FALL 2009

EPRI JOURNAL

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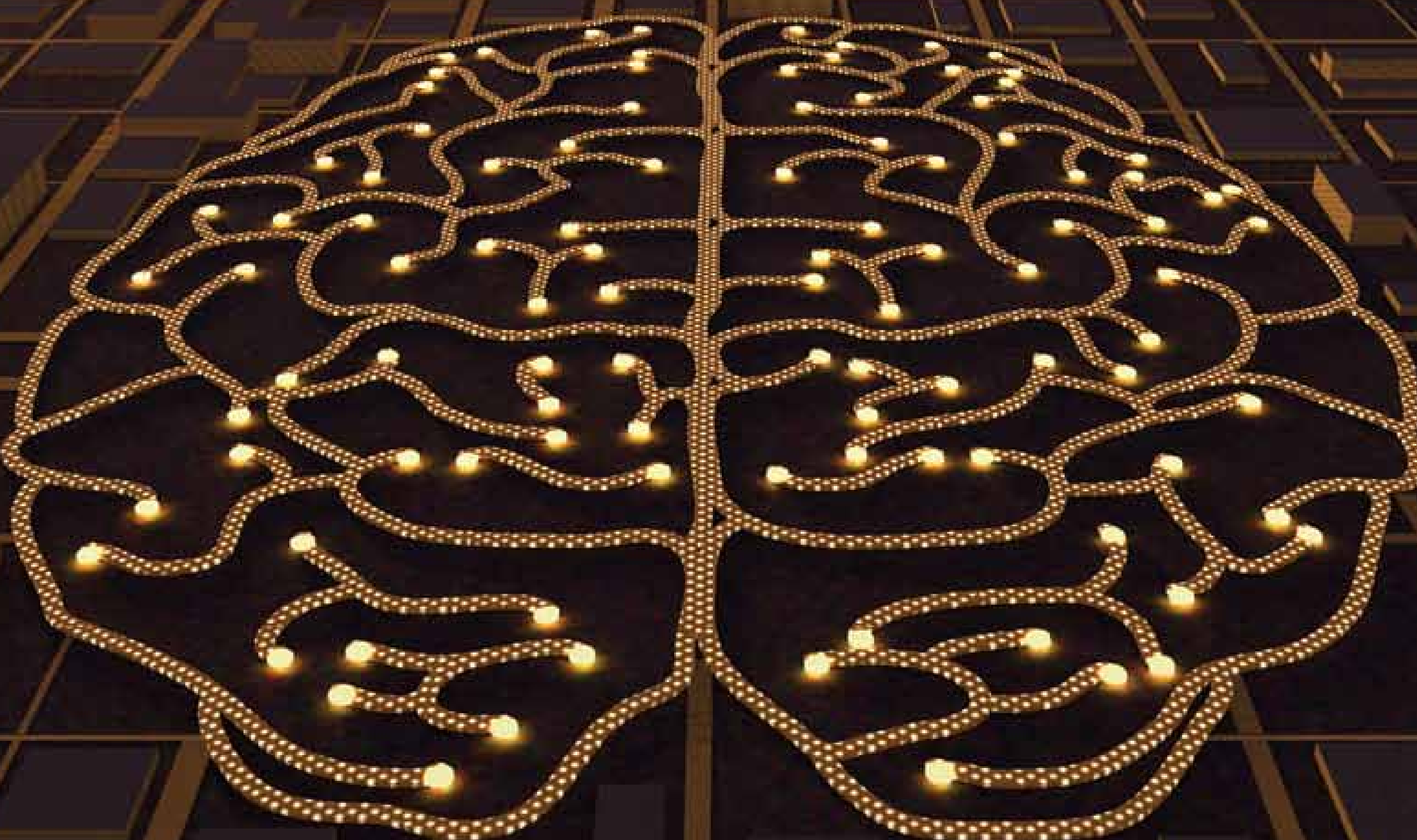
The **Smart** Grid: COMING OF AGE



ALSO IN THIS ISSUE:

Cleaning Mercury and Selenium From Scrubber Wastewater

High-Voltage Transformers: Increasing Reliability, Extending Life

ELECTRIC POWER
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The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

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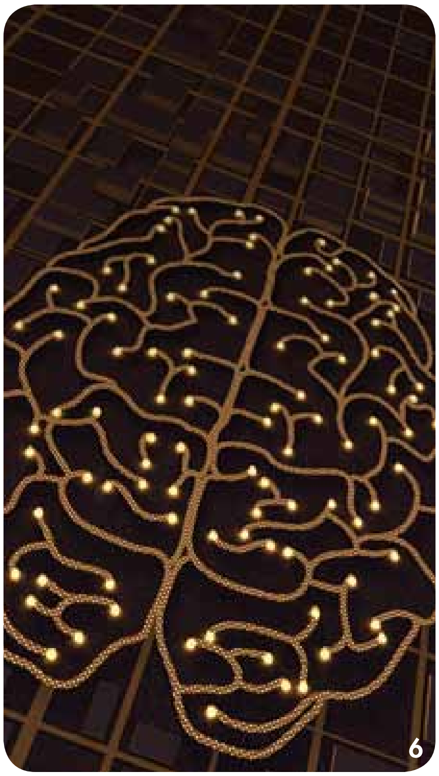


VIEWPOINT

by Steve Specker, President and CEO, EPRI

The Prism in Action

One of the great things about my job is the opportunity to take field trips all over the world to see firsthand the technologies that can enable the decarbonization of the electricity infrastructure over the next 40 years. During just the past six months, I have seen almost every element of the EPRI Prism in action:

- driving plug-in electric vehicles;
- watching the testing of the latest energy-efficient lighting technologies at EPRI's Knoxville laboratory;
- touring utility-scale solar thermal plants and a renewable control center in Spain;
- walking around the Shin-Kori site in South Korea, where four advanced light water nuclear reactors are under construction; and
- participating in the commissioning of the carbon capture and sequestration (CCS) project at the AEP Mountaineer plant in West Virginia.

At the solar thermal plants, I was dazzled by the trough and tower technologies, somewhat surprised by the size and scale of the balance-of-plant equipment, and sobered by the cost-reduction challenges required to make these technologies a viable part of the future low-carbon generation mix. It shifted my own thinking toward solar thermal hybrid plants, where solar-generated steam can be provided to fossil plants, delivering the benefits of solar without the additional balance-of-plant complexity and costs.

At Iberdrola's renewable control center, I watched wind turbines from all across Spain being monitored individually but appearing to the system operator as a single, "virtual" power plant. The visual impact of hundreds of megawatts of wind-generated electricity flowing on to the grid really helped me appreciate the reality and potential of large-scale wind resources.

To those who argue that we cannot decarbonize the electricity

infrastructure while continuing to have low cost (or lower cost) electricity, I say, go to South Korea! They are doing exactly that through the sustained, repetitive construction and operation of standardized advanced light water reactors. I came away from my week long visit to South Korea with great respect and admiration for what they are accomplishing with nuclear power, but sobered by how difficult it may be to duplicate this success in the United States.

At the Mountaineer CCS project, I saw the first-of-a-kind integration of CCS technology into an operating power plant. This was particularly gratifying because of EPRI's critical role in helping accelerate the commercial development of the chilled ammonia post-combustion CO_2 capture technology used at Mountaineer. However, as I took in the scope and complexity of this 25-MWe CCS project, I was again humbled at the daunting challenges that lie ahead in getting the scale up and the costs down for this and other CCS technologies.

I wish that more people could or would see firsthand what it really takes to develop and deploy cost-effective technologies at the scale needed to achieve an 80% reduction in GHG emissions by 2050. Perhaps if they did, there would be fewer ivory tower analyses that prematurely declare the winning and losing technologies and mislead policymakers and the general public into believing that we have the luxury of discarding technologies such as nuclear and CCS.

I certainly did not see everything in 2009, so I'm already putting together my 2010 field trip wish list. At the top of the list is a visit to a shale gas field to see firsthand the technologies that are revolutionizing America's natural gas industry and that could have profound impacts on the electricity sector. Also on the wish list is to drive one of the first production plug-in electric vehicles to come off the assembly line of a major automotive company.

I'm sure I'll be adding to the list. Field trips are so much better than sitting in the office!

SR Specker

Steve Specker
President and Chief Executive Officer

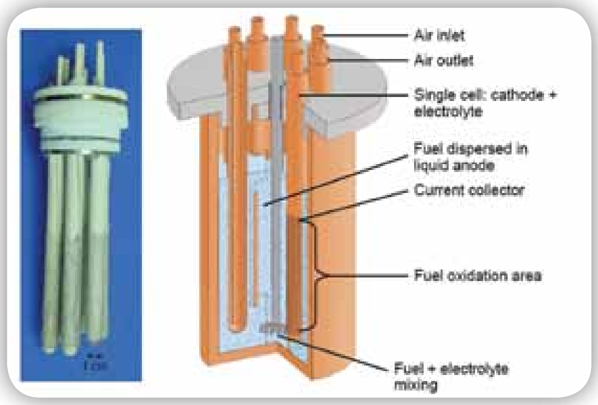
SHAPING THE FUTURE

Innovative approaches to upcoming challenges

Coal Power Without Combustion

Sustainable energy independence in the United States depends largely on the ability to continue to make electricity from coal—by far the country's most plentiful fuel. Clean coal combustion technologies now in development, such as integrated gasification–combined-cycle (IGCC) and oxyfuel combustion systems, are expected to help secure a place for coal in the next generation of power plants. But another innovative approach may offer a simpler option for the long run: direct electrochemical conversion of carbon into dc power via fuel cells.

Direct carbon fuel cells (DCFCs) have been under investigation for several years but have received less attention than fuel cells based on hydrogen and natural gas. The technological and financial risks associated with the development of DCFCs are significantly higher than those associated with their gas-fed counterparts, but the benefits could be substantial. With their potential for highly efficient, modular, clean coal conversion, DCFCs offer compelling possibilities for addressing national energy needs in a manner consistent with environmental constraints.



EPRI has evaluated SRI's tubular cell design for utility-scale direct carbon fuel application, along with designs from Contained Energy and CellTech Power. (Courtesy of SRI International)

Potential DCFC Benefits

Efficiency is a key advantage, and in theory cell efficiencies could approach 80%. Researchers believe that when fed with a processed, devolatilized coal stock, a DCFC generation system could achieve efficiencies of 50–60%, compared with 27–43% for conventional coal systems with CO_2 capture. Efficiencies for hybrid DCFC configurations could be even higher.

The process is remarkably clean. If pure carbon is used as the feedstock, the only gas generated at the fuel cell anode is CO_2 (in equilibrium with CO), making the fuel cell exhaust stream ideally suited for subsequent sequestration. In practice, coal would require processing to minimize impurities, which could compromise fuel cell life and durability.

IGCC and oxyfuel combustion technologies also can be configured to produce concentrated CO_2 streams. But these processes are quite complex, requiring an expensive, energy-intensive air separation unit to supply high-purity oxygen. Smaller, simpler DCFC units could have much lower CO_2 separation and storage costs and reduced parasitic power requirements.

Like other fuel cell technologies, the basic DCFC energy conversion equipment is modular, which allows systems to be built in relatively modest increments (tens of megawatts). As a result, DCFC capacity could be added incrementally and provide both electric and thermal energy services in efficient and flexible distributed generation systems.

Refining Technical Assessments

Further experiments and technical analyses are needed to determine whether DCFC technology can compete economically and match the reliability of other coal-based generation options. Particular focus is needed on fuel processing requirements and system durability. Analyses indicate that the fuel cell's stack life must exceed 60,000 hours to achieve an economically acceptable levelized cost of electricity while minimizing operation and maintenance costs.

Capital costs for DCFC systems are expected to be quite high compared with conventional generation. But considering the high efficiency, environmental benefits, relatively inexpensive fuel, and extremely simple operation, the overall economics could still be competitive, permitting higher "allowable" installed costs. As with all coal-based technologies, the economics will depend substantially on how carbon emissions are valued under future climate regulations.

EPRI convened a workshop in 2006 with seven leading DCFC developers to review and assess research and potential utility applications. The assessment (EPRI document 1013362) showed that the technology is still in an early stage of research and development and that each of the technology platforms examined has its unique challenges, limitations, and development hurdles. A subsequent study (EPRI document 1016170) provided more detailed analysis and experimental testing of DCFC components and developed conceptual system designs for utility-scale (100-megawatt) plants based on the three leading DCFC platforms.

Continued research and development is warranted to advance the science of DCFCs toward practical utility applications. Early applications may use biomass as a feedstock before coal-based systems are adopted.

For more information, contact Dan Rastler, drastler@epri.com, 650.855.2034.

New Coatings Promise Efficiency Gains for Photovoltaic Solar Cells

Elements with such unlikely names as erbium and ytterbium may help so-called third-generation photovoltaic (PV) technologies to at least double the efficiency of today's best commercial solar cells. First-generation flat-plate PVs still dominate the market, but their thin wafers of crystalline silicon are only 10–20% efficient in converting sunlight to electricity and are expensive to manufacture. Second-generation thin-film modules offer lower manufacturing costs and higher production flexibility but are far less efficient than crystalline wafer cells and have limited prospects for efficiency gains.

In 2007 EPRI, EDF, and the French National Center for Scientific Research (CNRS) joined to support a consortium of 20 international laboratories and universities in their work to identify, fabricate, and demonstrate materials and structures that could produce commercial PVs with conversion efficiencies exceeding 40%.

First- and Second-Generation Limitations

In PV cells, electricity is produced when absorption of a photon releases an electron in the cell's "p" layer (where most of the mobile charges are positive), and the electron is able to move across a junction to the cell's "n" layer (where most of the mobile charges are negative). The ability of photons to release the electron is constrained by an amount of energy known as the bandgap. First- and second-generation cells are able to take full advantage of only a small portion of the photons hitting the cell. Photons with energies less than the bandgap—most of those in the infrared range, for example—are not absorbed and not transformed into electricity. Also, the more energetic photons yield only the bandgap amount of useful energy when they are absorbed, meaning that most of the energy from these photons is wasted.

A third-generation approach called multilevel absorption uses materials that allow the PV cell to tap lower-energy photons. These materials operate as a sort of energy ladder by which absorption of low-energy photons can excite electrons across the bandgap. Research shows that this "up-conversion" of photon energies may be achieved by applying microphotonic coatings to the backs of conventional crystalline PV cells.

Promise in Rare-Earth Coatings?

The coatings are doped with rare-earth elements such as erbium and ytterbium. Incoming infrared light not converted into electricity by the conventional PV material is absorbed by erbium ions in the oxide coating. The photon energy absorbed by multiple erbium ions is transferred to individual ytterbium ions, bringing them to a highly excited state. The ytterbium ions then re-radiate the energy as visible light, which is reflected back through the PV cell for absorption and electricity generation.

Microphotonic coatings applied to the backs of conventional crystalline silicon PV cells could substantially increase their conversion efficiencies.

Researchers have succeeded in converting 17% of the photon energy within a narrow portion of the infrared band into visible light, an efficiency that far exceeds previous results. However, this result was achieved under favorable laboratory conditions, using highly concentrated light. Still, results indicate that a 1% relative increase in efficiency of crystalline silicon is feasible, and prospects for a 5–10% gain are being examined.

Much additional progress will be required before microphotonic coatings become available in commercial devices. Current research focuses on optimizing the up-conversion efficiency of today's best materials, exploring new materials, and combining materials to enhance up-conversion across a wider spectral range and under normal outdoor light. Development and testing of a proof-of-concept device are expected to begin in 2011, and commercial PV modules incorporating up-conversion technology appear possible within a decade.

For more information, contact Tom Key, tkey@epri.com, 865.218.8082, or Stan Rosinski, strosins@epri.com, 704.595.2621.

The **Smart** Grid: COMING OF AGE

THE STORY IN BRIEF

Having supported development of the smart grid concept for more than a decade through its IntelliGrid program, EPRI now is working directly with utilities to help implement smart technology on their transmission and distribution systems. Three forward-looking companies show how the smart grid is allowing them to break new ground in reliability, efficiency, and customer value.

