Generation Cycles for the 21st Century

ELECTRIC POWER RESEARCH INSTITUTE

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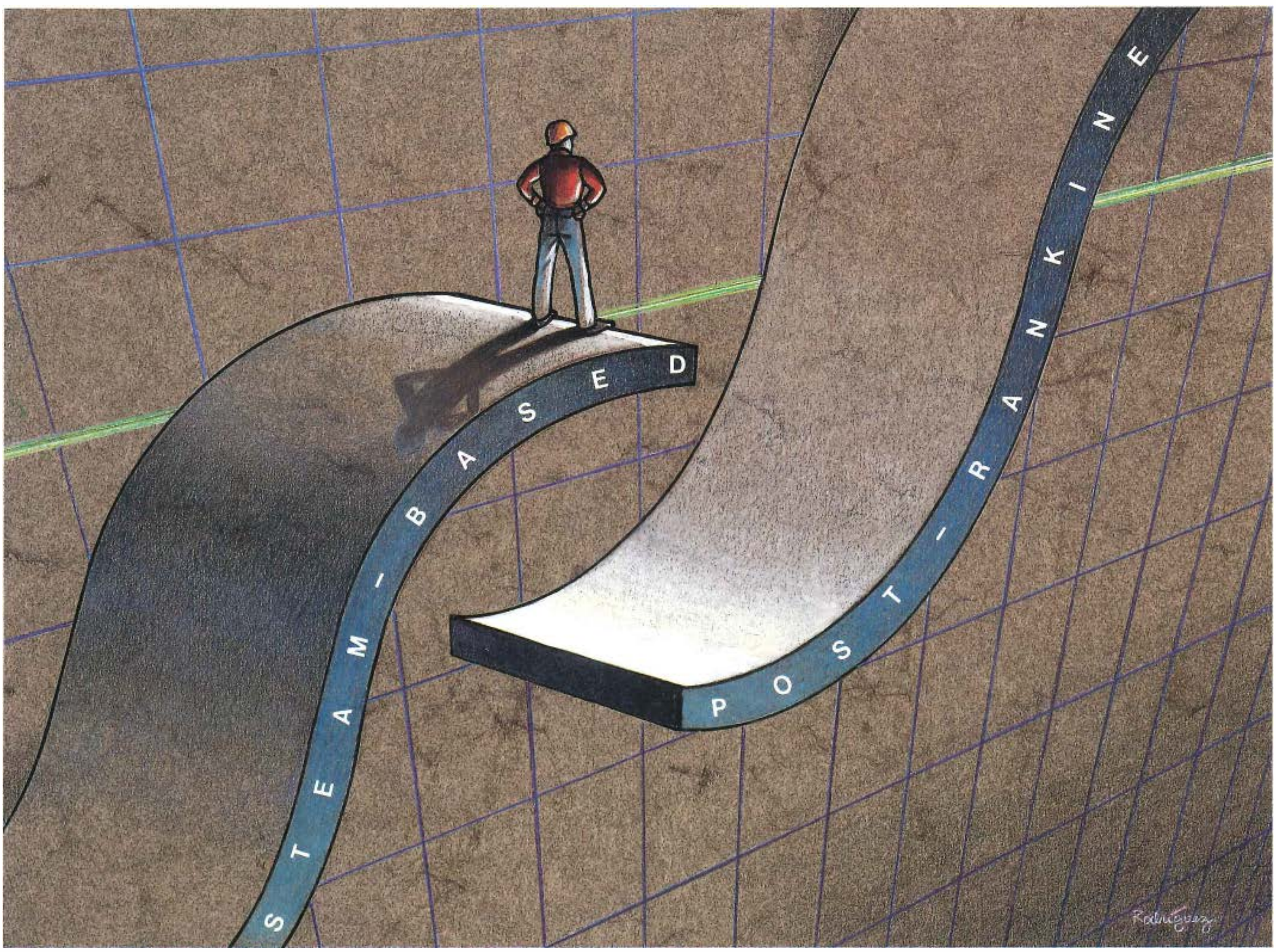

Also in this issue • *Commercial Market Segmentation* • *Dual-Fuel Heat Pump* • *FGD Economics*

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Cover: Technologies follow a classical S-shaped developmental curve, characterized first by rapid productivity increases as the technology matures and then by a leveling off as the technology nears its inherent performance limits. The utility industry, poised at the top of the curve for conventional coal-based power generation, will have to make the leap to a new technological life cycle to realize significant new gains in efficiency.

EDITORIAL

The Future for Coal-Based Generation

The value of coal for generating power in this country is enormous. About 800 million tons of coal are burned every year, producing more than half of the electricity used in the United States. Coal accounts for about 95% of U.S. fossil fuel reserves, and its low cost and ready availability throughout most of the nation have been key factors in keeping electricity costs down. On the global side, renewed hostilities in the Persian Gulf have again underscored the need for energy independence and the importance of making the most effective use of our indigenous resources.

For these reasons, coal continues to be an essential fuel for America's power needs. Recently, however, escalating environmental concerns have been threatening the continued use of this most valuable resource. Emission controls for current coal-fired plants have evolved sequentially over the past two decades—first to reduce particulate emissions, then sulfur oxide emissions, and most recently nitrogen oxide emissions. Added onto the back end of coal-fired plants for postcombustion cleanup, each of these systems adds to the investment required and reduces the efficiency of power generation. While today's control technologies can do the job in terms of meeting emission regulations, including the new Clean Air Act Amendments, the question is whether there are better approaches on the horizon.

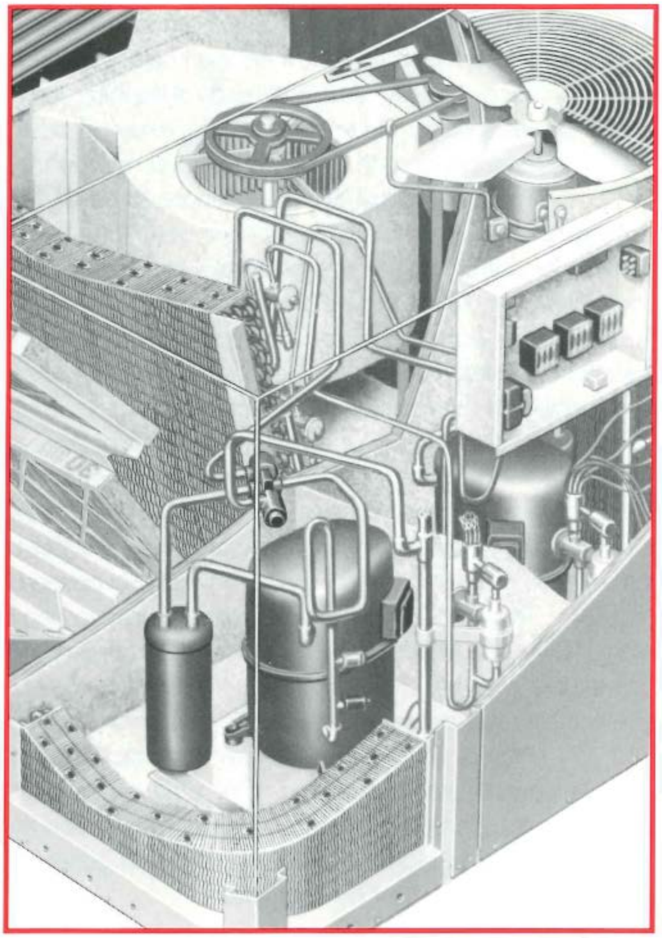
The answer is clearly yes. A number of advanced generation cycles—most of which are not constrained by Rankine efficiency limits—are at different stages of development, some ready for implementation now and others within the next decade. These technologies share two underlying premises with regard to the environment. The first is that it is better to avoid creating pollutants than to try to capture them after the fact. The second is that increasing system efficiency minimizes both the amount of fuel consumed and the volume of pollutants to be dealt with.

The industry has a historic opportunity to begin the transition to higher-efficiency, post-Rankine-cycle power plants. Given the status of technological development today, it appears that coal gasification will be the core technology for this change. Over the next 10 to 15 years, combustion turbines are likely to be used to convert the clean gas to electricity; fuel cells are expected to challenge strongly in the period thereafter, as their costs are reduced.

Precise predictions of the technological future are notoriously difficult to make, particularly in terms of timing. As development proceeds, some of the other technologies described in this issue may eclipse those noted above; this is one reason EPRI maintains a broad, robust, and flexible RD&D program. But whichever technologies win out, the change to cleaner, higher-efficiency coal-based generation will come. Coal is an extremely valuable resource to this nation. Its utilization must be continued.

Ronald Wolk

Ronald Wolk, Director
Advanced Fossil Power Systems Department



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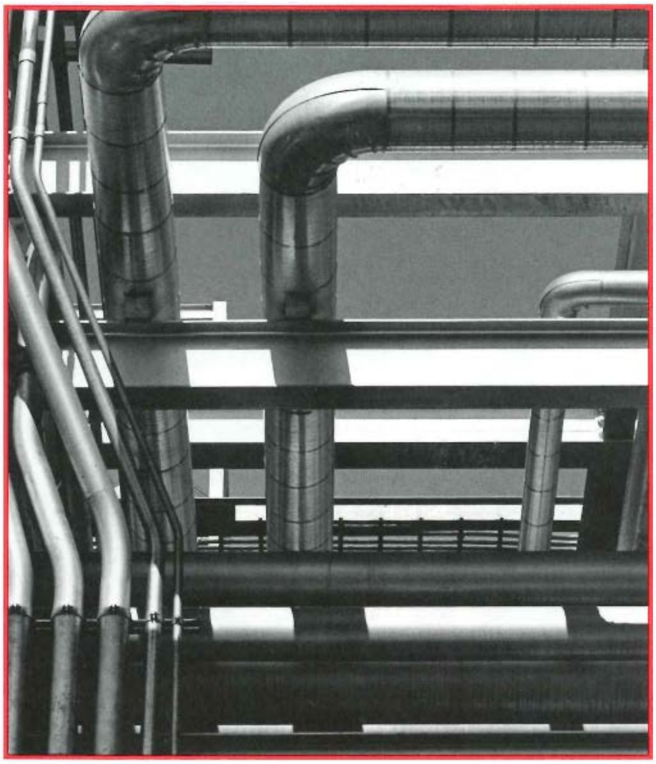
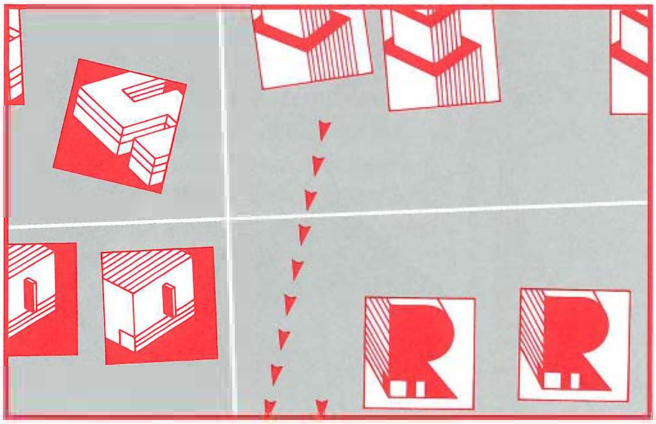
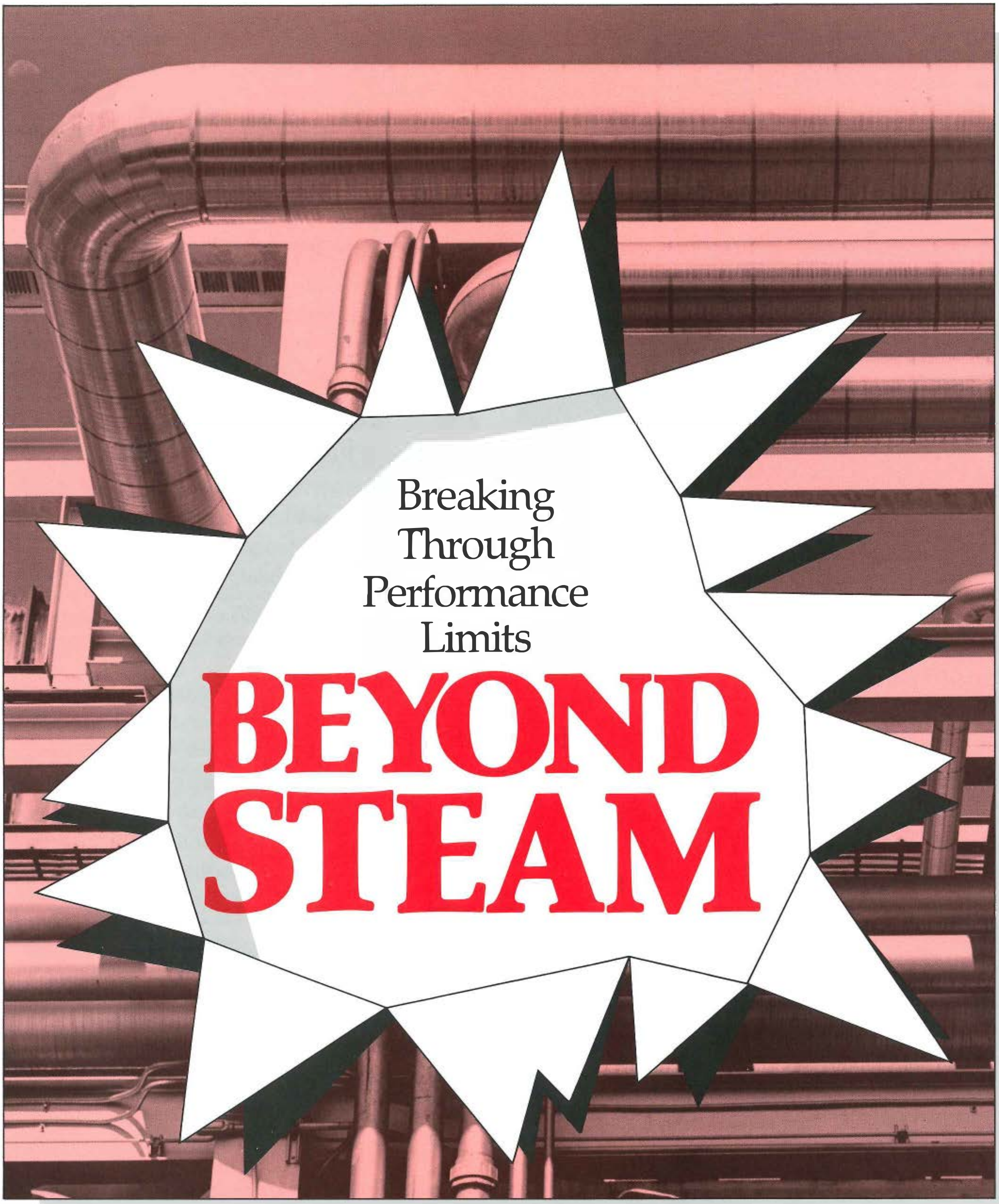


4 Beyond Steam

12 Commercial Customers




Breaking Through Performance Limits
BEYOND STEAM

The coal-fired steam plant has had a remarkable run as the workhorse of the electric power industry—accounting for well over half of total electric energy produced each year in the United States. First came the piston-driven models of the 1880s, with generating capacities of about 50 kW and an energy conversion efficiency of only 5%. Steam turbines with generating capacities of 5 MW were introduced just after the turn of the century, dramatically lowering costs and boosting efficiency. By the 1960s, steam generating plants with supercritical boilers had attained capacities of 1200 MW and efficiencies of about 40%.

For the last several years, however, performance has languished. Part of the problem is that fundamental practical limits have been reached in the efficiency of steam plants. Overcoming these limitations will mean shifting away from steam toward alternative methods of generating electricity from coal. Such a shift would have important strategic implications for the economy and the environment: increasing the efficiency of coal-fired plants reduces the amount of emissions—including carbon dioxide—for each kilowatthour of electricity generated.

The conversion of heat energy to work via steam can be described by a sequence of thermodynamic processes known as the Rankine cycle. The upper limit of efficiency that any engine can achieve is determined by the ratio of the maximum and minimum temperatures in its thermodynamic cycle. One of the most important factors currently limiting the efficiency of Rankine-cycle engines is that maximum steam temperatures have, for practical purposes, remained stuck around 1000–1100°F, because of boiler material constraints and other factors.

At the same time, the overall efficiency of coal-steam power plants is also being pushed down by the addition of flue gas desulfurization units, or scrubbers, which increase operating expenses and

THE STORY IN BRIEF

Coal combustion has provided the bulk of the nation's electric power for over a hundred years. But conventional coal technology, based primarily on the use of steam turbines, is nearing its theoretical efficiency limit—the so-called Rankine barrier. To increase performance further, coal power plants will have to move progressively away from steam-based systems toward advanced generation cycles centered around coal gasification technology. A new line of integrated gasification power plants incorporating advanced gas turbines or molten carbonate fuel cells is expected to boost efficiency well beyond today's level of around 37%—efficiencies may approach 60% by the year 2020. When fully realized, these advanced plants will coproduce electricity and such valuable chemicals as hydrogen, methanol, and gasoline, while nearly eliminating air emissions and solid wastes.

nearly double the production of solid waste. Scrubbers and other pollution control equipment now account for about 40% of the capital cost of a new coal plant and consume 2–4% of the gross energy produced.

Overcoming such steam plant limitations in both efficiency and emissions will require fundamentally new approaches to utilizing the energy of coal. EPRI has taken the lead in developing some of these approaches and is monitoring others on behalf of its utility members.

"Breaking the Rankine-cycle barrier in electric power production could have an impact like that of the jet engine on air travel 40 years ago," says EPRI's Kurt Yeager, vice president, Generation and Storage Division. "The United States is poised to provide world leadership for this transformation through a combination of advanced technology and vast coal resources. The result will be not only commercial advantage but also conservation of more limited resources, such as oil and natural gas, and environmental protection on a global scale."

Getting the most from steam plants

As engineers approach the thermodynamic limits of the Rankine cycle, they are trying to squeeze the last performance improvements out of steam plants. Using current technology, a good pulverized-coal plant with pollution controls to limit both sulfur and nitrogen oxide emissions might have a fuel-to-electricity heat rate as low as 9300 Btu/kWh. (Heat rate, which is inversely proportional to efficiency, is a more common measure of power plant performance. In the United States, it is conventionally based on the higher heating value of a fuel—that is, the heating value including the latent heat of vaporization for steam. A heat rate of 9300 Btu/kWh is equivalent to a thermal efficiency of about 37%.) A "state-of-the-art" pulverized-coal plant—not yet built but using advanced components whose effectiveness has been demonstrated—is expected to achieve a heat rate of around 8800 Btu/kWh (39% efficiency).

A major focus of R&D on steam plants in recent years has been on integrating pollution control into the generation process, rather than having to add flue gas desulfurization scrubbers. Fluidized-bed combustion addresses this problem by mixing coal with limestone particles and suspending them together in a stream of air from below. At atmospheric pressure, this arrangement does little to improve heat rate but does make it possible to use lower-grade fuels.

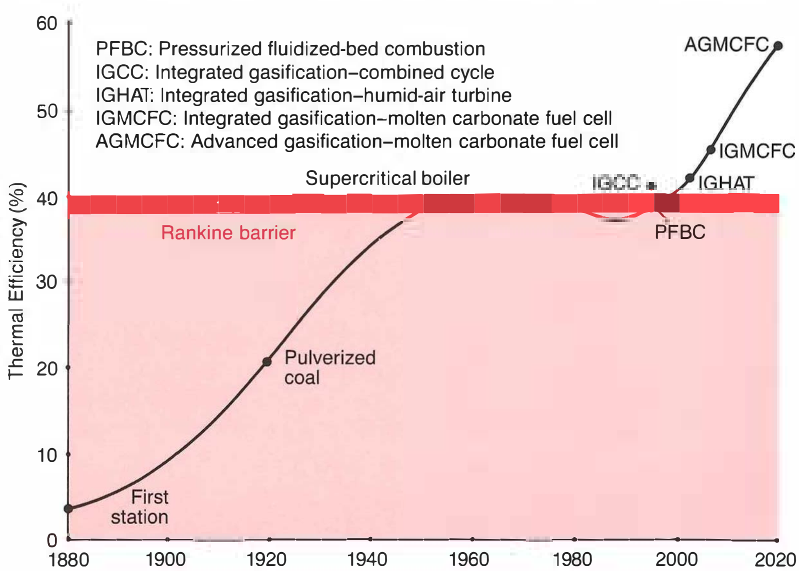
Heat rate improvements can, however, be realized in pressurized fluidized-bed combustion (PFBC). The trick is to supplement the steam cycle with an expansion turbine that runs off the pressurized gas exiting the boiler. By not relying on the Rankine cycle alone, PFBC plants may be able to achieve heat rates of 8700 Btu/kWh or better.

PFBC technology is now being demonstrated by American Electric Power at 70-MW scale; AEP plans to build a 330-MW plant by 1996. Both projects are being funded in part by the U.S. Department of Energy under the Clean Coal Program. EPRI is cooperating with DOE on a program to test high-temperature filters at the AEP plant that could protect the gas turbines from boiler fly ash. These filters are based in part on hot-gas-cleanup research that EPRI has been sponsoring, initially with the International Energy Agency and now with British Coal at the Grimethorpe PFBC Establishment.

Three other PFBC units in the 70- to

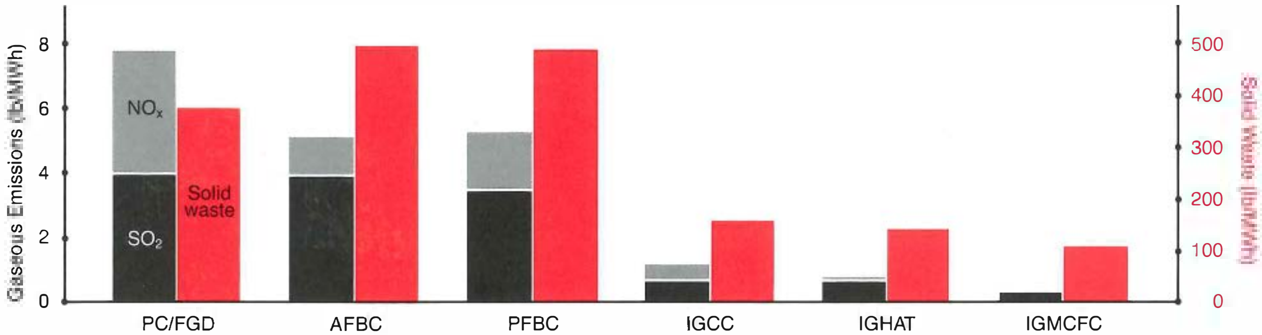
Evolution of Coal-Fired Power Plants

The efficiency of steam-based (Rankine cycle) power plants increased steadily for 80 years, nearing theoretical limits in the 1960s. Since then, efficiency has decreased somewhat because of the need to use energy to remove pollutants formed during combustion. Breaking the Rankine barrier of practical limitations on efficiency will require innovative approaches based on chemical energy conversion, such as coal gasification, and electricity generation by means of advanced combustion turbines and fuel cell technologies.



Environmental Trade-offs for Coal-Based Technologies

Flue gas desulfurization (FGD) units and fluidized-bed combustion—both atmospheric (AFBC) and pressurized (PFBC)—have been effective in reducing emissions of SO_2 and NO_x from coal-fired plants, but at the cost of producing substantial volumes of solid waste. Gasification-based generation options (IGCC, IGHAT, and IGMCFC) have the potential to cut those airborne emissions further and minimize solid waste without imposing an efficiency penalty on the overall system.



80-MW class also began commercial operation this year, in Europe.

Gasification—key to flexibility

The move beyond the Rankine cycle will take place in several stages. Already, significant efficiency improvements have been made by restricting the steam turbine to service as a bottoming cycle in plants whose primary energy conversion technology is the combustion turbine. Later, the bottoming cycle can also be replaced by nonsteam technologies.

Faced with rapidly escalating costs of coal-fired power plants and a virtual moratorium on nuclear power expansion, many utilities have turned to combustion turbines fueled with natural gas for new capacity. Operating at temperatures of up to 2300°F, such turbines are highly efficient, have low emissions, and are well adapted for intermittent use. If the current trend continues, the capacity of gas turbine equipment in the United States is expected to double during this decade, to about 100 GW.

To increase efficiency even further, utilities are increasingly using combined-cycle plants in which the hot exhaust gas from a combustion turbine is used to generate and heat steam to drive a steam turbine. A combined-cycle plant using natural gas can be built for about half the price of adding comparable coal-fired capacity. Also, since combined-cycle units are available with small capacities and can be installed quickly, a utility faces less financial exposure by building a series of small gas-based plants than by committing itself to a large coal facility.

Although natural gas now accounts for more than a quarter of total U.S. fossil fuel consumption—a share about equal to that of coal—gas resources are much smaller than those of coal. Over the long term, therefore, the price of gas is likely to rise substantially, compared with that of coal. In addition, only a fraction of the natural gas needed by electric utilities will be available on a firm, noninterruptible basis. Constraints on pipeline capacity are already being experienced in some regions.

