Building Demand-Side Management

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Cover: Utilities, regulators, environmentalists, and customers are working together to build demand-side management frameworks that are effective and make sense economically.

EDITORIAL

The Opportunity in DSM

Over the past year, increasing utility investment in demand-side management (DSM)—particularly in energy efficiency—has drawn the attention of the national media and business press. Articles on this topic have appeared in *The Wall Street Journal, Business Week,* and *Time*, among other publications. DSM and energy efficiency are being portrayed as the resource of the nineties, crucial to utilities' ability to meet future energy needs.

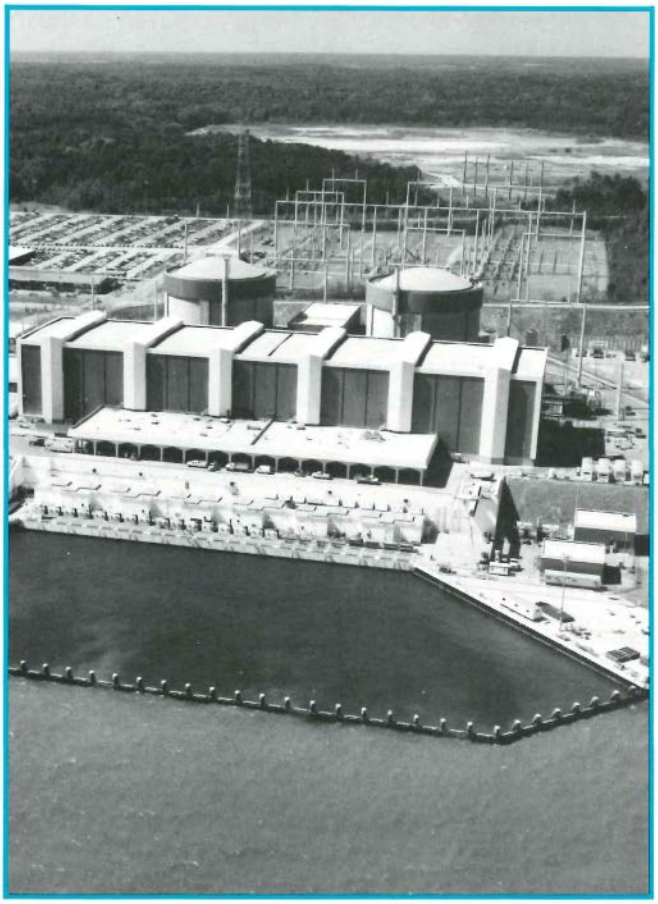
The vision of an industry spending money to "unsell" its own product is part of what makes the DSM story so captivating. Intentionally reducing electricity sales seems to contradict the very essence of U.S. business philosophy. However, this is only counterintuitive if one thinks of utilities as being solely in the commodity business of selling kilowatthours. If instead one remembers that customers don't buy kilowatthours but buy the services that electricity powers, and if one recognizes these energy services as a utility's products, then DSM makes perfect sense. From this perspective, energy efficiency programs are not a means of unselling a utility's product but an opportunity to enhance the value of electricity and to broaden the utility's business.

Providing quality energy services is, in fact, *the* essential ingredient of successful DSM. Unlike power plants, utilities can "construct" demand-side resources only when customers participate in utilities' programs and adopt DSM technologies. Customers will participate only if they perceive these programs as offering valuable improvements to their lifestyles or businesses. By offering utilities financial incentives for DSM investment, some state regulators have now opened the door to making a business out of the delivery of these energy services—a business attractive for both the utility and the customer.

This new path of DSM investment will not be an easy one to pursue. As this month's cover story describes, utilities are confronting a wide range of challenges, such as verifying the performance of DSM programs. No doubt the pioneers at the forefront of this venture will learn many hard lessons. But their experiences are paving the way for other utilities, both in the United States and abroad.

The next several years will be a period of rapid learning for utilities and others involved in this endeavor. During this time we will explore and gain experience with a broad variety of customer-focused programs. We will begin to answer the many questions asked today, learn what works and what doesn't, and understand—better than ever—the dynamics of the energy marketplace. This is an exciting time for electric utilities—a time to overcome the many challenges inherent in the profound changes that are taking place and to explore new ways to meet the needs of customers and society at large.

Veronika A. Rabl
Manager, Demand-Side Management Program
Customer Systems Division



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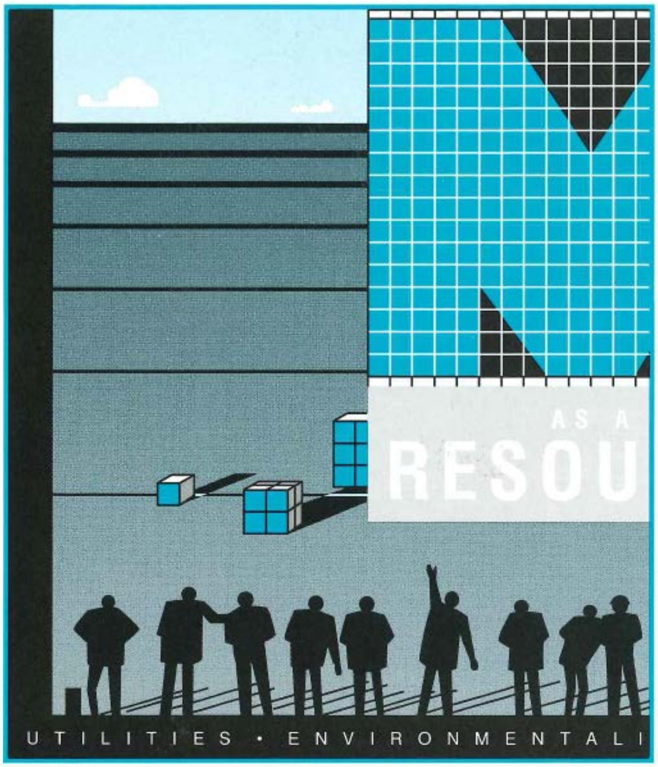

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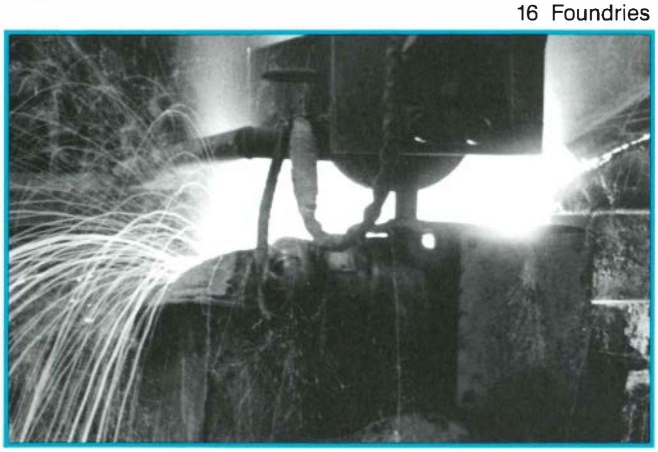
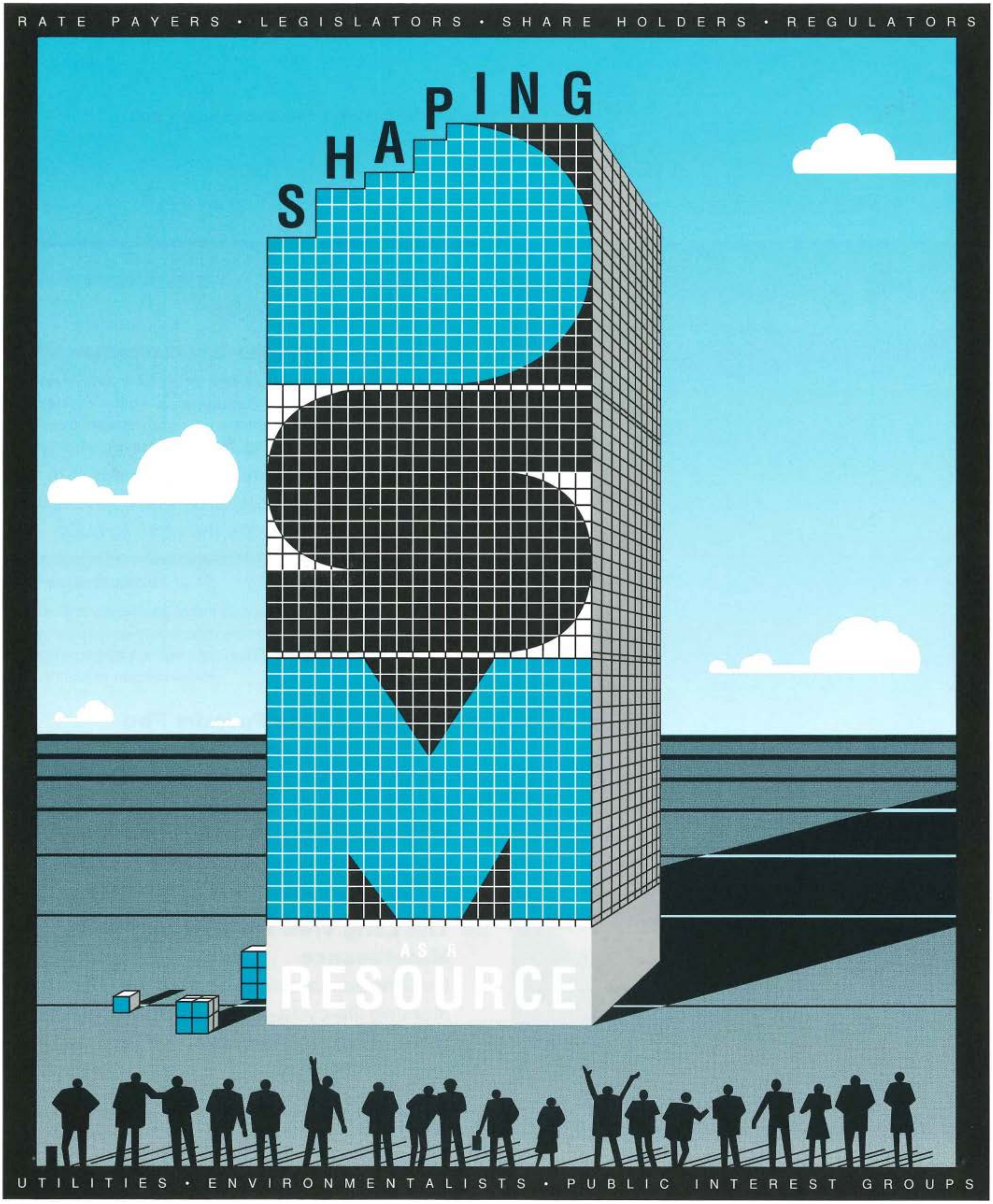



RATE PAYERS • LEGISLATORS • SHARE HOLDERS • REGULATORS
SHAPING
AS A
RESOURCE
UTILITIES • ENVIRONMENTALISTS • PUBLIC INTEREST GROUPS

We must implement DSM rapidly—if for no other reason, then as an insurance policy against continuing environmental degradation.

David Wolcott
New York State Energy Research & Development Authority

We're moving too fast in this area without good solid knowledge of where we're going or how we're going to get there.

John Anderson
Electricity Consumers Resource Council

These conflicting views of demand-side management (DSM) reflect both the confidence and the concerns about the role of DSM in utility business today. Some forms of DSM have been part of utility operations since the beginning of the industry's existence. But this nation's revived interest in energy efficiency and utilities' concerns about meeting demand for electricity with increasingly restricted supply-side resources have transformed the DSM concept and thrust it into the limelight of public scrutiny and expectations. Today, utility investment on the customer side of the meter is regarded by many as a resource more valuable than generation. DSM is being counted on to achieve ambitious efficiency goals while benefiting not only utilities and their customers but the environment and society at large.

What exactly is DSM? In its broadest definition, it incorporates all kinds of actions utilities take to modify their customers' demand for electricity. These actions can include the implementation of programs that aim to reduce electricity use, programs that redistribute electricity demand to spread it more evenly throughout the hours of the day, and even programs that encourage strategic load growth. Utility efforts to influence customer demand date back to the first generating station, Thomas Edison's Pearl Street facility in Manhattan. There in the 1890s, when nighttime lighting was the only load, Edison hired people to promote electric motors and other daytime uses of electricity.

As demand for electricity has increased dramatically over the years, utilities have developed more-sophisticated methods of influencing demand to make more-efficient use of available generating capacity. For instance, some utilities offer electric rates that vary with the time of day, being lowest during the periods of lowest demand. This gives customers an incentive to shift some of their electricity use away from the utility's period of peak demand. But of all DSM strategies, energy efficiency is the most recent endeavor, first propelled by the impact of the oil crises of the 1970s. Many experts today prefer the term efficiency over conservation because they feel that conservation conveys the notion of saving energy by sacrificing quality of life. Efficiency, on the other hand, stresses the ability of advanced technologies to maintain and even enhance the quality of life while using less energy.

The notion that a utility would want to sell less of its product certainly seems contradictory. However, if a utility manages to reduce electricity demand, it can postpone the need to build expensive new power plants. And one basic premise of efficiency programs is that, even accounting for program costs and the resulting lost revenues from decreased electricity sales, it is often cheaper to save kilowatthours and kilowatts of electricity than it is to build a power plant that could provide this electricity. Not surprisingly, it has generally been the capacity-constrained utilities that have taken the most initiative in implementing load-reducing DSM.

In the past, load-reducing DSM investment often did not make financial sense for a number of utilities that had plenty of available generating capacity. Because traditional ratemaking formulas linked profits to increased sales, utilities typically lost money in the short term when they invested in conservation. Also, under traditional formulas, utilities were not allowed to earn a return on their investments in DSM as they do on their investments in new power plants. Because of these two disincentives, utilities have often chosen supply-side resources over DSM options in their planning.

In an effort to encourage utilities to take advantage of DSM, energy planners in the mid-1970s developed a framework that explicitly incorporates the effects of demand-side measures in meeting future energy needs. This framework, called least-cost planning, aims to achieve a

THE STORY IN BRIEF

Energy efficiency programs are the new wave in demand-side management (DSM), and they have led to the rapid escalation of demand-side activity. This year utilities across the country will spend a record $1.5 billion on DSM, with some of the more active ones devoting 3–5% of their gross annual revenues to this area. Saving energy is not the only mission of today's DSM movement. Proponents are counting on DSM as a resource that can help the environment, postpone the need to build new power plants, and even revive regional economies. Regulators, environmentalists, utility customers, and others with a stake in energy planning have high expectations for what utilities can accomplish. Yet there are a number of logistical challenges the industry must overcome if it is to succeed in making this "resource of the nineties" live up to these expectations.

mix of supply- and demand-side resources that will satisfy energy needs at the lowest possible cost to utilities and consumers. The term integrated resource planning (IRP), which stresses a rational balance of supply- and demand-side options, is now used interchangeably with the term least-cost planning. IRP requirements adopted by state regulators have helped boost utility investment in DSM. As of July of this year, 31 states require utilities to use an IRP framework and at least 10 others are reviewing implementation options.

But IRP requirements by themselves are not enough to overcome the significant disincentives for utilities to invest in DSM. For this reason, utility regulators in recent years have adopted ratemaking reforms and financial incentives to make DSM as profitable as supply-side resources, if not more so. These incentives have been well received not only by utilities but also by consumer groups and others who have been critical of utilities. At least 31 states have already adopted some form of financial incentive. (The sidebar offers more details on these incentives.) Meanwhile, a number of bills have been introduced in Congress that would require states to consider—through formal hearings or other processes—implementing both IRP requirements and incentive mechanisms.

"All indicators point toward rapid increases in DSM activity over the next several years," says Veronika Rabl, manager of the Demand-Side Management Program at EPRI. Rabl notes that the attendance at the Fifth National DSM Conference in Boston last summer reflects the significant increase in DSM activity. The three-day conference, sponsored by EPRI, the U.S. Department of Energy, and the Edison Electric Institute, drew more than 1200 people from 48 states and 13 foreign countries. That figure is nearly double the attendance at the Fourth National DSM Conference two years ago, and nearly triple that of the Third National DSM Conference in 1987. Indeed, the growth of energy service companies and private consultants who help utilities design, implement, and evaluate programs has made DSM an industry in its own right, with annual revenues estimated to be in the hundreds of millions of dollars and with two professional associations of about 1000 members each.

"We're seeing significant resources—both people and dollars—being committed to DSM," Rabl says, noting that the utility industry will spend an estimated $1.5 billion on DSM in 1991 alone. Both the number of utilities pursuing DSM and individual utility expenditures are on the rise. With the rapid pace of change, it is difficult to track nationwide expenditures on DSM. However, a recent sampling of 14 utilities documents a trend toward increased spending. The sample shows that DSM budgets at these utilities increased from an average of 1.6% of gross revenues in 1989 to an average of 2.3% in 1991. Some of the more active utilities in the country now spend between 3% and 5% of their gross annual revenues on DSM.

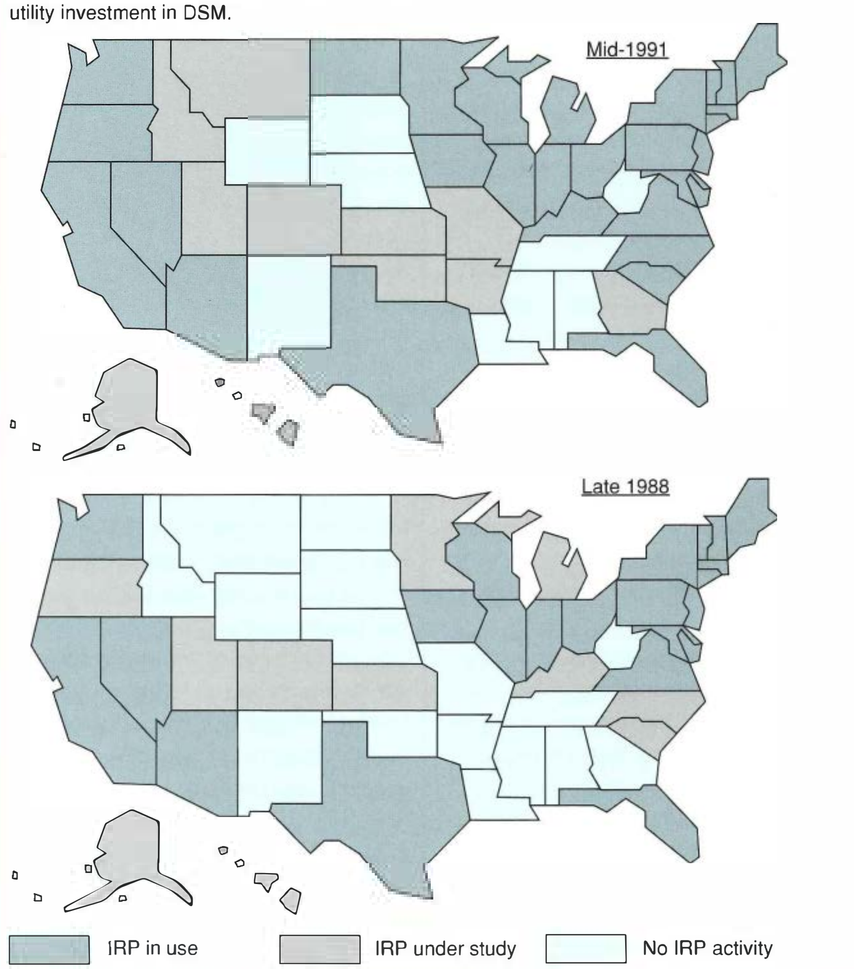
According to an EPRI report on DSM impacts (CU-6953), the combined effect of load-reducing and load-increasing DSM will reduce demand by approximately 25,000 MW over the next decade. That's equivalent to about 30% of new capacity requirements for the same time period. The report, issued in September 1990, also estimates that DSM activity nationwide will result in a reduction in electricity use of 107 billion kWh in the year 2000 from the level that would have resulted without DSM. Because of the significant increase in regulatory incentive activity, this forecast may have to be revised upward and could well be twice as high, Rabl says. According to EPRI's calculations, if DSM is in fact successful in reducing electricity use by about 200 billion kWh in 2000, it will simultaneously reduce carbon dioxide emissions by about 150 million tons.

With all of this activity, the United States has emerged as a leader in the DSM field. Countries around the globe are now turning to this nation for guidance on using DSM to help address capacity and environmental concerns. U.S. experts say DSM has other advantages too. It can be used to delay the upgrading of transmission and distribution systems, an investment that, over the next decade, is expected to exceed the investment in new generation. DSM is also expected to help revive regional economies by making utility customers more competitive.

Though skepticism and concerns still exist about whether DSM can live up to such high expectations, pressure to make the most of what is perceived as an environmentally benign resource propels the DSM movement forward. And the question for the 1990s is not whether utilities will use DSM, but how much they will use it and whether they can overcome

Integrated Resource Planning–Spreading Fast

As of July 1991, 31 states have integrated resource planning requirements in place. That's a 35% increase over the number of states requiring IRP only two and a half years ago. IRP, which aims to achieve a mix of supply- and demand-side resources that satisfies energy needs at the lowest possible cost to utilities and consumers, is intended to encourage utility investment in DSM.



the great challenges that exist in implementing DSM today.

Prove it

The earliest energy efficiency programs were purely informational, designed to increase customer awareness of energy options. Programs have since grown much more sophisticated, and utilities at the forefront of the efficiency movement now commonly offer rebates, audits, loans, and free installation of energy-efficient equipment, among other options. Many of these programs, first employed on a pilot basis, have since undergone full-scale implementation and are reaching much larger market segments.

Now that utilities have had some time to experiment with these more broadly based, sophisticated DSM programs, they are under pressure to verify the performance of the programs by showing actual results. Certainly it is in utilities' own interest to be able to calculate the impact of programs, for many are relying on them to delay the need to build new power plants. But there is significant pressure coming from external forces as well. Particularly now that utilities are making large monetary investments in DSM and receiving financial rewards for this investment, state regulators want to see validated results. "Given the huge sums that will be invested in DSM programs, the utility industry must be prepared to account for these investments and to verify the benefits," observes Arnold Fickett, vice president for EPRI's Customer Systems Division.

Yet quantifying the performance of DSM programs may be the greatest challenge facing utilities involved in DSM today. This task requires that utilities rigorously evaluate DSM programs to determine their kilowatt or kilowatthour impact. "In my view, evaluation is the most critical issue in DSM," says Alan F. Destribats, vice president of demand and least-cost planning at New England Electric System (NEES). As Destribats indicates, there are two key areas of focus in the evaluation of DSM programs—the administrative aspects of the programs, such as how efficiently they are delivered, and the effectiveness of the programs, including their kilowatt and/or kilowatthour impact. "Evaluation demonstrates the actual impact from programs; it demonstrates to customers the savings they are actually achieving; it shows the true cost-effectiveness of programs; and it provides the feedback required to modify and refine the programs for future implementation." Of NEES's $85 million DSM budget—equivalent to about 5% of the holding company's gross annual revenues—more than $3 million is spent on evaluating DSM programs. NEES has an evaluation staff of seven full-time professionals and also relies on outside consultants.

Because demand-side management programs necessarily involve a human element, they pose some unique challenges to the evaluator. To make matters even more complex, determining the impact of a DSM program requires that the evaluator identify a *change* in electricity use attributable to the program. And efficiency gains achieved through factors outside the utility's influence, like national efficiency standards for appliances, must be accounted for because they cannot be attributed to the DSM program.

To determine the actual kilowatt or kilowatthour impact of a DSM program, it is necessary first to estimate how much energy participants would have used had the program not existed. Obviously, this quantity can never be directly measured. Nevertheless, techniques have been developed to help evaluators more accurately estimate this level of energy use. EPRI has published a report (CU-7179) that details how these techniques can be used to obtain more-accurate evaluation results. As indicated in this report, the most effective evaluations employ a combination of metering, customer surveys, and computer modeling. More-advanced evaluation methodologies are still being developed.

