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US Heading For Merchant Plant Overdevelopment

by Christopher Seiple and Dr. Arnold Leitner, with RDI Consulting in Boulder, Colorado

Power shortages and price spikes in many areas of the United States this summer have put the electric power industry in the public spotlight and sparked demands for reregulation of the industry. However, our research indicates that that these price spikes and shortages will be temporary and that as early as next year some regions could be facing a glut of oversupply in the wholesale electricity market.

This glut is likely to begin just after developers and financiers ante up more than $30 billion in investment in new generating capacity.

Boom-and-Bust Cycles

Critical to success in a commodity market, such as electricity generation, is knowing when to buy, sell, or build generating assets. Academic research indicates that firms that are best able to drive their strategy by understanding cyclical trends are able to increase their return on investment by 3 to 4%.

No one can precisely predict boom and bust cycles in the future. However, a carefully structured analysis of the supply and demand balance that identifies the key sources of uncertainties and uses quantitative tools to assess the impact of these uncertainties provides a strong framework within which to develop a corporate strategy. To provide such an analysis, RDI employed a probabilistic model based on decision tree theory. This model incorporates uncertainty by applying probabilities to possible events and analyzing these events in hundreds of possible scenarios.

Our research indicates that four primary factors contribute to cyclical pricing trends in commodity industries.

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MERCHANT PLANT INTERTIES remain under study at the IRS.

Independent power companies must pay the cost of connecting their power plants to the utility grid. The power company usually reimburses the utility for the cost of the intertie and any system upgrades required. The utility owns this equipment. At least since 1988, the IRS has not taxed the utility on the value of the equipment.

However, Judith Dunn, the deputy IRS chief coun-

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Lumpy Capacity Additions

One of these factors is the lumpiness of capacity additions in relation to a commodity's demand growth. This typically occurs in new or small industries where there are large economies of scale associated with capacity additions in relation to overall demand growth. For instance, demand for a new product may be increasing at 30% per year, but the construction of one new manufacturing facility may double manufacturing supply. Such conditions would likely create oversupply conditions for this product.

RDI believes that this factor could influence generation markets that are small in size due to a lack of transmission interconnections to neighboring regions. For instance, in eastern New York – an area where capacity is currently scarce – the peak demand is approximately 10,000 megawatts. Due to weak transmission interconnections, eastern New York is relatively isolated from the rest of the New York electricity grid. PG&E Generating is currently pursuing development of a 1,000 megawatt power plant in the region. Such a plant would increase overall supply by more than 10% in a market that is growing at a rate of less than 2% a year. Such a large capacity addition could meet future demand growth for as much as the next five years, causing a prolonged bust period in electricity prices.

Supply-Side Uncertainty

Another factor contributing to cyclical pricing trends is supply-side uncertainty. In some markets, the industry as a whole may be unaware of how much new supply is in the pipeline. Thus, companies acting independently pursue new capacity development that results in oversupply for the market as a whole.

Many conditions point to supply-side uncertainty in electricity markets:

- The long lead time of new power plant development – up to three years – and the uncertainty associated with the likelihood of individual projects going forward.
- Increases in capacity at existing units are occurring without public announcements.
- The development of unanticipated distributed generation could add to existing supply.
- Improvements in plant performance, combined with additional interruptible demand, could reduce the amount of reserve capacity required to provide the same level of reliability.

New Capacity Additions (MW)

		OPERATING/UNDER CONST.			ADVANCED DEV.		
Region	EOY 1999 SUPPLY	2000	2001	2002	2001	2002	TOTAL AS % OF EOY 1999 SUPPLY
AZNMA/CANVA	78,767	620	3,578	0	1,553	5,390	14%
ECAR/MAIN	161,702	6,811	6,331	0	3,395	4,108	13%
ERCOT	60,876	6,388	8,623	0	3,300	1,100	32%
FRCC	42,342	694	860	3,601	850	1,852	19%
MAAC	57,333	580	700	2,130	165	0	6%
MAPP	42,239	100	984	0	0	0	3%
NEPOOL	25,950	1,911	4,148	0	2,359	3,342	45%
NWPA	51,706	2	734	0	248	1,347	5%
NYPP	36,536	0	0		0	1,440	4%
RMPA	10,674	561	0	80	214	680	14%
SERC	155,766	9,233	8,352	1,940	2,157	5,998	18%
SPP	41,799	2,000	2,633	800	0	1,208	16%
Total	765,690	28,900	36,943	8,551	14,241	26,465	15%

Source: August 15th Release of RDI Consulting's NewGen database

Our research indicates that development of new power plants is currently the key driver of potential market downturns in electricity. The table on the previous page provides RDI's most recent projections of new capacity additions. This table includes only plants that have begun operating, are under construction, or in the advanced stages of development. Developers have proposed a total of more than 290,000 megawatts of new capacity.

Availability of Capital

A third factor contributing to cyclical pricing trends is the availability of capital. In general, companies tend to invest only when returns are high and funds are available either internally or from capital markets. As a result, too much capacity is typically added at the top of a cycle and too little capacity is added at the bottom of the cycle. In most commodity industries, this is the primary driver of boom-and-bust cycles.

In electricity markets it is clear that substantial amounts of capital are currently available for investment. Electricity marketers, such as PECO Energy, Williams and Coral, have played a large role in supporting the availability of capital due to their willingness to sign 20- to 30-year power purchase agreements that limit risk for the developer and for banks financing the project. The substantial cash flow of utilities – especially those securitizing stranded costs – has also contributed to capital availability. Finally, the general fondness the stock market has shown for companies like Calpine and AES is a sign that capital markets are willing to make substantial amounts of capital available for merchant developers.

Incorrect Demand Forecasts

The final factor driving cyclical pricing trends is that producers planning new capacity forecast demand incorrectly. Incorrect demand forecasts have played a substantial role in contributing to the current price spikes of the market. In some regions

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sel, said in a letter to two congressmen the agency made public at the end of July that the IRS is studying whether this policy should continue to apply in "a deregulated marketplace where the producer's power is not sold to the utility but is transported over the utility's transmission lines into a 'power pool' where third-party buyers bid on the producer's power." Dunn said the concern is whether the generator is a "customer" of the utility. Payments by a *customer* to a utility are considered a payment for services and are taxable to the utility.

There have been two meetings this summer with IRS and Treasury officials. The IRS said it plans to issue a revenue ruling when the issues are resolved, but probably not before next year. IRS officials said they would continue to rule that utilities do not have to report interties as income in cases where the generator sells his power to the interconnecting utility under a long-term contract.

THE TREASURY ISSUED A DEPRECIATION STUDY at the end of July.

The long-awaited study was ordered by Congress in 1998 after several industry groups complained that they were being forced to depreciate equipment over a longer period than the real economic life.

