IGCC: New Fuels, New Players

Also in this issue • Efficient Office Equipment • Superconducting Energy Storage • Global Carbon Cycle

ELECTRIC POWER RESEARCH INSTITUTE

EPRI JOURNAL

JULY/AUGUST
1994

EPRI JOURNAL is published eight times each year (January/February, March, April/May, June, July/August, September, October/November, and December) by the Electric Power Research Institute.

EPRI was founded in 1972 by the nation's electric utilities to develop and manage a technology program for improving electric power production, distribution, and utilization.

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Cover: Countries around the world are counting on integrated gasification–combined-cycle plants to turn not only high-sulfur coal but also petroleum coke and heavy residual oil into clean sources of power. When integrated with petroleum refineries, the IGCC process can also enhance the production of higher-value fuel products like gasoline and kerosene.

EPRI JOURNAL

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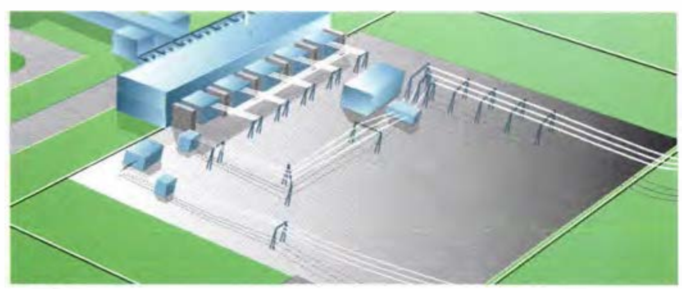

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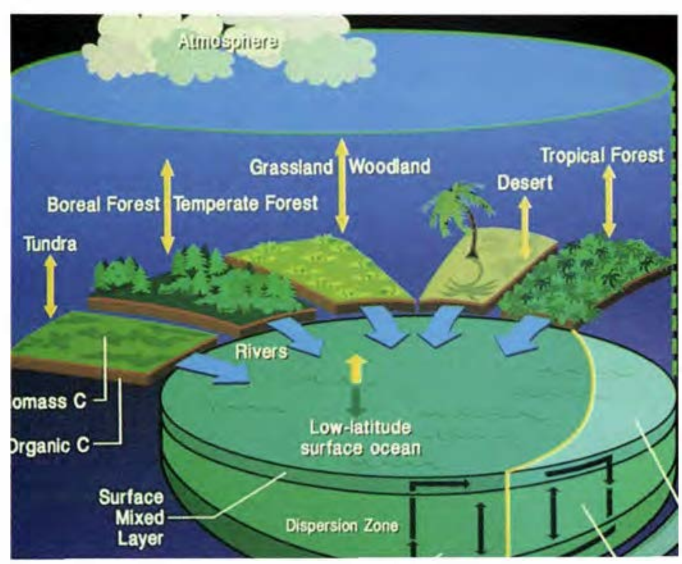

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For more information, contact Tom McCloskey, (415) 855-2655. To order, EPRI members should call the Electric Power Software Center, (800) 763-3772. Nonmembers should call Automation Technology, Inc., (408) 453-1099.

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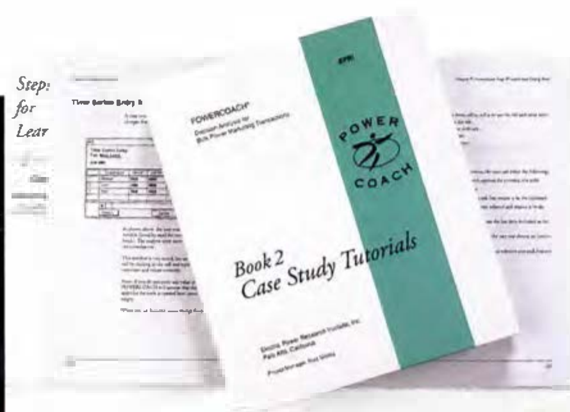
For more information, contact Ralph Bernstein, (415) 855-2023. To order, call the Electric Power Software Center, (800) 763-3772.



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For more information, contact Riaz Siddiqi, (415) 855-2619. To order, call the Electric Power Software Center, (800) 763-3772.

Trying to Take the Nitrogen out of Coal

Scientists believe that at the molecular level the nitrogen content of coal is bound up in hexagonal chemical structures similar to those in a honeycomb. Such structures are extremely strong, making the nitrogen difficult to remove. By contrast, a portion of the organic sulfur content of coal exists in chainlike structures that are much easier to break, allowing the partial removal of the sulfur through chemical cleaning.

Chemical cleaning processes have not yet been developed for removing nitrogen from coal. Current removal methods focus on taking the nitrogen out either during or after the combustion process, when nitrogen combines with oxygen to form nitrogen oxides. The most common method of NO_x control is the use of low-NO_x burners, which control oxygen, temperature, and fuel residence time in distinct flame zones. Selective catalytic reduction is a less common and more expensive postcombustion technique that converts NO_x back into nitrogen.

At the molecular level, the nitrogen in coal exists in a honeycomb-like structure.

As a first step in developing chemical techniques for nitrogen removal, EPRI has contracted with Babcock & Wilcox Company to explore potential methods. EPRI's Conrad Kulik, who is overseeing the research, notes that coal contains about 1.5% nitrogen by weight. "Anywhere from 50% to 80% of the NO_x emitted by coal-fired power plants comes from the nitrogen in the coal itself, rather than from the air involved in the combustion process," he says. "Removing the nitrogen from the coal before it is burned makes good sense."

The first experiments at B&W have involved the use of peroxide as an oxidizing agent. With the help of an iron catalyst, peroxide can oxidize the nitrogen, effectively burning it out of chemical compounds. The nitrogen is released as nitrate, an ion commonly used in preservatives. Kulik points out that while the nitrate still needs to be disposed of, nitrogen in this solid form is much easier to control than is the gaseous NO_x.

In the laboratory the B&W researchers have successfully oxidized pyridine and quinoline, both nitrogen-containing compounds similar to those present in coal. An important aspect of this work is determining the best temperatures and the most appropriate concentrations of peroxide to use.

Kulik notes that the chemical compounds used in the laboratory experiments were isolated. He points out that oxidizing the nitrogen contained in coal won't be so easy.

"We don't know exactly where the nitrogen is in the coal," says Kulik. "Coal is porous, like a sponge. If the nitrogen is physically accessible on the surface of the pores, it may be easy to remove. But it is possible that the nitrogen is much deeper in the structure, which will make removing it much more difficult." The key challenge is to remove the nitrogen without destroying any of the carbon and hydrogen in the fuel, since the latter components contain the fuel value.

If the peroxide approach is not successful, EPRI researchers will pursue other chemical techniques. "The approach we're working on now is somewhat simplistic," says Kulik. "We think it is likely that we'll try many other chemicals before we're successful. Our goal is to remove nitrogen before combustion. But as to what the best chemical technique may be, the jury's still out."

■ *For more information, contact Conrad Kulik, (415) 855-2818.*

Ultrasound Technique Could Help Utility Boilers

Most widely known for its use in monitoring fetal development, ultrasound technology is also employed in a variety of other applications, from detecting bubbles in blood transfusions to tracking yeast particles in the beer-making process. Now EPRI researchers are hoping to use the technology to detect iron oxide particles in the feedwater of utility boilers.

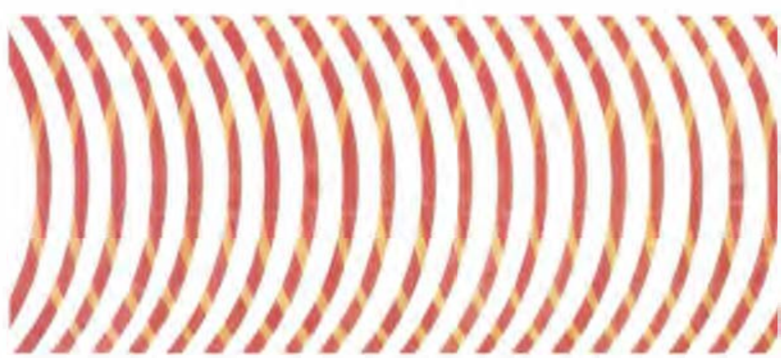
A product of standard feedwater system operations, powderlike iron oxide particles form on the interior surfaces of pipes and tubes and become entrained in the boiler feedwater. If deposited inside boiler tubes, the particles can cause boilers to overheat and even fail. An effective monitoring system could help utilities prevent such problems and provide information for optimizing feedwater chemistry on a regular basis to minimize the growth of iron oxide.

Current monitoring techniques involve analyzing water samples that are intermittently extracted from the feedwater just before it enters the boiler. But ultrasound technology could provide continuous in situ monitoring, says Barry Dooley, EPRI's manager for boiler and cycle chemistry. According to Dooley, two utilities in Japan have already used ultrasound technology for this purpose, although not on an in situ basis. Instead, the systems employed at these utilities monitor the feedwater in a sample room, using a continuous analysis technique.

Unlike the systems used for fetal observation, the power plant ultrasound systems do not provide a visual image. Rather, they generate electronic signals that, when translated by a computer, numerically indicate the quantity and distribution of existing particles.

EPRI researchers would like to see the ultrasound technology that has been employed in Japan—a technology manufactured in the United States—used in situ in U.S. power plants. Preliminary tests conducted under contract to EPRI indicate that the technology offers great promise for this kind of deployment. Now EPRI wants to test the technology in a U.S. power plant and is negotiating with a member utility about hosting a demonstration.

Because the acoustic transducers currently available cannot function properly in the high-temperature environment of boiler headers and piping (to which the transducers would be attached), the first ultrasound system tested would not offer true in situ observation. Instead, says Dooley, the transducers would be attached to the exterior of a side loop established off the boiler economizer header. Dooley notes that such a system would still offer continuous measurements. Researchers anticipate the successful development of high-temperature transducers that will in the future allow continuous in situ analysis.



■ *For more information, contact Barry Dooley, (415) 855-2458.*

by Leslie Lamarre

in Activity Worldwide

THE STORY IN BRIEF EPRI has pursued the development of integrated gasification–combined-cycle technology because it is the cleanest method available for making electricity from coal. Now, a decade after the establishment of the first IGCC demonstration plant, environmental regulations are encouraging the adoption of this technology

IGCC

253-MW coal-fired IGCC unit now operating in Buggenum, Netherlands

in a number of countries. An unexpected innovation is the use of residual oil as an IGCC feedstock, a practice that evolved naturally as a result of market forces. Experts are hopeful that the current momentum in IGCC will trigger the introduction of the technology in developing countries, many of which rely heavily on coal and oil for power generation.

A decade after the world's cleanest coal-fired power plant generated its first kilowatt of electricity in the southern California desert, the technology employed there is beginning to catch on. Buoyed largely by the wave of environmental regulations sweeping the globe, integrated gasification-combined-cycle (IGCC) technology is now being actively pursued or seriously considered in at least 21 countries. And in an interesting turn of events, oil-fired IGCC appears to be moving toward commercialization ahead of coal-fired IGCC.

Widely recognized as the cleanest method available for turning coal into electricity, IGCC systems gasify the fuel and remove pollutants before the combustion process. Demonstration projects have shown that IGCC can remove 99.9% of sulfur from coal, compared with the 90% typically removed by a conventional coal plant with scrubbers. The control of nitrogen oxides is even more dramatic, amounting to more than six times the control achieved by the low-NO_x burners usually employed in conventional plants. IGCC technology is also significantly more effective in reducing other types of pollutants, including particulates, trace metals like mercury and lead, and volatile organic compounds.

The opening of a 253-MW coal-fired demonstration plant in the Netherlands this spring marked the beginning of what is expected to be a series of IGCC startups around the globe over the next several years. According to public records, 8 countries have plans to establish a total of 18 fossil-fuel-based IGCC plants. Thirteen other countries are seriously considering the implementation of IGCC. While most of the planned projects will be in western Europe, some will be in the United States, eastern Europe, and the Far East. This high level of activity is expected to push coal-fired IGCC to commercial status by 2005.

Process and potential

In the gasification process, a feedstock fuel such as coal or oil is heated with steam and oxygen. The fuel's sulfur is converted to hydrogen sulfide, and its nitrogen is converted to molecular nitrogen, ammonia, and nitrogen compounds that can be removed before combustion. During the gas cleanup process, the hydrogen sulfide becomes elemental sulfur, a marketable substance that can be sold to chemical manufacturers and others who commonly use the material. Particulates too can be filtered out before combustion, leaving the final IGCC exhaust with about a third less particulate matter than the exhaust from a conventional coal plant with postcombustion particulate controls.

Once the manufactured gas is cleaned, it is burned in a gas turbine to generate electricity. For increased efficiency, heat is recovered from the turbine exhaust gases and used to power a steam turbine to generate even more electricity. This combined cycle of gas and steam turbines gives IGCC an efficiency of about 43%, compared with about 35% for conventional coal-fired power plants.

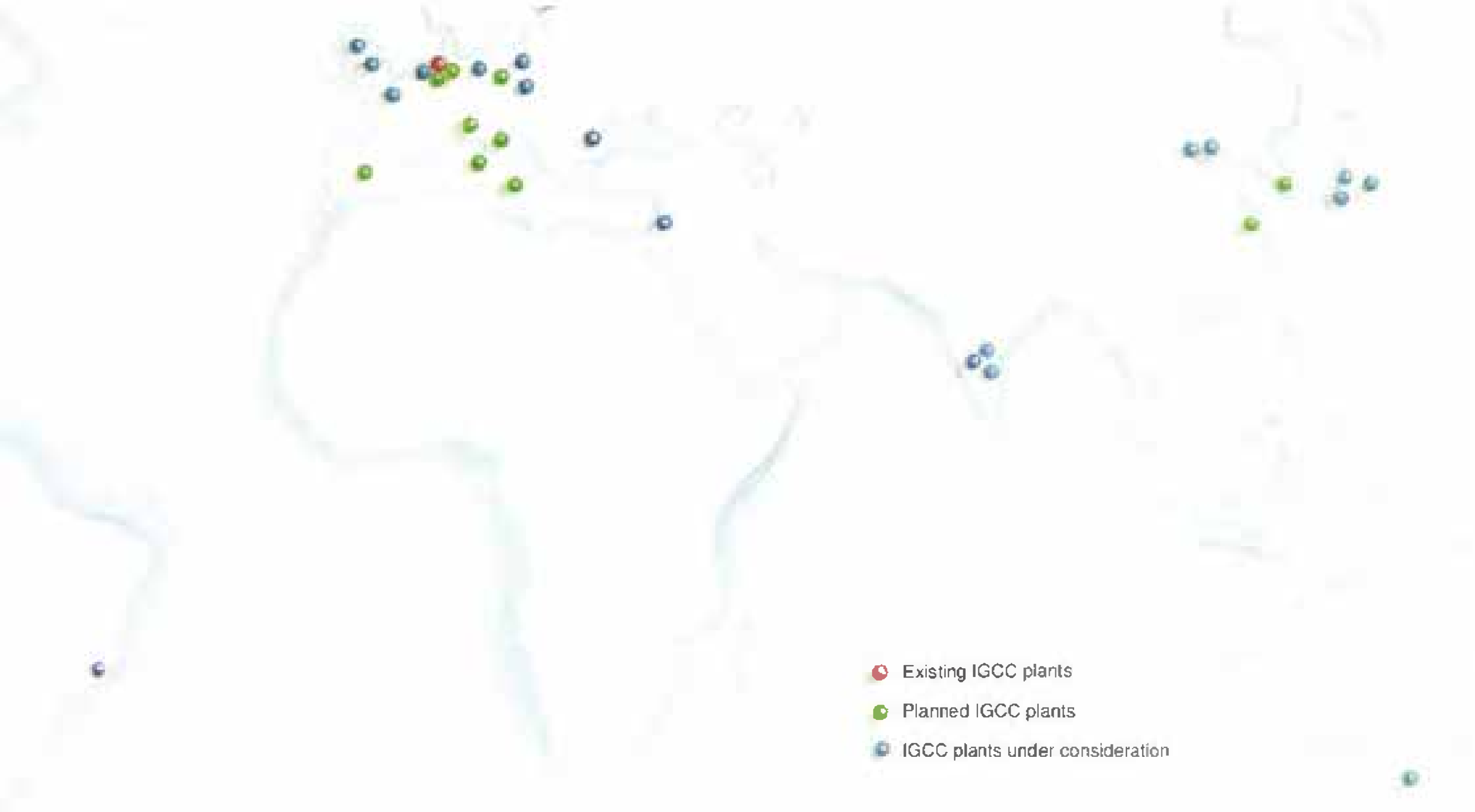
According to Neville Holt, who manages EPRI's IGCC research, the U.S. Department of Energy and gas turbine manufacturers are working to increase the efficiency of IGCC technology by developing bigger gas turbine systems with higher firing temperatures. Larger turbines will improve the economies of scale, lowering the cost of the technology. Holt says that the manufacturers are aiming for 50% thermal-to-electric efficiency in IGCC units introduced by the year 2010. He points out, however, that overall thermal efficiencies of more than 80% can be achieved with existing IGCC technology simply by using some of the steam directly in industrial applications or for district heating.

The success of the first IGCC demonstration plant, operated from 1984 to 1989 at Southern California Edison Company's Cool Water facility near the Mojave Desert town of Barstow, encouraged the establishment of other IGCC plants. Among them is Dow Chemical's 160-MW coal-fired IGCC plant in Louisiana, which opened in 1987. Although this plant has served Dow successfully, it is not considered commercial because it was established to assess the performance of the gasification technology developed by Des-

Existing IGCC Plants

Planned IGCC Plants

IGCC AROUND THE WORLD
First demonstrated in California a decade ago, integrated gasification–combined-cycle technology is beginning to catch on worldwide. So far, IGCC is being actively pursued or seriously considered in 21 countries. Eight of these countries have already undertaken plans to build a total of 18 fossil-fuel-based IGCC plants.



Location	Owner	Fuel	Size	Gasification Technology	Startup Date
Plaquemine, Louisiana	Destec	Coal	160 MW	Destec	1987
Buggenum, Netherlands	SEP	Coal	253 MW	Shell	1994
United States *Three additional plants, not shown on the map, are to be funded by DOE.*					
Terre Haute, Indiana	PSI Energy, Destec	Coal	265 MW	Destec	1995
Tampa, Florida	Tampa Electric	Coal	260 MW	Texaco	1996
El Dorado, Kansas	Texaco	Petroleum coke	40 MW	Texaco	1996
Tracy, Nevada	Sierra Pacific Power	Coal	95 MW	KRW	1996
Europe					
Litvinov, Czech Republic	SUV	Lignite and oil	400 MW	Texaco	1999
Porvoo, Finland	Neste Oy, IVO	Oil	500 MW	NA	1998
Falconara, Italy	API	Oil	225 MW	Texaco	1997
Priolo Gargallo, Italy	ISAB	Oil	500 MW	Texaco	1998
Sannazzaro, Italy	AGIP	Oil	250 MW	Texaco	1999
Sardinia, Italy	SARAS	Oil	500 MW	Texaco	1999
Pernis, Netherlands	Shell	Oil	80 MW	Shell	1997
Borsele, Netherlands	SEP	Coal	800 MW	NA	2002
Puertollano, Spain	Elcogas	Coal and petroleum coke	300 MW	PRENFLO	1996
Asia					
Shanghai, China	Shanghai Coke and Chemicals	Coal	60 MW	NA	1997
South Korea	KEPCO	Coal	250 MW	NA	2002

tec, a Dow subsidiary, and the project was subsidized. Other U.S. activity in IGCC has been initiated by DOE, which has allocated funding for six IGCC plants, three of which are scheduled to come on-line at EPRI member utilities within the next two years. Sites are being selected for the remaining three projects.

In Europe, meanwhile, coal-fired IGCC technology reached a milestone in May with the opening of a 253-MW plant in the southern Netherlands. This plant, which employs Shell's gasification technology, is considered a significant step toward the implementation of large-scale IGCC. Although the plant will be run commercially, it is characterized by Shell as a three-year demonstration plant. During this demonstration phase, Shell will attempt a variety of improvements, including changes to the gas cleanup process. Spain and the Czech Republic are among the other European countries planning to establish coal-fired IGCC plants within the next five years.

The potential for the additional use of coal-fired IGCC technology is enormous, given the world's dependence on coal for electricity and the increasing pressure to reduce related emissions. According to the World Energy Council (WEC), coal currently fuels about 40% of the world's power generation, and our dependence on this fossil fuel is not likely to decrease in the foreseeable future. The WEC predicts that even with the significant increases anticipated in electricity demand, the world's supply of coal—which is far greater than that of oil or natural gas—could easily meet our power needs for the next 200 years. Says Holt, "IGCC offers the means for making a plentiful yet dirty fuel resource suitable for sustainable development."

Oil action

Surprisingly, though, oil-fired IGCC appears to be closer to commercialization than coal-fired IGCC. "Ten years ago, as the Cool Water project was getting off the ground, we envisioned IGCC primarily as a coal-fired technology with some potential applications in petroleum coke," says Holt. "What we did not foresee was the use of this technology with heavy oil." As research organizations like EPRI worked to push coal-fired IGCC toward commercialization, evolving market forces began to prompt serious interest and activity in oil-fired IGCC. Oil prices declined (today they are about 50% below their early-1980s levels), diminishing the value of already cheap, bottom-of-the-barrel heavy residuals. Simultaneously, new environmental regulations limiting the sulfur content of fuel oil were adopted. Industry experts point out that this is a classic case of market pull (the oil-based applications) overtaking technology push (the coal-based systems). Market pull, they note, is almost invariably the stronger force.

Italy, Europe's largest consumer of oil for power generation, is feeling the pressure of these market forces particularly strongly. ENEL, the state-owned electric utility that supplies nearly 80% of the country's electricity, relies on oil for 53% of its generation. Most of the oil has a high sulfur content, averaging approximately 3%—about the same level of sulfur as in high-sulfur coal. And a new European Community directive known as 88/609 requires that the sulfur content of fuel oil be limited to 1% by 1998 and 0.25% by 2003.

Unlike the refineries in the United States, where the great demand for transportation fuels has led to the installation of sophisticated conversion and desulfurization equipment, the Italian refineries do not have much fuel oil conversion or desulfurization capacity. In order to meet the upcoming requirements, the refineries can install desulfurization equipment to produce an acceptable lower-sulfur oil; convert a portion of their heavy oil into more-valuable, lighter products like gasoline; or undertake a combination of these two alternatives. All of these options require an ample supply of hydrogen, a by-product of the gasification process.

Currently, four Italian refineries are planning to construct IGCC units that will come on-line between 1997 and 1999. The refiners intend to use gasification to provide the hydrogen they need to convert their heavy-grade, high-sulfur oil to lighter products, such as transportation fuels. The IGCC plants will also generate steam to power the refineries' processing units, as well as electricity—a total of 1500 MW—which will be sold to ENEL.

"Because it meets multiple objectives, the installation of IGCC is a good capital investment for the refineries," says Holt. "Such an application offers a major opportunity for synergy involving power production demands, new automotive fuels to reduce urban pollution, and the need for clean fuel oils."

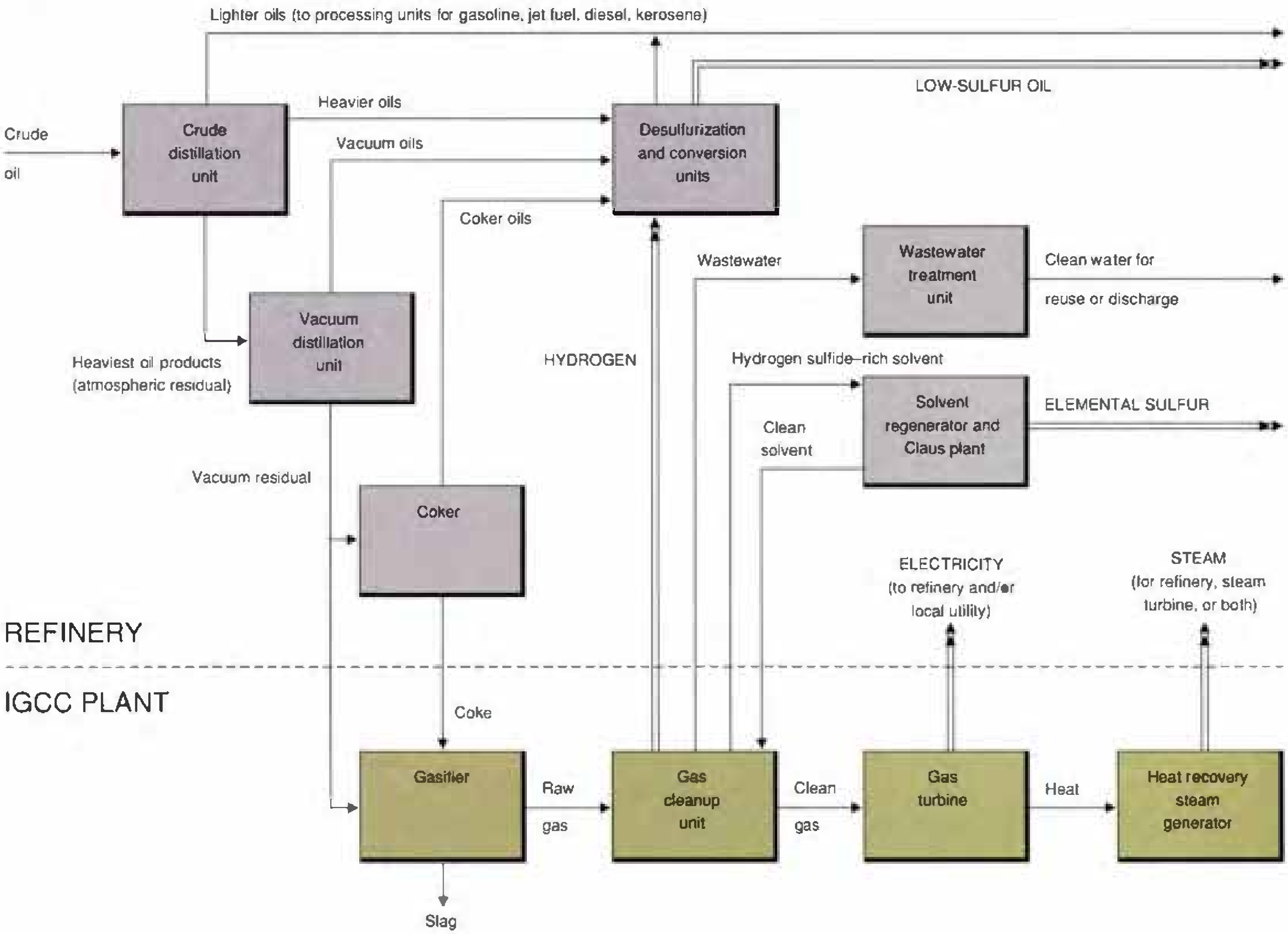
Italy's oil-fired IGCC units are considered commercial, and they are expected to become fully operational before coal-fired IGCC reaches commercial status. "I see oil gasification coming before coal gasification," says Alex Wechsler, vice president of Lurgi Corporation, the exclusive licenser of Shell's gasification technology for heavy residual oils. "The economics are better for oil." In addition to its ability to accept hard-to-convert high-sulfur residual oils, IGCC allows refineries to tap the energy value of low-value oil products like petroleum coke and possibly even Orimulsion™, a heavy bitumen-and-water mixture produced in Venezuela and marketed as a fuel. Wechsler points out that unlike coal, petroleum coke—a by-product of oil refining—does not have to be mined.

Some IGCC units, such as the 300-MW facility being planned by Elcogas for Puertollano, Spain, will use petroleum coke as a partial feedstock. In the Elcogas plant, which will run on a blend of 50% coke and 50% coal, the use of petroleum coke will help lower the overall feedstock cost. The coke will also increase the feedstock's heating value, since the available Spanish coal has a high ash content.

Coke too

A number of oil refineries are investigating the potential for using IGCC to gasify petroleum coke. Through an arrangement similar to that being pursued by the Italian refineries, such IGCC units could generate hydrogen, steam, and electricity for on-site use. Any excess electricity could be sold. The fact is that the relatively high sulfur content of petroleum coke—in the

THE POWER/PROCESSING SYNERGY **Oil refiners are finding that IGCC is a good capital investment because it uses low-value, high-sulfur fuels—such as heavy oils and petroleum coke—as feedstocks while generating hydrogen, a critical ingredient for desulfurization. Through desulfurization, refineries can produce a more marketable, lower-sulfur oil while recovering salable elemental sulfur. At the same time, IGCC generates electricity—typically far more than enough to meet a refinery's needs. Even more important is the production of steam, which can be used for the refinery's distillation processes. Many refineries planning IGCC units intend to sell their excess power to local electric utilities.**



United States it averages 5.5%—is making the product increasingly less attractive as a combustion fuel in a market that's already being pounded by sulfur dioxide emissions regulations. And just as the worldwide demand for petroleum coke is beginning to dry up, its production is increasing significantly.

