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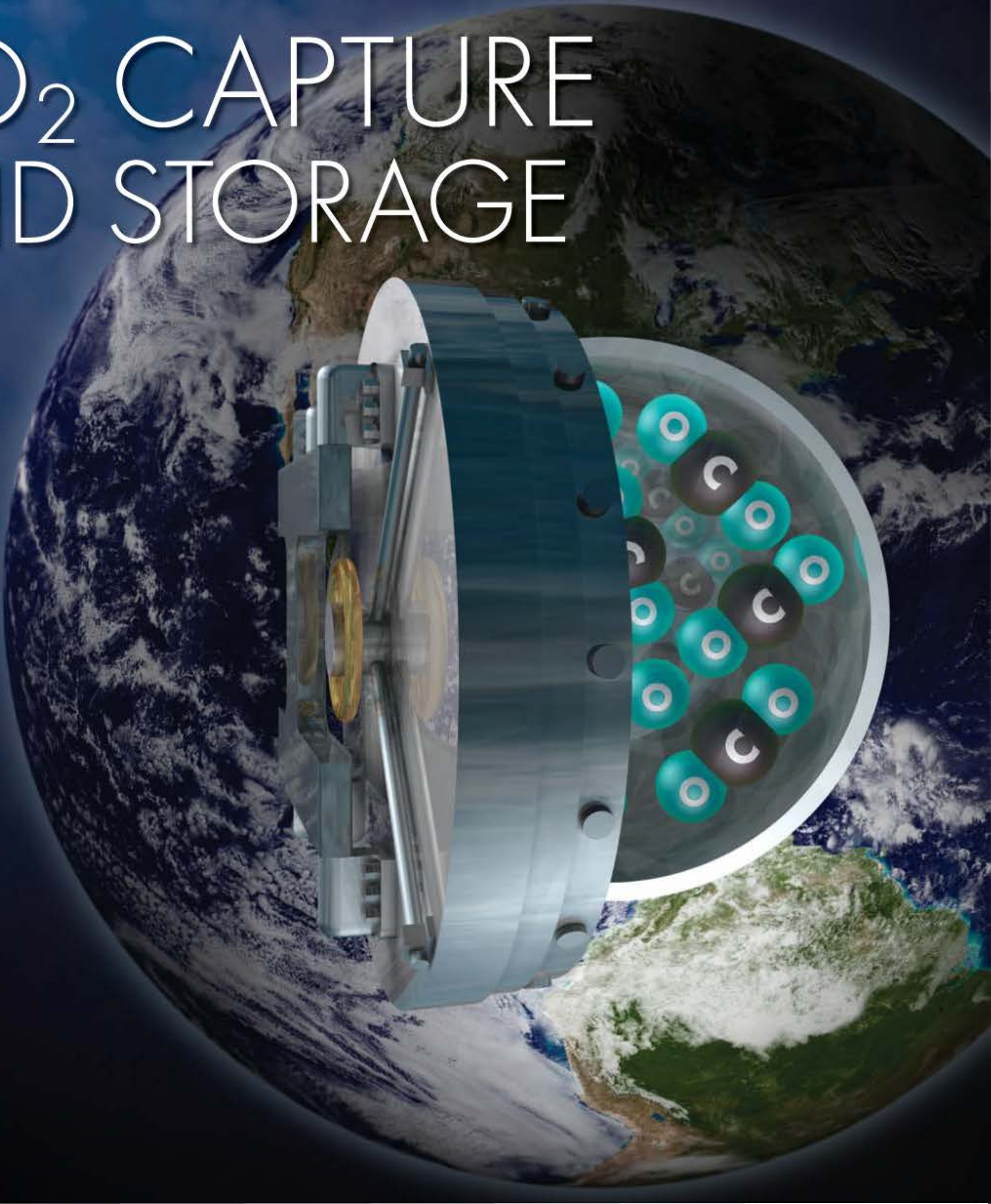
ELECTRIC POWER RESEARCH INSTITUTE

CO_2 CAPTURE AND STORAGE



The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California; Charlotte, North Carolina; and Knoxville, Tennessee, was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together members, participants, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of electricity generation, delivery, and use, including health, safety, and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents nearly 15% of EPRI's total research, development, and demonstration program.

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Editorial

CO_2 Emissions Reduction: Getting the Job Done

EPRI recently finalized the results of an assessment of technologies that have the potential for achieving significant CO_2 emissions reductions for the U.S. electric power sector within the next 25–30 years.

EPRI researchers used the U.S. government's Energy Information Agency Annual Energy Outlook 2007 as the baseline and calculated the CO_2 reductions that could potentially result from very aggressive development, demonstration, and deployment of a broad portfolio of technologies, including:

- Increasing end-use energy efficiency in homes, commercial buildings, and industry
- Boosting deployment of cost-effective large-scale renewable energy resources
- Continuing the operation of all existing nuclear generating plants and adding substantial new generation from advanced light water reactors by 2020
- Improving the efficiency of new coal-based generating plants
- Deploying CO_2 capture and storage technologies at most new coal-based generating plants by 2020
- Accelerating the wide-scale adoption of plug-in hybrid electric vehicles
- Expanding deployment of distributed energy resources, including solar photovoltaics

More details of the technical analysis, along with specific technology targets, can be found at www.epri.com.

Our analysis indicates that over the coming decades it is technically feasible for the U.S. electric power sector to first slow the increase in CO_2 emissions, then stop the increase, and ultimately reduce emissions while meeting an ever-increasing demand for reliable and affordable electricity. However, the challenges to actually achieving these reductions are daunting in their scope and complexity. It will require a decade or more of very aggressive development, demonstration, and deployment of a broad portfolio of technologies to achieve the desired goal of reducing CO_2 emissions in the electric power sector.

Nowhere are the technical challenges greater, or the stakes higher, than in the development of carbon capture and storage (CCS) technology. That is why we have devoted this issue of the *Journal* to the topic. Only CCS can reconcile the continued use of our enormous coal resources with the need to reduce CO_2 emissions. As you will see from the three feature articles, the necessary technology advances are now in view. However, a much more aggressive and accelerated development and demonstration effort is required.

With the time so short and the stakes so high, I hope you will join us in our resolve to have CCS technology ready for wide-scale commercial deployment for new coal-based generating plants entering service after 2020 and potentially for retrofitting the existing generation fleet.

Steven Specker
President and Chief Executive Officer

Contributors

WILSON RHUDY PARKES PHILLIPS DILLON VISWANATHAN

Because of the broad reach of the Institute's research on climate change, this issue of the *Journal* drew on the knowledge and expertise of a great many EPRI staff members. Prominent among these technical resources are Tom Wilson of the Environment Sector and Richard Rhudy, Jack Parkes, Jeffrey Phillips, John Wheeldon, Des Dillon, and R. Viswanathan of the Generation Sector.

Tom Wilson, manager of EPRI's Greenhouse Gas Reduction Program, came to the Institute in 1985 from an energy-environment consulting practice at ICF, Inc. For the past 18 years, he has led EPRI's research efforts to examine the potential impacts of climate change, climate and technology policy choices, possible emissions reduction investments, and corporate strategies. Wilson received a BS degree in mathematical sciences from the University of North Carolina at Chapel Hill and MS and PhD degrees in operations research from Stanford University.

Richard Rhudy is a principal project manager in the Environmental Control business area of the Generation Sector. His current research activities focus primarily on the CO_2 Capture and Storage Program, including management of EPRI's work in the DOE Regional Carbon Sequestration Partnerships. Rhudy came to EPRI from Bechtel Corporation in 1977, initially working on SO_2 control. He received a BS in chemical engineering from the University of California at Berkeley.

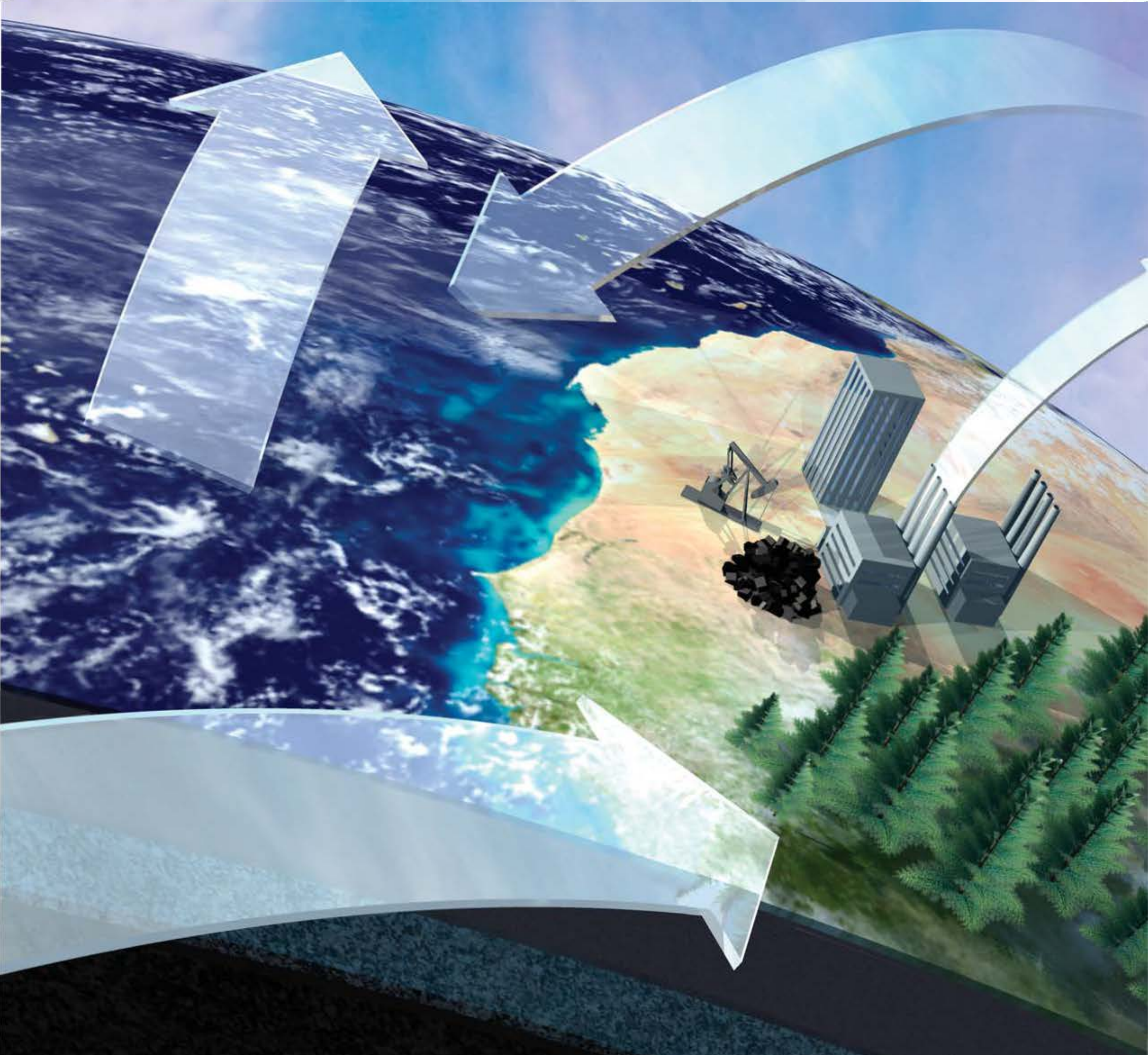
Jack Parkes has held senior management positions at EPRI, Bechtel, Ebasco, and GE involving the design, reliability, and performance of coal-based power plants and systems. In his current EPRI position, senior program manager for advanced generation, he directs the CoalFleet for Tomorrow® initiative. Parkes received a BSc from The Queens University of Belfast and an MS from Union College in New York, both in mechanical engineering. He also earned an MBA from the University of Santa Clara in California.

Jeffrey Phillips began his involvement with the Institute in graduate school, providing support to an EPRI-sponsored project as part of his PhD research. He joined EPRI's CoalFleet program in 2004 after working for 18 years on gasification and combined-cycle projects for the Royal Dutch/Shell group, Molten Metal Technology, and Fern Engineering. Phillips holds a BA in mathematics from Austin College, a BS in mechanical engineering from Washington University, and MS and PhD degrees from Stanford University, also in mechanical engineering.

John Wheeldon leads EPRI's research on combustion-based power plant technologies under the CoalFleet program. He joined the Institute in 1987 from the British Coal Corporation, where he worked on fluidized-bed combustion and gasification development projects. He has BS and MS degrees in chemical engineering from the University of Bradford (England).

Des Dillon, project manager, Advanced Coal Generation Technology, came to EPRI in 2006, having previously worked in the UK with Mitsui Babcock Energy Ltd., the National Engineering Laboratory, and Rolls–Royce. Dillon holds a BEng in design engineering from the University of Glasgow and an Industrial PhD in mechanical engineering from the University of Strathclyde.

R. Viswanathan, technical executive in the Materials and Chemistry Department, has been at EPRI since 1979. Before that, he worked for 14 years at the Westinghouse R&D Center on metallurgical applications for nuclear and high-temperature systems. Viswanathan received a BS in chemistry from Loyola College and holds three degrees in metallurgy—a BEng from the Indian Institute of Science, an ME from the University of Florida, and a PhD from Carnegie–Mellon University.



Closing the Fuel Carbon Cycle

The Story in Brief

The global carbon cycle involves constant exchange of carbon atoms between the atmosphere, land, and ocean through biological, chemical, and geological processes. This natural cycle of uptake and release of carbon is roughly in balance. However, the global industrialization of the past two centuries has released carbon to the atmosphere—mostly in the form of CO_2—that had been locked up in underground coal, oil, and natural gas deposits for millions of years. It is primarily combustion of these long-stored fossil fuels that threatens to tip the balance of the carbon cycle, leading to a substantial buildup of CO_2 in the upper atmosphere. Scientists believe that one key to stabilizing future atmospheric CO_2 concentrations will be essentially to close the fuel carbon cycle—to capture the carbon from fossil fuels before it is released to the atmosphere and return it to permanent reservoirs in the earth or oceans.

ART BY CRAIG DISKOWSKI/EDGE DESIGN. EARTH PHOTO COURTESY VISIBLE EARTH/NASA .

To address climate change, society must satisfy a growing world's demand for ample and affordable energy services while avoiding the release of increasing quantities of carbon dioxide (CO_2), the most important greenhouse gas. The technologies that underlie today's energy infrastructure are simply not up to this task. These difficulties have limited our progress toward the long-term goal of stabilizing atmospheric greenhouse gas concentrations globally "at a level that would prevent dangerous anthropogenic interference with the climate system," as called for under the United Nations Framework Convention on Climate Change (UNFCCC). They also account for the growing consensus within the science, industry, and policy realms that there is a pressing need for accelerated development and widespread deployment of a broad portfolio of advanced energy technologies.

Because coal, natural gas, and oil remain globally abundant and relatively inexpensive, society must learn how to extract energy from these resources—stored underground for millions of years—without reintroducing fuel carbon to the global carbon cycle. Lower-cost technologies for preventing CO_2 from reaching the atmosphere could reduce the costs of climate stabilization by trillions of dollars over the course of the twenty-first century. But the challenge is not exclusively technical: the complex economic, environmental, institutional, and social challenges associated with closing the fuel carbon loop on a massive scale and in a timely manner are only beginning to be appreciated.

Around the Cycle

Carbon is not among the top 10 most abundant elements on earth, but it is certainly among the most important. Complex carbon-containing compounds underlie all known life forms, CO_2 in the upper atmosphere helps maintain global surface temperatures within a habitable range, and carbon fixation by plants produces the oxygen upon which animal life depends. In addition, fossil fuels are currently used to meet most of the world's energy needs.

Carbon's roles in enabling life, regulating climate, supplying oxygen, and generating power are inextricably linked through the global carbon cycle. Scientific research over the past three decades has greatly advanced understanding of the cycle's macro-scale attributes and mechanisms as carbon moves through natural environments. These movements are tracked in gigatons (Gt), where 1 Gt is equivalent to 1 billion metric tons—the mass equivalent of about 2740 Empire State Buildings.

Four main reservoirs of carbon exist. From smallest to largest, they are the atmosphere, land, ocean, and deep underground. Cycling among the reservoirs occurs on several distinct timeframes. Over periods ranging from days to thousands of years, biological, chemical, and physical processes actively circulate organic carbon through atmospheric, terrestrial, and oceanic environments. Over millions of years, geological processes cycle organic and inorganic carbon through soils, rocks, minerals, and other substances.

About 2996 Gt of carbon dioxide ($GtCO_2$) are stored in the atmosphere. A small percentage of this total resides as CO_2 in the upper atmosphere, where individual molecules may remain for a century or more. The majority resides closer to earth, where it is available for circulation among other components of the carbon cycle. Annually, the most active exchanges occur at the land-atmosphere and atmosphere-ocean interfaces. These natural fluctuations are both massive and approximately in balance, with annual fluxes (exchange volumes) on the order of 440 $GtCO_2$ and 330 $GtCO_2$, respectively.

Between land and atmosphere, the most active cycling processes are photosynthesis, respiration, and decomposition. Plants remove CO_2 from the atmosphere to create biomass, while plants, animals, and soil microorganisms transform the carbon stored in living and decomposing organic matter back into CO_2. Current knowledge indicates that terrestrial environments today represent a net sink of about 7 $GtCO_2$ per year, and that more than 7300 $GtCO_2$ are stored as terrestrial biomass in the form of roots, compost, leaf litter, evergreen foliage, branches, trunks, and fallen trees.

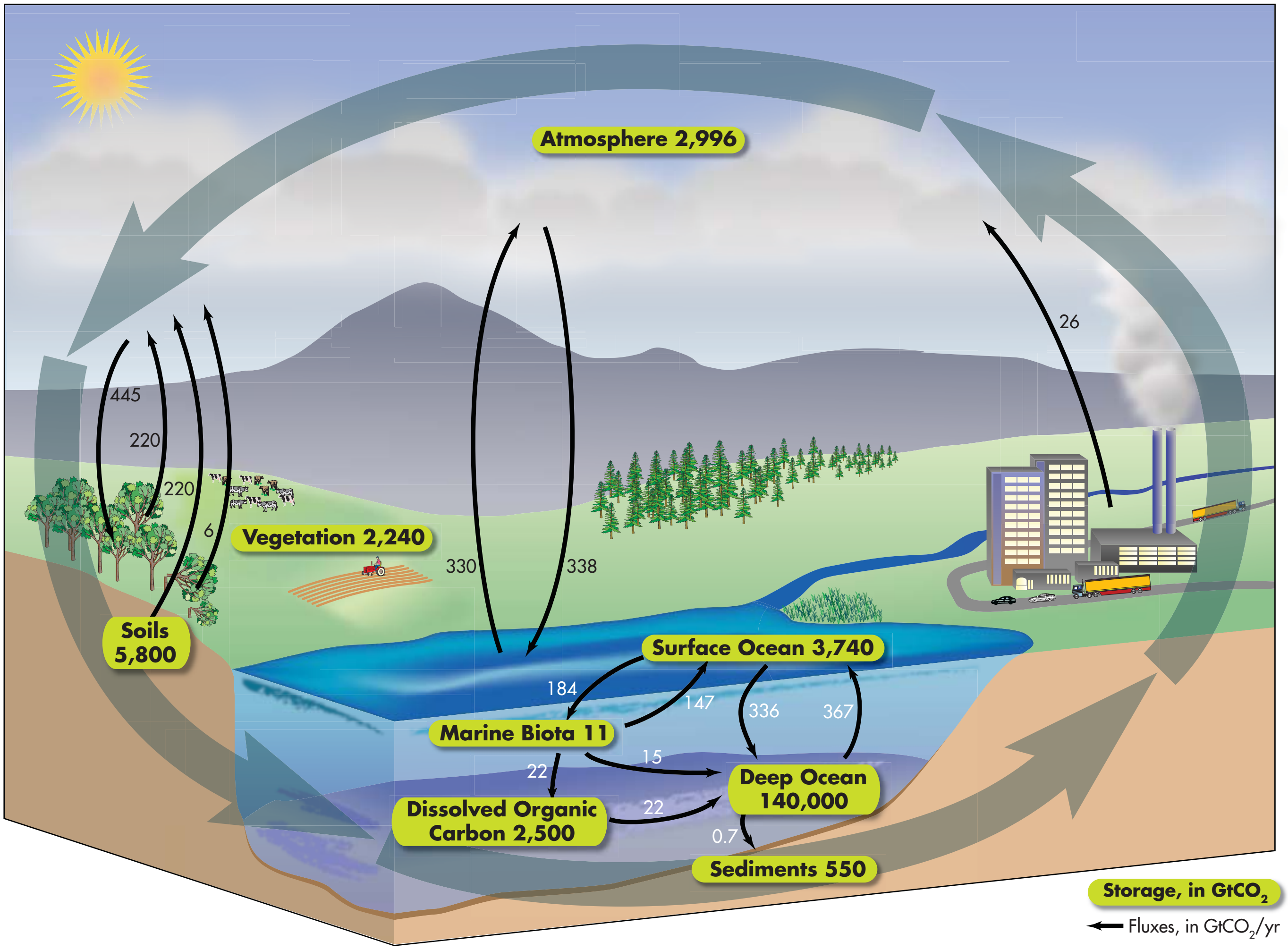
Between atmosphere and ocean, chemical and physical mechanisms account for the majority of active CO_2 exchange. Colder surface waters generally absorb more CO_2, while warmer regions release more to the atmosphere. Large-scale "conveyor belt" circulations transfer CO_2 to the deep ocean when cold water sinks, and they return stored CO_2 to the atmosphere in upwelling regions such as the tropical oceans. According to current estimates, about 95% of the almost 150,000 $GtCO_2$ stored in the ocean lies in deeper waters. Unlike on land, active biological storage of carbon is limited in the ocean because most photosynthetic microbes there are rapidly consumed by higher organisms.