Smart grid is no longer merely a buzzword or a vague, high-tech promise in a power company's 30-year plan. Utilities across the country are getting involved now, tapping smart grid capabilities to boost efficiency, enhance services, improve reliability, and possibly lower rates for their customers. Such improvements are driven by the complexity of the grid itself—an expansive collection of generation units, transmission and distribution lines, transformers, switches, and power-conditioning equipment, not to mention the millions of individual machines, devices, and appliances on the customer side of the meter. These many components typically operate with central coordination accomplished by control at the network's substations and power generation facilities.

Using broadly distributed sensors, microprocessors, and automated control units, smart grid technologies help coordinate the system as an efficient, integrated whole. As a result, grid operators gain improved knowledge of operating conditions and are better able to manage the system to what's actually happening throughout the system and in real time.

"We see the smart grid as a system of systems," said Don Von Dollen, manager of EPRI's IntelliGrid program. By using an open-standards-based communications architecture, utilities can not only integrate their own networks effectively but eventually monitor systems nationally to support a vastly improved power delivery system.

With EPRI's help, the National Institute of Standards and Technology is assessing and identifying interoperability standards that will make this possible, developing requirement specifications and communications protocols to help ensure that the various components of such a broad system will be compatible and able to work together seamlessly (see "The Push for Standards," p. 8).

"EPRI has been working on the smart grid for over a decade, refining the concept, developing foundational standards, and creating a methodology for utilities to use when launching smart grid applications," said Von Dollen. EPRI now has shifted to working directly with utilities, helping them implement smart grid technology on their power delivery systems. "Using the IntelliGrid methodology, companies are finding that a roadmap helps make the smart grid journey much easier to navigate," said Von Dollen. The same methodology also is used for EPRI's Smart Grid Industry Demonstration project, focusing on the integration of various distributed resources into a virtual power plant.

A number of utilities have used EPRI's methodology in their smart grid deployment projects, including FirstEnergy Corp., Salt River Project (SRP), and Southern California Edison (SCE). FirstEnergy and SRP worked directly with EPRI to develop their smart grid roadmaps; SCE employed EPRI's IntelliGrid methodology to develop its own roadmap. "Each utility has a different approach to its smart grid implementation, based on its own business and regulatory drivers," said Von Dollen.

FirstEnergy completed its IntelliGrid roadmap at the end of 2007. "The roadmap helped us establish where we were, where we should go, where the gaps were in technologies, and what the order should be for our smart grid implementation strategy," said FirstEnergy's Joe Waligorski, delivery operations technical advisor. "Basically, the EPRI roadmap helped us identify which technologies would be appropriate to evaluate for our smart grid initiatives and goals."

Waligorski noted that a guiding principle behind FirstEnergy's strategic approach to the smart grid is integrating communication and data for distributed components and their controls across all aspects of power delivery operations. "Leveraging technologies in this way allows us to benefit from economies of scale, standardized architectures, and corporate-wide sharing of information," he said.

Like FirstEnergy, SRP outlined an integrated control and data management architecture to facilitate monitoring, control, and automation functions at the transmission, distribution, and customer system levels. "We've looked closely at how we could integrate smart grid technologies into our infrastructure," said Joe Nowaczyk, SRP manager of electronic systems. "The challenge is to not oversell the smart grid—first, you have to determine whether it will be beneficial and cost-effective. We found that EPRI's IntelliGrid methodology helped us to focus our smart grid initiative on these issues and to develop internal synergy with the deployment of related technologies."

SCE used similar guidance from IntelliGrid in developing its own smart grid roadmap. According to Paul De Martini, SCE's vice president for advanced technology, "The EPRI methodology helped us zero in and understand what we wanted to accomplish and build a timeline for the plan."

Like Nowaczyk, De Martini recognized the need for selectivity and practical progression in developing systems unique to each utility: "We think of the smart grid as an a la carte menu."

In choosing their early smart grid implementation projects, all three companies have focused largely on two fundamental opportunities: optimizing system operations, and engaging customers with conservation programs that will help reduce demand. Both objectives require an enhanced energy information infrastructure.

The Push for Standards

On June 17, 2009, EPRI submitted its *Report to NIST on the Smart Grid Interoperability Standards Roadmap*. The impetus for the report was the Energy Independence and Security Act (EISA) of 2007, which assigned the National Institute of Standards and Technology (NIST) "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems" (EISA Title XIII, Section 1305).

In early 2009, responding to President Obama's national energy priorities, NIST acted to accelerate progress and promote stakeholder consensus on smart grid interoperability needs. On April 13, it announced a three-phase plan to expedite development of key standards.

EPRI—having engaged utilities, equipment suppliers, consumers, standards developers, and other stakeholders in a public process that identified smart grid interoperability standards, gaps in current standards, and priorities for new standardization activities—created a document that provides input for the first phase.

EPRI then developed a draft interim standards roadmap, which NIST used as the starting point for its own roadmap for interoperability standards, released September 24. NIST's roadmap sets priorities for interoperability and cyber security requirements, identifies an initial set of standards to support early implementation, and lists plans to meet remaining standards needs. Both the NIST roadmap and the EPRI report to NIST can be downloaded at http://www.nist.gov/smartgrid.

System Operations

Detailed, real-time information is key to effectively managing a system as large and dynamic as the power grid. SRP, through its extensive fiber-optic communications network, can monitor every substation and use remote distribution switches to reconfigure the network when local load grows beyond certain limits. SRP also is using synchrophasors, whose real-time information enhances the transmission operators' ability to monitor system dynamics and take corrective action if necessary.

Such information, automation, and operational flexibility make for improved system reliability, better equipment maintenance planning, and reduced outage response times. "Ultimately, automated devices will allow SRP to increase reliability on our entire transmission and distribution system," Nowaczyk said.

SCE has chosen an approach similar to SRP's for system monitoring by expanding the use of sensor technology across its system and is undertaking one of the world's largest synchrophasor deployments. The sophisticated synchrophasors on SCE's 230- and 500-kilovolt system allow monitoring of grid dynamics 30 times a second. "Electricity is the lifeblood of our modern economy, so high system reliability is tremendously important," said SCE's De Martini.

But the benefits of smart grid technology go beyond just reliability. "Being able to measure, control, optimize, and anticipate is crucial to future system operations," said De Martini. This is especially important now that large amounts of distributed resources such as solar and micro-wind installations are coming on to the grid. Significant improvements in system efficiency also are possible. De Martini notes that grid losses through an average system may be as great as 10%. "We estimate potential savings of 2.5% per year on distribution losses alone through integrated voltage control."

Demand Reduction

FirstEnergy has focused much of its smart grid effort on demand reduction programs, which in turn improve system operations. In June 2009, FirstEnergy's Jersey Central Power & Light (JCP&L) subsidiary implemented a comprehensive customer air conditioner monitoring and control program. It features direct load control of 4,000 residential air conditioners, monitoring and controlling noncritical customer electrical loads via two-way communications.

The program is part of the company's Integrated Distributed Energy Resource (IDER), which monitors the local distribution circuits for system reliability. The IDER platform enables JCP&L to reduce system load—especially during peak demand periods—by up to 8 megawatts, and there are plans to reduce load by an additional 30 megawatts.

"The goal of our pilot residential air conditioning monitoring program was to achieve a 5-megawatt load reduction capability," said Waligorski. "Initial data suggest that this has been achieved during the program's inaugural year."

SRP also is working with customers to monitor and reduce demand. Its advanced metering initiative boasts nearly half a million smart meters that enable two-way communication between the utility and individual customers. Through this link, SRP is offering a time-of-use rate with a 3-hour peak period to reduce peak load. According to Nowaczyk, "SRP's EZ-3 rate plan has been successful. We estimate a 1.5-kilowatt-per-customer coincident peak savings figure using the combined rate plan

SRP's time-of-use plan allows customers to monitor their on-peak electricity use (brown bars) through a secure Web page.

A technician tests the remote control interrupters on SCE's Avanti advanced distribution circuit.

and smart metering system."

SCE has pursued a smart metering program as well, designed to arm customers with data to help them manage their energy use and their bills. "We have a variety of customer-focused programs aimed at demand and energy-use reduction, including in-home displays, Web presentations, and energy analytics. We also have voluntary programs for dynamic pricing and controlling air conditioning thermostats," De Martini said. These customer options help SCE reduce expensive peak loads and reduce greenhouse gas emissions through conservation. "Customers will have a range of choices to improve the environment and manage their budgets," said De Martini.

Looking to the Future

Such fundamental changes can be difficult, especially when infrastructure and substantial capital costs are involved. De Martini of SCE made the point directly: "Before you launch a program like this, you have to determine whether your organization has the capacity to manage the change involved with adopting emerging technologies." For SRP, FirstEnergy, and SCE, the answer has been "yes," and all three are planning to build on what they have learned.

As SRP's Nowaczyk noted, getting cross-functional management to proceed on a common roadmap is the best way to align support across the organization. As a result, SRP continues to develop plans for integration of new metering, distribution, and transmission automation projects.

With the success of its JCP&L residential air conditioning project, FirstEnergy is evaluating additional smart grid technology for operational and demand reduction benefits, including energy storage units, load-shifting devices, line sensors, and substation device monitoring.

Meanwhile, as smart grid technology continues to evolve, innovation will help to overcome some of the inherent limitations of an aging infrastructure. According to De Martini, SCE will replace its distribution management system over the next three years. "We are preparing for the next wave of distributed resources, such as energy storage, renewables, demand response, and electric vehicles, and the new field equipment needed to enable this evolution," he said.

The company currently has nearly 600 staff involved in smart grid technology projects totaling $1.5 billion and involving smart metering, synchrophasors, and system controls. "These are not pilots. These are real programs that will benefit SCE's customers," said De Martini.

Nowaczyk agreed that value is the real issue: "We were implementing smart grid technology years before it was called smart grid, and we will continue after the hype of smart grid wanes. That's because adapting smart grid technologies makes sense from both a cost and a service perspective, and we will do the right thing for our customers."

This article was written by Lela Katzman. For more information, contact Don Von Dollen, dvondoll@epri.com, 650.855.2210.

Don Von Dollen, a program manager in EPRI's Power Delivery and Utilization Sector, is responsible for the IntelliGrid program, which focuses on accelerating the development and deployment of smart grid capabilities in the nation's power delivery infrastructure. As part of this work, he coordinates EPRI's smart grid activities with DOE, EEI, NIST, and other government and industry organizations. Before joining EPRI in 1991, Von Dollen was a research engineer with Pacific Gas and Electric Company. He holds a B.S. degree in physics from California State University, Sacramento.

Further Reading

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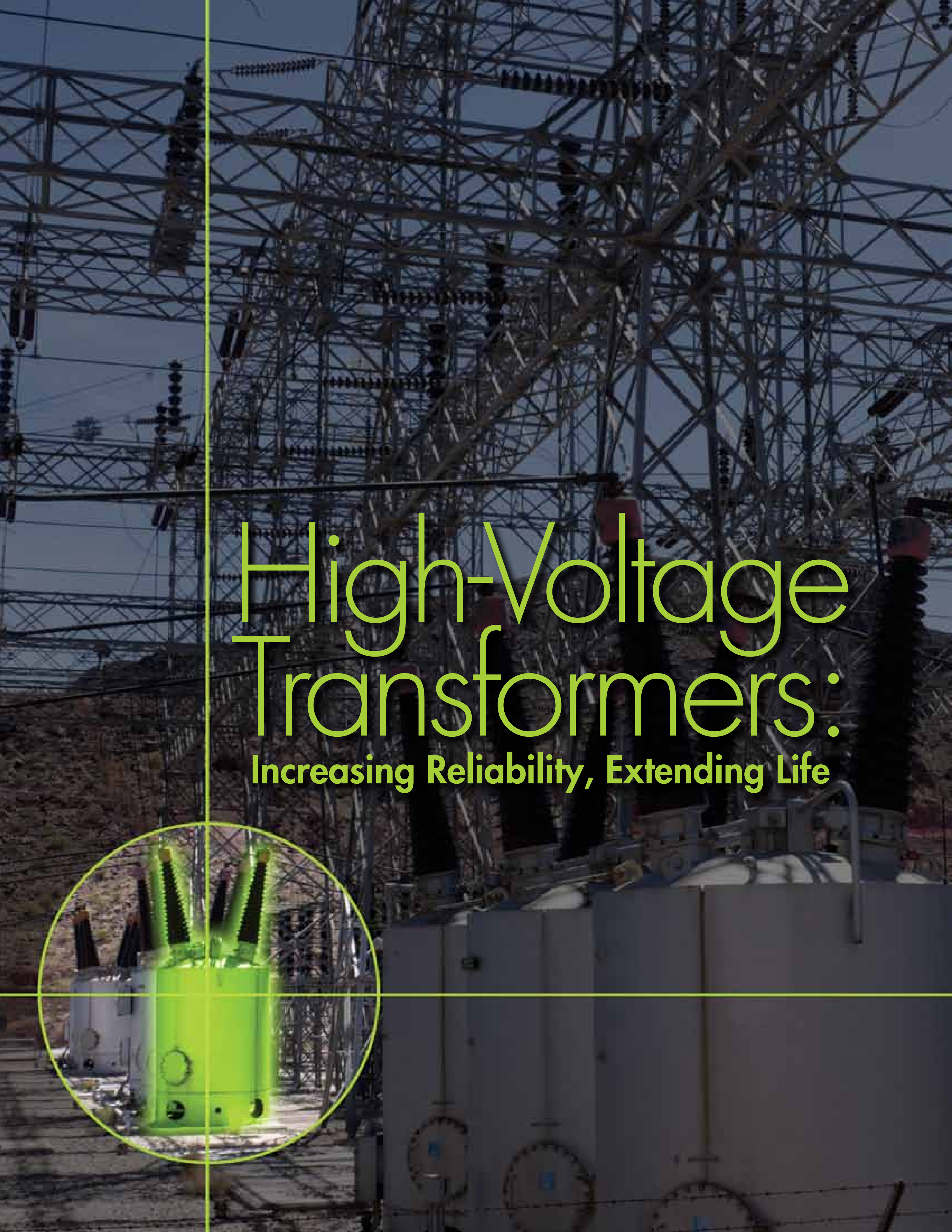


High-Voltage Transformers:

Increasing Reliability, Extending Life

THE STORY IN BRIEF

The reliability of transmission grids depends on the condition of aging high-voltage transformers that are expensive and time-consuming to replace. EPRI is building on decades of R&D to develop improved maintenance practices, novel sensors, and risk-based analytic techniques that will help prevent failures and maximize transformer life and performance.

In switchyards and substations around the world, high-voltage transformers operate around the clock to keep power flowing reliably through transmission grids. At nuclear and fossil-fired power plants, large transformers connect to the grid for delivering electricity and for powering auxiliary systems when a generator is off line. At substations across the power delivery system, other transformers "step down" the voltage for local distribution circuits. Transformers are crucial pieces of equipment, and expensive to replace. Keeping them operating reliably as they age is a key focus of research and development.

Many transformers were installed during the 1960s and 1970s and are nearing the end of their design lives. During the 1980s and 1990s, failure rates were low. But as transformers age, failure rates become higher; failures are difficult to predict, complicating decisions about resource allocation for repair or replacement. Over time, transformer loading levels have been increasing, along with demands for reliability. Step-up transformers at baseload plants typically are exposed to the most severe duty cycle, as these transformers continuously operate close to full capacity. Because they are connected directly to large generators, they can be exposed to extremely high fault currents.

Transformer failures can cause costly disruptions and sometimes involve oil spills, fires, and collateral equipment damage. It is expensive and time-consuming to replace transformers. Lead times extending to more than a year. The units' size and their weight—hundreds of tons—make them difficult to transport and install. Replacing the massive three-phase generator step-up units typically used at nuclear power plants often requires even longer lead times, and the units must be transported via special train car. A replacement unit might cost $3 million–$6 million, depending on the voltage and megawatt ratings.

"Power transformers present a point of vulnerability that can cause problems with the performance of the power system and with generation sources as well," said EPRI's Michael Howard, senior vice president of research and development. "If a transformer failure occurs in a switchyard that connects a power plant to the transmission grid, it has the same impact as a failure within the plant—and that could mean an involuntary plant shutdown."

"The consequences of a transformer failure at a nuclear plant can be severe," said Neil Wilmshurst, director of plant technology in EPRI's Nuclear Sector. "If a generator step-up transformer at a nuclear plant fails, it not only results in loss of generation but also challenges the operators and plant safety systems. If a spare or replacement transformer is not readily available, the lost revenue and cost of replacement power can be a million dollars or more per day. Catastrophic failures are of concern, since other switchyard equipment, including transformers, customized bus work, and buildings, are likely to be situated close by."

