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Global Power Report

November 18, 2004

TXU plans to mothball 2,516 MW of older gas-fired plants in Texas

The ready availability of newer, highly efficient gas-fired generating capacity in Texas is leading to still more "mothballing" by the owners of older gas-fired plants.

TXU Power, the generation subsidiary of TXU Corp., said Nov. 12 that due to "market conditions" it planned to take off line another 2,516 MW of older gas-fired capacity, which would bring to 3,612 MW the total amount of gas-fired capacity TXU has taken off line in the Electric Reliability Council of Texas region in the past several months.

TXU Power, which owns more than 18,000 MW of gas-fired, lignite-fired and nuclear capacity in Texas, said the facilities it planned to mothball could not compete with the thousands of megawatts of new gas-fired capacity that merchant power companies have brought on line in the past few years.

The plants to be mothballed include three units totaling 1,115 MW at TXU Power's Valley power station in Fannin County, three units totaling 715 MW at its North Lake station in Dallas County, and two units totaling 686 MW at its Morgan Creek station in Mitchell County. Two of the units started commercial operation

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Thailand prepares to launch bidding to develop up to 10,195 MW of projects

Thailand's Energy Policy and Planning Office is planning an auction for development of up to 23 new plants, including 9,800 MW of fossil fuel plants and 395 MW of renewable energy plants, that would come on line between 2011 and 2015, according to Energy Minister Prommin Lertsuridej.

The energy office has commissioned a study to evaluate the exact number of plants, the required capacity, types of fuels, and the tariffs for the electricity that would be sold to Electricity Generating Authority of Thailand. The study would then be submitted to Prime Minister Thaksin Shinawatra by the middle of next year.

Bidding would be open to EGAT and to local and foreign independent power producers. Local developers expected to bid include Thai Oil PLC, Ratchburi Electricity Generating Holding Co. PLC, and Tri Energy Co., all of whom are already planning to develop separate projects in different parts of the country.

Kraisi Karnasuta, EGAT's governor, said that the state-owned firm was ready to compete with private power producers. "I believe EGAT can offer competitive prices as we have resources and facilities available," he said. EGAT runs Thailand's electricity grid and owns 59% of the country's generating capacity.

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9th Circuit's decision changes equation for suppliers with pending refund claims

Power suppliers that have not yet reached settlement agreements for refunds stemming from the 2000-2001 Western energy crisis may be in a tougher negotiating position following the 9th Circuit Court of Appeals ruling in September, according to parties involved in the issue.

The size of the total estimated refunds varies considerably, depending whose calculations are used. They range from nearly $9 billion to virtually zero.

On Sept. 9 the appeals court dismissed California's challenge of FERC's market authority, but ruled that FERC was wrong in deciding that it could not make retroactive refunds stretching back further than the Oct. 2, 2000, date that the agency had set (GPR, 21 Oct, 1).

The court's decision to send FERC back to reconsider the basis for denying—or granting—refunds raises some weighty issues about how FERC goes about administering and monitoring its market-based-rate authority. Those issues are sure to be debated in the coming months, particularly in light of the fact that several wholesale suppliers are appealing the decision (GPR, 28 Oct, 16).

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But from the perspective of the companies in the middle of the California refund issue, the most crucial outstanding matter is the amount of the outstanding liabilities. The most visible and vocal calculation of that figure has been presented, repeatedly and vociferously, by California Attorney General Bill Lockyer, who insists that the state is owed $9 billion.

For all intents and purposes, that number has not changed, at least not substantially. In fact, the AG says, the 9th Circuit decision puts $2.8 billion back on the table.

At the urging of FERC, the state of California, other Western states, power agencies and utilities have reached settlements with companies that were accused of having manipulated the Western electricity markets during the crisis.

The AG's office concedes that the total size of the refund should be reduced by the amounts of the settlements reached to date. But the AG's office could not provide a simple calculation of that number because different settlements include different categories of payments.

To date, the California AG says it has reached eight energy crisis settlements representing a total value of $2.636 billion, which includes $1.775 billion earmarked as "direct ratepayer relief." If settlements for gaming proceedings and other matters are included, that figure rises to $3.5 billion, but only about $2 billion is related to refund issues (see table, page three). Aggregate amounts for the three "global" settlements reached to date—with Duke Energy, Dynegy and Williams—total about $906 million. Even reduced by that amount, Lockyer is still seeking to recover a little over $8 billion for California ratepayers.

"It's no secret that we think the 9th Circuit decision strengthened our hand" said Tom Dresslar, a spokesman for the AG's office. The 9th Circuit's decision opens the door for Lockyer to push for refunds on power sales that occurred before the October 2000 cut-off date set by FERC. But Lockyer also says it opens the door to two other issues: reconsideration of a FERC decision "to deny billions of dollars in refunds" to the California Dept. of Water Resources, and of "federal court rulings denying damages to California" in civil suits alleging antitrust violations by energy companies.

The battles over who is to blame and who should pay for the California energy crisis are being fought on multiple fronts in literally hundreds of lawsuits and proceedings. They fall into five broad categories: refunds, long-term contracts signed with the California Dept. of Water Resources, long-term power purchase contracts signed with various municipalities and out-of-state utilities, civil suits being brought against power suppliers by the California AG's office, and market manipulation and gaming allegations against Enron.

There were a total of 56 long-term power purchase contracts signed between energy companies and the DWR from February 2001 through August 2001, with a total projected cost of $42.5 billion. To date, DWR reports it has renegotiated 34 of those contracts. Fourteen more have expired and two have been terminated, leaving six contracts in their original form that are still under discussion with the counterparties, namely, Coral Energy, Dynegy, PacifiCorp and Sempra Energy. However, the Dynegy contract expires at the end of December, so it is not likely to be renegotiated. The projected cost of DWR's long-term contracts, after renegotiations and expirations, as of March 2004, was $28.3 billion.

The state of California also sought to have FERC dissolve or abrogate long-term contracts between power suppliers and various municipal and out-of-state entities such as PacifiCorp, Southern California Water, and Public Utility District No. 1 of Snohomish County, Wash. FERC denied California's requests, but the decision was appealed. Oral arguments are slated to begin soon at the 9th Circuit Court of Appeals (GPR, 28 Oct, 17).

The state of California in 2002 filed civil suits seeking damages for market manipulation during the 2000-2001 crisis.

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Officers of the Corporation: Harold McGraw III, Chairman, President and Chief Executive Officer; Kenneth Vittor, Executive Vice President and General Counsel; Robert J. Bahash, Executive Vice President and Chief Financial Officer; Frank Penglase, Senior Vice President, Treasury Operations.

To reach Platts
E-mail: support@platts.com
North America
Tel: 800-PLATTS-8 (toll-free)
+1-212-904-3070 (direct)
Latin America
Tel: + 54-11-4804-1890
Europe & Middle East
Tel: +44-20-7176-6111
Asia Pacific
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The AG alleged "illegal profiteering" in filings against all major market players. It also filed suits alleging violations of California's antitrust laws against Mirant and Reliant Energy. The AG has said that, taken together, all the suits could result in recovery of "well over $1 billion in damages."

Federal court rulings have denied the damages, but the AG believes that the 9th Circuit decision could open the door to revisit the decisions regarding the antitrust suits. The AG has not yet made a decision on what action to take, but it is basing any possible action on the court's criticism of the failure of wholesalers to file quarterly reports as required under FERC rules. The AG argues that could mean that there were no filed rates as defined by the Federal Power Act and, therefore, no filed-rate doctrine to preempt the state's damages claims.

Weaving through the refund issue, like a thread in a tapestry, are the Enron gaming proceedings. They embellish and complicate the refund complaint because FERC signed settlements with some of Enron's counterparties, but those agreements typically are separate from the refund complaints.

In June 2003, FERC issued two orders for power sellers to "show cause" why they should not forfeit profits earned by engaging in gaming activities or improper partnerships with Enron.

To date, FERC has accepted 21 settlements flowing from its show-cause order and has three settlements pending—two with Mirant and one with Public Service New Mexico. FERC puts the total value of those proceedings at just over $28 million, which includes nearly $5 million represented by the pending settlements.

In August 2002, FERC issued three enforcement orders against Enron and its counterparties, alleging gaming, charging unfair prices and engaging in unfair market practices. The counterparties, Avista, El Paso and Portland General Electric, have all reached settlements. But a FERC administrative law judge ruled that Enron should forfeit $32.5 million in unjust profits. The commission then ordered another ALJ, Judge Benkin, to determine how much more in unjust profits, going back to early 1997, Enron should forfeit. That case is still pending.

And, finally, there are the refunds. There are three distinct parts to the refund issue: (1) refunds for power sales made between Oct. 2, 2000, and June 21, 2001, (2) refunds for power sales made between May 2000 and Oct. 2, 2000, and (3) short-term or spot market purchases made with the DWR beginning in 2001 when the governor appointed the agency to step in to replace the state's ailing or bankrupt utilities as power purchaser.

From FERC's perspective, the DWR purchase cases have been resolved. FERC ruled that DWR was not entitled to refunds because DWR personnel were in the Independent System Operator's control room and, thus, were in a position to shop for the best deals in purchasing power to fill their needs. DWR has appealed FERC's decision. The case is pending before the 9th Circuit.

The issue of refunds for power sales between Oct. 2, 2000, and June 21, 2001, is fairly clear cut. Refunds apply for that period, and FERC has urged the parties involved to negotiate settlements.

For power sales before Oct. 2, 2000, the 9th Circuit told FERC that its decision to disallow retroactive refunds for the period was flawed because several companies violated the agency's quarterly reporting requirements. The court told FERC it must go back and re-examine those claims, which is why the California AG says that the court has put $2.8 billion back on the table.