Carbon cycling processes occurring over geological timeframes include weathering, sedimentation, and plate tectonics. Fossil fuels form when sedimentary deposits of organic and inorganic carbon are exposed to intense heat and pressure in the earth's crust over hundreds of millions of years. Carbonate minerals such as limestone evolve on similar timeframes from oceanic deposits of microskeletons and other substances. Subduction of ocean crust transfers carbon-based materials deep underground, while CO_2 releases during volcanic eruptions naturally return stored carbon to active circulation. Annual fluxes attributable to these geological processes are relatively small: on average, only about 0.7 $GtCO_2$ per year flow into long-term storage, and less than half this amount is vented to the atmosphere.

The Human Factor

From a climate perspective, the most critical attribute of the carbon cycle is the concentration of CO_2 in the atmosphere. It has increased from a preindustrial level of about 275 parts per million (ppm) to more than 380 ppm today.

At any given time, the atmospheric CO_2



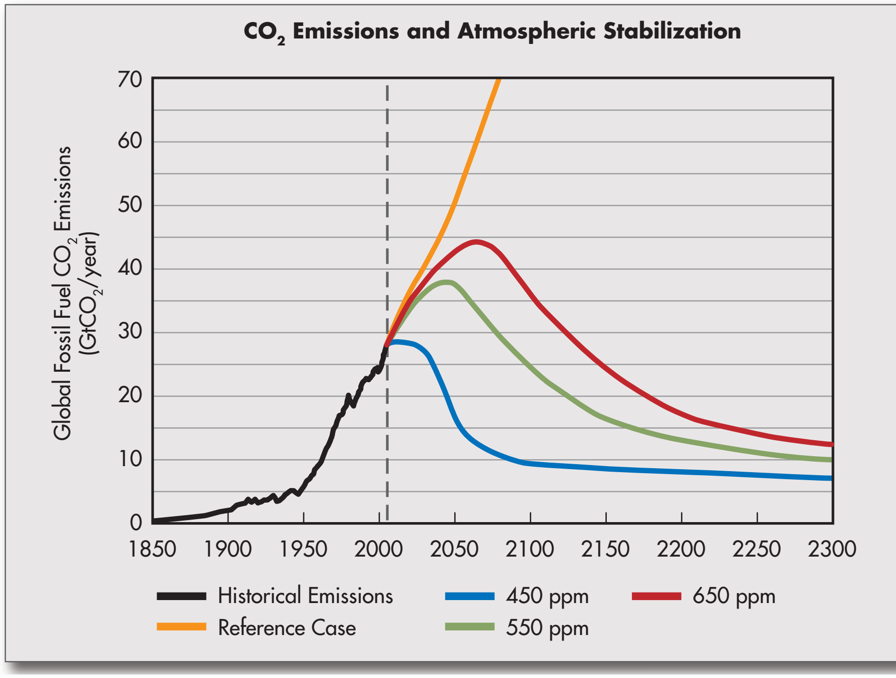
The global carbon cycle—the constant exchange of carbon atoms between the atmosphere, land, plants, and ocean—normally controls the concentration of CO_2 in the atmosphere, maintaining a balance that is fundamental to regulating earth's climate. The large-scale combustion of fossil fuels over the last century has begun to threaten this balance, with power plants, industrial processes, automobiles, and other anthropogenic sources currently adding about 26 Gt of CO_2 to the atmosphere annually. Substantially reducing such man-made emissions is seen as crucial to limiting concentrations and consequent global temperature increases over the coming centuries.

concentration depends on the status of biogeochemical mechanisms operating at different paces and scales. As has been the case for centuries, the carbon fluxes attributable to human activities such as deforestation and farming are small relative to the natural, large-scale, active carbon fluxes. Currently, land-use change contributes about 6 $GtCO_2$ in annual emissions, compared with the average uptake and release of about 440 $GtCO_2$ by terrestrial vegetation. By contrast, accelerating rates of fossil fuel extraction and use since the onset of the Industrial Revolution have far exceeded those from the natural geological cycle. At present, fossil fuel combustion annually liberates about 26 $GtCO_2$ from geologic storage—more than 70 times the average amount released by volcanoes.

Even though annual anthropogenic emissions are dwarfed by natural, active fluxes occurring at the ocean-atmosphere-land interfaces, they have added a new dimension to the carbon cycle's natural balance. About half of the anthropogenic loading attributable to land use change and fossil fuel combustion is ending up in the upper atmosphere. The rest is absorbed by the oceans and terrestrial ecosystems, but the relative magnitudes of uptake and feedback mechanisms are uncertain.

Once in the atmosphere, individual CO_2 molecules may remain there for well over a century. This means that current atmospheric CO_2 levels reflect cumulative human emissions since the beginning of the nineteenth century, and that stabilizing concentrations poses a very different challenge than simply stabilizing annual emissions. Even if annual emissions are held constant at current levels, concentrations will climb steadily. The amount of anthropogenic CO_2 entering the atmosphere each year will have to peak before 2100 and then decline continually for centuries just to prevent concentrations from exceeding twice the current level. More-stringent stabilization targets imply an earlier peak and a more rapid decline in annual emissions.

In light of these realities, stabilizing atmospheric CO_2 concentrations will require that we pursue as many options as possible, from expanded deployment of low- and non-emitting generation technologies to the development of complex engineered systems for carbon capture and long-term storage. Technology developers are now pursuing carbon capture and storage systems for integration within designs for the next generation of fossil fuel plants and possibly for retrofit application to existing point sources.



While near-term climate policies typically target certain percentage reductions in carbon emissions, the longer-term goal is stabilization of atmospheric concentrations of CO_2 at a specified level, such as 550 parts per million (ppm). Achieving stabilization will require the widespread deployment of truly advanced low- and non-emitting generation technologies that will stop the growth of global emissions in the next 50 years and drive them toward zero in the coming centuries.

Preventive Options

Any specific climate stabilization target defines a global emissions budget—the total amount attributable to human activities that may be released within a given timeframe. To achieve stabilization of atmospheric CO_2 concentrations below 450 to 650 ppm, current research suggests an emissions budget of no more than approximately 1760 to 3820 $GtCO_2$, respectively, over the course of this century. Projections of future carbon emissions vary widely, depending on assumptions regarding economic activity, population growth, technological progress, technology penetration, and policy implementation. Some estimates suggest that unless substantive action is taken to address climate change, annual carbon emissions could grow to more than three times the current level by 2100, while cumulative emissions could total more than 5400 $GtCO_2$ during the twenty-first century.

It's clear that reducing future carbon emissions by hundreds of gigatons or more will require major changes to the world's energy system. Numerous studies have concluded that there is no single technology solution. Certainly, an effective global carbon management portfolio will include carbon-free nuclear and renewable supply options, carbon-neutral bioenergy options, hydrogen-based systems, and highly efficient transmission, distribution, and end-use technologies across the electricity, heating fuel, and transportation fuel sectors. Practices for switching to less-carbon-intensive fossil fuels—changing from coal to natural gas, for example—will also be important, along with advanced combustion technologies that convert more of the chemical energy found in coal, natural gas, and oil into useful energy.

Because most studies anticipate substantial increases in fossil fuel consumption in coming decades as societies worldwide seek to maintain and elevate living standards, technologies for preventing fuel carbon from reaching the atmosphere will be essential. Two major options exist, one relying on human intervention in biological processes and the other based on engineered systems.

Biological capture and sequestration involves enhancement of naturally occurring CO_2 uptake and storage mechanisms, rather than control of emissions from specific sources. Given the huge scale of the carbon cycle's reservoirs and annual fluxes, methods for increasing storage in forests, soils, or the oceans have significant potential for offsetting energy-related emissions. Forestry-based sequestration projects—including efforts to protect existing forests from deforestation, to enhance the storage capacity of managed timberlands, and to plant new forests—are already being pursued as a relatively inexpensive approach for offsetting anthropogenic emissions. Projects to increase storage in soils by converting agricultural lands from standard to no-till cultivation offer similar opportunities. Oceanic fertilization, which involves the surface application of iron-rich compounds or other nutrients to stimulate CO_2 uptake by phytoplankton, is being researched by several private companies.

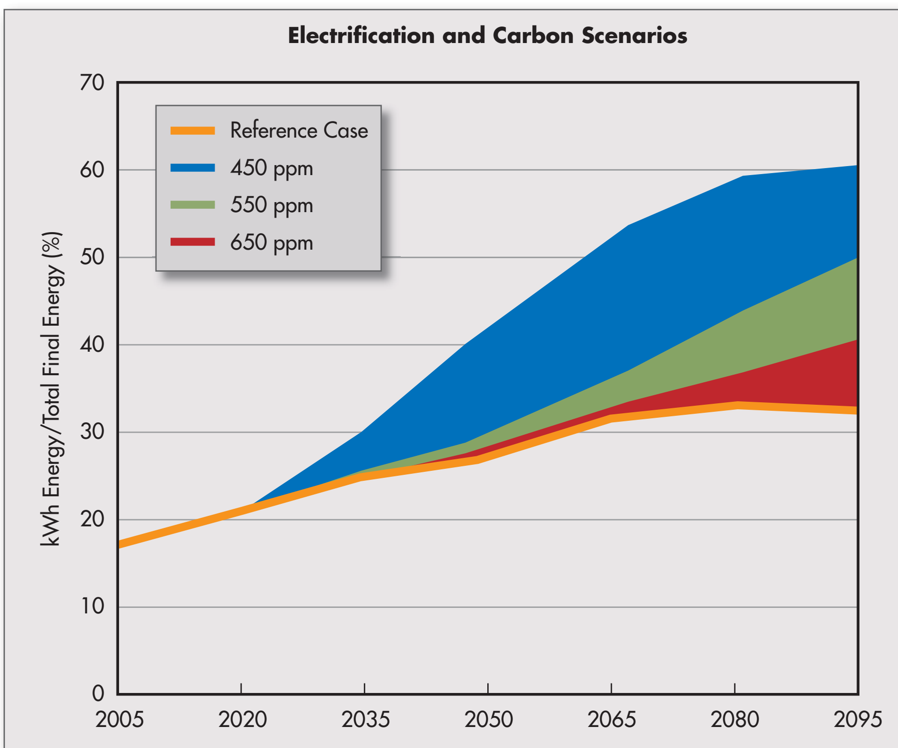
Unfortunately, these existing and emerging sequestration approaches share a common limitation: The overwhelming majority of the carbon in terrestrial and oceanic biomass remains available for active circulation over timescales ranging from days to years to decades, with only a small percentage entering long-term storage. In contrast, engineered approaches that involve direct carbon capture prior to, during, or after fossil fuel combustion include conveyance of captured CO_2 to reservoirs for long-term chemical or physical isolation from the atmosphere. Such integrated capture and storage systems are needed as an industrial-scale response to the global, intergenerational climate challenge.

An Integrative Approach

Integrated carbon capture and storage (CCS) systems bring together multiple technologies to limit the release of CO_2 to the atmosphere from fossil power plants and other industrial facilities. The potential for these systems to reduce the carbon footprint of the electricity sector and other industries is extremely large.

In 2000, more than 8100 facilities that release over 99,000 tCO_2/yr were documented worldwide; these existing power plants, natural gas processing facilities, cement plants, refineries, steel mills, and other large point sources were collectively contributing over 60% of the total anthropogenic loading. Coal-fired power plants dominate the list of the top 500 CO_2 emitters, and major additions to fossil generating capacity are projected over the next two decades, both to replace aging and less-efficient units and to meet growing electricity demands. Even the most-advanced central-station fossil plants will represent major emission sources unless they incorporate integrated CCS systems.

"Capture and storage innovations will certainly be critical to the continued use of fossil fuels for electric generation while limiting CO_2 emissions," says Tom Wilson, technical executive in EPRI's Environment Sector. "But in a carbon-constrained future, their influence will extend even more broadly: large amounts of low-emitting electricity will likely displace many direct uses of fossil fuels in the building, process heating, and transport sectors, transforming fossil-generated electricity from a major source of emissions to a major source of emission reductions across the economy."



A shift from direct consumption of fossil fuels to electric end uses is a key strategy for stabilizing atmospheric carbon concentrations, because the vast majority of low- or non-emitting energy technologies are associated with electricity. Greater electrification of industrial processes and residential and commercial heating could expedite progress toward stabilization, and successful electrification of the transportation sector—e.g., with widespread use of plug-in hybrid electric vehicles—would have an even greater effect.

The main elements in an end-to-end CCS system are capture, transport, storage, measurement, monitoring, and verification. Experience with large-scale, integrated CCS systems is limited at best. Some component technologies are in mature commercial use around the world, and others are in various stages of research, development, demonstration, and early deployment. These technologies, outlined briefly here, are explained and evaluated in greater detail later in this issue.

Capture options include postcombustion, oxyfuel-combustion, and precombustion systems. Postcombustion capture is applicable to conventional and advanced power plants firing pulverized coal, natural gas, and oil, as well as to existing and emerging fluidized-bed technologies; postcombustion systems typically employ solvents to remove CO_2 from a plant's flue gas, which contains relatively low CO_2 concentrations. In oxyfuel systems, pulverized coal is burned in high-purity oxygen rather than regular air, yielding flue gas with high CO_2 concentrations amenable to direct capture. Precombustion capture is applicable to integrated gasification–combined-cycle (IGCC) plants, which transform coal or other fuels into synthesis gas (syngas) containing high concentrations of hydrogen and, with an additional processing step, CO_2; the CO_2 is then stripped from the syngas before combustion. None of these technologies has been commercialized for application at power plant scale.

In contrast, CO_2 transport by pipeline is a mature technology applied largely in enhanced fuel recovery and industrial CO_2 markets, with about 3000 miles (4800 km) of dedicated pipeline in operation in the United States. Shipping of CO_2 via tanker or rail also occurs on a small scale, in a manner analogous to that for liquid fuel transport.

Several options exist for long-term storage of captured CO_2, including injection into onshore and offshore geological formations and delivery to deep ocean waters. Geological storage involves injection of CO_2 into permeable formations covered by layers of dense, solid materials—known as caprocks—that prevent leakage back to the surface. For ocean storage, one approach is based on injection of gaseous or liquid CO_2 at depths below about half a mile (0.8 km), where it would rapidly dissolve into the water column. A second option involves delivery of liquid CO_2 to depths below two miles (3.2 km), where CO_2 is denser than water and would pool on the ocean floor. Uncertainties over cost and environmental issues have substantially reduced interest in ocean storage technologies, and development has not yet progressed to the pilot stage. Returning fuel carbon to reservoirs deep underground is currently viewed as the most promising storage option, largely because such injection is routinely applied today for enhanced resource recovery by the oil and gas industries and because potentially suitable geologic storage sites are numerous, voluminous, and geographically dispersed.

Current knowledge indicates that properly sited, engineered, and managed geological reservoirs are likely to retain more than 99% of stored CO_2 for more than 1000 years. CO_2 release from oceanic storage is depth-dependent, with retention estimated at 65–100% after a century and 30–85% after 500 years. While these projections are encouraging, measurement, monitoring, and verification (MMV) methods will be required to ensure the long-term efficacy of CO_2 storage. Commercially available technologies offer relevant capabilities for evaluating storage sites, identifying and mitigating possible pathways for CO_2 migration and leakage, monitoring stored carbon, and verifying permanence, but more-sensitive techniques may also be needed.

Big Challenges

Although existing capture, transport, storage, and MMV technologies can be cobbled together to create an end-to-end CCS system, current applications are at a very small scale relative to the management of CO_2 emissions from power plants and other industrial sources in the carbon-constrained future. Moreover, from a climate mitigation perspective, many of these individual components represent precommercial or first-generation technologies. Fully integrated, industrial-scale CCS systems that are economically viable, environmentally sound, and publicly acceptable for site-specific applications are even further from commercial maturity.

The world's largest integrated CCS system designed for climate mitigation is installed on an offshore platform at a natural gas processing facility off the coast of Norway. Since 1996, CO_2 stripped from fuel using an amine-based capture system has been injected under compression into a saline aquifer about 0.6 mile (1 km) beneath the North Sea, and seismic imaging techniques have been applied to monitor its presence and movement deep underground. Approximately 990,000 tCO_2/yr are being captured and stored in this project.

By contrast, an end-to-end CCS system integrated with a new 600-MW coal-fired plant will have to prevent the release of around four times as much fuel carbon each year, and it will have to operate reliably over a 50-year project lifetime. Further, numerous analyses conclude that economically efficient approaches for stabilizing climate during the course of the twenty-first century will require deployment of hundreds to thousands of such CCS systems across the world, with significant market penetration beginning around 2020. Returning hundreds to thousands of gigatons of fuel carbon to permanent storage represents an enormous undertaking; some compare it to the effort required to deploy the infrastructure used today to extract, transport, and process fossil fuels and convert them into useful energy.

To address the economic, environmental, and social barriers associated with the scale-up and widespread application of CCS systems, EPRI is pursuing research, technology development, and demonstration activities in collaboration with energy companies, equipment manufacturers, government agencies and laboratories, universities, and nongovernmental organizations (NGOs). Reducing the costs of these systems and their impact on energy conversion efficiency is critical because applying today's technologies is projected to increase the cost of electricity dramatically. For example, postcombustion capture using currently available technology could add over 50% to the cost of electricity and reduce a plant's net output by 30%. EPRI is devoting particular attention to accelerating progress on CO_2 capture for pulverized coal (PC) plants, where the potential for dramatic improvement appears high. In one project, a 5-MW demonstration of an innovative postcombustion capture technology that may dramatically reduce energy losses and electricity cost impacts is scheduled to begin operation by late 2007 at a power plant in Wisconsin (see "The Challenge of Carbon Capture," page 14).

"Because PC plants—the workhorse of the U.S. and global generating fleets and a popular choice for capacity additions—represent the largest point sources of CO_2 emissions, driving down postcombustion capture costs is essential for reducing the societal costs of achieving climate policy goals," says Wilson. "Retrofit applications of postcombustion capture could become very important if tight constraints on emissions are imposed in the near term, but the real value of CCS will be for application in plants that are not yet built. Companies that start planning now for future CCS retrofitting—working it into plant designs, siting strategies, and asset management plans even before economical CCS technologies exist—could reap long-term economic benefits."

Commercial readiness for CCS technol-

CCS Component	CCS Technology	Maturity			
		Research Phase	Demonstration Phase	Economically Feasible Under Specific Conditions	Mature Market
Capture	Postcombustion			•	
	Precombustion			•	
	Oxyfuel combustion		•		
	Industrial separation (i.e., for ammonia production)				•
Transportation	Pipeline				•
	Shipping			•	
Geological storage	Enhanced oil recovery				•
	Depleted gas or oil fields			•	
	Deep saline formations			•	
	Deep unmineable coal seams		•		
	Basalt formations, oil shales, salt caverns	•			
Ocean storage	Deep dissolution	•			
	Pooling on sea floor	•			
Mineral carbonation	Natural silicate minerals	•			
	Waste materials		•		
Measurement, monitoring, and verification	Monitoring of injection well integrity				•
	Modeling/imaging of underground CO_2 migration			•	
	Measurement of stored CO_2 volumes		•		
	Groundwater/surface leak detection				•

Integrated carbon capture and control systems will be made up of a number of individual technology components that are currently in different stages of development. Specific pre- and postcombustion capture technologies are now nearing commercial readiness, as are several geological storage technologies. Measurement, monitoring, and verification technologies will also be required, and advanced techniques are now under development. (Sources: IPCC, EPRI)

ogy will depend on continued deployment of pre-commercial systems, positive operating experiences, and steady advances over the next decade. These things simply will not happen unless there is a substantial, worldwide increase in funding for research, development, and demonstration activities. And once the technology has been demonstrated, a handful of power plants around the world must agree to bear the "first-of-a-kind engineering" (FOAKE) cost burdens for deploying the first commercial integrated CCS systems. There are significant hurdles associated with the initial deployment of new capture technologies and the injection of CO_2 into various types of storage reservoirs. The challenge must be overcome quickly.

Because of the high cost and difficult-to-anticipate practical aspects of first-generation systems, early technology adoption often must be encouraged via government support for FOAKE costs, by vendors agreeing to subsidize or defray these costs over subsequent deployments, and by other public-private investments. The U.S. Energy Policy Act of 2005, for example,

Nontechnical Issues: Potential Show-Stoppers

Although some of the technologies involved in carbon dioxide capture and storage (CCS) are well established and others are actively being developed and demonstrated, the main barriers to their widespread deployment may turn out to be nontechnical. Numerous issues—including regulation, liability, risk perception, and public acceptance—need to be resolved before CCS can be applied on the massive scale required to affect atmospheric concentrations and potential climate change.

"Such nontechnical issues are likely to be a key limiting factor in deployment of carbon capture and storage technology," says Bryan Hannegan, vice president of EPRI's Environment Sector. "To make a real difference, fundamentally new approaches will have to be applied on a very large scale. In cases like permanent CO_2 storage, where there are few precedents to draw from, effective regulations can be extremely difficult to formulate, even before the many conflicting stakeholder concerns are considered."

