Comparing Advanced Technologies

ELECTRIC POWER RESEARCH INSTITUTE

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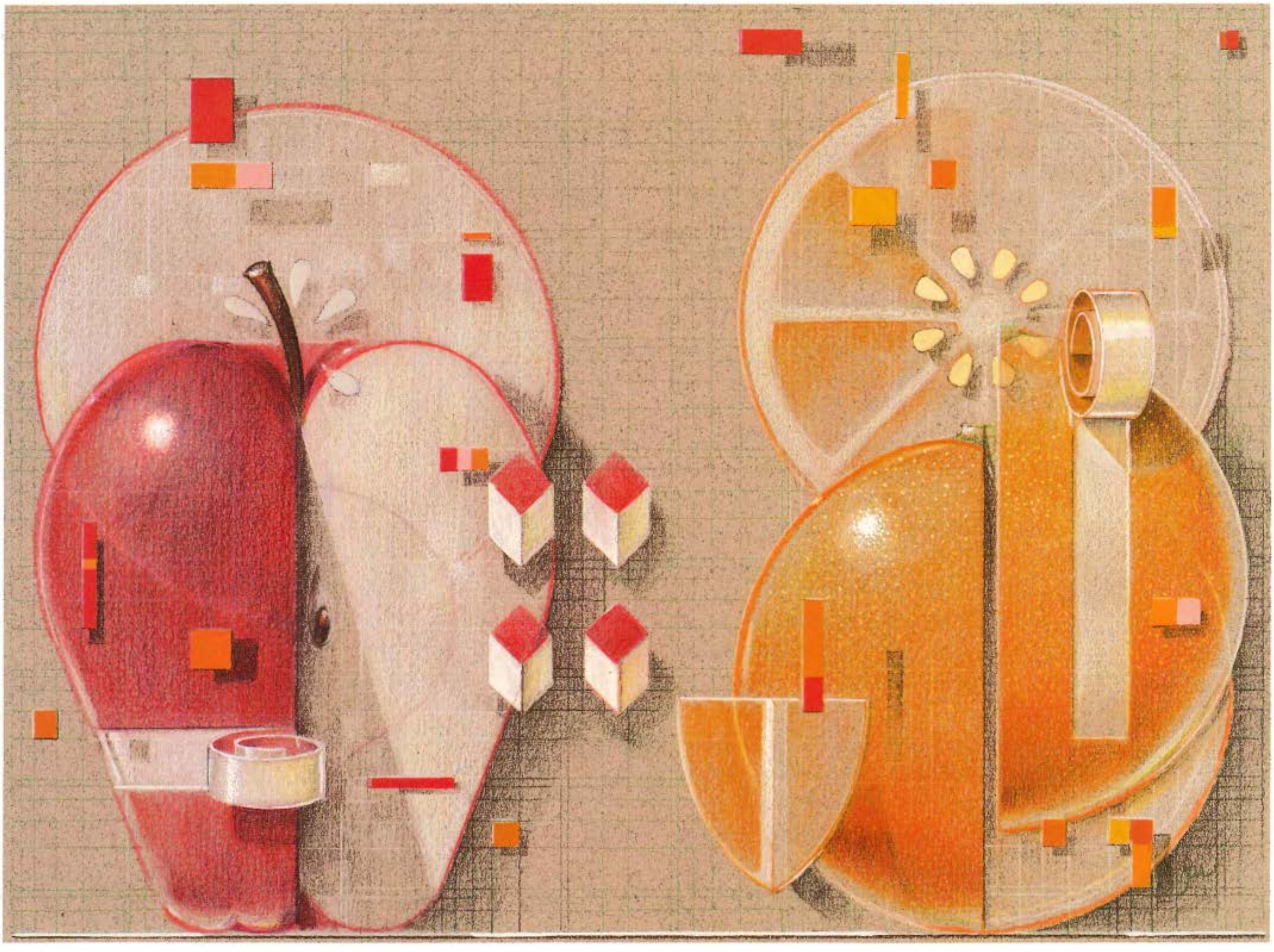

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Cover: Taking the measure of advanced generation technologies can be like comparing apples and oranges—most of them are good, but they each have unique attributes.

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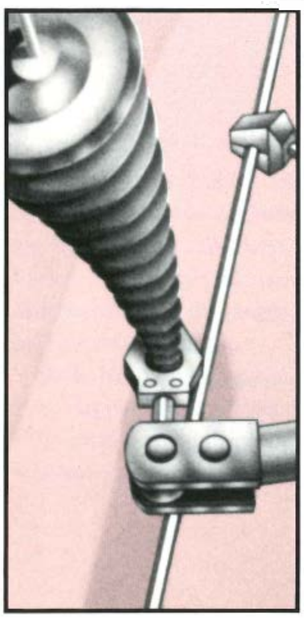

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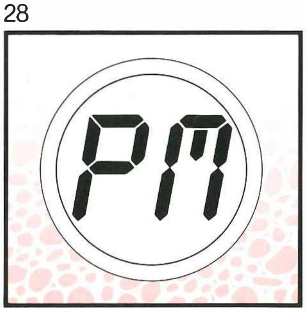


Strategic Diversity for an Uncertain Future

Zeren

We at EPRI have been hearing more and more about the need for additional generating capacity in the 1990s. A few recent new utility power plant orders means talk may become action. Utilities not yet formally committed to new construction have begun preliminary planning for the 1990s.

For most utilities, capacity decisions will reflect changing economic and social realities. Fundamental shifts in lifestyles and economic structure are changing customers' demand for energy services and, consequently, the operating demands on the power system. To meet growing competition from alternative energy services and electricity suppliers, utilities focus on being low-cost producers of highly valued service. The public's environmental ethic is firmly entrenched, and pressure to tighten requirements continues. Utilities also want to avoid large, long-term financial exposures and their attendant risks. They want economical, smaller generating units to match capacity expansion more closely to hard-to-predict load growth. They would like to take advantage of current low fluid fuel prices, while protecting themselves and their customers from possible price increases or supply shortages.

Fortunately, advanced generating technologies emerging from over a decade of industry RD&D offer utilities the flexibility to cope creatively with the new realities in the years ahead. Much of this work, including development of clean coal combustion systems and advanced nuclear reactors, is centered at EPRI.

Identifying the most promising technologies against the growing complexity of our members' needs occupies significant EPRI staff and contractor effort. Technical divisions pursue optimal configurations of each of the advanced technologies on the basis of performance and cost. The Planning and Evaluation Division, meantime, periodically organizes the best current technical and economic expectations in a consistent, comparative format both for reporting to our utility members and to assist in setting our funding and development priorities. Such analysis goes beyond simply crunching numbers to assessing other key factors in utility decision-making—identifying the important characteristics that make each technology more or less desirable to an individual utility. For R&D planning purposes, the numbers themselves are less important than the relative rankings and the strategic value of each technology.

Advanced technologies for baseload generation appear similar in their potential cost of energy, even when compared with today's technology built to current environmental standards. But more important, these new systems offer phased and modular construction, fuel flexibility, cost-effective environmental control, and retrofit potential.

If the utility industry has learned anything in the last 20 years, it is to expect the unexpected and unpredictable. EPRI is pursuing for its diverse industry membership a strategic diversity of generating technologies to help utilities cope creatively with the uncertain challenges of the future.

Richard W. Zeren, Director
Planning and Evaluation Division

Authors and Articles

Vejtasa Kennon Dooley Geraghty Rabl

How Advanced Options Stack Up (page 4) surveys the new power generation technologies coming up for commercial use and also the criteria by which they are evaluated for different utility circumstances. Written by Taylor Moore, senior feature writer of the *EPRI Journal*, aided by the staff of the Planning and Evaluation Division.

Stan Vejtasa, manager of technology evaluation since 1983, has worked in technical and economic analysis since he came to EPRI in 1976. Until 1981 he was with the Advanced Power Systems Division. Vejtasa was with Shell Development from 1969 to 1976, working successively in petrochemical process engineering and in the development of emission controls. A chemical engineering graduate of the University of Minnesota, he earned his MS and PhD at the University of Illinois. ■

Live-Line Repair With Tomcat (page 14) describes the advent of a remotely controlled manipulator for utility line crews to use in maintaining and repairing live circuits. Written by Jon Cohen, science writer, on the basis of information supplied by the staff of EPRI's Electrical Systems Division.

Dick Kennon, manager of the Overhead Transmission Lines Program since 1978, is also responsible for EPRI's transmission line mechanical research and high-voltage test facilities. He came to EPRI in 1975 after nearly 23 years with Westinghouse Electric, ultimately as manager of capacitor equipment engineering. Kennon received a BS in electrical engineering from the California Institute of Technology and an MBA from Indiana University. ■

Longer Life for Fossil Fuel Plants (page 20) reviews the major criteria for operating fossil fuel power plants beyond their planned lifetimes and describes how analytic tools developed by EPRI are used to select and evaluate major maintenance options. Written by John Douglas, science writer, with the principal assistance of two EPRI research managers.

Barry Dooley, since 1984 a project manager in the Availability and Life Extension Program of the Coal Combustion Systems Division, has special expertise in boilers and auxiliaries. Before joining EPRI, he was with Ontario Hydro for nine years, becoming manager of the chemistry and metallurgy department. For three earlier years he was with the materials division of the Central Electricity Research Laboratories in England. Dooley graduated in engineering metallurgy from the University of Liverpool and earned a PhD in metallurgy there.

Dom Geraghty, recently named assistant to EPRI's executive vice president, was previously a technical manager in the Institute's Utility Planning Methods Center, where he developed information on plant investment options, including analytic techniques and programs. Geraghty joined EPRI in 1977 after spending four years as an energy analyst and engineer with Irish government agencies. He has a BE and a PhD in chemical engineering from University College in Dublin and an MBA from the University of Santa Clara. ■

Rocks Around the Clock (page 28) summarizes the research and pilot testing of electric heat storage furnaces that can heat homes all day with off-peak energy. Written by Jon Cohen, science writer, with information from the staff of EPRI's Energy Management and Utilization Division.

Veronika Rabl has principal responsibilty for research in load management technologies for residential and commercial use. She has been with EPRI since 1981, following nearly seven years with Argonne National Laboratory, much of that time in technology assessment, including a year on assignment to the DOE Office of Energy Systems Research, where she headed a program of technical and economic analysis. Rabl graduated in physics from the Weizmann Institute of Science in Israel. She also has a PhD from Ohio State University. ■

How Advanced Options Stack Up

An EPRI comparison of the economics and performance of advanced generating options reveals the range of choices utilities will have for the 1990s.

Depending on one's point of view, the utility industry has been enjoying or suffering a low level of new power plant construction for several years, one that most utilities believe can't last forever. Even if the annual growth rate in electricity demand is as low as 1.4%, the nation will need as much as 250 GW of new capacity in place by the year 2010, goes the thinking at EPRI and in much of the industry these days. That is equivalent to 250 large 1000-MW coal or nuclear plants built in the next 22 years.

But the next generation of power plants won't necessarily resemble these present utility industry workhorses. Utilities will be considering a number of advanced options that are custom-designed for the environmental, economic, and competitive realities of the twenty-first century: emissions-free, noncombustion fuel cells; more-efficient and reliable gas turbines; clean coal gasification–combined-cycle and fluidized-bed coal combustion; advanced light water reactors; and energy storage systems for peaking service.

Some of the expected need for increased capacity may be counterbalanced by utility demand-side management programs. Plant life extension efforts at some current but aging generating stations will also affect the total amount of new capacity that is built in the next 20 years. But for utilities charting 15- and 20-year resource plans, new capacity must be built eventually—much of it, soon.

The question then becomes, what kind of capacity? Baseload (of which there is now a surplus in many parts of the country), intermediate cycling capacity, or peak generating facilities?

And for each type, how do the power options stack up against each other as well as against the traditional large coal and nuclear plants?

Such questions are crucial to EPRI as well as to utilities. EPRI pursues a portfolio of advanced generation technologies, each of which addresses strategic concerns and goals of the industry, including resource, environmental, and cost issues. Other technologies under development elsewhere, meanwhile, are only monitored for improvement or breakthroughs because of their higher technical development risks and the limited availability of R&D funds.

Periodically, all the generation options that EPRI pursues are reviewed and compared on as nearly equal a footing as possible to see if any emerge as strong winners, clear losers, or contenders otherwise. Just such a comparison was made last year by EPRI's Planning and Evaluation Division for consideration by the Research Advisory Committee (RAC). The panel—senior executives from member utilities—counsels and guides the technical content of the Institute's R&D program.

The results of the comparison are equivocal but encouraging, according to Stan Vejtasa, manager of technology evaluation. "The upshot of the study is that of the advanced generating options EPRI is working on, there is no superior technology in a generic sense. None of the new technologies appears to produce power significantly cheaper than anything utilities have out there already. The principal benefit of the new technologies is their business and technical flexibility in the face of competitive, financial, and environmental constraints," says Vejtasa.

"The inescapable conclusion from

the study is that as long as natural gas prices stay below about \$4.50/million Btu—and they're now below \$3.50/million Btu—gas-fired generating equipment will produce the lowest-cost power in the near term on a life-cycle basis," Vejtasa adds. "The key question, though, is how long we can expect gas prices to stay low."

"Gas turbines, especially the advanced high-efficiency design EPRI has helped develop for commercial availability next year, are ideal as the early stage, phased construction of gasification–combined-cycle (GCC) plants. The analysis also shows that each of the other advanced technologies we are helping to develop has characteristics that favor its economical deployment under various specific circumstances. That tends to confirm the portfolio approach to generation systems R&D. We have the major bases covered."

The new generation

Many, if not most, of the new power plants that enter service in the 1990s and beyond will be different from the large coal and nuclear steam plants built in the 1960s and 1970s. Those that involve coal combustion may have to meet ever-tightening federal standards for sulfur oxide, particulate, and nitrogen oxide emissions, as well as comply with increasing controls over solid wastes that result from removing those pollutants from flue gases.

The next generation of nuclear plants may have to reflect higher public standards of perceived safety and will certainly have to be significantly cheaper than many of the recently completed plants. Along with design improvements, stable and predictable licensing and regulation are keys to bringing costs down. All the power technologies must offer utilities reduced capital exposure and financing requirements, by lowered costs per unit of capacity, shorter construction times, or inherent design modularity that permits economical, incremental (tens or hundreds of megawatts) capacity additions as needed.

For the longer term, utilities need an even broader mix of options for reduced dependence on a single or scarce fuel (particularly oil or natural gas) or a single technology. Over time, the environmental issues associated with acid rain may be overshadowed by more global concerns, such as the carbon dioxide–induced greenhouse effect, in turn elevating the priority of noncombustion power systems, such as advanced nuclear reactors and photovoltaics.

Over both the near and the long term, utility generating costs must be made and kept competitive with other energy suppliers and sources, such as cogenerating industries, unregulated wholesale producers, and natural gas–fired industrial equipment. And amid all the trends, "Utilities realize they need to foster an improved public perception that the industry is taking a positive role in adapting to business and social risks and constraints—economic or environmental," Vejtasa adds.

Translating utilities' diverse strategic requirements into technical characteristics of preferred technologies is one of the jobs of EPRI's Planning and Evaluation Division. Analysts have quantified potential savings for several of the key variables by which options will be judged. The most significant is construction time. The value of cutting typical recent plant construction times of 5 to 10 years or more by a factor of 2 to 3—as promised by several emerging options—is estimated at \$100–\$150/kW of capacity, mainly by avoiding the financing costs afforded by a deferred decision to build the capacity.

Almost as valuable in terms of possible savings is the economy offered by smaller unit sizes of many advanced technologies, allowing capacity additions to more closely match demand growth in financially digestible bites, complemented by shorter construction times. Other things being equal, modular unit sizes can mean savings of \$50–\$100/kW of capacity.

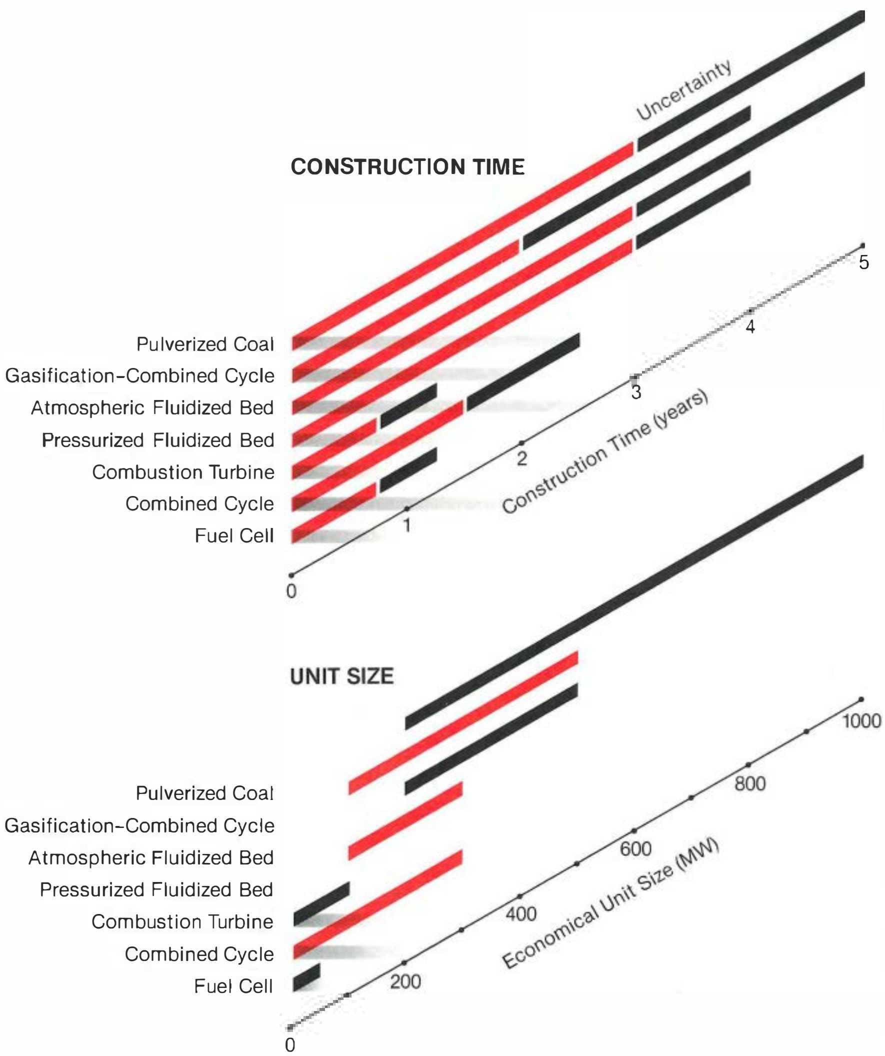
Also important, but more germane at the busbar cost-of-energy level, are low pollution emissions. This factor can make a difference of 1–2¢/kWh, equivalent to the difference in cost of energy between low- and high-sulfur coal. Another factor is a plant's flexibility to burn or convert to another fuel—say, from natural gas to clean synthetic coal gas. Fuel flexibility can give a technology an energy cost advantage of 0.5–1¢/kWh.

Other important, but less comparatively quantifiable, criteria include resource impacts, such as land and water requirements. Reliability and operability are always key questions for new technologies. Efficiency: more is better, but not if it hampers reliability. Public perception and acceptance are important, as is the practicality of retrofit or repowering applications that could benefit from already amortized plant investments (both fluidized-bed and GCC combustion offer such potential). "The commercialization barrier for a new technology can be very real if it can only be used in a large, new plant," notes Vejtasa. "The possibility for retrofit is very appealing to a utility."

With such requirements and desired features in mind, EPRI's strategy in advanced generation has been to develop the most promising technologies in parallel and cooperatively demonstrate

CONSTRUCTION

The unit construction time (from order to in-service) and economical unit size are key considerations in assessing the attractiveness of advanced fossil fuel technologies. Modular options, such as combustion turbines, combined-cycle units, and fuel cells, are the quickest to get on-line, significantly reducing financing costs; however, their relatively small unit sizes make these options attractive primarily for small capacity additions. Gasification-combined-cycle and fluidized-bed units compete directly for larger additions (100–500 MW), with GCC carrying a slight time advantage because of its capability for phased construction. None of the advanced options enjoy the scale-up advantages of pulverized-coal technology, but very large plants are somewhat less attractive today because of slow load growth and the need to avoid large capital exposure.



them in series with utilities and equipment vendors.

Scanning the lineup

The current lineup, largely unchanged for several years, looks like this: Among baseload systems under development, there are coal-fired fluidized beds, both atmospheric and pressurized; GCC systems; advanced pulverized-coal plants with cycling capability; and advanced light water reactors. Advanced combustion turbines and fuel cell power plants help cover the intermediate and peaking duty bases. Other peak power options that will soon be demonstrated are batteries and compressed-air energy storage (CAES). And two quite different technologies—hot-brine geothermal and photovoltaics—promise expanded utility use of renewable resources. Vejtasa ticks off some of the more salient features of each.

"From the advanced pulverized-coal plant EPRI is developing for the 1990s in an international collaboration with vendors and utilities, we're expecting incremental improvements in a proven technology—higher efficiency, greater reliability, and easier construction.

"GCC produces clean fuel gas that can be used in a variety of power cycles, and it can be built in phases starting with combustion turbines.

"Atmospheric fluidized-bed combustion (AFBC) is the more traditional approach to fluidized-bed; it retains the typical coal-steam boiler but adds direct in-boiler control of sulfur dioxide and has the flexibility to burn any coal and even other fuels.

"Pressurized fluidized-bed combustion (PFBC) is an extension of AFBC technology to higher efficiency and more-compact, modular designs, but many technical issues, such as hot gas cleanup and plant configuration, have yet to be resolved.

"The advanced light water reactor is based on simpler design with increased safety margins and improved construct-

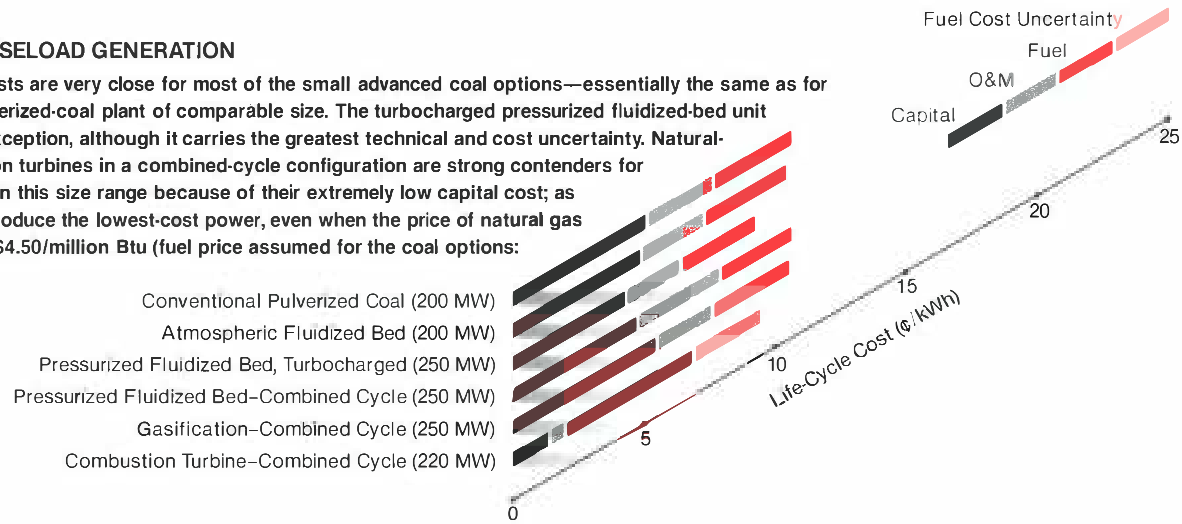
The Bottom Line for Power Options

COST

Although the availability of advanced power technologies will substantially increase utilities' planning flexibility, none of the new options are expected to offer significantly lower life-cycle power costs than conventional technology. The comparisons below are in current dollars and assume a 30-year life, 6% nominal inflation, and a 12.5% annual discount rate.

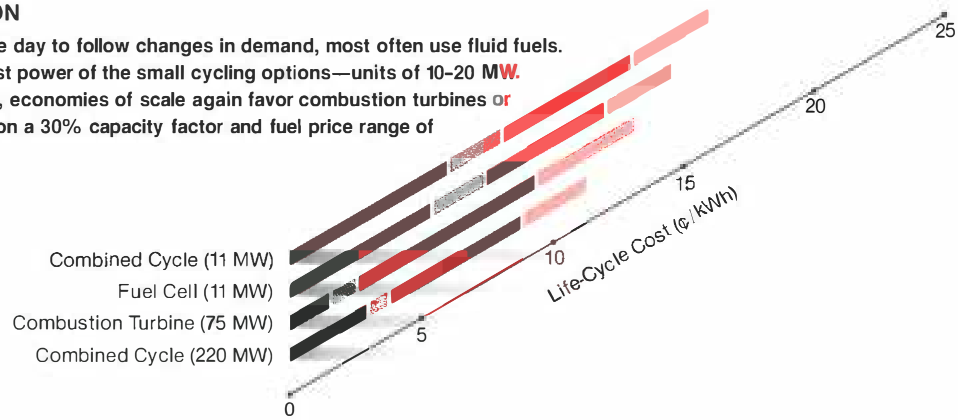
FOSSIL FUEL BASELOAD GENERATION

Life-cycle power costs are very close for most of the small advanced coal options—essentially the same as for a conventional pulverized-coal plant of comparable size. The turbocharged pressurized fluidized-bed unit appears to be an exception, although it carries the greatest technical and cost uncertainty. Natural-gas-fired combustion turbines in a combined-cycle configuration are strong contenders for capacity additions in this size range because of their extremely low capital cost; as shown here, they produce the lowest-cost power, even when the price of natural gas increases to $3.50-$4.50/million Btu (fuel price assumed for the coal options: $1.55/million Btu).



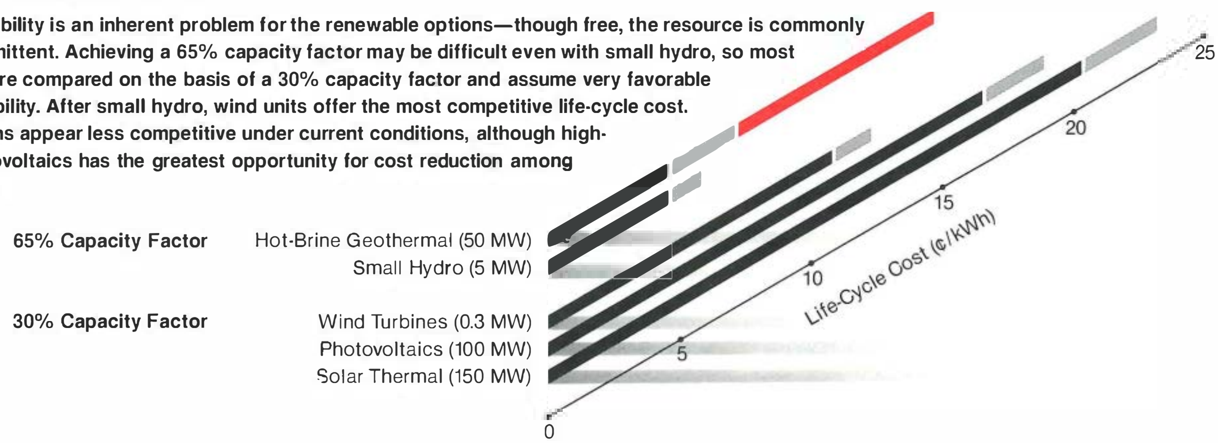
INTERMEDIATE/PEAKING GENERATION

Cycling units, switched on and off during the day to follow changes in demand, most often use fluid fuels. Fuel cells potentially produce the lowest-cost power of the small cycling options—units of 10-20 MW. However, when larger-size units are required, economies of scale again favor combustion turbines or combined-cycle units. Estimates are based on a 30% capacity factor and fuel price range of $3.50-$4.50/million Btu (oil or natural gas).



RENEWABLE RESOURCE OPTIONS

Resource availability is an inherent problem for the renewable options—though free, the resource is commonly diffuse or intermittent. Achieving a 65% capacity factor may be difficult even with small hydro, so most of the options are compared on the basis of a 30% capacity factor and assume very favorable resource availability. After small hydro, wind units offer the most competitive life-cycle cost. The solar options appear less competitive under current conditions, although high-efficiency photovoltaics has the greatest opportunity for cost reduction among the renewables.



ibility. A major R&D program is defining configurations for large- and medium-size pressurized and boiling water reactors for the next decade.

"Among cycling and peaking systems, the advanced combustion turbine now reaching the market promises much-improved reliability and efficiency, as well as excellent service as the prime mover in a full GCC plant. Fuel cells, still under development, are clean, small, modular, and highly efficient.

"Of the two renewables, solar photovoltaics is a real wild card, with many opportunities for continued technical breakthroughs. Although the cost is now and, to some extent, always will be high per kilowatt of capacity, it can be quickly deployed in small increments at very small scale. Meantime, EPRI's and the industry's successful development of binary-cycle geothermal technology has greatly extended the potentially economical underground resource in the country.

The most promising near-term energy storage option is compressed air (CAES), which employs standard components and can provide over 10 hours of megawatt-scale storage, but there are resource issues and even technical risks associated with the heat recuperator being developed for CAES. Battery peaking systems, however, are conceptually very appealing with their expected ease of siting, short lead time, and 3 to 5 hours' potential storage.

Technologies that EPRI only monitors for performance improvements or breakthroughs include liquid metal and high-temperature gas-cooled reactors, solar-thermal systems, superconducting magnetic energy storage, and wind turbines. Vejtasa notes that in the case of the breeder and gas-cooled reactors, the complexity and risks—hence, cost—of R&D are too great for EPRI to make a significant contribution without major concurrent government commitment. (Under present budget constraints the federal government's funds are dedicated to the advanced light water reactor.) In the case of wind turbines, on the other hand, commercial developers continue to improve already proven, reliable but expensive machines.

Additionally, in lieu of funding, EPRI keeps an eye on generating systems fired with municipal solid waste (MSW), space station and ocean-thermal solar concepts, magnetohydrodynamic power generation, fusion reactors, and biomass conversion. Vejtasa notes there is great diversity among utilities regarding MSW-fired generation; some are required to or voluntarily embrace it as a future option because of local circumstances, but others raise questions about reliability and regulatory uncertainty.

For the presentation to RAC, Vejtasa compared the five baseload, two cycling, and two renewable advanced technologies with their competitors within each group as if they were commercially available and technically mature. "We tried to make a balanced comparison, including both positive and negative aspects, so that we got a clear picture of what the incentives and development issues are for each," says Vejtasa. "We did not include the energy storage options (batteries and CAES) in the detailed analysis, partly because of time constraints but also because they pose a more difficult comparison. The value and worth of energy storage is very much tied to a specific utility system. That is true of all technologies to some extent, but particularly so for storage."

Bases for comparison

The technology comparison covered eight key factors, some quantitative, others semiquantitative. They range from the most generically quantifiable (capital costs, power costs) to site-specific quantifiable factors that could dominate a utility's decision (fuel flexibility, resource requirements, and reliability and operability), to more general but semiquantitative factors (construction flexibility, economical size ranges, and emissions control potential).

Although the comparison identified no hands-down winner among advanced generating technologies, it confirmed that specific niches exist for each of the major systems utilities will be pondering for purchase. "For our purposes at EPRI, the results of this kind of technology analysis are used for R&D planning guidance because they help eliminate the least promising technologies and avoid spending time and money on those that do not have the characteristics utilities need. Very seldom can you pick the true winner, which depends on utility and site-specific factors," explains Vejtasa, "and requires a second-order, more in-depth examination."