The study says the "class lives" on which tax depreciation is based are out of date, but it would take time and resources to update them. More than half of class lives were set in 1962 based on use studies conducted during the 1950's.

The study argues that economic studies — now 20 years old — suggest that tax depreciation is actually more generous in most cases than "economic" depreciation, or the rate at which assets actually depreciate in real life. One way to test this proposition is to look at whether the effective tax rate in an industry falls below the statutory rate of 35%. Treasury calculates the effective tax rate for electric light and

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of the country, electricity demand recently increased by more than 4% annually – substantially higher than was anticipated by most forecasters.

There is ample room for error when trying to predict future demand because of the many variables that must be taken into account. For instance, incorrect forecasts of gross domestic product can contribute to incorrect demand forecasts. Other variables that we considered in our analysis include price elasticities, the feasibility of developing dispatchable demand, the impact of computers on electricity demand, and the weather.

Key Findings

The following table shows our predictions of which regions of the country will be in boom portions of the cycle and which regions will be in bust portions of the cycle in the years 2000, 2001, and 2002. This is based on the results from our probabilistic boom-bust model using decision tree theory and taking into account all of the factors discussed earlier. Bust regions are assumed to have at least 5% more capacity than needed, and boom regions are assumed to have at least 1% less capacity than needed.

Forecast Of Market Conditions By NERC Region

2000			2001			2002		
Boom	Equil.	Bust	Boom	Equil.	Bust	Boom	Equil.	Bust
FRCC	AZ/CA	ERCOT	FRCC	MAAC	ECAR/MAIN		FRCC	AZ/CA
MAAC	ECAR/MAIN			MAPP	ERCOT		MAPP	ECAR/MAIN
SERC	MAPP			SERC	NEPOOL		SERC	ERCOT
	NEPOOL			AZ/CA	SPP		NWPA	MAAC
	NWPA			NWPA	SPP			NEPOOL
	SPP							NYPP
								SPP

Our analysis has led us to a number of other conclusions.

This year, most of the country will either be in a boom portion of the cycle or at least close to market equilibrium levels in which prices are high enough to support new capacity development. With almost 30,000 megawatts of new capacity coming on line, we expect 2000 to be the year in which supply catches up with demand.

Due primarily to new capacity development, it is extremely likely that many regions of the country will enter bust portions of the cycle next summer. In the space of just two years – 2000 and 2001 – a minimum of 60,000 megawatts of new capacity will come on line. It is likely that total capacity additions by the end of next year will reach 75,000 megawatts. Total capacity additions during all of the 1990s were only slightly higher than 75,000 megawatts. In Texas and the northeast, we expect the market will have at least 20% more capacity than is required. Almost all of this capacity is already under construction. Only retirement of substantial amounts of capacity in these regions could provide price recovery.

By 2002, nearly all large markets in the US will be in the bust portion of the cycle. SERC is the only large market we predict may be at equilibrium levels. However, we believe this finding must be heeded with a bit of caution in that surplus capacity in ECAR/MAIN and SPP could potentially depress pricing in SERC as well. In smaller regions such as MAPP – where we predict equilibrium conditions – it would only take one or two large projects to move the market into oversupply conditions.

The most attractive regions for new development efforts include the southeast and mid-Atlantic. Florida is another attractive region, but the political climate is currently stymieing the efforts of developers to build new plants.

Doom and Gloom Scenario

Based on the insights gained from the model, RDI identified a longer-term scenario that could potentially create a prolonged period of low prices and low returns for generators.

The first requirement for this scenario actually to occur is that electricity markets must be deregulated. That is, generators must be subjected to the disciplining force of market prices and consumers – or at a minimum marketers serving consumers – must be exposed to the volatility of these same prices. Price caps, standard offer rates, and partial deregulation in only a few states would impede the development of this scenario.

Because this scenario is driven by the imposition of supply and demand economics on the electric business, we refer to it as the economic rationalization scenario.

In this doom and gloom scenario, the imposition of supply and demand economics creates the following impacts. First, prior to 2003, generators build new capacity to meet expected demand as is occurring now. Next, persistent price spikes cause some level of dynamic demand to develop so that peak firm demand is reduced by 5% from expected levels between 2003 and 2008. Next, producers, trying to improve profitability, increase availability factors from an average of 82% to 88% between 2003 and 2008. Finally, generators are able to increase the capacity of their existing facilities by 1% per year between 2003 and 2008.

To consider the implications of this scenario, RDI used its electric simulation model to forecast future electricity prices in the midwestern US. In our base case, prices are at relatively high levels today due to shortages of capacity and high turbine prices. By 2002, prices reach long-run equilibrium levels and stay at that level over the forecast horizon. However, in the economic rationalization scenario, the combination of factors described above leads to substantial oversupply

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power companies, for example, is 31.5%. This compares to a corporate average of 30.9%.

Nevertheless, the study points to a number of factors in the power industry that will tend to make equipment in that industry obsolete more quickly. These include deregulation — generators are forced to maintain state-of-the-art equipment to remain competitive — advances in gas turbine technology, and the possible spread of distributed generation. The study also points to disparities in how the same generating equipment is depreciated depending on who owns it. For example, a power plant owned by a factory and used to generate power for internal consumption is depreciated over 15 years, while the same power plant owned by a power company and used to generate electricity for sale might be depreciated over 20 years.

What's next? Congress is unlikely to act on the report this year. Some action is possible next year, although neither presidential candidate has made this an issue and Rep. Bill Archer (R.-Texas) — the strongest advocate for updating depreciation allowances — is retiring from Congress.

A group organized by the Edison Electric Institute is lobbying Congress to allow all generating equipment to be depreciated over seven years. Most power plants are depreciated currently over 15 or 20 years.

CONNECTICUT said in a tax ruling that developers of merchant plants must pay sales taxes on machinery and equipment purchased for use in their projects, but at a 3% rate. This is half the normal rate.

