Financing and Licensing Nuclear Energy Parks

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Growing fears in the United States of the potential adverse effects of climate change have prompted many to consider lower carbon-emitting technologies for power generation. Nuclear power is becoming an attractive alternative because it offers clean, reliable baseload electricity. But solving the nuclear waste issue is a political challenge. Any proposal to increase power generation by building or expanding nuclear power plants must present a safe and politically viable option for managing nuclear waste.

Fortunately, new technologies may create the opportunity for a virtuous circle: by redeveloping older nuclear production facilities and sites, the United States may be able to develop lower-risk nuclear power plants that rely on used nuclear fuel to generate power, while preserving the communities, jobs, and technical knowledge of these facilities. This virtuous circle involves the development of so-called "energy parks," an alternative repurposing of older nuclear research laboratories and production facilities that promises multiple benefits. The hope is that by nurturing a public-private partnership of design-build firms, commercial operators, and research institutions, underpinned by both public and private finance, these sites can not only support a stronger economy and a cleaner environment, but represent an important opportunity to deploy emerging technologies that promise to "close" the nuclear fuel cycle by reusing fuel rods in a new power reactor.

This article describes the energy park concept, including the parks' initial formation, their future technologies, and financing and licensing. This concept is being driven by the benefits of a stronger economy, reduced carbon emissions, and closing the nuclear fuel cycle.

The U.S. Department of Energy (DOE) estimates that U.S. electricity demand will increase by 25 percent by 2030. U.S. energy policy has consistently taken a diversified portfolio approach to generating electricity. The country relies on nuclear power for 20 percent of its electrical supply. Also, U.S. energy policy has increasing concerns about dependence on imported oil. Finally, U.S. nuclear power facilities have achieved a marked and sustained improvement in availability, operating performance, and safety. Availability factors exceed 90 percent, and the U.S. nuclear industry is relied upon for baseload electricity. The safety of U.S. commercial nuclear power plants is unparalleled in the electrical generating industry: there has never been a worker fatality in a nuclear accident at an U.S. commercial nuclear power plant. Given these issues and increasing concerns about carbon emissions, the United States can meet at least part of the estimated 25 percent increase in demand by 2030 with nuclear power, if the nuclear waste issues are resolved.

Used nuclear fuel from the 104 currently operating plants in the United States must be permanently disposed of or recycled. The Nuclear Waste Policy Act of 1982 (NWPA) created a timetable and procedure for establishing a permanent, underground repository for high-level radioactive waste, such as used nuclear fuel. Under contracts signed with electric utilities pursuant to NWPA, the DOE committed to accepting used nuclear fuel at a federal storage or disposal repository, such as Yucca Mountain, by 1998. However, this deadline was not met, and such acceptance still has not occurred. If Senator Harry Reid's (D-NV) desires are met, Yucca Mountain will likely never be built. Recent government actions that may further delay or cancel plans for Yucca Mountain highlight the need to recycle used fuel and thus reduce the high-level waste products in a recycling reactor.

As an alternative to burying used nuclear fuel, the DOE is working with industry teams, including GE Hitachi Nuclear Energy (GEH), to solve the practical and technical challenges for safe, environmentally friendly, and economical methods of recycling used fuel. These plans involve a set of strategies for nuclear fuel recycling and the construction of recycling reactors that would consume recycled fuel, minimizing the need for its long-term storage and disposal, while generating low-carbon or no-carbon electricity. Early studies have shown that a GEH recycling reactor and fuel recycling center could produce power that would operate commercially over a sixty-year life without continued government assistance. This prospective solution faces three key requirements: it must be safe to the public and workers, have a low environmental impact, and be economical.

Public safety concerns, of course, include ensuring no nuclear materials that can make weapons can be diverted to such use. In the U.S. nuclear power industry, public safety

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and security concerns are paramount. GEH has proposed a proven technology to recycle used nuclear fuel and produce electricity, a solution that also reduces carbon emissions while minimizing the threat of proliferation. It meets the criteria of being safe to the public and workers, has a low impact on the environment, and is economical. GEH's proposed method of fuel recycling combines two technologies: electrometallurgical processing and a sodium-cooled recycling reactor. Bench-scale electrometallurgical processing of used nuclear fuel has been successfully demonstrated at U.S. national laboratories, and industrial-scale electrometallurgical processing has been used since the late 1800s in the U.S. aluminum industry.

Energy Parks to Generate Electricity for the Grid and to Perform Research

During the Cold War, the U.S. government developed laboratories and production facilities across the country to support the development and manufacture of nuclear weapons. For security and safety, these facilities were located in remote regions. Because the design, production, and maintenance of nuclear weapons require highly trained scientists, engineers, technicians, and production staff, many of these communities developed a highly educated workforce.