Concerted Effort

EPRI has performed decades of research focused on preventing failures and maximizing transformer life and performance. The research ranges from practical techniques and methods for transformer maintenance and life extension to the development of diagnostic and monitoring technologies that provide new insight into transformer condition and potential degradation conditions.

Currently, EPRI's Power Delivery and Utilization, Nuclear Power, and Generation sectors are collaborating to develop the *Power Transformer Guidebook*, referred to as the Copper Book, which for the first time will consolidate transformer information in one resource. EPRI and the Institute of Nuclear Power Operations also are working together to ensure that the Copper Book's guidance addresses needs and practices specific to nuclear plant transformers.

Collaboration among utilities, transformer suppliers, and users is central to the effort. To provide a forum for sharing transformer information and lessons learned, EPRI's Nuclear Maintenance Application Center formed the Transformer and Switchyard Users Group.

"The group's broad membership provides opportunities to collect, develop, and disseminate operating experience and best practices related to maintenance, equipment, and troubleshooting," said Wayne Johnson, senior project manager.

The users group consists of three working groups: Power Transformer, Switchyard Equipment, and Grid Reliability. The Power Transformer working group serves as a technical advisory committee for the Copper Book.

The *Power Transformer Guidebook* will contain the industry experience related to transformer design, factory testing, selection, purchase specification, procurement, operations, and maintenance, and also will explore research on advanced monitoring techniques, solar flares, and lightning strikes. It will provide guidance from a utility perspective on condition monitoring, testing, and maintenance of large power transformers and will serve as a resource for new component and system engineers. Because of the large volume of industry information, the guideline will take several years to complete.

"The Copper Book will be the first text that covers all aspects of transformer ownership from a utility perspective," said Luke van der Zel, a technical executive in EPRI's Power Delivery and Utilization Sector. "It will consolidate decades of EPRI research results and combine that information with the knowledge and practical experience of industry experts. It will complement EPRI's transformer R&D with analyses of failure mechanisms, advanced sensors, on-line condition monitoring, and transformer fleet management."

The Copper Book is produced by EPRI's substation research program, which develops technologies and tools to maintain and operate substation equipment, including diagnostics, monitoring, maintenance, and asset management.

Understanding Failures: Root Causes

Better understanding of transformer failure mechanisms and risk factors has helped guide research and development efforts to improve condition assessment and life extension.

"Transformers have four basic failure modes," said Nicholas Abi-Samra, senior technical executive in EPRI's Power Delivery and Utilization Sector. They are insulation failures, internal mechanical failures, failures due to severe internal overheating, and failures of ancillary equipment such as load tap changers or pumps. Risk factors include premature aging and degradation of insulation; insulation damage from applied voltage stresses such as lightning or switching surges; through-fault currents associated with external faults; and poor workmanship or design. In some locations, geomagnetically induced currents associated with solar storms overstress transformers and cause insulation failure.

"Transformer failure mechanisms are usually complex and difficult to classify," said Abi-Samra, "and may be due to a combination of factors. Internal insulation failures are the most serious and costly of transformer problems. Moisture is responsible for many premature failures of large extra-high-voltage units. Some recent failures have been attributed to corrosive sulfur in the transformer insulation cooling oil, which caused failure of insulating paper."

EPRI is compiling information from transformer teardowns to develop a forensics library that will provide new insights into degradation and failure processes.

Advanced Sensors for On-Line Monitoring

Transformer degradation mechanisms emit telltale signs that, if detected early, can provide condition and life expectancy information. These signs include partial discharge, hot spots in windings, and dissolved gases in the insulating oil that are produced by degrading insulation.

By measuring and tracking these signs, engineers can determine the rate of degradation and schedule preventive maintenance or repairs, possibly avoiding catastrophic and costly in-service failures. "Some of the best insurance for transformers is proper condition monitoring, which sets priorities for repair, refurbishment, or replacement," said Abi-Samra.

EPRI is developing sensors to provide insights into transformer health that can't be obtained with traditional techniques. As van der Zel put it, "We want to put sensors in places they've never gone before, we want sensors that are cheaper than ever before, and we want sensors that measure key condition indicators we've never captured before."

Fiber-optic sensors. Partial-discharge signals are typically difficult to measure. Traditional methods use sensors mounted outside the transformer, where they often pick up electrical interference signals. EPRI is developing fiber-optic sensors that extend inside a transformer tank to detect internal faults—both a transformer gas sensor and an acoustic sensor to detect partial discharge in high-risk regions of a transformer. Because the fibers are so small, a single sensor can be made up from a fiber bundle that can transmit many different signals—both electrical and thermal faults—pinpointing the origin of partial discharge and providing a temperature profile of the winding. Preliminary tests are promising, with additional lab testing and refinement needed before field testing begins.

Metal-insulator semiconductor sensors. EPRI's Office of Technology Innovation is developing solid-state microsensors that detect hydrogen (an indicator of partial discharges) and acetylene (an indicator of arcs) in transformers. These "sensors on a chip" promise to enable low-cost, on-line dissolved-gas monitoring. (See "Microsensors Show Promise for Transformer Monitoring," page 28).

Three-dimensional acoustic emissions sensors. Acoustic emissions technology is an established technique for detecting partial discharge. EPRI has conducted research into using it to detect the bursting bubbles of fault gases resulting from overheated transformer components. With the promise of locating bubbling sources in three dimensions, it is being demonstrated at member utility substations. EPRI research continues to refine algorithms to distinguish signs of incipient failure from signs of gradual aging and deterioration.

These technologies lay the groundwork for on-line continuous monitoring instrumentation to provide fast and economical methods for determining the condition of all transformers in a substation or power plant switchyard.

Analytics for Intelligent Fleet Management

Although advanced sensors will contribute to transformer condition assessment, utilities already possess information that can help them make better decisions regarding transformer repair and replacement, and ultimately increase reliability while reducing maintenance costs.

The key is an EPRI-developed methodology that ranks transformers on the basis of their operating environment and operating history—weighing factors such as thermal life consumption, lightning exposure, short-circuit magnitude and duration, insulation oil test results, and connected-load criticality.

"The ranking enables a utility to scan its transformer fleet and identify at-risk units for detailed testing and analysis," said Bhavin Desai, a senior project manager in EPRI's Substations program. "Focusing on high-risk units is far more cost-effective than conducting blanket inspections of an entire fleet. This approach uses available data from utilities' historical records, maintenance management systems, and rating guides. Diagnostic algorithms and expert system modules transform those data into useful information for decisions and action."

Duke Energy recently used the methodology to scan 222 transformers and identified 13 for detailed risk analysis. The system flagged units in two categories: those exhibiting abnormal conditions, which may be experiencing unexpected problems due to manufacturing defects or operating issues, and those exhibiting normal degradation, which may be approaching the end of their service life. Tri-State Generation and Transmission Association performed a similar analysis on 381 transformers in 2009 that flagged 12 for detailed analysis—five units for normal degradation and seven for abnormal conditions, including thermal, electrical, and internal copper core issues.

"As a new maintenance engineer with almost 400 transformers to evaluate, I've found this program a tremendous help," said Rosa DelaCruz, senior electrical engineer at Tri-State. "We can now concentrate on the flagged units to evaluate whether repairs can be made, or whether we should replace the units."

Transformer Database, Life Extension

To acquire additional performance data to support fleet management and maintenance, EPRI and member utilities are developing an industrywide database. This will allow broad-based analyses to better determine equipment failure rates, to identify bad actors early, and to help identify best maintenance and specification practices. The data include failure mode, operational and maintenance history, and equipment design and can be searched by transformer family, make, model, age, application, and risk profile.

"The industrywide database provides a means for sharing transformer data confidentially among participating utilities to support risk-informed asset management decisions," said Desai. "It supports maintenance scheduling, repair and replacement decisions, and asset management decisions to minimize life-cycle costs of equipment replacement and maintenance, including failure costs."

EPRI also publishes transformer life extension guidelines that provide utility staff with guidance on cost-effective transformer maintenance and condition assessment. The *Large Transformer End-of-Expected-Life* report, for example, alerts engineers to conditions indicating that long-term planning may be necessary to preclude failure or manage its impact. Making connections between condition monitoring and potential failure mechanisms enables plant engineers to assess alternatives, from replacement or refurbishment to using more robust condition-monitoring systems.

"Large transformers are essential to the reliable operation of generating stations and the power grid, and they represent the primary capital asset in substations," said Mike Howard. "EPRI's wide range of transformer R&D is helping utilities prevent transformer failures, extend transformer life, and improve reliability. The payoff is substantial savings in operating, repair, and downtime costs; delayed investment in new transformers; and a sound technical basis for transformer management decisions."

This article was written by David Boutacoff. For more information, contact Neil Wilmshurst, nwilmshu@epri.com, 704.595.2732; Luke van der Zel, lvanderz@epri.com, 704.595.2726, or Bhavin Desai, bdesai@epri.com, 704.595.2251.

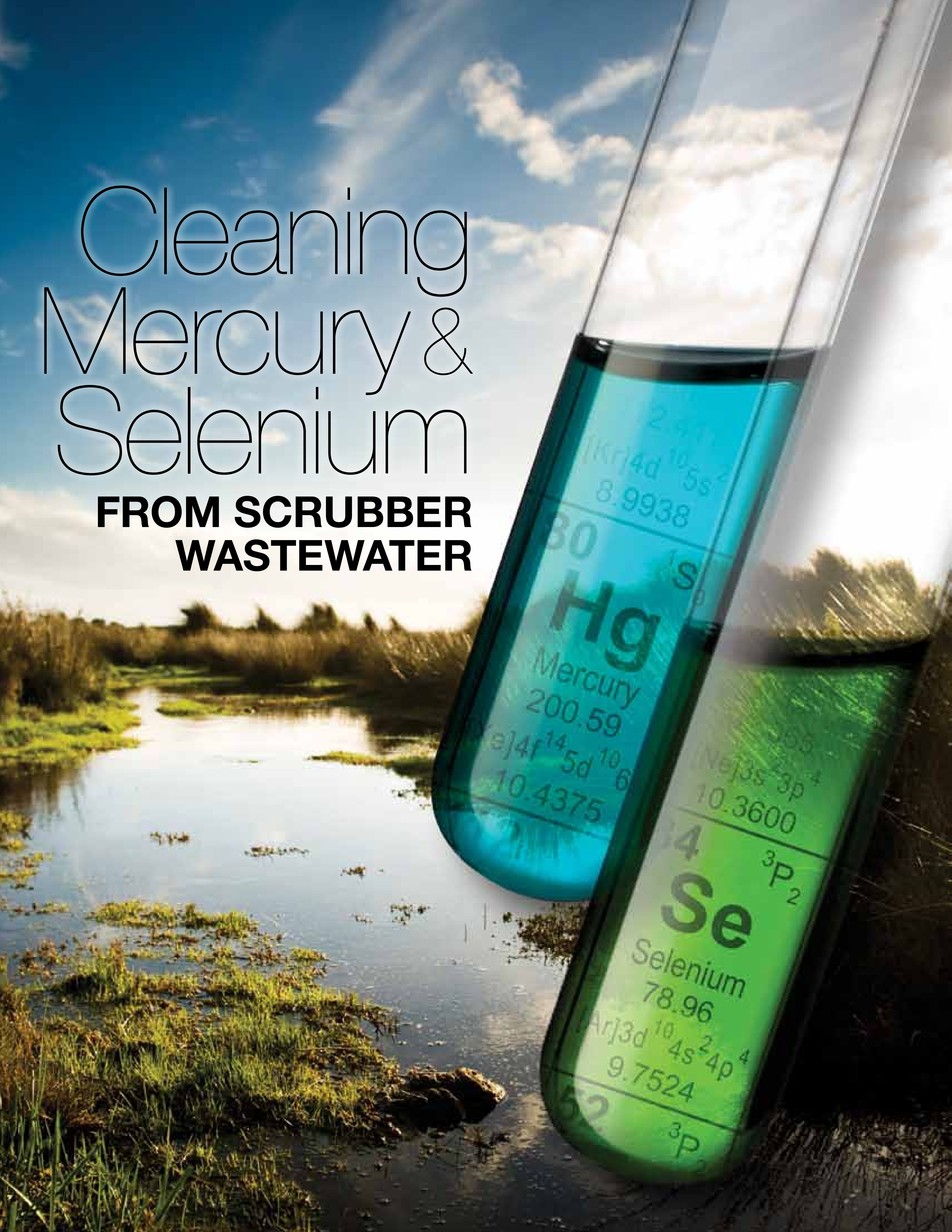
Neil Wilmshurst is director of plant technology in EPRI's Nuclear Sector. Before joining EPRI in 2003, he worked with AmerGen at Three Mile Island Unit 1 and with British Energy at the Sizewell B plant, having previously served for 13 years in the Royal Navy as a nuclear submarine engineer officer. Wilmshurst received a B.S. in electrical, mechanical, and control engineering from the Royal Naval Engineering College, Manadon, UK; a postgraduate diploma in nuclear reactor technology from the Royal Naval College, Greenwich, UK; and a master's degree in defense administration from Cranfield Institute of Technology, Shrivenham, UK.

Luke van der Zel is technical executive, transmission and substation in the Power Delivery and Utilization Sector. His current research includes work on gas-insulated substations, power transformers, and sensors for substation monitoring, with an emphasis on field applications of EPRI research results. Before joining EPRI in 2001, van der Zel worked for 11 years on substation projects at Eskom in South Africa. He received both B.S. and Ph.D. degrees in electrical engineering from the University of the Witwatersrand, Johannesburg, South Africa.

Bhavin Desai is a senior project manager in the Substations program area of the Power Delivery and Utilization Sector. His current research includes work on fleet management of substation assets, maintenance optimization for substation equipment, and circuit breaker life management, with an emphasis on developing analytics for risk-based decision making. Before joining EPRI in 2001, Desai worked for more than three years at Duke Energy in system and asset planning and technical studies. He received a B.S. from Saurashtra University, India, and an M.S. from Oklahoma State University, both in electrical engineering.

Cleaning Mercury & Selenium

FROM SCRUBBER WASTEWATER



Nearly two decades ago, Congress amended the Clean Air Act to limit sulfur dioxide emissions from the smokestacks of coal-fired power plants. Subsequent rulemakings by the U.S. Environmental Protection Agency (EPA) and the states have resulted in significant further reductions through utilities' installation of emissions controls. While these regulations have helped reduce acidic deposition, formation of secondary particulates, and ozone concentrations, they have created new challenges for the electric power industry.

THE STORY IN BRIEF

With revisions of federal effluent guidelines expected to include new discharge limits for mercury and selenium, power companies are looking for wastewater treatment options that can meet increasingly stringent requirements. EPRI is evaluating an array of technologies for boosting the removal of such trace elements from scrubber wastewater, including vertical flow wetlands, which use anaerobic bacteria to help remove contaminants in a passive treatment system.

Flue gas desulfurization (FGD) systems—called wet scrubbers—use a slurry of water and an alkaline material (such as lime or limestone) to absorb as much as 95–99% of a plant's sulfur dioxide emissions. However, wet scrubbers generate wastewater containing mercury, selenium, and other trace elements that may necessitate treatment of the wastewater before discharge. With sulfur restrictions being continually tightened, many more FGD systems are being installed, according to Paul Chu, an EPRI project manager.

While federal water discharge limits for the electricity industry (referred to as effluent guidelines) don't yet exist for selenium and mercury, the EPA recently announced plans to revise its technology-based effluent guidelines for power plants under the Clean Water Act. The agency's revisions may include limits on selenium and mercury in FGD wastewater, given concerns over their potential impacts on aquatic species. Many states already regulate selenium and mercury discharges through water quality standards. For example, states bordering the Great Lakes and the Ohio River have set goals of mercury levels between 1.3 and 12 parts per trillion. To date, however, no one has demonstrated a technology that is able to reduce concentrations to these extremely low levels.

To meet anticipated future limits, the industry will need new, cost-effective technologies, and EPRI is evaluating an array of technologies to remove mercury, selenium, and other trace elements from wastewater discharges. "We see EPRI's primary role as being an independent, third-party evaluator," said Chu, who heads the project to evaluate FGD wastewater treatment solutions.