Strictly on the basis of unit construction time (from order to in-service, not including design and licensing), phased construction of GCC offers modular increments (of about 100 MW) of fossil-fuel-fired capacity the quickest, according to the analysis. That could start with a current or advanced gas turbine, later a heat-recovery steam bottoming cycle could be added, and still later, a coal gasifier to feed the turbine with syngas. Combustion turbines and fuel cell plants (when fully developed) can be brought into service in about a year, with the simple combined-cycle phase of GCC requiring another year and a half. All these systems can be produced as shop-fabricated modules and quickly field-assembled.

A full GCC plant (300–500 MW) has an estimated construction time of two to four years. The modern pulverized-coal-fired and AFBC plants, similar but for their boilers, share estimated construction times of three to five years. PFBC features a modular, more-compact boiler, possibly cutting a year off its requirement compared with pulverized coal and AFBC.

Advanced fossil fuel options also have been configured to be economical in small unit sizes compared with pulverized-coal plants, which have significant economies of scale above 500 MW and up to about 1000 MW. GCC—comprising, like PFBC, parallel trains of modular, major components—looks good between 100 and 500 MW. The requirement for barge-shippable components limits PFBC's upper scale for now at an estimated 300 MW. Although AFBC should show scale economies similar to pulverized coal, remaining technical issues, including multiple-bed coal feeding and control, might cap its economic scale at 500 MW per unit.

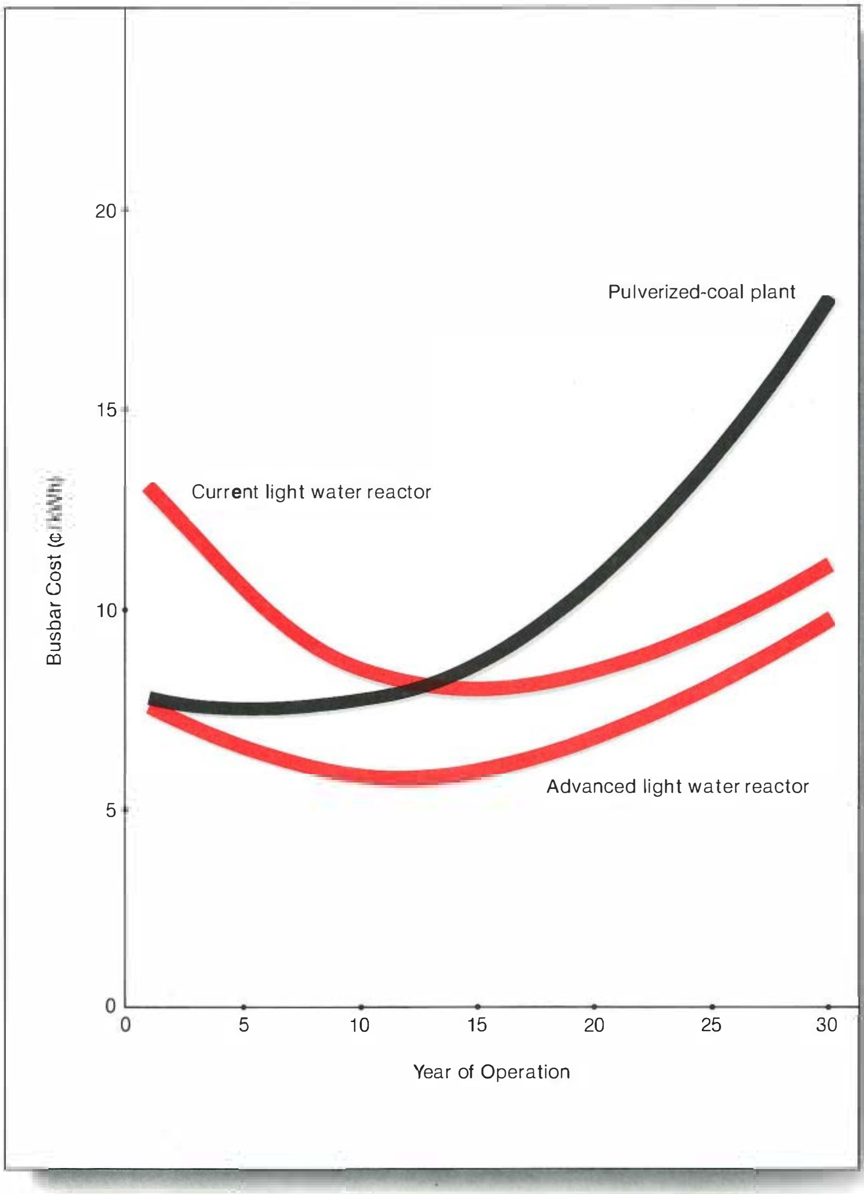
Clumped at the low end of unit sizes are simple combined-cycle plants, which are economical thanks to their high efficiency anywhere below 300 MW; combustion turbines, where about 130 MW is the commercially available limit; and fuel cells, which offer little, if any, economy of scale beyond replicating modules of 5–10 MW (a potential drawback as they compete for utility application).

But when capital costs are estimated for the fossil fuel options, assuming each technology is mature and competes under equal market conditions, "the differences in unit size appear to be more significant than differences in the technologies," concludes Vejtasa. Pulverized coal and AFBC show the greatest economies of scale, on the basis of estimated capital costs for 500-MW versus 200-MW units. But at 250 MW, the turbocharged PFBC system appears to offer the lowest capital cost ($1485/kW, 1985 dollars), although with the greatest attendant technical uncertainty. A GCC unit shows a more at-

Comparing Power Costs

COAL vs. NUCLEAR

The high cost of construction delays caused rate shocks that effectively stalled the nuclear option in the late seventies. A year-by-year power cost comparison shows that the capital cost of nuclear plants must drop by a third before their early-year rate impact will be comparable to that of coal plants. The advanced light water reactor is being designed to accomplish this by improving plant availability by 15–25% and by cutting construction times nearly in half. These goals would require labor productivities comparable to those achieved domestically in the early seventies and overseas today.



tractive capital cost with the replacement of the turbine by an advanced model delivering another 100 MW from the same-size gasifier; similar capital cost reductions on a kilowatt basis would also apply to a 250-MW GCC with an advanced turbine.

The differences between the technologies fade still further when the analysis is extended to life-cycle power costs at modest (200–250 MW) unit scale. That shows pulverized coal, AFBC, PFBC (in a combined-cycle configuration), and GCC neck and neck at about 10–10.6¢/kWh in current dollars, levelized over 30 years and assuming 6% annual inflation. A gas-fired combined-cycle plant comes in still better at 9.3¢/kWh—just above the turbo-charged PFBC system at 9.1¢/kWh.

The conclusion? Vejtasa offers several observations. "Although the turbo-PFBC has the lowest projected capital and life-cycle power costs at the 250-MW scale, it also has the greatest technical and cost uncertainties. On the other hand, at the same scale, the highest capital cost technology—GCC—shows substantial reduction with the substitution of an advanced turbine, and on a power cost basis, it is clearly competitive with all the coal options over the long term.

"No coal technology offers either substantial generic capital cost reduction or power cost reduction compared with prevailing conditions," says Vejtasa. "For some utilities, that may argue for life extension of existing coal and nuclear capacity or demand-side management to limit load growth and avoid building new capacity.

"In the near term, as long as natural gas prices stay low, gas-fired combined cycle appears to be the technology of choice among those commercially available. The strategic advantage of planning for that kind of capacity as part of phased GCC is that if fuel prices go up, you could add the coal gasifier and convert to coal," explains Vejtasa. The 1978 Fuel Use Act has prohibited new gas turbines from operating more than 1500 hours a year (confining them to peaking service); most provisions were repealed in a measure recently passed by Congress and signed by the president in May, however.

Despite the lack of standout economic choices among coal options, their comparative environmental control potential reveals some clear differences. Vejtasa ranked the technologies by using federal New Source Performance Standards for a conventional pulverized-coal plant equipped with flue gas desulfurization as the reference starting point. On a scale of the lowest emissions control potential to the greatest, he lists PFBC, baghouse-equipped AFBC, advanced pulverized coal with flue gas desulfurization, GCC, and a fuel cell plant coupled with GCC, in that order.

"With respect to meeting more-stringent emissions standards, the fluidized-bed options would probably have the most difficulty without the use of add-on controls similar to those required for pulverized-coal plants," says Vejtasa. "GCC appears the most flexible because it takes care of gas cleanup before combustion, with the ultimate in emissions control potential being GCC with a fuel cell topping cycle."

On the basis of qualitative judgments that consider other important factors affecting the fossil fuel options, GCC coupled with either a combustion turbine or a fuel cell scores the most points. "GCC may be viewed in some quarters as complex—more like a chemical plant than a traditional power plant—but the highly successful demonstration at Cool Water in southern California has confirmed its environmental performance and greatly advanced the technology, which some other utilities are now actively planning to order," notes Vejtasa.

Beyond coal

Besides the baseload coal options, similarly extensive analysis was applied to small-scale (under 250 MW) oil- and gas-fired intermediate and peak generation options. On a capital cost basis, fuel cells promise the lowest in the 10-MW size range, assuming a favorable market (150 units or more) for the now commercially available 11-MW modules. If development and cost goals are met, fuel cells could come in at $850/kW in 1985 dollars, compared with an 11-MW modular combined cycle at $950/kW. But as Vejtasa points out, "If larger unit sizes are required, the economies of scale clearly favor the combustion turbine ($300/kW at 75 MW) or the 220-MW combined cycle ($515/kW)."

A similar conclusion is reached when looking at 30-year levelized life-cycle power costs from small fluid-fueled plants. Oil and gas prices were assumed to range from about $20/bbl for oil and $3.50/million Btu for gas to $28/bbl ($4.50/million Btu equivalent). According to Vejtasa, the 11-MW fuel cell competes very well with a 75-MW combustion turbine (14.4¢/kWh versus 13¢/kWh, respectively, assuming high fuel prices). An 11-MW combined cycle does almost as well (15.8¢/kWh). "But again, if larger (100–300 MW) unit sizes are desired, scale economies still favor the combustion turbine combined cycle, with an estimated power cost of 11.1¢/kWh," he adds.

A brief comparison of conventional pulverized coal with current and future nuclear generation costs argues for advancing the nuclear option against a backdrop of growing concern over total atmospheric pollution loading from fossil fuel combustion, as well as over the strategic need for fuel diversity and security. The comparison shows that if capital cost and performance goals for the next generation of light water reactors can be met, they will produce the least-expensive baseload electricity over their life. The "rate shock" phenomenon that makes some new nuclear plants uncompetitive with pulverized coal in the critical early years of plant life would be eliminated. Advanced nuclear plants could also provide process heat for industry without carbon dioxide emissions.

"But capital costs for advanced reactors must be reduced by one-third from present levels, availability must improve 15–25%, and construction times must be cut about in half compared with current conditions before the advanced light water reactor's early-year rate impact and financial risk are comparable to conventional coal-fired generation," notes Vejtasa. "These goals are based on building a nuclear plant with labor productivities comparable to those achieved in this country in the 1970s and overseas today." The 30-year levelized power cost comparison shows that the advanced reactor's cost is about 15% lower than that of the pulverized-coal plant. Both options produce virtually the same cost of power in the early years, with nuclear costs lower over the later years.

Cost estimates for renewable resource power plants are probably less important to most utilities than how coal options stack up or how those options compare with nuclear. But they are particularly instructive

A Checklist for Critical Choices

CHARACTERISTICS

Advanced fossil fuel technologies feature combinations of attributes that can match specific utility needs and are generally more forgiving of regulatory and economical uncertainty than are conventional options. Plus signs indicate potential for improvement over the reference base-case technology—conventional pulverized-coal plants with flue gas desulfurization (circles indicate no significant improvement). The comparison is qualitative and doesn't consider developmental issues; for example, although the advanced pulverized-coal plant has the fewest number of enhancements, it is the lowest-risk approach because it incorporates incremental improvements into an existing technology.

Characteristics ▼ / Technologies ▶	Pulverized Coal With Flue Gas Desulfurization	Advanced Pulverized Coal With Flue Gas Desulfurization	Atmospheric Fluidized Bed	Pressurized Fluidized Bed	Gasification-Combined Cycle	Fuel Cell With Gasification-Combined Cycle
Short construction	●	●	●	+	+ +	+ +
Small unit sizes	●	●	+	+	+ +	+ +
Low emissions	●	●	●	●	+	+ +
Fuel flexibility	●	●	+	+	●	●
Land/water use	●	●	+	+	+ +	+ +
Reliability	●	+	+	●	+	+
High efficiency	●	+	●	+	+	+ +
Retrofit/repower	●	+	+	+ +	+	●

for R&D planning purposes. With renewable—particularly solar—options, capital costs per unit of generating capacity are necessarily high because the diffuseness (solar, wind) or low quality (geohydrothermal) of the resource requires more capital investment to exploit it. "Alternatively," Vejtasa notes, "unit sizes for renewable technologies are usually small, resulting in small capital exposure."

On a capital cost basis, a 50-MW geothermal hot brine power plant (not including resource development) competes well with a 5-MW small-hydro facility at around $1700/kW, also the estimate for 300-kW (0.3-MW) wind turbines. A power-tower-type 150-MW solar-thermal station looks prohibitively steep at nearly $3500/kW, while the goal for a 100-MW photovoltaic central station based on high-efficiency concentrator cells lies in between wind and solar-thermal at about $2400/kW—less than a third of the current cost. For comparison, a typical 75-MW combustion turbine costs about $300/kW.

"If the resource is available, small hydro and wind offer the most competitive power costs of the renewables," says Vejtasa. But a 50-MW hot brine plant operating at a somewhat optimistic 65% capacity factor does almost as well on a busbar basis as the 300-kW wind park at 30% capacity factor (the wind is also nondispatchable). The geothermal unit's power costs an estimated 14.6¢/kWh to produce, compared with 12.1¢/kWh for the wind turbines and 5.6¢/kWh for the small hydro generator. (The reference gas turbine comes in at 13¢/kWh at a 30% capacity factor.)

Almost as high as solar-thermal at the high end of the renewable power cost range, Vejtasa notes, "Photovoltaics has the greatest potential for cost improvement and its eventual successful deployment could have a major impact on utilities and their customers. Moreover, it can be tested and deployed on a small scale by many parties. But under current fuel price and economic conditions, none of the solar options appears competitive." The analysis estimates that if goals are reached for utility photovoltaics, a 100-MW field could produce power at a levelized 30-year cost of 18.8¢/kWh.

For all the technologies—coal, nuclear, renewables, or baseload, intermediate, or peaking—residual issues and strategic concerns and opportunities can have an important influence on any utility's capacity expansion decisions. For example, utilities are well aware that their competitors in power generation, even some of their customers, may use such advanced technologies as GCC (particularly as part of a methanol production operation), fuel cells, or, eventually, photovoltaics.

The evolution of advanced technologies can also drive regulatory changes, making what may be proved only on a limited scale today the standard for tomorrow. The lack of sufficient technical and institutional infrastructure for an emerging technology may alternatively impede its commercial availability, with examples including fuel cells and advanced reactors. Public perceptions and related political pressures can come to dominate a utility's choice of technology.

New environmental concerns, such as carbon dioxide emissions or solid-waste management, could pose a potential problem for some advanced coal options and, in turn, make nuclear more appealing. A clear potential for major cost and performance improvements can help maintain utility interest in a currently uneconomical technology.

Because capital requirements for adding new capacity incrementally through retrofit or repowering are likely to be considerably less than building a new facility, the ease with which a technology can be integrated with existing capacity through retrofit or repowering could tilt the balance at some utilities in favor of FBC or GCC options.

The luxury of choice

Despite the lack of a standout among advanced generating options, Vejtasa says that the most positive message from EPRI's comparison is that utilities will have the ability to deal with uncertainty on the supply side in the years ahead. "R&D gives utilities the flexibility to choose technologies that are least likely to give them problems later on, when conditions change. These technologies could form the building blocks for a more-flexible response as conditions continue to move away from business-as-usual to more uncertainty.

"But there's a paradox with flexibility: it costs something. It means that later on, as things play out, whatever you have chosen will not be the optimum because you couldn't have chosen the optimum and enjoyed the flexibility as well," says Vejtasa. "In the absence of an optimal choice, there will always be 20/20 hindsight. But having the flexibility of different options means a utility won't get itself into a bind, but the choice will probably never be quite perfect, either. A true hero perceives or guesses the optimal path and looks real smart when he gets there. Our analysis of advanced generating options for utilities suggests there will be more than one optimal path." ■

Further reading

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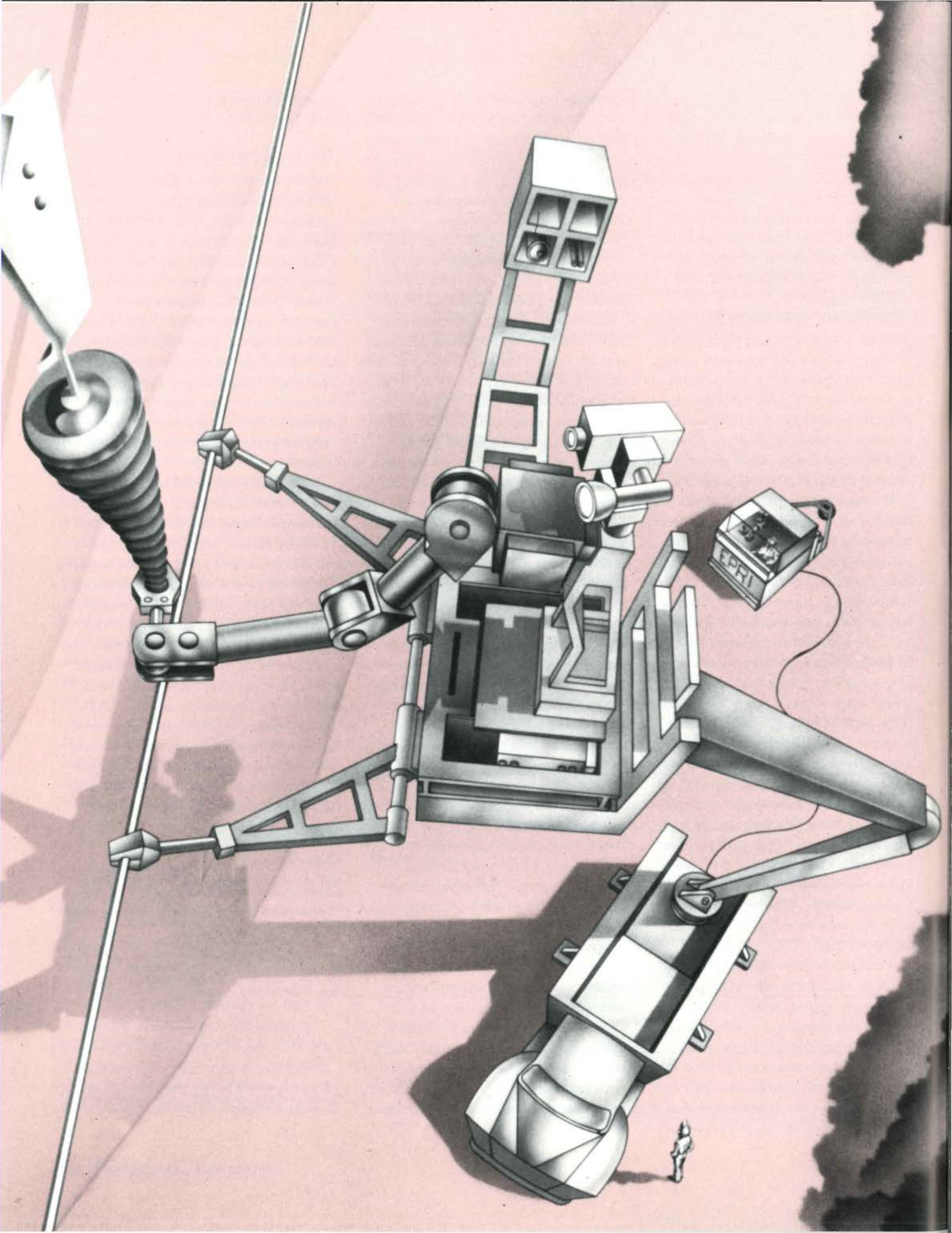
This article was written by Taylor Moore. Technical background information was provided by Stan Vejtasa, Planning and Evaluation Division.


EPRI

Live-Line Repair With Tomcat

When overhead lines are too hot to handle, a new remote-controlled manipulator arm can do maintenance and repairs that would otherwise put half-a-dozen linemen at risk.

Live-line maintenance of overhead transmission systems is a physically demanding task in which the stakes are high and the voltages can be lethal. In order to "barehand" energized lines, linemen must stand on insulated platforms and wear protective suits that are electrically linked to the conductor with tail-like cords. For other live-line tasks, such as insulator changeout, linemen perched on towers or bucket trucks normally touch and manipulate the energized line with insulated tools called hot sticks.

Utilities are increasingly relying on these live-line maintenance methods to ensure system reliability and avoid outages and replacement energy costs of a thousand dollars a minute and more. Live-line maintenance on overhead lines is restricted, however, by the same weather conditions that can damage the lines in the first place. Work must stop if lightning is present or imminent; rain or other precipitation creates prohibitive electrical hazards; and high winds can make it difficult to climb structures and maintain safe clearances. In addition, bitter cold and broiling sun can limit the performance of linemen, who must reach the overhead lines with their heavy, hand-held tools.

The encouraging news from recent industry demonstrations is that the obstacles to live-line maintenance are being surmounted by remote-control technology. A new system called Tomcat, now in the demonstration phase of development, allows linemen to change insulator strings and perform other live-line maintenance tasks while remaining at a safe and comfortable distance from the energized line.

Tomcat (teleoperator for operations, maintenance, and construction using advanced technology) is the first remotely controlled system designed specifically for overhead transmission line maintenance. Its major component is an arm-like mechanical manipulator that can bend at the elbow and wrist, lift heavy objects, and perform delicate manipulations with various tools in its robot grip. Equipped with television cameras, the Tomcat manipulator is mounted in place of the bucket on an insulated boom truck, boosted up to the level of the conductor, and then controlled from the ground by a lineman viewing the work area on a video console.

Because it can be programmed to repeat certain movements automatically, Tomcat can function part of the time as a robot or robotic system. For most applications, however, Tomcat is under direct human control and functions as a teleoperator, or master-slave device. Recently, with its operators seated in a van on the ground, Tomcat passed a crucial test of its ability to change out insulators on an energized overhead line. EPRI research managers expect the system to be commercialized by the end of the decade, with utilities likely to gain large benefits through the improved maintain-ability and reliability of overhead transmission lines and other electrical systems.

Life begins in the ocean

The inspiration for the development of Tomcat came from Philadelphia Electric, a utility that has been a pioneer in the use of insulated tools for live-line maintenance. Joseph Van Name, an operations manager at the utility, hatched the idea in 1976 after inspecting a remotely controlled underwater device used to maintain oil rigs in the North Sea. Although this underwater system was designed to be mounted on a submersible vehicle, it featured the same kind of mechanical arm and video system that would later be incorporated in the Tomcat prototype.

"We had a close look at this underwater manipulator in 1977, when General Electric had one in for maintenance," Van Name explains. "In 1979 we arranged with General Electric to drydock one of these systems so we could demonstrate its potential for transmission line work. When the system showed promise in the demonstration, we presented the concept to EPRI for further development."

The Institute's first response was to study the feasibility of modifying the undersea system into a cost-effective and practical tool for transmission line maintenance. The study identified the potential for a range of overhead transmission applications, including changeout and repair of insulators, conductors, and other transmission line hardware. Adapting the same system for use on underground cables and for the in-service cleaning and replacement of components in switchyard and substation equipment also looked promising.

This initial study also indicated that the system could be a worthwhile investment for electric utilities. "With replacement energy costs for key transmission lines at a hundred thousand dollars an hour and more, it shouldn't take Tomcat long to justify its purchase," says Richard Kennon, the program manager for overhead transmission lines research in EPRI's Electrical Systems Division. "In many situations, the system could pay for itself by saving an hour or two of outage time."

Toughening Tomcat

The positive results of the initial study convinced EPRI to move the project forward and develop a prototype system. Development work was contracted to Southwest Research Institute (SwRI), with additional funding and program direction from the Empire State Electric Energy Research Corp.

A first system, pieced together for laboratory evaluation, was based on one of the commercially available arm-type manipulators designed for undersea use. This hydraulically driven slave was fitted with two television cameras and hot-stick tools specially modified for a trial application: the changeout of a 230-kV insulator string. A master control system, complete with a throttle-like controller and double viewing monitors, was connected to the slave by hydraulic hoses to drive the manipulator and fiber-optic links for both manipulator control and video signal transmission.

As development progressed to the prototype phase, the manipulator was ruggedized to withstand the considerable electric charge it receives while in contact with a live transmission line. Also, the manipulator's feedback controls and the master control system were shielded from the electromagnetic interference generated by energized transmission conductors. To ensure that the new manipulator would remain easy to lift and transport, its weight was kept at 100 pounds. Strength and dexterity, however, were not sacrificed. The current prototype can lift a 55-pound object, bend at the elbow to extend the object 51 inches, and apply 200 pounds of force with its grip. Its wrist joint bends both vertically and horizontally, and it can rotate the tools in its grip a full 360°.

The prototype's control system is equipped with an electronic memory to permit users to program the manipulator to automatically repeat certain operations on command. By first conducting a series of maneuvers in this programming mode, operators can be assured that the system will not go beyond a safe envelope of operation when repeating these motions. This initial step helps prevent accidental contact between the manipulator and the transmission line, which might cause short circuits in the transmission system or damage to lines or towers.

Refinements of the viewing system included full pan and tilt capability and independent control of each television camera. By providing two separate views of the work site, the system compensates for a single camera's lack of peripheral vision and depth perception. With the addition of a spotlight to illuminate work areas, the viewing system can be used for night inspections or repairs.

Tomcat in action

Before the first demonstration of the prototype's ability to change out overhead insulators, the manipulator and the master controls were installed in a conventional bucket truck. The November 1985 demonstration was performed on a deenergized line at Philadelphia Electric's Overhead Transmission Center in Berwyn, Pennsylvania. In the course of these trial runs, personnel from the utility, SwRI, and EPRI were able to establish a procedure of discrete maneuvers for insulator changeout that would be repeated a year later in demonstrations on an energized line.

To change out the 150-pound string of insulators, a rack of specially modified hot-stick tools was first hoisted manually to working level and suspended on a tool line. Operators seated in the back of the truck used Tomcat to support the transmission line with strain poles, select

Working Lines With Hot Sticks

Tomcat is being developed as an alternative or complement to live-line maintenance with hot-stick tools. Use of hot sticks is physically demanding because linemen must manipulate the conductors at a considerable distance with long, heavy tools. Under some circumstances, workers can also "barehand" energized lines while standing on insulating platforms in protective clothing that is electrically linked to the conductor.

tools from the tool line, and use them one at a time. Individual tasks included removing the cotter pins that held the insulator string in place at top and bottom and positioning a lifting prong beneath the insulators. Once the prong was in place and the pins were removed, the operators lowered the insulators manually to the ground on a specially rigged line. To finish the changeout, they hoisted the new insulators to conductor level and then used Tomcat to pin them in place.

These trials on deenergized lines helped demonstrate Tomcat's ease of use. Although some linemen and transmission engineers have expressed skepticism about using such sophisticated equipment for everyday maintenance, the demonstration and subsequent use of the prototype at Philadelphia Electric have shown that experienced linemen can quickly learn to control the system.

"Tomcat can be programmed to repeat some basic operations automatically, but its use doesn't require any experience in computer programming or robotics," comments Jerry Henkener, a research manager at SwRI who helped design the prototype. "As we've demonstrated, this is a hands-on tool that helps experienced linemen use their skills to better advantage."

Charles Zebraski, a veteran Philadelphia Electric lineman who has operated the system in tests and demonstrations, adds his perspective: "I don't foresee any barrier to this system's being accepted or learned by linemen. Rather than sitting up there cooking in the sun while trying to change a string of insulators in 90° heat, the lineman could do the same work from an air-conditioned cab."

Real-life conditions

Doubts about the usefulness of Tomcat were dispelled further when the system had a chance to prove itself in work on energized equipment. For its first in-service application (in 1985) Tomcat was equipped with a water-lancing tool and

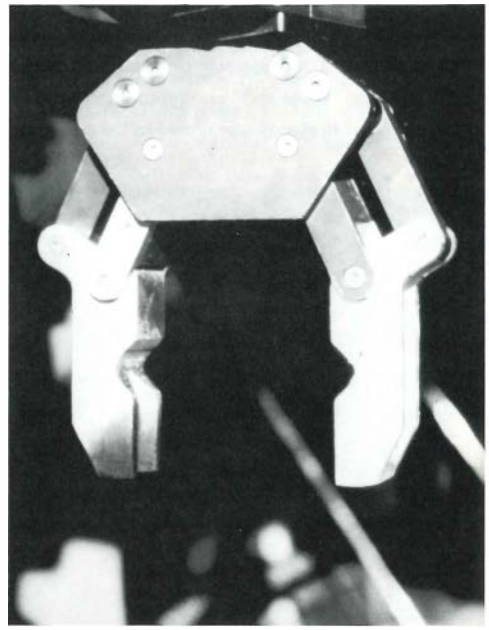
Live-line Maintenance by Remote Control

Safe from electrical hazards and inclement weather in the cab of a specially fitted bucket truck, a lineman controls the Tomcat manipulator to perform such tasks as insulator changeout and inspection of transmission lines. The arm is driven by a hydraulic system, with the operator's view provided by fiber optic links to dual closed-circuit television cameras that can be used with a spotlight for night work. For most tasks the operator directly controls the manipulator to grip and use a selection of modified hot-stick tools, but the system can also be programmed to automatically repeat certain movements on demand.

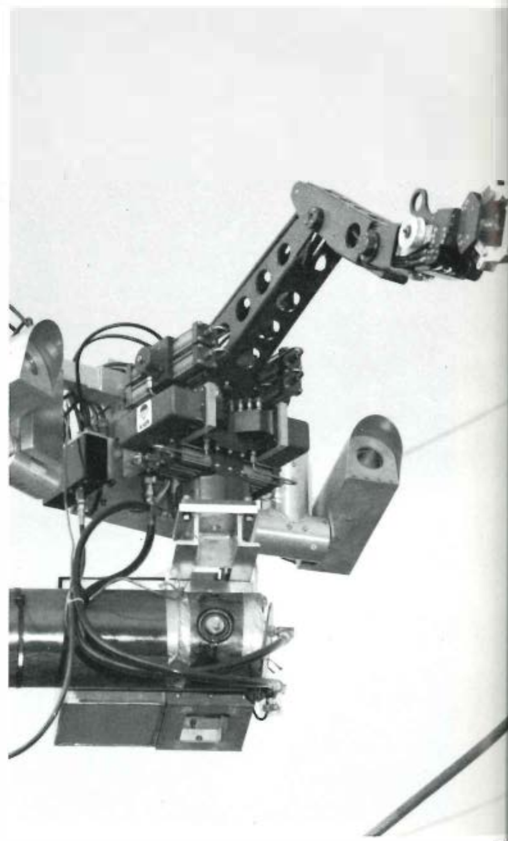
Control booth in modified bucket truck

Master control system

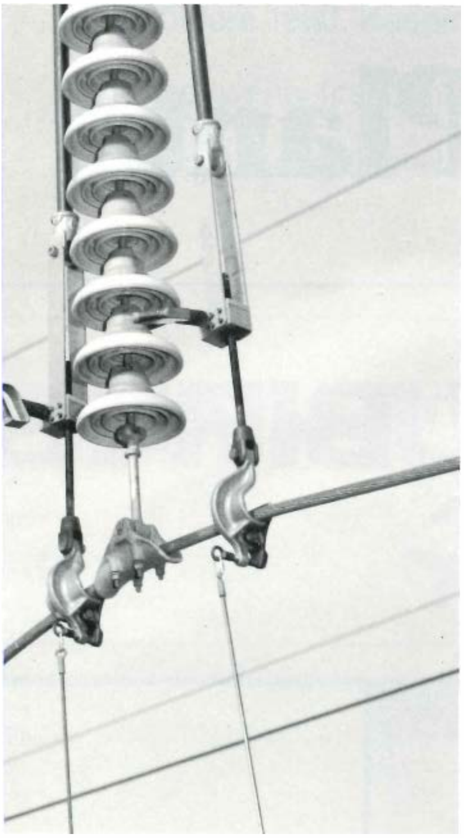
Mechanical hand for gripping tools



Insulator changeout



System mounted on boom vehicle



used to clean transformer cooling coil fins in the switchyard of Philadelphia Electric's Peach Bottom nuclear power plant. Later, toward the end of 1986, Tomcat repeated its earlier success in changing insulator strings, this time on a fully energized 230-kV line at EPRI's High-Voltage Transmission Research Center in Pittsfield, Massachusetts.