FERC has declined to appeal the 9th Circuit's decision, but it is being appealed by wholesale generators and is sure to be tied up in legal wrangling for some time to come. The parties signing the appeal were Avista, Coral Power, El Paso Merchant Energy, Mirant, Powerex, PPL Energy Plus, Public Service Co. of New Mexico, Public Service Co. of Colorado, and Sempra Energy Trading.

Several other parties have already reached refund settlements either with the state of California or with FERC. Some of the deals are small and specific, such as the $8.5 million deal the state reached with Calpine/Constellation to settle both refund claims and civil suits, and the $8 million settlement with AES/Williams. But three of the settlement agreements are termed "global."

Duke, Dynegy and Williams have all signed global agreements. Two of them have been approved by FERC. The Duke settlement is pending before FERC, and Duke is pressing the commission for a decision before year end.

According to all parties involved, the global settlements appear to resolve all refund issues and to be secure against further claims, even against claims for the period prior to Oct. 2, 2000.

As Williams spokesman Brad Church said, "Our obligation [to the state of California] is virtually zero." Williams, in fact, signed two settlements, one with the state—for $1.4 billion, including a $417 million cash payment—and one with California's three largest investor-owned utilities for $140 million.

"All that is left," said Church, "are some small parties that wanted to pursue deals on their own," which he said amounted to "maybe 3% of any potential refund liability." Williams is working on an individual basis with those parties.

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Payback

Settlement agreements with energy suppliers during the 2000-2001 Western energy crisis ($million)

Company	total value	direct ratepayer relief
AES/Williams	8.0	
BP Energy (gaming issues)	3.0	
Calpine/Constellation	8.5	
Duke Energy	207.5	172.0
Dynegy/NRG/West Coast Power	281.5	256.4
El Paso (gas/electricity pricing, Enron related)	1,400.5	1,340.5
Portland General Electric (Enron related)	6.1	6.1
Reliant (trading related)	50.0	
Williams	1,400.0	
Williams (with California utilities)	140.0	
Totals	**3,504.6**	**1,775.0**

Sources: California Attorney General's office, Federal Energy Regulatory Commission, company releases and filings

TXU plans to mothball 2,516 MW of older gas-fired plants in Texas ... from page 1

in 1959; the other six came on line in the 1960s.

The company said it would contact ERCOT to discuss its decision to mothball the eight units. "ERCOT may request that any of the units continue operating under contract with ERCOT, based on its assessment of grid reliability requirements," TXU said. It said that, once mothballed, the units "could be restarted if market conditions made it economical to operate them."

TXU Power said that mothballing the plants was expected to save the company about $14 million/year, while unspecified additional "operations adjustments" across TXU's gas-fired fleet were expected to reduce annual expenses by another $6 million.

Earlier this year, TXU Power permanently retired eight older gas-fired units totaling 653 MW. It also mothballed three units totaling 443 MW and agreed to continue operating three additional units it had planned to mothball under a "reliability must-run" contract with ERCOT (GPR, 1 April, 1).

TXU Power noted that it recently initiated studies to examine the economics of repowering "various units in the fleet to meet future needs for more efficient generating capacity." It said that repowering could mean "replacing existing steam units with combustion turbines, switching some units to burn coal or implementing other options." The company said it was uncertain when the studies would be complete.

An ERCOT spokeswoman said that the region should have sufficient generating capacity—and a reserve margin of more than 18%—in 2005, even with TXU Power's newly proposed closures. Still, she said that ERCOT would undertake a detailed study over the next 60 days to determine whether any of the eight plants TXU wants to close is needed to maintain the reliability of the local transmission system.

If ERCOT made such a finding, it would enter into an RMR contract with TXU for one or more of the plants.

Thailand prepares to launch bidding to develop up to 10,195 MW ... from page 1

Prommin said a regulatory body that is being set up for the electricity sector would determine electricity tariffs, gauge demand and secure supply.

Prommin also said the country plans to buy as much as 500 MW from companies with backup generators in 2006.

Thailand's domestic power demand is expected to reach 40,978 MW in 2015, based on forecasted annual growth of 7%.

FINANCE

Hedge funds' stake in power industry rises to $2.6 bil., according to Lazard

Hedge funds boosted equity investment in the power sector by roughly $2.6 billion in the year ended June 30, including a $2.1 billion (48.3%) hike, to about $6.6 billion, in utility companies, according to Lazard Asset Management figures presented to a Platts conference in New York City.

But due to rising share prices, the amounts equal about 3% of total power sector equity, the same levels as the last 18 months.

In six merchant energy companies—AES, Calpine, Dynegy, NRG Energy, Reliant Energy, and Texas Genco Holdings—hedge fund equity ownership was about $783 million on June 30, up $470 million (150.1%) from $313 million a year before. That boosted funds' ownership of those six from about 5% to 7%.

"People have seen hedge funds as providers of last resort, but that's not the case at all," said Lazard Managing Director George Brokaw, at the "Financing U.S. Power" conference. "They are mainstream players, not just knee-breakers or those working in dark alleys. The market has not focused on that."

Many hedge funds have large concentrated pools of capital and can replicate the scale of public financings, or leveraged buyout funds, Brokaw continued. In contrast to traditional private equity investors, who usually want to become directors, hedge funds do not want to be considered "insiders" under Securities and Exchange Commission rules to avoid limits on their ability sell investments, he noted. "The nice thing" about such investors is they can exit relatively quickly, Brokaw noted.

In dollars, according to Lazard's presentation, the electric utility with the biggest amount of stock held by hedge funds is PG&E Corp., with $1.06 billion (8.5%) on June 30, up from $514 million (4.1%) the year before. In second place was TXU Corp., with $620 million (4.2%) of its common stock owned by hedge funds on June 30, up from $151 million (1%).

In ownership, the largest is Allete with $184 million (18.9% of shares) held by hedge funds on June 30, up from $43 million (4.4%) a year before. In second place was UniSource Energy, with $150 million (17.9%).

A consortium of eight primary hedge funds advised by Lazard made a "highly competitive bid" for CenterPoint Energy's share of Genco, Brokaw noted, but it fell just short of the successful $3.65 billion offer by affiliates of The Blackstone Group, Hellman & Friedman LLC, Kohlberg Kravis Roberts & Co. L.P. and Texas Pacific Group.

S&P says it would review its treatment of long-term PPAs as debt equivalents

Standard & Poor's said it would review how it treats long-term power contracts when rating electricity purchasers.

At a conference on financing U.S. power in New York City sponsored by Platts, Suzanne Smith, S&P director of rating services, said the rating agency plans next year to examine current policy that considers long-term purchased-power deals as debt equivalents.

The approach, which S&P has used since passage of the Public Utility Regulatory Policies Act, may need to be modified to fit conditions in today's deregulated market, she said.

Regulators, developers and those in the financial community have argued for change. Merchant power plant developers in particular claim the current method, which views the contracts as debt-like obligations, may make some purchasers wary of entering into long-term purchase agreements.

Smith said not to look for any radical changes in the current policy, saying that S&P is more likely to only "soften" the existing treatment. S&P, like Platts, is a unit of The McGraw-Hill Companies.

TransCanada Power takes on $175 mil. credit facility to cover plant acquisitions

TransCanada Power LP has entered into a CAN$210 million (US$175.7 million) new credit facility that will be used mostly to repay CAN$188 million of debt that was used to finance acquisitions of four plants this year.

The new five-year non-amortizing credit facility with a syndicate of Canadian banks provides for optional repayments of principal without penalty, the Calgary, Alberta, based company said. It will retire the $188 million of debt that had been arranged under a CAN$500 million acquisition credit facility. The interest rate after consideration of forward contracts is 5.2%.

The company acquired the 300-MW Manchief gas-fired plant in Brush, Colo., and the 60-MW Curtis Palmer hydroelectric facility in Corinth, N.Y., from TransCanada Corp. in April. It acquired the 50-MW Mamquam hydro plant and the 6-MW Queen Charlotte hydro plant that both are in British Columbia from affiliates of Hydro Investment Corp. in July.

TransCanada Corp. subsidiaries that own 30.6% of TransCanada Power manage and operate the plants. TransCanada Power owns 11 plants in Canada and the U.S. totaling 744 MW.

ASIA/PACIFIC RIM

World Bank study supports 1,070-MW Laos hydro project

A World Bank team has concluded that the 1,070-MW Nam Theun-2 hydroelectric project in Laos is economically viable, paving the way for the bank to provide a financial guarantee to the project.

Sources from the bank said that the findings would likely be endorsed by the executive board. They said the World Bank would issue its decision by year end, but Kimberly Versak, head of the World Bank's External Affairs for Cambodia, Laos, and Thailand, stressed that it had not yet made a final decision on the issue and no time frame was set for making such a decision.

Electricite de France International holds a 35% stake in NTPC, while Electricity Generating Co. PLC and state-owned Electricite du Laos each own 25%. Thai construction firm Italian-Thai Development has 15%. The developers said they would not proceed with the project without a guarantee.

Thailand plans to buy up 95% of the expected annual electricity production from the project, with the rest to go to the Laotian electricity grid. The Laos government said the plant could generate $2 billion in revenue over 25 years.

Datang International Power Generation starts up 900 MW of new capacity in China

Chinese generator Datang International Power Generation brought on line two units totaling 900 MW in October.

The plants include the 600-MW Unit 4 at the Tuoketuo coal-fired plant in the Inner Mongolia Autonomous Region. The installation of the unit completes the 2,400-MW plant, which is owned by the Inner Mongolia Dating Tuoketuo Power Generation Co. in which DIPG owns a controlling stake.

Also commissioned was the 300-MW Unit 2 at the 600-MW Tangshan power plant in Hebei Province. The project is owned by the Hebei Datang International Tangshan Thermal Power Co., in which DIPG owns a controlling stake.

