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SECTION OF ENVIRONMENT ENERGY AND RESOURCES

Energy Committees Newsletter

Vol. 3, No. 1 **October 2005**

NOTE FROM THE EDITOR

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Vice Chair, Publications
Renewable Energy Resources Committee

This is the first of two issues on the subject of emerging connections between energy and environmental goals. While the number of developments in this area is large enough to fill the pages of numerous issues of the Energy Committees Newsletter, we are fortunate to have an interesting and diverse array of articles for this issue and the next.

The first article, by Johannes Pfeifenberger and Samuel Newell, addresses innovative state regulatory and policy tools, such as environmental rate riders and tax-exempt bonds, to help finance new environmental regulatory programs in the utility industry. The next two articles concern the use of liquified natural gas (LNG). The first of the two LNG articles, by Paul Boehm, Harri Kytömaa and Piotr Moncarz, presents a technical and policy analysis of the risks and benefits of LNG. This is followed by a legal discussion of open loop LNG terminals in the Gulf of Mexico written by Meredith Cody and John Pearce. These two articles are particularly timely in light of recent events in the Gulf which have heightened concern about environmental and safety risks as well as the need for additional sources of fuel. The fourth article, by Covert Geary, Boyd Bryan and Eric Whitaker, discusses the restoration of leased land contaminated by oilfield development. The final article, by Jonathan Peress and Kenneth Colburn, addresses the opportunity for pairing reduction in greenhouse gas emissions with measures to ensure adequate electric capacity.

The next issue of the Energy Committees Newsletter will address a number of additional connections between energy and environmental goals, including green building design, geological sequestration of greenhouse gases, environmental and land use issues in wind energy development, and transfer of clean energy technologies to developing countries.

For more information on this subject, see the ABA Renewable Energy Resources Committee Brownbag/ Teleconference Material Archives for the May 11, 2005 teleconference entitled "Growing Linkages between Renewable Energy and Environmental Goals" (available at www.abanet.org/environ/committees/renewableenergy/teleconarchives/051105/). Topics addressed in these materials include opportunities for clean energy in air quality planning and enforcement, renewable energy and environmental policy, and corporate leadership in energy and the environment.

ENERGY COMMITTEES

To learn more about the Energy Committees visit www.abanet.org/environ.committees/descriptions.html.

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Vol. 3, No.1, October 2005

On behalf of the energy committees, Joseph Siegel was editor of this issue. The other Energy Committee newsletter vice chairs are Jay Hickey, Richard Roos-Collins, Peter Mostow, Bill Burton, Lauren McGregor and Marla Mansfield.

In this issue:

This newsletter is a publication of the ABA Section of Environment, Energy, and Resources, and reports on the activities of the committee. All persons interested in joining the Section or one of its committees should contact the Section of Environment, Energy, and Resources, American Bar Association, 321 N. Clark St., Chicago, IL 60610.

COMMITTEE NEWS

Renewable Energy Resources

The Renewable Energy Resources Committee continues its monthly teleconference series as follows:

Oct. 19, 2005
The Energy Policy Act of 2005: Impacts on Renewable Energy Resources
The provisions of the new Energy Policy Act of 2005 will be reviewed by a panel of experts to assess their impact on the development of renewable energy resources. To register log onto: http://store.mountainmedia.com/ceepinc/calendar.cfm?do=detail&d=3191&c=4943&p=31066.
This teleconference will be hosted jointly with the other Energy Committees as part of a new teleconference series on the Energy Policy Act of 2005 (see below).

Nov. 16, 2005
Meeting Expectations? An Overview of Renewable Portfolio Standard (RPS) Programs Implementation Experiences
RPS programs promulgated to encourage the development of new renewable energy projects have drawn a mixed response with some developers finding states without such programs to be more hospitable while others have been able to use these programs to obtain the contracts or funding needed to build new power plants. This program will explore what is happening with these RPS initiatives and look at some of the key issues, such as renewable energy credits, that have yet to be resolved. To register log onto http://store.mountainmedia.com/ceepinc/calendar.cfm?do=detail&d=3191&c=4943&p=31066.

Dec. 14, 2005
Federal Electricity Regulation and Alternative Energy
A discussion by a panel of experts on how renewable energy and distributed generation are affected by federal supervision of deregulated markets, including the impact of the Energy Policy Act of 2005 on these issues. To register log onto http://store.mountainmedia.com/ceepinc/lendar.cfm?do=detail&d=3191&c=4943&p=32910.

Joint Energy Committees

Quick Teleconference Series on the Energy Policy Act of 2005

The Energy Policy Act of 2005 promises new developments to meet the nation's energy needs. The Section of Environment, Energy, and Resources' energy committees arranged a quick teleconference (QT) on Aug. 16 to give an overview of the act, and they are now preparing a series of monthly QTs this fall and winter. Each QT will focus on a particular subject addressed by the Act, including:

- repeal of the Public Utility Holding Company Act,
- siting of energy facilities and transmission lines,
- hydroelectric power,
- oil and gas,
- coal,
- renewable energy and
- impacts on the electric industry.

The committees will convey notices of the particular dates of the Qts via e-mail and the committees' Web sites. The committees are seeking recommendations for topics and speakers. If you would like to contribute ideas for topics or indicate a manner in which you would like to participate, contact Bill Kinsey at wwkinsey@bpa.gov.

Conference of Interest

Oct. 24- 26, 2005
Tenth National Green Power Marketing Conference, Austin, Texas, Austin Marriott at the Capitol
The conference program will include best practices in utility green pricing program design, effective marketing strategies and tools for acquiring customers, defining renewable energy attributes and values, and the interplay of voluntary and compliance markets. For more information, see www.eere.energy.gov/greenpower/conference.

INNOVATIVE REGULATORY MODELS TO ADDRESS ENVIRONMENTAL COMPLIANCE COSTS IN THE UTILITY INDUSTRY

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On Aug. 1, 2005, the Environmental Protection Agency told 28 states that it plans to order specific pollution cuts from their power plants under the March 2005 Clean Air Interstate Rule (CAIR) if state officials do not implement their own compliance plans by the fall of 2006. This is only the latest news in a steady stream of proposed modifications to the current patchwork of federal, state, and local environmental regulations faced by electric utilities. While the exact shape of future environmental requirements for utilities is still uncertain, there is little doubt that the next several years will bring more stringent emission limits for sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury. Many industry observers also expect that emission rules for greenhouse gases, in particular for carbon dioxide (CO_2), will also be imposed on U.S. utilities within the next 5 to 10 years. These additional but still uncertain air quality standards and their obvious implications for the utility industry have attracted the attention of credit rating agencies, state energy officials, and state regulatory commissions. A number of states have responded to this challenge already with approaches that contain useful lessons for the states yet to do so.

Concerns Over Utilities' Credit Ratings

Exposure to large and growing environmental compliance costs have become an important financial risk in the utility industry. Rating agencies point out that in recent years utilities have announced plans to add scrubbers to 23,000 megawatts of generating capacity solely to comply with SO_2 limits. Shifting environmental requirements and unclear technological solutions will only add to the concerns and uncertainty over such environmental investments. (See FitchRatings, *Status of Environmental Regulation*,

Oct. 12, 2004; FitchRatings, *Fitch Comments on EPA's Clean Air Interstate Rule*, Mar. 16, 2005; FitchRatings, *Emission Trading*, Dec. 7, 2004; Standard & Poor's, *Peer Comparison: Three U.S. Power Giants' Environmental Costs and Strategies*, June 15, 2005.)