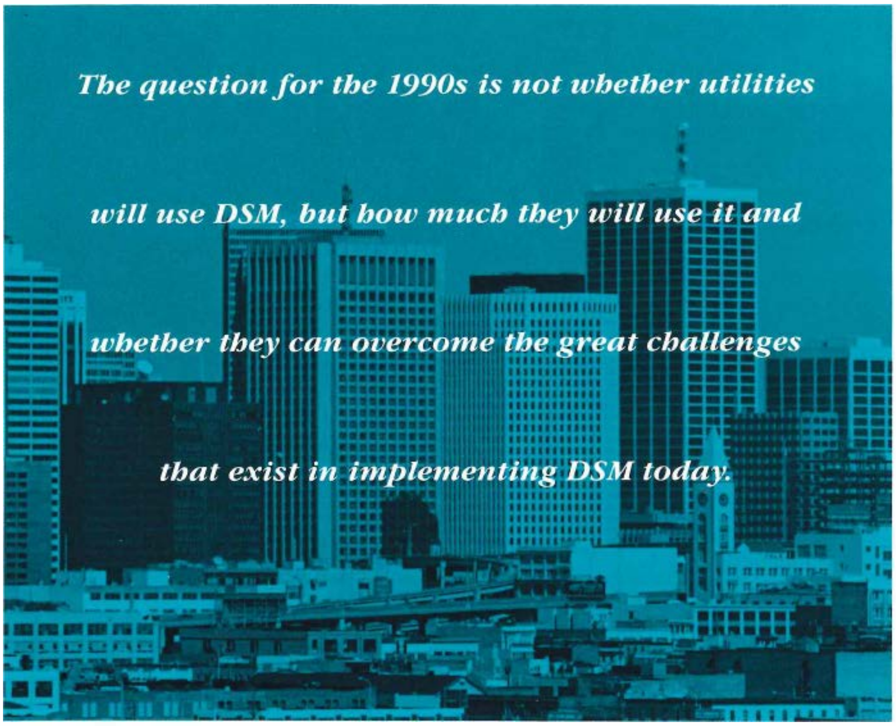
"It is important that an evaluation not only estimate the most likely impacts of a program but also quantify the risk of those estimates," says Phil Hanser, a senior project manager in EPRI's Demand-Side Management Program. "It is misleading to treat the impact estimates as fact. What they really are is a calculated conclusion based on the best available data and techniques."

One fairly standard statistical approach that utilities have employed in their impact evaluations compares the electricity use patterns of a group of customers participating in a DSM program with those of a group of nonparticipants. The consumption patterns of the nonparticipants serve as an indication of the naturally occurring change in electricity use—that is, the change (be it an increase or a decrease in electricity use) that would have occurred among the participants in the absence of the DSM program. This change is compared with the participants' change in electricity use to determine how much of any overall change should be credited to the program.

One difficulty with this technique is establishing a nonparticipant group that is as comparable as possible to the participant group. Another challenge is avoiding the possible "contamination" of nonparticipant groups with customers who have participated in past or separate programs. As time goes on and more utility programs are instituted, it becomes more difficult to find nonparticipants. A separate issue that has emerged in impact evaluations is a problem called snap-back, or rebound, effects. This refers to the tendency of some participating customers to reduce the program's impacts by increasing their energy use after they see lower energy bills.

Regardless of how utilities choose to conduct their program evaluations, public utility commissions are expected to be firm about requiring proven results. In fact, financial incentives such as shared savings, which bases utilities' monetary reward on a share of the electricity savings resulting from DSM programs, require accurate estimates of program impacts before payments can be calculated. Some in the industry are concerned that, despite the fact that the science of evaluating utility programs is still evolving, regulators may hold utilities and their evaluations to unrealistic expectations of accuracy and accountability.

Many observers caution that, regardless of regulatory enthusiasm for load-reducing DSM at this stage, the industry could suffer an experience similar to the era of disallowed costs on nuclear plants. As part of their mission to protect the interests of ratepayers, regulators can subject past utility resource decisions to so-called prudence reviews. During prudence hearings in the late 1970s and early 1980s, utility regulators ruled that some $10 billion worth of utility investments in new power plants was not prudent and therefore utilities would not be allowed to recover the investments. "Eight to ten billion dollars in prudence hearings was scary to utilities," says Robert Obeiter of Xenergy, Inc., former director of demand-side programs at NEES. "I hope history doesn't repeat itself in prudence hearings 10 years from now on our demand-side investment in the nineties."



But there are some indications that the prudence review process is changing. Members of the National Association of Regulatory Utility Commissioners are revising a document that, if adopted by NARUC's executive committee, would serve as a policy statement encouraging states to adopt a "rolling" prudence review process. One aspect of the rolling review process would stipulate that utility selections of resources be evaluated up front, before investments are made. "The idea is that the utility would not be penalized for proceeding down a particular path if it seemed like a good decision at the time," says Stephen Wiel, a member of Nevada's commission and of NARUC's executive committee. He notes that an approval resulting from up-front evaluations would not guarantee that utilities could recover all investments. Regulators could still penalize them for not managing a project prudently.

Wiel points out that the work on NARUC's document is a reflection of activity that has already taken place in a number of states. In fact, the concept of up-front reviews is an integral part of the IRP process. "When we told utilities that we wanted to review their long-range plans, we accepted some of the responsibility for decisions made on resources," Wiel says of Nevada's commissioners. However, he acknowledges, just because another state commission has IRP requirements in place does not necessarily mean that that commission accepts such responsibility.

DSM and the environment

Pressures to improve the environment are among the leading forces propelling the DSM movement today. This is apparent in the statements and actions of regulators, environmentalists, and others who are encouraging utilities to investigate DSM options. "We're all reacting to public concerns about the environment," says Wiel. "We're all pushing toward the same goal from different perspectives." This is also apparent in the direction some environmental legislation has taken. For instance, the Clean Air Act Amendments of 1990 include an incentive for utilities to invest in DSM programs that promote the increased use of efficient technologies.

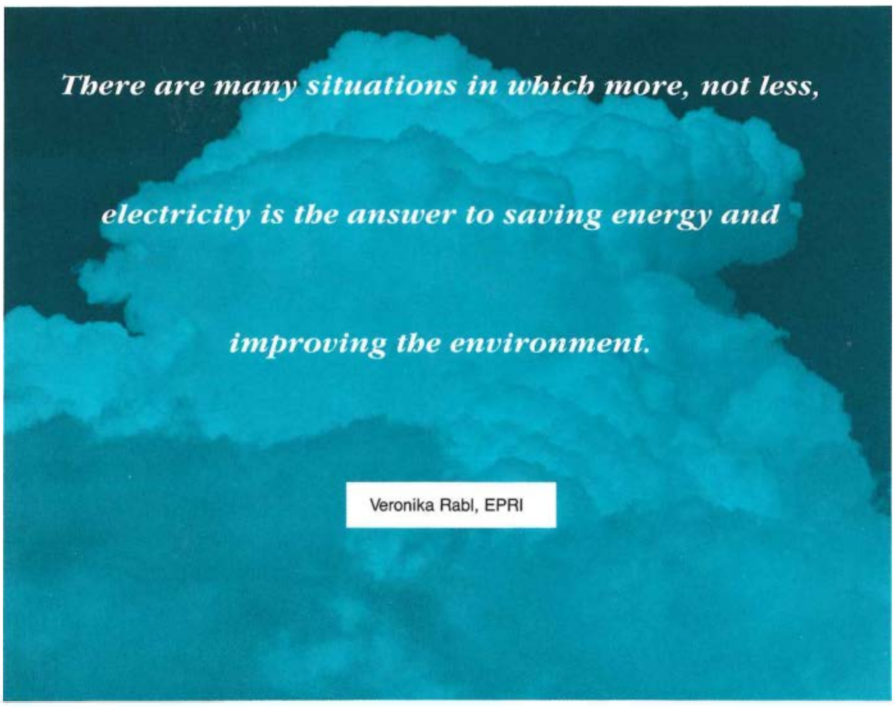
Perhaps an even more significant aspect of this new law is that it specifies that in order for utilities to qualify for the incentive, their state commissions must have IRP requirements in place, as well as some mechanism to ensure that the utilities won't lose money from their efficiency programs. Already this has prompted some DSM action. For example, regulators in Ohio responded by adopting reforms that make DSM investments profitable for utilities and their customers.

DSM's environmental benefits are also now being recognized in the utility planning process, through the use of "externalities" in developing an IRP. Externalities are the impacts—both positive and negative—of supply- and demand-side resources on society that are not reflected in the market prices of resource options. These impacts can be social, economic, or environmental, including issues of human health, recreational opportunities, and visual air quality. Since load-reducing DSM programs do not generate emissions, including environmental externalities in the IRP process gives this type of DSM a clear advantage over most supply-side options.

Various techniques have been devised to account for environmental externalities in the development of a least-cost plan. Some involve a ranking, or point, system that recognizes the attributes of all resource options and allows planners to weigh them against one another. Other methods give the externalities a relative value that can be either added to the cost of generation or subtracted from the cost of a DSM program. Still other techniques assign a specific dollar value (in cents per kilowatthour) to the costs of each resource option.

Clearly, assigning any sort of value to externalities is a difficult task. Making this task even more complex is the fact that the environmental impacts of various emissions are still being determined. As new information emerges, the costs that regulators attribute to externalities are likely to change. An added concern is that if externalities are incorporated into the electric utility IRP process, they should also be applied to all other fuels, so that electricity does not suffer an unfair competitive disadvantage.

Despite these challenges, a number of



Just as a utility customer may require an incentive like rebates to participate in energy efficiency programs, utilities also may need incentives to sponsor such programs. As in most businesses, revenues of investor-owned utilities have traditionally been linked to sales. That is, the more kilowatthours of electricity a utility sold, the more money it could make; the fewer it sold, the less it made. This type of business environment created a disincentive for a utility to implement energy efficiency programs and other types of demand-side management (DSM).

What's worse, under most traditional ratemaking formulas, utilities in many states could never fully recover money spent on DSM programs, nor could they recover revenues lost from decreased electricity sales. Put bluntly in a report issued by the staff of Oregon's public utility commission, "Utility incentives for acquiring demand-side resources are poor, even perverse under conventional ratemaking practices."

In an effort to give utilities at least the same incentives to use demand-side resources as they have to use generating resources, regulators have been revamping traditional ratemaking formulas and implementing financial incentives. While such efforts date back to about 1980, most of the activity has taken place over the past three years. This activity was spurred in part by a National Association of Regulatory Utility Commissioners (NARUC) resolution in 1988 that urged regulators to "seek to make the least-cost plan a utility's most profitable resource plan."

Certainly, regulatory command itself offers some degree of incentive for

Financial Incentives

Type of Incentive	Description	States Offering (as of Aug. 1991)
Cost recovery	Allows utilities to recover costs involved in implementing DSM programs	CA, CO, CT, DC, FL, GA, HI, IA, ID, IL, IN, MA, MD, ME, MI, MN, MT, NC, ND, NH, NJ, NV, NY, OH, OK, OR, PA, RI, TX, VT, WA, WI
Lost-revenue recovery	Allows utilities to recover revenues lost through efficiency programs	CA, CT, GA, IA, MA, MD, ME, NH, NY, OH, OR, VT, WA
Pure incentive	Offers bonuses that go beyond offsetting costs associated with DSM programs	CA, CO, CT, GA, IA, ID, MA, MD, ME, MI, MN, NH, NY, OH, OR, RI, TX, VT, WA

utility action on DSM. But alone it is not enough, says Stephen Wiel, a regulator in Nevada who was chairman of NARUC's conservation committee when it sponsored the 1988 resolution. "When we first started ordering demand-side management, we were using sticks," Wiel says. "The whole reason for this incentives movement was because some of us began to realize that using sticks without any carrots was not the most effective approach. As a matter of fact, we were using sticks at the same time we were taking carrots away."

Nevertheless, some utilities were motivated by other factors, such as a desire to postpone the construction of new power plants. In other cases, activity was prompted by federal mandates requiring utilities to offer certain conservation programs. "And some enlightened utility executives were simply doing it for the sake of customer relations," Wiel says. "What this new incentives movement is all about is boosting conservation activity of utility companies beyond what they've already been doing. The goal, in my mind, is to make conservation and load management by utilities a major profitable activity instead of a casual sideline."

As of August of this year, regulators in at least 31 states have adopted some type of financial incentive for DSM investment. However, these incentives vary widely in form, which can make a significant difference in the extent to which they encourage DSM investment. Generally, the financial incentives fall into three categories: cost recovery, lost-revenue recovery, and pure incentives.

Cost recovery incentives allow utilities to recover money spent on DSM programs. One typical method of cost recovery is to treat DSM as an investment rather than as an expense. This allows costs associated with DSM programs to be accumulated over a number of years and figured into the financial base upon which rates are determined. In this way, utilities can earn a return on DSM investments just as they do on power plants.

Revenue recovery incentives do away with the profit-sales link that causes utilities to lose revenues when they sell less electricity. This link can be broken in two ways. One method, called decoupling, simply divorces profits from sales in ratemaking formulas. The second method is to allow utilities to recover lost revenues after the fact.

The third category, pure incentives, goes beyond offsetting costs associated with DSM programs to offer bonus profits for utilities. This money comes from the savings that otherwise would be fully reflected in customers' bills. In other words, pure incentives allow utilities to share some of the customers' savings. These incentives can be configured in a number of ways. Some regulators offer them as rewards for achieving conservation goals. Others simply offer a higher return on investment in the demand side than that allowed on the supply side.

Regulators have experimented with several ways to implement incentives in each category. Of the three categories, pure incentives have probably drawn the most criticism. Some critics argue that utilities should not need "bribes" to invest in DSM. Others feel that pure incentives are necessary only in the short term, to make DSM a more attractive option than supply. These proponents maintain that once utilities are accustomed to heavier demand-side investment, such incentives may not be needed.

Another point raised by many involved in the incentives movement is that incentives should encourage only DSM investments that are cheaper than the supply-side alternative of building power plants. The concern is that if incentives encourage utilities to invest in more-expensive options, they will lead to rate increases. □

states, including New York, Wisconsin, Vermont, and Oregon, are already practicing the inclusion of externalities in the IRP process. Vermont's commission, for instance, requires that utilities add 5% to the costs of supply-side resources to reflect environmental impacts and deduct 10% from DSM resources to account for their lower risk.

Richard Cowart, chairman of the Vermont commission, explains that DSM resources involve less risk than most supply-side options in part because they can be delivered in small increments. While a utility can build a DSM program gradually, it cannot build and use a power plant in similar increments. By the same token, if a power plant is taken out of service for repairs or maintenance, a significant chunk of a utility's resource becomes unavailable. If there are problems with a DSM program, however, a utility can refine some aspects of the program while keeping it in operation.

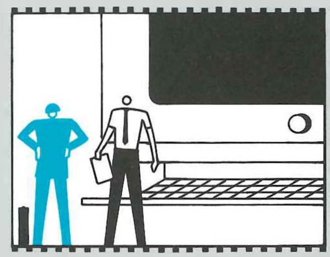
Cowart explains that the 5% and 10% figures are proxies being used temporarily, pending further investigation into the environmental impacts of various resource options. "We recognize as we go forward that the environmental analysis has to be fine-tuned," Cowart says. "But we didn't want the benefits of the energy efficiency programs to be held up." Cowart acknowledges that the figures are likely to change as new information emerges. "The first lesson is humility," he says. "One must recognize that most of the factors we will need to examine are not amenable to precise monetary measurement. But to do nothing is unacceptable. If you do not include some factor for environmental costs, you're essentially valuing them at zero." EPRI's Hanser points out that if externalities are included in IRPs, they should only account for the residual emissions that are above and beyond those controlled by current environmental regulations. In practice, however, this is not always the case.

As research on the externalities issue progresses at the state and federal levels, EPRI has initiated its own projects to address some of the crucial concerns. A report published in May of this year (CU/EN-7294) outlines the environmental externalities issue and discusses techniques used to quantify externalities and to incorporate them into utility planning. EPRI also is establishing a clearinghouse that will use its electronic network EPRINET™ to keep abreast of externalities issues. In addition, the Institute has initiated two related research projects. One involves investigating the im-

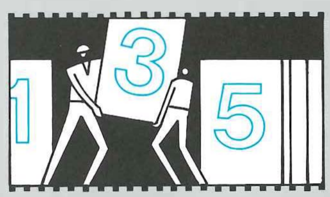
Three Elements of DSM Program Evaluation

DSM program evaluations are conducted primarily to verify how electricity use changes as a result of a given program and to determine how efficiently programs are administered. Three key elements of program evaluations are outlined below. A recently published EPRI evaluation guide (CU-7179) details how these elements can be combined for the most effective results.

Field data include all kinds of information about customers and their energy use, such as that obtained from metering and customer surveys. Comprehensive and accurate field data are crucial to successful evaluations, but this information alone will not allow utilities to determine how effective programs are and how efficiently they are delivered. To complete the picture, field data must be plugged into the framework of tools like engineering simulations and statistical models.



Engineering simulations are computer models containing algorithms that can calculate the energy use of a building, given detailed information on the building and the end-use technologies inside. The models can be used to determine which technologies will offer the biggest electricity savings for a particular customer or group of customers. To create a realistic picture of electricity use, information on weather patterns, hours of occupancy, and other factors affecting customers' electricity consumption must be input.



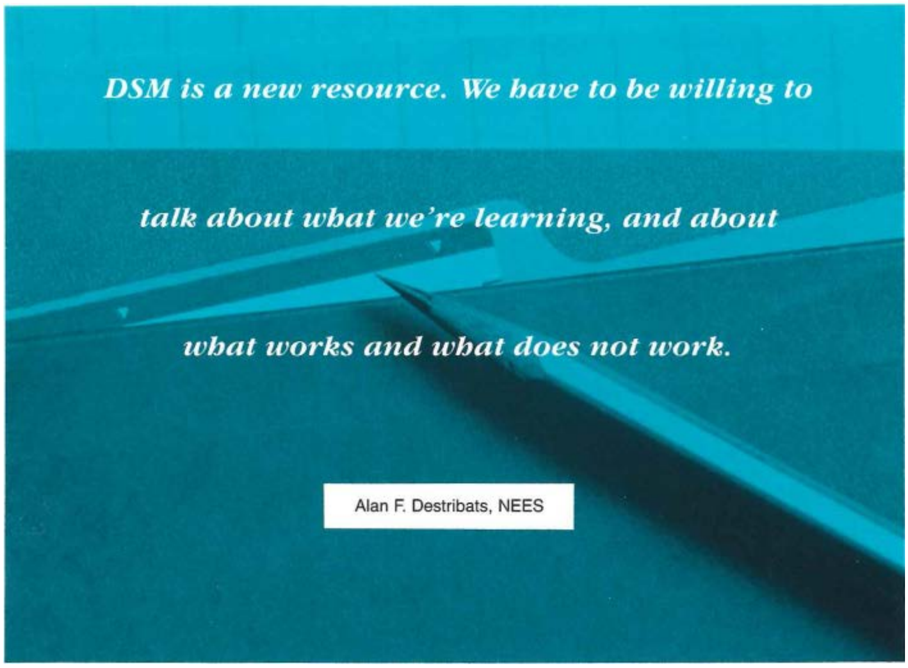
Statistical models are built around extensive customer information, including demographic and energy use data. These models can be used to determine what kind of program would be most successful in a given area, and they can also indicate the electricity savings attributable to a particular program already in place. While helpful in accounting for behavioral patterns, these models lack the technical detail provided by engineering simulations.

plications of including environmental externalities in least-cost planning. The other aims to understand the role of end-use technologies in addressing environmental concerns.

One troubling issue that externalities raise for electric utilities is that they contribute to the perception that less electricity is better for the environment. "We need to realize that there are many situations in which more, not less, electricity is the answer to saving energy and improving the environment," says Veronika Rabl. While advanced end-use technologies like computers and fax machines have clearly added to the demand for electricity, they have also contributed to the enhancement of society and saved gasoline, postage, and time, among other things. In addition, there are a number of sophisticated electric technologies and processes that can be directly substituted for less efficient fossil fuel alternatives, resulting in significant overall reductions in primary energy use. Freeze concentration, for instance, is typically at least three times as efficient as the fossil-fuel-fired processes of distillation and evaporation that it replaces. That's because it takes about 1000 Btu per pound to vaporize water but only 144 Btu to freeze it.

According to EPRI's figures, beneficial electric technologies have the potential to add as much as 700 billion kWh to electricity use by 2010. But that is not bad news for society, Rabl says. Because of the efficiency gains these technologies offer over their fossil fuel alternatives, the additional demand would result in a commensurate reduction in total energy use of 7.7 quadrillion Btu and a reduction in carbon dioxide emissions of over 350 million tons. According to Arnold Fickett, "EPRI's goal is to achieve energy savings through both the wiser use (DSM) and the wider use (beneficial electrification) of electricity."

Consultants specializing in developing DSM programs have acknowledged that there appears to be fertile ground for cost-effective substitution of advanced electrotechnologies for fossil fuel technologies, particularly in the industrial sector. But few have explored the potential for using such fuel-switching strategies in DSM programs. In fact, there has been some movement in the opposite direction, due to the currently low operational cost of certain gas end-use devices. Regulators in some states have required electric utilities to develop programs that encourage customers to use gas air conditioning or to switch from electric to gas heat. Some critics argue that aside from giving gas an unfair competitive advantage, these fuel-switching programs may be counterproductive in their mission to improve efficiency.



John Chamberlin, executive vice president of Barakat & Chamberlin, an energy consulting firm, is among those who propose that regulators who want to mandate such fuel substitution programs should first introduce a consistent pricing framework based on marginal costs for all energy sources. While marginal costs have been used to develop electricity rates for some time, few states have investigated the use of marginal costs in setting gas rates. Chamberlin says consistent pricing signals will allow electric and gas utilities to compete on an equal footing, leaving the consumer with "the last word on the true cost or resource advantage of a particular appliance type."

Growing pains

Increasing DSM activity is a crucial part of a fundamental shift in the electric utility industry—a shift that is transforming utilities from commodity producers into service providers. Clearly this is no simple transition. As challenges like proving the impact of DSM programs and incorporating externalities indicate, the transition calls for significant changes in the way utilities conduct their business. Implementing DSM today means that utilities have to pay more attention not only to customers but to society at large.

"Meeting our customers' needs—whether as a supplier of energy or of energy-related services—involves more-complex relationships than we've ever had in the past," says Bernard Reznicek, president and CEO of Boston Edison, where DSM programs over the past four years have reduced energy use by about 237 million kWh. "For us to be successful today means partnerships with regulators, partnerships with legislators, and some very strong partnerships with customers. We can't just do it within our own four walls."

One direct manifestation of this need to link with outside entities is the trend toward involving third parties in the development of DSM programs and related policies. This so-called collaborative planning process entails working with environmentalists, consumer advocates, and others who have traditionally opposed utilities in rate cases before state regulatory commissions. The intent is to reach a consensus in an informal and congenial atmosphere, outside the framework of regulatory proceedings. Utilities in a number of states, including California, Connecticut, Massachusetts, New York, and Vermont, have already undertaken collaborative efforts.

The collaborative process has been credited with expanding DSM programs and incentives for utilities. A number of utility representatives have reported great success with the process. Chris Chouteau of Pacific Gas and Electric, which participated in the collaborative effort that led to the energy efficiency blueprint for California, reports that the five-month process resulted in "surprising agreement on new energy efficiency programs, financial incentives for utilities, and the framing of a host of related policy issues." Though the process can be time-consuming, he says, "it compares favorably with the alternative of spending time and resources developing adversarial positions in regulatory proceedings."

But not all utilities report good results from collaborative efforts. One complaint has been that nonutility parties have negotiated among themselves first, then presented proposals to the utility. In the words of Thomas Boucher of Green Mountain Power in Vermont, "It is difficult to negotiate a change from a negotiated position." Boucher's utility agreed to enter collaborative proceedings with groups including the Conservation Law Foundation, the Vermont Public Interest Research Group, and the Vermont Natural Resources Council after receiving public criticism of its integrated resource plan, released in 1989. What Boucher describes as "a painfully slow process" took until the spring of 1991 to result in a product that looks much like the utility's 1989 plan.

As with other relatively new aspects of the DSM discipline, there is certainly room for improvement in the collaborative process. Those who have learned from experience stress that negotiating principles and objectives up front, and even developing a common understanding of basic terms like energy efficiency and DSM, can speed up the process significantly and make it more productive. Learning through experience—painful or not—is critical to the evolution of

Load-Reducing DSM: Why Some Utilities Do It, Why Some Don't

Why are energy efficiency programs offered by some utilities and not others? Some key factors are highlighted below.