DIPG noted that the tariffs for the Tuoketuo 4 and Tangshan 2 had been set at 3.2 cents/kWh and 3.6 cents/kWh, respectively. The company said the projects had been completed 28 and 17 months ahead of schedule, respectively, and that both would sell their power into the Beijing-Tianjin-Tangshan grid. The projects boost DIPG's operating capacity from 8,710 MW to 9,610 MW.

Zhang Yi, DIPG's vice chairman and president, said that as the "Tuoketuo Power Plant is close to a coal mine, fuel costs are low." He added that the "proportion of the company's generation capacity with low fuel costs out of total installed capacity has increased." As such, he noted, "the company will still have room to lower its average unit fuel cost amid tight coal supply and increased coal prices."

Meanwhile, China Power Investment Corp. reported a series of advances in the development of two of its projects.

The state-owned China Power Investment is one of the five core generation holding companies formed out of the State Power Corp. in late 2002.

China Power Investment reported that the first 300-MW unit at the 1,500-MW Gongboxia hydroelectric power station had entered operation at the end of September. The company added that the commissioning was noteworthy because it took China's total installed hydroelectric capacity to 100 GW.

The five 300-MW units comprising the Gongboxia Hydropower Station are on the Yellow River and were developed as part of the west-east electricity transmission project by one of China Power Investment's subsidiaries, the Huanghe Hydropower Development Co. The plant is due to be complete in 2006.

China Power Investment also said the feasibility study for rehabilitation of the 600-MW Yongji Cogeneration Power Plant in Shanxi province has been approved by the State Development and Reform Commission. The project will involve the installation of two 300-MW air-cooled turbo-generators.

Construction is scheduled to begin in December 2004 with the first unit scheduled to enter commercial operation in September 2006.

India's Communist parties attack proposed new electricity policy

India's leftist parties, which provide crucial support to the United Progressive Alliance coalition government, have attacked the administration's proposed national electricity policy. The policy is due to be finalized by the end of November.

All states will witness protest rallies against the 2003 Electricity Act during November, and a major demonstration is planned outside parliament on Dec. 10, according to the Communist Party of India's General Secretary AB Bardhan.

The leftist groups argue that the draft national electricity policy has been prepared without a review of the 2003 Act, and that this reneges on an agreement made when the parties formed the coalition in May.

The communists are critical of the reform-oriented 2003 law, which seeks to encourage competition and private investment in the power sector. "The Act creates a competitive framework for the distribution business, offering options to consumers, through the concepts of open access and multiple licensees in the same area of supply," the draft policy states.

One key sticking point is tariffs. The draft policy says that tariffs should progressively reflect the cost of electricity supply and "reduce and eliminate cross-subsidies."

Retail tariffs for agricultural and many domestic consumers, in addition to being directly subsidized by state governments, are also subsidized by the high tariffs prescribed for commercial and industrial consumers. This allows the supply of power at below cost or even free for agriculturalists in particular.

The leftist parties want the words "reduce" and "eliminate" to be deleted in order to retain cross subsidies.

However, the draft policy only proposes retaining cross subsidies for five years. "The tariffs for such categories of consumers may be pegged by regulatory commissions at a level even below the average cost of service. The matter regarding cross subsidies will be further re-examined in the light of its sustainability after five years," according to the draft.

It adds that "while there is an urgent need for ensuring recovery of cost of service from consumers to make the power sector sustainable, a minimum level of support will be required to make the electricity affordable for consumers of very poor category."

The leftist parties argue that elimination of the cross subsidies will "have serious implications on agriculture, power looms, street lights, waterworks and 75% of rural population." They add that "the basic provision of electricity for all households is necessary for fulfilling human development objectives."

In this connection, the communists also want the central government to share with the states the cost of supplying subsidized electricity to the countryside. They demand that the Act be amended "so that the obligation to electrify rural areas rests both upon the central and state governments."

The communist parties are also against the unbundling of integrated state-owned utilities into separate generation, transmission and distribution operations. "There is a distinct advantage in integrating the activities within a single organization structure," they argue, claiming that the results of unbundling in Delhi, Orissa and Andhra Pradesh have been "disastrous."

The authority vested with the electricity regulatory commissions is also a sore point for the left block. They insist that regulators cannot "overrule or ignore the declared objectives of the state governments," adding that the latter "have been burdened with a lot of responsibility but with almost no authority."

Specifically, they want the regulatory authorities to be deprived of the power to issue licenses for electricity distribution and supply to consumers, saying that this should be done by state governments. "Distribution licensees should be granted by the state governments only. Otherwise, all lucrative areas for distribution are likely to be picked up by private distribution licensees to the detriment of the state electricity boards and distribution companies."

Another demand raised by the left block is that profits of power companies should be capped on the basis of the Reserve Bank of India's prime lending rate, and "not an arbitrary fixture like 14% to 16%," given the current low interest rates. The rate of return allowed to power generators was reduced to 14% from the previous 16% under the five-year tariff order issued by the Central Electricity Regulatory Commission earlier in 2004.

The left also rues what it describes as the "emasculation" of the Central Electricity Authority, which operates under the Power Ministry and has had its authority to approve new power projects reduced considerably in recent years. "The CEA was an institution that thrived as long as the government was rooted in its conviction that power sector would never be privatized," they said.

India's Gujarat Ambuja Cements Ltd. plans 60-MW coal-fired project in Gujarat State

Gujarat Ambuja Cements Ltd. of India has confirmed plans to develop a 60-MW coal-fired plant at Ambujanagar in Amreli District, Gujarat State.

The company's Executive Director Anil Singhvi said that the plant would cost approximately $42 million.

Singhvi said that "the cement manufacturing unit at Ambujanagar currently draws power from the 54-MW captive power plant based on liquid fuel and the cost of generation has gone up considerably owing to rising furnace oil prices." He added that "the company is looking at setting up a thermal power plant as furnace oil prices have increased sharply and are expected to remain volatile."

The average cost of power generation from the existing plant has increased to 5.93 cents/kWh compared with the 5.75 cents/kWh recorded in 2003 because of the increase in furnace oil prices. Gujarat Ambuja Cement already imports coal through its port facilities at Muldwarka, about eight kilometers away from Ambujanagar.

The new project is scheduled to be commissioned in two equal phases, with the first 30 MW scheduled for operation by February 2006. The remaining 30 MW is due on line by December 2006.

The project will be funded primarily with internal cash flow.

Rating Agency Malaysia reaffirms ratings on Sarawak Electricity's debt securities

The Rating Agency Malaysia has reaffirmed its "AA1" rating for the $159 million of Al-Bai Bithaman Ajil Islamic debt securities of Malaysia's Sarawak Electricity Supply Corp. The outlook is described as stable.

SESCO is responsible for the generation, transmission and distribution of electricity in Sarawak. It is 51.6% owned by the Sarawak state government and 45% by the Sarawak Enterprise Corp. Bhd., with the rest of the stake held by employees of SESCO. The state government is planning to transfer its stake in SESCO to SECB, in which it holds a major stake.

SESCO owns 36 plants totaling 553 MW in the state.

RAM said that the rating was premised on SESCO's "robust financial profile and its strategic role as the sole electricity utility company in Sarawak State." The agency added that the "proposed corporate restructuring exercise involving SECB and SESCO, through which the latter will end up as a wholly owned subsidiary of the former, would not dilute the strong implicit support which SESCO currently enjoys from the state government."

The state would continue to wield considerable influence over the electricity industry in Sarawak by virtue of its majority shareholding in SECB, RAM observed.

Indeed RAM said that it viewed the proposed restructuring exercise as positive in overall terms. In addition to offering improved financial flexibility through easier access to the equity market, it meant that SESCO would be able to focus solely on its core business activity as the state's electricity provider since its non-core investments in education and telecommunications would be divested.

SESCO's involvement in other business activities had earlier been highlighted as a risk factor, RAM explained, "given the possibility of the state requesting the company to gear up to fund such investments."

However, balancing the strengths RAM noted that SESCO would remain exposed to "inherent business risks as a state utility provider." It explained that "tariff rates continue to be a highly political issue and are unlikely to be revised over the intermediate term, despite escalating fuel costs." And, "although its profit margins have improved, persistently rising fuel prices and other operating expenses will continue to exert pressure on the company's profitability over the coming years," RAM said.

In addition, capital expenditure would remain significant over the next 10 years and would have to be prudently funded to ensure that SESCO's balance sheet remained intact. And RAM believed that "being a wholly owned subsidiary of a listed company" would provide a new set of challenges to SESCO's management team, "in terms of balancing its public role as the state utility provider against its obligation to maximize shareholders' value and profits."

Meanwhile RAM has also reaffirmed its rating of the $28 million of fixed rate serial bonds issued by Musteq Hydro Sdn. Bhd. Musteq Hydro owns and operates a 20-MW hydroelectric plant at Sungai Kenerong in Kelantan State.

The performance of the build-own-operate project had continued to improve, RAM said. Output generated during 2003 reached 129.99 TWh, up 13.9% from the 114.16 TWh posted in 2002.

RAM noted that the plant's future operations and maintenance remained uncertain since the operation and maintenance contractor Projass Engineering was facing liquidation. However, the agency said that it did not expect "any problem to surface should Musteq Hydro decide to perform the O&M in-house or appoint another operator, as we understand that the existing personnel at the plant would be retained under any circumstances."

Musteq Hydro is being sold by current shareholders Projass Engineering and Musteq Holdings to Eden Enterprises' subsidiary Langkawi Batik Enterprises for $10.2 million. The acquisition was approved by the Securities Commission in late September 2004.

Asian briefs

■ Hong Kong-listed **Citic Pacific** plans to acquire a 12.5% stake in a 600-MW plant in Annhui, China, for $17.8 million.

Citic Pacific would buy all the shares in A-A Dynamic from its parent Citic Group, funding the acquisition with internal resources. A-A Dynamic's only asset is the 12.5% interest in Huaibei Guoan Power Co., which is a Sino-foreign cooperative joint venture established in 1997 with a total investment of $341 million.