EPRI researchers also are working to understand how trace elements such as selenium behave chemically in FGD wastewater. The hope is that greater understanding will lead to new ways of dealing with these contaminants.

A Focus on Mercury and Selenium

Like sulfur, mercury and selenium occur naturally in coal. When the coal is burned, these constituents vaporize and can end up in the fly ash and be removed in the scrubber or be released up the stack. In the scrubber, some portion ends up in the solids (e.g., gypsum), with the remainder in the wastewater.

Selenium and mercury are both difficult to remove from wastewater, but for different reasons. "What makes selenium so difficult to treat is that it can be present in different chemical forms," Chu said. The two forms most common in wastewater are selenate and selenite. While selenite is relatively easy to remove, selenate is quite difficult.

Other forms of selenium exist as well, some easier to remove than others. Naomi Goodman, a chemist at EPRI, has spent the past several years trying to figure out what forms of selenium FGD wastewaters contain. "If we don't know what we are trying to treat, that makes it harder," she said.

To remove mercury from wastewater, power companies typically use compounds known as organosulfides. Sulfide reacts with mercury to form insoluble cinnabar. The problem, Chu said, is that the reaction happens so fast that the cinnabar particles are minuscule and difficult to collect. Some companies have tried to combine sulfide with other compounds to make bigger molecules that are easier to filter. The lowest mercury levels that can be achieved by using this method are typically in the range of hundreds of parts per trillion.

In 2008, EPRI began to search for new technologies to remove mercury and selenium. Depending on the developmental status of the individual technologies, EPRI's objective is to conduct laboratory evaluations followed by field testing of the most promising options.

Vertical Flow Wetlands

On North Carolina's Lake Norman, Duke Energy operates a 2,000-megawatt coal-fired power plant that relies on several acres of man-made wetlands to filter the plant's FGD wastewater. To boost selenium reductions, EPRI project manager John Goodrich-Mahoney recommended, and Duke agreed, to construct a pilot-scale vertical flow wetland. In this system, the water travels down through the substrate rather than horizontally across the wetland surface, as in traditional treatment wetlands. The anaerobic bacteria that live inside a vertical flow wetland remove selenium more effectively than the aerobic bacteria in the horizontal flow counterpart.

The pilot-scale wetland uses a 3,000-gallon plastic tank, at the bottom of which lies a drainage bed composed of 1 foot of aggregate covered with a woven organic-mesh fabric. Above the mesh is a 4-foot layer of compost, a by-product of local mushroom cultivation. "The water enters from the top and percolates down through the system and out," Goodrich-Mahoney said. As the water travels through the compost, anaerobic bacteria reduce selenium to its elemental form or to selenium precipitates. "We build wetland treatment systems because they're very cost-effective," he said. "The up-front capital costs can be similar to those of more traditional physical or chemical treatments, but the operation and maintenance costs are always significantly lower."

Passive treatment systems such as this have been used to treat other kinds of wastewater, but this is the first study to evaluate the treatment of FGD wastewater. And it seems to be working. Weekly water sampling began in May 2008. Mercury and selenium levels in the influent were already low, but the wetland treatment system brought levels even lower. "It seems to do the trick as far as reducing our effluent to acceptable levels," said Ron Lewis, an environmental scientist at Duke Energy.

In fact, the system worked so well that Duke is planning to build a full-scale system of six wetland cells to handle all the wastewater generated by its FGD system. Each cell will cover roughly half an acre; the complete system, with access roads and piping, will occupy 5.6 acres and, like a natural wetland, will be covered with vegetation. Costs are projected to be $3.3 million for construction and roughly $32,000 a year for operation and maintenance. The plan is to have the new wetland up and running before 2012.

"Not every power company has enough space to build a wetland treatment system. That's one of the real constraints," Goodrich-Mahoney said. "We are looking at how to minimize the footprint."

Other Approaches

One biological option with a potentially smaller footprint is a bioreactor. "Chemically, the technologies appear to be quite similar," Chu said. Both use anaerobic conditions and microbiology to remove selenium and mercury. But there are differences: In a vertical flow wetland, bacteria colonize the substrate naturally. In a bioreactor, various bacteria are selected to optimize selenium and mercury removal for each specific water matrix. Also, the bioreactor is a constructed treatment system with traditional tanks, pumps, and piping and with precise process control. The vertical flow wetland is more passive. Chu pointed out that the underlying chemistry of these systems is not well understood. EPRI has launched a project to characterize the specific reactions that are taking place inside the compost beds.

EPRI began testing a full-scale bioreactor at another Duke power plant in North Carolina last December. The bioreactor is more intensively managed than the vertical flow wetland. "They're constantly feeding and monitoring the bacteria within that bed to optimize selenium removal," Lewis said. At this plant, too, mercury and selenium levels in the wastewater are already low, but the bioreactor lowers them further. "This is a very promising technology," Chu said.

EPRI also is testing technologies that rely on chemical precipitation and adsorption to remove trace elements. "We tried to evaluate and screen as many technologies as are out there," Chu said. "We threw the net as wide as possible." Some of the

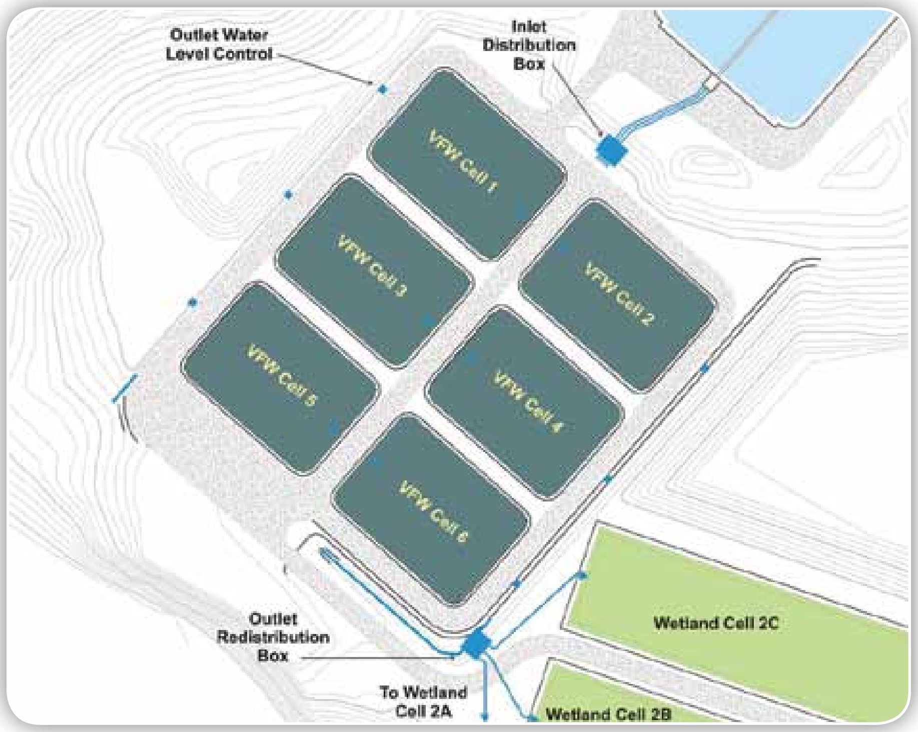
Pilot-scale vertical flow wetland

most promising technologies were tested in a series of pilot studies at a power plant in the Midwest.

The current technology to deal with selenium involves iron coprecipitation, where dissolved metals are adsorbed onto the surface of iron particles, which are then removed. This process is limited because iron reacts preferentially with selenite, leaving much of the selenate in solution. EPRI is investigating an advanced technique, called iron cementation, to help chemically reduce the selenate species to selenite, which can be dealt with more easily.

At one test site, iron cementation brought selenium levels down from roughly 6,000 parts per billon to, in the best case, under 200 parts per billion. "It shows that this technology has promise," Chu said, "but it didn't get down to the very low levels we had hoped to see."

EPRI also evaluated several technologies designed to address mercury. One technology relies on the standard technique of using sulfides to trap mercury in tiny particles that can then be captured by a microfilter. This approach brought mercury levels down from several hundred parts per trillion to about 90 parts per trillion. The potential benefits of microfiltration for mercury removal may vary with FGD water makeup, however, because of differences in the mercury particle-size



Duke Energy plans to modify an existing FGD wastewater treatment system in North Carolina with six full-scale vertical flow wetland cells.

distribution. More important, long-term operation of microfiltration has not been demonstrated for FGD waters, which may have high scaling potential; thus further evaluation is required.

Two technologies use advanced filtration combined with adsorption media designed specifically to capture mercury. One system demonstrated potential for reducing mercury levels to below 100 parts per trillion, while the other adsorption medium did not effectively remove mercury in the pilot study. Both technologies will need much more study and development before any commercial use.

Mysterious Molecules

One of the most puzzling aspects of this research is the wide variation in the makeup and treatability of FGD wastewater. At the two Duke test sites in North Carolina, much of the mercury and selenium from the flue gas ends up in the FGD solids. At other plants, however, the mercury and selenium stay dissolved in the FGD wastewater, making treatment more difficult.

EPRI will test the most promising technologies at various sites to see how they perform with different kinds of wastewater. "Every FGD wastewater is different, so removal performance for any technology will likely vary," Chu pointed out. "Until we truly understand the chemistry behind mercury and selenium, it will be difficult to predict removals from individual wastewaters.

"We think there are a number of different things that affect the fate of mercury and selenium," Chu said. Research shows that mercury is more likely to form particles when iron levels are higher in the wastewater. With respect to selenium, oxygen could be a factor. In most new FGD systems, air is blown into the FGD slurry to convert the solids to gypsum, a form that's more easily managed and can be sold as wallboard. "We think that in that process selenite is oxidized to selenate—the more difficult form to treat," Chu said. But even similar systems can generate widely varying wastewaters. "Different metals in the FGD water may facilitate that chemical reaction, and other compounds may slow it down," Chu said. Variations in the power plants themselves and in the coal they burn also may influence the makeup of FGD wastewaters.

Once scientists understand the chemistry, plant managers might be able to manage the conditions in the FGD system itself to favor the development of selenite over selenate or to ensure that more mercury and selenium fall out with the solid particles. "If we can do that, we can potentially avoid the wastewater treatment needs," Chu said. "That will be the way of doing it in the future."

This article was written by Cassandra Willyard. For more information, contact Paul Chu, pchu@epri.com, 650.855.2362, or John Goodrich-Mahoney, jmahoney@epri.com, 202.293.7516.

Paul Chu is a senior project manager in the Land and Groundwater program area of the Environment Sector. His current research activities focus on air and water toxics. Before joining EPRI in 1992, he worked at Babcock & Wilcox, where he was involved in various development projects related to flue gas cleanup of SO_2, NOx, and particulates. Chu received a B.S. in chemical engineering from the University of Arkansas in Fayetteville and an M.S., also in chemical engineering, from the University of Texas at Austin.

John Goodrich-Mahoney is a senior project manager in the Water and Waste Management program area of the Environment Sector. He manages research on toxic metals in the aquatic environment and on ecological issues associated with transmission and distribution systems. Before joining EPRI in 1990, Goodrich-Mahoney worked at the U.S. Environmental Protection Agency in Washington, D.C., the University of Wisconsin–Madison Water Resources Center, and the Woods Hole Oceanographic Institution. Goodrich-Mahoney received a B.S. in geology from St. Lawrence University and an M.S. in geochemistry from Brown University.

DATELINE EPRI

News and events update

High-Voltage Direct Current Gets Closer Look in Mile-High City

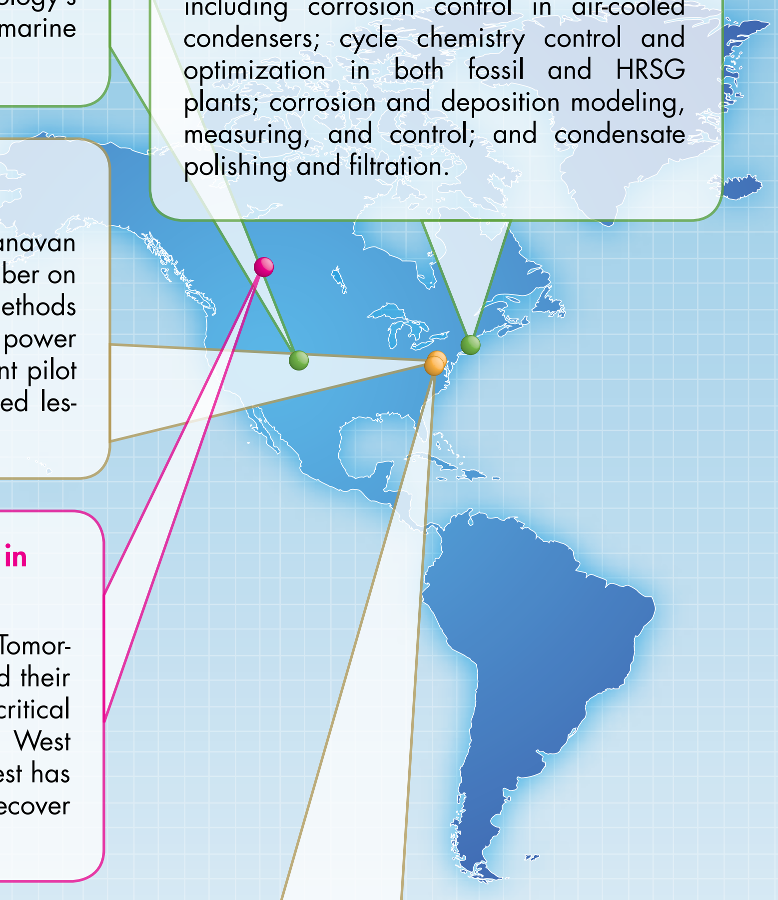
DENVER, Colo. – Tri-State Generation and Transmission Association hosted EPRI's HVDC Conference, which was attended by more than 60 representatives of utilities, manufacturers, academia, and consultants. The conference looked at both high-voltage direct current and flexible AC transmission systems (FACTS). HVDC and FACTS use similar technologies to control power, and discussions included maintenance and life extension of existing systems and new technologies. In addition to traditional applications of HVDC to bulk power transfer, conferees looked at HVDC technology's compatibility with renewables such as wind, including submarine cables being planned for offshore wind farms.

Experts From Five Continents Convene on Corrosion

BOSTON, Mass. – EPRI hosted its 9th International Cycle Chemistry Conference, which focused on online corrosion monitoring and targeting corrosion control during unit shutdown. More than 125 participants from Asia, Australia, Europe, South America, and North America examined an array of steam and water cycle chemistry topics, including corrosion control in air-cooled condensers; cycle chemistry control and optimization in both fossil and HRSG plants; corrosion and deposition modeling, measuring, and control; and condensate polishing and filtration.

EPRI Briefs NRC on Probabilistic Risk Assessment

ROCKVILLE, Md. – EPRI senior program manager Ken Canavan briefed the U.S. Nuclear Regulatory Commission in November on the development and use of probabilistic risk assessment methods for determining the risks associated with fires at nuclear power plants. Canavan shared industry experience with the recent pilot application of the risk-informed methodology and described lessons learned that can guide future improvements.