The ruling — issued this summer — said four things. First, many states exempt equipment purchased for use in "manufacturing" facilities altogether from sales tax. Connecticut does, too, but the ruling said Connecticut does not consider generating electricity "manufacturing." Second, in Connecticut, a

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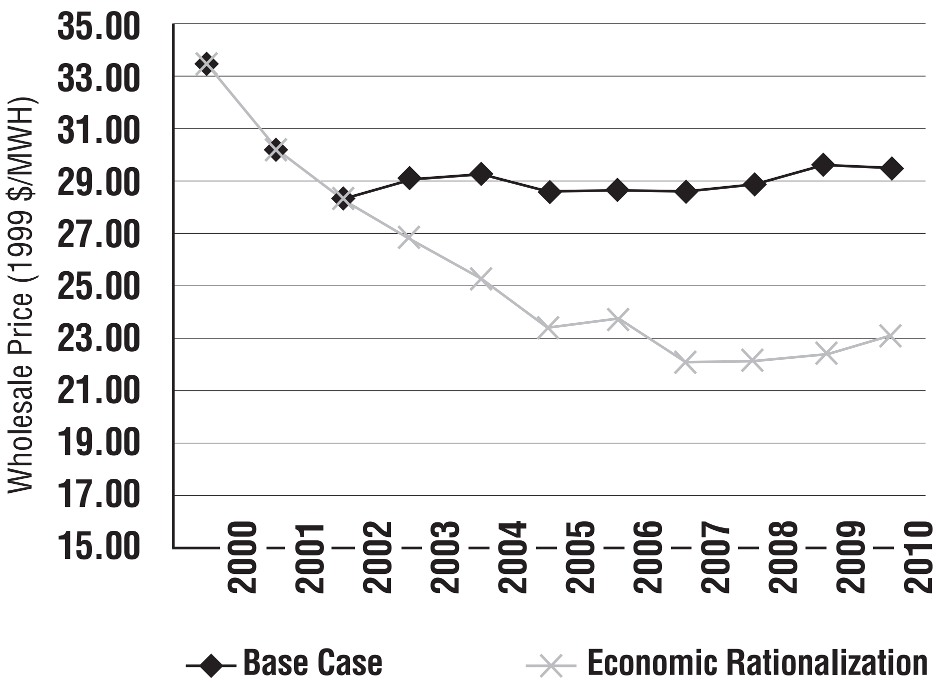
conditions for the duration of the forecast horizon. Prices are approximately 20% lower than in the base-case forecast.

This oversupply occurs for several reasons. First, the development of dynamic demand causes modest reductions in firm demand. Second, generators are able to produce more capacity from the existing system and improvements in availability factors also create more capacity. Third, the development of dynamic demand in combination with more reliable generators results in the market being able to provide the same level of reliability to customers with less capacity. Thus, overall target reserve margins are reduced.

It is difficult to assess the likelihood of this scenario actually occurring, but we believe it is an important scenario to watch for. Early signs of development would include the development of the infrastructure to facilitate dispatchable demand, continued price spikes, and improvements in plant performance.

Future Wholesale Electricity Prices Under Alternative Scenario



Policy Implications

Developers, power marketers and capital markets have responded to power shortage conditions and are rapidly building new plants that will provide customers with a reliable supply of electricity. New power plants are getting built in markets with regulated reserve requirements – like NEPOOL – and in markets with no reserve requirements – like Texas and western states. They are getting built in regions with independent system operators, or "ISOs," and in regions without ISOs. New power plants are even getting built in markets with significant regulatory risk – like California — or significant permitting and environmental hurdles – like the northeast. Our analysis indicates that developers should worry more about their investment returns than regulators should worry that plants will not get built in a deregulated market. Policymakers just need to ensure that the power plant development process is as easy, quick and fair as possible.

Finally, even though we expect most regions of the country will soon head into a period of low electricity prices, someday in the not too distant future, boom conditions will again return to the marketplace. Our analysis indicates that slight changes in the supply-demand balance can cause large changes in electricity prices. Markets with a 2% capacity shortfall have experienced significant price spikes, but regions with a 2% surplus have experienced very low electricity prices. There is one unknown that could reduce the threat of extreme price spikes – if customers begin to develop demand that can be curtailed during peak hours, price spikes could be diminished. Development of such demand should therefore be an important policy imperative. ■

Spotlight On Section 45 Credits

by Keith Martin, in Washington

The federal government offers a tax credit of 1.7 cents a kilowatt hour for generating electricity from wind, closed-loop biomass or poultry waste.

This article explains what qualifies for the credit and how to structure deals to transfer credits in cases where the developer lacks the tax appetite to claim them.

Credits run for 10 years after a power plant is first placed in service. However, the project must be in service by December 2001 to qualify. There is a fairly good chance that the US Congress will extend the deadline next year and also expand the list of eligible fuels.

Eligible Fuels

"Closed-loop biomass" means plants that are grown "exclusively" for use as a fuel in a power plant. Congress had in mind so-called electricity farms where plants are grown specifically to be burned as fuel. A Congressional committee report said in 1992 when the tax credit was enacted,

> "Accordingly, the credit is not available for use of waste materials (including, but not limited to, scrap wood, manure, and municipal waste) to generate electricity. Moreover, the credit is not available to a taxpayer who uses standing timber to produce electricity."

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reduced tax rate of 3% applies to equipment used in "processing" operations. Electricity generation is "processing." Third, spare parts and other supplies used "directly" in generating electricity are exempted from sales taxes under a special rule. Finally, there is no relief for material that ends up as part of the smokestack. Taxes must be paid on it at the full rate of 6%. That's because the smokestack is "real property" rather than equipment because it is affixed to land. The same logic probably applies to any portion of the project that is considered a "building" for tax purposes.

SECTION 29 TAX CREDITS come under fire.

The United States allows a tax credit of $1.035 an mmBtu for producing unusual fuels. The credit was enacted in 1980 after the Arab oil embargo. The idea was to reduce the need to import oil from the Middle East by inducing Americans to look in unusual places for fuel.

One of the things the credit encourages is production of "synthetic fuel from coal." Congress probably had in mind expensive and untested technologies like coal gasification or coal liquefaction. In the mid-1990's, several companies developed binders for gluing together waste coal fines recovered from gob piles and silt ponds and making pellets that could be burned as fuel in power plants. All remaining projects had to be placed in service by June 1998 to qualify for tax credits. Fifty-two plants for binding together coal fines were operating by the deadline, with many rushing to get into service in the last week of June.

The binders have not worked as well as hoped. Meanwhile, the IRS said in private rulings that the facilities could be moved to new locations and could qualify for tax credits by applying the binders to "run-of-mine" coal. As a consequence, a number of these facilities have been moved near utility power plants and are adding binder to coal that would have been

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Congress added poultry waste to the list of eligible fuels in 1999 after lobbying by Fibrowatt, a UK developer of chicken litter projects. "Poultry waste" is defined as "poultry manure and litter, including wood shavings, straw, rice hulls and other bedding material for the disposition of manure."

Congress did not address what happens if a project mixes an eligible fuel with another fuel that does not qualify for credits. An example is where 20% of the fuel is poultry waste and the rest is wood chips. The Internal Revenue Service views this as a question without an answer and has not yet taken a position. There is precedent for looking to the primary fuel in terms of Btu content or to awarding the credit on the same percentage of electricity as the eligible fuel going into the plant.

New Projects

Congress intended the credit as an inducement to build new projects. Thus, wind projects qualify for tax credits only if they were "originally" placed in service during the period 1994 through 2001. (The credit was enacted at the end of 1992.) The window period for closed-loop biomass projects is 1993 through 2001. It is 2000 through 2001 for poultry waste projects.