Regulatory incentives

Regulators in some states offer utilities financial incentives to invest in load-reducing DSM programs. Regulators in other states don't.

Capacity margins

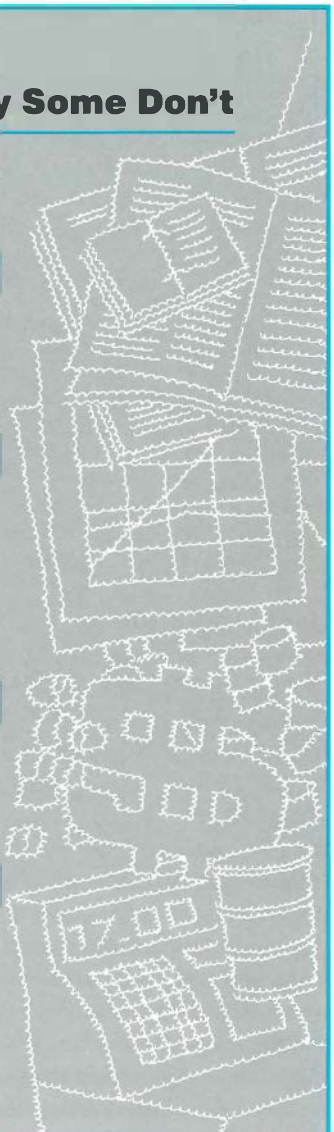
Utilities whose peak demand is nearing system capacity can use efficiency programs to reduce demand and postpone the need to build new power plants. Utilities with ample capacity reserve margins face no such imminent need to reduce demand.

Fuel costs

Utilities with high fuel costs may opt to implement efficiency programs to reduce the use of expensive fuels like oil. Utilities with low fuel costs lack this incentive.

Local economy

A robust local economy is likely to increase electricity consumption, and utilities can use load-reducing programs to keep demand at an appropriate level below capacity. A sluggish economy, in contrast, is likely to decrease demand, preempting the need to reduce load.



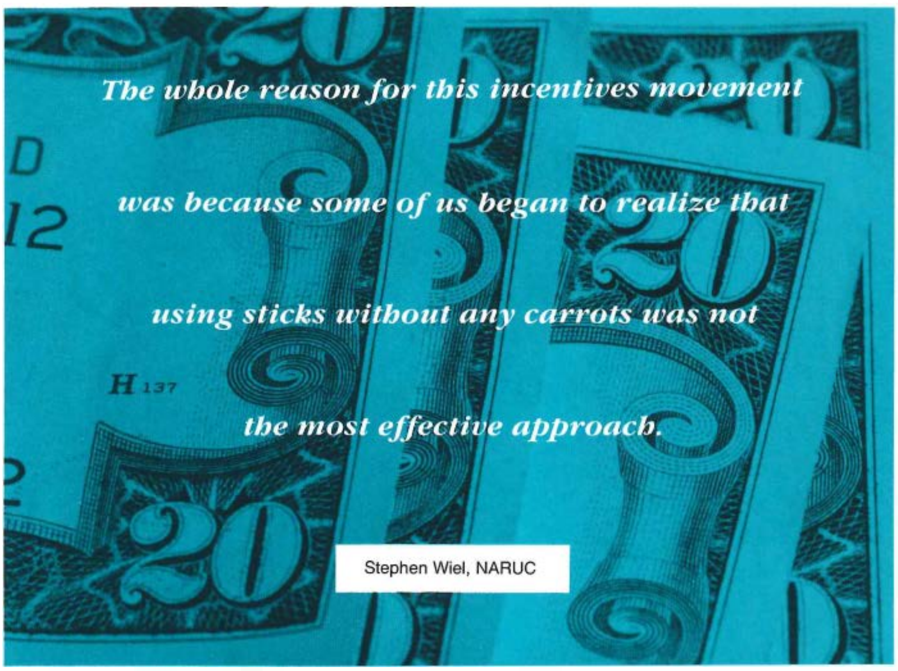
DSM, say experts who characterize bad experiences as growing pains. In fact, the value of learning from mistakes as well as successes was reflected in the "building on experience" theme of the Fifth National DSM Conference.

"We all need to admit that we are still in a period of learning as an industry," says Rabl. "That includes utilities, regulators, the intervenors—everyone. And we need to realize that some of this is going to be risky and some of it is not going to work out, and that we'll have successes along with failures." Alan Destribats agrees. "DSM is a new resource," he says. "We have to be willing to talk about what we're learning, and about what works and what does not work."

Pleasing everyone with DSM is not easy, nor is it always possible. Fundamental issues like who pays for and benefits from programs make it difficult to maintain the delicate balance among the interests of the many stakeholders in the utility planning picture today. Conflicts can arise between the interests of DSM participants and nonparticipants, ratepayers and utility shareholders, utilities and other DSM service providers, and ratepayers and society.

While there are a number of utilities who have embraced the challenge of maintaining that delicate balance through the implementation of DSM programs, there are still many who have not. "Let's face it," Bernard Reznicek says, "DSM is still considered the black sheep cousin to generation by many in our industry, including many in the executive suite." Indeed, largely because of the financial risks of DSM investment under traditional ratemaking mechanisms, most of the energy efficiency activity is concentrated in the northeastern states (including New Jersey and New York), along the Pacific coast, and in the upper Midwest (including Wisconsin and Minnesota). But the financial incentives that state commissions have been adopting at an increasing rate are helping to dissolve this risk factor, and utilities are expected to respond swiftly.

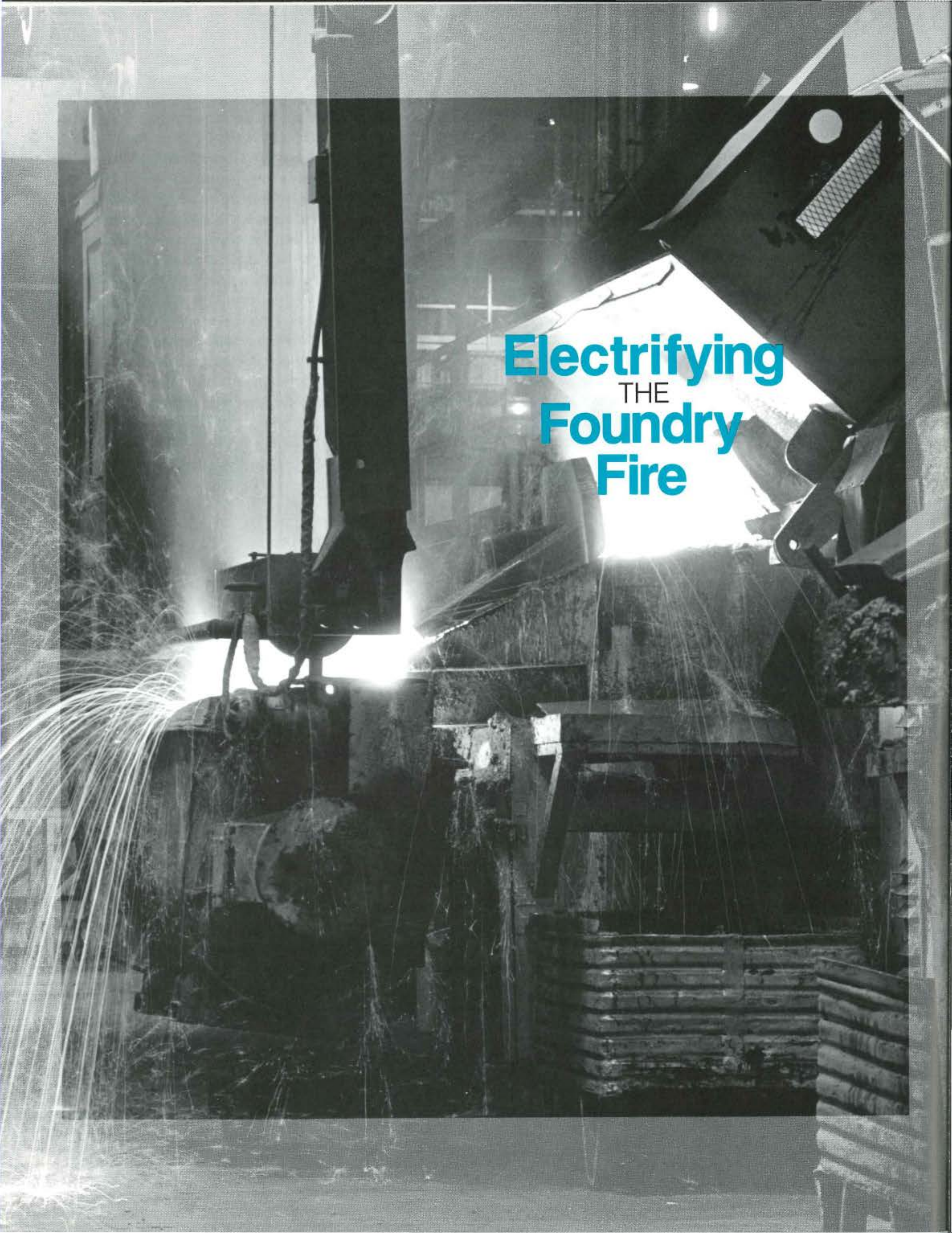
Utilities are not the only ones who have shown aversion to massive investments in energy efficiency programs. Perhaps the most vocal nonutility critics are large energy users in the industrial sector represented by groups like Multiple Intervenors and the Electricity Consumers Resource Council (ELCON). In New York, Multiple Intervenors even took the state commission to court to fight the implementation of financial incentives for utilities. The industrial users argue that they will wind up subsidizing costly DSM programs targeted at nonindustrial customers. Anthony Cortese, dean of environmental programs at Tufts University and a former commissioner with the Massachusetts Department of Environmental Protection, draws a parallel to criticism in the early stages of environmental regulation.



"When we first got into the environmental protection business in 1970, the regulations we put into effect were very crude, and businessmen came into the room with the same criticisms that I'm hearing about energy regulation today," he says. "But we all hung in there, and the regulatory process improved tremendously. We are getting much more effective programs." Cortese cites as an example the Clean Air Act Amendments of 1990, with their market-based approach to compliance, which gives companies some freedom in choosing how they will reduce their emissions.

"Just because demand-side management raises some difficult issues doesn't mean that we should not move forward on something that is basically very sound—that is, to use energy much more efficiently than we're using it today," Cortese says. "The issue is not whether we do it just with demand-side management or whether we do it just with the supply side. It's going to be a combination of both." ■

This article was written by Leslie Lamarre. Background information was provided by Veronika A. Rabl and Phil Hanser, Customer Systems Division.



Electrifying THE Foundry Fire

THE STORY IN BRIEF

The casting of metals for machinery components is an important part of this country's overall manufacturing capability. Foreign competition has prompted U.S. metal foundries to pursue technologies that boost productivity, and increasingly stringent environmental regulation requires that production processes be cleaner than ever before. Electric technologies—unique in their precision, flexibility, and controllability—satisfy both needs, and their use is steadily increasing in the foundry industry. Electric furnaces have already lowered emissions and improved efficiency and product quality. Now, even more advanced melting and refining techniques based on plasma technology are being developed through the Foundry Office of EPRI's Center for Materials Production. The center is also working on innovative casting techniques and methods of reclaiming the sand from casting molds so that it can be reused rather than discarded as waste.

The casting of metals has been a fundamental technology of civilization ever since the Egyptians first poured bronze into molds some 3500 years ago. Today, about 90% of all manufactured goods and virtually all industrial machinery contain cast metal, usually produced in shops called foundries. Many of these shops are relatively small; the melting capacity of most foundry arc furnaces, for example, is less than 20 tons, compared with a capacity of hundreds of tons for the arc furnaces in major steel mills. Like many other smokestack industries, the foundry business has recently experienced wrenching changes.

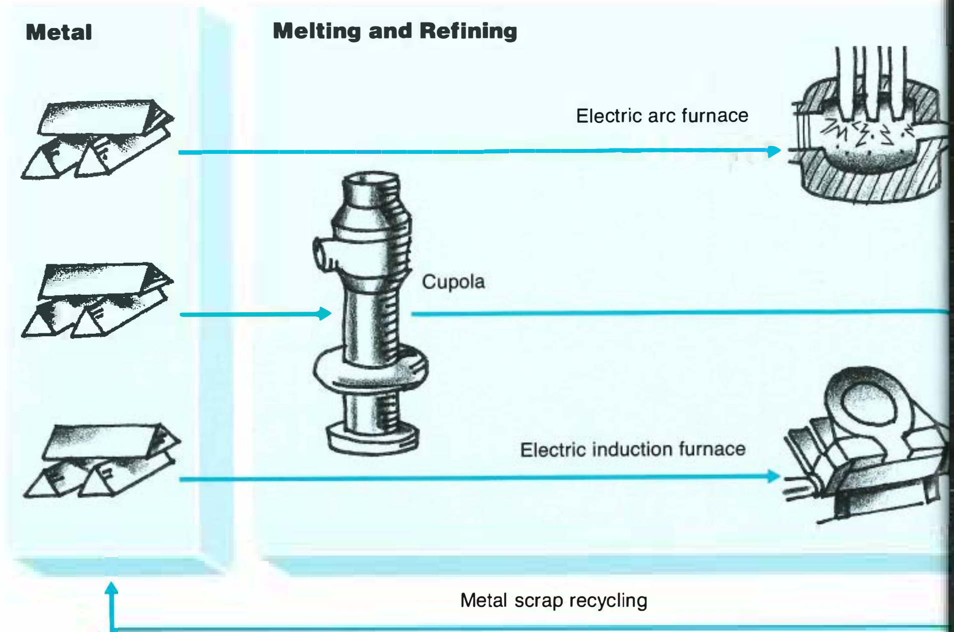
As the U.S. economy slipped into a recession in the early 1980s, many foundries were hard hit. By 1986, ferrous casting production had dropped to less than one-half its level only eight years earlier. During approximately the same period, the number of foundries decreased by almost half. Although plant closures have now leveled off—with about 3400 foundries distributed throughout all 50 states—total capacity remains well below historical levels.

The reasons for this decline are numerous, but two stand out: increasingly stringent environmental regulation and aggressive competition from abroad. Foundries that have survived the industry shakeout are facing these challenges by modernizing their equipment and practices and by emphasizing product quality. Rapid introduction of advanced electrotechnologies is aiding this effort. Such technologies enable foundries to melt, refine, and cast metals with greater precision and less environmental impact. They can also increase overall plant productivity and reduce costs.

If U.S. foundries are to compete successfully in an increasingly global marketplace, however, more research is needed on several specific electrotechnologies. In most other industrialized nations, such research is being conducted in government-funded institutes. In the United States, the American Foundry-

The Foundry Process

Foundries follow a basic process sequence that has changed little over a thousand years: metal is melted, refined, and poured from a ladle into a prepared mold, after which the casting is cooled, removed from the mold, and finished for use. While modern electric furnaces have significantly improved product quality, energy efficiency, and productivity, research at EPRI's Center for Materials Production continues on advanced melting and refining, casting techniques, and sand reclamation.



men's Society and other trade associations have traditionally funded most foundry research. Recently, electric utilities have also begun to realize their stake in helping to keep American foundries viable. Not only are foundries major consumers of electricity—at about 7.5 billion kWh per year—but their modernization initiatives usually involve its increased use.

For this reason, the EPRI Center for Materials Production (CMP) has become a significant funding participant in foundry research. To help coordinate this research and to work directly with foundries that are trying to improve their operations, CMP opened a Foundry Office in the metropolitan Chicago area in 1989. Through this office, several demonstration projects are getting under way to foster the introduction of promising electrotechnologies into foundries around the country.

"Metal casting is a cornerstone technology of an industrial economy," declares Patrick McDonough, manager for materials production and fabrication in the Customer Systems Division at EPRI. "Foundries make many things—from fire hydrants to engine blocks, from light alloys for airplanes to tough coverings for military tanks. When foundries began closing, we saw the effects ripple throughout the economy as waiting times for delivery of vital parts sometimes doubled. Plant modernization using electrotechnologies has helped to turn things around. And I believe that the research we're conducting through CMP has the potential to help foundries even more in the future."

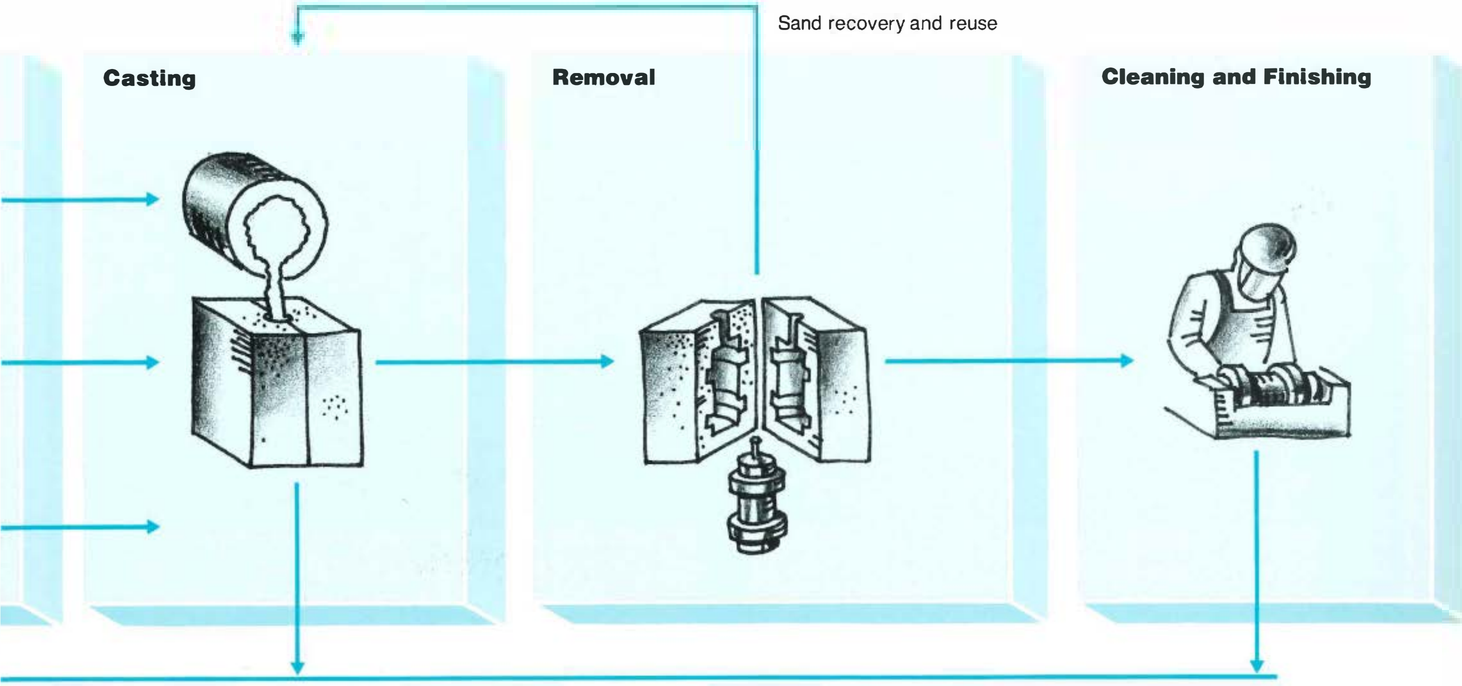
From scrap to finished product

Foundry work begins with the pattern—a wood, plastic, or metal model of the finished metal product, which is used to create a mold. In the most common foundry process, sand is placed around a wood pattern and compacted. For a "green sand" mold, the grains of sand are bonded with clay and water; for a chemically bonded mold, a liquid binder cured with either a catalyst or heat is used. Molds are usually assembled in two halves, with channels to control the flow and solidification of molten metal.

The most common melting unit for the production of cast iron is a cupola, or vertical-shaft furnace, which is charged at the top with a mixture of scrap and coke. Combustion of the coke, sustained by a blast of hot air from below, provides the heat. For melting steel, an electric arc furnace is more commonly used. The arc is struck between graphite electrodes and the metal surface, using relatively low voltages and high currents. Typical electricity consumption for arc melting is 500 kWh per ton of steel; total electricity consumption for the finished product is roughly 800 kWh per ton.

An increasingly popular alternative to these two technologies is the electric induction furnace. This unit uses a powerful magnetic field to induce an electric current inside the metal. The induced current heats the metal and provides an efficient stirring action. A helical, water-cooled copper coil that surrounds the furnace creates the magnetic field. Although capacity is limited to about 70 tons, induction furnaces are particularly flexible, energy-efficient, and clean, so more of them are being used in foundries for both melting and holding molten materials.

After melting, the metal is separated from floating slag and placed in a ladle, which can be used both for transportation to molds on the pouring floor and for further chemical and physical refining of the metal. Metal is poured directly from the



ladle into molds and allowed to cool. The mold is then broken, and the casting undergoes treatment to remove remnants of metal from the pouring channels and to prepare the surface of the finished product.

As might be expected in a process that has evolved slowly over so many centuries—the ancient Egyptians forced air into their iron-making furnaces with bellows made of goat skin—various steps of melting and casting can still be improved to take advantage of new technologies and to satisfy new priorities. In particular, environmental protection and energy costs were not major considerations throughout most of the history of metal founding. Now they are matters affecting the very survival of foundries.

How electrotechnologies can help

Over the past several years, the foundry industry has been severely affected by safety and environmental regulations related to air quality, water quality, solid waste, and occupational safety and health. Satisfying these regulations has already been costly for the industry, and environmental control looms as an even greater concern for the future. One of the most pressing current issues is how to meet provisions of the Hazardous and Solid Waste Amendments of 1989. Some foundries generate wastes that are now classified as hazardous and can no longer simply be discarded. In addition, corrective actions may have to be taken to prevent the release of hazardous material from existing disposal sites.

Energy efficiency is also becoming a more important concern, as a way both to increase productivity and to reduce environmental impacts. Total energy costs run about 10% of sales revenue for the average foundry, with natural gas accounting for roughly two-thirds of the total and electricity for one-third. The current trend is toward increasing the use of electricity for certain melting, refining, and waste treatment processes because it can provide greater process flexibility, heating precision, and automation of control.

A recent success story involving the plasma-fired cupola illustrates the environmental and economic benefits that can be derived from introducing new electrotechnologies into foundries.

In conventional cupolas, the velocity of gases rising through the coke-iron mixture is so great that small bits of iron scrap can be entrained in the gas stream. This effectively eliminates the direct use of fine materials, such as turnings and borings, which are much cheaper than conventional scrap. To circumvent this problem (as well as achieve other advantages), EPRI jointly sponsored research with Westinghouse, General Motors, and Modern Equipment Company that led to the development of a cupola in which much of the energy for melting comes from plasma torches.

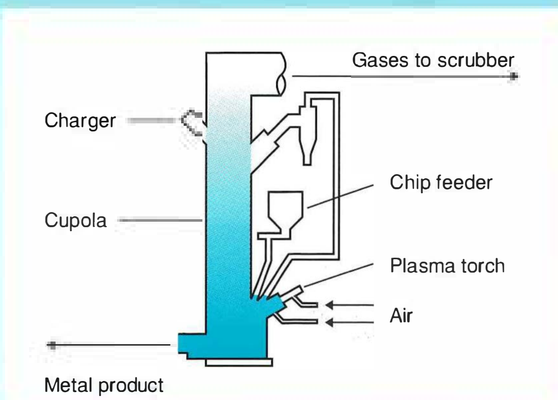
Plasmas are gases heated to a temperature so high that electrons are torn from their atomic orbits, creating positively charged ions. In a plasma torch, a gas such as argon is passed between positive and negative electrodes, which ionize the gas and create a flame-like plasma stream. Placed at the bottom of a cupola, such torches significantly increase the operating temperature (10,000°F, compared with 3000°F for fossil fuels) and can boost melting capacity by as much as 50%. The velocity of gases rising through the cupola shaft, however, is reduced enough so that low-cost fine scrap can be fed directly. In addition, coke consumption is minimized, reducing emissions levels proportionately.

Developing the Foundry's Future

Research at the Foundry Office of EPRI's Center for Materials Production is delivering electricity-based improvements that are expected to have a lasting impact on foundries in the United States and abroad.