EPRI Advisors See Ultrasupercritical, CO_2 Technologies in Canada

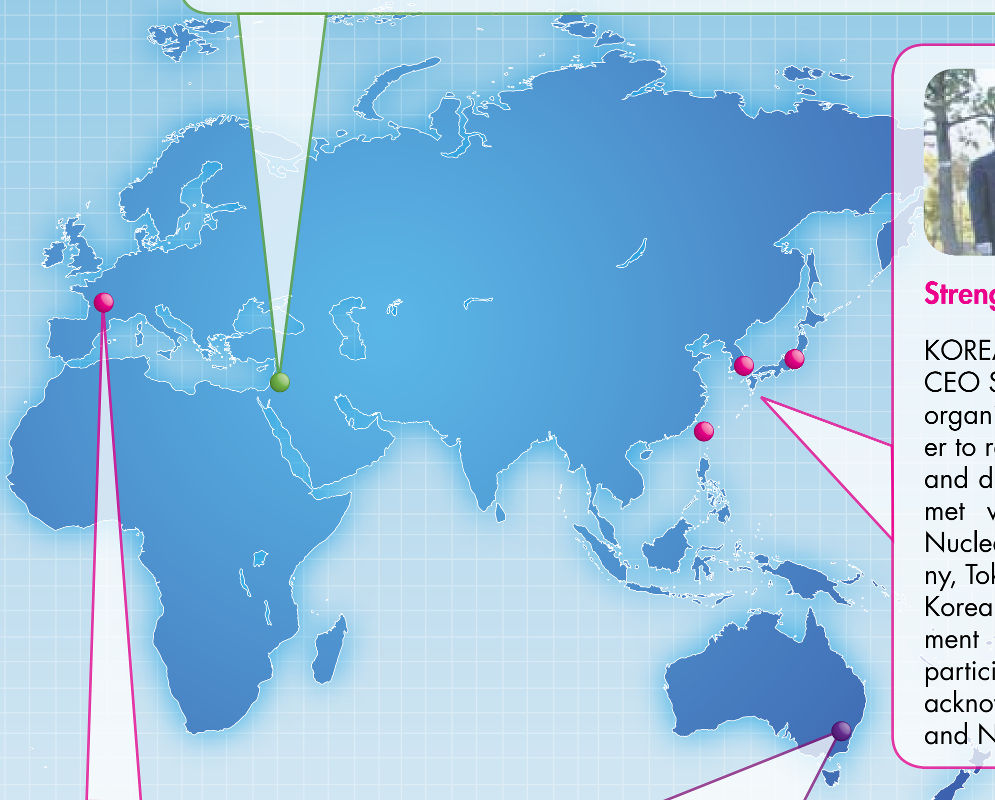
EDMONTON, Alberta – Advisors for EPRI's CoalFleet for Tomorrow and Carbon Capture and Storage programs conducted their first joint meeting, which included visits to a new ultrasupercritical minemouth power plant and its coal mine, and to a Penn West CO_2-enhanced oil production facility. In 20 years, Penn West has injected more than 1 million tons of CO_2 and expects to recover about 16% of the oil in place over the life of the operation.

EPRI Briefs OMB and CEQ on Coal Combustion Products

WASHINGTON, D.C. – EPRI Senior Project Manager for Land and Groundwater Ken Ladwig briefed congressional staff and administration officials on EPRI research in sustainable management of coal combustion products (CCPs). The federal agencies and congressional committees included the U.S. Office of Management and Budget (OMB), the Council on Environmental Quality, the U.S. Department of Energy, the Federal Energy Regulatory Commission, the Senate Environment and Public Works Committee, and the House Energy and Commerce Committee. Ladwig discussed the environmental and economic implications of designating CCPs as hazardous waste. The U.S. Environmental Protection Agency recently submitted a proposal to OMB outlining options for regulating these products, including hazardous waste regulation, non-hazardous waste regulation, and a hybrid of the two.

EPRI TransExpo Conference Looks to Strengthen Studies of Childhood Leukemia

JERUSALEM – EPRI sponsored its fourth TransExpo research conference in September. TransExpo is a case-control study of leukemia in children age 14 and younger who live in apartment buildings with built-in transformers. Measurements from Finland, Hungary, and Israel indicate that magnetic fields and exposures are significantly higher in apartments immediately above or next to a building's transformer than in apartments elsewhere in the building. This allows researchers to identify highly exposed children without selection bias, a factor invoked to explain the reported association between childhood leukemia incidence and magnetic field exposure above 0.4 μT. EPRI is encouraging more countries to join the eight current participants to provide a statistically stronger sample size of children who are highly exposed and who also contract leukemia. Qualifying countries must have transformers inside apartment buildings, a reliable cancer registry, a reliable population registry, and an electric company able to identify transformer locations inside buildings.



Strengthening Ties in Asia

KOREA-JAPAN-TAIWAN – EPRI President and CEO Steve Specker visited members, research organizations, and an equipment manufacturer to reinforce EPRI's international commitment and discuss expanded collaboration. Specker met with EPRI members Korea Hydro & Nuclear Power, Korea Electric Power Company, Tokyo Electric Power Co., and TaiPower. In Korea, during a visit to the Nuclear Environment Technology Institute (NETEC), Specker participated in a tree-planting ceremony acknowledging the strong ties between EPRI and NETEC.

Materials Aging Institute Dedicated

LES RENARDIÈRES, France – EPRI participated in the dedication of the Materials Aging Institute on November 16, 2009. Along with EDF and Tokyo Electric Power Co., EPRI is a founding member of the institute, which conducts research and development on the aging of materials used in electric power facilities. About 150 utility managers, directors, project leaders, scientists, journalists, and political leaders attended the event.

Projects Focus on Decarbonizing Down Under

CANBERRA – EPRI's Advanced Generation staff recently completed two major projects for organizations affiliated with the Australian government. The first study assessed cost and performance of various low-emission technologies for the federal Department of Resources, Energy and Tourism. The second study, as part of a team led by WorleyParsons, provided the newly formed Global Carbon Capture and Storage Institute with an analysis of the global status of carbon capture and storage. The Australian government launched the nonprofit institute to speed development of carbon capture and storage technology. The report identifies research and development gaps and recommends ways to help close those gaps.

Cycling Baseload Plants

Driving to better understand, manage, and mitigate the impacts

In a sense, operating a coal-fired power plant is akin to driving a modern car. Both will be most reliable and efficient if steady operation is sustained. A car consistently driven on extended trips at a steady 55 miles per hour can be expected to operate more efficiently and reliably over the long term than a car driven an equal number of miles with the continual acceleration and deceleration of stop-and-go traffic. For a coal-fired power plant, the impact of acceleration and deceleration of electrical output takes a similar toll on efficiency and reliability.

For baseload, coal-fired power plants, today's low natural gas prices, increased renewable generation, and economic downturn have created the utility equivalent of heavy traffic. The existing U.S. fossil-fired generation fleet, designed for long stretches of "freeway" operation, now must cycle, or "follow the load"—frequently reducing output or even shutting down for brief, unscheduled intervals.

This new duty cycle forces the plant and equipment to be operated closer to—or beyond—nominal design limits and through more cycles than originally anticipated. The result is increasing rates of damage to a variety of plant systems that could lead to more equipment reliability problems in the long term.

THE STORY IN BRIEF

Baseload coal-fired plants have been designed for consistent, round-the-clock operation at full load. But today's low natural gas prices and increased dispatch of intermittent renewable generation are encouraging the use of baseload plants for cycling duty, which can lead to component damage and reliability problems. EPRI is working with member utilities on an integrated framework of analysis, operating strategies, and design modifications that will help minimize these impacts.

A Growing Problem

Cycling and load following are not new. In recent decades, EPRI workshops and studies have evaluated and addressed impacts of cycling operation, such as accelerated damage to boilers and turbine problems associated with boiler water chemistry. Top-down empirical analyses using industry data have correlated plant cycling with operating costs.

Nevertheless, there are gaps in knowledge about the impacts of cycling, and current knowledge of cycling effects needs to be better integrated with decision making. Studies are needed to quantify the impacts of cycling on environmental control equipment, such as particulate controls, post-combustion NO_x controls, FGD systems, and waste management systems. Impacts of cycling on heat rate (plant efficiency) as well as on many damage mechanisms, such as boiler circumferential cracking and fireside corrosion, need to be considered.

Changes in plant operations also pose new challenges. "Some baseload capacity is being replaced by gas-fired units and heat recovery steam generators," said Kent Coleman, a senior project manager in EPRI's Boiler Life and Availability Improvement program. "Baseload dispatching traditionally taps nuclear plants first and then the least costly coal plants," Coleman said. "But as gas prices have come down, gas plants have displaced more of the coal plants."

Also important are the effects of variable resources, such as wind and solar energy. "When the output from a wind farm abruptly goes down, dispatchers have to come up with more generation from somewhere, so they dispatch the coal units to follow that load," Coleman said.

"You can see these difficulties playing out in the Midwest, where a lot of wind is coming on line," said Tony Facchiano, a senior program manager and one of the leaders of EPRI's environmental controls research. "The problem is, the wind typically picks up at night just as the load drops. You have all this renewable energy just when you need it least, so the baseload plant shuts down at night. In the morning, you get a one-two punch—the load picks up and the wind dies—and you have to get the plant back on line.

"Load following, low loads, and turning units off and on all present operational problems," Facchiano said. "Plants are designed to operate at full load. Everything is optimized for a full load, and when you operate at lower loads, you're compromising performance. In all three cases, your heat rate goes up, which means the operating efficiency of your plant goes way down. And there are issues with emissions and keeping your environmental controls operating properly.

"If you take a plant off line, you have to make good guesses about when it's going back on. Do you send people home or have them stay on site? Do you keep the plant on hot standby? Do you go for a cold start or a hot start? A lot of folks think that if you need power at 8 o'clock in the morning, you just press a button and out comes the power. It doesn't work that way."

"In normal operation, there's a certain amount of time when you're letting things heat up and expand at a slow, uniform rate to control the stresses," Coleman explained. "You're not making any power, but you are burning fuel, so some utilities have tried to shorten that time as much as possible by ramping up quickly. But the shorter you make that warm-up, the more damage you can do to your unit. It's a trade-off between spending money on fuel and spending money on maintaining equipment throughout the plant."

"When you talk about load following, you're talking about rapid increases and reductions in temperatures and velocities, and a lot of thermal stress is created," Facchiano said. "When loads change in a plant, the consequences are numerous—pulverizers or mills go off and on, fans speed up and slow down, furnace temperatures and heat profiles are altered, pollution control requirements change, steam and flue gas velocities vary, and so on. All of these changes create stresses. Things are unsteady, and there's a transient period when things are out of sync."

Taking the Long View

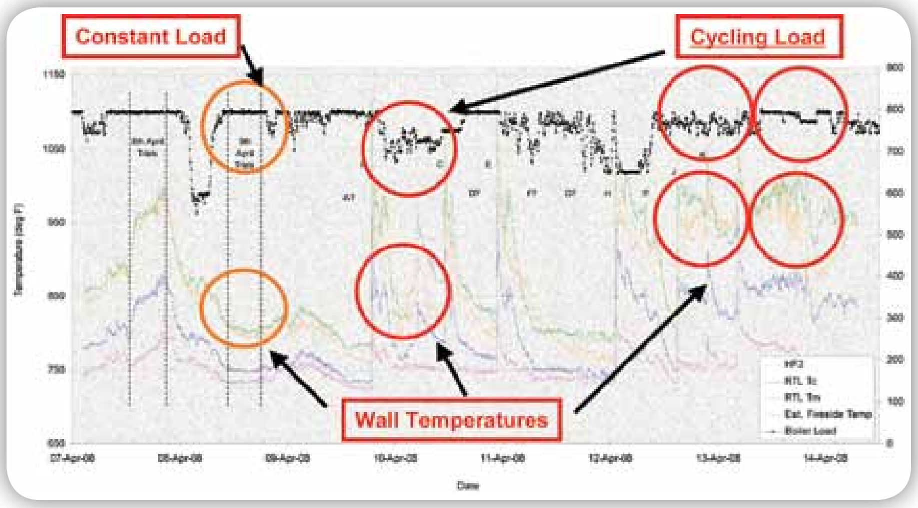
Coleman said today's decisions about which plants to operate and how to use them often come down to minimizing fuel costs or emissions—which plant produces less carbon dioxide, for example. Many decisions do not take into account longer-term life-cycle costs. Facchiano cited the car analogy to help explain.

"If I run my car at 70 miles per hour at a mostly constant speed, my car might last 15–20 years. But if I am doing a lot of starting and stopping, that car may last only 5–10 years. After the first year, I might think everything is fine, but I'll see the impacts later on. The same thing applies to the impacts of cycling on power plants today. A lot of the consequences are long term. Thermal fatigue, for example, develops over a long period," Facchiano said.

"All the top failure mechanisms for the boiler and turbine generator are effects of cycling," Coleman said. "We're already seeing a lot of corrosion fatigue and thermal fatigue in boilers as a direct result of this kind of operation. Industry maintenance costs have increased quite a bit over the last few years because of it. Power plant owners are changing out waterwalls and boiler headers because the units are old and they've been run hard. It increases the risk of unplanned outages, equipment failure, and personal injury."

"And all this is happening at the same time orders for new units are being canceled, so now you have older units that are being asked to run longer," Facchiano added. "Cycling only increases the wear and tear, so it's kind of a perfect storm."

In order to manage plants and fleets effectively, it's important to understand the critical risks, such as higher costs, increased probability of failure, and rate of equipment degradation. Past research has demonstrated that the detrimental effects of cycling operation might not show up in the short term and that unique unit characteristics (age, design, metallurgy, etc.) and operational regimes make it difficult to accurately quantify and predict cycling impacts. Quantifying these impacts inherently entails a high degree of uncertainty. Plant design, cycling regime, equipment condition, changes in operating practices, and changes in fuel all make it unlikely that a one-time assessment will produce an accurate result that can be used in the long run.



Operational trials at PPL's Brunner Island Unit 3 showed steep temperature excursions in the boiler's front wall under cycling duty. Such rapid heat variations can lead to thermal fatigue and component failure.

An Integrated, Real-World Approach

EPRI is looking at a long-term approach for studying the impacts of cycling. Because these impacts differ from plant to plant, the research will use members' generation assets as "laboratories" to study cycling impacts over several years. The work has three objectives:

- Develop and validate an integrated framework to quantify the cost, performance, and reliability impacts of various fossil plant cycling scenarios;
- Define critical operating practices and design modifications that mitigate or better manage these impacts; and
- Develop and demonstrate an approach for modeling the response of generation assets to various dispatch scenarios that optimizes fleet deployment on the combined basis of generation cost and equipment degradation.

This integrated framework would include information and analyses from various EPRI programs and experts. The effort would entail the following steps:

- Define all sources of costs resulting from cycling—impacts on power-block equipment, emissions controls, coal feed processing, and overall heat rate penalties—that can manifest themselves as reduced service life, increased forced outages, compliance violations, higher operating costs, or lower efficiency.

- For each unit, determine the first-order causes likely to contribute most significantly to costs.
- On a unit level, quantify costs as a function of all major operational and design parameters believed to be critical, including ramp rate and a comparison between historic (baseload operation) costs and the increased cost due to cycling.
- Define additional unit data that need to be acquired, along with instrumentation necessary to monitor and/or quantify the critical impacts.
- Evaluate plant simulator technology with system-level cost functions as a possible analysis "test bed."
- Develop and demonstrate a fleetwide optimized cycling dispatch model, using unit-level cost functions associated with various modes of cycling operation. It might be possible to create scenarios that could demonstrate the subtle changes in dispatch that have unexpectedly large benefits for the cost of cycling. Tracking and optimizing asset life consumption could be a new role for the emerging fleetwide monitoring centers. Information could be sent to a central location, where all monitoring, trending, and analysis could be done.

This approach will require an up-front assessment for each generating asset faced with cycling duty and then periodic follow-up assessment of impacts over a period of two or three years. The goal is to develop a validated approach and framework for quantifying the impacts of cycling at the unit level and for developing an asset deployment strategy for the fleet. It is likely that a mix of top-down empirical analyses and engineering calculations using physics-based models will be required.

"There are two key needs we have to address," Facchiano said. "One is to be able to better quantify the cost of cycling. Utilities need that information to make a decision when asked to cycle a unit. What's the break-even point? It doesn't make sense to generate power if I'm going to lose money, so I need to factor in the impacts of cycling to know where that point is.

"Our R&D should also focus on the other need: identifying tools and technologies that can minimize the impact if units must be cycled. There's a lot that can be done in this area. For example, a more responsive control system could help minimize the impacts of transients, or an improved boiler design could reduce stresses due to thermal transients.

"We've already started. A lot of work EPRI has been doing for some time is applicable to understanding and advancing the resolution of this issue," Facchiano said. "What we need to do now is compile what we already know and figure out what we still need to learn. Much of our work in 2010 will apply to cycling; we already have a lot of tools we can apply. And we're going to get smarter as we go."

This article is based on a white paper being developed by EPRI's Generation Sector. Background information was provided by Norris Hirota, nhirota@epri.com, 650.855.2084; Tony Facchiano, afacchia@epri.com, 650.855.2494; and Kent Coleman, kcoleman@epri.com, 704.595.2582.

Norris Hirota, a director in the Generation Sector's Operations and Maintenance program area, has overall responsibility for the development and deployment of technology for improving plant performance and reliability. Hirota joined EPRI in 1980 and has managed numerous programs in both the Nuclear and Generation Sectors relating to equipment and plant reliability and O&M cost reduction. He has also led several large initiatives to apply EPRI-developed technologies at member companies. Hirota received B.S. and M.S. degrees in mechanical engineering from the University of Santa Clara.