The IRS said in a 1994 revenue ruling that an existing power plant might be considered brand new if it is extensively rebuilt. A windpower developer planned to make extensive upgrades to an existing wind farm in 1994. The IRS said it would look at each turbine, tower and pad as a separate facility, and it would treat each one as brand new – thus qualifying for tax credits – if the cost of the upgrades accounted for more than 80% of the facility's value after the renovations.

The project must be in the United States. "United States" is defined broadly to include US possessions, like Puerto Rico, the US Virgin Islands and Guam.

Amount

The credit is adjusted each year for inflation as measured by the GDP implicit price deflator.

It is subject to a haircut to the extent the project benefited from tax-exempt financing, federal, state or local government grants, other tax credits, or "subsidized energy financing." An example of subsidized energy financing is "governmental programs to compensate financial intermediaries for extending low-interest loans to taxpayers who purchase or construct qualifying facilities." Only subsidies paid by a government in the United States are taken into account. Thus, for example, export credits from Sweden or Germany on equipment purchased in those countries would apparently not reduce the credit.

The haircut is calculated by putting in the numerator of a fraction the amount of the tax-exempt bonds, government grants or other benefits. The denominator is the total capital cost of the project.

Once tainted, a project remains tainted even in the hands of future owners. However, additional capital spending on improvements has the effect of reducing the haircut.

The credit begins automatically to phase out if the "reference price" for electricity ever tops 9.0 cents a kWh. It phases out as electricity prices move across the next three cents from 9 cents to 12 cents per kWh. Thus, if the reference price in 2002 is 10 cents, then taxpayers will qualify for only two-thirds of the normal credit that year. (The 9 cents is adjusted for inflation. The 3-cent range is not.)

There seems little danger of a phaseout in the near term. The IRS said the reference price for wind electricity was 4.836 cents in 1999. It was 0.0 cents for electricity from closed-loop biomass and poultry waste (because there were apparently no such projects in operation.)

The reference price is the average price at which electricity produced using the same fuel was sold in the United States during the year. Only sales under post-1989 "contracts" are taken into account. Thus, spot sales through power pools are not counted.

Location

The project must be in the United States to qualify. "United States" is defined broadly to include US possessions, like Puerto Rico, the US Virgin Islands and Guam. There is no bar against selling the electricity across the border – for example – into Canada or Mexico. However, Canada recently complained to the World Trade Organization that the United States is using so-called section 29 tax credits to reward US producers of syncoal – some of which is sold in Canada at subsidized prices that make it hard for Canadian coal companies to compete.

Whose Credit?

The credit belongs to the company that is the "owner" of the power plant and the "producer" of the electricity. It must be both. Thus, for example, if Company A owns the power plant but leases it to Company B, neither will qualify for tax credits since one is the owner and the other is the producer.

There is one exception: credits may be claimed by a lessee or operator of a power plant that burns poultry waste when the power plant is owned by a "governmental entity."

A contract operator of a power plant is not the producer. The company hiring the operator is still considered the "producer" as long as the operator contract is not recharacterized by the IRS as some other relationship due to profit sharing or other unusual contract terms.

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burned anyway in the power plants and without bothering to turn the output into pellets.

Kentucky Governor Paul Patton (D.) wrote US Treasury Secretary Lawrence Summers in late July that "the way this program is being used is an outrage" and said he would "seek to follow up personally" on the issue. Three congressmen from coal states sent the IRS and Treasury a similar letter in late July. Patton complained that the tax credits are depressing coal prices. Coal companies cannot afford to compete with synfuel producers whose tax subsidy is about $25 a ton.

The Treasury is now looking into the charges. It has asked the Department of Energy laboratory for its views on the chemical effects of adding binders. The IRS view is that material made from coal is a "synthetic fuel" if it differs significantly in chemical composition from the coal.

The IRS continues to issue private rulings in syncoal transactions in the meantime. However, the agency said it expects to ask more questions than in the past, and rulings may take a little longer than usual. Rulings had been taking four to six months.

Ruling requests will go to a different branch of the IRS starting October 1. This is a workload issue. The branch that had been fielding ruling requests on syncoal projects is overworked.

Meanwhile, the IRS released two interesting private letter rulings in late summer that bear on syncoal and landfill gas projects. In one, a partnership that owns a syncoal facility was sold to a buyer who paid the selling partners an amount in cash plus agreed to make contingent payments over time that are a percentage of section 29 tax credits. The partnership had an outstanding debt to the selling partners. The buyer agreed to make capital contributions to the partnership to pay off this debt, but not until – among other things – the project cleared an IRS audit without the IRS questioning whether

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Electricity Sales

Tax credits are triggered by sale of the electricity to an "unrelated person." In general, the electricity purchaser must be unrelated to the owner of the power plant. The IRS has ruled privately that there can be up to 50% overlapping ownership. Thus, for example, a utility can own up to 50% of a power plant in partnership with a developer – and claim half the tax credits – and also buy all the electricity.

It is unclear to whom the electricity purchaser must be unrelated in poultry waste projects where credits are claimed by the lessee or operator of the project.

Certain Wind Projects

Congress voted last year, after lobbying by the California utilities, to deny section 45 tax credits to any wind project that the taxpayer places in service after June 1999 to the extent the electricity is sold under a power sales agreement with a utility signed before 1987. The only exception is if the contract is amended to limit the electricity that can be sold under the contract at above-market prices to no more than the average annual quantity of electricity supplied under the contract in the five years 1994 through 1998 or to the estimate the contract gave for annual electricity output. "Above market" means for more than the avoided cost of the electricity to the utility at time of delivery.

This provision could come into play if an existing wind project is sold to a new owner.

Other Rules

Tax credits cannot be used by a company to reduce its corporate income taxes below a floor. The floor is 75% of the company's regular tax liability or the amount it would owe under the alternative minimum tax. Any credits that go unused because of this limitation can be carried back one year and forward for 20 years.

Structures

Many power plant developers have too little tax appetite to use tax credits efficiently. There are ways to transfer tax credits to other companies that can use them.

The simplest approach is to sell the project. The developer can be hired back as the operator.

An alternative is to sell limited partner interests in a partnership that owns the project but to remain part owner as the general partner. Developers ask about the possibility of allocating the tax credits disproportionately to the limited partners in such cases. IRS regulations require that tax credits like this one must be shared among partners in the same ratio as they share in gross receipts from electricity sales.

The IRS ruled privately in 1994 that a developer could sell interests in his project to limited partners and remain the general partner. The partnership planned to hire the developer as the operator for a fixed fee "plus a variable fee dependent on the [project's] productivity." It also planned to pay the developer a percentage of gross receipts under a separate contract for handling administrative services. (Paying the general partner a percentage of gross receipts is not a good idea – even with a ruling – because of the risk the IRS will reallocate credits to the general partner.)