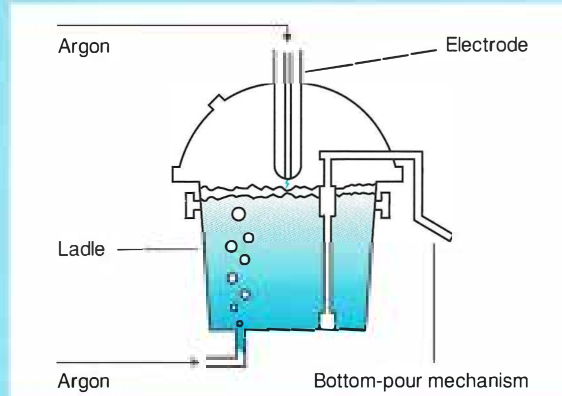
High-efficiency melting

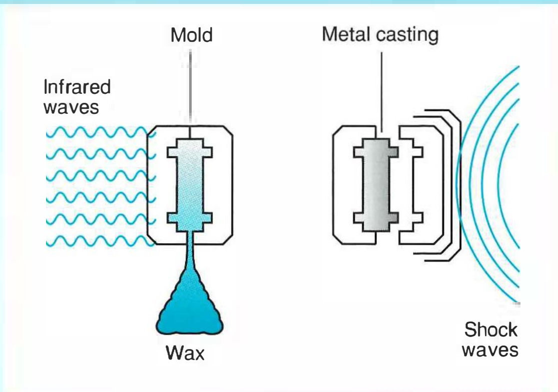
The electric plasma-fired cupola, already in commercial use at a General Motors foundry in Ohio, incorporates a plasma torch to boost melting capacity by up to 50% over conventional cupolas. In addition to reducing combustion emissions, the advanced cupola makes it possible to use fine metal scrap (e.g., turnings and borings), which is cheaper than conventional scrap.



Ladle refining

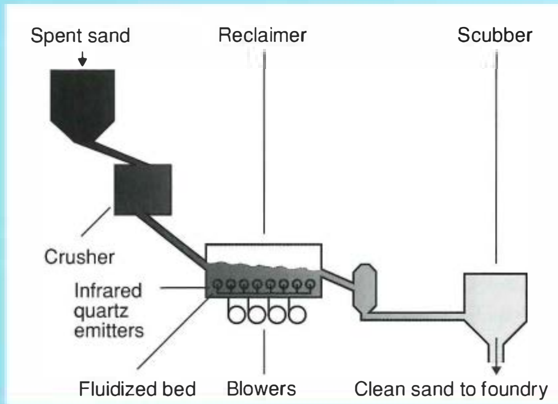
An argon plasma, created by a direct-current arc between the graphite electrode and the molten metal, provides heat for high-quality-steel refining right in the pouring ladle. Additional argon injected at the bottom of the ladle stirs the melt and lies on its surface as an inert, protective cap. The plasma ladle refiner is being constructed at a foundry in Milwaukee.





Casting techniques

Microwave melting of the disposable wax "positive" used in making ceramic molds can be accomplished with a fraction of the energy required for fossil fuel dewaxing. And shock wave propagation may be effective for removing the mold after the metal casting is made. CMP is now pursuing demonstration projects for both of these innovative techniques.



Sand reclamation

Landfill disposal of sand from foundry molds is becoming increasingly problematic, both economically and environmentally. An advanced process that features infrared heating and a fluidized bed can clean sand from clay-bonded molds for reuse. Sand from chemically bonded molds can be treated in a new electric resistance sand reclaimer. Demonstrations of both processes will get under way in 1992.

The first commercial plasma-fired cupola—rated at 45 tons per hour—was installed at General Motors Central Foundry Division in Defiance, Ohio, and produced its first castings in 1989. This demonstration showed that plasma technology could be retrofitted on a conventional cupola—in this case a 13-foot-diameter unit, to which six plasma torches were added. In a related development, a Peugeot foundry in France has retrofitted a portable plasma torch to an existing cupola, enabling it to operate at higher temperatures.

In addition to adopting new electrotechnologies developed with EPRI help, foundries are also beginning to make greater use of some other, well-established electrotechnologies. Induction furnaces, for example, are replacing traditional coke-fired cupolas for producing some common types of iron. Such furnaces are relatively simple to operate, produce little or no air pollution, provide high melting rates, and offer maximum flexibility for controlling metallurgical characteristics. For melting aluminum, foundries are turning to both induction furnaces and electric resistance furnaces to replace furnaces fired with fossil fuels, in an effort to achieve higher energy efficiency and greater yields of high-quality product.

Meanwhile, research emphasis has been refocused on several promising new areas of electrotechnology—sand reclamation, ladle refining, and improved casting techniques—with some major demonstrations either under way or scheduled to begin soon.

Sand reclamation

When molten metal is poured into bonded-sand molds, the high temperatures burn out the binders and leave a residue that hampers reuse of the sand. In the past, this spent sand—some 7.2 million tons each year—was simply discarded, usually in landfills. Environmental and economic concerns are now making this procedure less attractive, and foundries are looking for ways to reclaim and reuse their sand.

With chemically bonded sand, which is often used by smaller, jobbing foundries, thermal reclamation can be accomplished at relatively low temperatures (around 1000°F). Either gas-fired or electric resistance heaters are adequate for this purpose, but an electric system has some unique advantages. These include greater energy efficiency, elimination of the possibility that the sand might be contaminated with combustion products, and the minimization of sand grains cracking from thermal shock. A few of these electric units are currently in use in the United Kingdom and Canada.

One of the first electric resistance sand reclaimers in the United States is to be installed at Empire Steel Casting in Reading, Pennsylvania, in November 1991. The 1.5-ton-per-hour unit, which was built by Castec, Inc., is being demonstrated with funding from CMP, the Pennsylvania Electric Energy Council, and the Pennsylvania Energy Office. This reclaimer is expected to save significant energy and to reduce the company's landfill requirements by about 90%.

With sand in clay-bonded molds another approach is needed, since reclamation requires temperatures of 1600°F—too high for electric resistance heating. In search of an alternative, CMP provided funding to BGK Finishing Systems to develop an infrared (IR) sand reclaimer. In this system, used sand molds are crushed and the sand is fed into a heating unit. There a stream of air suspends the sand in a fluidized bed around infrared quartz emitters. The reclaimed sand is then cooled and scrubbed to remove fine particles of clay.

A testing program on this IR sand reclamation system is under way, using a 500-pound-per-hour pilot unit installed at BGK. Construction of the first commercial unit—a 2.5-ton-per-hour system at the Indianapolis Casting Corporation foundry in Indianapolis—is scheduled to begin in January 1992. Preliminary evaluations indicate that electricity-based IR reclamation of green sand, using about 140 kWh per ton, will be competitive with fossil fuel systems.

Plasma ladle refiner

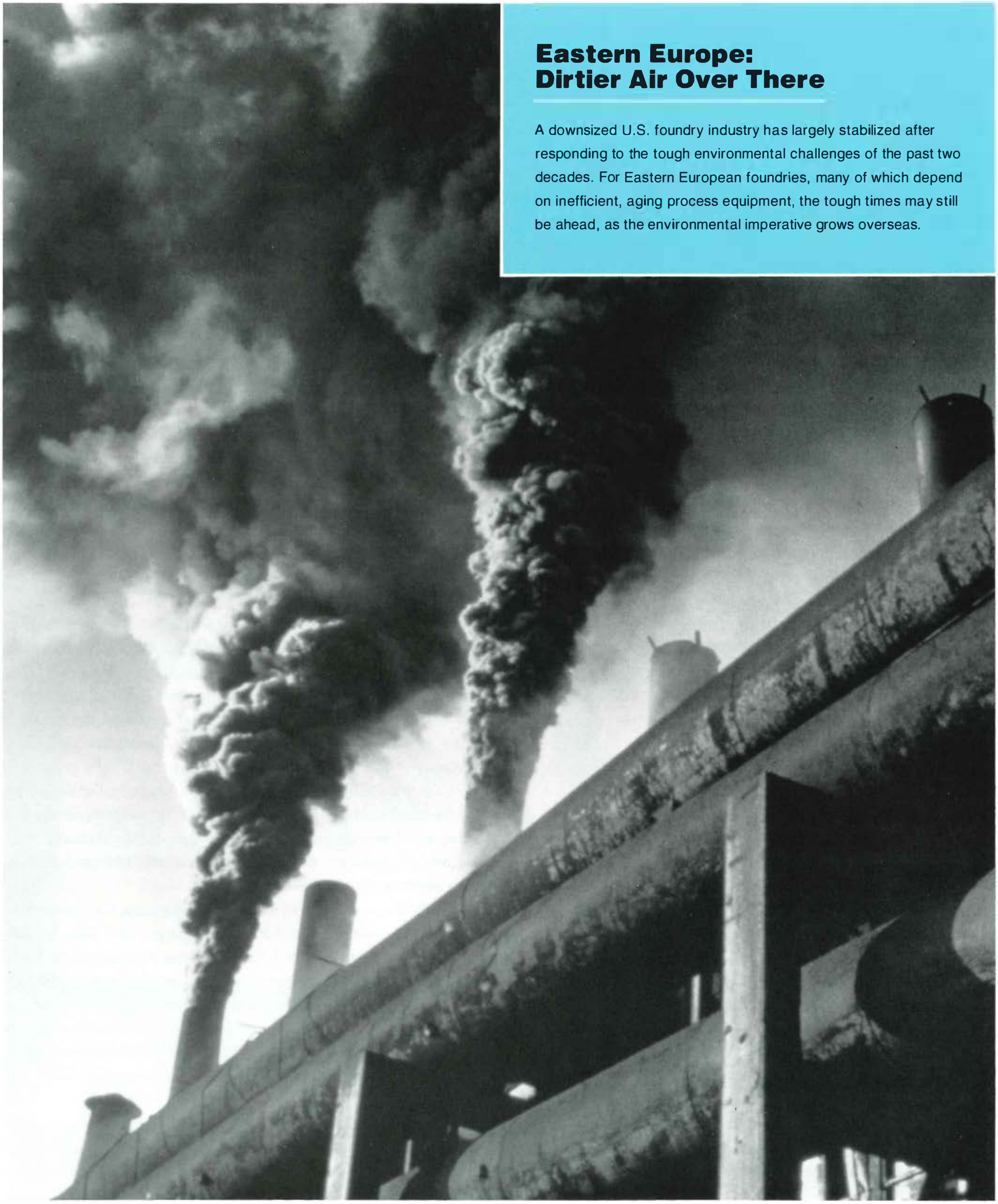
As international competition intensifies and buyers demand higher-quality castings, foundries are placing greater emphasis on producing "clean steel"—that is, steel with low levels of sulfur and phosphorus, low gas content, and a minimum of oxide inclusions. Making such steel generally requires a longer refining time, during which the metal must be kept hot. Most melting furnaces, particularly arc furnaces, are very inefficient refining vessels because of their shape, power input levels, and lack of stirring capability. Integrated steel mills get around this problem by conducting metallurgical refining in heated ladles with capacities of 25–230 tons. This option has been difficult to transfer to foundries, however, since their ladles are so small—generally around 5 tons in capacity.

In such small ladles, heat loss may be too rapid to allow time for sufficient metallurgical treatment without further heating. But heating a small ladle with an arc from conventional overhead electrodes is difficult because it creates hot spots and excessive wear on the ladle's refractory lining. In addition, slags that are effective in lowering the sulfur and oxygen content of the metal often have relatively high melting points and tend to form a crust in the ladle.

To solve these problems, CMP has sponsored the development of a plasma ladle refiner. The plasma is created as argon passes through a single hollow graphite electrode and into a direct-current arc set up between the electrode and the surface of the metal in the ladle. This plasma heats the metal efficiently, melts the slag crust, and minimizes refractory damage. Additional argon is injected into the ladle from the bottom to stir the molten metal. The presence of argon also provides a protective cover over the melt that pre-

Eastern Europe: Dirtier Air Over There

A downsized U.S. foundry industry has largely stabilized after responding to the tough environmental challenges of the past two decades. For Eastern European foundries, many of which depend on inefficient, aging process equipment, the tough times may still be ahead, as the environmental imperative grows overseas.



Andrew Holbrooke/Black Star

vents oxidation at the surface.

The first plasma ladle refiner—a converted 8-ton, bottom-pour ladle at Maynard Steel Casting in Milwaukee—will begin operation in November 1991. Wisconsin Electric Power is cooperating in its evaluation and providing energy monitoring services. The use of such plasma ladle refiners instead of a melting furnace for refining operations is expected to increase productivity in the melting operation by some 20–30%.

Improved casting techniques

In addition to the widely used sand molds, foundries sometimes use other casting techniques for special purposes. Ceramic molds, in particular, can produce castings with fine detail, smooth surfaces, and excellent dimensional accuracy. Removal of these molds—especially the ceramic cores used to form casting interiors—can be quite difficult. Such cores are generally removed by dissolving them with a hot caustic bath, but disposal of the caustic solution is coming to be considered environmentally unacceptable. Removal of outer ceramic shells from a casting can also be tedious, sometimes requiring manually operated jackhammers. Foundries are thus seeking more-efficient and environmentally benign methods for removing ceramic cores and shells.

One promising electrotechnology now being investigated is shock wave propagation—a technique similar to that used to break up kidney stones as an alternative to surgery. Preliminary review of the technology at the Metal Casting Technology Center of the University of Alabama indicates that it may be a suitable removal method. Consequently, CMP is planning a development project in collaboration with the U.S. Department of Energy and the American Foundrymen's Society. The two-year project, expected to begin late this year at the University of Alabama, will aim at proving the technology and developing a working model for evaluation in a foundry. Portland General Electric, Alabama Power, and Wisconsin Electric Power have all expressed interest in supporting the demonstration of shock wave propagation for ceramic core and shell removal.

One of the oldest and still most popular ways of making ceramic molds is the so-called lost-wax process, in which a disposable wax pattern is encased in ceramic material, then removed by melting. Usually the wax pattern is melted in either a fossil fuel furnace or a steam autoclave. Both systems are now considered energy-inefficient and environmentally undesirable because of the wax fumes and products of combustion.

A promising alternative approach would be to use microwaves to melt the wax. This process would not produce fumes or waste energy because of the low temperatures involved. The electric energy required would represent only about 1% of the energy used in gas-fired dewaxing, at a much lower cost. In addition to being exceptionally clean, microwave dewaxing could easily be automated, resulting in further savings in labor for handling and processing. Also, more of the wax would be acceptable for reuse, providing another economic incentive. CMP is currently organizing a demonstration project for this technology and seeking a host facility.

A matter of survival

In addition to sponsoring the development and demonstration of new foundry technologies, CMP is providing analytical tools that utilities can use to evaluate potential opportunities for their foundry customers. One such tool is a two-tiered model of costs for producing iron with different types of melting systems. This model, developed by Hatch Associates, makes a preliminary estimate of overall production costs based on such data as output levels, raw material costs, fuel costs, and electricity rates. This estimate may be sufficient if the decision is clear-cut; if further analysis is required, a more detailed, computer-based model is used.

The first EPRI utility to demonstrate this model was Pennsylvania Electric, in an effort to help its foundry customer, EMI, choose a new melting unit as part of plant expansion. The results of the analysis showed that the lowest operating cost was achieved by a medium-frequency induction furnace that could take advantage of low off-peak electricity rates. On the basis of these figures, EMI is reportedly planning to purchase an induction furnace when business conditions warrant.

The CMP Foundry Office has also initiated a project to develop analytical tools for better demand-side management by utilities that have foundry customers. This project will focus on foundry operations and increased energy efficiency. The initial phase will include a scoping study and a collaborative effort with participating utilities to provide energy audits for their foundry customers. Later steps will involve a full industrial efficiency program for foundries.

"Advanced electrotechnologies can make the difference in survival for American foundries," says John Svoboda, a consultant for the CMP Foundry Office and author of *Foundry Technology—An Overview* (CMP Report No. 91-1). "U.S. utilities are now quite competitive in international markets, and their prospects for increasing exports are bright, particularly exports of alloys such as ductile iron. Electrification of the industry is increasing, as is computer simulation of foundry processes. This trend can help foundries make environmental improvements and increase their energy efficiency. Our task at the CMP Foundry Office is to fund the research needed to support these trends, as well as to provide both foundries and their electric utilities with information about the opportunities available." ■

This article was written by John Douglas, science writer. Background information was provided by Patrick McDonough, Customer Systems Division.

The Long View for Nuclear Plant Maintenance

Planning and integrating maintenance activities is taking a new form at many of the nation's 111 nuclear power plants as a number of reactors approach the expiration of their current operating licenses. (Some licenses expire in the next decade.) The new strategy incorporates effective measures to address age-related degradation of safety systems and equipment covered under federal regulations that govern the renewal of current licenses. But it is also, more broadly, a comprehensive approach to plant maintenance that is geared to ensuring economical, reliable operation over an extended period.

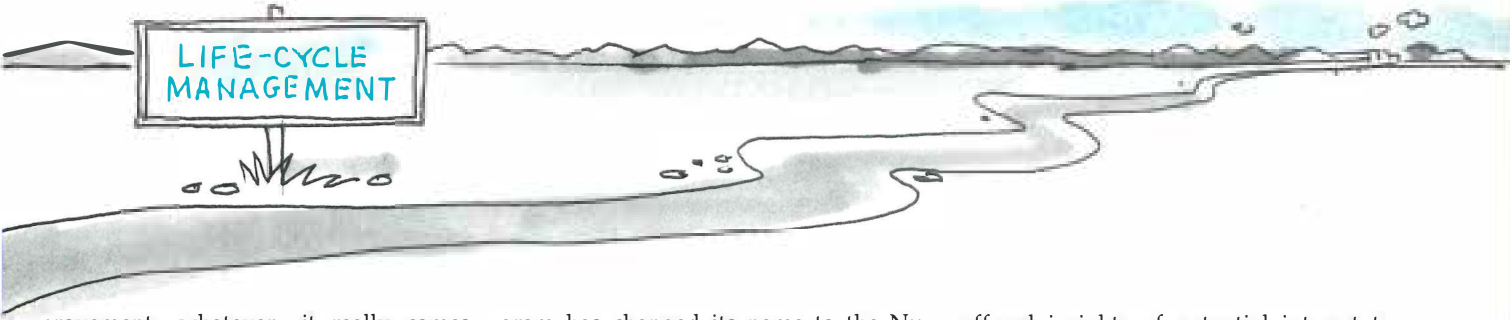
Variously known as life-cycle management, life optimization, or aging management, the concept is somewhere between a philosophy and a methodology at this stage, although utility operators of as many as 20 plants have established programs and begun planning. Their ranks are likely to increase as a result of separate, recent regulatory developments that spell out requirements for renewing licenses and that mandate the adoption by all utilities of performance-based maintenance programs, beginning in 1996.

Life-cycle management (LCM) also represents a semantic refinement of the term life extension, which has now been largely abandoned by the industry because it incorrectly connotes the operation of plants and major components beyond their intended life. The LCM approach, which encompasses maintenance planning both leading up to license renewal and continuing through the current and extended operating periods, explicitly recognizes that plant systems, structures, and components are subject to age-related degradation. But LCM asserts that this can be effectively managed through an integrated, forward-looking preventive maintenance and monitoring program that optimizes the use of personnel and capital resources to maintain the material condition of valuable, performing assets.

"Call it life extension, life-cycle management, plant operating lifetime im-

The Path to Long-Term Plant Operation

Life-cycle management as a route to extended plant operation involves a departure from the type of maintenance planning that focuses on getting through the next one or two fuel cycles. Life-cycle management requires both a longer planning perspective and comprehensive retrospective evaluations in order to determine the long-term viability of a nuclear plant investment.



provement—whatever—it really comes down to a cost-effective, technically adequate program for long-term maintenance of any given item," says John Carey, a program manager in EPRI's Nuclear Power Division. Aging management is the language used in the Nuclear Regulatory Commission's proposed license renewal rule, says Carey, but that phrase has also become politically charged as critics of nuclear power question the safety of reactors approaching the end of their original license terms.

Life-cycle management—this more sophisticated, anticipatory approach to maintenance—seeks to coordinate the work of diverse, ongoing plant activities within a planning framework that extends for 5 to 10 scheduled outages (or more) into the future. The approach also involves improving and making greater use of the extensive computer databases that contain details of plant configurations, operating histories, and maintenance and performance records of systems, structures, and components. While many such records must be maintained to support an application for license renewal, they also contain valuable signposts for maintenance planning.

To reflect the broader perspective on long-term plant operation and maintenance that is emerging in the industry, EPRI's Nuclear Plant Life Extension Program has changed its name to the Nuclear Life-Cycle Management Program. It still encompasses the series of projects and activities in direct support of license renewal. These include the development of referenceable, topical industry reports on major technical issues, and participation, along with the Department of Energy, in utility-led demonstrations of license renewal at Northern States Power's Monticello plant and Yankee Atomic Electric's Yankee Rowe plant. Studies of new methods to better address age-related degradation mechanisms and their effects are ongoing as well.

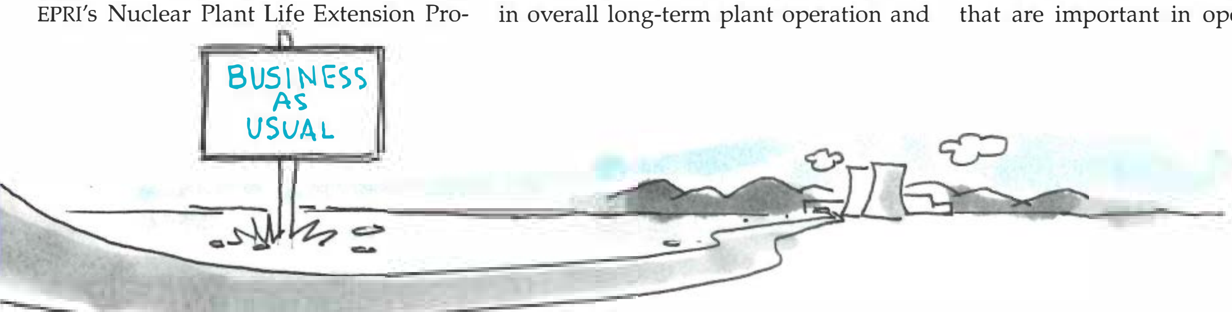
But EPRI's program is now also developing new tools for economic evaluation and for applying LCM approaches to maintenance planning. EPRI has begun what may become a series of collaborative efforts with selected utilities to conduct complete life-cycle evaluations of major plant systems, structures, and components, which should yield generic guidelines of broad value to the industry. Research managers hope to complete over two dozen such evaluations and make the results available to utilities over the next five years.

Utility engineers at several operating plants that have already initiated programs or efforts in life-cycle management recently spoke about their programs' role in overall long-term plant operation and offered insights of potential interest to other utilities. Their views reflect a consensus that the early establishment of an LCM program can produce tangible, near-term operational benefits as well as help provide the most informed basis for decision making about a license renewal application when the time comes.

A sign of maturity

Every nuclear plant has an ongoing maintenance program, and if a plant applies for license renewal, it must demonstrate to the NRC that it has effective programs to address age-related degradation in safety-related systems, structures, or components (SSCs), as well as in certain nonsafety SSCs. While these categories include much of the plant—from the reactor pressure vessel, primary pressure boundary and cooling system, and containment all the way to the emergency diesel generators—they exclude many types of SSCs that, although not critical to safety, can significantly affect a plant's operating economics, such as the turbine generator.

Life-cycle management extends the application of systematic screening and evaluation, preventive maintenance prioritization and strategic scheduling, condition monitoring, and wear and repair data collection and analysis to all SSCs that are important in operating a plant



THE STORY IN BRIEF

A strategic, anticipatory approach to maintenance is key to the long-term viability of today's nuclear power plants. As many as 20 plants around the country now have life-cycle management (LCM) programs in place—integrated, forward-looking preventive maintenance and monitoring programs that preserve the plant's material condition and extend economical operation. Besides reducing the need for "pounds of cure" decades in the future, LCM programs can produce significant near-term gains in plant performance and are valuable in addressing license renewal concerns. EPRI is supporting the industry's LCM activities with research on age-related degradation mechanisms, development of economic evaluation tools for applying LCM approaches, and assistance with life-cycle evaluations of major plant systems, structures, and components at selected utilities.

safely, reliably, and economically.