"Eventually, many of these new power plants that initially rely on natural gas may have to switch to gas produced from coal," says Sy Alpert, an EPRI Fellow with long experience in the gasification field. "The large number of combustion turbines now being installed essentially guarantees that coal gasification will play a large role in the future. It's just a matter of price.

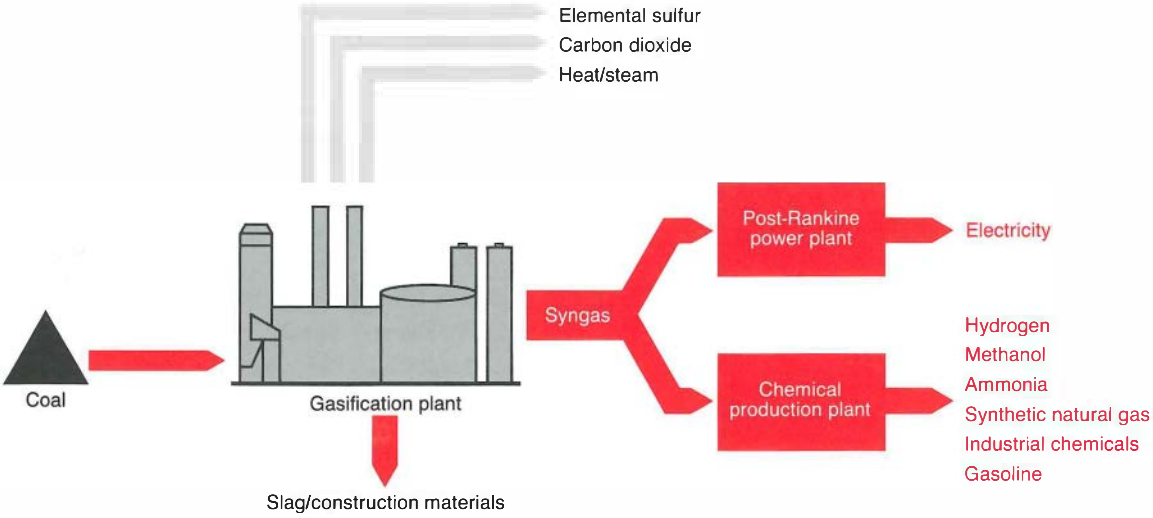
"Economic crossover will occur when the price of gas reaches about $4 per million Btu. I believe we can expect to see that price sometime after oil reaches $30 a barrel. Oil and gas prices often escalate together, since the two fuels are interchangeable for many applications, although the price of gas usually lags because it is no longer directly linked to oil production." (As this article was being written, oil had reached $40 a barrel in a highly unstable market.)

Power plants based on coal gasification offer three great advantages. They can break the Rankine-cycle barrier for efficiency. Their emissions are well below what is possible with the current generation of coal plants. And they offer unparalleled flexibility, since the coal gas can also be used as raw material for manufacturing a variety of important synthetic products.

High efficiency is achieved by burning the coal gas in a combustion turbine and then using a steam bottoming cycle to recover low-level heat from both the gas

Integrated Energy Facility

Gasification of coal opens opportunities to coproduce electricity and chemical products. An integrated energy facility based on this concept would produce synthetic gas continuously, using it both as fuel to generate electricity and as a feedstock for manufacturing a broad range of chemicals; waste heat from the plant could be used for district heating or industrial purposes. This approach maximizes energy efficiency, minimizes capital investment, minimizes air emissions and solid waste, and could provide an economic source of salable chemicals. Melding of coal gasification with electric power production was pioneered by the Cool Water integrated gasification–combined-cycle demonstration plant, which operated in southern California from 1984 to 1989.



Cool Water IGCC demonstration plant

turbine exhaust and the gasification process itself. Using current technology, such a first-generation integrated gasification–combined-cycle (IGCC) plant should be able to achieve heat rates as low as 8200 Btu/kWh (42% efficiency).

Environmental protection also depends directly on the gasification process. Sulfur can be recovered chemically from the coal gas in elemental form, which can then be sold. The formation of nitrogen oxides is inhibited during combustion by saturating the coal gas with water vapor to reduce flame temperature. The volume of solid waste produced by a gasification-based plant is less than half that of a conventional coal plant with scrubbers, and the product is an inert slag that can be used as a construction material.

Several U.S. utilities are actively pursuing IGCC projects, following the successful demonstration of the concept at EPRI's 100-MW Cool Water facility, which operated from 1984 to 1989. In addition, Destec, a wholly owned subsidiary of Dow Chemical, is currently operating a 160-MW IGCC plant in Plaquemine, Louisiana. Abroad, SEP—the joint operation authority for electricity production in the Netherlands—is now constructing a 250-MW IGCC plant based on Shell gasification technology. That plant is scheduled to start operation in 1993.

Beyond the steam bottoming cycle

Just as plant efficiency can be increased by using a combustion turbine instead of a steam turbine as the primary power source, further gains could be expected if a suitable alternative were found for the steam-dependent part of a combined-cycle plant. One attractive solution would be for this bottoming cycle to recover heat from the combustion turbine exhaust in such a way that it could be used again in the same turbine.

Recently, engineers at Fluor Corporation have proposed an improved concept for recovering the exhaust heat. Rather than having air pass directly from the compressor stage of a gas turbine into the combustion stage, this process diverts it into a cooler and then into a vessel known as a saturator. After the compressed air enters the bottom of the saturator, it flows upward against a stream of water that has been heated by the turbine exhaust, the compressed-air cooler, and any other sources of low-level heat. When the air leaves the top of the saturator, it has been humidified to between 10% and 40% water vapor. This humidified air is then further heated by the turbine exhaust and sent to the combustor, where fuel is added and burned.

Such a humid-air turbine (HAT) gains efficiency by greatly increasing the mass flow through its expansion stage for a given amount of air flowing through the compressor and by having a higher input temperature at the combustor. A power plant based on a coal gasifier and this turbine could have a heat rate as low as 8100 Btu/kWh (42% efficiency) without using a steam bottoming cycle but still reclaiming low-level heat that would be difficult for other cycles to utilize.

In addition, use of the HAT cycle could help lower the capital cost of a gasification-based power plant by some 20%, compared with the IGCC approach. The reason is that in an IGCC plant, heat for raising steam is obtained by passing the coal gas through large coolers, which are the most expensive components of the gasification system. With HAT, the gas could simply be quenched with water.

"The HAT cycle looks very attractive as a way to significantly lower costs and somewhat increase the efficiency of coal plants with gasifiers," says technical manager Arthur Cohn. "Although a prototype of this turbine has not yet been constructed, it is based on current component technology and might be able to reach commercialization within three to five years. In order to find out the likely development costs and schedule, a request for proposal has gone out to manufacturers potentially willing to build a HAT prototype."

Two other turbine designs are also being considered as alternatives to the steam bottoming cycle of a gasification-based power plant. The intercooled steam-injected gas turbine (ISTIG) uses heat from the turbine exhaust to produce steam that is then injected into the gas stream in three stages. General Electric has conducted initial studies on ISTIG using computer models and, with EPRI, is now doing a more detailed analysis. EPRI is also sponsoring a site-specific technical assessment of the concept with Florida Power.

A closely related concept is the chemically recuperated gas turbine (CRGT). Like the ISTIG, this turbine uses exhaust heat to generate steam, but this steam is then mixed with the fuel, with which it reacts chemically before combustion. The California Energy Commission has recommended development of the CRGT, and EPRI is conducting some preliminary analyses of the concept as part of the project with GE.

Electrochemical conversion

The next step in efficiency improvement involves a fundamentally different approach to generating electricity from coal gas—eliminating the combustion turbine altogether and relying on electrochemical conversion through a fuel cell. Such direct conversion potentially offers the highest efficiency and lowest emissions of any coal-based plant yet devised.

The operation of a fuel cell is similar to that of an ordinary battery. Electrodes immersed in an electrolyte act as sites for chemical reactions that release or absorb electrons. In a battery, the electrodes themselves provide the fuel for these reactions and thus eventually deteriorate. In a fuel cell, the electrodes act as catalysts for the continuous oxidation of a stream of hydrogen-rich fuel.

Ideally the fuel cell selected for use with a coal gasification unit should operate at about the same temperature as the gasifier. One promising candidate, the molten carbonate electrolyte fuel cell

(MCFC), is just now approaching utility demonstration. A 100-kW MCFC unit developed by Energy Research Corporation will go on-line at Pacific Gas and Electric's San Ramon Research Center in 1991, cosponsored by EPRI, PG&E, and the California Energy Commission.

Although this first demonstration unit will be fueled with natural gas, EPRI is negotiating with Dow Chemical to test a 20-kW MCFC at the company's Plaquemine gasification facility. Meanwhile, EPRI and the American Public Power Association are working with a group of utilities representing all segments of the industry to promote commercialization of a 2-MW MCFC system. Construction of early demonstration units will begin in mid-1993.

In its current configuration, an MCFC plant would use a conventional steam bottoming cycle to recover heat from exhaust gas leaving the fuel cell. Such a plant is expected to have a heat rate of about 7500 Btu/kWh (45% efficiency) when used with a coal gasifier. Future improvements, including recycling of hydrogen to the gasifier, could lower the heat rate to perhaps 6000 Btu/kWh—in other words, a coalpile-to-busbar efficiency approaching 60%, compared with about 37% for today's best pulverized-coal technology.

"The molten carbonate fuel cell combined with a gasifier would be the cleanest, most efficient coal power plant ever devised," according to fuel cell program manager Edward Gillis. "What we're trying to do is jump-start the process by commercializing the fuel cell as a stand-alone unit run on natural gas. This will provide the confidence and commercial scale necessary to marry the fuel cell with coal gasification."

Adds Neville Holt, program manager for gasification power plants: "It's not yet clear just which gasification process would be most appropriate to get the best performance from an MCFC. In choosing a gasifier for use with a fuel cell, you want to maximize the chemical energy content of the gas. Another important issue is how to clean up the gas so it doesn't poison the fuel cell. We're working very closely with the Department of Energy to study the various options."

Fuel Cells for Top Efficiencies

Molten carbonate fuel cells, which can chemically convert gaseous fuels into electricity without combustion, have the potential to raise power plant efficiencies to unprecedented levels. EPRI, Pacific Gas and Electric, and the California Energy Commission have cosponsored the development of a 100-kW MCFC test unit that will be demonstrated on-line at PG&E's San Ramon Research Center in 1991. The technology will eventually be paired with advanced coal gasification systems in integrated utility power generation facilities.

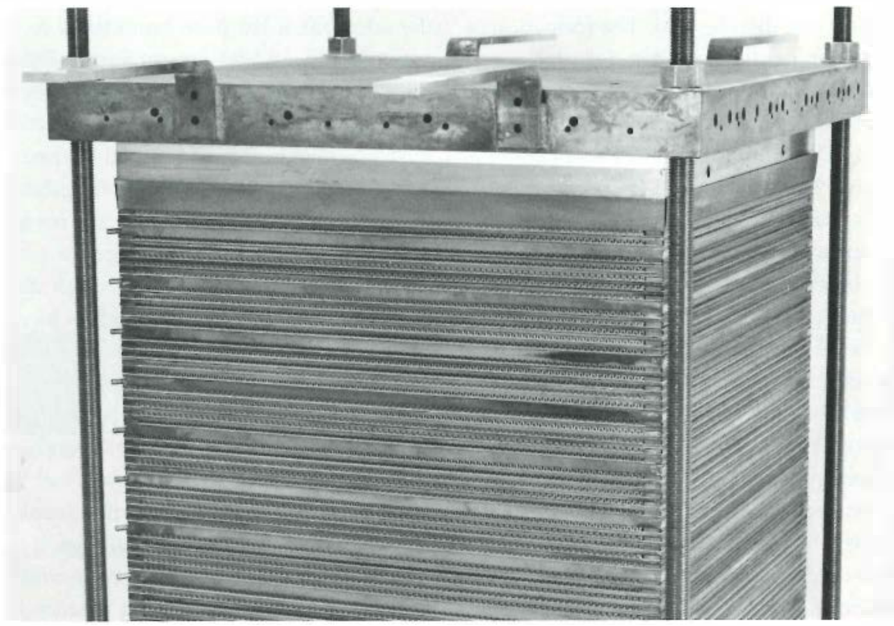


Photo courtesy of Energy Research Corp.

Nongasification approaches

Several other approaches to improving coal plant efficiency, which do not involve gasification, are also being considered. Although these advanced technologies might eventually have cost and efficiency advantages over the gasification-based options just discussed, none has reached a comparable stage of development.

The concept of a magnetohydrodynamic (MHD) power plant has been pursued for many years. In the MHD process, coal is burned at temperatures high enough to ionize the combustion gas. This gas is then seeded with small amounts of potassium to make it conductive and passed through a strong magnetic field. The magnetic field diverts the electrons, creating an electric potential. The electrons are then collected at electrodes to produce a current.

The advantage of the MHD process is that it can burn coal directly, without a gasification step, and has the potential to recover the energy in a highly efficient manner. The primary technical challenge is how to deal with a very hot, ionized gas. Once the gas has passed through the MHD converter, it still retains considerable heat energy at over 3500°F. Recovering this energy in a heat exchanger poses severe materials problems. Assuming successful development of an appropriate advanced heat exchanger—which is not yet under way—an MHD plant might achieve a heat rate of 6000–6500 Btu/kWh (52–57% efficiency).

The Department of Energy will sponsor operation of a 2-MW MHD component development and integration facility, scheduled for completion in 1993, which should provide a better basis for estimating the viability of the MHD concept. EPRI is cooperating with this effort by sponsoring studies of the interface problems that would be involved in adding MHD units at two existing coal-steam plants to boost their power output. Full-scale development is not expected for 20–30 years.

Another option, an indirect-fired turbine, would replace the usual combustor with a heat exchanger, in which heat from burning coal would be transferred to the turbine air stream between the compression and expansion stages. Such a turbine would not have to be ruggedized, since combustion products would never come in contact with the delicate internal components. The heat exchanger, however, would have to be built of some unconventional material, such as ceramics, since metals would be practical only for temperatures lower than about 1500°F—below the level needed for an economically viable power plant. Assuming successful development of an appropriate heat exchanger, a plant with an indirect-fired turbine might be able to achieve a heat rate as low as 7000 Btu/kWh (49% efficiency), but the rate could be as high as 9000 Btu/kWh.

Toward integrated energy facilities

"We believe gasification-based technologies are the way to go to improve coal plant performance," says Ron Wolk, director of EPRI's Advanced Fossil Power Systems Department. "They are an order of magnitude cleaner than existing plants, and even the first-generation IGCC units indicate a cost and efficiency competitive with pulverized-coal plants, once you add the extensive emission controls that are now required. With a HAT cycle, and maybe 10 years later a molten carbonate fuel cell, the gasification approach will be even more attractive. Some other technologies may also contribute, but probably not for another two or three decades."

The ultimate advantage of coal gasification is that its flexibility extends not only to generation of electric power but to coproduction of many commercial chemicals as well. Such coproduction in an integrated energy facility—sometimes called a coal "refinery"—could both reduce the cost of electricity generated and provide a utility with an additional profit center. Heat from the gasification process could also be used directly in industrial processes or for district heating.

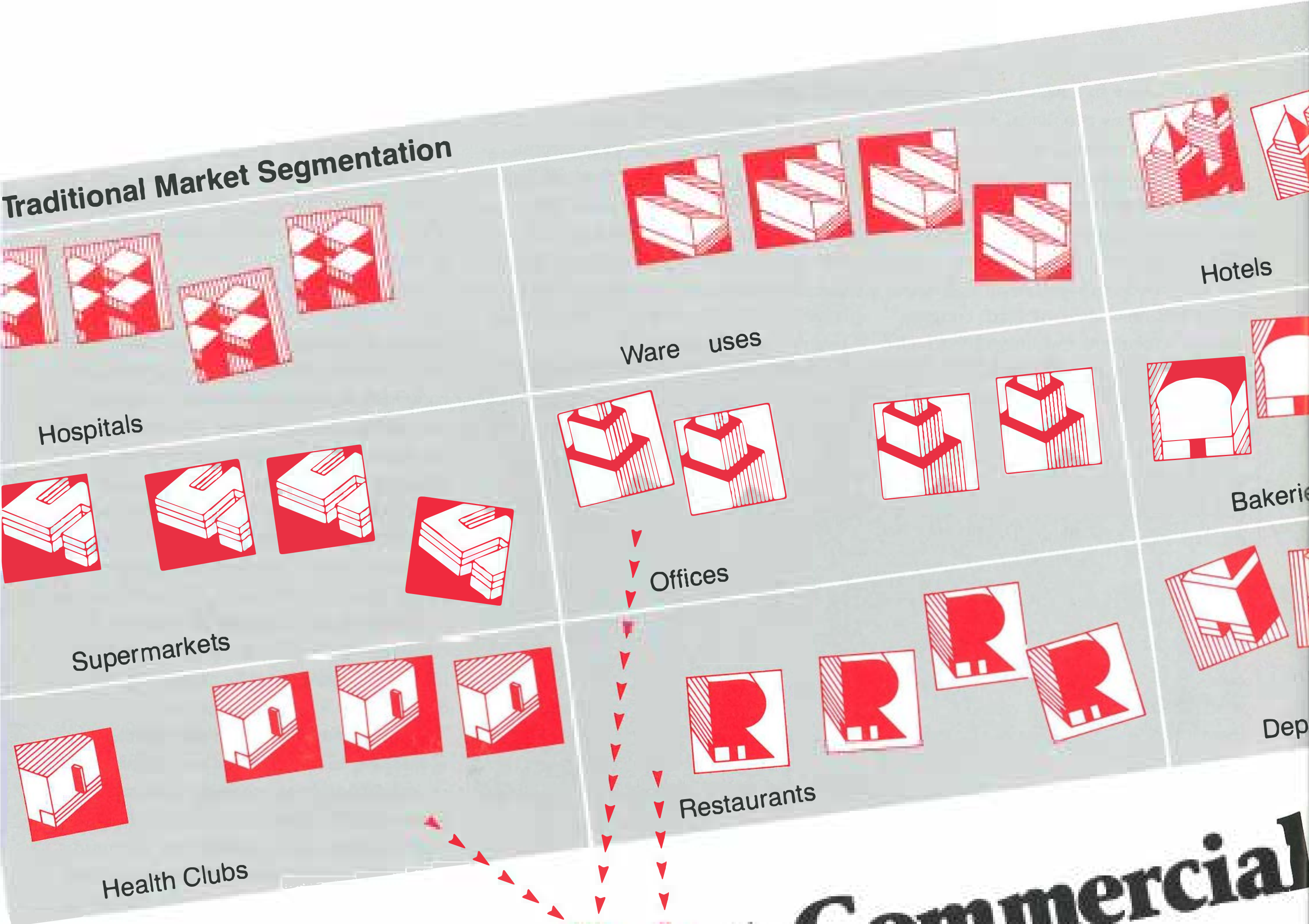
The idea of producing electric power and chemical feedstock at the same plant is surprisingly old. Some of the first power plants in Europe were based on a process that removed volatile compounds from coal to produce chemicals, leaving a char that was burned to drive a gas engine. More recently, gasification of coal without coproduction of electricity has been highly developed to meet specific needs. For example, South Africa's three large SASOL gasification plants produce much of the country's gasoline, jet fuel, ammonia, and industrial chemicals. Other applications include the production of acetic anhydride by Tennessee Eastman at Kingsport, Tennessee, and the production of ammonia by Ube Chemical in Japan.

Gasification of coal produces a mixture of hydrogen and carbon monoxide. These products can be reacted in the presence of a catalyst to form methanol, which can serve as the raw material for making numerous industrial chemicals. Commercial processes are available, for example, to convert methanol into acetic acid, formaldehyde, and proteins. It can also be used directly as a fuel for turbines or automobiles. Alternatively, the hydrogen and carbon monoxide can be used to form gasoline, through the well-established Fischer-Tropsch process; or the hydrogen can be separated and reacted with nitrogen to form ammonia for fertilizer.

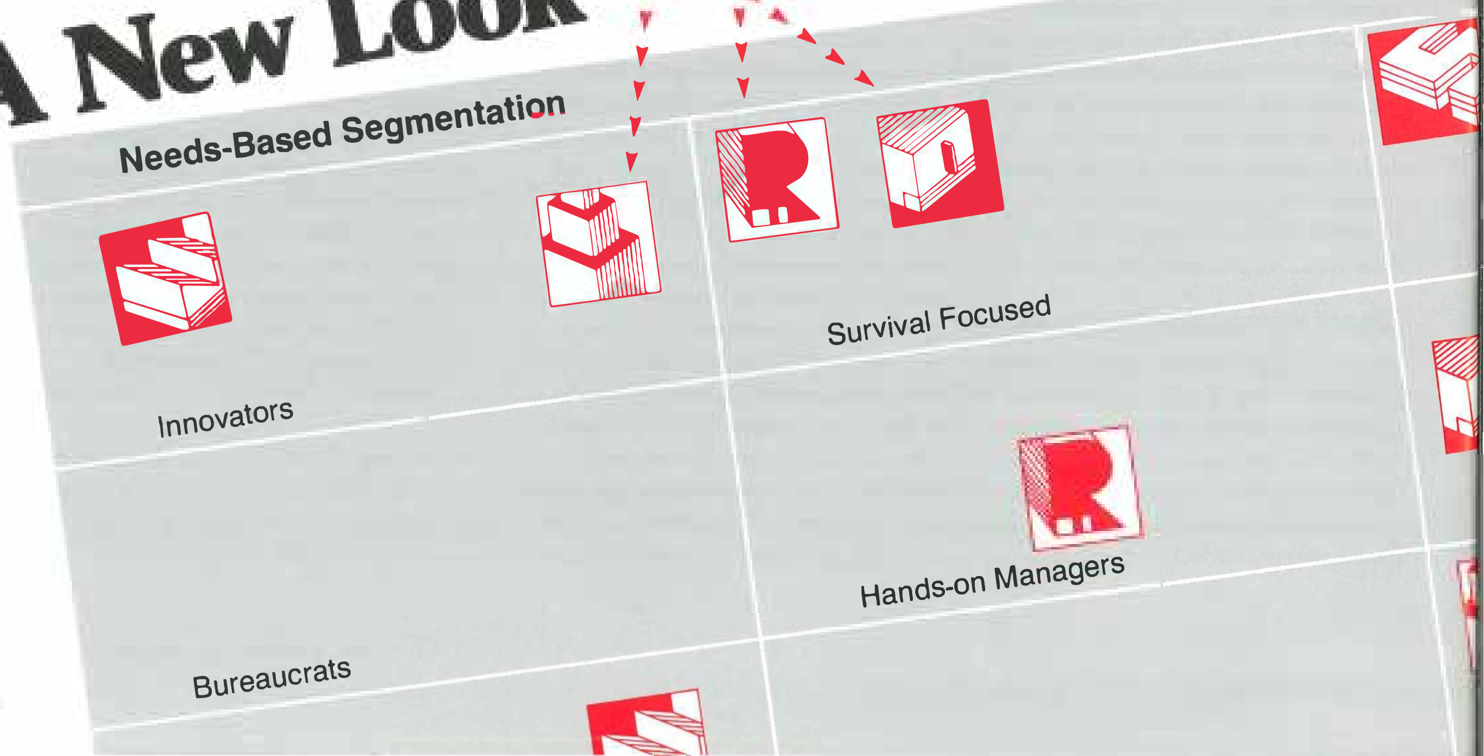
In an integrated energy facility, the coal gas could be used directly in a combustion turbine to produce electricity during hours of peak demand and then converted to chemical feedstocks during off-peak hours. A 400-MW power plant, if operated with a 90% capacity factor—generating power 65% of the time and chemicals 25% of the time—could produce 3000 barrels a day of chemicals and save 33% on the cost of generating electricity. If the market selling price of the chemical products were to increase sufficiently, the after-tax return on the incremental investment in the chemical production plant could be nearly 40%.

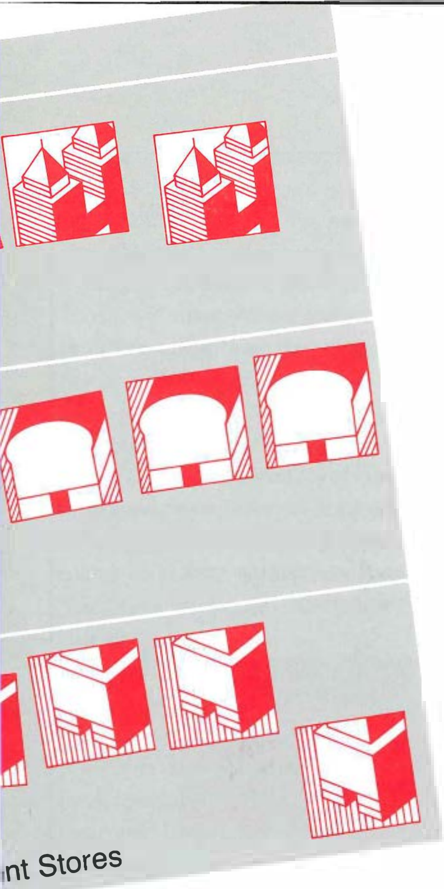
"The economics are complex, but time is working in favor of this integrated approach," concludes Michael Gluckman, director of technical evaluation and strategic planning in the Generation and Storage Division. "For the last several years, capital has been relatively expensive and oil has been relatively cheap. That's bound to change. Eventually we're going to have to pay more attention to conserving *both* capital and fuel. An integrated energy approach is the way to do that. Any coal plant requires a major capital investment. Why run it at 65% capacity factor? With gasification and coproduction of chemicals, you can make the plant do double duty. New technologies will be needed for utilities to stay competitive. And integrated energy facilities offer unique opportunities for enhancing financial flexibility while conserving resources and protecting the environment." ■

This article was written by John Douglas, science writer. Technical background information was provided by Ronald Wolk, Michael Gluckman, Edward Gillis, Neville Holt, and Arthur Cohn of the Generation and Storage Division and by Sy Alpert, EPRI Fellow.