Citic Pacific already owns and operates the Huaibei No. 2 Power Plant, which comprises two 300-MW units. The Anhui Wan'neng Co., a subsidiary of the Anhui Energy Group, also owns a stake in the project.

■ Philippine-based **Luzon Hydro Corp.** has abandoned plans to expand its hydroelectric power generation project on the Bakun River between Benguet and Ilocos Sur provinces because of deteriorating financial prospects, following delays in implementing the project.

Luzon Hydro is an equal joint venture of Aboitiz Equity Ventures and Australia's Pacific Hydro. Luzon Hydro operates the 70-MW Bakun AC hydroelectric project, which it was awarded in 1996 on a build-operate-transfer basis.

In 2000, the company announced plans to expand the output of the plant by 10 MW through the Kayapa diversion project, which would have increased the dry season water flows available to the plant from the Poy-Ocan and Kayapa Rivers.

But delays in securing approval from landowners for the construction of the access road and other facilities had made the project untenable, given the declining power sales tariff available from the National Power Corp.

The original 70-MW phase began operating in February 2001 and sells its power to National Power Corp. under a 25-year power purchase agreement.

EUROPE/MIDDLE EAST

Enel of Italy reaches deal to take 66% stake in Slovak generator Slovenske Elektrarne

Italian energy firm Enel has reached an agreement with the Slovak government to take a 66% controlling stake in Slovak generator Slovenske Elektrarne for Eur840 million ($1.09 billion).

The deal is subject to Slovak authority approval, and the government is due to vote on the deal on Nov. 24.

Enel beat competition from Russian firm Inter RAO, Austrian power company Verbund and Czech power firm CEZ. Negotiations for the sale had been slowed in previous weeks by objections from some corners of the Slovak government to Enel's majority state ownership. The company is 51% owned by the Italian government, which, as a concession to the Slovak government's concerns, has announced plans to float up to 20% of Enel.

Slovenske Elektrarne produced 84% of the Slovak Republic's 28.9 TWh of generation output in 2003. The company owns and operates 6,900 MW of plant, including the Bohunice and Mochovce nuclear power plants, totaling 3,520 MW, two coal-fired thermal plants of 522 MW and 660 MW, respectively, and several hydro plants.

The Slovak government is still negotiating with Enel over how it will operate the nuclear plants, which are ageing and of Soviet design, and about its commitment to complete two unfinished reactors at Mochovce. Enel has yet to say whether it would complete these reactors, but it previously said that it would not take ownership of the two older reactors at Bohunice, which the Slovak Republic committed to close down in 2006 and 2008 as part of its European Union accession treaty. Slovak Economy Minister Pavol Rusko plans to try to persuade the European Commission, the administrative arm of the E.U., to postpone the reactor closure dates in an attempt to persuade Enel to take on the reactors.

The Slovak Republic has drawn energy investor interest because of its advantageous position as a transit country between the Czech Republic, Poland, Hungary and Ukraine. In June the government agreed to sell a 51% stake in the country's largest distributor ZSE, combining a direct sale to 40% shareholder E.ON Energie of Germany with a flotation on the Bratislava stock exchange.

Bulgaria approves sale of 67% stake in distribution firms to Czech firm CEZ

The Bulgarian government has approved the sale of majority stakes in three power distribution companies to Czech power company CEZ.

CEZ will take a 67% stake in the companies, which supply power to about 1.9 million customers in the cities of Sofia and Pleven. The company paid Eur281.5 billion ($365 billion) for the stake.

The Bulgarian government has undertaken the sales of other regional distributors in recent months to E.ON of Germany and EVN of Austria. In October it awarded the northeastern distribution package to E.ON, whose bid of Eur140.7 million ($169 million) beat three rival bids from CEZ (Eur121.5 million), Enel (Eur120.6 million) and PPC of Greece (Eur80 million).

EVN won the rights to the southeast package with an offer of Eur271 million, Eur70 million more than the next highest bid from Italian firm Enel, and nearly Eur100 million more than a bid by CEZ.

The largest of the three distributors is the western package, comprising Elektrorazpredelenie Stolichno EAD, which serves the city of Sofia, Elektrorazpredelenie Sofia Oblast EAD, and Elektrorazpredelenie Pleven EAD, with just less than 1.9 million customers and annual sales in 2002 of 7.5 TWh.

Second largest is the southeastern package, which includes the regions of Plovdiv and Stara Zagora, with 1.5 million customers and annual 2002 sales of 6.3 TWh. The northeastern package includes the regions of Varna and Gorna Oryahovitsa and has 1.14 million customers with annual sales of 4.8 TWh.

European/Middle Eastern briefs

■ **Sweden Offshore Wind** plans to submit an application to the Swedish government in early December to build a 640-MW wind farm offshore Kriegers Flak in southern Sweden.

The project would comprise 128 turbines, each with 5 MW capacity, and the company expects annual output from the plant to total 2,100 MWh.

Swedish Offshore Wind board member Achim Berge said it would take around six months to obtain approval for the project. The company then needs to gain approval to build a connection from the farm to the Swedish high-voltage grid. Sweden Offshore's German sister company has already handed in an application to German authorities for a 320-MW wind farm in the German waters off Kriegers Flak, which the company expects will be approved in January or February next year.

■ Swedish company **Sydkraft** will change its name to **E.ON Sweden** in early 2005, in recognition of its majority owner E.ON's 55% stake. Statkraft of Norway owns 44.6%. Other entities own 0.4%. Sydkraft is Sweden's second largest generator after Vattenfall. In 2003 its power output was 23 TWh.

■ German company **Energie Baden Wurttemburg** reported a net profit for the first three quarters of 2004 of Eur183.7 million ($237.1 million), from a loss of Eur1.011 billion in the corresponding period in 2003. Earnings before interest, tax, depreciation and amortization in the first three quarters of 2004 amounted to Eur1.553 billion, an increase of 169% or Eur975.4 million over the same period in 2003.

■ Portugal's council of ministers has approved a decree calling for the termination of long-term power purchase agreements and the creation of compensation measures to replace them. Although details have not been disclosed, **Energias de Portugal** Nov. 11 said it could be granted between Eur2.6 billion ($3.35 billion) and Eur3.2 billion in compensation over a 23-year period based on information already revealed by the government.

As previously indicated by the Portuguese government, the compensation amount for the PPAs will be based on the difference between each contract and forecast revenues, using a reference annual market price of Eur36/MWh, according to EdP. During the first 10 years of the measure, the amounts will be adjusted upwards or downwards based on real market revenues, after which they will be subject to a final adjustment based on expected revenue projections.

■ **Endesa Italia** has completed the repowering of one unit of its four-unit 1,280-MW Tavazzano oil-gas fired plant in the northern Lombardy region, parent company Endesa of Spain said Nov. 15.

The repowering, which raised the plant's capacity to 800 MW from 320 MW, is the first phase of a larger Eur400 million ($520 million) project and entailed converting the generator into a combined-cycle facility. The second phase, scheduled to be completed in 2005, would convert a second unit to a combined-cycle operation, raising its capacity to 400 MW from 320 MW in the process.

The other two Tavazzano units, at 320 MW each, are not slated for conversion. Endesa Italia, with 6,300 MW of installed capacity, plans to reach 8,000 MW in 2008.

■ **Endesa** has completed construction of a 76-MW wind farm in Spain's northwest Galicia region, the Spanish generator said Nov. 11.

The new installation, named Fonagrada-Punago, cost Eur65 million ($85 million) and raises the company's renewables capacity in the region to 400 MW and in Spain to 2,123 MW. Endesa is targeting 4,000 MW of domestic renewables capacity by year-end 2008.

■ Spanish generator **Hidrocantabrico** is moving ahead with a proposal to build an 800-MW coal-fired plant at its existing two-unit Abono generator near Gijon in the northern Asturias region.

The Abono-3 project, budgeted at Eur687 million ($893 million), has reached the public input stage following completion of an environmental impact assessment, according to a notice published Nov. 11 in Spain's official state gazette.

Hidrocantabrico, which previously disclosed it planned to invest Eur1.6 billion over the 2004-2007 period, hopes to complete the power plant in 2010.

The Spanish energy company, controlled by Energias de Portugal, has 1,588 MW of operating coal-fired capacity in Spain, including the 360-MW Abono-1 unit and the 556-MW Abono-2 generator.

■ Israel's National Infrastructure ministry has granted **American Israel Paper Mills Ltd**. a license to build a 400-MW, $250 million cogeneration plant at its Hadera complex. The firm is one of Israel's largest industrial users of electricity.

American Israel Paper said several local investors would be involved in the project, which would run on gas from the planned common carrier transmission network. The Israel Electric Corp. is building the marine segment of the network. Its terminus will be at Dor, along the central Mediterranean coast of Israel.

The plant would replace an existing generation facility and would produce 210 tons of steam per hour and over 50 MW of electricity. The remainder would be sold to nearby factories in the Hadera industrial zone. The plant is due on line in 2007 or 2008.

LATIN AMERICA

EdF's Edenor in Buenos Aires launches $65-million buyback offer for some debt

Edenor, the electric distributor serving the northern half of Buenos Aires, last week launched a buyback offer for a portion of its $500-million total debt.

The utility, controlled by Electricite de France, said in a filing with the Buenos Aires stock exchange that it would spend up to $65-million on the debt repurchase and would pay between $0.70 and $0.75 on the dollar in the offer, which runs from Nov. 10 to 5pm New York time on Dec. 10.

Edenor has been paying interest on its debt, most of which is dollar-denominated, since Argentina devalued the *peso*, converted electricity and other public service tariffs from dollars to *pesos*, and put a freeze on the tariffs in January 2002, but it has failed to pay off any principal during this time. In its statement filed with the stock exchange Edenor said its continuing interest payments along with the new buyback offer represent the company's signals of good faith to creditors that it wants to resolve its debt problems.