The rating agencies have expressed particular concerns over the current lack of clarity in environmental regulations, the added financial burdens of significant investments required to comply with new rules, and the risk that utilities may not be able to recover these costs in full or on a sufficiently timely basis. The agencies fear that due to the combination of growing compliance costs, high electricity prices and an inconsistent and incoherent regulatory approach to cost recovery, these cost recovery risks will not abate in the near future.

Rate adjustment mechanisms that allow for the pass-through in retail rates of costs that are uncertain, substantial and beyond the direct control of utility management are frequently-used regulatory tools that can also significantly mitigate these financial concerns. Such rate riders are already commonplace for fuel and purchased power costs, but have recently been implemented by an increasing number of states to address environmental compliance costs as well. It is thus not surprising that rating agencies have noted in the above-cited reports that implementation of such environmental riders alleviate their credit concerns by facilitating full and timely recovery of the utilities' environmental compliance costs. (See also, FitchRatings, *New Missouri Bill Supports Utility Credit*, June 1, 2005 and Moody's, *Credit Opinion: Kentucky Utilities Co.*, June 2, 2005.) Mitigation of these financial risks not only reduces the financing cost of utility infrastructure, but it also reduces economic and financial barriers to improving the environmental performance of the industry.

Role of State Energy Officials and Regulators

While the precise regulatory path that state and federal officials will choose for further reducing utilities' air emissions is not yet specified, state energy officials and state regulators realize that future emissions regulation will be more stringent. They also recognize that they play an important role in improving the environmental performance of the electric utility industry.

A 2004 study by the National Association of Regulatory Utility Commissioners (NARUC), the Environmental Council of States (ECOS) and the National Association of State Energy Officials (NASEO), surveyed the regulatory tools and incentives used in 15 states to improve the environmental performance of existing and future coal-fired power plants. (NARUC, *A Survey of State Incentives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities: Policy and Regulatory Initiatives*, June 2004). This survey identified a lack of regulatory certainty and high implementation costs as major barriers to improving the environmental performance of baseload electricity generation facilities. The study points out that more widespread and consistent incentives can help utilities offset the high cost of environmental upgrades and encourage increased regulatory certainty, thereby enabling utilities to initiate widespread environmental upgrades. The NARUC study also notes that traditional regulatory recovery mechanisms are often time consuming, expensive and uncertain, which imposes financial risks on utilities and investors. This creates a need for regulatory tools that will provide full and timely cost recovery of environmental investments.

The state regulatory and policy tools identified in the NARUC study including, for example, environmental cost recovery riders and environmental financing mechanisms, are already surprisingly widespread. In a comprehensive survey of such tools in traditionally regulated states, we found that nearly half of these states now allow targeted cost recovery and/or financing mechanisms to facilitate environmental compliance investments by electric utilities.

Cost Recovery in Restructured and Non-Restructured States

In restructured states, utility and non-utility generators are affected by environmental regulations similarly to other competitive industries that recover their

compliance costs through higher market-based rates for their products. Unless average market prices are high enough to cover unavoidable environmental costs in the long run, some producers will exit, which in turn will increase prices. However, there are examples in which non-market-based compensation has been provided to pay for environmental compliance even in restructured states.

In traditionally-regulated states, utilities are allowed to recover through regulated rates all prudently incurred costs, including environmental compliance costs. Rates are adjusted to reflect costs in rate cases, which typically occur only once every several years. In the intervening years, the costs of environmental projects might be borne by the company without an offsetting change in their current rates and revenues. As a result, such costs deteriorate cash flow and cause significant financial pressure for the utility. To address this concern, many traditionally-regulated states now allow for the recovery of environmental capital costs through rate riders similar to fuel adjustment clauses and/or allow the issuance of tax-exempt bonds.

Environmental Financing Tools

Utilities in the traditionally regulated states of West Virginia, North Carolina and Wisconsin are able to finance environmental projects using tax-exempt bonds. West Virginia and Wisconsin also allow utilities to recover the costs of environmental bonds, including interest, through rate riders.

Under Wisconsin's "Environmental Trust Financing" mechanism, for example, bonds can be issued under the authority of an order of the Wisconsin Public Service Commission to be repaid from revenues collected from surcharges placed on the bills of the utility's customers. The property right to the collected fees is securitized, transferred to a third party for repayment of the debt and, as a result, not shown on the books of the utility. Provisions regarding the treatment of bonds and revenues collected for repayment of the bonds and financing costs ensure that the bonds receive high credit ratings. Under this provision, Wisconsin Electric Power Company has received permission for $430 million in environmental financing. West Virginia recently made a similar financing option available to facilitate significant environmental investments by a utility with poor credit rating.

Environmental Rate Riders

A significant number of traditionally-regulated states now provide for the recovery of environmental compliance costs through rate riders. In addition to the already-discussed riders in Wisconsin and West Virginia, such environmental rate adjustment mechanisms also are used or allowed in Alabama, Arkansas, Colorado, Florida, Indiana, Kentucky, Minnesota, Mississippi and Missouri. Among the non-restructured states that derive more than 50 percent of their electricity from coal, nearly half (9 of 19) now allow such riders. Most of these states are located in the central or southeast regions of the United States. In addition, at least two restructured states, Ohio and Virginia, similarly use rate riders for the recovery of utilities' environmental compliance costs.

The rate riders in these states provide for the timely recovery of prudently-incurred costs for environmental projects without having to go through time-consuming and expensive full rate cases. This pass-through of environmental costs benefits the utility by ensuring timely recovery of investments. It also benefits customers by reducing overall administrative costs, by avoiding an increase in utility financing cost, and by maintaining management efficiency incentives that would otherwise be eliminated through more frequent full rate cases.

Environmental cost riders work similarly to existing riders for fuel and purchased power, which are used in 28 of the 30 non-restructured states, except that the environmental cost riders are concerned primarily with capital costs rather than variable costs. Alabama, Colorado, Florida and Kentucky's environmental riders also include the costs of purchasing emission allowances or other environmental variable costs, but such variable costs are more commonly included in fuel adjustment riders. Environmental capital costs are generally recovered through rate surcharges designed to provide the same additional revenues that the utility

would have been allowed to collect if the additional expenditures had been included in the previous rate filing.

Our survey evaluated a number of important design elements of environmental rate riders, including: scope, timing of commission approval of expenses, inclusion of construction work in progress (CWIP), rate incentives and surcharge limits.

- *Scope*. Most states that allow environmental rate riders include all investments that are necessary to comply with environmental regulations. Colorado's rider also considers investments that achieve over-compliance. Florida's includes clean coal and renewable projects. Indiana's also includes projects that qualify as clean coal technologies and that promote coal usage in the state.