The coking process enables the conversion of the heaviest oil products left after crude oil is distilled, such as residual fuel oil and asphalt. From these heavy residuals, coking yields more-valuable, lighter products, such as gasoline, jet fuel, and diesel fuel, as well as the by-product petroleum coke.

Largely because of its high demand for transportation fuels, the United States is the world's largest producer of petroleum coke, accounting for 67% of the worldwide production, according to Pace Consultants, a firm that tracks the coke market. Pace reports that between 1980 and 1992, U.S. coke production jumped a whopping 71%. Statistics show that the consumption of crude oil by U.S. refineries did not increase during this period.

This significant rise in coke production is not just a factor of mounting demand for transportation fuels. It is also a reflection of the changing nature of the oil coming out of the ground. A look at the oil reserves known today suggests that the oil industry has already exploited the bulk of the lower-sulfur oils, which are easier to convert to lighter products like gasoline. Roughly three-quarters of the currently known reserves harbor a heavier, higher-sulfur petroleum. In order to process the larger quantities of heavier crude they are receiving, oil refineries around the world are installing more cokers.

Pace projects an additional 40% increase in worldwide coke production between 1992 and the year 2000. And as Ray Dymond, director of petroleum coke and residual upgrading for Pace, points out, there is reason for concern. "Petroleum coke is a very volatile commodity, and we're looking at a tremendous supply," he says. "Unless some new applications evolve, producers will have a really big problem on their hands."

In 1992, the United States exported roughly 56% of its petroleum coke. The rest was sold in the domestic market for such applications as aluminum manufacturing, electricity generation, iron and steel making, and cement production. "For U.S. coke producers to be this heavily dependent on the export market could be risky," notes Dymond. For instance, Turkey, a major consumer of petroleum coke, has threatened to limit the sulfur content of imported solid fuels.

Refinery-based gasification of petroleum coke provides a way to use up coke supplies while generating hydrogen for refinery desulfurization processes. That is exactly what Mexico is considering.

Interest from Mexico

Currently, over half of Mexico's power comes from the direct burning of heavy fuel oils derived from such crude sources as Maya crude, which is 3.1% sulfur and results in a petroleum coke with a sulfur content of 8–10%. Such a high sulfur content has become a more-pressing issue since the 1993 passage of the North American Free Trade Agreement and since Mexico's adoption of more-stringent regulations on SO_2 control in the same year. At the same time, Mexico is unable to meet its total demand for gasoline and must import some of it from the United States.

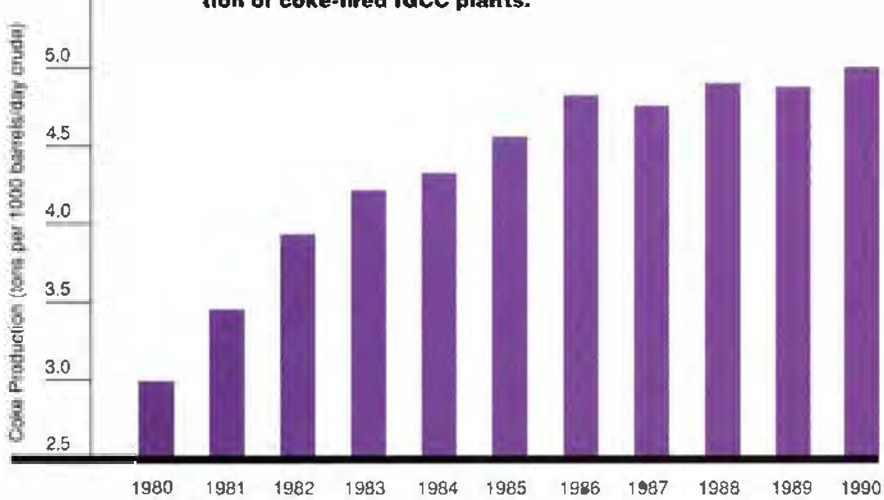
The gasification of petroleum coke, among other fuels, could provide a way for refineries to comply with the new environmental regulations while increasing the production of gasoline and other lighter products. In fact, Texaco is currently consulting with Mexico's state-owned oil company, Petroleos Mexicanos (PEMEX), about a potential gasification project. "PEMEX is extremely interested in Texaco's gasification process," says Texaco's Jim Falsetti, who has been involved in the dialogue with PEMEX. Specifically, PEMEX is considering the installation of gasification technology at a proposed addition to a refinery in the west coast city of Salina Cruz, in the state of Oaxaca. The resulting electricity could be sent to the state-owned utility network nearby.

Ernesto Mariaca Dominguez of the Mexican Petroleum Institute reports that PEMEX this spring actually approved a plan that would add a coker and a gasifier to the Salina Cruz refinery. The coker, he says, would help increase the country's production of gasoline. The gasifier, meanwhile, could turn the petroleum coke byproduct into hydrogen, steam, and electricity. As is the case with other projects involving major investments, Mariaca says, the final decision on the Salina Cruz project has been postponed until after Mexico's upcoming elections. The concern is that a new administration with different priorities could decide to terminate such a project.

Forecasts by the WEC predict a 130% increase in Mexico's per capita power consumption between 1990 and 2010. Falsetti is among those who believe that IGCC is likely to supply at least some of this demand. Already, SO_2 and other pollutants from conventional fossil-fired generating plants have been linked to health problems in big metropolitan areas like Mexico City. And other generation options, such as nuclear power and hydropower, raise environmental concerns.

"I can see Mexico adopting IGCC technology in the near future," Falsetti says, noting that the cost of establishing the facilities to ship petroleum coke from the Salina Cruz refinery to overseas markets could be cost-prohibitive. "It's better to upgrade the product and use it domestically. PEMEX needs hydrogen, steam, and power for its refineries anyway." He notes that PEMEX, which is the world's eighth-largest oil company and generates one-third of Mexico's foreign exchange revenues, is currently under pressure to produce even more income. IGCC may very well provide the means for achieving that goal.

THE COKE MARKET **U.S. refineries in 1990 produced 70% more petroleum coke per unit of crude oil than they did in 1980. The increase is due largely to the heavier nature of the oil coming out of the ground today and to the increasing production of refined products like gasoline. The growing supply of petroleum coke, combined with environmental regulations that discourage the direct burning of this high-sulfur refinery by-product, is encouraging the implementation of coke-fired IGCC plants.**



U.S. perspective

Oil refineries in the United States are also becoming interested in gasifying petro-

The Making of IGCC

Cool Water, the first IGCC demonstration plant

Practical applications of coal gasification date back to 1792, when a Scottish inventor used gasified coal for lighting in his home. Coal gas—also called manufactured gas or town gas—was used widely in the United States and other countries for both heating and lighting until the 1950s, when natural gas distribution systems became well established. Countries like China, which do not have extensive natural gas reserves, still rely on manufactured gas for lighting and heating, especially in homes.

A far more common use for coal gasification today is in the production of chemicals, including ammonia, methanol, and urea. Gasification generates hydrogen, carbon monoxide, and carbon dioxide—gases that are critical to the production of such chemicals. For instance, the reaction of hydrogen and nitrogen produces ammonia, an important ingredient in fertilizer.

Although gasification technology and gas turbine power plants—the most efficient electricity generators available—have coexisted for decades, it wasn't until 1984 that the two were wedded in the first commercial-scale integrated gasification–combined-cycle system. This 100-MW IGCC demonstration plant was located at Southern California Edison's Cool Water facility near Barstow, California. The plant operated successfully for five years, until the low price of natural gas made its continued use impractical.

Nevertheless, the plant's environmental advantages were clearly proved. Among other achievements, emissions of sulfur dioxide and nitrogen oxides were about 10 times lower than the limits set by the federal New Source Performance Standards. "Gasification is the cleanest way to use coal and low-value fuels because it removes emission-forming constituents prior to the electricity generation process," says Neville Holt, manager of EPRI's IGCC research. Other technologies, such as flue gas desulfurization systems and fluidized-bed combustion, rely on limestone or dolomite to control sulfur. Not only do these approaches require the mining of additional resources, but they also generate a larger volume of material for disposal. □

leum coke. Historically, some U.S. utilities have burned the fuel in their boilers. But the Clean Air Act Amendments of 1990 set strict limits on SO_2 emissions, making the domestic markets for petroleum coke (in its conventional applications) even less promising than the global markets.

"There's a flurry of activity in the United States right now regarding potential projects for gasifying petroleum coke," says Holt. Most of these projects are in the early stages of investigation. Others, however, are progressing quickly. For example, Texaco recently announced its plan to build an IGCC unit at its refinery in El Dorado, Kansas. The unit will consume about 170 tons of petroleum coke and other refinery by-products daily to meet all of the refinery's electricity needs while supplying 40% of its steam. Construction is set to begin early in 1995, with startup scheduled for mid-1996.

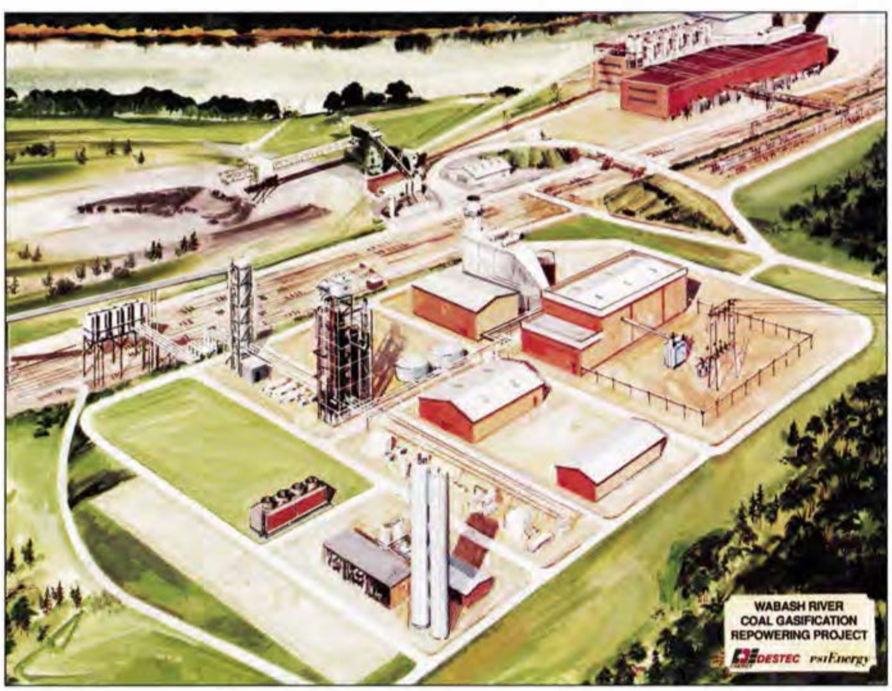
EPRI researchers are encouraging utilities to develop partnerships with their refinery customers to establish IGCC plants. In many cases, a refinery is a utility's largest single load. And as Holt points out, many refineries today are undertaking plans to construct their own generating plants. Typically, the supply of petroleum coke produced on-site is more than sufficient to meet a refinery's electricity needs. Through a partnership that could involve shared ownership of an IGCC plant, the refinery could deliver its excess electricity to the grid. The utility, meanwhile, could offer the refinery the electricity it needs when the IGCC unit is not available. (As 24-hour operations, refineries ordinarily require availabilities approaching 100%, but IGCC technology offers availabilities of about 85%.) Through such partnerships, utilities could retain their refinery customers and even benefit from the new generation capacity while offering the refinery something valuable in return.

In U.S. refineries, the biggest potential hurdle for the use of IGCC technology is the competition from natural gas, which could just as easily supply the hydrogen that gasification produces. Cheap and abundant at this time, natural gas is available at many refineries. Nevertheless, IGCC remains an attractive option because it offers the additional benefit of putting increasing supplies of low-value petroleum coke to productive use. Holt also points out that some consider the supply of low-cost natural gas beyond the year 2000 uncertain.

Indeed, the uncertainty of future natural gas prices has gotten a number of EPRI member utilities interested in IGCC. Some are considering phased construction, which involves less financial risk. In the phased-construction approach, utilities could begin with the installation of gas turbines to serve peak demand. This installation could be followed by the addition of a heat recovery steam generator and a steam turbine for greater efficiency. Later, if the price of natural gas climbs, gasification could be added to the system. The capacity of the IGCC system could be increased at any time by adding a second train of equipment. Dow Chemical's 160-MW IGCC plant in Louisiana was established through phased construction, starting with a natural-gas-fired combined-cycle unit, to which a gasifier was added three years later. "Several utilities have phased IGCC into their generation expansion plans," says Holt. "It's a pragmatic approach to planning that a lot of utilities are coming to value."

Another way to reduce capital costs is to repower existing equipment and add the required components. For instance, PSI Energy, one of the utilities involved in the DOE-sponsored IGCC projects, is in the process of repowering an existing steam turbine as an integral part of a new IGCC unit. The remaining IGCC components will be added to the existing 100-MW plant.

CUTTING CAPITAL COSTS
PSI Energy has chosen an innovative approach to implementing its 265-MW IGCC unit: it is repowering an existing steam turbine and adding the remaining components. Another cost-cutting approach planned by some U.S. utilities is to implement IGCC in phases, starting with a gas turbine to serve peak demand, then adding a heat recovery steam generator and a steam turbine for greater efficiency. A gasification system could be added when the price of natural gas rises, as some observers anticipate after the year 2000.



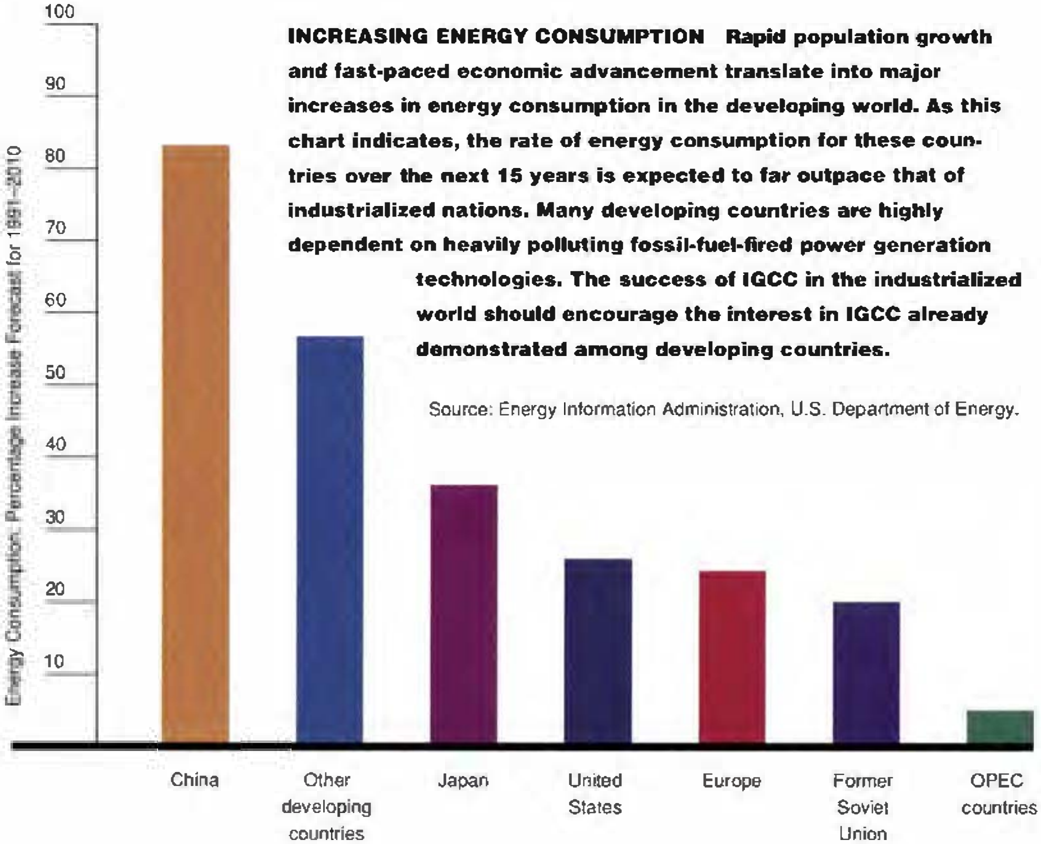
China involved

It is in developing countries like Mexico that IGCC could have its greatest impact in terms of reduced air emissions. These countries are expected to account for the bulk of the growth in power generation over the next couple of decades. And most of them now are heavily dependent on conventional, relatively dirty power-generating technologies fueled by coal and oil.

Of all the developing countries, China offers perhaps the best single market for IGCC, in part because of the magnitude of its anticipated economic growth. China's need for increased power generation is critical, with some 150 million people living without electricity. And the country's free-market efforts are fueling rapid, double-digit economic growth that hit 12% last year and is expected to remain robust. According to China's Power Industry Ministry, the country is expected to add power plants at the rate of about 1500 MW per month between now and the year 2000.

Experts agree that the most likely fuel for this future power generation is coal, China's cheapest and most abundant power resource. Already, coal supplies 75% of the country's electricity, and the remaining reserves appear ample for the increased demand. Even though the sulfur content of China's coal is relatively low, averaging about 2%, the country's anticipated huge growth in coal-fired capacity raises concerns about air quality. Uncontrolled SO_2 emissions have already left their mark on major industrial cities like Beijing and Xi'an, where air pollution makes the sky appear overcast even on sunny days.

In recent months, officials in China have publicly expressed concern about air quality and stated their intention to do something about it. Just this May, Lu Xinyan, deputy director of China's National Environmental Protection Agency (NEPA), announced plans to impose a nationwide tax on SO_2 emissions by the end of 1994. He said that the chief factor behind such action was acid rain, which reportedly causes 16 billion yuan ($2 billion) in damage to China's crops, forests, and buildings each year. NEPA has already run a



INCREASING ENERGY CONSUMPTION Rapid population growth and fast-paced economic advancement translate into major increases in energy consumption in the developing world. As this chart indicates, the rate of energy consumption for these countries over the next 15 years is expected to far outpace that of industrialized nations. Many developing countries are highly dependent on heavily polluting fossil-fuel-fired power generation technologies. The success of IGCC in the industrialized world should encourage the interest in IGCC already demonstrated among developing countries.

Source: Energy Information Administration, U.S. Department of Energy.

test implementation of an SO_2 tax in the southern provinces of Guangdong and Guizhou.

According to Ted Atwood, the DOE program manager for international activities in clean coal, IGCC plays an important role in the plan China is developing for sustainable development following the 1992 Earth Summit in Rio de Janeiro. "China's strategic plan for the future includes IGCC projects," he says. "This technology is one of the most likely candidates for future power generation. Certainly the Chinese see it as the best technology option in the long term."

Taking action

One indication of China's significant interest in IGCC technology is the country's pursuit of a 200–400-MW IGCC demonstration project. According to Atwood, China has assembled a high-level team of government officials to oversee the project, which began with a prefeasibility study that is scheduled to be completed by the end of the year. If all goes well, the plant would be established in the Beijing area.

The success of such a project could open up a vast market to U.S. companies—for example, Texaco and Destec, both providers of coal gasification technology, and General Electric and Westinghouse, which make turbines. In a recent joint venture with a U.S. firm, China demonstrated its receptiveness to foreign-developed clean coal technologies. The joint venture established a consulting firm in Shanghai whose mission is to help outside investors and suppliers of clean coal technologies into the Chinese power market.

As activities in China and Mexico indicate, developing countries are showing serious interest in IGCC. But the biggest barrier for these potential users is the cost of the technology. IGCC's current capital costs are roughly 10% higher than those of coal-fired plants with emissions controls and as much as 30% higher than those of conventional coal plants with no such controls. Industrialized countries typically consider life-cycle costs when selecting a technology, factoring in IGCC's higher efficiencies and environmental benefits. But many developing countries have not yet adopted this perspective. "Developing countries have a short-term view because they have so many problems that require the direct allocation of funds," notes Bertrand de Frondeville of Deutsche Bank, which is financing Elcogas's 300-MW coal- and coke-fired unit in Spain.

According to one DOE official, China alone will need more than $250 billion to finance new generation capacity between now and 2010. Traditional sources for such financing include the World Bank, the Asian Development Bank, and the Overseas Economic Fund of Japan. And new sources of funding are emerging, such as the Global Environment Facility (GEF). So far, two dozen countries have committed a total of $2 billion to the GEF to address the issues of global climate change, biodiversity, international waters, and depletion of the ozone layer. Admittedly, this sum is a drop in the bucket compared with the needs of the developing world. But many view it as a step in the right direction.

"The important thing," says Holt, "is that many organizations and countries are coming together to follow through on the commitment made at the Earth Summit in Rio to help ensure that the next generation of power plants in the developing world is a clean one." ■

Background information for this article was provided by Neville Holt, Generation Group.

THE ENERGY-EFFICIENT

Electronic office equipment represents the fastest-growing electrical load in the fastest-growing utility market segment. As personal computers, printers, copiers, and fax machines have proliferated throughout the commercial sector, they have had a significant impact on utility peak demand. Meanwhile, commercial customers are facing their own infrastructure problems related to the growth in the use of office equipment—for example, wiring overloads, overworked air conditioning systems, and too few wall plugs. In response, EPRI is leading a national effort to develop more-efficient electronic office equipment and encourage its market penetration.

Working with several electric utilities, government agencies, and other research organizations, EPRI helped create—and is now managing the research of—the Office Technology Efficiency Consortium, which has drawn equipment manufacturers and major commercial customers into a dialogue on how to improve the energy performance of office automation products. Specifically, the consortium seeks to promote improvement of the energy efficiency, electricity demand, and power quality of these products without compromising their competitive features or user productivity. For utilities, these improvements promise reduced peak demand, better overall load factor, and fewer concerns about power quality at the point of use. For customers, they mean increased immunity to power line disturbances, avoidance of wiring overloads or expensive upgrades, and reduced demand on heating, ventilating, and air conditioning (HVAC) systems.

"I've never seen such a level of cooperation and commitment to bring about significant change in a major group of products," says Morton Blatt, who heads EPRI's research on residential and small commercial systems. "Even two years ago, very little had been done to heighten awareness of the importance of office equipment energy use. Now, improved technologies are being commercialized very quickly, field demonstration programs are getting under way, and awareness of office equipment issues is growing. Manufacturers are collaborating with both utilities and their commercial customers to bring more-efficient equipment to market."

Problem and potential

In a large office, electronic equipment has typically accounted for about 8.4% of direct electricity use and 7.0% of peak demand. If the reckoning includes the additional HVAC use required because of heat given off by this equipment, the combined load represents some 10–12% of the office's total electricity demand. Since this demand occurs primarily during business hours, the rapid growth of office automation has been a major factor in worsening utility load factors. Moreover, the internal electrical systems of many office buildings are approaching the limits of their capacity, raising the specter of expensive upgrades to handle future equipment additions.

Further growth seems inevitable. The past few years have seen a dramatic shift from central photocopiers and mainframe computers to dispersed copiers and increasingly powerful desktop computers. Laser printers have largely replaced the much less energy-intensive impact and dot matrix printers. And new types of equipment, such as optical scanners, are being introduced at a surprising rate. Energy consumption by computers and printers alone has been increasing at 7–8% per year nationwide. The total could rise from about 40 billion kWh in 1990 to 70–125 billion kWh in 2000, depending on equipment efficiency and the penetration of new technologies and services. According to a study by the Massachusetts Institute of Technology, however, the adoption of energy-conserving procedures and the incorporation of more-energy-efficient technologies into these devices could actually lower the total demand in 2000 to 30 billion kWh.

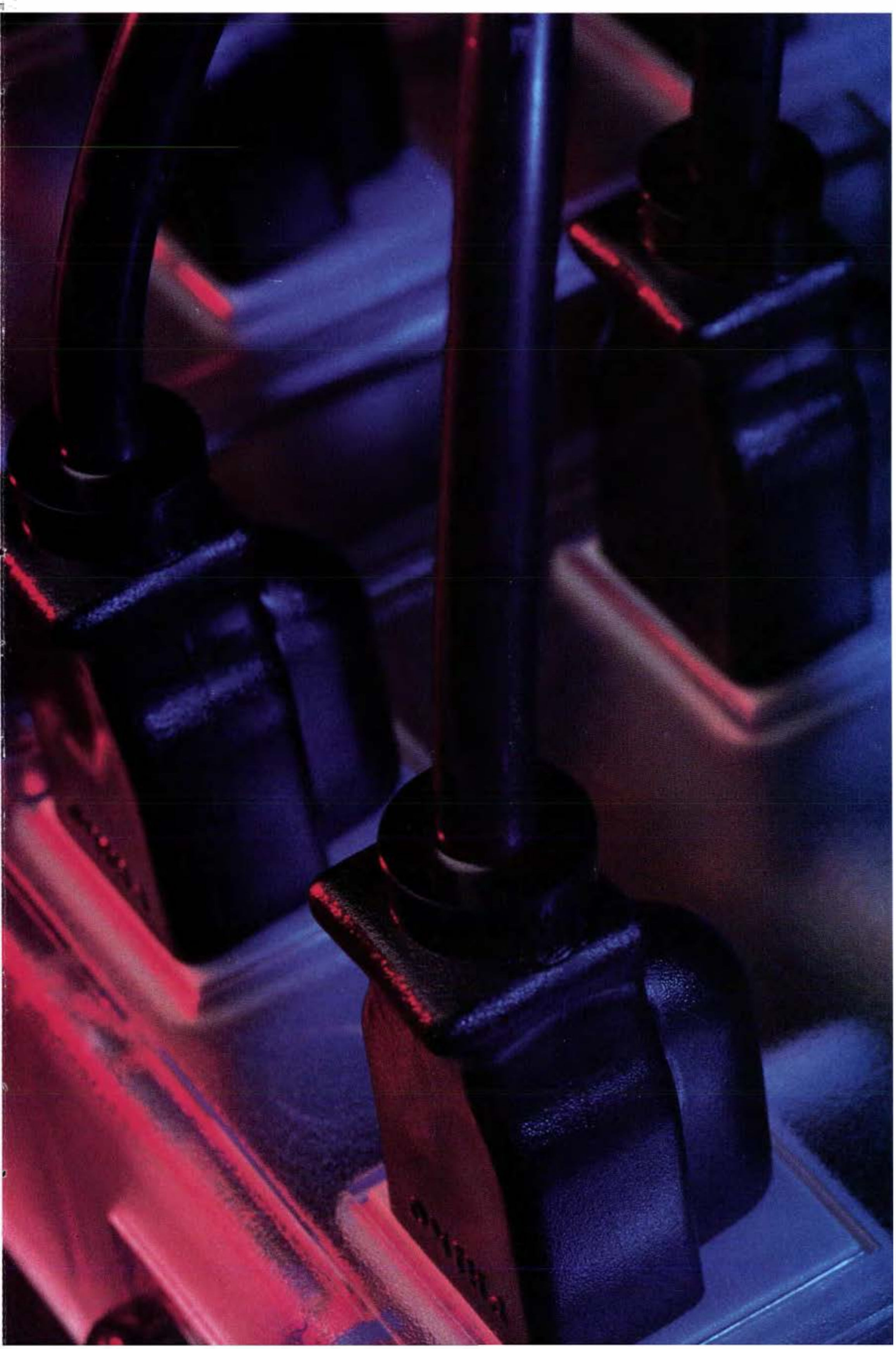
"Most efficiency improvements will come in small bites, but the potential impact is large," according to Jeff Harris, chairman of the Office Technology Efficiency Consortium and deputy director of the Washington, D.C., office of the Energy and Environment Division of Lawrence Berkeley Laboratory. "The intrinsic energy requirements of electronic office equipment are very small because these devices move and store information. People began to think about energy efficiency when notebook computers became popular, because of the need to preserve battery life. Now we need to begin applying efficiency-enhancing technologies to desktop equipment."

Was your computer on last night?

Even without further technological innovation, considerable energy can be saved by simply changing the way office equipment is used. The most obvious step, of course, is to turn off computers and other desktop devices at the end of the workday. One study indicates that American businesses waste some $4 billion worth of electricity each year by leaving lights and office equipment on when they are not needed. The energy cost savings potential of turning off a personal computer (PC) and its associated printer (average combined load of around 180 W) during nights, weekends, and holidays is $73–$126 per year. Even if the computer itself must be run continuously because of a network connection, just turning off the

OFFICE

THE STORY IN BRIEF Rapid growth in the use of electronic office equipment is increasing utility peak demand and putting a strain on the electrical systems of some commercial buildings. A broad-based consortium of electric utilities, government agencies, R&D organizations, and public interest groups is working on research projects to help reduce energy use in this customer segment. Manufacturers have been very receptive, with changes already occurring in the marketplace. EPRI, a founding member of the consortium, has organized and helps manage the research efforts funded by the consortium members.



