
Environmental Policy and Regulatory Constraints to Natural Gas Production

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Environmental Policy and Regulatory Constraints to Natural Gas Production

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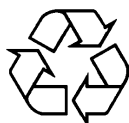
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NOTATION

The following is a list of the acronyms and abbreviations (including units of measure) used in this report. Acronyms and abbreviations used only in tables may be defined only in those tables.

ACRONYMS AND ABBREVIATIONS

AGA	American Gas Association
APD	application and approval of permit to drill
API	American Petroleum Institute
BART	best available retrofit technology
BLM	Bureau of Land Management
CAA	Clean Air Act
CBM	coal bed methane
CEQ	Council on Environmental Quality
CFR	<i>Code of Federal Regulations</i>
CMP	coastal management program
COE	U.S. Army Corps of Engineers
CROMERRR	Cross-Media Electronic Reporting and Record-Keeping Rule
CSU	controlled surface use
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
3-D	three-dimensional
DEN	<i>Daily Environment Report</i>
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
E&P	exploration and production
EA	environmental assessment
EFH	essential fish habitat
EIA	Energy Information Administration
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency
EPCA	Energy Policy and Conservation Act
ESA	Endangered Species Act of 1973
FERC	Federal Energy Regulatory Commission
FLPMA	Federal Land Policy and Management Act of 1976
FR	<i>Federal Register</i>

FS	USDA Forest Service
FWPCA	Federal Water Pollution Control Act
FY	fiscal year
GCVTC	Grand Canyon Visibility Transport Commission
HAP	hazardous air pollutant
H.B.	House Bill
HCA	high consequence area
H.R.	House Resolution
INGAA	Interstate Natural Gas Association of America
IOGCC	Interstate Oil and Gas Compact Commission
IPAA	Independent Petroleum Association of America
IRA	inventoried roadless area
LEAF	Legal Environmental Assistance Foundation
MACT	maximum achievable control technology
MDEQ	Montana Department of Environmental Quality
MEPA	Montana Environmental Protection Act
MMS	Minerals Management Service
NAAQS	National Ambient Air Quality Standards
NAPSR	National Association of Pipeline Safety Representatives
NEP	National Energy Policy
NEPA	National Environmental Policy Act of 1969
NFS	National Forest System
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
NO _x	nitrogen oxides
NOAA	National Oceanic and Atmospheric Administration
NPC	National Petroleum Council
NPDES	National Pollutant Discharge Elimination System
NSO	no surface occupancy
NWP	nationwide permit
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OMB	Office of Management and Budget
OPS	Office of Pipeline Safety
PM	particulate matter
PM _{2.5}	particulate matter with a mean aerodynamic diameter of 2.5 μm or less
POD	Plan of Development and Production
POE	Plan of Exploration

PSD	Prevention of Significant Deterioration
Pub. L.	Public Law
R&D	research and development
RMP	Resource Management Plan
ROD	Record of Decision
ROW	right-of-way
RSPA	Research and Special Programs Administration
SIP	State Implementation Plan
SO ₂	sulfur dioxide
SOS	Special Ocean Site
SPCC	Spill Prevention Control and Countermeasures Plan
SWANCC	Solid Waste Agency of Northern Cook County
TL	timing limitation
TMDL	total maximum daily load
TPH	total petroleum hydrocarbons
UIC	underground injection control
USC	<i>United States Code</i>
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
WRAP	Western Regional Air Partnership
WSA	Wilderness Study Area

UNITS OF MEASURE

dB(a)	A-weighted decibel(s)		
ft	foot(feet)	mg	milligram(s)
ft ³	cubic foot (feet)	MMCF	million cubic feet
gal	gallon(s)	mi	mile(s)
hp	horsepower	MW	megawatt(s)
kg	kilogram(s)	s	second(s)
lb	pound(s)	TCF	trillion cubic feet
m ³	cubic meter(s)	µg	microgram(s)
MCF	thousand cubic feet	µm	micrometer(s)