- *Timing of Approval*. Mississippi, Indiana, Minnesota and Wisconsin provide for pre-approval of environmental compliance plans and associated costs. Such pre-approval reduces the risk of disallowances of large investments, which often amount to hundreds of millions of dollars for retrofitting a single plant.

- *CWIP*. Most states do not make rate adjustments until the capital is "used and useful," but Kentucky, Minnesota and West Virginia also allow for recovery of CWIP.

- *Rate incentives*. Minnesota provides for a reduction in return-on-equity if actual costs exceed estimates. Indiana allows, but has not yet implemented, a 300 basis point adder to encourage "clean coal" projects.

- *Surcharge limits*. Colorado and Missouri limit the size of rate adjustments that are allowable under the environmental rate rider.

Conclusions

Many utilities are facing substantial capital projects to comply with existing and likely new environmental regulations. Credit rating agencies point out that the additional financing requirements will add significant pressure on utility credit ratings unless full and timely cost recovery can be provided. State energy and regulatory officials recognize that they play an important role in improving the environmental performance of the electricity industry and have started to develop and implement tools to encourage increased regulatory certainty, to offset high implementation costs and to facilitate improved environmental performance of existing and future power plants. In response to these financial pressures and state environmental initiatives, a significant number of traditionally-regulated states have already provided mechanisms to facilitate the financing and/or cost recovery of environmental capital projects. These mechanisms— which include environmental rate riders and pollution control bonds—can also be helpful tools for state regulators and policy makers in other states.

LIKE TO WRITE?

The Energy Committees welcome the participation of members who are interested in writing articles for this newsletter. Please submit a one-paragraph article proposal to Joe Siegel at siegel.joseph@epa.gov.

Prior issues of this newsletter and other committee newsletters can be found at www.abanet.org/environ/pubs/newslettershome.html.

LNG PROJECTS: MYTHS AND REALITIES OF ENVIRONMENTAL AND SAFETY RISKS

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Introduction

In a rapidly evolving global economy securing supplies of energy adequate for economical development is a major challenge facing most countries of the developed world. However, no energy sources and no development strategies are risk-free. Therefore, the dynamic development of energy resources—whether fossil fuel (oil and gas), wind, nuclear, hydro or solar-based—needs to be grounded on scientifically based risk assessment, coupled to policy-based risk management and risk communication. This article presents an overview of the perceptions and realities of risk related to liquefied natural gas (LNG) development and relates those risks to other fossil fuel energy development.

Decreasing natural gas supplies in the United States, coupled with increasing demand and the availability of gas reserves elsewhere in the world, have created both market and new technology drivers in the United States for the importation of LNG. Natural gas, also that delivered through LNG, provides major environmental advantages over other fossil fuels. According to the U.S. Department of Energy (DOE), in 2015 LNG imports to the United States will surpass pipeline imports from Canada. LNG will provide at that time 15 percent of U.S. gas consumption versus 1 percent in 2002 (International Energy Outlook 2005). Part of the LNG supply chain is the offloading of LNG tankers or carriers, the regasification of LNG at terminals and the insertion of these natural gas supplies into the pipeline infrastructure. As onshore and offshore LNG terminal concepts have been proposed in the United States, perceptions of risk have escalated even though regulatory rules that apply to these facilities have rapidly evolved.

Five LNG terminals are now operating on the U.S. East and Gulf Coasts, with many others on all coasts in progress or planned. Many of these LNG projects are controversial due to location-specific safety concerns, concerns over new energy infrastructure, and specific environmental impacts to air and water quality including impacts on essential fish habitat. As a result, questions have been raised about the real risks of LNG development and how LNG projects compare to other energy resources and their associated delivery systems. Additional questions are raised with regard to the composition and properties of LNG-derived natural gas. It has been suggested that LNG quality issues may have implications regarding the efficiency, reliability and useful life of gas turbines and other combustion equipment as well as environmental implications on the production of NOx, CO and emissions of unburned hydrocarbons.

Overview of Risks

Engineers, economists and scientists simulate potential future events and use the result of the simulations in their decision-making. Where safety and security are addressed, the process involves risk analysis and risk management. The definition of a potential scenario, the likelihood of that scenario taking place, and the predicted consequences of such an occurrence form the basis for risk analysis. The quantification of risk then allows decisions to be made leading to maximum risk reduction within available means.

It can be debated whether LNG constitutes a higher risk to society than other forms of fuel, which have a significant history of fires, explosions and environmental pollution. However, LNG remains a liquid form of natural gas which has been an integral part of U.S. energy needs for a long time. Many examples over the years have shown clearly that the risk management effort is not a theoretical exercise when it comes to the issues related to fuel supplies, and is rooted in the realities of fuel transportation, processing and use.

LNG risk can be attributed to three well-defined stages of the value chain: (1) The liquefaction facility where LNG is first made. This is typically onshore at

the end of the gas pipeline that delivers the gas from the gas field. While this is far from U.S. shores, an accident at the production facility can have a ripple effect on the entire LNG economy around the world. (2) LNG transportation in ocean-going tankers, bringing large quantities of liquefied gas to U.S. shores, entering navigational channels and areas of other ocean use within continental waters near infrastructure and centers of population or moorings at or near port facilities. (3) Unloading, storage and regasification of LNG at U.S. shore facilities. Each of these stages carries its own risk and each step needs to be analyzed separately, drawing on the physical characteristics of LNG as well as site-specific factors such as the system configuration, operational procedures and maintenance.

The statistics of cargo ships' safety records are not very encouraging, particularly when it comes to port maneuvering and inland waters navigation. The U.S. Coast Guard shows that the annual number of ship and barge *allisions* (ships and barges ramming into a steady structure) and *collisions* (ship-to-ship impacts) includes about 3,000 incidents. However, the 40 years of LNG carrier operations around the world have reportedly not generated a single failure of an LNG cargo tank or spill due to a marine accident. It is possible that, because of the high value of these ships and the required higher sophistication of the crew, the probability of an LNG tanker accident is lower than for other similar types of vessels. The size of the LNG tankers (up to 200,000 cubic meters of LNG or, when regasified, 4.3 billion cubic feet of gas), the sophistication of the thermal controls, the cryogenic cargo transfer equipment and the uniqueness of their propulsion systems necessitate a higher degree of training and greater level of sophistication from their crews than from those of other cargos.

Protection of onshore LNG facilities has attracted a great deal of attention since 9/11; however, the challenges are no different from those of protecting other petrochemical and chemical plants and their shipping operations. The increasing interest in offshore terminal solutions has created a challenge that needs to be addressed with the technical attention and appropriation of resources to provide concrete and defensible answers to minimize and mitigate risk. The use of new surveillance and monitoring technologies is a part of the approach to addressing this new challenge. Recent events suggest the potential for damage to a ship's hull through terrorist action (*e.g.*, the *USS Cole* Navy Destroyer in October 2000 and the *Limburg* oil tanker in October 2002). Risk management tools have improved significantly through technological developments of the last few years, *i.e.*, technologies matched with operations can help defend against maritime improvised explosive devices (IEDs). Examples of such technologies include network enabled subsurface monitoring, unmanned systems and explosive sensors.