The IRS has approved a "pay-as-you-go" structure for use in section 29 projects. This structure should also work in transactions to transfer section 45 credits. Under this structure, the developer sells the project to an institutional equity participant for an amount in cash plus contingent payments

Many power plant developers have too little tax appetite to use tax credits efficiently. There are ways to transfer tax credits to other companies that can use them.

over time that are a percentage of the tax credits. The IRS requires that the contingent payments be no more than 50% of the total purchase price in present-value terms. The developer can be hired to operate. The institutional equity will probably require the developer to get a private letter ruling on the structure from the IRS. The equity usually has an option to unwind the transaction if the developer cannot get a favorable ruling. If the project expectedly runs operating deficits, tax credit payments are diverted to cover operating costs, although the equity remains liable to the developer for the amount ultimately with interest.

The following variation would not require an IRS ruling. The developer sells the project to an institutional equity for a fixed purchase price. The purchase price is paid partly in cash at closing and a note is given for the balance with the note to be paid gradually over time with interest. There is some leeway to suspend payments on the note in quarters when the project has too little cash flow to make debt service. There can be a one-time reset in the purchase price up to two years out after the equity gets a better sense for what the project is capable of producing.

Depreciation

Most projects qualify for depreciation over five years using the 200% declining-balance method.

There are differing views among equity participants in pay-as-you-go structures about how to treat the portion of the purchase price tied to tax credits. Some equity treat this is part of the cost of the project and claim depreciation on the amount, but not until the amounts are actually paid. IRS contingent debt regulations require the equity to back out the portion of each payment that is interest. That part gets deducted immediately. The balance is added to the tax basis of the project for depreciation. A more conservative approach is to treat the balance as basis in an intangible asset – almost like "going concern value" since someone

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the facility made it into service by the June 1998 deadline to qualify for credits. Under the deal with the sellers, the buyer could also reduce the contingent payments tied to tax credits for any reserve deposits to cover cleanup and operating costs as well as operating deficits and by "certain specified yearly amounts per ton."

In the other ruling, the IRS said it would not allow section 29 credits to be claimed on landfill gas from expansion wells added to a landfill after June 1998.

Meanwhile, the American Petroleum Institute is arguing with the Treasury about whether a rule that section 29 credits cannot be used to offset alternative minimum taxes should be applied on a consolidated group basis or to each company separately. API argues the rule applies to the consolidated group. It sent Treasury a long memo on the subject at the end of July.

PENNSYLVANIA released a study of the effects of electricity deregulation on state tax collections. The study by the Department of Revenue — released August 1 — said tax collections over the next three years are expected to be only 92% of what they would have been without deregulation.

A SALE-LEASEBACK TRANSACTION ends up in court.

Florida Power & Light bought 48% interests in two windpower projects in 1989 and 1990 and leased back the projects to the seller. The utility claimed it could treat 94% of the purchase price in one project — and 91% in the other — as basis in equipment qualifying for investment tax credits and 5-year ACRS depreciation. The IRS is arguing that some of the increment that FP&L paid for the assets above what they cost to construct is "intangible property" not qualifying for these tax benefits. The case is now before the US Tax Court.

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had the foresight to put all the pieces of the project together in time to qualify for tax credits. In this case, the balance is recovered on a straight-line basis over 15 years. There is a risk the IRS will disallow any cost recovery above the hard replacement cost of the project under a line of cases that denies deductions for payments for tax benefits.

Outlook

Congress is expected next year to have a large budget surplus to spend on tax relief. Chances are fairly good that it will extend the credit. The odds are higher if Albert Gore, Jr. wins the presidential election.

Many groups are lobbying to expand the list of eligible fuels.

Biomass groups want the list to include all types of biomass – not just closed-loop – but to exclude municipal garage and recyclable paper products. This proposal was part of the budget that the Clinton administration sent Congress earlier this year. Congress did not act on it. Gore has said it will be part of his platform if he is elected president. It is also part of an omnibus republican energy bill that was introduced this summer by Senate majority leader Trent Lott (R.-Miss.) and Rep. Wes Watkins (R.-Okla.). The biomass groups also want a rule that it is enough to burn at least 75% biomass in a power plant – all the electricity would qualify for credits – and they want a 1 cent credit (as opposed to 1.7 cents) for electricity from coal-fired power plants that burn up to 25% biomass.

Meanwhile, landfill gas companies want tax credits for electricity produced from methane gas. The Clinton budget this year would have permitted this, but the credits would have been at a reduced rate. The rate was 1.0 cents per kWh in cases where the landfill is already obligated by federal "new source performance standards" the US Environmental Protection Agency issued in 1996 to dispose of the gas. It would have been 1.5 cents per kWh for gas from other landfills. The landfill gas provision is not included in the omnibus republican energy bill.

Steel companies want credits for electricity from "steel cogeneration," meaning from a power plant at a coke, iron ore, iron or steel factory. The power plant would have to use waste gases or heat from the mill.

Finally, Alaskan fisheries are lobbying for section 45 credits on the Btu value of the heat they produce from burning fish oil. ■

Doubts Persist About European Gas Market

by David Schumacher, in Washington

Doubts persist — barely a few weeks after the deadline for implementing legislation — about whether the European experiment with open gas markets will lead to truly open markets.

Most European Union countries passed laws that require competition in gas markets, including nondiscriminatory access to pipelines. However, the hard truth is anyone planning to develop gas-fired power plants in Europe with the expectation of buying gas at the field and paying a pipeline to transport it may find this model used in the United States is still not ripe for use in many parts of Europe.

EU Gas Directive

In 1998, the European parliament directed member states to implement by August 10, 2000 laws that would bring competition to the natural gas sector within the European Union as a whole and in each member state. This "gas directive" required each member state to ensure that at least 20% of its natural gas market is open to competition by August 2000. By 2007, that percentage is required to increase to 28% and, by 2020, the percentage is required to increase to 33%. "Eligible customers," which are the entities that can contract for natural gas under the terms of the gas directive, must include all gas-fired power generators and other entities that consume more than 25 million cubic meters of gas per year.

In order to achieve this opening of the gas market, entities providing gas transmission, storage and distribution service, or "natural gas undertakings," must provide eligible customers with nondiscriminatory access to their systems. The terms of such system access can be negotiated or established by a regulator and set out in public tariffs. However, a natural gas undertaking is exempted from the open access requirement if the gas company has no unsubscribed capacity on its system, or if the open access requirement would prevent the the gas company from carrying out certain public service obligations or would cause financial harm due to take-or-pay commitments.

The gas directive also requires member states to establish a procedure whereby entities can obtain authority to construct natural gas facilities, including to bypass a distribution system and interconnect directly with a consumer. This procedure must be clearly defined, transparent, nondiscriminatory and verifiable.