A New Look at Commercial





Customers

THE STORY IN BRIEF

From supermarkets to health spas, restaurants to retail stores, the expanding commercial sector offers opportunities for utilities to improve their load shapes with demand-side management. But the number of commercial businesses participating in DSM programs remains low. One reason is that existing market segmentation techniques fail to provide the type of information about customers that utilities need in order to efficiently match programs to customer needs. EPRI has developed a new approach for segmenting the commercial market that defines customers according to their needs and decision-making behavior rather than what kind of business or building they are in. Understanding what motivates customer groups can help utilities design, market, and deliver the services each segment is likely to value most highly—thus satisfying customers while raising the participation rate for DSM programs.

The commercial sector presents electric utilities with both opportunities and challenges. As the United States continues to move from a manufacturing- to a service-based economy, commercial businesses represent the fastest-growing market for electricity. Consuming almost 800 billion kilowatthours of electricity per year, or more than 30% of electricity sales, the commercial sector has an appetite for electric power that is expected to grow at an annual rate of 3%. Recognizing that their future success is aligned with that of their commercial customers, utilities are paying closer attention to the energy needs of this market, forging stronger customer-utility relationships aimed at helping both sides deal with the issues confronting them.

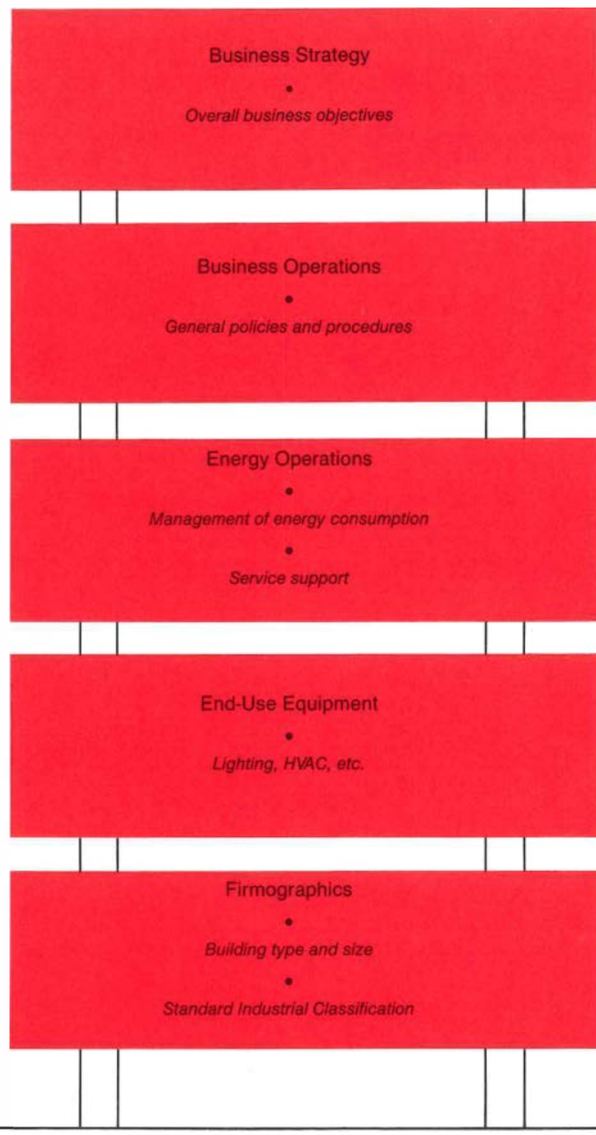
For utilities, commercial-sector issues include strong competition from gas-fired equipment such as furnaces, water heaters, and packaged cogeneration systems. Utilities need efficient electric equipment that increases the value of electricity for commercial customers. By providing and promoting efficient products that customers will purchase, utilities can achieve their load-shaping objectives.

For commercial businesses, improving productivity and competitiveness is an ongoing challenge. Reducing energy expenses, either by improving equipment efficiency or by taking advantage of economical off-peak power, can help a business maintain its competitive edge. Even more important can be the use of electricity to increase worker productivity, since labor costs in a commercial enterprise typically exceed energy costs by a factor of 100. A better lighting system or air conditioning system that allows workers to function more efficiently clearly has implications beyond energy use considerations.

In response to the challenges confronting commercial businesses and the utilities serving them, EPRI's Customer Systems Division is developing equipment that uses electricity more efficiently and

A Multilevel Approach

Commercial businesses have a hierarchy of concerns that affect decision making at different organizational levels. Efforts to segment the commercial market for promotion of energy programs have traditionally focused on the lower two rungs of this ladder, which describe customers in physical terms. But such approaches fail to account for how customers think—for differences in business strategy and operations that may strongly affect a customer's decision to participate in a particular utility program. By examining the full spectrum of concerns, the EPRI-developed segmentation framework can help utilities better understand their commercial customers and present programs and services most likely to win their acceptance.



productively and is also developing demand-side management (DSM) tools to help utilities modify the way customers use electricity, which will help utilities control costs and achieve a more desirable load shape. The intent is to benefit both the utility and the customer. By influencing demand, the utility can use its resources more efficiently and improve financial performance. Meanwhile the customer enjoys the benefits of reduced energy costs and more efficient operations. DSM programs and services come in many flavors: a utility can promote the use of technologies that reduce energy consumption, such as high-efficiency lighting, or those that don't use power during periods of peak demand, such as thermal storage systems that use off-peak power to heat or cool buildings during peak periods. Utilities can also shape their load by means of rate structures that encourage customers to shift demand to off-peak hours.

But having these technologies and programs available isn't the same as putting them to work. That requires customer participation—and participation is voluntary. Many utilities have offered seemingly attractive programs and services to their customers only to be met with a lukewarm reaction. This is especially true in the commercial sector, where participation in DSM programs has been relatively low—about 11% of the commercial businesses nationwide.

The Customer Systems Division's Market Assessment Program is helping utilities increase customer acceptance of new technologies and DSM programs by using market strategies and tactics. Although the analytical methods for doing this are sophisticated, they are grounded in a traditional principle: Know the customers, and give them what they want.

"For demand-side management to be successful, utilities have to achieve a deeper and broader understanding of their customers," says program manager Larry Lewis. "Utilities can then use that knowledge to develop DSM programs that are likely to win customer acceptance."

Focusing on needs

Lewis heads up the division's customer preference and behavior project, which seeks to help utilities better understand their customers' energy needs. A key component of the project is to devise methods for grouping customers according to these needs. This process, market segmentation, serves to divide a large and heterogeneous mass of customers into smaller, more homogeneous markets. Once this is done, a utility can tailor products to fit the needs of each segment, then market the products to the target groups.

"Segmenting the customers promotes more cost-effective marketing and selling," explains Lewis, "because it focuses efforts on targeted groups of customers that are likely to produce the best rate of return on investment. Moreover, segmentation can be used to produce increased levels of participation within the target groups."

This was shown to be the case when the customer preference and behavior project applied market segmentation techniques to the residential sector. Using data obtained from residential customers' energy needs and preferences, the researchers grouped customers into six distinct segments. Incorporating this knowledge into program design and marketing efforts has paid off in helping utilities achieve higher rates of residential customer participation in DSM programs. "Our residential work showed us that we can increase program participation somewhere between 15% and 20% by doing a better job of targeting the programs," says Lewis.

The residential segmentation framework, embodied in a software program called CLASSIFY, is based on identifying the needs that customers try to satisfy in deciding whether to participate in utility energy programs. This approach, known as needs-based segmentation, can help utilities obtain a better understanding of their customers' energy needs. It can also provide ideas for new programs and services and help utilities develop a more effective program marketing mix.

Building on the foundation established by this residential-sector work, EPRI has turned to the commercial market. The vast and varied commercial sector presents stiff challenges for marketers of DSM programs. Commercial businesses range from fast-food outlets and hotels to department stores and hospitals. Each company has its own culture, operating strategy, requirements for energy, and hardware. Furthermore, the decision to purchase a new piece of equipment or participate in a utility program isn't made by a head of household, as in the residential sector; instead, the decision may be influenced by several individuals, each of whom considers the purchase on the basis of different needs.

This seemingly impenetrable complexity has hindered the development of effective tools for segmenting the commercial market. The primary approach used today involves segmenting commercial customers according to Standard Industrial Classification (SIC), building type and size, and mix of end-use equipment.

This approach is useful, but it suffers from a fundamental weakness: it assumes that all customers within a particular segment will behave in the same way. For example, it assumes that retail establishments that have similar amounts of building space and similar peak electric demand, and that air-condition a similar amount of floor space, would respond similarly to a proposed space-cooling program. But is that a realistic assumption?

"On paper, those businesses may look the same," says Lewis. "Yet they may well have very different business strategies and operational needs. Consequently, their buying behaviors and their willingness to participate in a particular program may be very different. For example, Bloomingdale's and K-Mart fall under the same SIC and business type, but they have very different strategies and operating philosophies.

"Segmentation techniques that don't account for differences in strategic and operational needs are unlikely to produce good marketing yields. They just don't offer much insight into the underlying needs of the company or how a particular utility product or service might meet those needs."

Some utilities have experienced firsthand the limitations of the traditional approach. In attempting to get a commercial business to participate in a DSM program—a cool storage system, for example—the utility may win the support of the manager responsible for the company's energy operations. But the decision to participate will often be deferred to higher levels in the organization—to the vice president of operations, perhaps, or even to the chief executive officer. If these people don't perceive the system as meeting the company's business operations needs or its strategic goals, they may veto the proposal.

What's called for, Lewis suggests, is a new way of looking at commercial businesses—an approach that takes into account the factors that determine *why* a customer is likely or unlikely to participate in a utility program.

Top down, bottom up

Such an approach is being developed by National Analysts, a subsidiary of Booz, Allen & Hamilton, under the sponsorship of EPRI's customer preference and behavior project. The approach uses an expanded version of the CLASSIFY code, called Commercial CLASSIFY, along with a set of comprehensive questionnaires designed to obtain data from companies not only on their energy-related needs but also on their overall strategy and operations. By providing insight into the needs and purchase-decision processes of commercial customers, this framework is intended to help utilities target DSM programs to specific commercial customer segments, as well as predict their level of participation in the programs. In addition to being a valuable tool for program planning, Lewis notes, the framework can help utility field representatives to better understand their commercial customers and so serve them more effectively.

In developing the approach, National Analysts conducted a series of interviews with businesses across the United States that had recently made decisions to participate or not participate in utility demand-side management programs.

"In virtually every case," says John Berrigan, vice president of National Analysts, "several dimensions of needs were reflected in the decision process." These multidimensional needs, he explains, include those that relate to the overall strategic objectives of the business and those that relate to the operating policies and procedures designed to secure the strategic objectives. In addition, there are needs associated with the delivery of basic utility services and more-specialized needs related to particular end uses. These basic needs can be compared to the rungs of a ladder: business strategy is at the top, while business operations, energy operations, and end use are successively lower rungs. The bottom rung, called firmographics, consists of data such as SIC, building type and size, and mix of end-use equipment—the kinds of information that utilities now use to segment the commercial market.

When a company's needs are viewed in this manner, it becomes clear that the traditional approach which focuses on the needs at the lower rungs of the ladder—provides a one-dimensional, bottom-up perspective that ignores the other levels of needs that influence a company's decision to participate in utility programs. This suggests, according to Berrigan, that a systematic top-down *and* bottom-up approach to the identification of needs is necessary to adequately segment the commercial market.

National Analysts then conducted interviews with business strategy and operations consultants, as well as managers and executives in the commercial sector. The firm also worked with Wisconsin Electric and Baltimore Gas & Electric to survey a broad sampling of the two utilities' commercial customers. The survey respondents included managers responsible for their companies' energy-related needs, as well as senior executives who could speak knowledgeably about their companies' business strategies and operations. Each participant answered a series of needs-based questions on a six-point agree/disagree scale. The results were then used to identify the dominant needs corresponding to each rung of the ladder. These needs were defined along a continuum from strongly positive to strongly negative.

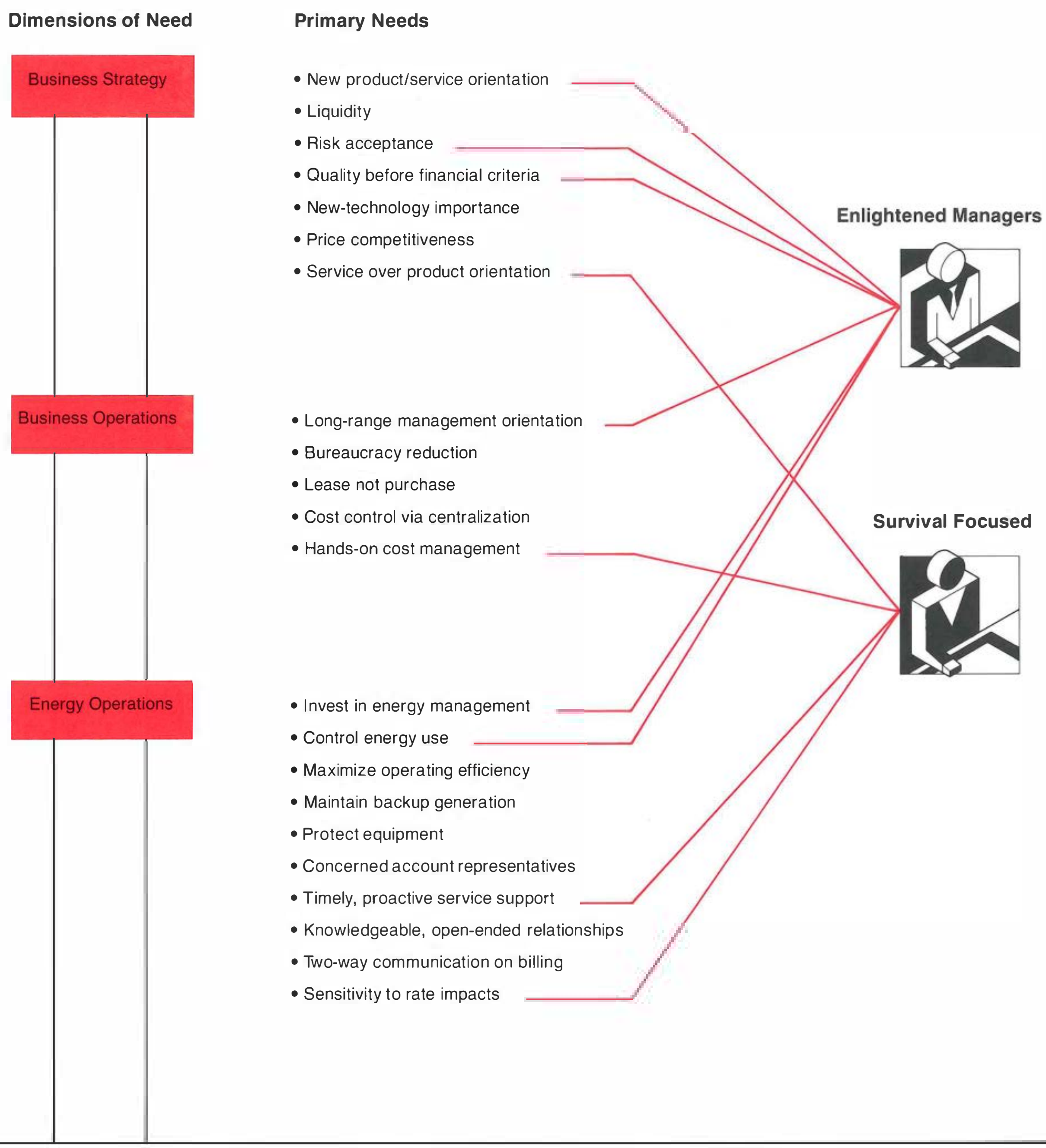
This work helped bring the picture into sharper focus. National Analysts identified 22 primary needs that commercial businesses will seek to satisfy when considering energy-related products and services. These 22 needs are distributed among the rungs of the framework. For example, the business strategy dimension reflects the needs that a company's owners or chief executive officer will attempt to satisfy to reach their strategic objectives. The next level, business operations, represents the needs that the chief financial officer or vice president of operations will seek to satisfy in managing the day-to-day administration of the company. Energy operations embodies the needs of the functional manager responsible for energy operations, while end use reflects the needs associated with specific end uses such as heating, cooling, and refrigeration.

Defining the segments

Individual businesses vary considerably in the degree to which they value each need—their responses may range from a strong positive orientation to a strong

Identifying Customer Segments

EPRI-sponsored researchers have identified 22 primary needs—distributed among the dimensions of business strategy, business operations, and energy operations—that commercial customers will attempt to satisfy when considering energy-related products and services. On the basis of their responses to questionnaires, customers are characterized by the degree to which they value each of these needs. A software program processes the data and partitions customers into segments that display unique patterns of needs. Two of these segments are shown here.



negative orientation. One company may, for example, assign a high value to liquidity but a low value to long-range planning. Another company may exhibit just the opposite orientation.

Despite this diversity, commercial customers do fall into groupings that reflect unique patterns of needs. "We applied a statistical procedure called cluster analysis and identified nine needs-based segments in the commercial sector," says Berrigan. Each segment is assigned a label that describes its dominant characteristics. Berrigan cautions, however, that "one shouldn't become too enamored of the labels; instead, the focus should be on the needs possessed by each group."

Owing to its unique pattern of needs, each segment presents utilities with different energy marketing opportunities and challenges. For example, innovators, a segment representing about 11% of the commercial sector nationally, experience slow and steady revenue growth, and as the label implies, their business strategy is based on constantly presenting new products and services. This commitment to innovation, National Analysts found, extends to their business and energy operations as well as their purchase behaviors. Innovators are generally driven to accept risks and adopt new technologies. In addition, their energy consumption is relatively low, yet they are committed to energy management.

Complacents, another segment, are highly flexible service-oriented institutions that emphasize quality in a mature market yielding steady revenue growth, according to National Analysts. Complacents believe their primary strategic objectives are to provide quality service, remain liquid, and preserve steady, relatively high rates of return. They tend to be averse to risk and unwilling to invest in new technologies and are not particularly sensitive to cost control. Energy consumption is high among complacents, yet they generally don't think energy is a significant operating expense.

"These types of insights into the needs and behavior of each customer segment can help utilities determine which segments will best respond to particular energy programs," says EPRI's Larry Lewis. "They also help utilities understand the marketing and sales trade-offs to be considered when approaching a particular segment."

For example, National Analysts' research indicates that innovators are generally interested in energy issues and will look to their utility as a source of advice on energy-related acquisitions. These are favorable characteristics as far as the utility is concerned, but they must be weighed against the small effect on utility loads that these customers would have, since they don't consume a lot of energy. Complacents, by comparison, do show a high level of energy consumption, and thus their participation in DSM programs could have a large impact on utility loads. But these customers are generally indifferent to energy-related matters, so a utility would have to mount a sustained marketing effort to sign them up.

Using the framework

Just how would a utility go about using this multidimensional framework to induce commercial customers to participate in demand-side programs? The first step, according to Lewis and Berrigan, is to administer the segmentation questionnaires to a large sample of commercial customers in the utility's service territory. Sometimes a single individual at a company—often the vice president of operations—can provide all the information required. In other cases, up to three individuals, representing different levels in the organization, may have to answer questionnaires. The resulting data are then fed to the Commercial CLASSIFY program, which partitions the customers into segments and supplies a wealth of information on the characteristics of each segment. This information includes projected estimates of the percentage of customers in each segment, as well as a description of each segment's general business strategy, business operations, and energy operations needs; firmographic and energy consumption profiles; and decision-making-unit analyses, program participation propensities, and channel preferences—that is, what types of promotional media and intermediaries such as equipment suppliers would be most effective.

Using this information, the utility can develop a market structure analysis that provides additional depth and detail on the characteristics of the commercial customers in its service territory. This analysis is a breakdown of each segment's prevalent needs, firmographics, and propensities toward specific programs and services.

Taking aim

Once armed with the knowledge and understanding such an analysis provides, a utility can develop a portfolio of programs and services aimed at satisfying the needs of the customer segments and so ensure high levels of customer participation. In addition, a utility can use this information to identify unmet needs that may warrant the development of new programs or services.

To identify target segments for each program in the portfolio, a utility would examine how its current and planned

Understanding the Commercial Market

Each of the nine commercial customer segments exhibits a unique pattern of needs that characterizes its business philosophy and decision-making behavior. It's interesting to note that companies can transfer from segment to segment over time. A young company, for example, may fall into the survival-focused segment, then move into another category as it matures.

Enlightened Managers

Enlightened managers are high-growth early adopters who apply sound business practices when they acquire products and services. This segment's main strategic objectives are preserving high rates of revenue growth and liquidity through high-quality new product and service offerings. These businesses closely monitor and control energy consumption and expense, and they seek to maximize equipment efficiency and reliability.

Hands-on Managers

Businesses in this segment have a simple decision-making structure anchored by a single individual directly involved in daily operations. Their rather conservative business strategy focuses more on decreasing the cost of operations than on increasing revenue, and they tend to avoid financial risk and investments in new technologies regardless of the potential benefits.

Constrained Relationship-Seekers

These businesses are relatively large electricity consumers and make a significant contribution to peak loads. But high debt loads and lack of cash prevent them from acquiring fuel-efficient technologies and the expertise to manage energy consumption. Instead, they look to utilities for help and support in managing and controlling energy costs.

Bureaucrats

Experiencing slow but stable growth, businesses in this segment tend to be shortsighted, risk averse, and somewhat cash constrained. Their dominant strategic need is to maintain procedural layers of formal review and approval to ensure financial control. Energy is typically not a significant portion of their operating costs, so controlling energy costs is a low priority. Multiple sources of influence and a lengthy, formal decision cycle can be expected.

Operating-Cost Sensitives

These businesses experience significant volatility in revenue growth and are concerned with managing and containing operating costs. They apply centralized management to minimize duplication of effort and use a rigorous set of financial criteria to guide acquisition decisions and performance.

Uninvolved

Averse to risk and resistant to technology, these customers have a spartan business strategy focused on offering mature products in mature markets. Their energy consumption is low, and they tend to view energy as a trivial operating expense—they don't feel the need to manage and control energy consumption or costs. Generally speaking, these customers simply want to be left alone.

Survival Focused

Near the edge of bankruptcy, these businesses are focused almost exclusively on activities that will generate cash to meet day-to-day operating costs. Senior management directly supervises daily operations, emphasizing revenue generation over cost reduction. Survival-focused firms tend to minimize financial risks, even if they hold opportunities for growth, and remain committed to an established core service or product.

Innovators

Experiencing slow but steady revenue growth, innovators present a continuous stream of new products and services to the market. This commitment to innovation characterizes their business and energy operations as well as their purchasing behavior. Consequently, they are willing to adopt new energy management techniques and invest managerial time in monitoring and controlling energy costs.

Complacents

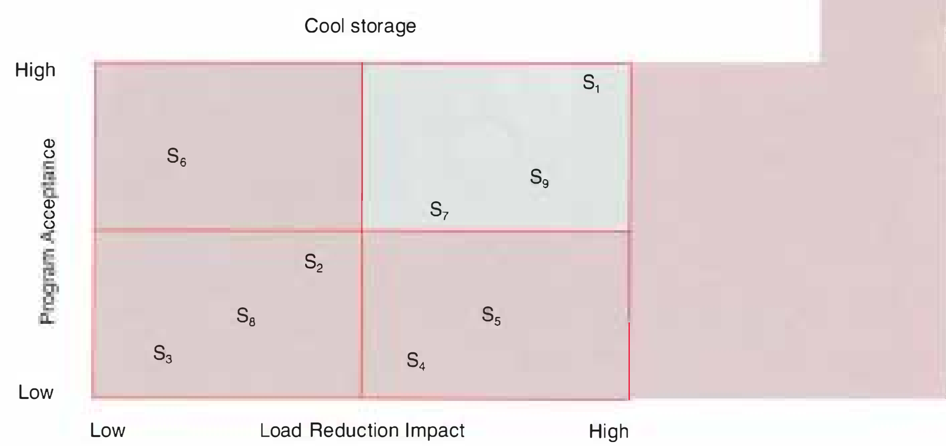
Complacents believe their primary strategic objectives are to provide quality service, remain liquid, and preserve steady, relatively high rates of return. They tend to be risk averse and unwilling to invest in new technologies, and they are not particularly sensitive to cost control. Even though they are among the largest consumers of electricity, they show little interest in controlling energy consumption or investing in energy-efficient equipment.