Risk Perceptions Versus Reality

Safety Risk: What are the real public safety risks associated with LNG? During the course of the heated public debate about the risk associated with LNG tankers passing close to infrastructure or near communities and centers of population, real risk has been often confused with perceived risk. For example, LNG tankers have been compared to ships laden with high explosives; however, LNG will not detonate and will not explode like a bomb because methane is one of the slowest burning fuels. This argument is akin to equating a large pile of wood to a bomb. Wood will burn, but it will not explode. Aside from the inaccurate, popular, common portrayals of the dangers of LNG, it is important to the industry to rigorously predict and then communicate the real risks of LNG transportation to onshore and offshore terminals by identifying all plausible accident scenarios and quantifying their expected rates of occurrence. From the day the *Methane Pioneer* made its maiden voyage in 1958, the LNG fleet has grown to 177 tankers. In the worst grounding accident of a loaded LNG tanker, the *El Paso Kayser* ran onto rocks and grounded at 19 knots in the Straits of Gibraltar in June 1979, loaded with 99,500 cubic meters of LNG. The *Kayser* suffered heavy bottom damage over the whole length of the cargo spaces, as well as flooding to the starboard double bottom and wing ballast tanks. However, the membrane cargo containment was not breached and no LNG was spilled. This impeccable safety record has made it difficult to predict the precise impacts and frequency of accidents.

Research has shown that as LNG spills onto water, it creates a boiling liquid pool on the water surface (the density of LNG is less than half of water). The gas boiling off from the pool forms a cold and heavy plume (the boiling temperature of LNG is minus 260 degrees Farenheit). The plume initially hugs the water; then, as it warms, it begins to rise and dissipate. The gas cloud will move with the wind. If it reaches a remote ignition source, onshore or elsewhere, it can ignite if the gas concentration is within its flammable limits. The resulting flash fire may, under the right circumstances, burn back to the LNG pool and become a pool fire that burns until all spilled fuel has been consumed. A number of recent studies address the various phases of an LNG spill over water. Of the studies published to date, a study by Sandia Laboratories on the risk associated with LNG transportation by ship is the most sophisticated. Despite this technical sophistication, a current lack of understanding of certain phenomena, such as the details of the flow of cryogenic LNG out of the breached tank or the radiation from very large pool fires, have forced analysts to conservatively assume the worst case outcome and therefore over-predict the impact of the postulated scenario.

Quantifying the impact of each LNG spill scenario is only half the battle. The other half is evaluating its expected frequency of occurrence. This is difficult to estimate because of the absence of any past accidents of the kind that are being contemplated. The absence of any such event in the past may also suggest that its future likelihood is low. As there exists a shortage of well-trained LNG tanker officers, additional trained LNG tanker officers will be required to support the expanding LNG fleet and ensure that the outstanding safety record of LNG transportation remains intact.

Environmental Risk: The environmental risks of the exploration, production, and transport of conventional oil and gas resources are well known. Regulations in the United States evolved rapidly after the *Exxon Valdez* oil spill with the enactment of the Oil Pollution Act of 1990. With this legislation came a host of new regulations and, as a result, the numbers and sizes of oil and refined product spill-related accidents in the United States have decreased dramatically (www.uscg.mil/hq/g-m/nmc/response/stats/Summary.htm). Major oil spills, however, have continued to occur outside of the United States (www.itopf.com/stats.html), with prominent spills occurring off the coasts of France (*Erika*) and Spain (*Prestige*). Though the risks of petroleum-related tanker spills in the United States have decreased, several key incidents have occurred over the past year in the Aleutian Islands, the Delaware River and Puget Sound. Spills of crude and refined oils are accompanied by potential injuries to natural resources over an extended time frame (months to several years). It is the risks of oil spills and the perceived impacts that have truncated many offshore oil and gas development plans along the U.S. East and West Coasts. More important than accidental spills, however, is the introduction of petroleum residues into the coastal zone though chronic non-point source treatment plant inputs, a byproduct of the use of petroleum products in society.

LNG projects do not present similar environmental concerns and risks as oil spills. In the discussion of LNG risk analysis and risk management, one needs to remember the most basic truth—that LNG is composed of the lightest of all hydrocarbons and burns with very little pollution. Further, there is no environmental residue from an LNG spill. Unlike petroleum spills, any potential spillage of LNG will have a very short duration and little significant environmental consequences given the rapid volatilization and dissipation of LNG itself. The environmental concerns of LNG developments arise mainly from the construction of the LNG terminals themselves in coastal and nearshore locations with potential loss of fisheries and wetlands; from operations of the carriers; and especially, from the operation of the terminals themselves. Given that environmental impact concerns have been faced and resolved as part of a long history of coastal infrastructure development, undoubtedly it is not the construction concerns, but rather operational concerns that present the greatest risk assessment and management challenge to scientists, policy makers, regulators and industry.

A major present concern, especially in the Gulf of Mexico, focuses on the use of Open Loop

Vaporization (OLV) systems in the conversion of LNG to natural gas (*i.e.*, regasification). Though a number of different technologies have been developed to provide the heat source to effect the liquid-to-gas conversion and the introduction of the energy resource into the pipeline infrastructure, OLV systems have been preferred for terminals by many in the industry for over 30 years. Over 100 million gallons of seawater—along with its associated assemblage of biota—plankton, fish eggs, and juvenile fish larvae—are used by each OLV heat exchanger daily. This seawater is slightly chlorinated to avoid fouling, and is cooled as much as 10 degrees Celsius before being discharged. Another concept for deepwater terminal application is a new generation of LNG carriers with the ability to regasify LNG onboard. The regasification is achieved in a largely closed system that feeds the gas into a submerged buoy system linked to pipeline infrastructure, without the need for terminal LNG storage.

Opposition to OLV systems has arisen because of potential impacts on Gulf fisheries due to egg and larval mortalities and projected effects on fish stocks themselves. While the various environmental impact statements (EISs) have modeled these impacts from a facility-specific and cumulative impact perspective and concluded that risks are acceptable, the fishing industry, the state governments and the National Marine Fisheries Service have questioned the conclusions and oppose the use of OLV systems as having unacceptable risks. Central to the question here is the adequacy of the methodology and data being used in the predictions by those on all sides of the issue, the application of those data to complex models with inherent large uncertainties and, hence, the predicted impacts to fish landings from the cumulative impacts of multiple LNG terminals. Is the current methodology adequate or does it significantly overestimate the potential for adverse impacts of LNG facilities—both individual and multiple or "cumulative"? This is one current focus of controversy regarding the real environmental risks of LNG developments.

Conclusion

Few energy developments have been as dynamic or demonstrated the need for rigorous safety and environmental risk assessment methodologies and risk communication practices as the LNG supplies in the post-9/11 world. While typically acknowledging the environmental benefits of natural gas (LNG) over other fossil fuels, the public, state governments and many regulators are concerned about transportation, public safety and environmental risk with LNG infrastructure development and fuel use. However, recent risk assessments indicate that, while no energy development is without risk, less-than-rigorous analyses have created the myths of unacceptable risk in LNG development. In contrast, sound scientific-based assessments of the LNG supply chain suggest a much more benign reality.

