of internal control reports along with the companies' annual reports.

The SEC requires that both the CEO and the CFO of a company certify for every report the company filed with the SEC that they have reviewed the report, it does not contain any material misrepresentations or omissions, the financial statements fairly present the financial condition and results of the company, they are responsible for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting for the company, and they have disclosed any fraud and all significant deficiencies concerning the internal controls.

The SEC also requires management to provide an "internal control report" that contains a statement about the quality of the company's internal controls. Management must confirm that it has responsibility for maintaining adequate internal controls over financial reporting. It must describe how it evaluates the effectiveness of the internal controls. It must give its assessment about whether the internal controls work. And it must state that the company's auditor attested that the internal controls that the company has in place work. In sum, sections 302 and 404 of the Sarbanes-Oxley Act require public energy companies and their executives to stand by the financial statements of the company, ensure they are correct by implementing strong internal controls, and explain what those internal controls are and how effective they are.

The SEC increased its scrutiny of oil company reserves following the recent announcement by Shell Oil that it was restating its reserves. Officials from the SEC enforcement division said at an "SEC Speaks seminar" in Washington in early March that one of the enforcement practices to be expected in coming years is for the staff to examine several companies within an industry when the agency finds problems at just one company within the industry.

When to Restate

Unfortunately, the SEC has not explained how to estimate reserves. Not all companies or independent estimators use the same methods. Technology advances also contribute to differences in methods. Thus, there is room for a wide variety of conflicting opinions about reserve estimates.

Companies should follow some simple rules of thumb to avoid violating US securities laws when experts disagree about the size of their oil and gas reserves.

However, SEC rules do explain how reserves should be classified. Classification of reserves involves determining whether a company's oil and gas reserve estimates can be categorized as "proved oil and gas reserves," and if so, whether they are developed or undeveloped. The definitions for these classifications are set out in what is referred to as SEC Rule 4-10(a).

Rule 4-10(a) defines "proved oil and gas reserves" as "the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with *reasonable certainty* to be recoverable in future years from known reservoirs under existing economic and operating conditions, *i.e.*, prices and costs as of the date the estimate is made."

"Reasonable certainty" of recoverability is subjective and can easily be an area of disagreement among advisers. In 2001, the SEC staff attempted to explain what constitutes "reasonable certainty" by issuing an "interpretation and guidance" essentially stating that, in order for there to be reasonable certainty, there must be geological and engineering data supporting the amount of estimated proven reserves. Accordingly, more supporting data justifies classifying more reserves as proven, and less data requires a more conservative approach, whereby fewer estimated reserves are classified as proven. More recently, a member of the SEC staff defined "reasonable certainty" as situations where there is little doubt that the reserves could be higher.

In speeches to industry groups, SEC staff members have provided fairly objective examples of when reasonably certainty does *not* exist. Such certainty does not exist in a number of situations. One is where the assumptions are at odds with current economic and operating conditions. Another is where a company defers the same project year after year and appears unwilling or unable to proceed with production. A third is where management has not made a substantial financial commitment, does not have sufficient funds to make such a commitment, or lacks requisite legal permits or concessions to pursue the project.

In 2001, in a case called *In re Triton Energy Ltd. Securities Litigation*, a federal district court in Texas acknowledged similar indicia of a lack of reasonable certainty and refused to dismiss a civil compliant alleging that an oil company materially misstated its proved reserves. The facts that the court found significant were a lack of facilities to process and transport reserves to market, no commitment to install such facilities, no definitive contract, no success in obtaining a definitive contract despite repeated attempts, and no capital to overcome contingencies to obtaining a definitive contract.

Any company that is faced with different opinions about its reserve classifications should review the classifications in light of each of the factors listed above. This would go a long way toward determining whether sufficient "reasonable certainty" of recoverability exists in order to classify the reserves as "proven," and would probably resolve most points upon which the advisers differ.