The company will use funds from its cash flow to buy back debt under the current offer. Edenor had been hoping to formulate a plan to restructure by the end of 2005 its entire debt burden, based on projections of revenue increases in 2005 driven by tariff hikes. However, negotiations to raise tariffs for Edenor and other public utilities have been delayed because the Kirchner government recently extended through 2005 the country's economic emergency law. As long as the emergency law, first enacted in January 2002, remains in force, the government can stall its promised renegotiation of all public utilities' concession contracts, including new tariff structures.

Edenor serves 2.2 million customers, around 20% of Argentina's electricity market. Also in Argentina, EdF had controlled Mendoza provincial utility Edemsa but in July reached agreement with an investor group to sell off its 51% stake. The French company continues to own majority interests in two hydro generators in the country totaling 648 MW, as well as 51% of the Distrocuyo electric transmission system in Mendoza, but the French press reported recently that EDF intended eventually to exit Latin America.

Eletropaulo shows $2.26 million loss in 3Q, while Tiete has $25 mil. profit

AES Corp.'s Eletropaulo distribution subsidiary in Brazil turned in a R$6.3 million (US$2.26 million) net loss in the third quarter, while its major generating business in that market, 2,644-MW Tiete, registered a R$69.7 million (US$25 million) quarterly profit.

Eletropaulo's quarterly loss contrasted sharply with the R$7 million profit it showed in the same period of 2003 and disappointed investors who had expected a strong positive performance from Brazil's largest stand-alone electric distributor in this year's July-September period. Over the first nine months of 2004, Eletropaulo had a net loss of R$12 million (US$4.2 million), reversing last year's R$131.3 million nine-month profit.

Eletropaulo attributed the loss in part to a 22% year-to-year increase in operating expenses, which in turn reflected such items as higher purchased-power costs and transmission charges, as well as higher financial expenses. Operating revenues from January through September rose by 16.9% over last year, due to double-digit tariff increases in 2003 and 2004. Power sales volumes–8,081 GWh in the third quarter, 24,404 GWh year-to-date–are little changed from last year, although residential and commercial sales have grown this year while Eletropaulo so far in 2004 has lost 41 industrial customers to the free market.

Despite the negative showing for the year to date, AES officials noted positive developments in Eletropaulo's financial profile. The share of foreign currency—predominantly U.S. dollar-denominated debt—has shrunk from 35% of the total at year-end 2003 to 21% now, with 79% of its R$5.5 billion

(US$1.97 billion) total debt now *real*-denominated. Additionally, 78% of Eletropaulo's total debt is now long term, since the company succeeded through various debt restructuring deals in cutting its short-term obligations to 22% of the total.

Although the deal has not been finalized, Eletropaulo hopes by year end to receive R$777 million (US$278 million) in financing from national development bank BNDES under its so-called capitalization project, said AES chief operating officer Joseph Brandt Nov. 15 at Banc of America Securities' Energy and Power Conference. Eligibility for the capitalization funds depends on Eletropaulo's adoption of various corporate governance reforms that will increase transparency of financial information and assure a free float of at least 25% of Eletropaulo shares. Receipt of the BNDES funds would allow the distributor to take out existing commercial lenders, cutting principal payments by US$200 million over the 2005-2008 period and replacing existing debt with a new, 10-year, *real*-denominated loan.

AES Tiete's third-quarter profit was 3.3% less than last year's result. For the year, however, Tiete's accumulated R$209.9 million profit is 64.6% greater than its January-September 2003 profit. Tiete does not plan to offer any volumes for sale in Brazil's upcoming "old energy" auction slated for early December, the company said, because its output is currently committed under existing contracts. Eletropaulo is one of Tiete's largest customers.

Enersis of Chile closes on $600 million refinancing, split with subsidiary Endesa

Chilean power holding company Enersis, controlled by Endesa of Spain, last week closed on a $600 million syndicated debt deal, whose proceeds will refinance existing debt of Enersis and its primary generation subsidiary, Endesa Chile.

The deal is expected to cut the holding's annual financing expenses by $4 million. It was led by BBVA Securities, Caja Madrid, Citigroup Global Markets, and Santander Investments. Of the $600 million, $350 million will be applied to refinance Enersis debt, while the remaining $250 million will go to EOC.

The refinancing operation marks the latest in a series of actions taken by Endesa starting last year to cut Enersis' overall debt and strengthen its financial position. From September 2003 to September 2004, Enersis eliminated $310 million of debt, bringing its total obligations to $6.386 billion. The company's success in restructuring its financial profile helped contribute to a 36.2% year-to-year increase in Enersis' net profits in the third quarter.

The new $350-million credit facility for Enersis matures in 2008, and replaces debt that had come due in 2006. For EOC, the new credit carries a six-year term, maturing in 2010, which represents a three-year extension over its previous debt. The interest rate for both new credit facilities is 0.375% over the London Interbank Offered Rate, compared to the current LIBOR-plus-1.15% rate.

Enersis in a statement said the refinancing operation reflected the company's improved access to credit markets in the wake of its improved financial situation and positive expectations for Enersis' future performance.

Colbun resumes development of 70-MW Chilean hydro plant after four year delay

Chilean generator Colbun, owned by Belgian firm Tractebel, has decided to proceed with construction of the 70-MW Quilleco hydro plant in the country's southern Region VIII, after putting development plans on hold in 2000.

Resumption of Quilleco, which received its environmental permitting in late 1999, comes as Chile's energy policy makers are touting the benefits of diversifying the power generation mix to reduce dependence on imported natural gas. Although delivery volumes are close to normal now, earlier this year Argentina slashed its natural gas exports to its neighbor by as much as 50%. In the wake of this disruption alternative resources such as hydro, coal and geothermal are expected to receive greater consideration by Chilean project developers while new gas-fired plants may be less likely to go forward in the next few years. Gas-fired capacity represents around 37% of Chile's total generation portfolio. The country imports all of its gas to fuel these projects from Argentina.

Colbun is the only generator in Chile now building a gas-fired plant, 250-MW Candelaria in Region VI, and gas distributor Innergy hopes to proceed with its proposed 405-MW Campanario facility in Region VIII, if it can line up a development partner (GPR, 14 Oct, 8). But unless and until Chile can ensure that future gas deliveries—whether from Argentina or other neighboring gas exporters—will be secure, new gas projects are not likely to be proposed in the near term.

Quilleco, utilizing two 35-MW turbines, would be on the Rio Laja and would operate in conjunction with Colbun's existing 160-MW Rucue plant, which came on line in 1998. Construction will cost an estimated $80 million and take 20 months. Given that schedule, Quilleco should enter operation in late 2006. Of Colbun's 1,328 MW of existing on line capacity, around 700 MW are hydro.

AES sells 50% stake in Dominican distributor Ede Este to TCW Energy for $109 million

AES Corp. this week announced the sale of its 50% interest in Dominican power distributor EdeEste to an investor group called Dominican Energy Holdings LP, whose lead shareholder is TCW Energy Advisors LLC, a unit of Los Angeles-based Trust Company of the West.

AES had been seeking a buyer for loss-making EdeEste since earlier this year. In September 2003, the other private investor in the Dominican Republic's electric distribution sector, Union Fenosa, sold its 50% stakes in distributors Ede Sur and Ede Norte back to the government. The companies had been privatized in 1999 under arrangements in which the government retained 50% ownership but management control was handed to the winning bidders. AES paid $109.3 million for its EdeEste investment.

Under the terms of its EdeEste sale, AES will continue to manage the utility's daily operations on behalf of Dominican Energy Holdings. Other sales terms, including price, were not disclosed. AES also owns generation assets in the Dominican Republic—210-MW Los Mina, 310-MW Andres, and 25% of 587-MW Itabo—and will continue to operate those businesses as usual.

The sale of EdeEste follows the release of a Dominican government audit last week charging the distributor with improper accounting practices. AES, along with other private companies operating in the country's power sector, has been working with the government of Leonel Fernandez, since it took office in mid-August, to resolve disputes over delinquent payments owed to generators. AES in recent weeks has received several payments to cover past power sales (GPR, 28 Oct, 10). The government this week said retail electric tariffs for consumers using over 200 kWh a month would rise 30% in order to help pay down the sector's chronic debts.

In brief...

Spanish generator Iberdrola is building a 100-MW wind farm in Mexico and a 50-MW wind farm in Brazil, company chairman Inigo de Oriol said Nov. 17 during a Latin America-Europe business forum in Madrid.

The Mexican facility is being installed in Oaxaca state and the Brazilian unit in Rio Grande do Norte State, with both due on line in 2006.

The company expects to have 26,400 MW of installed capacity by year end, including 3,400 MW in Latin America.

NORTH AMERICA

PROJECT NEWS

AEP considers two sites in Indiana for IGCC project of up to 1,200 MW

American Electric Power is considering a pair of sites in Indiana, at its 2,600-MW Rockport coal-fired plant in Spencer County and at a 400-MW coal plant closed a decade ago in Sullivan County, for an integrated gasification combined-cycle project whose location announcement may come sooner than expected, according to AEP spokesman Mike Brian.

Indiana and neighboring Kentucky, states whose electric industries have not been deregulated and whose regulators may allow the cost of an IGCC project in the ratebase of an AEP subsidiary, are thought to be frontrunners for an IGCC project. AEP said it intends to place at least one IGCC plant in the range of 1,000 MW to 1,200 MW in commercial operation in the 2010 or 2011.

Rockport, operated by AEP's Indiana Michigan Power subsidiary, is AEP's largest plant in Indiana. Near the Ohio River between Evansville, Ind., and Louisville, Ky., the plant cost more than $2 billion to build and comprises twin 1,300-MW units that went into operation in 1984 and 1986, respectively.

Brian said AEP was also evaluating the old Breed property on the Wabash River for an IGCC plant. Breed was shut in 1994. Breed is a possibility, he said, because of its proximity to water, chemical plants, railroads and because a 765-kV electric transmission line runs from Rockport through the Breed property.