EPRI research managers say the growing utility interest in LCM represents a departure from the traditional, short-term attitudes regarding maintenance that have sometimes prevailed. Melvin Lapides, a Nuclear Power Divison technical specialist who managed some of the earliest industry studies of the feasibility of plant life extension, points out that many of the plants operating today—both nuclear and fossil fuel—were built in an era when it was expected that continued load growth and technical obsolescence would obviate the necessity of maintaining generating assets much beyond a 25-year operating life. Now, lowered expectations of growth and a very different capital and operating cost structure have forced utilities to plan on operating any kind of baseload unit for 50 to 60 years, if possible.

"What you do to maintain a plant is dependent on how long you think it's going to need to run," notes Lapides. The average operating time for nuclear plants of the current generation is only about 15 years. "Despite the industry's operating record, the number of years of experience in operating the bulk of our nuclear generating capacity is relatively small, compared with the periods of time we are now contemplating running the plants. Most utilities are only a little way out on their overall plant life cycle."

Lapides says it is a sign of maturity for a plant's management to become less preoccupied with fulfilling regulatory requirements and responding to daily operational challenges and more able to take a long-term perspective with a focus on investment protection. "All utility power plants, especially nuclear ones, are amazingly well engineered, so you've got to look deep into the nooks and crannies to really find out what happens as they get old. You're only going to find that from an in-depth evaluation of the kind that can be easily deferred because, well, the issue is 10 or 20 years in the future. But investment protection for a nuclear plant requires stepping back and integrating the total plant operating experience—and for other than regulatory reasons. This is a new concept for many utilities."

Lapides adds, "Generic plant studies conducted over the last decade have all concluded that, barring substantial increases in O&M costs unique to nuclear operations, sustained major refurbishment of most current reactors for planning horizons of 10–30 years beyond the initial license term appears both feasible and economically attractive. The essential reasons for this are the current and projected nuclear-to-fossil-fuel cost differential; the fact that current costs for maintaining a nuclear unit as good as or better than new are also an investment in service extension; and the fact that only a small fraction of the total plant cost is associated with those elements that deteriorate significantly."

According to Lapides, a major benefit assigned to extended service in economic evaluations is the deferral of capital expense for a new unit, which can have a value easily exceeding $200 million a year, assuming a size of about 650 MW, the average for currently operating nuclear units. A major cost of extended service, on the other hand, is the cost of replacement power required during the perhaps longer or special maintenance shutdowns that could be required. Extended outages can substantially diminish the potential economic benefit of extended service, which suggests that LCM to minimize outage time may be essential.

Yet "for most studies of license renewal performed to date, the pre-40-year costs to ready a plant for extended service were paid back after only 1–6 years of operation beyond the original license term, largely through the deferral of capital expense," Lapides adds. "The relatively short payback periods suggest minimal investment risk, barring a continued increase in nuclear O&M costs." According to the Utility Data Institute, annual average nuclear O&M costs decreased by about 3% in 1990—the first decline in 10 years.

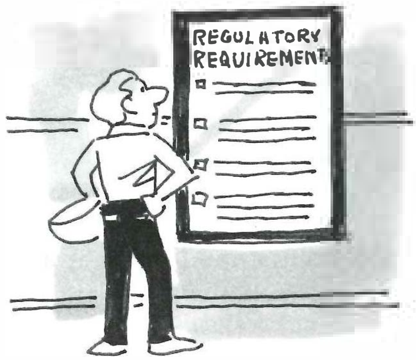
Carey says the LCM concept is a logical extension of long-term maintenance to all parts of a plant that are important to economical, long-term operation. "The lead plant license renewal demonstrations will identify a range of options for managing age-related degradation of safety-related SSCs, but most of these approaches will also apply to aging management of any SSC that is nominally supposed to last for a long time. So the emphasis in LCM is to look at all the plant's major systems, structures, and components that are supposed to have a long life and ask yourself what can be done to ensure that they do."

Looking under the rocks

In the colorful phrasing of a senior industry veteran of plant operations and maintenance, LCM "is going a little further than required by the regulators to turn over the rocks and see if there are any worms under them." Gerald Neils, an executive engineer at Northern States Power (NSP), says that LCM "requires a change in attitude and an acknowledgment that most of the existing maintenance programs—such as check-valve maintenance, erosion-corrosion pipewall thinning measurement, motor-operated-valve maintenance, and others that the NRC compels us to do—we should perhaps be doing more thoroughly than the NRC insists, as part of a long-term maintenance strategy.

"Life-cycle management is a process of using more-comprehensive inspection and monitoring to maintain an improved knowledge of the material condition of the plant. This knowledge improves the capability to plan and schedule the maintenance and replacements in order to avoid the unpleasant surprise of individual catastrophic equipment failures." Adds Neils, "The goal is to avoid those nasty surprises that cause forced outages or pop up as unplanned work that extends a scheduled outage. When those surprises do arise, repair and recovery is usually an emergency of crisis management. In such an environment, recovery and repairs always cost more and often do not solve the underlying problems. We could spend a bundle to get the plant back on-line, and then it is just a matter of time before it happens again."

Asked to give examples of preventive maintenance, Neils cites the monitoring of pipe thinning—"so you know when to



Maintenance Focus

Many current plant maintenance programs are geared toward compliance with numerous regulatory requirements. These can dominate near-term refueling and maintenance outage planning to such an extent that important plant improvements not mandated by the Nuclear Regulatory Commission may be deferred.

The life-cycle management path goes beyond near-term regulatory compliance and views maintenance planning in terms of what is required to ensure economical, long-term power production from an operating asset.

replace a chunk of pipe and you have enough lead time to obtain a material with more resistance to the degradation that's causing the problem." Similarly, he continues, "regular inspection and maintenance of critical building structures is important in northern-tier states because of the effects of severe weather. Regular inspection and grout-filling of concrete cracks and spalls is much cheaper than waiting until you have a real problem on your hands with exposed rebar. Likewise, when you see salts accumulating on a crack in a below-grade wall, you know you have a moisture problem to seal up. You want to take care of that before you see rust, which indicates rebar corrosion."

Planning Horizon

Maintenance planning driven by regulatory requirements typically is focused on the next 18–24 months.

Life-cycle management for long-term plant operation involves strategic planning of maintenance for perhaps five to six fuel cycles, or as far as 10 to 15 years into the future.

Neils says NSP has followed a long-term approach to plant maintenance at its Monticello and twin-unit Prairie Island plants from the start. But in the 1980s, "the short deadlines of action plans stemming from the Three Mile Island accident and from other regulatory backfits were pushing us toward a short-term goal of surviving until the next refueling outage. The LCM program strategy helped us get back on the long-term track." Initial plant evaluations for license renewal went beyond the anticipated scope of regulatory review. Neils says NSP sees life-cycle management as evolving to a form of reliability-centered maintenance (RCM) in the nuclear industry, an approach that was originally developed in the aircraft industry and that relies on review of failure data to set maintenance and replacement frequency. "It doesn't make any difference whether you call it life extension, life assurance, or life-cycle management, because the same, long-term operating and maintenance program strategy is needed in each case."

Explains NSP's Tim Bailey—whose title, project manager of plant life extension at Monticello, retains the earlier jargon—"Many of the basics of our program are similar to an RCM program, where you look at specific maintenance activities and verify that it is appropriate to be doing those kinds of things at the frequencies you're doing them. We're basically taking credit for our life extension work as the first phase of our RCM program. Future phases may emphasize life-cycle management of systems that might be highly rated in priority from a probabilistic risk perspective. That means we would take a closer look at systems that could initiate events. So that's a future phase, to integrate plant-specific risk factors identified from the probabilistic risk analysis and individual plant evaluation process with our maintenance planning."

Looking under the rocks, as Neils calls it, can lead to near-term savings in operating and maintenance costs, even revealing unanticipated degradation that can be remediated before it poses an operational safety problem. At NSP's 536-MW Monticello plant, the lead BWR plant for license renewal, EPRI and the utility first joined forces in 1985 to conduct an extensive inspection and evaluation for life extension during a scheduled outage. More than 400 improvements in plant operations were recommended, representing potential savings of over $3 million over the life of the plant.

Moreover, the inspection identified a previously undetected mechanism of corrosion at a seal in the floor of the plant's drywell sand gap. NSP instituted a monitoring and mitigation program on the problem that earned it kudos from the NRC. As other examples of maintenance improvements that have resulted from a more anticipatory approach, Bailey cites keeping closer tabs on interior coatings of containment vent headers and more-systematic diesel generator maintenance.

As for Monticello's pressure vessel, Bailey says, "we're in good shape" regarding a capability to detect and monitor any neutron-radiation-induced embrittlement on the basis of surveillance samples of vessel materials placed inside the reactor. Those samples will be periodically removed and analyzed for evidence of embrittlement resulting from the interaction of neutron radiation from the fission process with impurities in the steel and weld materials.

"We have in place a plan to make sure we have a long-term capability to monitor the material condition of the pressure vessel," says Bailey. (Concern about potential age-related embrittlement of the Yankee Rowe PWR pressure vessel has led to a delay in that plant's application for license renewal, pending further metallurgical analysis.)

A strategic focus for maintenance

Utilities that are adopting LCM programs stress the value of a strategic focusing exercise that brackets and positions diverse maintenance activities over a long planning horizon. A leader among utilities in this area is Baltimore Gas & Electric, which operates the twin-unit Calvert Cliffs nuclear plant on Chesapeake Bay. Some of the earliest service life evaluations of major components, including the reactor pressure vessel, were begun at Calvert Cliffs as early as 1988, and the plant has had a formal LCM program in place since mid-1990. Its Unit 1 license will not expire until 2014, but the LCM program is designed to position BG&E to apply for a 20-year renewal as early as 1999 if it chooses.

Explains Charles Cruse, manager of the nuclear engineering department at Calvert Cliffs, "We started our LCM program with a focus on trying to position BG&E for license renewal, but we also had a vision that the process could help us operate in a safe and reliable manner during the current license term. The program was originally, and is still, justified on the basis of the economics of extending Calvert Cliffs' life by 20 years, but as the project has progressed and we have learned what LCM can do for us operationally, we have come to believe LCM can have significant benefits in the current license term. My gut feeling is that at least half of the overall benefit may turn out to come in performance gains or cost savings realized during the original license term."

Cruse offers several insights regarding BG&E's experience with LCM: "It provides a focal point for our known, long-term technical issues, such as pressurized thermal shock–pressure vessel embrittlement, which we know we have to address during the current license term. We think the LCM screening and evaluation process provides a framework for identifying and prioritizing other potential technical and maintenance issues for the current license term, as well as providing a basis for license renewal.

"We've added a capital planning work group to our LCM unit. They're gathering and integrating information about the plant from all sources to produce a rough scope for future capital improvements, prioritization, and an outage-by-outage strategic implementation plan for later assignment to a project management group."

Some of the key challenges in making LCM work, says Cruse, are "striking the optimal balance between near-term and long-term plant support; communicating the LCM approach and philosophy, especially the potential near-term benefits, to plant personnel; effectively integrating the LCM process with other site initiatives while avoiding duplication; maintaining the flexibility to adjust to changing regulatory requirements; and remaining cost-effective."

Adds Barth Doroshuk, principal engineer of the LCM unit, "If you're letting the problems in the plant drive the outages, then you are not looking far enough down the road. What we're trying to do at Calvert Cliffs is develop an organization with a vision that looks 2–4 years down the road and can head off some of the things that have come up and bitten us in the past."

BG&E is undertaking a series of life-cycle evaluations of major systems, structures, and components at Calvert Cliffs that are important both to license renewal and to long-term power production; the objectives are to develop and test the LCM process within its program and to identify near-term plant improvements that could have a long-term payoff. The first such evaluation under way involves the reactor pressure vessel, where surveillance and monitoring programs are in place. It is to be followed by similar top-to-bottom, 60-year-service-life evaluations of Calvert Cliffs' saltwater service system, the reactor cooling system, the compressed-air system, and the control room heating, ventilation, and cooling system. Doroshuk says the utility hopes to have all the studies near completion by mid-1992.

Because of their value as prototypes to other utilities who will someday face similar evaluations, BG&E's pressure vessel and saltwater system evaluations at Calvert Cliffs are being cosponsored by EPRI under its new tailored-collaboration program. Doroshuk says the evaluations will be comprehensive and will consider

Scope of Work

Maintenance activity driven by short-term schedule requirements may end up crowding activities important to long-term power production out of the planned-outage schedules.

Maintenance programs guided by a life-cycle management philosophy find the time to look, as one industry executive says, under the rocks in all areas of a plant to catch potential surprises before they can progress to costlier repairs.

all options, from preventive measures to repair, upgrade, and replacement, as appropriate. Research managers say that in the case of the reactor vessel, options to be considered include thermal annealing, an approach to relieving neutron-induced embrittlement that is as yet untried in this country.

As for Calvert Cliffs' saltwater system, which includes extensive underground piping, utility engineers readily acknowledge that corrosion-related problems have caused the plant's reliability to suffer at times. That is why they want to conduct a complete analysis, at this point in the life of the plant, of what options are available—or will be, down the road. "Here's something that is really going to limit us 10–15 years from now and will definitely limit us for 60-year operation," explains Doroshuk. "It's almost staring us in the face now because of the long lead time required to address the issues posed by the saltwater system. We need to address this up front.

"We're not saying we're going to make the saltwater system last for 60 years. But if we take a focused look at it, we can save money by doing the right activities now—we'll be able to predict that in 20 years a potential replacement of the system will be a lot cheaper because of the changes we could make today." Doroshuk concludes, "It really boils down to how well you manage the assets. Adopting an LCM approach now in the case of the saltwater system—and, we think, in general—will spread out the cost of whatever we must do to keep the units safe and reliable over a reasonable number of years, rather than create a bow wave of capital costs and legal obstacles during the last years of operation under the current license term that may make any extension prohibitively expensive and too risky to consider."

Another utility that has made an early commitment to life-cycle management is Commonwealth Edison. With 12 operating units at six plants, representing about 10% of the installed U.S. nuclear generating capacity, Commonwealth is a microcosm of the industry in many ways. It has boiling water reactors and pressurized water reactors. It has some of the oldest units in the industry but also operates some of the newest. Licenses for six of Commonwealth's reactors—at Dresden, Quad Cities, and Zion—will expire by 2014. Within another decade from then, licenses for the remaining six will begin expiring at a rate of one unit per year.

"Our strategy is to preserve our substantial investment in all of these nuclear plants regardless of individual license renewal decisions that may eventually be taken," says George Wagner, the utility's nuclear engineering manager.

In recent remarks before the Midwest Engineering Managers' Forum, Cordell Reed, Commonwealth Edison's senior vice president for nuclear generation, said that refinements in the methodology for performance trend analysis in plant components and the incorporation of strategic maintenance plans into daily plant operational activities are examples of how Commonwealth Edison intends to manage age-related degradation problems.

"The resources which any utility will need to initiate and maintain a program may be substantial, both in dollars and manpower. However, the impact can be minimized if proper planning of detailed action plans to manage component aging are integrated into the plant's daily activities," Reed said.

"An effective nuclear plant aging program is important to us at Commonwealth Edison," he went on, "because we will need it to get plant life extension and license renewal. We only paid $1.2 billion for our first six nuclear units at Dresden, Quad Cities, and Zion. I don't know what replacement costs will be for 5200 MW in the year 2010 timeframe, but I hope we can extend that decision until well after the year 2030. Therefore, we have a substantial vested interest to keep these plants in good working order."

Commonwealth Edison began planning a lifetime component management program in 1989. Several elements are now under way that are likely to be found in many utility LCM programs, including configuration management to document important plant and equipment changes with a bearing on maintenance planning, as well as an effort to locate and preserve all plant documentation pertinent to an application for license renewal. The utility is also developing guidelines, where

Long-Term Economics

A short-term focus that fails to provide the maintenance necessary for long-term power production can lead to uneconomical operation, resulting in untimely plant closure and decommissioning.

Life-cycle management envisions continued economical power generation under extended plant operation and provides the investment and maintenance planning necessary to reach that goal.

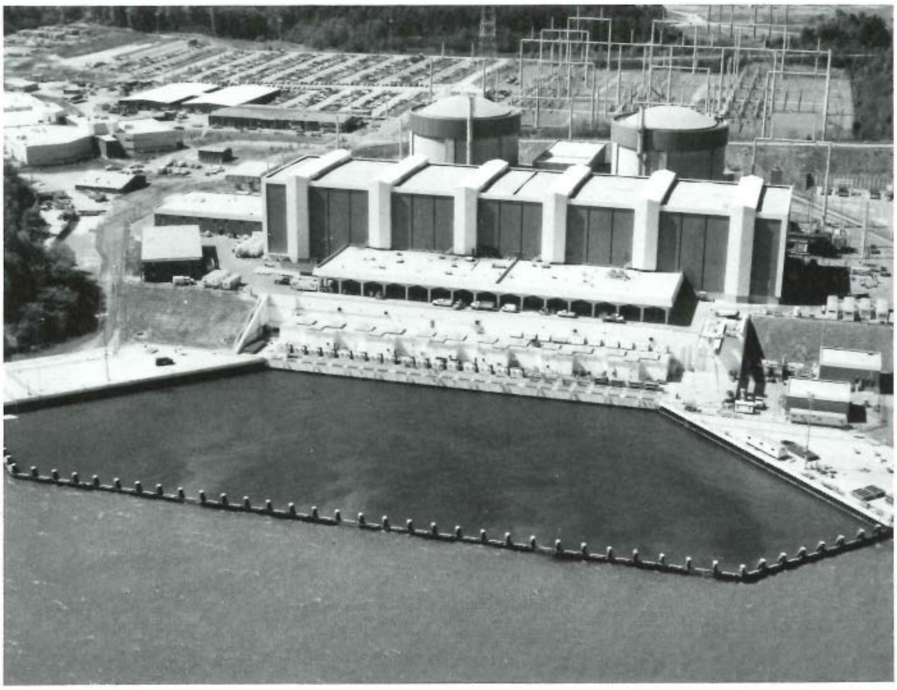
appropriate, for component cycle counting and fatigue monitoring and has performed environmental map study surveys of the present condition of cables in selected areas at its six older units. Assessments of the underground piping systems and critical concrete structures, such as the reactor and turbine buildings and containment internal structures, either are in progress or have been completed at the Dresden, Quad Cities, and Zion stations. The Dresden Unit 2 condenser was extensively evaluated for erosion-corrosion degradation in 1990.

On the corporate level, Commonwealth Edison is developing a strategic maintenance plan that will integrate the planning of specific programs to cover all NRC-identified plant aging issues, says Don Eggett, program manager for nuclear plant aging and license renewal. "We want to position ourselves today in order to identify the things that we need to be doing over the short term in a strategic and sequential manner, as well as prepare ourselves to make individual plant decisions on applying for license renewal in the later years." Eggett says he has recently visited all of Commonwealth's nuclear plants to educate the staff on the philosophy and approach of the company's aging-management program and what it will mean to each station's daily activities. "Station management is extremely interested and supportive. They know we should be more proactive than we presently are when monitoring and trending equipment and structures."

Eggett says that with the NRC's passage of plans to institute formal requirements for utility maintenance programs beginning in 1996, Commonwealth Edison and other utilities with LCM programs in place are in just that much better position to adapt to changing requirements as they relate to aging management. "The activities that will need to be carried out to meet the requirements of 10CFR50.65—the maintenance rule—will aid in facilitating the plans we're developing and implementing with LCM or aging management. They just can't function separately. Any existing, effective maintenance program that manages age-related degradation should see only minimal impact from the requirements of the maintenance rule. This would be true of any utility. We believe the rule will just make our company's aging-management program that much stronger."

Calvert Cliffs Pursues LCM

Baltimore Gas & Electric's twin-unit Calvert Cliffs nuclear plant is one of about 20 in the country with a life-cycle management program under way. BG&E has begun a series of comprehensive life-cycle evaluations of major systems, structures, and components that are important both to license renewal (Unit 1's license expires in 2014) and to long-term power production. One such evaluation will focus on the coastal plant's seawater cooling system.

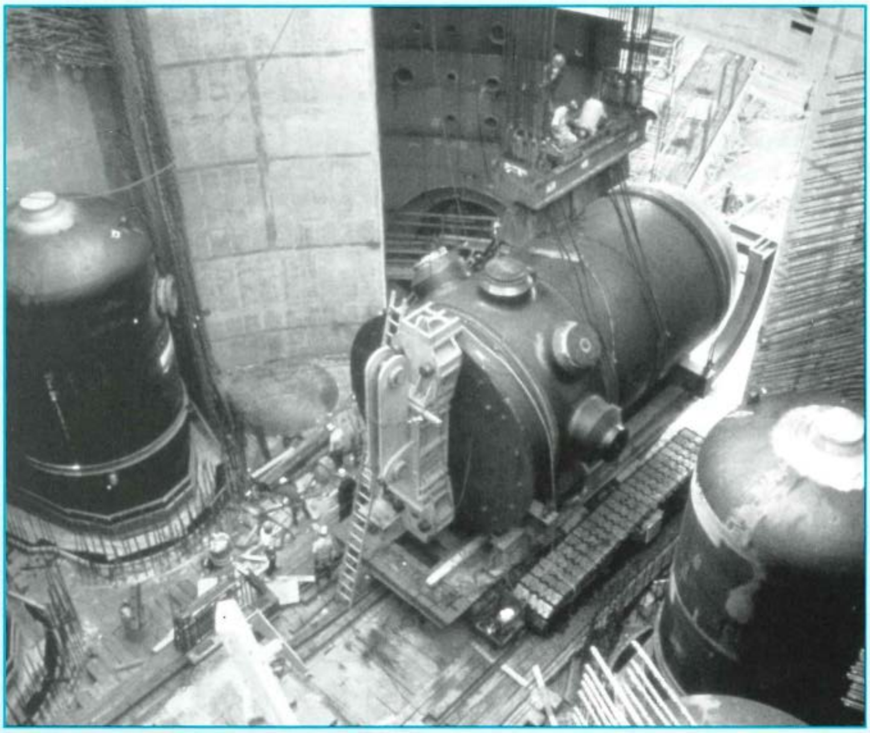


Bottom-line incentives

Some utilities with nuclear plants substantially further out on the license renewal horizon than those of NSP, BG&E, and Commonwealth Edison are putting LCM programs in place. At least one has discovered an added incentive to pursue life-cycle management, beyond the potential O&M savings and extended service life. At its Davis-Besse plant on Lake Erie near Toledo, Centerior Energy is seeking to maintain the good performance levels recently reattained after an 18-month shutdown following a June 1985 loss-of-feedwater incident. Davis-Besse's current operating license runs until 2017, but in planning for extended plant service, Centerior has found that possible changes in the treatment of plant depreciation expenses could significantly help improve the company's short-term earnings outlook. The utility has already realized similar fiscal gains from life extension planning at some of its fossil units.

Deborah Staudinger heads Davis-Besse's incipient LCM program, now evolving from planning and feasibility studies to defining specific aging-management activities. "We decided to take an LCM approach because we have built up a good predictive and preventive maintenance program, we have a good configuration

Pressure Vessel Life-Cycle Management



The reactor pressure vessel is the largest and most integral major structural component of a nuclear plant. Because the vessel is exposed to a large amount of neutron radiation over its lifetime, its material condition is one of the main concerns in an evaluation of the plant for extended service and is a key focus of utility LCM programs. The steel vessel, which can weigh as much as 250 tons, contains the core of uranium fuel where nuclear fission produces heat for steam-to-electricity generation.

Fission also produces intense neutron radiation, which, over many years of service, can cause embrittlement of the reactor vessel as a result of interaction with impurities in the steel. This is mainly a concern for vessels in early-vintage pressurized water reactors. NRC regulations specify a maximum permissible level of embrittlement to ensure safe operation of the vessel and to prevent brittle fracture during a pressurized thermal shock transient. Such an unlikely event could challenge the integrity of a reactor vessel as a result of the sudden injection of cold cooling water followed by repressurization of the vessel during certain accident scenarios.