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GOVERNING OPEN-LOOP TERMINALS: THE CONTROVERSY IN THE GULF STATES

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Importation of liquefied natural gas (LNG) remains problematic for the domestic energy sector and has become the subject of intense controversy along the Gulf Coast. During the last year, officials in Louisiana, Mississippi and Alabama joined with local fishing and environmental groups to oppose proposed LNG terminals in the Gulf of Mexico suggesting that "open-loop" facilities present a considerable threat to indigenous fish and other marine organisms.

Natural gas reserves exist throughout the world but often are not close to existing pipelines or markets. The process of liquefying natural gas facilitates its delivery from remote areas bridging the gap between supply and demand. This access is important given increasing demand and rising prices.

LNG is natural gas condensed to liquid form after being cooled to a temperature at or below minus 260 degrees Fahrenheit. When subsequently warmed, LNG "regasifies" and may be transported and used in the same manner as conventional natural gas. Liquefying the gas reduces its volume as much as 600 times allowing it to be stored and transported more efficiently from countries where natural gas is abundant, such as Indonesia, Russia, Iran, Qatar and Venezuela. Rebecca Mowbray, *Louisiana and LNG? A Natural—State in Good Spot, Forum Experts Say,* THE TIMES-PICAYUNE, Oct. 30, 2004, at Money, 1. LNG is carried on insulated ships to the United States and then stored at terminals. Equipment at the terminals processes the LNG by slowly warming it until it returns to a gaseous state. It then can enter the domestic pipeline system.

Responding to growing demand for natural gas, companies are applying for licenses to build LNG terminals in the Gulf of Mexico. However, approval of these terminals has been challenged by local environmental groups and state officials who criticize the method by which LNG is reheated. They explain that in an "open-loop" system 200 million gallons of Gulf water per day must be run through the system to reheat the gas. Bob Marshall, *Permits have Anglers Boiling Mad,* THE TIMES-PICAYUNE, Apr. 10, 2005 at Sports, 12. Numerous environmental groups, recreational and commercial fishermen, and some state officials have united to protest the open-loop terminals claiming that those systems will kill billions of fish, fish eggs, and other marine organisms. Matthew Brown, *Governors Close Ranks on Open Loops—Blanco, Others Call LNG Ports Risky to Fisheries,* THE TIMES-PICAYUNE, June 22, 2005, at National, 6. Opponents contend that the fish and larvae will die when sucked through the system or crushed against the intake screens. They also argue that fish will die from the sudden drop in water temperature or from exposure to chemicals used in the process.

Some fisheries experts have expressed particular concern regarding construction of terminals in the "Fertile Fisheries Crescent," the area thought to be the most biologically productive in the entire Gulf of Mexico ecosystem. Bob Marshall, *Fisheries Could be Hurt by Streamlined Regulations,* THE TIMES-PICAYUNE, Jan. 16, 2005, at Sports, 12. Species which use this area for breeding grounds and nurseries include redfish, Spanish mackerel, white and brown shrimp, speckled trout, flounder and blue crab. *Id.* Opponents believe that the loss of billions of fish eggs and larvae throughout the Gulf will imperil the 800 million dollar per year Gulf fishing industry. State officials, including the governors of Louisiana, Mississippi and Alabama, have explained that they will not support development of open-loop systems unless they receive satisfactory scientific proof that marine resources will be protected.

Many opponents of open-loop terminals emphasize that they do not oppose LNG terminals altogether; rather, they insist that a "closed-loop" system be used employing gas-fueled burners for reheating. The closed-loop process uses about two percent of the imported natural gas as fuel to reheat the LNG supply but does not present the same potential threats to marine resources as does the open-loop process. Bob

Marshall, *LNG Proposal Deals Blow to Louisiana*, THE TIMES-PICAYUNE, Feb. 20, 2005, at Sports, 14. Proponents reply that closed-loop systems are significantly more expensive to operate than open-loop and that reconfiguring the proposed terminals to closed-loop systems is cost-prohibitive. Proponents are reluctant to switch to closed-loop systems given the considerable time already invested in the various projects; substituting closed for open-loop terminals may result in the loss of two or three years in the permitting process. Matthew Brown, *Governors Close Ranks on Open Loops—Blanco, Others Call LNG Ports Risky to Fisheries*, THE TIMES-PICAYUNE, June 22, 2005, at National, 6. Proponents of open-loop systems further insist that loss of fish and other marine life will be minimal. They explain that the benefits of the new facilities include stabilization of current and future energy prices and the creation of thousands of construction jobs. Thus, open-loop system proponents maintain that the benefits outweigh the potential harm and will help the United States meet critical energy needs in a cost-effective manner.

As mentioned above, Louisiana, Mississippi and Alabama's governors have opposed development of several proposed open-loop LNG ports advising that they will continue to oppose such terminals absent proof that impact on fisheries will be negligible. Although the governors have the right to preclude construction of offshore terminals in federal waters, they do not have express authority to prevent construction of ports on state lands or in state waters. However, they may rely on the permitting requirements of existing federal statutes to block construction on state lands or in state waters.

LNG Facilities Located Offshore in Federal Waters

Under the Deep Water Port Act governors have the right to refuse to approve license applications for LNG ports located offshore in federal waters, *i.e.*, those located beyond the three-mile limit of the state's territorial waters. 33 U.S.C. §1503(c)(8)(West 2005); 151 CONG. REC. S6982 (daily ed. June 22, 2005). In 2002 Congress amended the Deep Water Port Act to regulate the siting of offshore LNG terminals. *See* Maritime Transportation Security Act of 2002, 107 Pub. L. No. 295, § 106, 116 Stat. 2064, 2086-87 (2002). Terminals in federal waters must be approved by the U.S. Maritime Administration, the U.S. Coast Guard, and the governor of the affected adjacent coastal state. 151 CONG. REC. S6982 (daily ed. June 22, 2005). Governors in states along the Gulf Coast may use that power to block construction of proposed terminals in their jurisdictions. It remains to be seen whether one of these governors will actually exercise that power or whether open-loop proponents will agree to monitor and mitigate the effects of the ports on marine life and thereby satisfy the states' concerns. One company, for example, has proposed a port off the Louisiana coast and has agreed to conduct more stringent research on the port's potential effect on fisheries. If an unacceptable impact on marine life is likely to result, that company has agreed to undertake mitigation measures in the area. Such undertakings may reduce or eliminate the competing interests of terminal proponents and environmental groups and make the proposed LNG ports a reality in a time of escalating natural gas pricing.

LNG Facilities Located on State Lands or in State Waters

Under the Energy Policy Act of 2005, the Federal Energy Regulatory Commission (FERC) is granted exclusive authority over the siting of LNG facilities onshore or in state waters. 151 CONG. REC. S6981 (daily ed. June 22, 2005). A recent proposed amendment would have given each state's governor veto power over such LNG facilities. Under that proposed amendment, governors would have had 45 days to approve, veto or attach conditions to an LNG project located onshore or in state waters after FERC issued its final environmental impact statement. 151 CONG. REC. S6981 (daily ed. June 22, 2005). The governors of Louisiana, California, Massachusetts, Rhode Island, New Jersey and Delaware co-authored a letter to the Senate Energy Committee urging the committee's support of concurrent state and federal jurisdiction over LNG facilities rather than exclusive jurisdiction in the FERC. *Id.* Absent state jurisdiction, they explained, "there is no guarantee that a project

will be consistent with the homeland security or environmental requirements for a particular locality." *Id.* Protection of fisheries and the surrounding environment is a concern of those governors as is the possibility that LNG facilities could become terrorist targets. *Id.* at S6983. The amendment failed and consequently states were denied express power to prevent construction of LNG facilities on state lands or in state waters. Notwithstanding that denial, states argue that other authority exists under current federal statutes allowing them to block development of LNG facilities.