With the end of the Cold War, cleaning up these sites became a primary mission of the government. Policymakers began to consider how to best utilize such sites after weapons production and cleanup were completed and how then to redeploy the sites' resources (their workforce, assets, and infrastructure) in the communities that had grown up around these sites. More recently, public awareness of climate change and the contribution of carbon emissions to such change has begun to drive U.S. government policy towards reducing those emissions. The DOE, which has responsibility for operation of the national laboratories, has taken a leading role in trying to prompt this redeployment of resources by establishing its Energy Park Initiative, which is not strictly related to new nuclear projects. DOE is conducting public meetings in the communities surrounding its facilities to seek input from stakeholders. *See* 2009 DOE Regional Nuclear Suppliers Outreach Event, 74 Fed. Reg. 7225 (Feb. 13, 2009).

Burning fossil fuels to produce energy is the cause of approximately one-third of carbon emissions in the United States. Clean nuclear power can, therefore, play a role in reducing carbon emissions, and closing the nuclear fuel cycle offers options for safe management of used fuel. The DOE's Advanced Fuel Cycle Initiative (AFCI) has the mission to develop fuel cycle technologies that will meet the need for economical and sustained nuclear energy production while satisfying requirements for a controlled, proliferation-resistant nuclear-materials management system. AFCI can achieve the goals of developing American nuclear technologies and jobs in generating environmentally friendly electricity while resolving nuclear waste issues. AFCI develops used fuel-treatment technologies to support an expanding role for nuclear power in the United States; taken together with increases in wind, solar, and geothermal power generation, these technologies promise to lead the United States to lower carbon emissions from electricity production. AFCI technologies, when eventually commercialized, could directly create U.S.-based jobs in the low-carbon nuclear industry as well as support thousands of good-paying jobs. DOE Programmatic Environmental Impact Study (Oct. 2008), www.ne.doe.gov/peis/Draft_PEIS/Chapter_1.pdf. Investing in U.S. nuclear workers to meet U.S. energy needs is much better for the U.S. economy and national security than sending billions of dollars overseas to foreign oil- and gas-exporting nations.

After the recycling reactor fuel research and development is completed, something that is expected to require up to ten years, any used nuclear fuel stored at the energy park could be recycled and used in the proposed GEH recycling reactor. The risk of transporting spent fuel rods will be eliminated in such cases because the used nuclear fuel will already be on site. An energy park could consolidate used nuclear fuel from across the state in which it is constructed. Moreover, the state could negotiate acceptance of used fuel from neighboring states; this approach could also provide income from storage fees as well as feedstock for future reactor fuel.

The GEH fuel recycling process separates used nuclear fuel into three components: uranium that can be used in Canadian (CANDU) reactors or be reenriched and used in the current fleet of U.S. reactors; actinides, the long-lived radioactive material in used nuclear fuel that can be recycled into new fuel for recycling reactors; and fission products, the real waste in used nuclear fuel. The fission products would be separated out during the electrometallurgical process and stabilized in glass and metallic form for geologic disposal in a repository or elsewhere with a significantly shorter half-life—hundreds of years rather than millions of years—than the used fuel that is currently planned to go into the Yucca Mountain repository, thus reducing risk and extending the useful life of the repository.

GEH proposes use of the electrometallurgical fuel reprocessing technology rather than the conventional aqueous reprocessing technology because it is proliferation resistant, more environmentally friendly, and more economically viable. GEH has reviewed aqueous reprocessing and has concluded that it is neither economical nor environmentally friendly enough for use in the United States. The La Hague nuclear fuel recycling facility in France uses aqueous reprocessing, which according to Nuclear Energy Agency OECD (ISBN 92-64-02146-9) evaporates its radioactive effluent to minimize *but not eliminate* radioactive liquid waste discharge to the environment. This radioactive discharge would not be acceptable in the United States.

Conversely, GEH's electrometallurgical process does not use water, generates much less nuclear waste, and discharges no liquid waste to the environment. It uses electric current passing through a salt bath to separate the actinides (long-lived elements such as plutonium, americium, neptunium, and curium) from the fission products. In this process, plutonium is never separated from the other actinides, rendering it use-less for making a weapon and thus minimizing the threat of proliferation. These actinides can, however, be made into fuel rods for use in GEH's recycling reactor, which fissions or splits the actinides, destroying them forever into shorter-lived fission products that can then be encapsulated in glass and buried in much smaller quantities in a geological repository. The recycling reactor produces heat, which is converted into electrical energy in a conventional steam turbine. Recycling reactors are generating electricity today in Japan, France, and Russia and have operated safely at more than twenty sites around the world. They were operated safely at DOE laboratory sites for more than a decade until they were shut down in favor of the current light-water reactor technologies.