Uncertainty about the level of pressure vessel embrittlement at the 175-MW Yankee Rowe PWR in Massachusetts has led to a shutdown and a deferral in that plant's application for license renewal until further tests and analyses are completed.

Neutron damage to reactor vessels is carefully monitored at all operating nuclear plants. The information, along with trend-curve prediction methods, permits utilities to assess the current and future condition of the vessel material under continued neutron exposure. Utilities can take steps to mitigate the effects of vessel embrittlement and remain within allowable regulatory limits. Decisions to implement remedial measures for the vessel must also take into account the overall life-cycle management strategy for the remainder of the plant's projected operating life. To help with these decisions, EPRI is developing analysis software—the VTESTER code—to apply decision analysis methods in evaluating strategies for dealing with pressure vessel embrittlement in PWRs.

Utilities are now actively taking steps to control the level of vessel embrittlement and to reduce the risks of brittle fracture as a result of pressurized thermal shock. Condition monitoring of the vessel through material surveillance and periodic inspection is part of the maintenance program at all nuclear plants. In addition, during the initial licensed operating term, mitigation measures can be initiated that will extend the service life of the vessel. These include reducing the neutron flux at the vessel wall by changing the fuel arrangement in the core and by installing shielding material between the core and the vessel wall. A third option for managing vessel embrittlement is thermal annealing to restore toughness and ductility to the steel.

Choosing the best options for managing vessel embrittlement is difficult, because utilities must consider both long-term objectives (e.g., plant license renewal) and short-term goals and constraints (e.g., plant reliability and availability, utility revenue requirements). Many plants have already initiated some form of neutron flux reduction. But there may be cases where flux reduction alone is insufficient to achieve the desired projection of vessel life and where vessel annealing may become a more attractive option for the long term.

Thermal annealing of a reactor vessel to remove some or all of the effects of neutron embrittlement is performed in place. Although it has yet to be applied at any commercial reactor in the United States, the technique has been used successfully at nine PWRs in the Soviet Union. With the vessel defueled, special heaters are used to raise the metal temperature in the critical vessel welds to 454°C (850°F) for about six days. EPRI has evaluated the Soviet technique, and research managers say that considerable technical and regulatory effort would be required to develop and demonstrate the technology for reactors in this country. Annealing could be the most expensive of the three embrittlement management options, but depending on the additional service life it could give a reactor vessel, the economic benefit in the long run could easily be worth the cost.

Another option being explored is wet annealing, which can be performed with only minor plant modifications. The reactor vessel and primary cooling circuit are brought up to a temperature of about 340°C (650°F) for six days solely by friction from operating the main reactor coolant pumps. While the benefits of wet annealing are not as great as those of the higher-temperature, Soviet-style dry annealing procedure, the wet procedure could add a few years to a vessel's service life each time it is performed. The chief appeal of the wet procedure is that it can be performed periodically.

"I believe there is a good chance that we will see an American utility elect to perform vessel annealing in the near future," says EPRI's John Carey. "There is gathering momentum in this country to demonstrate, at least on an engineering level, that annealing is a feasible and practical option for managing vessel embrittlement." He adds that EPRI, the NRC, and DOE's Sandia National Laboratories are initiating a cooperative research effort to develop the annealing option.

In meeting a utility's longer-term objectives for resource planning, it may be necessary to investigate more-permanent, longer-lasting fixes instead of building a new plant to replace the capacity of an existing plant. In this case, replacement of the major components may be considered, and "that includes the pressure vessel," says Carey. No nuclear plant in the world has replaced its reactor vessel, but some 17 plants here and abroad have replaced large steam generators over the last decade—a task researchers say is not that different from replacing a vessel. Early EPRI plant life extension studies at the start of the 1980s concluded that vessel replacement was a viable option. The potential scope and cost of the job was estimated in these studies.

To be sure, vessel replacement would be a capital-intensive, labor-intensive, and occupational radiation exposure–intensive operation. But for a plant with otherwise favorable operating economics and the potential for a 20-year operating license extension, the cost might be acceptable, all things considered. "It's very likely that a utility could come out ahead by replacing a vessel and getting another 20–30 years of service from a plant, compared with building a new one," says Carey. □

management program, and we've made a lot of upgrades since our shutdown," she says. "We want to maintain the good condition of the plant after all the work we did."

Typically, when the subject of life-cycle management is raised, says Staudinger, "I imagine the most difficult question for most utilities out there is, why now? Why today? Why not 10 years from now or 20 years from now? If your license expires in 2000, the answer is easy. But for us, why not wait until 2010 to do any work? The answers we came up with are the desire to maintain the good material condition of the plant, to begin an aging-management program as soon as practical, and to improve short-term earnings. Also, we feel we're going to need a fair amount of time to make a decision about whether and how to replace our 880 MW of net demonstrated capacity."

Staudinger says that according to her preliminary analysis, operating Davis-Besse beyond the current license term looks to be about $60 million a year cheaper than the next most economically attractive generating option: installing new gas-fired, combined-cycle capacity. But, echoing the results of studies by EPRI and others, that estimate depends on containing the nuclear unit's O&M costs and outage times and avoiding the need for replacement power.

"The challenge is to get hold of and contain O&M costs," says Staudinger. "Fortunately for us, the picture at Davis-Besse has been improving steadily since our 1985 outage, so our O&M costs have been coming down. And that's another reason we want to adopt life-cycle management. If we can keep those O&M costs down, continue to keep the fuel costs low, and hold ourselves to a reasonably low level of capital cost, even a combined-cycle plant can't touch us on a future cost-of-capacity basis." ■

This article was written by Taylor Moore. Background information was provided by John Carey and Melvin Lapides, Nuclear Power Division.

TECH TRANSFER NEWS

Trauma Center Pioneers Electrical Burn Treatment

The country's first trauma program for the treatment of limb- or life-threatening injuries caused by contact with high-voltage electricity was recently begun at the University of Chicago Medical Center (UCMC) in collaboration with EPRI and other utility sponsors. Each year, several thousand people—many of them utility employees, electricians, and children—are seriously injured by contact with high-voltage systems. Lightning is another major cause of electrical injury, which may lead to progressive, deep tissue damage over weeks or months.

The UCMC program will apply and build on the results of recent EPRI-sponsored research that has yielded improved diagnostic tools and therapeutic strategies for reducing electrically induced tissue damage. The new treatment program is expected to save lives and prevent disabilities, according to Dr. Walter Weyzen, EPRI project manager for occupational health. "Currently, more than 85% of people suffering from electrical trauma requiring hospitalization are injured to the point that they can never return to work," says Weyzen. "The treatment being pioneered at UCMC offers significant new hope for future electrical burn victims."

New diagnostic tools that are under development include electrophysiological mapping of peripheral nerve injury with positron-emission-computed tomography and magnetic resonance imaging. These allow medical specialists to detect the extent and pattern of injury in time to implement therapeutic procedures that can limit the extent of irreparable tissue damage.

Dr. Raphael Lee, a physician and plastic surgeon specializing in electrical injuries who also holds a PhD in electrical engineering, is the director of UCMC's Electrical Trauma Program. "To our knowledge, there is no other burn center in the United States or Canada with the capability in place to distinctly focus on electrical injury victims as opposed to burn victims in general. If we can accurately quantify the extent and identify the location of the damage, we can surgically and medically optimize the chance for limb or victim survival," says Lee.

The UCMC program makes use of the University of Chicago Aeromedical Network for rapid transport of critical-care patients. UCAN-affiliated aircraft can deliver electrical trauma victims to a UCMC rooftop helipad from most locations in the United States within six hours. The Electrical Trauma Program's resources also include a multidisciplinary team of surgeons, radiologists, critical-care nurses, and researchers in biophysics, biochemistry, and molecular dynamics.

In addition to developing diagnostic procedures, the UCMC program employs a full-time staff of scientists working exclusively on techniques for treating electrical injuries; the center is planning a clinical research effort to test the efficacy of several new drugs. The diagnostic tools and therapeutic strategies come from research sponsored by EPRI and several utilities over the past five years at the Massachusetts Institute of Technology, where Dr. Lee previously served on the faculty (holding a joint appointment there and at the Harvard University Medical School). MIT professors Ernest Cravalho and Dr. Mehmet Toner have been coinvestigators in the work with Lee since 1988. Lee transferred to UCMC in 1989, and collaborative research on the fundamentals of electrical and thermal injuries continues at both institutions.

In addition to EPRI, other utility organizations that have sponsored this research include Boston Edison, Eastern Utilities Associates, the Empire State Electric Energy Research Corporation, Northeast Utilities Service Company, Pacific Gas and Electric, Pennsylvania Power & Light, Public Service Company of Oklahoma, and Public Service Electric & Gas.

For more information about the UCMC Electrical Trauma Program, contact Dr. Raphael Lee, (312) 702-6302. ■ *EPRI Contact: Dr. Walter Weyzen, (415) 855-2175*

EPRINET Wins First Prize in SIM Competition

A paper describing EPRI's electronic communications and information network—EPRINET™—has been awarded first prize in an international competition sponsored by the Society for Information Management (SIM), an organization of 4000 information systems executives in 35 countries. The competition honors outstanding achievements implementing "cutting-edge information systems applications in a real-world environment." Previous first-prize winners in the competition have included Xerox, American Telephone & Telegraph, and the cabinet of Egypt.

The award, made at the SIM annual convention in October, was accepted on behalf of EPRI by the paper's senior author, Marina Mann, director of the Information Technology Division. Coauthors of the paper, "EPRINET: Leveraging Knowledge in the Electric Utility Industry," were Richard Rudman, EPRI senior vice president for business operations; Thomas Jenckes, manager of technology transfer at Pacific Gas and Electric; and Barbara McNurlin, an information systems writer.

The EPRINET paper describes the vision and details of how EPRI is responding to the challenges posed by the enormous amount of information from sponsored research. "EPRI has a tremendous wealth of knowledge that can really make a difference for the utility industry," comments Mann. "The EPRINET system—with global, 24-hour access—allows us to leverage the expertise of EPRI's staff, making it broadly and instantly available as a strategic business resource for our members."

EPRINET is unusual among electronic information systems in the breadth of its capabilities: it offers not only technical information, news, and catalog services but also electronic mail connections between users, interactive special-interest forums, file transfer services, and direct ordering of EPRI reports. According to Donald Marchand, dean of the School of Information Studies at Syracuse University and chairman of the 1991 SIM awards committee, "The EPRINET information system stands out not only because it was well marketed as it developed but also because of its innovative packaging and information services, which make use of several types of on-line and off-line technologies to provide maximum flexibility for the user community." ■ *EPRI Contact: Marina Mann, (415) 855-2536*

Emissions Trading Simulation Laboratory

Last year's revision of the Clean Air Act gives utilities the flexibility of trading emissions allowances in meeting sulfur dioxide reduction targets. The Chicago Board of Trade recently announced plans to establish a market for emissions allowances, beginning in 1993. Allowance trading could reduce compliance costs by billions of dollars, but it will also complicate utility planning and operations. To help utilities and others better understand the implications of such trading, EPRI is developing an emissions trading simulation laboratory that will realistically represent the formation of an SO_2 emissions allowance market under a variety of scenarios. The goal is to build awareness among utility staffs about how the market will work and about potential problems that could affect its formation or performance.

The simulation laboratory, now being packaged for independent application by utilities, involves the use of spreadsheet computer software by 6 to 10 participants in a session. Each participant is given a simulated utility to operate under controlled conditions over three time periods—before the new compliance requirements take effect and during Phases 1 and 2 of the revised Clean Air Act. The software will calculate each utility's costs and how those change as participants decide which of their generating plants to run (each utility has five plants) and whether and how to control sulfur emissions from each plant during the two compliance periods. Control options include switching to low-sulfur coal and installing flue gas desulfurization scrubbers.

"Each participant's goal is to meet a specified demand for electricity at the lowest cost, but in doing so, they must end up with emissions allowances at least equal to the total emissions from their operating plants. They can accomplish this either by reducing emissions or by purchasing allowances from other participants," explains Gordon Hester, a project manager in EPRI's Integrated Energy Systems Division.

Participants attempt to reduce their utilities' compliance costs by making profitable buy and sell trades with each other in both bulk power and emissions allowances. A trade's profitability will depend on how a specific participant's generation and SO_2 control costs compare with those of other utilities in the simulation and the price at which the trade is made. At the conclusion of a laboratory session, participants compare their results against an optimal market result calculated in advance. "The six simulation sessions conducted to date have been lively and interesting, and many participants have actually matched the market solution," says Hester. "The sessions have been particularly effective in demonstrating in realistic terms how people competing against each other can end up helping each other to lower their costs. The sessions have also demonstrated the complexity of interactions between the bulk power market and the emissions allowance market created by the new law."

Among the insights gained from experience with the laboratory so far, Hester says, are that people trading in their own self-interest can reduce the overall cost of meeting emissions reduction targets and of operating power systems; that achieving such savings is aided by access to timely information on market transactions; that there may be a hidden cost of less savings from bulk power transactions during the compliance periods; and that new analytical approaches based on marginal-cost comparisons will help utility planners to better evaluate compliance strategies in the new market.

The laboratory package, expected to be available to utilities this November, will have two parts: a notebook with instructions on how to set up and conduct a trading session, and the software for simulating the utilities and calculating compliance costs. Future modifications may enable investigation of specific aspects of the emissions allowance market, such as how it interacts with the bulk power market and with the fuel procurement process, and how utilities can make optimal scrubber investment decisions in the face of market uncertainties. ■ *EPRI Contact: Gordon Hester, (415) 855-2696*

Power System Analysis

Steady-State Stability Monitor

by Rambabu Adapa, Electrical Systems Division

The electricity delivery system—the link between generation and the customer—must be reliable. Today, as power systems transfer more power than ever before, reliability is being challenged; some systems are pushed close to stability limits almost daily.

Power system stability is crucial to reliability. Stability analysis is conducted to determine whether the parts of a system will "hold together"—not only under normal operating conditions but also after small disturbances, such as load fluctuations, and large disturbances, such as transmission system faults.

Existing software

Power system analysis software can model power systems under the full range of normal and transient conditions. For example, users can model high-speed electromagnetic transients—which generally last only fractions of a second—by using the Electromagnetic Transients Program (EMTP), jointly developed by EPRI and the EMTP Development Coordination Group. Transients caused by lightning, line faults, substation switching functions, and other events along a utility network must be taken into account both in choosing equipment ratings and in setting power system operating parameters.

To analyze large-signal transients lasting a few seconds to a few minutes after a major disturbance, utilities can use EPRI's Extended Transient–Midterm Stability Program (ETMSP). Filling the gap between short-term and long-term dynamics, ETMSP helps system planners simulate power system transients after the loss of a generator or a line and helps engineers design systems that can withstand such disturbances.

While EMTP and ETMSP address major disturbances to a power system, another EPRI product, the Small Signal Stability Program (SSSP), addresses system performance when there are small changes from a normal, steady-state operating point. Such low-frequency oscillations (small signals) can grow into destabilizing modes that disrupt the normal, smooth operation of a power system or even break it apart. Primarily an off-line planning tool, SSSP can be used by utilities to address dynamic response issues important in transmission planning, to design power system controllers and determine where to place them in a system, and to design modulating controls for dc links.

The challenge facing EPRI and the industry today is the need to monitor steady-state system performance on-line. Several factors, including the delay or cancellation of generation and transmission projects and the increase in generation by independent power producers, have resulted in greater demands on existing transmission systems. Hence utilities must operate their power systems closer to steady-state stability limits—a situation that requires fast, accurate on-line stability analysis tools. Although existing EPRI models can be used to evaluate steady-state stability offline, they were designed for planning purposes and their level of modeling detail precludes real-time use.

New software

In response to the need for on-line analysis capability, EPRI is developing the Steady-State Stability Monitor, now in the prototype stage. By using industry-proven approximation techniques, this software is fast enough to aid in

ABSTRACT *As transmission networks become more heavily loaded, control center operators must operate power systems closer to steady-state stability limits; however, conventional analysis methods and models are not fast enough to advise operators on-line when power systems approach these limits. EPRI is developing a computer program that uses intelligent simplifying assumptions in calculating steady-state stability. Now in the prototype stage, the Steady-State Stability Monitor will provide data to operators continuously, making it possible to operate closer to stability limits. This program is one of several software tools EPRI has produced to meet utilities' power system analysis needs.*

real-time control center dispatch. It is also sufficiently accurate to be used in operations planning.

Developed by SYDETECH (System Development Technologies, Inc.), the Steady-State Stability Monitor prototype indicates how close a power system is operating to its steady-state stability limit (Figure 1). It ranks generating units according to the risk they pose to reliable operation of the power system and provides additional data that operators can use in developing strategies for remedial action. For example, the software determines the maximum power that can safely be generated while maintaining an adequate steady-state stability reserve margin.

The Steady-State Stability Monitor prototype can be used either in an advisory mode or as a stability filter. In the advisory mode, it can function as an off-line, stand-alone tool with which planners or operators can perform steady-state stability calculations, review cases processed earlier, and examine power flow data. The software can also be upgraded to operate in the advisory mode in real time, either at regular intervals or upon operator request.

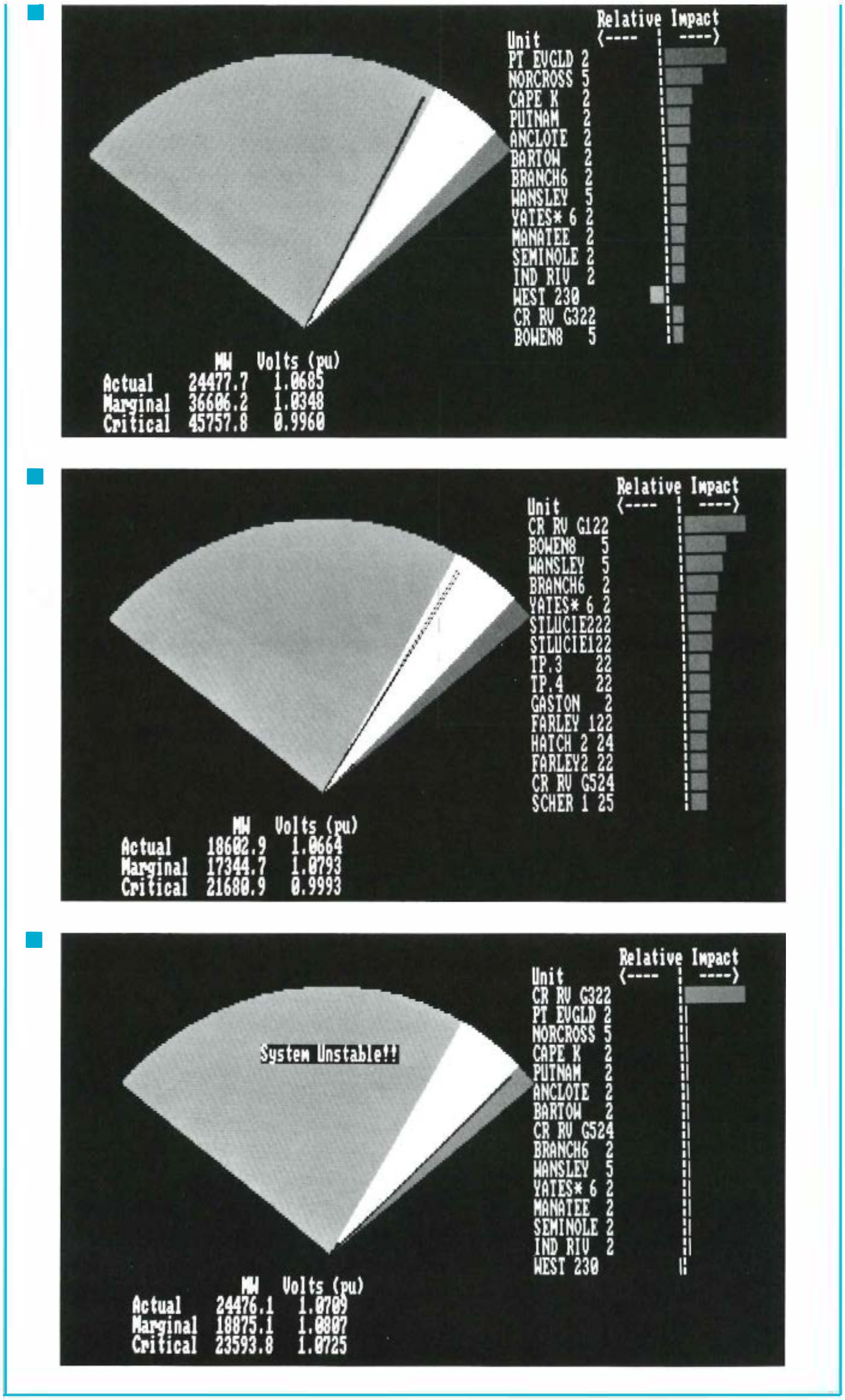
In the stability filter mode, the Steady-State Stability Monitor prototype can be used in conjunction with a security assessment system that performs contingency evaluations. This application enables security assessment systems (like EPRI's Static Security Enhancement System) to quickly identify prealarm states in which minor contingencies could lead to major disturbances.

Input data for the new software include generator parameters and a power flow base case. In the advisory mode, the power flow is either the real-time case computed by the state estimator and external model computation programs, or a study case used in operations planning for postulated future system conditions. In the stability filter mode, the power flow is the base case used for contingency simulations.

Making smart assumptions

The Steady-State Stability Monitor prototype addresses power system stability during gradual changes in load. Making an exact

Figure 1 The speedometer-like output of EPRI's Steady-State Stability Monitor prototype shows, in real time, how close a power system is operating to its steady-state stability limit. The needle registers the system's current status in one of three zones—stable operation (e.g., top screen), a warning area (middle screen), or unstable operation (bottom screen). The software also lists units according to their relative impact on system stability.



representation and detailed analysis of such states requires extensive data and is computationally intensive. Hence it is virtually impossible to conduct detailed stability simulations when a quick decision is needed.

Steady-state stability phenomena can, however, be modeled by making certain simplifying assumptions that increase the computational speed while maintaining adequate accuracy. A method that has been used in Europe makes such assumptions to provide quick solutions. Known as either Dimo nodal analysis or REI equivalencing, the method greatly simplifies steady-state stability computations by first replacing loads with constant admittances and then delinearizing them and grouping them into a single-load equivalent bus.

Such an equivalent enables planners to study an entire system as if its MW and MVAR load were concentrated on a single bus. Yet this method does not eliminate generators; it retains their individual identities and represents them through constant transient reactances, providing reduced models that are virtually exact.

The implementation of this method in the Steady-State Stability Monitor prototype is very fast, even for large systems, and requires few data, making it attractive when quick steady-state stability checks are needed. The user interface consists of clearly designed menus, windows, data forms, and help facilities that make the software easy to execute, even for first-time users. The software has been designed for speed, portability, and small size and is supported by extensive documentation.

On-line benefits

By allowing power systems to be operated closer to their stability limits, the Steady-State Stability Monitor prototype has the potential to save utilities millions of dollars in deferred investments and increased power sales. Using information provided by the software, utilities can devise new and effective strategies to:

- Supply more load and sell more power without adding new generation and transmission facilities
- Delay costly investments until system expansion is really needed
- Reduce the number and size of emergency power purchases
- Identify (through remedial action scenarios) units that can degrade the current system state and units that can make the greatest contribution to improved stability
- Improve the contingency screening process

To date, SYDETECH has developed a DOS version of the Steady-State Stability Monitor prototype under a cofunding agreement (RP2473-43) with EPRI and Southern Company Services. The Southern Company is evaluating the software, most recently in a study of its system's Florida-Georgia interconnection. The early test results are encouraging and confirm the ability of the Steady-State Stability Monitor prototype to instantly identify system states that are, or can become, unstable.

Nuclear Plant Training and Diagnostics

Improving Instrument Air System Performance

by Harvey Wyckoff, Nuclear Power Division

Historically, air supplies have been among the least glamorous systems in power plants. Air systems at nuclear plants provide support to front-line systems and are generally classified as non-safety-grade. In fact, nuclear plant designs allow safe shutdown even if air pressure is lost. Components such as air-operated valves are designed to fail to a safe position (open, closed, or as is) upon loss of air. Components that must have uninterrupted pressure, such as those in safety systems, have backup sources—for example, accumulators, stored nitrogen, or a safety-grade air supply. Given this low profile and non-safety-grade status, it is not surprising that in terms of both design and operation, a plant's normal air systems have lower prior ity than the safety-grade front-line systems.