Applying the Framework

The multidimensional segmentation framework provides utilities with a wealth of information on the energy-related needs and the decision-making behavior of each customer segment. Armed with this information, a utility can identify the groups most likely to participate in specific demand-side management programs. Moreover, the information can be used to estimate a program's potential impact on utility loads, as well as the cost of delivering the program to each group. In addition to developing target markets, the framework helps utility field representatives identify key decision makers to whom they can communicate the benefits of specific utility programs and services.

Programs	Enlightened managers S_1	Bureaucrats S_2	Survival focused S_3	Hands-on managers S_4	Operating-cost sensitives S_5	Innovators S_6	Constrained relationship-seekers S_7	Uninvolved S_8	Complacents S_9
Heat pump water heating	●					●			
Efficient lighting		●	●	●	●			●	●
Cool storage	●					●	●		●
Air conditioner maintenance	●			●	●		●		●
Interruptible load	●		●				●		
Time-of-use rates	●		●	●			●		●
Commercial cooking	●			●					
Insulation	●								
Efficient chillers	●					●			
Delamping		●	●	●	●		●		●
Daylighting	●					●			
Heat recovery	●			●					

● High program participation propensity



programs fit each segment's propensities toward particular programs. For example, companies in the customer segment known as innovators are prime targets for cool storage and interruptible-load programs, while those in another segment, hands-on managers, are more inclined toward efficient lighting programs.

Next, the utility would estimate the load impact value for each segment by program, then specify the potential delivery cost for each segment by program. Combining this load impact and cost analysis determines the optimal portfolio for the commercial sector as a whole. The target segments are thus selected not only by their program preferences but also on their potential impact on utility loads relative to the utility's costs in delivering the program to them.

The power of the multidimensional framework is such that it could be harnessed not only to help utilities win customer acceptance of existing end-use equipment but to aid in developing new equipment, according to Morton Blatt, manager of the Customer Systems Division's Commercial Program. "We think we can use this research to develop goals for hardware development by identifying unmet needs," he says. "It can help us look beyond existing hardware toward more efficient new technology that will help commercial customers be more productive."

Adjusting the mix

In addition to strategic applications, the multidimensional framework can help utilities realize two important tactical objectives. The first is positioning, developing messages to inform key decision makers how the programs offered will satisfy their needs. The second is tailoring the marketing mix—which includes elements such as pricing and promotion—to make the package as attractive as possible to the largest number of customers.

Positioning is challenging in the commercial sector because needs exist at several levels and purchase decisions are often influenced by several individuals. Again, this has been a major stumbling block of traditional marketing approaches, which focus mainly on a company's energy and end-use needs: the positioning messages are directed at the manager responsible for energy operations. While this manager may be won over by the proposal, higher-level executives may veto it because the positioning message doesn't fit their needs.

But because the multidimensional framework considers business strategy and operational needs as well as energy needs, it permits a utility to develop separate messages for each decision maker. In addition, the information developed by the framework provides the utility with direction on who in the organization is likely to influence the decision and what type of positioning message is most likely to succeed.

To help utilities design commercial DSM programs and fine-tune the marketing mix, EPRI has developed a software product called PULSE Plus, which can be used to estimate the likelihood of customer participation for specific programs. PULSE Plus, an expanded version of the PULSE code developed for the residential market segmentation project, is a simulation program that allows a utility to foresee how alternative program designs will affect participation by each segment. In the case of a heat pump program, for example, PULSE Plus will allow a utility to see how each segment would respond to changes in attributes such as warranties or incentives offered with the program. "PULSE Plus may show that changing the warranty or incentive can boost the level of participation from, say, 12% to 18%," says EPRI's Lewis. "It also reveals which segments are likely to participate in a particular program and which are not likely to participate."

A customer-driven approach

The new multidimensional segmentation framework uses sophisticated market research and statistical techniques to enable utilities to meet their demand-side management goals with programs that meet customer needs. It all boils down to that basic principle: Know the customers, and give them what they want.

"This is a customer-driven approach rather than a utility-driven approach," concludes Larry Lewis. "By looking at commercial customers in terms of their needs, rather than in terms of building type and end-use equipment, utilities can tailor their DSM programs to meet those needs. The bottom line is that such programs are more effective in increasing customer participation, improving utility loads, and increasing overall customer satisfaction." ■

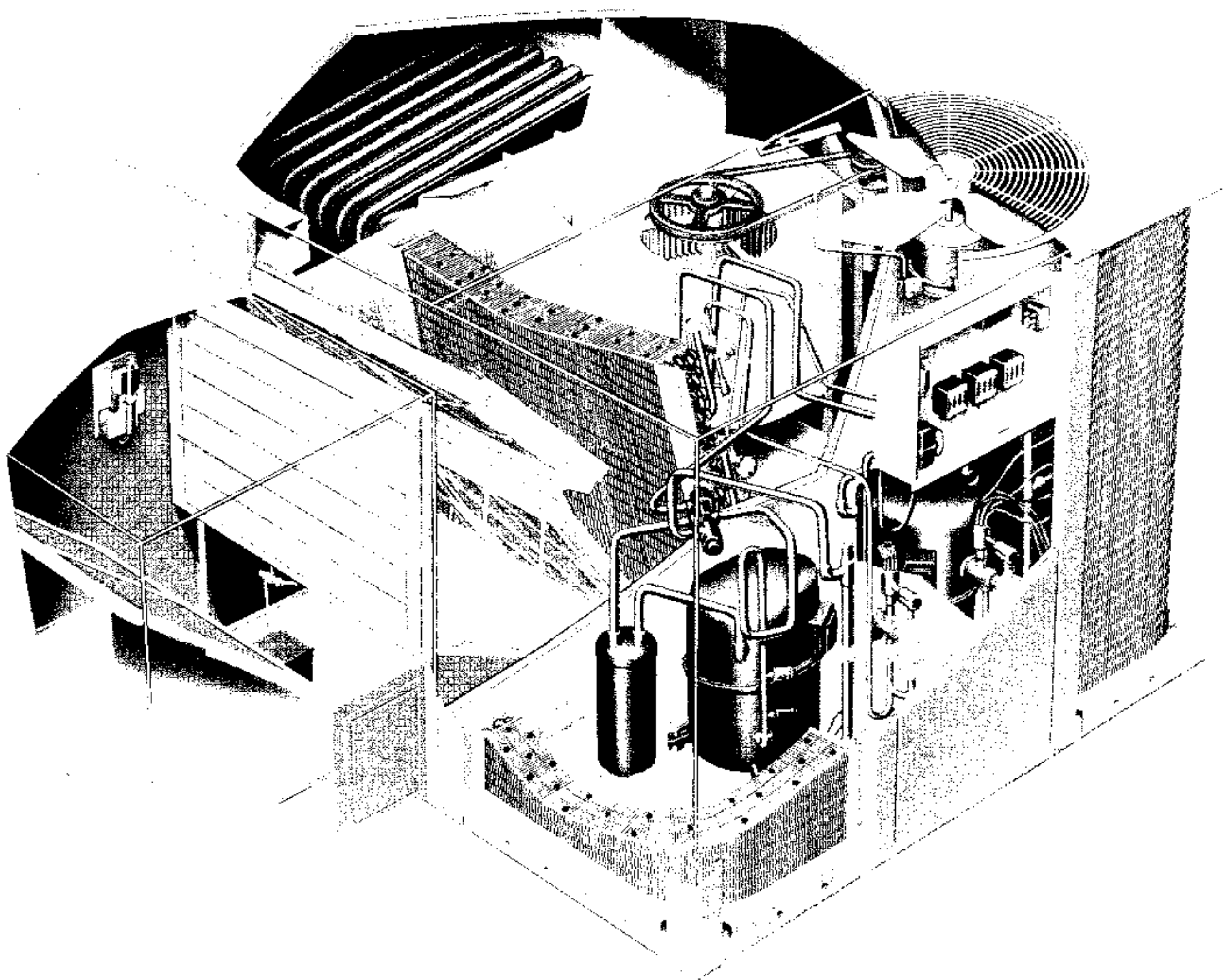
Further reading

"An Overview of the Commercial Market Segmentation Framework." Draft report prepared by National Analysts. April 1990.

"Understanding the Consumer." *EPRI Journal*, Vol. 11, No. 7 (October 1986), pp. 4–11.

This article was written by David Boutacoff. Background information was provided by Larry E. Lewis and Morton Blatt, Customer Systems Division, and John Berrigan, National Analysts.

HEAT PUMPS



Developing the Dual-Fuel Option

In the 1960s and 1970s, hundreds of thousands of gas-electric heating-cooling units were installed on the rooftops of commercial buildings across the United States. These units were fairly straightforward in design and operation, consisting of a natural gas furnace to provide heat in the winter and an electric air conditioner for summer cooling. As these conventional rooftop units wear out and have to be replaced in the 1990s, the obvious question arises: what is the best replacement technology?

For many situations, electric heat pumps would be an obvious choice for space conditioning of buildings, since they can operate at higher heating efficiencies than conventional gas-fired furnaces. Because the heating output of a heat pump declines as the outdoor temperature declines, however, supplementary heating is required when the ambient air is very cold. As a result, an all-electric heat pump is usually installed with an electric resistance heater, which serves as a backup when the building heating load exceeds the heat pump capacity.

Such a backup heater requires an increase of about 50 kW in electric service over the 10 kW or so already in place for the electric air conditioner in a typical 7.5-ton application. In some cases, the cost of upgrading the service connection for this increase can approach the cost of the replacement unit itself, making it too expensive to replace existing equipment with the usual heat pump options.

An innovative pairing of technologies now avoids this problem while offering additional flexibility advantages that promote low operating costs. Developed jointly by EPRI and Lennox Industries of Dallas, Texas, and introduced commercially by Lennox last December, the Fuelmaster dual-fuel heat pump (DFHP) consists of an electric heat pump combined with a gas furnace for backup heating, all in a single package.

The heat pump handles almost all of the heating duty in winter, extracting heat

THE STORY IN BRIEF

The dual-fuel heat pump incorporates a winning combination for commercial space conditioning—an electric heat pump for high efficiency and a gas furnace for economical supplementary heating during cold snaps. Developed jointly by EPRI and Lennox Industries, the Fuelmaster DFHP can be programmed to automatically choose the optimal mix of electric and gas operation to deliver uncompromised performance at the lowest cost. The unit's programmability also provides a hedge against fuel price changes and allows the customer to take best advantage of utilities' time-of-use rate incentives. On the other side of the meter, the DFHP can help electric utilities efficiently expand their share of the U.S. space-heating market—traditionally dominated by natural gas suppliers—without unduly affecting winter demand requirements.

from outside air and delivering up to three times as much energy as input. In summer the heat pump acts just like a conventional electric air conditioner. The gas furnace, used for backup during the heating season, can be connected to existing gas service lines. Because there is no need for electric service upgrades, the DFHP is an ideal system for replacing a worn-out gas furnace–electric air conditioning unit.

Dwight Matthews, an energy applications specialist at Portland General Electric Company, which performed some of the original DFHP prototype testing, calls the new system "a tremendous advance—a real boon for customers." Matthews believes the DFHP will be widely accepted among PGE customers because it combines more precise environmental control of buildings with more efficient operation. "You get the best of both worlds," says Matthews, "reliable heating and cooling at all temperature levels and at a lower cost than with conventional equipment."

Operation of the DFHP is relatively simple. At the heart of the unit is a controller that incorporates a time clock connected to an indoor and an outdoor thermostat. When the indoor thermostat calls for heat, the controller checks the outdoor thermostat and also the time clock, then selects the least costly operating mode—the heat pump, the gas furnace, or both—on the basis of the outdoor temperature and gas and electric rates for the time of day.

These factors—ambient temperature and fuel cost—are the keys to how much economic advantage the DFHP can deliver in a particular application. Generally, the more hours the unit can operate economically in the heat pump mode, the more attractive the application. From a temperature standpoint, this means climates with cold to medium-cold temperatures and long heating seasons. On the fuel price side, cost savings are greatest in locales where electricity is relatively inexpensive vis-à-vis natural gas. In this situation, the economic break-even temperature—the temperature at which it becomes economically advantageous to switch over entirely to gas furnace operation—is low, resulting in long operating hours for the heat pump.

To program the unit for least-cost operation, during installation its outdoor thermostat is set at the economic break-even temperature. Building operators can further customize the heat pump controller to take advantage of local electric rates to get the best savings. For example, in areas with on-peak and off-peak winter rates, the DFHP time clock can control the heat pump to take advantage of time-of-use electric energy rates or to minimize demand charges for commercial buildings.

Most forecasts predict that gas prices will rise faster than electricity prices in the near future. The fact that the DFHP's economic break-even temperature can be reset to reflect fuel price changes over the unit's life offers insurance against increases in gas prices, a feature not available with conventional gas-electric units. Customers are thus assured of minimum operating costs regardless of changes in the fuel market, an important consideration in a risk-averse market for commercial heating, ventilating, and air conditioning (HVAC) equipment. Customers will be able to use whichever fuel is more economical at any given time.

Product development

"The ability to use the heat pump as the primary heating means—rather than the gas furnace—is the principal advantage of the DFHP over the gas-electric unit it replaces. This advantage was the central concept in the technology's beginnings," says Morton Blatt, manager of the Commercial Program in EPRI's Customer Systems Division. The incentive for commercializing the dual-fuel heat pump emerged after an EPRI-sponsored research workshop held in August 1986 in Palo Alto. Twenty-seven experts from the electric utility and HVAC industries met to discuss U.S. needs for commercial space-conditioning equipment.

In the course of these discussions, attendees pointed out the need for alternative equipment to the tried-and-true rooftop systems. One utility representative said that he could save commercial customers as much as one-third on their annual electric bills if a dual-fuel heat pump could be used to replace existing gas-electric systems. Others at the meeting voiced a similar need for such a product for their commercial customers.

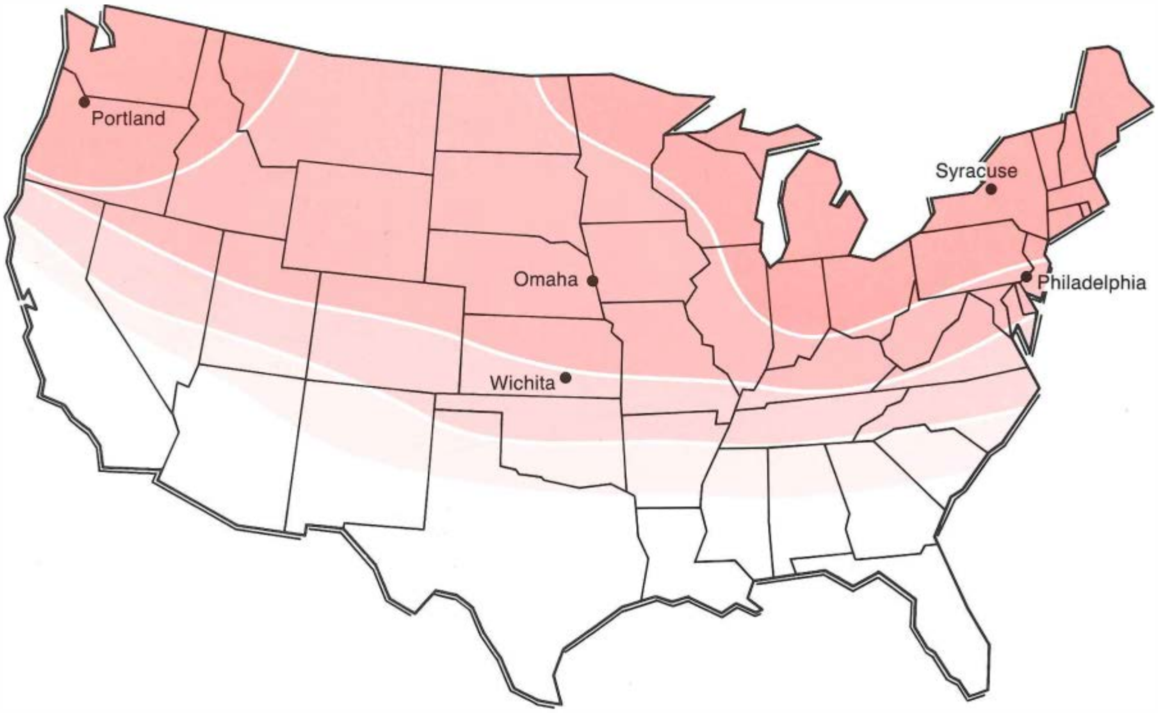
Following the workshop, EPRI decided to take the idea further. To investigate whether a DFHP would be economically sound, the Institute commissioned an economic analysis of the technology by the consulting firm Arthur D. Little. ADL used the EPRI-developed ESPRE energy economics model to determine how a heat pump coupled to a gas furnace would perform in different climates, and under different electric and gas rates, throughout the United States. The initial analysis results—for the St. Louis, Minneapolis, Chicago, and Columbus (Ohio) areas—were encouraging.

The researchers predicted that in regions with relatively long heating seasons and moderately cold temperatures (along with relatively low electricity prices and high gas prices), the heat pumps could operate at distinctly higher efficiencies and therefore at lower cost than gas furnaces. For the locations studied, ADL predicted that annual savings could range from $100 to $200 at current utility prices. Gas price escalation would increase these savings substantially.

Follow-up studies forecast even greater savings, up to $400 a year, on the basis of more-detailed cost analyses completed for Portland, Oregon, and Columbus, Ohio. ADL calculated the estimated savings by comparing a 7.5-ton DFHP unit with a conventional heating-cooling unit of the same capacity. "Geographically, we found that the best markets would be the Pacific Northwest, the Midwest, and other selected areas in the northern half of the United States," says Blatt. "We felt

Focus on Climate

While the attractiveness of the DFHP option in a particular application depends greatly on the relative prices of electricity and natural gas, climate is also a key factor. The technology's potential advantages are highest in the darkest-shaded areas of the map, where the winter is cold and the heating season long. Field test units were installed and operated successfully in the five locations shown here.



that this gave us enough viable markets to justify production of the units."

Armed with this information, EPRI contacted potential heat pump manufacturers and eventually convinced Lennox to build six prototype units that could be field-tested by EPRI and its member utilities. The unit's development costs were minimal, since the components could be taken from the company's existing equipment lines and put into a new package. All components had been used in other equipment before—they were field-proven.

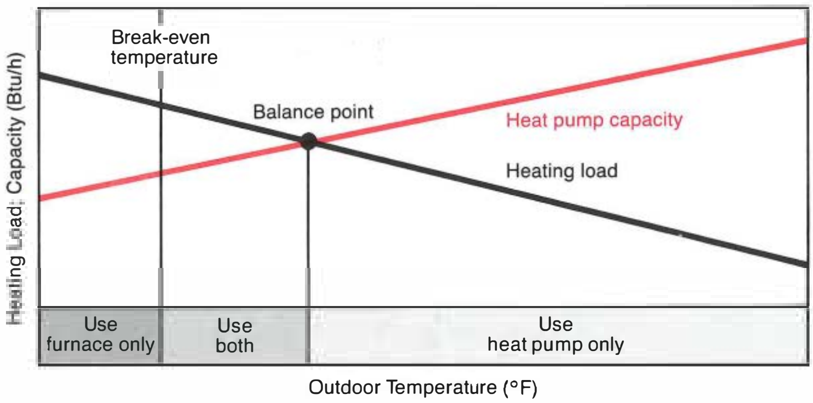
The evaluations began during the winter of 1987–1988 and were completed after the 1988–1989 heating season. One unit was sent to the Lennox test laboratory; four were field-tested by participating utilities in Philadelphia, Omaha, Wichita, and Portland; and the sixth unit was installed at the field test contractor's headquarters. This last unit allowed implementation and testing of any changes that might be required to improve the operation of the other field test units.

In fact, the only changes made during the tests were to the controller. The original controller did not allow optimal recovery of the DFHP after night setback, when buildings are unoccupied and need no heat. The original control units had been specifically designed for all-electric heat pumps and were configured to minimize electric resistance backup during the recovery from night setback. Lennox replaced these with controls designed for use with gas equipment, which do not unnecessarily constrain operation of the gas furnace. The new controls have been installed on the production units.

The participating utilities took the lead in finding locations for the test units, negotiating with the building owners for their installation, and overseeing their installation, operation, and servicing. The utilities then supervised the routine maintenance and monitoring of the units. In addition, they provided feedback on the units' operation by means of a utility interest group sponsored by EPRI.

Flexible Control

The DFHP's control equipment ensures that the most economical mode of heating is used during any given weather. The unit's thermal balance point—above which only the heat pump is used—is determined at the time of purchase, according to the building's heating load and the capacity of the unit's heat pump. On days when the outdoor temperature is below the balance point, the heat pump cannot handle the entire heating load, and the gas furnace must be used as a supplement. The break-even temperature, dependent on the relative prices of electricity and gas, is the outdoor temperature at which heat pump and gas furnace operating costs are equal. Below this point, the gas furnace is operated alone. The break-even temperature can be adjusted when fuel prices change, offering insurance against energy price fluctuations.



Into the marketplace

Results from the two-year field test were highly favorable. The owner of a 2700-square-foot restaurant in Portland saved $432 in annual heating bills by using the DFHP in place of a conventional unit. The owner of a small shopping center in Omaha reported that one of his tenants reduced his $400–500 monthly utility bills by 41%.

The test results established that at many sites current electricity charges can allow the heat pump to operate economically down to nearly the coldest temperatures of the season. Two examples are Tulsa, where temperatures were found to dip below that region's break-even level of 15° only 40 hours of the year, and Seattle, which experienced only 3 hours below its break-even temperature.

These results not only impressed building owners and participating utilities but encouraged Lennox to move into commercial production. EPRI calculates the retrofit market for existing gas-electric units to be about 10–15% of the space-cooling capacity sold in the U.S. commercial sector annually. This corresponds to about 100,000 to 125,000 aging gas-electric units that will need replacement each year (with a cumulative capacity of 750,000 to 850,000 tons). Market projections indicate that the DFHP could capture from 15% to 20% of this market.

Lennox is test-marketing its initial 7.5-ton and 10-ton models in three areas: Columbus (Ohio), Tulsa, and the Puget Sound region of Washington. As market acceptance increases, the company will expand production in order to extend sales to other markets. Lennox has positioned its 7.5- and 10-ton models to meet the heating and cooling demands of small commercial buildings ranging from 2000 to 4000 square feet, such as office buildings, restaurants, and retail stores.

Anticipating strong demand for the rooftop DFHP units, Lennox has shifted into commercial production at its Stuttgart, Arkansas, plant to build inventory for its target markets. Lennox is closely watching those markets, anticipating that it might introduce a full product line beyond the first 7.5- and 10-ton capacity sizes, says Roger Hundt, a marketing executive based in Dallas. "The reception has been great; the DFHP has been enthusiastically accepted by both customers and utilities."

Tom Kerfonta, senior engineer in commercial and industrial services at Puget Sound Power & Light in Bellevue, Washington, says acceptance of the new DFHP among the utility's customers has been very encouraging. Puget Power is promoting the DFHP through newsletters and circulars to all potential users among its customers, as well as to dealers and installers, who may have little knowledge of the DFHP's advantages over the conventional units they sell.

Kerfonta notes that customers for the DFHP units so far "range from doctors' offices to car dealers to drugstores." He adds, "It's a good choice for our customers because it offers the energy savings they want." A dozen units have been installed to date in the Northwest target market, with full-scale marketing by Lennox just beginning. The prospect for future orders looks promising.

Benefits for utilities

The DFHP can help electric utilities cost-effectively expand their share of the U.S. space-heating market—a market dominated by natural gas suppliers in the winter months. Space heating accounts for 47% of total U.S. commercial-sector energy use, and natural gas suppliers have more than 75% of this market. Clearly, there is room here for electric utilities to increase their market share through the sale of efficient electric heat pumps.

The DFHP is a product that allows electric utilities to do that and to use generation and transmission equipment more efficiently, thereby reducing service costs to customers. Compared with an all-electric heat pump, the DFHP provides 50–88% of the electricity revenue with only about 20–25% of the off-peak electric demand requirements. The connected load for a 7.5-ton DFHP is about 10 kW, compared with 30–60 kW for an all-electric heat pump. This could substantially improve a utility's load factor.

Moreover, since the DFHP can be controlled to operate only during the off-peak period, this demand does not have to coincide with the utility's peak. The potential increase in electric energy sales for the DFHP unit ranges from approximately 700 to 1500 kWh per ton, depending on climate and electricity and gas prices—with no increase in winter peak demand.

Sal Termini, marketing services manager at Public Service Company of Oklahoma, notes that his South Central utility will be able to increase off-peak electricity sales in the winter months, when it has excess capacity. "We are anxious to find new equipment that will generate additional electricity sales and yet save money for our customers," says Termini. He notes that the DFHP will also help reduce peak demand in the summer months because of the heat pump's improved cooling efficiency. The energy efficiency ratio (EER) for the DFHP is 8.3, compared with 7.0 for the old conventional gas-electric units being replaced.