Conclusion

To sum up, differences in opinion concerning oil and gas reserve estimates and classification may result from errors or from the use of different methods, economic assumptions or geological and engineering data. These differences may be resolved through a review of the supporting methodologies, assumptions and data. If differences in estimation of proven reserves cannot be reconciled in this way, then they may be addressed by conferring with the SEC staff engineers responsible for oil and gas issues or by disclosing an explanation of the difference in either a note to the company's financials or a Form 8-K. If a review reveals an error in the estimation of proven reserves, and that error materially affects the company's financial statements, then they must be restated. ◎

IN OTHER NEWS

against the owner was not a "tax" but rather a general unsecured debt. The only "tax" was owed by the corporation; its claim against someone else for the amount was just a general debt.

However, a US appeals court said in May that while the bankruptcy court may have been right technically, its decision made no sense as a policy matter.

The court said transferee liability for taxes should be treated as a "tax" for purposes of what gets discharged in bankruptcy. The case is McKowen v. IRS.

MINOR MEMOS. The US Treasury is being urged to waive withholding taxes on dividends that US companies pay to shareholders in the United Kingdom. A tax treaty between the two countries bars the United States from collecting withholding taxes on dividends paid to UK shareholders, but only to UK shareholders who own at least 80% of the US company *directly*. The US Treasury is being asked to allow *indirect* shareholders also to benefit. This would let a UK company that owns at least 80% of the US shares, but through more than one subsidiary, benefit from the treaty. If the US Treasury relents, then the same principle should apply to US outbound investment into the United Kingdom . . . . The US Tax Court said in May that large gasoline tanks that last more than 60 years and weigh up to a million pounds are not "inherently permanent structures" for US tax purposes. The conclusion means that the tanks can be depreciated over five years. The case is *PDV America v. Commissioner*.

— contributed by Keith Martin, Samuel R. Kwọn and Micaela Garcia-Ribeyro in Washington, Ayse Yüksel in New York, José Ibarra in Mexico City, Maximiliano Batista in Buenos Aires, Ana Karina de Souza and Camila Silva in São Paulo, and Maria Dimitrova in Sofia.

Environmental Update

Kyoto Protocol

The news in late May that Russia will ratify the Kyoto protocol means that power companies operating in countries outside the United States will have to take steps to limit carbon dioxide.

Russian President Vladimir Putin unexpectedly announced on May 21 that Russia would move rapidly to ratify the protocol. The protocol to the "United Nations Framework Convention on Climate Change" was adopted in 1997 and sets deadlines for reducing greenhouse gas emissions. The first compliance period is 2008 to 2012.

Just last December, a senior aide to Putin said Russia would not ratify the Kyoto protocol in its current form because the treaty would hamper economic growth in Russia. Russia's abrupt turnaround may have been driven by concessions that Russia received from the European Union, including an invitation to join the World Trade Organization and an agreement to allow gas prices paid to Russian producers to double by 2010.

The Kyoto protocol will enter into force after it has been ratified by 55 or more countries whose combined emissions levels represent at least 55% of the carbon dioxide or CO_2 emissions from industrialized Annex I countries in 1990. As of April 15, 2004, 122 nations had ratified the treaty, and those nations accounted for 44.2% of the 1990 CO_2 emissions. Russia alone accounts for 17.4% of the 1990 CO_2 emissions. The United States has rejected the treaty citing serious concerns about the potential effect of implementing dramatic reductions in greenhouse gas emissions on the US economy and asserting that large developing countries, such as China and India, should also be obligated to cut greenhouse gas emissions if the US is expected to do so.

Notwithstanding the Bush administration's objections to implementing mandatory greenhouse gas emission reductions, state governments in the United States are pressing forward with their own efforts to address climate change issues on a statewide or regional basis. In May, the Connecticut legislature passed legislation that calls for the reduction in greenhouse gas emissions to 1990 levels by January 1, 2010, and 10% below the 1990 levels by January 1, 2020. The Connecticut legislation also requires the state Department of Environmental Protection to report annually on the progress toward achieving the mandated reductions. The measure had not yet been signed into law by the Connecticut governor as the *NewsWire* went to press.