For example, under section 1341 of the Clean Water Act, an applicant for a federal license or permit to conduct any activity (including facilities construction and operation) which may result in any discharge into navigable waters must provide the licensing or permitting agency with an approval certification from the state in which the discharge will originate. 33 U.S.C. § 1341(a)(1) (West 2005); 151 CONG. REC. S6982 (daily ed. June 22, 2005). If a state refuses to issue such certification for an LNG project, construction of the project may not be authorized unless the applicant successfully appeals that denial.

Similarly, section 1456(c) of the Coastal Zone Management Act (CZMA) requires an applicant for a federal license or permit to conduct an activity affecting the coastal zone to provide the federal licensing or permitting agency with certification that the proposed activity complies with the policies of the affected state's coastal zone management program. 16 U.S.C. § 1456(c)(3)(West 2005). If the state does not concur with the certification, the federal license or permit may not be issued absent certain circumstances, including appeal. *Id.* Because LNG projects will often be located in the coastal zone, construction of such facilities will be quite problematic if a state does not agree with CZMA certification by an applicant.

Finally, states may effectively block a proposed LNG port under section 502 of the Clean Air Act, which provides that it is unlawful for any person to operate a source of air pollution except in compliance with a lawfully issued permit. 42 U.S.C. § 7661(a)(West 2005); 151 CONG. REC. S6983 (daily ed. June 22, 2005). Some contend that LNG terminals will result in increased air pollution from the influx of tankers and other equipment necessary to construct and secure the operation. By showing that the terminals constitute a source of air pollution, states may attempt to deny an LNG terminal applicant a Clean Air Act permit under this section.

Thus, states may employ several methods to block or attempt to block construction of a proposed LNG terminal on state lands or in state waters. At this time, of course, it is unknown whether governors will take advantage of these several methods, or whether compromises will be reached with the terminal applicants. The friction between environmental concerns and robust demand may well result in litigation testing the licensing of any open-loop ports or the attempt to deny such a license under the statutes mentioned above. In any event, the open-loop LNG facility controversy is not likely to fade, as gas prices and demand continue to increase in the wake of Hurricane Katrina. In fact, gas shortages and elevated prices brought about by this recent disaster may likely make LNG an attractive option for meeting energy needs.

THE OBLIGATION TO RESTORE OIL AND GAS PROPERTIES: THE VIEW FROM LOUISIANA AND OTHER STATES

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This article is adapted from papers presented by Covert Geary at the 2005 Annual Meeting of the American Association of Professional Landmen in Banff, Canada, and by Boyd Bryan at the 51st Annual Rocky Mountain Mineral Law Institute in Portland, Oregon, in July 2005.

Introduction

The convergence— and conflict— between the goals of a healthy oil and gas industry and environmental protection is demonstrated by the recent proliferation of oilfield site restoration litigation. This article considers the mineral lessee's obligation to restore in Louisiana and other states, certain limitations on who may assert claims for restoration and when they may be asserted, and the applicable cleanup standard.

What Restoration Obligations Are Owed?

The Analysis in Louisiana

The Louisiana Supreme Court has issued two landmark decisions since February 2003 addressing a lessee's obligation to restore leased property. The decisions clarify that the legal analysis depends on whether the claim is based on contract, the Louisiana Mineral Code or tort.

Corbello v. Iowa Production, 2002-C-0826 (La. Feb. 25, 2003), 850 So.2d 686, involved a surface lease that required the lessee to "reasonably restore the premises as nearly as possible" to its condition at the start of the lease. The court affirmed a judgment based on breach of the contractual obligation, and awarded the landowners $28 million for injury to an aquifer near the leased premises, plus $5 million for damage to the surface itself—*the total award being more than 300 times the fair market value of the property*. It reasoned that the contract constitutes the law between the parties, and the contract did not limit the lessee's liability for reasonable restoration to the market value of the property. The court also concluded that it had no authority to modify a damage award in a breach of contract case to require the money be spent on restoration absent legislation mandating such a result, and that "[p]rivate landowners in Louisiana have no duty to seek relief from an administrative agency before filing suit against an oil company." *Id.* at 701.

Predictably, Louisiana courts have applied the same rules where restoration obligations are contained in mineral leases. *See Hazelwood Farm, Inc. v. Liberty Oil and Gas Corp.*, 2002-266 (La. App. 3d Cir. Apr. 2, 2003), 844 So.2d 380, *writ denied*, 2003-1585 and 2003-1624 (La. Oct. 31, 2003), 857 So.2d 476. And although post-*Corbello* legislation mandates that damages awarded for contamination of "usable ground water" must be paid into the court registry and expended on remediation, LA. REV. STAT. 30:2015.1 (2003 La. Acts No. 1166), its efficacy is limited by the fact that damages awarded for cleanup of soil, surface water or "non-usable" ground water must still be paid directly to a successful plaintiff, without any restoration requirement.

Terrebonne Parish School Board v. Castex Energy, Inc., 2004-C-0968 (La. Jan. 19, 2005), 893 So.2d 789, addressed whether a mineral lessee had an implied duty under the Louisiana Mineral Code to restore the surface of the leased premises *absent a contractual obligation* to do so. The court held that "in the absence of an express lease provision, article 122 [of the Mineral Code] does not impose an implied duty to restore the surface to its original, pre-lease condition absent proof that the lessee has exercised his rights under the lease unreasonably or excessively." *Id.* at 801. Thus, Louisiana plaintiffs face a heavier burden of proof if there is no contractual obligation to restore.

A third analysis applies if the claim is in tort. Louisiana courts have held that in tort cases, if the restoration costs are "disproportionate to the value of the property

or economically wasteful," the damages are limited to the difference in the value of the property before and after the harm, *unless* there is a reason personal to the owner for restoring the property to its original condition or there is a reason to believe the owner will, in fact, make the repairs. *See Grefer v. Alpha Technical*, 2002-1237 (La. App. 4th Cir. May16, 2005), 901 So.2d 1117, 1137, 1141-42, *citing Roman Catholic Church of the Archdiocese of New Orleans v. Louisiana Gas Service Company*, 92-C-0071 (La. May 24, 1993), 618 So.2d 874.