For the test at the HVTRC, Niagara Mohawk Power Corp. provided material to build a wood-pole H-frame structure to support a 230-kV line. All three phase conductors were strung between poles, with the center phase weighted with concrete cubes to represent the load of a full span of wire. Tomcat was then used to replace the center-phase insulator string in about the same time needed to do the job with hand-held hot sticks.

Now that Tomcat has cleared the hurdle of energized lines, researchers under contract to EPRI are working to develop and refine a large array of special hot-stick tools for the system. The goals are to improve its quickness in completing jobs and to expand its applications. As demonstrated at Peach Bottom, Tomcat has the potential for many inventive uses. In time, these may include the washing of insulators, the mending of frayed conductors, and the cleaning and repair of many different kinds of substation and switchyard equipment. The system also has a large potential for live-line maintenance on underground transmission cables, a kind of work that is often restricted or complicated by rain and runoff filling manholes and underground vaults. A. B. Chance Co., a leading manufacturer of hot-stick tools used in conventional live-line maintenance, has been granted a license by EPRI to commercialize the system after its potential is fully developed and demonstrated.

In the meantime, developers at SwRI are working to enhance the system's reliability by hardening it further against both electric charging arcs and electromagnetic fields. In addition, a more compact base is being developed for the manipulator so that accidental contact with a conductor or tower will be less likely.

Before commercialization, developers are likely to integrate the entire system into a single streamlined and self-contained package without exposed hydraulic hoses or control cables. "The first commercial version of the system may be designed for retrofitting on existing utility vehicles, or it may also be marketed with the manipulator mounted on a boom vehicle and the controls installed in a specialized van or truck," explains Kennon. "There are several packaging and applications decisions to make before Tomcat is ready for commercialization."

A future enhancement just now being considered is a force feedback system that will allow the operator to feel the effect of his actions through a corresponding pressure on the controls. This may expand the system's ability to perform the very delicate manipulations involved in some kinds of conductor repair.

In the near term, an especially important step for Tomcat will be to perform demonstrations of insulator changeout and other tasks on energized lines in the field. All system components are now ready to perform effectively in such demonstrations, which are likely to mark the beginning of widespread use of Tomcat in the utility industry. ■

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This article was written by Jon Cohen, science writer. Technical background information was provided by Richard Kennon, Electrical Systems Division.

Longer Life for Fossil Fuel Plants

Many utilities now face major decisions about their older fossil fuel power plants. By 1990 more than half of U.S. fossil fuel plants will be more than 30 years old. Traditionally, that has been their expected useful lifetime, based on the assumption that new generating units would be added to meet load growth requirements and produce power at lower cost because of advances in technology. In recent years, however, slower load growth and the increasingly high economic risks associated with building new plants have made many utilities consider ways to improve the performance of older units and keep them on-line well beyond originally anticipated retirement dates.

Unlike the celebrated "one-hoss shay," which kept on going until it completely fell apart, a power plant doesn't so much wear out as become uneconomical to use. Given careful operation and maintenance, a plant can continue to generate power safely and reliably for 50 to 60 years, or longer. The challenge now facing utilities is how to make such performance improvement and life extension more economical.

Major decisions

A wide spectrum of options is available to utilities that are trying to get the most out of their aging fossil fuel plants. At one extreme, a utility with zero load growth and excess capacity would probably choose to derate or even decommission some older plants. At the other extreme, a utility with continued load growth and low reserve margins would probably benefit from upgrading some existing plants.

Several major decisions have to be made before choosing among the available options. A utility must determine what levels of availability and efficiency are acceptable from an older plant, given the increasingly difficult task of main-

taining it. The effect of significant changes in inspection and maintenance procedures also has to be considered. And the utility has to judge the level of investment it can budget over an additional 20–40 years to sustain a plant. Depending on the outcome of such decisions, specific technologies and procedures can be evaluated. Upgrading, for example, could involve conversion to fluidized-bed combustion, with its advantages of greater fuel efficiency and inherently low emissions. A less-ambitious program might focus on reducing forced outages by requiring more-frequent and more-detailed inspections. Such a program has reaped considerable success on a nationwide scale in Japan, where reserve margins are considerably lower than those in the United States. There, for example, boilers are inspected every year and turbines every two years.

EPRI's strategy is to provide utilities with both the analytic tools that can help in making major decisions about older plants and some increasingly sophisticated monitoring technology that can help in implementing the option chosen. Recently published generic guidelines outline a phased approach to fossil fuel plant life extension that utilities can use to help establish programs related to their own needs. Economic analysis of related case studies shows how such programs can save a utility hundreds of millions of dollars, compared with the cost of replacing older plants. EPRI is now working with 10 utilities to determine how the generic guidelines can best be implemented.

Economic advantages

Over the lifetime of a typical utility power plant, the cost of producing electricity often follows a broad U-shaped

The utility industry has a large investment in fossil fuel plants built before 1960. Keeping these plants operating economically into the twenty-first century is becoming more and more important for utility system planning.

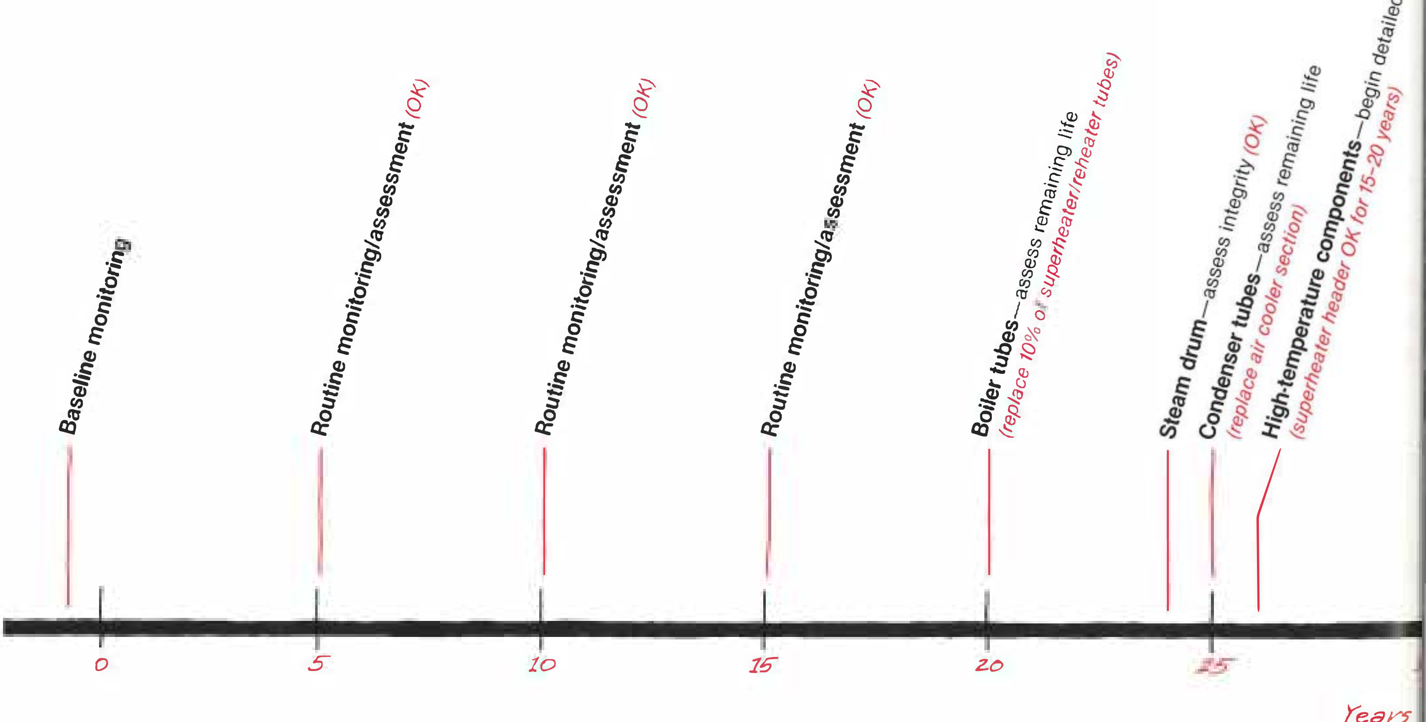
curve, commonly known among planners as the bathtub curve. Early in a plant's life, costs fall rapidly as utility personnel become familiar with the new equipment and put it through a shakedown period. A long period of relative cost stability follows, until costs begin to rise as increased expenditures are required to maintain the aging equipment. Such expenditures are accelerated if a plant is shifted to cycling or peaking duty.

Several factors make life extension programs strategically attractive at the present time. Such programs are generally less capital-intensive than new plant construction. Depending on the specific plant characteristics, investments in the range of $125/kW to $625/kW could be expected for life extension, compared with $1300/kW to $1900/kW for a new plant. In addition, life extension usually involves relatively short lead times and can be implemented in small increments. The programs may, however, require a relatively long payback period because major economic benefits are greatest after the time when new capacity—with its heavy up-front costs—would otherwise have had to be built.

To evaluate the economic advantages of life extension more precisely, EPRI researchers interviewed utility personnel and proposed representative case studies that illustrate a range of scenarios. These analyses confirmed that life extension generally offers the highest savings for plants with high utilization factors, large potential for performance improvement, low variable costs, high replacement power costs, or opportunities for off-system sales of electricity. The case studies showed that some utilities could save hundreds of millions of dollars through a systemwide program of life extension. "Utilities have been considering several nontraditional alternatives to investment in new generating capacity," says Dom Geraghty, who was project manager for much of the economic analysis of life extension. "They are considering load management options, conservation programs, and cogeneration, in addition to extending the life of certain

Preventive Maintenance—A Sample Schedule

Close monitoring and regular assessment of components are the surest ways to maximize the useful life of a power plant. A regular inspection schedule, such as the much simplified example shown below, anticipates the most likely problems for major component groups and allows repairs to be handled largely during scheduled outages.

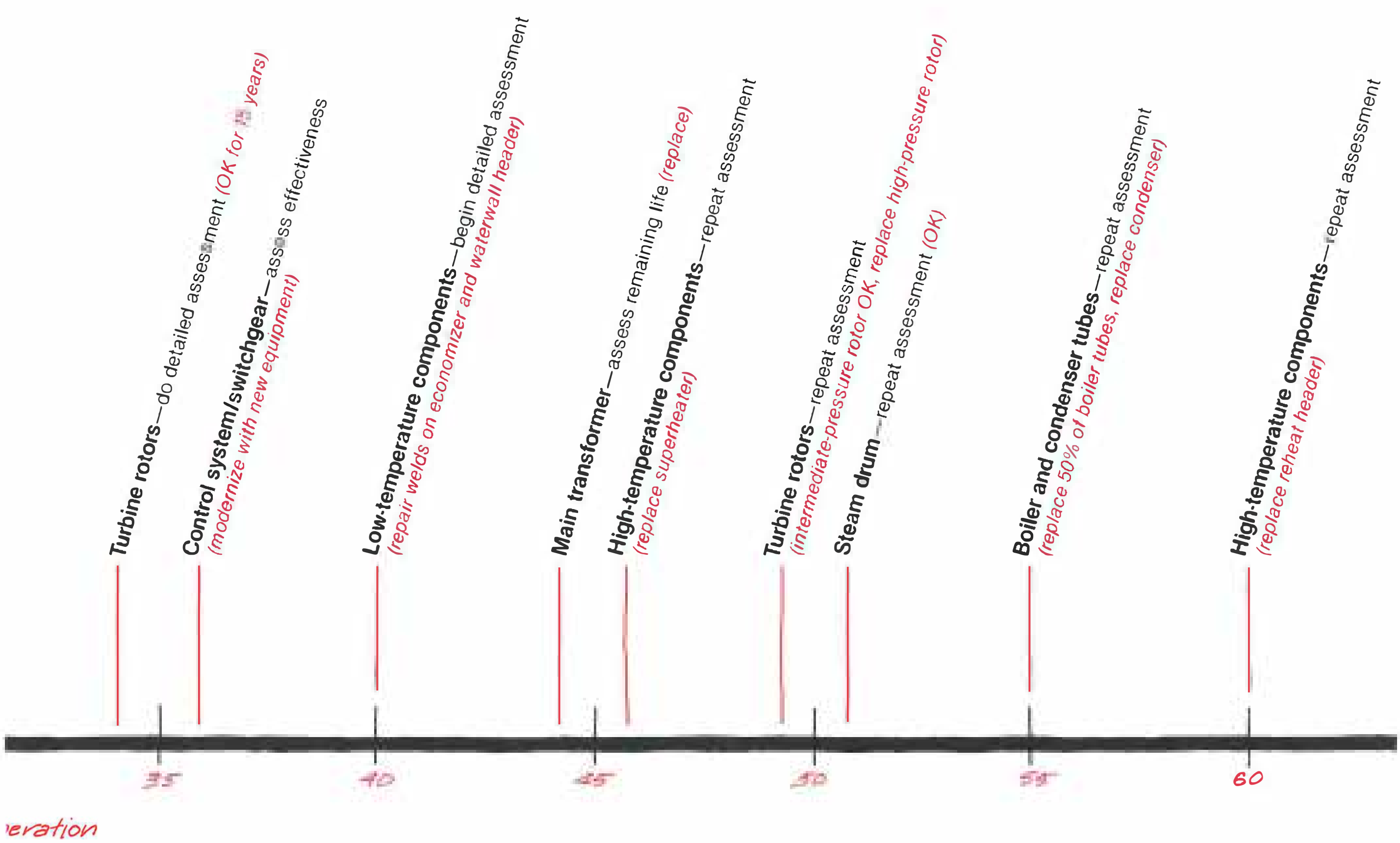


plants. Our work has shown that life extension programs can be very attractive but that they need to be evaluated systematically, with fair comparison with other options in terms of how they meet broad corporate objectives."

A four-stage strategy

Just such a systematic approach is presented by the recently published *Generic Guidelines for the Life Extension of Fossil Fuel Power Plants* (CS-4778). These guidelines were developed for EPRI by Daedalus Associates and Delian Corp., based on specific life extension projects at several U.S. utilities and on information gathered from foreign utilities. The purpose of the guidelines is to encompass this technical experience in a framework that other utilities can use to develop life extension programs tailored to fit their individual needs. The guidelines are organized around a life extension strategy that consists of four sequential stages: corporate planning, plant assessment, component assessment, and refurbishment and follow-up. Information from each stage is brought together in a computerized data base called the Integrated Life Extension Management (ILEM) Model. During the first stage, corporate planning, a benefits analysis is performed that considers a broad range of life extension alternatives. Much of the work in this stage consists of gathering and analyzing data related to the entire utility system. The eventual product includes a ranking of plants to be considered for life extension, based on their economic value to the system as a whole, together with an estimate of costs and a schedule for implementation.

Historical data on specific candidate plants are gathered and analyzed during the second stage. This information can then be evaluated in the context of data from sister plants, available from the North American Electric Reliability Council (NERC). One of several approaches can then be used to rank critical plant components for further study. One utility, for example, might rank components on the basis of expected remaining life, postponing further action until



necessary. Another utility might prefer to act immediately to refurbish equipment whose improved performance would provide the fastest payback. Yet a third might focus on preventive maintenance at its highest-value generating units.

The component assessment stage leads up to a final decision on which components in the selected plants will be refurbished and the schedule for doing so. This stage involves a three-level assessment of various components to estimate their remaining life expectancy and to refine estimates of refurbishment costs. Each level requires more-accurate data and more-rigorous inspection of individual pieces of equipment. If the assessed remaining life of a plant component is less than the proposed life extension period for that plant, the utility then decides whether to repair, modify, or replace it. Once these critical decisions have been made, refurbishment of a plant can proceed through normal procurement procedures, usually during regularly scheduled outages. As part of this final stage of life extension, several follow-up activities may be needed to maintain performance of the refurbished plant. These activities might include, for example, the use of on-line monitoring systems to fine-tune operations at a plant or the establishment of a special data base and inspection system to track the history of major pieces of equipment throughout a utility.

EPRI has developed a variety of monitoring systems that can help utilities bolster inspection and improve plant availability. A boiler stress analyzer, for example, tracks long-term creep fatigue in headers, drum, and steam lines. A computer-based vibration monitoring system can detect such damaging conditions as misalignments and blade rubbing in turbine generators, pumps, and fans in time to prevent major failures. EPRI studies have indicated that 30–50% of all plant downtime is attributable to problems in such rotating equipment.

"Much of what we've included in our life extension guidelines is already standard practice in other countries," says Project Manager Barry Dooley. "The monitoring and assessment procedures we're suggesting can be applied to new plants as well as old—and doing so will help increase plant availability later in life. That's why a phased approach is so important. It enables a utility to plan ahead and minimize outage time."

Case studies

The experience of several utilities throughout the country helps to illustrate some of the benefits that can be expected from life extension programs. A particularly useful example is provided by Potomac Electric Power (Pepco) because postrefurbishment data are available to compare with forecasts made before the work was done. This program involved five units at the company's Potomac River station, ranging in age from 28 to 36 years. Analysis of the units began with an extensive review of Pepco and NERC data on plant availability and later included a comprehensive inspection plan and a materials sampling program. As a result of these efforts, a decision was made to refurbish some components in each of the generating units. Third-stage superheaters, for example, were replaced in three units, boiler casings were patched in two units, and turbine rotors were replaced in two units—in addition to other work.

Results for Unit 1 show that before refurbishment, availability at the unit had been declining steadily, but after major boiler work, availability of the unit rose 9%. Similarly, net heat rate at the unit was lowered to 12,600 Btu/kWh from a projected 13,200 Btu/kWh, which would have been expected if refurbishment had not taken place.

A case study sponsored by EPRI involved a systemwide assessment of 15 coal-fired and 2 oil-fired units at Consumers Power. Scenarios were developed that assessed the value of individual life-extended units to the system as a whole. The study concluded that all the company's existing fossil fuel plants would make good candidates for a life extension program and that both customers and investors would thus benefit.

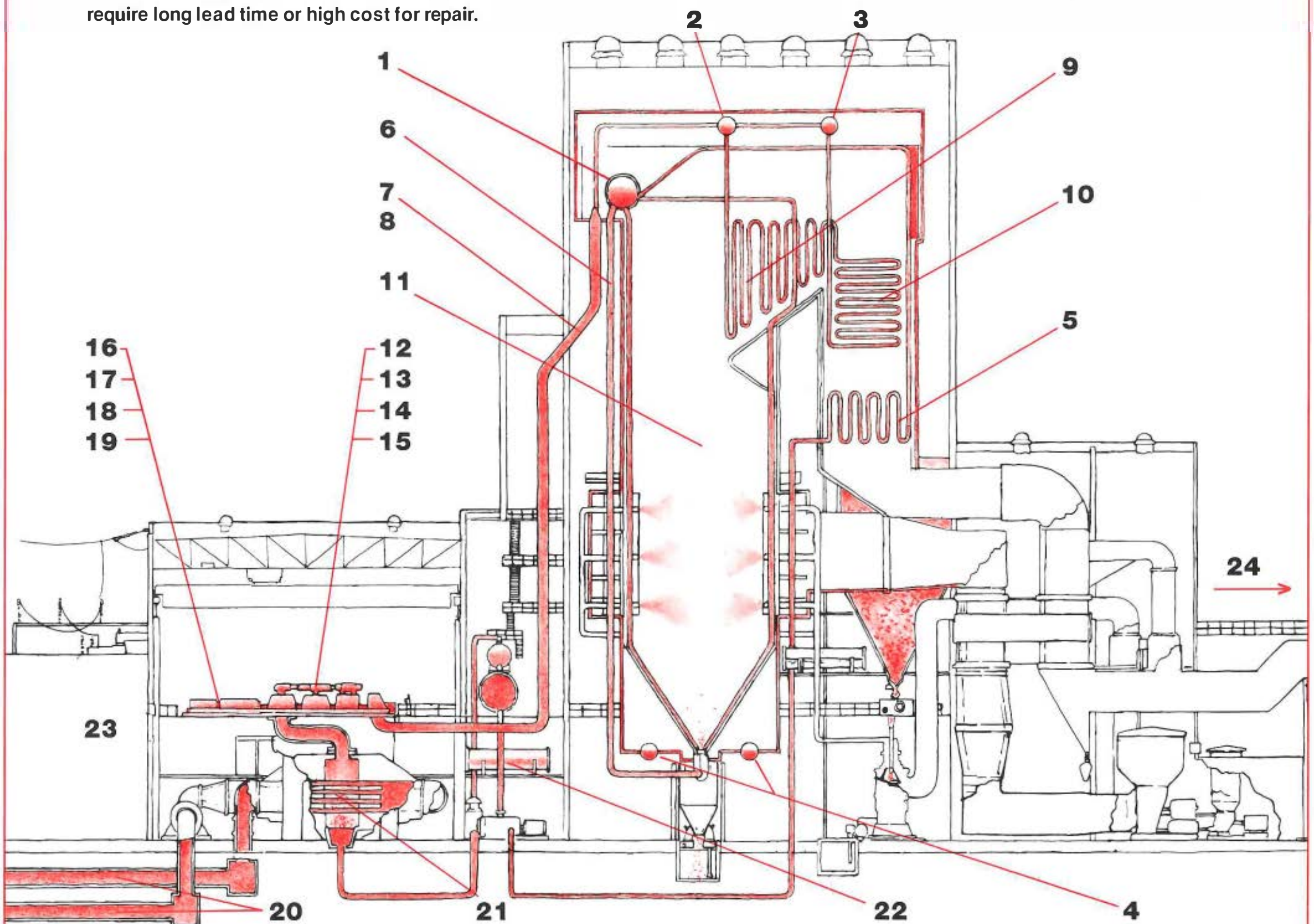
"This work has helped us identify some problem areas and gives us a head start if plant modifications are undertaken," says John Reynolds, who was the utility's project manager for the case study. "One benefit was to show that the long-term phased approach is the most rational. A couple of years ago vendors were beating the bushes for major plant overhauls—lump sum projects. Our work with EPRI shows that this is not necessarily the most economical approach. A better idea is to pursue enhanced maintenance." Similar convictions are expressed by Richard Borsellino, the supervisor of mechanical engineering at Niagara Mohawk. "A phased approach," he says, "is paramount to any successful life extension program. If you miss any step, then later on you could wind up without enough information on a systemwide basis to justify the work needed. By conducting the sort of systematic assessments needed to answer that question, we've learned a lot about our equipment and discovered flaws that might have gone unnoticed in routine examination." He concludes that correcting these problems is a modest expense compared with building new capacity—about $200/kW for most of the Niagara Mohawk plants examined so far.

Risk assessment

Although the costs and risks associated with life extension programs are much smaller than those involved in building a new plant, various uncertainties have to be taken into account. Some of these uncertainties are related to unforeseen malfunctions or catastrophic failures at refurbished plants, and their effect can be

Critical Components

About two dozen critical components are responsible for the majority of problems in aging fossil fuel plants. Their failure, resulting from such mechanisms as fatigue, creep, corrosion, erosion, and mechanical wear, can force an outage, endanger plant personnel, or require long lead time or high cost for repair.



1 Drums
2 Superheater headers
3 Reheater headers
4 Waterwall headers
5 Economizer inlet headers
6 Downcomers
7 Main steam piping
8 Hot reheat piping
9 Superheater tubing
10 Reheater tubing
11 Waterwall tubing
12 Turbine valves
13 Rotor
14 Steam chest
15 Turbine casing and shells
16 Rotor shaft
17 Stator windings
18 Stator insulation
19 Retaining rings
20 Intake and discharge structures
21 Condenser
22 Feedwater heaters
23 Main transformers
24 Stack liners

analyzed by using available risk assessment tools. Less amenable to analysis, however, are the uncertainties that result from unresolved regulatory issues. To help with technical risk assessment in a life extension program, EPRI has developed a microcomputer spreadsheet that can quickly analyze a variety of scenarios. This model was developed by contractor Temple, Barker & Sloane, which was also involved in most of the other EPRI work on the economics of life extension. For each utility, this relatively simple spreadsheet can be individually calibrated with two runs of a large production cost model. Using the microcomputer model, risk assessment relevant for life extension has been demonstrated for a sample project involving a cracked turbine rotor. Three increasingly sophisticated types of analyses were performed, including identification of critical variables, determination of an economic breakeven point within a given range of variables, and a probabilistic analysis involving joint occurrence of undesirable events. These analyses were conducted by considering the economic risks of three different strategies: immediate retirement of the plant, replacement of the rotor in kind, and upgrade of the turbine in conjunction with rotor replacement.

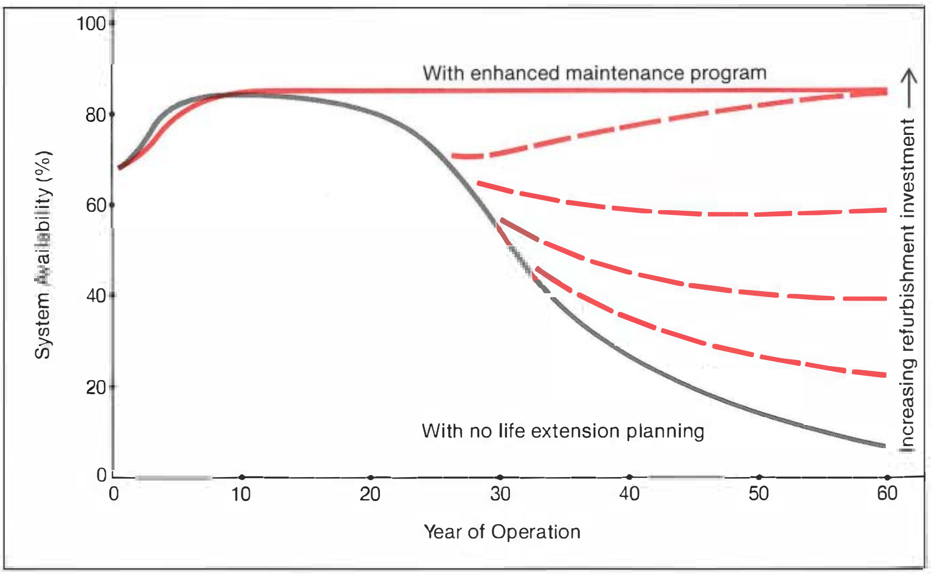
According to the scenario judged most likely, simple replacement of the rotor would return $13.5 million (net present value) on an investment of $4.7 million, whereas upgrade would return $13.9 million on an investment of $6.6 million. The probabilistic analysis showed, however, that the upgrading strategy involved more downside risk than did the replacement strategy. "Actual results for a real utility would depend on specific circumstances," comments EPRI's Dom Geraghty, "but the fact remains that there will be considerable uncertainty about the availability and reliability of a life-extended plant. If, in a particular situation, a plant had a catastrophic failure within 15 years after refurbishment, the utility could suffer a net loss on its investment, depending on such factors as demand growth and capacity margins."

Far more difficult to estimate are the risks involved in questions of compliance with air quality regulations. According to the Clean Air Act, if the cost of refurbishment exceeds 50% of a "comparable new facility," a plant may be deemed "restructured" and thus subject to New Source Performance Standards (NSPS). This regulation has not yet been tested, and utilities are unsure whether the 50% trigger refers only to a one-time capital expenditure or to aggregated refurbishment costs over several years. In addition, an extended-life plant could also be subject to NSPS if the emission rate of any pollutant covered by these standards is increased by refurbishment. Congress is now considering several pieces of legislation related to this issue. The most stringent would require all plants that are 30 years old by 1991 to retire or comply with NSPS.

The bill would also require all units to meet stringent emissions requirements

Approaches to Life Extension

Experience has shown that as a generating unit nears the end of its useful operating life, deteriorating component reliability sharply reduces the plant's availability. Life extension procedures begun around year 25 generally require major plant refurbishment, with the results roughly proportional to the amount of additional investment. Some utilities have found that an enhanced maintenance program over the entire life of the system, involving relatively modest efforts beyond a standard program, will avoid the availability dip altogether. This approach has the advantage of spreading the incremental cost of improvement over the entire operating life of the plant.



or be restricted in their total hours of remaining life. Additional legislation on acid deposition could also affect a utility's ability to extend the life of certain plants. Whether life extension would remain economically attractive if refurbished plants had to comply with NSPS would depend on the specific cases.

"NSPS compliance is a risk that depends on regulatory interpretation," responds the manager of life extension projects at a major eastern utility. "But even if we have to comply, the dollars involved are still less than the cost of a new unit—unless there's some specific problem like not enough room at the site for adding a flue gas desulfurization unit." Utilities are also considering a variety of new clean coal technologies, such as advanced coal cleaning and sorbent injection, that might ultimately be retrofit on older plants with lower cost and operating impact. Yet another alternative already being demonstrated by the utility industry is refurbishing, repowering, and reducing emissions with fluidized-bed combustion.

Preparing for the future

The next stage in EPRI's work on fossil fuel plant life extension will be a series of demonstrations involving use of the generic guidelines at 10 utilities. This two-year demonstration program is already getting under way, with selection of contractors and host utilities. The goal of this work will be to demonstrate the generic guidelines by having each utility determine the approach to life extension that best meets its individual needs. Actual plant refurbishment would follow later, and its cost is not included as part of the demonstration program. As a first step, contractors will prepare training materials for three major areas of activity: corporate planning, residual life assessment, and development of the ILEM model. These materials can then be used by utility personnel to choose various planning options and determine the most cost-effective way to do plant life extension assessments. Contractors will provide technical support to the host utilities as they proceed in implementing the guidelines. "We're choosing host utilities to cover a spectrum of needs," says Barry Dooley. "Some utilities have extensive inspection programs in place and might only be interested in adding the ILEM model. Others are just beginning and would start at the earliest stages of corporate-level planning. On the basis of the experience gained in these demonstrations, we expect to get better estimates of costs and benefits for different life extension approaches. We'll also be updating the guidelines themselves from what we learn."

Even before the guidelines were published, EPRI held a series of life extension advisory group meetings that provided an opportunity for both technology transfer to utilities and feedback on various approaches. Such direct, two-way communications between EPRI and member utilities on the subject of life extension will continue in conjunction with the demonstration program. "I got a lot of help from EPRI, even though we're already using our own phased approach," comments Herbert Stowe, plant life extension project manager for New England Power. "The advisory meetings were tremendously effective; they provided a smorgasbord of choices from what other people were doing. It's nice to see we aren't working in a vacuum." New England Power is now in the second stage of a life extension program involving detailed inspection of all its generating units over a five-year period.