Massachusetts Governor Mitt Romney released a comprehensive climate change protection plan in May that calls for the same levels of reductions in greenhouse gas emissions as Connecticut. The plan urges all sectors to partner with the state in reducing greenhouse gas emissions to 1990 levels by 2010. The plan calls for a further 10%reduction in greenhouse gas emissions by 2020 to be achieved through strict standards for coal-fired plants, the promotion of renewable energy, increased energy efficiency and cleaner burning vehicles. The Connecticut and Massachusetts efforts follow up on a regional commitment that the Conference of New England Governors and Eastern Canadian Premiers adopted in August 2001 to address greenhouse gas emissions.

The news that Russia will ratify the Kyoto protocol means that power companies operating in countries outside the United States will have to take steps to limit carbon dioxide.

In related news, the European Commission recently warned several European Union countries that they could be obligated to compensate companies for potential losses due to delays in implementing the EU emissions trading program that is scheduled to take effect on January 1, 2005. Only nine of the EU member countries have submitted their national emission allowance plans: Germany, Finland, Ireland, Denmark, Austria, Luxembourg, the Netherlands, Sweden and the United Kingdom. The EU emissions trading program is one of the key elements of the group's commitment to achieve its Kyoto protocol target of reducing greenhouse gas emissions to 8% below 1990 levels during the 2008 to 2012 time period.

Mercury

Three environmental groups sued in late April to force the US Environmental Protection Agency to issue final maximum achievable control technology or MACT standards quickly for new and existing coal and oil-fired power plants.

The environmental groups charge that the proposed "utility mercury reductions rule" is inadequate and fails to comply with the MACT-setting standards of the Clean Air Act. The environmental plaintiffs also charge that EPA was supposed to come out with the final rules by December 20, 2002 — two years after EPA made a finding that the regulation of hazardous air pollutants or HAPs from coal and oil-fired power plants was "appropriate and necessary."

The environmental suit appears aimed at pressuring EPA into promulgating a final rule that is more stringent than the current proposal. The current schedule for issuing a final rule to regulate HAPs from coal and oil-fired power plants came out of a 1998 settlement between the Natural Resources Defense Council, or NRDC, and EPA. In the mid 1990s, NRDC filed a similar suit alleging that EPA had failed to take action to regulate HAPs emitted by such plants. The three environmental groups will probably take the position that they are not bound by the NRDC-EPA settlement, and will press the US court of appeals in Washington to set an expeditious briefing schedule.

The appeals court may be reluctant to hear the case because EPA already has a schedule for writing the rule, and an analysis of whether EPA's mercury rule ultimately complies with the requirements of the Clean Air Act is an issue that will not be "ripe" until after the final rule is issued.

The lawsuit highlights the intense scrutiny that EPA's proposed utility mercury reductions rule is facing. At public hearings earlier this year, EPA received a barrage of negative comments, and numerous public interest groups, politicians, and local and state agency air officials urged that the proposed rule be withdrawn and rewritten. In mid-May, seven Democratic Senators asked the inspector general at EPA to review the process that the agency followed in developing the proposed mercury rule. Opponents of the EPA proposal claim that the "cap and trade" option is not authorized by the Clean Air Act, the mercury reduction targets are not sufficiently stringent, and the compliance deadline for achieving the emission reductions under the "cap and trade" approach is too far off. Some industry groups have also criticized the rule as favoring western coal over eastern coal.

Despite the strong dissent, EPA has affirmed that it will not withdraw the rule, but it did agree to extend the comment period for 60 days to June 29, 2004. NRDC also agreed to allow EPA to extend the deadline to finalize the utility mercury rule from December 15, 2004 to March 15, 2005. EPA said it intends to conduct additional analysis during the next few months, including addressing whether a mercury trading rule could cause local spikes or "hotspots" in mercury pollution. Any additional EPA analysis will be made available for public comment before the rule is finalized.