The 104 operating nuclear reactors in the United States currently produce approximately 2,000 tons of used nuclear fuel per year. Over their sixty-year operating life, these reactors will generate approximately 120,000 tons of used nuclear fuel. Twenty-six GEH recycling reactors and fuel recycling centers could use the entire 120,000 tons of used nuclear fuel while generating electricity, avoiding the emission of 400 million tons of CO_2 every year and reducing the amount of waste that would end up in a geological repository.

Under a DOE and industry energy-park approach, an energy park could be initially based on a government-built, commercially operated, conventional light-water reactor similar to the 104 reactors currently generating electricity in the United States today. A 1.3 gigawatt light-water nuclear reactor, operating at 93 percent capacity and producing electricity at 4 cents per kilowatt hour, could generate over $400 million in revenue annually. This cash flow, not dependent on year-to-year federal government appropriation, could fund research on new fuel recycling technologies and the new recycling reactor. The energy park will reduce financial risks in developing new technologies and is likely to involve public-private partnerships with a greater opportunity for public financing. The public-private partnerships—comprising design-build firms, commercial operators, and research institutions—would be devoted to redeveloping technology and infrastructure and reusing used nuclear fuel as the feedstock for such repurposed plants.

Economics of New Nuclear Technologies

Predictably, before investing in this new technology, power-generating utilities and the financial markets that fund such infrastructure will require proof that a full-scale recycling reactor and fuel recycling center can be built and operated successfully. Overall credit risk may be viewed as high until the first few plants have been built, but arguably the DOE can facilitate this new technology at energy parks across the country, using the infrastructure and U.S.-based nuclear talent already in place.

Determining the viability of financing new nuclear plants means having to accurately compute the cost of the power that will be generated and then comparing it to the cost of energy produced from alternative sources. One must consider capital costs, along with the costs for fuel, operations and maintenance, waste disposal and/or management, and decommissioning. Capital costs include plant construction and major planned modifications, factoring in the inflation over the initial construction period. Nuclear capital costs are higher than for other energy forms because of higher regulatory standards for containment buildings, safety-related equipment, and redundancy in safety-related systems.

On the other hand, fuel costs and carbon emissions associated with nuclear power are lower than those for power generated from fossil fuels. The cost of nuclear fuel includes mining uranium ore, converting it to so-called "yellowcake" (uranium oxide, or U_3O_8) and then to uranium hexafluoride gas, enriching the gas from 0.7 percent U^{235} to between 2 and 5 percent U^{235}, and then converting this enriched gas back into a solid in the form of uranium dioxide (UO_2) pellets. The pellets are then loaded into rods approximately 13 feet long, dozens of which are formed into a fuel assembly. Waste-related costs include the $0.001 per kilowatt-hour surcharge levied by the DOE for ultimate storage of the high-level waste in a repository such as Yucca Mountain. This money is currently in the U.S. Treasury's general fund and amounts to more than $20 billion. Decommissioning costs include restoring the site back to "greenfield" status. Usually, such restoration would occur over a long period of time, e.g., twenty years. However, current industry practice is that most sites will be used in perpetuity similar to the DOE energy parks for power-generation activities.

To determine the appetite for debt and/or equity financing of new nuclear technologies, GEH and Ernst & Young conducted interviews of personnel in three key groups in the financial community: equity investors, including utility operators and infrastructure funds, debt providers—institutions that issue and sell debt securities or provide credit enhancement/financial guarantees; and ratings agencies, which independently evaluate and rate corporate credit and project financing, as well as analyze credit risk.

Until the recent credit crunch, there was an appetite to fund economically feasible, investment-grade, long-term infrastructure and power assets. *See New Nuclear Generation in the United States: Keeping Options Open vs. Addressing an Inevitable Necessity* MOODY'S CORPORATE FINANCE (Oct. 2007). However, that credit environment no longer exists and may not exist for another year or more. Even after the credit environment normalizes, attracting debt lenders to new nuclear power projects will first depend on successful demonstrations at energy parks.

There is general consensus in the capital markets that nuclear power has a role to play in the future energy supply mix. However, few nuclear power projects exist in the U.S. market today as precedents on which credit markets can rely for financial modeling. To accept the risk of new commercial development, even after successful demonstrations at energy parks, capital markets may require greater financial liquidity, lower leverage in investments, and greater commitments of support or outright credit from the U.S. government.