Anthony Facchiano, senior program manager for environmental controls in EPRI's Generation Sector, manages research on boiler performance, in-furnace and postcombustion NOx control technologies, and boiler operability issues associated with low-NOx combustion. Before coming to EPRI in 1993, he worked at Coen Company, Bechtel Power Corporation, and Exxon Research and Engineering Company, where he specialized in product development, emissions testing, and full-scale demonstration of combustion systems. Facchiano holds B.S. and M.S. degrees in mechanical engineering from Manhattan College.

Kent Coleman is a senior project manager in EPRI's Boiler Life and Availability Improvement program, focused on the development of non-destructive examination methods, reduction of boiler tube failures, and development of remaining-life tools for boiler pressure parts and piping. Before joining EPRI in 1999, he was a specialty engineer for Western Resources (WR) for 17 years and administered boiler repair and life assessment programs for Kansas Gas and Electric Company, a WR subsidiary. Coleman received a B.S. in mechanical engineering from Wichita State University.

FIRST PERSON *with Brad Stokes*

Moving the Earth
Moving the Industry:

South Carolina Electric & Gas prepares to build a new generation of nuclear plants

In the rolling hills near South Carolina's Broad River, South Carolina Electric & Gas is moving more than just red clay. With more than 200 pieces of earthmoving equipment reshaping the landscape to accommodate two new nuclear generating units, the utility's undertaking is a harbinger of the U.S. nuclear industry's emergence from a decades-long construction hiatus.

EPRI Journal traveled to the V.C. Summer Nuclear Station, a one-unit, 966-megawatt plant that is jointly owned by SCE&G and the South Carolina Public Service Authority, to discuss the two new nuclear units that will add more than 2,200 megawatts of zero-emissions capacity to the two utilities' generation portfolios.

EPRI Journal spoke with Brad Stokes, engineering design manager for SCE&G, who is overseeing project engineering.

EJ: How would you summarize the business case for building two new units at V.C. Summer?

Stokes: One of the main things that turned us to nuclear was the economics. Nuclear plants are expensive to build, but with capacity factors greater than 90% and the low cost of nuclear fuel, we can anticipate a good return over the 40-plus-year economic life of a plant. The possibility of a constraints on CO_2 emissions was a consideration. Fuel diversity in our generation mix was also a major consideration. We have about 5,750 megawatts of capacity, of which about 75% is coal or gas, about 11% is nuclear, and a similar amount is hydro. That mix can make us susceptible to gas prices going up, like when we had Hurricane Katrina interrupt gas supplies in the Gulf. We've also seen fluctuations in coal prices. So, a more diverse fuel supply gives us options—a good mix. Also, by 2019 or 2020, when the second new unit comes on line, however, we'll be able to reduce our carbon emissions back to mid-1990s levels. At that point, we could see nuclear account for as much as half of our production.

EJ: What are you doing with your work force as you go from one unit to three units?

Stokes: We have the same issues as other utilities. Our work force is older, so we need to train and bring on new folks. We have to continue operating the existing plant successfully and economically, and we have to be careful how we bring employees over from our existing unit to our new units. So we are developing new talent. We're working with local colleges and tech schools, including the University of South Carolina's graduate program in nuclear engineering, South Carolina State University's undergraduate engineering program, and Midlands Technical College, where we've been cooperating to develop an operator training program. We recently brought in 15 people from the Midlands Tech program to see what operations is all about, and we got to see what kind of employees they would be. We expect to hire some of the folks out of this program.

EJ: Are you concerned about the limited experience of your new work force?

Stokes: Of the 15 engineers I have on board right now, about half have less than five years of experience.

EJ: By the time the second new unit comes on line, however, they will have 15 years of experience.

Stokes: That's right, and they will have had time to be mentored by my senior engineers here. Plus, by being involved with the project from day one, they will get to see what the issues are, how we solve problems as we go through the design and construction. You learn more about the plant by participating in construction, and I think that makes you a more informed plant engineer once the plant starts operation.

EJ: Where is the project in broad terms of the schedule and milestones that you have established?

Stokes: We are in a preconstruction stage right now. From a regulatory standpoint, we can't start nuclear construction until we get our license from the NRC (U.S. Nuclear Regulatory Commission). We expect our NRC license in 2011, sometime between June and October, depending on approvals for the Westinghouse AP1000 Design Certification Document and review of the standard plant combined operating license application. We expect to start nuclear construction on Unit 2 in late 2011, and from then until late 2015 we'll be in construction mode. Then fuel loading late in 2015, start-up testing, and check-out. We'll go operational in April of 2016. The timeline for Unit 3 will track about three years later. The timing of bringing on our second unit is based on our system load growth.

EJ: So what are you doing on site right now?

Stokes: In 2008, we received approval from the South Carolina Public Service Commission to begin preconstruction activities so we could stay on our overall schedule. To start with, we had to reroute the existing railroad spur that supported Unit 1. Unit 1 required the rail spur to support an upcoming outage, and we needed to move the rail spur to allow preparation of the site. This required quite a bit of excavation, but we met the need for Unit 1's outage, and the rail spur is now in place to support construction. We will need the new spur to bring in the steam generator, reactor vessel, and other large components for Units 2 and 3.

We'll have to accommodate 3,000 people during construction, so we are building a "construction city," an administration building, and a training facility. We're already installing modular buildings for construction, engineering, quality assurance, and licensing. We probably have more than 200 vehicles involved in earthwork. By January, we expect to have the "tabletop"—where the two new units will be situated—down to its final grade in the area of Unit 2. Then we can start excavation for the units, but we cannot start safety-related vertical construction until we receive NRC license approval.

EJ: What are the key differences in the technology of Unit 1 and the two new units?

Stokes: They are all Westinghouse units. Unit 1 is a three-loop pressurized water reactor that relies on active systems for reactor cooling and containment pressure and temperature control during accident conditions. The new AP1000 units are Generation III+ plants, which rely on passive cooling for reactor safety. The advanced designs also allow for a smaller plant footprint, with fewer pumps, fewer valves, and significantly less electrical wiring. There is going to be less equipment for us to maintain and an increased level of safety well beyond the already high levels of safety at our current plant.

EJ: Are you working in concert with other companies that are building this same design?

Stokes: Very much so. One big benefit to this new wave of nuclear plants is the close cooperation. Most of the utilities considering new nuclear in the Southeast selected the AP1000 design. A number of these utilities formed a group to collaborate on design, construction, and operation of the AP1000 design. We are working closely with Southern Company, which is developing new nuclear units at their Vogtle plant; with Progress Energy, which recently signed a contract to develop a new plant in Florida; and with Duke Energy and Florida Power & Light, which are also considering new AP1000 plants.

We're also involved with the EPRI Advanced Nuclear Technology program. This includes utilities developing new plants based on other nuclear plant designs—Constellation, Entergy, Exelon —and international nuclear utilities such as EDF [France], Endesa [Spain], and KHNP [Korea].

EJ: That in itself represents a departure from the earlier generation of building, doesn't it?

Stokes: I was not around for the construction of the last generation of plants in the 1970s and '80s, but it's my impression everybody built plants using their own design philosophy. This resulted in a lot of unique plants, even though a lot of plants used similar nuclear steam supply technology. Now, after 25-plus years of operation, we are very interested in building standard plants and doing things the same way. We expect this method will help make the Generation III+ plants safer and more economical to build and operate.

EJ: What are some of the areas where your company and the others in EPRI's Advanced Nuclear Technology (ANT) program have focused your attention?

Stokes: We look at lessons learned from our operating experience at the existing units, to make sure those lessons are applied in the future. For example, as a result of issues related to alloy 600 in pressurized water reactors, we are using alloy 690 in the new AP1000 design. We learned the importance of materials selection, how those materials degrade, and how you can most effectively inspect those materials. Existing plants over the past 10 years have developed materials management matrix documents through their interaction with EPRI. One of the first things we did in ANT was develop materials management matrix documents for the new AP1000 design so that we would start off knowing the materials we're using, their abilities, how we should inspect them, and what we need to factor into our inspection processes going forward.

We're also making sure that risk-informed initiatives are in place for managing new nuclear plant operation and maintenance. Instead of the deterministic methods that were used historically, EPRI is investigating probabilistic approaches. Here's one example. By applying risk-informed techniques to the in-service inspection of welds at new plants, we can determine if it's possible to reduce the number of required inspections.

Another example is with nuclear fuel. We're looking to make sure that the fuel guidelines developed to help the industry meet its "Zero by 10" commitment [zero fuel failures by 2010] are applicable to the new nuclear plant designs. An EPRI project is currently under way to investigate if there's anything different about the fuel design or the way we are operating the fuel in new plant designs that might require some change to the guidelines for the new generation of plants.

EJ: Are program members looking at anything related to plant construction?

Stokes: We're collecting operating experience to see what we can learn about modular fabrication and construction over the past 5 or 10 years. What do companies do for testing, in shipping, to make sure that the modules are preserved and arrive on site in factory condition. We have an ongoing project to benchmark different companies that are using modular fabrication and construction, to find out what they have learned, how they have changed their business, what problems they encountered, and how they have improved their processes over time.

EJ: How are you approaching engineering, procurement, and construction (EPC) for these two units?

Stokes: We realized early on that the process would be much better and much more beneficial to us if we were part of the team with Westinghouse and Shaw in completing our project under an EPC arrangement. Westinghouse is the plant nuclear steam supply system designer, and Shaw is performing site-specific designs and is the project constructor. The consortium [Westinghouse and Shaw] has worked closely with SCE&G to build our project team. My engineers are a part of the design team for our project. We participate in design reviews, provide design inputs and operating experience, and review and comment on design documents. People from our engineering group actually spend a couple of days a week in the Shaw offices in Charlotte and often travel to Westinghouse's home office in Pittsburgh to make sure that we are up to speed with what is going on in our project.

EJ: Do you have a sense that you're helping restart the nuclear industry in terms of construction? Of being out in front of the pack and having attention focused on you?

Stokes: I don't focus on whether we are leading or not. It's important for us to stay on schedule and to stay on budget and to do things the right way. The way the Vogtle project goes and the Summer project goes and other projects—they're going to set the pace for the rest of the industry. If we can build on schedule and within cost and meet all the regulatory requirements, that makes it easier for the next group coming through and helps ensure that there is a revitalization of the nuclear industry.

EJ: It sounds like collaboration really is at the heart of it, too.

Stokes: I have never known another industry to share information as openly from company to company. It has been that way with Unit 1 since I have been here. If I need information from Duke or Progress, I call their engineering lead and ask for it. They share procedures and technical experts and will even send staff to our site for consultation. We openly share information that other industries might hold to themselves for advantage, and it makes us all stronger.

EJ: Even though start-up is years away, what are you doing now to ensure that it goes smoothly?

Stokes: We know that there are experts and lessons learned out there, but not all in one spot. We have a project through the EPRI ANT program to actively look for operating experience from start-ups—whether it's in China, with TVA plants [that recently came on line after construction was suspended decades ago], or with some of the start-up engineers that were around for start-up of the last generation of nuclear plants, constructed in the 1970s and 1980s. The program is investigating what was learned—what were the big hurdles—and looking at how can we address those now. We certainly don't need to learn those lessons over again.

We'll start hiring start-up engineers in 2011 to 2012. We're using a team approach for that too. Westinghouse will have the lead, with Shaw and SCE&G providing support. Westinghouse is writing the start-up procedures, which will be based in part on the experience and insights that will be captured in the EPRI start-up report, reflecting input from Japan, Korea, the U.S., and elsewhere. We'll get this EPRI product just in time to help in developing these procedures. In addition, we will be able to capture lessons learned from start-up of the AP1000 units being built in China.

Brad Stokes on collaborative nuclear R&D

At one point in the interview, the conversation touched on the timing and value of collaborative R&D for nuclear utilities.

"We realize that some projects are not going to be finished in time to support Vogtle and Summer. They are still important—they still need to be done. We fund them because the industry needs them. Even if we can't take advantage of them right now, we know the industry can. On the other hand, some of the projects that we're benefiting from right now are being funded by companies with no immediate need for the results. They're confident they'll benefit from them in the future, and they recognize their importance to the industry."

With an emphasis on standardization, modular construction, and passive safety systems, the Westinghouse AP1000 is one of the most advanced nuclear power plants available in the world today.

Microsensors Show Promise for Transformer Monitoring

Periodic condition assessments are key in avoiding transformer failures and associated customer inconvenience and outage costs. The assessments identify pre-failure fault conditions by detecting degradation products in the transformer's insulating oil or paper. These products—usually dissolved gases—are generated as problems develop in the transformer.

Among existing diagnostic methods, the dissolved gas analysis technique is the most widely used, offering an easy-to-apply means to assess in-service transformers. But it requires field sampling of the oil and laboratory analysis, which can be expensive and sometimes unreliable when poor sampling methods are used.

Recently, several on-line dissolved gas analysis monitoring systems have become commercially available, offering the advantage of continuous monitoring while the transformer is in service. Most of these systems employ gas chromatography, mass spectrometry, or other sophisticated techniques to identify degradation products. Although they provide accurate analysis, their complexity and high cost can be justified only for large power transformers at power plants and substations. Smaller transformers still require labor-intensive, on-site sampling and laboratory analysis.

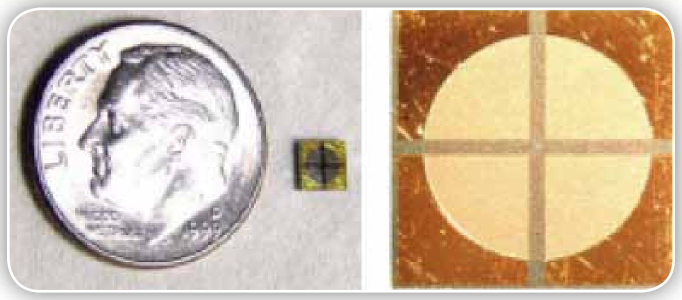
Low-Cost Gas Analysis

EPRI's Office of Technology Innovation is developing solid-state microsensors that promise to enable on-line dissolved gas analysis monitoring for both power and distribution transformers at far lower cost. The new sensors, based on metal-insulator-semiconductor technology, are being designed to detect the presence of hydrogen, which indicates partial discharges, and acetylene (C_2H_2), which indicates arcing.

The hydrogen sensor can be placed either in the gas space or in the transformer oil. At the sensor's surface, hydrogen gas dissociates into hydrogen atoms, which filter through the sensor layers and alter a measurable parameter at the sensor leads according to the amount of hydrogen present. Less than a millimeter square, the sensor consumes less than a microwatt of power.

A Steady Development Process

EPRI began to develop the hydrogen sensor in 2000 and constructed the first prototype that same year. Laboratory work in 2001 established the technology's practicality, and a second prototype, in 2005, significantly improved on the sensor's



This 4-mm chip contains four hydrogen microsensors. (Photo courtesy of Sandia National Laboratories)

sensitivity and selectivity. Laboratory tests with a model transformer in 2008 confirmed that the sensor could detect hydrogen in amounts lower than 10 parts per million, with a response time of less than a second and at temperatures between 25˚C and 200˚C.

In 2009, "drift tests" in flowing oil—fresh, aged, and very aged—have determined both the stability of the measured signal over several months and the impact of flow rate on signal output. Plans for 2010 include field research on the hydrogen sensor in four transformers at member host substations. These field trials will examine additional parameters that are difficult to simulate in the laboratory.

Progress also has been made in developing an acetylene sensor, and potential prototypes are being laboratory-tested. For acetylene detection, EPRI is investigating prepared metal-insulator-semiconductor gate compositions to determine promising combinations of materials.

Broad Application, High Value

Metal-insulator-semiconductor sensors are expected to be applicable to virtually all of the more than 400,000 transformers worldwide, protecting an investment of several hundred billion dollars. Utilities will be able to reduce maintenance costs by providing just-in-time maintenance, gathering information remotely rather than dispatching personnel into the field, and avoiding equipment replacement costs due to catastrophic failure. The sensors are expected to reduce the cost of on-line dissolved gas analysis monitoring by an order of magnitude.

Better-informed run/refurbish/replace decisions for transformers also will result from this monitoring, and its "intelligent" diagnostic capability is expected to be a function of the smart grid. EPRI is examining other applications, including on-line diagnostics of oil-filled cables.