But customer acceptance will not be automatic. The selling price of the Lennox DFHP is higher than that of the conventional gas heating–electric cooling equipment that could be used to replace existing units. Although this higher capital cost is offset by a lower cost of operation, consumers have historically been influenced in their buying decisions much more strongly by first costs than by life-cycle costs, which often penalizes advanced technologies in the marketplace.

The electric utility industry has an important financial stake in promoting the DFHP. The manufacturer and the installer make about the same amount of money whether they sell a conventional system or a DFHP, but a utility stands to generate thousands of dollars more in revenue over the operating life of a DFHP because it primarily uses electricity rather than natural gas. While the dual-fuel heat pump won't generate as much revenue for the electric utility as the all-electric heat pump, it will clearly generate more than today's conventional systems.

One recently completed EPRI study shows that utilities average $45,000 in revenue over the life of an all-electric heat pump and $27,000 over the life of a gas heating–electric cooling unit. The DFHP will probably generate between $36,000 and $42,000 for the electric utility. Clark Gellings, director of EPRI's Customer Systems Division, sees this as a crucial point: "The manufacturer will sell whatever is easiest to sell, whatever the customer wants. It is up to the electric utility industry to encourage customer purchase of heat pumps to ensure that the most efficient end-use equipment is used."

The development of the dual-fuel heat pump underscores the challenges of transferring ideas from the laboratory to the marketplace. It is especially important to bring manufacturers into research projects at the beginning, as was done at the EPRI HVAC workshop. "We prefer to work with manufacturers that have strongly established distribution channels, because they offer a clear path to commercialization," explains Gellings.

Enthusiasm for the DFHP also demonstrates that collaborative efforts involving EPRI, utilities, manufacturers, and customers can be very effective in bringing new high-efficiency products to the marketplace. "When a market opportunity like this comes along," concludes Gellings, "we try to take advantage of it, especially when there are clear benefits for the utility, its customers, and society." ■

Promoting the Technology

The DFHP offers advantages to both utilities and their commercial customers, but the technology is largely unfamiliar in the heating, ventilating, and air conditioning community. A number of utilities are spreading the word through newsletters and circulars sent not only to customers but also to engineers, equipment dealers, and installers.

Further reading

Field Testing of a Dual-Fuel Rooftop Heat Pump. Final report for RP2891-6, prepared by the Fleming Group. November 1990. EPRI CU-7084.

Dual-Fuel Heat Pumps: New Options for Commercial Buildings. EPRI brochure CU.2027R.6.90.a.

Dual-Fuel Heat Pumps for Improved Load Factors and Commercial Customer Savings. EPRI brochure CU.2027.11.89.

Commercial Unitary Heat Pumps: An Assessment Study. Final report for RP2480-2, prepared by Joseph A. Pietsch. May 1989. EPRI CU-6371.

ESPRE: Tools for Energy Systems Analysis. EPRI brochure CU.2014R.

This article was written by Thomas York, science writer. Technical background information was provided by Morton Blatt, Customer Systems Division.

TECH TRANSFER NEWS

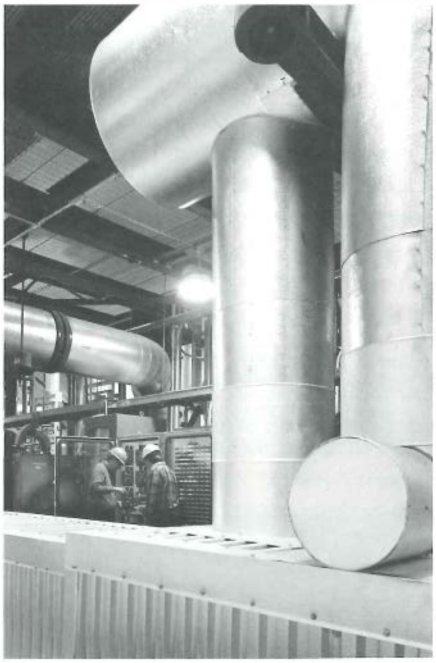
Controlling FGD Process Chemistry

Over the past decade and a half, EPRI research on flue gas desulfurization process chemistry has helped utilities improve the efficiency, reliability, and cost-effectiveness of their FGD systems. "Understanding and controlling process chemistry is the most important factor in the successful operation of an FGD system," says Robert Moser, a project manager in EPRI's SO_2 Control Program. The recent passage of a new clean air act that imposes further reductions in SO_2 emissions will require additional scrubber installations, underscoring the need for more-efficient system operation through improved control of process chemistry.

Three recently released EPRI reports—two new titles and an update of a popular handbook—contain information that can help utilities raise the reliability and lower the operating costs of FGD systems and can also help in the design of new ones.

Investigation of Flue Gas Desulfurization Chemical Process Problems (GS-6930) documents the results of investigations of various chemical-related problems that affect the operability and reliability of lime/limestone and dual-alkali FGD systems. The problems include inadequate SO_2 removal, mist eliminator scaling, poor solids dewatering, problems with water management, and insufficient process control. Acting on utilities' requests to identify and solve such problems, the project team visited FGD-equipped plants to gather information from operating and engineering personnel and acquire samples of various FGD streams for off-site chemical analysis. After evaluating the data and analytical results, the team issued a technical note to each utility with a detailed interpretation of the problems and with recommended solutions.

The project report compiles technical notes issued to utilities between 1982 and 1988; applications are grouped into common problem areas. Though problems were diverse, the utilities implemented solutions in every case, documenting benefits of more than $55 million.



"FGD chemistry is complex, but the process is quite manageable when its principles are understood and applied to system design," says Moser. "Furthermore, ongoing research on the use of performance additives builds on the current knowledge of process chemistry and promises to improve system efficiency and reliability while providing an even greater degree of process control. This project offers a valuable tool for translating research into practical utility applications. In fact, utilities may apply the same methodology used in these applications to solve most FGD process chemistry problems."

Another new report, *EPRI High-Sulfur Test Center: Wet Flue Gas Desulfurization Baseline Limestone Tests* (GS-7043), describes initial testing on a 4-MW pilot wet limestone system at the Institute's research facility near Buffalo, New York. HSTC investigators conducted a series of tests to improve the fundamental understanding of how process design, operating variables, and process chemistry affect the operation of wet limestone FGD systems. The research focused on four major areas of process performance and operation: SO_2 removal efficiency, limestone utilization, sulfite oxidation, and properties of waste solids.

"By presenting basic data with which future HSTC research data can be compared, this report will improve the understanding and operation of existing limestone FGD systems while aiding in the design of future systems," says Moser.

The Institute has also released a new, revised version of a popular FGD handbook that has been an industry standard since it was first published in 1984. Entitled *The FGD Chemistry and Analytical Methods Handbook, Vol. 1: Process Chemistry—Sampling, Measurement, Laboratory, and Process Performance Guidelines* (CS-3612, Vol. 1, Rev. 1), the new report includes the latest information on process performance sampling and monitoring.

The handbook incorporates feedback from utilities based on five years of experience in using the Institute's FGD analytical procedures. It includes new information on which performance indicators need monitoring, why monitoring is necessary, and how often it should be performed. The revised version also reflects EPRI's most recent experience in field chemical process problems and applications and includes the results of FGD process chemistry research conducted since the handbook was first released. ■ *EPRI Contact: Robert Moser, (415) 855-2277*

New Video Champions Utility Environmentalists

A new EPRI video documents the efforts of environmental scientists working in the utility industry. *The New Environmentalists* (EN-90-01) illustrates that many utilities are responding to environmental issues in a more sophisticated manner as industry staff expand their scientific knowledge and expertise, according to Steven Lindenberg, manager of technology transfer in the Environment Division. "These people are working successfully, with their own knowledge and the help of EPRI results, to solve tough environmental problems," he says. "And for the most part, their efforts have received little notice outside their own profession."

The half-hour-long video highlights work in three locations. In California a team of biologists employed by Pacific Gas and Electric studies the ecosystem around the Diablo Canyon nuclear power plant to better understand the plant's impact on marine life ranging from plankton to elephant seals. In Florida a biologist with Florida Power & Light advises company employees on dealing with the environmental aspects of everyday utility problems, such as line maintenance and cooling-water discharge. And in Texas a life-long conservationist turned environmental manager leads an effort by Texas Utilities to restore land after a strip-mining operation, an effort aiming to make the land more productive than it was before being mined. In the three segments, the scientists tell their own stories and describe their work as the camera captures them on the job. Voice-over narration is kept to a minimum.

Utilities ordered nearly 500 copies of *The New Environmentalists* within three weeks of its August 15 release, an unprecedented response, according to EPRI's video producer, Dennis Clinthorne. "The video describes the process of applying the results of environmental research to the real world," says Lindenberg. "It delivers the message that we can both supply the power we need and preserve our future through stewardship of the environment." *The New Environmentalists* is available to EPRI member utilities, educational institutions, and government agencies by calling (415) 934-4212. ■ *EPRI Contact: Steven Lindenberg, (415) 855-2736*

Tube Life Assessment

As utility boilers age, it becomes increasingly important to assess the condition of their critical components so that they can continue to operate reliably. Two major causes of forced outage in power boilers are tube failures due to creep rupture and failures of tube-to-tube dissimilar metal welds due to creep and creep fatigue. These two failure modes can occur independently, so either one can determine the economic life of the superheater/reheater assembly.

Until recently, deciding when to replace selected tube circuits—or the entire tube bank—has largely been a matter of guesswork. By removing tube samples and performing destructive tests on them, utilities have been able to estimate the tubes' remaining life, but this approach has limitations. Temperature varies widely in the tube bank, so evaluating a few samples doesn't always provide a complete picture of the remaining life of the entire bank. This incomplete information has sometimes resulted in unanticipated failures or in premature, conservative replacement.

Responding to the need for a more cost-effective technique for assessing the condition of tubing, EPRI's Generation and Storage Division has developed a PC-based computer code, TUBELIFE, that estimates the remaining life of tubes by using measurements of the thickness of oxide scale on the steam side of the tubes. Data on oxide thickness can usually be obtained nondestructively by using recently validated ultrasonic techniques. Armed with this approach, a utility can perform wide-coverage ultrasonic testing to identify tubes that are at risk.

Another computer code developed by EPRI, PODIS, performs remaining-life assessment of dissimilar welds. PODIS (for prediction of damage in service) computes the current level of dissimilar-weld damage on the basis of operating temperature, the number and nature of cycles, and system stresses.

Using these two codes in combination gave Arizona Public Service a powerful tool for evaluating the superheater assembly at its Cholla station. Although no tube leaks due to creep rupture or dissimilar weld failures have occurred after 210,000 operating hours and 290 cold starts, information from PODIS and TUBELIFE and from metallurgical laboratory evaluations shows that both the T22 alloy tubing section and the T22/P347H stainless steel dissimilar welds may fail between the unit's 1991 and 1997 major overhauls. Consequently, maintenance personnel at Cholla have scheduled superheater replacement during the 1991 overhaul.

Says EPRI project manager Vis Viswanathan, "These methods minimize the need for tube sample removal, save laboratory evaluation and tube replacement costs, and allow more comprehensive monitoring of tube assembly degradation." ■ *EPRI Contact: Vis Viswanathan, (415) 855-2450*

Acidic Deposition

Limestone Treatment for Managing Acidic Ecosystems

by Donald B. Porcella, Environment Division

As human societies take more responsibility for the earth's biosphere, it is becoming increasingly apparent that management tools and techniques are needed to maintain or restore environmental quality. One management tool in growing use is liming—the use of limestone to treat acidic ecosystems. Extensive liming programs are currently operated by public and private agencies in Sweden, Norway, and the United States. Liming has an important mitigation role even when emission controls are implemented because it produces a rapid response to acidic conditions and also provides benefits beyond acid neutralization.

EPRI's lake acidification mitigation project (LAMP) is a multilake experiment in the Adirondack Mountains of New York, where scientists are observing and evaluating the effects of adding limestone to natural ecosystems. The project was designed to investigate the ecological effects and efficacy of liming acidic ecosystems and to study the cycling of hydrogen, calcium, trace metals (e.g., aluminum), and other ions in relation to their biological effects.

LAMP began in January 1984 with preliming studies of three lakes to establish a baseline of ecosystem behavior; then the lakes were treated by direct application of slurried limestone powder to the water surface (Table 1). Two of the lakes were treated more than once, and in October 1989 Woods Lake was treated by liming of the watersheds of its two major tributaries, an area of about 35% of the total watershed (*EPRI Journal*, January/February 1990, p. 28).

Major LAMP objectives are to identify and evaluate the ecological effects of liming in dilute water ecosystems, to see whether liming effectively mitigates the episodic acidification associated with snowmelt and storms, and to identify the most cost-effective liming treatments for a range of typical conditions. Phase 1 of the project entailed the direct liming of lake surfaces, and many of the in-lake biological studies were completed in this phase. Phase 2 is evaluating watershed liming, with a focus on the terrestrial environment, and is in its first year of posttreatment study.

ABSTRACT *EPRI's lake acidification mitigation project is investigating whether liming is an effective and environmentally sound method of managing acidic aquatic ecosystems. In over five years of ecological study, no deleterious effects have been found to occur from liming, and results show that treatment programs can be designed to meet water quality objectives in any ecosystem. The most effective management technique appears to be watershed liming, since this treatment creates and maintains suitable chemical quality in terrestrial, tributary, and lake environments.*

Besides EPRI, the Empire State Electric Energy Research Corporation and Living Lakes, Inc. (LLI), have funded large parts of the research. LLI initiated the watershed studies and has provided most of the funding for them. The U.S. Geological Survey matched the private-sector funding of hydrologic research, and the U.S. Fish and Wildlife Service funded parallel research that contributed valuable information to LAMP objectives. A related research effort in the Black Forest is being funded by the German state of Baden-Württemberg.

The prime contractor for LAMP is Cornell University (management, soil biochemistry, and aquatic biology); subcontractors are Syracuse University (water and soil chemistry), Indiana University (phytoplankton and macrophytes), Smith College (soils and hydrogeology), and SUNY–ESF at Syracuse (forest response). Clarkson University is funded directly by the Germans for testing of the ILWAS model and for Black Forest comparison studies. The Black Forest research is being conducted by the Institute of Soil Science and Forest Nutrition of Albert-Ludwigs University in Freiburg.

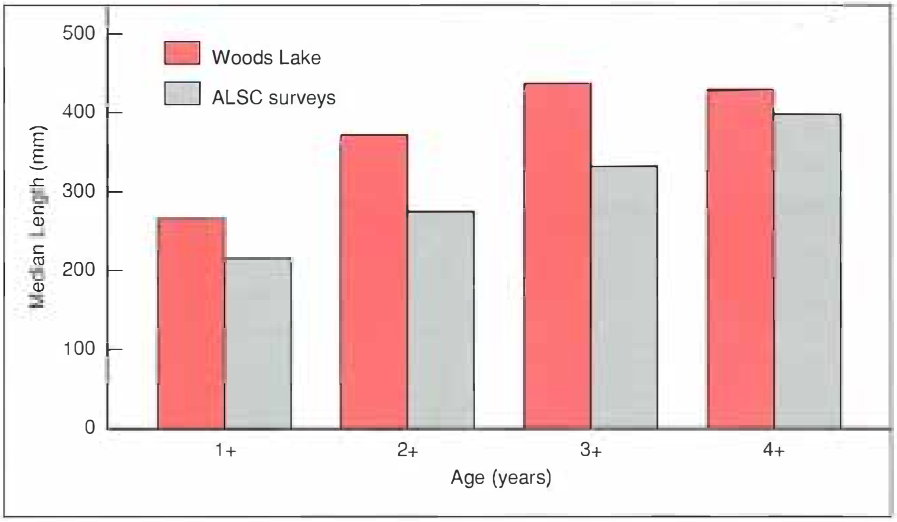
Direct lake liming

The surface-water-liming operations under LAMP involved seven different calcite ($CaCO_3$) treatments. These were designed to produce a pH greater than 6.5 and an acid-neutralizing capacity (ANC) greater than 50 μeq/L, levels accepted by most investigators as realistic targets to maintain desirable ecosystems. Major factors controlling the effective duration of a treatment are hydraulic residence time, sediment interactions, and calcite characteristics (e.g., particle size and purity). Each treatment design has economic and logistical advantages and disadvantages, which together dictate the choice for a given site. Treatment design relies to a great extent on computer models that simulate ecosystem response to liming.

For Woods Lake, calculations of the relative acid neutralization effected by direct liming indicate that although virtually all of the calcite dissolved, only 15% of it reacted with acid; the rest was flushed out of the lake by incoming water.

Regarding ecological effects, the LAMP studies' concern has not been whether adding limestone to a lake changes the existing community of organisms. There is no question that it does—there is a shift from an acid-tolerant community to one associated with near-neutral pH conditions. Rather, the LAMP evaluations of organism responses have been concerned with whether limestone treatment produces deleterious biological effects in the ecosystem. No such deleterious effects have been found over the five years of study. The most obvious ecological effects occurred because of the introduction of fish (stocking) to a fishless lake. A series of articles describing many of the ecological results from the LAMP studies was published recently in the *Canadian Journal of Fisheries and Aquatic Sciences* (1989, 46:246–359).

Figure 1 A comparison of brook trout from Woods Lake with those from collections by the Adirondack Lake Survey Corporation shows that fish from Woods are longer than same-age fish in the general population. However, in the older age classes, the Woods Lake fish weigh less and are in poorer condition than their counterparts.



Results from five years of fisheries studies at Woods Lake indicate that the lake habitat itself limits the growth of fish populations. Fish productivity in Woods Lake is not unlike that of lakes with near-neutral pH, but productivity is on the low end of the scale for the set of comparison lakes used. While Woods Lake brook trout are generally longer than those of other Adirondack brook trout lakes (Figure 1), their weight and condition factors are lower than expected for unstressed fish.

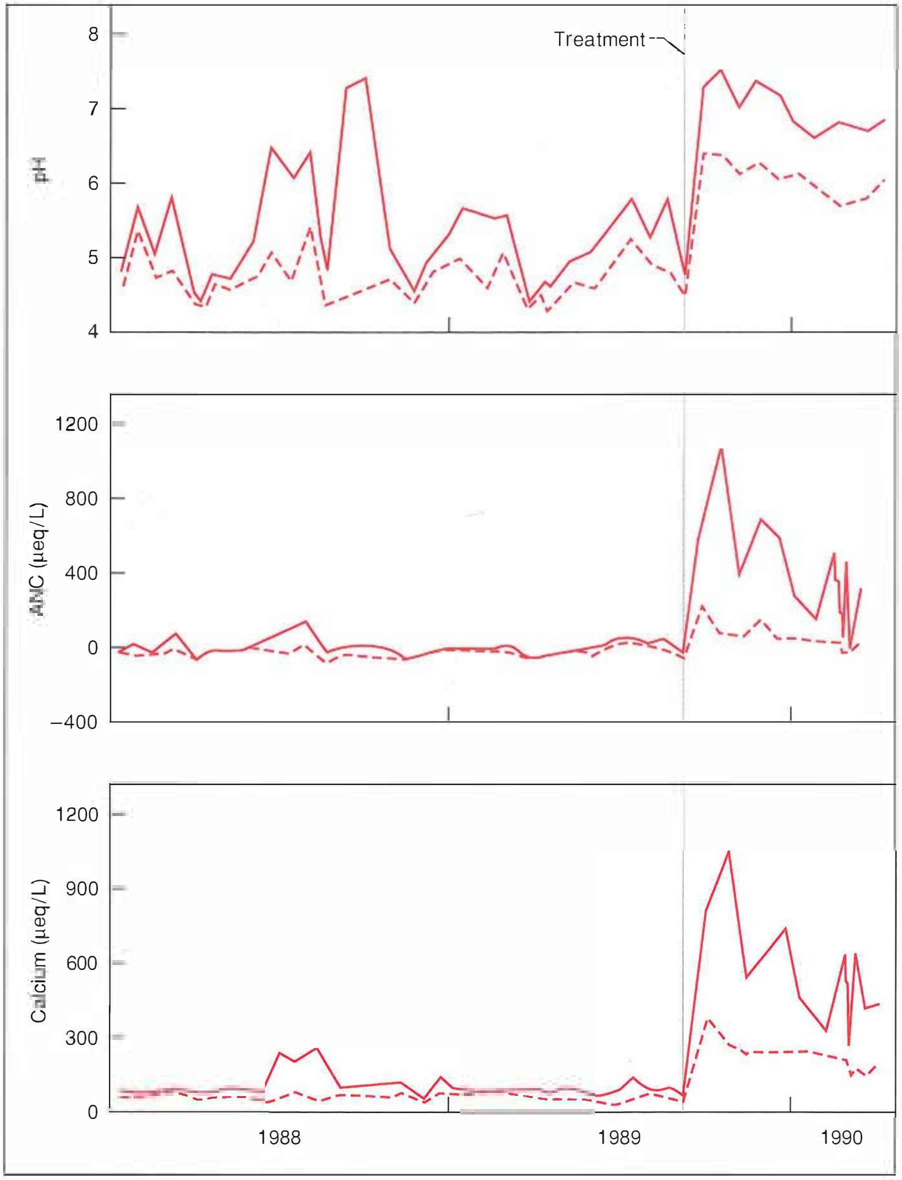
Increased competition for food resources appears to be the reason for the recent decline in the condition of the Woods Lake trout. The lake's low nutrient levels prevent development of the food base necessary to maintain the numbers of stocked fish in a healthy condition. In effect, Woods Lake was overstocked with brook trout relative to the food supply. In addition, the physical habitat for spawning is inadequate; recruitment of new fish to Woods Lake from in-lake spawning has apparently occurred only once. Predation by fish-eating loons and mergansers appears to have resulted in lower trout survival rates in Woods Lake than in other Adirondack brook trout lakes.

After snowmelt and storms, episodic acidification occurs in near-shore areas and surface waters as a result of high concentrations of hydrogen ions. The aluminum concentration often increases in these waters because of low pH, while the calcium ion concentration is decreased by dilution. High concentrations of H^+ and aluminum coupled with low Ca^{++} affect organism survival and potentially could make important near-shore habitats less usable, interfering with the reproduction and recruitment of fish and insects. LAMP results have shown that direct lake liming provides protection for some species that use deeper near-shore waters for early life stages, but that

Table 1
LAKE AND WATERSHED LIMING IN LAMP

	Cranberry Pond	Woods Lake	Little Simon Pond
Area (ha)	7.2	23	63
Maximum depth (m)	7.6	12	33
Lake-to-watershed ratio (%)	5	10	10
Hydraulic residence time (mo)	2	6	15
Lake liming			
Date	5/85	5/85, 9/86, 10/88	8/86, 8/88
Calcite added (1000 kg)	7	23, 35, 2	86, 66
Concentration (mg/L)	34	28, 44, 2.5	13, 10
Watershed liming			
Date		10/89	
Calcite added (1000 kg)		1100	

Figure 2 Generally, the two major inlet streams to Woods Lake are characterized by low pH, low acid-neutralizing capacity (ANC), and low calcium levels. After the watershed was limed, these streams showed rapid and sustained improvement despite storm and snowmelt events. Differences between the two streams result from differences in the hydrologic and hydraulic aspects of their drainages.



watershed liming may be required to protect species, such as brook trout, that use shallower waters. In Woods Lake, the physical habitat limits the success of in-lake spawning. Recent results from the watershed liming study show that brook trout are using the now-neutralized lake inlet streams for spawning. Successful recruitment of these fish would create a self-maintaining fishery in the lake.

Watershed liming

The results on the direct lake treatments provide a background against which the watershed liming of Woods Lake can be contrasted. The watershed research is primarily focused on the terrestrial environment, but some of the in-lake biological studies continue.

Fish bioassay results for the near-shore areas suggest that episodic acidification events have largely been eliminated by watershed liming. In contrast to direct lake liming, watershed liming not only protects the near-shore habitats but restores additional habitats in the tributary streams that enter lakes. One hypothesis is that nutrient inflow to Woods Lake may increase as a result of watershed liming. If nutrients do increase in the lake, fish condition should improve over that observed after direct lake liming. The previous overstocking of fish provides a population poised to take advantage of additional productivity, and changes in fish condition measured in the summer of 1991 will provide a sensitive indicator of the complex process of food web and nutrient interactions.

The major integrating element of the watershed studies is the use of EPRI's ILWAS (Integrated Lake-Watershed Acidification Study) model, a hydro-biogeochemical simulation model that embodies almost all of the present-day theory on acidification processes in watersheds and lakes. ILWAS calculates material transfers and transformations between various compartments—such as soil layers, vegetation categories, and tributaries and lakes—so that alternative scenarios can be evaluated. The model has been modified to calculate limestone dissolution processes, and initial simulations suggest that several calibration changes are needed to encompass processes unique to liming but not important for other simulations.

ILWAS simulations are being coupled with hydrochemical measurements and detailed transect studies of trees, undercanopy vegetation, and soil chemistry and biochemistry. The transect studies compare treated and untreated subwatersheds to evaluate the terrestrial effects of liming and to provide data for evaluating how well ILWAS simulates watersheds. In addition to this testing, ILWAS plays important roles in coordinating the various disciplines of the LAMP studies and in integrating LAMP with its sister project in the Black Forest.