As of August 10, 2000, only Germany, France and Luxembourg had failed to enact the legislation required to implement the gas directive fully. However, in Germany, legislation is in place that – while not meeting all requirements of the gas directive – has significantly opened the German gas market. In France, while legislation has languished, Gaz de France has voluntarily opened its transmission system in a manner consistent with the gas directive.

Structural Impediments

The EU member states have made significant progress toward creating a competitive gas market

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TAX-FREE MERGERS became a little easier under regulations the IRS issued at the end of August.

In the past, when one corporation wanted to acquire another company but structure the deal as a "tax-free reorganization," the shareholders in the target company had to remain in place after the deal. They were given shares in the acquiring corporation in exchange for their existing shares. The IRS has now made it easier for shareholders of the target who want to cash out before the deal. Starting in September, the target can redeem, or repurchase, shares from any shareholders who want out before the acquisition, as long as the target can show the acquiring company did not supply the cash to buy out these shareholders.

MAURITIUS will subject all offshore companies to income taxes at a 15% rate starting in July 2003, regardless of when the companies were incorporated.

The country has been under fire to impose real taxes on holding companies based in Mauritius in order to justify the claim that these companies qualify for benefits under tax treaties that Mauritius has with other countries. A company must be a "tax resident" of Mauritius to qualify for treaty benefits. Mauritius will continue after July 2003 to allow taxes paid to other countries to be credited against the Mauritius tax, but the tax can only be reduced by 80% by such credits, leaving a net tax to pay of least 3%.

Mauritius has been used as a beachhead for investments into India, Pakistan and China.

INDONESIA has revoked its tax treaty with The Netherlands. Negotiation of a new treaty is expected to get underway this autumn. The Netherlands has proposed that the two countries grant informal relief from double taxation in the meantime on the basis of reciprocity.

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European Gas Market

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in Europe. The EU estimates that 80% of this market is now open to competition.

While in theory this may be the case, there are certain structural impediments in the European gas market that may hinder the development of a fully competitive market.

Competition remains thwarted or at least limited in many countries by the lack of multiple supply sources. Unlike the United Kingdom, where there are multiple suppliers competing in a market that has been open for a number of years, countries such as Germany, France and Italy rely on imports from three main sources – Russia, Norway and Algeria – with sales from these countries dominated by single-selling entities. Without multiple sources of supply, there is no pressure on existing suppliers to lower prices.

There are certain structural impediments in the European gas market that hinder the development of a fully competitive market.

Existing take-or-pay contracts also limit the opening of the market. Many gas distributors and transporters in EU countries have entered into long-term, take-or-pay contracts in order to ensure a secure supply to meet their public service obligations. Because of the financial commitments under these take-or-pay contracts, gas distributors and transporters are often reluctant to open their pipeline systems to other sources of supply if it will prevent them from selling adequate supplies of gas to meet their take-or-pay commitments.

Although the gas directive may increase competition in the gas markets of member states, there is some question whether this competition will have any significant impact on overall energy prices in the EU. First, on average, gas consumption represents only 22% of total energy consumption in EU member states. While gas consumption is predicted to increase over the next 20 years, natural gas is not expected to become the dominant fuel source in most EU countries. Moreover, because the price of gas in most EU countries is tied to oil prices, actual price competition may be limited.

Finally, cross-border competition is limited by technical problems. For example, technical codes and specifications for the design and construction of pipelines differ among the member states, often making cross-border interconnection difficult. In addition, gas quality specifications often differ from one country to the next, limiting access to upstream pipelines. Finally, diverse approaches to metering and accounting standards cause difficulties in measuring delivered gas supplies. ■

Dispute Over Coal Ash Spills Into Court

by Roy Belden, in Washington

Environmental groups filed suit in federal court in late August to force the US government to regulate ash and other wastes from the combustion of fossil fuels, including coal, waste coal, and petroleum coke, as a hazardous waste. Such regulation would make it more expensive to use coal as fuel in US power plants.

The groups include the Citizen's Coal Council, the Izaak Walton League of America, and the Conservation Law Foundation. The suit challenges a decision last May by the US Environmental Protection Agency not to regulate fossil fuel combustion wastes as hazardous under the Resource Conservation and Recovery Act. Earlier this year, EPA created a firestorm of protest from Congressional leaders and industry by indicating that it was leaning toward regulating such wastes as hazardous.

Environmental groups have charged that coal and petroleum combustion wastes should be subject to more stringent regulation to prevent groundwater pollution.

Most fossil fuel combustion ash is currently exempted from regulation as a hazardous waste and is managed as a "solid waste." Past EPA studies have concluded that most coal combustion ash has low toxicity and generally does not present a risk to human health and the environment.

Last May 22, EPA concluded that fossil fuel combustion wastes do not warrant regulation as a hazardous waste. However, it determined that national solid waste regulations are warranted for coal combustion wastes that are disposed in landfills or surface impoundments or are used to fill surface or underground mines. Instead of regulating the ash as hazardous, EPA's approach would build on the existing solid waste regulations for municipal landfills which require liners and leachate collection systems. However, the implementation of such standards will require a rulemaking process, and it will be several years before new requirements are in place.

The EPA has projected that if fossil fuel combustion ash is regulated as a hazardous waste, the annual compliance costs for industry could exceed $1 billion a year. In addition, higher electric utility rates could be passed through to consumers to offset the increased management, transportation and disposal costs. The stigma of regulating fossil fuel combustion ash as hazardous could curtail many existing beneficial uses.

The environmental groups' lawsuit is intended to force EPA to go back to the drawing board to address fossil fuel combustion wastes. A decision in the lawsuit is not expected until late 2001 or early 2002. ■

In Other News *cont.*

MEXICAN president-elect Vicente Fox said he plans to offer a 1-year income tax holiday to encourage more foreign investment, but he declined to say whether the holiday would be limited to particular industries.

USING SWAPS TO REPATRIATE EARNINGS does not work, the IRS said.

Most US companies that invest in offshore power plants and other infrastructure projects structure the investments so that US taxes can be deferred for as long as the earnings remain offshore. This requires investing through an offshore holding company in a tax haven. Over time, earnings build up and must be reinvested in other offshore projects. Tax directors at many US utilities are under pressure to come up with ways to bring earnings back to the US without triggering US taxes.

One US parent recently entered into a complicated series of swap transactions with a bank. It then assigned its right to receive payments under the swap to a foreign subsidiary in exchange for an upfront cash payment from the subsidiary. The IRS said in a recent "field service advice" — or memo from the national office to an agent in the field — that the transactions lacked any business purpose and were in reality loans from the foreign subsidiary to the US parent. A loan of offshore earnings back to the US parent triggers immediate US taxes under section 956 of the US tax code.