In the proposed utility mercury reductions rule, EPA took a unique approach in releasing two alternative approaches toward regulating mercury emissions from coal-fired plants and nickel emissions from oil-fired plants. The first approach is a traditional "command and control" MACT standard that would require achieving mandated air toxics reductions by December 2007. The second approach is an emission "cap and trade" program that is designed to use market forces to achieve the necessary reductions. The Bush administration favors the latter approach.

Environmental groups claim that EPA should set a specific MACT standard requiring at least a 90% reduction in mercury from coal-fired power plants. According to EPA, emissions from coal-fired power plants would be reduced by about 30% by 2007 under the MACT standard option and by approximately 70% by 2018 under the "cap and trade" approach. EPA projects */ continued page 34*

that mercury emissions would be reduced from current levels of about 49 tons to 34 tons under the proposed mercury MACT alternative.

Under the "cap and trade" approach, EPA would impose a 34-ton mercury emission cap for the first phase starting in 2010, and a 15-ton cap for the second phase commencing in 2018. One mercury allowance would authorize the emission of one ounce of mercury, and allowances would be issued to coal-fired plants based on a unit's share of the total heat input from existing coal units, multiplied by an adjustment factor that depends on the type of coal. Lignite coals would have a higher adjustment factor because it is generally harder to remove mercury from the emissions of a lignite-fired plant. EPA has proposed adjustment factors of 1.0 for bituminous, 1.25 for sub-bituminous and 3.0 for lignite coals. EPA has also proposed a "backstop" price of $2,187 per ounce of mercury that would effectively cap the price of a mercury allowance under the cap-and-trade option.

EPA's proposed rule would affect a significant number of coal and oil-fired power plants, and the costs to comply with the new rule are expected to be substantial. The rule would apply to power plants with a capacity of more than 25 megawatts that sell their entire output and cogeneration facilities that sell more than one-third of their capacity and more than 25 megawatts.

Ozone Nonattainment Areas

EPA released two significant rules in April as part of the implementation of the 8-hour ozone national ambient air quality standard. The first rule identified all or part of 474 counties in 32 states that currently fail to meet the 8-hour ozone standard. Ozone or ground-level smog is caused by the chemical reaction of NO_X and volatile organic compounds or VOCs in the presence of sunlight.

The number of new nonattainment areas is over twice the 221 counties that are currently out of attainment with the old 1-hour standard. EPA issued the new 8-hour ozone standard in 1997, but implementation of the rule was delayed by protracted legal challenges to the standard. The new 8-hour standard is 0.08 parts per million averaged over an 8-hour period. The old standard was 0.12 parts per million averaged over one hour. States will now have three years, until June 15, 2007, to propose rules designed to achieve reductions in ozone precursors — NO_X and VOCs. These new requirements will take effect over the 2007–2021 period, and may ultimately require the upgrading or installation of additional pollution control technology at existing power plants and industrial facilities.

The second rule addresses implementation of the 8-hour rule and identifies various classifications of nonattainment areas based on the severity of the ozone pollution. Areas that are meeting the old 1-hour ozone standard, but not the new 8-hour standard, are classified as "basic" nonattainment areas, and states have a greater degree of flexibility in determining the reduction measures that will apply in those areas. The 94 basic nonattainment areas must meet the 8-hour standard by June 2009. The implementation rule revokes the less rigorous 1-hour standard on June 15, 2005; however, the rule contains an anti-backsliding provision that requires the specific control measures for the 1-hour standard to remain in place until an area meets the 8-hour standard.