Capital markets have five key considerations related to nuclear power and carbon: investment risks, construction risks, economic performance risks, financial structure concerns, and the risk-adverse nature of regulated utilities. First, capital markets will require that commercial nuclear projects demonstrate liquidity and proactive risk management to minimize financial exposure and maintain investment-grade credit ratings. Key investment risks include regulatory or licensing delays and changes, difficulties in finding sites or developing infrastructure, challenges in technology and/or design, and construction delays. Debt financing for regulatory approvals, licensing, and siting activities will generally be limited, as there is an expectation that these costs would be borne by the project's sponsor or equity investor (i.e., the utility or government). Given that there are currently no nuclear power plants in operation in the United States that close the fuel cycle, technology risk is a key concern. Although technology and design risks may be mitigated through fixed-price, scalable, turn-key solutions with appropriate warranty provisions, demonstrating the performance of the technology at energy parks will be key to long-term success.

Second, construction risk stands out as a significant risk and concern of capital markets participants, in part due to negative experiences that have plagued large, capital-intensive infrastructure projects in general, particularly from the nuclear industry in the last round of plant construction. Developments such as standardized designs, the combined construction and operating licensing process with the U.S. Nuclear Regulatory Commission (NRC), financial incentives from the federal government, and the use of fixed-price construction contracts and best-practice construction management are all viewed as strategies that should mitigate concerns and lower the risk of cost overruns and project delays. Investors would seek protection against rising steel and concrete costs, regional shortages of experienced and skilled labor, the possibly inadequate supply of key components, such as forged reactor vessels, and increased U.S. and international demand for new nuclear power plants that could have the potential to extend or delay construction schedules. Given the lack of recent construction experience and precedents, capital markets generally remain skeptical regarding first-of-a-kind facilities and are expected to stay on the sidelines until the DOE funds the first-of-a-kind plant at the energy park and it clears these design and construction hurdles.

Decommissioning and used nuclear fuel storage are generally not viewed as significant credit risks, as the existing nuclear decommissioning funding of $0.001 per kilowatt hour is generally viewed as adequate for the corresponding asset retirement obligations and because the DOE still assumes responsibility for long-term storage of used nuclear fuel under the NWPA of 1982.

Third, the economic and financial performance of nuclear power that closes the fuel cycle will be critical to overall commercial interest and financial viability. The availability and so-called "busbar costs" for plants that close the fuel cycle—that is, the cost per kilowatt hour of producing electricity, including capital and debt service, operation and maintenance, and fuel—must be competitive in the current electrical generation market. Cash flows must be sufficient to service debt with an appropriate cushion and under appropriate circumstances must also allow for equity distribution. Because an extended unplanned outage is a primary credit risk, nuclear operators will need a financial cushion and additional liquidity to maintain their investment-grade credit ratings. Expectations for such liquidity could reach as high as twice the annual fixed charges of providing for debt service, fixed operations and capital costs, and the cost of replacement power.

> Even after the credit environment normalizes, attracting debt lenders to new nuclear power projects will depend on successful demonstrations at energy parks.

Potential carbon legislation may provide a future cash-flow benefit to the nuclear power industry due to its low-carbon contribution to the electric energy mix. Several participants in the capital markets believe that carbon legislation will be implemented in the United States by 2013.

The fourth key consideration involves the financing structure, which includes traditional corporate-finance and project-finance structures. Under the former, the operator is the borrower with the backing of a parent company, typically an integrated utility. Operators with investment-grade credit ratings have been typically capitalized with upwards of 60 percent equity. Utilities may explore a "carve-out" of their nuclear assets into a separate company. There is a general view that these stand-alone entities would have higher leverage with potentially lower (noninvestment-grade) credit ratings.

Project finance structures in the broader power sector remain robust in the United States; however, they have not been used on nuclear projects. A project finance structure typically is a nonrecourse financing of a single asset or portfolio of assets where the lenders rely only on those specific assets to generate the cash flow needed to service its fixed obligations, chief of which are interest payments and repayment of debt. The lender's security is limited to the project's contracts and the physical assets. The amount of debt in a project finance structure is significantly higher than in a corporate financing, reaching upwards of 90 percent, depending on such factors such as the concession agreements and project risks.

It is unlikely that nuclear operators in unregulated markets would be able to build new nuclear power plants, except on a project-finance basis, with debt secured by the federal government. Merchant power producers, unlike regulated utilities, typically do not have the balance-sheet strength or capacity to finance these multibillion-dollar projects without access to highly leveraged, limited-recourse, project-finance structures. However, there still may be challenges to achieving a project-finance structure. Long-term off-take, concession, or power-purchase agreements are fundamental underpinnings to a project finance structure. In merchant power markets, these may not be available, which may impact the project's overall structure and financial viability.