Another EPRI effort may affect how utilities approach life extension issues related to rising competition in electric power supply. A recent EPRI study was conducted on how such increased competition could lead to new production strategies. Life extension was considered as a key option for reducing costs and increasing profitability.

Under the previous, less competitive conditions, the report concludes, prolonged outage or retirement of a plant at a particular utility would probably result in less electricity supply for a given customer demand and thus result in higher prices for electric power. In today's increasingly competitive marketplace, however, prolonged outage or retirement of the plant would more likely result in a loss of market share to another supplier. In one example considered during the study, retirement of a coal-fired plant resulted in loss of about 80% of the sales represented by the plant's output.

"Today's marketplace for electric power is rapidly rendering older production strategies obsolete, and life extension programs have to be considered in that context," concludes Geraghty. "If we adopt a price-driven perspective, instead of the load-driven perspective of the past, one of the main opportunities a utility has to improve its competitive position is through improving the performance and extending the lives of existing plants. In addition, we can also help improve the productivity of the U.S. economy by making fullest use of valuable existing assets." ■

Further reading

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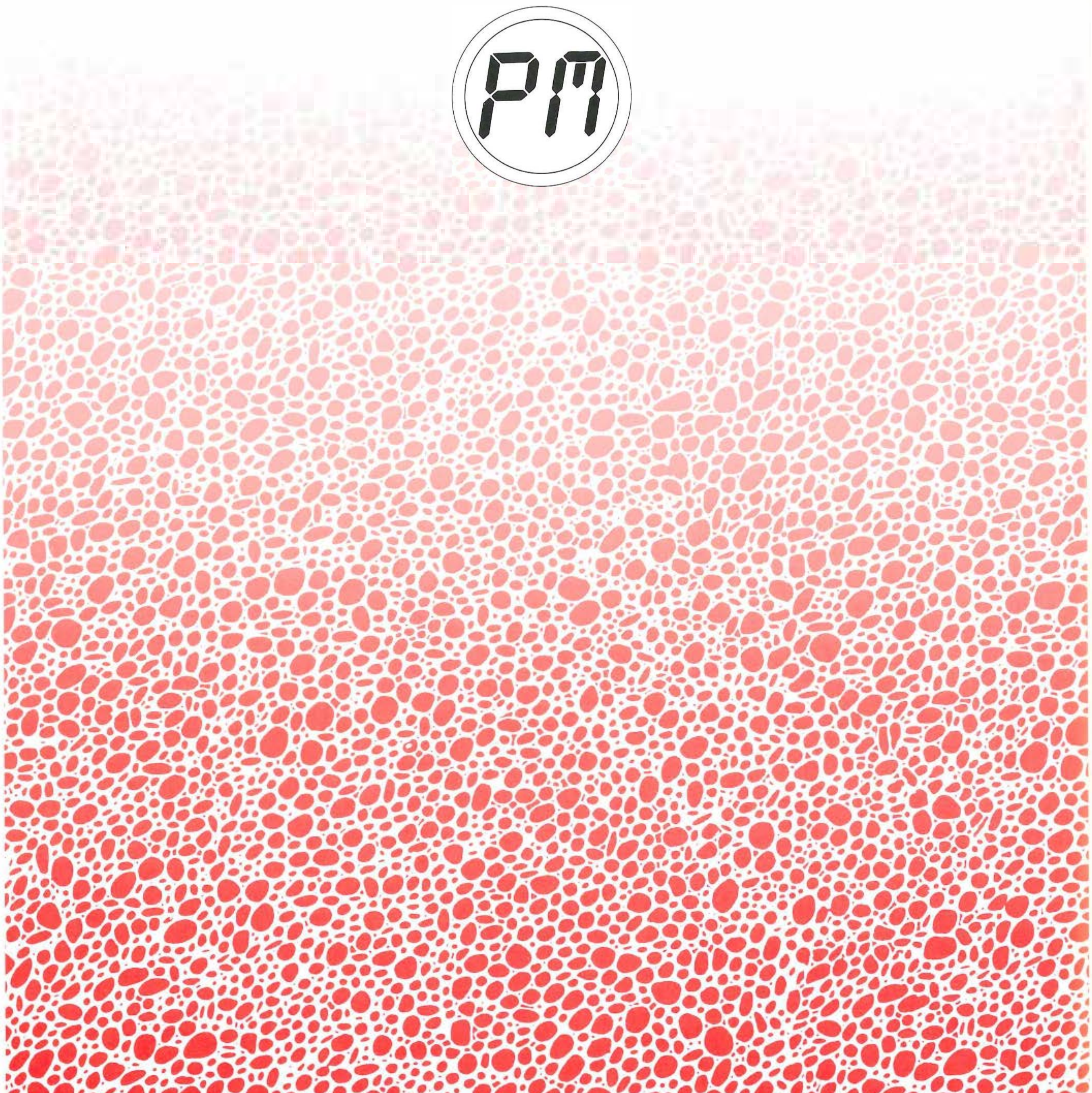
This article was written by John Douglas, science writer. Technical information was provided by Barry Dooley, Coal Combustion Systems Division, and Dom Geraghty, assistant to the executive vice president of research and development. Additional information was provided by Jeff Byron, Ed Cichanowicz, and Mike Miller, Coal Combustion Systems Division, and by Stan Vejtasa, Planning and Evaluation Division.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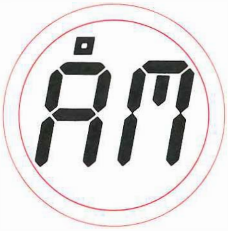


ROCKS AROUND THE CLOCK

A new
heat storage furnace
that uses
ordinary crushed rock
allows customers
to do
daytime heating
at nighttime
electricity prices.

Electric thermal storage (ETS) for space heating is a time-tested concept that is just now becoming competitive in the U.S. energy market. Europeans, faced with limited supplies of fuels and electricity, have used electric storage heaters for more than 30 years to generate heat during off-peak nighttime hours, store it in ceramic bricks, and then use it during daytime periods of peak demand. ETS space heating is a part of life in millions of European homes today, including 7% of all residences in Germany and more than 14% in England and Wales.

The European experience shows that ETS can be an effective customer-side tool for utility load management. Utility customers with heat storage systems can shift all their space heating demand to off-peak hours and shave load from the next day's peak, a pattern that can help utilities make more-efficent use of baseload capacity and, in some situations, avoid huge costs for building new power plants. These potential benefits are especially enticing to the hundreds of utilities in the United States with poor winter load factors. Nevertheless, ETS space heating has yet to win widespread acceptance among consumers in the United States. The high initial cost of the equipment has been the main obstacle.

Now, however, ETS space heating is about to get a boost from a new kind of central storage furnace that will outperform previously available systems, while costing significantly less. The key to these cost and performance improvements is a new material to replace the expensive ceramic bricks used as heat storage media in other ETS furnaces. This ground-breaking material is not the high-tech polymer or aerospace alloy one might expect from today's science, but is ordinary crushed rock.

Developers under contract to EPRI, working with individual utilities, have produced a crushed-rock heat storage furnace that will become commercially available in 1987 at a cost 30–40% less than comparable ETS systems. Called Thermostone III by its manufacturer, CaliDyne, Elk River, Minnesota, the furnace is likely (according to a recent EPRI market assessment) to achieve several thousand residential and commercial installations by the end of the decade and significantly expand the market for central ETS space heating. "ETS is a sleeping giant," says Vance Zehringer, manager of energy management at the United Power Associaton, a utility cooperative in Minnesota. "And the utility industry is using hot rocks to help wake him up."

Charging up on the night shift

In the early 1980s scientists under contract to EPRI identified excellent heat storage properties in an inexpensive basalt gravel—the same material is used as ballast for railroad tracks. "The original materials research was related to compressed-air energy storage systems, but those of us investigating ETS saw the potential for using the same crushed rock to reduce the cost of heat storage furnaces," explains Veronika Rabl, manager of EPRI's load management technologies.

Subsequent R&D led to the commercialization of the concept by CaliDyne, which is now filling orders for the system in three sizes of storage capacity: 130, 160, and 190 kWh. The 130-kWh unit is designed to meet the space heating needs of a typical three-bedroom house or a small commercial establishment, with the more powerful units built for larger homes or businesses.

From the outside, the CaliDyne furnace appears as a 78-in-tall steel hexagon and an adjoining rectangular box that together occupy (depending on storage capacity) between 13 and 16 ft^2—a footprint no larger than that of comparably powerful ceramic systems. The rectangular unit holds a fan and conventional electric resistance heater. The crushed rocks are contained in the attached hexagonal unit, or storage chamber, which is insulated inside with a thick vermiculite lining. The storage chamber is assembled from 24-in-high modular sections that can be carried easily down stairways and through narrow doors.

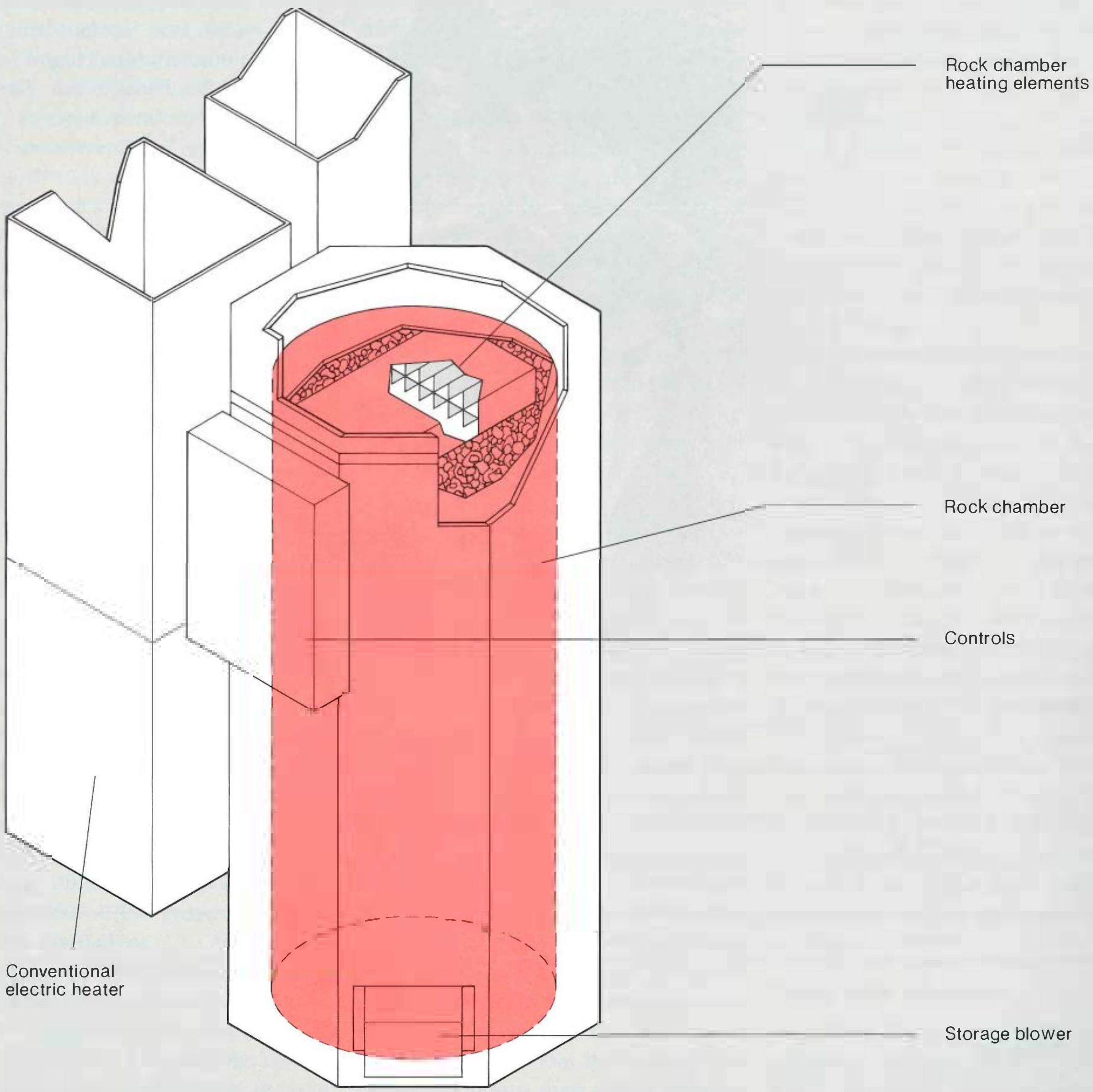
During the night, while the conventional heater provides space heating, separate heating elements at the top of the storage chamber are activated to heat the crushed rocks. A special storage fan at the bottom of the chamber draws air past these heating elements and down through the rock bed, charging the rocks to temperatures as high as 1050°F. When daytime comes, the storage fan is reversed to push air through the hot rock bed and mix it with the return air stream to provide space heating.

Although this system is more complex than conventional electric heating, it is not difficult to operate. The owner adjusts temperature in the home or business with an ordinary thermostat; the furnace does the rest of its work automatically. An outdoor temperature sensor, linked to controls in the storage chamber, determines the amount of heat needed to charge the rock bed at night. If outdoor temperatures indicate that only moderate heating will be needed the next day, as often happens in spring and fall, the rocks get only a partial charge. Both partial and full charging are controlled by a random timer that protects utilities from the possiblity of numerous systems in a service area starting up at the same time. In addition, internal sensors measure and control the temperature of the rocks. If enough heat for the following day is already in the rock bed, a signal turns off the storage heating elements.

This control system helps the owner take advantage of the unique heat storage properties of the crushed rock. Compared with ceramic bricks, the crushed rock offers more surface area for heating and cooling and shorter conduction paths from the surface to the center of the rock fragments. The rocks are easier to heat to a uniform temperature than are

The Crushed-Rock Furnace in Operation

The CaliDyne crushed-rock ETS furnace is used in residences or business establishments to shift space heating requirements to off-peak hours. At night, space heating is provided by a conventional electric heater and blower positioned adjacent to the rock chamber. But at the same time, special heating elements at the top of the rock chamber and a separate, reversible storage blower are used to heat the bed of crushed rock. During daytime hours the storage blower is reversed to move air over the charged rock bed and to supply space heating. An automatic control system, linked to temperature sensors in the furnace and outdoors, regulates the heat received by the rock bed and prevents energy from being wasted on mild days.



A Comfortable Alternative

Utility incentives and the low cost of the crushed-rock storage media combine to make ETS systems more competitive with such alternatives as oil-fired furnaces. The table below, which assumes a $600 utility rebate, compares the capital and operating costs of the CaliDyne furnace with an oil-fired furnace in a new, insulated three-bedroom house in Minnesota.

		ETS	*Oil*
Capital Cost	Furnace	$2250*	$1200
	Installation	1000	800
	Ductwork	1100	1100
	Chimney		400
	Tank		200
	Rebate	– 600	
		$3750	$3700
Operating Cost**		$620/year	$706/year

*Price will depend on quantity purchased by distributor.

**Assumes 22,150 kWh at 2.8¢/kWh and 830 gal No. 2 Oil at 85¢/gal.

ceramic bricks and are faster at relinquishing heat when exposed to cooler air. Because of these properties, the furnace can self-adjust to the heating requirements, storing progressively less heat during a prolonged period of low demand. This saves electricity for the owner, while also minimizing heat losses from the chamber that could overheat a home or business on a mild day. Some loss of heat from the storage chamber is inevitable, but the crushed-rock furnace keeps unrequested heat below levels where it might cause discomfort.

Overall, the crushed-rock furnace is equally as clean, comfortable, and convenient as conventional electric heating systems. "ETS is more than a load management tool; it's also a means to provide people with the benefits of electric heating," says Henry Courtright, residential marketing manager at Pennsylvania Power & Light. "Customers warm up to the concept when they learn that it doesn't affect their lifestyle."

A key role for utilities

Even though the performance of the crushed-rock furnace is crucial to its ability to compete in the marketplace, it arrives as a product that must have active utility support to succeed. At a purchase price somewhere between $2000 and $3000 (depending on quantities purchased), the furnace represents a 30–40% saving over ceramic brick central storage furnaces; yet, it is still likely to cost more to buy and install than conventional electric heating or fossil fuel furnaces. For a typical installation of a central crushed-rock furnace, the customer may still be looking at an installed cost some $500–$1000 greater than conventional alternatives.

To compensate the consumer for this added investment, dozens of U.S. utilities are marketing ETS systems with such incentives as low, off-peak electric rates and cash rebates. Most of the programs promote a full range of ETS technologies, including room heaters, storage water heaters, and hydronic systems that deliver hot water from storage to radiators in the conditioned space. Although these programs vary from one utility to another, they share a goal of making off-peak heating a sound investment for utility and customer alike.

United Power Association (UPA), for example, plans to use its existing program of rebates and off-peak rates to distribute and promote the CaliDyne system. UPA is a generation and transmission cooperative providing wholesale power to 15 member rural cooperatives in Minnesota and Wisconsin, a winter-peaking service area where approximately 30% of peak load in winter comes from electric space and water heating. To make more-efficient use of its baseload capacity, UPA began an ETS promotion program in 1980 and has since become a distributor for ETS furnaces and other storage equipment to both its own membership and utilities in other states. By serving as a distributor for ETS systems, the cooperative is able to purchase equipment in large quantities and reduce the eventual cost to consumers.

The cornerstone of the ETS program at UPA is an average off-peak rate to the cooperatives of 2.8¢/kWh, compared with an average standard rate of 7.6¢. Taking advantage of the lower rate, owners of central ETS furnaces save hundreds of dollars each year over the cost of conventional electric, oil, or propane heating. If the cost of the furnace is being included in the price of a home mortgage, the consumer is likely to enjoy a positive cash flow, with the monthly saving on the electric bill far outweighing any monthly payment for the added cost of the furnace. In addition, UPA and other cooperatives and utilities are guaranteeing their off-peak rate structure to assure consumers that their energy cost saving will return their added initial investment. UPA guarantees a wholesale off-peak rate to its members for 5 years, based on a formula of 30% over fuel cost for baseload plants; the cooperative also guarantees to continue an incentive off-peak rate program for a full 10 years.

UPA and other utilities add a cash rebate to their off-peak rates as a further incentive to consumers to purchase ETS equipment. UPA's rebate for ETS furnaces is $25/kW of load connected to the storage chamber, meaning that the owner of CaliDyne's 190-kWh furnace would get back $600. Many utilities combine off-peak rates and rebates to provide a reasonable payback period for the customer's added investment over conventional electric heating. Pennsylvania Power & Light, for example, bases cash grants ranging from $800 to $1500 on a 5-year payback period for residential customers. Other utilities, with different rate structures and generating costs, can use comparable rebates to achieve payback in 3 years or less.

By combining incentives with the lower cost of the CaliDyne furnace, utilities should be able to shorten these payback periods and expand the market for central ETS heating. Because of the high cost of ceramic central heating units, most of the market for ETS heating so far has been restricted to smaller, less-expensive room units. Now, by reducing the typical purchase cost to a distributor or user by $1000 or more, CaliDyne hopes to establish a wide market for central ETS furnaces as well. "If it can bring purchase costs down 30–40%, this furnace could help open up the niche for ETS in central heating," predicts Joseph Murphy, a marketing specialist who helps promote ETS equipment at New York State Electric & Gas. "That could help utilities move more load off-peak, and in larger increments."

Forces in the marketplace

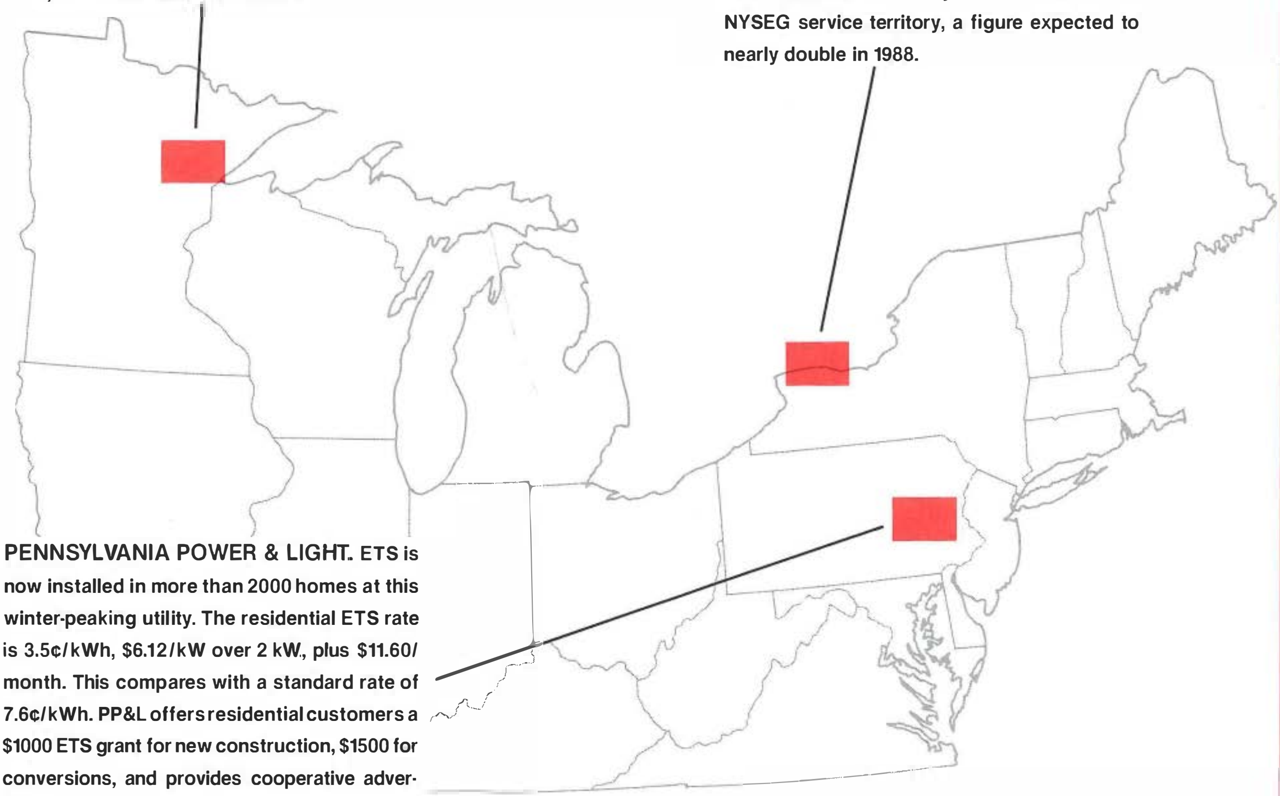
As reflected by different utility incentive programs, the economics of owning the CaliDyne furnace will vary with energy costs in different parts of the country. Off-peak rates and utility rebates are cru-

Incentives for Residential Customers

Utilities are marketing ETS technology with incentive programs designed to make off-peak electric heating an economically attractive option for residential customers. Incentives, such as off-peak rates and rebates, vary with utility load factors, generating costs, and the utilities' role in equipment distribution.

UNITED POWER ASSOCIATION. This midwestern generation and transmission cooperative maintains an average ETS rate of 2.8¢/kWh versus a standard rate of 7.8¢/kWh. The marketing plan for ETS equipment includes equipment service, three-year warranty, and a one-year satisfaction guarantee; it also provides 5% loans, and rebates of $25/kW for ETS. UPA sold over 1500 ETS space heating units to member cooperatives in 1986. The target is a three-year deferral of a new plant to 1994, which will save $25 million.

NEW YORK STATE ELECTRIC & GAS. NYSEG plans for 3.7% off-peak load growth in 1987, most of it in ETS. The standard residential rate is 8.97¢/kWh, whereas the time-of-day rate is 9.6¢/kWh on-peak and 4.1¢/kWh off-peak, with an additional monthly customer charge of $1.37. The utility also offers rebates of $100/kW for ETS room units (less than 85% of the heating load) and $125/kW for full ETS systems to customers who do not displace equipment currently fueled by NYSEG. ETS is now installed in nearly 600 homes in the NYSEG service territory, a figure expected to nearly double in 1988.



PENNSYLVANIA POWER & LIGHT. ETS is now installed in more than 2000 homes at this winter-peaking utility. The residential ETS rate is 3.5¢/kWh, $6.12/kW over 2 kW., plus $11.60/month. This compares with a standard rate of 7.6¢/kWh. PP&L offers residential customers a $1000 ETS grant for new construction, $1500 for conversions, and provides cooperative advertising, warranties, and training programs.

cial to the commercial viability of the systems, but other factors play a role in the energy cost saving the systems can provide, including the base costs for electricity and fuels, the climate in different regions, and the availability of natural gas.

In March of 1986 Energy International completed a market assessment for EPRI that identified the northeast and north central regions as areas where large heating loads and high energy costs will make the CaliDyne furnace most competitive. According to the assessment, which is deemed conservative by many utilities, the market for the crushed-rock furnace in these regions could quickly expand by the end of the decade to 6000–10,000 residential units and 10,000–15,000 commercial systems installed each year. Fortunately for the utility industry, these are the same regions of the country where the systems offer the largest potential benefit to load management programs and long-range capacity planning.

The most obvious benefits to utilities from this expanding equipment base will be valley filling during off-peak hours, as well as reductions in peak demand at cooler times of the year. Through promotion of the systems, utilities have an opportunity to gradually move megawatts of load off-peak, a key to generating more electricity with underutilized baseload capacity and deferring construction of new power plants.

UPA, for example, promotes ETS and other load management technologies in an ambitious program that reduced the cooperative's 1984–1985 winter peak demand by 35 MW (7%) and the summer peak demand by 15 MW (3%). Largely through promotion of ETS, the cooperative managed these load shifts without any loss of kWh sales or any need to promote nonelectric heating. "To the contrary, promotion of ETS systems is an effective strategy for reducing electric heating costs for consumers and competing better with fossil fuels," adds Zehringer.

Developing utility programs

In the long range the contribution made to the utility industry by the CaliDyne furnace and other ETS equipment will depend on the industry itself. To help utilities take advantage of the opportunity presented by the crushed-rock furnace, EPRI is now developing tools and guidelines for ETS load management and promotional programs. The market assessment completed in 1985 contains tables that utilities can use to judge the competitiveness of the furnace in their service territories and adjust their rate structures and rebates accordingly. EPRI is also developing a PC-based software package that utilities can use to size the furnaces for their customers and inform customers of expected energy cost savings.

To stimulate the market for the crushed-rock furnace and at the same time collect data that will be useful in future ETS promotional and load management programs, EPRI is coordinating a field demonstration this fall in which furnaces will be purchased by utilities and then installed and instrumented at customer sites. The participating utilities will each collect data on the energy consumption and load-shape characteristics of about 10 furnaces. This will help researchers quantify the benefits available to utilities and customers alike, while also familiarizing both groups with the crushed-rock concept.

In the future the crushed-rock storage medium may be applied to other ETS systems, such as electric water heaters, hydronic radiators, or central units that could store heat for both water and space heating. An immediate possibility is attaching an electric heat pump to the CaliDyne system, which can function as a supplementary heat source.

"The CaliDyne furnace and other applications of the crushed-rock storage medium should produce an added appeal to the consumer, and with it an expanding opportunity for utilities to improve load factors and conserve generation," comments Rabl. "As the technology continues to gain acceptance and come down in cost, we should see more utilities seize this opportunity to shape their loads and enhance the portfolio of electric heating options for their customers." ■

Further reading

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This article was written by Jon Cohen, science writer. Technical background information was provided by Veronika Rabl, Energy Management and Utilization Division.

TECH TRANSFER NEWS

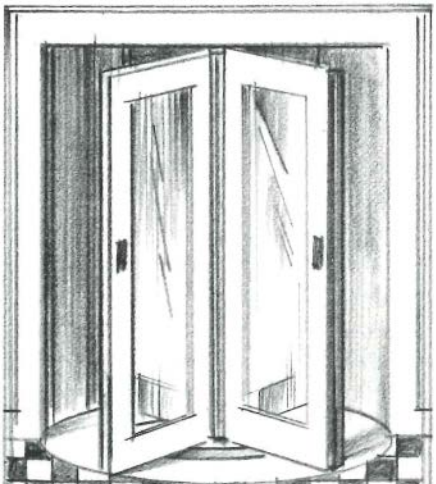
Fossil Fuel: Coast-to-Coast Coverage

Successful technology transfer is a revolving door designed for two-way traffic. In one direction EPRI disseminates information to its member utilities, and in the other direction, EPRI receives valuable data from these utilities; becomes informed about plant technical problems and tries to match them with solutions; develops personal relationships with plant personnel; keeps EPRI informed about industry problems. Two EPRI Coal Combustion Systems Division offices have been keeping that door revolving in the heart of fossil fuel country.

Billy McKinney in Chattanooga, Tennessee, and Clark Harrison at the Coal Cleaning Test Facility (CCTF) in Homer City, Pennsylvania, are fossil fuel specialists. Providing access to EPRI's services on the East Coast, these two men welcome requests from utility people at all levels. EPRI handles a broad range of requests that includes making presentations on emerging technologies, responding to technical problems, and using EPRI studies to help utilities make planning and design decisions.

Member utilities are taking advantage of this resource in their midst. Harrison participated in a weekly program at Pennsylvania Electric Co. (Penelec) that brought utility customers and Penelec guides to CCTF after they had toured the utility's power plant next door. Having been briefed at the power plant on local coal use, the customers then toured CCTF and learned about EPRI. This program not only informed the public and enhanced Penelec's image but also raised utility staff awareness of EPRI and its programs.

This awareness was recently expanded to include Pennsylvania state representatives when Penelec and General Public Utilities arranged for the Pennsylvania Acid Rain Caucus to visit local facilities. The caucus, composed of members of both houses of the Pennsylvania legislature, toured CCTF, where Harrison spoke about coal cleaning and quickly reviewed other technologies. The caucus wanted to know more about those technologies and invited him to give a public briefing—no recommendations, just the facts.



On May 27 Harrison reviewed the state of development of each emerging clean-coal technology and its current funding. With utility representatives in the gallery, the caucus questioned him about existing plants and the limitations of available clean-coal technologies. Harrison believes the presentation benefited both the state of Pennsylvania and EPRI member utilities by providing a chance for caucus members to objectively assess the array of available clean-coal technologies. The utility observers also had the opportunity to share the latest information on these emerging technologies.

The problems brought to EPRI are wide-ranging. Ron Boals, plant manager of Cleveland Electric Illuminating Co.'s Eastlake station, needed help to determine the cause of a series of mill fires in a coal pulverizer. After the utility narrowed the problem to one coal source, Harrison, with CCTF staff and resources, ran an analysis, looked at the facility, and worked with the suppliers, suggesting modifications and ideas for testing. Although the problem has not been fully resolved, no fires have occurred since the supplier implemented the modifications suggested by EPRI. McKinney and Harrison also field problems that are only indirectly related to fossil fuels. As an example, Tennessee Valley Authority called EPRI for help in solving a recurring turbine blade problem at its Cumberland plants.

In addition to requesting help with technical emergencies, utilities often call McKinney and Harrison for advice in planning new facilities or testing new equipment. John Tihansky, manager for mining at Pennsylvania Power & Light, has used EPRI resources on many occasions, ranging from finding the most effective designs for coal preparation plants at the Tunnelton and Florence mines to testing the SuperScalper, a precleaning device.