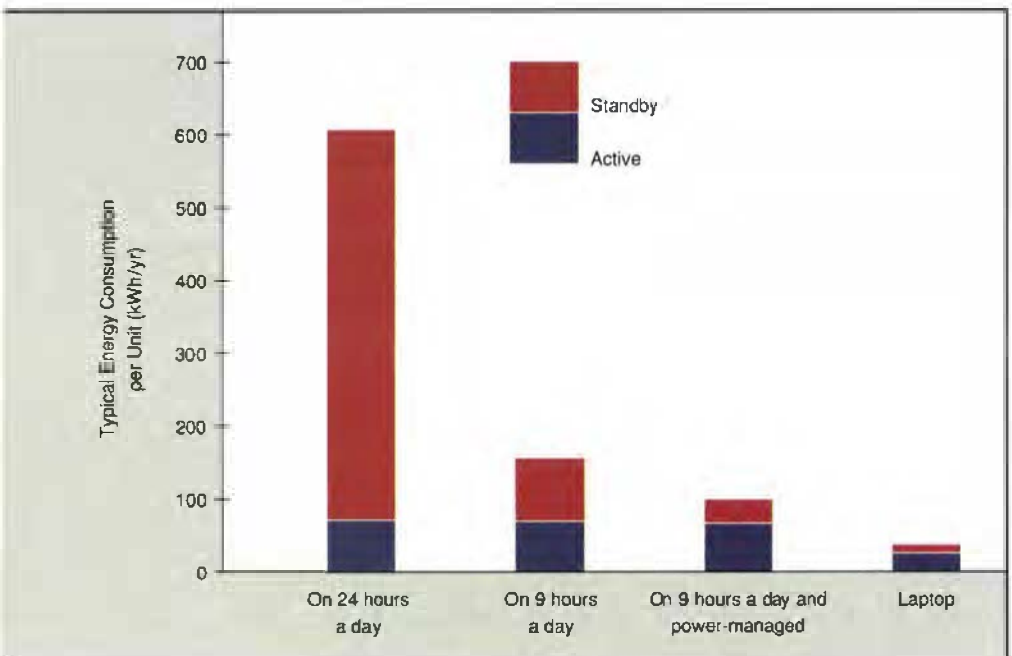
by John Douglas

monitor could save 30–60% of the computing unit's energy consumption.

The effectiveness of reducing energy consumption by introducing improved work practices has been shown through several individual company programs. IBM, for example, estimates that it saved $17.8 million in 1991 by encouraging employees to turn off equipment after completing tasks and to moderate their use of lighting. Through similar measures, Xerox Canada's corporate headquarters has reduced its energy use by 17–23%.

Consolidated Edison Company of New York, which forecasts that its office technology load could double by the year 2000 unless steps are taken to reduce consumption, has been working closely with key commercial companies in its service territory to implement conservation programs. One of these companies is American Express, whose headquarters in Manhattan has 10,000 PC users. Together, Con Edison and American Express produced a brochure informing employees about the benefits of turning off equipment when it is not in use. The plan has reduced the facility's electric bill by more than $700,000 a year. Through such direct cooperation with key customers, Con Edison hopes to avoid adding 400 MW of on-peak load during the rest of the decade—and thus to avoid exceeding the capacity of some existing distribution facilities. The utility estimates potential savings of more than $300 million.

TURN IT OFF **Turning computers off at night and on weekends is the first line of defense against high office energy bills. Power management features, which allow computers to "sleep" when not in use, can further reduce energy consumption. By far the most energy-efficient option is the laptop computer; because these units had to be designed to run on batteries, low energy consumption was a primary consideration in their basic development.**



Another utility with an active energy efficiency program for office equipment is Pacific Gas and Electric Company (PG&E), which has focused attention on ways to improve overall customer "energy productivity" and to respond to environmental concerns. This approach is based on the realization that savings on electric bills may be much smaller than indirect savings related to worker productivity or customer infrastructure investment. As one example of the potential for such indirect savings, the utility cites a California state agency that had to spend $60 per square foot to upgrade the wiring in a new office building to accommodate its computer-related load. Similarly, preventing even a few minutes of downtime due to overloaded circuits or power quality problems can yield savings that exceed the direct savings resulting from the use of more-efficient equipment. PG&E has therefore concentrated on stimulating market-based solutions, including the establishment of voluntary energy standards for office equipment, the development of criteria customers can use when buying equipment, and the creation of new testing procedures so that equipment from various manufacturers can be compared fairly.

Developing strategies

To build on such individual utility programs and develop strategies for a broad national effort to increase office equipment efficiency, the Office Technology Efficiency Consortium held a workshop in San Jose, California, in June 1992. Approximately 100 representatives of equipment manufacturers, utilities, and researchers attended and made specific recommendations on how to accelerate market penetration of more-efficient equipment. A highlight of the workshop was the U.S. Environmental Protection Agency's announcement of its Energy Star Computers Program, together with responses from several manufacturers.

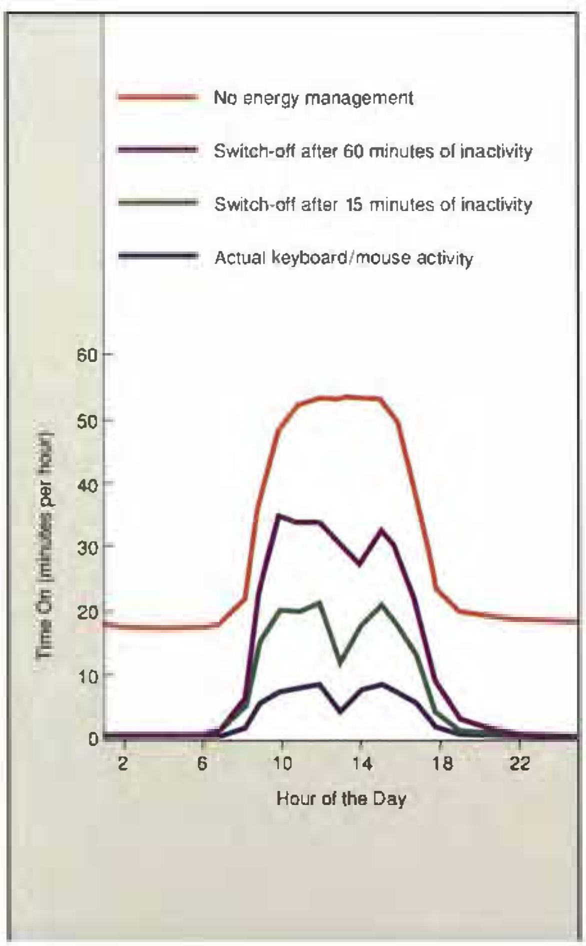
The objective of the Energy Star program is to encourage manufacturers to develop desktop PCs and monitors that go into a standby mode automatically after a period of inactivity. Specifically, to be eligible to use the Energy Star logo for marketing purposes, manufacturers must produce PCs and monitors that consume less than 30 W each in the standby mode. The program was expanded in 1993 to include computer printers.

The Energy Star program has received very positive responses from manufacturers. At the 1992 workshop, Omar Khalifa of Apple Computer observed that the program is particularly important because it levels the playing field: "For the first time, a customer will have a way to at least recognize a more energy-efficient computer." Louis Abernethy of IBM also praised the program: "We think improving the energy efficiency of equipment is good business for our customers and for our computers. . . . Our customers get lower electric bills. They might even get quieter units with no fans. There are possible reliability improvements from lower thermal stresses."

To date, over 300 manufacturers of computers, monitors, and printers have joined the EPA's Energy Star program. These manufacturers, who as a group are responsible for over 75% of PC shipments and over 90% of printer shipments, have introduced more than 2000 qualified Energy Star products. In addition, several organizations, including the federal government, have instituted Energy Star purchasing policies. "We expect to see the number of Energy Star products increase until they represent the majority of computer equipment sales within a few years," says the EPA's Linda Latham. "Several manufacturers have told us that they plan to convert their whole product line over to meet the Energy Star guidelines. In fact, Hewlett-Packard recently updated its printer product line so that all the printers it currently manufactures are Energy Star compliant."

On another front, the National Energy Policy Act of 1992 called for the creation of "testing procedures that will enable purchasers of commercial office equipment to make more-informed decisions about the energy efficiency and costs of alternative products." This effort is being run by the newly formed Consortium on Office Product Energy Efficiency, or COPEE, which was put together by the computer equipment industry. As a result, information on the energy consumption of office equipment may begin showing up on products by 1996.

REAL-WORLD DATA **Studies by the National Research Council of Canada have traced desktop computer use patterns in actual office environments. The mean overall daily use profiles for 94 machines, shown here, prove the value of energy management systems that automatically switch off a computer after a specified period of keyboard and mouse inactivity.**



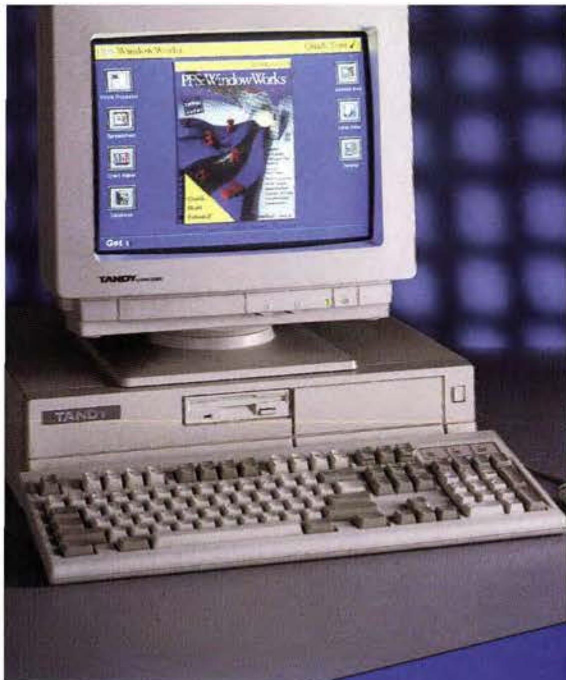
Buyers' guide

In the meantime, the Office Technology Efficiency Consortium can provide help with equipment purchase and use. In one of its first projects the consortium last year published the *Guide to Energy-Efficient Office Equipment*, which provides consumers with a general reference on the energy consumption characteristics of various types of electronic office products. Because no standardized test procedures were available for determining average consumption under typical operating conditions for specific models, no product names are given. The guide was prepared by the American Council for an Energy-Efficient Economy. An updated version of the guide, including specific model designations and the results of new test protocols, is being prepared and should be available in early 1995.

According to the guide, photocopiers typically consume several times as much electricity as individual computers, but since most offices have many more computers, these tend to dominate overall energy consumption. The total energy use for all kinds of office equipment is approximately equal to that for lighting in some commercial buildings. For a typical office of 200 employees, the annual direct energy cost for office equipment is about $44,050. Using more-energy-efficient equipment, however, could reduce this cost to $7550. This reduction could be realized by substituting low-power laptops for some of the desktop computers, replacing laser fax machines with ink-jet units, reducing the number of printers, and using twice as many ink-jet printers as laser-based models.

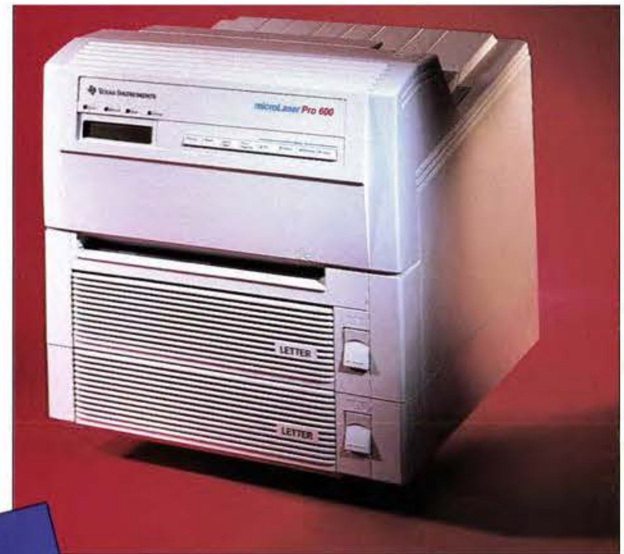
Using a laptop computer as a desktop substitute is one option for saving considerable energy, even if the laptop is used with a full-size monitor during office hours. Several energy-saving technologies that are already being used in laptop computers could also be adapted for use in future desktop units. These include low-voltage architecture, low-energy hard disk drives, CMOS (complementary metal oxide semiconductor) circuit chips that require very little energy to sustain memory, and advanced power management technology for putting the computer into standby mode after a period of inactivity. Also, the liquid crystal monitor used by a laptop consumes only 10–20% as much power per square inch as an ordinary color monitor based on a cathode-ray tube. By using such technologies, a typical laptop draws a maximum of only 15 W of power, compared with a typical desktop computer and its monitor, which draw about 130 W.

As the guide points out, however, a consumer looking at the manufacturer's nameplate would usually see a rating substantially greater than the actual consumption level, since many computers



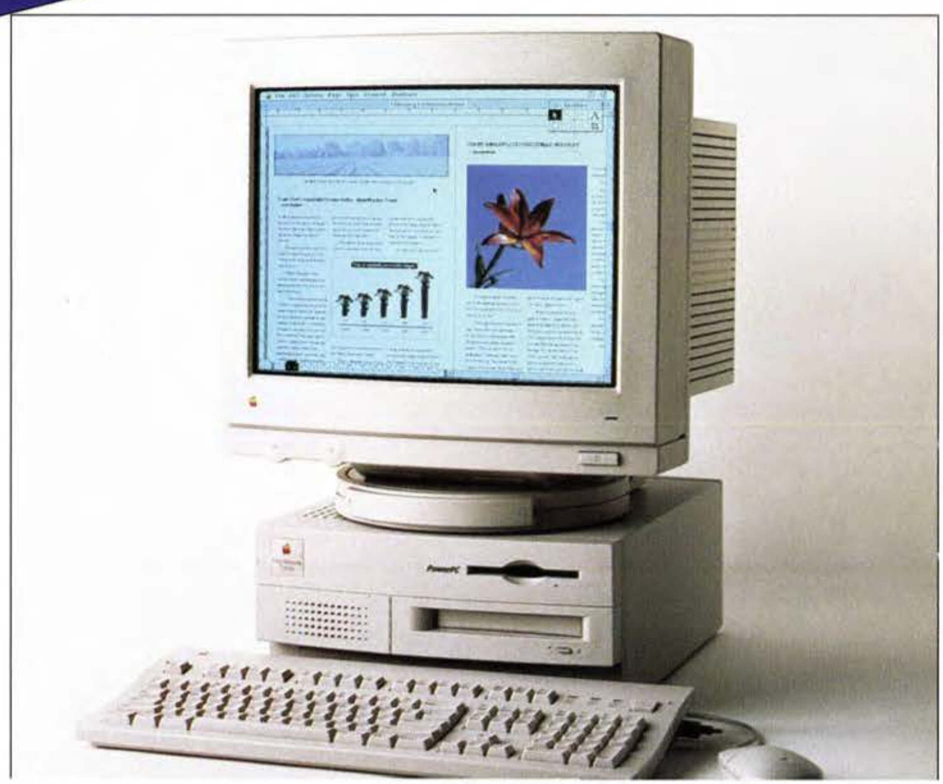
ENERGY STAR ON THE RISE

The EPA's Energy Star Computers Program, which encourages equipment manufacturers to build energy management capabilities into their product lines, has been a tremendous success in its first two years. To date, over 2000 computer, monitor, and printer models have met the efficiency criteria that allow them to display the Energy Star logo.



energy

EPA POLLUTION PREVENTER



have relatively large power supplies to accommodate future circuit boards or other add-ons. Thus a PC that operates with a full power load of 100–150 W might have a nameplate rating of 300 W. The development of new test procedures should help overcome such discrepancies and provide buyers with the type of information they need to make energy-conscious purchasing decisions.

Hard-copy savings

The guide also recommends using printers and fax machines based on ink-jet technology, rather than laser or thermal imaging technologies, as a way to reduce energy consumption when preparing hard copies of documents. A typical ink-jet printer with a printing speed of three pages per minute, for example, consumes 8–12 W of power when idle and 15–23 W when printing. A laser printer with a printing speed of eight pages per minute consumes 75–100 W when idle and 250–300 W when printing. Also becoming available are ink-jet photocopiers, which require much less energy than copiers that use heat and pressure to fuse powdered toner onto a sheet of paper. The ink-jet copiers require a separate digital scanning step, however, and thus are slower and more expensive than conventional copiers.

Because fax machines typically run 24 hours a day, the vast majority of a unit's energy consumption occurs during periods of inactivity. For this reason, it's particularly important to choose equipment that is efficient in the standby mode. Ink-jet fax machines use considerably less energy than those based on the direct thermal process or on laser technology. Another important consideration with fax machines is paper use. Today's most popular models use heat-sensitive, coated paper that cannot be recycled. Ink-jet models can use plain paper, whose cost is one-third to one-fifth that of thermal paper. Thus, assuming a volume of 50 sheets per day, the more expensive ink-jet fax machine can pay for itself in less than a year through savings on paper alone.

In the future, several peripheral functions are expected to be incorporated into single machines, popularly called hydras. These machines typically combine printing, scanning, faxing, and copying in a single unit. They are expected to help reduce office energy use by replacing multiple machines that would each consume considerable power during periods of inactivity. Data are sparse, but the hydra-type machine offered by one manufacturer reportedly has a standby power consumption of only 40 W and an active-mode consumption of 300 W.

As the guide notes, office paper consumption itself represents a large amount of energy consumption; accounting for this energy is difficult, however, since its cost is already included in the price of the paper. A sheet of plain paper requires 10–30 Wh of energy to produce—three times the energy needed to make a sheet of paper using recycled materials. Nationwide, therefore, encouraging less paper use and more paper recycling could make a major contribution to energy conservation.

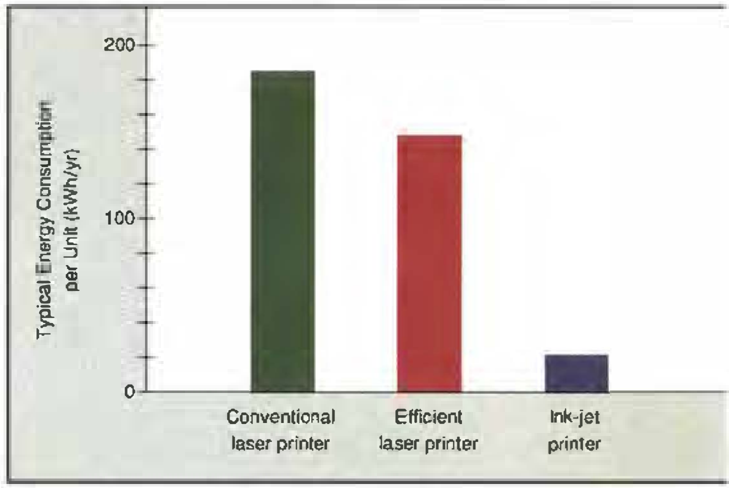
Only about 20% of high-grade paper from commercial offices is now recycled, and paper consumption in some offices runs as high as 8000 sheets per employee per year. The guide suggests placing recycling bins at more-convenient locations throughout an office; it notes that because over 40% of typical office solid waste is paper, it may be possible to reduce waste disposal costs through recycling. Another suggestion is to increase the use of electronic mail and thus reduce the amount of paper needed for routine office communication.

Next steps

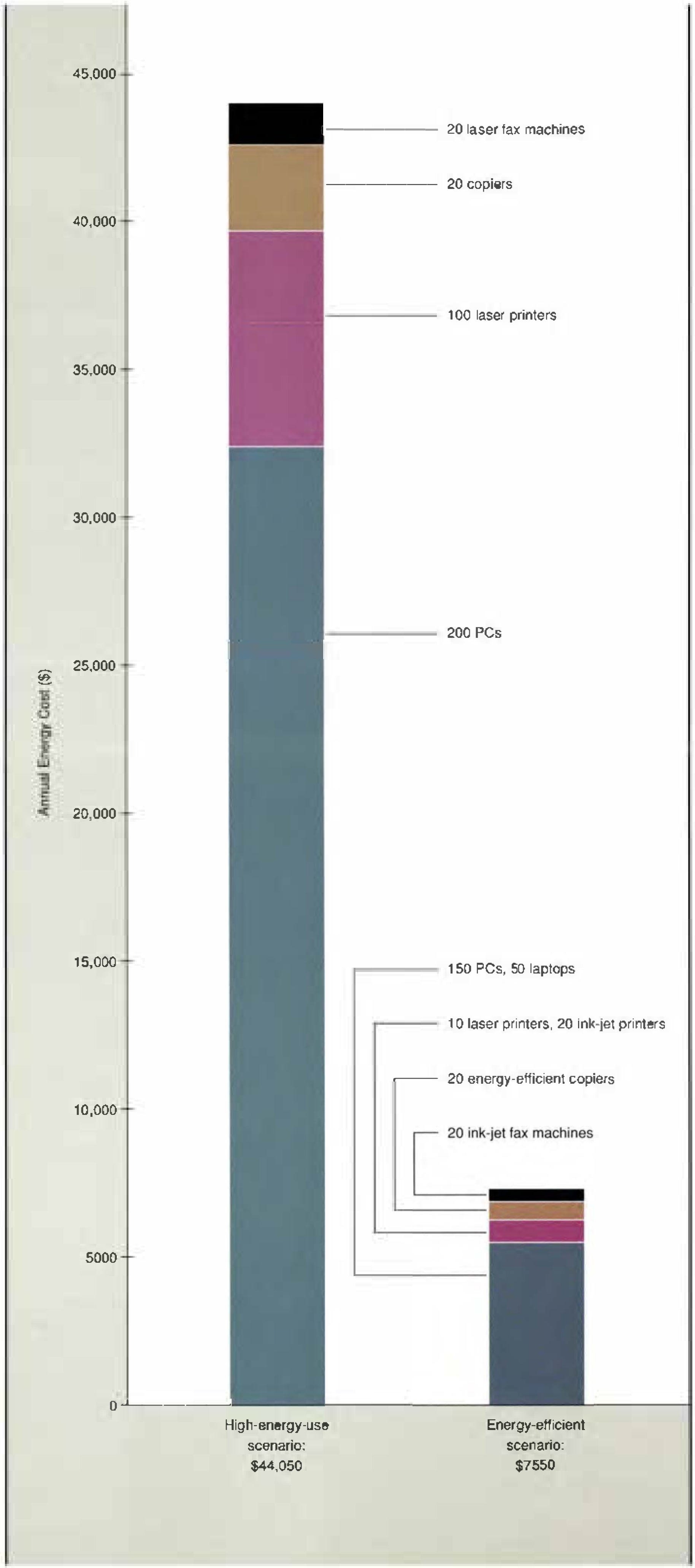
In addition to preparing an updated guide, the Office Technology Efficiency Consortium is taking other steps to encourage the development and use of more-energy-efficient office equipment. This coming October 17–19, an international seminar will be held in New York City to acquaint utility marketing representatives, research professionals, policymakers, and demand-side management planners from around the world with the latest developments in this fast-moving field. The seminar will highlight new products and emerging technologies, with particular emphasis on network compatibility and power quality issues; current utility and user programs; progress in the EPA's Energy Star initiative; and other "market-pull" programs. Panel discussions and presentations will emphasize experience with energy-efficient equipment and measured energy use.

The consortium is also coordinating work with other industry groups to characterize power supplies now used with office equipment and to identify more-efficient technical alternatives. The trend in recent years has been for manufacturers to spend less money on power supplies in order to compete with low-cost imports and off brands. As a result, the energy performance and power quality characteristics of some power supplies have been ad-

CHOOSE YOUR TECHNOLOGY CAREFULLY Looking for equipment that incorporates energy-saving features is a good idea, but sometimes changing to a completely different technology can mean far greater



savings. As shown here, an ink-jet printer, which does not employ a heat-fusing mechanism, requires only a fraction of the energy used by the current generation of energy-efficient laser printers.



Founding Members of the Office Technology Efficiency Consortium

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Electric Power Research Institute
New York State Energy Research & Development Authority
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Southern California Edison Company
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National Renewable Energy Laboratory
National Research Council of Canada
North Carolina Alternative Energy Corporation
NUTEK (Swedish National Board for Industrial and Technical Development)
Ohio Department of Development
Rocky Mountain Institute
State of Iowa
U.S. General Services Administration

WHAT CAN BE DONE TODAY? Currently available hardware and efficient use strategies can make a dramatic difference in officewide energy consumption. In the two scenarios shown here, shrewd equipment choices, the turning off of equipment after work hours, and the additional sharing of computer printers reduced annual energy costs by over 80%.

BUY RIGHT, USE RIGHT **The Office Technology Efficiency Consortium's equipment guide provides general recommendations on equipment purchase and use for maximizing energy efficiency. These suggestions can help lower a company's energy bills, and some have additional benefits. For example, double-sided copying, reuse of single-sided documents, and use of electronic mail save both on an office's paper costs and on the energy expended for paper manufacture nationwide.**

	Recommendations for Buying	Recommendations for Operating
Personal Computer	• Buy a laptop computer • Buy an Energy Star computer	• Turn off at night and on weekends • Activate power management features • Turn off when not in use during the day
Computer Monitor	• Buy an Energy Star monitor • Consider a monochrome monitor • Consider an active-matrix color LCD • Buy monitor only as large as needed • Buy only as much screen resolution as needed	• Turn off at night and on weekends • Activate power management features • Turn off when not in use during the day
Computer Printer	• Consider an ink-jet printer • Buy an Energy Star printer • Consider sharing a printer • Consider a unit with double-sided printing	• Turn off at night and on weekends • Activate power management features • Reuse paper • Use electronic mail
Copier	• Choose a properly sized unit • Consider a copier not based on heat- and pressure-fusing technology • Compare ASTM ratings • Buy a unit with power management features • Choose a unit offering convenient two-sided copying	• Turn off at night and on weekends • Activate power management features • Use two-sided copying whenever possible • Batch copy jobs
Fax Machine	• Buy a unit with a low standby energy rating • Consider a plain-paper fax	• Reuse paper • Use electronic mail

versely affected. A PC power supply represents about 2–5% of the total cost of the computer—typically about $50 for a $2000 PC. Prior research indicates that enhancing the power supply (raising this price to $87) could significantly improve energy efficiency and power quality. The results of the power supply study will be presented at the New York seminar.

"Previous EPRI work at the Power Electronics Applications Center has provided a markedly improved design for power supplies," comments Wade Malcolm, who manages the Institute's research on power electronics and controls. "By using a high-frequency switching design, we can provide higher-efficiency conversion of ac to dc power for computers, in a smaller package than conventional power supplies. This design should also prove to be more reliable because it has fewer components. Filters can be added to mitigate harmonics, and impedance matching can provide an improved power factor. We are now discussing these possibilities with manufacturers and interested utility representatives."

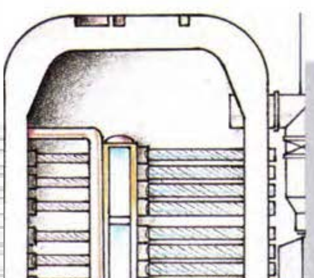
Finally, the consortium is planning to sponsor field demonstrations of Energy Star computers and printers, to be conducted by 5 to 10 utilities at commercial customers' premises. At these pilot sites, office equipment will be tested according to new protocols in order to determine both typical and best-practice characteristics for energy use, peak demand, and power quality. Each participating utility will be responsible for day-to-day maintenance of the test equipment and for data handling. The results will be shared through the consortium.

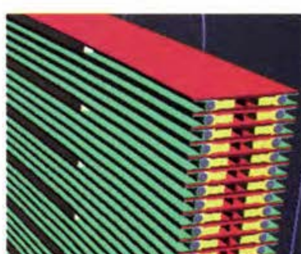
"Improving the energy efficiency of office equipment can be a win-win-win situation for users, manufacturers, and utilities," concludes Morton Blatt. "Customers will enjoy lower costs with at least comparable equipment performance. Manufacturers can use this opportunity to enhance their products and thus improve their competitive position in the marketplace. And utilities can breathe a sigh of relief at avoiding expensive additions to their distribution systems by limiting on-peak demand. Also, there can be environmental quality payoffs from overall energy conservation that will benefit everybody." ■

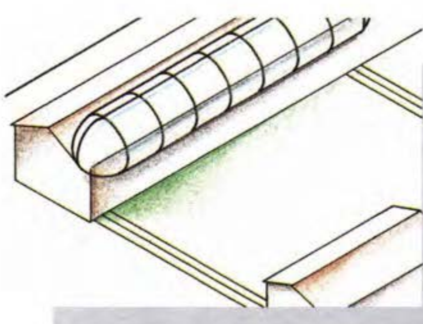
Background information for this article was provided by Morton Blatt, Customer Systems Group.