Banks, utilities, and nuclear operators have little incentive to invest in technologies that close the nuclear fuel cycle because DOE is responsible for the long-term storage of used nuclear fuel.

The fifth key consideration in financing new nuclear power projects focuses on risk-adverse regulated utilities. There is a general consensus that new nuclear power projects will be built in regulated markets where the cost can be recovered and risk allocated to the rate base. These projects will have little difficulty attracting equity and debt financing once the technology has been proven. Given the general risk-adverse nature of utilities, combined with the size and scale of investment in new nuclear projects, utilities may move slowly and cautiously into opportunities that close the fuel cycle to avoid "big bets." Banks, utilities, and nuclear operators have little or no incentive to invest in technologies that close the nuclear fuel cycle because, under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the long-term storage of used nuclear fuel.

Licensing and Regulatory Issues

The NRC is responsible for licensing commercial fuel cycle facilities and nuclear power plants in the United States. In 2006, the NRC and the DOE established a Memorandum of Understanding for exchanging information related to AFCI activities. Also, as early as 2006, GEH briefed the NRC staff regarding DOE and GEH concepts for a fuel recycling facility and for completing the licensing and commercialization of such a recycling reactor. At that time, the NRC was monitoring DOE activities regarding closing the fuel cycle to determine its role. In 2007, the NRC authorized the NRC staff to identify what changes in NRC regulatory requirements would be necessary to license a reprocessing facility and recycling reactor. *See* NRC, Staff Requirements – SECY-07-0081 Regulatory Options for Licensing Facilities Associated with the Global Nuclear Energy Partnership (GNEP) (June 27, 2007). The NRC initially intended to await DOE actions, but after the DOE delayed its initial decision regarding a path forward for the chosen used fuel reprocessing technology, the NRC determined it would move forward with used fuel reprocessing regulatory development. *See* SECY-08-0134, "Regulatory Structure for Spent Fuel Reprocessing" (Sept. 12, 2008). The staff's analysis of the regulatory framework explained that 10 C.F.R. Part 50 applies to licensing of utilization facilities, such as a reprocessing facility, but that it has evolved to be a light-water reactor regulatory process. Fuel cycle facilities are licensed under 10 C.F.R. Part 70, which may provide a more logical regulation for amendments to address specific hazards of reprocessing or recycling facilities. 10 C.F.R. Part 52 provides a framework for issuing both a construction authorization and operating license in a single-step process, while relying on the technical requirements delineated in Part 50. Part 70 could be structured similarly for reprocessing facilities. The NRC's Office of Nuclear Material Safety and Safeguards leads efforts regarding advanced fuel cycle facility licensing, while the recycling reactor licensing was handled largely as a potential research activity until recently, when the NRC established the Advanced Reactor Program division in the Office of New Reactors.

The NRC's decision to move forward was, in part, due to expressions of interest by the nuclear industry. On August 19, 2008, GEH submitted a letter indicating its interest in the NRC developing an updated regulatory framework for licensing an AFCI fuel recycling facility and a recycling reactor. GEH suggested that modifications to 10 C.F.R. Parts 50 and 70 may be appropriate for an AFCI and that Parts 50 and 52 both may provide acceptable processes for licensing a recycling reactor, with some exceptions. Nevertheless, these licensing actions will be challenging for both the NRC and the applicants.

GEH developed a licensing plan as part of the DOE activity and continued interactions with DOE and NRC staff throughout 2007 and 2008. As of this writing, it is not clear when the DOE AFCI program will again engage with potential commercial companies and licensees. The policy aspects influence any funding that might be made available, but, as discussed above, government support (both policy and funding) will likely be imperative to minimize the initial licensing and financing risks involved in commercial projects for used fuel recycling.

Government funding could demonstrate licensing an advanced fuel cycle by the NRC and could be available through the AFCI program. Specifically, Section 953 of the Energy Policy Act of 2005 (Pub. L. 109-58, Aug. 8, 2005) addressed AFCI, directing DOE's Office of Nuclear Energy, Science, and Technology to conduct research, development, and a demonstration program to evaluate proliferation-resistant fuel recycling and transmutation technologies that minimize environmental, public-health, and safety impacts as an alternative to aqueous reprocessing technologies deployed as of the date of the Act. These activities are to support evaluation of alternative technologies for used nuclear fuel and the Generation IV advanced reactor concepts. The DOE, in its FY 2009 budget, however, proposed AFCI funding for only research and development *See* www.whitehouse.gov/omb/budget/fy2009/energy.html. Accordingly, GEH is not assured of continuing work on a demonstration project, although some research and development could continue.