Although data are not yet sufficiently complete to evaluate ILWAS, results from the first year of study support initial hypotheses about watershed liming. Tributary and lake pH, ANC, and Ca^{++} all increased after treatment and have remained elevated even during high flows (Figure 2). Aluminum decreased and has remained low. In the terrestrial environment, similar results occurred in the organic layers of soil near the surface, although calcite solutes have not penetrated substantially into the deeper soil strata of the inorganic layer.

So far, results indicate that only about 1% of the watershed treatment limestone has dissolved, but water quality has been maintained at desirable levels for fish throughout the snowmelt and spring mixing periods. In fact, throughout the postliming period, downstream reaches of the stream draining Woods Lake have shown marked improvements in ANC until diluted by low-ionic-strength tributaries from other watersheds.

Although it already appears that watershed treatment is the optimal mitigation strategy for acidic lakes, continued analysis is necessary to provide a definitive assessment of the treatment as well as to complete the testing of ILWAS.

Environmental Control

FGD Economics

by Paul Radcliffe, Generation and Storage Division

ABSTRACT *With the passage of the Clean Air Act Amendments of 1990, utilities are developing strategies for complying with the new SO_2 emission regulations. Working with a utility project advisory group, EPRI is updating commercial and technical evaluations for 26 flue gas desulfurization processes. Completed cost estimates for 15 of the processes show that FGD capital costs are lower than previously estimated, and that levelized control costs are very similar for many technologies. A new computer model now being tested will allow utility planners to make site-specific FGD cost estimates with increased accuracy.*

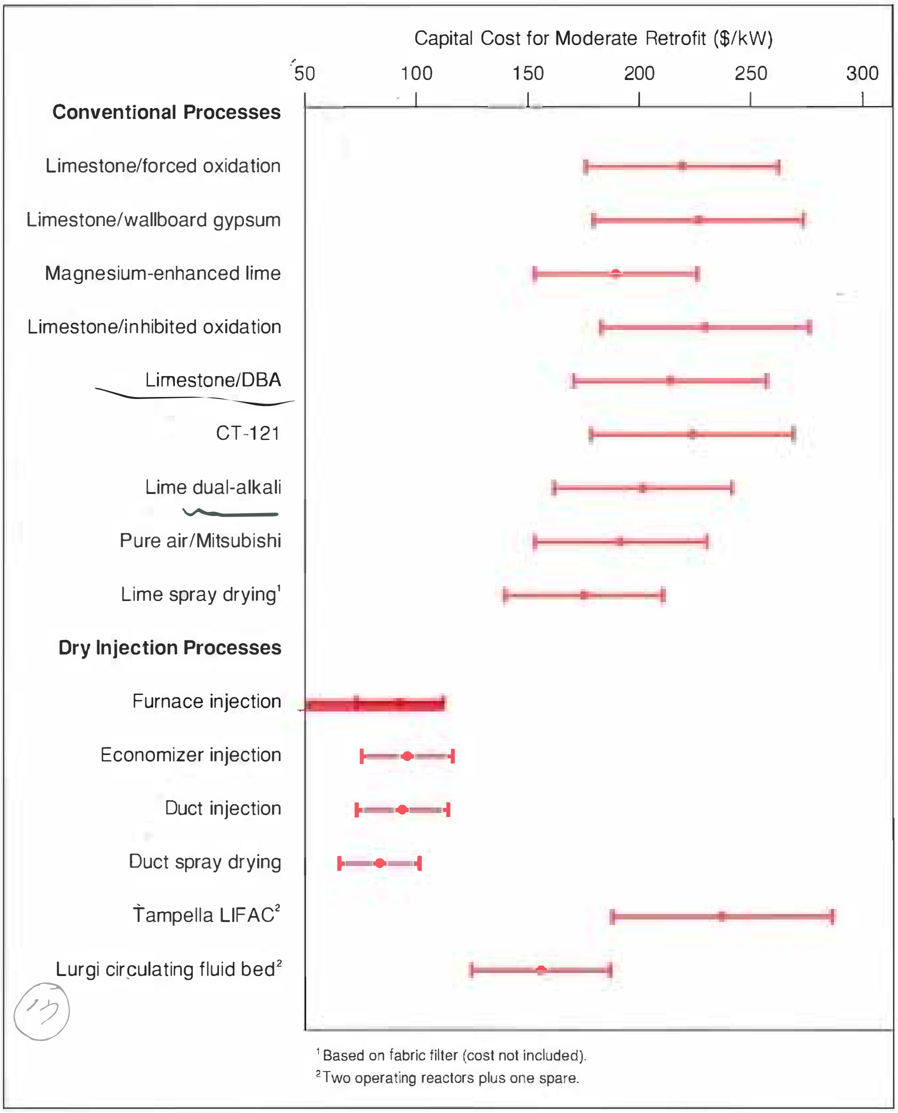
Public concern with air quality and acid rain has spurred Congress and the administration to amend the Clean Air Act. The new bill was signed by President Bush on November 15, 1990. In anticipation, many utilities have been preparing plans for complying with legislation that will mandate substantial reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). An effective compliance strategy must consider a broad spectrum of legal, political, and technical issues, with financial impact a major consideration. Recognizing the utilities' need for accurate, objective, and up-to-date information on the options available for controlling SO_2 emissions, EPRI has made a commitment to periodically assess available SO_2 control technologies and update cost estimates for flue gas desulfurization (FGD) processes.

The choice of an appropriate FGD system can save a utility millions of dollars in initial capital outlay alone. FGD systems installed at new plants can account for 10–20% of the total plant capital cost, and the cost of retrofitting FGD at existing plants can be considerably higher. EPRI is conducting technical and commercial evaluations of 26 FGD processes, including both wet and dry technologies; cost estimates have been completed for the first round of 15 processes (see list, page 36). Results for these 15 processes are being published in an EPRI report, which should be available by the end of this year. In addition, a new computer model for estimating site-specific costs, FGDCOST, will be made available to member utilities upon completion of demonstration testing—currently in progress—by the utility project advisory committee.

Cost estimates

Results for the first 15 FGD processes evaluated indicate that the cost escalation experienced in the past has been halted, at least temporarily. Figure 1 shows current capital cost estimate ranges for all 15 processes, including conventional, high-efficiency wet FGD processes and dry injection technologies. The estimates are for a moderately difficult retrofit and do not cover plant modifications beyond the FGD system, such as stack relining/rebuilding and particulate control upgrades to accommodate the FGD system. Site-specific retrofit factors will have a signifi-

Figure 1 Capital cost estimates for nine conventional, high-efficiency FGD processes and six dry injection processes. These estimates assume a moderately difficult retrofit for a 300-MW unit, 2.6% sulfur coal, and the use of two operating absorber modules (or reactors) plus one spare. The estimates are in 1990 dollars and are given as ranges. Site-specific factors will have a significant impact on actual costs.



cant impact on actual costs. Figure 2 shows corresponding 30-year-levelized costs (assuming no inflation) in $/ton of SO_2 removed.

The cost estimates are based on retrofitting a single 300-MW unit, burning 2.6% sulfur coal, and using two operating absorber modules plus one spare. This design basis is different from the one used in previous EPRI FGD cost estimates, which were developed for new plant sites with two 500-MW units, 4% sulfur coal, and three plus one absorber modules. The lower-sulfur coal used for the current estimates is more typical of the coals burned today. Engineering needs have been reduced to reflect the experience and knowledge gained from the first generation of scrubbers. The maturing of FGD technology has led to simplified, more standardized designs and hence reduced contingency fees. With the reduced unit size and correspondingly shorter construction period, the allowance for funds during construction (AFDC) is lower.

Several important conclusions can be drawn from the work to date, including these:

- A buyer's market exists today, which may be contributing to the fact that FGD costs are lower than previously expected. The Clean Air Act Amendments could bring a seller's market, with higher prices, but the impact is not certain.
- The lower costs may result in more scrubbing relative to coal switching, although noncost issues may govern some decisions.
- Costs per ton of SO_2 removed are very close for many technologies.
- Compared with wet FGD, dry injection processes have lower capital costs but higher costs per ton of SO_2 removed.
- Design simplification can save more than 30% of the capital cost of conventional FGD.

The cost estimates can be summarized by major process category as follows (capital costs in 1990 dollars; control costs levelized over 30 years in constant 1990 dollars):

	Capital Cost ($/kW)	Control Cost ($/ton SO_2)
Wet processes	150–280	350–600
Spray drying	140–210	360–540
Dry injection (U.S.)	70–120	420–750

Technical and economic evaluations were also made for two European dry injection processes, Tampella's LIFAC process and Lurgi's circulating fluid bed. (Figures 1 and 2 include these estimates.) Levelized control costs per ton of SO_2 removed are higher for the dry injection technologies because of their lower SO_2 removals and higher reagent costs. The dry injection technologies require much less capital, but they suffer from higher operating costs as a result of greater reagent consumption and cost. With these technologies we are further back on the learning curve, and at their current stage of development they carry relatively more risk. On the other hand, they may be a practical choice for older, smaller units with limited space for retrofitting wet FGD.

Cost-saving concepts

In parallel with EPRI's efforts to update FGD cost estimates, another research project now under way is investigating alternative ways to control and minimize the cost impacts of retrofitting FGD at existing plants. This project has identified cost- and space-saving design concepts that can be applied today to retrofit FGD systems without reducing their ability to achieve greater than 95% SO_2 removal, maintain an overall reliability of greater than 99%, and consume less than 2% of station energy input.

Cost-saving features being studied include the following:

- Larger absorber modules
- Wet stack operation (no reheat)
- Performance-enhancing additives
- Improved materials of construction
- Simplified dewatering techniques

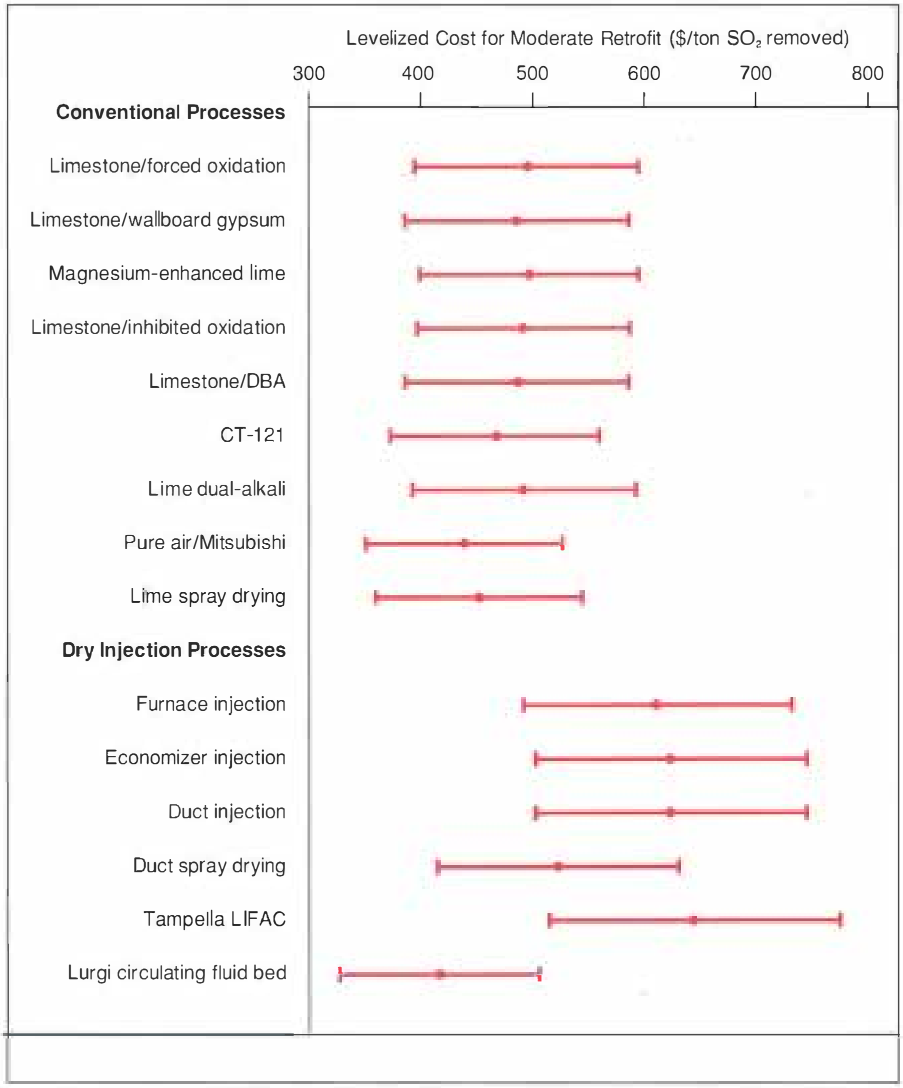
Compared with "conventional" wet FGD systems, advanced designs incorporating these features can achieve 30% savings in capital costs and 25% savings in operating and levelized control costs, without loss of reliability.

FGD market

A utility entering the FGD marketplace today would find it to be a buyer's market. Very few FGD systems have been sold in the past few years, and suppliers are quite willing to discount their prices to keep their shops busy. With the new clean air legislation, a large number of buyers will be entering the marketplace. The magnitude of their market impact is difficult to quantify, and it will vary with the type of FGD process under consideration. Any tendency toward cost increases will be restrained to some degree by penetration of foreign FGD system suppliers, who have been actively developing their processes in Europe, where stringent acid rain retrofit programs have been completed.

Utilities would be wise to proceed with broad Clean Air Act response strategy planning and retrofit cost studies now in order to explore all the available options and determine their cost implications. The utilities that fully comprehend the economic and technical impacts associated with FGD will be in a better position to respond to clean air legislation. The final report on EPRI's work will include commercial and technical evaluations as well

Figure 2 Total levelized FGD costs over 30 years (constant 1990 dollars). Despite their lower capital costs, the dry injection processes have higher levelized costs than the conventional processes because of their lower SO_2 removal efficiencies and higher reagent costs.



as cost estimates, which should provide utilities with the means for making informed choices when screening alternative FGD technologies. In order to provide advance information to member utilities on the economics and technical merits of various SO_2 control technologies, a special EPRI executive-level white paper was prepared last March; it is available to member utilities on request. All the processes that are currently scheduled to be evaluated are presented in the list on page 36. Additional processes for evaluation are being considered.

Cost model

A new computer model for estimating FGD system costs (FGDCOST) is currently undergoing utility demonstration and should be available early next year. It will help utilities tailor these cost estimates to specific plant sites. The model is a menu-driven, spreadsheet template (one spreadsheet for each technology). It uses internally stored design information to enable users to readily estimate capital, operation and maintenance, and total levelized costs for both new and retrofit applications. The model computes costs by using

FGD PROCESSES FOR EVALUATION

Completed

Limestone/forced oxidation
Limestone/wallboard gypsum
Magnesium-enhanced lime
Limestone/inhibited oxidation
Limestone/DBA
CT-121
Lime dual-alkali
Pure air/Mitsubishi
Lime spray drying
Furnace sorbent injection
Economizer sorbent injection
Duct sorbent injection
Duct spray drying
Tampella LIFAC
Lurgi circulating fluid bed

In Progress

SOXAL
Wellman-Lord
Magnesium oxide
Limestone dual-alkali
Saarberg Holter
Northern States Power bubbler
Passamaquoddy
ISPRA
HYPAS
Damp/ADVACATE
SO_2 advanced retrofit

site-specific data entered by the user and default values for the selected FGD process. User inputs revolve around economic criteria, boiler and coal characteristics, site conditions, and retrofit difficulty.

Sensitivity analyses can be performed for variations in utility economic and design criteria as well as for site-related alternatives. (User input can be saved as a worksheet file to be retrieved for use in subsequent runs.) Through these analyses, users can determine the relative importance of different cost elements, such as equipment, energy, manpower, and reagent.

The new model will replace RETROFGD, a computerized FGD cost estimating code released by EPRI in 1987. With the help of a software developer, EPRI is investigating alternative ways of enveloping the spreadsheet models in a more user-friendly interface to expedite and simplify the data-inputting process. (Each spreadsheet now takes more than 300K of memory.) The model will be segmented into distinct modules that can be stored separately, so that the entire spreadsheet will not have to be rerun each time a sensitivity case is run.

EPRI is using FGDCOST in developing its updated cost estimates. All cost evaluations are performed within the framework of EPRI's *Technical Assessment Guide,* which was updated in September 1989 (P-6587-L). Capital cost estimates for the more conventional systems are considered to be Detailed (Class III); estimates for the less developed systems are considered to be Preliminary (Class II). Overall, the estimates have an absolute accuracy of ±20% and a relative accuracy of ±10%. FGDCOST presents a breakdown of capital requirements for each process, along with levelized annual costs in $/kW-yr, mills/kWh, and $/ton of SO_2 removed.

In the wake of the new clean air legislation, EPRI remains strongly committed to providing utilities with the information and analytical tools they need to make informed, cost-effective decisions about controlling plant emissions. For their part, utility planners are urged to approach compliance from the broadest perspective first—addressing such options as unit retirement, repowering, least-emission dispatch, and fuel switching, as well as SO_2 and NO_x control technologies. It would be prudent to proceed with planning and cost studies now in order to explore all available options. Extensive front-end planning and risk evaluation can be more cost-effective than jumping into any specific technological fix.

Control and Information Systems

Bridging the I&C Gap for Nuclear Plants

by Siddharth Bhatt, Joseph Naser, Lester Oakes, William Reuland, Joseph Weiss, and Dan Wilkinson, Nuclear Power Division

When the nation's first generation of commercial nuclear plants was designed in the 1960s, the instrumentation and control (I&C) systems were a combination of old and new art. They employed the traditional balance-of-plant systems that had served well in the petrochemical, pulp, and paper industries, as well as in fossil fuel power plants. For the control and monitoring of the new part of the nuclear plants, the reactor and its component systems, industry turned to technology that had been developed in the national laboratories, where nuclear energy was harnessed.

In the first nuclear plants, the I&C systems for both the nuclear island and the balance of plant were analog; the age of digital technology was not quite yet at hand. To be sure, these original systems have done what was expected of them. They have provided comprehensible pictures of plant conditions and have allowed adequate plant control. These systems have brought nuclear power a long way, but they may require upgrading because of equipment and technology obsolescence. Spare parts are no longer available in many cases, and some vendors no longer support the aging equipment.

Control technology has come a long way since the original, analog systems were designed. Digital electronics now perform functions that were unimaginable when the existing plants were conceived. Advanced instrumentation can project the status of a process in more ways than analog instrumentation alone. Moreover, digital equipment can do this with outstanding reliability. Although the older, analog systems do their job, they contribute to a significant number of plant trips in nuclear and fossil plants. Advanced equipment has the potential to eliminate many I&C-caused outages and to minimize current maintenance requirements. Digital systems can be designed to be fault-tolerant and redundant. And because of digital control flexibility, control functions that previously required difficult manual action can now be performed automatically.

The challenge ahead

Utility industry goals over the next five years will be influenced by competition with energy suppliers, both inside and outside traditional service areas. Competition will increase the demand for more reliable and more efficient electricity production, transmission, and distribution. To ensure optimal utilization of resources and competitive kilowatthour costs, utilities need to be able to rapidly determine generating-plant status and also load demand. Major goals are to increase plant reliability and availability and to reduce operation and maintenance (O&M) costs while protecting the utility capital investment. Beyond plant boundaries, utilities need to have up-to-the-minute knowledge of the status of their transmission and distribution systems and of the costs of power delivery. Public image and customer satisfaction are also becoming more important factors.

To meet the demands of increased competition, utilities must focus attention on improving the reliability and capability of their I&C systems. The contributions of these systems to plant unavailability and O&M costs can be reduced by implementing new I&C technologies to improve plant performance. In this context, I&C is interpreted more broadly than in the past. It includes not only the traditional instrumentation and control functions but a wide range of other functions that support power plant operation, maintenance, and engineering (Figure 1).

An EPRI workshop on the status of various I&C technical elements was held in New Orleans in March 1990. There were over 200 participants from EPRI member utilities, foreign utilities, vendor companies, regulatory bodies, universities, and national laboratories. Presentations were made on solutions to the problems of equipment obsolescence, research on and applications of modern I&C technology, and potential problems that the modern technologies will pose. An EPRI report, NSAC-153, summarizes those presentations and the conclusions reached at the workshop. The consensus was that an opportunity now exists for a planned and integrated approach to upgrading and replacing I&C systems and components. EPRI has taken the initiative in formulating such a plan.

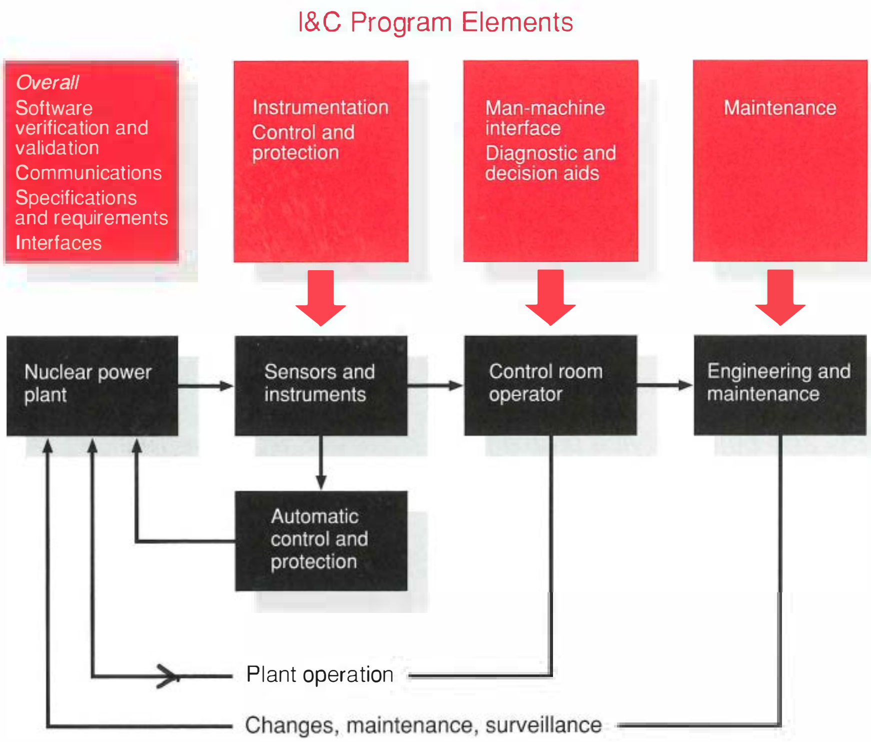
Concurrent with the advance of digital control technology, communications technology has been moving ahead at a rapid pace. EPRI's Electrical Systems Division, in concert with the Institute's other divisions, including Nuclear Power, has completed the integrated Utility Communications Architecture (UCA) and is developing Database Access Integration Services (DAIS), due for completion in the third quarter of 1991. UCA and DAIS may form an information framework for both the data acquisition and control functions of I&C applications. They provide a planned and integrated approach for all activities of the utility enterprise. The UCA and DAIS design is based on the Open Systems Interconnection (OSI) reference model of the International Organization for Standardization. The OSI model has become the internationally accepted nonproprietary architecture for all digital communication.

Motivations for change

There are a number of strong motivations for nuclear plants to upgrade I&C systems. Al-

ABSTRACT *Instrumentation and control technology has advanced more rapidly and dramatically than any other discipline important to a nuclear power plant. Modern I&C systems can outperform their predecessors of only a few years ago in most ways. They are smarter, can provide highly analyzed status information, can control complex functions in a more refined way, are more reliable and economical, and make possible a higher level of automation. Because of stalled growth, the nuclear power industry has been slow to use this new technology. However, the growing unavailability of replacement parts and other service problems with present equipment, along with the much-superior monitoring and control capability of the advanced technology, have prompted a new look at I&C. EPRI has taken a leading role in the effort to bridge the gap between existing and future I&C systems.*

Figure 1 An industrywide effort led by EPRI is focusing on the major technical elements (color) involved in upgrading instrumentation and control systems at nuclear power plants. These elements fit into the fundamental plant control loops as shown. Modern I&C systems incorporating digital and other advanced technologies can perform a variety of functions that support plant operation, maintenance, and engineering. Potential benefits for utilities include higher plant availability, improved reliability, and lower O&M costs.



though the total number of Licensee Event Reports has decreased over the past several years, the number of events attributable to I&C problems has not decreased. I&C systems are now the leading cause of event reports, contributing to over 60% of the total. Many of these events are due to errors in testing. When critical testing errors occur when a power plant is on-line, reactor scrams often result, and these in turn may cause extensive plant shutdowns. Although the number of trips has been reduced in recent years, further reduction—through digital automation of testing, for example—would improve availability significantly. Other I&C advances, including improved man-machine interfaces and computerized decision aids, offer opportunities for additional availability increases by lowering the number of scrams related to human error.

It was pointed out at the I&C workshop that routine I&C calibration and testing performed during one plant operating cycle and one refueling outage can require 26,000 man-hours or more per nuclear unit. I&C improvements can help reduce planned-outage as well as forced-outage time. Better diagnostic instrumentation, monitoring sensors, and controllers can support preventive, predictive, and on-line maintenance techniques that permit opportune scheduling of maintenance and replacement of components. And capacity can be increased by more-accurate process measurements.