Nuclear power plants generally have two classes of air systems: instrument air and ser vice air. Instrument air systems provide high-quality air for safety- and non-safety-grade instruments and controls (e.g., operating valves and dampers). Service air systems support air-operated tools and meet other maintenance-related needs. Because of the nature of its use, service air (also called station air or plant air) is permitted to carry higher levels of contaminants than instrument air. It usually plays no role in the direct operation of the plant and hence is less critical.

Instrument air which at some plants is called control air, is attracting growing attention within the nuclear power industry and at EPRI. This air must be free of oil and particulates that could clog the fine passages of instruments and controls and could inhibit the movement of their working parts. Also, in order to avoid condensation in the system and the formation of rust, instrument air must have a very low moisture content. Moisture can quickly render an air system and the equipment it supplies unreliable, if not inoperable.

The growing interest in instrument air systems has come directly from plant personnel, some of whom feel that the current balance between problem prevention and problem correction may not be optimal. As a result, plants appear ready to give instrument air systems greater attention and to increase preventive maintenance. The goal is to reduce the overall effort and cost of keeping instrument air systems operating reliably.

Given this willingness to pay more attention to instrument air, the next step is to identify practices that have proved to be, or show promise of being, effective in improving air system reliability and reducing overall costs. EPRI is developing information and products that can help utilities in this effort.

ABSTRACT *Instrument air systems support the front-line operating systems at nuclear power plants by providing high-quality air to instruments and controls. Since plants are designed so that this air is not needed for achieving safe shutdown, instrument air systems do not have to be safety-grade. From the standpoint of electricity production, however, it is vital that they be as reliable and economical as possible. EPRI is developing information and products to help utilities improve the performance of these complex systems. Three reference reports are already available, and a new computer-based system, the Instrument Air Diagnostic Advisor, is nearing completion. Intended to be both a training and a diagnostic tool, IADA can help plant personnel consider the full range of possible problems and corrective actions.*

How instrument air systems work

Instrument air systems are complex: they contain many components, most of which can malfunction or fail. As shown in Figure 1, air enters the system through an inlet filter, which removes dust and other large particles. A compressor increases the air pressure to about 110 psig, and an aftercooler then removes the heat generated during compression. (Multistage compressors use intercoolers to remove heat between compression stages.) An air receiver located downstream of the compressor and the aftercooler acts as a buffer, supplying air during demand surges and minimizing pressure fluctuations.

From the receiver, the air flows through a dryer prefilter—which removes water, oil, and particulates—and then through a dryer, which removes water vapor. Two types of dryers are common. A refrigerant dryer cools the air to about 35°F (35°F dewpoint) to condense out moisture. A desiccant dryer sends the air through a bed of special material, which absorbs water from the air. Most nuclear plants use desiccant dryers for instrument air. Each desiccant dryer has two beds: one dries the

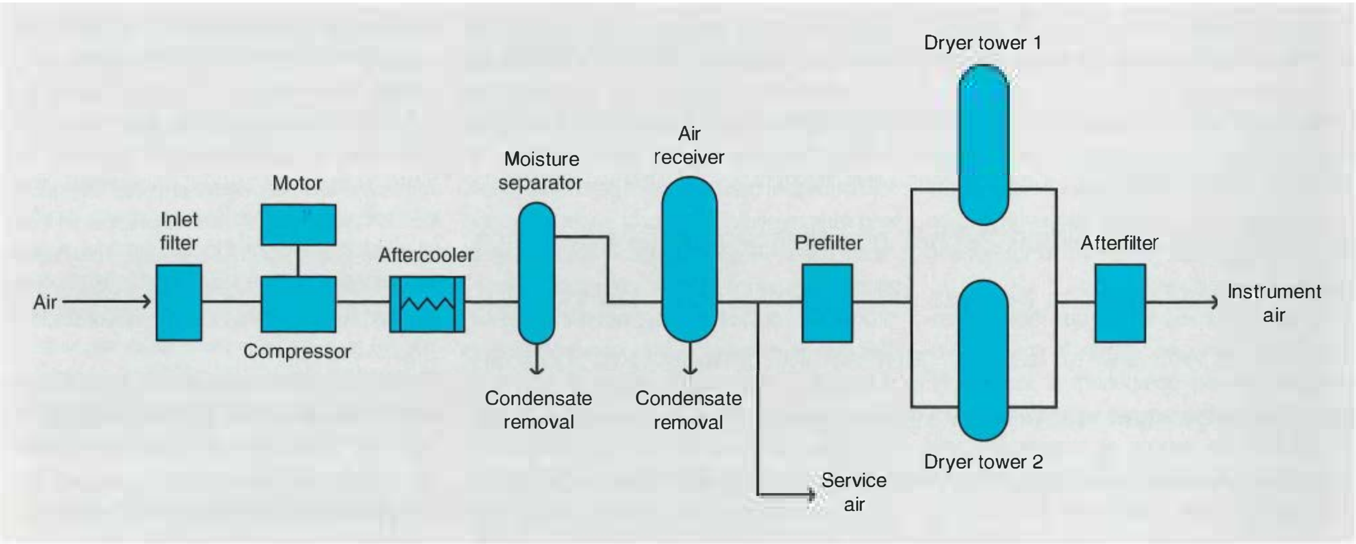


Figure 1 Simplified instrument air system. Typically these systems, which supply high-quality air to plant instruments and controls, include redundant components to ensure availability.

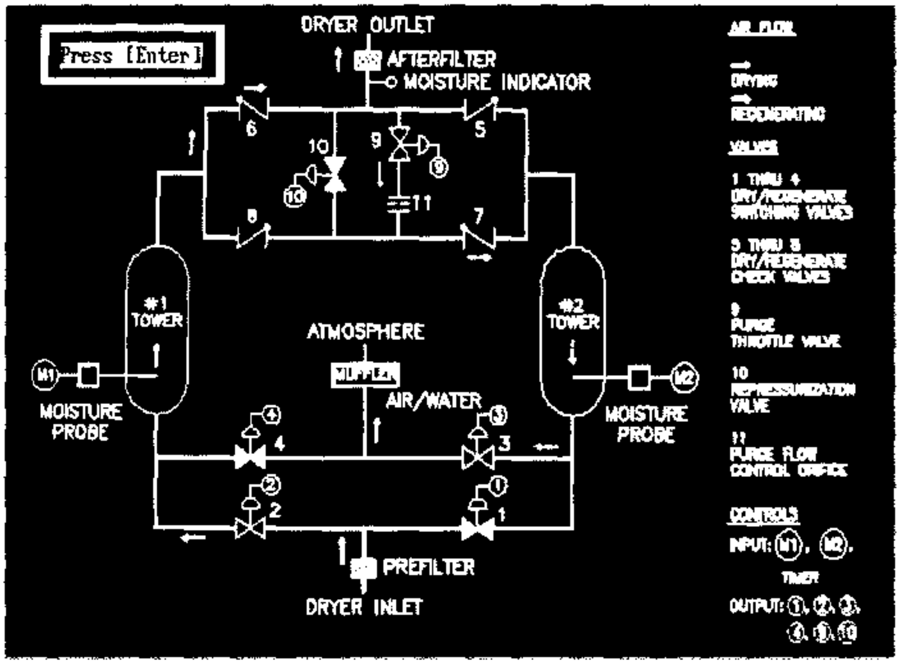


Figure 2 IADA screen display. Given the symptoms of a problem, IADA identifies possible causes and suggests corrective actions. It can serve as a training aid as well as a diagnostic tool.

air while the other is being regenerated (either by heating or by sending a flow of purge air through it to remove accumulated moisture). Desiccant dryers provide dewpoints well below 0°F, and many nuclear plants with desiccant dryers specify design dewpoints of about −40°F. Air systems with desiccant dryers have afterfilters to remove fine particles of the desiccant material, which can inadvertently be carried out of the dryer.

The clean, dry, pressurized air exiting the afterfilters enters a distribution network, which carries it to individual components. Some components have filter-regulators in the air piping just upstream to filter the air further and reduce the pressure.

Typical instrument air systems have redundant compressors and dryers to ensure availability when one component is inoperable. Also, most instrument air systems are connected with the service air system. In some cases, the same compressors are used for both service and instrument air. In other cases, the instrument air has its own compressors, and the service air compressors act as backups.

Reference reports

EPRI has published three reports that are useful for utilities seeking to improve their instrument air systems. In 1988 the Nuclear Safety Analysis Center (NSAC) issued *Pneumatic Systems and Nuclear Plant Safety* (NSAC-128), which summarizes 200 air-system-related problems experienced at nuclear plants. Many of these problems resulted in a partial or complete loss of instrument air. Offering a big picture of the kinds of problems affecting air system performance, this report provides information that can help plant personnel select and rank remedies. Of equal importance, the report assembles in one document five sets of recommendations from a variety of industry groups for improving air system performance. The report concludes that contamination is the cause of the largest number of air system problems.

In 1990 NSAC issued *Maintaining Operability of Nuclear Plant Air Systems* (NSAC-137), which summarizes the lessons utilities have learned in responding to the Nuclear Regulatory Commission's Generic Letter 88-14, "Instrument Air System Problems Affecting Safety-Related Equipment." The report includes recommendations on maintaining instrument air system operability.

In late 1990 EPRI's Nuclear Maintenance Applications Center released *Instrument Air Systems—A Guide for Power Plant Maintenance Personnel.* This reference manual is designed to help maintenance personnel understand, evaluate, and solve instrument air system problems. It is also useful as a training guide for maintenance personnel and system engineers. The manual describes instrument air systems and their components in detail, surveys common air system problems and their causes, and suggests ways to maintain air systems so as to meet the quality requirements of a nuclear plant.

IADA

A new EPRI product to help in training and problem diagnosis will be available by the end of the year. The Instrument Air Diagnostic Advisor, or IADA, is a menu-driven program that runs on IBM-compatible personal computers. When given the symptoms of an air system problem, IADA first identifies additional information needed from the user and then analyzes the data to determine possible causes and suggest corrective actions.

Input to IADA includes symptoms of the problem, observations and measurements, and the user's independent evaluations and judgments. Users enter their insights by selecting from several diagnostic paths that IADA offers. IADA's output includes the probable cause of the instrument air problem and recommended corrective actions. The output can be printed as a summary report and can also be stored for future review. This feature allows users to analyze IADA diagnoses for trends and thus helps them uncover underlying causes.

IADA has a plant parameters database that utilities can customize with plant-specific design and operating data. If no plant-specific air system data are input, the program uses parameters for a typical nuclear plant instrument air system. In addition to providing diagnostic guidance, IADA includes a notebook capability that allows users to record air system operation and maintenance experience for future reference and trending.

The IADA user interface has an easy-to-use menu style and many other features based on the EPRIGEMS™ format. The Advisor feature of IADA allows users to interrupt a current investigation to revisit a previous case. The View feature provides access to the information recorded in the plant experience notebooks. View also includes a cross-referenced glossary of instrument air terminology and permits viewing of IADA investigation report files and IADA drawings. The Tools feature allows users to edit the plant experience notebooks and review and edit the plant parameters database. The File feature provides an on-line description of IADA and the capability to print investigation report files, notebooks, and databases.

Interactive program help is always available when using IADA, as is access to air system schematics, the glossary, and the plant experience notebooks. In addition, IADA's Note feature allows a user to make entries in a notepad provided for each screen. Through comments in these notepads, users can provide each other with guidance on various parts of the system. Figure 2 shows an example of an IADA screen display during a diagnostic run.

Because of the complexity of instrument air systems, a malfunction or failure may be difficult to diagnose; a variety of failures may produce very similar symptoms. IADA's deductive reasoning capability and extensive knowledge base can help in training personnel and in tracking down air system problems. For further information, contact Harvey Wyckoff at (415) 855-2393 or Ray Torok at (415) 855-2776.

Fossil Power Plants

Using Ice Storage to Enhance Gas Turbine Capacity

by Henry Schreiber, Generation and Storage Division

ABSTRACT *A gas turbine's power output increases with the mass flow rate of air through the engine. Peaking gas turbines provide capacity when hot summer weather creates a large residential and commercial air conditioning load. But hot, humid air is less dense than cold, dry air, thus reducing a gas turbine's capacity when it is most needed. Cooling and dehumidifying the gas turbine inlet air by using stored ice made with cheap, off-peak power can improve gas turbine capacity and efficiency during peak demand periods. A project to demonstrate this technology is under way.*

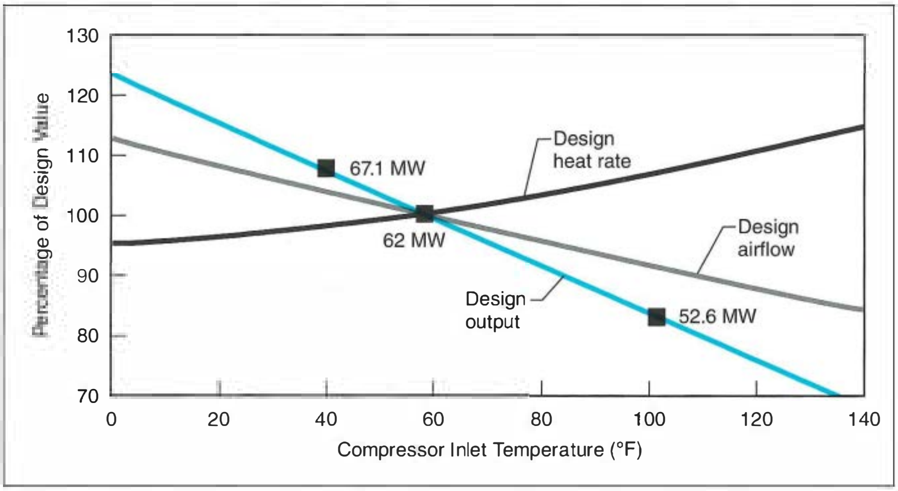
The capacity of a gas turbine is directly related to the mass flow rate of the air entering the compressor. At its maximum-capacity inlet guide vane setting, a gas turbine compressor essentially ingests a constant volume of air per unit of time at a given ambient condition. An increase or decrease in air density at the compressor inlet (bell mouth) therefore has a directly proportional effect on engine mass flow and hence capacity.

Manufacturers generally rate gas turbine performance at the internationally accepted standard conditions of 15°C (59°F) ambient temperature, 101.3 kPa (14.7 psia) atmospheric pressure, and 60% relative humidity. Figure 1 shows the effects of compressor intake air temperature on engine capacity and heat rate for a General Electric MS7001B gas turbine generator, nominally rated at 62 MW. Cooling and dehumidifying the compressor intake air on a hot summer afternoon would result in a large increase in power and efficiency.

In 1990 Nebraska's Lincoln Electric System (LES) asked EPRI for technical support in designing and building a demonstration thermal energy storage–based system to increase the peaking capacity of its Rokeby unit, which features a simple-cycle General Electric MS7001B gas turbine generator. This unit was originally equipped with an evaporative system to cool the inlet air by drawing it through water-wetted media ahead of the bell mouth.

Evaporative cooling lowers the temperature of the intake air by a nominally adiabatic process. There are two major limitations to its efficacy, however. First, the temperature of the cooled air can at best only approach the wet-bulb temperature. Second, the process of

Figure 1 Effects of compressor inlet air temperature on the performance of a gas turbine nominally rated at 62 MW. A project is under way to demonstrate a thermal energy storage–based system designed to cool inlet air from 101.5° to 40°F, thereby increasing the engine airflow rate and boosting output from 52.6 to 67.1 MW.



evaporative cooling humidifies the air beyond its ambient absolute humidity. This humidification is counterproductive in that water vapor is less dense than air at the same temperature and pressure. Hence the density increase due to the lower temperature of the air–water vapor mixture entering the bell mouth is offset in part by the density decrease due to the greater amount of water vapor present. The thermal energy storage–based process selected by LES, in contrast, removes both heat and water from the incoming air–water vapor mixture. Both of these effects tend to increase the mixture's density and consequently the engine capacity. Figure 2 illustrates the two cooling processes.

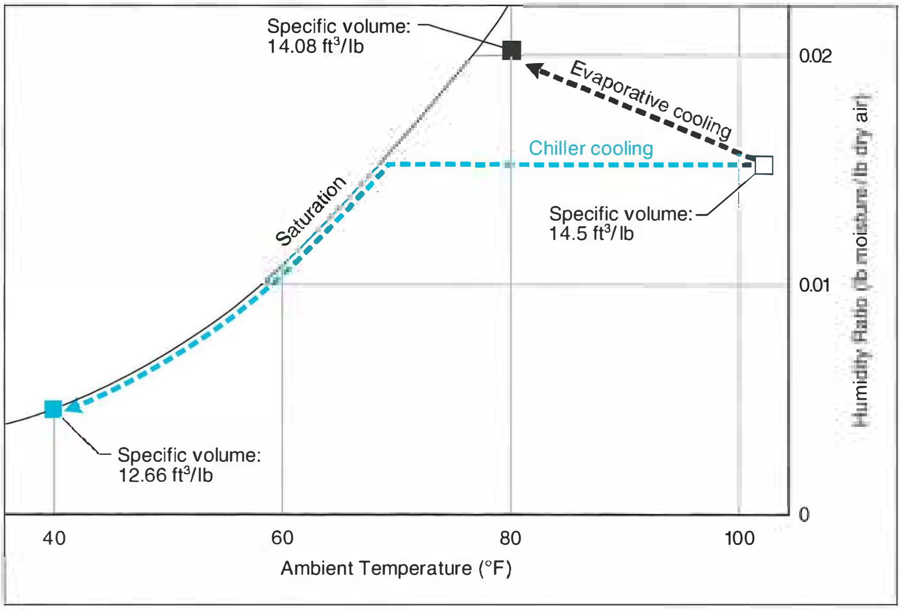


Figure 2 This graph of the properties of air-water mixtures shows the relative effects of evaporative cooling and chiller cooling on air density. The chiller system, based on thermal energy storage, dehumidifies as well as cools the air, thereby increasing its density in two ways.

LES undertook this project because it will receive a direct financial benefit from its power pool if it can demonstrate higher instantaneous peaking capacity. Since the objective is to maximize the instantaneous capacity, the system design minimizes parasitic electrical loads and other performance penalties during turbine operation.

The system is designed to condition turbine intake air from 101.5°F and 34.5% relative humidity to 40°F and 100% relative humidity (see Figure 2). This results in a theoretical increase in gas turbine capacity from 52.6 MW (i.e., the capacity without evaporative cooling) to 67.1 MW, a 27.6% increase. The real net capacity increase will be slightly smaller because of the parasitic electrical load imposed by the two 5000-gal/min, 250-hp chilled-water circulating pumps, and because of the air intake pressure drop imposed by the finned-coil water-to-air heat exchanger through which the air to the compressor is drawn. The previously used evaporative cooler has been removed.

The relatively large electrical load for driving the refrigeration system that supplies the three ice-making machines (about 700 kW) is not parasitic, since ice will be made only when the gas turbine is not running. To provide the design-basis chilled-water capacity, ice will be made on a weekly cycle. The dispatch schedule calls for the gas turbine to run 4 hours each weekday afternoon, or 20 hours per week. The refrigeration and ice storage system is sized to meet this schedule at design ambient conditions by running 148 hours per week.

Sizing this system required engineering trade-offs between refrigeration system capacity and storage tank size. The final configuration, released for construction last spring, calls for a screw compressor–type ammonia refrigeration system with evaporative condensers. The ice storage tank is a cylindrical reinforced-concrete tank with a capacity of 1.1 million gallons. Three ice-making machines situated on its roof will discharge ice into the tank at the rate of 24.4 tons per hour. Another major engineering trade-off involved whether to use an open, air-wash heat exchanger, where the air passes directly through a water spray or wetted media, or a closed, extended-surface coil-type heat exchanger. The latter was chosen for economic and operating reasons.

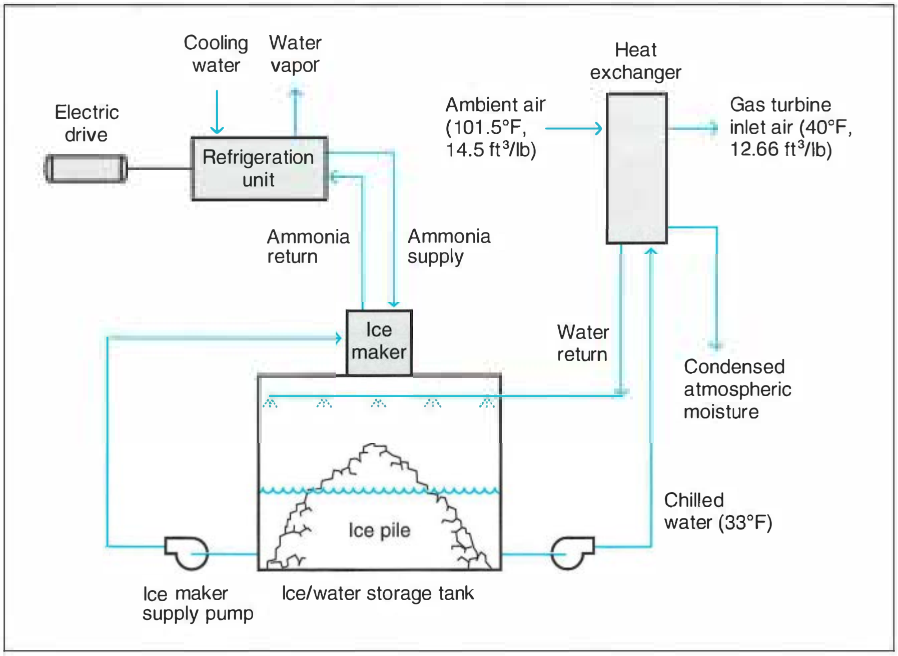
In designing the system, which is shown schematically in Figure 3, other potentially capacity-limiting conditions had to be addressed. It was necessary to analyze the potential thermal limitations of the air-cooled generator and transformer to ensure that they would not overheat when operating at 101.5°F ambient at an electrical load corresponding to 40°F ambient. An evaluation of the cost and complexity of adding an auxiliary cooling system to the generator and the transformer versus tolerating a slightly shorter economic life favored the latter. Accessory cooling and lube oil cooling were also addressed and were found to be adequate.

Design provisions had to be made to positively prevent icing at the engine air intake structure and bell mouth. Icing could lead to solids impacting the compressor blading, with consequent engine damage. It was determined that 40°F was the lowest safe temperature for air at saturation. An array of temperature sensors will provide closed-loop feedback control to throttle the flow of chilled water if the temperature of the air exiting the chilling coil drops below 40°F.

The design incorporates control interlocks to prevent cooling below 40°F when the ambient air temperature is below design conditions or during periods of reduced engine airflow, such as startup and shutdown. Another analysis addressed the thermal transient the engine would experience if its intake air temperature suddenly changed from 101.5° to 40°F or vice versa. Differential thermal expansion of the compressor rotor and stator had to be analyzed to ensure that there would be no rubbing of the compressor blading. To avoid distress due to dimensional change, it was decided to use a five-minute air cool-down ramp after the engine reaches full speed. Likewise the cooling system will be shut down along a five-minute ramp.

Another unique challenge involved the water supply and return system in the ice storage tank: it had to be designed to prevent the

Figure 3 In the gas turbine inlet air cooling system being demonstrated by Lincoln Electric System, ice made with off-peak power is stored and used to chill water that circulates through a heat exchanger. The denser air yielded by this system increases the gas turbine's peaking capacity.



circulating water from tunneling through the ice pile and exiting the tank prematurely, thereby decreasing the heat transfer capability. Also, controls to prevent rapid closure of the large circulating-water valves and thus prevent water hammer damage were considered. A design analysis was performed to ensure complete drainability of all pipe subject to freezing. The main ice storage tank was designed to be two-thirds buried so that it would not freeze in winter. No heaters were provided.