Assuming that government policy issues are resolved in the near future, GEH would propose to submit an application for an advanced fuel cycle with a partnership of industry and government entities, based on the energy park concept. If submitted in the near term, the application would fall into the scope of NRC regulations in 10 C.F.R. Part 50. NRC's policy for siting fuel reprocessing and related waste-management facilities provides that the facilities may be on government or private land (10 C.F.R. pt. 50, App. F), but the energy park concept favors siting the first such facility on government land. The regulatory policy specifically addresses "high-level liquid radioactive wastes" resulting from aqueous process solutions, which would not apply to the GEH metallurgical separation process. However, one important component of the policy regarding dry, high-level radioactive wastes—presumably from any separation process—is that only the federal government may dispose of the wastes. Under the GEH concept of using a recycling reactor, the high-level radioactive wastes requiring eventual disposal would be reduced significantly, and much of the product that results from the separation process can be recycled as nuclear fuel for the current fleet of reactors in the United States and Canada and in the recycling reactor itself, reducing the burden on the federal government for ultimate disposal.

GEH's Licensing Plans for the Recycling Reactor

As noted above, closing the fuel cycle requires a recycling reactor. GEH proposes the Power Reactor Innovative Small Module (PRISM) sodium-cooled reactor for an NRC license application. NRC reviewed a previous application submitted by the DOE for the PRISM reactor as part of DOE's Advanced Liquid-Metal Reactor Program and issued a pre-application safety evaluation documented in NUREG-1368 (Feb. 1994). One purpose of the NRC review was to identify those policy and technical issues that would require NRC guidance or staff resolution for design certification, and those issues were documented in SECY-93-092. The NRC staff concluded that "no obvious impediments to licensing the PRISM design had been identified." GEH would now build on the work done in the late 1980s and early 1990s. GEH informed the NRC in a letter dated March 19, 2009, that it is considering submittal of a PRISM reactor design review application as early as mid-2011. The first PRISM reactor to be constructed would be the prototype reactor, which would be used to prove the concept and serve to license the advanced fuels designs being considered for transuranic (heavier than uranium, e.g., plutonium, neptunium) destruction. The licensing is expected to require up to ten years. Because it is a modular design, the PRISM prototype reactor would be the first of several PRISM modules to be licensed and constructed at a facility.

GEH would anticipate one or more licensing processes available under current regulations as potentially applicable to the PRISM reactor modules. One is the design certification process in 10 C.F.R. Part 52, which results in a rule in which the NRC certifies the design for reference in a construction permit, operating license, or combined license application by an operating company. Another licensing process GEH is considering, alone or in conjunction with a design certification process, is the manufacturing license process (also in 10 C.F.R. Part 52), which would allow GEH to manufacture the modules in advance of an order for a specific end-use application. Prior to submitting one or more of these applications, GEH would propose to evaluate options and engage in discussion with the NRC staff and potential customers regarding advantages offered by the various licensing processes related to an overall project and facility.

While the financing has yet to be worked out in practice, the basics of an investment cost-benefit analysis are in place, with new technologies and a changing political climate appearing now more than ever before to favor alternative energy development. Those alternatives can and likely should include nuclear power, especially because nuclear-generated electricity has proven to be safe, practical, environmentally friendly, and economical in the United States over the past four decades. The GEH-proposed recycling reactor and fuel recycling center promise to close the fuel cycle while generating electricity cost effectively. The energy park concept can attract the necessary investment and help return the older nuclear research and production facilities, their workforces, and their communities to full and productive strength. GEH has proposed a process for closing the nuclear fuel cycle based on electrometallurgical separation, which offers benefits as a dry (nonaqueous) process and one that is proliferation resistant.

GEH likely cannot proceed without the involvement of government and industry partners. The financial risks associated with government policy changes regarding closing the nuclear fuel cycle must be considered in a commercial project for AFCI and an associated recycling reactor. The economics of investing in such facilities are influenced by numerous factors, and government support will likely be necessary for at least the first project in a public-private partnership option supporting the DOE Energy Park Initiative. However, a financial model for the GEH facilities could include sales of fuel and generation of electricity by the recycling reactor, and eventually the facilities could pay for themselves. Licensing of the facilities will be done under the NRC regulatory process. The current light-water reactor regulatory structure can support and provide a guide in completing the licensing actions, with exceptions for unique features not currently addressed. The NRC is already taking actions to be prepared for future licensing actions to close the nuclear fuel cycle.