ENVIRONMENTAL POLICY AND REGULATORY CONSTRAINTS TO NATURAL GAS PRODUCTION

by

Deborah Elcock

ABSTRACT

For the foreseeable future, most of the demand for natural gas in the United States will be met with domestic resources. Impediments, or constraints, to developing, producing, and delivering these resources can lead to price increases or supply disruptions. Previous analyses have identified lack of access to natural gas resources on federal lands as such an impediment. However, various other environmental constraints, including laws, regulations, and implementation procedures, can limit natural gas development and production on both federal and private lands. This report identifies and describes more than 30 environmental policy and regulatory impediments to domestic natural gas production. For each constraint, the source and type of impact are presented, and when the data exist, the amount of gas affected is also presented. This information can help decision makers develop and support policies that eliminate or reduce the impacts of such constraints, help set priorities for regulatory reviews, and target research and development efforts to help the nation meet its natural gas demands.

1 INTRODUCTION

U.S. demand for natural gas is expected to continue into the future. Further, the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA) has forecast that U.S. annual natural gas consumption will increase from 23 trillion cubic feet (TCF) in 2000 to 35 TCF in 2025 (EIA 2003). The factors driving this demand continue to mount. Foreign oil price instability related to tensions in the Middle East and Latin America could further shift demand from oil to less costly and domestically produced natural gas. Air pollution regulations favor the burning of clean natural gas over coal; while coal is more abundant, its use is of greater environmental concern. Energy price spikes and brownouts, such as those that occurred in California in 2001, could occur again if the delicate supply-demand balance is disrupted. Weather patterns can further increase demand.

In 1999, the National Petroleum Council (NPC) reported that the demand for natural gas was growing and that the resource base was adequate to meet this demand; however, certain factors needed to be addressed to realize the full potential for natural gas use in the United States (NPC 1999). In 2001, the National Energy Policy Development Group (NEPDG), established by the President to develop a plan to help the private and public sectors promote dependable,

affordable, and environmentally sound energy for the future, presented its National Energy Policy (NEPDG 2001). The NEP recommendations included investigating several areas that could be limiting domestic natural gas production. The potential for a near-term natural gas shortage prompted a June 26, 2003, Natural Gas Summit, designed to give the Secretary of Energy and other DOE officials information on the ramifications and potential resolutions of short-term challenges to the natural gas industry. In September 2003, the NPC released an update to its 1999 study (NPC 2003). In the update, the NPC reports that government policies encourage the use of natural gas but fail to address the need for additional natural gas supplies. The 2003 report states that a status quo approach to these conflicting policies will result in undesirable impacts to consumers and the economy. A key issue raised but not fully explored in these efforts was how environmental and regulatory policy constraints, which were developed to meet national environmental protection goals, can, at the same time, limit natural gas exploration and production (E&P) and transportation. Recent studies have examined limitations to accessing natural gas, particularly in the Rocky Mountain region, but even after the gas is accessed, numerous additional environmental policy and regulatory constraints can affect production and delivery to consumers.

The purpose of this Phase I study is to identify specific existing and potential environmental policy and regulatory constraints on E&P, transportation, storage, and distribution of natural gas needed to meet projected demands. It is designed to provide DOE with information on potential constraints to increased natural gas supply and development in both the long and short terms so that the Department can develop, propose, and support policies that eliminate or reduce negative impacts of such constraints, or issues, while continuing to support the goals of environmental protection. It can also aid in setting priorities for regulatory reviews and for research and development (R&D) efforts.¹ A possible future Phase II study would identify potential short-, mid-, and long-term strategies for mitigating these environmental policy and regulatory constraints.

1.1 SCOPE

The scope of this study is limited to traditional natural gas (or gas). It does not address liquefied natural gas or methane hydrates, nor does it describe constraints to increased use of other fuels such as coal. The importance of economic constraints and safety issues is acknowledged, but only environmental policy and regulatory impediments are addressed. Constraints are identified for the E&P and transportation phases, not end use. The focus is on existing, national-level constraints, although important state requirements and overlaps with state jurisdictions are included, as are regulations that are being considered or developed that could impede natural gas production.