An important motivation for change is the increasing obsolescence of the balance-of-plant I&C equipment and, to a lesser extent, the nuclear portion of the nuclear island I&C equipment. It is difficult to replace older, analog systems with digital systems, however, because of the difference between the data transmission systems of the two. Furthermore, standards for digital systems have not yet been widely accepted by the nuclear industry. Without industry standards, replacing obsolete equipment is often more expensive and time-consuming than originally estimated.

Analog instrumentation technology has given way to digital signal processors and digital data highways in other industries. The infrastructure supporting analog technology is being replaced by vendors that provide digital systems. In many cases, vendors and spare parts for existing equipment are no longer available.

Technology developments

I&C technology has made dramatic advances in recent years, and EPRI has been in the forefront of the activity. The Institute has developed expertise in I&C and has provided I&C assistance to utilities, utility owners groups, and standards organizations. Its involvement includes R&D projects in the following areas:

- Digital control system development
- Signal validation techniques
- Sensor calibration reduction methodology
- Surveillance and testing optimization
- Control room enhancements
- Sensor development
- Process instrument accuracy
- Alarm system improvements
- Software verification and validation techniques
- Development of radiation-hardened components
- Simulator qualification
- Computerized O&M aids
- Instrumentation systems
- Design change guidelines
- Set-point methodology
- Human factors guidelines

The advanced I&C equipment now available can perform with outstanding accuracy and reliability. Fault-tolerant, redundant digital systems are being implemented to greatly extend overall I&C system reliability. The low-drift and self-checking capabilities of digital systems significantly reduce surveillance and testing requirements. Moreover, modern digital control equipment makes possible new control algorithms, data fusion, and enhanced analysis and display. It can perform many useful functions that are impossible or very difficult to perform with analog equipment.

The proliferation of digital electronic systems has made it possible to have distributed control of power plants. Microprocessors are located close to the points of control to store readings, process data, and, with the operators' oversight, actually control the plant. A major benefit of distributed control is that if one aspect of a control system fails, other aspects can still carry on the intended operation because of the distributed intelligence.

Both U.S. and foreign utilities have reported excellent results with new maintenance techniques that use the predictive capability of diagnostic and surveillance information to optimize equipment replacement and overhaul. Significant improvement in plant availability has been attained through the enhanced ability to schedule repair and replacement work. Unnecessary maintenance, which imposes costs in both outage time and man-hours, can be avoided.

Technology concerns

The most persistent concern regarding the reliability of digital systems involves software verification and validation. Cases of serious misoperation of systems employing digital control components continue to be reported in all industries. Resolution efforts are expected to develop verification and validation methods to ensure high-quality software for digital systems. Because software is easily modified, configuration control will be necessary throughout the system lifetime.

Compared with older equipment, the advanced equipment tends to be less immune to radiation damage, radio-frequency interference (RFI), and electromagnetic interference (EMI). There are means of minimizing the effects of RFI and EMI, however; and work is under way to develop prototype radiation-hardened equipment, as well as guidelines for producing equipment and components for application in nuclear radiation environments.

Monitoring and control systems that use digital equipment require changes in operator interfaces. Much of the R&D that has been done on human response and behavior will be directly applicable in developing improved man-machine interfaces and new control room designs. Existing research results will be a valuable starting point for making the transition from current systems to new layouts that use both existing and new equipment in an optimal manner.

Although analog equipment is becoming obsolete within the lifetime of current plants, digital equipment will become obsolete even faster. Utilities that have extensive experience with digital control systems in nuclear plants believe that digital equipment will become obsolete in 5–10 years. This estimate is typical of experience with equipment like personal computers and programmable logic controllers. However, users of digital control systems for both nuclear and other systems suggest that the original functionality of the equipment will be adequate for a plant life expectancy of 30–40 years. Therefore, strategies for ensuring the availability of appropriate replacement hardware and software must be addressed during the design phase. One such strategy, for example, is to use the EPRI UCA and DAIS architectures, which provide nonproprietary protocols for multiple suppliers.

Strategy for improving I&C

A structured program is necessary to solve I&C problems. One substantial objective is to improve plant availability and reliability. An integrated I&C plan covering the expected life of a plant should address the following issues:

- Functional requirements consistent with plant goals
- Strategies for implementing cost-effective upgrades in current systems compatible with functional requirements
- Strategies for improving availability and reliability and reducing costs with existing equipment
- Licensing and standards implications
- Standards for data communication and software
- Hardware interface requirements and plant design bases
- Verification and validation of software and software configuration control

In the short term, high priority is being given to the components and systems that are the most troublesome with respect to capacity, availability, reliability, or O&M costs. Specific priorities are being established through interactions with utilities. Operating data are being evaluated in order to determine which components and systems are of concern.

Although the immediate goal is to help solve problems in existing I&C systems, it is desirable that short-term solutions that require system upgrades conform to the functional requirements of the final, integrated system. An integrated plan will ensure that short-term upgrades will be compatible, where possible, with long-term strategies. The short-term programs currently under way may be more expensive and more time-consuming than programs done on a generic, integrated basis. Solutions that are applicable to a number of plants will require utility and industry coordination to develop basic units that can be easily tailored to plant-specific use. Methods and guidelines will be developed to help determine where generic solutions are applicable and how to implement changes successfully.

In the implementation of new equipment, a systems engineering strategy is important because it affords an opportunity to reexamine the I&C design in light of the possibilities offered by new technology. The full potential of new equipment may not be utilized in a retrofitting operation, but retrofitting compatible equipment will keep various options available to maximize the benefits of future upgrades and new designs.

Introducing modern I&C technology on a plantwide scale requires a coordinated effort by several areas of the industry. This effort will benefit from strategic alliances that ensure a user base of sales and developmental support. Such a base will encourage industrial suppliers to participate. Ongoing technology exchanges and cooperative efforts between EPRI and other domestic and foreign organizations—including power plant designers and architects, I&C system vendors, and the U.S. Department of Energy—will be useful.

At EPRI, technical work in the I&C area is being carried out in several divisions. To maximize the benefit to the utility industry, the work is coordinated within the Institute. The emphasis is to build on the existing I&C infrastructure as much as possible. An integrated plan will provide the details of activities and resource requirements for the various technical elements.

Future directions

It is difficult to visualize to what state I&C systems may eventually evolve. However, it is reasonably certain that the changes will occur in distinct phases. The near-term changes will be driven by the necessity of solving current problems that contribute to generation unavailability and large operating costs. The first phase will be a mix of digital and analog technology. This mix will probably last for the life of some plants, where it is impractical or uneconomical to replace all the older, analog equipment.

In the future, most analog equipment will be replaced with digital equipment. There will be extensive utilization of the expanded capabilities that modern I&C technology makes possible. Advances will include automation; operator diagnostic aids; robust, intelligent control systems; and highly reliable and safer protection. New control rooms and operator interfaces will be required.

In the final analysis, how the gap between current and future I&C systems will be bridged will depend heavily on the direction the nuclear power industry takes. The key task in bridging the gap is to take advantage of modern I&C technology to effectively revitalize existing plants through I&C system upgrades. With the active support of a U.S. utility advisory group, EPRI is leading a comprehensive I&C initiative to formulate a plan and coordinate the major elements of this task; nuclear industry suppliers, I&C vendors, national laboratories, and other development agencies are also actively involved. The vision of the initiative is that I&C systems for elective upgrades at existing plants and for new plants will be designed to make effective use of modern technology and standardization in order to respond to industry needs to control costs and improve plant performance.

Utility Waste Management

Handling Noncombustion Wastes

by Mary McLearn, Generation and Storage Division

Utility wastes are typically grouped into three categories: high-volume wastes, such as fly ash and scrubber sludge; low-volume wastes, such as boiler blowdown and coal pile runoff; and noncombustion wastes. EPRI has defined noncombustion wastes as those generated as a result of power plant operations and maintenance, system performance monitoring and environmental monitoring, and electric power distribution.

Noncombustion waste streams- for example, used oil, mercury relays, paint sludges, spent batteries, and debris from spill cleanup—may be continuous or intermittent or may result from extraordinary incidents like fires or spills. Their volumes range from thousands of tons to fractions of ounces. They may be regulated under the Resource Conservation and Recovery Act (RCRA), the Toxic Substances Control Act, the Clean Water Act, or a myriad of other federal, state, and local laws. They may be classified as hazardous, as nonhazardous, or as special wastes.

Waste management options

The various options for managing noncombustion waste are directed toward efficient operation of utility facilities and protection of the environment. Options include substitution or elimination of the waste by process changes; recovery and reuse for the same or a different purpose; capture and destruction; capture and treatment; and capture and disposal in a landfill or surface impoundment. The potential liabilities associated with these options are greatest for disposal and smallest for substitution and elimination. EPRI is defining options for handling noncombustion wastes to maximize efficiency and to minimize costs and liability for waste management.

Waste minimization is a key principle in waste management strategies. It can be applied at all utility facilities. It may be mandated by federal, state, or local regulations, and it is often rewarded by measurable cost savings.

Waste minimization requires careful planning and sustained implementation to guarantee its effectiveness. To achieve waste minimization, utilities must understand the wastes they generate: their physical and chemical characteristics; their volume and the frequency with which they are generated; the process by which they are generated; and their regulatory status. Armed with this information, utilities can apply the hierarchy of generic options presented in Figure 1 to design an individual waste minimization strategy.

EPRI has identified and defined 16 noncombustion waste streams that pose management challenges to, and create expenses for, utilities. The 16 waste streams are used oil, waste mercury, used batteries, treated utility poles, wood-treating wastes, pesticide wastes, paint wastes, oily wastewater and storm water, rags, liquid-filled power fuses, containers, equipment contaminated with PCB substitutes, cooling-tower wood, oil ash, chromate-contaminated water, and automotive antifreeze.

EPRI applied the waste minimization strategy to each of these waste streams and has developed management options. Options for three of the waste streams are described below. These examples demonstrate the approach taken in EPRI's project, the complexity of the problem of noncombustion wastes, and the breadth of potential solutions.

Automotive antifreeze

Utilities generate spent antifreeze from the draining of radiator cooling systems. Spent antifreeze is generated continuously as part of the routine maintenance of vehicle fleets. It consists of ethylene glycol, water, and various impurities, including metals, organic impurities, dirt, silt, and mineral salts. Waste antifreeze is not a hazardous waste under federal regulation unless it fails the RCRA toxicity test for metals.

Management options for spent antifreeze include source reduction, recycling, and treatment. No satisfactory substitutes for ethylene glycol are currently available commercially.

Source reduction is achieved by instituting careful procedures to minimize spills; by changing coolant on an as-needed basis (using a simple pH-screening test to determine need) rather than on a preset schedule; and by segregating waste antifreeze to avoid cross-contamination with a federally designated hazardous waste.

Recycling of antifreeze is accomplished either by distillation or by filtration and chemical treatment. Additives removed during distillation must be replaced to reconstitute the antifreeze for automotive uses. Alternatively, ethylene glycol recovered by distillation can be sold for other uses. The second recycling approach consists of mechanical filtration to remove suspended impurities, precipitation or filtration of dissolved metals, and neutralization of ethylene glycol breakdown products, followed by reconstitution by replacement of additives.

Treatment methods for spent antifreeze include incineration, wet air oxidation, and biological treatment. All three methods destroy the ethylene glycol.

The costs of recycling and destroying spent antifreeze are presented in Table 1. An important consideration in choosing the best option is the cost of replacing antifreeze, which has risen to about $8 per gallon. One large utility implemented a recycling program for spent antifreeze on the basis of EPRI's study and estimates annual savings of $90,000.

Paint wastes

Utilities generate paint wastes through routine painting and cleaning operations. In addition, unused paints may be discarded intermittently because of age, changing regulations, or other factors. Paint wastes consist of un-

Figure 1 Waste minimization hierarchy. By starting at the top of this hierarchy of generic options and working down, a generator can design a strategy to minimize long-term liability for disposed waste.

used paints, paint containers, paint sludges, and equipment-cleaning wastes (organic- or water-based). Unused paints and paint sludges may exhibit the federally defined hazardous characteristic of ignitability. Some cleaning solvents, including chlorinated solvents, are listed as hazardous wastes.

Management options for paint wastes depend on the specific material. For unused paint, options include minimization through improved materials control, use of painting contractors, and treatment by incineration or solidification. Empty containers can be reused, returned, disposed of in landfills, or incinerated. Sludges can be minimized through good practices, then recycled. Cleaning wastes can be minimized through operations planning, recycling, or the substitution of other, more easily handled materials.

Materials control is critical to the minimization of unused paint wastes; paint should be used up whenever possible. Centralized purchasing of paint materials, with an attempt to standardize paint types and colors and solvents, results in more-uniform waste. This improves the economics of recycling and treat-

ABSTRACT *Utility noncombustion wastes derive from operations and maintenance, performance and environmental monitoring, electricity distribution, and extraordinary incidents. They are managed in compliance with a complex set of federal, state, and local regulations. Strategies for handling noncombustion wastes emphasize waste minimization—for example, through good purchasing and management practices, product substitution, and recycling/reuse. Treatment, destruction, and disposal are other viable options for handling these wastes. EPRI has identified management options for 16 noncombustion waste streams, including automotive antifreeze, paint wastes, and batteries.*

Table 1
OPTIONS FOR HANDLING SPENT ANTIFREEZE

Technology	Technical Considerations	Cost
Distillation	Recovers ethylene glycol: additives needed to restore antifreeze	\$1.60/gal on-site; \$1.50–2.00/gal additional for hauling off-site
Filtration and chemical treatment	Filtration/precipitation removes impurities; additives needed to restore antifreeze	\$1.20/gal on-site, plus cost of treating/disposing of hazardous sludge
Incineration	Destroys antifreeze	\$1.40/gal, plus \$8.00/gal for replacement
Wet air oxidation	Destroys antifreeze	\$1.00/gal, plus \$8.00/gal for replacement

Note: Purification options, such as distillation or filtration, must be followed by reconstitution to render the antifreeze effective Destroyed antifreeze must be replaced.

ment options, as well as facilitating the review of purchases and stocks with respect to current and proposed environmental regulations. Decreasing the variety of paints and solvents used also allows for bulk purchasing, which decreases the number of containers generated. Often bulk containers can be returned for deposit, further decreasing the number of waste containers.

Utilities can hire contractors for painting jobs, who will then handle the purchase and disposition of all paint-related material. This option is particularly effective for small jobs, which may require nonstandard materials or smaller quantities than a utility can reasonably purchase in bulk.

Unused paints found in rusted or unlabeled containers that cannot be salvaged may require incineration. In a small number of cases, unused paint may be solidified and disposed of in a landfill.

Paint containers should be reused wherever possible. Drums and other bulk containers can usually be returned for deposit. Paint can be dispensed from bulk to smaller (1- or 5-gallon) containers before use. The smaller containers should be dedicated to a single paint product and color; then they can be reused for an extended period of time. Using all the paint in a container will minimize the formation of paint sludge over time. It also will allow a container to be classified as empty under federal regulation, which permits landfill disposal for an empty container whose lifetime is over. An exception is made for containers that held paints blended with solvents on the EPA's p-list, which must undergo additional treatment before being classified as empty. A utility should carefully study the regulations and consider its options before disposing of these containers; hazardous waste disposal and incineration should be compared to determine the best available option.

Cleaning wastes from painting operations may be recycled off-site, an attractive option for materials containing at least 60% solvent. On-site recycling by distillation is currently being implemented or considered by several utilities, and vendors claim that the economics are favorable. Substitute products that can reduce the generation of cleaning wastes include monomer and powder coatings (for use instead of solvent-based paints). The increased initial costs for powder coatings may be offset by decreased costs for maintenance and disposal of solvent-based coatings.

Batteries

Utilities generate spent lead-acid batteries through changeout of automotive batteries; nickel-cadmium batteries through maintenance of emergency lighting systems and changeout of batteries in power tools, flashlights, radios, and other small devices; and lithium batteries through changeout of batteries in computers and time-of-use meters.

Lead-acid batteries contain lead and sulfuric acid in a polypropylene, rubber, or plastic container. They are federally classified as hazardous waste because of their lead (toxicity characteristic) content and their sulfuric acid (corrosivity) content. They are exempt from regulation as hazardous, however, when recycled or reclaimed. Nickel-cadmium batteries may contain sodium and potassium hydroxides in addition to nickel and cadmium. They may be federally classified as hazardous waste because of the toxicity characteristic for cadmium. Lithium batteries may contain lithium iodide, lithium thionyl chloride, or other lithium compounds. They may be federally classified as hazardous waste because of reactivity, depending on the lithium compound used.

Management options for batteries include good maintenance and testing to ensure maximum lifetime; return of batteries to the point of sale when purchasing new batteries (to foster recycling); separation and recycling of components; incineration; and disposal.

Careful maintenance and recharging of lead-acid batteries extends battery lifetime and reduces the number of spent batteries. For lead-acid batteries, the Battery Council International recommends routine visual inspection, external cleaning, and maintenance of proper electrolyte levels. Nickel-cadmium batteries are rechargeable, so using them is a waste minimization measure. Their lifetime can be prolonged by proper charging practices; some nickel-cadmium batteries should be recharged only when they have been fully discharged, while others may be charged continually. Proper attention to manufacturers' instructions will increase battery life.

Lead-acid batteries are commonly recycled, while the options for recycling nickel-cadmium and lithium batteries are more limited. Many states require that retailers or wholesalers of lead-acid batteries accept used batteries from customers in quantities equal to those being purchased. The batteries are then sent to a recycler/reclaimer for processing. There are commercial battery recyclers in some locations in the United States; state and local waste exchanges can be consulted to help locate such a recycler and ensure that it is reputable. In addition, many communities sponsor collections of used lead-acid batteries. Although some commercial facilities advertise that they recycle nickel-cadmium batteries, the collection and recycling of nickel-cadmium and lithium batteries has yet to receive much attention because of the smaller quantities of spent material.

When spent lead-acid batteries cannot be recycled or returned, on-site separation (battery breaking) and the recycling of components may be a reasonable option. Recovered spent acid is sold to acid recyclers. Battery breaking has significant disadvantages, however; employee safety must be managed carefully, and on-site battery breaking subjects the corporation to regulation as a battery reclaimer. On-site reclamation does not appear to be an option at this time for nickel-cadmium or lithium batteries.

Various treatment options are available for batteries, and these are generally performed by battery specialists. For example, lithium batteries can be treated to reduce their reactivity, and nickel-cadmium batteries can be treated to leach out the toxic metals. The residual materials are then disposed of in accordance with regulations. Nickel-cadmium and lithium batteries can be incinerated in most hazardous waste incinerators. In the recent past, batteries have been disposed of as hazardous waste in secure landfills. Nickel-cadmium batteries will be subject to the federal land ban on May 8, 1992. In response to increased regulation, recycling opportunities are expected to grow in the next few years.

Integrated waste management

EPRI's study has identified management options for 16 different noncombustion wastes. An EPRI manual on options for handling noncombustion waste was published this fall (GS-7052), along with separate manuals on boiler-cleaning waste and spent solvents. Three new wastes will be added to a revised manual scheduled for completion in mid-1991. On-site testing of options will begin at utility sites in 1991.

Several themes reappear throughout EPRI's work: good product specification and purchasing procedures, such as specification of one product for several functions; careful operations and maintenance procedures, such as segregating hazardous and nonhazardous wastes and avoiding spills; and worker awareness and attention to health, safety, and environmental concerns.

Integrated waste management is one additional step toward the efficient, cost-effective handling of waste. Integrated waste management incorporates the themes addressed in EPRI's study, including waste minimization and waste accounting. It looks at systems as a whole, considering comanagement of different waste streams as well as the interrelationships of waste management options. Over the next few years, as EPRI documents the application of options for handling noncombustion wastes, the institutional and environmental concerns that are involved will be considered along with the technical and cost implications. The desired goal is waste management fully compatible with the principles presented in Figure 1.

Market Assessment

Residential Energy Usage Comparison

by Larry Lewis, Customer Systems Division

To assess the energy performance and customer acceptance of new electric and natural gas appliances, EPRI and Southern California Edison (SCE) undertook a joint research project called the residential energy usage comparison, or REUC, project (RP-2863-3). Traditional studies of the relative energy efficiencies of electric and natural gas end-use technologies have relied on laboratory settings or computer simulation models. In contrast, the REUC project moved away from the laboratory; instead of relying on simulated usage, it examined the energy demand and customer behavior of actual households. As a result, it has illuminated many subtle but important determinants of appliance usage, including household characteristics, that are not captured in engineering models.

This innovative demand-side project involved a strategically designed sample of 92 households in Orange County, southeast of Los Angeles, representing an important segment of SCE's residential customers—new, owner-occupied single-family houses in a high-growth area. The REUC households were characterized by relatively high levels of education (about three-quarters included a resident with at least a bachelor's degree) and income (31 households had annual income below $50,000, 52 had income of $50,000–80,000, and 9 had income over $80,000). Half of the houses were smaller than 1750 square feet, a quarter were 1750–2000 square feet, and a quarter were larger than 2000 square feet.

The REUC results illustrate the value of two unique facets of the project's design: first, end-use load data were collected for both electric and natural gas appliances; and second, these data were supplemented by customer survey data collected from the participants. End-use load data collection was begun in late 1986 for a portion of the sample; customer survey data collection was begun in mid-1987. All data collection was concluded in December 1989.

Electric versus gas appliances

A principal objective of the REUC project was to measure, at the point of use, electric and natural gas appliance energy consumption. SCE identified four residential energy uses to be considered in the project: space condition-

ABSTRACT *A joint effort by EPRI and Southern California Edison has measured and analyzed typical energy consumption patterns for comparably efficient residential electric and natural gas appliances. New space-conditioning, water-heating, cooking, and clothes-drying appliances were installed in customers' homes and metered; and the household residents were surveyed to obtain data on their energy needs and their acceptance of the appliances. By integrating load data and customer survey information, this innovative project has provided important new insights on residential energy usage.*

ing, water heating, clothes drying, and cooking. This selection was based on the direct competition between electricity and natural gas for these end uses and on the desire to assess new, high-efficiency electric technologies.

Half of the REUC sample households, referred to as the electric sample, received new electric heat pumps for both space conditioning (typical seasonal energy efficiency ratio, or SEER, of 9; heating season performance factor of 7) and water heating (coefficient of performance of 3). The other half, the natural gas sample, received new gas furnaces (80% efficiency), electric air conditioners (typical SEER of 9), and gas water heaters (58% efficiency). New gas and electric clothes dryers were also installed. Cooking appliances were replaced for only half of the electric sample, where new electric induction ranges were installed. Since this area of the SCE service territory is typically dominated by natural gas for space and water heating, most of the electric sample households represented conversions from gas to electricity for those major end uses.

Figure 1 shows the average annual energy consumption at the point of use for the REUC space-conditioning appliances (electric heat pumps relative to gas furnaces in combination with electric air conditioners), water heaters (electric heat pumps relative to gas heaters), clothes dryers, and cooking appliances. These results are based on appliance energy data gathered over a one-year period, from February 1988 through January 1989. For space conditioning, the electric heat pumps consumed less than 45% of the energy consumed by the natural gas systems. For water heating, the energy consumption of the electric appliances amounted to only 40% of that of their natural gas counterparts. Electric clothes dryers and ranges consumed, respectively, 80% and 38% of the energy of natural gas dryers and ranges.

The average annual household consumption of electricity amounted to 2970 kWh for space conditioning (810 kWh for the summer months and 2160 kWh for the rest of the year), 2750 kWh for water heating, 1100 kWh for clothes drying, and 390 kWh for cooking. The average total household consumption was 14,100 kWh.