These issues typically include difficult questions of timing. In particular, the electric power industry faces a classic chicken-or-egg problem in deciding what investments to make prior to enactment of regulations related to CO_2 emissions. While many electric power industry executives believe that emissions regulations are inevitable, there is little consensus on their likely form, timetable, or stringency. Justifying investments today that add costs but would yield significant savings under only some of the proposed future climate policies is a complex and contentious business.

Regulatory Uncertainties

The most basic question, of course, is what limits are likely to be put on CO_2 emissions at the national level. Various proposals for mandatory controls have been made in Congress in recent years, but none has gained much traction in the shadow of the war in Iraq and other pressing geopolitical issues. Renewed interest in CO_2 control legislation has already surfaced in the new Congress, however, and new pledges of partisan cooperation signal an increased likelihood of passage. In any case, federal action, incentives, and rulemaking are likely to be informed by the approaches and outcomes of regional programs, such as the Regional Greenhouse Gas Initiative in the Northeast, and state measures, such as California's ambitious emissions reduction program.

Meanwhile, regulatory dispute is already brewing over whether underground injection of CO_2 should be controlled by the federal Environmental Protection Agency or by state agencies. Some states have already begun regulating the experimental wells used to conduct CCS research, and in July 2006, EPA announced it would also begin issuing permits (called Underground Injection Control permits) for such wells under authority provided by the Safe Drinking Water Act. Tentatively, EPA has classified the experimental projects as Class V wells, putting them in the same category as storm drain runoff and agricultural waste. The agency warned, however, that this classification for the wells might change "if and when, in the future, they begin to sequester CO_2 for permanent storage" or if they begin functioning as commercial operations rather than for R&D purposes only.

Reclassification of CO_2 injection wells could have a profound effect on their cost and the difficulty of obtaining permits. In particular, regarding them as Class I wells—hazardous waste wells—might make geologic storage prohibitively expensive. Alternatively, EPA might create a special new classification for CO_2 storage wells. Whether any new EPA classification would create conflict with state regulations remains to be seen.

Legal Issues

A related legal issue involves uncertainty over the long-term liability associated with geologic CO_2 storage. The very purpose of such stor-

provides a range of incentives aimed at speeding initial deployment of advanced coal technologies, renewables, and new nuclear plants.

Down the road, government/industry partnerships will likely be required to get early CCS systems installed, proven, and improved. In the meantime, substantial public and private funding commitments, tax credits, and other types of incentives are needed to adequately fund the multidisciplinary research, development, and demonstration activities required to ready CCS technology for commercial application.

Today, utility engineers, financial analysts, and capacity planners are being challenged to prepare for an extremely uncertain future as they evaluate capital investment decisions on assets having a lifetime of 50 years or more. Climate and energy policy, technological advances, resource constraints, market forces, and other contingencies are what will determine the future cost-competitiveness of current technology choices.

"Increasingly, companies are considering CCS in near-term capacity planning and plant engineering decisions to begin preparing for a retrofit decision that might not make sense for 20 years," notes Wilson. "Capacity investments that leave open the option to capture carbon emissions in the future—and make it easier to install a CCS system when and if it makes sense—are currently a topic of active study."

Gaining Acceptance

The environmental and social obstacles associated with widespread deployment of integrated CCS systems are at least as formidable as the economic ones. Public perceptions, regulatory and permitting quesage—to sequester CO_2 for hundreds to thousands of years—inherently raises unprecedented questions about who will be responsible for monitoring the gas underground and ensuring the safety of the site over such a long period. "Over even a century, the plot of land over a storage site may change hands several times in the course of normal commerce," Hannegan points out. "In some cases, the original owner of the land—or of the CO_2—may no longer even be in business. Who holds the legal responsibility for leaks or other problems in such cases?" A similar problem surfaced in the 1970s, when a number of utility companies discovered that they had inherited potentially toxic coal tar wastes produced and buried by local manufactured-gas companies as early as the 1880s; in those cases, the utilities were assigned a substantial degree of responsibility in the site remediation.

Several potential ways to handle the large, enduring legal responsibility for stored CO_2 have been suggested, although no consensus has been reached on which might be the most suitable. A federal cap on liability might be imposed, for example, as in the case of nuclear power. Alternatively, states might accept some responsibility or utilities might establish an insurance pool. In any case, considerable legislative and judicial review of such liability issues seems likely, and the review process itself may delay the time when utilities become willing to adopt CCS as commercially viable. "Regulatory and legal risks could become real showstoppers to widespread use of geologic CO_2 storage," says Richard Rhudy, principal project manager. "EPRI has conducted studies to help our members better understand the nature of the liability issue."

Risks and Perceptions

Underlying the regulatory and legal concerns are the physical risks posed by the presence of large quantities of CO_2 kept in geologic storage over long periods of time. The International Energy Agency Greenhouse Gas Program, BP, and EPRI held a workshop in 2004 to assess various potential leakage mechanisms and propose steps that could be taken to prevent or mitigate them. On the basis of experience with enhanced oil recovery (EOR), the risk of leaks was concluded to be low, although concern was expressed that better methods are needed to model and predict leakage. According to a special report on CCS by the Intergovernmental Panel on Climate Change (IPCC), with an appropriate monitoring system in place, the risks of geologic storage "would be comparable to the risks of current activities, such as natural gas storage, EOR, and deep underground disposal of acid gas."

Whether this level of risk would be acceptable to the public, however, is another matter. Currently, public awareness of efforts to capture and store CO_2 is extremely limited. According to a public opinion survey conducted by the Laboratory for Energy and the Environment at the Massachusetts Institute of Technology in 2004, climate change is not a pressing concern for the majority of the public, and only 3.9% of people surveyed had heard or read about carbon capture and storage in the preceding year. While the public's interest in the issue has increased substantially in the last several years, climate still appears to rank well below such concerns as terrorism, health care, the economy, and unemployment. Public understanding of approaches to mitigating climate change is even lower.

The MIT study concluded that, because of this lack of knowledge, public opinion will have only limited influence on the early stages of CCS policy development. On the other hand, local opposition may become significant as specific storage sites are chosen—a manifestation of the NIMBY (not in my backyard) effect. "In the early stages of development, local residents will be asked to take a cost for the global good," according to a report on the study. "There will be diffuse benefits and concentrated costs, a situation where opposition is traditionally very effective."

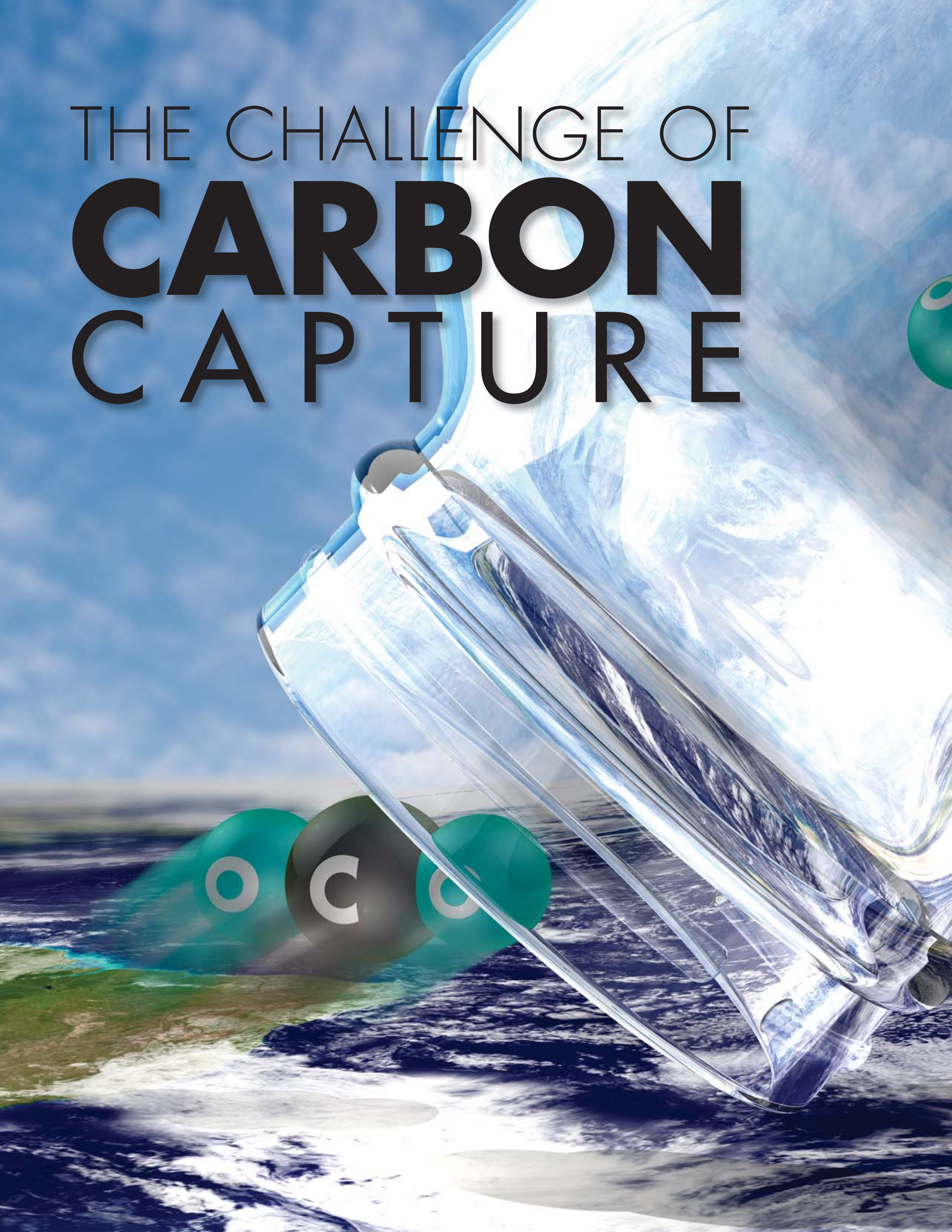
tions, and legal risks are just a start. The large-scale infrastructure required for conveying captured CO_2 to storage sites may face siting obstacles as well. And the potential for physical leakage of CO_2 from storage reservoirs raises a number of issues, including possible ecosystem impacts and risks to human health and safety.

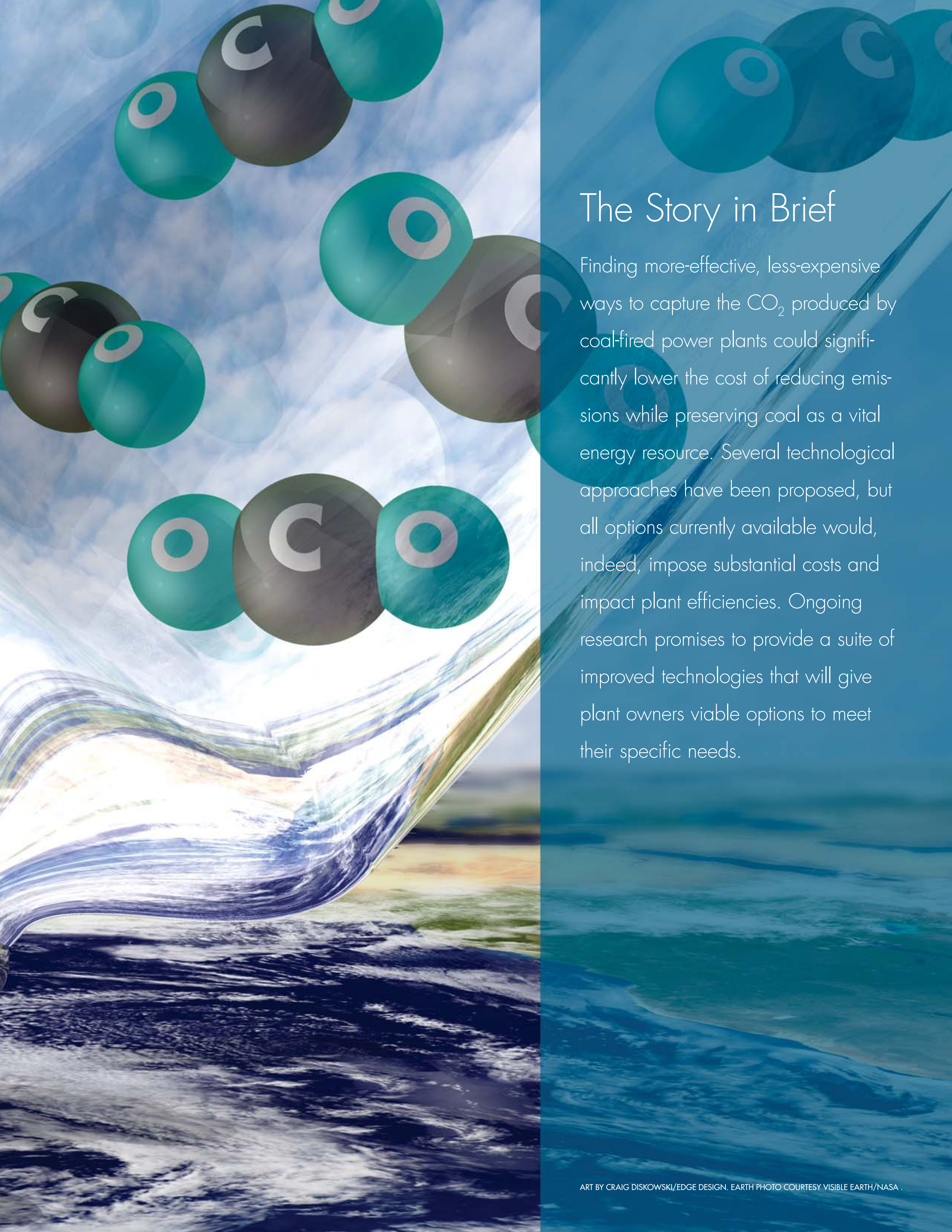
EPRI is actively working with the scientific community, regulatory agencies, NGOs, and other stakeholders to understand and mitigate these issues and impacts, which pose technical, economic, and legal risks that may lead to significant increases in MMV requirements and in the cost of locating, building, and operating integrated CCS systems. Ongoing research and demonstration projects in the United States and elsewhere are thus critical for gaining experience with integrated systems and individual components, as well as for addressing cost-benefit tradeoffs. Ultimately, public attitudes—toward capture and storage, other carbon management options, and climate change itself—will have the greatest influence on the role of integrated CCS systems in meeting societal objectives.

"Looking back on the history of advanced energy technologies, the incubation period between initial demonstration at specific sites and commercial maturity across a range of applications has often been measured in decades," says Wilson. "For carbon capture and storage, accelerating the process won't be easy, but the potential benefits are huge."

This article was written by Christopher R. Powicki. Background information was provided by Tom Wilson (twilson@epri.com).

THE CHALLENGE OF CARBON CAPTURE





The Story in Brief

Finding more-effective, less-expensive ways to capture the CO_2 produced by coal-fired power plants could significantly lower the cost of reducing emissions while preserving coal as a vital energy resource. Several technological approaches have been proposed, but all options currently available would, indeed, impose substantial costs and impact plant efficiencies. Ongoing research promises to provide a suite of improved technologies that will give plant owners viable options to meet their specific needs.

ART BY CRAIG DISKOWSKI/EDGE DESIGN. EARTH PHOTO COURTESY VISIBLE EARTH/NASA .

The most expensive part of the overall carbon capture and storage (CCS) process is capturing CO_2 from a power plant. The importance of finding ways to reduce this cost can hardly be overestimated: coal now accounts for half the electricity generated in the United States and produces a large percentage of the CO_2 emissions from the power sector because it has higher carbon content than other fossil fuels.

Maintaining coal as a viable source of electric power thus depends critically on improving plant efficiency in order to produce less CO_2 for a given amount of power generation and on finding more-cost-effective ways to capture the CO_2 produced—either before or after combustion. Precombustion efforts have focused largely on integrated gasification–combined-cycle (IGCC) systems, in which coal is processed with oxygen and steam under pressure to form a synthesis gas—consisting mainly of CO_2, carbon monoxide (CO), and hydrogen—which can be fired directly in a gas turbine. The CO_2 can be removed relatively efficiently from the synthesis gas but the CO cannot, so before firing, the gas is sent to a water gas shift reactor that converts the majority of the CO to CO_2 and hydrogen. For economic reasons, the extent of CO_2 removal by this means is currently limited to around 90%.

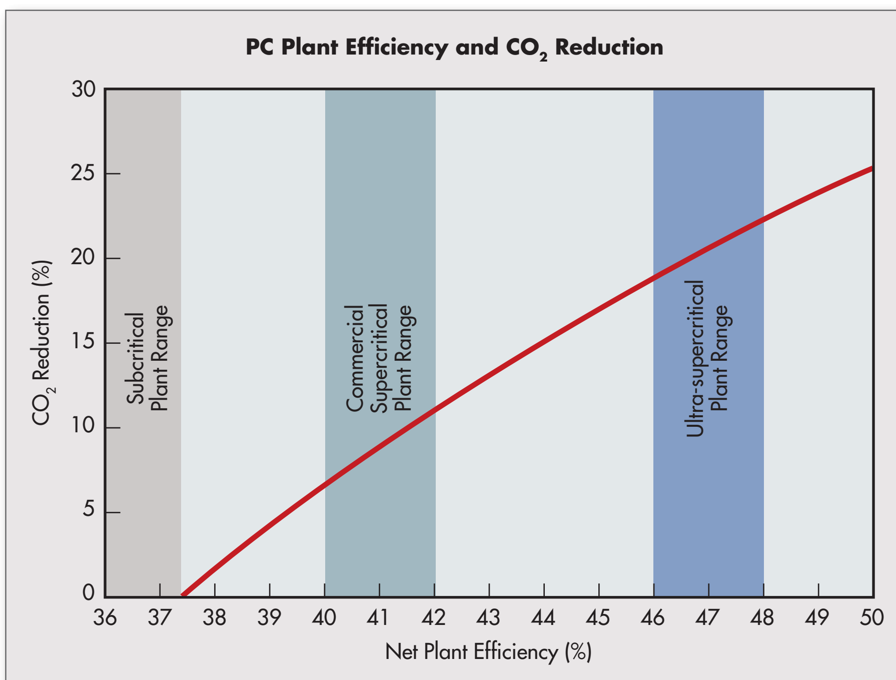
Conventional coal plants are faced with the more difficult task of capturing postcombustion CO_2 from flue gas at atmospheric pressure. The concentration of CO_2 in flue gas from a pulverized-coal (PC) power plant is typically less than 15%, with most of the rest being nitrogen from the air used to support combustion. Nevertheless, 80–95% of the CO_2 can potentially be removed from the flue gas by postcombustion capture systems, with the exact percentage dependent mainly on economic trade-offs.

A major study conducted in 2000 with joint funding by EPRI and the U.S. Department of Energy (DOE) concluded that the cost of electricity from a power plant using bituminous coal and fitted for CO_2 capture would be lower for IGCC plants using the precombustion capture option than for PC plants with postcombustion capture. "The study was completed for high-grade bituminous coal, for which IGCC is well suited," cautions EPRI senior project manager Jeffrey Phillips. "Currently with high-moisture, low-rank fuels—such as subbituminous coal and lignite—IGCC performance is degraded to the point that the cost of electricity is at least as high as that for a supercritical PC plant when the two are compared with and without CO_2 capture."

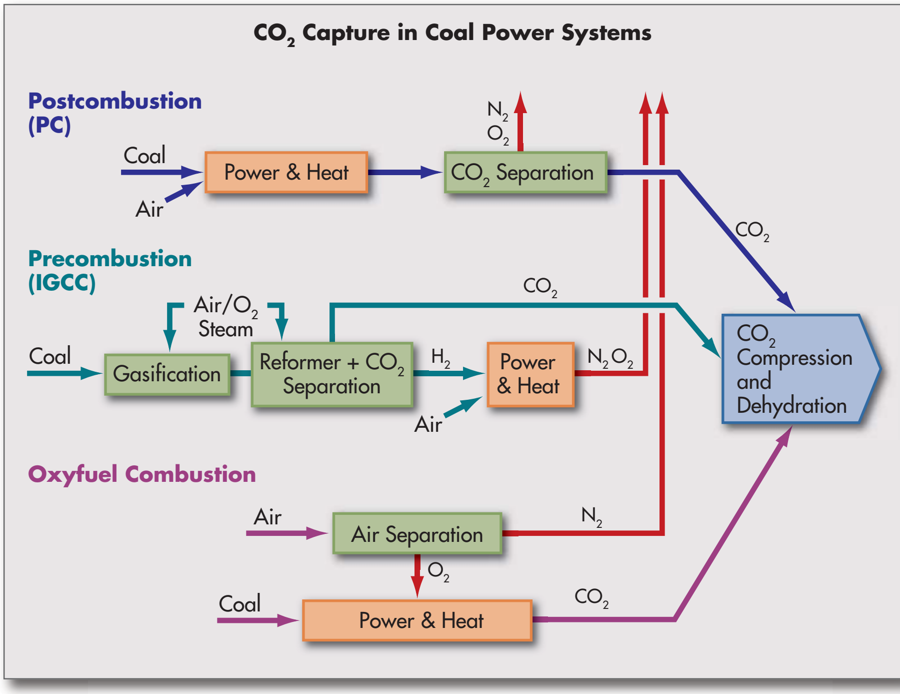
Indeed, since publication of the study, several improvements have been identified that potentially could sufficiently enhance the thermal and economic performance of PC plants using postcombustion capture that they would be competitive with IGCC using precombustion capture. Such judgments, however, must still be considered preliminary, since IGCC technology is also undergoing rapid improvements, notably in the ability to use a wider range of coal types. For both IGCC and PC technologies, another important goal of research is to enable plants to operate at greater efficiency and thus produce less CO_2 from the outset.