¹ The data collection and analyses for this Phase I study were conducted between 2001 and 2003. Since then, some of the details regarding individual constraints may have changed. For example, it is possible that the development status of certain regulations may have changed from proposed to final, or that certain agencies may have taken actions intended to mitigate identified constraints. The current status of individual constraints should be verified prior to using them for decision making.

1.2 METHODOLOGY

The 1999 NPC study and the NEP were used as departure points for the current study.² The NPC highlighted access to natural gas resources as a critical factor for meeting projected demand. It did not address environmental constraints beyond access, but it did recommend assessing the impact of existing and proposed environmental regulations on the natural gas supply. The NEP also contains several recommended study areas related to natural gas production. These include the role of expediting permits, the examination of land status and lease stipulation impediments to gas leasing, the requirements for siting energy facilities in the coastal zone and the Outer Continental Shelf (OCS), and the regulatory process for permitting interstate natural gas pipeline projects. This study reviews and updates the access issues as presented by the NPC and investigates issues raised in the NEP. In addition, it identifies and describes more than 30 additional environmental policy and regulatory constraints to natural gas production and delivery.

To identify and assess environmental policy and regulatory constraints, existing studies were reviewed, and detailed issue investigations were conducted by examining existing and proposed statutes. Information published on proposed and final rules in the *Federal Register* was assessed, and issues were discussed with trade associations and industry and with state and federal government officials. Comments on proposed regulations and congressional testimony on issues and legislation that could affect natural gas production were reviewed. Information was also obtained from meetings on environmental policy relevant to natural gas conducted by the U.S. Commission on Ocean Policy, the Interstate Oil and Gas Compact Commission (IOGCC), the Minerals Management Service (MMS), the National Oceanic and Atmospheric Administration (NOAA), the Integrated Petroleum Environmental Consortium, the U.S. Environmental Protection Agency (EPA), and others.

Once potential policy and regulatory constraints were identified, an attempt was made to determine the nature of the impact and the amount of gas that each constraint could affect. It was determined that a given constraint could affect the natural gas supply in one or more of the following ways: (1) make natural gas resources unavailable; (2) delay E&P or transportation; or (3) increase costs to the extent that some operators might stop operations, particularly if subjected to multiple costly regulations. To estimate the amount of gas a given constraint could affect, existing resource estimates were used. These estimates were reported in units of TCF and prepared by organizations such as the NPC, EIA, MMS, the U.S. Geological Survey (USGS), and an interagency group that studied U.S. oil and gas resources in five western basins (DOI, USDA, and DOE 2003). No attempt was made to develop independent estimates for amounts of gas that could be affected by the constraints, nor was an attempt made to normalize the estimates by year or form of estimate (e.g., technically recoverable, economically recoverable). As a result, these estimates can provide an indication of the order of magnitude of impact, but they should not be used to make direct comparisons among the various constraints. Some gas supplies are

² The conclusions of the 2003 NPC report are consistent with those of the 1999 report; that is, action is required to address the need for additional natural gas supplies. Also consistent with the 1999 report, the 2003 report acknowledges the importance of environmental policy and regulatory issues but does not address them in detail.

constrained by more than one factor. Therefore, the estimates are not additive, and eliminating one constraint may leave the gas supply affected by one or more other constraints.

1.3 ORGANIZATION

The remainder of the report consists of four chapters. Chapter 2 provides very brief summaries of the environmental policy and regulatory constraints, organized by type of impact. Chapter 3 provides more detail on each of the constraints and includes a discussion of the issue, the source of the constraint (e.g., statute, regulation, implementation), the lead player(s) (e.g., Bureau of Land Management [BLM], EPA), and the development phase affected by the constraint (e.g., E&P, transportation). Chapter 4 presents conclusions, and Chapter 5 provides a list of references cited in this report.

2 ISSUE SUMMARIES

A regulatory constraint can impact natural gas by any one or any combination of the following:

- Restricting access to the gas, thereby making it unavailable for E&P;
- Delaying E&P or transportation; or
- Increasing costs, which could delay production, increase economic limits resulting in earlier well abandonment, and cause operators to leave the market, thereby reducing the gas supply in the short term and possibly increasing consumer costs in the long term.