McKinney and Harrison welcome calls from member utilities. They field queries, put callers in touch with the appropriate EPRI project managers, and supply some of the most popular EPRI reports from stocks kept in their offices. ■ *Contacts: Ron Boals, Cleveland Electric Illuminating; John Tihansky, Pennsylvania Power & Light; Billy McKinney, EPRI (615) 899-0072; Clark Harrison, EPRI (412) 479-3505*

Help for TVA's Turbine Blade Problem

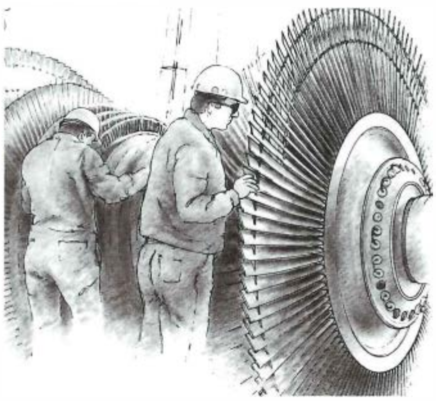
"We've got a problem. Can you help?" John Reese, the plant manager of TVA's Cumberland fossil fuel power plant, had never called EPRI with a problem. He and his staff usually consulted EPRI reports for answers to technical questions, but this was no ordinary problem.

Reese was calling Billy McKinney in EPRI's Southeastern Office in Chattanooga, Tennessee. After an annual outage at the Cumberland plant, workers had found 24 cracked steel blades in the low-pressure turbine L – 1 rows, and Reese realized he had a serious problem. In his words, "We needed quick answers based on sound engineering facts and evidence." The vendor had provided recommendations, and Reese wanted an analysis of the blade failures and an evaluation of the vendor's recommendations.

McKinney put Reese in touch with EPRI's Tom McCloskey, project manager for BLADE, a software package for three-dimensional modeling and analysis of turbine blade stress, vibration, and fatigue life. Demonstration testing of the package had just begun (testing will continue through 1988). At McCloskey's suggestion, TVA brought a blade sample to Stress Technology, Inc., the software contractor, for an evaluation.

Basically, BLADE models the forces and stresses experienced by turbine blades during operation. A turbine blade resembles a tuning fork that vibrates naturally at specific frequencies. The analysis examines the relationship between the blade frequencies and the harmonics of the turbine's running speed. Any coincidence between the two causes resonance, leading to fatigue. Using animation, BLADE can slow down the process on a computer monitor so the blade vibrations can easily be seen.

The Cumberland analysis took three months, and both the old and the new blade designs were tested. TVA now knows the cause of its blade failures and also received an independent evaluation of the vendor's recommendations. According to Reese, "TVA was very gratified to have EPRI respond so quickly. This experience has built my confidence that EPRI is addressing problems that are relevant to the everyday operating environment."



In this case, the benefit was a two-way street because the BLADE developers have been able to use the TVA data as a base case in the software validation. TVA has joined the BLADE Advisory Committee and is participating with at least 10 other utilities in testing the code. ■ *Contacts: John Reese, Tennessee Valley Authority; Tom McCloskey, EPRI (415) 855-2655; Billy McKinney, EPRI (615) 899-0072*

Welding Technique to Prevent IGSCC in BWRs

The reduction of welding residual stresses in type-304 stainless steel recirculation piping in BWRs can aid efforts to prevent intergranular stress corrosion cracking (IGSCC). Utilities can reduce these residual stresses and also stop the propagation of some minor IGSCC cracks with a recently developed technique called last-pass heat sink welding (LPHSW). Boston Edison Co. and a Spanish utility, Hidroeléctrica Española, have already applied the technique to good effect in BWRs.

The LPHSW technique was jointly developed by EPRI, General Electric, and individual BWR utilities. It involves the application of a high-energy last welding pass, or the remelting of the external weld crown, and the simultaneous cooling of the interior of the pipe with water. This changes tensile (crack-causing) stresses at the inner surface to compressive stresses, which do not promote cracks. By changing the residual stresses in this manner, the technique can arrest the propagation of existing minor cracks.

Boston Edison, an active participant in the development of the technique, used LPHSW to modify the residual stresses of five production welds at the Pilgrim station in 1984. The application of LPHSW followed the replacement of older, type-304 stainless steel piping with IGSCC-resistant type-316 nuclear-grade piping. The technique was applied as a preventive maintenance measure to key welds joining the new piping to the old. Boston Edison is now negotiating with NRC for a reduction in weld inspection requirements.

By providing a basis for reducing inspection requirements, LPHSW can help utilities avoid inspection costs and personnel radiation exposures. These factors add to the technique's appeal as a means of preventing IGSCC without costly pipe repair or replacement. In 1985 Hidroeléctrica Española applied the technique to five welds in the type-304 stainless steel recirculation system of the Cofrentes BWR. The EPRI licensee is General Electric. ■ *EPRI Contact: Wylie Childs (415) 855-2058*

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

DIAGNOSTIC INSTRUMENTATION FOR COMBUSTION

*A multitask research effort aimed at the development of reliable diagnostic instrumentation for use in the hot gas path of combustion turbines is under way (RP2102). During October 1985 a series of advanced diagnostic instruments was installed on gas turbine Unit 41 at Houston Lighting & Power's Wharton Station (*EPRI Journal*, April/May 1986, pp. 34–36). In roughly 3000 hours of cumulative on-stream monitoring, the instruments and data acquisition system have been thoroughly tested to ensure correct output. Over that period, the sensors proved reasonably durable. Such instruments were tested previously in aircraft engine test cells, but only for short periods. Long-term durability is therefore an important goal for the sensors in the current study.*

Five advanced diagnostic instruments were developed for specific application in the hot gas path of a utility combustion turbine (Figure 1).

▫ A high-temperature resistance temperature detector, or RTD (Kaman Instrumentation), to measure gas temperature at the first-stage turbine rotor

▫ An optical-fiber pyrometer (Solar Turbines, Inc.) to measure first-stage turbine blade metal temperatures

▫ An optical-fiber combustion viewing system (United Technologies Research Center) to provide temporal and spectral information on flame quality and stability

▫ An acoustic probe (Battelle, Columbus Laboratories) to measure acoustic pressure variables in the gas turbine hot section

▫ An optical-fiber thermometer, or OFT (Accufiber, Inc.), to measure fluctuations in exhaust temperature

Test results

Several problems occurred with the durability of the combustor viewing probe, ranging from image conduit fractures to loss of purge air and premature shutoff of cooling water, and the probe had to be repaired several times during the tests. Despite such problems, the viewing probe demonstrated its usefulness in locating the combustor flame; determining its size, extension, and orientation; indicating light-off (ignition), flame-out, full-speed, no-load, and on-load conditions; and determining the presence of water injection, cross-fire flow, and intermittent water injection (Figure 2). Investigators examined standard videotape records and computed flame pattern parameters to learn what to expect in terms of flame signal levels, typical variations, and the number of frames to average. Flame wavelength and flicker signals were observed and studied but not tracked for any extended period. The usefulness of these last two parameters is still not fully apparent. However, researchers now understand the signal characteristics better and how to measure and average them. They also learned what to expect from the operation of a viewing probe in the utility turbine's environment. This information will greatly assist in the design of a more durable and lasting probe.

Field testing of the OFT has been very encouraging. The devices were accurate and reasonably durable. After approximately 1000 hours of engine operation, all four exhaust temperature sensor assemblies were removed for inspection. Two of the sensors were submitted for metallurgical examination. The other two sensor assemblies were checked for calibra-

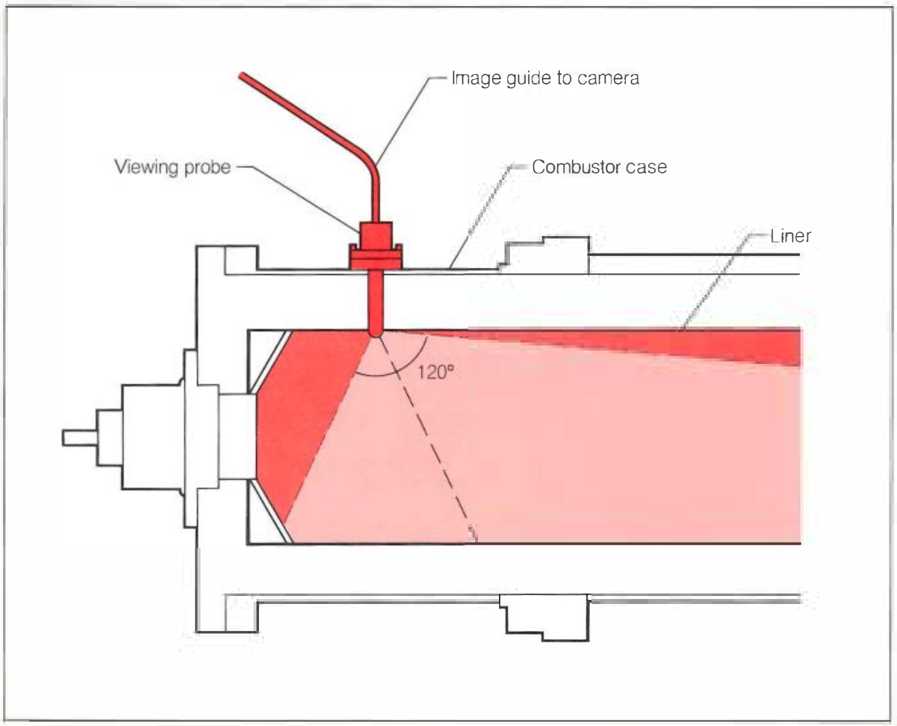
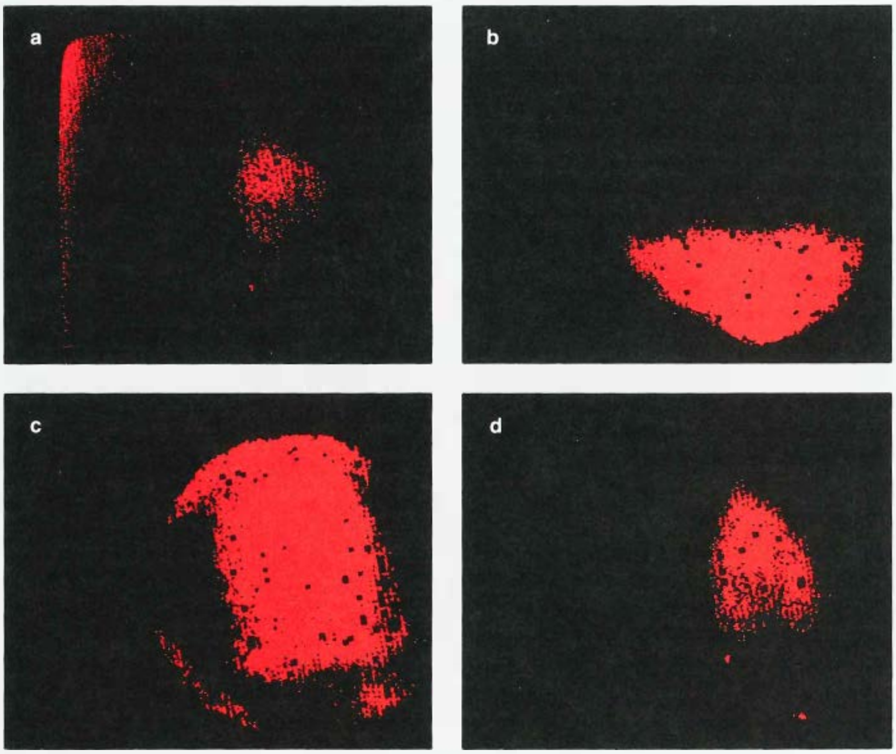


Figure 1 The combustor viewing probe is mounted through the spark ignitor opening in the MS7001B combustor liner. The direction of view (black dashed line) is 25° to the probe axis and encompasses an area from just ahead of the fuel nozzle to the combustor exit. The field of view (gray dashed lines) is 120°.

Figure 2 Typical examples of the combustor flame images with the fiber-optic viewing probe. (**a**) One can observe the turbine ignition on the video monitor as a weak flame near the center of the screen. (**b**) Broken fibers cause the black squares in this view. When the turbine is brought to the full-speed no-load condition, the flame becomes brighter, then settles back toward the fuel nozzle (located at the bottom of the view) and remains fixed in location in the lower third of the screen. (**c**) At full load the flame becomes brighter and appears to extend the entire length of the combustor. (**d**) When water is injected for NO_x control, the flame becomes very bright, then soon diminishes to an intensity level that is about an order of magnitude less than the flame without water injection. Not only is a large drop in flame intensity created, but the position of the flame centroid shifts away from the fuel nozzle and the second-order moments decrease in size.



tion drift and replaced for further field evaluation. On inspection, no damage was evident in either the exposed or sheathed black body coatings on the tips of the fiber elements. The exposed black body tips were covered with a very thin film of iron oxide but were otherwise indistinguishable from a new black body. There was also no evidence of harmful deposits on the surface of the exposed aluminum oxide crystal. It appears that the combustion of natural gas is so clean that very few corrosive compounds exist in the engine, and excessive foreign object damage or corrosion of the OFT thin films is not expected.

The remaining OFT sensors operated until late July 1986, when the cooling water was prematurely shut off following an emergency shutdown and the low-temperature optical-fiber cable couplers were damaged. The probes had accumulated approximately 1700 hours of engine operation. The OFT cooling-water glands that protect the coupler between the low-temperature transmission fiber and the sapphire sensor have been redesigned; cooling capacity and system logic have also been changed to avoid future failure.

RTDs, measuring gas temperature downstream of the first-stage turbine blades, indicated the boundary layer is thicker than had been presumed; that is, a 1.5-in (38-mm) probe does not see the highest temperatures. However, because of their rapid response, the OFT probes show greatest promise for tracking temperature streaks through the hot gas path from combustor to exhaust. Accordingly, plans are now being made to install one or more OFT probes aft of the first-stage blades, using a traversing mechanism to measure the boundary layer temperature profile more accurately.

The preliminary results from the optical pyrometer are among the most useful to date. The optical pyrometer has generated a profile of the average and peak temperatures on each of the 92 blades on the first-stage rotor. Three blades appear to be significantly hotter than the adjacent blades, perhaps due to plugged cooling holes. This may lead to a greater wear rate for those blades. The optical pyrometer also has the potential to diagnose other turbine blade problems, such as missing, eroded, or cracked blades, and to give indications of underfired or overfired operating conditions.

The blade profile data appear to be valid, whether from a single rotor revolution or from a number of revolutions averaged mathematically. Resolution of individual blade termperature profiles appears to be adequate, considering the size of the target spot, and is not causing a significant loss of amplitude (or rounding) of the temperature peaks.

The optical pyrometer lens appears to be clouding with time. The exact cause has not been confirmed. However, indications are that the purge air system has not functioned properly. Blade-cooling efficiencies calculated from the optical pyrometer temperature were approximately 14–17% initially. The pyrometer output decreased over time, showing an apparent increase (of several percent) in the calculated cooling efficiencies by October 1986. Because other plant parameters did not substantiate this change, contamination of the pyrometer lens is now suspected.

Data from the acoustic probe were compromised when the probe length was changed because of a location conflict with the combustor viewing system. Thus, the frequency response of the probe was limited and may have excluded important diagnostic information. Project personnel felt that the probe should be redesigned and properly installed to collect additional information.

Future plans

This field test is currently entering the second phase, in which researchers will concentrate on durability and performance improvements to the combustor viewing system, optical pyrometer, and OFT. A new retractable OFT will be installed just aft of the first-stage blades and ahead of the second stationary stage of the turbine. The probe will traverse this portion of the gas path radially to establish a profile of gas temperature over a range of engine operation, including both steady state and transient conditions.

Future development of the combustor viewing system will benefit from the information gained to date, and a more durable and less costly probe will be built. There are three approaches based on recent developments in fiber optics that could be used to design an improved probe. A high-resolution leeched fiber bundle that has no epoxy binders could be used for the image transmission. These image guides will remain an expensive item in the viewing system, especially for the 17-ft (5-m) and longer distances. A second approach would be to use a lower resolution and a much less costly fiber bundle of metal-coated, low-loss silica fibers. These fibers are hermetically sealed, stronger, and do not have the light loss of the glass fibers that are currently being used. The number of fibers or picture elements would be from 50 to 100. A third approach, and the most appealing, is to use a single-fiber image guide consisting of a 0.5-mm-diam. silica fiber with 4000–5000 picture elements. This number of elements represents a medium resolution and is equivalent to the 64 × 64 image array found adequate to describe the flame pattern. The single-fiber image guide could also be metal-coated for high strength. This last approach, however, will require some development work. The cost of the single-fiber guides could be brought down to the $100/m range, making a viewing probe that uses this image guide very cost-effective.

An advanced two-color optical pyrometer will be evaluated to combat the lens contamination problems discussed earlier. The optical head will have two parts: a base that is permanently fastened to the turbine case, and a head containing the lens system and fiber-optic interface, which attaches and detaches from the base. A new pyrometer mounting will be designed to permit the optical head to be removed conveniently for lens cleaning or for moving the instrument to other turbine units in the field. This pyrometer will also have a lower minimal threshold temperature (600°F versus 1000°F; 316°C versus 538°C) to better chart startup transients.

Another feature to be tested with the pyrometer is a special high-temperature fiber coupler that can withstand the hot turbine case environment without a liquid cooling gland.

These advancements are expected to be operating during the latter portion of 1987 and will develop a more complete body of information and application data from the instruments being evaluated. Additional sensors to measure blade tip clearances and internal seal clearances are being considered for future installation. *Project Managers: Leonard Angello and George Quentin*

BIOLOGIC PROCESSING OF COAL

There are two major reasons for the substantial current interest in biologic processing. First, bioprocessing takes place at ambient temperatures and pressures. The ultimate economic potential of such processing is tremendous. Second, microbiology is perhaps the most rapidly advancing field of research today because of the large number of researchers working in the field and because of the sizable amount of research funds being spent. In the past this formula has usually led to major breakthroughs, not only in the immediate area of study but also in unrelated areas. Microbiology appears to be no exception. Biotechnology was originally applied only to high-value, low-volume products, such as medicine or specialty chemicals. Although biotechnology is still in its infancy, its scope has already spread to lower-value, higher volume fields, such as agriculture and environmental cleanup. In the future the field may even be commercially applied to coal. There are reasons why this may not be outside the realm of feasibility.

Coal is a material that has already undergone extensive biologic processing. Early in the coal-forming process, plant remains were degraded by microorganisms. Aerobic microbial processes and burial created anaerobic conditions. Anaerobic microbial processing of the material continued until it was arrested either by an accumulation of toxic metabolic by-products or by a decrease in available water. Microbial cell debris may indeed constitute a large part of fossil fuels, including coal. The microbial history of coal, therefore, would lead one to suspect that coal is open to further microbial processing. Researchers have indeed found this to be the case.

Processing applications

Bioprocessing of coal has three general applications: coal cleaning, coal conversion, and by-product use and/or recovery. The objective of coal cleaning is obvious: removal of undesirable impurities from the coal. These undesirable impurities may include pyritic, organic, and elemental sulfur; nitrogen heterocycles and amines; and other organic and inorganic metals. Organisms exist that have the ability to use each of these impurities. Needless to say, the bioconversion or bioextraction of these constituents would produce a cleaner boiler fuel.

The objectives of biologic coal conversion are more diverse. The end goal is to produce a new form of fuel. However, the fuel forms and the bioprocesses that yield them may differ significantly. Houston Lighting & Power Co. is searching for organisms that will convert lignite directly to methane (i.e., biogasification). Another route, one that EPRI is pursuing (RP8003), is conversion of the coal into a liquid product (i.e., bioliquefaction). In the first of these processes, biogasification, the product is the new fuel form. In the second process, the biogenerated coal liquid may simply be an intermediate product subject to further processing.

A third application, by-product use and/or recovery, may be a side benefit derived from the other two applications. Hydrocarbon degrading microbes frequently synthesize and excrete extracellular chemicals, such as proteins, carbohydrates, amino acids, fatty acids, and so on. The excreted chemicals fall into two main groups: biosurfactants and bioemulsifiers. These by-products may be recovered for other uses or aid in the handling, transportation, and/or use of the coal products.

To date, EPRI's program in bioprocessing of coal has focused on microbial liquefaction, or bioliquefaction. This work is being performed at Battelle, Pacific Northwest Laboratories (RP8003-5) and at the University of Hartford (RP8003-6 and -10). Although both fungal and bacterial strains have been reported to solubilize coal, fungi were the first to yield sufficient products for chemical analyses. Therefore, most of EPRI's work has been performed with a variety of fungi that are known lignin degraders.

Microbial liquefaction

Polyporus versicolor and *Poria monticola* were the first fungi to yield significant liquid products from coal. *Polyporus,* which uses a white-rot mechanism, was the more effective of the two fungi. *Polyporus* digests lignin; *Poria* digests cellulose. Since this early work, a number of additional fungi have been studied at both Battelle and the University of Hartford (*Phanerochaete chrysosporium, Candida Cunninghamella, Penicillium*, and so on).

In the early experimental work, the fungi were grown in a broth culture at very mild conditions (30°C, 84–98% relative humidity, and pH = 5.8). Sterilized lignite pieces were then added to the continuous hypal mat that formed on the agar. The process of solubilization activity was usually evident within 24 hours and continued, with the amount of bioextract increasing over several days. The lignite pieces became pools of black viscous liquid (bioextract). The bioextract was then harvested for analysis.

It was discovered early in the work that for the fungi to degrade the lignite effectively, some form of pretreatment of the lignite was necessary. This discovery came about because although *Polyporus* was very proficient at degrading the investigator's original lignite sample, it was inactive with several other lignite samples. Upon investigation, researchers found that the initial lignite sample was actually leonardite, a well-oxidized form of lignite. Subsequent oxidative pretreatment of the nondegradable lignites was positive. Oxidation of the lignites activated *Polyporus.*

The rate of biosolubilization has been investigated through the pretreatment of several lignites, subbituminous, and bituminous coals (Table 1). Exposure, temperature, and chemical means have been used to induce the oxidation. Some of these pretreatments have been very effective, equaling or surpassing nature's pretreatment (leonardite); others have had little or no effect. The addition of oxygen is

Table 1
COALS UNDER STUDY

Coal Type	Origin
Lignite	Beulah Zap Beulah Zap Plus Beulah Standard No. 3 Texas lignite Fort Union bed Vermont lignite Mississippi lignite Leonardite
Bituminous	Pennsylvania Upper Freeport Pittsburgh No. 8 Illinois No. 6 Pocahontas No. 3
Subbituminous	Wyodak

probably the critical oxidation step necessary for the microbial degradation of coal.

Extracellular coal solubilization

Although 100% solubilization was achieved in some of these experiments, the process is long, taking up to eight days. When dealing with a low-value, high-volume entity, such as coal, lengthy processing is unrealistic (unless performed in situ). Thus it became a major thrust of the EPRI research to investigate the feasibility of extracellular solubilization.

Microorganisms function by producing enzymes that then react with certain chemical bonds. Enzymes are complex proteins that are highly specific catalysts for the chemical reactions in biologic processes. In other words, bioprocessing has two steps: production of enzyme and enzymatic reactions with coal. The first step, enzyme production, is lengthy. The second step, enzymatic reaction, is rapid. Therefore, separating these two steps is desirable, especially because the first step does not involve large volumes of coal. (Some coal may be necessary as nutrient for the fungi.) Achieving the separation of the steps first requires isolation of the enzyme. Achieving this goal in biologic research usually represents a major breakthrough.

The enzyme (or enzyme mixture) responsible for the dissolution of leonardite by *Polyporus* has been isolated by EPRI's research team in a cell-free medium. Initial experiments with the cell-free enzyme extract indicate that the rate of solubilization depends on protein concentration, time, and temperature. Through optimization of these variables, complete coal solubilizations have now been achieved in minutes.

The products produced during biosolubilization are of high molecular weight, are highly polar, and are water soluble. The product has more oxygen, less aliphatic carbon, and more carboxylate carbon than does the parent coal. All products tested to date show no genetic toxicity (as determined by the Ames test). The analyses of the bioextracts show them also to be free of the known toxic compounds associated with coal liquefaction. (This fact would indicate that these compounds are not in the coal, but formed during the thermal liquefaction process.)

Although, on an elemental basis, the bioextract does not appear to be as good as the coal, one invaluable goal has been achieved. Coal has been solubilized at room temperature and pressure in a matter of minutes into a liquid product. All the sulfur and nitrogen in the coal have been exposed to the solution. These sites are now available for further processing, such as rapid attack by microorganisms (bacteria) that will remove them.

Future directions

The rapid advances made in these projects have far outdistanced expectations. However, the research still has a long way to go. Several important areas will be investigated in the future.

- Phase 2 reactions will be studied, including those mentioned above for removal of sulfur and nitrogen from the bioextract, as well as microbial conversion of the extract to methane.
- Other enzymes (or enzymatic systems) will be isolated from other fungi that have demonstrated activity for coal. A combination of these enzymes may have a synergistic effect for coal solubilization.
- Model compound studies will also be used to determine the mechanism of the biosolubilization. If the bonds that are being cleaved are known, it may be possible to seek more-effective enzymes or enzymatic systems.
- Determining material balances for the process has been a major difficulty throughout the work because of incorporation of protein and nutrients in the extract. To maximize conversion, some method must first be found to determine conversion. Such a measure will also help determine the variables that influence conversion.
- Screening studies of other organisms, coals, and pretreatments will continue at a steady pace throughout the work.

Scale-up to a bioreactor will be the next step on the road to commercialization. *Project Manager: Linda Atherton*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

BOILER FEEDPUMP RELIABILITY

Boiler feedwater pump failures are a major cause of power plant unavailability. According to North American Reliability Council statistics, from 1976 to 1985 fossil fuel plants lost, on an average, 10.5 million MWh a year because of forced outages resulting from problems with feedpumps. In 1984 and 1985 feedpumps were the leading cause of unplanned deratings in fossil fuel plants. For fossil fuel and nuclear plants, feedpump-related forced and scheduled outages resulted in an estimated $1 billion in replacement power costs during 1985. Surveys sponsored by EPRI have identified reduced-load operation as the major cause of failure in high-energy feedpumps. The current trend of using large fossil fuel units in cycling or peaking service has increased the number of hours during which high-energy feedpumps are required to operate at reduced loads. To address the issue of feedpump reliability, EPRI is sponsoring a broad program of analytic and experimental research aimed at improving pump design, procurement, and operation (RP1884).

The key to improving feedpump reliability is a better understanding of a pump's hydraulic and mechanical behavior, particularly at off-design conditions. EPRI's current and planned research seeks to develop a design approach based on fundamental insights into the physics of fluid flow in high-energy pumps—a contrast to the classical approach, which is based principally on design extrapolation.

Because the reliability of a feedpump is a function not only of its internal hydraulic and mechanical design but also of the design and operation of the feedwater system, the current EPRI-sponsored work is focusing on three major areas: hydraulics, cavitation, and system interactions. The total effort includes developing the technology to improve hydraulic and mechanical characteristics, demonstrating the technology through laboratory and field testing, and preparing documentation to help utilities and their agents specify, test, operate, and maintain feedpumps and their related systems. The near-term objective is to develop components with improved reliability that can be retrofit to existing installations and that can serve as a technology base for the design of new installations.

Hydraulics

In a feedpump at its design flow rate (i.e., at the point of best efficiency, or BEP), the motion of the fluid conforms to the physical contours of the hydraulic passages. Consequently the flow exerts minimal forces on the pump components. When the load on the plant varies significantly, the feedpumps no longer operate at or near the BEP. The fluid no longer follows the contours of the passages, and the flow separates from the walls at one or more locations. This flow separation produces secondary flows—that is, regions of stall and recirculation. The secondary flows cause fluctuating pressure distributions, resulting in additional hydraulic forces that act on both rotating and stationary parts. These varying forces produce axial and radial vibration of the rotor and the casing.

Early work sponsored by EPRI (CS-1445) identified the secondary flows that exist in the region between the impeller shrouds and the casing (Figure 1) as a major source of large dynamic axial forces and poor hydraulic performance during reduced-load operation. Because all feedpumps do not respond the same at reduced flow rates, current research is investigating the factors that influence the onset and intensity of secondary flows. Flow visualization tests on a typical feedpump stage have shown that as the load is reduced, flow separation and recirculation occur first within the diffuser. Recirculation in the diffuser influences the performance of the impeller and leads to the onset of recirculation there. Thus proper design of the diffuser—or the volute, the corresponding component in some pump models—is vital to controlling dynamic hydraulic forces and pump performance.

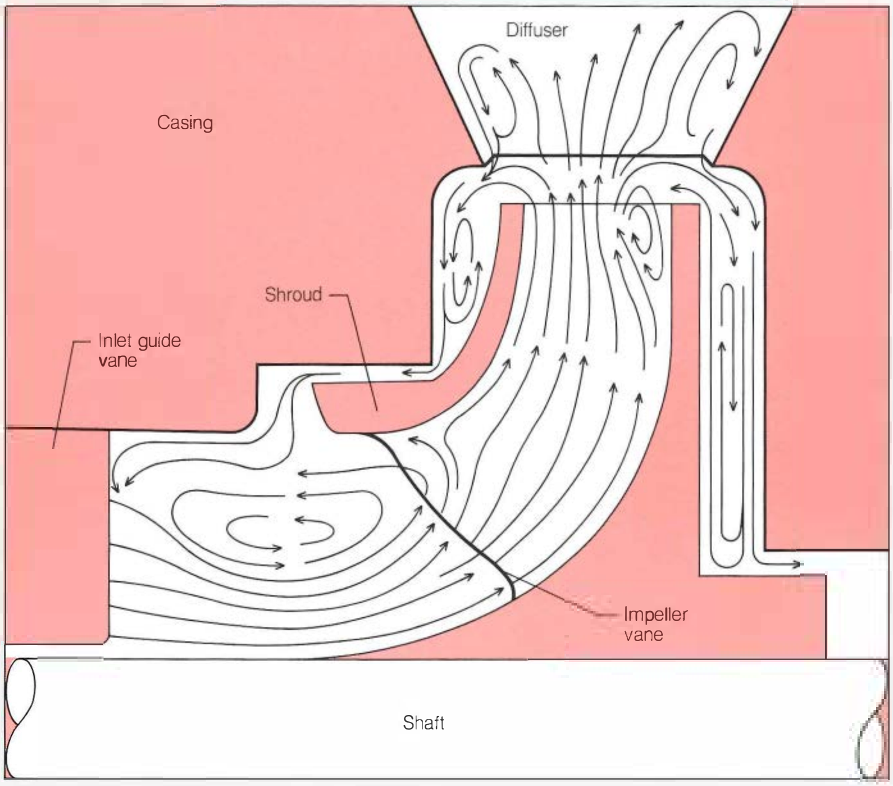
The flows in the various components of a pump stage are highly interactive. Because there is no analytic technique that can predict the flows at every location in a pump stage, particularly with reduced flows when recirculation is present, it is difficult to establish specific criteria for an acceptable hydraulic design. The objective of the current program in hydraulics, therefore, is to establish the relative influence of various geometric parameters on the pump performance curve (which defines the relation between capacity and head for a given pump), efficiency, pressure pulsations, and radial and axial hydraulic thrust. It is expected that this work will produce new insights into how the primary and secondary flows in a pump stage interact and how the energy transfer between these flows can be controlled. Guidelines developed from this investigation will help pump designers and utilities identify pump geometries that are less sensitive to the adverse effects of reduced-load and cycling operation.

Cavitation

Cavitation occurs in a pump when the local pressure of the fluid is reduced to the vapor pressure. Vapor bubbles form in the low-pressure areas at the first-stage impeller inlet and are swept by the flow into regions of higher pressure, where they collapse. If the bubbles collapse at or near a material surface and with sufficient intensity, erosion occurs (Figure 2). In severe cases erosion can lead to destruction of the impeller within several hundred hours of operation.