A site decision could be announced by late December or early 2005. AEP said it was interested in building more than one IGCC plant. Though more expensive to build than conventional coal-fired generating stations, IGCC technology results in far fewer air emissions and generally attracts less opposition from environmentalists.

Norton Energy allows permit to install expire on 2,700-MW compressed air project in Ohio

Norton Energy Storage LLC allowed an Ohio Environmental Protection Agency permit to expire in mid-November, leaving uncertain the fate of a 2,700-MW compressed air energy storage project the company planned to build in Summit County, Ohio.

NES, owned by its management and by private equity funds managed by Haddington Ventures, the general partner of Haddington Energy Partners, received a one-year extension of its permit to install from OEPA in November 2003. To retain the permit, NES needed to start construction before the extension expired, according to a spokesman for the state agency.

But it failed to do so.

Columbus, Ohio, attorney Langdon Bell, who represents NES, said he did not know what the company's plans were for the ambitious $1.5 billion project announced nearly four years ago. "The issue comes down to this ... energy markets are depressed but it looks like they're starting to come back again," he said.

According to Bell, it was clear NES would have to amend the OEPA permit "to reflect changes in proposed equipment for the project." The company may file a revised permit application, he suggested, though neither NES nor Haddington Ventures officials could be reached for comment.

NES still has nearly two years to begin construction under a separate, five-year permit issued by the Ohio Power Siting Board.

The project has been billed as one of the largest CAES facilities in the world. It would be built on 92 acres at a 2,200-foot-deep former limestone mine about 35 miles south of Cleveland.

Work continues on Calpine's 704-MW Fremont Energy gas-fired plant in Ohio

Though it has flown under the radar for months, construction, albeit slowly, continues on Calpine's 704-MW Fremont Energy Center LLC gas-fired plant in Sandusky County, Ohio.

A minor development in mid-November underscored the California company's determination, if not eagerness, to complete the $260 million project by Fremont's revised June 2006 in-service target. Calpine and American Transmission Systems Inc. asked the Ohio Power Siting Board for a change in the project's certificate of environmental compatibility and public need that relates to a switching station built at the site.

Calpine wants to convey the small, 2.37 acre site on which the switchyard is located to ATSI.

Construction on Fremont began more than three years ago, in September 2001. The plant originally was scheduled for operation in the summer of 2003 but was delayed after wholesale power prices began plummeting. It subsequently was delayed until June 2005 and then to June 2006.

Exergy Development gains regulator approval of PPA with Idaho Power for 10-MW project

Exergy Development Group has received approval from Idaho regulators for a contract to sell Idaho Power 10 MW for 20 years from a new plant near Hageman, Idaho.

The project will be built by the Montana-based Exergy's unit Fossil Wind Gulch Park LLC. The plant, which will produce its first power in a start up mode Dec. 15 and go on line fully Jan. 1, is a qualifying facility built under the Public Utility Regulatory Policies Act.

An agreement signed between the utility and Fossil Gulch used current avoided cost rates of 5.5 cents/kWh that rise to 6 cents/kWh. Costs will be recovered from utility customers.

Fossil Gulch has agreed to keep its generation below 10 MW of firm energy so it can qualify as a QF (GPR, 21 Oct, 12). If more than 10 MW is produced, the power would be considered "inadvertent energy" and sold on the market. The plant will comprise seven 1.5-MW 77 SLE General Electric wind turbines.

Idaho Power filed the contract request with the Idaho Public Utilities Commission in October and asked for a fast-track process because the plant was about to go into commercial operation.

The utility's transmission lines run through the property.

Idaho Power said in a recent resource plan that it intended to buy 360 MW of wind energy to help diversify its power resources over the next 10 years. It also is open to adding other renewables and plans to buy 100 MW of geothermal power over the next decade.

Thompson River Co-Gen prepares to start up 16.5-MW plant in Montana

By mid-December, Thompson River Co-Gen LLC's new 16.5-MW coal-fired cogeneration plant in Montana is expected to begin producing electricity near the site of a lumber mill operated by parent company Thompson Lumber.

The cogen facility is nearly four miles east-southeast of Thompson Falls, Mont.

The company began making plans to fire up the facility after its revised air quality permit won approval from the Montana Dept. of Environmental Quality. The agency made some changes to the permit, requiring Thompson River Co-Gen to monitor the plant's air emissions every three days year-round. The draft permit had mandated monitoring only one day in every six during the summer.

The permit is scheduled to become final Nov. 23.

Plant manager Curt Boydston said in mid-November that the cogen facility was ready to start production soon afterward. The cost of the project was not disclosed.

"Our plant will put out its first electricity in mid-December and a full load by mid-January," he said. Though some of the power will be used by the lumber mill, most probably 14 MW or so will be sold to NorthWestern Energy, Boydston said.

The plant is capable of burning up to 25% wood waste, or biomass, and 75% coal. At least for now, it only will consume about 10% biomass from the lumber company. "There just wasn't enough wood available," he said.

Columbia Energy Partners signs purchase agreement with 104-MW Oregon project

Columbia Energy Partners has signed a memorandum of understanding with PacifiCorp to supply power from a $120 million, 104-MW wind farm the developer plans near Arlington, Ore., that would go on line by late 2005.

The Ta-My-Y-Slah wind project will have the Confederated Tribes of the Umatilla Indian Reservation as a minority partner. The tribe will put equity into the eastern Oregon project and receive a share of the profits, said Chris Cowley, president of the Portland, Ore.-based Columbia Energy. The project is fully permitted.

A PacifiCorp spokesman confirmed the MOU was signed and said the utility had compiled a shortlist in a solicitation for 1,100 MW of renewable power over the next seven years. It plans to announce all winning bidders by year end.

Crowley said the Arlington community with an agriculture base is economically depressed and residents have provided strong support for the wind farm. He said the project would not be very visible because it would be tucked between two regional landfills owned by waste management companies. The project also has had support from Oregon congressmen who are eager to bolster the community's economy.

The developer also is developing near Arlington a 5-MW wind project in which PacifiCorp also is the power buyer.

Western Wind, Clean Power Income Fund plan to develop wind farm in New Brunswick

Western Wind Energy has found a partner for its planned 20-MW wind farm on Grand Manan Island, New Brunswick, and possibly for other projects as well.

The Clean Power Income Fund said Nov. 16 that it reached an agreement to become a 50:50 partner with Western Wind on the CAN$31.2 million (US$26.1 million) Grand Manan project, whose output would be sold to New Brunswick Power under a previously announced 20-year, CAN$90-million-plus power purchase agreement.

The joint-venture agreement, which is subject to due diligence expected to be completed by early February, calls for Clean Power to pay Western Wind CAN$7 million for a half stake in the wind farm. Toronto-based Clean Power also would negotiate a CAN$22.5 million, 20-year senior debt facility that would be used to fund the construction and operation of the project.

Still further, the Clean Power/Western Wind agreement gives Clean Power a three-year "right of first offer and negotiation" on other wind projects that Western Wind may develop in North America. Currently, Western Wind is developing projects totaling more than 500 MW in Arizona, Alberta and Ontario.

A spokesman for Coquitlam, B.C.-based Western Wind said that, with the Clean Power agreement in hand, "we really are on track" to start and finish the Grand Manan wind farm during 2005. Western Wind will act as the project's construction manager, and, upon its completion, as the wind farm's operator.

He said that Western Wind had not yet selected the supplier for the project's wind turbines.

CALIFORNIA

9th Circuit's decision changes equation for suppliers with refund claims ... from page 1

Dynegy's settlement with California, reached this April and approved by FERC on Oct. 25, calls for the Houston company to assign all its receivables, approximately $259 million plus interest, from the California Power Exchange and the California ISO "to the settling parties for ultimate distribution to all market participants." The settlement also called for Dynegy to place $22.5 million into escrow accounts for distribution to various California energy purchasers.

Duke reached its settlement agreement in July. It calls for a $207.5 million payment in cash and credits for which the company took a $104.9 million pre-tax charge in the second quarter. A Duke spokesman said, "We do not see any additional refund exposure as a result of the 9th Circuit decision."

El Paso Corp., in June 2003, struck a "master settlement agreement" that resolved litigation, claims and regulatory proceedings arising out of the sale or delivery of natural gas and/or electricity to the Western United States. The value of the deal, which includes cash payments as well as modifications to existing power supply agreements, was about $1.4 billion. The settlement included a $78.6 million cash payment and a payment of $45 million annually for 20 years.

In fourth-quarter 2002, El Paso recorded a $899 million pretax charge related to its Western energy settlement, and in second-quarter 2003 recorded an additional pretax charge of $104 million.

El Paso's footprint as an electricity supplier in California, however, was very small and, therefore, the company says, it is not involved in a significant way in any of the refund issues.

The state of California is still pursuing refunds from a long list of power suppliers. The biggest ones are Enron, Mirant, Powerex, Reliant, and Sempra Energy.

Those parties are now under even greater pressure to reach a settlement, but arguably the balance of power has tipped in favor of California.

The unsettled suppliers could elect to wait out the appeal process, but because the court has directed FERC to reconsider granting retroactive refunds and, perhaps more importantly, because the court has questioned FERC's monitoring of wholesale prices, the decision bolsters California's contention that the wholesale market was flawed.

As FERC Chairman Pat Wood III said recently, "If ever you needed an incentive to settle, the 9th Circuit provided it."

Meanwhile, several parties are trying to reach a resolution regarding the Western crisis. Mirant is still in discussions with various "California parties" regarding Western energy crisis refunds. In a statement, the company said, "Mirant is pleased that the [9th Circuit] Court upheld the ability of electricity suppliers to charge market-based rates, but we are disappointed that the court has remanded the case to the FERC over what we and FERC viewed as a technical reporting requirement."