BULGARIA is expected to cut its corporate income tax rate to 15% effective January 1, 2001. There will be no change in the 10% municipal tax. The municipal tax is deducted before paying the corporate income tax, making the new combined tax rate 23.5%. These changes are expected to be debated in the legislature this fall.

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Peru Moves To Reduce Mining Incentives

by Luis Torres and Noam Ayali, in Washington

New legislation took effect in early September that could increase the cost of mining operations in Peru. Companies with existing stabilization agreements are not affected. The new legislation will have a significant effect on the international mining and project finance communities.

Tax Exemption Scrapped

Mining companies were previously exempted from Peruvian income taxes on 80% of their earnings for as long as the earnings were not distributed to shareholders and the companies presented investment plans for approval by the government showing how the tax savings would be reinvested. Under the new legislation, mining companies will be fully taxed on earnings whether or not they are distributed.

Holding Rights

The new legislation also increases the price for holding mining rights, or *Derecho de Vigencia*, for large-scale operations from US$2 an hectare to US$5 an hectare. The price for small-scale operations remains the same at US$1 an hectare.

Non-Producing Concessions

Mining companies holding concessions must begin production within seven years after obtaining the concession. If the concession holder fails to meet the 7-year deadline, penalties begin to accrue at the start of the seventh year. Penalties for large-scale operations amount to US$6 an hectare per year. Penalties for small-scale operations amount to US$3 an hectare per year. Penalties are increased if the concession holder has not begun operations by the 12th year from the date of the concession.

Stabilization Agreements

The new legislation amends the standard terms for tax stabilization agreements that mining companies might sign in the future with the government. A tax stabilization agreement is a promise by the government not to change the taxes that would apply to a mining company for a period of years. These are given to induce companies to invest. Under the new legislation, tax stabilization agreements can still be entered into, but on a limited basis. New stabilization agreements will guarantee tax stability for 10 or 15 years — depending on the amount invested — with respect to the tax on revenues, or *Impuesto a la Renta*, the general sales tax , or *Impuesto General a las Ventas*, and the selective tax on consumption, *or Impuesto Selectivo al Consumo*. The tax on revenues will be set at the rate existing on the date the contract is signed plus a 2% premium. The minimum investment required for mining companies to enter into a tax stabilization agreement is US$10 million.

The new legislation significantly alters the consequences for companies that withdraw from tax stabilization agreements. In the past, a company could withdraw from such an agreement entirely or partially. For example, a company would withdraw from the tax on revenues but not from the general sales tax. Moreover, if regular tax treatment presented conditions more favorable than those under the stabilization agreement, a company had the ability to choose the regular tax treatment and make this regime its new stabilization regime. Under the new legislation, companies that withdraw from stabilization agreements cannot do so partially, only entirely.

The new legislation is not retroactive. Thus, mining companies that have signed tax stabilization agreements with the Peruvian government are protected under the old legal regime. Companies that had merely applied for tax stabilization agreements when the new law took effect will still be able to enter into agreements under the old rules, but only through 2003.

The new legislation will test the appetite of the international mining community for Peruvian mining projects. As a country rich in mineral resources, especially gold, copper, silver, lead and zinc, Peru has been a key country for many international mining companies. In the last decade, several high-profile projects, including the expansion of the Cuajone mine, and the Cerro Verde, Yanacocha and Antamina projects, successfully achieved financial closing. Although some industry observers have indicated that large projects with existing concessions are likely to continue – they are protected under stabilization agreements – it is now up to private investors to determine whether new projects will be considered under the new legislation. Among the large scale projects pending in Peru are La Granja (copper), Quellaveco (copper), La Quinua (gold - an expansion of Yanacocha), Tambogrande (gold, silver, copper and zinc) and Bayóvar (phosphates). ■

New Rules For Undersea Mining

by Noam Ayali, in Washington

Regulations issued by the International Seabed Authority this summer set new rules for undersea mining of manganese, nickel, cobalt and copper. The new rules apply to such mining in international waters.

The International Seabed Authority is an autonomous organization established in 1994 to help implement a 1982 United Nations Convention of the Law of the Sea. At this writing, 133 countries have ratified the convention, and another 49 countries – including the United States – are "observers." The convention and the regulations implementing it are considered part of international law.

The seabed authority is expected to turn next to

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A STRATEGY SOME FOREIGN COMPANIES USE TO STRIP EARNINGS FROM THEIR US SUBSIDIARIES is expected to be shut down.

A Treasury lawyer said in August regulations will be issued "soon." In one version of the strategy, a foreign parent owns a US holding company that, in turn, owns US operating subsidiaries. The US holding company is a "reverse hybrid." It is treated as a corporation for US tax purposes but as transparent for tax purposes in the parent's home country. The US holding company receives dividends from its operating subsidiaries. It pays the money up to the parent in the form of interest. However, the parent company is viewed at home as receiving the dividends directly because of the transparency of its US holding company. The dividend either escapes tax in the parent's home country or brings with it foreign tax credits.

Meanwhile, the US views the US holding company as having made a deductible interest payment. The interest qualifies for a reduced withholding rate under a US tax treaty.

The US government is also concerned about variations on this base case.

ENVIRONMENTAL CLEANUP COSTS could not be deducted, a US appeals court told Dominion Resources in late July.

Dominion Resources owns land in Richmond, Virginia where a former power plant sits. The power plant was built in 1901 and decommissioned in 1973. The utility transferred the land between two of its subsidiaries in the late 1980's for a "sales price" of $870,167 and then tried unsuccessfully to sell the land. In 1991, it ended up spending $2.2 million to remove asbestos-containing materials, sludge and assorted contaminants and tried to deduct the cost of the cleanup.

The 4th circuit court of appeals said the costs had

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regulations on undersea mining of massive sulphides, concentrated around undersea volcanic hot springs, and ferromanganese crusts, lying along ocean ridges at boundaries between tectonic plates. Work on these is expected to start next year.

The new regulations contain several provisions of particular interest to mining companies looking for manganese, nickel, cobalt and copper on the ocean floor.

Mining Claims

The regulations provide that "prospecting" – or searching for nodules on or just below the surface of the deep seabed that contain manganese, nickel, cobalt and copper – does not give rise to any exclusive rights. Nodules containing these materials are called "polymetallic nodules."

Mining entities and consortia should be aware that prospecting on the seabed and ocean floor is different than similar activities on land. Under most legal jurisdictions, a mining license or concession for a certain area of land confers upon the license- or concession-holder the exclusive right to conduct prospecting activities in the area. However, under the regulations, prospecting on the ocean floor does not confer on the prospector any rights over the resources. Moreover, the regulations provide that prospecting may in fact be conducted simultaneously by more than one prospector in the same area.