New Supreme Court Clean Water Decision: Here We Go

Mark A. Ryan

The U.S. Supreme Court has recently shown renewed interest in environmental cases, especially those arising under the Clean Water Act (CWA). Between 2006 and 2009, the Court issued three CWA decisions: *United States v. Rapanos*, 547 U.S. 715 (2006) (jurisdiction), *S.D. Warren v. Bd. of Envt'l Protection*, 547 U.S. 370 (2006) (401 certification) and *Entergy Corp. v. Riverkeeper, Inc.*, ___ U.S. ___, 2009 WL 838242 (2009) (cooling water intakes). *Rapanos*, as I have written in the past, is a train wreck of a decision that leaves both the regulators and the regulated scratching their collective heads as to its meaning. Given the Court's recent propensity for writing highly fractured decisions, I read each new one with some trepidation.

On June 22, 2009, the Court issued its fourth CWA decision in three years with its ruling in *Coeur Alaska Inc. v. Southeast Alaska Conservation Council*, ___ U.S. ___, 2009 WL 738643 (2009). The issues addressed in *Coeur* are factually and legally complex, and I will address them only superficially in this short article. But the issues are fundamental to the entire permit system of the CWA and are important to understand if one practices in this area. Because *Coeur* deals with such important fundamental issues, much mischief can come of the decision.

Coeur Alaska has been constructing the Kensington gold mine north of Juneau, Alaska, for several years. [In the interest of full disclosure, note that I work at the U.S. Environmental Protection Agency (EPA) on issues involving the Kensington mine.] The mine is largely finished but lacks a place to dispose of its mine tailings, which are the leftovers from the mining and milling process. Modern gold mines using chemical-extraction processes such as the froth floatation method Kensington will employ are able to recover very small concentrations of gold from the ore. Consequently, they mine a lot of rock to recover a small amount of gold—and they generate very large volumes of tailings.

Coeur Alaska has to figure out what to do with all those tailings. They studied "dry stack" and "paste" disposal methods before settling on the idea of pumping the tailings into Lower Slate Lake, a small alpine lake located near the mine. The plan is to build a dam at one end of the lake to increase its capacity and then fill the lake with tailings. The tailings, before they ultimately fill the entire lake, will kill everything currently living in the lake. The water left in the lake will contain pollutants and will likely need to be treated before flowing downstream into Lower Slate Creek. The company applied to the U.S. Army Corps of Engineers (Corps) for a Section 404 permit to fill the lake with tailings, and the Corps granted the permit. That's when the lawsuits started flying.

The case is about the interplay between three sections of the CWA. That interplay is complicated, especially when viewed in the context of the implementing regulations and the regulatory history. But the general scheme is fairly straightforward. Section 402 governs the discharges of traditional pollutants such as pulp mill wastes and municipal sewage. It is more commonly known as the National Pollutant Discharge Elimination System or NPDES, for short. Section 306 of the Act requires EPA to promulgate effluent guidelines (discharge standards) for various industrial sectors, and all Section 402 permits issued for specified industrial sectors must incorporate those standards. EPA and the states run the NPDES program. Section 404 governs the discharges of dredged and fill material, and that program is run by the Corps (in all but two states).

Kensington Mine's froth floatation method of gold extraction is subject to an EPA effluent guideline that prohibits the discharge of process wastewater, including solid wastes. The Corps' Section 404 permit authorizes Coeur to discharge tailings to the lake. EPA issued a separate NPDES permit (containing limits based on the Section 306 guidelines) for the discharge of tailings-contaminated water *from* the lake to Lower Slate Creek. If Section 306 applies to the tailings discharge *to* the lake (as opposed to the discharges *from* the lake), Coeur Alaska could not discharge its tailings to the lake at all, and the Section 404 permit issued by the Corps would be illegal. The Ninth Circuit sided with the citizen group that challenged the Section 404 permit, holding that the appropriate permit for the mine tailings disposal to the lake was an NPDES permit, not a Section 404 permit.

In a 6–3 vote, the Court reversed the Ninth Circuit and held that where a discharge meets EPA's and the Corps' definition of fill material, Sections 402 and 306 play no role. The Court gave deference to the Bush administration's argument that the gold-mine processing effluent guidelines should not apply to discharges that are subject to a Corps-issued Section 404 permit. The citizen group plaintiffs failed in their argument that *any* discharge that is subject to an established effluent guideline under Section 306 must, by definition, be regulated under the NPDES program, rather than the Section 404 program. The Court's ruling raises a number of issues. I will address just a few.