For more information, contact Luke van der Zel, lvanderz@epri.com, 704.595.2726, or Andrew Phillips, aphillip@epri.com, 704.595.2728.

Nanofluids Could Boost Thermal Performance of Nuclear Plants

Nanofluids—colloidal suspensions of extremely small (1- to 100-nm) particles in a base fluid—have been found to enhance heat transfer and are being explored for advanced computer core cooling, solar energy conversion, refrigeration, and other applications. Their higher thermal conductivity, heat transfer coefficients, and boiling critical heat flux may be able to improve nuclear power plant performance when they are used in place of conventional cooling water. For example, using a nanofluid as coolant in a pressurized water reactor (PWR) could increase the critical heat flux of the core, and the fluid could be used in the emergency deluge system in a loss-of-coolant accident.

EPRI has conducted tests to confirm the potential of these advanced coolants in nuclear applications and determine the technical and practical barriers to their further development.

Nanofluid Selection and Testing

Materials used for nanoparticles include chemically stable metals; metal oxides such as alumina, zirconia, silica, and titania; and carbon in various forms, including diamond, graphite, and carbon nanotubes. For nuclear applications, EPRI reviewed the literature on more than a hundred substances and chose alumina, zinc oxide, and diamond for further evaluation. The key selection criteria were chemical, radiological, and physical (dispersion) stability under PWR conditions.

Pool boiling experiments (EPRI document 1016913) measured the three nanofluids' enhancement of critical heat flux—the point at which the transition from nucleate boiling to film boiling limits the effective transfer of heat. While high-concentration nanofluids presented some viscosity/pressure concerns, low particle concentrations (less than 0.1% in volume) of all three fluids were shown to increase critical heat flux by up to 85%.

Experiments showed that most of the enhancement results from nanoparticles deposited on the heater surfaces rather than from free particles in the fluids themselves. A 2- to 3-µm coating can be easily applied by simply boiling the fluid through the system for a short period of time. The increased wettability of the coated surface was identified as the primary factor in critical heat flux enhancement.

Sharper Focus on Diamond

Diamond nanoparticles are of particular interest because they are chemically inert, making them ideal for the reactor environment, where radiation and chemistry can exert harsh effects on many substances. Further tests investigated potential drawbacks to diamond nanofluids, including metal surface erosion and negative effects on ion-exchange resins (EPRI document 1019325).

Tests involving high-pressure water jets showed no discernible difference between diamond nanofluids and a water control in the cavitation erosion of test samples.

Earlier erosion tests (EPRI document 1016281) on a flow loop and a nine-rod simulated fuel bundle indicated that the presence of diamond nanoparticles is not likely to cause undue erosion of the core or coolant system. More severe, accelerated wear testing with a high-pressure (2,500-psi) water jet supported this conclusion, showing no discernable increase in cavitation erosion for aluminum and Zircaloy samples at nanofluid concentrations up to 0.01%.

Ion-exchange resins are important for filtering certain radioactive cation species from the cooling water and removing minerals that can cause crud buildup. Researchers built dual ion-exchange columns to compare the effects of diamond nanofluids and a control (deionized water) on a typical PWR ion-exchange system. Tests showed no statistical differences in the resin performance.

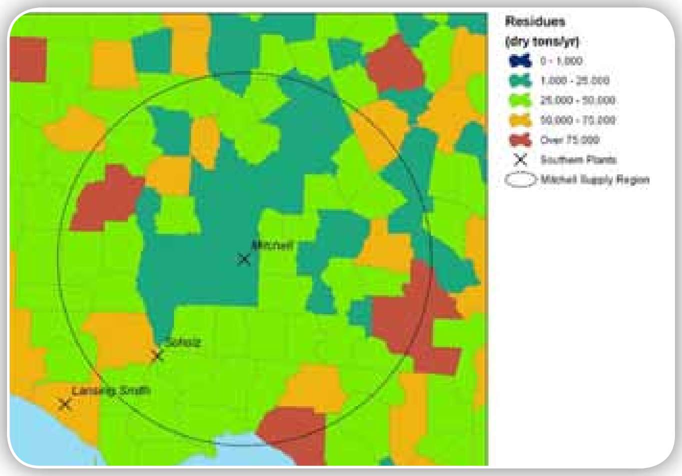
While these laboratory experiments have resulted in a better understanding of heat transfer characteristics and have explored some potential limitations, nanofluid coolants are still at the early stages of development. Substantial research on specific applications in real-world environments will be required in order to establish nanofluids as practical advanced coolants in nuclear reactors.

For more information, contact Heather Feldman, hfeldman@epri.com, 704.595.2735.

Plant Mitchell Moving From Coal to Biomass

Georgia Power's Plant Mitchell, which began operation in the early 1960s, is facing a challenge common to many vintage coal-fired plants. Continued use of coal may require significant capital investment to meet tightening air emissions requirements, making the 155-megawatt (MW) unit uneconomical. Georgia Power, with help from EPRI, is pursuing an option to keep Plant Mitchell economically and environmentally viable: conversion to biomass fuels.

A study by EPRI and Antares Group confirmed that Plant Mitchell is an excellent candidate for repowering to biomass. Ample space exists for the increased storage volume required for biomass fuel, and fuel delivery access options are good. Plant Mitchell's size will allow retrofit to a large-scale (96-MW) biomass power application, and most of the plant's existing equipment can continue to be used with biomass combustion.



A study of unmerchantable timber and harvest residues within a 100-mile radius of Plant Mitchell confirmed that biomass fuel for the plant will be plentiful.

Retrofit Planning

Study results indicated that retrofitting the plant's boiler for biomass operation would be significantly less costly than adding a new biomass boiler and could achieve a level of efficiency comparable to that of a new biomass plant of similar scale. Antares investigated stoker-fired and fluidized-bed options, each of which is proven and brings advantages and disadvantages. Stoker firing was selected because of its lower capital costs, reduced operational complexity, and successful operational history.

Conversion to stoker-fired operation will involve removing the bottom of the existing boiler and replacing it with a stoker grate and associated bottom ash removal equipment. Fuel conveyors, combustion air equipment, and overfire air piping and nozzles will be replaced, along with certain ductwork, controls, and wiring. With new mechanical particulate collectors upstream of the precipitator, the existing electrostatic precipitator can continue in service with minimal upgrade while maintaining or improving existing particulate emissions rates.

Fuel Supply

Plant Mitchell is expected to consume about 1.1 million tons of wood fuel per year. The primary fuel will be clean wood chips from timber harvest residues and timber considered unmerchantable because of species, form, or damage. These resources could be supplemented with wood residue by-products (sawdust, shavings, etc.) from existing local wood product manufacturers or with chipped whole trees, if necessary.

A study that assessed the wood supply within a 100-mile radius of Plant Mitchell showed that the region could sustainably yield at least seven times more fuel than the plant will require. Even with potential competing demand from uses such as wood pellet production, cellulosic ethanol conversion, or additional biomass power plants, the region could still yield about twice the total supplies needed. Fuel costs are expected to average between $23 and $29 a ton.

Moving Ahead

Recommissioning Plant Mitchell for carbon-neutral biomass generation is now under way. Taking into account the EPRI/Antares studies, the Georgia Public Service Commission approved the plant's conversion from coal to wood firing earlier this year, and retrofitting is slated for completion in 2012. Additional studies across the country are expected to confirm biomass conversion/repowering as a cost-effective, low-risk way to revitalize aging coal-fired generation assets.

For more information, contact Dave O'Connor, doconnor@epri.com, 650.855.8970.

Guarding Against Counterfeit Nuclear Plant Components

Spurred by enormous growth in new manufacturing capabilities around the world, counterfeit components are finding their way into alarming places—aircraft carrier and fighter jet systems, commercial airliners, pharmaceutical and petrochemical plants, and U.S. Department of Energy (DOE) facilities. In 2008, U.S. customs agencies seized $272.7 million worth of these spurious goods, a 38% increase over such seizures in 2007. This rise, coupled with the potential for substantial new construction of nuclear power plants, poses a significant safety challenge for the global nuclear industry. Expanding on work from the 1990s, EPRI is updating guidance to help nuclear utilities guard against increasing risks posed by counterfeit components.

Although to date there are no known incidents of counterfeit components installed in U.S. nuclear plants' safety-related systems, such components have been discovered recently in non-safety-related systems. For example, the Plant Hatch nuclear facility in Georgia discovered an installed counterfeit valve, and Duke Energy discovered that its Catawba plant in South Carolina may have purchased fraudulently labeled circuit breakers.

A counterfeit stop check valve was discovered in a non-safety-related application at Plant Hatch in 2007.

New Concern Over an Old Problem

The issue is not new. Responding to a 1989 Nuclear Regulatory Commission (NRC) industry directive to improve the detection of counterfeit components, EPRI produced several technical reports with industry guidance. "Since implementation of these guidelines, there have been very few such items found in U.S. nuclear power plants—particularly in the past 10 years," said Marc Tannenbaum, a senior project manager in EPRI's Nuclear Sector. "Existing facilities have seen less interest from counterfeiters because of the smaller market for the '70s-era components typically found in U.S. plants."

However, the global spread of manufacturing technology—most significantly in China—has increased the number and expertise of counterfeiters. Counterfeiters now employ quality-control measures to ensure that fake products appear genuine. The resurgence of U.S. nuclear construction, combined with the decline of U.S. manufacturers, will challenge nuclear builders to procure quality nuclear components. Particularly at risk are the thousands of high-demand, moderately priced, smaller parts and materials—including pumps, valves, fans, pipes, bolts, and state-of-the art electronic and digital devices—supplied by global manufacturers and their sub-vendors.

A Blueprint for Prevention

The Plant Hatch and Catawba examples prompted the NRC to issue a notice in April 2008 on the renewed need for strong preventive measures against counterfeit parts. In a 2007 speech, NRC Commissioner Dale Klein asked, "Is industry doing enough to establish more rigorous safeguards and oversight in procurement? Find quality vendors and ensure that they maintain high standards? Make quality assurance a top priority?"

In response, EPRI formed a technical advisory group to update and enhance guidance on the issue. The advisory group includes members of the industry's Nuclear Procurement Issues Committee and has worked closely with the NRC. It has conducted benchmarking programs with the DOE, the Department of Commerce, the Government-Industry Data Exchange Program, and manufacturers recognized as anti-counterfeiting experts.

EPRI used this benchmarking to develop a report (EPRI document 1019163) that recommends immediate actions to reduce risk and outlines a blueprint for enhanced prevention. Improving qualification of and communication with suppliers is key to this process. Among the questions nuclear utilities should ask suppliers are these:

- Do you dedicate resources and staff training programs to address the problem of counterfeiting?
- Can you substantiate that you are authorized by the original manufacturers to distribute items within approved distribution networks?
- How do you handle incidents of counterfeiting, and are customers notified of such incidents?
- Do you test components and raw materials critical to the design and function of the products you distribute?

Other preventive measures include educating utility procurement staff, vigilantly inspecting purchased items, enhancing capabilities to identify suspected counterfeits, and developing industry-wide online tools to effectively gather and share information about counterfeiting incidents.

Anti-counterfeiting efforts are already yielding fruit. "In late August, a supplier to nuclear plants in the United States and Canada identified a counterfeit electronic component after implementing enhanced quality controls in response to presentations at recent EPRI and industry meetings," said Tannebaum. "The incident was reported to EPRI, and pertinent information was shared with other members of the nuclear community."

For more information, contact Marc Tannenbaum, mtannenbaum@epri.com, 704.595.2609.

Better Understanding of Distribution Arc Flash Improves Worker Safety

An arc flash erupting from a distribution circuit fault can be life threatening for nearby workers. Electric utilities have long tried to prevent arc flash injuries by disabling circuit reclosing during work, by adopting practices that keep personnel at a safe distance from potential flashover points, and by issuing flame-resistant clothing. Unfortunately, the severity of an arc flash is difficult to predict because it depends on a variety of complex factors, including the worker's position relative to a fault, the duration and current level of the fault, and the arc length. No single approach to analyzing these factors has been universally accepted.

To better understand such risks, the National Electrical Safety Code (NESC) and the Occupational Safety and Health Administration (OSHA) are revising electrical safety rules, which will require utilities to perform additional analyses of arc flash hazards and could potentially make significant changes in worker protection. In 2008, EPRI launched a research project to help utilities prepare for these rule changes.

Assessing Current Models

The project's first phase has been completed, with results published in three reports. One research area evaluated methods currently used to estimate arc flash energy and provided guidance for utilities in applying these tools to choose the most suitable safety measures. Comparing results from current analytical models with data from field tests conducted by EPRI and study participants revealed some significant discrepancies.

Tests on arcing from overhead lines, for example, showed that arc lengths assumed in standards tables are unrealistically short and that in many scenarios an arc may quickly grow to several inches or even a few feet. Tests also showed that the fireball surrounding the arc tends to get pushed away from the source because of magnetic forces, especially in a phase-to-phase fault. Open-air testing to measure heat energy in arc flash exposure will be necessary to determine if and how work practices for line workers may need to be changed.

Additional testing and analysis are also needed to evaluate secondary network systems. Network protectors are of particular interest for utilities with secondary networks because fault currents often exceed 50 kiloamperes with long clearing times and because it can be difficult to de-energize the system to perform work. Project testing established that sustained arcs are possible in 480-volt network protectors and can produce a large fireball; similar tests on pad-mounted transformers, however, found no instances of sustained arcing.

Tests also showed that flame-resistant clothing may not provide sufficient protection from arc flashes, particularly if the worker is exposed to a focused fireball emitted from enclosed equipment. In 20 tests, samples of flame-resistant fabric were subjected to varying levels of incident energy (all below the fabric rating); in 75% of the tests, enough heat penetrated the samples to cause a second-degree burn.

Surveying Industry Practices

The EPRI research also studied existing and developing industry practices for analyzing and protecting workers against arc flash hazards. A formal utility survey and discussions at meetings revealed broad similarities but also specific differences in such practices. Gap distance assumptions did not vary greatly among utilities, but about half of utilities assume a line-to-ground fault for evaluating overhead hazards, while half do not. Significant differences were revealed in approaches to arc energy mitigation, with 46% of utilities reporting the ability to enable instantaneous tripping on all their feeders, while 17% reported that ability on fewer than a quarter of their feeders.

The project's second phase, now under way, will conduct tests that can help refine analytical techniques, improve worker protection, and enhance flame-resistant clothing. In particular, standard clothing tests, which have relied mainly on subjecting a fabric to radiant energy from an arc flash, will be supplemented with direct exposure to the fireball created. Additional equipment testing is also expected to provide better estimates of safe working distances.

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Antenna Array Pinpoints Problems in the Substation

The insulation on high-voltage equipment deteriorates with time, and being able to identify and replace equipment that has degraded significantly in substations is important to both economy and safety. While deterioration may result from a variety of mechanisms, a certain marker can warn of impending problems: in many cases, degradation is preceded by electrical partial discharges. But because partial discharges occur intermittently, they are notoriously difficult to detect during inspection. Hard-wired continuous monitoring is one solution, but it is expensive, typically requiring many electrical connections between monitoring equipment and individual substation components.

Early research funded by Britain's Engineering and Physical Sciences Research Council (EPSRC) and National Grid UK proved that a non-contact remote-sensing technology was technically feasible and potentially more economical for detecting partial discharges. EPRI was instrumental in forming a large, multi-utility collaborative research and demonstration project to further this work. The new approach detects the radio-frequency emissions created by partial discharges rather than measuring the discharges themselves, identifying and locating degraded insulation from analysis of the pattern of impulse emissions.

The emissions are detected by an array of four antennas mounted within the substation—usually on top of a building or trailer. Using high-speed, wide-band digitizing hardware, custom software, and computational algorithms, the technology records the radio-frequency signal, analyzes the time of flight to the antennas, and triangulates on the location of the partial discharge source. The specially designed, omni-directional disk-cone antennas have a relatively flat frequency response over the range of 100–1,000 megahertz.

Technology Demonstrations

Expanding on EPSRC's proof-of-concept work, National Grid conducted the first demonstration of the antenna array on its power delivery system and subsequently installed the equipment at three additional sites. The system's effectiveness was first corroborated in 2003, when the array detected and pinpointed a failing current transformer in a 400-kilovolt substation.