Postcombustion Capture: The Search for Better Solvents

Typically, postcombustion capture involves two stages: First, flue gas is passed through an absorber, where a solvent removes most of the CO_2 through a chemical reaction. Then this CO_2-rich solvent goes to a stripper, where it is heated to release the CO_2 and produce a regenerated solvent, which is returned to the absorber. Recent studies suggest that the largest near-term contribution to reducing the cost of postcombustion capture could come from finding better solvents for absorbing and desorbing CO_2—specifically solvents that could process larger amounts of CO_2 for a given mass of solvent and that would require less energy to drive the desorption process.



Increasing the efficiency of power generation can significantly reduce the volume of CO_2 produced and should be pursued in parallel with the development of carbon capture technology. Improvements in ultra-supercritical PC plants that would allow them to operate reliably at efficiencies approaching 50% (HHV) are expected within ten years.



Current designs for advanced coal-based power plants approach CO_2 capture in different ways. PCs burn coal conventionally and then remove CO_2 from the flue gas by means of solvents. IGCC plants separate CO_2 from the fuel (also with solvents) after the coal gasification process but before combustion. Oxyfuel combustion systems use oxygen rather than air for combustion, resulting in a flue gas stream that is over 95% CO_2.

The solvent in most common current use for CO_2 capture is monoethanolamine (MEA), which has a relatively low CO_2 loading capability and a relatively high energy requirement for regeneration. The MEA process is used commercially in such industrial applications as providing CO_2 for use in beverages and chemical production, but at scales smaller than would be required for power plant applications. The 2000 EPRI-DOE study concluded that if the process were scaled up for use in the current generation of supercritical PC plants fired with high-grade bituminous coal, the energy needed to run the stripper stage would require diversion of steam from the steam turbine—reducing net power output by 29% and raising the cost of electricity by 65%. In contrast, adding CO_2 control to the IGCC process was estimated to reduce its net power output by 15% and raise its cost of generating electricity by 25%

More-recently-developed chemical absorption processes that use proprietary amine-based solvents have been commercialized for urea production on a scale appropriate for capturing emissions from a very small (<10-MW) power plant. Using data provided by the CO_2 Capture Project—a collaboration involving DOE and major energy companies—EPRI has examined how these solvents might perform in a 500-MW coal-fired power plant similar in design to that modeled in the 2000 study. The results indicate that postcombustion capture using these solvents would reduce net power output by 19% and raise the cost of electricity by 44%—a substantial improvement over the original MEA process, but still not a competitive alternative to IGCC-based precombustion capture.

A new process that might close the gap further is based on the use of chilled ammonia as a solvent. The process—being developed through funding by EPRI, ALSTOM, and Statoil—was recently evaluated in bench-scale experiments, with very promising results. In this process, CO_2 is absorbed by a solution of ammonium carbonate at low temperature and atmospheric pressure, forming ammonium bicarbonate. Compared with amines, ammonium carbonate has over twice the CO_2 loading capacity and requires less than half the heat to regenerate the solvent. Further, as regeneration occurs under high pressure, the CO_2 that is released is already partially pressurized; therefore, less energy is required for compression prior to storage. This approach is not possible with amine solvents, since they degrade at the slightly higher steam temperatures required for regeneration at pressure. As a result, power reduction from a full-scale supercritical PC plant using chilled ammonia could be as low as 10%, with an associated cost-of-electricity increase of about 25%.

CCS Demonstrations

Before postcombustion CO_2 capture systems can be installed with confidence on large, coal-fired power plants, current and emerging technologies must be scaled up many-fold. For example, the largest industrial application (not coal fired) of the MEA process captures 800 metric tons of carbon dioxide per day (tCO_2/d), by means of two parallel process trains. A 500-MW power plant, in contrast, would require a capacity of roughly 9000–10,000 tCO_2/d, assuming 90% capture. At present, there is no U.S. pilot facility that could be used to test the new postcombustion capture technologies at a credible scale, using actual flue gases from a coal-fired power plant in a realistic operating environment.

To advance this critical work, EPRI has developed preliminary engineering plans for a CCS test center that will focus on postcombustion CO_2 capture and, eventually, CO_2 transport and geologic storage. The first step will be to build a 5-MW(th) pilot plant focusing specifically on the chilled-ammonia process. EPRI and ALSTOM have agreed to jointly fund the $11 million pilot plant at the We Energies Pleasant Prairie Power Plant in southeast-

Lab-test absorber tower

Pleasant Prairie Plant

Pilot plant site

EPRI-funded laboratory-scale tests of ALSTOM's chilled-ammonia postcombustion capture process led to plans for a 5-MW pilot plant, to be built this year at the We Energies Pleasant Prairie Power Plant. If technology development goes well, the pilot may be expanded to enable further scale-up of the chilled-ammonia process and study of CO_2 transport and storage technologies.

ern Wisconsin. ALSTOM will design, construct, and operate the pilot facility; EPRI will collect data and provide evaluation of the facility's performance, using funds already committed by 26 utility participants, with additional utilities expected to join.

The pilot plant is slated to begin operation in the third quarter of 2007 using flue gas from the adjacent power plant. Initial tests are scheduled to last about a year, to be followed by a few months of technical and economic analysis. The 5-MW pilot will capture about 100 tCO_2/d and will be a critical step toward commercializing the chilled-ammonia process. Additional 1-MW pilots may also be constructed if other sufficiently attractive capture processes are identified. The next phase of the project could involve building a larger plant to demonstrate scale-up.

"The 5-MW pilot plant is big enough to use commercial components designed for an application like this," says Richard Rhudy, the principal project manager. "Teaming with ALSTOM, which would be the process supplier, will help accelerate its commercialization."

In addition to the EPRI-ALSTOM pilot plant, postcombustion test facilities are being built in other countries as well. The European Commission is supporting a large program involving utilities, equipment manufacturers, and research institutions from several countries aimed at developing more-cost-efficient CO_2 capture technologies; called ENCAP, the program has a specific target of achieving 90% CO_2 capture from power plants at half the present cost. The European CASTOR project, with 30 institutional participants from 11 nations, is sponsoring CCS research largely focused on the search for improved solvents, including tests conducted at a 24-tCO_2/d pilot plant. The University of Regina in Saskatchewan, Canada, has a similar program using a 4-tCO_2/d pilot plant, and the Commonwealth Scientific and Industrial Research Organization (CSIRO) of Australia has developed several new solvents, which will be tested at a 2-tCO_2/d pilot plant. CSIRO also plans to build a 175-tCO_2/d demonstration plant. Clearly, additional scale-up demonstrations will be required for all postcombustion technologies.

"Experience gained from demonstrations under way in Europe and elsewhere is being shared with American utilities through EPRI's CoalFleet for Tomorrow® program," says Desmond Dillon, a project manager in advanced generation. "Advancing the state of the art helps everybody. At the same time, however, there are some important differences in the technological needs of the United States and other countries, largely because of the different kinds of coal they rely on. International coordination is needed to provide individual countries a choice among carbon capture options so that they can adopt the ones that best suit their needs."

Other Postcombustion Advances

A variety of other technological developments may also help make postcombustion CO_2 capture more attractive. Potentially the most far-reaching of these advances is the planned deployment of a new generation of ultra-supercritical (USC) pulverized coal power plants, designed to operate with a heat-to-electricity conversion efficiency of up to 50% (higher heating value [HHV]). The greater efficiency of such plants would not only enable them to save on fuel costs but also substantially reduce the amount of CO_2 that would have to be captured for a given amount of electricity generation. In addition, USC plants have economic advantages resulting from lower balance-of-plant costs, such as those for coal pulverization, ash handling, and fuel transportation.

Supercritical steam conditions are achieved when the water and steam are at a pressure of 3206.2 psi (221.2 bar) with a corresponding saturation temperature of 705.40°F (374.15°C). At this and higher conditions, the liquid is indistinguishable from the vapor, and the steam-water separation stage needed for subcritical boilers is not required. USC steam conditions are arbitrarily defined as those occurring above about 1050–1100°F (566–593°C).

During the 1960s the United States was a leader in building supercritical coal-fired power plants. These early units initially suffered from a variety of problems, including lower availability and higher maintenance costs, which have been progressively overcome. The solutions included improved feedwater treatment using oxygenation procedures, superior tube and pipe material properties, and improved operation resulting from sliding pressure control. Although installation of supercritical plants in the United States peaked during the 1970s, there has been a recent resurgence of interest; several new units are planned, with MidAmerican's Council Bluffs Unit 4 coming on line in 2007. Worldwide, there are more than 500 supercritical units currently in operation, and they have become the technology of choice in several coal-dependent countries, such as China.

Faced with rising fuel costs and the prospect of mandatory controls on CO_2 emissions, the U.S. electric power industry is seeking ways to increase the efficiency of coal-fired power plants beyond supercritical levels. In particular, major advances in materials for the steam plant and steam turbines have made it possible to build plants operating at USC steam conditions. More than a dozen plants worldwide are operating close to these conditions, and both Europe and Japan have aggressive R&D programs in place to advance the technology further. In order to reassert a U.S. presence, DOE and the Ohio Coal Development Office have launched an ambitious project to develop advanced materials for USC plants that will operate with steam conditions as high as 1400°F (760°C) and 5000 psi (345 bar). The project is based on an R&D plan developed jointly by EPRI and major domestic boiler manufacturers, and this consortium provides cost sharing for the project. It is anticipated that the initial USC plants will be built with less-aggressive steam conditions, possibly starting at around 1200°F (649°C).

Preliminary conceptual design, materials evaluation, and economic analysis for a 750-MW plant has confirmed that the USC target conditions can be met. The five-year project includes assessment of the mechanical properties of advanced alloys, their oxidation and corrosion resistance, and methods for fabricating and welding major plant components made with the new materials (see sidebar). The plant is expected to achieve an efficiency of 45–47% (HHV), thus enabling it to save nearly $16.5 million annually in fuel costs and reduce CO_2 emissions by more than 30%, compared with a 35% efficient plant. In addition, it is believed that the unit could be designed to operate with an oxy-fuel combustion system, which uses pure oxygen rather than air for combustion and produces a concentrated stream of CO_2. Such operation could reduce the cost of postcombustion capture and possibly eliminate some of the currently required air quality control equipment.

"This USC technology is a major step toward achieving the goal of having near-

New Alloys Enable Ultra-supercritical Steam Conditions

The maximum metal temperature achievable using currently available ferritic steels is 1160°F (627°C). In order to meet the ambitious goals of the ongoing public-private program to design an ultra-supercritical (USC) pulverized coal plant with steam conditions as high as 5000 psi (345 bar) and 1400°F (760°C), high-nickel alloys will be needed for the construction of both the steam plant and the steam turbine. Such alloys are expensive enough that new designs will be needed to minimize their use. One manufacturer has already proposed a horizontal design that would reduce the length of superheat and reheat piping runs between the steam plant and the steam turbine.

Several existing alloys from various manufacturers have been identified—on the basis of creep strength and other properties—as candidates for use in different plant components. Tests on these materials, conducted as part of EPRI's ongoing R&D program, are encouraging, indicating the feasibility of designing a 750-MW USC plant at 1350–1400°F (732–760°C) using existing materials. Such a design would provide enough fuel cost savings over a 20-year break-even period to allow the plant to be cost competitive even if its capital cost turns out to be 12–15% higher than that of a comparable facility with a conventional boiler.

It is anticipated that USC plants operating at 1150°F (621°C) using ferritic steels may be offered commercially in only one to two years and that a 1200°F (649°C) plant using advanced alloys may be five years away. EPRI's CoalFleet initiative will use the results of the design study and materials testing to help power producers evaluate the risks and benefits of participating in a later project to deploy highly advanced USC plants operating at 1400°F (760°C).

zero emissions in future pulverized-coal power plants," according to R. Viswanathan, EPRI technical executive. "The United States originally pioneered supercritical technology, and the current reengagement in this area will not only help make coal-fired power plants more economically attractive but also make an important contribution to controlling CO_2 emissions."

Other postcombustion advances include the development of membranes that could decrease the size of capture equipment and thus reduce capital costs, and design improvements that could help integrate capture more effectively with power production. Membrane processes are already used commercially for removal of CO_2 and hydrogen sulfide from natural gas under pressure, but they face severe challenges in being adapted for use with flue gases at atmospheric pressure and lower CO_2 concentrations. Recent research in the area has focused particularly on developing hybrid systems, in which a membrane provides a greater surface area for increased mass transfer between the flue gas stream and a solvent.

Assessment studies indicate that a USC plant incorporating design improvements and using the chilled-ammonia process with a membrane contactor could lower the increase in electricity cost associated with CO_2 capture to only 11%. These latest studies indicate that the improvement in performance since the original EPRI-DOE study arises primarily from the improved solvent, followed closely by the move to higher steam conditions.

As indicated earlier, oxyfuel combustion has the potential to reduce the cost of postcombustion CO_2 capture for PC plants. Using pure oxygen eliminates nitrogen from the flue gas and produces a stream that is over 95% CO_2 (dry basis), making capture significantly easier. Several demonstration projects for this approach are under way. A 30-MW(th) oxyfuel pilot plant is being constructed in Germany, and tests are expected to begin in 2008. Saskatchewan Power recently announced plans to build a 450-MW (gross), 300-MW (net) supercritical PC oxyfuel unit that is expected to enter operation in 2011. If it proves to be economically viable on a large scale, oxyfuel combustion is expected to play an increasingly important role in American USC projects. The main developmental challenge to the oxyfuel approach is lowering the cost of oxygen production, which would also help lower the cost of IGCC plants.

Precombustion Capture Research

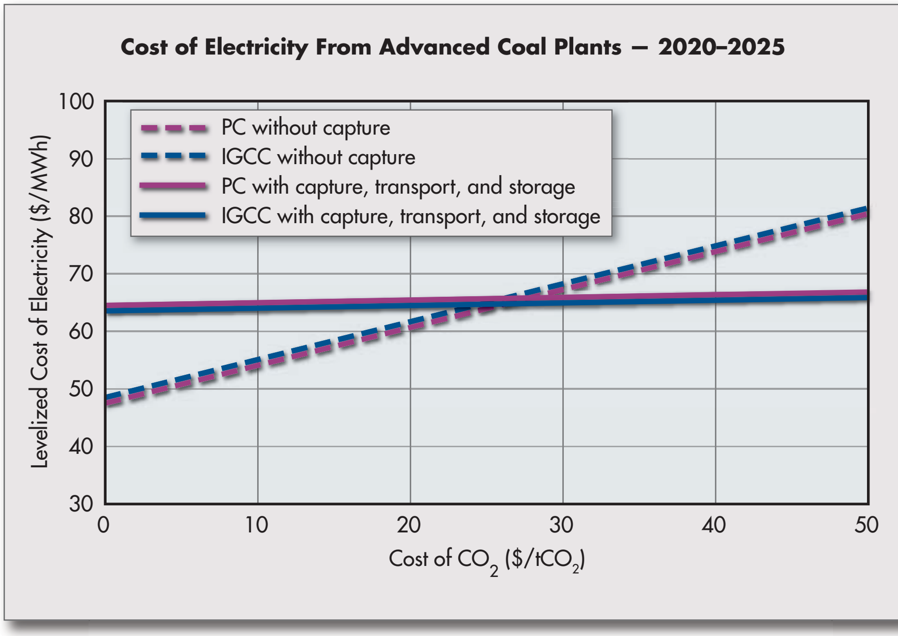
Precombustion CO_2 capture is also undergoing improvements—mostly evolutionary—in a variety of areas, building on the advantages of removing CO_2 from a concentrated IGCC syngas stream at high temperature and pressure. Under these conditions, a low-energy process involving physical absorption—rather than a chemical reaction—is possible.

Currently physical solvents, such as Selexol and Rectisol, are most commonly employed to remove both CO_2 and hydrogen sulfide from the precombustion gasification stream in industrial coal gasification plants used in the production of petrochemicals, fertilizer, and substitute natural gas. Most IGCCs have used chemical solvents because of their lower initial costs; however, the 110-MW Cool Water IGCC demonstration plant sponsored by EPRI in the 1980s used Selexol, and many of the IGCC power plants currently on the drawing board will use physical solvents in order to achieve deeper sulfur removal and to make the plants more amenable to CO_2 removal. So far, CO_2 capture has not been demonstrated in a large, coal-fired IGCC power plant, but CO_2 capture is used commercially in several industrial gasification facilities. Most of those facilities simply vent the CO_2 to the atmosphere after removal from the coal gas, but the Great Plains Synfuels plant in North Dakota compresses 8000 tCO_2/d (equivalent to that emitted by a 400-MW coal power plant) to 2800 psi (193 bar) and sends it through a 200-mile pipeline to an oil field in Saskatchewan. The CO_2 is then pumped into the oil reservoir to facilitate extraction of additional oil from what was a dying field.

Other efforts to improve IGCC technology are also under way, with a particular emphasis on cost reduction—whether or not CO_2 capture is involved. Without CO_2 capture, electricity from the first group of U.S.-based IGCC plants is expected to cost about 15–20% more than electricity from conventional PC units with SO_2 and NO_x controls. EPRI estimates that IGCC-related research, development, and demonstration (RD&D) projects currently under way or planned will decrease the 30-year levelized cost of electricity from these plants (without CO_2 capture) by $6/MWh by 2012, compared with technology available in 2004. Since this decrease would still not be enough to make IGCC plants competitive with PC plants unless subsidies were provided, EPRI's CoalFleet for Tomorrow® program has identified an additional 18 short-term RD&D projects whose successful completion should bring the two technologies into cost parity.

Looking further into the future, CoalFleet has also developed a long-term RD&D roadmap for IGCC technology with CO_2 capture that, by 2025, could potentially produce electricity more economically than today's IGCC plants without capture. Some of the technological advances anticipated by the roadmap include eliminating the need for a spare gasifier by improving equipment reliability, introducing more-efficient gas turbines, installing new clean-up technology that eliminates the need for extra equipment to reduce nitrogen and sulfur emissions, and eventually adding a fuel cell to the combustion turbine to achieve fuel gas-to-electricity conversion efficiencies in the range of 60–70%.

Another technological improvement anticipated by the long-term roadmap involves the use of ion transport membranes (ITMs) for oxygen production. Compared with current technology based



The PC and IGCC plants available in 15–20 years are expected to be quite competitive with each other in terms of the levelized cost of electricity (COE). Site- and fuel-specific issues are likely to drive the choice of technology. (For plants with capture, COE includes an allowance of \$10/tCO_2 for the cost of CO_2 transport and storage.)

on a cryogenic separation process, ITMs are expected to reduce the cost of oxygen production equipment by 35% and power consumption by 37%. An ITM pilot plant is currently producing about 5 t/d of oxygen, but a commercial-scale gasifier will consume closer to 2000 t/d. As mentioned earlier, reducing the cost of oxygen production could greatly enhance the competitiveness of oxyfuel combustion in PC plants as well.

The use of membranes, rather than solvents, could also significantly improve the efficiency and economics of separating CO_2 from the synthesis gas in an IGCC plant. Because the stream of CO_2 would exit the membranes at a much higher pressure than the stream leaving the solvent-based capture process, less auxiliary power would be needed to compress the gas for transport and storage. In addition, the auxiliary power and process steam required for CO_2 capture would be considerably less than in the case of solvent-based capture. Altogether, the use of membranes is expected to reduce both capital cost and auxiliary power requirements by half, compared with today's technology. Membrane separation of CO_2 is currently in the laboratory stage of development, with several organizations pursuing different approaches.

Recent Cost Comparisons

Two studies were recently completed comparing performance of IGCC and supercritical PC plants incorporating CO_2 capture. The first was completed by the International Energy Agency (IEA) Greenhouse R&D Programme. This study compared the performance of two hypothetical 750-MW power plants using bituminous coal at a greenfield site on the northern coast of the Netherlands. The IGCC plant was a slurry-fed design supplied by GE. For 90% CO_2 capture, the cost of electricity from the PC plant was 10% higher than that from the IGCC plant.