THE STORY IN BRIEF *Long envisioned as an almost ideal way to store large amounts of electricity with virtually no losses, superconducting magnetic energy storage technology has been under development by both the government and the utility industry for over a decade. Meanwhile, a new perspective has emerged on the value to utilities of the technology's dynamic operating benefits—enhanced frequency regulation, transmission stabilization, and load-following capability, for example. These benefits and the benefits of the technology in a conventional energy storage role, coupled with recent design advances, are leading to renewed efforts to build and demonstrate SMES systems for utility application. The technology has already been commercialized at small scale as a solution to short-term power quality disturbances and outages at industrial and military sites.*

Storing SM







Megawatthours With MES

by Taylor Moore

Laboratories around the world continue to make significant strides in developing electric power applications for recently discovered high-temperature superconducting materials—materials that lose electrical resistance when cooled to the temperature of liquid nitrogen. But a major application of superconductivity based on the more commercially and technologically mature low-temperature superconductors—superconducting magnetic energy storage (SMES)—has already entered the commercial market, although in a different size and type of application than that originally of interest to utilities. This development highlights an emerging new perspective on the value of SMES technology's dynamic operating benefits, both to utilities and to their customers.

SMES promises to be the ultimate realization of the utility industry's long-running quest for a truly high-power, high-efficiency, rapid-response, and reliable energy storage system. Using what is essentially a large coil of conductor maintained at a superconducting temperature, SMES is the only technology that stores energy directly in the form of electricity. Even accounting for the conversion of ac into dc—the form of electricity stored in the coil—and its later reconversion to ac, SMES can offer an unprecedented round-trip dispatch efficiency of 95% or more. That compares with 70–75% for other forms of storage, such as compressed air, pumped hydro, or lead-acid batteries, which must convert electricity into stored potential mechanical or chemical energy and then turn it back into electricity when needed.

Its high storage efficiency and high power capacity, together with a response time that is measured in milliseconds, make SMES ideal for a large spectrum of utility operational uses. These range from stabilizing power system voltage and frequency to serving as a large reservoir of megawatthours that, if necessary, can go

BENEFITS ACROSS THE BOARD **The new perspective on SMES is that the technology offers a wide range of strategic and dynamic benefits in addition to its usefulness in conventional, load-leveling energy storage. The use of SMES to enhance both generation system and transmission and distribution system assets can translate into significant strategic competitive advantage for utilities. In power quality and protection applications at the microscale level of energy storage, SMES also offers benefits directly to customers.**

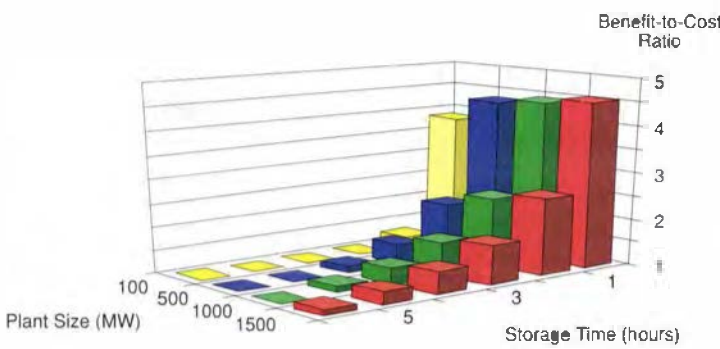
EXAMPLES OF APPLICATIONS AND BENEFITS				
	Generation	**T&D**	**Corporate**	**Customer**
Strategic benefits	Reduced/shifted emissions	Fewer outages	Lower fuel-shock risks	Fewer blackouts
Dynamic benefits	Improved frequency control	Improved power quality	Less reliance on purchased power	Improved power quality
Load-leveling benefits	Increased utilization of baseload plants	Improved grid utilization	Potential wheeling revenue	Improved customer retention

from charging to discharging to the grid at full power in 4 milliseconds. That interval is about one-quarter of 1 of the 60 cycles per second in 60-Hz ac power systems. And SMES units should be able to operate through millions of charge-discharge cycles over as long as 40 years with no significant deterioration in performance or efficiency. Except for the cryogenic pumps that maintain the required temperature of the coil, there are no moving parts, and the only energy losses—about 4% with today's technology—occur in the power converter.

SMES was first proposed over 30 years ago as an alternative to pumped-hydro storage. Its use on a significant scale by utilities in the next century could transform the economics of power generation and system operations. SMES could greatly improve asset utilization of both generating plants and transmission networks—a growing priority for increasingly competitive electric utilities.

By enabling the routine storage of excess, low-cost energy from baseload plants for dispatch during periods of peak demand (when the incremental cost of additional generation is highest), SMES could flatten the cost differential between peak and off-peak generation and decouple the production of electricity from the constraint of having to instantaneously serve fluctuating demand. SMES could also store low-cost, off-peak electricity purchased from other utilities or third parties, or produced by intermittent renewable resources, for distribution to customers on-peak.

A paradigm shift in perceptions about the dynamic operating benefits of SMES is occurring as a result of recent design breakthroughs for lower-cost, lower-capacity SMES units than were originally envisioned. In such applications as transmission system stabilization, SMES could enable higher loading and increased power transfers over long-distance transmission lines. Moreover, EPRI has estimated that the projected need for additional generating capacity in the future could be reduced by as much as 15% by the widespread use of energy storage systems like SMES. (For more information about energy storage technologies and strategies, see the *EPRI Journal*, July/August 1989, p. 4.)



SPOTLIGHT ON DYNAMIC BENEFITS **Recent EPRI studies of the dynamic utility benefits of SMES reveal a substantial positive benefit-to-cost ratio for units with higher power ratings but shorter energy storage times than were originally considered appropriate for SMES. The graph shows results from an analysis of the use of SMES for frequency regulation and transmission stability by a hypothetical utility with the same mix of generating capacity as the mix for the entire United States. In these applications, the benefit-to-cost ratio is greatest for a unit configured to provide high output power with 1 hour or less of discharge time.**

The new appreciation of the dynamic operating benefits of SMES is expanding the range of the technology's potential power system applications for utilities. But even as interest in such cost-effective uses continues to develop, industrial and commercial customers with operations that are sensitive to power quality disturbances are already beginning to apply SMES at the microscale level of up to several megawattseconds (MWs). For about two years, a Wisconsin firm has commercially offered a mobile, trailer-installed superconducting storage system that can protect against costly shutdowns caused by power disturbances. The system has been demonstrated at several industrial and manufacturing sites, and EPRI and Carolina Power & Light Company are collaborating to document and evaluate tests at three of the utility's industrial customers (see sidebar). The U.S. Air Force, meanwhile, has ordered several units for power conditioning and protection at its installations.

Early studies

Some of the first studies of SMES for utility use were conducted in France (in the late 1960s); at the University of Wisconsin, under the sponsorship of Wisconsin utilities and the predecessors of the U.S. Department of Energy; and at the DOE-funded Los Alamos National Laboratory. EPRI established a long-term program on SMES in 1980 and in 1982 began studies of the technology's engineering, performance, constructibility, and costs. In 1983, EPRI developed a business plan for an engineering test model (ETM) to serve the utility industry as a commercial prototype pilot plant.

The physics of a SMES coil and the then-high cost of low-temperature superconductors (LTSCs) drove early designers to large-scale systems. High current capacity was a major goal, since the amount of energy that can be stored increases by a factor of 4 with a doubling of the current. And the more energy that is stored, the more kilowatthours there are over which to spread a SMES plant's cost: the early studies determined that a doubling of storage capacity reduced the cost per stored kilowatthour by 20%.

EPRI's evaluations assessed the initial capital cost of a large SMES device (1000 MW of power for 5 hours) at over $1300/kW—at that time (the mid-1980s), about 30% higher than pumped-hydro and twice as high as compressed-air energy storage. A long-term R&D effort could, it was estimated, reduce the capital cost to below $900/kW, around the high end of the cost of other forms of storage.

A 1000-MW, 5-hour SMES coil (the largest plant size that was ever envisioned for utility use) would be large indeed—1000 meters in diameter. The mechanical stress and radial forces that, at large scale, would be exerted on the coil during current charging led to an underground design to take advantage of low-cost earth support—for example, in 9-meter-deep, concrete-lined trenches that would contain the vacuum-vessel cryogenic enclosure for the conductor coil.

But even with the scale factor at work, a 5-GWh SMES plant would have cost over $1 billion. EPRI and its early design contractors, Bechtel Group and General Atomics, decided to pursue a technology development path that would begin in smaller terms—with an ETM capable of providing a few tens of megawatts for a couple of hours.

Around the same time, a significant demonstration of SMES on a smaller scale helped provide a design basis for estimating the cost of larger units and successfully showed the basic operational function and reliability of SMES. With DOE funding, the Los Alamos National Laboratory and its contractors built a 10-MW, 3-second SMES coil that was installed in 1984 on the Bonneville Power Administration transmission system at a Tacoma, Washington, substation.

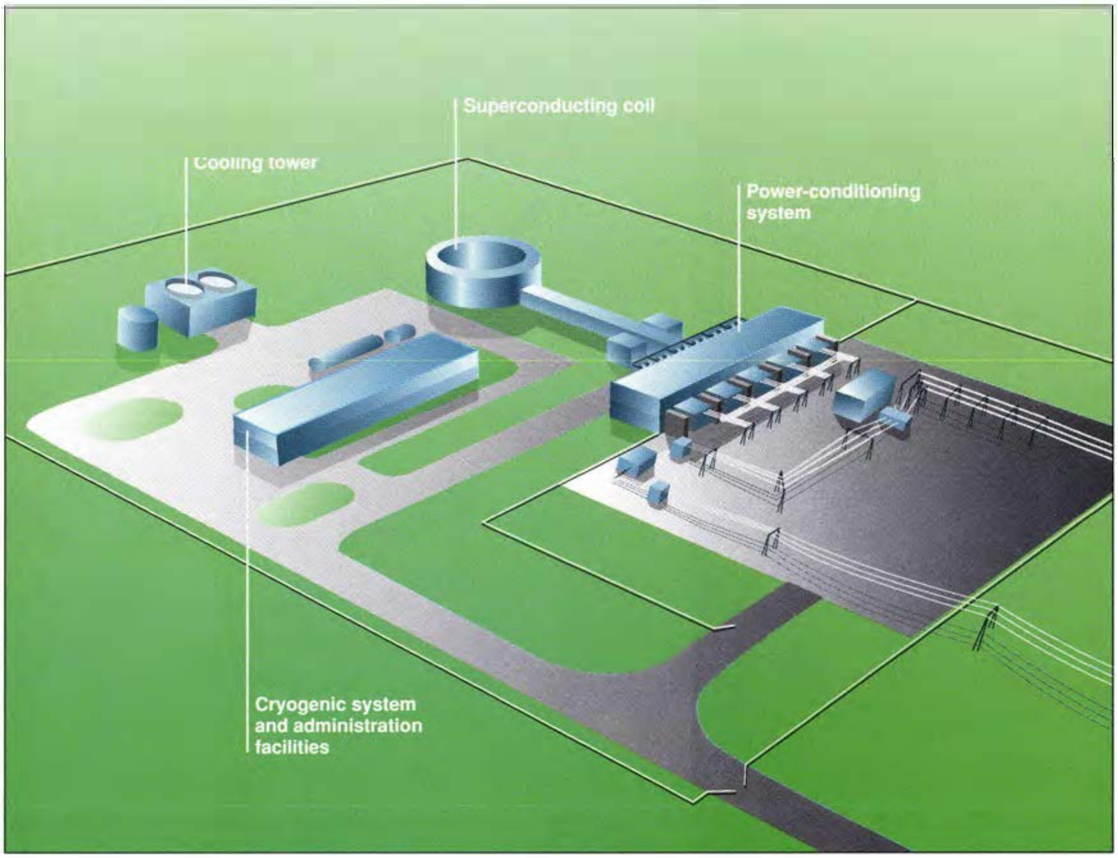
The unit successfully operated for over a million charge-discharge cycles and convincingly demonstrated a fast-response capability for stabilizing BPA's 500-kV network, which helps move large amounts of power between the Pacific Northwest and southern California on a seasonally alternating basis. After several months of operation, however, the SMES unit's refrigeration system failed; because of budget constraints, the system was not repaired, and the project was terminated. Even so, the BPA experience effectively demonstrated the integration of SMES into a utility system and validated one of the key dynamic benefits that would be pursued in later projects. Today, SMES coils for an intermediate range of power rating and energy storage are being evaluated as part of EPRI's development of FACTS (flexible ac transmission system) technology.

Technology development continues

The future direction of SMES and of ETM development remains uncertain. Supporters still have hopes of winning sufficient congressional and administration support for starting construction on some sort of demonstration unit, pending a redefinition of the government program's sponsorship within the U.S. Navy and DOE.

While administration support and the actual budget for demonstrating SMES have varied over the years, the fundamental technology has continued to develop. The two contractor teams working on SMES designs—which are headed by Bechtel and Raytheon-EBASCO Division (formerly EBASCO Services)—have updated their designs as commercial LTSCs have reached new heights of performance in terms of current-carrying capacity. LTSC cables are now available that have a current-carrying capacity well over the design criterion considered necessary for large-scale SMES coils. Last fall, Bechtel achieved a world-record 303,000 amperes (dc) at 1.8 K in a 5-tesla magnetic field in tests of a full-scale coil conductor designed for the Bechtel team by General Dynamics and made from LTSC niobium-titanium wire.

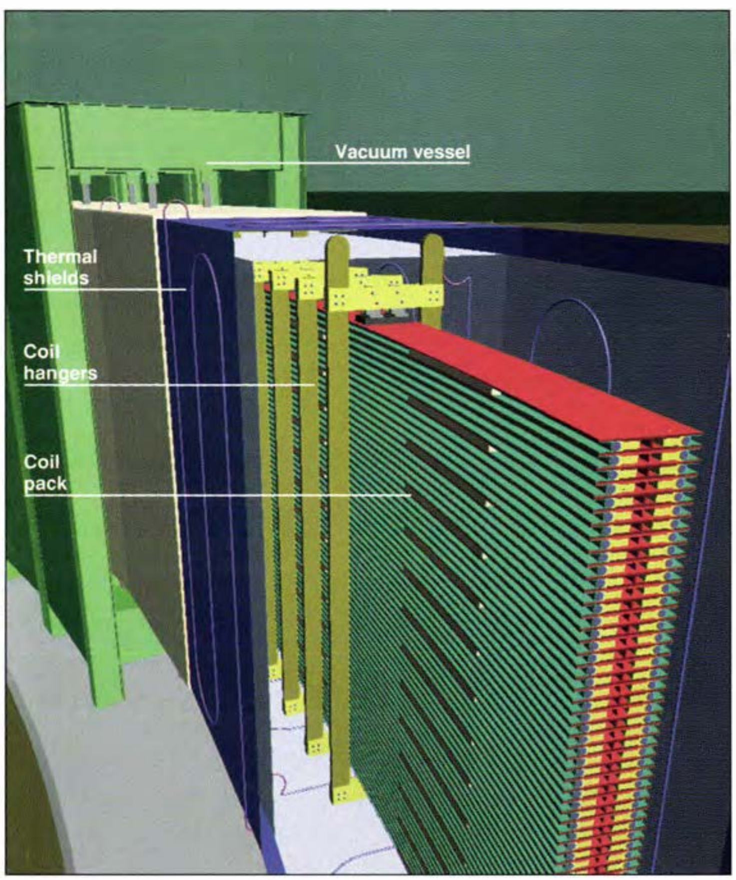
The tests used a cable-in-conduit conductor—in which liquid helium fills the hollow center of a multistrand cable. According to Bechtel, this and other innovations enable a SMES design breakthrough that promises a substantially-lower-cost, aboveground coil design and therefore a more affordable plant. Bechtel says that, compared with earlier designs, such a self-supporting coil could cut the capital cost of a SMES unit by up to 30%, and that it should also shave a full year from the pro-



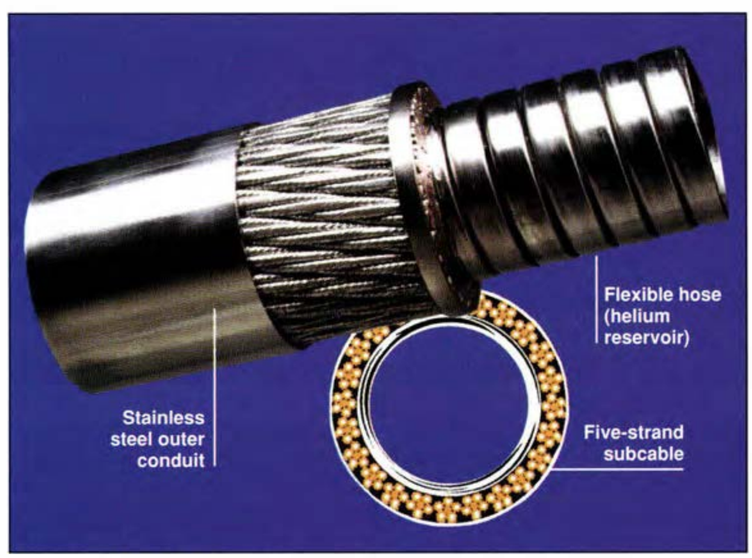
SMES-1 site arrangement

SELF-SUPPORTED COIL KEY TO NEW BECHTEL DESIGN

Bechtel says that a design breakthrough permitting a self-supported, ground-level storage coil could reduce the capital cost of a SMES unit by up to 30%, compared with earlier earth-supported, lined-trench designs. The new design concept, which also shortens the estimated construction schedule for a typical unit from four years to three, has been developed by Bechtel for a 300-500-MW plant with 9-90 seconds of storage. The plant is dubbed SMES-1.



Self-supported coil



Liquid-helium-filled cable-in-conduit conductor jected four-year construction schedule for a device on the scale of an ETM.

Perhaps most important, the breakthrough to a self-supported coil design makes possible a much more scalable technology development path. This means that a demonstration unit smaller than envisioned for the ETM could be scaled up in power rating and capacity in commercial designs all the way to the equivalent of 1000 MWh of storage, with costs and performance confidently predicted through straightforward engineering. EPRI has recently estimated, on the basis of the latest design and cost estimates, that commercial, large-scale (500-MW, 2-hour) utility SMES units could cost about $600/kW, assuming sales of more than two units a year.

Bechtel has now designed a smaller, aboveground demonstration unit, dubbed SMES-1, that would have a power rating of 100–500 MW for 7.2–360 seconds of storage and would cost $50 million to $100 million as a first-of-a-kind unit. Its principal application would be for transmission stability. In contrast to the ETM design's 100-meter-diameter coil, the diameter for a unit the size of SMES-1 would be only about 20 meters. It is expected that a unit even of this scale could provide the necessary operating and test data to demonstrate nearly all of the potential utility applications of SMES, possibly even including spinning reserve and peak shaving.

EXAMPLES OF SMES APPLICATIONS: POWER LEVELS AND DURATIONS **This table indicates the range and diversity of SMES applications in the areas of utility energy management and power quality. Larger SMES units would be capable of providing multiple benefits, including some of the benefits of small units.**

Type of Application	Power	Duration
Customer level		
Power interruptions	0.2–5 MW	0.1–5 seconds
Carryover	0.2–5 MW	0.1–5 seconds
Distribution feeder		
Power interruptions	1–5 MW	0.1–5 seconds
Voltage/VAR support	1–5 MW	0.1–5 seconds
Load leveling/peak shaving	1–5 MW	1 minute–2 hours
Transmission substation		
Transmission stability	10–500 MW	1–30 seconds
Voltage/VAR support	10–500 MW	0.1–0.5 second
Transient damping	10–500 MW	1–4 hours
Generation system		
Frequency control	100–1000 MW	10–60 seconds
Spinning reserve	100–1000 MW	15–30 minutes
Dynamic response	100–1000 MW	1–2 hours
Load leveling	100–1000 MW	1–5 hours

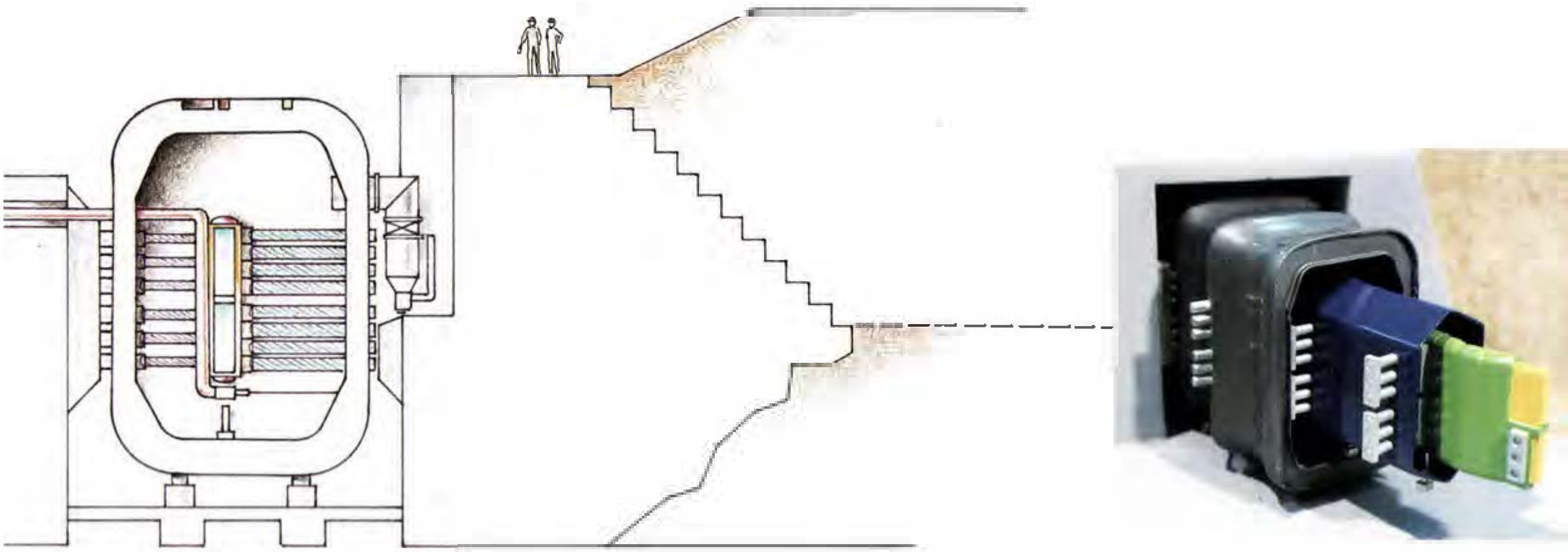
The company is proposing a dual-use technology project to build a SMES-1 unit under a 50% cost-sharing arrangement between industry and the government (whose share could come from defense conversion funding under the Department of Defense's Technology Reinvestment Program). Meanwhile, Raytheon–EBASCO Division says that it also has a scalable, aboveground design for a system on the order of an ETM (about 20 MWh of energy storage), as well as a design for a self-supported, low-cost smaller unit for lower levels of energy storage. In fact, the technology for SMES systems is within the capabilities of many power engineering companies.

EPRI is currently in active discussion with officials of the Navy and DOE about the possibilities for a SMES demonstration. San Diego Gas & Electric Company is considering a pilot plant the size of SMES-1 that it believes could benefit a number of utilities in the Southwest. Other utilities remain interested in the bulk storage and load-leveling benefits of SMES, in addition to its dynamic benefits, and are hopeful of seeing the technology demonstrated at the scale of the earlier ETM design.

Meanwhile, government funds are already committed for a $25 million project to demonstrate SMES on a smaller scale for a limited range of utility applications. In a DOE-managed project funded by a grant from the Pentagon's Technology Reinvestment Program via the Advanced Research Projects Agency, Babcock & Wilcox Company is designing a 30-MW, 60-second SMES unit for installation on the 115-kV transmission system of Anchorage (Alaska) Municipal Light & Power Company.

The unit, which may be operating by late 1997, will be used primarily for shifting some spinning-reserve duty from combustion turbines to hydro units. That will allow Anchorage ML&P both to save fuel costs and to reduce the number of power outages that result from brief system disturbances. The SMES unit will also provide voltage and VAR support and is thus expected to increase transmission stability limits, which, in turn, will allow increased power transfers with neighboring utilities.

As a result of analyses sponsored in part by EPRI, Anchorage ML&P estimates that



EBASCO'S DESIGN COULD NOW GO ABOVE GROUND Raytheon–EBASCO Division, which heads a second SMES design team under the joint government-industry technology development effort, says it also now has a ground-level, fully scalable SMES coil design that could be built in smaller sizes for lower energy storage levels than called for in earlier designs. The cutaway drawing depicts EBASCO's version of a 10-MW, 2-hour SMES coil installed at grade. The photograph of a cutaway model shows an earlier, below-grade design concept.

the SMES system could provide benefits, largely in the form of fuel savings, worth $2 million a year. The cryostat, measuring about 21 meters long and 4 meters in diameter, would be pad-mounted on its side at a transmission substation, with small buildings for the refrigeration system and the power converter nearby.

Benefits becoming more apparent

Anchorage ML&P's estimates of the value of operating a small SMES unit on a relatively small utility system are only the latest in a growing list of utility benefits assessments sponsored by EPRI and now DOE that strongly point to a multitude of tangible daily operating advantages afforded by the technology's flexibility. Most of these utility studies have involved extensive use of three EPRI software packages—DYNAMICS, DYNASTORE, and the Extended Transient–Midterm Stability Program (ETMSP).

The first two are specialized software packages that incorporate realistic unit commitment and dispatch simulations and model hourly utility generating costs, allowing the first real evaluations of the dynamic benefits of energy storage, as opposed to its conventional load-leveling benefits. Dynamic benefits include the ability to use storage for spinning reserve, frequency regulation, rapid load following, and transmission stabilization. The ETMSP software is used for transmission stability calculations.

EPRI is sponsoring a joint SMES benefits study by five West Coast utilities that routinely buy and sell power among themselves. The project is investigating how SMES could increase effective transmission capacity—and, in turn, regional power transfer capability—by dampening subsynchronous resonance among generation sources that can cause damaging power system oscillations. BPA, Los Angeles Department of Water & Power, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company are providing system data and results review to EPRI's contractor, Battelle Pacific Northwest Laboratories (PNL). Bechtel is providing SMES system design support and application cost data. The project will quantify SMES benefits and compare SMES with other transmission stabilization technologies, such as static VAR compensators.

PNL used ETMSP to model the West Coast transmission system with SMES units at several different locations. So far, the study has found that SMES may have as much as a 2-to-1 power transfer enhancement ratio as a result of its ability to dampen system oscillations. This means, for example, that a 250-MW SMES coil could increase power transfer over the Pacific Intertie—a series of interconnected lines extending from the BPA system all the way to southern California—by 500 MW, using only seconds of electricity storage. By itself, this would be worth several millions of dollars a year in avoided fuel costs. And as seen in other studies, SMES could help provide spinning reserve, reducing such requirements from other types of generation. Results of the West Coast study are expected to be published by EPRI this year.

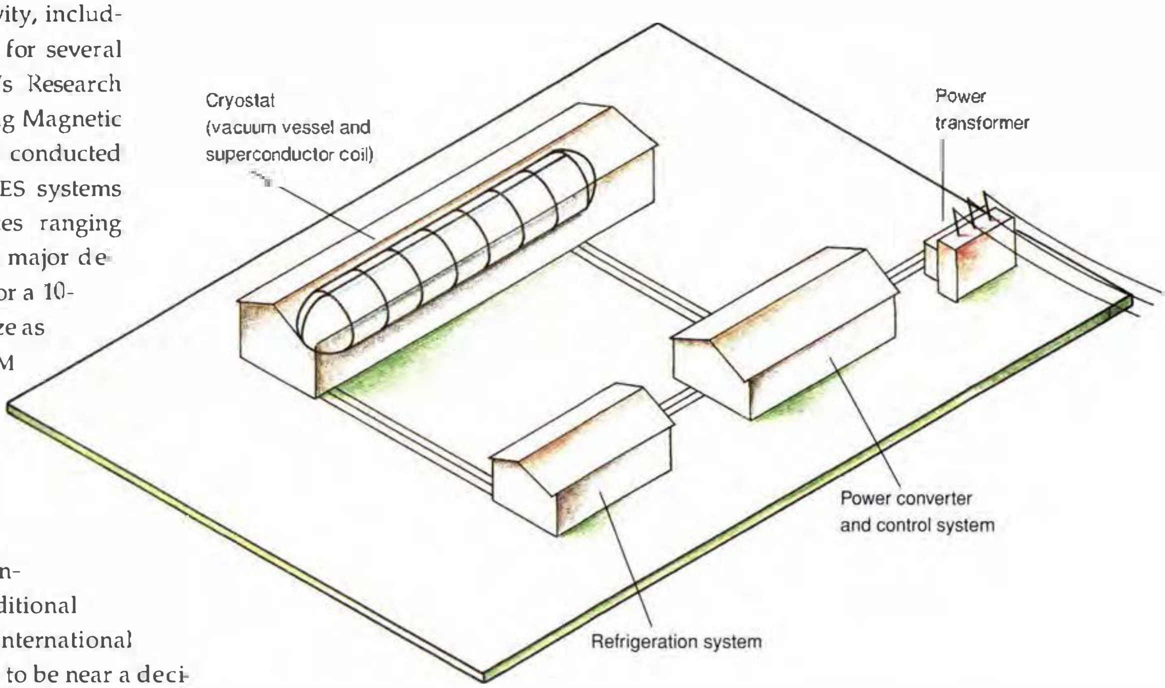
EPRI's benefits studies have highlighted the variety of roles SMES can play in power system operations, revealing the nonintuitive nature of both the applications and the potential unit sizes. These multiple functions enhance the benefit-to-cost ratio for a given utility scenario, although the benefits are highly system specific. In another EPRI-sponsored study, BPA used EPRI's DYNASTORE code to analyze specific scenarios and discovered that the most cost-effective SMES unit would require about 1200 MW for 1 hour—less than one-sixth of the storage capacity originally considered necessary.