The criterion used to determine minimum pump suction conditions is frequently at the root of cavitation failure. Basing the minimum feedpump suction conditions on the net positive suction head (NPSH) that produces a 3% loss in first-stage differential pressure—the approach recommended by the Hydraulic Institute—is not adequate to prevent cavitation damage. A significant amount of cavitation must already have occurred to result in the 3% loss in performance. Attempts to improve this criterion by using correction factors or smaller

Figure 1 Secondary flows in and around a pump impeller during off-design (reduced-load) operation. Such flows are a principal cause of large dynamic axial forces and hence poor pump hydraulic performance.



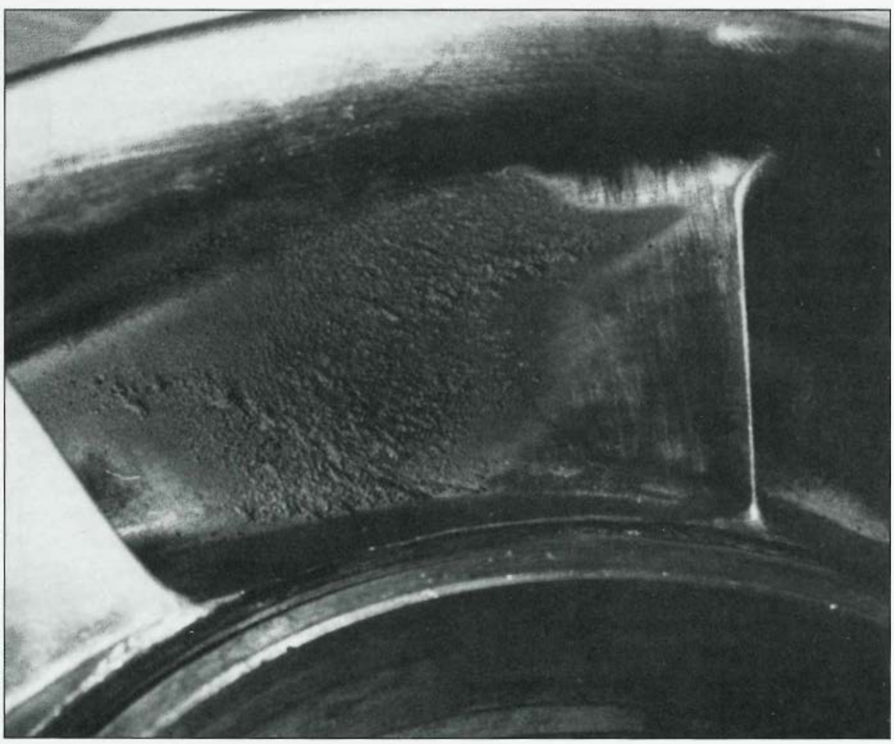


Figure 2 Cavitation erosion on a pump impeller vane. Damage of this kind can rapidly destroy an impeller. EPRI is working to develop improved methods of erosion prediction and risk assessment.

percentages of performance loss have not been satisfactory.

Cavitation inception (i.e., initial bubble formation) can begin at NPSH values of more than five times the NPSH required for a 3% loss in performance. Flow visualization tests with stroboscopic lighting have revealed that the inception point, the cavitation bubble length, and the erosion damage rate are very sensitive to inlet geometry and inlet flow symmetry. Field data have shown that variations in vane inlet angle of approximately half a degree can produce measurable differences in erosion rate without any effect on the NPSH measured at 3% or 0% performance loss. What is needed is a method that relates pump suction conditions to cavitation erosion, not to performance loss.

EPRI-sponsored research has developed two methods of correlating suction conditions to erosion: one method is based on measurement of the length of the cavitation zone on the impeller vane; the other is based on measurement of the waterborne noise produced by cavitation.

The correlation using the length of the cavitation zone is based on plant data and special erosion tests carried out under RP1884-10. The correlation takes into account all the factors generally recognized as important in determining the erosion rate. The length of the cavitation zone can be determined by stroboscopic observation of the impeller inlet in a specially designed test pump or by tests in which a soft coating is applied to the impeller vanes and subsequently examined for damage.

Because both the flow visualization tests and the soft-coating tests must generally be performed in the manufacturer's shop, a second method, based on measurement of cavitation noise, was developed. When a cavitation bubble collapses, it emits a pressure pulse. This waterborne "noise" can be measured by a pressure sensor mounted in the pump inlet. The noise level will continue to increase with increasing cavitation intensity until a sufficient two-phase flow exists between the location of bubble collapse and the sensor to absorb the sound energy. With the cavitation noise correlation, predictions of erosion can be made on the basis of field measurements as well as measurements taken in the manufacturer's shop.

There is a degree of uncertainty associated with each of the new correlations. So far only a limited number of data are available for establishing the correlations, and the scatter is rather large, particularly in the case of the noise data. Nonetheless, the correlations do permit a reasonable assessment of the risk of cavitation erosion, which was not previously possible, and are good tools for evaluating changes in impeller inlet design. Work is continuing in order to develop data to improve these correlations.

System interactions

Three types of interaction are being considered in the current research program: hydraulic, mechanical, and pump–feedwater system. The first two areas concern pump dynamic performance, whereas the third concerns how pump reliability and performance are affected by the deaerator, the pump bypass arrangement, the prewarming arrangement, and the suction piping configuration.

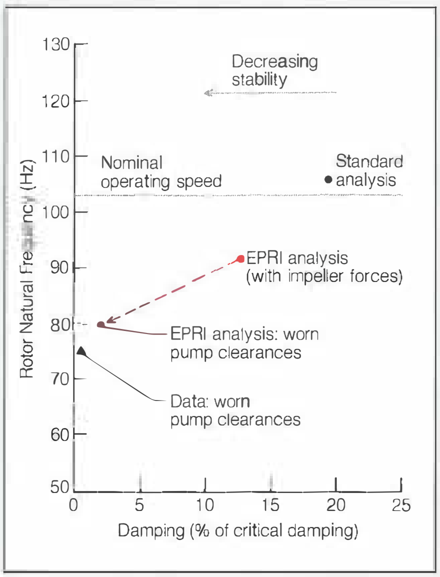
The hydraulic interaction work is investigating the dynamic stability of the feedwater system by means of an analytic system model. In the past such studies have been hampered by the lack of a validated model for the feedpumps. EPRI's initial effort therefore focused on constructing and validating a pump model. Tests on a reduced-scale single-stage pump were performed in a test loop whose dynamic properties could be easily varied. On the basis of these tests, decisions were made about the properties the pump model should cover (e.g., inertia, damping, and resistance). The tests also provided valuable information on how to measure these characteristics in an actual pump. In the next part of the study, such measurements will be made on both a full-scale single-stage pump and a multistage feedpump in a laboratory environment. The pump model developed from these data will be the basis for studying various pump characteristics and feedwater system configurations and for developing system design guidelines.

Feedpump mechanical interactions include the effects on rotor dynamic behavior of the driver, coupling, casing, piping, and foundation. An analytic model of a typical pump has been developed by using the best available information on bearings, interstage seals, axial thrust balancing devices, and hydraulic forces. The analyses have focused on three major areas of concern: hydraulic forces, rotor-casing-foundation interactions, and torsional excitation by variable-speed synchronous electric motor drives.

The hydraulic forces acting on the rotor can be classified as excitation forces, which result from the flow of fluid through the pump, and hydrodynamic interaction forces, which result from the vibration of the rotor in the flowing fluid. The importance of both types has been known for some time. Hydraulic excitation forces, in conjunction with mass imbalance, are the principal cause of rotor vibration. Recent studies under RP1884-10 show that hydrodynamic interaction forces play a major part in determining the magnitude of rotor vibration.

Before the EPRI-sponsored work, adequate data were not available for properly assessing the importance of hydrodynamic interaction forces in feedpumps. Figure 3 shows the results of rotor dynamic analyses of a four-stage, 6200-rpm feedpump with a balancing drum to control axial thrust. As calculated by standard analysis procedures, which do not account for impeller-fluid interaction forces, the natural frequency of the rotor is above the nominal operating speed; hence, according to this analysis, the rotor is operating below its natural frequency with a high degree of damping. An analysis incorporating the EPRI-developed data on impeller forces, however, shows that in reality the rotor's natural frequency is below the operating speed. Even more important is the EPRI model's prediction of the natural frequency after the pump's internal clearances have increased with wear: this point indicates very low damping and the approach of dynamic instability. It compares well with actual (experimental) data taken from the modeled pump operating with twice the normal internal clearances. It is evident that understanding hydrodynamic interaction forces is important to designing pumps with good rotor dynamics.

Figure 3 EPRI-developed data on impeller-fluid interaction forces can improve the accuracy of rotor dynamic analysis, as shown here for a four-stage feedpump. An analysis including such data gives a more realistic assessment of initial system stability than the standard method; moreover, in predicting the effect of worn (doubled) internal clearances in the pump, the EPRI method shows good agreement with experimental data.



The feedwater system study examined various configurations of pump suction systems and their influence on pump operation during transients. A survey of the literature was made to evaluate and organize the available information on these topics (CS-4204). Interviews with utilities experiencing feedwater system problems were conducted, and a series of laboratory tests has been defined. Methods of protecting feedpumps on standby from adverse thermal effects have been evaluated. Guidelines will be established to assist pump and plant designers in developing systems that minimize pump thermal distortion and adverse effects from suction piping systems.

Future work

The next phase of the feedpump reliability project entails documenting the results and demonstrating improved reliability in the field. Two sets of utility guidelines are in preparation: procurement guidelines (RP1884-24) and operation and maintenance guidelines (RP1884-23). The research results and guidelines will be implemented through competitively selected contracts with utilities, manufacturers, and architect/engineers. The field work is expected to start in 1988 with host utility demonstrations of the procurement guidelines. *Project Manager: Stanley E. Pace*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

Narain G. Hingorani, Vice President

UNDERGROUND TRANSMISSION

Gas-in-oil analysis for HPOF cable

Underground transmission circuits that employ a dielectric system of paper and oil undergo aging or degradation from thermal and electric stress. By analyzing the by-products of aging (gases), one may be able to determine a cable's remaining life. Under a current research project with Detroit Edison Co. (RP7895), it is apparent that because particular aging events have occurred, certain gases are diffused in the pipe fluid and retained there. By regularly analyzing these gases, researchers can put together a hypothetical history to predict cable performance.

Researchers in this project are measuring certain gas parameters in the various types of cable fluids available today. The determination of what part of the cable system is producing which gases is being conducted by separate analysis of both the oil and the paper. Approximately 15 different gases are suspected as degradation by-products and are being analyzed. Diffusion rates and solubility limits have been carried out for all of these gases at a variety of pressures and temperatures.

The most common gases sampled in both the cables and transformers are hydrogen, carbon monoxide, carbon dioxide, nitrogen, and methane. Under this contract researchers are also measuring higher-molecular-weight hydrocarbons, such as acetylene, isobutane, *n*-butane, and ethane. By measuring all the possible combustible gases, more-accurate trends can be determined for each cable system, and recommendations can be made should a catastrophic failure occur.

Analyses of three cables in the field have been made to date. The gases quantified were hydrogen, nitrogen, carbon monoxide, carbon dioxide, methane, acetylene, isobutane, isobutylene, ethane, ethylene, n-butane, 1-butylene, 2-butylene, propane, and cyclopropane (trimethylene). Of importance in obtaining accurate data is the method with which the oil samples are taken and stored before chromographic analysis. A novel method of taking and containing samples before laboratory analysis has been developed and extensively used on the project. The results are highly repeatable and less susceptible to losing gas concentrations, compared with standard practices. Information on equipment, and more important the methodology, has been submitted to EPRI as a patent disclosure.

Currently, a subsidiary of Detroit Edison Co. (Utility Technical Services, Inc.) is negotiating with EPRI for a license agreement to provide a gas-in-oil analysis service to the utility industry. *Project Manager: Thomas J. Rodenbaugh*

TRANSMISSION SUBSTATIONS

Optical voltage and current measurements

Voltage and current are by far the most important quantities that must be measured in power systems. The increasing complexity of the power grid, the wheeling of larger amounts of power, and the need for real-time control raise concern that the existing measurement systems may not be adequate for future needs.

To examine these needs, EPRI joined Bonneville Power Administration (BPA), Empire State Electric Energy Research Corp. (Eseerco), and the National Bureau of Standards (NBS) in a jointly funded program designed to assess the need for, and the potential of, new measurement technology (RF2748). The program was structured as two, closely related investigations. One examined the economic motivation for improving power system voltage and current measurements, with special emphasis on the prospects for doing this with optical technology. The other investigated the technical limits, such as precision, stability, and reproducibility of voltage measurements using electrooptic sensors and of current measurements using magnetooptic sensors. Data were combined with survey information to identify those areas in which improved measurements will be needed and to assess the future availability of the required technology.

A consensus in the technical community is that a long-term trend toward optical measurement systems has begun (Figure 1). This trend appears to be in response to one or more of the following trends in power systems.

- The demand for more-accurate metering will increase as the cost of electricity increases.
- The greater cost of voltage transformers and current transformers at higher voltages will open the door for lower-cost alternatives, such as optical systems.
- Optical systems are broadband, very fast, and free from electrical interference, properties that will become increasingly important as computer control of power systems increases.
- Increasing computer control of the grid will require more real-time data on the system status.

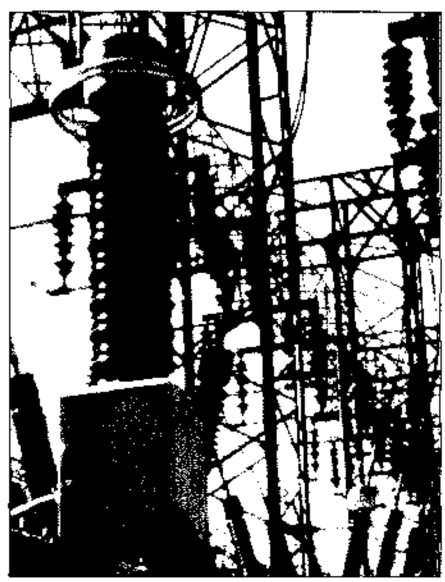


Figure 1 First operational optical current-measuring device installed in the United States, which meters current in a 161-kV yard at TVA.

□ Optical sensors will have a greater share of the market for nonelectrical measurements, such as temperature and pressure, within 5 to 10 years.

□ Conventional current transformers can fail explosively, while optical systems are inherently explosion-proof.

This study, however, identified no significant, widespread inadequacy of the existing technology for present measurement needs. There is time to develop optical systems, prove their applicability and reliability, and demonstrate their advantages before conventional systems have to be replaced. The principal difficulty with existing systems is maintaining measurement accuracy over a wide temperature range. It was concluded that typical system approaches can be expected to yield variations in response of about ±1% over a temperature range of 100°C. The study reports, however, that techniques are becoming available to reduce that variation to about ±0.1%.

Study results, as well as related contributions from utilities and manufacturers, will be the subject of a three-day workshop sponsored by the project sponsors and scheduled to be held in Gaithersburg, Maryland, September 16 through 18, 1987. *Project Manager: Selwyn Wright*

Light-fired thyristors

The first self-protected, light-fired thyristors ever installed in an operating system were energized at the beginning of 1987 at Minnesota Power Co.'s Shannon substation (Figure 2). The substation has had two brief shutdowns, but otherwise the static VAR generator containing the thyristors has been operating smoothly with self-protected thyristors in one phase and regular light-fired thyristors in the other phases, both types developed in RP567.

The first shutdown was the result of a faulty purification element in the water cooling system; the second shutdown was caused by the failure of two thyristors. These failures can be attributed to the newness of the technology. As of this writing, the valve has performed well since being reenergized in February 1987.

In all other respects, this development has produced the benefits expected of it: fewer thyristors needed for a given rating and both longer life and lower maintenance as a result of protection from uncontrolled voltage breakover (avalanche) during system transients. The static VAR generator will be operated for the rest of 1987 and data taken on its performance. The final report, EL-5125, is available from the Research Reports Center. *Project Manager: John Marks*

OVERHEAD TRANSMISSION

Modeling: key ingredient of successful design

One of the more challenging and, in some cases, frustrating tasks required of a utility structural engineer is to translate detailed transmission structure drawings into a computer model—a model that allows the structure to be analyzed to determine if it is adequate, as designed, for the predicted loads. Traditionally a computer model of a structure is quite different from the actual structure shown in the drawings. In the model, structural members may be deleted or added and connection details may be simplified. These differences result from decisions made by the engineer in an attempt to balance two needs: (1) the need for a computer model that mimics the response of the actual structure, and (2) the need for a computer model that can be developed in a reasonable length of time and that is consistent with the simplifying assumptions inherent in the analysis software.

The development of a computer model for a structure is as much an art as a science. The quality of the computer model, as measured by its ability to simulate the actual behavior of the structure, depends largely on the engineer's experience with the type of structure being studied, the engineer's familiarity with the limitations of the particular connection details of the structure, and the capabilities and limitations of the structural analysis software being used. For example, the engineer has to determine if the computer simulation must be modeled in sufficient detail to generate the correct member moments, if the simulation must include actual material properties, and which structure members must be included as elements of the model. In addition, the engineer must determine if the expected behavior of the structure is consistent with the simplifying assumptions of the software.

One of the major tasks of the EPRI structural development project (RP2016) is to determine how closely current modeling techniques and computer analysis software can duplicate the actual behavior of a structure. Tests of instrumented, full-scale structures at the Transmission Line Mechanical Research Center (TLMRC) provide the actual tower response characteristics needed as a reference for comparison with computer analysis results. Data from more than 35 full-scale tests conducted at the site have provided valuable insight into the capabilities of current software and into requirements for the model definition

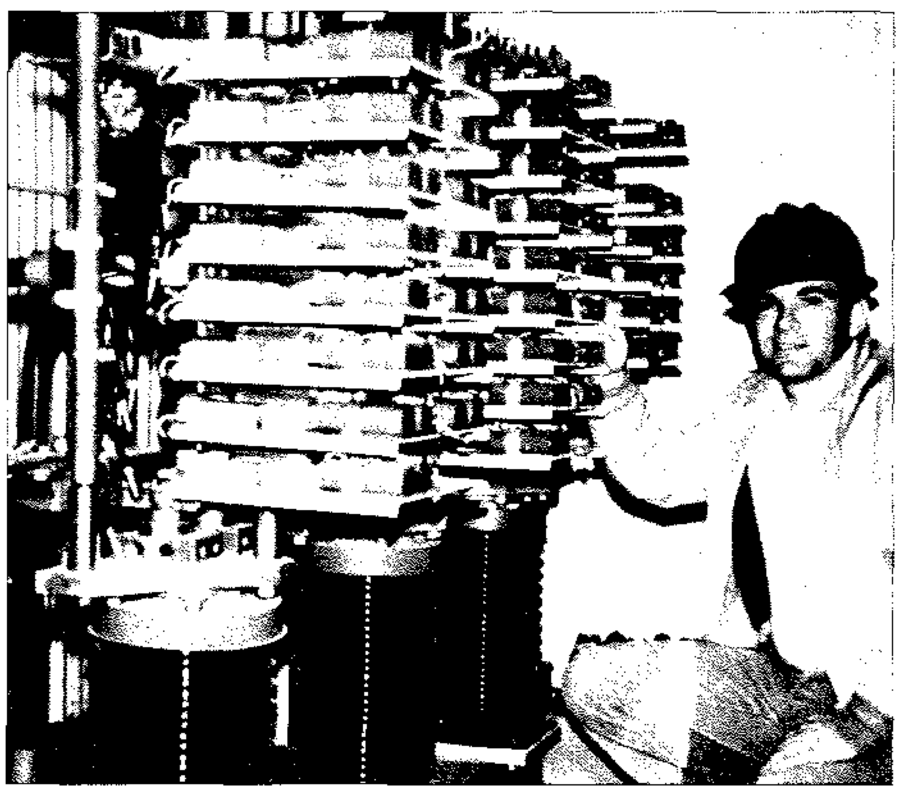


Figure 2 Light-fired thyristor installation at Minnesota Power's Shannon substation; this static VAR system has worked without interruption since February 1987.

process. In most of the modeling experiments at the center, researchers compare the responses of several computer models, each using different simplifying assumptions, with test data. In a more extensive experiment, however, test data were compared with 17 models of a given tower generated by 17 utility and engineering organizations who used 12 different tower analysis programs. The primary purpose of this experiment was to identify the different modeling techniques and software used by transmission engineers worldwide.

What insights concerning computer analysis models do these experiments give researchers? In general, the more complex the subject structure, as measured by the number of members in the structure and the complexity of the connections, the greater the difference between test and analysis results. The more complex the load case applied, as measured by the number of load lines, the greater the difference between test and analysis results. A test data set resulting from multiple load cases generally compares more poorly with analysis than does a data set resulting from a single load case. In the absence of test data, engineers of equal experience and ability may make different "correct" simplifying assumptions when creating a computer analysis model of a structure. And these different assumptions can produce large differences in predicted tower response and capability.

The experiments have also shown that given the results of a full-scale test, a computer model can be developed that will mirror the actual behavior of the structure. At first glance, this capability may seem trivial and reminiscent of classic chicken-or-egg debates; however, the ability to modify a computer model to match known test data represents a powerful design and analysis tool that is not being fully utilized by the industry. Testing a prototype or tower similar in detail to the desired final product gives engineers the necessary experience to make the correct simplifying assumptions and include the proper level of detail in the model so that it will simulate the behavior of the actual structure.

This approach is particularly powerful and cost-effective for upgrading existing structures. The designer/analyst can use the results of a full-scale test of the existing structure to tune the computer model; then he can use this model to study and verify the response and capability of the modified structure under the new set of design loads. The approach is equally useful for new tower designs. For a new line of 50 to 100 mi (80 to 160 km), the cost of designing, fabricating, and testing a prototype structure in order to tune the computer model is more than offset by the final design's increased strength and/or reduced weight and lower cost.

The goal of the EPRI structural research project is to produce computer analysis software that will eliminate the need for most, if not all, simplifying assumptions currently used in analyzing a utility structure and will permit direct modeling from the detailed drawings. However, such software is still several years away. In the interim an approach that combines full-scale testing (to provide experience specific to the structure under design or modification) and the best verified computer model can result in the most efficient new design possible or in an upgraded structure of maximum capability at the lowest cost. *Project Manager: Paul Lyons*

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

Capability of stator turn insulation in large ac motors

Most large ac motors have multiturn, form-wound stator coils. Under normal 60-Hz operating conditions, the turn insulation of the stator winding is not highly stressed. However, fast-rise-time surges, such as those created during circuit breaker operations, can result in severe stress across portions of the stator turn insulation. The failure of this insulation will eventually lead to a motor ground fault and, in the case of a critical power plant motor, can result in a costly unit outage.

The recent introduction of vacuum switchgear has promised reduced maintenance costs and longer equipment life. However, concerns that vacuum switchgear may cause many large, steep-fronted surges—despite improvements in contact materials and protective devices—have limited its widespread use by utilities.

To determine the actual surge environment for motors in power plants and to establish the capability of turn insulation in large ac motors to withstand these surges, EPRI initiated RP2307. As part of this project, researchers used high-speed digital monitoring equipment to measure switching surges on 33 motors in normal service at 11 utilities. Of the 33 motors monitored, 26 were controlled by air-magnetic breakers and 7 by vacuum breakers. Motor ratings ranged from 4 to 13.2 kV and from 200 to 12,500 hp. The motors and switchgear covered a range of manufacturers.

Significant surges were detected only during circuit breaker closing operations for either air-magnetic or vacuum breakers. The largest surge measured during the three years of plant monitoring was 4.6 pu with a rise time of 0.6 μs, which was recorded on a motor controlled by a vacuum circuit breaker. The largest surge recorded on a motor switched by an air-magnetic circuit breaker was 4.4 pu with a rise time of 0.2 μs. (One pu is the peak line-to-ground rated voltage of the machine.)

For motors controlled by vacuum switchgear, multiple preignitions were observed during each breaker closing operation. However, a comparison of surge characteristics showed similar rise times and magnitudes for the two types of switchgear. The monitoring of a motor switched first by an air-magnetic breaker and then by a vacuum breaker also showed no significant difference in the recorded surge rise times and magnitudes. Although many components of the supply system may influence the surges appearing at the motor terminals, the supply cable to the motor was the only parameter that showed a significant correlation with the measured surge magnitudes.

Impulse strength was measured for 17 stators that covered a wide range of ratings, winding designs, insulation systems, and time in service. A Marx-type impulse generator designed to provide a 0.1/40-μs wave was used to measure breakdown voltages for individual coils and complete parallels. (A parallel consists of several coils connected in series from a line terminal to the machine neutral.)

For most of the stators tested, the breakdown voltages for impulses with a 0.1-μs rise time were greater than 3 pu for single coils and greater than 5 pu for complete parallels. The failure sites were predominantly in the overhang or end-winding region. There was some evidence that inconsistency in the quality of coils may be largely responsible for the very low impulse strength of some machines. For one machine there was some evidence of general aging of the turn insulation under normal service stresses. Tests on new stators indicated that manufacturers have the capability and expertise to produce motors with an impulse strength of over 10 pu and to maintain a consistent quality.

The surge strength of most motors exceeds the surge magnitudes that can occur during normal service. The only motors that had a surge strength below the highest surge voltages measured either were damaged from severe aging or had poorly made turn insulation in some coils (compared with other coils in the same stator). Vacuum circuit breakers do not appear to pose a greater hazard to motor windings than conventional air-magnetic breakers, as long as the vacuum breaker does not interrupt motor starting currents. Improved quality control tests are required to enable manufacturers to identify the few defective coils a stator may have. *Project Manager: D. K. Sharma*

R&D Status Report ENVIRONMENT DIVISION

George Hidy, Vice President

BIOLOGIC EFFECTS OF PLUME FLY ASH

Atmospheric emissions from coal fired power plants include many materials. Some are of potential health concern and are subject to environmental regulations or are likely air toxics. There is much information on combustion byproducts inside the stack, but there are no data on the biologic activity of inhalable particles (plus the trace metals and organic compounds associated with them) after emission to the atmosphere. Indeed, the sparse chemical and physical data on such emissions, which are called plume fly ash (PFA), suggest that they may differ greatly from the original materials in the flue. EPRI is sponsoring a project on the biologic effects of plume fly ash (BEPFA) to fill key gaps in our knowledge (RP2482). The first experimental phase is under way, with a field study planned for this summer. Reports and preliminary conclusions will be available in 1988.

Several years ago EPRI conducted a planning study (RP1598) for the BEPFA project, which led to an eight-phase research plan. The BEPFA project has three objectives. The first is to describe the biologic, chemical, and physical differences between samples collected from the stack of a coal-fired power plant and samples collected at various locations in the plume. The second objective is to describe the variability in PFA biologic activity attributable to the variability in operating conditions at a coal-fired power plant. The third objective is to reduce the uncertainty in data on PFA.

PFA is defined as atmospheric particulate matter that is inhalable and originates in a power plant stack as particles and/or vapors. (Figure 1 shows two examples of inhalable particles.) The plume is the region near a plant where concentrations of stack-derived emissions are high in comparison with concentrations in ambient air. PFA is the utility portion of plume particulate matter, or PPM—the mixture of power plant emissions and other particles in the ambient air near a plant.

The first experimental phase of the BEPFA project—Phase 2, the evaluation of storage techniques—is under way; completion is expected in 1988. Preliminary work for Phase 3, a study of a rural plant, is piggybacked onto Phase 2 to capitalize on procedural similarities and minimize costs. The plan is to collect samples from the plume close to the plant, the air just upwind of the plant, the electrostatic precipitator, the coal pile, the stack, and a dilution/aging device attached to the stack. These will be used to develop a detailed description of PFA and PPM; to examine the efficacy of low temperatures for storing samples between the time they are collected and the time they are analyzed; to assess, on a preliminary basis, changes in combustion byproducts as they are emitted and move through the atmosphere; and to develop a preliminary description of the variability of emissions across time.

In the course of meeting its primary objectives, the project will provide the first detailed source signature of a coal-fired power plant, which will be useful to EPRI's Air Quality Studies Program in source apportionment and receptor modeling studies. It also will yield detailed analyses of carefully stored electrostatic precipitator ash samples, which will be useful for EPRI's solid-waste environmental studies (RP2485). In addition, Phase 2 includes scoping studies of the dilution/aging device, essentially a plume simulator, to help plan future BEPFA research and to provide backup samples for key parts of the study.

Rationale and approach

A driving force for the BEPFA project has been the possibility that EPA would establish a standard based on total thoracic particles to replace the existing standard, which is based on total suspended particles. The term *total thoracic particles* refers to particulate matter that is mostly 10 μm or less in aerodynamic diameter; another designation for this matter is PM_{10}.

On June 3, 1987, EPA set the 24-hour primary (health-based) standard for PM_{10} at 150 $\mu g/m^3$ and the annual standard at 50 $\mu g/m^3$. These numbers are at the lower end of the concentration range originally considered, and they represent a modest tightening of the old total

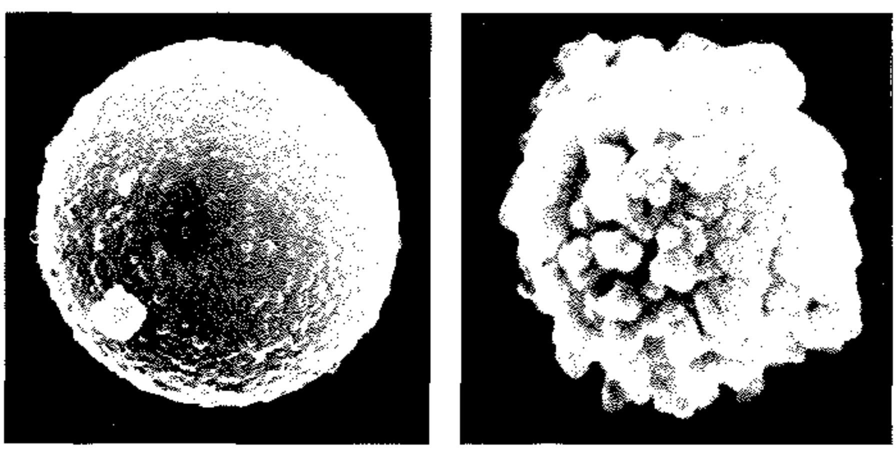


Figure 1 Particles of fly ash small enough to be inhaled and to deposit in the lungs. (The particle on the left is about 5.5 μm in diameter; that on the right, about 1.2 μm.) To some degree, material from the surface of such particles may dissolve and interact with biologic tissue.

suspended particle standards. EPA concludes that the new standards "will protect the public health with an adequate margin of safety" and that the "cost of meeting the PM_{10} standards is estimated . . . to be \$1.9 billion." Industries likely to bear these costs are the electric utility industry and five others. Areas of the country not expected to meet the standards include about 70 counties (or parts thereof). These areas must demonstrate attainment and maintenance of allowable levels within three to five years. Likely options for utilities in these areas include replacing suboptimal control equipment with state-of-the-art baghouses or electrostatic precipitators; fuel switching; or taking units out of service.

The BEPFA project will provide utilities facing major decisions on particulate emission control with information on atmospheric PM_{10} emissions from a modern coal-fired unit equipped with state-of-the-art electrostatic precipitators. The project is also examining the usefulness of state-of-the-art sampling and analysis techniques that will be available to individual utilities for evaluating their own situation. This information will be helpful in the near term, and it will also be useful when the standards are reexamined in five years, as mandated under the amendments to the Clean Air Act. The BEPFA results, together with results from other efforts, may lead to discussions of the merits of considering PM_{10} regulations in terms of the various sources of the particles and the potential health impact ascribable to each.