As a result of EPRI's collaborative work, the demonstrations have grown to include 13 additional pilot installations on three continents, each of which is providing valuable data to refine the system's signal analysis. The demonstration program's results led to the creation of Elimpus Ltd, a spin-off company from Strathclyde University in the UK that will provide the equipment and related services to the industry.

Disk-cone antennas on the corners of a trailer detect radio-frequency emissions that indicate the location of deteriorating substation equipment.

The antenna array's monitoring capabilities are ideal for a number of applications: helping extend asset life, investigating suspected problems, checking components that have failed catastrophically at other utilities, and monitoring background partial discharges to alert site workers to health and safety issues. Because the array requires no physical sensors or communication cables on the equipment, the technology can provide continuous nonintrusive monitoring of an entire unmanned substation, resulting in significant savings in hardware and maintenance. By enabling the diagnosis of multiple substation components using a single, central device, the array reduces the time personnel would need to spend evaluating any one device.

Future Research

Drawing on the pilot demonstrations, EPRI is developing case studies that prove the technology's effectiveness in predicting and preventing failures of substation components such as instrument transformers, power transformers, and bushings. The comparatively low cost of antenna array equipment (compared with other solutions) is expected to drive its adoption by utilities, especially given their significant investment in the equipment that this technology protects from failure.

Further research is under way on real-time signal analysis to identify or classify discharge activity and intensity levels. Future data sets of monitored signal sources will form the base criteria for estimating the seriousness of discharge activity and will serve as a guide for developing maintenance practices.

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TECHNOLOGY AT WORK

Member applications of EPRI science and technology

Engineering Fundamentals Training Prepares New Generation of Nuclear Professionals

Like other nuclear utility companies, Duke Energy provides technical orientation training to help new engineers make the transition from the classroom to hands-on work in the plant. For decades, Duke used off-site classroom training that was resource intensive and was burdensome to the students and their home organizations, requiring several weeks away from work. A reduction in new hires, resulting from industry downsizing, made the classroom approach even less cost-effective.

Now Duke and a growing list of other utilities are using EPRI's online Engineering Fundamentals Training Program to prepare new engineers for their careers in the nuclear power industry. The program consists of a series of computer-based courses and examinations that are accessed through the Institute of Nuclear Power Operations' National Academy for Nuclear Training e-Learning.

Use of these engineering fundamentals courses, packaged in discrete topic modules, avoids the cost and lost time related to off-site training and substantially reduces or eliminates the need for utilities to develop and maintain their own courses. Eight course modules are currently available:

- Basic Atomic and Nuclear Physics (1019164)
- Chemistry (1016696)
- Civil Engineering (1014968)
- Electrical Engineering (1014969)
- Heat Transfer and Fluid Flow (1016515)
- Mechanical Engineering (1012064)
- Nuclear Power Plant Materials (1014970)
- Process Control Systems (1016697)

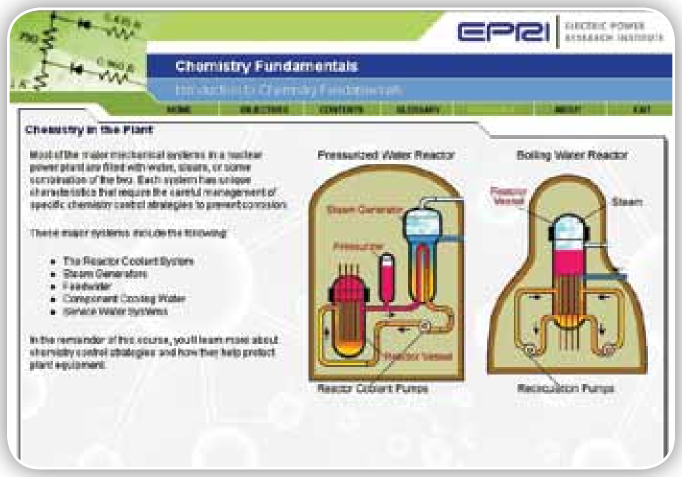
A Core Protection module will be added to the program in early 2010.

Engineers have completed about 2,250 training courses through October 2009, and EPRI continues to work with utility members to refine the content and examinations and to improve the program's effectiveness. Utilities can supplement the training with company- or site-specific information, as needed.

Developing a Better Approach

Duke had been looking for a better solution to technical orientation for some time and even tried a self-study workbook program developed by another utility. While this method eliminated off-site training, the workbooks focused on a standard engineering curriculum, offering few real-world nuclear specifics.

"We wanted to present information that was more relevant and practically applicable in a nuclear power plant," said Dr. Henry Nicholson, an engineering instructor at Duke Energy's Oconee Nuclear Station. "We also wanted to establish some consistency in the educational content for new engineers in common training programs—not only consistency within the individual utility fleet, but also within the national industry."



A course on nuclear plant chemistry is one of eight modules available in EPRI's online Engineering Fundamentals Training Program.

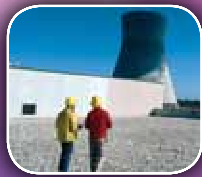
Duke and other utilities teamed with EPRI to develop a better approach. EPRI engaged utility working groups—including both engineering training specialists and subject matter experts—to develop the training modules. The working groups shared their experiences, their requirements, and their philosophies, choosing content that would expose new engineers to the full spectrum of engineering disciplines in nuclear plant operations.

"Rather than presenting an engineering topic from the perspective of the undergraduate engineering curriculum, the lessons incorporate physical, practical applications of the engineering discipline," said Nicholson. "There may be some fundamental engineering theory, such as basic electrical current laws, but there is also presentation of the applications of those engineering laws in the nuclear facility, such as overcurrent protection and breaker function."

A Wealth of Benefits

By focusing on practical issues and a range of topics, the EPRI Web-based training encourages understanding and cooperation among engineering disciplines in nuclear plants. It also standardizes orientation training and promotes a consistent knowledge base across the industry.

Through the Internet, students can access the modules and review the material when and where they choose and take the

exam when they're ready. EPRI member utilities can review and download the training materials from epri.com before logging into INPO's system.

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EPRI-NRC Collaboration Enables Revision of Pressurized Thermal Shock Regulations

The reactor pressure vessel is a critical safety-related component in nuclear power plants. Repairing or replacing this vessel in a pressurized water reactor (PWR) is not practical, yet its mechanical integrity must be conservatively demonstrated for 80 years or more of operation. Vessel embrittlement and the postulated effects of pressurized thermal shock have been of particular concern, and the U.S. Nuclear Regulatory Commission (NRC) issued a rule in the mid-1980s that limits the embrittlement allowed before additional evaluations or corrective actions are required.

One plant, Yankee Rowe, shut down prematurely in 1992, partly because of the high cost and difficulty of demonstrating pressure vessel integrity under postulated pressurized thermal shock conditions. Other plants have faced premature shutdown when it was expected they would exceed regulatory limits before reaching the end of their operating licenses.

EPRI's Materials Reliability program recognized the urgent need to address the issue with the latest knowledge and technology and developed a collaborative research program with the NRC to completely reanalyze pressurized thermal shock.

Defining the Issue

Pressure vessel embrittlement occurs during normal plant operation, when neutrons impinge on the vessel wall, reducing its strength and ductility over time. In accident scenarios where cold water is introduced into the reactor pressure vessel, rapid cooling could produce large thermal stresses that initiate cracks. During repressurization, these cracks could propagate in the embrittled vessel material, possibly breaching the vessel wall.

Although such a failure has never occurred, utilities operating older nuclear plants have found it difficult to adequately demonstrate reactor pressure vessel integrity by using the 1970s-vintage analytical assumptions in the NRC's original rule.

Some plant operators approached the problem by adopting costly strategies to reduce neutron exposure. Palisades Power Plant purchased fuel with a higher enrichment—at an increased cost of $500,000 annually—to maintain heat output while shielding bundles to protect the reactor pressure vessel from neutron impingement. Beaver Valley Power Station used hafnium suppression assemblies to reduce neutron exposure, at a cost of $1 million to $1.5 million per cycle.

Only one available alternative actually improves pressure vessel mechanical properties: an *in situ* thermal annealing heat treatment that costs $25 million to $30 million per unit.

A Complete Reanalysis

EPRI's collaborative approach was to get back to basics—to fully re-evaluate pressurized thermal shock with modern tools and knowledge and determine whether the 25-year-old rules were still reasonable or were overly conservative. The study incorporated technical advances and improved fundamental understanding in areas such as probabilistic risk assessment, fracture mechanics, thermal hydraulics, and human performance.

Researchers examined events that could initiate pressurized thermal shock, assessed their thermohydraulic severity, and applied new probabilistic fracture mechanics analyses to determine whether a range of assumed stresses were sufficient to propagate cracks through the vessel wall. Researchers ran millions of fracture mechanics analyses under a multitude of scenarios to calculate the probability of failure.

To ensure a sound, credible result, the collaboration included some 20 technical organizations, representing academia, national laboratories, utilities, vendors, contractors, the NRC, and EPRI. All parties shared results from individual research projects and provided independent technical input to one another's research.

Results

The reassessment demonstrated that pressure vessels are significantly more resistant to fracture than predicted in the original NRC rule. The research showed that the U.S. PWR fleet could operate safely through 60 years, and likely 80 years, and effectively eliminated pressurized thermal shock as a challenge to reactor pressure vessel integrity.

In response to the research findings, the NRC published a proposed revision to the rule in 2007, which is expected to become final in 2009. As a result, at least 12 nuclear plants will be able to avoid permanent shutdown, preserving about 15,000 megawatts of generating capacity.

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REPORTS & SOFTWARE

Key deliverables now available

The following is a small selection of items recently published by EPRI. To view complete lists of your company-funded research reports, updates, software, training announcements, and other program deliverables, log in at www.epri.com and look under My Research Areas.

The Legal Rights and Liabilities of Underground CO_2 Storage (1017647)

This report investigates key issues related to the transport and storage of CO_2 and provides background for future studies on managing CO_2 liability. The report provides a base of information on current regulatory practices, reviewing and analyzing the rules of local, state, and federal agencies that have or will have jurisdiction over legal and regulatory aspects of CO_2 storage. In addition, the study identifies gaps that must be addressed in important areas, such as the permitting of CO_2 injection wells, pore space ownership, methods for securing injection rights, options for liability management, and requirements for well closures and post-injection care.

Amorphous Metal Transformer: Next Steps (1017898)

Amorphous metal transformers (AMTs) were developed in the United States in the early 1980s by EPRI and General Electric Company. U.S. demand for these highly efficient units disappeared in the late 1990s with the onset of deregulation, and over 90% of global production and use of AMTs is now located in Asia. With today's concerns over energy costs and climate change, U.S. recommercialization of AMTs could make sense, helping utilities improve distribution system efficiency and reduce emissions. This white paper traces the technology's history, documents the current state of AMT product globally, discusses the Department of Energy's ruling on minimum efficiency of distribution transformers, and lays out the AMT value proposition under the current environment.

The Potential to Reduce CO_2 Emissions by Expanding End-Use Applications of Electricity (1018871)

Replacing fossil-fueled end-use technologies with more efficient electric technologies can both save energy and reduce CO_2 emissions. This report identifies and quantifies opportunities in the residential, commercial, and industrial sectors where such substitution could make a considerable difference between 2009 and 2030. Results show that the residential sector holds the greatest technical potential for energy savings and emissions reductions, and that the cumulative technical potential across all three sectors represents a 4.7% decrease in CO_2 emissions relative to the Energy Information Administration's 2030 baseline forecast. The report presents technical and realistic potential values for energy savings and CO_2 reductions by technology, region, and end-use sector.

Materials Reliability Program: Technical Bases for the Chemical Mitigation of Primary Water Stress Corrosion Cracking in Pressurized Water Reactors (MRP-263) (1019082)

Two methods of chemical mitigation are considered especially practical for reducing primary water stress corrosion cracking (PWSCC) in thick-walled components of Alloy 600: zinc injection and hydrogen optimization. This report reviews available experimental and plant data on such chemical mitigation, assesses the statistical confidence in these results, and quantifies the benefit of each mitigation technique. This information defines the technical bases for improvements in asset preservation and for potential changes to current inspection requirements for pressure boundary components susceptible to PWSCC.

Modularization of Equipment for New Nuclear Applications (1019213)

The next generation of nuclear plants is expected to take significant advantage of modular construction techniques, which can save time, improve quality, and reduce the number of construction personnel required for a project. To ensure the quality and practicality of this approach, equipment modules should be thoroughly shop-tested before installation. This report describes the results of benchmarking visits to three companies to investigate the methods used to test and inspect a module before shipment to the construction site. This work will provide a basis for specific recommendations for module applications in new commercial nuclear plant construction.

Program on Technology Innovation: Advanced Control Room Information Management Strategies (1020361)

In modern power plants, operators rely on distributed control system (DCS) graphical displays to convey the critical, moment-by-moment flow of information required to assess plant status. But while digitization has improved the reliability and accuracy of a plant's control systems, there has been little emphasis on human factors engineering. The data are there but are often not easily assimilated by the operator, the result being reduced situational awareness. This report examines opportunities to improve the interface between plant and operator, ranging from relatively low-cost solutions for existing systems to suggested design features that could be included in the next generation of DCS displays. The evaluation tools described allow engineers and designers to quantify the situational awareness quality of their systems.

WIRED IN

Perspectives on electricity

Speaking Truth *of* Power

James L. Turner *is group executive, president, and chief operating officer of U.S. Franchised Electric and Gas for Duke Energy. He serves as vice chairman of EPRI's board of directors.*

As I watch events unfold in the electric power industry these days, I keep reflecting on the prophetic words of a philosopher of our time who said, "There's something happenin' here; what it is ain't exactly clear."

So maybe Buffalo Springfield isn't exactly Immanuel Kant. But you have to admit that the steady drumbeat of buzz phrases such as "Waxman-Markey," "smart grid," "green jobs," and "nuclear renaissance" is clear evidence that the times, they are a-changin'.

You say you want a revolution? How about this for a radical idea: increasing the use of electricity is the key to enhancing our nation's energy security and independence while at the same time growing our economy and improving our country's record of environmental stewardship.

Now wait a minute, Turner. How can the sector that accounts for 40% of the CO_2 emissions in the United States today increase its importance to the U.S. economy and enhance our nation's energy security while simultaneously decreasing its contribution to our greenhouse gas emissions profile? You must be smoking something.

No, I'm not. But I am very high on the Electric Power Research Institute and its ability to help us achieve these seemingly contradictory objectives.

Why? Because EPRI is uniquely positioned to help us "speak truth of power" (if you'll excuse the slight prepositional tweak to yet another '60s reference).

Our industry faces the most comprehensive and consequential change and challenge since electrification began sweeping across the United States some eight decades ago. We need to educate policymakers, regulators, opinion leaders, and ordinary citizens alike in some fundamental truths about our business and the actions we will need to take if the contemplated changes are to become a reality.

Speaking truth of power means asking tough questions and talking honestly about the nature and magnitude of the challenges we face, being sober about our limitations—in everything from physics to human behavior—but also being open to the possibility that technological evolution (and perhaps even revolution) may offer exciting new possibilities for our old ways of doing things.

How do we meet the growing demand for electricity in a more sustainable way? Can electricity become the "fuel of choice" for our automobiles and our industrial manufacturing base? How smart can the grid really be? Can we figure out how to capture and store CO_2 from our coal plants at sufficient scale? Can intermittent wind and solar resources really replace significant amounts of baseload coal generation? Can we develop the next generation of nuclear energy—the most reliable "carbon-free" electricity—in a safe and reliable manner that is also affordable to build? Can we find ever more innovative ways to help customers use electricity more efficiently?

EPRI's commitment to research and development and technological innovation positions it to play a critical role in informing the discussion of these issues and helping policymakers understand what it will take to move us from mere wishful thinking to real solutions.

Now is the time to reaffirm our commitment to research and development and to advance our investment in technological innovation. This means we must eschew the temptation to think of R&D as a discretionary expense, to be slashed during tough economic times. It also means we need to redouble our efforts to persuade legislators and regulators to implement the ratemaking and other mechanisms necessary to stimulate such investments.

Research and development in the electricity sector will be the cornerstone of our search for the truth. It will speak to us objectively about how far we have come and how far we are from our technological, operational, and public policy goals.

Let's support EPRI in its quest to "speak truth *of* power."

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