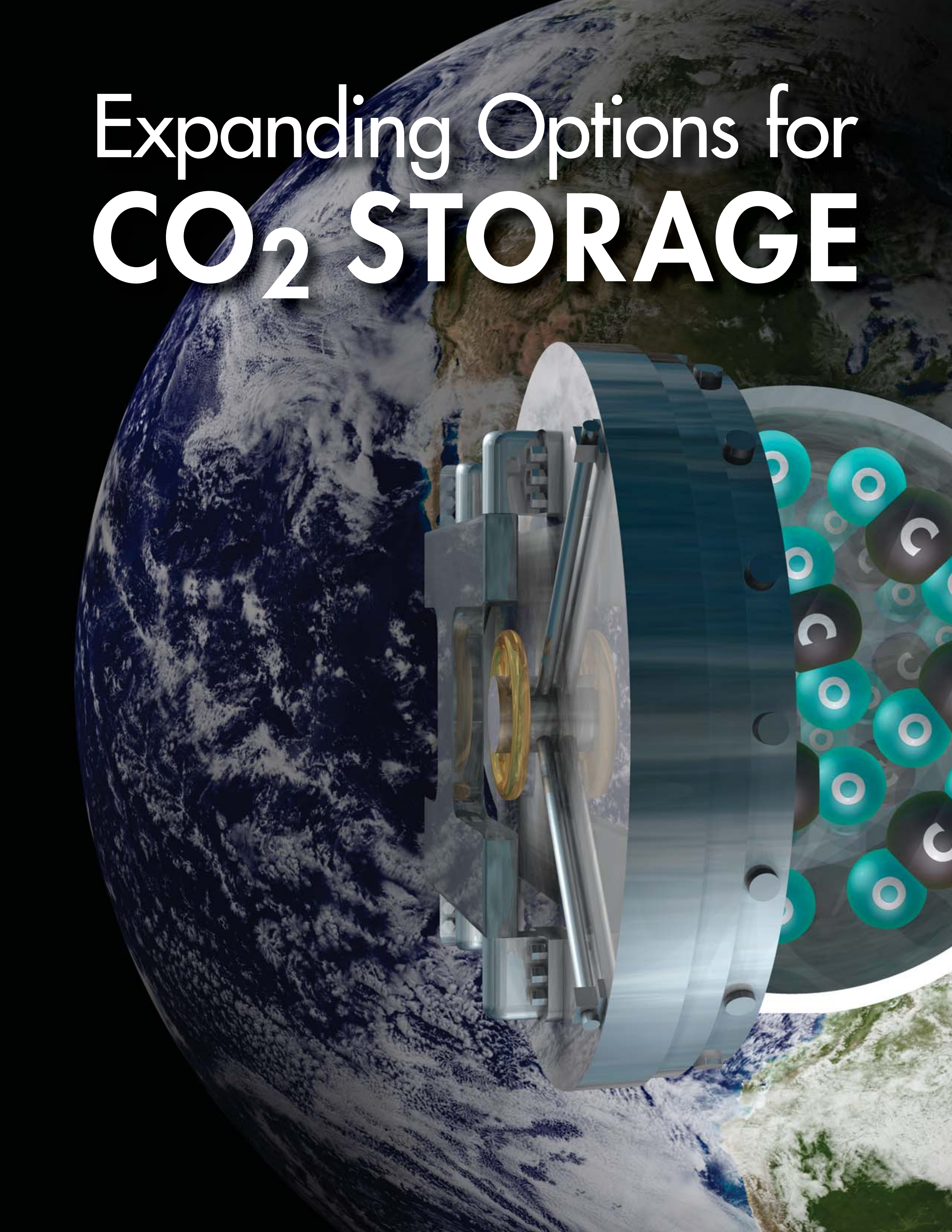
The second study, by CPS Energy, compared the performance of two hypothetical 550-MW power plants using subbituminous coal at a greenfield site on the Texas Gulf Coast. The IGCC plant was a dry-fed design supplied by Shell. For 90% CO_2 capture, the cost of electricity from the PC plant was 5% lower than that from the IGCC plant. The percentage difference would probably be greater for lignite feed, which normally has a higher moisture content than subbituminous coal.

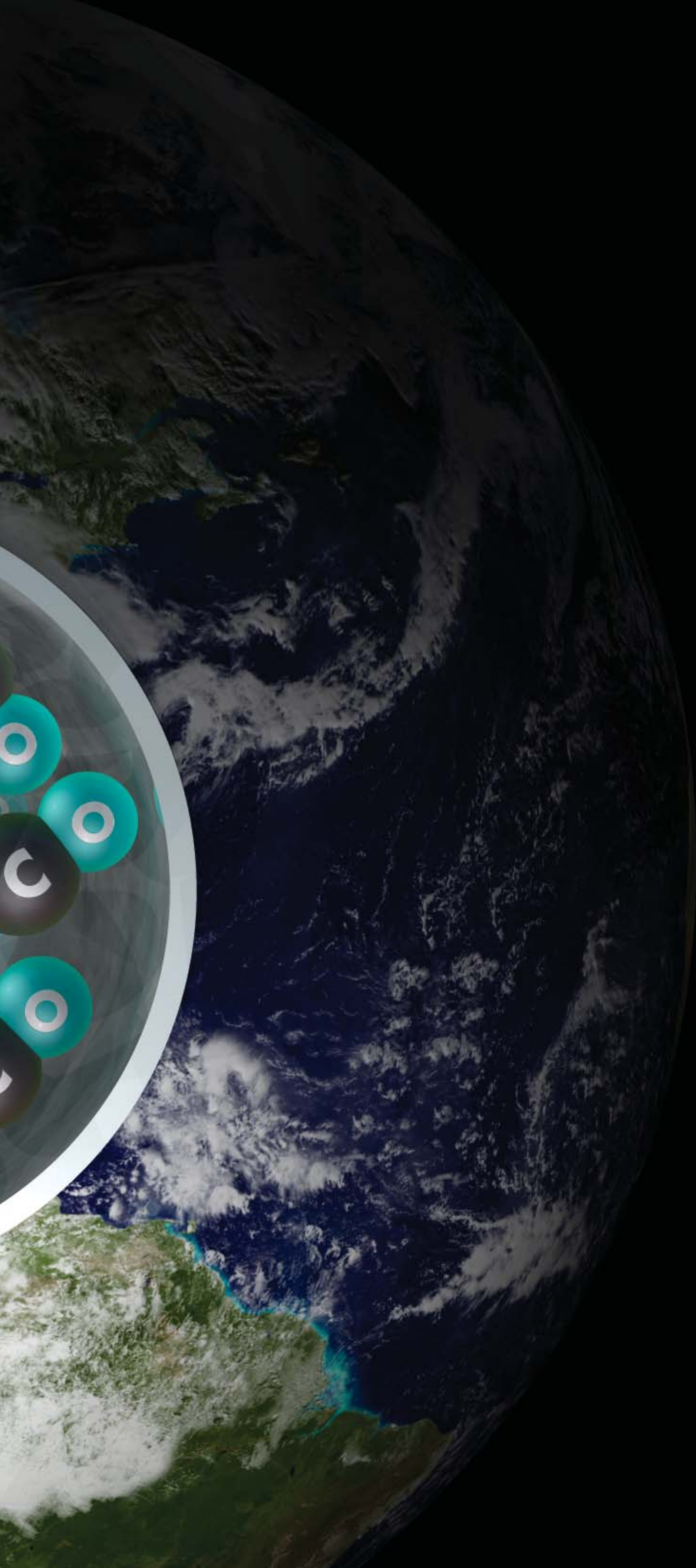
Both studies used current state-of-the-art plant designs and did not include any of the enhancements for pre- and post-combustion capture identified by the CoalFleet program. As a result, these cost-of-electricity comparisons are likely to change with time as design improvements are identified and incorporated in future assessment studies.

Through the efforts of CoalFleet, EPRI has shown that significant improvements can be made to CO_2 capture technologies by following a recommended RD&D program. Interpreting current results, John Wheeldon, a member of the CoalFleet team, concludes: "IGCC and pulverized-coal technologies are going through a period of major enhancement. If all the improvements identified are successful, both technologies are expected to achieve similar levels of performance, with IGCC perhaps being preferred for high-rank fuels and pulverized coal for lower-rank fuels. As there is no certainty that all the improvements will be fully realized, advances in both technologies must be pursued. This approach will ensure that power producers have the ability to choose the generating technology with CO_2 capture that best suits their economic and operating circumstances and allows them to continue providing affordable power to their customers."

This article was written by John Douglas. Background information was provided by Richard Rhudy (rrhudy@epri.com), John Wheeldon (jowheeld@epri.com), Jack Parkes (jparkes@epri.com), Jeffrey Phillips (jphillip@epri.com), Neville Holt (nholt@epri.com), Desmond Dillon (ddillon@epri.com), and R. Viswanathan (rviswana@epri.com).

Expanding Options for CO_2 STORAGE





The Story in Brief

While carbon capture gets much of the attention in climate discussions, storage of CO_2 is nonetheless a critical component of the overall climate challenge. Geologic formations potentially suitable for long-term carbon dioxide storage are relatively abundant and widely dispersed in the United States, and technologies for CO_2 transportation and subsurface injection are well established on an industrial scale. But massive expansion of the present infrastructure will be required before enough CO_2 can be stored to make a substantial difference in mitigating atmospheric concentrations. A variety of additional technical and nontechnical concerns also need to be addressed.

ART BY CRAIG DISKOWSKI/EDGE DESIGN. EARTH PHOTO COURTESY VISIBLE EARTH/NASA .

For carbon capture and storage (CCS) to make a major contribution to reducing atmospheric concentrations of greenhouse gases, ways must be found to store CO_2 securely and cost-effectively for centuries or longer. In many ways, the development of storage science and technology is ahead of that for the carbon capture process. Oil companies have been injecting CO_2 into deep geologic formations for more than 30 years to help recover additional petroleum from fields depleted during initial production. Such enhanced oil recovery is currently supported by approximately 3000 miles (4800 km) of dedicated CO_2 pipeline in North America alone, with individual pipes extending for distances up to 500 miles (800 km). In addition, other types of subterranean formations are routinely used for disposal of waste fluids in many parts of the world. Little is known, however, about how suitable various types of underground reservoirs might be for long-term storage of CO_2 and what kinds of risks might be involved. To address these and related issues, a variety of exploratory CCS projects are needed.

The critical challenge will be how to scale up CCS deployment to store huge volumes of CO_2 from the world's power plants and other major facilities—enough to make a significant contribution to stabilizing atmospheric concentrations of this major greenhouse gas. Currently, human activity results in annual carbon dioxide emissions of about 26 gigatons (billion metric tons), or 26 $GtCO_2$. It is expected that modest amounts of capture will be achieved in the first few decades as CCS technology is being developed, but by the end of the century—when international cooperation firmly takes hold and CCS technology is deployed worldwide—the bulk of anthropogenic CO_2 emissions will be captured and stored. Under a hypothetical stabilization policy aimed at keeping atmospheric concentrations below 550 parts per million (ppm), storage of 2 $GtCO_2$/yr will be required around the globe by 2050 and over 22 $GtCO_2$/yr by 2100.

"The United States is fortunate to have an abundance of theoretical CO_2 storage potential, well distributed across most of the country," according to a recent report from the second phase of the Global Energy Technology Strategy Program (GTSP), sponsored by several major research institutions, including EPRI. The report concludes that CO_2 capture and storage sufficient to result in atmospheric stabilization of greenhouse gases "will likely require thousands of CCS-enabled plants deployed over the course of this century, beginning early enough so that gigatons of CO_2 per year are routinely being stored in deep geologic formations around the world by mid-century." The big question is whether sufficient resources can be made available to accomplish this goal.

Storage Basics

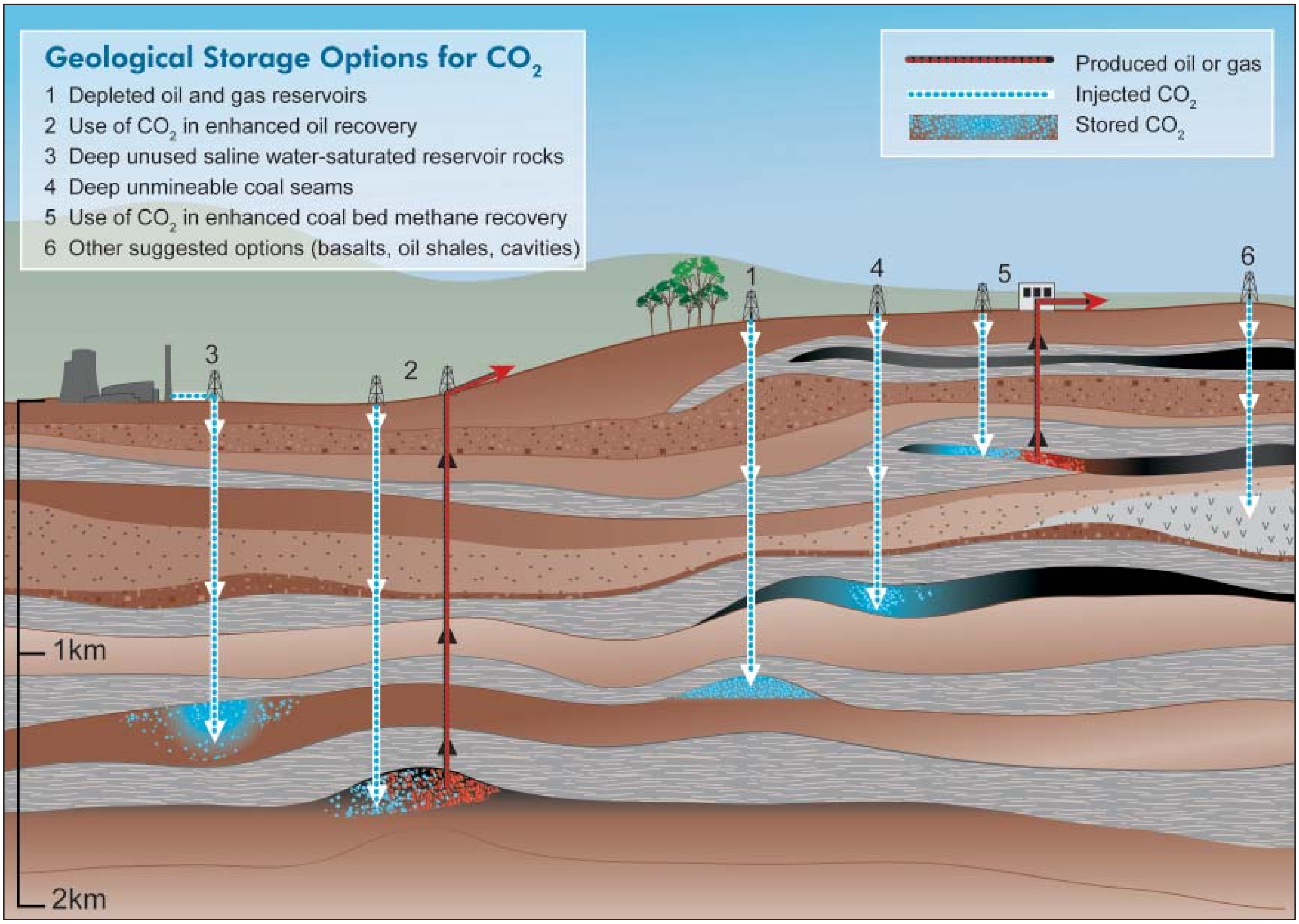
After capture from a power plant, CO_2 would be compressed to a supercritical state in preparation for transport to a suitable storage site. As a supercritical fluid, CO_2 is as dense as a liquid but has gas-like viscosity, making it easier and less costly to transport through dedicated pipelines, which operate in a single, "dense phase" mode at high pressure but ambient temperature. CO_2 can also be further cooled to liquefaction temperature and transported for longer distances by marine tankers in a process similar to that currently used for liquefied natural gas. Each of the individual technologies involved in the transport portion of the CCS process is mature, but integrating and deploying them on a massive scale will be a complex task.

"The question is, how would the necessary pipeline network be established and evolve?" asks EPRI project manager Richard Rhudy. "In particular, early CCS installations will have to create more of their own CO_2 transportation infrastructure than later plants, which will probably have access to a more mature pipeline network."

Initially, the most likely storage sites will be deep geologic formations where porous sediments have been covered by impermeable caprock that can hold the CO_2 in place. In order to maintain the CO_2 in a supercritical state, target reservoir formations will be located at depths greater than about half a mile (0.8 km). By far the most abundant such sites are deep saline formations, where sandstone and carbonate rocks (limestone or dolomite) have numerous voids now partially filled with brine. Injected CO_2 would move into available voids and dissolve in the water, eventually forming stable, solid carbonate compounds with the surrounding material—a process called mineralization.

Depleted oil and natural gas fields, where they are available, also make attractive candidate storage sites. Previously tapped natural gas formations are already often used for gas storage purposes, and the process of injecting CO_2 into such reservoirs would be very similar to the process for storage in deep saline formations. Although CO_2 injection to enhance oil recovery is well established, little is known about how adequately these depleted oil fields might retain CO_2 over a long period, particularly since a significant portion of the currently injected gas re-emerges with the oil produced. An industrial-scale project to clarify the practicality of such storage following enhanced oil recovery is under way in Canada.

Another storage option now being investigated experimentally is to use CO_2 for enhanced methane recovery from unmineable coal seams. In this case, injected CO_2 would chemically bind to the surface of the coal, displacing previously bound methane. One advantage of this approach is that it could take place at shallower depths than those involved in saline formations or depleted oil fields and thus might require less-extensive drilling. Estimates of the potential storage capacity of unmineable coal seams vary widely, however, and the potential of such seams for long-term CO_2 storage remains uncertain. Even less well understood is the possibility of using other types of deep geologic structures, such as porous "interflow" zones in basalt formations, which theoretically might provide an enhanced potential for mineralization.



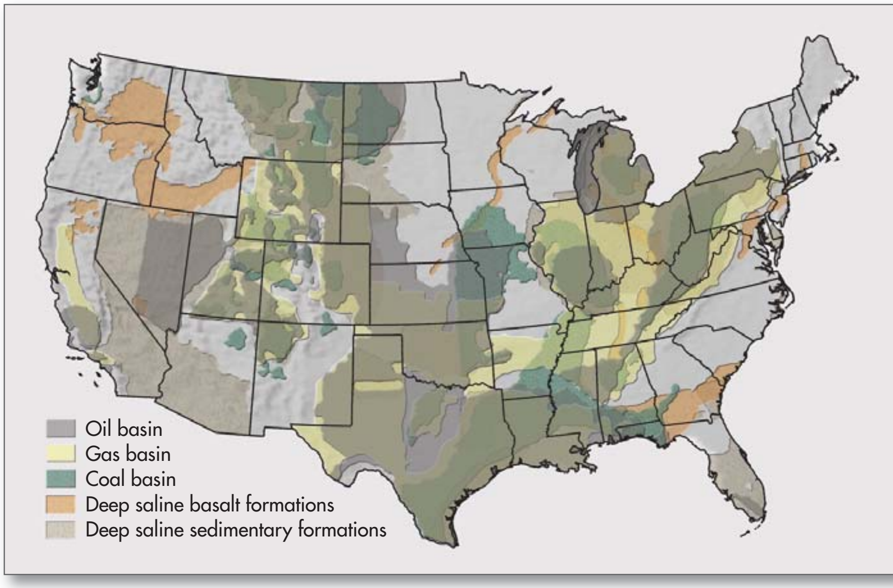
Geologic reservoirs are seen as the best near-term option for the long-term storage of CO_2. Although injection of CO_2 to enhance oil recovery from depleted fields is already a commercially established technique, availability of these fields is likely to be limited. Deep saline formations underlying impermeable caprock will probably provide the largest storage capacity over time, and a number of demonstration projects at such sites are currently under way. Coal seams situated too deep to mine economically present another possibility. (Illustration courtesy Peter Cook, CO2CRC)

Ocean storage has also been suggested, but the idea has aroused objections from the environmental community, and development has not yet progressed to the pilot stage. Nevertheless, the ocean's storage capacity is huge—many times greater than all the currently known geologic sites put together. Because carbon dioxide is soluble in water, natural exchange of CO_2 between the atmosphere and the ocean surface already takes place on a massive scale. Current proposals for ocean storage focus on two possibilities: dissolving the CO_2 in seawater at depths greater than half a mile (0.8 km) or depositing liquefied CO_2 on the sea floor at least 2 miles (3.2 km) down; at this depth, liquid CO_2 is denser than water, so it would form a "lake" on the ocean floor. The potential ecological impacts of such storage options need to be determined, however, before oceans can be used as major CO_2 repositories.

Injection and Leakage

While the concept of geologic storage seems simple enough, a CO_2 injection well is a surprisingly complicated system. Multiple cement casings and provisions for monitoring are required to ensure that the supercritical fluid reaches only appropriate storage formations and stays there. In particular, steps must be taken to keep the CO_2 from interfering with sources of drinking water at shallower depths. In the injection zone itself, special cement must be used to prevent damage to the casing from acids that form when CO_2 reacts with the in situ saline solution. Although the basic technologies for injecting CO_2 safely into deep geologic formations are well established, more-advanced drilling and injection techniques will be needed to optimize storage on the massive scale required. Lateral drilling and injection into multiple, vertically stacked reservoirs, for example, could help make a broader range of potential storage sites accessible.

A variety of measurement, monitoring, and verification (MMV) technologies will also need to be incorporated into a complete storage system to make sure the CO_2



Unlike many other nations, the United States has abundant, well-distributed sites for potential geologic CO_2 storage. Site-specific evaluations will be needed to confirm the sustainability of any particular reservoir.

is not leaking into the surrounding environment. Some off-the-shelf technologies, such as seismic imaging of subterranean formations, are already being used to track the underground migration of injected CO_2, and sampling of groundwater could prove useful for detecting leakage directly. Detecting small rates of leakage over long periods of time, however, will require higher-resolution measurements and the development of highly precise baseline data. More-sensitive MMV techniques that can measure the actual amount of CO_2 in storage may also be needed for purposes of greenhouse gas mitigation reporting.

The issue of leakage is critical from both global and local perspectives. Even gradual leakage from numerous sites may provide enough CO_2 reentering the atmosphere to undermine efforts to stabilize greenhouse gas concentrations. Locally, leakage from an underground storage site could present an immediate hazard to humans and ecosystems. The most dramatic type of CO_2 release would come from a blow-out at an injection well, which could produce high enough concentrations (7–10%) of the gas in the vicinity to endanger human life. Fortunately, this type of release can be detected quickly and stopped using currently available techniques.