Mirant is one of the parties appealing the 9th Circuit's decision.

If FERC were to order Mirant to pay additional refunds, Mirant said those refunds would become claims in the company's bankruptcy case. A Mirant spokesman added that the company has reserved about $295 million for losses related to its California operations during the 2000-2001 event.

Powerex, the wholesale trading unit of BC Hydro, on the other hand, is holding firm. Elisha Moreno, a company spokeswoman, said, "We are disappointed with the 9th Circuit's ruling. It sets the clock back" and fosters "paralyzation" of the power market. She went on to say that Powerex does not believe that the Sept. 9 decision substantiates California's demands, adding that the company has not made a refund settlement because it would be an admission of wrongdoing. FERC basically admitted that the power markets during the California energy crisis were faulty, she said. "If the rules were faulty, it had nothing to do with Powerex."

Sempra Energy, whose Sempra Energy Trading unit has made a $7.2 million settlement with FERC on gaming and partnership involvement issues, has not made a settlement regarding refund claims. Sempra Energy Trading has recorded reserves for refund amounts, but has not released the amount of those reserves.

Meanwhile, the company awaits the results of further FERC actions. In its third-quarter 10-Q filing with the Securities and Exchange Commission, Sempra stated, "it is possible that the FERC could order 'refunds' or disgorgements of profits … and substantially increase the refunds that ultimately may be required to be paid by SET and other power suppliers."

Reliant has reached two settlements regarding the Western energy crisis, but they do not cover refund obligations. Both are related to trading and marketing investigations concerning withholding generation from the market. The aggregate value of Reliant's completed settlements is about $50 million, but the amount could vary because it includes a $25 million cash payment, as well as the value of power that FERC has directed Reliant to provide to California at below-market rates (GPR, 30 Sept, 14).

In its third-quarter 10-Q filing with the SEC, Reliant stated, "We are not in a position to predict the ultimate impact of the [9th Circuit] court's decision, which we have appealed." Reliant did, however, point out that the court denied the AG's request for the court to order FERC to make refunds. Under the court order, FERC need only reconsider the issue.

Reliant has reserved $103 million for refund liabilities.

An offsetting factor in the consideration of any refunds is the fact that many power suppliers are carrying on their books back payments owed to them by the California ISO and the California Power Exchange related to power sales during the energy crisis. One upshot of that is that settlement payments might not necessarily be in cash.

Reliant, for instance, estimates that it is owed $230 million by the California ISO and Cal PX, after backing out its $69 million refund obligation and including $31 million in interest. Reliant's estimates do not include any additional possible refunds from the pre-October 2000 period that might result from the 9th Circuit decision.

The balance between how much money suppliers are owed and how much they owe offtakers is being determined by a process known as "The Refund Rerun."

According to a preliminary finding by a FERC administrative law judge in December 2002, power buyers owed power suppliers $3 billion in aggregate for sales between Oct. 2, 2000, and June 21, 2001. Adjusted for $1.8 billion that FERC deemed suppliers had overcharged California during that period, the net amount came to $1.2 billion. FERC adopted the ALJ's numbers in March 2003, but adjusted them with a new estimate for natural gas prices that increased the refund obligations to more than $3 billion from $1.8 billion.

Using those numbers, the California ISO completed a "Preparatory Rerun" in the third quarter. Responsibility for power sales made to the PX, which suspended trading on Jan. 30, 2001, and filed for bankruptcy court protection on March 9, 2001, has been transferred to the California ISO.

According to Stephanie McCorkle, a spokeswoman for the ISO, "In the preliminary rerun, we were getting the volumes correct. Now, in the final rerun, the volumes are correct, the transactions are correct, but the price formula needs to be approved by FERC." The California ISO expects to finish its final rerun by first-quarter 2005.

Several observers, not including the California AG, estimate that the eventual calculation will balance out to $3 billion on both sides of the equation. In other words, the amount suppliers are owed in aggregate will cancel out how much suppliers owe in aggregate. Like other matters in the Western energy crisis, this one is also tangled up in court cases. There are several appeals pending at the 9th Circuit Court on various aspects of the refund order.

In a larger context, questions have been raised regarding whether or not the court's decision questioning FERC's methodology could undermine the commission's market-based-rate authority. Further, if sellers of wholesale power could be subject to refunds, even if they follow FERC's rules, it could discourage investment in the sector.

According to Merrill Kramer, a partner with Chadbourne & Parke LLP, the court's decision has created additional uncertainty for suppliers that did not adhere to reporting requirements. "They could face exposure," he said, but the 9th Circuit decision does nothing to undermine the concept and practice of wholesale rates and *post hoc* reporting. "That is an important part of the fabric of the wholesale market."

That position was bolstered recently by a Nov. 12 decision by the U.S. Court of Appeals for the D.C. Circuit in the case of the Midwest Independent Transmission System Operator v. FERC. The MISO and the New York ISO were claiming that FERC, in the wake of the Western energy crisis, had changed its fee assessment methodology by shifting its focus from volume to sales. But the court ruled that the Western energy crisis was a "singular event," in FERC's words, "a perfect storm."

Meanwhile, the California parties and the unsettled suppliers are still engaged in "a game of chicken," as one attorney close to the situation called it. Some suppliers are putting their stock in legal arguments. Others have weighed the risks and decided to settle. There are many elements to balance in deciding whether or not to settle, but in some respects time is weighing against the unsettled suppliers because, as the attorney said, the litigation costs are getting "very high."

There is no word yet on FERC's timing for the re-examining the retroactive refunds. Chairman Wood has said that closing the books on the lingering issues revolving around the Western energy crisis is a priority for both him and the commission, but neither he nor the commission has set out a time table. Wood's tenure as chairman expires in June 2005.

—Peter Maloney

California ISO endorses PG&E's plan to shut about 570 MW of S.F. plants

The California Independent System Operator board Nov. 10 unanimously endorsed an action plan to enable the retirement of old San Francisco power plants, but prefaced this move on the completion of certain transmission projects to prevent any upset of local system reliability.

The plan, forged by the city of San Francisco and local utility Pacific Gas and Electric, rests on the completion of 14 PG&E transmission projects and four city-sponsored peaking power plants, which when done, would allow for the closure of PG&E's 210-MW Hunters Point Units 1,2, 3 and 4 and Mirant's 360-MW Potrero Unit 3, 4, 5 and 6, and the Cal-ISO's release of their reliability-must-run contracts.

Key projects include upgrades at PG&E's 115-kV Newark-Dumbarton and 230-kV Jefferson-Martin transmission lines. The utility expected those projects to be completed by mid-2006. Other projects, such as upgrades at the 115-kV Bair-Belmont line and 230-kV Metcalf-Hicks and Metcalf-Vasona lines, are under evaluation by PG&E with an estimated completion date for 2007.

Local residents for years have worked to close down the plants, which both burn gas and oil, over fears about environmental and public health impacts. The Cal-ISO, however, has been concerned about shutting down these plants and causing problems with maintaining local reliability. San Francisco and the small peninsula it tops have been highlighted as an area in the state of power import and transmission problems due to its unique location and high demand needs.

At the board meeting, Randy Abernathy, ISO vice president of market services, said that the plan is "condition certain, not date certain." Consequently, the grid operator will not move on removing the RMR contracts until safe and reliable grid operations are certain, he said. A PG&E spokesman said at the meeting that the utility is looking to close Hunter's Point by early 2006. "We are fully committed to an expedited closure," he said.

Also at the meeting, the Cal-ISO board unanimously approved PG&E's five-mile, 115-kV Martin-Hunters Point underground cable project, which is one of the 14 transmission projects in the plan. The $35-million project is scheduled for operation in the summer of 2007.

Wind power developers in Tehachapi Pass face three year wait for SoCal Ed grid funds

Wind power developers will have to wait until 2008 to bring new projects on line in the Tehachapi Pass, California's premier wind resource, according to Southern California Edison's current projected schedule for building new transmission capacity there.

This is bad news for the three developers that plan to build more than 700 MW of wind power in the area. PPM Energy wants to have the first of its two 200-MW Fairmont wind projects operating by 2006 and Coram Energy says it could install an additional 45 MW at its wind farm if transmission capability were available in the area.

The California Independent System Operator identified in a July 23 report to its Board of Governors the two PPM Energy wind projects and a third unnamed 300-MW wind project in its Interconnection Queue waiting for transmission interconnections (GPR, 5 Aug, 12).

The Tehachapi Pass has constrained transmission capability, and the area is limited to the 645 MW currently installed. A collaborative study group made up of stakeholders working under California Public Utilities sponsorship is planning a phased transmission development process that could eventually result in an infrastructure that could accommodate 4,475 MW of new generation in the Tehachapi Pass.

The California Energy Commission believes the development of this transmission capacity is important in order that the state can reach the renewable portfolio standard goal of producing 20% of the state's generation requirement through renewable resources by 2010. However, SoCal Ed, the logical buyer of power produced in Tehachapi, is not motivated to build any new transmission capacity soon, since it has nearly reached its 20% goal as mandated by state law. It now acquires or produces about 19% of its generation needs through renewable resources.

SoCal Ed is preparing to file applications in December at the PUC for certificates of public necessity for permission to build each of the three segments of the Vincent-to-Antelope-to-Tehachapi route as outlined by the PUC collaborative study group and approved by the Cal ISO. This will provide enough transmission capacity for the three projects identified by the ISO, but likely not more.

Charles Adamson, SoCal Ed's project manager for what the utility is calling the Antelope project, said the regulatory review process would take 18 to 24 months and would determine who would pay for the construction, which would take another 18 months. Adamson said the three segments would cost $200 million to construct and would allow 700 MW of new wind power production in the Tehachapi area.