Construction is still under way as of this writing, so data on operating and maintenance economics are not available. At the beginning of the project, LES estimated a constructed cost of under $200 per kW of incremental capacity (between 52.6 and 67.1 MW). In contrast, new peaking gas turbine capacity has an installed cost of approximately $400 per kW and subjects the owner to new permitting procedures. The increase in gas turbine efficiency at the lower inlet air temperature produces fuel savings that tend to offset the off-peak electric energy cost of charging the ice storage tank.

EPRI's role in this project was to help LES develop the final ice storage and chilled-water system design concept through technical and economic evaluation of trade-offs. In addition, EPRI and its consultants performed technical studies and made recommendations regarding generator, transformer, and accessory cooling; closed versus open heat transfer to the compressor inlet air; and engine thermal transient and anti-icing design concepts. They also reviewed and commented on procurement and construction specifications and drawings.

When the system becomes operational, LES will collect operating and maintenance data (using an instrumentation and data acquisition system cofunded by EPRI) and will provide EPRI with this information. EPRI will prepare a final report that documents the design concepts, trade-off considerations, and operating and maintenance experience and costs. The report is expected to be published in December 1992, after one full summer of operation.

Low-Level Waste Research

by Carol Hornibrook, Nuclear Power Division

In late 1985, the U.S. Congress passed the Low-Level Radioactive Waste Policy Amendments Act. The new law directed states to take responsibility for locally generated radioactive waste, calling on each state either to build its own disposal site or to join a regional compact with other states to construct a joint disposal site. The act also authorizes compact regions and states with existing low-level waste (LLW) disposal sites to exclude from disposal any waste generated by utilities outside the compact region after December 31, 1992. As a result, the majority of nuclear utilities face the possibility that disposal facilities may not be available at that time.

The state of Michigan, with five nuclear plants, has been denied access to existing disposal sites. Moreover, the Midwest compact recently elected to exclude Michigan, which was serving as the host state—resulting in a major setback for that compact. The New York state legislature, recognizing the inevitable delays ahead, has approved $800,000 for research into 10-year storage options for LLW. Overall, of the 111 nuclear plants in the United States, 94 are located in states that appear to be making only moderate progress in developing new disposal sites.

The potential exclusion of most nuclear plants from existing disposal sites touches on all facets of radioactive waste management. It involves the generation of waste at the source, recovery and recycling operations, volume reduction through improved processing and packaging techniques, decontamination processes, on-site interim storage, disposal site criteria and technical considerations, and long-range environmental models for estimating doses to future generations.

As 1993 approaches, concern about on-site LLW storage and the development of new disposal sites is becoming acute. Since the unavailability of disposal sites could have a significant impact on many nuclear plants and since it affects a wide range of technical areas, this problem has become the focus of EPRI's Low-Level Waste Management Program.

ABSTRACT *Because of delays in the development of new low-level radioactive waste disposal sites, a majority of U.S. nuclear plants face exclusion from waste disposal sites beginning in 1993. As a result, utilities are investigating interim storage and alternative disposal solutions. EPRI's Low-Level Waste Management Program is responding to this need with a three-part research effort. The program will help remove technical obstacles to developing new disposal sites, provide guidelines on interim on-site storage, and develop waste management options that minimize dependence on disposal sites.*

To respond to concerns about disposal and storage, EPRI has developed two long-range goals in connection with this program: to ensure 100% disposal by the year 2000, and to help utilities reduce radioactive waste volumes 35% from 1990 levels by 1996. All of the related issues have been organized into three major LLW research areas. EPRI's approach to meeting its long-range goals is shaped by these three areas, each with its own challenges and objectives:

- LLW disposal site development—help utilities and states remove technical obstacles to developing new disposal sites
- On-site LLW storage—provide technical solutions for interim on-site storage
- Alternative LLW management approaches—develop waste management options that minimize dependence on disposal sites

Developing new disposal sites

The technical obstacles that could potentially delay disposal site development relate to the accuracy of source terms and environmental transport models for the long-lived radionuclides listed in 10CFR61. Further research is necessary to assess the source terms for these radionuclides and to evaluate the potential transport of radioactivity via groundwater. EPRI will support efforts in each of these areas.

Source term research will aim to improve the accuracy of curie content determinations for difficult-to-measure radionuclides, particularly iodine-129. Research on environmental models will aim to develop more-accurate representations of the pathways for human uptake of carbon-14 and iodine-129.

For the protection of future intruders, further evaluation of the need for and benefit of expensive existing stabilization requirements is warranted. Research on waste forms and engineered barriers will evaluate capabilities for meeting current stabilization requirements; it will also address proposed new requirements, which are even more stringent. Alternative disposal configurations may be more effective in reducing potential exposures, and work is necessary to evaluate and develop such options. Therefore, the EPRI program will also investigate possible modifications in trench design, waste placement, and facility configuration that could enhance the protection of potential intruders.

On-site LLW storage

It is not realistic to assume that all the required new disposal sites will be completed and in operation by 1993. Nor is it likely that the existing compact regions will continue to accept low-level waste from all nuclear plants. A more prudent assumption is that the majority of nuclear plants will have to implement plans for the interim storage of LLW until an alternative waste management mechanism or a location for permanent disposal becomes available.

If no disposal sites or off-site interim storage options are available, utilities will have to store LLW on-site at one or more of their nuclear stations. However, on-site storage beyond a few years could present a number of technical problems related to packaging and waste form. And the necessary term of storage is unknown. For many utilities, a nearby disposal site may be only a few years away. For other utilities, disposal sites may not be available before the end of the century. Therefore, guidelines are needed to ensure safe storage of LLW for extended periods of time.

In seeking to mitigate the impact of these technical storage issues, the EPRI program will take three approaches:

- Investigate options for minimizing waste generation so as to optimize storage capacities, minimize the liabilities of on-site storage, and reduce storage costs.
- Improve processing techniques in order to further decrease the volume of waste that must be stored and eventually disposed of.
- Develop on-site storage guidelines providing utilities with generic guidance that can easily be tailored to meet the needs of individual nuclear facilities. These guidelines will focus on regulatory and licensing issues, storage facility design, waste characterization and volume estimates, containers, waste forms, and decontamination wastes.

Reducing disposal site dependence

The most desirable situation for utilities would be to eliminate all dependence on disposal sites. Although disposal regulations make this objective impractical, utilities can certainly reduce their dependence by decreasing the volume of LLW to be disposed of and by striving to reduce the curie content of the waste they generate.

One part of the ongoing effort in this area will emphasize aggressive volume reduction techniques. Researchers will seek to identify high-technology solutions and equipment for reducing the industry's contribution to commercial LLW.

Methods to be investigated include resin destruction, selective ion exchange, resin decontamination, and new filtration techniques. Such processes could dramatically reduce the final packaged volume that utilities must ship for disposal at LLW facilities.

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Customer Systems		
Marketing Infrastructure of Efficient End-Use Technologies: A Case Study Approach (RP2788-42)	$60,000 5 months	Barakat & Chamberlin/ *C. Gellings*
MarketTREK Case Study With Pacific Gas and Electric (RP2864-4)	$176,000 8 months	Research Triangle Institute/ *T. Henneberger*
Cost-Effective Heat Pump With Dedicated Water Heating Mode (RP2892-19)	$130,000 29 months	Nordyne/ *A. Lannus*
Advanced Transportation Systems Technical Support (RP3025-2)	$103,800 12 months	Bevilacqua-Knight/ *L. O'Connell*
COMTECH Enhancements and Support (RP3141-9)	$160,200 12 months	Regional Economic Research/ *K. Johnson*
Machinery, Transportation, and Equipment Fabrication (RP3244-2)	$969,600 24 months	Battelle Memorial Institute/ *P. McDonough*
Electric Vehicle Battery and Associated Component Testing (RP3271-2)	$378,800 12 months	Electrotek Concepts/ *R. Swaroop*
Extended-Range Electric G-Van (RP3299-1)	$61,900 6 months	McKee Engineering Corp./ *G. Purcell*
Electrical Systems		
Flexible AC Transmission System (FACTS): Implementation and Demonstration of Adaptive Out-of-Step Protection (RP3022-10)	$292,000 24 months	Virginia Polytechnic Institute and State University/ *S. Nilsson*
Application of a Static-Phase-Shifting Transformer on the Minnesota Power–Ontario Hydro 115-kV Interface (RP3022-12)	$77,200 8 months	Ontario Hydro/ *M. Lauby*
Evaluation of FACTS Technologies on the Southern Electric Transmission System (RP3022-14)	$51,400 9 months	Southern Company Services/ *M. Lauby*
Power System Dynamic Security Analysis Using Artificial Intelligence Techniques: Phase 1, Feasibility (RP3103-2)	$355,100 18 months	ABB Systems Control/ *G. Cauley*
HVDC Study Tools Handbook (RP3158-1)	$426,300 23 months	General Electric Co./ *S. Wright*
Flow Electrification of Liquid-Insulated Electrical Equipment (RP3334-1)	$300,000 24 months	Massachusetts Institute of Technology/ *S. Lindgren*
Electrokinetic Effects in Power Transformers (RP3334-2)	$111,400 24 months	Rensselaer Polytechnic Institute/ *S. Lindgren*
Reduction of Magnetic Fields Associated With Power Delivery (RP3335-1)	$100,000 9 months	ESEERCO/ *G. Rauch*
Magnetic Field Management Research at the High Voltage Transmission Research Center (RP3335-2)	$208,200 12 months	General Electric Co./ *G. Rauch*
Microscopic and Mechanical Investigation of the Interfacial Bond Strength of Polypropylene Laminates (RP7880-12)	$100,100 19 months	University of Akron/ *B. Bernstein*
Underground Transmission Workstation (RP7913-1)	$926,000 31 months	Power Technologies/ *T. Rodenbaugh*
Improved XLPE-Insulated Cable (RP7917-1)	$1,317,000 36 months	Cable Technology Laboratories/ *F. Garcia*
Environment		
AC Field Exposure Study (RP2966-7)	$231,400 24 months	Enertech Consultants/ *S. Sussman*
Management Coordination for the Tropospheric Model Development and Evaluation Project (RP3189-1)	$541,800 35 months	Sigma Research Corp./ *A. Hansen*
Improved Methods for Air Pollution Studies (RP3253-1)	$965,000 36 months	Roth Associates/ *A. Silvers*
Exploratory and Applied Research		
Effect of Hydrogen on Amorphous Silicon Material and Device Stability (RP8001-9)	$102,500 23 months	University of Delaware/ *T. Peterson*
Development of Bragg Grating Sensors for Electric Utility Applications (RP8004-9)	$261,800 47 months	United Technologies Corp./ *J. Weiss*
Theoretical Study of the Transport Properties of the Oxide Superconductors (RP8009-18)	$171,000 17 months	University of California, Santa Barbara/ *T. Schneider*
Generation and Storage		
Cycle Chemistry Guidelines for Fluidized-Bed Combustion Plants (RP979-29)	$127,800 9 months	Sargent & Lundy/ *B. Dooley*
Strongly Textured Ti-6Al-4V 40-Inch Bimodal Blades (RP1264-5)	$177,200 8 months	Bohler GmbH/ *T. McCloskey*
Innovative Systems for Waste Isolation and Containment (RP1457-10)	$454,400 38 months	Radian Corp./ *M. McLearn*
Coal Ash Behavior in Reducing Environments (RP1654-51)	$90,000 36 months	University of North Dakota/ *W. Bakker*
FGD Sparing Analysis System (RP1872-7)	$51,300 13 months	Arinc Research Corp./ *C. Dene*
Biofouling R&D Technical Support (RP2300-20)	$95,800 22 months	Marine Biocontrol Corp./ *W. Micheletti*
Development of High-Concentration Silicon Photovoltaic Cell (RP2703-4)	$2,833,000 41 months	Sunpower Corp./ *F. Goodman*
Cycle Chemistry Improvement Demonstration Program for Fossil Plants (RP2712-11)	$212,500 21 months	General Physics Corp./ *B. Dooley*
Behavior of Sodium Phosphates Under Boiler Conditions (RP2712-12)	$217,300 16 months	ABB Combustion Engineering/ *B. Dooley*
Nuclear Power		
Maintenance Guide for Solenoid Valves (RP2814-36)	$68,000 11 months	Strategic Technology and Resources/ *V. Varma*
Motor-Operated Butterfly Valve Operation Forces Evaluation (RP2814-41)	$78,000 8 months	Kalsi Engineering/ *B. Curry*
Vertical Centrifugal Pumps: Predictive and Preventive Maintenance Guide (RP2814-44)	$81,400 11 months	Hydro Engineering Services/ *K. Barry*
Development of Expert System for Water Hammer Diagnosis (RP2856-5)	$98,800 13 months	Bechtel Group/ *M. Merilo*
Reliability-Centered Maintenance Analyst's Handbook (RP2970-6)	$62,400 7 months	NUS Corp./ *D. Worledge*
Heat Exchanger Performance Test and Monitoring (RP3052-5)	$50,900 14 months	Matney-Frantz Engineering/ *R. Edwards*
BWR Shutdown Risk Assessment and Management Guidelines (RP3114-66)	$415,400 24 months	Erin Engineering and Research/ *S. Kalra*
RELAP5/MOD3 Simulation of the Effect of Noncondensable Gases on Decay Heat Removal (RP3114-69)	$57,200 5 months	Texas Engineering Experiment Station/ *S. Oh*
Root-Cause Analysis Workstation (RP3235-1)	$59,000 8 months	Failure Prevention/ *J. Sursock*
Root-Cause Analysis Expert System Support (RP3235-2)	$50,000 20 months	Kaman Sciences Corp./ *J. Sursock*
Advanced LWR Program Support (RP3260-5)	$1,989,900 19 months	S. Levy, Inc./ *R. Burke*

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 pay 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

Customer Backup Generation: Demand-Side Management Benefits for Utilities and Customers
CU-7316 Final Report (RP2950-5); $200
Contractor: Energy International, Inc.
EPRI Project Managers: W. LeBlanc, P. Hanser

Acquisition of Third-Party Demand-Side Management Resources
CU-7362 Final Report (RP3086-1); $200
Contractor: Charles River Associates, Inc.
EPRI Project Managers: W. LeBlanc, V. Rabl

Supermarket Refrigeration Assessment for the New England Electric System
CU-7378 Final Report (RP2569-8); $200
Contractor: Foster Miller, Inc.
EPRI Project Manager: M. Khattar

Proceedings: 5th National Demand-Side Management Conference—Building on Experience
CU-7394 Proceedings (RP2548-10); $200
Contractor: Energy Investment, Inc.
EPRI Project Managers: W. LeBlanc, V. Rabl

ENVIRONMENT

Microbiology of a Coal-Tar Disposal Site: A Preliminary Assessment
EN-7319 Final Report (RP2879-5); $200
Contractor: Cornell University
EPRI Project Manager: I. Murarka

EXPLORATORY AND APPLIED RESEARCH

Research on Very High Temperature Gas Reactors
ER/NP-7372 Final Report (RP8000-58); $200
Contractor: University of Tennessee, Knoxville
EPRI Project Manager: E. Rodwell

GENERATION AND STORAGE

Cycling Operation of Fossil Plants, Vol. 1: Cycling Considerations for Niagara Mohawk's Oswego Unit 5
GS-7219 Final Report (RP1184-17); $300
Contractor: Niagara Mohawk Power Corp.
EPRI Project Managers: D. O'Connor, G. Poe

Cycling Operation of Fossil Plants, Vol. 2: Converting PG&E'S Moss Landing 6 and 7 to Cycling Duty
GS-7219 Final Report (RP1184-20); $300
Contractors: Pacific Gas and Electric Co.; Ebasco Services
EPRI Project Managers: D. O'Connor, G. Poe

Cycling Operation of Fossil Plants, Vol. 3: Cycling Evaluation of Pepco's Potomac River Generating Station
GS-7219 Final Report (RP1184-21); $300
Contractor: Potomac Electric Power Co.
EPRI Project Managers: G. Poe, D. O'Connor

Demonstration of EPRI Heat-Rate Improvement Guidelines
GS-7295 Final Report (RP2818-2); $200
Contractors: TU Electric; Sargent & Lundy
EPRI Project Manager: S. Gehl

WEIPLOT: Final Report and Computer Code User's Guide
GS-7323 Final Report (RP128-14); $200
Contractor: Electrochemical Engineering Consultants, Inc.
EPRI Project Manager: R. Schainker

Lessons Learned in Hydro Relicensing (1984–1989): Trends, Costs, and Recommendations
GS-7324 Interim Report (RP3113-2); $200
Contractor: Richard Hunt Associates
EPRI Project Manager: C. Sullivan

Repowering With Pressurized Fluidized-Bed Combustion Units
GS-7328 Final Report (RP2428-3); $200
Contractor: Foster Wheeler Development Corp.
EPRI Project Manager: S. Drenker

Manual of Bearing Failures and Repair in Power Plant Rotating Equipment
GS-7352 Final Report (RP1648-10); $200
Contractor: Mechanical Technology, Inc.
EPRI Project Managers: T. McCloskey, S. Pace

Proceedings: Effects of Coal Quality on Power Plants—Second International Conference
GS-7361 Proceedings (RP2256-8); $200
Contractor: Combustion and Environmental Consulting
EPRI Project Manager: A. Mehta

Proceedings: Shanghai 1991 Ash Utilization Conference, Vols. 1–3
GS-7388 Proceedings (RP2422); $350
Contractor: Shanghai Research Institute of Building Sciences
EPRI Project Manager: D. Golden

INTEGRATED ENERGY SYSTEMS

Engineering and Economic Evaluation of CO_2 Removal From Fossil-Fuel-Fired Power Plants, Vol. 2: Coal Gasification–Combined-Cycle Power Plants
IE-7365 Final Report (RP2999-10); $500
Contractor: Fluor Daniel, Inc.
EPRI Project Manager: G. Booras

NUCLEAR POWER

Main Feedwater Isolation Valve Maintenance Guide
NP-7212 Final Report (RP2814-27); $6000
Contractor: Anchor/Darling Valve Co.
EPRI Project Manager: R. Kannor

Seismic Margin Assessment of the Edwin I. Hatch Nuclear Plant, Unit 1
NP-7217-M Final Report (RP2722-22); $200
Contractors: Georgia Power Co.; Southern Company Services, Inc.; RPK Structural Mechanics Consulting; Woodward-Clyde Consultants; EQE, Inc.
EPRI Project Manager: R. Kassawara

Sulfate Ingress and Steam Generator Hideout at Saint Lucie Unit 1
NP-7237 Final Report (RPS401-11); $200
Contractor: NUS Corp.
EPRI Project Managers: C. Welty, P. Millet

EPRI Guide to Managing Nuclear Utility Protective Clothing Programs
NP-7309 Final Report (RP2414-34); $200
Contractor: Right Angle Industries
EPRI Project Manager: C. Hornibrook

Urania-Gadolinia Thermal Properties Data: An Evaluation of Extrapolation Above 2000°C
NP-7345-D Final Report (RPX101-10); $5000
Contractor: Tom Thornton
EPRI Project Manager: S Yagnik

The December 7, 1988, Armenia Earthquake: Effects on Selected Power, Industrial, and Commercial Facilities
NP-7359-M Final Report (RP2848-6); $200
Contractor: EQE, Inc.
EPRI Project Manager: R. Kassawara

Investigation of Lead as a Cause of Stress Corrosion Cracking at Support Plate Intersections
NP-7367-M Final Report (RPS407-16); $200
NP-7367-S Final Report (RPS407-16); $5000
Contractor: Babcock & Wilcox Co.
EPRI Project Managers: P. Paine, C. Shoemaker

Destructive Examination of Tube R31C66 From the Ginna Nuclear Plant Steam Generator
NP-7371-M Final Report (RPS407-40); $200
NP-7371-S Final Report (RPS407-40); $5000
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: P Paine

CALENDAR

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

DECEMBER

3–4
Workshop: Integrated Generation and Transmission Resource Planning
Washington, D.C.
Contact: Rambabu Adapa, (415) 855-8988

5–6
Workshop: Noncombustion Waste
Orange County, California
Contact: Mary McLearn, (415) 855-2487

10–13
Transformer Performance, Monitoring, and Diagnostics Course
Eddystone, Pennsylvania
Contact: Stan Lindgren, (415) 855-2308

12–13
NMAC Workshop: Low-Voltage Circuit Breaker Maintenance
Charlotte, North Carolina
Contact: Jim Christie, (704) 547-6053

JANUARY 1992

14–16
Rolling Element Bearings: Life Improvement Course
Eddystone, Pennsylvania
Contact: Murthy Divakaruni, (415) 855-2409

21–23
Motor Monitoring and Diagnostics Course
Eddystone, Pennsylvania
Contact: John Scheibel, (415) 855-2850

23–24
Workshop: Static Electrification in Power Transformers
San Jose, California
Contact: Stan Lindgren, (415) 855-2308

29–31
Conference: Steam and Combustion Turbine Blading
Orlando, Florida
Contact: Lori Adams, (415) 855-8763

FEBRUARY

4–7
Advanced Machinery Vibration Diagnostics Course
Eddystone, Pennsylvania
Contact: Murthy Divakaruni, (415) 855-2409

5–7
Advanced Digital Computers, Controls, and Automation Technologies
San Diego, California
Contact: Pam Turner, (415) 855-2010

11–13
Industrial Safety Innovations in Nuclear Power Plant O&M
Charlotte, North Carolina
Contact: John O'Brien, (415) 855-2214

24–25
Seminar: Nuclear Power Plant Performance Improvement
Miami, Florida
Contact: Bob Edwards, (415) 855-8974

MARCH

3–5
Seminar: Substation Voltage Uprating
Denver, Colorado
Contact: Joe Porter, (202) 872-9222

16–17
Investment and Research Planning Forum
Atlanta, Georgia
Contact: Susan Bisetti, (415) 855-7919

APRIL

8–9
Asbestos Control and Replacement for Utilities
Pittsburgh, Pennsylvania
Contact: Linda Nelson, (415) 855-2127

22–24
Seminar: Corrosion in Power Plant Service Water Systems
Clearwater, Florida
Contact: Bob Edwards, (415) 855-8974

MAY

13–15
NMAC Workshop: Solenoid Valve Maintenance
Philadelphia, Pennsylvania
Contact: Vic Varma, (415) 855-2771

26–29
NDE Workshop: Balance-of-Plant Heat Exchanger
Key West, Florida
Contact: Kenji Krzyowsz, (704) 547-6096

31–June 4
International Conference: Mercury as a Global Pollutant
Monterey, California
Contact: Pam Turner, (415) 855-2010

JUNE

1–3
2d Annual ISA-EPRI Controls and Automation Conference
Kansas City, Missouri
Contact: Lori Adams, (415) 855-8763

3–5
International Conference: Interaction of Iron-Based Materials With Water and Steam
Heidelberg, Germany
Contact: Barry Dooley, (415) 855-2458

23–25
Seminar: Noncombustion Waste
Boston, Massachusetts
Contact: Mary McLearn, (415) 855-2487

JULY

6–9
1992 Meeting on Electric Thermal Storage and Thermal Energy Storage
Minneapolis, Minnesota
Contact: Linda Nelson, (415) 855-2127

8–10
Workshop: NO_x Control
Boston, Massachusetts
Contact: Pam Turner, (415) 855-2010

AUGUST

24–26
Optical Sensing
Philadelphia, Pennsylvania
Contact: Linda Nelson, (415) 855-2127

25–27
Effects of Coal Quality on Power Plants
San Diego, California
Contact: Susan Bisetti, (415) 855-7919

SEPTEMBER

13–16
International Conference: Avian Interactions With Utility Structures
Miami, Florida
Contact: Pam Turner, (415) 855-2010

21–24
5th Conference on Incipient Failure Detection
Knoxville, Tennessee
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28–30
Conference: Power Quality
Atlanta, Georgia
Contact: Marek Samotyj, (415) 855-2980

Authors and Articles

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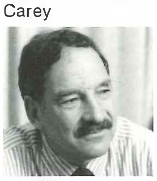

Lapides

Shaping DSM as a Resource (page 4) was written by Leslie Lamarre, *Journal* feature writer, with assistance from two members of the Customer Systems Division.

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Electrifying the Foundry Fire (page 16) was written by science writer John Douglas with information provided by **Patrick McDonough**.

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The Long View for Nuclear Plant Maintenance (page 24) was written by Taylor Moore, *Journal* senior feature writer, with assistance from two members of EPRI's Life-Cycle Management Program.

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