Fill material is defined in the EPA/Corps regulations as any "material [that] has the effect of . . . [c]hanging the bottom elevation" of the receiving water, and it includes "slurry . . . or similar mining-related materials" 40 C.F.R. § 232.2. One could argue that any discharge that "has the effect of changing the bottom elevation" of the receiving water is fill material and therefore would not require an NPDES permit. Certain industries currently regulated under the NPDES program, such as seafood processors and log transfer facilities, discharge waste materials that raise the bottom elevation of the receiving waters. Seafood processors, for example, grind the parts of the fish they cannot sell and discharge those fish wastes into the ocean. They often create very large "zones of deposit" that cover acres of the ocean floor, smothering the benthic community and lowering dissolved oxygen in the water, among other things. If a typical factory discharge has a high solids content that will cause a buildup on the floor of the receiving water, should it now apply for a Section 404 permit? Can it escape the stricter discharge standards of an effluent guideline by claiming it is fill instead of waste material? The Court discounted this potential problem but gave little assurance that some dischargers will not begin aggressively pursuing this option. For example, the Court noted that EPA has the authority under Section 404(c) of the CWA to veto any Corps-issued permit. But where EPA has invoked that authority only twelve times nationwide since 1972 when the Act was passed, one might question how often EPA would use that tool going forward. It is a trigger EPA seldom pulls.

Another problem emerges from the decision. The Bush administration promulgated in late 2008 the so-called water transfer rule, 40 C.F.R. § 122.3(i), which was recently upheld by the Eleventh Circuit in *Friends of the Everglades v. South Florida Water Mgmt. Dist.*, ___ F.3d ___, 2009 WL 1545551 (11th Cir. 2009). The rule states, in a nutshell, that any discharge from a water of the United States (WOUS) to another WOUS without an "intervening industrial, municipal, or commercial use" does not require an NPDES permit. A common example of a water transfer would be an irrigation system in the West that moves water from one watershed to another. Under the new rule, those systems need not obtain an NPDES permit to move water from one river or lake to another (or from the ocean to a freshwater creek).

Kensington Mine, and other similarly situated mines, may now try to argue that they do not need an NPDES permit to discharge wastes from the lake into the downstream creek. Remember that the company has a Section 404 permit from the Corps to discharge tailings (fill material) into Lower Slate Lake. The Supreme Court made it clear that the lake remains a WOUS. (If you are now wondering why the waste treatment exclusion does not apply here, you are not alone. But that discussion will have to be addressed in a future article.) If Lower Slate Lake is a WOUS, and the creek is also a WOUS, under the Bush administration's water transfer rule, Coeur Alaska might argue that no NPDES permit is needed to discharge water from the lake into the creek if there is no "intervening industrial, municipal, or commercial use." The only possible intervening use would be the water treatment plant planned to treat the water leaving Lower Slate Lake. Whether that constitutes an "intervening industrial, municipal, or commercial use" remains to be seen.

The Supreme Court made much of the fact that the discharges from the lake would be run through a treatment plant and would be subject to the terms of an NPDES permit. But Coeur Alaska may now argue that it does not need a permit for that discharge. If not, one of the main supporting arguments for the Court's rationale disappears. The Court does not appear to have considered the water transfer rule in *Coeur*, and the Bush administration never briefed the issue to the Court.

The final aspect of this case worth highlighting is the deference the Court gave to EPA's unofficial interpretation of the CWA. Under the *Chevron* doctrine, courts are to give deference to an agency's interpretation of the statute for which Congress gave it oversight authority. Traditionally, courts have looked to official agency interpretations of statutes, such as rulemakings, to determine whether the agency has reasonably interpreted the statute. In *Rapanos* and its predecessor, *Solid Waste Agency of Northern Cook County v. Corps of Eng.*, 531 U.S. 159 (2001), the Court did not give deference to EPA's interpretations of the jurisdictional reach of WOUS. What is noteworthy in *Coeur* is that the Court gave deference—albeit not full *Chevron* deference—to an internal EPA memorandum stating that if something is fill material it is not subject to Section 402 requirements. Similarly, the Court in *Entergy* gave deference to the Bush administration's arguments that the CWA allows EPA to use a cost-benefit analysis in establishing performance standards for cooling-water intakes at power plants. If this is a trend that will continue, agencies will be given much broader authority to interpret the statutes they implement. If, on the other hand, *Coeur* and *Entergy* are merely examples of the Court giving deference where it otherwise agrees with the agency's decisions, then those cases will not stand for a trend, but will serve to misguide the lower courts in how to apply *Chevron*. Only time will tell.

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