Different Approaches in Texas, Oklahoma and Mississippi

Texas is a far less plaintiff-friendly forum than Louisiana for recovery of restoration damages. An owner seeking compensation for surface damage must prove either (1) that the operator failed to use reasonable care in conducting its exploration and extraction activities, or (2) under what is known as the "accommodation doctrine," that the operator could have accomplished its ends through reasonable alternative means without damaging the land. *See Tarrant County Water Control & Improvement Dist. v. Haupt, Inc.*, 854 S.W.2d 909, 911 (Tex. 1993). Damages are classified as either temporary or permanent, but in either case they are limited to no more than the diminution in the fair market value of the property. *See Mieth v. Ranchquest*, No. 01-02-00461-CV, 2005 WL 615594, at *4 (Tex. App. – Houston Mar. 17, 2005). *Corbello*-type damages therefore do not appear possible.

Oklahoma is similar to Texas in that damages to land are classified as either temporary or permanent, but in either event damages are limited to the reduction in the land's fair market value. *Schneberger v. Apache Corp.*, 890 P.2d 847, 853 (Okla. 1994). In Oklahoma, however, the Surface Damages Act (SDA), 52 Ok. St. § 318.2 *et seq*., requires the lessee, before entering the leased premises, to post security to cover surface damage that may be caused by future operations. While the SDA does not bar a landowner from subsequently bringing a tort action for pollution damages, s*ee Ward Petroleum Corp. v. Stewart*, 64 P.3d 1113 (Okla. 2003), *Corbello*-type awards still are not likely to occur given that damages are limited to diminution in fair market value.

Mississippi landowners are required, under *Chevron, U.S.A., Inc. v. Smith*, 844 So.2d 1145 (Miss. 2002), to exhaust their administrative remedies before the state's Oil and Gas Board before filing suit. Through this decision, the Mississippi Supreme Court appears to have imposed a formidable roadblock to *Corbello*-type damage awards, since restoration cases are unlikely to ever reach a jury.

Who May Sue? And When?

Under state law, a buyer of contaminated oil and gas properties may not have the right to assert a restoration claim absent an assignment of the claim from the seller. For example, in January 2005, a federal district court in Louisiana dismissed a restoration suit on grounds that the plaintiff landowner, which purchased the property *after* the alleged oil and gas contamination occurred, lacked standing to sue for its restoration. *See Frank C. Minvielle, L.L.C. v. IMC Global Operations, Inc.*, 2004 WL 3418335 (W.D. La. Oct. 19, 1904), *motion to vacate denied* (Jan. 12, 2005); c*f. Exxon Corp. v. Pluff*, 94 S.W.3d 22 (Tex. App. Tyler 2002), *pet. denied*.

Another issue is whether restoration claims may be asserted while mineral operations are ongoing. At least one restoration suit has been dismissed as premature because the mineral lease had not yet terminated. *See Grand Lake Hunting Club v. BP America Production Co.*, Docket No. 2002-4112, 12th Judicial District Court, Avoyelles Parish, Louisiana, Judgment on Exceptions dated Nov. 6, 2003. A Louisiana appellate court, however, recently reversed a similar dismissal, holding that claims seeking damages and costs of restoration based on negligence, breach of contract, exemplary damages, trespass and maritime tort may be brought despite continuing operations on a portion of the property. *Dore Energy Corp. v. Carter-Langham, Inc.*, 04-1373 (La. App. 3d Cir. May 4, 2005), 901 So.2d 1238.

What is the Cleanup Standard?

An emerging issue in oilfield restoration litigation concerns the cleanup standard. The resolution will likely hinge on which regulatory agency has jurisdiction over the cleanup. Many regulators and members of the regulated community have generally understood that the Louisiana Department of Natural Resources (LDNR) has jurisdiction over the operation and cleanup of oil and gas properties, while the Louisiana Department of Environmental Quality (LDEQ) has jurisdiction over the cleanup of other types of contamination and over oilfield wastes that are released off-site. Louisiana plaintiffs are challenging this division of authority, apparently seeking to apply the more stringent LDEQ cleanup standards to the restoration of oil and gas properties, and recent court decisions support their efforts.

For example, in *Dore Energy Corp. v. Bohlinger*, 2003-2768 (La. App. 1st Cir. Oct. 29, 2004), 889 So.2d 295, *rehearing denied* (Dec. 29, 2004), the court ordered LDEQ to review an oilfield site remediation plan submitted by the landowner in order to set up a restoration cost recovery claim under Chapter 12 of the Louisiana Environmental Quality Act (LEQA), La. R.S. 30:2271, *et seq.*—sometimes referred to as Louisiana's "mini-Superfund" statute—which is administered by LDEQ. The court approved LDEQ's referral of the plan to LDNR for review, but concluded that ultimate responsibility for approving or disapproving the plan remained with LDEQ.

Moreover, two Louisiana federal courts recently remanded cases based on the oil company defendants' failure to show that the landowners had no possibility of recovering from LDEQ on grounds that the agency negligently failed to inspect oilfield production facilities. In so ruling, the courts at least implicitly rejected the argument that LDNR, in lieu of LDEQ, has jurisdiction over oilfield wastes. *See Sarpy v. Energen Resources*, 2005 WL 2036880, 2005 U.S. Dist. LEXIS 17820 (E.D. La. July 25, 2005); *Hebert v. Energen Resources Corp.*, No. 05-541 (W.D. La. June 27, 2005).

Conclusion

Oilfield site restoration litigation will undoubtedly continue to be a battleground between landowners and the oil and gas industry. It is hoped that the legislatures, agencies and courts grappling with these issues will be able to strike a balance that promotes the vitality of the industry as well as environmental protection.

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CONNECTING MARKET DESIGN: FROM CARBON TO ELECTRIC CAPACITY

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Two current and seemingly disparate policy developments, the Federal Energy Regulatory Commission's (FERC's) efforts to assure adequate electricity supplies and regional initiatives to reduce greenhouse gas (GhG) emissions, share an intrinsic link. Just as a key aspect to electricity reliability is the deployment of new supply resources, achieving GhG reduction targets similarly requires deployment of new electric supply resources (with lower carbon profiles). Recognition of the intersection of these developing policies can provide the dual benefit of efficiently enhancing reliability (*i.e.*, resource adequacy) while reducing the carbon intensity of the respective regional wholesale electric markets. Although ongoing GhG reduction and resource adequacy initiatives in the Northeast provide the foundation for this observation, tying together reliability-based electric resource adequacy with carbon reduction objectives is applicable in other wholesale markets where carbon dioxide (CO_2) reductions are being considered.

Proposed capacity market designs within the various wholesale electric regions will create new revenue streams (and ratepayer costs) to assure reliability by providing added financial incentives for existing and future electric supply resources. Carbon reduction initiatives such as the northeast Regional Greenhouse Gas Initiative (RGGI) can consider the magnitude of projected resource deployment resulting from electric capacity markets in setting annual emissions caps. Likewise, decreasing the carbon intensity of the electric system can be a discernable benefit, as a market-driven outcome, of regional resource adequacy markets.

Optimizing carbon policy and capacity market designs requires recognition of the capacity value of resources that decrease carbon emissions. Ultimately, this will lead to greater deployment of efficiency and other demand-side resources because as capacity resources, these measures are generally less costly than new generation capacity. Appropriate consideration of demand-side measures as electric capacity resources also provides a means to link carbon reduction requirements with electrical demand (load). Expanding the reach of carbon intensity initiatives into the wholesale market can enhance efforts to cap CO_2 emissions from electric generators and will achieve reductions in carbon intensity more efficiently.