Undetected leakage from a faulty well or through ground fractures would probably be more diffuse and primarily affect groundwater and surface ecosystems. In particular, aquifers used as a source of drinking water could be harmed, either by acidification resulting from direct contact with large amounts of CO_2 or by the seepage of brines displaced by CO_2 during the injection process. Because CO_2 is heavier than air, it also could accumulate in low-lying geographic areas or in basements and potentially threaten human health.

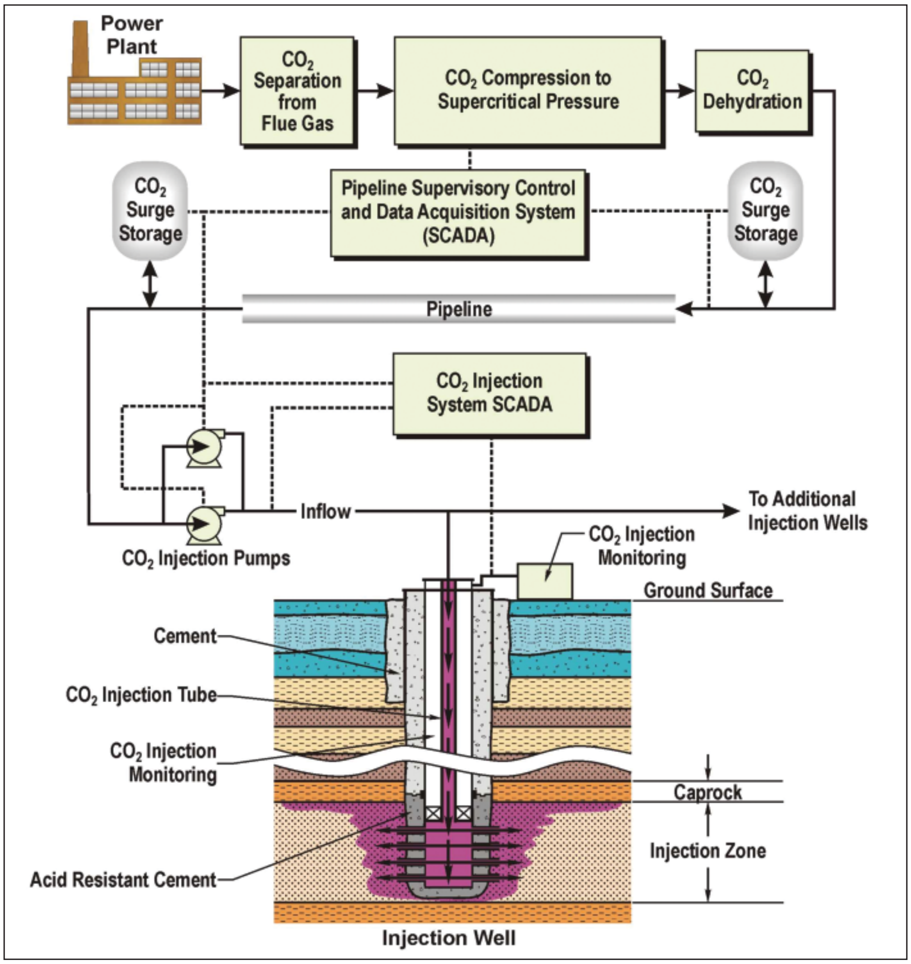
Research is currently under way to improve CO_2 leak detection and develop possible remedial measures. Specifically, MMV technologies are needed that would detect potential leaks long before they pose any danger to water supplies or surface ecosystems. Seismic imaging, for example, can reveal deep subsurface faulting and abandoned wells that might permit leakage by providing a route to the surface, and this type of examination is expected to become a routine part of storage site evaluation. In addition, some experiments are under way to begin to investigate leakage rates for different types of storage and under a variety of injection conditions. Several kinds of remediation techniques also need to be explored, including the extraction and purification of contaminated groundwater, the interception and reinjection of leaking CO_2, and the removal of stored CO_2 for injection elsewhere.

"Careful storage system design and siting, together with methods for early detection of leakage (preferably long before CO_2 reaches the land surface), are ways of reducing hazards associated with diffuse leakage," according to a recent special report by the Intergovernmental Panel on Climate Change (IPCC). "The available monitoring methods are promising, but more experience is needed to establish detection levels and resolution."

Storage Sites and Costs

Like other subterranean resources, potential storage sites for CO_2 are unevenly distributed around the world. Although the United States is particularly fortunate in having abundant, well-distributed sites, other countries may face a real dilemma as they attempt to balance the use of indigenous fossil fuels against the need to curb greenhouse gas emissions in the face of limited CO_2 storage capacity. According to initial GTSP estimates, the world theoretically has more than enough storage capacity—11,000 $GtCO_2$—to meet projected needs for at least a century. Assuming that a variety of carbon management technologies are deployed—including nuclear power, renewable resources, and enhanced end-use efficiency—the demand for CO_2 storage is not expected to exceed 2200 $GtCO_2$ over this century.

Storage adequacy in individual countries, however, varies widely. Japan and Korea, for example, may have their future use of fossil fuels constrained by a lack of onshore geologic CO_2 storage capacity. With their advanced economies, these two countries might potentially be able to meet future limits on greenhouse gases by purchasing emission credits or looking at other options, including offshore geologic storage. However, the case is more problematic for developing countries such as



Future CCS systems will have to integrate CO_2 capture at the power plant with transport, geologic injection, and storage monitoring technologies in a seamless whole on a very large scale. While most of the individual components have been demonstrated in specific applications, experience with integrated end-to-end systems is extremely limited, and large-scale demos for such systems are needed. (Source: Battelle, Joint Global Change Research Institute)

China and India, which depend heavily on readily available coal but have relatively little known CO_2 storage capacity—less than 400 $GtCO_2$ apiece, compared with 3900 $GtCO_2$ in the United States. Little information is available on potential storage sites in these countries, and new surveys of candidate reservoirs will be needed before their capacity is firmly established.

In a carbon-constrained future, storage capacity will, in fact, become an important variable in the global energy/environment equation. "CO_2 storage capacity needs to be seen as a valuable resource," says Tom Wilson, manager of EPRI's Greenhouse Gas Reduction Program. "Regions with abundant storage capacity will be in a better position to continue relying on indigenous fossil fuels and avoid premature retirement of coal-fired power plants."

The largest existing CO_2 point sources are heavily concentrated in a few regions of the world. Those in the United States are responsible for 20% of all global emissions, followed by China, at 18%. The cost of storing the CO_2 from these point sources—dominated by power plants—will be determined by a variety of factors, including availability of suitable geologic formations, distance to a suitable storage site, and competition for the most valuable sites. Developing countries will be particularly challenged to find adequate storage in the midst of rapid economic growth.

Under the most favorable circumstances, CO_2 capture and storage can actually be profitable. An ammonia plant located near a depleted oil field, for example, could sell its CO_2 to a company engaged in enhanced oil recovery. Profit is possible because ammonia plants already produce a fairly pure stream of CO_2, and the major expense involved in the transaction is just the energy used to compress the gas into a supercritical state. By contrast, the net cost of employing CCS at a coal-fired power plant is dominated by the cost of CO_2 capture, which will likely remain greater than any potential profit that could be realized from selling the gas. According to GTSP 2006 estimates, the most favorable situation for a power plant would be a large, coal-fired unit located within 10 miles (16 km) of an opportunity for enhanced coal bed methane recovery—in which case, the net cost would be just over \$20/tCO_2. A more common scenario, in which a coal-fired power plant is located within 25 miles (40 km) of a deep saline formation or within 50 miles (80 km) of a depleted gas field, would involve CCS costs of around \$50/tCO_2.

The specific components that contribute to overall cost estimates for CCS vary widely. The cost of capture and compression can be as low as \$6–\$12/tCO_2 for industrial facilities, such as ammonia or ethanol plants, that already produce a CO_2 stream. In contrast, capture and compression costs for a conventional coal plant using a currently available chemical solvent process would be \$25–\$60/tCO_2, dominated by capital costs and the energy requirements for solvent recycling. For an integrated gasification–combined-cycle (IGCC) power plant using physical absorption, the projected cost is \$25–\$40/tCO_2, dominated by capital expenses. On top of this, long-term transportation and storage costs are expected to stay below approximately \$12–\$15/tCO_2 in the U.S., where access to deep saline formations is readily available. Finally, long-term MMV costs may be as low as a few pennies per ton.

Such cost estimates, however, cannot be considered in isolation by potential CO_2 storage customers in either industrialized or developing economies. The timing of investment presents a particularly difficult dilemma. Should U.S. power producers, for example, just assume they will eventually need access to large storage capacity and preemptively seek out low-cost opportunities, such as those involving enhanced oil and natural gas recovery? Or should they cede these early opportunities to industrial users who could take advantage of them without having to wait for deployment of improved capture technology? Also, from a global perspective, how can the task of establishing a massive new CO_2 transportation and storage infrastructure be initiated and shared most efficiently among various parties to promote the most effective, economical long-term results?

Getting Started

Answers to these questions will ultimately depend on when greenhouse gas restrictions become a fully accepted fact of life for the global electric power industry; nevertheless, some initial efforts need to be started immediately if the necessary technologies and operating experience for CO_2 storage are to be available when needed. A particularly urgent requirement is to gain more experience with integrated, end-to-end CCS systems under realistic conditions. Gaining this experience will take several years' work at utility-scale demonstration projects, some of which are now getting under way in various countries around the world. At the same time, more basic research is needed to develop surveys of candidate CO_2 reservoirs in developing nations like China and India. Such surveys will allow these countries to plan their new generation capacity in a way that will allow future deployment of CCS systems and that may also influence the evolution of their energy infrastructures.

Research is also needed to better understand how CO_2 injection can help improve oil and gas recovery from depleted fields. So far, most analyses have assumed constant incremental recovery improvement, but in fact the response to injection appears to be that production initially increases for

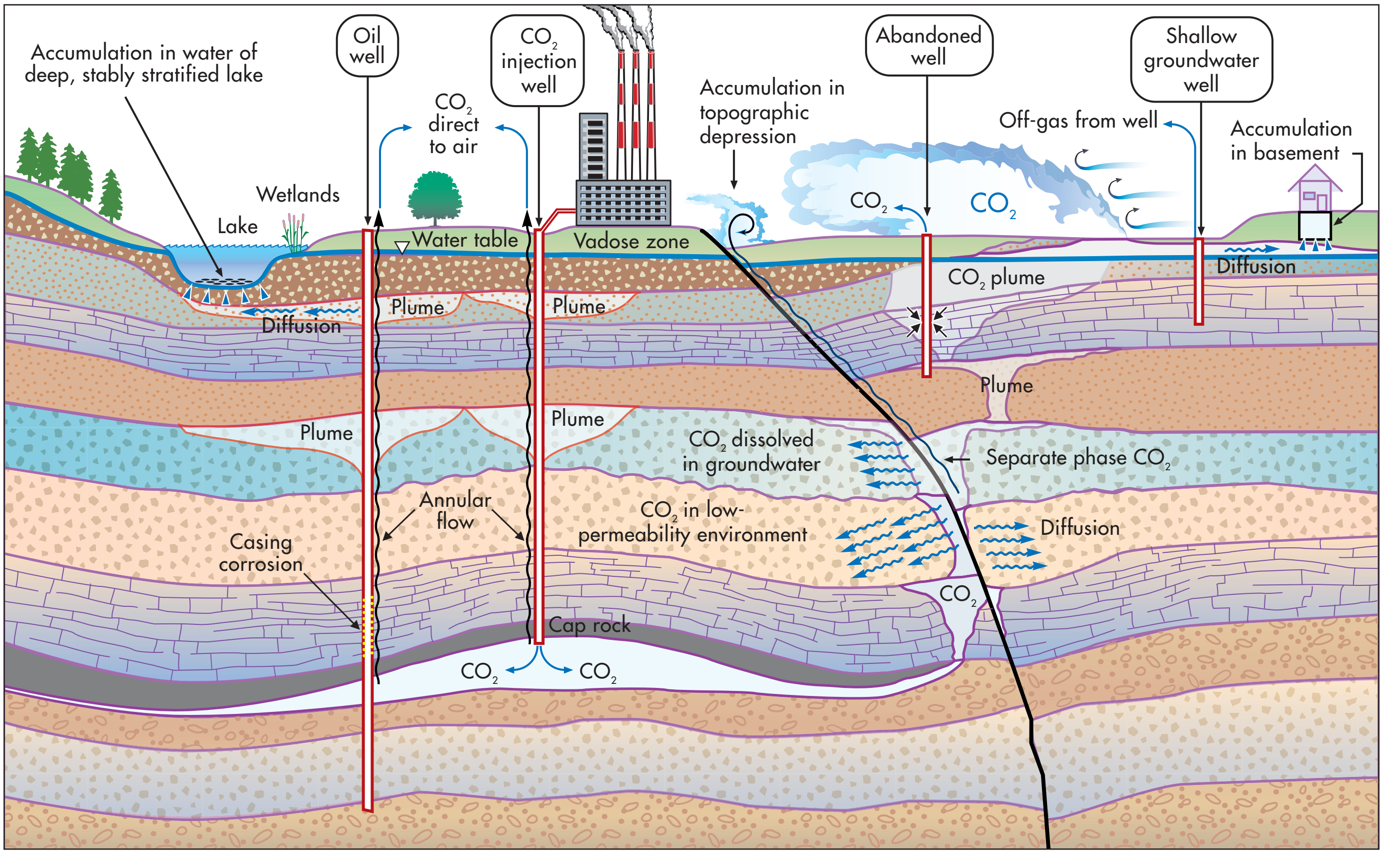
Public-Private Partnerships

For the CCS option to be available in time for large-scale deployment when needed, a series of field tests and integrated technology demonstrations will be required, involving both public and private stakeholders in various geographic regions. To meet this need, the U.S. Department of Energy has launched seven Regional Carbon Sequestration Partnerships, involving state agencies, universities, research organizations, and private companies. (DOE uses the term *sequestration* to include both geologic storage of CO_2 and other efforts to reduce atmospheric concentrations of the gas, such as planting forests.) EPRI is managing specific projects in the West Coast and Southeast regional partnerships (WESTCARB and SECARB, respectively).

The first phase of the partnerships—begun in 2003 and completed in 2005—focused on characterizing regional opportunities for carbon capture and sequestration, and on identifying priorities for field tests. Each of the partnerships developed region-specific data on emissions sources and the potential storage capacity of various geologic formations, and also identified terrestrial ecosystems in the area that might have the capability for enhanced carbon uptake. This information has been incorporated into the National Carbon Sequestration Database (NATCARB) and was also used by the partnerships to calculate the capacity of potential CO_2 storage sites near a specific power plant or other source of emissions and even to estimate the cost of building a pipeline between the source and storage sites. Efforts were also made to identify and address issues related to CCS technology deployment, including safety, public perception, and permitting.

In the second phase of the partnership program, now under way, the task is to conduct 22 geologic injection field tests spread among the partnerships, as well as 13 terrestrial sequestration field tests. The overall goal of these tests is to validate the efficacy of various sequestration technologies in a variety of geologic and terrestrial CO_2 sinks. Specifically, in SECARB, EPRI and Mississippi Power are conducting a pilot project to inject CO_2 into a saline reservoir near Mississippi Power's Plant Daniel; EPRI is managing the pilot with technical support from Southern Company Services (SCS) and cost sharing from SCS, TVA, Mid-American, We Energies, and Ameren. In WESTCARB, the Salt River Project (SRP) and EPRI are conducting an injection test in a saline reservoir in Arizona; EPRI, SRP, and Lawrence Berkeley National Laboratory are managing the project with cost sharing from SRP. These tests will help validate and refine current models for storage in different geologic formations and demonstrate the effectiveness of available monitoring technologies to measure CO_2 movement through a formation. Eventually, the information gathered from the pilot projects will be used to produce guidelines for well construction and operation and to develop strategies for sequestration projects that can be used to optimize the storage capacity of various sink types.

The third, deployment, phase of the program is scheduled to begin in 2008 and continue through 2018. The large-volume storage demonstrations (0.4–4 $MtCO_2$) to be conducted as part of this phase are designed to address long-term issues, such as assessing the ability to sustain high levels of CO_2 injection at a site, improving well design to ensure integrity and increase storage volume, and determining the behavior of geologic formations in response to prolonged injection. The amount of CO_2 stored at individual sites during these demonstrations will approximate the scale needed by commercial facilities.



Properly sited, engineered, and managed geological reservoirs are expected to retain stored CO_2 for hundreds to thousands of years. However, effective monitoring systems will have to consider possible underground CO_2 migration paths through soils and groundwater and likely escape routes, including seismic fissures, abandoned water wells, and the injection wells themselves.

a number of years before peaking and eventually declining. Being able to optimize this process could have a significant impact on the cost of CO_2 storage.

New MMV technologies are also needed that are appropriate for storage systems in many different kinds of geologic formations and under a wide variety of circumstances. Such technologies are likely to provide information about the advantages of pursuing specific types of candidate storage facilities, as well as establishing empirical data on which new regulations and operating procedures can be based.

Finally, the potential for ocean storage of CO_2 may need to be explored more thoroughly, in terms of both risks and costs. One concern is that injection of CO_2 would lead to acidification of seawater—a process already taking place at the ocean surface because of increasing atmospheric concentrations and air-sea exchange of the gas. At present, the effect of increased acidity on marine ecosystems is unknown, and research is urgently needed to improve understanding of the risks involved, with or without injection. The costs of ocean storage also remain highly uncertain, with IPCC estimates ranging over a factor of 5, depending on specific technology and location choices.

"The next decade will be a critical time for developing CCS technologies and gaining experience with operating them," says Tom Wilson. "The vast amount of CO_2 storage ultimately required to make a difference in atmospheric concentrations of greenhouse gases represents a fundamental technological shift. Achieving success in this transition could well determine the long-term viability of coal as a major source of electricity."

In turn, a successful transition will depend on taking a highly proactive approach, adds Richard Rhudy: "What's needed is better-coordinated research into the outstanding questions about storage feasibility and more-systematic development of the massive infrastructure needed."

This article was written by John Douglas. Background information was provided by Tom Wilson (twilson@epri.com) and Richard Rhudy (rrhudy@epri.com).

Further Reading

Carbon Dioxide Capture and Geologic Storage. Technology report from the second phase of the Global Energy Technology Strategy Program (GTSP). 2006. http://www.battelle.org/gtsp.

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Innovation

Emerging technologies and cutting-edge engineering

Grid Shock Absorber Shows Promise

The large, interregional ac electricity grids on which the North American power infrastructure is based have inherent limitations that will increasingly hinder the ability to meet future demands for supply reliability and transmission services in a cost-effective way. Chief among the challenges facing these grids are the need to accommodate more-complex market operations, continued demand for transmission capacity expansion, and increasing vulnerability to interregional cascading outages. Most of the R&D related to these challenges has focused on the development of advanced ac-based technology capable of enhancing grid security and minimizing cascade events. This strategy will require great investment in equipment and very complex systems, some of which are still in relatively early stages of development. Moreover, installing more ac ties and devices will add to the complexities of grid operations and dynamics, which are at the core of increased concerns over supply reliability.

One promising alternative is the concept known as the grid shock absorber: the reconfiguration of existing large interregional networks into sets of asynchronously operated sectors, connected exclusively by links based on new dc technology. It is believed that such dc-aided segmentation would minimize, and possibly eliminate, system stability issues and improve the control of power flows between sectors under both normal and emergency conditions. This system could also facilitate expanded transfer capability and enhance the position of states in the structuring and regulation of electricity markets.

Collaborative Development

DC Interconnect (DCI) has been developing the grid segmentation concept, which takes advantage of both ac and dc technologies, as a way to help the electric power industry meet future needs in a cost-effective manner. Independently, EPRI has been developing the dc-integrated grid shock absorber concept to increase the robustness and integrity of large interconnected transmission grids; this concept is an extension of EPRI's work on transmission controllers based on the voltage-sourced converter (VSC). Together, DCI and EPRI have embarked on a collaborative research effort to ascertain the benefits and cost-effectiveness of grid segmentation and the grid shock absorber concept within a test area comprising a large section of the U.S. Eastern Interconnection (EI). Initial results from simulations of power flow dynamics in the EI showed marked improvements in grid reliability and power transfer capability.

The DCI-EPRI collaboration started with a proof-of-concept evaluation of the benefits of inserting VSC-based dc links into a portion of the EI. The simulated dc links were inserted at appropriate locations as back-to-back pairs having VSC-based ties. Limiting this phase of the study to the VSC converter pairs was a measure of expediency to facilitate an initial look at the concept. In practice, segmentation will also involve converting ac lines into dc lines and potentially investing in long-haul high-voltage dc (HVDC) transmission in addition to inserting back-to-backs.

Reliability improvements were assessed by examining the dynamic performance of the grid before and after segmenting it, using a year 2011 model of the EI loads, resources, and transmission systems. The results of the assessment support the technical feasibility of using the grid shock absorber and grid segmentation

Increased Vulnerability to Cascading Outages

The risk of cascading outages is rising for three reasons: there are more initiating events to contend with, the frequency of occurrence of random initiating events is on the increase because of equipment aging, and network dynamics are becoming more complex.

The spectrum of the initiating events of concern includes poor right-of-way management (e.g., tree trimming), extreme weather excursions, operator error, and acts of sabotage. The last two categories are attracting particular attention from policymakers and transmission operators because the expansion of power trading and scheduling activities has increased opportunities for operator error, and political strife has added to the potential for sabotage.