SoCal Ed is now enmeshed in litigation with the PUC over who would pay for the construction. SoCal Ed sued the PUC in November 2003, claiming that its July 2003 ruling requiring utilities to pay for transmission upgrades clashed with rulings by the Federal Energy Regulatory Commission that independent power developers should pay for all transmission needed to connect their projects to the grid. The matter is now before the California Supreme Court awaiting a final ruling.

Coram Energy owns and operates an 11.3-MW wind farm in the Tehachapi Pass and sells power to SoCal Ed under three power purchase agreements. Brian O'Sullivan, Coram Energy's president, said if transmission capacity was adequate the company could install 30 new 1.5-MW GE Wind turbines in addition to the six it is now installing in its repowering effort.

Coram Energy holds a winning 7-MW proposal in SoCal Ed's 2003 solicitation for renewable resources and O'Sullivan is now negotiating a contract. However, the project could not be built until new transmission capacity is built. SoCal Ed has not announced the winners of its solicitation.

PPM Energy would like to build its two 200-MW wind projects in Tehachapi in 2006 and 2007, respectively. The 200-MW Fairmont wind project is first in line for connection to SoCal Ed's 230-kV system via the first segment of the projected Antelope line once it is built. A company representative did not return phone calls requesting comment on SoCal Ed's transmission construction time line.

Cal-ISO wants to forge RMR contract with Dynegy for 670-MW El Segundo

The California Independent System Operator wants to forge a reliability-must-run contract with Dynegy to ensure its 670-MW El Segundo Units 3 and 4 jointly owned with NRG Energy are around to provide power next summer, according to Jim McIntosh, Cal-ISO director of grid operations.

During a Nov. 10 presentation to the Cal-ISO board, McIntosh said Houston, Texas-based Dynegy last month told the grid operator that it planned to mothball the gas-fired units due to depressed wholesale market prices, but Southern California Edison and Cal-ISO determined that they were critical to ensuring reliability in the Los Angeles Basin in 2005. Those units are not part of the companies' ongoing effort to get California Energy Commission approval to replace El Segundo's non-operational, 335-MW Units 1 and 2 with a new gas-fired, 630-MW facility.

Dave Byford, Dynegy spokesman, would not confirm whether Units 3 and 4, which are under contract with the state Dept. of Water Resources until year end, are slated to be mothballed or whether the companies are in talks with the Cal-ISO. "The ISO's intention to negotiate a RMR contract represents a positive development for West Coast Power [the joint venture of Minneapolis, Minn.-based NRG and Dynegy] and for grid reliability in the Los Angeles area," he said.

Yearly RMR contracts, whereby the Cal-ISO pays for plants to remain on line to ensure local grid reliability, have become important for next summer as California could face serious power supply emergencies, especially in the southern part of the state, McIntosh said. The Cal-ISO has already moved ahead on forging new RMR deals, announcing in June that it signed a contract with Reliant Energy to bring back by year end its mothballed, gas-fired Etiwanda Units 3 and 4 totaling 640 MW.

McIntosh highlighted the California Energy Commission's 2004 Integrated Energy Policy Report Update, which warned the region's power reserves under normal hot weather would be around 4%, below the 7% need to meet regional reliability standards. Under hotter unusual weather conditions, reserves will drop to below 4% of what the region needs to just its peak demand, he said.

The state has already been lucky, avoiding any supply emergencies this past summer when a record peak demand of 45,597 MW hit on Sept. 8, McIntosh said. The Cal-ISO, which oversees around 75% of the state's grid, avoided problems with unprecedented power import levels and only 100 MW of generation offline, he said. "That will never happen again … We walked to the edge of the cliff and hung there for hours," he said.

Aware of the looming problem, the Cal-ISO, CEC, state Public

Utilities Commission and the governor's office have formed the Joint Energy Action Forum, which is working on solutions to address the summer 2005 problem, McIntosh said. Some solutions include delaying the 676 MW of expected plant retirements and accelerating the addition of 500 MW of new generation, he said.

Sempra Energy on track to begin running 550-MW Palomar plant by this summer

Sempra Energy's 550-MW Palomar Energy power plant is on schedule to be operational in the summer of 2006, according to Don Felsinger, Sempra COO, during his Nov. 16 presentation at a Banc of America Securities energy conference in Las Vegas, Nev.

The California Public Utilities Commission in June approved the San Diego-based company's request for its Sempra Energy Resources power producer arm to build the gas-fired plant north of San Diego in Escondido as a turnkey project. Once completed, SER will sell the plant to Sempra's San Diego Gas & Electric utility arm, which will operate the facility as a utility-owned, rate-based generation resource. SER in July began construction of the project, which was approved by the state Energy Commission in August 2003.

The Palomar project is one of five power purchase proposals designed by SDG&E to meet its short-term and long-term reliability needs. The other projects, which were also approved by the PUC in June, include a 10-year contract with Calpine Corp.'s 585-MW, gas-fired Otay Mesa power plant starting Jan. 1, 2008, and the purchase of Ramco's 45-MW, gas-fired project to meet the utility's intermediate power needs starting in 2005.

Also during the call, Felsinger said that SDG&E is "going forward" with the PUC's Oct. 28 power resource adequacy decision requiring load-serving entities to meet their power needs plus a 15% reserve margin starting in June 2006. He said that SDG&E has a request for offer looking for energy and another one specifically for renewable energy to meet the state's 20% renewable portfolio standard by 2010. SDG&E currently has around 5% of renewables in its energy portfolio.

Felsinger said that the state will need to significantly expand its transmission system to get new renewables, such as wind and solar, to the marketplace. "The goal of 20% can be met as long as the facilities are in place to accommodate the new infrastructure needed to get them to market," he said.

SECONDARY MARKETS

DENA sells 570-MW project in New Mexico for $40 million

Duke Energy North America continued to pare down its merchant business last week by selling its partly built, 570-MW Luna merchant project near Deming, N.M., to PNM Resources, Tucson Electric Power Co. and Phelps Dodge Corp. for $40 million.

TEP, a UniSource Energy subsidiary, Phelps Dodge Energy Services and PNM will each own one-third of the plant, the companies said Nov. 12. The companies expect to spend up to an additional $110 million to finish building the plant and buy needed inventory items. Once fully constructed, the plant will have a cost basis of about $260/kW, one of the lowest costs in the region for a combined-cycle gas plant, according to PNM, which will oversee construction and run the plant when it starts operations in the summer of 2006.

PNM plans to use its 190-MW share in the plant to boost its wholesale supply business.

TEP will pay cash for its portion of the plant, and will issue no new debt to complete the transaction. The Luna Energy Facility would provide TEP with 190 MW of power to serve its wholesale and retail customers, boosting the company's overall generating capacity to about 2,193 MW.

Phelps Dodge Energy Services, a subsidiary of Phelps Dodge Corp., plans to use the power to support its expanding mining operations in eastern Arizona and New Mexico, the company said. Excess energy can be dispatched to wholesale market hubs in Phoenix, Las Vegas, and the Four Corners region, the company said. Duke suspended construction on the Luna plant in 2002 after investing about $275 million in its development (GPR, 22 Aug '02, 9). The plant is fully permitted and about 50% complete, TEP said.

PNM will pay cash for its portion of the plant and intends to issue about $100 million of mandatory convertible securities at or near the close of its TNP Enterprises acquisition, PNM said. The funds will be used for plant purchases and further growth opportunities, the company said.

The sale represents one more step in Duke's effort to reduce its merchant energy business. Total sale proceeds and tax benefits to Duke will be about $125 million, the company said. Duke Energy has one other facility in a deferred construction status, the 620-MW Grays Harbor plant in Washington State.

This year, Duke Energy has announced or closed asset sales that will provide the company with about $3.1 billion in proceeds including $750 million in tax benefits, and $840 million in debt reductions, the company said. Duke is seeking a partner for its money-losing merchant operations (GPR, 30 Sept, 3).

TransAlta plans to sell 50% of 220-MW cogeneration plant to its affiliate firms

TransAlta Corp. said it plans to sell its 50% interest in the 220-MW gas-fired Meridian cogeneration plant in Lloydminster, Saskatchewan, for C$110 million (US$91.6 million) to its TransAlta Cogeneration LP affiliate.

TransAlta Corp. owns 50.1% of TransAlta Cogeneration. TransAlta Power LP owns 49.99% of TransAlta Cogeneration. TransAlta said it would record a C$10 million after-tax gain on the deal and use the proceeds to repay short-term debt. The sale is expected to close by Dec. 1, 2004. The plant went into operation in 1999. Husky Oil Ltd. owns 50% of the plant.

Steve Snyder, TransAlta Corp. president and chief executive said the sale would increase its financial flexibility. TransAlta Cogeneration will fund the acquisition with C$50 million cash on hand and by issuing C$30 million of units to each of TransAlta Corp. and TransAlta Power.

TransAlta Power said it would finance its purchase with a loan under an existing credit facility with TransAlta

Cogeneration that it would repay over the next year partly through funds on hand.

Government-owned SaskPower has a power purchase agreement that includes the cost of gas and expires in December 2024.

LEGISLATION

House energy chair Barton sees slim chance for energy bill this term

A slight opportunity still exists to pass the broad energy bill, which would provide incentives to domestic energy producers, in the brief post-election session of Congress that opened on Nov. 16, said House Energy and Commerce Committee Chairman Joe Barton, R-Texas.

Barton cited expensive fuel to generate power and heat homes in the coming winter as the deal maker. "We have this final, slim chance to break the deadlock on a comprehensive energy bill that will generate energy at prices people can afford."

The House cleared the legislation a year ago, but the measure hit a filibuster in the Senate over a provision to protect makers of the fuel additive MTBE from certain lawsuits, a provision Barton insisted on. Barton and other proponents of the bill say only two Senate votes are needed to pass it in the lame duck session.

If not, Congress will have to start a new bill in 2005. Asked if the dynamics have changed for passage, incoming Democratic Whip Dick Durbin, who opposed the bill with the MTBE provision, said "not at this moment."