Not surprisingly, the new rule has come under fire from environmental groups, state and local air regulators, and certain industry groups. Even though the new 8-hour standards have swept an additional 253 counties into EPA's ozone nonattainment regulatory regime, environmental groups have criticized the rule as allowing several major cities to be reclassified to less stringent ozone classifications. For example, the Washington, DC area is being reclassified from a "severe" area under the old 1-hour standard to a "moderate" area under the new standard. The difference in classification typically means that emission reduction requirements may not need to be as stringent to reach attainment. EPA's new rule will also push out the time periods for complying with the new standard.

State and local air officials and environmental groups have also criticized a provision of the implementation rule that allows states to exempt "new source review" or NSR requirements from the anti-backsliding provisions. This means that an area that is reclassified to a lower level of nonattainment will have a higher threshold for triggering NSR permitting requirements, including lowering ratios for emissions offsets that are necessary for the siting of new and modified sources in ozone nonattainment areas.

On the heels of the newly-designated ozone nonattainment areas, EPA is readying its nonattainment area designations for the fine particulate matter or PM2.5 standard. In July 1997, EPA issued a new PM2.5 standard, and the agency anticipates that it will issue preliminary PM2.5 nonattainment area designations in August and will finalize the designations by December 31, 2004.

EPA's designation of new 8-hour ozone and PM2.5 nonattainment areas is expected ultimately to trigger the imposition of costly emission reduction requirements, and many of these areas will face significant NO_X, VOC and PM2.5 emission reduction requirements for the first time.

Regional Haze

EPA reissued a proposed rule in April to reduce haze-forming air emissions from power plants and certain other industrial facilities built between 1962 and 1977.

It applies to such power plants and industrial facilities with a potential to emit over 250 tons a year of any of five visibility-impairing pollutants that affect 156 national parks and federal wilderness areas, so-called "class I" areas under the Clean Air Act. The five pollutants are NO_X, SO_2, particulate matter, VOCs and ammonia. The proposed rule establishes guidelines for the states to determine the best available retrofit technology or BART standards for these older plants.

Under the regional haze rule — issued in July 1999 — emission sources that are reasonably anticipated to cause or contribute to class I visibility impairment must install BART controls. The rule was immediately challenged in court, and in 2002, a US appeals court in Washington set aside a key provision of the rule that would have allowed states to impose pollution control requirements on a group of sources instead of individual sources. In *American Corn Growers Assoc. v. EPA*, the court concluded that before BART controls may be imposed, the Clean Air Act requires a finding that a particular source contributes to visibility impairment at a class I area.

The proposed amendments to the regional haze rule respond to the appeals court decision. Under the proposal, states would now be required to consider a particular plant's individual impacts on visibility conditions in a class I area when determining whether that source will need to install BART controls. The proposal includes an individual source exemption process where a state can use air modeling data to demonstrate that a plant does not affect a class I area.

The proposed rule revises the BART guidelines that were originally proposed in 2001, and it also adds a specific emission standard for NO_X and refines the SO_2 standard. For power plants, the proposed rule recommends an SO_2 removal efficiency of either 95% or an emission rate ranging from 0.10-0.15 lb/MMBtu. The presumptive NO_X emission standard for units with selective catalytic reduction systems or SCRs calls for operation of the SCRs year round. Affected plants without SCRs would need to achieve a presumptive NO_X emission rate of 0.20 lb/MMBtu.

Under the regional haze rule, states must identify facilities required to install BART controls by January 2008. The reductions required by the regional haze rule would begin to take effect in 2014, with full implementation before 2018. EPA's regional haze rule is expected to affect a number of older power plants and other industrial facilities that have not previously been required to install or upgrade pollution controls to reduce NO_X, SO_2, particulate matter and VOCs.

Interstate Air Quality

EPA released a supplement to its interstate air quality rule in May. The supplemental proposal includes implementation details and a model multi-state cap-and-trade program designed to reduce SO_2 and NO_X emissions from power plants. In implementing a cap-and-trade program, EPA would determine the state emission budgets and the states would be responsible for allocating the allowances to the affected sources.