A mining entity involved in prospecting can only get exclusivity rights once it enters into a contract with the International Seabed Authority for "exploration," which is defined as the search for deposits of polymetallic nodules, the analysis of such deposits, the testing of collecting systems and equipment, processing facilities and transportation systems, and the carrying out of studies of environmental, technical, economic, commercial and other appropriate factors that must be taken into account in exploitation. At this stage, the mining entity or consortium receives exclusive rights to explore an area covered by a plan of work for exploration.

It is important to understand that the exclusivity granted is not for the physical area, but for exploration of the specific polymetallic nodules in the area.

The regulations leave open the possibility that other contractors may be granted rights in the same area, but for different resources. However, the seabed authority is required to ensure that no other entity operates in the same area for other resources in a manner that would interfere with the operations of the contractor. As part of the protections granted to a contractor, the regulations grant the contractor a preference and priority among applicants submitting plans of work for exploitation of the same area and resources. However, this priority and preference may be withdrawn by the seabed authority if the contractor fails to comply with the requirements of its approved plan within the time period specified in a written notice from the seabed authority to the contractor specifying the noncompliance.

The regulations provide that "prospecting" does not give rise to any exclusive rights.

Another interesting aspect of the regulations is the requirement for mining entities to obtain a certificate of sponsorship from the country where they are incorporated or by whose nationals they are controlled. The main purpose of the certificate of sponsorship is a declaration by each such sponsoring country that it assumes responsibility to ensure that seabed and ocean floor mining activities, whether carried out by the country itself, a state enterprise, or a private entity, are carried out in conformity with the relevant part of the 1982

United Nations Convention on the Law of the Sea and its annexes. The law-of-the-sea convention imposes liability on countries for damages caused by their failure to carry out that responsibility. However, there is no liability if a country has taken "all necessary and appropriate measures to secure effective compliance under" the relevant convention provisions. Neither the convention nor the regulations elaborate on what a country must do to satisfy the requirement of "all necessary and appropriate measures." This could be a problem if and when the seabed authority ever tries to enforce this liability.

Environmental Protection

Environmental protection is one of two areas to which the seabed authority had to devote the most time when writing the regulations. (The other is the issue of confidentiality of data and information.) A particularly sensitive provision of the regulations is the one that requires each contractor to provide a guarantee of its financial and technical capability to comply promptly with emergency orders from the seabed authority in order to allow the authority to take necessary emergency measures of environmental protection. If the contractor does not provide such a guarantee, the sponsoring country is required, in response to a request from the authority, to take necessary measures to ensure that the contractor provides such a guarantee or to ensure that assistance is provided to the authority in the discharge of its responsibilities.

The regulations do not provide any specific guidance as to the type and scope of the required guarantee from the contractor, nor do they provide any guidance as to the "necessary measures" that a country is required to take to "ensure" that the contractor provides such a guarantee. Recognizing that this lack of specificity could be a problem in the future, the authority's governing council, in a separate decision, decided to consider the matter of a guarantee prior to the phase of testing of collect-

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to be added to the tax basis in the land. The issue was whether the spending was closer to a "repair" or a "capital improvement." The court said it found it hard to believe that spending $2.2 million to clean up land worth only $870,167 was merely a repair, and that the spending had substantially altered the character of the land by lifting it out of "what was essentially a condition of uselessness."

The IRS said in a separate "field service advice" released in early September that utilities may not deduct the cost of removing asbestos insulation at power plants.

CONNECTICUT SLAPPED A RETROACTIVE TAX on scrap tires that a power project uses as fuel.

Oxford Tire Supply collects millions of scrap tires each year and delivers 95% of them to a power plant owned by Exeter Energy. CMS Energy owns 100% of Oxford and 50% of the Exeter project. During the period 1989 to 1994, Oxford did not collect any sales taxes from the garages that paid it to haul away their scrap tires on grounds that its service involved "removal of hazardous waste," which is exempted from sales taxes. A Connecticut court agreed with the company. However, while the state tax department was appealing the case, it persuaded the Connecticut legislature to amend the tax laws retroactively to exclude scrap tires from the definition of hazardous waste. Oxford then lost the case on appeal. The appeals court announced its decision in late July.

AN INDIAN TRIBE could not tax utility property on its reservation, a US appeals court said.

The Crow Indian tribe imposed a 3% ad valorem tax on utility power lines running across its reservation in Montana and barred the Big Horn Electric Cooperative, which owned the lines, from passing the tax on to Crow customers.

The United States treats Indian tribes as sover-

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ing systems and processing operations for the exploitation of polymetallic nodules, with a view to adopting appropriate forms of guarantee, and requested the authority's secretariat to carry out studies of appropriate instruments or arrangements that may be available for this purpose and to report back.

Confidentiality

Confidentiality of data and information was another key part of the regulations that received special attention. The regulations provide that information submitted by any person participating in any activity or program of the seabed authority that is designated by such person as confidential shall be treated as confidential unless the information falls in one of the following categories:

- The information is generally known or publicly available from other sources.
- It has been previously made available by the owner to others without a confidentiality obligation.
- It is already in the possession of the seabed authority with no confidentiality obligation.

Unlike some confidentiality arrangements under oil and gas production sharing regimes or mining agreements, which run for the life of the production sharing or mining concession, in this case the regulations provide that 10 years after the earlier of submission of the confidential information or the expiration of the contract for exploration, and every five years thereafter, the seabed authority will review information submitted to it as confidential to determine whether it should remain so. Information will remain confidential if the contractor establishes that there would be a substantial risk of serious and unfair economic prejudice if the information were released. ■

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eign nations with their own taxing and police powers. However, the federal courts apply the law of the states where a dispute arises. In this case, Montana law says that – absent an express treaty or federal law to the contrary – Indians have no right to apply their laws to non-Indians except in two situations. The exceptions are the tribe can regulate non-Indians who enter into "consensual" commercial relationships with Indians, and it can exercise police power over non-Indians when they are on Indian lands and engaging in conduct that threatens the tribe.

The 9th circuit court of appeals said the tax in this case did not fall into either exception. It also said the power lines ran technically over non-Indian land since the US secretary of the interior had granted the electric cooperative a right of way to run its lines over the reservation, making the area under the lines "equivalent to" non-Indian land. The court released its decision this summer.

Crow Indians make up roughly half the customers of the Big Horn cooperative.

BRIEFLY NOTED: The European Commission said this summer that it is investigating tax breaks given to companies on the Portuguese island of Madeira because the tax breaks may constitute illegal aid . . . . West Virginia is considering increasing its coal tax from 2 cents to 3.5 cents a ton and also increasing fees for mining permits. The changes are expected after the federal government warned West Virginia in August that it would take over inspection of coal mines unless the state hired more staff.

— contributed by Keith Martin and Heléna Klumpp in Washington

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