A possible downside of SMES involves concern over potential human health risks of exposure to electric and magnetic fields (EMF). The magnetic field generated by a SMES coil, although quite strong, is a dc field. In contrast, research that is being conducted on possible EMF health effects, including the substantial effort sponsored by EPRI, focuses on ac fields. Researchers have suggested that the possible biological effects of EMF exposure are due to interaction mechanisms that depend on the alternating nature of ac fields. Still, this important technical distinction between ac and dc may not prevent the issue from being raised about utility SMES systems, from the standpoint of both public siting and worker exposure. As is the case with most ac magnetic fields, the strength of a SMES coil's dc field diminishes rapidly with distance, and an exclusion perimeter around a SMES unit would substantially limit exposures.

Worldwide SMES development

An extensive and coordinated scientific and technology development effort in all applications of superconductivity, including SMES, has been going on for several years in Japan. The country's Research Association of Superconducting Magnetic Energy Storage (RASMES) has conducted design studies of several SMES systems with coil energy storage sizes ranging from 100 kWh to 5 GWh. One major design and cost study has been for a 10-MW, 2-hour plant, the same size as the U.S. government-utility ETM pilot plant design of the 1980s. RASMES is funded by six Japanese utilities and 39 major manufacturers and construction companies, with major Japanese research institutes and universities as additional members. Japan's Ministry of International Trade and Industry is believed to be near a deci-

SMALL SMES UNIT PLANNED FOR ANCHORAGE ML&P **A 30-MW, 60-second SMES unit to be used primarily for spinning reserve and for increasing transmission stability limits is planned for installation on the Anchorage (Alaska) Municipal Light & Power system. DOE is managing the $25 million project, funded mainly by the Pentagon's Technology Reinvestment Program through a grant from the Advanced Research Projects Agency. Babcock & Wilcox is designing the system, which may begin operation by late 1997. The current design calls for a cryostat 4 meters in diameter and 21 meters long to be pad-mounted at a transmission substation; the installation will also include small buildings for the refrigeration system and the power converter.**



Electric utilities view superconducting magnetic energy storage (SMES) and other forms of energy storage as a highly flexible type of generating capacity that can also provide a suite of quantifiable dynamic operating benefits. But at the microscale of a few to several tens of megawattseconds (MWs) of energy, SMES is already available in the commercial market as an uninterruptible power supply (UPS) and as a solution to customer power quality problems.

In these microscale applications, SMES is evaluated on a different economic basis. It competes with battery-fed UPS systems for use by large industrial customers for whom millions of dollars are at stake when short-term power disturbances cause sensitive production equipment or systems to trip off-line. According to some estimates, power quality problems cost U.S. manufacturers $26 billion a year in downtime.

Trailer installation at CYANCO plant, Winnemucca, Nevada

Micro-SMES Powers Critical Customer Processes

Superconductivity, Inc., of Madison, Wisconsin, currently offers a micro-SMES system—the Superconducting Storage Device, or SSD®—in two sizes: 750 kWs and 1.4 MWs. The SSD—installed in a semitrailer, along with an integrated liquid-helium cooling system, a power supply, and a voltage regulator—either can be connected to an existing variable-speed motor drive to protect it from momentary power disturbances, or can be shunt-connected with a high-power inverter and isolation switch to serve as a short-term UPS that can sustain voltage for the few seconds when a sag might otherwise shut down production systems. The company's first commercial shunt-connected SSD was sold to Central Hudson Gas & Electric Corporation and was successfully used for 18 months at an IBM computer-chip-testing plant in Fishkill, New York.

Superconductivity, Inc.'s micro-SMES SSD

A chemical-processing plant in Winnemucca, Nevada, reports a substantial improvement in its on-line productivity since the May 1993 installation of an SSD on a 4.1-kV, 400-horsepower blower motor that is part of a continuous catalytic process. Officials at this CYANCO plant, which produces liquid sodium cyanide used in the mining industry, say that the unit helps the plant avoid an average of four days of lost production a month.

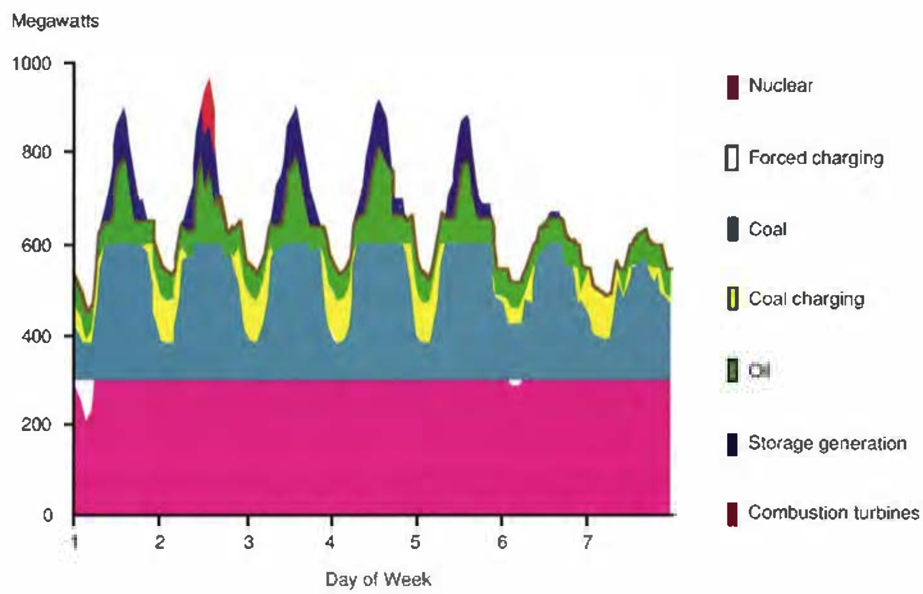
Recently, Superconductivity, Inc., received an $8.6 million order from the U.S. Air Force's Power Conditioning and Continuation Interfacing Equipment Office at McClellan Air Force Base near Sacramento, California, for up to five SSDs to improve power quality at various installations over the next three years. The Defense Nuclear Agency of the Department of Defense is providing the funding.

EPRI is working with Carolina Power & Light Company in a tailored collaboration project to evaluate SSD units for one year each at three industrial customer sites in CP&L's service area. The utility was eager to test the system in customer applications as part of its proactive power quality program. Testing of a 750-kWs SSD was recently completed at a Sonoco Products polyethylene-bag-extrusion plant in Mount Olive, North Carolina. And testing of a second 750-kWs unit began in April at ITW Angleboard, which makes reinforced container corners from recycled plastic. The Hartsville, South Carolina, plant is on the far end of a distribution circuit that has over 200 miles of exposure to potential faults. A third CP&L customer site has yet to be determined.

Meanwhile, EPRI and Pacific Gas and Electric Company have worked with the Bay Area Rapid Transit (BART) system to evaluate SMES as a possible solution to the brief power losses experienced by traction motors on some of BART's electric trains when they pass through the tunnel running beneath San Francisco Bay. Originally, voltage sags were thought to cause the problem, but PG&E has determined that is not the case. Ongoing studies could lead to the eventual testing on the BART system of micro-SMES coils with a storage capacity of 5–10 MWs.

For micro-SMES as well as larger-scale SMES units, there are strong near-term prospects for reducing resistance losses at the converter and lowering the energy load of the refrigeration system. This will be done by using new high-temperature superconducting materials, which require only inexpensive liquid-nitrogen cooling (77 K, or −321°F). These materials will be substituted for copper in the cold-to-warm transition leads connecting the SMES coil, which operates at liquid-helium temperature (4 K, or −452°F), to the ambient-temperature power converter. □

DYNASTORE CALCULATES IDEAL DISPATCH WITH STORAGE **EPRI's DYNASTORE, a chronological production-cost simulation model, uses actual utility operating data to calculate and graphically display the daily mix of generation categories, storage generation, and sources of forced charging for a full week. (Forced charging involves energy that would have been sold below cost if storage were not available.) The software can also calculate and report the total and disaggregated benefits of energy storage, with an emphasis on dynamic benefits. DYNASTORE and two other EPRI software packages—DYNAMICS and ETMSP—can help utilities gain an in-depth understanding of system-specific SMES benefits.**



sion on whether to fund a significant SMES demonstration project.

Meanwhile, the multinational engineering giant ABB Asea Brown Boveri has built and successfully tested a 330-kVA, single-phase superconducting transformer in Sweden. ABB says the project has led to new insights about how superconductivity can be applied in ac power systems, for example as current limiters that could reduce the cost of circuit breakers. (Southern California Edison is involved in a government-funded effort in this country to develop superconducting current limiters.) In addition, ABB has investigated a project to build a small (180-MWs) SMES coil for peak shaving at the main electric rail station in Zurich, Switzerland.

In Canada, the Quebec provincial government reportedly has considered the construction and testing of a prototype (10-MW, 3-second) SMES unit on the Hydro Quebec system. Small test coils have also been built in Russia and South Korea.

EPRI continues to monitor SMES developments overseas, where an increasing share of the active development work on medium- and large-scale systems is occurring. There is agreement here and abroad that the technology for all components and subsystems of SMES is ready to be demonstrated at utility scale. A national effort to demonstrate SMES for commercial applications could help the United States retain a degree of technical leadership in superconductivity. EPRI stands ready to assist utilities in a government-industry collaborative effort to demonstrate SMES at a scale appropriate for improving utility transmission, distribution, and generation asset utilization. That would set the stage for more-cost-effective generation and delivery systems in the next century. ■

Background information for this article was provided by Steven Eckroad, Terry Peterson, and Robert Schainker, Generation Group.


Understanding

One of the most important uncertainties in the debate over the potential for climate change due to rising emissions of greenhouse gases is the question of how fast these gases will actually accumulate in the atmosphere over the next 50–100 years. Carbon dioxide, the primary greenhouse gas, is released from all fossil fuel combustion, and CO_2 emissions are increasing, particularly in developing countries as they industrialize. If these emissions remain unchecked, atmospheric CO_2 can be expected to reach a level double the preindustrial level sometime within the next century. Computer simulations conducted for the Intergovernment Panel on Climate Change (IPCC) predict that such a doubling will result in the elevation of average global temperature by about 1.5–4.5°C. Many natural processes and human activities may speed up or slow down the rate of atmospheric CO_2 accumulation, however, and the integrated effect of these processes is not yet well understood.

Of particular importance is the existence of natural "sinks" that remove CO_2 from the atmosphere. Oceans, for example, constantly exchange CO_2 with the atmosphere in both directions and now serve primarily as a net sink. As the concentration of CO_2 in the atmosphere rises, the rate at which it is taken up at the ocean surface also increases, contributing to a growing oceanic pool of inorganic carbon compounds. Photosynthesis by marine organisms converts some of this inorganic carbon to organic compounds, and a fraction of these wind up in sediments. At the moment, however, the rate of organic sedimentation is not increasing because the rate of photosynthesis in the oceans is apparently limited by a lack of other nutrients, such as phosphorus and iron.

The net influence of terrestrial ecosystems is less clear. Plants take CO_2 from the atmosphere through photosynthesis and convert it to organic compounds, but their respiration and decomposition break down these compounds again and release CO_2 back to the atmosphere. For many years, it was assumed that the overall impact of the terrestrial biosphere (the total of all land organisms) was not a major net sink. Recently, however, evidence has been discovered to indicate that some terrestrial ecosystems—particularly temperate forests—act as important but highly variable sinks for atmospheric CO_2.

To help clarify some of these uncertainties, EPRI has been conducting a long-range program of research on the global carbon cycle. An important product now emerging from this program is GLOCO, a microcomputer model that simulates

THE STORY IN BRIEF Efforts to mitigate possible climate change due to rising atmospheric concentrations of greenhouse gases focus mostly on manipulation of the global carbon cycle—the movement and storage of carbon among the world's oceans, atmosphere, and terrestrial systems. But predicting the likely effectiveness of various strategies to ameliorate global warming requires careful modeling of the complex processes that drive carbon cycling and determine atmospheric levels of carbon dioxide, and some of these processes are still not well understood. A new EPRI microcomputer model called GLOCO simulates many of the processes and can be used to perform quick "what if" strategy analyses. In addition, ongoing field studies are providing important new insights into the uptake of atmospheric carbon by forest and grassland ecosystems. Efforts are also under way to develop a much more complex computer program that can model the global carbon cycle with reference to specific geographic patterns.

the Global Carbon Cycle

by John Douglas

many of the processes involved in controlling atmospheric CO_2 concentrations and that can be used to perform quick "what if" strategy analyses. In addition, basic research on specific ecosystem responses to elevated CO_2 levels is beginning to resolve some of the puzzles about terrestrial sinks. Finally, a major new modeling project will develop a state-of-the-art analytical tool that can provide specific estimates of the location and magnitude of carbon sinks.

EPRI's carbon cycle studies are an integral part of its climate change research program, the overarching goal of which is to help policymakers understand the costs and impacts of climate change management proposals. At the present time, uncertainties surrounding the carbon cycle present a key obstacle to providing a consistent and comprehensive perspective on this issue. The research described in this article will provide essential tools and information for forthcoming integrated assessments.

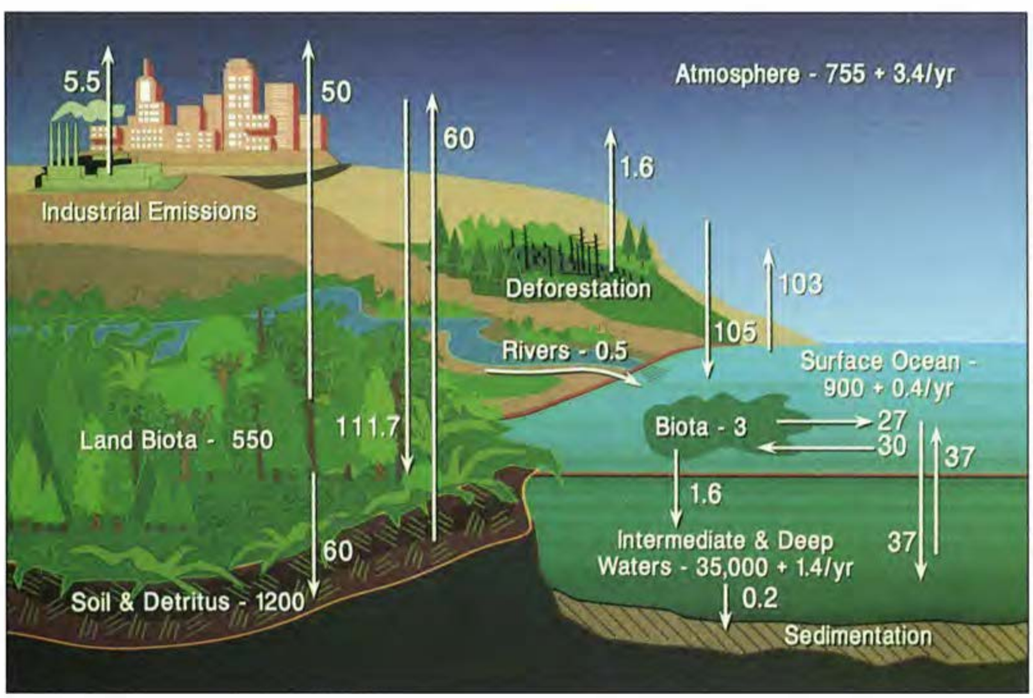
Focus on feedback

As the amount of CO_2 in the atmosphere rises in response to increases in human activities, many natural processes may act as feedback mechanisms that affect the accumulation rate. Laboratory experiments have shown, for example, that a greater availability of CO_2 can enhance terrestrial plant photosynthesis, thus increasing the rate at which the plants remove CO_2 from the atmosphere. Whether such a fertilization effect takes place over long time periods in natural ecosystems, however, remains unclear. Other natural processes may instead provide positive feedback; that is, they may accelerate the buildup of atmospheric CO_2. As global temperatures rise, for example, some forest areas may experience dieback—emitting more CO_2 through decomposition of soil organic matter and thus reinforcing the greenhouse effect. On the other hand, rising temperatures can increase decomposition, hence increasing available nitrogen for terrestrial plants and accelerating plant growth and the sequestration of carbon. Determining the net effect of such conflicting processes will require additional experimental work and careful modeling to understand the interactions.

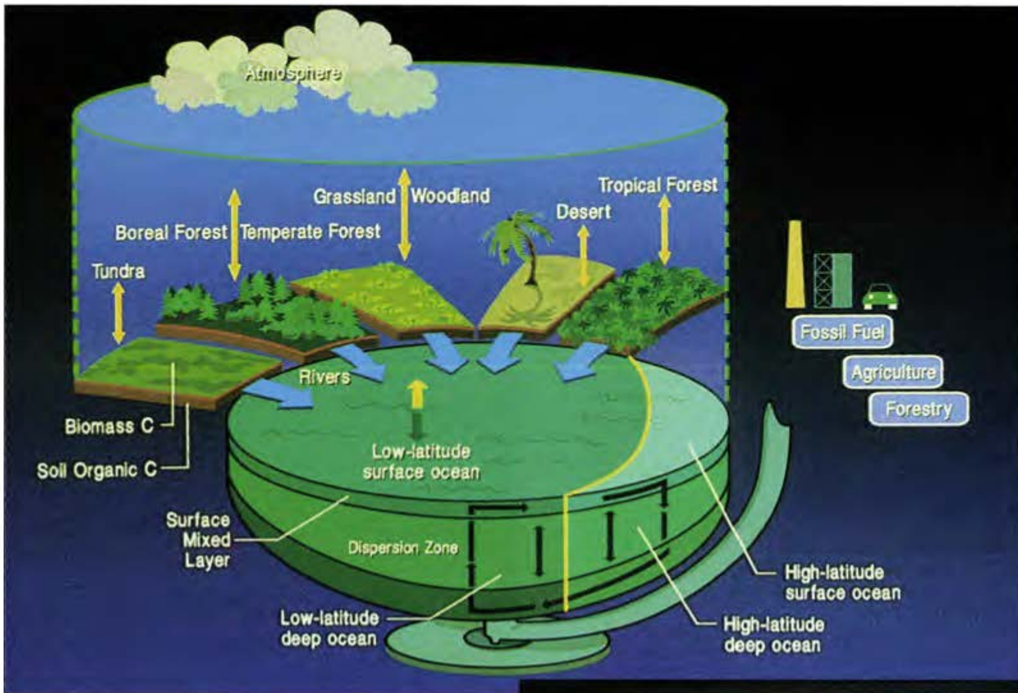
In order to estimate the effectiveness of various mitigation strategies—such as halting tropical deforestation—policymakers need a model that focuses on the interaction of the various processes that can affect the global carbon cycle as a whole. Initially, such a model would not need to show in fine resolution how the effects vary spatially. GLOCO fulfills these requirements by simulating carbon cycle processes in considerable detail but for a greatly simplified spatial world. The model divides the earth into a few physical compartments: one atmosphere, seven natural terrestrial biomes, and two oceans (which are further compartmentalized by depth). Major biological, chemical, and physical processes are specified for each compartment. The model simulates the resulting carbon fluxes from one compartment to another, as well as the redistribution of carbon among the chemical species and biological components within the compartments. It also simulates four human activities: fossil fuel combustion, agriculture, forestry, and land use changes.

Only total areas, not geographic locations, are specified for each of the terrestrial biomes—tropical forest, temperate forest, boreal forest, woodland, grassland, tundra, and desert. The two oceans, low latitude and high latitude, interact in a way that simulates global ocean circulation. Temperatures related to climate change can be specified for each biome and for the ocean surfaces as a function of atmospheric CO_2 and a characteristic lag time. Alternatively, specific temperature scenarios can be defined. Process rates in the model are temperature dependent.

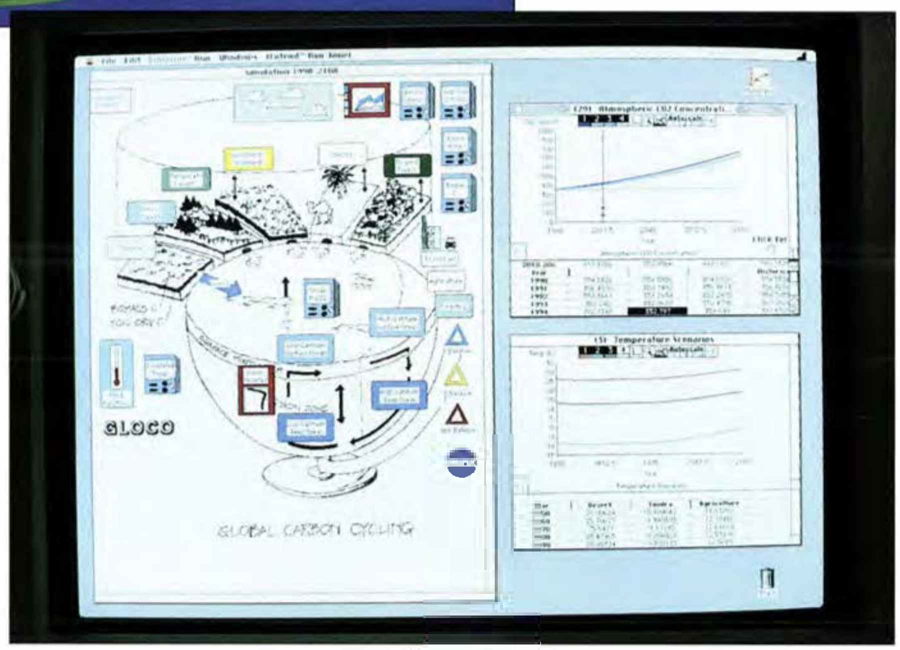
Developed for EPRI by Tetra Tech of



FLUXES AND RESERVOIRS Carbon is continuously transferred back and forth between the atmosphere, the oceans, and terrestrial ecosystems. This snapshot of the global carbon cycle shows the size of carbon reservoirs and the annual carbon fluxes between them in metric gigatons (10^{12} kilograms). Fossil fuel combustion represents less than 3% of the total annual flux of carbon to the atmosphere. (Adapted from Moore and Braswell, 1994.)



GLOBAL CARBON CYCLE MODEL **GLOCO is a new microcomputer model that simulates many of the processes involved in the global carbon cycle. The model greatly simplifies the real world by aggregating the earth into a dozen discrete physical compartments: one for the atmosphere, seven for natural terrestrial biomes, and four for oceans. The model simulates net carbon fluxes from one compartment to another under various assumptions about natural processes and human activities.**



Lafayette, California, GLOCO has been designed as an easy-to-use Macintosh computer program capable of integrating current information about the global carbon cycle. In addition to analyzing policy alternatives, it can be used to plan experimental research by testing scientific hypotheses and identifying parameters that require more-precise measurement. GLOCO is available from EPRI's Electric Power Software Center.

The missing sink

One of the most important early applications of GLOCO has been to suggest a possible solution to the problem known among researchers as the missing carbon sink. Worldwide fossil fuel emissions of carbon are known to be approximately 5.5 ± 0.5 metric gigatons per year. (A gigaton, or Gt, equals 10^{12} kilograms.) The rate of increase of atmospheric carbon has been carefully measured at 3.4 ± 0.2 Gt/yr. Therefore, terrestrial and oceanic sinks must be absorbing carbon at about 2.1 Gt/yr. But measurements of carbon uptake by these systems are less certain, and attempts to reconcile them have produced a puzzling result.

Analysis of sea surface data and modeling indicate that the net oceanic uptake of carbon from the atmosphere is 2.0 ± 0.8 Gt/yr. This would imply that the terrestrial biosphere is about neutral as a net source or sink. But the terrestrial biosphere also is an important *source* of CO_2 emissions—from land use change and tropical deforestation. This source is estimated to be 1.1 ± 1.2 Gt/yr. To counterbalance these emissions and account for the carbon not being taken up by the oceans, there would have to be an unexplained terrestrial sink roughly half as large as the oceanic one. Today's best estimate of the size of this missing sink is 1.2 ± 1.6 Gt/yr of carbon uptake.

Working under EPRI sponsorship, Robert Hudson of the Institute of Marine Sciences at the University of California, Santa Cruz, and Steven Gherini of Tetra Tech have used GLOCO to try to explain this missing sink in terms of increased terrestrial carbon sequestration resulting from fertilization effects in the terrestrial biosphere. Previous attempts to explore this possibility have focused primarily on the fertilization effect of increased atmospheric CO_2, which is known to stimulate photosynthesis and enhance water use efficiency in plants. The EPRI researchers, on the other hand, examined the effect of simultaneous increases in CO_2, temperature, and nitrogen deposition from the atmosphere.

In preindustrial times, most nitrogen deposition resulted from the conversion of elemental nitrogen in the atmosphere by lightning. Since then, nitrogen deposition rates have increased some fivefold, primarily because of emissions of NO_x (nitrogen oxides) and NH_3 (ammonia) from human activity. By modeling net terrestrial CO_2 emissions (and uptake) from 1850 through 1985, the researchers found that the combined fertilization effect of increases in CO_2, temperature, and nitrogen could, indeed, account for the missing sink within the limits of measurement uncertainty. They also found that 40–70% of the total fertilization could have been the consequence of rising nitrogen emissions from human sources.

"This is an important hypothesis that will have to be taken into account in future modeling work," says Robert Goldstein, EPRI manager for GLOCO research. "We also have to consider the effect of future changes in nitrogen fertilization on the terrestrial carbon sink. On the one hand, tighter NO_x emissions controls in today's industrialized countries should reduce the growth of nitrogen deposition from the atmosphere in the North Temperate Zone. On the other hand, nitrogen emissions are likely to grow at an increasing rate among developing countries, many of which are in the Tropics or farther south. Also, increasing temperatures due to climate change could accelerate the release of nitrogen from decomposition of plant matter in the soil. The combined effect of these changes on overall terrestrial carbon uptake will have to be considered carefully."

Insights from field studies

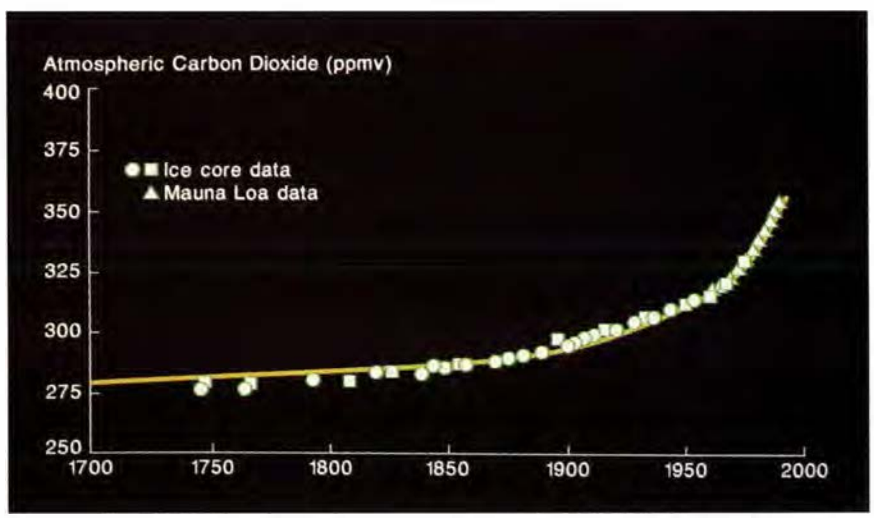
Further evidence of the importance of terrestrial biosphere fertilization in accounting for the uptake of CO_2 from the atmosphere is provided by ongoing EPRI studies of forest and grassland ecosystems. In particular, these field and laboratory studies support the hypothesis, raised by GLOCO modeling, that ecosystem responses to rising atmospheric CO_2 levels depend significantly on the amount of nitrogen available.

Two organizations have almost completed forest response experiments funded jointly by EPRI and Southern California Edison Company. The Desert Research Institute in Nevada is concentrating on ponderosa pines, which grow in relatively dry western soils that often experience nitrogen deficiencies. Duke University in North Carolina is focusing on loblolly pines, which inhabit relatively moist soils that also sometimes lack nitrogen. Experiments are being conducted both in greenhouses with controlled atmospheres and at representative field sites.