Thirty years ago, power transfer limits were dictated by a single, "most severe" contingency, where a line or a transformer is loaded to its limit. Today's increasingly meshed systems and higher line loadings bring into play multiple contingencies and wider impacts that push more lines to their operating limits and more areas to their voltage stability limits. Each contingency tests the system more rigorously, and the contingencies now arise more often. The risk of triggering hidden failures, overload cascading, voltage collapse, or operator error is much higher than it was in the days of relatively sparse and lightly loaded networks.

concepts for improving grid reliability and power transfer capability in large transmission interconnections. The reliability benefits were evident and clear, and gains in the form of increased power transfer capability were strongly indicated.

The Advantages of Asynchronous Segmentation

One of the most important goals in enhancing grid integrity is to keep local power flow instabilities from escalating into a systemwide cascading outage; such an outage occurred on August 14, 2003, when much of the greater EI Northeast was blacked out. The problem is that on an ac network, the entire system must operate at a fixed frequency (60 cycles in the United States) with nearly exact synchronicity to remain stable. When even relatively small disturbances occur and throw the local frequency off, the rest of the grid can be affected because of its tight interconnection. The entire grid becomes vulnerable to every contingency on the system.

With asynchronous dc links in place to segment the whole, each sector's frequency is allowed to deviate quasi-independently from the nominal level in response to disturbances within a sector, with segmentation limiting the effects on neighboring areas. For instance, loss of a generator will result in a drop in frequency within a sector, causing the sector's other generators to attempt to compensate for the loss; generators in neighboring sectors, however, will respond only to the extent that support is delivered by the links, preventing a cascade scenario from developing. The ability of the VSC-based links to supply reactive power also helps ensure stability. The DCI-EPRI simulations show that segmenting a grid with a system of dc links would completely eliminate the regional stability limitations of ac ties and their inherent power flow patterns.

The work reported here is based on simple controls applied on each dc link; no central control is necessary beyond scheduling normal-condition flows through the links themselves. The dc links increase or decrease power flow in response to changes in frequency on either side of a link, responding much the way a typical turbine-generator governor mechanism does. Other, more-elaborate, control approaches are also possible.

A segmented power grid would be made up of asynchronously operated ac sectors (oval shapes) linked by dc "shock absorbers" (green rectangles) in the form of back-to-back VSC-based dc controllers. Full implementation of the concept may include conversions of existing ac lines to dc (blue lines) and the addition of long-haul HVDC lines (yellow lines).

The primary focus of the initial work was on demonstrating reliability improvements, although power transfer capability gains were also observed. By eliminating instability constraints, the dc links can increase the use of a sector's spinning reserve, greatly reducing the amount of tie capability that must be set aside to cover loss of generation. Nearby ac lines can be operated closer to their thermal limits because the dc link can quickly reduce power to correct overloads during ac contingencies. The links also allow power to be routed to stronger routes that may inherently be less fully utilized. Finally, converting ac lines to dc could double the current capacity of some rights-of-way. The combination of these benefits has the potential to more than double the transfer capability of many regional interfaces.

Next Steps

The proof-of-concept research reported here has clearly shown that segmenting existing ac interconnections with back-to-back VSC-based controllers can improve grid reliability and increase transfer capability, although the latter capability has not yet been quantified. A major advantage of the concept is that the required technology already exists—no major technical hurdles are foreseen. Still, the electricity industry is heavily invested in ac-based infrastructure; the challenges the concept must overcome are largely economic and institutional. A full EI implementation will have a high cost but potentially greater benefits than more-traditional approaches. Whether the benefits are sufficiently higher to overcome the institutional barriers won't be evident until completion of the technical and economic assessment of EI-wide grid segmentation.

With the successful completion of the proof-of-concept research, DCI and EPRI are now proceeding with the remaining phases of the grid shock absorber research project. The completed research will include identification of the optimal number of sectors for the EI, a thorough technical feasibility study, and a cost-benefit analysis to test the economic viability of implementing a segmentation scheme. A similar effort is being launched for the U.S Western Interconnection.

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Technology at Work

Member applications of EPRI science and technology

PSE&G and PG&E Test Helicopter Live Work at EPRI's Lenox Center

With today's interconnected and heavily loaded transmission network, putting lines out of service for maintenance is becoming less economically viable. Live working—performing maintenance on energized lines—is an increasingly attractive option. Public Service Electric and Gas Company (PSE&G) has been a pioneer in live-line work since the 1970s, making worker safety its top priority. Beginning with land-based procedures using ladders and bucket trucks to put workers into position, PSE&G progressed in the 1990s to aerial live work—using helicopters to speed workers to remote areas to perform repairs.

Although some private companies were already performing helicopter live work, their equipment and practices were not backed by thorough engineering or uniform safety standards. A particular problem was the worker platform, typically mounted on the helicopter landing skid so the legs of a worker seated on the platform extended below the skid. This presented two problems: serious leg injuries in the event of a hard landing and the risk that dangling legs would impinge on the air insulation space between wires, which can cause sparkover.

PSE&G worked with George Washington University to design an ergonomically advanced helicopter platform for live work. The new platform is mounted higher to keep the worker's legs within the helicopter envelope, an arrangement that helps maintain proper clearance between phases and reduces the risk of leg injuries. To test the new platform's performance, PSE&G turned to the EPRI Lenox Center in Massachusetts. The center has a large array of transmission structures and high-voltage test equipment to allow full-scale engineering testing that replicates real-world conditions; it is the only laboratory with the equipment and expertise to perform extensive tests on energized high-voltage lines with a helicopter fully loaded with fuel and operating at full throttle.

Building on its experience in testing helicopters in energized environments, the Lenox Center staff performed a series of electrical tests to evaluate the platform's performance in an actual live work situation. For example, tests were conducted to detect any voltage differences between the platform components or between the platform and a mannequin representing the worker. Such a voltage differential could cause sparks that might affect the worker or interfere with the helicopter's instruments. Findings showed no voltage differences between platform components, although some signs of low-level sparking were observed between the platform and mannequin; the center staff recommended minor modifications to minimize this occurrence. The staff also made recommendations for maintaining a good electrical connection between the bonding wand and the platform to ensure worker safety.

While helicopter live work has been performed for some years on 500-kV and 345-kV lines, the technique has generally not been tried on lower-voltage lines, which have smaller interphase spaces. As PSE&G gained experience and proficiency with aerial live work, the utility sought to extend its capability to such lower-voltage lines. In collaboration with Pacific Gas and Electric Company (PG&E) and EPRI, PSE&G and the center staff recently completed a series of helicopter live work tests at Lenox on 230-kV transmission lines with vertical phase configuration. The tests included evaluation of helicopter approach positions to ensure that proper distances could be maintained between phases; it also involved training in live work procedures with the new worker platform. Results demonstrated that helicopter live work on 230-kV lines is feasible and that proper minimum approach distances can be maintained.

"Live work requires extraordinary attention to worker safety, especially in aerial work, where the combination of high-voltage wires and hovering helicopters offers scant margin for error," says PSE&G's Tom Verdecchio. "Using the EPRI Lenox Center to perform electrical testing of the new helicopter platform and live work procedures has helped us increase worker safety and improve our transmission line maintenance. This collaboration with EPRI also allows us to share what we've learned with the rest of the industry."

Building on their own live work experience and EPRI research, PSE&G and PG&E continue to work with EEI, IEEE, IBEW, OSHA, FAA, and EPRI to develop uniform safety standards for aerial live work that will help ensure industry-wide adoption of safe practices.

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BPA Uses Daytime Corona Camera to Identify Faulty Insulator

Maintenance costs are among the largest expense items in the operation of overhead transmission systems, and detecting faulty power system components before they fail or cause damage is a particularly effective way to keep these costs under control. Inspecting equipment while it is in service can be challenging, however, especially in cases of difficult-to-access transmission line components suspended high over inhospitable terrain.

Corona or arcing activity is one telltale indicator of faulty components; detection of such electrical discharge can pinpoint the location of problems, especially those involving polymer (non-ceramic) insulators. Unfortunately, discharge activity is nearly impossible to see in daylight, and night viewing is impractical and expensive. To help assess the condition of in-service transmission components, the Bonneville Power Administration (BPA) turned to advanced visualization technology—a daylight corona detection camera. The EPRI-developed camera lets users clearly see corona activity that is virtually invisible during the daytime, enabling utility staff to perform in-service inspections and identify faulty components before they can lead to costly failures.

BPA recently used the camera to inspect components on its 500-kV Colstrip line, a three-phase, double-circuit line that carries power from Montana to Washington across the peaks and canyons of the Rocky Mountains. Crossing the rugged landscape requires long spans between towers, and the structures face punishing winds. To protect the conductors from the effects of high winds, BPA installed

polymer insulators between phases. These interphase spacers keep the conductors safely separated to prevent galloping and flashover, which could cause mechanical and electrical failure. Because these spacers perform a critical role, inspecting their condition is essential—yet it is virtually impossible with conventional visual techniques. At the distances involved, binoculars and spotting scopes cannot detect small cracks or other defects that could lead to insulator failure and perhaps to a costly forced outage.

Using the daytime corona camera, BPA staff clearly observed corona and arcing activity at one of the line's interphase spacers. Having located the potential problem, a maintenance crew used a spacer cart to replace the component—which proved to be cracking and deteriorating—during a scheduled maintenance outage. Further deterioration of the interphase spacer could have led to mechanical or electrical damage and possibly disruption of power system operations and customer service across a large portion of the Pacific Northwest. Removal of the cracked component from service will also allow BPA and EPRI to investigate degradation mechanisms and apply the lessons learned to future preventive maintenance efforts.

The camera works by blocking out sunlight and capturing images of both the corona discharge and the object under investigation. A bi-spectral imaging process then superimposes the corona image on the object image to pinpoint the location of the discharge. The camera's high sensitivity and narrow field of view enable long-distance operation, allowing inspection of components that are difficult to access. In addition to the inspection of overhead transmission and distribution lines, the camera can be used in the detection of corona and arcing at substations; it is also able to locate sources of radio frequency interference and audible noise.

To help users successfully apply the daytime corona camera in the field, EPRI has developed two practical references: *Guide to Corona and Arcing Inspection of Transmission Lines* (Report 1001910) and *Guide to Corona and Arcing Inspection of Substations* (Report 1001792). These guidebooks catalog discharge activity through infrared and visual images that illustrate conditions commonly affecting transmission line and substation components. The guides are designed to aid utility field crews in using the results of a daytime corona inspection to assess the condition of components, identify specific problems, and determine a course of action. EPRI has also established the Daytime Discharge Inspection User Group for utilities, camera manufacturers, and contractors; the user group promotes personnel training, the sharing of utility and vendor experience, and the development of field guides and inspector requirements.

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Technical Reports & Software

For more information, contact the EPRI Customer Assistance Center at 800.313.3774 (askepri@epri.com). Visit EPRI's web site to download PDF versions of technical reports (www.epri.com).

Environment

Scaling Restoration Projects for 316(b) Compliance
1010110 (Technical Report)
Program: Section 316(a) and (b) Fish Protection Issues
EPRI Project Manager: Douglas A. Dixon

Benefits Valuation Studies Under Section 316(b) of the Clean Water Act: An Overview
1012539 (Technical Report)
Program: Section 316(a) and (b) Fish Protection Issues
EPRI Project Manager: Douglas A. Dixon

Introduction to Radio Frequency Measurements
1012568 (Technical Report)
Program: EMF Health Assessment and RF Safety
EPRI Project Manager: Robert I. Kavet

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1012569 (Technical Report)
Program: Occupational Health and Safety
EPRI Project Manager: Gabor Mezei

Development of a Method to Identify Respirable Crystalline Silica (Quartz) in Coal Fly Ash
1012571 (Technical Report)
Program: Occupational Health and Safety
EPRI Project Manager: Gabor Mezei

Program on Technology Innovation: Managing the Risks of Climate Policies
1012577 (Technical Report)
Program: Greenhouse Gas Reduction Options
EPRI Project Manager: Thomas F. Wilson

Characterization of Field Leachates at Coal Combustion Product Management Sites
1012578 (Technical Report)
Program: Groundwater Protection and Coal Combustion Products Management
EPRI Project Manager: Kenneth J. Ladwig

Field Evaluation of the Comanagement of Utility Low-Volume Wastes With High-Volume Coal Combustion By-Products: PA Site
1012580 (Technical Report)
Program: Groundwater Protection and Coal Combustion Products Management
EPRI Project Manager: Kenneth J. Ladwig

MANAGES 3.0, Groundwater Data Management and Evaluation Software, Version 3.0
1012581 (Software)
Program: Groundwater Protection and Coal Combustion Products Management
EPRI Project Manager: Kenneth J. Ladwig

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1012582 (Technical Report)
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EPRI Project Manager: Kenneth J. Ladwig

Chemical Constituents in Coal Combustion Product Leachate: Beryllium
1012583 (Technical Report)
Program: Groundwater Protection and Coal Combustion Products Management
EPRI Project Manager: Kenneth J. Ladwig

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1012584 (Technical Report)
Program: Groundwater Protection and Coal Combustion Products Management
EPRI Project Manager: Kenneth J. Ladwig

Chemical Attenuation Coefficients for Selenium Species Using Soil Samples Collected From Selected Power Plant Sites
1012585 (Technical Report)
Program: Groundwater Protection and Coal Combustion Products Management
EPRI Project Manager: Kenneth J. Ladwig

Demonstration of Decision Tool for Selection of Distribution Poles
1012598 (Technical Report)
Program: Transmission and Distribution Soil and Water Issues
EPRI Project Manager: Mary E. McLearn

Modeling Arsenic Fate and Transport in Groundwater
1012604 (Technical Report)
Program: Transmission and Distribution Soil and Water Issues
EPRI Project Manager: Mary E. McLearn

Power Plant Integrated Systems: Chemical Emissions Studies Database (PISCES Database), Version 2006a
1012611 (Software)
Program: Plant Multimedia Toxics Characterization (PISCES)
EPRI Project Manager: Naomi Lynn Goodman

Technical Resource Document for Modified Ristroph Traveling Screens
1013308 (Technical Report)
Program: Section 316(a) and (b) Fish Protection Issues
EPRI Project Manager: Douglas A. Dixon

Design Considerations and Specifications for Fish Barrier Net Deployment at Cooling Water Intake Structures
1013309 (Technical Report)
Program: Section 316(a) and (b) Fish Protection Issues
EPRI Project Manager: Douglas A. Dixon

Program on Technology Innovation: Analyses of International T&D Systems With the Contact Voltage Modeler (CVM) Program
1013310 (Technical Report)
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EPRI Project Manager: Robert I. Kavet

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1013313 (Technical Report)
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EPRI Project Manager: Paul Chu

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1014334 (Software)
Program: EMF Health Assessment and RF Safety
EPRI Project Manager: Brian Cramer

Ohio River Ecological Research Program
1014337 (Technical Report)
Program: Section 316(a) and (b) Fish Protection Issues
EPRI Project Manager: Douglas A. Dixon

Program on Technology Innovation: Water Resources for Thermoelectric Power Generation
1014487 (Technical Report)
Program: Watershed Management and Water Resource Sustainability
EPRI Project Manager: Robert A. Goldstein

Modeling Deposition of Atmospheric Mercury: Case Studies
1014683 (Technical Report)
Program: Air Toxics Health and Risk Assessment
EPRI Project Manager: Leonard Levin

Generation

Boiler OIO 2.0—Boiler Overhaul Interval Optimization Software, Version 2.0
1008125 (Software)
Program: Boiler Life and Availability Improvement Program
EPRI Project Manager: Richard Tilley

Fossil Power Plant Cost and Performance Trends
1009966 (Technical Report)
Program: Understanding Power and Fuel Markets and Generation Response
EPRI Project Manager: Jeremy B. Platt

RLSM 1.0—Remaining Life Simulation and Monitoring, Version 1.0 on CD for Win 2000/XP
1010177 (Software)
Program: Boiler Life and Availability Improvement Program
EPRI Project Manager: Richard Tilley

EPRI Coal-Flow Loop: Evaluation of Extractive Methods—Addendum
1010319 (Technical Report)
Program: Boiler Life and Availability Improvement Program
EPRI Project Manager: Jose C. Sanchez

Renewable Energy Calculator, RECALC, Version 1.2
1010408 (Software)
Program: Combustion Performance and NO_x Control
EPRI Project Manager: Charles R. McGowin

Technical Assessment Guide (TAG)—Power Generation and Storage Technology Options
1012192 (Technical Report)
Program: Technology-Based Business Planning Information and Services (TAG)
EPRI Project Manager: Gopalachary Ramachandran

Condensate Polishing State of Knowledge Assessment
1012208 (Technical Report)
Program: Boiler and Turbine Steam and Cycle Chemistry
EPRI Project Manager: Kevin Shields

Generator On-Line Monitoring and Condition Assessment
1012216 (Technical Report)
Program: Steam Turbines, Generators, and Balance-of-Plant
EPRI Project Manager: Jan Stein

Turbine Cycle Heat Rate Monitoring: Technology and Application
1012220 (Technical Report)
Program: Steam Turbines, Generators, and Balance-of-Plant
EPRI Project Manager: Stephen H. Hesler

CoalFleet User Design Basis Specification for Coal-Based Integrated Gasification Combined Cycle
1012227 (Technical Report)
Program: Future Coal Generation Options (Including CO_2 Capture)
EPRI Project Manager: Jeffrey Phillips

Natural Gas Price Uncertainty: Establishing Price Floors
1012249 (Technical Report)
Program: Understanding Power and Fuel Markets and Generation Response
EPRI Project Manager: Jeremy B. Platt

Framing SO_2 Market Expectations
1012250 (Technical Report)
Program: Understanding Power and Fuel Markets and Generation Response
EPRI Project Manager: Jeremy B. Platt

Slag Deposition Monitoring Using Strain Gage Technology
1012261 (Technical Report)
Program: I&C and Automation for Improved Plant Operations
EPRI Project Manager: Aaron James Hussey

Maintenance Excellence Self Assessment (MESA) Computer-Based Training (CBT) Version 1.0
1012278 (Software)
Program: Maintenance Management and Technology
EPRI Project Manager: Ray Henson Chambers

Guidelines for Enhancing the Functions of Critical Equipment Owners at Fossil Power Plants
1012279 (Technical Report)
Program: Maintenance Management and Technology
EPRI Project Manager: Ray Henson Chambers

Outage Management Guidelines for Fossil Fueled Power Plants
1012281 (Technical Report)
Program: Maintenance Management and Technology
EPRI Project Manager: Ray Henson Chambers

EPRI Coal-Flow Loop
1012640 (Technical Report)
Program: Combustion Performance and NO_x Control
EPRI Project Manager: Jose C. Sanchez

Sixth Intelligent Sootblowing Workshop Proceedings
1012646 (Technical Report)
Program: Combustion Performance and NO_x Control
EPRI Project Manager: Jeffrey Stallings

Protocol for Laboratory Testing SCR Catalyst Samples
1012666 (Technical Report)
Program: Post-Combustion NO_x Control
EPRI Project Manager: David R. Broske

IECCOST 2.0—Economics of Integrated Emissions Control Technology, Version 2.0
1012670 (Software)
Program: Integrated Environmental Controls (Hg, SO_2, NO_x, and Particulate)
EPRI Project Manager: Charles E. Dene

Mercury Control Technology Selection Guide
1012672 (Technical Report)
Program: Integrated Environmental Controls (Hg, SO_2, NO_x, and Particulate)
EPRI Project Manager: Ramsay Chang

Mercury Emissions From Curing Concretes That Contain Fly Ash and Activated Carbon Sorbents
1012696 (Technical Report)
Program: Coal Combustion Product Use
EPRI Project Manager: Kenneth J. Ladwig

Heat Recovery Steam Generator (HRSG) Chemical Cleaning Guidelines Case Studies
1012756 (Technical Report)
Program: Heat Recovery Steam Generator (HRSG) Dependability
EPRI Project Manager: Barry Dooley

SAFER-PC Version 2.2, Stress and Fracture Evaluation of Rotors—Personal Computer, Version 2.2
1013044 (Software)
Program: Steam Turbines, Generators, and Balance-of-Plant
EPRI Project Manager: Paul Zayicek

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1013262 (Technical Report)
Program: Grid Operations and Planning
EPRI Project Manager: Charles R. McGowin

NO_x Emission Case Studies for Wall-Fired Boilers Firing Bituminous Coal
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Program: Combustion Performance and NO_x Control
EPRI Project Manager: Richard Marshall Himes

The Effect of SO_3 Sorbents on ESP Performance: A State-of-the-Art Review
1013348 (Technical Report)
Program: Particulate and Opacity Control
EPRI Project Manager: Ralph F. Altman

FMAC: Coal-Handling Maintenance Guide
1013349 (Technical Report)
Program: Fossil Maintenance Applications Center (FMAC)
EPRI Project Manager: Leonard Loflin

Proceedings: International Conference on Boiler Tube and HRSG Tube Failures and Inspections
1013629 (Technical Report)
Program: Boiler Life and Availability Improvement Program
EPRI Project Manager: Barry Dooley

Proceedings: International Conference on the Interaction of Organics and Organic Cycle Treatment Chemicals With Water, Steam, and Materials
1013630 (Technical Report)
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EPRI Project Manager: Barry Dooley