Average winter weekday load profiles were developed for both electric and natural gas space-conditioning appliances (electric heat pumps and gas furnaces). As was the case with annual energy consumption, hourly energy consumption during the morning peak period was lower for electric heat pumps than for gas furnaces (Figure 2). This was due in part to the higher efficiency of the electric ap-

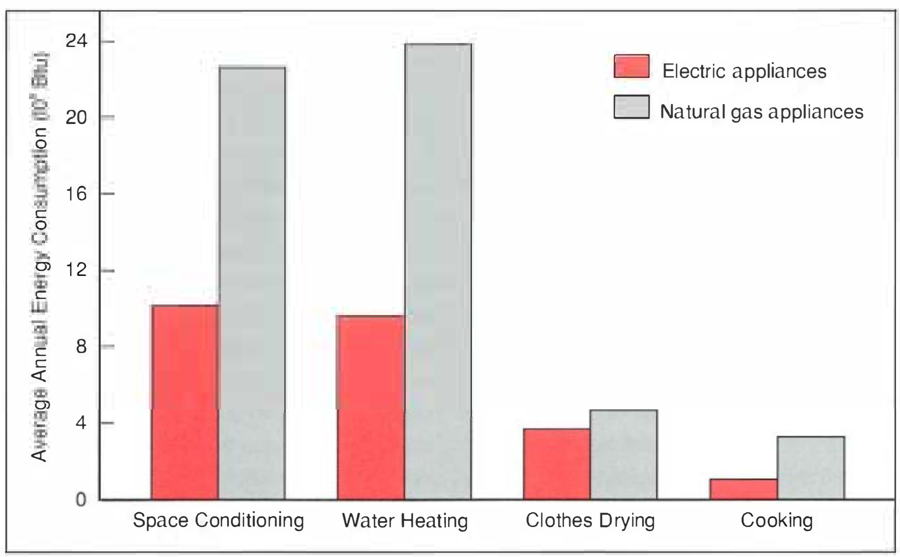
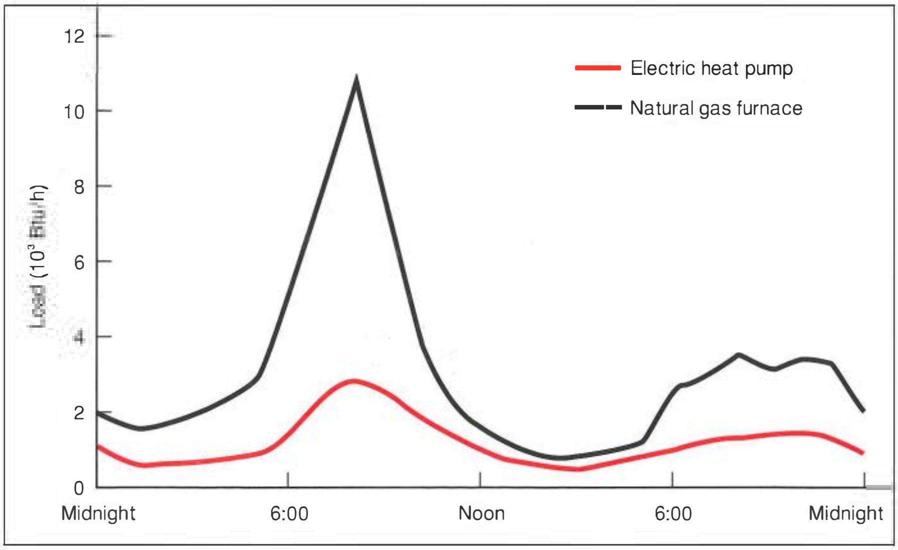


Figure 1 The REUC project researchers metered electric and natural gas appliances in a 92-household sample and determined average annual energy consumption for four major end uses. The electric appliances—especially the heat pumps used for space conditioning and water heating—consumed less energy than their natural gas counterparts.

Figure 2 Average load profiles for winter weekday space conditioning developed in the REUC project. The electric heat pumps had a lower morning peak than the natural gas furnaces because of greater efficiency as well as electric rate differentials. REUC load data like these, together with the customer survey information obtained from the sample households, have provided valuable insights into the patterns of residential energy usage.



pliances and in part to electric rate differentials, which tend to shift consumption off-peak. The electric heat pumps showed a diversified peak load of about 3000 Btu per hour (or 1 kW), compared with about 11,000 Btu per hour for gas furnaces, and they drew smaller amounts of energy over longer periods of time during the day.

Load shapes were also calculated for various sample subgroups, or market segments, which were defined in three ways: by the energy needs–based system used in EPRI's CLASSIFY code (see EPRI report EM-5908), by a fuel-image characterization described below, and by standard demographic characteristics. In many cases, the segmentation schemes were characterized by distinctly different load-shape patterns.

Customer acceptance of appliances

Measuring customer acceptance of the new appliances was another objective of the REUC project. This was accomplished by means of surveys in which the participants rated their new appliances in terms of various attributes, including reliability, operating cost, response time, and maintenance.

The results indicated that electric heat pumps for space heating were well accepted. Of the participants whose natural gas furnaces were replaced with heat pumps, 50% changed their space-heating fuel preference from gas to electricity. The acceptance ratings for electric heat pump water heaters, however, were not as high as the ratings for gas water heaters. The survey responses indicated that participants apparently found heat pump water heaters too slow to respond. The acceptance ratings for cooking appliances, including electric induction stoves, were strong. Of the households retrofitted from gas ranges to electric induction stoves, 50% expressed a preference for electricity as a fuel for cooking.

Integrated market research

Integrated market research involves the creative synthesis of load research data and customer survey information to develop insights about consumers' patterns of energy usage. The REUC project is an example of this approach.

The REUC surveys included questions designed to estimate the participants' appliance investment payback requirements on the basis of their implied discount rates. The higher an individual customer's discount rate for an appliance investment, the shorter the required payback period for the investment. The payback periods required by the REUC participants were generally quite short: over 40% of the households required paybacks of less than two years, and 30% required paybacks of between two and five years.

The surveys also included questions designed to elicit the participants' images of electricity and natural gas. Aside from providing valuable market research information, fuel images were found to be useful factors for defining customer segments. Factor analysis of the REUC participants' fuel images yielded two key factors: a quality factor (which combines safety, convenience, service, and reliability considerations) and a value factor (which combines appliance cost, general expense, and monthly utility bill considerations). The REUC participants tended to rank electricity high on the qualities of cleanliness and safety, but they considered electricity a higher-cost fuel than natural gas.

Research benefits

As a result of the REUC project, SCE and the utility industry have gained an improved quantitative understanding of energy consumption patterns for comparable electric and natural gas appliances as they are operated in consumers' homes. Utilities can use this information, which is presented in EPRI CU-6952, to compare the cost-effectiveness of various options for their customers as part of a demand-side management or market-planning process. In addition, the project yielded insights about consumers' attitudes toward fuel types and new appliances. This information can be useful in assessing the value that consumers place on electricity and on the various appliances studied. Finally, the integrated load and market research of the REUC project makes it possible to calculate load-shape data for different market segments and to examine the likely load impacts of attracting particular types of customers through targeted marketing programs.

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Customer Systems		
HELM–PC Development (RP2863-9)	$130,000 11 months	ICF Incorporated/ *P. Hummel*
Service Life of Commercial Unitary Heat Pumps (RP2891-13)	$65,100 16 months	Policy Research Associates/*M. Khattar*
Air Conditioning and Refrigeration Research Center (RP2892-11)	$120,000 36 months	University of Illinois/ *A. Lannus*
Ground-Source Heat Pump Marketing Manual (RP2892-16)	$73,000 8 months	Dynamic Strategies Group/*P. Joyner*
Glass Technology Development (RP2893-9)	$150,000 9 months	Mellon Institute of Research/*R. Jeffress*
High-Frequency Series-Resonant DC Link Power Conversion System: Design and Testing (RP2918-6)	$109,600 16 months	University of Wisconsin/ *B. Banerjee*
Advanced Battery-Charging Technologies: Status Assessment (RP2918-12)	$53,400 8 months	San Jose State University Foundation/*B. Banerjee*
Customer Purchase Criteria for Cogeneration (RP2950-7)	$75,100 9 months	RCG/Hagler Bailly/ *W. LeBlanc*
Innovative Distribution Opportunities for Energy Products and Services (RP2979-6)	$75,000 5 months	Macro Consulting/ *T. Henneberger*
Evaluation of the Unity-Plus Rewinding Technology for Induction Motors (RP3087-4)	$67,500 8 months	Tennessee Center for Research and Development/*B. Banerjee*
Residential Refrigerator Electric Energy Monitoring (RP3188-1)	$74,900 22 months	ESEERCO/*P. Joyner*
Electrical Systems		
Scoping Study for Sunburst System (RP3211-1)	$55,000 3 months	Electric Research & Management/*B. Damsky*
Nonlinear Control and Operation of FACTS (RP4000-6)	$101,000 22 months	Oregon State University/ *D. Maratukulam*
Resonant Series Compensator Current Limiter (RP4000-21)	$100,000 20 months	Arizona State University/ *D. Maratukulam*
Development of High-Temperature Superconducting Wires and Ribbons With Film Deposition Techniques (RP7911-13)	$937,800 35 months	Bellcore/*D. Sharma*
Studies of Superhigh-Temperature Superconductors and High Critical Current Density (RP7911-18)	$50,000 12 months	Lockheed Space & Missile Co./*M. Rabinowitz*
Environment		
Lymphatic Leukemia in Mice Exposed to 60-Hz Magnetic Fields (RP2965-11)	$1,567,800 58 months	UCLA/*C. Rafferty*
Forest Response to Carbon Dioxide (RP3041-2)	$3,170,200 60 months	Desert Research Institute/ *L. Pitelka*
Human Health Effects and Short-Term Air Pollution Exposure (RP3215-1)	$1,396,200 34 months	Los Amigos Research and Education Institute/ *W. Weyzen*
Generation and Storage		
Dry Cooling: Future Needs (RP422-13)	$73,600 9 months	Yankee Scientific/*J. Bartz*
Demonstration of Strategies for Improved Baghouse Performance at Bunner Island (RP1129-24)	$99,500 15 months	Southern Research Institute/*R. Chang*
Use of Acoustic Ranging to Monitor Fouling in Coal Gasifiers (RP1654-46)	$81,400 23 months	Kema/*W. Bakker*

Project	Funding/ Duration	Contractor/EPRI Project Manager
Design and Construction of Catalyst Test Facility (RP1835-22)	$190,500 13 months	Southern Company Services/*R. Altman*
Corrosion Control by Impressed Currents in FGD Outlet Ducts (RP1871-25)	$140,800 24 months	Harco Technologies Corp./*B. Syrett*
Microcomputer Software for Power Plant Water Management (RP2114-10)	$114,000 28 months	Personal Science Co./ *W. Micheletti*
Development of an Improved Slagging Index (RP2425-10)	$60,000 24 months	PSI Technology Co./ *A. Mehta*
Engineering and Economic Evaluation of Whole Tree Burn Technology (RP2612-15)	$194,100 5 months	Research Triangle Institute/*J. Berning*
High-Temperature Winkler (HTW) Gasification Tests (RP2656-5)	$94,600 9 months	Rheinbraun Engineering und Wasser/*M. Epstein*
High-Concentration PV Cell Manufacturing Development (RP2703-3)	$1,960,000 6 months	Amonix/*F. Dostalek*
Control System Retrofit Guidelines (RP2710-15)	$203,500 12 months	Sargent & Lundy Engineers/*M. Divakaruni*
Control Retrofit Assessment Library System (RP2710-19)	$93,700 18 months	Decision Focus/ *M. Divakaruni*
Nuclear Power		
Free-Motion Scanner for Manual Ultrasonic Testing (RP2687-9)	$75,500 8 months	Structural Integrity Associates/*M. Avioli*
Interfacing-Systems LOCA Issues Resolution (RP3114-41)	$128,800 11 months	Science Applications International Corp./ *E. Dietrich*
Evaluation of Effectiveness of Post–TMI-2 Instrumentation and Control Strategy (RP3114-42)	$50,700 11 months	Mollerus Engineering Corp./*L. Oaks*
Probabilistic Risk Analysis Manual for Nuclear Plant Engineers (RP3114-44)	$51,600 9 months	Tenera Operating Co./ *W. Reuland*
Guidance for Self-Assessment Programs (RP3114-46)	$75,100 9 months	MPR Associates/ *W. Reuland*
HVAC Safety and Reliability (RP3114-48)	$85,300 8 months	Pickard, Lowe, and Garrick/*W. Reuland*
NSAC Database Development (RP3114-50)	$72,900 10 months	Tenera Operating Co./ *E. Dietrich*
Technical Support for Addressing LWR Safety Issues (RP3114-51)	$50,000 8 months	Computer Simulation and Analysis/*S. Oh*
MAAP Development for Severe-Accident Management Applications (RP3131-2)	$475,800 8 months	Fauske & Associates/ *E. Fuller*
Specification for Reliability-Centered Maintenance Workstation (RP3134-1)	$99,400 8 months	Erin Engineering & Research/*R. Colley*
Testing and Implementation of ARRIS (RP3147-1)	$99,100 8 months	Science Applications International Corp./*S. Liu*
Experimental Modeling of Eddy-Current Response (RPS404-28)	$195,800 18 months	Westinghouse Electric Corp./*C. Welty*
Analysis of Alloy 600 Caustic Stress Corrosion Cracking (RPS407-38)	$58,600 12 months	Modeling & Computing Services/*P. Paine*
Large Eddy Simulation of Turbulent Fields in Steam Generators (RPS410-15)	$206,800 23 months	Texas A&M University/ *D. Steininger*
Seismic Qualification Utility Group Support Tasks (RPSQ1-2)	$220,000 27 months	MPR Associates/ *R. Schaffstall*
Planning		
Field Test of Priority-Service Methods (RP2801-4)	$191,200 9 months	Laurits R. Christensen Associates/*H. Chao*

New Technical Reports

Requests for copies of reports should be directed to Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081. There is no charge for reports requested by EPRI member utilities, U.S. universities, or government agencies. Reports will be provided to nonmember U.S. utilities only upon purchase of a license, the price for which will be equal to the price of EPRI membership. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of EPRI reports on request. To order one-page summaries of reports, call the EPRI Hotline, (415) 855-2411.

CUSTOMER SYSTEMS

Industrial Load Shaping: An Industrial Application of Demand-Side Management—Vol. 1 (Overview)
CU-6726 Final Report (RP2224-12); $100
Contractor: Bules and Associates
EPRI Project Managers: P. Meagher, W. Smith

Cost and Performance Characteristics of Small Cogeneration Systems, Vols. 1 and 2
CU-6842 Final Report (RP2950-1); $495 each volume
Contractor: Synergic Resources Corp.
EPRI Project Managers: H. Gransell, W. LeBlanc

Proceedings: Power Quality for End-Use Applications Conference—1988
CU-6884 Proceedings (RP2935-1); $100
Contractor: TEM Associates, Inc.
EPRI Project Manager: M. Samotyj

Rate Design: Traditional and Innovative Approaches
CU-6886 Final Report (RP2343-4); $100
Contractor: Barakat & Chamberlin, Inc.
EPRI Project Manager: P. Hanser

Evaluation of Electric Vehicle Battery Systems Through In-Vehicle Testing
CU-6888 Final Report (RP1136-33); $100
Contractor: Electrotek Concepts, Inc.
EPRI Project Manager: R. Swaroop

Competitive Procurement of Electric Utility Resources
CU-6898 Final Report (RP3086-1); $295
Contractor: Charles River Associates
EPRI Project Manager: W. LeBlanc

DSM: Transmission and Distribution Impacts—Vols. 1 and 2
CU-6924 Final Report (RP2548-1); Vol. 1, $100; Vol. 2, $1000
Contractors: ABB Power Systems, Inc.; Southern Electric International
EPRI Project Managers: T. Yau, W. Smith

ELECTRICAL SYSTEMS

TLWorkstation™ Code, Version 2.0, Vol. 8: DYNAMP Manual
EL-6420 Final Report (RP2546-1); $25
Contractor: Georgia Institute of Technology
EPRI Project Manager: V. Longo

TLWorkstation™ Code, Version 2.0, Vol. 10: RNOISE Manual
EL-6420 Final Report (RP2025-1); $25
Contractor: Washington State University
EPRI Project Manager: V. Longo

TLWorkstation™ Code, Version 2.0, Vol. 16: CUFAD Manual
EL-6420 Final Report (RP1493-6); $32.50
Contractor: Cornell University
EPRI Project Manager: V. Longo

TLWorkstation™ Code, Version 2.0, Vol. 17: MFAD Manual
EL-6420 Final Report (RP1493-7); $25
Contractor: GAI Consultants, Inc.
EPRI Project Manager: V. Longo

Characteristics of Lightning Surges on Distribution Lines: First-Phase Report
EL-6782 Interim Report (RP2542-1); $40
Contractor: Power Technologies, Inc.
EPRI Project Manager: V. Longo

Direct Embedment Foundation Research: Load Test Summaries
EL-6849 Final Report (RP1280-7); $47.50
Contractor: GAI Consultants, Inc.
EPRI Project Manager: V. Longo

Advanced Packages for Power Devices
EL-6851 Final Report (RP2443-8); $25
Contractor: General Electric Co.
EPRI Project Manager: H. Mehta

EXPLORATORY RESEARCH

Improved Superclean NiCrMoV Rotor Steel
ER-6887 Final Report (RP2426-4, RP2741-4); $32.50
Contractor: Bethlehem Steel Corp.
EPRI Project Manager: R. Jaffee

Doped Cerium Oxide for Molten Carbonate Fuel Cell Cathodes
ER-6983 Final Report (RP2278-6); $25
Contractor: Case Western Reserve University
EPRI Project Manager: W. Bakker

GENERATION AND STORAGE

Texaco Coal Gasification Wastewater Handling and Treatment Pilot Plant, Vols. 1 and 2
GS-6819 Final Report (RP1459-30, -31); $200 each volume
Contractors: Texaco Port Arthur Research Laboratories; Radian Corp.
EPRI Project Manager: E. Clark

Repair, Upgrade, and Closure of Underground Storage Tanks
GS-6830 Final Report (RP2795-1); $25
Contractor: Roy F. Weston, Inc.
EPRI Project Manager: M. McLearn

Full-Scale Demonstration of Additives for NO_2 Reduction With Dry Sodium Desulfurization
GS-6852 Final Report (RP1682-2); $32.50
Contractor: KVB, Inc.
EPRI Project Managers: R. Rhudy, B. Toole-O'Neil

Preliminary Guidelines for Integrated Controls and Monitoring for Fossil Fuel Plants
GS-6868 Interim Report (RP2922-2); $2500
Contractor: Southern California Edison Co.
EPRI Project Managers: M. Divakaruni, M. Blanco

Optimization of Electricity-Methanol Coproduction
GS-6869 Final Report (RP2771-1); $47.50
Contractor: Chem Systems, Inc.
EPRI Project Manager: W. Weber

Evaluation of a Gas Turbine Inlet Air-Cooling System
GS-6874 Final Report (RP2832-4); $32.50
Contractor: Joseph Technology Corp., Inc.
EPRI Project Manager: H. Schreiber

NUCLEAR POWER

Concrete Containment Integrity Software: Procedure Manual and Guidelines
NP-6263-M Interim Report (RP2172-1); $25
NP-6263-SD Interim Report; $50,000
Contractor: ANATECH Research Corp.
EPRI Project Manager: H. Tang

Effects of LOMI Decontamination Process on Ultrasonic Response From Intergranular Stress Corrosion Cracking
NP-6836-D Final Report (RPC105-2); $20,000
Contractor: Ishikawajima-Harima Heavy Industries Co., Ltd.
EPRI Project Manager: M. Behravesh

Acoustic Emission for Detecting Crack Initiation in Stainless Steel
NP-6844 Final Report (RP2812-7); $25
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: R. Pathania

Precipitate Stability in Zircaloy-2
NP-6845-D Final Report (RP1250-16); $15,000
Contractor: General Electric Co.
EPRI Project Managers: P. Rudling, R. Yang

The BWR Emergency Operating Procedures Tracking System (EOPTS): Evaluation by Control-Room Operating Crews
NP-6846 Final Report (RP2347-22); $32.50
Contractor: Accident Prevention Group
EPRI Project Managers: B. Sun, S. Bhatt

CALENDAR

For additional information on the meetings listed below, please contact the person indicated.

FEBRUARY

5–8
Advanced Machinery Vibration Diagnostics Course
Eddystone, Pennsylvania
Contact: Richard Colsher, (215) 595-8870

6–8
Symposium: New Equipment and Services for Foodservice Customers
New Orleans, Louisiana
Contact: Susan Bisetti, (415) 855-7919

13–15
Evaluation of Demand-Side Management Impacts
Denver, Colorado
Contact: Bill LeBlanc, (415) 855-2887

MARCH

5–6
Instrument Air Systems
Baltimore, Maryland
Contact: Lori Adams, (415) 855-8763

5–7
Bearing Diagnostics Course
Eddystone, Pennsylvania
Contact: Richard Colsher, (215) 595-8870

6–8
Value-Based Transmission
Washington, D.C.
Contact: Pam Turner, (415) 855-2010

18–22
Acoustic Leak and Crack Detection Course
Eddystone, Pennsylvania
Contact: Richard Colsher, (215) 595-8870

25–28
1991 Symposium on Stationary NO_x Control
Washington, D.C.
Contact: Maureen Barbeau, (415) 855-2127

APRIL

2–5
International Conference: Improved Coal-Fired Power Plants
San Francisco, California
Contact: James Valverde, (415) 855-7998

9–11
Radiation Field Control
Palo Alto, California
Contact: Lori Adams, (415) 855-8763

17–19
Power Plant and Power System Training Simulators and Modeling
Miami, Florida
Contact: Pam Turner, (415) 855-2010

24–25
Power Plant Electrical Auxiliary Systems
Princeton, New Jersey
Contact: Maureen Barbeau, (415) 855-2127

25–26
1991 Utility Strategic Planning Forum
Baltimore, Maryland
Contact: Susan Bisetti, (415) 855-7919

MAY

1–3
Evaluation of Demand-Side Management Impacts
Chicago, Illinois
Contact: Bill LeBlanc, (415) 855-2887

1–3
International Symposium: Biological Processing of Coal
San Diego, California
Contact: Susan Bisetti, (415) 855-7919

7–9
Conference: Heat Rate Improvement
Scottsdale, Arizona
Contact: Pam Turner, (415) 855-2010

13–15
Workshop: Optical Sensing
San Francisco, California
Contact: Lori Adams, (415) 855-8763

JUNE

4–6
Conference: Cycle Chemistry
Baltimore, Maryland
Contact: Maureen Barbeau, (415) 855-2127

18–20
Workshop: Condensate Polishing
Scottsdale, Arizona
Contact: Lori Adams, (415) 855-8763

24–26
1991 EPRI Technology Transfer Meeting
Palo Alto, California
Contact: Joanne Peterson, (415) 855-2716

26–28
Information and Automation Technology
Washington, D.C.
Contact: Pam Turner, (415) 855-2010

26–28
Power Plant Pumps
Tampa, Florida
Contact: Susan Bisetti, (415) 855-7919

JULY

16–18
Steam Turbine Generator Life Assessment and Maintenance
Charlotte, North Carolina
Contact: Tom McCloskey, (415) 855-2655

30–August 1
5th National Demand-Side Management Conference
Boston, Massachusetts
Contact: Bill LeBlanc, (415) 855-2887

SEPTEMBER

9–11
Expert Systems
Boston, Massachusetts
Contact: Susan Bisetti, (415) 855-7919

18–20
International Conference: Use of Coal Ash and Other Coal Combustion By-products
Shanghai, China
Contact: Dean Golden, (415) 855-2516

OCTOBER

8–11
Coal Gasification
San Francisco, California
Contact: Lori Adams, (415) 855-8763

8–11
PCB Seminar
Baltimore, Maryland
Contact: Maureen Barbeau, (415) 855-2127

15–18
Meeting Customer Needs With Heat Pumps
Dallas, Texas
Contact: Pam Turner, (415) 855-2010

28–November 1
Particulate Control
Williamsburg, Virginia
Contact: Susan Bisetti, (415) 855-7919

Authors and Articles


Wolk


Holt

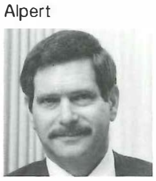

Cohn


Gillis


Gluckman


Alpert


Lewis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Beyond Steam: Breaking Through Performance Limits (page 4) was written by John Douglas, science writer, with guidance from a number of EPRI staff members.

Ronald Wolk, director of the Advanced Fossil Power Systems Department since 1980, managed EPRI's research on clean liquid and solid fuels before that. He came to EPRI in 1974 after 16 years with Hydrocarbon Research. Wolk holds BS and MS degrees in chemical engineering from the Polytechnic Institute of Brooklyn.

Neville Holt, senior program manager for gasification power plants, joined EPRI in 1974 after serving as manager of synthetic fuels at Cities Service Company. Earlier, from 1964 to 1970, he was with C. F. Braun & Company. Originally from the Isle of Wight, Holt is a graduate of Peterhouse, Cambridge University, with BA and MA degrees in chemistry.

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Seymour Alpert, named EPRI's first Research Fellow in 1988, has been at the Institute since 1973, serving as technical director for a broad range of research on synthetic fuels, renewables, and energy storage. Before joining EPRI, he worked for 15 years at Hydrocarbon Research and briefly at Chem Systems and SRI International. Alpert graduated in chemical engineering from the Polytechnic Institute of Brooklyn and earned an MS in economics at Rutgers. ■

A New Look at Commercial Customers (page 12) was written by David Boutacoff, *Journal* feature writer, with information provided by **Larry Lewis**, manager of EPRI's Market Assessment Program.

Lewis came to the Institute in 1986 from Applied Management Sciences, where he was director of utility market planning. Previously he was with Battelle, Columbus Laboratories, and still earlier he worked for 14 years in rate and market research with Consumers Power Company. Lewis has an MA in economics from the University of Michigan. ■

Heat Pumps: Developing the Dual-Fuel Option (page 22) was written by science writer Tom York, with technical guidance from **Morton Blatt**.

Blatt, manager of the Commercial Program, came to EPRI in 1985 after seven years with Science Applications International, where he worked on the development of energy-efficient HVAC equipment. Before that, he worked for 12 years with General Dynamics. Blatt graduated in mechanical engineering from Cooper Union, earned an MS in industrial engineering at New York University, and has a master's degree in business administration from San Diego State. ■

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