Initial results from these experiments indicate that both tree species require sufficient nitrogen in order to show accelerated growth in response to elevated CO_2. In the slower-growing ponderosa pines, the results were particularly interesting. At 700 ppm CO_2, growth was stimulated at all three nitrogen levels, but the relative degree of stimulation was greater when nitrogen was more abundant. At 525 ppm CO_2, there was virtually no stimulation of growth regardless of the nitrogen level, suggesting a complex and not completely understood relationship among the variables.

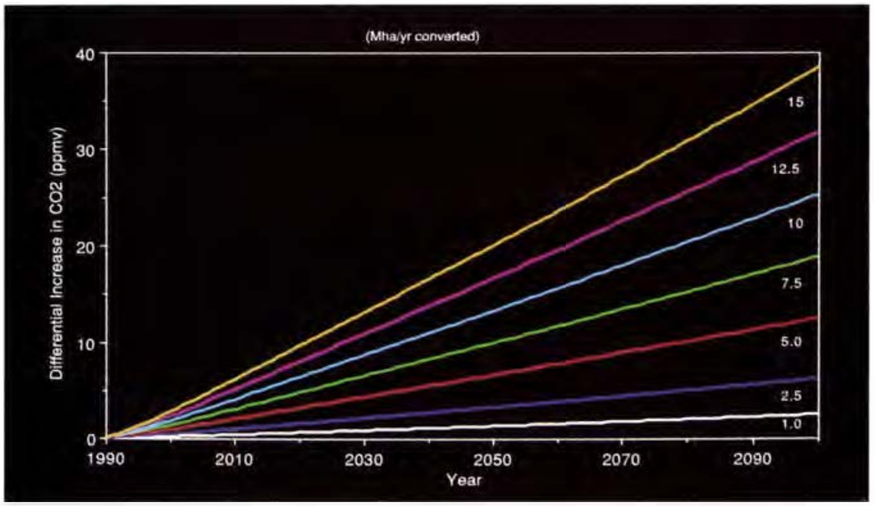
EPRI studies of carbon sequestration in grasslands are being conducted at the Commonwealth Scientific and Industrial Research Organization in Canberra, Australia. Results so far tend to confirm the conclusions reached in forest studies. Greenhouse experiments with controlled atmospheres indicate that elevated CO_2 levels cause grass to accumulate about 50% more carbon when high levels of nitrogen are available; the experiments show reduced stimulation by CO_2 when the nitrogen supply is insufficient. There is a suggestion that the rate of carbon storage may decline with time, however, so the long-term effect of elevated atmospheric CO_2 on the grassland biome remains unclear.

A different approach to trying to identify the nature and magnitude of the missing carbon sink in the terrestrial biosphere has been undertaken by Science and Policy Associates (SPA) of Washington, D.C., with funding from EPRI, the U.S. Environmental Protection Agency, and Forestry Canada. Initial results from the SPA study support the hypothesis that accelerated tree growth (possibly resulting in part from the fertilization effect) and improved control of forest fires are important driving forces behind increased carbon uptake by the terrestrial biosphere. They also show that the uptake rate is highly variable and closely linked to changes in temperate and boreal forests.



RIGHT ON TARGET The GLOCO simulation of historical atmospheric CO_2 concentrations (curve) closely matches atmospheric measurements (Mauna Loa data) and the levels found in air extracted from Antarctic ice.

SIMULATING GLOBAL EFFECTS GLOCO allows modelers to run quick "what if" projections of the long-term effects of a wide variety of scenarios. In this case, the effect on atmospheric CO_2 levels of converting tropical forests to agricultural use is calculated for seven specific conversion rates.



Of particular concern is the observed dieback of hardwood forests in several northern temperate regions around the world, including the United States and Canada. The SPA researchers conclude that this phenomenon is caused primarily by freezing and moisture fluctuations resulting from current climate changes, including a recent sharp increase in average temperature in some of the regions under study. (Climatic periods marked by rising *average* temperature are often accompanied by greater temperature *variability*, including more-extreme winter and spring conditions that can damage trees.) In the past this dieback was blamed by some on acidic deposition, but climatic stress is now thought to be the more likely cause. A disturbing side effect of the dieback is that it creates more CO_2 emissions because of decomposition and increased susceptibility to fire—reducing the effectiveness of forests as a carbon sink and thus potentially reinforcing the climate change.

If this hypothesis stands up to further testing, more species that are resistant to freezing and drought stress may have to be introduced into the affected forests, and replanting schedules may have to be revised to alter forest mean-age structures. "It is possible that forest dieback is closely linked to global climate change and is now a significant and increasing source of CO_2 in the atmosphere," says SPA researcher Allan Auclair. "If this is so, forest policy will be required to minimize the risk of further serious dieback. Mitigation programs designed to abate acidic deposition as a means of reducing the dieback risk are likely to be minimally effective or ineffective."

"The ecosystem response and forest dieback studies we've conducted support the idea that terrestrial ecosystems can be either sources or sinks for atmospheric carbon, depending on factors such as nitrogen availability, climatic stress, and forest condition," says the EPRI manager for these studies, Louis Pitelka. "Several factors—including increasing nitrogen deposition from the atmosphere—may be reinforcing the uptake of atmospheric CO_2 by plants and might have to be taken into account during the development of climate management strategies."

Management strategies

Most suggestions for mitigating potential climate change focus on regulating the global carbon cycle—specifically by reducing CO_2 emissions and enhancing the activity of natural sinks. In order to compare the potential effectiveness of such diverse management strategies, GLOCO is being used to analyze the response of various components of the carbon cycle to changing human activity. Some recent examples include studies of land conversion for agriculture, the enhancement of CO_2 uptake by high-latitude oceans, and the response of ocean circulation to rising atmospheric CO_2 levels.

With human populations worldwide still growing, the conversion of natural ecosystems to agricultural uses shows no sign of abatement. The GLOCO analysis revealed, however, that the response of the atmosphere to such conversion varies widely among the different types of ecosystems involved. For example, the conversion of temperate or boreal forest to agricultural use releases about twice as much CO_2 to the atmosphere as the conversion of an equal area of tropical forest and more than four times as much as the conversion of an equal area of grassland. The implication is that when more agricultural land is needed to support an increasing population, grassland should be used preferentially, assuming that adequate water resources are available.

Conversely, the reconversion of agricultural land to natural ecosystems as a strategy for reducing the atmospheric buildup of CO_2 would be most effective in areas that would revert to temperate or boreal forest. Such reforestation would have a longer time lag in recapturing the carbon, however, compared with reconversion to tropical forest or grassland. In any case, it takes considerably longer to recapture carbon through reconversion to a natural ecosystem than to release carbon initially through the transition to agriculture.

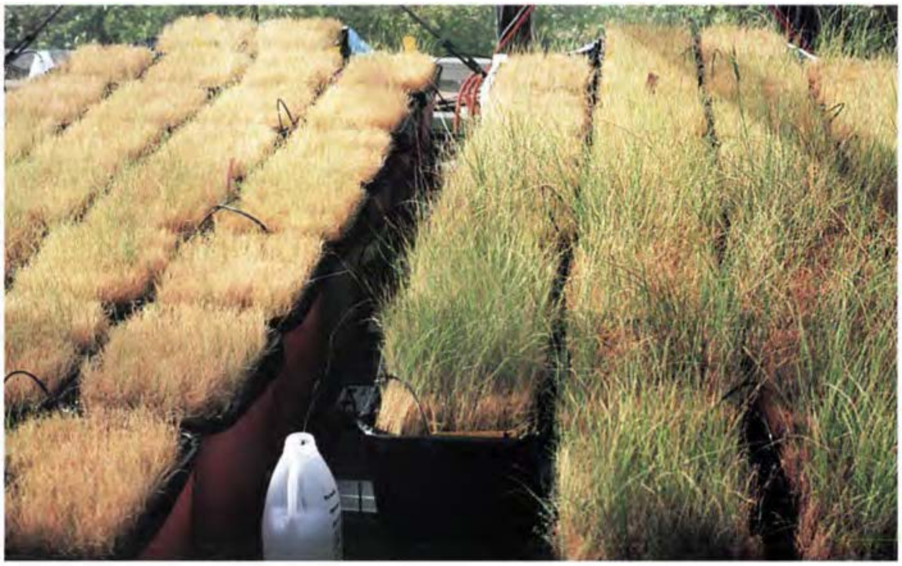
Management strategies based on changing land use patterns must also take into account the relative magnitude of existing agricultural conversion activities around the world. About 8.5 million hectares (Mha)—or 21 million acres, an area about the size of Maine—of tropical forest are now being cut annually for agriculture, releasing some 0.7 Gt of carbon a year to the atmosphere. This amount is equivalent to about 12% of the 5.5 Gt of CO_2 now emitted from fossil fuel combustion each year. For comparison, about 1.0 Mha (2.5 million acres) of temperate forest are converted each year, emitting 0.17 Gt/yr of carbon, or the equivalent of 3% of the fossil fuel emissions. According to GLOCO simulations, immediately halting tropical deforestation would reduce the atmospheric concentration of CO_2 by only about 4% from its expected level in the year 2100, under the so-called business-as-usual scenario projected by the IPCC.

A somewhat larger effect might be achieved by trying to stimulate greater CO_2 uptake by the oceans' "biological pump." Carbon fixation through photosynthesis by oceanic organisms in the midlatitudes has been hypothesized to be limited at the present time by the supply of iron, a trace nutrient. Fertilization of these oceans with iron has thus been proposed as a means of reducing future increases in atmospheric carbon. GLOCO simulation of this management strategy, using the IPCC business-as-usual scenario, indicates that ocean fertilization would reduce the projected CO_2 concentration for the year 2100 by about 10%.

Another concern for policymakers is the possible effect of rising atmospheric CO_2 levels on ocean circulation. GLOCO uses a net upwelling velocity parameter to approximate this circulation. An increase in upwelling would drive circulation at a faster rate, presumably stimulating greater surface exchange of gases with the atmosphere and thus increasing CO_2 uptake. When the sensitivity of this process to changes in upwelling was tested by GLOCO simulation, however, even a doubling of the upwelling term had only a small effect on the oceanic uptake of atmospheric carbon.

Toward a comprehensive model

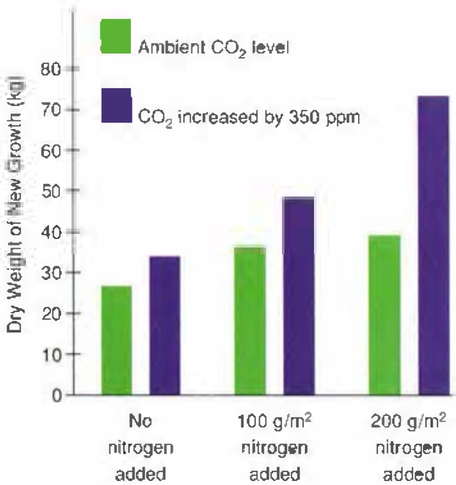
The complexity of the carbon cycle and of resolving uncertainties about important sources and sinks clearly requires a multipronged strategy involving experimentation, observation, and modeling. No single model is likely to meet all needs. GLO-



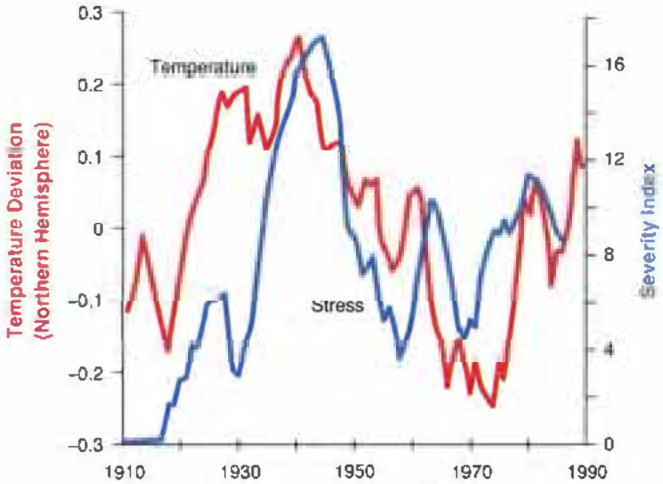
Australian grassland studies

Growing ponderosa pine in central California

CO_2, NITROGEN, AND PLANT GROWTH
Higher levels of atmospheric CO_2 and nitrogen may accelerate terrestrial plant growth, thereby increasing sequestration of carbon through so-called fertilization effects. Field and laboratory studies in the United States and Australia are under way to test this hypothesis for forests and grasslands. The early results for ponderosa pine, shown here, support the idea that ecosystem responses to rising levels of atmospheric CO_2 may depend significantly on nitrogen availability.



CLIMATE AND FOREST DIEBACK Dieback of hardwood forests in northern temperate regions was originally hypothesized to have been caused by acid rain, but new evidence points to a broader climate change hypothesis. Specifically, the more extreme seasonal temperature and moisture variability that accompanies periods of rapid global warming may cause increased plant stress, represented by a severity index. The stress trend shown here for sugar maple, birch, and ash follows global temperature deviation reasonably closely.



CO concentrates on modeling carbon cycle processes without reference to highly resolved spatial location. Its advantages include speed and ease of use. But there is also a need for models that are highly resolved, both spatially and temporally.

Over the past decade, an extensive network of observation stations has been established that routinely measures the concentrations of carbon compounds in the atmosphere, including the ratios of their isotopes ($^{13}C/^{12}C$ and $^{14}C/^{12}C$). When compared with the spatially and temporally explicit predictions of a highly resolved model, these data permit a much more stringent validation of the model and improve our understanding. A geographically resolved carbon cycle model could also identify specific sources and sinks for consideration by policymakers and provide a guide for where to concentrate further scientific research and measurement efforts. Finally, such models eventually will be linked with the large, complex computer programs called general circulation models (GCMs) that are used to project how climate will respond to increasing levels of greenhouse gases.

EPRI has just launched a new research effort to accelerate and facilitate the development of a comprehensive carbon cycle model (CCCM) of this sort over the next five years. The project takes advantage of the fact that the United States and other governments are already funding the development of components of global carbon cycle models. The EPRI Carbon Cycle Model Linkage Project is being conducted by research teams at six universities and institutes in four countries, headed by the Max Planck Institute for Meteorology in Hamburg. The final model will consist of coupled, interactive models of the oceans, atmosphere, and terrestrial biosphere carbon pools. It will run on supercomputers and will provide a high-resolution global representation of carbon chemistry, transport, and exchange. The goal of EPRI funding in this effort is to serve as a catalyst to encourage the timely development of an integrated model.

A critical step in the development process will be to validate the geographically disaggregated model by using new data about the carbon cycle that are now becoming available. Infrared and radar images from satellites, for example, will be used to determine the distribution and changes in biomass and foliage cover of terrestrial vegetation. CCCM will also be used to make more spatially detailed simulations than are possible with GLOCO about the impact on the global carbon cycle of fossil fuel emissions, deforestation, and land use conversion.

"GLOCO and CCCM are complementary models that should ultimately provide results that are in agreement," says Robert Goldstein. "The big difference is that a century-long simulation on GLOCO takes a few minutes on a desktop computer, while a similar run on CCCM will probably require many hours on a supercomputer. That means GLOCO will remain the first choice for testing numerous management strategies and research hypotheses before examining the most promising ones in more detail."

Louis Pitelka adds: "CCCM will be very important to climate modelers and carbon cycle researchers. Now, GCMs must simply assume a scenario for carbon in the atmosphere; the new model will allow for GCMs to be dynamically linked with a carbon cycle model, allowing for feedbacks between carbon cycling and climate change. CCCM will also help scientists test their understanding of the global carbon cycle and will thus also serve as a validation for simpler models and response functions that will be used by policymakers to evaluate management strategies."

"It is very difficult to evaluate the impacts of CO_2 management proposals without a better understanding of the relationship between emissions and atmospheric concentrations," says EPRI's Richard Richels. "This research will contribute significantly to our ability to provide a balanced perspective on this issue." ■

Further reading

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Background information for this article was provided by Robert Goldstein and Louis Pitelka, Strategic Development Group.


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GOLDSTEIN


PITELKA

Worldwide Activity in IGCC (page 6) was written by Leslie Lamarre, *Journal* senior feature writer, with guidance from **Neville Holt** of the Generation Group. Holt, who manages EPRI's IGCC research, came to the Institute in 1974. Before that, he was with Cities Service Company for four years, first as a senior research engineer and then as manager of synthetic fuels. Holt has BA and MA degrees in chemistry from Cambridge University. ■

The Energy-Efficient Office (page 16) was written by science writer John Douglas, with technical information provided by **Morton Blatt** of the Customer Systems Group. Blatt, who manages EPRI's Residential and Small Commercial business unit, joined the Institute in 1985. Earlier he was manager of end-use efficiency programs at Science Applications International Corporation. Blatt received a bachelor's degree in mechanical engineering from Cooper Union, an MS in industrial engineering from New York University, and an MS in business administration from San Diego State University. ■

Storing Megawatthours With SMES (page 24) was written by Taylor Moore, *Journal* senior feature writer, with assistance from three members of the Generation Group.

Robert Schainker has overseen energy storage research since 1985. He joined EPRI in 1978, after nine years as an engineer and program manager with Systems Control. Schainker received a BS in mechanical engineering, an MS in electrical engineering, and a PhD in applied mathematics, all from Washington University in St. Louis.

Steven Eckroad manages research in battery and SMES technology. He joined EPRI in 1992 after two years as a private consultant in the utility industry in the area of battery energy storage systems. From 1979 to 1990, Eckroad was an engineer at Bechtel Group, where he worked on battery storage demonstrations and other energy storage projects. He received a BA in physics from Antioch College and did postgraduate study in electrical engineering at the University of Missouri at Rolla.

Terry Peterson manages work in thin-film photovoltaics as well as SMES. Before joining EPRI in 1986, he spent eight years at Chevron Research Company, where he was involved in catalyst and solar cell research. Peterson holds a BS in physics from the University of California at San Diego, as well as an MA in physics and a PhD in materials science and engineering from the University of California at Berkeley. ■

Understanding the Global Carbon Cycle (page 34) was written by science writer John Douglas, with technical information from two members of EPRI's Strategic Development Group.

Robert Goldstein, manager of environmental risk analysis, has been with the Institute since 1975, primarily focusing on atmospheric deposition effects, forest stress, and genetic ecology. Goldstein previously worked for more than five years as a systems ecologist at Oak Ridge National Laboratory. He has a BS in engineering and MS and PhD degrees in nuclear science and engineering from Columbia University.

Louis Pitelka, manager of biochemistry research, has overseen a wide range of projects concerning the effects of air pollution and climate change on terrestrial ecosystems. Before coming to EPRI in 1984, he was director of the National Science Foundation's program on population biology and physiological ecology. Pitelka received a BS in zoology from the University of California at Davis and a PhD in biological sciences from Stanford University. ■

Toledo Edison Validates Demineralizer Operation at High Temperatures

In pressurized water reactors with once-through steam generators, moisture separator drains have a higher concentration of corrosive ions like sodium, chloride, and sulfate than do most other points in the secondary coolant loop. The higher ionic concentration means that a demineralizer could operate with far greater efficiency there than elsewhere in the loop. But utilities have seldom placed a demineralizer at that point because the higher temperatures decrease the useful life of the demineralizer resin typically employed.

A recent EPRI project has shown that the reduction in resin life is not so great as to make moisture separator drain demineralizer (MSDD) operation impractical. In fact, the disadvantage of shorter demineralizer resin life is offset by large increases in the useful life of condensate polisher resins and significant increases in thermal efficiency with MSDD operation.

Toledo Edison Company, a subsidiary of Centerior Energy Corporation, wanted to validate MSDD operation at elevated temperatures at its Davis-Besse nuclear plant. To be able to implement MSDD operation at times when the economic benefit would be significant, however, it was necessary to have an accurate, sensitive, and reliable on-line analytical system for monitoring coolant chemistry. The utility installed such a system at its own expense, and EPRI provided the technology and operating funds to validate high-temperature resin operation.

Resin suppliers specify a temperature limit for commercial applications. Higher temperatures may cause resin degradation. Toledo Edison determined in the tests cosponsored with EPRI that resin beds effectively removed impurities for reasonably long periods without loss of performance when the MSDDs were operated at up to 265°F. Thus it was possible to return water from the moisture separator drains directly to the feedwater heaters. This reduced the ionic burden on the plant's main condensate polishers by a factor of 6 or more, improving plant efficiency by about 5.42 MW as well as reducing costs for resin and radioactive waste disposal.

The improved plant heat recovery that resulted from this work translated into an increase in overall plant efficiency valued by Toledo Edison at approximately $900,000 a year. Savings from less-frequent resin replacement in the condensate polishers are estimated at $450,000 a year. Toledo Edison estimates that the total savings from applying this technology at Davis-Besse over the next 10 years will amount to $11 million.

■ *For more information, contact Tom Passell, (415) 855-2070.*

Clean Air Requirements

Study to Assess Emissions Trading

As electric utilities with coal-fired power plants are well aware, the big date is approaching. On January 1, 1995, the first coal plants subject to regulations stemming from the 1990 Clean Air Act Amendments must comply with the new sulfur dioxide limits set by the amendments. The biggest unknown is how well the emissions allowances market will work in reducing compliance costs.

Under the new law, utilities are allotted allowances equal to the number of tons of SO_2 they are allowed to release annually. In complying with the law's more-stringent SO_2 limits, utilities have many choices, including installing emissions control technologies, switching to a lower-sulfur fuel, or buying emissions allowances from another utility. A utility with more allowances than emissions may sell the extra allowances or bank them for future use.

The emissions trading concept is not new; it has already been used on a regional basis for SO_2, nitrogen oxides, and particulate emissions. But the 1990 Clean Air Act Amendments have created the first national market for emissions allowances. And utility industry analysts are eager to see how things play out.

EPRI has launched an in-depth study of the SO_2 emissions trading program and the utility industry's experience with it. The intent is to evaluate how well the program is working and to use that insight to assess the potential for applying emissions trading strategies in the control of other emissions, such as nitrogen oxides, on a national basis. Another goal is to improve the SO_2 emissions trading program over the long term.

"We'd like to be able to apply the lessons learned through this first nationwide experience with emissions trading," says EPRI's Gordon Hester, who is managing the study. The study will examine various factors—including public utility commissions' treatment of the trading, which can affect incentives for utilities to pursue different compliance strategies. Information on the utility experience will be available for regulators to consider in their oversight of current and future emissions trading. Hester notes that the study will also compare the emissions control approach of the Clean Air Act Amendments with a more traditional command-and-control approach in terms of cost and effectiveness.

National Economic Research Associates, the firm conducting the study, plans to release its first report late in 1995 and a second report late in 1996.

■ *For more information, contact Gordon Hester, (415) 855-2696.*

Process Industries

EPRI Sees Big Potential in Electroseparation

Not long ago, the best means available for cleaning up a site contaminated by metal spills was simply to excavate the dirty soil—a labor-intensive and costly task. But researchers in the United States and Europe are developing a more efficient and effective technique called electrokinetic soil remediation. In this approach, probes are inserted into the ground and electrified. The resulting current dissolves the metal species and moves them through the ground to an area where they can be extracted.

Electrokinetic remediation, which is still being tested on a pilot scale, is just one type of electroseparation process that EPRI is reviewing in a recently initiated scoping study. Other potential applications exist in a variety of process industries. For instance, in the production of dry foods, electroseparation could be used to remove moisture from various food products. In the chemical and mining industries, electroseparation could be used to separate solvents from chemicals or minerals. The intent of the scoping study, being conducted by Oak Ridge National Laboratory, is to survey the established and emerging opportunities in electroseparation to determine where EPRI should focus its research efforts.

"Electroseparation processes offer a very positive role for electricity to play," says Ammi Amarnath of EPRI, who is managing the project. "When substituted for conventional techniques, electroseparation can offer a significant reduction in energy use and dramatic savings in capital costs."

According to Charles Byers, the Oak Ridge scientist heading up the investigation for EPRI, conventional separation and purification processes consume more than 4 quads of energy annually, primarily through either boiling or agitation to remove and recycle liquids. This is more than 4% of the total energy consumed in the United States.

One application under review by Oak Ridge is solvent extraction. Conventional means of solvent extraction involve the agitation of solutions in tanks about 10 times larger than the units currently being developed for electroseparation. The smaller units not only offer significantly reduced capital costs and space requirements but can be activated more quickly. "When we use a pulsed electric field instead of the conventional techniques, we increase the efficiency by easily an order of magnitude," Byers says. He notes that electroseparation processes can also help alleviate difficulties process industries may encounter in trying to meet environmental regulations on their waste streams.

The scoping study is expected to be completed by the end of the year. In the meantime, Byers is also helping EPRI establish collaborative alliances with other groups that are performing electroseparation research, including the National Science Foundation and the Department of Energy.

■ *For more information, contact Ammi Amarnath, (415) 855-2548.*

Right-of-Way Management

Researchers Developing Smaller Trees for Utility Use

Trees are certainly an attractive sight along many rights-of-way. But utility personnel are all too familiar with the constant battle of keeping tall vegetation from interfering with overhead power lines. According to one estimate, the industry spends about $1.5 billion annually on tree trimming and herbicide application.

EPRI-sponsored researchers with the Center for the Development of Hardy Landscape Plants, headquartered at the University of Minnesota, believe there's a better way. The researchers, headed by Harold Pellett, a professor at the university and the coordinator of the center, recently initiated a project to develop small, tough tree species that utilities can plant along rights-of-way to keep taller growth at bay. Not only would this tack offer a more environmentally benign method for tall-vegetation control (it would significantly reduce the need for herbicide application), but it is also expected to cost significantly less than current methods.

Pellett says that the EPRI-sponsored research builds on the work already under way at the center, which involves scientists at 80 institutions across the United States, Canada, and northern Europe. Among the tree varieties that the researchers are currently breeding for utility use are ornamental pear and a variety of maple. Pellett says that these species can survive in most climates of the United States. And because of their attractiveness, they are promising candidates for use on residential streets. According to Pellett,

some utilities already have programs that offer such trees to residential customers as replacements for tall, old trees that can brush up against power lines.

To the non-tree expert, it might seem that an ample stock of smaller trees is already available for such application. However, as Pellett points out, many of these varieties are susceptible to disease and drought. Also, the growth range of these species is not always predictable. Researchers at the center are using hybridization techniques to breed smaller trees that can stand up to insect attacks and disease as well as stressful weather conditions. This work will also result in a wider variety of species from which to choose.

EPRI has committed four years' worth of funding to the small-tree project, which got under way last January. As Lou Pitelka, who is managing the project for EPRI, explains, breeding is a long-term process. "It takes a lot of time and effort to get the kind of attributes you want," he says.

■ *For more information, contact Lou Pitelka, (415) 855-2969.*

Fossil Plant Air Quality Control

Developing Mercury Removal Methods for Power Plants

by Ramsay Chang and David Owens, Generation Group

Trace substance emissions in utility power plant flue gas have increased in importance since the passage of the Clean Air Act Amendments (CAAA) of 1990, which mandate the Environmental Protection Agency to conduct a three-year study of public health hazards that could be attributed to emissions from fossil-fuel-fired power plants. The EPA is directed to regulate the utility industry for air toxics if its three-year study indicates that such regulation is necessary and appropriate. Three other studies mandated by the CAAA—one assessing the environmental health and water quality effects of air toxics on the Great Lakes and coastal waters, and two involving the health and environmental impacts of mercury emissions—could also affect power plants.

EPRI, anticipating the increased scrutiny of trace substance emissions, is conducting an extensive program to address these issues. One aspect of this program is the assessment and development of effective control alternatives. An EPRI search of the literature on utility emissions has shown that 37 of the 189 substances listed by the CAAA as hazardous air pollutants have been detected in power plant flue gas. Of these 37 substances, 11 are trace metal species. Trace metals in flue gas are normally condensed on fly ash particles and can be removed effectively by an efficient particulate collector. Mercury seems to be the most difficult trace metal to collect, since it is present mainly in vapor form and tends to pass through particulate control devices like baghouses and electrostatic precipitators (ESPs).

Several methods of mercury control are being used at waste incineration plants, especially in Europe. Mercury concentrations in flue gas from utility boilers, however, are several orders of magnitude lower than those in flue gas from waste incineration plants—1 to 10 versus 50 to 500 micrograms per standard cubic meter ($\mu g/m^3$). Thus it is uncertain whether any of these methods would be effective for power plant applications and what the cost implications would be. It is also uncertain how much mercury, if any, must be removed from utility flue gas. Compounding these difficulties is the lack of validated methods for measuring the low concentrations of mercury in utility flue gas and for distinguishing the different species of mercury present. While substantial advances have recently been made in mercury measurement methods, the accuracy of concentration and speciation measurements is still highly uncertain.