Program on Technology Innovation: Materials Degradation in Wind Turbines
1013662 (Technical Report)
Program: Technology Innovation and Generation
EPRI Project Manager: Barry C. Syrett

NO_x Reduction Study at New York Power Authority's Charles Poletti Station
1013671 (Technical Report)
Program: Combustion Performance and NO_x Control
EPRI Project Manager: Anthony Facchiano

Program on Technology Innovation: Fossil Power Plant Cost and Performance Trends
1014405 (Technical Report)
Program: Understanding Power and Fuel Markets and Generation Response
EPRI Project Manager: Jeremy B. Platt

FMAC Technical Library CD—2006
1014411 (Technical Report)
Program: Fossil Maintenance Applications Center (FMAC)
EPRI Project Manager: Leonard Loflin

Understanding Mercury Chemistry in Coal-Fired Boilers
1014418 (Technical Report)
Program: Integrated Environmental Controls (Hg, SO_2, NO_x, and Particulate)
EPRI Project Manager: George R. Offen

Assessment of FTIR and Tunable Diode Laser Monitoring of Combustion-Based Species
1014434 (Technical Report)
Program: Combustion Performance and NO_x Control
EPRI Project Manager: Richard Marshall Himes

Comparison of Furnace Flue Gas Temperature Monitors
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Program: Combustion Performance and NO_x Control
EPRI Project Manager: Richard Marshall Himes

Program on Technology Innovation: Proceedings of the Expert Workshop on Creep-Fatigue Damage Interaction
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EPRI Project Manager: David W. Gandy

Program on Technology Innovation: Assessment of Advanced Feedwater Filtration for Electric Power Generating Stations
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Triple Junction Module Performance in Low Light Conditions
1014526 (Technical Report)
Program: Renewable Energy Technology and Strategy
EPRI Project Manager: Alejandro Jimenez

Rich Reagent Injection Technology for NO_x Control in Cyclone-Fired Boilers
1014530 (Technical Report)
Program: Combustion Performance and NO_x Control
EPRI Project Manager: Richard Marshall Himes

Maintenance Work Package Planning Guidance for Fossil Power Plant Personnel
1014547 (Technical Report)
Program: Maintenance Management and Technology
EPRI Project Manager: Ray Henson Chambers

Productivity Improvement for Fossil Steam Power Plants, 2006
1014598 (Technical Report)
Program: Steam Turbines, Generators, and Balance-of-Plant
EPRI Project Manager: Stephen H. Hesler

Nuclear Power

Plant Support Engineering: Guidelines for the Technical Evaluation of Replacement Items in Nuclear Power Plants
1008256 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Leigh Aparicio

BWRVIP-163: BWR Vessel and Internals Project—Evaluation of Advanced Mitigation Techniques for BWR Internals
1009878 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Rajeshwar Pathania

Characterization of Neutron-Irradiated 300-Series Stainless Steels
1009896 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Rajeshwar Pathania

Aging Assessment Field Guide—Japanese Translation for TEPCO Customers Only
1012063 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Neil Wilmshurst

Technical Basis for Steam Generator Tube Integrity Performance Acceptance Standards
1012984 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Mohamad M. Behravesh

Beaver Valley-1 Noise Pilot Project Results, Experience, and Recommendations
1012985 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Mohamad M. Behravesh

Steam Generator Integrity Assessment Guidelines
1012987 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Mohamad M. Behravesh

User Manual—Crystal Ball Monte Carlo POD Simulator
1012988 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Mohamad M. Behravesh

Plant Support Engineering: Life Cycle Management Planning Sourcebooks—Medium-Voltage (MV) Cables and Accessories (Terminations and Splices)
1013187 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Gary John Toman

Optimization of Fire Protection Impairments at Nuclear Power Plants
1013211 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Robert Kassawara

Materials Reliability Program: Screening, Categorization, and Ranking of B&W-Designed PWR Internals Components (MRP-189)
1013232 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Hui-Tsung Tang

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1013233 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Hui-Tsung Tang

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Program: Nuclear Power
EPRI Project Manager: Hui-Tsung Tang

Materials Reliability Program: Assessment of RHR Mixing Tee Thermal Fatigue in PWR Plants (MRP-192)
1013305 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Christine King

BWRVIP-164: BWR Vessel and Internals Project, Distributed Ligament Length (DLL) Version 3.0, Structural Analysis Software for BWR Internals
1013367 (Software)
Program: Nuclear Power
EPRI Project Manager: Robert G. Carter

MULTEQ 4 Web Version
1013368 (Software)
Program: Nuclear Power
EPRI Project Manager: Keith Paul Fruzzetti

EPRI Primary System pH Calculator, PHC Version 3.1
1013369 (Software)
Program: Nuclear Power
EPRI Project Manager: Keith Paul Fruzzetti

Fuel Reliability Database, FRED Version 2.1
1013370 (Software)
Program: Nuclear Power
EPRI Project Manager: Erik Mader

Steam/Feedwater Application, SFA Version 2.2
1013375 (Software)
Program: Nuclear Power
EPRI Project Manager: Albert J. Machiels

Corrosion Calculator for Cavitation, Version 1.0, Web Application Only
1013376 (Software)
Program: Nuclear Power
EPRI Project Manager: Albert J. Machiels

Waste Logic Liquid System Multi-Site Manager (LSMSM), Version 1.0
1013379 (Software)
Program: Nuclear Power
EPRI Project Manager: Sean P. Bushart

Program on Technology Innovation: Prediction and Evaluation of Environmentally Assisted Cracking in LWR Structural Materials
1013380 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Rajeshwar Pathania

An Interim Review of the Cooperative Irradiation-Assisted Stress Corrosion Cracking Research (CIR) Program
1013381 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Rajeshwar Pathania

Lead Adsorption on Nickel Alloys and Magnetite Under Faulted PWR Secondary Side Conditions
1013382 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Keith Paul Fruzzetti

Multivariable Assessment of Flow-Accelerated Corrosion and Steam Generator Fouling
1013383 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Keith Paul Fruzzetti

Pressurized Water Reactor Lead Sourcebook
1013385 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Keith Paul Fruzzetti

BWRVIP-157: BWR Vessel and Internals Project, Evaluation of RAMA Thermal Neutron Fluence Predictions
1013388 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Robert G. Carter

BWRVIP-161: Evaluation of Hatch Head Bolt Samples Using RAMA
1013393 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Robert G. Carter

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1013394 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Jeff Landrum

BWRVIP-160: BWR Vessel and Internals Project, BWRVIP Inspection Trends, 2006 Update
1013395 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Robert G. Carter

BWRVIP-100-A: BWR Vessel and Internals Project, Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Core Shrouds
1013396 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Robert G. Carter

BWRVIP-159: BWR Vessel and Internals Project, HWC/NMCA Experience Report and NMCA Applications—Guidelines
1013397 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Rajeshwar Pathania

BWRVIP-162: BWR Vessel and Internals Project, Analysis of a Noble Metal Surface/Crack Deposition Monitoring Specimen
1013398 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Rajeshwar Pathania

Materials Reliability Program: Reactor Vessel Head Boric Acid Corrosion Testing (MRP-164, Revision 1)
1013412 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Christine King

Materials Reliability Program: Destructive Examination of the North Anna 2 Reactor Pressure Vessel Head (MRP-197)
1013413 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Christine King

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1013414 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Christine King

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1013415 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Jack C. Spanner, Jr.

Materials Reliability Program: Transmission Electron Microscopy Evaluation of BOR-60 Irradiated Materials (MRP-200)
1013416 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Hui-Tsung Tang

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EPRI Project Manager: Hui-Tsung Tang

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1013418 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Hui-Tsung Tang

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1013420 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Keith Paul Fruzzetti

On-Line NobleChem™ Demonstration Fuel Surveillance Program for 2005
1013422 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Boching Cheng

Axial Offset Anomaly (AOA) Mechanism Verification in Simulated PWR Environments
1013423 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Jeffrey Charles Deshon

New Experimental Studies of Thermal Hydraulics in Rod Bundles (NESTOR)
1013424 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Jeffrey Charles Deshon

Evaluation of Fuel Cladding Corrosion and Corrosion Product Deposits From Callaway Cycle 14
1013425 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Jeffrey Charles Deshon

Fuel Reliability Program: Examination of GNF Channels From Nine Mile Point Unit 2 and Peach Bottom Unit 3
1013428 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Erik Mader

Poolside Fuel Inspection and Fuel Deposit Evaluation at Columbia Generating Station (Cycles 16 and 17)
1013431 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Boching Cheng

QUAD Cities-2 EOC 18 Fuel Examination and Assessment of Ultrasonic Cleaning
1013432 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Boching Cheng

NFIR-V Dimensional Stability Project
1013433 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Suresh Yagnik

NFIR-IV Disc Irradiation Project
1013434 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Suresh Yagnik

Guide Tube Creep and Growth
1013435 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Suresh Yagnik

Program on Technology Innovation: Effects of Multiple Seismic Events and Rockfall on Long-Term Performance of the Yucca Mountain Repository
1013444 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: John Kessler

Program on Technology Innovation: EPRI Yucca Mountain Spent-Fuel Repository Evaluation
1013445 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: John Kessler

Spent-Fuel Transportation Applications: Modeling of Spent-Fuel Rod Transverse Tearing and Rod Breakage Resulting From Transportation Accidents
1013447 (Technical Report)
Program: Nuclear Power
EPRI Project Manager: Albert J. Machiels

Power Delivery and Markets

Managing Transmission Line Wood Structures
1012308 (Technical Report)
Program: Overhead Transmission
EPRI Project Manager: Fabio Bologna

Overhead Transmission Inspection and Assessment Guidelines—2006
1012310 (Technical Report)
Program: Overhead Transmission
EPRI Project Manager: Fabio Bologna

EPRI Transmission Line Reference Book: Wind-Induced Conductor Motion
1012317 (Technical Report)
Program: Overhead Transmission
EPRI Project Manager: John Kar Leung Chan

Mitigation of Geomagnetically Induced Currents in Transformers
1012352 (Technical Report)
Program: Substations
EPRI Project Manager: David P. Rueger

Life Extension Guidelines—Knowledge Asset: Web Application, LEG-KA Web, Version 1.2
1012354 (Software)
Program: Substations
EPRI Project Manager: Bhavin Desai

Medium-Voltage Solid-State Current Limiter
1012368 (Technical Report)
Program: Substations
EPRI Project Manager: Ashok Sundaram

Improved Smart Ground Multimeter
1012386 (Technical Report)
Program: Substations
EPRI Project Manager: George Gela

Harmonization of IEC 61970, 61968, and 61850 Models
1012393 (Technical Report)
Program: Substations
EPRI Project Manager: Joseph William Hughes, Jr.

Distribution Fault Location
1012438 (Technical Report)
Program: Distribution System Operations, Maintenance, and Reliability
EPRI Project Manager: Matthew G. Olearczyk

Assessment of Elevated Neutral to Earth Voltages in Distribution Systems
1012439 (Technical Report)
Program: Distribution System Operations, Maintenance, and Reliability
EPRI Project Manager: Matthew G. Olearczyk

Lightning Surge Impact Module, LSIM Version 1.0
1012449 (Software)
Program: Power Quality Analysis Tools and Testing
EPRI Project Manager: Marek J. Samotyj

Guideline for Reliability Assessment and Reliability Planning—Evaluation of Tools for Reliability Planning
1012450 (Technical Report)
Program: Power Quality Analysis Tools and Testing
EPRI Project Manager: Marek J. Samotyj

The Effects of Post-Sag Inrush on Residential Equipment
1012451 (Technical Report)
Program: Power Quality Analysis Tools and Testing
EPRI Project Manager: Marek J. Samotyj

FastFit 2.5—FastFit, Version 2.5
1012472 (Software)
Program: Value and Risk in Energy Markets
EPRI Project Manager: Art M. Altman

Volatility and Variance
1012473 (Technical Report)
Program: Value and Risk in Energy Markets
EPRI Project Manager: Art M. Altman

Transmission Price Risk Management
1012475 (Technical Report)
Program: Value and Risk in Energy Markets
EPRI Project Manager: Art M. Altman

PSVSR—Power System Voltage Stability Region, PSVSR Version 1.0
1012479 (Software)
Program: Grid Operations and Planning
EPRI Project Manager: Pei Zhang

Probabilistic Load Flow Version 4.0
1012484 (Software)
Program: Grid Operations and Planning
EPRI Project Manager: Pei Zhang

Probabilistic Reliability Assessment (PRA) Version 4.0
1012485 (Software)
Program: Grid Operations and Planning
EPRI Project Manager: Pei Zhang

Asset Management Self-Assessment Guide for Power Delivery
1012495 (Technical Report)
Program: Power Delivery Asset Management
EPRI Project Manager: Jeremy Bloom

Guidelines for Power Delivery Asset Management: Long-Range and Strategic Planning
1012496 (Technical Report)
Program: Power Delivery Asset Management
EPRI Project Manager: Jeremy Bloom

Equipment Failure Modeling for Underground Distribution Cables
1012498 (Technical Report)
Program: Power Delivery Asset Management
EPRI Project Manager: Jeremy Bloom

Wood Poles Population With Testing
1012499 (Software)
Program: Power Delivery Asset Management
EPRI Project Manager: Jeremy Bloom

Guidelines for Intelligent Asset Replacement
1012500 (Technical Report)
Program: Power Delivery Asset Management
EPRI Project Manager: Jeremy Bloom

Value Modeling for Reliability of Distribution and Transmission Systems
1012501 (Technical Report)
Program: Power Delivery Asset Management
EPRI Project Manager: Jeremy Bloom

Transformer Population Model With Testing
1012504 (Software)
Program: Power Delivery Asset Management
EPRI Project Manager: Jeremy Bloom

New Approaches to Managing Transmission Project Risk
1012506 (Technical Report)
Program: Power Delivery Asset Management
EPRI Project Manager: Jeremy Bloom

Power System and Railroad Electromagnetic Compatibility Handbook
1012652 (Technical Report)
Program: Power Transmission and Substation Electromagnetic Compatibility (EMC)
EPRI Project Manager: Brian Cramer

Load Model Parameter Derivation Program (LMPD), Version 1.0
1013217 (Software)
Program: Grid Operations and Planning
EPRI Project Manager: Pei Zhang

Guide for Transmission Line Grounding
1013594 (Technical Report)
Program: Overhead Transmission
EPRI Project Manager: Andrew John Phillips

Human Operational Errors Involving Control, Relay, and Auxiliary Equipment
1013596 (Technical Report)
Program: Substations
EPRI Project Manager: George Gela

OTLOT 2.0: EPRI Overhead Transmission Line Inspection—Online Training, Version 2.0
1013616 (Software)
Program: Overhead Transmission
EPRI Project Manager: Fabio Bologna

European Demonstration of CIM-Based Products
1014384 (Technical Report)
Program: Grid Operations and Planning
EPRI Project Manager: David Becker

Measurement-Based Load Modeling
1014402 (Technical Report)
Program: Grid Operations and Planning
EPRI Project Manager: Pei Zhang

Testing of All Natural Tropical Wood Poles and Cross Arms to Meet ANSI 05.1 and 05.3
1014412 (Technical Report)
Program: Distribution System Operations, Maintenance, and Reliability
EPRI Project Manager: Ashok Sundaram

Program on Technology Innovation: Five-Wire Feasibility on Con Edison's Distribution Systems
1014413 (Technical Report)
Program: Distribution System Operations, Maintenance, and Reliability
EPRI Project Manager: Ashok Sundaram

Evaluation of Medium-Voltage Cable Joints
1014439 (Technical Report)
Program: Underground Distribution Systems
EPRI Project Manager: Robert John Keefe

Outage Scheduling Graphical Viewer, OSV Version 1.0
1014441 (Software)
Program: Grid Operations and Planning
EPRI Project Manager: Peter Hirsch

Applying Smart Logic for Fast Fault Screening to Entergy's Power System
1014544 (Technical Report)
Program: Grid Operations and Planning
EPRI Project Manager: Peter Hirsch

Generic OTS, EPRI Generic Operator Training Simulator, Version 2.0
1014566 (Software)
Program: Grid Operations and Planning
EPRI Project Manager: Peter Hirsch

Program on Technology Innovation: Wide-Area Frequency-Based Event Location Estimation
1014569 (Technical Report)
Program: Grid Operations and Planning
EPRI Project Manager: Peter Hirsch

ESVT, Energy Storage Valuation Tool—Modeling Stakeholder Costs and Benefits, Version 1.0
1014595 (Software)
Program: Energy Storage for Transmission or Distribution Applications
EPRI Project Manager: Robert B. Schainker

Profiling and Mapping of Intelligent Grid R&D Programs
1014600 (Technical Report)
Program: Intelligrid
EPRI Project Manager: Joseph William Hughes, Jr.

Chip-Scale Atomic Clocks (CSACs)
1014614 (Technical Report)
Program: Grid Operations and Planning
EPRI Project Manager: Peter Hirsch

Technology Innovation

Program on Technology Innovation: Scenario-Based Technology R&D Strategy for the Electric Power Industry—Final Report
1014385 (Technical Report)
Program: Technology Innovation
EPRI Project Manager: Robert B. Schainker

Program on Technology Innovation: Identification of Embedded Applications for New and Emerging Distributed Generation Technologies
1014570 (Technical Report)
Program: Technology Innovation
EPRI Project Manager: Stephen M. Gehl

EPRI Events

For further event listings, visit EPRI's web site (www.epri.com).

March

13–14
Technology Management Committee (TMC)
Charleston, South Carolina
Contact: Jane Faust, 704.595.2264, jfaust@epri.com

13–16
Third Power Delivery Asset Management Conference
Kansas City, Missouri
Contact: Angelica Kamau, 650.855.7987, akamau@epri.com

15
EPRI's Aging Assets Analysis Tutorial and Training and Focus Session on Reusable Analytics in Asset Management
Kansas City, Missouri
Contact: Angelica Kamau, 650.855.7987, akamau@epri.com

15
Higher-Voltage Resistive Heating Element Workshop
Charlotte, North Carolina
Contact: Laura Goldie, 650.855.2560, lgoldie@epri.com

20
Power Delivery Applications for Superconductivity
Charlotte, North Carolina
Contact: Amy Carreras, 704.595.2085, acarreras@epri.com

20–22
CoalFleet General Technical Meeting
Tampa, Florida
Contact: Carol Holt, 650.855.2436, cholt@epri.com

21–23
Forward Price Forecasting Workshop
Orlando, Florida
Contact: Suzette Yu, 650.855.2798, syu@epri.com

22–23
First Western Forum on Energy and Water Sustainability
Santa Barbara, California
Contact: events@epri.com

27–28
Transmission Design Task Force Meeting
Palo Alto, California
Contact: Laura Goldie, 650.855.2560, lgoldie@epri.com

April

3–5
Insulators and L&G TF Meeting
San Antonio, Texas
Contact: Tamara Clark, 202.293.6182, tclark@epri.com

May

8–11
Continuous Emission Monitoring User's Group Meeting
Phoenix, Arizona
Contact: Tina Jackman, tijackman@specialevents.com

June

5–7
EPRI 2007 Condensate Polishing Workshop
Palm Springs, California
Contact: Linda Nelson, 518.374.8190, lnelson@nycap.rr.com

6
Steam-Turbine and Generator Torsional Vibration Seminar
Birmingham, Alabama
Contact: Laura Goldie, 650.855.2560, lgoldie@epri.com

6–7
PSE Preserving Equipment Qualification Training Course
Charlotte, North Carolina
Contact: Beth McRimmon, 704.595.2036, bmcrimmon@epri.com

11–15
EPRI Redbook Seminar at Lenox
Lenox, Massachusetts
Contact: Tamara Clark, 202.293.6182, tclark@epri.com

11–15
Power Quality Applications (PQA)/ Advanced Distribution Automation (ADA) 2007 Conference
Long Beach, California
Contact: Lisa Wolfenbarger, 865.218.8026, lwolfenbarger@epri.com

12–13
PSE Cable Aging Management Training Course
Charlotte, North Carolina
Contact: Beth McRimmon, 704.595.2036, bmcrimmon@epri.com

18–22
Rod Control System Reliability Committee and Workshop
Lake Buena Vista, Florida
Contact: Linda Parrish, 704.595.2061, lparrish@epri.com

25–26
ASME/EPRI Radwaste Workshop
Ledyard, Connecticut
Contact: Linda Nelson, 518.374.8190, lnelson@nycap.rr.com

26–28
2007 EPRI International LLW Conference and Exhibit
Ledyard, Connecticut
Contact: Linda Nelson, 518.374.8190, lnelson@nycap.rr.com

July

16–18
26th Steam Generator NDE Workshop
Big Sky, Montana
Contact: Brent Lancaster, 704.595.2017, blancaster@epri.com

17–20
Infrared Thermography Utility Group (IRUG)
Beaver Creek, Colorado
Contact: Brent Lancaster, 704.595.2017, blancaster@epri.com

23–25
PSE Nuclear Utility Procurement Training Course
Charlotte, North Carolina
Contact: Beth McRimmon, 704.595.2036, bmcrimmon@epri.com

23–27
NMAC Terry Turbine Workshop
Chicago, Illinois
Contact: Linda Parrish, 704.595.2061, lparrish@epri.com

26–27
PSE ASME Procurement Training Course
Charlotte, North Carolina
Contact: Beth McRimmon, 704.595.2036, bmcrimmon@epri.com

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ELECTRIC POWER RESEARCH INSTITUTE

SPRING 2007

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