Although they were not a major issue when the BEPFA project was designed, air toxics have become a focus of regulatory attention. The emissions exiting a stack contain a wide array of organic and inorganic materials, some of which may be considered air toxics. The BEPFA project will obtain data on concentrations of individual emission components and on their combined activity in biologic tests. This information may be especially important, since there are few data on atmospheric organic and inorganic emissions from power plants—and no data on their biologic activity or lack thereof. It should be noted that most of the currently available data on fly ash are from electrostatic precipitator ash, baghouse ash, and stack ash; while this information may be relevant to occupational and solid-waste issues, it is much less relevant to atmospheric emissions.

The planned sampling for the Phase 2 field study, and most of the testing, will occur this summer; the testing is scheduled to be completed by the end of the year. In 1988 reports will be prepared, and key aspects of the results will be synthesized in a summary report by EPRI managers, consultants, and project contractors. At the end of the Phase 2 work, there will be a pause to consider the timing, nature, and extent of further research. This pause, which represents a new decision point in the project plan, is appropriate because more data than originally expected will be available on key topics bearing on the feasibility of the later phases. These topics include field collection techniques, particle storage, dilution/aging systems, emissions variability, and particle resuspension.

Sample collection and storage

During the past 18 months virtually all the preparations for the Phase 2 field study have been made. In some cases there have been changes in the project design details. Originally, for instance, PPM was to be collected as a bulk material that could be resuspended for inhalation studies. Preliminary studies found, however, that plume particle concentrations were too low for the proper functioning of a bulk sampler; as a result, there was a high potential for artifact formation—an unacceptable situation for studies on sample storage and stability. Filters are being used instead, because they circumvent many of the problems associated with baghouse collection and most other collection technologies. Although filters cannot provide material for inhalation studies with laboratory animals, they promise to be useful in identifying sampling situations that warrant detailed examination by such studies later in the project. On the basis of these considerations, a very large sampler using filters has been designed and assembled. It accommodates eight 8- by 10-in (20- by 25-cm) quartz filters, smaller nuclepore filters, and vapor traps—all of which can be rapidly removed and stored under appropriate conditions.

Since the early stages of the project, a helicopter has been deemed the best way to situate the sampling package in the plume. This is still the case, but there has been a change in approach—from a package suspended below the helicopter by a cable to a package fastened to the helicopter belly. The change was made to maximize maneuverability, minimize safety concerns, and optimize logistics. The helicopter will fly through the plume in a figure-eight pattern for at least eight periods of about 2 hours each. The total amount of PPM collected is expected to be as much as 4 g. An identical sampling package will be used for collecting background samples at a similar altitude near the plant.

Phase 2 of the project includes a study of the changes that may occur between the time a sample is collected and the time it is analyzed. The original project design called for comparing the effects of sample storage at −78.5°C, 4°C, and 20°C. That plan entailed the establishment of a laboratory repository and the construction of shipping containers suitable for air freight transport and for use as field repositories for up to a month. Because of technical and funding considerations, storage studies will be conducted only at −78.5°C and 20°C and surrogates for PFA will be used. Experiments have been conducted to select receptacles to hold the individual filters in the shipping containers and the laboratory repository. The most workable means of minimizing artifactual changes seems to be to use a glass petri dish, close it with several wrappings of Teflon tape, and then wrap it in aluminum foil.

Analyses

A battery of biologic, chemical, and physical techniques will serve throughout the project as screening tests to address hypotheses related to PFA's potential for health effects. The biologic screening tests produce the kinds of data that are relevant to health, and they are economical to perform on many samples. The results of the chemical and physical screening tests will help researchers understand the origins of any biologic response, but they cannot take the place of data on actual biologic responses to a complex material like PFA or PPM. The amount of PPM obtained for testing will be very limited, despite an extensive effort to maximize sample collection. Sample scarcity greatly limits the array of biologic, chemical, and physical tests that can be conducted. The tests selected represent a careful balancing of sample quantity used, cost, and potential yield of information.

The original plan emphasized the testing of intact particles—that is, testing without performing solvent extraction. Where possible, tests on intact particles have been selected. Unfortunately, the key samples must be collected on filters, from which the particles are not readily removed. Attempts have been made to adapt one biologic test, the Ames test, for application to particles on filters. The Ames test measures base-pair and frameshift mutations in the genetic material (DNA) of bacteria. The bacteria have been designed to have mutations that make them dependent on food supplements for normal growth. After exposure to certain chemicals, some of the bacteria mutate back to a state in which they do not require food supplements. When these bacteria are grown in a minimal food supply, they produce visible colonies, whereas those bacteria still dependent on food supplements do not. Thus the number of colonies produced indicates the amount of mutation caused by the chemical.

One variant of the Ames test, the spot test, can be done with filters, but at best it yields only rough, qualitative results. To obtain quantitative results, extraction appears necessary. Preliminary results suggest that extracts of unacceptably large samples may be needed to test project hypotheses with the regular Ames test. But another variant of the Ames test, called the Kado modification, helps minimize the amount of sample extract needed and may be suitable when microtechniques are used to further reduce sample requirements.

Although it will also require extraction, a bacterial DNA repair test has been added to the list of biologic tests. Both this and the Ames test assess the genetic toxicity of samples and tend to focus on their organic constituents. There are subtle but important differences, however, between the two tests. Whereas the Ames test has the advantage of detecting mutagenicity, the DNA repair test has the advantage of being potentially more sensitive and can thus backup the Ames test.

Unlike the Ames test and the DNA repair assay, the final biologic test—the macrophage clonal toxicity assay—focuses on mammalian cells of the general type responsible for defending the region of the lung where fly ash may deposit. The test examines the ability of single cells to form colonies, which is a simple model for the complex tasks that the macrophage must perform in the intact animal. As with all the other tests, the selection of this assay was based on the extreme scarcity of test material.

Chemical and physical tests have also been selected to accommodate the small quantities of sample and the desire to avoid extraction. Four techniques will be used. Three—computer-controlled scanning electron microscopy, polarized-light microscopy, and instrumental neutron activation analysis—focus on inorganic materials, do not require extraction, and can be done with very small samples. The fourth technique, gas chroma tography/mass spectrometry, does require extraction; however, it allows much easier identification of a wide array of organic compounds in a complex mixture than does sublimation/mass spectroscopy, the most sensitive alternative that requires no extraction. *Project Manager: Blakeman S. Smith*

SOLID-WASTE ENVIRONMENTAL STUDIES

A major concern associated with the land disposal of utility solid wastes is the release and migration of solutes to groundwater. Protecting groundwater from contamination is a principal objective of regulations being developed, or already proposed, under the Resource Conservation and Recovery Act (and its 1984 amendments), EPA's Groundwater Protection Strategy, the Safe Drinking Water Act (particularly the wellhead protection requirements in the 1986 amendments), and various state and local rules. Any change in waste disposal management requirements can have a large economic impact on the electric utility industry, which generates 80 million tons of solid waste annually and disposes of 80% of it on land. Utilities operate over 1000 landfills or ponds for waste disposal. Accurate predictions of changes in groundwater quality due to leachates are required for making cost-effective decisions about when and to what extent control technologies, if any, should be applied at disposal sites. Actions based on an inadequate understanding could result in controls that are either more or less stringent than necessary for environmentally safe disposal. In either case, costs could increase for the utility industry. Hence EPRI undertook research to develop methods and data for assessing how the disposal of solid residues from fossil fuel combustion affects groundwater quality; in 1983 this work was consolidated into the solid-waste environmental studies (SWES) project (RP2485).

The overall goal of SWES research is to develop and validate methods (models) for predicting the release, transformation, transport, and ultimate fate of inorganic chemicals from utility solid wastes. This goal is being met through the following seven research efforts.

- Leaching chemistry studies (RP2485-8)
- Chemical attenuation studies (RP2485-3)
- Subsurface transport studies: saturated-zone dispersion (RP2485-5) and unsaturated-zone dispersion (RP2485-6)
- Geohydrochemical models evaluation and interim development (RP2485-2)
- Field sampling methods evaluation and improvement (RP2485-7)
- Development of improved geohydrochemical models (RP2485-15)
- Field validation of predictive methods (RP2485-9)

Research under SWES includes evaluating existing predictive models; assembling interim models; and conducting experiments to quantify waste leaching characteristics, dispersion/dilution through physical processes, and attenuation through geochemical transformations during transport. In addition, research is being conducted to quantify the accuracy and precision of field measurement methods and groundwater sampling techniques and, as necessary, to develop improved methods for making environmental measurements. Eventually SWES researchers will develop improved models and validate them with field data from waste disposal sites. A 25-member advisory committee from the utility industry, universities, and government agencies provides technical guidance for SWES.

An earlier report (*EPRI Journal,* June 1986, p. 52) described several results and products of the SWES research. This report summarizes the progress made in three of the seven research areas since that time.

Leaching chemistry

In work on the leaching chemistry of utility wastes (RP2485-8), Battelle, Pacific Northwest Laboratories has completed a review of data in the literature, an analysis of fossil fuel combustion wastes collected from 46 power plants, and a further evaluation of leaching tests used for regulatory purposes. A two-volume report (EPRI EA-5176) presenting the results of the literature review and an annotated bibliography will be published soon. The report includes information on 28 inorganic constituents and selected organic compounds.

In the evaluation of applicable leaching reactions, 99 samples of fly ash, bottom ash, scrubber sludge, and oil ash from 46 power plants were analyzed. Several extraction methods were used to determine the samples' chemical composition and the solubility of their constituents. A report on this evaluation will be available late this year (EA-5321). Sixteen wastes from 10 power plants have been selected for continued laboratory experiments to quantify leaching rates, concentrations of leachate constituents, and leaching duration.

Leaching chemistry studies are also being conducted at existing waste disposal sites. A site containing sludge from a wet limestone flue gas desulfurization (FGD) system was sampled to investigate whether a mechanistic approach based on fundamental reaction chemistry is applicable to the estimation of leachate composition. Data from the literature review (EA-5176), chemical attenuation studies (EA-3356 and EA-4544), and feasibility experiments on waste leaching (EA-4215) were used to predict concentrations of cadmium, chromium, copper, lead, and zinc in the sludge leachates under real-world conditions. A direct analysis of the leachates from the FGD sludge site confirmed these predictions. Both the predictions and the observations indicated that because of the geochemical environment and the resulting reactions, the concentrations of these elements in leachate from the FGD site are below analytic detection limits. These concentrations are well below the drinking water standard. Three more field-scale investigations are planned for the next four years, along with the fundamental laboratory experiments now under way. An interim leachate generation model (FOWL) is being developed for release at the end of 1987.

Chemical attenuation

Predicting the mobility of solutes in groundwater requires information on various chemical transformation processes, including precipitation/dissolution, adsorption/desorption, oxidation/reduction, and aqueous phase speciation. Battelle has been conducting experiments with selected soil minerals and five soils collected at utility disposal sites to investigate these processes for arsenic, boron, cadmium, chromium, selenium, vanadium, and zinc (RP2485-3).

The chemical attenuation research began with chromium. A report on certain geochemical reactions of chromium was published in May 1986 (EA-4544), and a second one—on the remaining reactions—is being reviewed for publication later this year. Also available is an EPRI Technical Brief (TB.EAE.7.6.86) that summarizes the chromium research. A report on the application of the chromium results at utility sites is being prepared. The results also have been incorporated into FASTCHEM, an interim hydrogeochemical model being developed under the SWES project.

Solubility, sorption, and kinetic studies are under way for cadmium. Limited experiments have been initiated to identify the solubility-controlling solid phases for arsenic, boron, and selenium. Future experiments will investigate vanadium and zinc.

The results on cadmium to date suggest that solution concentrations under oxidizing alkaline conditions are controlled by the solubility of cadmium carbonate ($CdCO_3$). Although cadmium is not a redox-sensitive element, its concentrations under highly reducing conditions (in FGD sludges, for example) are expected to be controlled by cadmium sulfide (CdS). Before EPRI conducted its research, $(Ca,Cd)CO_3$—rather than $CdCO_3$—had been implicated as the solubility-controlling solid. The EPRI research conclusively shows, however, that $(Ca,Cd)CO_3$ is not an important solubility-controlling solid for cadmium. Under acidic conditions, most cadmium solids are highly soluble.

EPRI research has produced new results that quantify the adsorption of Cd^{++} on several soils and soil minerals. These results indicate that Cd^{++} is strongly adsorbed by such soil minerals as iron oxide and montmorillonite. Cadmium adsorption increases as the pH of the system increases above 7; however, competing ions in solution (e.g., Ca^{++}) decrease the adsorption of Cd^{++}. Unlike chromium adsorption, cadmium adsorption is not affected by the presence of sulfate ions. Reports of the new results on cadmium are being prepared and will be published by the end of 1987. These thermodynamic, kinetic, and adsorption results will also be incorporated into FASTCHEM.

Subsurface transport

Dispersion is a critical process that affects the downgradient distribution of all solutes. For some solutes, such as sulfate and chloride, dispersion may be the only in situ process that reduces downgradient concentrations. Separate investigations are being conducted into dispersion in the saturated zone and dispersion in the unsaturated zone.

After two years of extensive preparation, in October 1986 researchers from the Tennessee Valley Authority injected seven tracers into an aquifer in Columbus, Mississippi, to initiate the saturated-zone dispersion experiment (RP2485-5). Five injection wells provide a line source into the middle of the heterogeneous aquifer, which comprises sands, gravels, and clays. About 120 multilevel sampling wells have been installed for surveys of the tracer plume. Altogether 350 wells will be installed during the 2–3 years of this field-scale macrodispersion experiment (designated MADE).

As of May 28, 1987, four tracer plume surveys had been taken. Initial estimates based on these surveys indicate that the introduced tracers are moving upward, following the hydraulic gradient and the more conductive layer. The centroid of the tracer plume is traveling at a rate of about 0.2 ft (6.1 cm) a day. The tracer plume is already showing three-dimensional dispersion, which indicates that the dilution of chemicals in groundwater may be greater than current theoretical assumptions would suggest.

A separate set of experiments is being conducted by researchers from the University of California at Riverside to clarify the mechanisms responsible for the transport and spreading of chemicals in the unsaturated subsurface environment (RP2485-6). Cofunded by Southern California Edison Co., the unsaturated-zone dispersion experiments (called UDEX) are taking place at two California sites, Moreno and Etiwanda.

Preliminary experiments at the Etiwanda site show an increase in macrodispersivity between the depths of 0.5 and 3 m, followed by a substantial decrease in macrodispersivity between the depths of 3 and 4.5 m. An initial analysis of these results indicates that hydraulic conductivity variations in unsaturated soils have a large effect on dispersion. The results also indicate that flow and transport models must be improved significantly if the necessary prediction accuracies are to be attained.

In conclusion, the solid-waste environmental research of EPRI's Land and Water Quality Studies Program has produced results that are already being used by the utility industry (e.g., Utility Solid Waste Activities Group, Empire State Electric Energy Research Corp., New York State Electric & Gas Corp., Pennsylvania Power & Light Co., Tennessee Valley Authority), by researchers (e.g., University of Wisconsin at Madison, New Mexico State University), and by regulators (e.g., EPA, Wisconsin Department of Natural Resources). The three technology transfer seminars held to date have disseminated SWES results and provided training to participants from utilities, consulting firms, academia, and state and federal agencies. In the fall of 1987 EPRI will offer six regional seminars to further increase the use of SWES results. Also, SWES project staff at EPRI will provide users from member utilities with technical assistance in applying the results. *Program Manager: Ishwar P. Murarka*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

CALCULATION OF GAMMA DETECTOR RESPONSE FUNCTIONS

The development of detectors sensitive to gamma rays for measurement of light water reactor (LWR) core power distributions has created a need for an analytic capability that can be used for predicting the characteristics of the gamma flux. EPRI has recently developed an extension to lattice neutronics codes that can calculate the behavior of gamma rays in LWR cores under various operating conditions.

Detectors sensitive to gamma radiation instead of neutrons possess certain advantages that make them attractive for use in measurements of LWR core power distributions. In particular, such detectors have a potential for much longer life because the sensitive material is not depleted as it is in most neutron detectors.

Gamma detectors can also be more accurate, particularly when used in boiling water reactors (BWRs) as traversing in-core probes (TIPs). Such instruments are typically inserted into the gaps between fuel assemblies, where the corners of four adjacent assemblies come together. At that location, thermal neutron fluxes exhibit a sharp peak; therefore small variations in the lateral positioning of a neutron-sensitive probe (misalignment) will result in large changes in the instrument response, thereby leading to the possibility of misinterpretation of the power level in the adjacent assemblies. Because the gamma flux is much smoother, gamma detectors are much less prone to such position-dependent uncertainties.

Primarily, two types of gamma detectors have thus far been developed by vendors in the United States, Canada, and Europe (Figure 1). One type measures the electric current from the ionization caused by gamma rays penetrating the detector. This approach is the basis for the gamma TIPs developed by General Electric Co. and introduced into at least six BWRs in the United States. The second type is based on measurements of the total energy deposited in the detector in the form of heat. Thermocouples are used to measure the temperature differential between an insulated and a cooled section of the detector. This type of detector is referred to as a gamma thermometer. Development and use of gamma thermometers have been pioneered in France and Sweden, where, because of the longer life expectancy of the thermometers, they are being proposed for long-term monitoring of power distributions in PWRs.

To correlate gamma detector readings to fuel assembly power under different reactor operating conditions, it is necessary to know the neutron reaction rates, which are a major source of gamma rays, as well the gamma transport properties of the assembly. Gamma rays are created by neutron-induced fission, by the radioactive decay of fission products, by inelastic scattering of neutrons, and by parasitic capture of neutrons in fuel, structural materials, control rods, or burnable absorbers. Each of these sources produces gamma rays of different energies, at different locations, and in the case of fission products, at different times.

The strength of these sources will vary with exposure as certain isotopes are depleted and new ones are created. Although it may be possible to develop some general correlations that will provide estimates of detector responses on the basis of the neutronic state of an assembly, it is preferable, as well as more accurate, to directly calculate the production and transport of gamma rays at each exposure point in

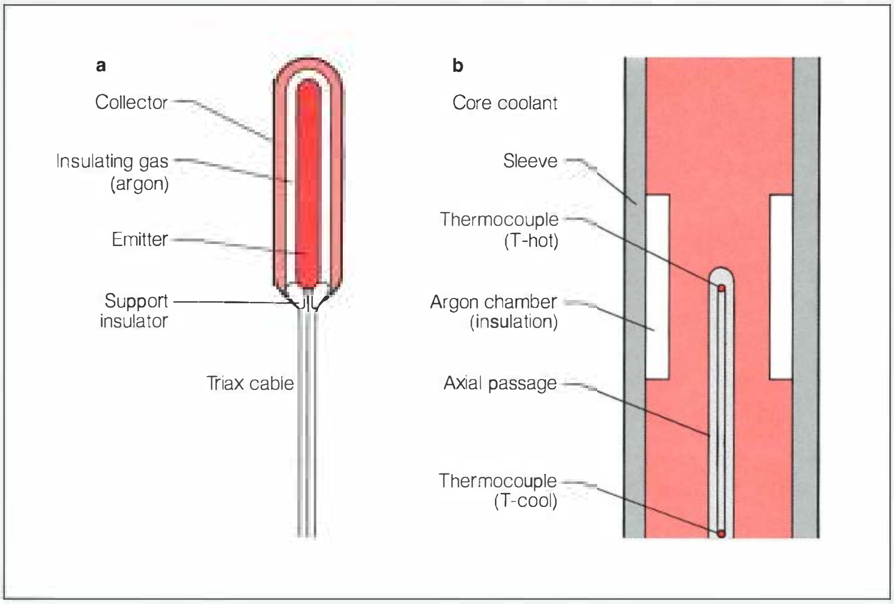


Figure 1 Two basic types of gamma detectors. In the voltage-driven detector (**a**), gamma rays are measured in terms of the electric current that is caused to flow as a result of ionization induced by the gamma rays. The gamma thermometer (**b**) measures a temperature gradient created in the detector by gamma heating and the presence of an insulating region. The drawing indicates the position of thermocouples in the axial passage, which measure the temperature difference.

the fuel assembly of interest because of the large number of design configurations that otherwise would have to be represented and the number of independent variables that would have to be accounted for.

EPRI has supported the development by Studsvik Energiteknik of a computer code module that can be used as an extension to fuel assembly neutronics codes for calculating gamma fluxes and, given a detector sensitivity function, the response of gamma detectors in any typical LWR fuel assembly (RP2352-1). This calculation can be carried out at all exposure points, taking into account all variable conditions—for example, moderator density or voiding, control rod presence or absence, and burnable poison depletion status—that may affect the response of the detector.

EPRI's gamma module uses the neutron reaction rates provided to it at each exposure point by the assembly neutronics code that acts as a driver. These reaction rates are used to determine the sources (location and energy) of gamma rays. The transport of gamma rays from their point of origin to the location of the detector is then calculated by using a collision theory approach in two-dimensional rectangular geometry. In this approach, however, the cylindrical representation of the fuel pins is maintained to avoid homogenization problems that would be caused by the fact that fuel pins are nearly opaque to gamma rays, whereas the moderator and most structural components of the assembly are more or less transparent.

The original development of the gamma analysis capability was carried out by Studsvik by using the CASMO-1 code as the neutronics driver program. The collision probability code CPM–HET, which was developed previously with the needed combination of cylindrical and rectangular geometry for validating assembly neutronics codes, was adapted for use in the gamma transport problem. A library of gamma production and gamma interaction cross sections has been developed under a subcontract with Rensselaer Polytechnic Institute (RPI), using an existing library (SAILOR) for shielding applications as a starting point. RPI's contribution consisted of evaluating the performance of this library for in-core applications and extending its features in areas found to be deficient.

Since this initial development, the gamma module has been incorporated into a version of the CPM-2 assembly neutronics code as well. Thus the module can be used as an extension of either CASMO-1 or CPM-2.

Benchmarking and validation of the new gamma analysis capability involved three phases: benchmarking the capability of estimating gamma production rates; benchmarking the gamma transport calculations; and validation against plant data. The benchmarking activity in the first two phases consisted of comparing the predictions of the new gamma module driven by CASMO-1 against more-rigorous Monte Carlo calculations. Brookhaven National Laboratory used the SAM–CE program to provide the needed benchmarking results (RP2352-2). SAM–CE is a highly sophisticated Monte Carlo program that uses data from the state-of-the-art ENDF/B–V nuclear data library to follow neutrons, gamma rays, and secondary electrons in complex geometries. Nevertheless, generating results with sufficient statistical accuracy proved to be a problem, which was resolved by benchmarking the gamma production and gamma transport capabilities separately.

The gamma production capability was benchmarked by comparing the predicted gamma ray spectra (edited into 18 groups) that would be produced by a 4% enriched PWR fuel pin under cold, hot, beginning-of-life, and end-of-life conditions. The total gamma energy generation predictions were found to differ from the Monte Carlo values by less than 2%. Although bigger differences were observed in individual energy groups, these were considered to be caused by uncertainties in the basic data, and thus not to have a significant effect on the analytic ability to predict integral detector responses.

Benchmarking of the transport calculation was done by comparing predicted detector responses in five BWR and two PWR fuel assembly configurations. To eliminate differences in the treatment of neutronics and to focus exclusively on the gamma transport problem, the neutron reaction rates calculated with CASMO-1 were imposed as a source onto the Monte Carlo calculation. This comparison showed an agreement to within 5% or better between the two predictions.

The plant data comparisons were accomplished by using data from cycle 3 of the Hatch Unit 1 BWR. These data include gamma TIP readings, as well as gamma scans carried out following the end of the cycle (NP-2106; NP-562). Using the power distributions deduced from the gamma scans in conjunction with detector response functions calculated by the new capability, it has been possible to match the TIP readings with an RMS error for all nodes of 2.7%, which is within a standard deviation of the experimental data. The results showed no trends or discrepancies with void level, burnup, fuel type, or presence of control rods.

Since the implementation of the gamma module into CPM-2, a subset of the benchmark calculations was redone to demonstrate the proper functioning of the module in its new environment.

EPRI's new gamma analysis capability has been made available for prerelease testing by utilities as part of either CASMO-1 or CPM-2. The CPM-2-driven version has been implemented at Public Service Electric & Gas Co., where it is being used for the analysis of TIP data from the Hope Creek BWR, and at Cleveland Electric Illuminating Co. for analysis of data from Perry Unit 1. Although only preliminary results from PSE&G are available, they indicate good agreement at hot, full-power operating conditions. *Project Manager: Odelli Ozer*

PUMP SHAFT INSPECTION

Reactor coolant pumps are integral parts of reactor cooling systems in nuclear power plants. Because they pump coolant into the reactor core during operation, a pump failure could result in exceedingly high core temperatures. The shafts of these coolant pumps carry high torque loads that make them vulnerable to fatigue failures, thus necessitating reliable inspection techniques.

The reactor coolant pump is a high-horsepower unit. The pump shaft, which is usually fabricated from a heavy stainless steel section, must transform the torque of the motor into pumping power and is subjected to very high stresses. Therefore, pump shafts are susceptible to fatigue cracking caused by large cyclic stresses. Any defects along the length of the shaft can act as stress risers and, ultimately, as crack initiation sites. Because of the crack growth characteristics, it is important to be able to detect flaw depths as small as 0.200 in (5 mm).

Failure of a reactor coolant pump shaft was first reported in the Crystal River-3 nuclear plant on January 1, 1986. As a result of that failure, several utilities were required to inspect the pumps and provide pump condition data to NRC. To comply with this requirement the Davis Besse nuclear power plant used ultrasonic techniques to inspect several pump shafts. Those inspections showed indications of cracking, but when the pumps were disassembled and the shafts examined with liquid penetrant, no cracks were found. As a result, questions were raised about the reliability of ultrasonic inspection as a means of detecting cracks in the pump shaft.

Conventional inspection techniques

A reactor coolant pump shaft is a long, large-diameter cylindrical body that has many variations in diameter along its length. The pump shaft is directly mated to the pump impeller and sustains a great amount of stress in converting the torque of the high-horsepower motor into pumping force.

Pump shafts can be inspected in several ways, each of which requires that the pump be disassembled to some extent. One approach is to completely disassemble the pump and to examine the shaft with liquid penetrant techniques. However, disassembly of the pump is costly and time-consuming.

The most commonly used nondestructive examination (NDE) method for inspecting pump shafts in situ is ultrasonics. Two ultrasonic techniques have been used: zero-degree longitudinal wave (L-wave) and high-angle longitudinal wave.

When the zero-degree L-wave is used, the cover of the pump must be removed to expose the flat end of the pump shaft. To use the high-angle L-wave technique, further disassembly of the pump is required so that almost the entire length of the pump shaft is exposed (Figure 2). Unfortunately, neither technique has yielded conclusive results.

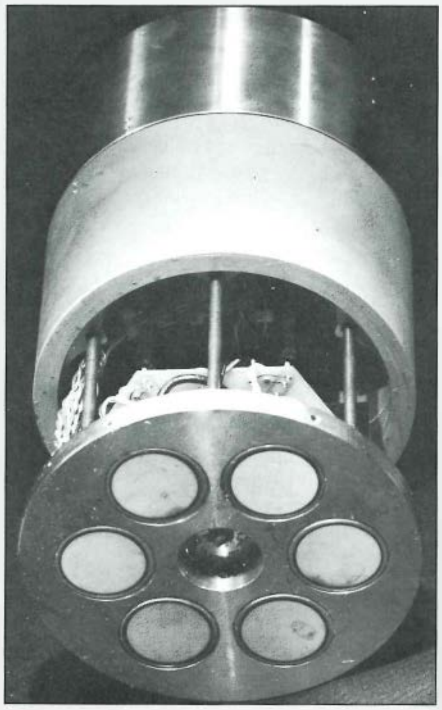
In the conventional zero-degree L-wave technique, a transducer with a frequency in the range of 1 to 2.25 MHz is used to scan the surface of the exposed end. There are two major problems associated with this method: first, the asymmetry of the sound beam propagation leads to mode-converted signals that can be difficult to interpret; and second, because the shafts are very long and usually made of highly attenuative steel, it is difficult to generate sufficient sound energy to receive reflections from small defects within pump shafts.

The use of the angle beam technique, on the other hand, requires much more extensive pump disassembly in order for the sound beam to intersect the regions of interest. This technique has also been somewhat unreliable because of false indications deriving from metallurgical variations in the pump shaft.

New NDE technique

To solve these problems of pump shaft inspection, EPRI contracted with Southwest Research Institute to develop a new NDE technique (RP2179-2). The new technique is a modified version of the cylindrically guided wave technique previously developed under the same contract for the inspection of long studs (*EPRI Journal,* June 1985, pp. 60–61). It uses a matrix of 1-in-diam (2.5-cm-diam) transducers arranged in a circle with a diameter of approximately 5 in (12.7 cm) to form a large transducer head (Figure 3). Each transducer is provided with a hybrid pulser-preamplifier; the pulser-preamplifiers are mounted very near the transducers they serve, thus permitting the transducers to emit strong ultrasonic waves without incurring great losses induced by the impedance of the piezoelectric crystal material and the cables. The transducers are pulsed simultaneously. Return pulses are received by using differential receiver technology. The received signals obtained from the differential receivers are then summed and amplified. The result is a single, high-amplitude ultrasonic signal. Because the matrix transducer is applied to the center of the pump shaft diameter, the signal is not greatly affected by asymmetric mode conversions.

Figure 3 The cylindrically guided wave technique uses a matrix of 1-in-diam (2.5-cm) transducers, arranged in a circle with a diameter of approximately 5 in (13 cm). Each transducer has its own hybrid pulser/receiver nearby to emit a high-powered ultrasonic wave.



Initial testing of the new matrix transducer was conducted on the Crystal River pump shaft mock-up, which contained three notches that were approximately 0.20 in (5 mm) deep. All the notches were easily detected with a signal-to-noise ratio in excess of 10 to 1. Subsequent testing was conducted on long studs that had geometries similar to those of the pump shaft and had defects that were about 0.08 in (2 mm) deep.

A field demonstration of the technique was conducted at the Maine Yankee nuclear power plant on a spare shaft. The results of that inspection indicated no defects of any significance, although no calibration standard was available with which to quantify the results. This evidence was further verified by liquid penetrant examinations. However, inspection of this shaft by conventional ultrasonic testing techniques revealed indications of defects that could not be confirmed.

In future efforts, the cylindrically guided wave technique will be integrated with automated ultrasonic testing systems and that technique will then be evaluated in tests of field samples. *Project Manager: Soung-nan Liu*

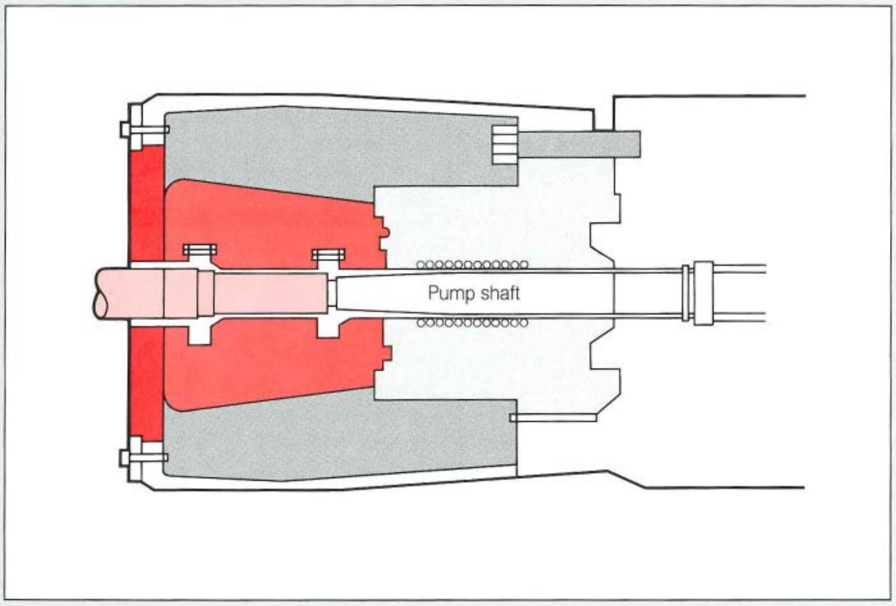


Figure 2 Schematic of a reactor coolant pump and housing. The new cylindrically guided wave technique and the conventional zero-degree L-wave technique require removal of the components in color. The angle beam inspection technique requires the removal of the components shown in gray in addition to those in color. The pump shaft is approximately 80 in long (203 cm), and its diameter increases from 5 in (13 cm) to 13 in (33 cm).