CO_2 Emissions Reduction Initiatives and Demand-Side Resources

Numerous GhG emissions reduction initiatives throughout the country target the electric industry. The RGGI state staff proposal provides for a cap and trade program in the Northeast limiting electric generator CO_2 emissions in two phases, calling for a 10 percent reduction between 2015 and 2020. It also envisions "public benefit" allowance allocations to promote renewables and energy efficiency. RGGI, Revised Staff Working Group Package Proposal, Aug. 24, 2005; (www.rggi.org/). A number of states, notably California, are incorporating carbon reduction values, such as energy efficiency and demand side management, into their oversight of utility resource adequacy planning. California Public Utilities Commission, Decision 04-12-048, Dec. 16, 2004. In any analysis of electric market policy options to reduce CO_2 emissions, deployment of energy efficiency and other demand-side measures provide demonstrable benefits.

Beyond CO_2 reductions, modeling conducted as part of the RGGI process concludes that deployment of efficiency and demand-side resources reduces the cost of system-wide emissions reductions and decreases leakage, which arises when carbon caps on generators result in increased electricity imports and additional emissions from neighboring generators that are not subject to CO_2 emissions limits. *See*, IPM Modeling Results, Sept. 21, 2005; (www.rggi.org/documents/

htm). Studies by the Regulatory Assistance Project (RAP) find that investments in energy efficiency provide a means to lower emissions CO_2 caps because they provide for more cost-effective reductions than other methods. RAP, *Electric Energy Efficiency and Renewable Energy in New England*, May, 2005; (www.raponline.org).

As useful as energy efficiency and demand-side measures are in reducing the cost of carbon reductions, they are also cost-effective electric capacity resources. RAP determined that, in New England, existing energy efficiency programs (without the benefit of RGGI incentives) decrease CO_2 emissions from the electric sector by greater than 4 percent. The cost of energy efficiency as an electric supply alternative is 2.4 cents per kWh, substantially lower than the benchmark cost of new generation supply assumed for the proposed capacity market design in New England. *Id.* at 2; *see also*, FERC, *Initial Decision, Devon Power LLC, et al.*, 111 FERC ¶ 63,063, June 15, 2005, pp. 14-21. Due to the demonstrable benefits of energy efficiency and demand-side resources for CO_2 emissions reductions and as a potential low cost capacity resource (supply substitute), these resources should be fully and fairly valued within electric wholesale markets.

Integrating Carbon Considerations into Wholesale Electric Market Design

Competitive wholesale regions administer capacity markets in order to assure resource adequacy by providing additional revenues as incentive for deployment of electricity supply resources. *See e.g.*, FERC, *Order on Rehearing and Clarification, Devon Power, LLC*, 110 FERC ¶ 61,315, Mar. 23, 2005, p. 32. Resource adequacy means having sufficient electric supply resources in place to maintain reliability using the "one day in ten year" standard (*i.e.*, reliable supply 99.97 percent of the time). Capacity markets pay owners of electric supply resources for making their output available to the market as necessary to meet the reliability standard. More recently, FERC is requiring *localized* capacity markets so that the value of capacity more accurately reflects local, as opposed to regional, supply and reliability needs. *Id.* at 20. Locational installed capacity markets are being designed and/or implemented in the NYISO, ISO-NE and PJM regions.

Installed capacity markets generally impose obligations upon load serving entities (LSEs) to have available adequate supply resources to meet maximum load conditions based on estimated peak system demand. LSEs supply power to electricity end-users and procure power in the wholesale market to meet their respective supply obligations. They may be regulated distribution companies or competitive energy suppliers.

LSEs are in the resource procurement business. They contract bilaterally with suppliers of capacity and are best situated to hedge and trade-off among generation, transmission and demand-side resources to procure energy at the lowest cost and with the highest reliability. As resource procurers, LSEs are the lynchpin to resource deployment decisions and collectively influence the carbon intensity of the electric supply portfolio. Putting aside offsets (*e.g.*, carbon sequestration), carbon emissions are a function of the specific supply resources from whom LSEs purchase energy and capacity. Through the energy and capacity markets, LSE supply portfolios essentially determine what supply resources are deployed.

Given their role in the market, it may be most efficient to impose CO_2 caps directly upon and allocate allowances directly to LSEs. *See*, Cowart, Richard, *Another Option for Power Sector Carbon Cap and Trade Systems—Allocating to Load*, Concept Memo prepared for RGGI, May 1, 2004. Likewise, capacity markets and carbon reduction targets can be optimized simply by assuring that low carbon resources are appropriately valued within the wholesale market. Demand-side measures are intrinsically valuable as capacity resources, considering their cost-effectiveness, within the rubric of resource adequacy. That value is enhanced by enforceable carbon emissions limitations, implemented through cap and trade programs, as further incentive for low carbon capacity resource deployment.

FERC supported wholesale market design concepts provide a means for assuring that competitive

wholesale electric markets value low carbon/demand-side resources for their capacity and reliability attributes. Establishing the parameters for resource adequacy is within the purview of the states. FERC, *White Paper on Wholesale Market Reform*, July 7, 2003. Underlying the role of LSEs in procuring capacity, the states in each wholesale region provide oversight as to the level and types of capacity that constitute resource adequacy. This oversight can be undertaken in a manner that does not disturb the paramount role of markets as the primary mechanism for capacity and resource deployment decisions.

Regional State Committees (RSCs), comprised of representatives of each state within each regional electric market, provide a conceptual structure for state oversight of resource adequacy. *See,* FERC, *Notice of Proposed Rulemaking on Standard Market Design*, Docket RM01-12-000, July 31, 2002, pp. 551-554. Under FERC's proposal, each independent system operator or regional transmission organization would work with the respective RSC to seek regional solutions to issues that fall within federal, state or shared jurisdiction. Included among the RSCs' major areas of responsibilities is to determine the role of generation, transmission, energy efficiency and demand response in resource adequacy within a given region. Presentation of Pat Wood, FERC Chair, June 5, 2003. FERC's view of wholesale market design provides that the RSCs "will determine the approach for resource adequacy for the region." *Id*.

Carbon-intensity both as an emissions issue and as a resource adequacy attribute is squarely within the purview of the RSCs' domain. Although two separate issues addressing two distinct societal interests, GhG emissions reduction initiatives and resource adequacy market design share supply resource deployment as the unifying characteristic that determines whether each functions effectively and efficiently. The states, through RSCs, can oversee market policy to direct complimentary outcomes so that efforts to assure reliability are harmonized with GhG initiatives, maximizing the efficacy of these initiatives.

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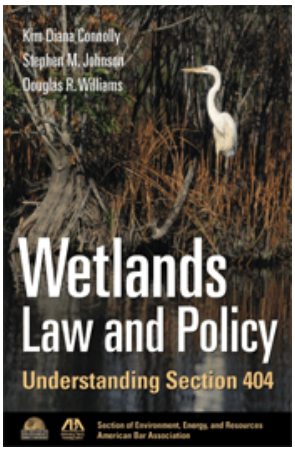

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