As far as can be determined by using current measurement techniques, the mercury species present in utility flue gas appear to be highly variable and to be dependent on coal type, flue gas composition and temperature, and boiler operating conditions. This variability is illustrated in Figure 1, which shows flue gas mercury concentrations for two coal types as measured in a laboratory combustor. Vapor-phase mercury was found to be present mainly as elemental or oxidized species. The two coals, a low-sulfur subbituminous coal and a high-sulfur bituminous one, produced quite different mercury species results. For the subbituminous coal, significant amounts of mercury were condensed on the fly ash particles at low temperatures. For both coals, the levels of mercury species appeared to vary with flue gas temperature.

The development work to date on mercury control technologies has found mercury removal effectiveness to be strongly dependent on the mercury species present. Some initial results on two of the mercury removal technologies assessed, activated-carbon injection and wet scrubbing, are discussed here.

Activated-carbon injection

The direct injection of activated carbon into the flue gas stream of a utility boiler has

ABSTRACT *The ability to remove mercury from power plant flue gas may be an issue in light of the 1990 Clean Air Act Amendments' requirement that the EPA assess health risks associated with trace substance emissions. Two approaches currently being tested are the direct injection of activated carbon into flue gas and the use of wet scrubbing. Pilot results to date suggest that both approaches hold promise for mercury removal, although significant work must be completed to determine if they are applicable under the wide range of flue gas conditions encountered in fossil-fuel-fired power plants, as well as to assess their cost to the utility industry.*

been proposed as a relatively simple approach for controlling mercury, since the carbon can be collected in the existing particulate control device. This method has been evaluated fairly extensively for waste incinerators and has been found to be capable of high mercury removal efficiencies. Because power plant flue gas has such low levels of mercury, however, and because it differs significantly from incineration plant flue gas in composition and is believed to differ in mercury speciation, the effectiveness of activated-carbon injection for mercury removal at power plants is uncertain.

Activated-carbon injection was initially assessed in tests at a 1-MWe transportable pulse-jet baghouse at Public Service Company of Colorado's (PSCCO's) Comanche station and in tests at a pilot facility at the Energy and Environmental Research Center (EERC) in North Dakota. Tests were run with various amounts of carbon, with various coals, and at various temperatures.

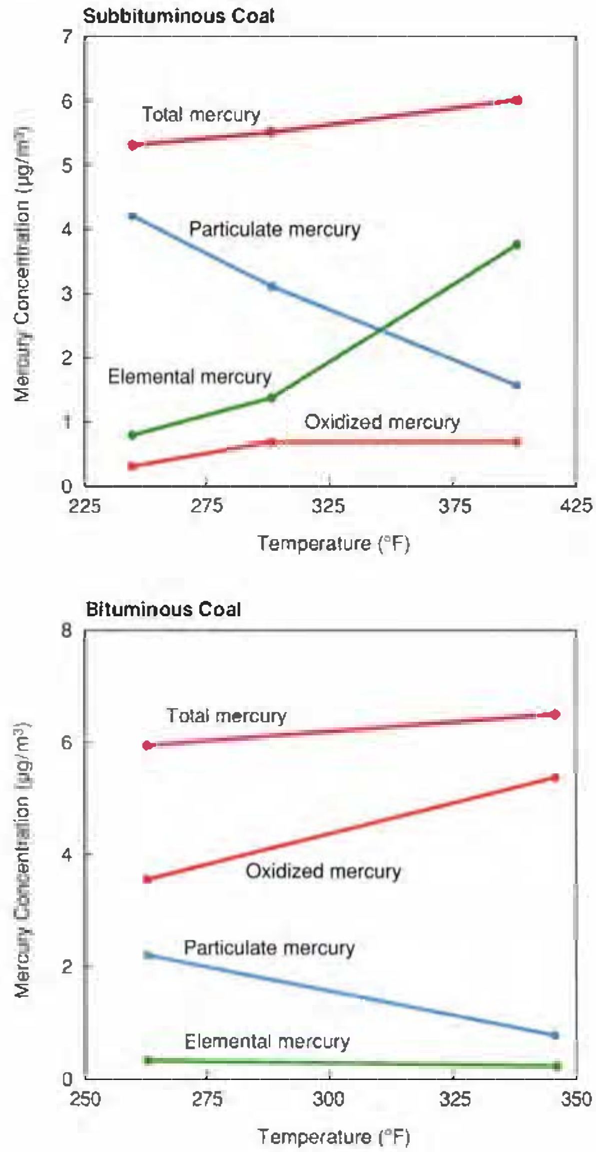
Results from the two test facilities indicate that the effectiveness of activated-carbon injection in removing the trace amounts of mercury found in flue gas depends on several factors: coal type, flue gas composition and temperature, mercury species present, carbon properties and injection rate, and operating conditions. While high mercury removal efficiencies were observed in some tests, low to moderate efficiencies were measured at other typical power plant conditions. Thus it is not yet possible to predict with confidence the level of flue gas mercury control achievable with activated-carbon injection.

Illustrating this difficulty, Figure 2 shows results on vapor-phase-mercury removal from five tests—four at EERC and one at PSCCO—using activated-carbon injection ahead of a pulse-jet baghouse. The test conditions are summarized in Table 1. The amount of carbon used is expressed as a carbon-to-mercury weight ratio (weight of carbon injected per weight of mercury present).

Lowering the flue gas temperature from 345°F to 250°F improved mercury removal efficiency from 0% to 37% (tests 1 and 2). In earlier testing at PSCCO (not shown), 98% vapor-mercury removal was measured at 190°F. It is uncertain whether this level of removal is achievable for other coals and at other sites. Moreover, such low temperatures are not typical of boiler flue gas entering an ESP or a baghouse. A normal temperature for flue gas at the ESP or baghouse inlet is 250–350°F. Cooling flue gas requires the injection of large amounts of water, which can cause significant problems with fly ash deposition and corrosion on the duct walls and the ESP or the baghouse. The potential impact of moisture and low temperatures on ESP and baghouse operation must be assessed.

Increasing the amount of activated carbon used from a carbon-to-mercury ratio of 3000:1 to 10,000:1 almost doubled the mercury removal efficiency (tests 2 and 3). Other tests show that the relationship is not linear, however, and it is difficult to extrapolate these results. Tests 2 and 4 illustrate differences resulting from coal type, and tests 4 and 5 show variations in the results obtained at different sites under similar conditions. In test 4, conducted at EERC, the mercury removal efficiency was much lower than the efficiency in test 5, conducted at PSCCO. The data are not sufficient for the researchers to determine whether this is due to differences in the two types of low-sulfur coal used or to other factors, such as mercury speciation.

Figure 1 Measurements made in a laboratory combustor indicate the mercury species present in flue gas from a low-sulfur subbituminous coal and from a high-sulfur bituminous coal. Development work on mercury control technologies suggests that the forms of mercury present in flue gas are an important factor in removal efficiency.



Judging from these preliminary test results, activated-carbon injection appears to be able to remove mercury from flue gas, but its performance can vary considerably. Thus a better understanding of the various factors affecting mercury removal is necessary to determine if the method can be effective under the wide range of conditions encountered in utility fossil fuel plants. The impact of injected carbon on existing equipment, such as downstream ESPs and baghouses, must be assessed carefully. Also to be explored is the use of other sorbents—such as diatomaceous earth, zeolites, and various high-surface-area and chemically active materials. These will be tested to determine if any are more cost-effective than carbon. Finally, the issue of waste disposal must be addressed to ensure that the mercury collected will not revolatilize in a landfill or become a solid or liquid waste problem.

Wet scrubbing

Of the approximately 325 GW of coal-fired capacity in the United States, about 68 GW have flue gas desulfurization systems for complying with regulations on sulfur dioxide emissions. About 90% of these FGD systems are wet systems. And it is expected that an additional 17 GW of FGD systems (again primarily wet systems) will be installed by the year 2000. Thus there is significant interest in the capability of wet FGD systems to simultaneously remove SO_2 and trace chemical species, including mercury.

TABLE 1
Carbon Injection Test Conditions

	Temperature (°F)	*Carbon-to-Mercury Ratio*	*Coal Type*
Test 1 (EERC)	345	3200:1	High sulfur
Test 2 (EERC)	250	3000:1	High sulfur
Test 3 (EERC)	250	10,000:1	High sulfur
Test 4 (EERC)	260	3400:1	Low sulfur
Test 5 (PSCCO)	240	3500:1	Low sulfur

A typical wet FGD system has a gas-liquid contactor, such as a spray tower, in which an alkaline, limestone-based slurry is sprayed in the same or the opposite direction of the gas flow, absorbing and neutralizing the acidic SO_2. The removal of mercury in a wet FGD system would also occur by absorption into the scrubbing slurry. However, there are two main differences between mercury and SO_2 absorption. First, since the concentration of mercury in flue gas is orders of magnitude lower than SO_2 levels, it is possible that more gas-liquid contact would be required for mercury removal. Second, mercury solubility in the scrubbing slurry depends on the mercury's form. Elemental mercury is essentially insoluble in FGD scrubbing slurry, while some of the oxidized species, such as mercuric chloride, are very soluble. Therefore, oxidized mercury should be easily absorbed with sufficient gas-liquid contact, but the removal of elemental mercury would remain limited.

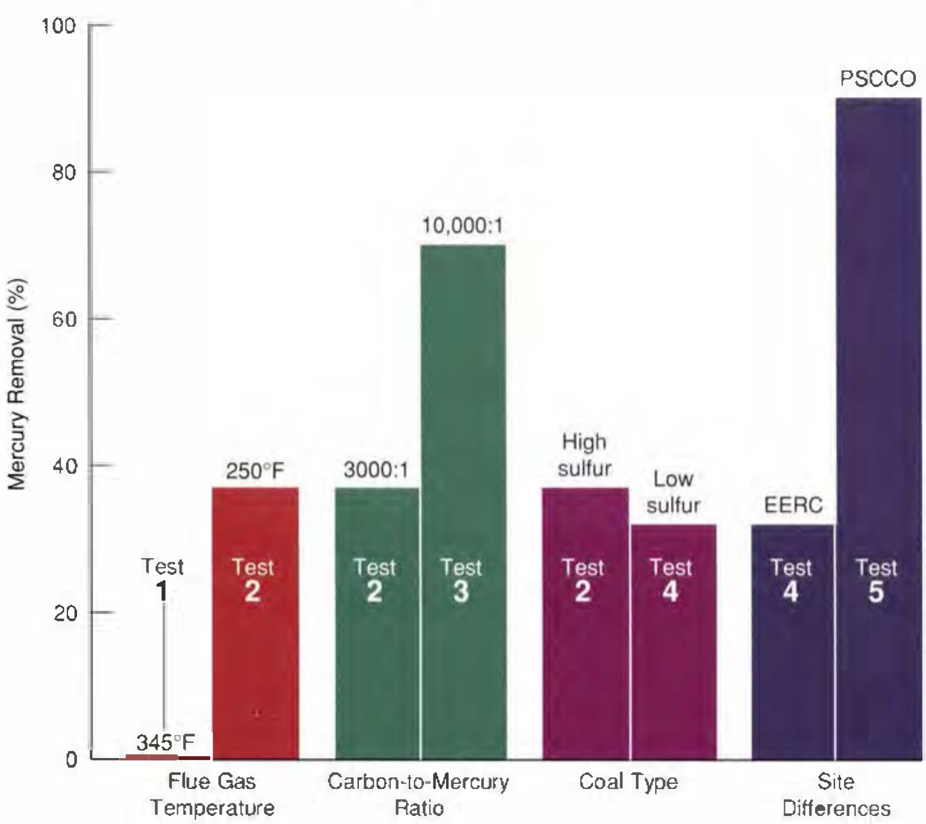


Figure 2 The effectiveness of activated-carbon injection in removing vapor-phase mercury from flue gas was assessed in tests at two pilot facilities. Mercury removal efficiency was found to depend on flue gas temperature, the amount of carbon used (expressed as a weight ratio of carbon injected to mercury present), coal type, and other site conditions.

To evaluate the potential of wet FGD systems to remove mercury, tests were conducted at EPRI's Environmental Control Technology Center (ECTC), formerly the High-Sulfur Test Center. The tests used a pilot wet FGD system (4 MW equivalent). The system has a spray tower as the gas-liquid contactor and obtains flue gas via a slipstream from New York State Electric & Gas Corporation's Kintigh plant, which burns a high-sulfur eastern coal.

The wet scrubber removed only the oxidized mercury present. Inlet vapor-mercury concentrations averaged 9 μg/m^3, with approximately 98% in the oxidized form. Total outlet mercury averaged 0.5 μg/m^3, with about 70–75% in the elemental form. Overall mercury removal efficiency averaged 96% because of the high concentrations of oxidized mercury.

In the ECTC tests, the FGD system was operated under various conditions to simulate the range of typical utility FGD operating conditions. Among the conditions varied were reaction tank pH and the concentrations of chloride, adipic acid, and formic acid in the scrubbing slurry; also, both forced and natural oxidation were used. None of these changes affected mercury removal.

Since the concentrations of elemental mercury in the flue gas were too low to provide accurate measurements and determinations of removal efficiency for this species, elemental mercury was added to the flue gas in some tests. It was found that 50% of the spiked elemental mercury was converted to oxidized mercury. The removal of oxidized mercury was much lower than observed in the tests without the added elemental mercury (80% removal versus over 97%), suggesting that different species of oxidized mercury may have been present. The test results confirm that elemental mercury is not easily removed across a scrubber, and they indicate that the removal effectiveness for oxidized mercury may be dependent on the oxidized species present.

Field measurements of mercury removal efficiency at full-scale wet scrubbers have ranged from 20% to over 90%. These results and the ECTC tests show that mercury speciation and removal mechanisms across a wet scrubber are not well understood. Work is being conducted to clarify these phenomena and to provide the basis for developing modifications to wet scrubbers for more-effective mercury removal.

In conclusion, EPRI wishes to acknowledge the participation of Public Service Company of Colorado and the ECTC cosponsors: New York State Electric & Gas Corporation, Empire State Electric Energy Research Corporation, the U.S. Department of Energy, Electric Power Development Company, and Babcock & Wilcox Company.

Electric Transportation

USABC Jump-Starts EV Battery Development

by Robert Swaroop, Customer Systems Group

Faced with severe air quality problems, California adopted regulations in 1990 that may revolutionize the automotive world. The California rules require that 2% of the automobiles and light-duty trucks produced for sale in the state in 1998 be zero-emission vehicles (ZEVs); by 2003, the requirement increases to 10%. In 1992 and 1993, other states adopted ZEV regulations, and more states are expected to follow suit.

Electric vehicles (EVs) are the only currently viable technology that meets the ZEV criterion. But legislation alone cannot guarantee that consumers will buy EVs, which lag behind conventional vehicles in cost-competitiveness and driving range. Widespread market acceptance of EVs will hinge on the development of lower-cost, higher-performance batteries.

Developing such batteries has proved difficult. To compete with vehicles powered by internal combustion engines, EVs need propulsion batteries that meet demanding requirements. For example, to give vehicles the capability for frequent, rapid acceleration and the range for long-distance trips, these batteries must have high specific power, high specific energy, and high energy density. Further, they must be low in cost, easy to maintain, safe under all conditions, and tolerant of the abuse that vehicles suffer in daily operation. Finally, they must be made from widely available materials and be environmentally benign.

Coordinated effort

To meet these requirements, the three largest U.S. automakers—Chrysler Corporation, Ford Motor Company, and General Motors Corporation—decided to pool resources. In 1991, they established the U.S. Advanced Battery Consortium (USABC), a research consortium that also includes EPRI, several utilities, and the U.S. Department of Energy (Figure 1). On behalf of the U.S. electric utility industry, EPRI is providing funding and battery expertise to the USABC and will also research and resolve issues related to EV infrastructure in the United States. EPRI involvement highly leverages utility industry funding and enables the industry to take part in the largest national battery development effort.

Several electric utilities have also become major USABC participants, providing funding and expertise. To date, these include Pacific Gas and Electric Company, Public Service Electric & Gas Company, Southern California Edison Company, Southern Company Services, and Empire State Electric Energy Research Corporation, a consortium of utilities in the state of New York.

The USABC's goal is to develop for commercialization advanced battery systems that will increase the range and improve the performance of EVs in the latter part of the 1990s. To this end, the USABC has committed $262 million to battery development; 50% is government funding through DOE, and 50% is from EPRI and the utility participants, the Big Three automakers, and battery developers.

The consortium has established cost and performance criteria for two classes of batteries—midterm and long term (Table 1).

ABSTRACT *Several states have adopted regulations that mandate the production of large numbers of zero-emission vehicles by 1998. At present, electric vehicles (EVs) are the only viable zero-emission technology. But so far, despite worldwide efforts, no battery meets all the criteria defined for a high-performance EV. To solve this problem, the three largest U.S. automakers, EPRI and several individual utilities, and the Department of Energy have joined forces in the U.S. Advanced Battery Consortium. Under USABC sponsorship, battery developers around the world are working to develop and test a variety of new battery types. While some of these technologies are targeted for vehicles of the late 1990s, other higher-performance technologies will power the EVs of the next decade.*

Midterm EV battery technologies have potential for prototype production by 1995 and for mass production between 1995 and 1998. These technologies will probably power some of the EVs that will be sold in the late 1990s, when the first phase of the mandates takes effect. Long-term batteries, according to the USABC criteria, must demonstrate commercial viability by 1996 and must be capable of mass production in the next decade. These technologies are targeted for the widespread EV use expected after the year 2003.

Figure 1 Through the U.S. Advanced Battery Consortium—established by the Big Three automakers (General Motors, Ford, and Chrysler) and EPRI—industry and government are working together to develop high-performance EV batteries. To date, the USABC has committed over $260 million to this effort.

Midterm batteries

The USABC criteria call for midterm EV batteries to cost less than $150/kWh, last five years or more, and provide specific power of more than 150 W/kg and specific energy of more than 80 Wh/kg.

One promising midterm technology is the sodium-sulfur battery. Many researchers believe that this technology may give Evs a range of 125–150 miles by the end of this decade. Developed originally by General Electric Company in the 1960s, with later development by Ford, the sodium-sulfur battery uses a ceramic beta-alumina electrolyte tube with sodium negative electrodes and molten-sulfur positive electrodes in a sealed, insulated container. The battery pack itself is further insulated, since the modules operate at 350–380°C (662–716°F). This operating temperature and sodium's reactivity require a rugged design for safe use. Although sodium-sulfur batteries currently cost at least two times more to produce than nickel-iron batteries—and seven times more than lead-acid batteries—they have low projected costs for volume production, thanks to inexpensive materials.

Ford is now purchasing sodium-sulfur batteries for testing and evaluation in its Ecostar vans, and the USABC has awarded a $12.1 million contract to Silent Power in the United Kingdom for research on advanced sodium-sulfur batteries. The consortium also has signed cooperative research and development agreements, or CRADAs, with Argonne National Laboratory and Idaho National Engineering Laboratory for sodium-sulfur battery testing.

The nickel-metal hydride battery may also meet the USABC midterm goals. Composed of nontoxic, completely recyclable materials, this battery is environmentally friendly and, if successfully developed, may provide double the range and twice the cycle life of current battery technology. The battery is composed of nickel hydroxide and an engineered hydride alloy consisting of vanadium, titanium, zirconium, nickel, and other metals in small quantities. It is sealed, is maintenance-free, and can be recharged in as little as 15 minutes.

Ovonic Battery Company—a Troy, Michigan, subsidiary of Energy Conversion Devices—received a $19.9 million contract from the consortium to develop large-scale nickel-metal hydride battery packs for EVs. In March 1994, General Motors and Ovonic announced an agreement for the further development, manufacture, and commercialization of Ovonic nickel-metal hydride batteries for EVs. The USABC also awarded a nickel-metal hydride battery development contract to SAFT, a French battery company that has agreed to manufacture EV batteries in the United States if the development effort succeeds. In addition, the USABC has signed a CRADA with Argonne National Laboratory for nickel-metal hydride battery testing.

Long-term batteries

For the longer term, the USABC is seeking EV batteries that will cost less than $100/kWh in volume production, boast a life of 10 years or more, and provide specific power of more than 400 W/kg and specific energy of about 200 Wh/kg.

One technology with potential for meeting the USABC long-term performance requirements is the lithium-metal sulfide battery. This elevated-temperature battery is based on a lithium alloy–molten salt–metal sulfide electrochemical system. This system provides high power capability, which translates into better acceleration for EVs. Further potential advantages of this battery include its relatively small size and low weight, a cost per kilowatthour comparable to that of today's least-expensive batteries, and low manufacturing costs. In addition, the battery is composed of iron disulfide and a lithium-aluminum alloy, materials that are completely recyclable.

Under the terms of a three-year, $17.3 million USABC contract, SAFT America, Inc., will pursue a bipolar form of the lithium-aluminum-iron disulfide battery first developed at Argonne National Laboratory. Also, the USABC has signed a $7.3 million, 38-month CRADA with Argonne for further research on lithium-metal sulfide technology.

Lithium-polymer battery technology is a second strong long-term candidate. Ambient- and elevated-temperature lithium batteries may provide high energy and power densities, and polymer electrolytes add packaging opportunities not available with liquid systems. Nonrechargeable batteries using lithium or lithium alloys for negative electrodes have been under development for several years and are now used in electronics applications. However, considerable R&D is needed in order for rechargeable lithium-polymer systems to become viable for EV propulsion.

To move toward harnessing the potential of this technology, the USABC has awarded a three-year, $24.5 million contract to W. R. Grace and Company and its partners (Johnson Controls, SRI International, EIC Laboratories, and UCAR Carbon Company); has awarded a $32.9 million contract to 3M Company (with Hydro Quebec and Argonne National Laboratory); and has

TABLE 1
USABC Performance Criteria for EV Batteries

	*Current Lead-Acid**	*USABC Midterm Goal*	*USABC Long-Term Goal*
Specific energy† (Wh/kg)	33	80	200
Energy density† (Wh/L)	92	135	300
Specific power‡ (W/kg)	75	150–200	400
Recharge time (hours)	9–17	<6	3–6
Cycle life‡ (no. of cycles)	400	600	1000

*Sealed lead-acid batteries.
†Discharge of capacity in 3 hours.
‡80% depth of discharge.

signed a $3 million CRADA with Sandia National Laboratory.

Other USABC efforts

Although some of the technologies under development are achieving significantly higher energy than current batteries, all are still extremely high in cost and will require extensive manufacturing and process development to achieve the USABC criteria for ultimate price. To address the issue of commercial feasibility, USABC projects develop in-depth cost models when R&D has shown sufficient progress.

The USABC has also developed and published an interim procedure for laboratory testing of advanced batteries. This procedure will ensure consistent data and relevant comparisons of all technologies. The consortium has initiated benchmark testing of currently available technologies in order to properly characterize midterm and long-term advanced technologies. So far, three of the development contracts in place at the beginning of 1993 have produced working battery hardware that is being evaluated at the DOE national laboratories.

Although the USABC work is focused on batteries, the consortium has also identified vehicle integration as a key area for research. This area involves many aspects of the battery system, including voltage, power-to-energy ratio, and battery-vehicle partitioning requirements.

Other EPRI R&D

EPRI's portfolio of EV battery projects is designed to use the utility industry's experience and resources to best advantage in overcoming technological barriers. To make better batteries available as soon as possible, EPRI is developing and testing near-term batteries. For example, it is helping to fund Electrosource, Inc.'s development of battery technology and processes for initial, limited production of an advanced lead-acid battery called the Horizon®. This effort will yield a commercial battery by 1995. (For more information on the Horizon battery, see the *EPRI Journal*, April/May 1994, p. 6.) With DOE, EPRI is also supporting basic research on electrochemical systems for EV batteries and on new materials for electrodes and electrolytes.

If successfully developed, advanced battery systems promise substantial benefits to society. Even when emissions from electricity generation are taken into account, EVs are expected to cause far lower emissions than gasoline vehicles—the major source of urban air pollution. The greater use of electricity in transportation would also help reduce the consumption of imported petroleum. The economic benefits of a strong EV market could include such business opportunities as new advanced manufacturing technologies, vehicle and battery leasing, and battery recycling. At the same time, electric utilities stand to gain a large new market for off-peak electricity—which, by allowing better asset utilization of generation, transmission, and distribution systems, could help stabilize rates for all customers.

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Customer Systems		
Codisposal of Brine and Other Effluent (RP2662-72)	$247,300 11 months	Energy and Environmental Solutions/ *K. Carns*
Energy Management System Control Strategies for Real-Time Pricing at the Marriott Moscone (RP2830-17)	$346,300 12 months	Honeywell/*L. Carmichael*
Development of a Low-Cost Refrigerator Monitor (RP3188-10)	$84,300 10 months	NYSERDA/*T. Statt*
Demand-Side Management Evaluation Database (RP3269-29)	$210,000 9 months	Xenergy/*R. Gillman*
Applications Engineering Manual for Cold-Air Distribution Diffusers and Air Terminals (RP3280-39)	$165,700 24 months	Titus/*R. Wendland*
Implementing Uses of Thermal Storage (RP3280-48)	$190,000 22 months	Dorgan Associates/ *R. Wendland*
Advanced Water-Loop Heat Pump Controls Development (RP3371-6)	$63,800 10 months	GC Controls/*M. Khattar*
Economics of Ethylene Manufacture From Natural Gas Using Microwave Technology (RP3633-1)	$75,400 9 months	High Technology Associates/*A. Amarnath*
Market Analysis of Demand-Side Management Program Penetration (RP3741-3)	$157,000 9 months	Research Triangle Institute/*P. Meagher*
Evaluation of Adjustable-Speed-Drive Systems in the Process Industry (RP3775-1)	$424,000 13 months	CRS Sirrine Engineers/ *M. Samotyj*
EPRI/E-Tech Heat Pump Water Heater Applications Research Field Test (RP3799-1)	$187,900 18 months	AIL Research/*C. Hiller*
Improvement of Public Transportation Interfaces (RP3805-1)	$52,800 4 months	Bevilacqua-Knight/ *P. Symons*
Heap Leaching of Refractory Gold Ores: Proof of Concept (RP3827-6)	$292,100 26 months	U.S. Bureau of Mines/ *E. Eckhart*
Ground-Coupled Heat Pump Field Monitoring and Analysis (RP3848-1)	$523,600 26 months	Richard Stockton College of New Jersey/ *M. Khattar*
Industrial Efficiency Optimization Using Pinch Analysis: Potlatch Mill (RP3879-2)	$110,000 5 months	Linnhoff March/ *A. Amarnath*
Industrial Efficiency Optimization Using Pinch Analysis: Pennzoil's Atlas Refinery (RP3879-3)	$100,000 4 months	Linnhoff March/ *A. Amarnath*
Industrial Efficiency Optimization Using Pinch Analysis: Smethport, Pennsylvania (RP3879-4)	$56,900 4 months	Linnhoff March/ *A. Amarnath*
Small Packaged Cool Storage System: Demonstration and Evaluation (RP3906-1)	$116,700 12 months	Powell Energy Products/ *R. Wendland*
Environment & Vital Issues		
Watershed-Based Risk Management of Water Quality (RP3221-4)	$50,000 10 months	Systech Engineering/ *R. Goldstein*
Modeling Change in the Breeding Distribution of Bird Species in Response to Climate Change (RP3316-6)	$99,700 13 months	National Fish and Wildlife Foundation/*L. Pitelka*
Utility Near-Term Climate Decision Support (RP3441-18)	$119,700 11 months	Decision Focus/*T. Wilson*
Evaluation of Market Mechanisms to Control NO_x (RP3835-1)	$156,800 24 months	Resource Strategies/ *G. Hester*
Integrated Assessment of Mercury in Florida, Phase 1 (RP9050-2)	$130,000 11 months	Decision Focus/*L. Levin*
Delineating Fracture Systems at a Former Manufactured Gas Plant Site (RP9054-1)	$104,700 9 months	Atlantic Environmental Services/*I. Murarka*