R&D Status Report
PLANNING AND EVALUATION DIVISION

Richard W. Zeren, Director

STRATEGIES FOR COPING WITH DROUGHT

EPRI is sponsoring a project to assess the extent of drought problems in the electric utility industry, to define current drought planning and operational management practices, and to develop new methods and strategies for coping with drought (RP2194-1). The project began with extensive interviews of electric utilities, private consultants, and government agencies. According to their responses, the drought planning and operations methods used in the electric utility industry are based almost exclusively on the critical-period approach. This approach, whose key assumption is that the worst drought of historical record will recur, has some serious limitations. As a result, the project contractor, the Department of Civil Engineering of the University of Washington, investigated an alternative method that combines stochastic hydrology with water resource system simulation modeling. This approach allows explicit estimation of system reliability, as well as formal consideration of the range of possible future drought conditions. Demonstration results clearly illustrate the differences in system performance that result from alternative, equally probable future streamflow sequences, and they show why it is essential that drought planning studies treat system reliability explicitly.

In the recent past, several severe droughts in the United States have significantly affected electric power generation. The West Coast drought a decade ago had by far the greatest economic impact. This drought began in October 1975 in central California and expanded in the winter of 1976–1977 to cover most of the western and north central plains states. During water year 1977 (October 1976 through September 1977), record-low runoff was recorded for a number of California streams for which there are close to 100 years of records. There are hydroelectric power generation facilities on many of these streams, and the cost of the oil to replace the lost hydropower generation was about $700 million. In the Pacific Northwest as well, the regional economic impact of the drought-related electric power generation shortfalls was in the hundreds of millions of dollars.

Despite the recent droughts in this country, relatively little is known about the susceptibility of the electric power industry to drought. To learn more about the extent of drought problems in the industry, a two-phase interview program was designed. In the first phase, a number of utilities and other organizations involved with electric power generation were interviewed by telephone. The interviewees—47 in all—represented a range of geographic locations, types and sizes of power generation facilities, and generation mixes. Of these 47 organizations, 17 were then visited by the interview team. Summary reports of the interview visits were subsequently compiled.

The interviews revealed that a large number of utilities across the country have experienced difficulties related to drought or can expect such difficulties in the future, as competition for limited water supplies increases. In most cases, droughts have not prevented utilities from delivering electricity. Instead, they have resulted in direct economic losses, as utilities have been forced to obtain power from more expensive sources. The magnitude of the drought losses incurred by a utility is highly dependent on the specific circumstances of that utility, the most important of which is the cost of replacement power.

Traditional design and planning practices

As expected, the interviews confirmed that the principal drought problems occur for hydroelectric systems and for thermal systems that use relatively small streams for cooling purposes (either in once-through cooling or as the source of makeup water for cooling ponds or towers). The interviews also showed that drought design and planning for hydroelectric plants and for thermal-plant water supply systems have been based almost exclusively on critical-period methods; that is, the facilities have been sized for the most severe drought of historical record or some fixed multiple thereof.

The critical-period approach has three significant drawbacks. First, the severity of the design conditions depends on the length of the hydrologic record. Second, because the approach does not consider the probability of the critical event's recurrence, it gives no indication of the reliability of the system design. Third, the approach does not consider potential events more severe than the critical event of record.

According to the interviews, the risk of water shortages that would require curtailing or ceasing plant operation is generally given much more attention at hydroelectic installations than at thermal ones. Because streamflow is the generation source for a hydroelectric plant, its variability is a primary consideration in system design and operation.

Stochastic hydrology as a planning tool

An alternative approach to critical-period planning makes use of stochastically generated streamflows. This method begins with the identification of historical streamflow records for specified control points, or nodes. From these historical records, investigators estimate statistical parameters that probabilistically characterize the processes assumed to underlie the historical flows. Conceptually, it is as if the historical streamflow record is the outcome of an experiment that can have an infinite number of alternative outcomes. The underlying process—that is, the experiment—is characterized by the statistical parameters estimated from the historical record. The parameters define a model from which alternative streamflow sequences are generated. These can be considered equally likely future streamflow scenarios.

A number of mathematical models for generating synthetic streamflows were reviewed, and specific recommendations for implementation will be made in an EPRI report to be published soon.

The most straightforward approach to generating seasonal streamflows at multiple sites (which is usually the level of detail required for drought planning studies) seems to be the coupling of an annual streamflow generation model with a procedure for disaggregating the annual flows into seasons.

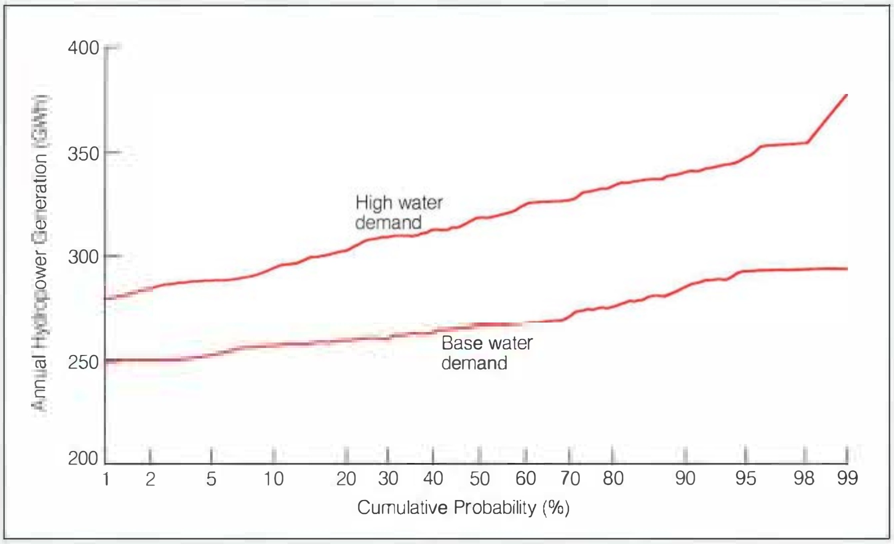
System performance evaluation

The motivation for developing a streamflow generation model is to capture the structure of the natural variability of the streamflow process, which occasionally gives rise to extended and/or extreme low flows. To assess drought probabilities, it is also necessary to characterize the physical configuration of the water resource system in question and its operating policy. A system simulation model can be used to predict how, given the inflows to the system (e.g., the synthetic streamflows), the system would be operated.

To illustrate drought planning that uses synthetic streamflows coupled with a system simulation model, the investigators applied the method to the Salt River Project. SRP is a private utility, originally established in 1903 to supply irrigation water to the lower Salt River Valley in Arizona. SRP is now also a major electricity supplier in the Phoenix area.

One of the important features of the Salt River system is the interaction between water demand and hydropower production. Because many SRP member lands have undergone a transition from agricultural to residential and other urban uses, SRP's water demands have decreased somewhat over time; it is expected that by the year 2030 essentially no agricultural lands will remain within the SRP water service area. The long-term water demand (including deliveries to member lands and contract sales) is projected to decrease until about 2000 and then increase.

Figure 1 The average annual hydropower production of a utility system was analyzed probabilistically for two levels of water demand by using an approach that combines a stochastic streamflow generation model and a water resource system simulation model. These curves show the probability that power production will not exceed a given level. The analysis approach, which was studied in RP2194-1, promises to help utilities plan more realistically for drought.



A streamflow generation model for the Salt and Verde rivers was developed and implemented. In addition, an existing system simulation model (SRPSIM) was adapted to predict the performance of the system for each set of synthetic streamflows. The two models were then used together to explore the performance of the SRP hydropower system.

Figure 1 shows the type of summary information that can be obtained from the stochastic analysis. It presents the empirical probability distribution of average annual hydropower production (in GWh) for two levels of water demand. The higher demand level tends to deplete the reservoirs. Thus, with higher demand, more upstream storage capacity is generally available to accommodate high inflows, and the need to spill water is reduced. As a result, more of the Salt River reservoir releases pass through the turbines, and power generation is increased. (The Verde River dams have no hydropower generation facilities.)

The same analysis method can be applied to any system that is dependent on streamflow for power generation or for cooling water. The forthcoming project report will give full details of the method and the SRP application. It will also include an example involving the estimation of reliability for a cooling reservoir that serves a coal-fired power plant. *Project Manager: Edward Altouney*

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Advanced Power Systems		
Uplift Pressures in Cracks and Drain Effectiveness (RP2917-7)	$377,500 3 years	Regents of the University of Colorado/*D. Morris*
Coal Combustion Systems		
Pilot Testing: ESP Retrofit Technologies (RP1835-9)	$477,100 1 year	University of Denver/ *R. Altman*
Pilot Evaluation of Reburning for Cyclone Boiler (RP2154-11)	$240,000 21 months	Babcock & Wilcox Co./ *M. McElroy*
Testing and Evaluation: AFBC Concepts (RP2303-20)	$126,700 9 months	Combustion Systems, Inc./*E. Petrill*
Characterization of Coal Gasification Slags (RP2708-3)	$94,000 11 months	Praxis Engineers, Inc./ *D. Golden*
Demonstration: EPRI Heat Rate Improvement Guidelines at SCE's Ormond Beach-2 (RP2818-1)	$430,000 28 months	Southern California Edison Co./*G. Poe*
Full-Scale Testing and Evaluation of a Retrofit Low-NO_x PM Burner System (RP2916-3)	$1,145,400 25 months	Fossil Energy Research Corp./*D. Eskinazi*
Assessment of Utility Needs for Expert Systems (RP2923-2)	$77,800 7 months	Expert-Ease System, Inc./ *M. Divakaruni*
Energy Management and Utilization		
Service Life of Water Loop Heat Pumps (RP2480-6)	$30,900 7 months	Policy Research Assoc./ *M. Blatt*
Handbook of Electric Alternatives to Cogeneration (RP2480-7)	$36,300 5 months	Resource Dynamics Corp./*M. Blatt*
Comfort Criteria in a Low-Humidity Environment (RP2732-10)	$48,500 5 months	The John B. Pierce Foundation Laboratory/ *R. Wendland*
Industrial Technical Assessment Guide (RP2788-9)	$69,000 5 months	Resource Dynamics Corp./*T. Yau*
Survey and Integration of Utility End-Use Projects (RP2884-1)	$145,000 10 months	Battelle Memorial Institute/ *T. Oldberg*
Commercial Building HVAC System Analysis (RP2891-2)	$50,000 4 months	Arthur D. Little, Inc./ *M. Blatt*
Nonmetals Technology Transfer (RP2893-4)	$100,000 11 months	Battelle Memorial Institute/ *A. Karp*
Mineralogical and Geochemical Assessment of Porous Media for Compressed-Air Storage (RP8000-9)	$169,000 14 months	Core Laboratories, Inc./ *B. Mehta*
Power System Applications of Fiber Optic Sensors (RP8004-1)	$66,100 7 months	Tennessee Valley Authority/*N. Hirota*
Gas Turbines Heat Transfer With Multiple Cooling Fluids (RP8006-5)	$95,500 1 year	General Electric Co./ *A. Cohn*
Environment		
Formation and Deposition of Acid Cloud Water (RP2023-9)	$369,000 32 months	University of Manchester Institute of Science and Technology/*A. Hansen*
Technology Transfer: RILWAS (RP2174-14)	$49,700 8 months	Tetra Tech, Inc./ *R. Goldstein*
SWES Technical Advisers and Consultants (RP2485-12)	$524,000 43 months	Ethuar/*I. Murarka*
Pathophysiology of Electric Injuries (RP2914-1)	$400,000 42 months	Massachusetts Institute of Technology/*W. Weyzen*
Nuclear Power		
In-Reactor Monitoring for Component Life Prediction (RP2006-17)	$497,000 9 months	General Electric Co./ *R. Pathania*
Application of the Cylindrically Guided Wave Technique and Pump Shaft Inspections (RP2179-6)	$40,000 8 months	Southwest Research Institute/*S. Liu*
Detection and Sizing of Flaws in CCSS Pipes With Rayleigh and Lamb Waves (RP2405-23)	$61,000 9 months	Georgetown University/ *M. J. Avioli*
Radwaste Generation From Nonroutine Activities (RP2414-11)	$57,700 4 months	Analytical Resources, Inc./ *F. Gelhaus*
Problems in Nuclear Plant Pneumatic Systems (RP2420-54)	$60,000 8 months	Pickard, Lowe & Garrick, Inc./*W. Reuland*
Preventative Maintenance Planning (RP2508-9)	$73,700 6 months	Science Applications International Corp./ *J. Gaertner*
Implementation: CAE Guidelines (RP2514-6)	$148,900 1 year	Duke Power Co./ *J. Carey*
Component Reliability Parameter (RP2681-1)	$401,550 32 months	Science Applications International Corp./ *J. Gaertner*
Personal Protection Management (RP2705-6)	$297,300 10 months	Commonwealth Research Corp./*J. O'Brien*
Analytic Correlation of Fukushima In-plant Vibration Data (RP2723-2)	$41,000 5 months	Bechtel Group, Inc./ *H. T. Tang*
Passivation of PWR Primary Material (RP2758-2)	$74,000 11 months	Radiological and Chemical Technology, Inc./*C. Wood*
Implementation of the Dynamic Flow Regime Model in Thermal-Hydraulic Codes (RP2806-1)	$49,800 6 months	Jaycor/*G. Srikantiah*
NDE Through Coating (RP2904-1)	$51,600 6 months	EG&G Idaho, Inc./*S. Liu*
Support for Implementation of the Anchorage Guidelines (RP2925-1)	$50,000 7 months	URS/John A. Blume & Assoc./*A. Singh*

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. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of EPRI reports on request. For information on how to order one-page summaries of reports, contact the EPRI Technical Information Division, P.O. Box 10412, Palo Alto, California 94303; (415) 855-2411.

ADVANCED POWER SYSTEMS

Analysis of the Off-Design Performance and Phased Construction of Integrated Gasification–Combined-Cycle Power Plants

AP-5027 Final Report (RP2029-12); Vol. 1, $32.50; Vol. 2, $40
Contractor: Stanford University
EPRI Project Manager: M. Gluckman

Pilot Plant Evaluation of Illinois No. 6 and Pittsburgh No. 8 Coal for the Texaco Coal Gasification Process

AP-5029 Final Report (RP1459-12, -17); $25
Contractor: Texaco, Inc.
EPRI Project Manager: N. Hertz

Characterization of KILnGAS Wastewater

AP-5030 Final Report (RP2526-2); $25
Contractor: Oak Ridge National Laboratory
EPRI Project Manager: M. Epstein

Liquid-Entrained-Catalyst Operations at LaPorte Pilot Plant for Liquid-Phase Methanol Process, 1984–1985

AP-5049 Final Report (RP317-3); $40
Contractor: Air Products and Chemicals, Inc.
EPRI Project Manager: N. Stewart

Coatings Technology for Hot Components of Industrial Combustion Turbines: Review of the State of the Art

AP-5078 Final Report (RP2388-3); $25
Contractor: Southwest Research Institute
EPRI Project Managers: R. Viswanathan, C. Knauf

Workshop on Retrofit Controls for Combustion Turbines

AP-5098-SR Proceedings; $99.50
EPRI Project Manager: G. Quentin

COAL COMBUSTION SYSTEMS

Slagging and Fouling Consequences of Furnace Limestone Injection

CS-5020 Final Report (RP899-2); $40
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: D. Eskinazi

Performance of Mechanical Systems for Condenser Cleaning

CS-5032 Final Report (RP2300-11); $25
Contractor: Sargent & Lundy
EPRI Project Manager: J. Bartz

Corrosion-Product Transport in a Cycling Fossil Plant

CS-5033 Final Report (RP1184-9); $32.50
Contractor: NWT Corp.
EPRI Project Manager: J. Scheibel

Evaluation of the PM Burner: A Low-NO_x Pulverized-Coal-Firing System for Tangentially Fired Utility Boilers

CS-5034 Final Report (RP1836-1, -2); $47.50
Contractors: Mitsubishi Heavy Industries, Ltd.; Combustion Engineering, Inc.
EPRI Project Manager: M. McElroy

Aqueous Discharges From Steam-Electric Power Plants: Reference Guide for Monitoring Six Selected Conventional and Nonconventional Pollutants

CS-5035 Final Report (RP1851-1); $55
Contractor: TRW, Inc.
EPRI Project Manager: W. Chow

Precipitator Performance Estimation

CS-5040 Final Report (RP629-5); $32.50
Contractor: Southern Research Institute
EPRI Project Manager: R. Altman

Prevention, Detection, and Control of Coal Pulverizer Fires and Explosions

CS-5069 Final Report (RP1883-1); $550
Contractor: Riley Stoker Corp.
EPRI Project Manager: D. Broske

Bench-Scale Combustion Characterization of Cleaned Kentucky No. 9 Coals

CS-5070 Final Report (RP2425-4); $25
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: A. Mehta

Fireside Corrosion and Fly Ash Erosion in Boilers

CS-5071 Final Report (RP2711-1); $550
Contractor: Battelle, Columbus Division
EPRI Project Manager: A. Mehta

ELECTRICAL SYSTEMS

Extended Transient–Midterm Stability Package: Technical Guide for the Stability Program

EL 2000-CCM Computer Code Manual (RP1208); $85
Contractors: Arizona Public Service Co.; Arizona State University; Boeing Computer Services; ESCA Corp.; Ontario Hydro; Systems Control, Inc.
EPRI Project Manager: J. Lamont

Extended Transient–Midterm Stability Package: A User's Manual for the Stability, Output Analysis, and Transient Equivalent Grouping Programs

EL-2001-CCM Computer Code Manual (RP1208); $55
Contractors: Arizona Public Service Co.; Arizona State University; Boeing Computer Services; ESCA Corp.; Ontario Hydro; Systems Control, Inc.
EPRI Project Manager: J. Lamont

Extended Transient–Midterm Stability Package: User's Manual for the Power Flow Program

EL-2002-CCM Computer Code Manual (RP1208); $32.50
Contractors: Arizona Public Service Co.; Arizona State University; Boeing Computer Services; ESCA Corp.; Ontario Hydro; Systems Control, Inc.
EPRI Project Manager: J. Lamont

Extended Transient–Midterm Stability Package: Support Programs Technical Guide

EL-2003-CCM Computer Code Manual (RP1208); $40
Contractors: Arizona Public Service Co.; Arizona State University; Boeing Computer Services; ESCA Corp.; Ontario Hydro; Systems Control, Inc.
EPRI Project Manager: J. Lamont

Extended Transient–Midterm Stability Package: Test Case Manual

EL-2004-CCM Computer Code Manual (RP1208); $32.50
Contractors: Arizona Public Service Co.; Arizona State University; Boeing Computer Services; ESCA Corp.; Ontario Hydro; Systems Control, Inc.
EPRI Project Manager: J. Lamont

Extended Transient–Midterm Stability Package: Final Report

EL-4610 Final Report (RP1208); $62.50
Contractors: Arizona Public Service Co.; Arizona State University; Boeing Computer Services; ESCA Corp.; Ontario Hydro; Systems Control, Inc.
EPRI Project Manager: J. Lamont

Metallurgical Development and Manufacture of Large Heavy Structures for Cryogenic Applications

EL-4912 Final Report (RP1473); $77.50
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: J. Edmonds

Compact Distribution Substation Design: Feasibility Study

EL-4979 Final Report (RP2201-1); $32.50
Contractor: Ebasco Services, Inc.
EPRI Project Manager: T. Kendrew

Direct Analysis of Transient Stability for Large Power Systems

EL-4980 Final Report (RP2206-1); $40
Contractor: Ontario Hydro
EPRI Project Manager: J. Mitsche

Synchronous Machine Operation With Cutout Coils

EL-4983 Final Report (RP2330-1); $32.50
Contractor: Power Technologies, Inc.
EPRI Project Manager: J. White

Load Modeling for Power Flow and Transient Stability Computer Studies

EL-5003 Final Report (RP849-7); Vol. 1, $32.50; Vol. 2, $40
EL-5003-CCM Computer Code Manual; Vol. 3, $32.50; Vol. 4, $47.50
Contractor: General Electric Co.
EPRI Project Manager: J. Mitsche

ENERGY MANAGEMENT AND UTILIZATION

Residential Response to Time-of-Use Rates: Assessing RETOU's Out-of-Sample Performance
EM-3560 Final Report (RP1956-1); Vol. 4, $25
Contractor: Laurits R. Christensen Associates, Inc.
EPRI Project Manager: P. Hanser

Demand-Side Planning Program: Projects and Products, 1974–1986
EM-5062-SR Special Report; $25
Contractor: William Nesbit & Associates
EPRI Project Manager: C. Gellings

Moving Toward Integrated Resource Planning: Understanding the Theory and Practice of Least-Cost Planning and Demand-Side Management
EM-5065 Final Report (RP2548-3); $32.50
Contractor: Barakat, Howard and Chamberlin, Inc.
EPRI Project Manager: C. Gellings

Cost-Benefit Analysis of Demand-Side Planning Alternatives
EM-5068 Final Report (RP1613); $32.50
Contractor: Decision Focus, Inc.
EPRI Project Manager: P. Hanser

Survey of Utility Lighting Programs
EM-5093 Final Report (RP2418-4); $25
Contractor: Analysis and Control of Energy Systems, Inc.
EPRI Project Manager: G. Purcell

ENVIRONMENT

Artificial Streams for Ecosystem Toxicity Studies
EA-5079 Final Report (RP2046-1); $40
Contractor: Oregon State University
EPRI Project Manager: D. Porcella

Modeling the Polluted Coastal Urban Environment
EA-5091 Final Report (RP1630-13); Vol. 1, $40; Vol. 2, $32.50
Contractors: San Jose State University; Stanford University
EPRI Project Manager: G. Hilst

NUCLEAR POWER

ARMP-02 Documentation: NORGE-B2 Computer Code Manual
NP-4574-CCM (Part II, Chap. 12) Computer Code Manual (RP1252-9); Vol. 1, $25; Vol. 2, $32.50; Vol. 3, $32.50
Contractor: S. Levy, Inc.
EPRI Project Manager: O. Ozer

Loss-of-Feedwater, Steam Generator Tube Rupture, and Steam Line Break Experiments: Steam Generator Transient Response Test Program
NP-4786 Interim Report (RP1845-8); Vols. 1 and 2, $77.50
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: P. Kalra

Properties of Colloidal Corrosion Products and Their Effects on Nuclear Plants
NP-4817 Final Report (RP966-2); $25
Contractor: Clarkson University
EPRI Project Manager: T. Passell

Improvement of a Portable High-Energy Radiographic Inspection System
NP-4848 Final Report (RP822-8); $32.50
Contractor: Schonberg Radiation Corp.
EPRI Project Manager: M. Lapides

Experimental Studies of the Seismic Response of Piping Systems Supported by Multiple Structures
NP-4865 Final Report (RP964-8); $32.50
Contractor: University of California at Berkeley
EPRI Project Manager: Y. Tang

Status of Nuclear Class 1 Component Requalification
NP-4889 Final Report (RP1756-5); $25
Contractor: Teledyne Engineering Services
EPRI Project Manager: S. Tagart

Removal of a Tubesheet Sample From a Retired Point Beach Unit 1 Steam Generator
NP-4901 Final Report (RPS304-17); $32.50
Contractor: NUS Operating Services Corp.
EPRI Project Managers: P. Paine, C. Shoemaker

Approach to the Verification of a Fault-Tolerant, Computer-Based Reactor Safety System: Case Study Using Automated Reasoning
NP-4924 Interim Report (RP2686-1); Vol. 1, $25; Vol. 2, $32.50
Contractor: Argonne National Laboratory
EPRI Project Manager: R. Colley

Proceedings: 1985 EPRI Workshop on Remedial Actions for Secondary-Side Intergranular Corrosion
NP-4929 Proceedings (RPS302-22); $70
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: P. Paine

Methods for Evaluating Steam Generator Hideout Return Data: Case Study at North Anna
NP-4940 Final Report (RP2599-1); $25
Contractor: NWT Corp.
EPRI Project Managers: C. Welty, S. Hobart

COBRA-NC Code Analysis of the Heiss-dampfreaktor (HDR) Containment Building Following a Small Steam Line Break
NP-4941 Final Report (RP2600-4); $32.50
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: M. Merilo

Further Studies of Degraded-Core Coolability: The Effect of Pressure and Coolant Flow From Below
NP-4942 Interim Report (RP1931-1); $32.50
Contractor: University of California at Los Angeles
EPRI Project Manager: M. Merilo

Application of Leak-Before-Break Approach to PWR Piping Designed by Babcock & Wilcox
NP-4972 Final Report (RP2420-31); $32.50
Contractor: Babcock & Wilcox Co.
EPRI Project Managers: B. Chexal, D. Norris

Natural Versus Artificial Aging of Nuclear Power Plant Components
NP-4997 Interim Report (RP1707-13); $25
Contractor: University of Connecticut
EPRI Project Manager: G. Sliter

PWR Radiation Fields at Combustion Engineering Plants Through Mid-1985
NP-4998 Final Report (RP825-6); $32.50
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: R. Shaw

Sealing of Nuclear Plant Electrical Equipment
NP-5000 Final Report (RP1707-12); $25
Contractor: Wyle Laboratories
EPRI Project Manager: G. Sliter

Characterization of the Performance of Major LWR Components
NP-5001 Final Report (RP2643-6); $25
Contractor: The S. M. Stoller Corp.
EPRI Project Manager: M. Lapides

LWR Plant Life Extension
NP-5002 Interim Report (RP2643-1, -2, -11); $62.50
Contractors: Virginia Power Co.; Northern States Power Co.; Grove Engineering
EPRI Project Manager: M. Lapides

Evaluation of Sulfur Hexafluoride and Helium for Steam Generator Leak Location
NP-5008 Final Report (RP2599-2); $25
Contractor: NWT Corp.
EPRI Project Manager: S. Hobart

Application of Leak-Before-Break Analysis to PWR Piping Designed by Combustion Engineering
NP-5010 Final Report (RP1757-54); $25
Contractor: Combustion Engineering, Inc.
EPRI Project Managers: D. Norris, B. Chexal

Fracture Testing of Ductile Steels
NP-5014 Final Report (RP1238-2); $25
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: D. Norris

PLANNING AND EVALUATION

Developing Competitive Power Production Strategies for Existing Power Plants
P-5046 Final Report (RP2074-1); $25
Contractor: Temple, Barker & Sloane, Inc.
EPRI Project Manager: D. Geraghty

Examination of Models of Issue Development: Environmental Scanning Using On-Line Data Bases
P-5061 Final Report (RP2345-44); $32.50
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EPRI Project Manager: S. Feher

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HARMFLO: Harmonic Power Flow Program
Version 4.0 (IBM, IBM PC); EL-4920-CCM
Contractor: Purdue Research Foundation
EPRI Project Manager: J. Mitsche

HELM: Hourly Electric Load Model
Version 1.1 (IBM); EA-3698
Contractor: ICF, Inc.
EPRI Project Manager: Ray Squitieri

ILWAS Data Base: Integrated Lake-Watershed Acidification
IBM
Contractor: Tetra Tech, Inc.
EPRI Project Manager: R. Goldstein

REEPS: Residential End-Use Energy Planning System
Version 1.1 (IBM)
Contractor: Cambridge Systematics, Inc.
EPRI Project Manager: S. Braithwait

SGA–SGSYS: Substation Grounding Analysis
Version 4.0 (IBM)
Contractor: Georgia Institute of Technology
EPRI Project Manager: Giora Ben-Yaacov

UCBM: Utility Cost-Benefit Analysis Model
Version 1.2 (IBM PC)
Contractor: Michael J. Blazquez
EPRI Project Manager: S. Vejtasa

UNIRAM: Power Generation System Availability Assessment Model
Version 1.1A (IBM PC); AP-3956
Contractor: Arinc Research Corp.
EPRI Project Manager: Jerome Weiss

CALENDAR

SEPTEMBER

15–16
Coal Markets and Utilities' Compliance Decisions
Washington, D.C.
Contact: Jeremy Platt (415) 855-2628

16–18
Workshop: Optical Sensors for Power System Voltage and Current Measurements
Gaithersburg, Maryland
Contact: Selwyn Wright (415) 855-2283

22–24
Condenser Technology
Providence, Rhode Island
Contact: John Tsou (415) 855-2220

23–25
Seminar: Meeting Customer Needs With Heat Pumps
New Orleans, Louisiana
Contact: Sharon Luongo (415) 855-2010

OCTOBER

6
Predicting Groundwater Quality Changes and Assessing Solid-Waste Disposal/Use
Los Angeles, California
Contact: Ishwar Murarka (415) 855-2150

6–8
1987 Fuel Supply Seminar
Baltimore, Maryland
Contact: Jeremy Platt (415) 855-2628

6–9
1987 PCB Seminar
Kansas City, Missouri
Contact: Claudia Runge (415) 855-2149

7
Predicting Groundwater Quality Changes and Assessing Solid-Waste Disposal/Use
Dallas–Fort Worth, Texas
Contact: Ishwar Murarka (415) 855-2150

9
Predicting Groundwater Quality Changes and Assessing Solid-Waste Disposal/Use
Atlanta, Georgia
Contact: Ishwar Murarka (415) 855-2150

13–15
Effects of Coal Quality on Power Plants
Atlanta, Georgia
Contact: Arun Mehta (415) 855-2895

13–16
Workshop: Para-analytic Techniques and Applications
Chicago, Illinois
Contact: Jeremy Platt (415) 855-2628

14–16
5th International Conference on Solving Corrosion Problems
Buffalo, New York
Contact: Charles Dene (415) 855-2425
or Robert Moser (415) 855-2277

20–22
Workshop: Fossil Fuel Plant Cycling
Princeton, New Jersey
Contact: Murthy Divakaruni (415) 855-2409

21–22
1987 Fuel Oil Utilization Workshop
Boston, Massachusetts
Contact: Bill Rovesti (415) 855-2519

26–29
7th Annual Coal Gasification Contractors' Conference
Palo Alto, California
Contact: Neville Holt (415) 855-2503

26–30
Rotor Bearing Analysis Technique
Charlotte, North Carolina
Contact: Stanley Pace (415) 855-2826

27–28
Coal Markets and Utilities' Compliance Decisions
St. Louis, Missouri
Contact: Jeremy Platt (415) 855-2628

28–30
Fish Protection at Steam and Hydro Power Plants
San Francisco, California
Contact: Wayne Micheletti (415) 855-2469

NOVEMBER

10–12
Conference: Boiler Tube Failures in Fossil Fuel Plants
Atlanta, Georgia
Contact: Barry Dooley (415) 855-2458
or David Broske (415) 855-8968

17–18
8th Annual EPRI NDE Information Meeting
Palo Alto, California
Contact: Soung-Nan Liu (415) 855-2480

29–December 2
Fly Ash and Coal Conversion By-products
Boston, Massachusetts
Contact: Ishwar Murarka (415) 855-2150

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