EPA proposed its interstate air quality rule in January 2004. It directs 29 states and the District of Columbia to issue new regulations that will require major SO_2 and NO_X reductions in two stages. The proposed rule calls for a 3.9 million ton emission cap on SO_2 emissions from affected sources by 2010, approximately a 40% decrease from current SO_2 emission levels, and a further cut to a cap of 2.7 million tons of SO_2 emissions by 2015, for a total reduction of about 70% from current SO_2 levels. Under the proposed rule, NO_X emissions would be reduced to a cap of 1.6 million tons by 2010, with a further reduction to a cap of 1.3 million tons by 2015, for a total NO_X reduction of about 65%.

In the proposed supplemental rule, EPA is also tentatively concluding that emission reduc- */ continued page 36*

Environmental Update

continued from page 35

tions achieved by power plants under the model cap-and-trade program in the interstate air quality rule would be sufficient to satisfy the BART requirements imposed under the regional haze rule discussed earlier. EPA believes that the interstate air quality rule will achieve more stringent reductions in NO_X and SO_2 than potentially required under the regional haze rule.

Brief Updates

The Maryland legislature passed a renewable portfolio standard or RPS bill in mid-April that is currently awaiting signature by Governor Robert Ehrlich. If signed into law, 3.5% of the state's electricity would have to come from renewable sources such as wind, solar and biomass starting in 2006. Under the legislation, the RPS requirement would gradually ramp up to a level of 7.5% by 2019.

A recent decision by a US appeals court in *U.S. v. Allegheny Ludlum Corporation* recognized that "laboratory error" resulting in the overreporting of wastewater discharges is an acceptable defense to a mitigate Clean Water Act penalties.

A May 4 decision by another US appeals court called into question the ability of a company to expand its existing facilities when it has outstanding noncompliance issues at other facilities. In *Sierra Club v. EPA*, the court concluded that EPA improperly rejected the Sierra Club's concerns that a new source review or NSR permit to construct a new unit at an exiting plant should not have been issued by the state of Georgia because one of the owners of the new unit was part owner of another plant in Georgia that was subject to a pending NSR enforcement complaint.

In May, an Ohio citizens group with members living near the James A. Gavin power plant sued American Electric Power Co. alleging that sulfuric acid mist emissions from the plant violate the Resource Recovery and Conservation Act by imposing a "substantial and imminent" danger to public health. The coal-fired plant is equipped with selective catalytic reduction systems or SCRs that use ammonia as a catalyst to reduce NO_X emissions. Operation of the SCRs increases the formation of sulfuric acid mist. The lawsuit also charges that the utility violated the "Superfund" statute by failing to report sulfuric acid releases.

Opening briefs were filed recently in *New York v. EPA*, a lawsuit challenging a December 2002 rule the US Environmental Protection Agency issued to revise the NSR permitting program applicability provisions. Fourteen states and the District of Columbia filed a brief in support of their challenge to the rule. A coalition of environmental groups and a group of 10 US Senators filed separate briefs in support of the states' position. A decision on the challenge is not expected until later this year or early next year.

— contributed by Roy Belden in New York

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

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

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

350 South Grand Ave.
Suite 3300
Los Angeles, CA 90071
(213) 892-1000

Beijing Representative Office
Beijing Kerry Centre
1 Guang Hua Road, Chao Yang District
Beijing 100020, China
+86 (10) 8529-8892

Riverside Towers
52/5 Kosmodamianskaya Nab.
Moscow, Russian Federation 115054
+7 (095) 974-2424
Direct line from outside C.I.S.:
(212) 408-1190

11 Mykhailivska Street, 4th Floor
Kyiv 01001, Ukraine
Telephone +380 (44) 230-2534
Facsimile +380 (44) 230-2535

Chadbourne & Parke
Radzikowski, Szubielska and Partners LLP
ul. Emilii Plater 53
00-113 Warsaw, Poland
Telephone +48 (22) 520-5000
Facsimile +48 (22) 520-5001

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