Project	Funding/ Duration	Contractor/EPRI Project Manager
Generation		
Fossil Plant Wear and Tear Cost Estimation (RP1184-42)	$59,400 4 months	Decision Focus/ *D. O'Connor*
Predictive Maintenance Benefit Development (RP2817-37)	$189,000 12 months	Bogan/*R. Colsher*
Investigation of Lightweight High-Volume Fly Ash Systems (RP3176-12)	$137,200 45 months	Canada Centre for Mineral and Energy Technology/*D. Golden*
Prototype 20-kW Integrated High-Concentration Photovoltaic Array: Design, Development, and Deployment (RP3256-5)	$851,100 21 months	Amonix/*F. Dostalek*
Control System and Intelligent Tutoring System Interface for Cope Station Training Simulator (RP3384-18)	$1,185,900 26 months	Foxboro Co./*R. Fray*
Minnesota Agricultural Wood Energy Scale-Up (RP3407-18)	$134,600 35 months	Wesmin Resource Conservation and Development Dist./ *J. Turnbull*
Economic Development Through Biomass Systems Integration (RP3407-20)	$90,500 9 months	Niagara Mohawk Power Corp./*J. Turnbull*
Economic Development Through Biomass Systems Integration (RP3407-22)	$56,500 11 months	Pacific International Center for High-Tech Research/*J. Turnbull*
Mercury Speciation in Utility Flue Gas (RP3471-6)	$54,700 7 months	Frontier Geosciences/ *B. Nott*
Value-Based Capital Budget Allocation (RP3611-3)	$265,000 9 months	Strategic Decisions Group/*M. Blanco*
Technology Development for Reducing Exhaust Hood Losses and Improving Turbine Blade Performance (RP3648-1)	$2,307,200 48 months	Stress Technology/ *T. McCloskey*
Demonstration of Fossil Plant Automation Concepts (RP3690-1)	$452,000 15 months	Leeds & Northrup Co./ *D. Broske*
Rotating Machinery Workstation (RP3693-2)	$400,000 35 months	Automation Technology/ *T. McCloskey*
Water Management Benefits Methodology for Hydro Plants (RP3713-2)	$267,100 12 months	Resources for the Future/*C. McGowin*
In Situ Bioremediation of Sites Contaminated With Transformer Oil (RP3734-3)	$141,900 12 months	Radian Corp./*S. Yunker*
Fossil Power Plant Cost and Quality Management (RP3854-1)	$470,000 36 months	Organizational Learning Center/*R. Pflasterer*
EPRIWORKS: EPRI/LILCO Software Interoperability Demonstration (RP3865-1)	$385,300 30 months	Automation Technology/ *R. Pflasterer*
Fabry-Perot High-Temperature Strain System Feasibility Study (RP3876-6)	$202,400 14 months	Mechanical Technology/ *J. Weiss*
Accelerated Advanced Hydro Turbine Program (RP3944-1)	$50,000 9 months	Hydro Research Foundation/*C. Sullivan*
Investigation of the Interaction Between $NaHCO_3$, NO, and SO_2 (RP9018-2)	$91,000 15 months	University of Cincinnati/ *B. Toole-O'Neil*
Nuclear Power		
Cost-Benefit Software for Analysis of Radiation Control Measures (RP1935-32)	$595,000 32 months	Decision Focus/ *H. Ocken*
Babcock & Wilcox Owners Group Generic License Renewal Program (RP3075-12)	$604,000 12 months	B&W Nuclear Service Co./*J. Carey*
Crack Growth in Alloy 600 Vessel Head Penetration Materials (RP3223-7)	$370,200 21 months	Westinghouse Electric Corp./*R. Pathania*
Fire Risk Studies (RP3234-7)	$184,600 11 months	Science Applications International Corp./ *R. Oehlberg*

Project	Funding/ Duration	Contractor/EPRI Project Manager
Simplified BWR: Conformance Assessment Support (RP3260-39)	$175,000 8 months	S. Levy/*R. Burke*
Dry Transfer System Design for Spent Fuel (RP3290-9)	$1,163,400 21 months	Transnuclear/*R. Lambert*
Root-Cause Advisory Workstation (RP3323-4)	$150,000 14 months	FPI International/ *A. Singh*
Use of Pen-Based Computers to Automate System Engineers' Duties at Nuclear Power Plants (RP3333-1)	$80,000 7 months	Science Applications International Corp./ *A. Singh*
Quality Class Redefinition Pilot Study (RP3477-9)	$50,000 11 months	ERIN Engineering and Research/*F. Rahn*
CORETRAN Analysis Program: Fuel Behavior Development (RP3574-6)	$150,000 24 months	Anatech Research Corp./*L. Agee*
Coolant Activity Analysis for Fuel Failures Involving Severe Degradation (RP3609-2)	$120,000 14 months	S. Levy/*O. Ozer*
NMAC Boric Acid Corrosion Evaluation Program, Phase 2, Task 1 (RP3714-1)	$70,900 10 months	Dominion Engineering/ *J. Jenco*
Risk-Based Prioritization Working Group (RP3719-4)	$88,000 15 months	ERIN Engineering and Research/*F. Rahn*
Axial Power Offset: Root-Cause Investigation (RP3771-1)	$453,200 29 months	Westinghouse Electric Corp./*B. Cheng*
Impact of Primary Coolant Chemistry on PWR Fuel Performance (RP3771-2)	$66,600 9 months	NWT Corp./*B. Cheng*
NMAC Static Seals Maintenance Guide (RP3814-6)	$59,800 10 months	QES, Inc./*J. Jenco*
International Risk- and Reliability-Based Applications and Technology Transfer Alliance (RP3888-1)	$1,209,000 41 months	Science Applications International Corp./ *R. Oehlberg*
Verification and Validation of Knowledge-Based Systems Using Computer-Aided Software Engineering Tools (RP4352-1)	$474,700 25 months	Science Applications International Corp./ *S. Bhatt*
Materials Condition Monitoring (RP5365-10)	$292,800 12 months	Pennsylvania State University/*M. Lapides*
Corrosion Potential Measurements and Modeling of Simulated PWR Steam Generator Secondary Environments (RPS520-13)	$450,000 36 months	Pennsylvania State University/*P. Millett*
Molar Ratio Control Guidelines Development (RPS520-14)	$109,400 12 months	GEBCO Engineering/ *P. Millett*
Automated Diagnostics and Classification of Eddy-Current Signals (RPS530-3)	$97,900 24 months	University of Tennessee/ *M. Behravesh*
Thermal Hydraulics and Fouling Analysis of Steam Generators (RPS543-3)	$50,000 11 months	CFD Research Corp./ *G. Srikantiah*
Tube Vibration Data Review and Forcing-Function Evaluation (RPS544-1)	$219,000 24 months	Argonne National Laboratory/*G. Srikantiah*
Steam Generator Degradation-Specific Management Database (RPS550-13)	$171,600 9 months	Science Applications International Corp./ *R. Thomas*
Technical Support for Regulatory Review of Steam Generator Degradation-Specific Management (RPS550-14)	$191,000 9 months	Failure Analysis Associates/*R. Thomas*

Power Delivery

Project	Funding/ Duration	Contractor/EPRI Project Manager
Research on Furaldehyde in Transformer Oil (RP2445-6)	$218,200 23 months	Powertech Labs/ *S. Lindgren*
Utility System Studies Using VSTAB (RP3040-2)	$115,100 5 months	General Electric Co./ *D. Maratukulam*
Distribution Engineering Workstation Development, Phase 2 (RP3079-3)	$520,000 12 months	Power Computing Co./ *H. Ng*
Characterization and Detection of Low-Current Faults on Low-Voltage Power Systems, Phases 2 and 3 (RP3202-4)	$149,800 16 months	Texas Engineering Experiment Station/ *T. Kendrew*
INTELLCAD: Software to Enhance CAD and Database Management Systems (RP3573-14)	$50,000 6 months	Opercon Systems/ *D. Sobajic*
Computer-Based Work Management–Process Automation System: General Design Specification (RP3573-16)	$68,000 6 months	Yanco Associates/ *D. Sobajic*
Line-Segment Assessment and Inspection Methods: Field Experiment (RP3621-1)	$534,300 10 months	Engineering Data Management/*P. Lyons*
Distribution Automation/Demand-Side Management Demonstration (RP3674-5)	$3,642,500 37 months	San Antonio City Public Service/*R. Bernstein*
Utility and Customer Communication Infrastructure Alternatives and Protocols (RP3674-10)	$200,000 13 months	First Pacific Networks/ *R. Bernstein*
Power Plant Performance Instrumentation System (RP3732-1)	$600,000 25 months	Potomac Electric Power Co./*D. Maratukulam*
Solid-State Breaker Development and Demonstration (RP3783-1)	$595,500 69 months	Westinghouse Electric Corp./*H. Mehta*
Characterization of Aged Polymer Insulators (RP3787-5)	$174,500 25 months	Arizona State University/ *A. Hirany*
FACTS Requirements Study for Increasing the Arizona-to-California Transfer Capability (RP3789-4)	$144,000 8 months	San Diego Gas & Electric Co./*R. Adapa*
Development of Rock Steering Head for Small-Diameter Boring Tool (RP3927-2)	$347,000 22 months	Underground Research/ *T. Kendrew*
Advanced Techniques and Tools for the Removal of Jammed Cables (RP3927-6)	$526,700 24 months	Underground Research/ *T. Kendrew*
A PC-Based Dielectric Materials Database (RP7913-8)	$68,100 5 months	Power Computing Co./ *T. Rodenbaugh*
Complete Construction of Cable Life Evaluation Bays (RP7924-2)	$86,300 5 months	R. O. Wilkinson/ *J. Shimshock*

Strategic R&D

Project	Funding/ Duration	Contractor/EPRI Project Manager
Genetic Algorithm Test Bed for Expert Systems Testing (RP8015-5)	$70,000 6 months	DHR Technologies/ *M. Wildberger*
Evolution of Complex Cellular Automata for Power Grid Simulation (RP8017-6)	$72,600 22 months	San Jose State University Foundation/ *M. Wildberger*
Artificial Neural Networks for Dynamic System Identification and Control (RP8030-11)	$100,000 31 months	Marquette University/ *B. Banerjee*
Intelligent Automatic Control of Power Systems (RP8030-12)	$100,000 23 months	Mississippi State University/*P. Hirsch*
Intelligent Unified Control of Unit Commitment and Generation Allocation (RP8030-13)	$100,000 28 months	University of Michigan/ *P. Hirsch*
Intelligent Control of Dynamic Systems (RP8030-14)	$100,000 35 months	University of Illinois/ *M. Lapides*
Intelligent Control of Dynamic Systems (RP8030-15)	$100,000 31 months	University of Illinois/ *C. Lin*
Development of Multidimensional Two-Fluid Model of Turbulent Boiling Flow (RP8034-4)	$68,700 12 months	Arizona State University/ *P. Kalra*
Novel Concept for Heat Transfer Enhancement: Applications of Ferrofluids in Oscillating Magnetic Fields (RP8034-5)	$75,000 12 months	Energy International/ *J. Maulbetsch*
Bifurcation and Chaos in Power Systems (RP8050-9)	$252,500 24 months	University of California, Berkeley/*T. Schneider*
CeO_2 Electrolytes for Solid Oxide Fuel Cell Applications (RP8062-4)	$170,900 20 months	Ceramatec/*W. Bakker*
Synthesis and Characteristics of New Oxide and Sulfide Materials as Potential New Superconductors (RP8066-1)	$150,000 35 months	University of Maryland/ *P. Grant*

New Technical Reports

Requests for copies of reports should be directed to the EPRI Distribution Center, 207 Coggins Drive, P.O. Box 23205, Pleasant Hill, California 94523; (510) 934-4212. There is no charge for reports requested by EPRI member utilities. Reports will be provided to others in the United States for the price listed or, in some cases, under the terms of a license agreement. Those outside the United States should contact the Distribution Center for price information.

CUSTOMER SYSTEMS

Pilot Study of Magnetic Fields in Electric Vehicles
TR-103275 Final Report (RP3304-7); $200
Contractor: Electric Research and Management, Inc.
EPRI Project Manager: G. Purcell

Performance Evaluation of the HydroTech 2000, Vol. 2: Cooling Season
TR-103803 Final Report (RP2892-20); $200
Contractor: GEOMET Technologies, Inc.
EPRI Project Manager: J. Kesselring

Assessment of Refrigerated Display Cases
TR-103981 Final Report (RP2983-19); $50
Contractor: Energy International, Inc.
EPRI Project Manager: M. Khattar

Characteristics and Energy Use of the Convenience Store Industry
TR-103982 Final Report (RP2983-19); $50
Contractor: Energy International, Inc.
EPRI Project Manager: M. Khattar

ENVIRONMENT & VITAL ISSUES

Calcium-Based Flue Gas Desulfurization Sludge Disposal Ponds
TR-103914 Final Report (RP2485-8); $200
Contractor: Battelle Pacific Northwest Laboratories
EPRI Project Manager: I. Murarka

Sodium-Based Flue Gas Desulfurization Sludge Disposal Ponds
TR-103915 Final Report (RP2485-8); $200
Contractor: Battelle Pacific Northwest Laboratories
EPRI Project Manager: I. Murarka

GENERATION

History of First U.S. Compressed-Air Energy Storage (CAES) Plant (110 MW, 26 h), Vol 2: Construction
TR-101751-V2 Final Report (RP2894-1); $10,000
EPRI Project Manager: R. Pollack

Coal Pretreatment Processes to Enhance Conversion
TR-101810 Final Report (RP2147-16); $200
Contractor: Clint W. Williford, University of Mississippi
EPRI Project Manager: B. Weber

CQE Coal Characterization Studies, Vol. 1: Powder River Basin Subbituminous Coals
TR-103041-V1 Final Report (RP1400-25); $200
Contractor: CQ Inc.
EPRI Project Manager: D. O'Connor

Standard Compressed-Air Energy Storage Plant: Design and Cost
TR-103209 Final Report (RP2894-12); $200
Contractor: Energy Storage and Power Consultants
EPRI Project Manager: R. Pollak

Proceedings: Integrating Natural Gas Technologies Into Coal- and Oil-Designed Boilers
TR-103469 Final Report (RP2819-25); $200
Contractor: Reaction Engineering International
EPRI Project Manager: A. Mehta

Shell Coal Gasification Process Solid By-Product Utilization
TR-103512 Interim Report (RP2695-1); $200
Contractor: Shell Development Co.
EPRI Project Manager: N. Stewart

Solid Particle Erosion Technology Assessment
TR-103552 Final Report (RP1885-10); $200
Contractor: Encor-America, Inc.
EPRI Project Managers: T. McCloskey, B. Dooley

Steam Turbine Rotor Life Assessment, Vols. 1–5
TR-103619-V1–4 Final Report (RP2481-8); $10,000 each volume
TR-103619-V5 Final Report; license required
Contractor: Mitsubishi Heavy Industries, Ltd.
EPRI Project Manager: R. Viswanathan

Measurement and Assessment Guide (MAG) for Improving Operations of Combustion Turbines
TR-103620 Final Report (RP2989-6); $10,000
EPRI Project Manager: R. Frischmuth

Header Feedwater Heater Retrofit Demonstration
TR-103651 Final Report (RP1403-46); $200
Contractor: Encor-America, Inc.
EPRI Project Manager: J. Bartz

Steam Turbine Rotor Life Assessment and Extension: Evaluation of Retired Rotors, Vol. 1—Quantification of NDE Uncertainty
TR-103702-V1 Final Report (RP2481-5); $10,000
Contractors: Southwest Research Institute; J. A. Jones Applied Research Co.
EPRI Project Manager: R. Viswanathan

Steam Turbine Rotor Life Assessment and Extension: Evaluation of Retired Rotors, Vol. 2—Mechanical Properties of Service-Exposed Rotors
TR-103702-V2 Final Report (RP2481-5); $1000
Contractor: Southwest Research Institute
EPRI Project Manager: R. Viswanathan

Proceedings: 1993 Strategic Resource Planning and Asset Management Forum—Opportunities, Challenges, and Responses for the 1990s
TR-103739 Proceedings (RP3605); $200
Contractor: American Productivity and Quality Center
EPRI Project Manager: L. Rubin

SNCR Feasibility and Economic Evaluation Guidelines for Fossil-Fired Utility Boilers
TR-103885 Final Report (RP2869-14, RP9037-1); $5000
Contractors: Radian Corp.; Fossil Energy Research Corp.
EPRI Project Manager: J. Stallings

NUCLEAR POWER

Radwaste Desk Reference, Vol. 3, Parts 1 and 2
NP-7386-V3P1, NP-7386-V3P2 Final Report (RP2414-34); $200 each part
Contractor: Right Angle Industries
EPRI Project Manager: C. Hornibrook

Calibration of Radiation Monitors at Nuclear Power Plants
TR-102644 Final Report (RP2409-24); $200
Contractors: Louisiana Laissez-faire, Inc.; Pedro Point Technology, Inc.; TARAwest Technologies
EPRI Project Manager: R. James

Determination of Susceptibility of Alloy 718 to Intergranular Stress Corrosion Cracking
TR-103290 Final Report (RP2181-10); $5000
Contractor: CORTEST Columbus Technologies, Inc.
EPRI Project Manager: J. Nelson

Evaluation of Precoat Filter Septa Performance Using a Powdered Resin Test Skid
TR-103294 Final Report (RP2977-5); $200
Contractor: GEBCO Engineering, Inc.
EPRI Project Manager: T. Passell

Guidelines for Instrument Calibration Extension/Reduction Programs
TR-103335 Final Report (RP2409-21); $200
Contractor: Edan Engineering Corp.
EPRI Project Manager: R. James

Molten Corium Concrete Interactions: Advanced Containment Experiments (ACE) Project (Summary Report)
TR-103483 Final Report (RP2802); call for price
Contractors: Argonne National Laboratory; AEA Technology; University of Wisconsin
EPRI Project Manager: M. Merilo

Corrosion Evaluation of Service Water System Materials
TR-103500 Final Report (RP2939-12); $1000
Contractor: Stone & Webster Engineering Corp.
EPRI Project Manager: B. Cubicciotti

BWR Water Chemistry Guidelines, 1993 Revision: Normal and Hydrogen Water Chemistry
TR-103515 Final Report (RP2493); $200
EPRI Project Manager: C. Wood

Guidelines for Optimizing the Engineering Change Process for Nuclear Power Plants
TR-103586 Final Report (RP3186-17); $200
Contractor: CYGNA Energy Services
EPRI Project Manager: W. Houston

Reliability Centered Maintenance Implementation in the Nuclear Power Industry: Guidelines for Successful RCM Implementation
TR-103590 Interim Report (RP2970-6); $50,000
Contractor: Halliburton NUS Corp.
EPRI Project Manager: D. Worledge

Evaluation of Amine Inhibitors for Suitability as Crevice Buffering Agents
TR-103721 Final Report (RPS409-14); $200
Contractor: SRI International
EPRI Project Managers: P. Millett, P. Paine

Effect of the Surface Film Electric Resistance on Eddy Current Detectability of Surface Cracks in Alloy 600 Tubes
TR-103750 Final Report (RP3500-10); $200
Contractor: Technical Research Centre of Finland
EPRI Project Manager: P. Paine

Examination of Crystal River Unit 3 Steam Generator Tube Sections
TR-103756 Final Report (RPS413-6, -7, -8); $500
Contractors: B&W Nuclear Technologies, Babcock & Wilcox Co., Adams & Hobart, EPRI NDE Center
EPRI Project Managers: P. Paine, A. McIlree

Low Level Waste Inventory Management Program for Storage and Disposal: SourceDk 1.0—Software Description and User's Manual
TR-103810 Final Report (RP2691-10); $1500
Contractor: Grove Engineering, Inc.
EPRI Project Manager: C. Hornibrook

PWR Full Reactor Coolant System Decontamination Qualification Program: Decontamination and Reirradiation of PWR Fuel Assemblies
TR-103816 Final Report (RP2296-20); $200
Contractor: Westinghouse Electric Corp.
EPRI Project Managers: H. Ocken, C. Wood

Galling Wear of Cobalt-Free Hardfacing Alloys
TR-103845 Final Report (RP1935); $2500
Contractor: ABB Atom
EPRI Project Manager: H. Ocken

Chemistry of Titanium Dioxide in Steam Generators
TR-103849 Final Report (RPS510-5); $200
Contractor: Sonoma Research Co.
EPRI Project Manager: P. Paine

POWER DELIVERY

High-Voltage Direct-Current (HVDC) Converter Station Electromagnetic Noise Study, Vols. 1 and 2
TR-102313-V1, TR-102313-V2 Final Report (RP1769-2); $5000 each volume
Contractor: Ohio State University
EPRI Project Managers: B. Damsky, S. Wright

Visualizing Power System Data
TR-102984 Final Report (RP8010-25); $200
Contractor: University of Washington
EPRI Project Manager: R. Adapa

A Guide to Monitoring Distribution Power Quality, Phase 1
TR-103208 Final Report (RP3098-1); $5000
Contractor: Electrotek Concepts, Inc.
EPRI Project Manager: H. Mehta

Value-Based Transmission Resource Analysis, Vols. 1 and 2
TR-103587-V1, TR-103587-V2 Final Report (RP2878-2); $5000 each volume
Contractor: RCG/Hagler Bailly
EPRI Project Manager: A. Vojdani

Proceedings: Disaster Preparedness Conference II
TR-103596 Proceedings (RP3225-2); $400
EPRI Project Managers: B. Damsky, T. Kendrew

Experimental Study of Drained Behavior of Drilled Shafts During Cyclic Inclined Loading
TR-103597 Final Report (RP1493-4); $5000
Contractor: Cornell University
EPRI Project Manager: A. Hirany

Detected Lightning Data in the United States: 1988–1991
TR-103603 Final Report (RP2431-1); $5000
Contractor: State University of New York, Albany
EPRI Project Manager: V. Tahiliani

Long-Term Dynamic Requirements Study: User Needs, Existing Models, Data Availability
TR-103606 Final Report (RP3144-2); $5000
Contractor: Ontario Hydro
EPRI Project Manager: P. Hirsch

Superconducting Low-Voltage Direct-Current (LVDC) Networks
TR-103636 Final Report (RP7911-12); $5000
Contractor: University of Wisconsin, Madison
EPRI Project Manager: R. Adapa

Multi-Area Unit Commitment With Security Evaluation
TR-103637 Final Report (RP4000-10); $5000
Contractor: University of Oklahoma
EPRI Project Manager: R. Adapa

Real-Time Phasor Measurement for Improved Monitoring and Control
TR-103640 Final Report (RP1999-12); $5000
Contractor: Virginia Polytechnic Institute
EPRI Project Manager: R. Adapa

Optimization of the Unit Commitment Problem by a Coupled Gradient Network and by a Genetic Algorithm
TR-103697 Final Report (RP8010-29); $200
Contractor: Wayne State University
EPRI Project Manager: R. Adapa

Analysis of Stressed Interconnected Power Networks
TR-103704 Final Report (RP8010-28); $200
Contractor: Iowa State University
EPRI Project Manager: R. Adapa

New Computer Software

The Electric Power Software Center (EPSC) provides a single distribution center for computer programs developed by EPRI. The programs are distributed under license to users. EPRI member utilities, in paying their membership fees, prepay all royalties. Nonmember organizations licensing EPRI computer programs are required to pay royalties. For more information about EPSC and licensing arrangements, EPRI member utilities should contact the Electric Power Software Center, Power Computing Co., 1930 Hi Line Drive, Dallas, Texas 75207; (800) 763-3772. Other organizations should contact EPRI's Manager of Licensing, P.O. Box 10412, Palo Alto, California 94303; (415) 855-2866.

ARROTTA: Advanced Rapid Reactor Operational Transient Analysis
Version 1.10 (RS6000-AIX; Sun-UNIX)
Developer: S. Levy Inc.
EPRI Project Manager: Lance Agee

ASAPP™: Accounting Software Application for Pollution Prevention
Version 1.0 (PC-DOS)
Developer: Radian Corp.
EPRI Project Manager: Mary McLearn

BaSES: Battery Storage Evaluation Software
Version 2.0 (PC-DOS)
Developer: Electric Power Consulting, Inc.
EPRI Project Manager: Steven Eckroad

CPM-2: Two-Dimensional Lattice Physics Code
Version 3-A (Sun-UNIX)
Developer: S. Levy Inc.
EPRI Project Manager: Lance Agee

IOSS OF LLW: Interim On-Site Storage of Low-Level Waste
Version 1.0 (PC-DOS; PC-Macintosh)
Developer: James & Associates
EPRI Project Manager: Carol Hornibrook

RETRAN-03: A Program for Transient Thermal-Hydraulic Analysis
Version MOD001 (Sun-UNIX)
Developer: Computer Simulation and Analysis, Inc.
EPRI Project Manager: Lance Agee

SSPS™: Site Screening and Priority-Setting System
Version 1.0 (PC-DOS)
Developer: Decision Focus Inc.
EPRI Project Manager: Robert Goldstein

TREGRO: Response of Plants to Interacting Stresses
Version 3.0 (PC-Macintosh)
Developer: Boyce Thompson Institute
EPRI Project Manager: John Huckabee

EPRI Events

SEPTEMBER

22–23
Codes for Addressing Groundwater Assessment and Remediation
Irving, Texas
Contact: Audrey Dreifuss, (415) 855-2919

22–23
Intercontrol Center Communications Protocol
Loveland, Colorado
Contact: Linda Nelson, (415) 855-2127

26–27
Center for Materials Production (CMP) Economics and Technology Workshop
San Francisco, California
Contact: John Kollar, (412) 268-3496

OCTOBER

3–5
International Joint Power Generation Conference and Exposition
Phoenix, Arizona
Contact: Cynthia White, (212) 705-7637

4–6
Pollution Prevention Seminar
Scottsdale, Arizona
Contact: Pam Turner, (415) 855-2010

5–7
Flexible AC Transmission Systems (FACTS) Conference
Baltimore, Maryland
Contact: Lori Adams, (415) 855-8763

12–13
Fuel Oil Utilization Workshop
Tampa, Florida
Contact: Stephanie Drees, (714) 259-9520

17–18
Center for Materials Production (CMP) Economics and Technology Workshop
Pittsburgh, Pennsylvania
Contact: John Kollar, (412) 268-3496

17–19
Energy-Efficient Office Technology
New York, New York
Contact: Lori Adams, (415) 855-8763

19–21
13th Conference on Coal Gasification Power Plants
San Francisco, California
Contact: Linda Nelson, (415) 855-2127

19–21
Fuel Supply Seminar
Chicago, Illinois
Contact: Susan Bisetti, (415) 855-7919

24–27
Power Quality Applications, 1994
Amsterdam, Netherlands
Contact: Carrie Koeturius, (510) 525-1205

28
Municipal Wastewater and Energy Conference
New York, New York
Contact: Keith Carns, (314) 935-8598

31–November 3
Decision Analysis for Utility Planning and Management
New Orleans, Louisiana
Contact: Katrina Rolfes, (415) 926-9227

NOVEMBER

1–3
Substation Equipment Diagnostics Conference
New Orleans, Louisiana
Contact: Kathleen Lyons, (415) 855-2656

10–12
3d International Workshop on Rough Sets and Soft Computing
San Jose, California
Contact: T. Y. Lin, (408) 924-5121

15–17
Primary Water Stress Corrosion Cracking in Alloy 600 PWRs
Tampa, Florida
Contact: Linda Nelson, (415) 855-2127

15–18
Market Research Symposium
Marina del Rey, California
Contact: Susan Bisetti, (415) 855-7919

28–December 1
Fuel Cell Seminar
San Diego, California
Contact: Ed Gillis, (415) 855-2542

DECEMBER

5–7
12th International Electric Vehicle Symposium
Anaheim, California
Contact: Pam Turner, (415) 855-2010

FEBRUARY 1995

8–9
Energy Efficiency and the Global Environment
Newport Beach, California
Contact: Marcia Littell, (610) 667-2160

22–24
1995 Foodservice Symposium
New Orleans, Louisiana
Contact: Susan Bisetti, (415) 855-7919

MARCH

22–24
Verification and Validation of Digital Systems
Nashville, Tennessee
Contact: Linda Nelson, (415) 855-2127

28–31
1995 SO_2 Control Symposium
Miami, Florida
Contact: Pam Turner, (415) 855-2010

MAY

3–5
Continuous Emissions Monitoring Users Group Meeting
Atlanta, Georgia
Contact: Linda Nelson, (415) 855-2127

8–10
13th International Conference on Fluidized-Bed Combustion
Orlando, Florida
Contact: Shelton Ehrlich, (415) 855-2444

15–19
Joint Symposium on Stationary Combustion NO_x Control
Kansas City, Missouri
Contact: Lori Adams, (415) 855-8763

JUNE

19–21
ISA POWID/EPRI Controls and Instrumentation Conference
San Diego, California
Contact: Lori Adams, (415) 855-8763

28–30
7th National Demand-Side Management Conference
Dallas, Texas
Contact: Pam Turner, (415) 855-8900

JULY

10–12
Low-Level-Waste Conference
Orlando, Florida
Contact: Linda Nelson, (415) 855-2127

12–14
EPRI/ASME Radwaste Workshop
Orlando, Florida
Contact: Linda Nelson, (415) 855-2127

AUGUST

15–18
Particulate Control/Managing Hazardous Air Pollutants
Toronto, Canada
Contact: Lori Adams, (415) 855-8763

29–31
PCB Seminar
Boston, Massachusetts
Contact: Linda Nelson, (415) 855-2127

SEPTEMBER

13–15
1995 Heat Rate Improvement Conference
Dallas, Texas
Contact: Susan Bisetti, (415) 855-7919

OCTOBER

4–6
Biodiversity and Ecosystem Health
Jackson Hole, Wyoming
Contact: Pam Turner, (415) 855-2010

18–20
1995 Fuel Supply Seminar
New Orleans, Louisiana
Contact: Susan Bisetti, (415) 855-7919

25–27
Gasification Power Plants Conference
San Francisco, California
Contact: Linda Nelson, (415) 855-2127

NOVEMBER

28–30
Predictive Maintenance and Refurbishment
Orlando, Florida
Contact: Susan Bisetti, (415) 855-7919

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EJ-104259