This section describes various environmental policy and regulatory constraints in terms of these impacts. First are issues that may limit access to gas supplies. These include the following:

- Coastal Zone Management Act (CZMA) consistency provisions,
- Endangered Species Act of 1973 (ESA) requirements,
- U.S. Department of Agriculture (USDA) Forest Service (FS) restrictions,
- Outdated BLM land use plans,
- Lease stipulations,
- Monument designations,
- OCS moratoria,
- Permit restrictions,
- Bans on drilling in the Great Lakes,
- The “Roadless Rule,” and
- Wilderness Area designations.

Issues likely to produce delays include the following:

- Coal bed methane (CBM)-produced water and potential regulations to manage such water,

- Drilling permit delays,
- Essential fish habitat (EFH) regulations,
- Fracturing operations and the possibility of future rules that could limit this practice,
- Changes in nationwide permits (NWP) issued by the U.S. Army Corps of Engineers (COE),
- National Environmental Policy Act of 1969 (NEPA) requirements,
- Pipeline certification issues,
- Pipeline safety regulations, and
- Wetlands mitigation issues.

Existing and potential issues likely to increase costs include the following:

- Regulations for cooling-water intake structures at offshore extraction facilities,
- Electronic reporting requirements,
- Lack of incentives to go beyond compliance,
- State waste disposal regulations,
- Maximum achievable control technology (MACT) rules,
- Mercury discharge regulations,
- Nitrogen oxides (NO_x) requirements,
- Noise regulations,
- Nonroad diesel regulations,
- Ocean discharge criteria,
- Particulate matter (PM) regulations,
- Pipeline gathering definitions,
- Regional haze rule,

- Spill prevention and control and countermeasures regulations,
- Standards for closing wells,
- Storm water construction permits, and
- Total maximum daily load (TMDL) regulations.

The following paragraphs summarize these environmental policy and regulatory constraints and include, where available, an estimate of the amount of gas potentially affected. No priorities have been assigned to these issues, and no inferences regarding priorities should be made from the order in which they are presented. Chapter 3 provides greater detail on each of these issues.

2.1 ISSUES LIKELY TO LIMIT ACCESS

2.1.1 Coastal Zone Management Act Consistency Provisions

The CZMA requires that each federal agency activity within or outside the coastal zone that affects any land or water use or natural resource of the coastal zone must be undertaken in a manner consistent “to the maximum extent practicable” with the enforcement policies of approved state coastal management programs (CMPs). Nonfederal applicants for federal licenses or permits must comply with state CMP enforcement policies. Federal approvals may not be granted until the state concurs, or, if the state objects, until the Secretary of the Department of Commerce, on appeal by the applicant, overrides the state’s CMP objections. These provisions have caused duplications and costly delays to federal leasing and production activities. Also, once a lease has been obtained, the CZMA can still limit or prevent exploration, development, and production for that lease. (See related issue, OCS Moratoria — West Coast.)

TCF Affected: 362.2

2.1.2 Endangered Species Act

The ESA can limit access to gas resources and cause delays in permitting on both federal and private lands. Court-interpreted definitions have expanded the scope of what is considered a “take” under the ESA to include habitat modification, such as clearing or similar development that occurs with natural gas E&P. Similarly, the U.S. Fish and Wildlife Service (USFWS), an implementing agency for the ESA, often treats sensitive species as requiring the same or similar protections as species that are actually listed as endangered or threatened.

TCF Affected: Not estimated.

2.1.3 Forest Service Restrictions

FS restrictions contained in Records of Decision (RODs) for development of natural gas resources in three areas — Beaverhead National Forest, Helena National Forest, and Lewis and Clark National Forest — are limiting the ability to access and produce natural gas.

TCF Affected: 10 to 30

2.1.4 Outdated BLM Land Use Plans

The Federal Land Policy and Management Act of 1976 (FLPMA) established land use planning requirements on federal lands, and *United States Code*, Title 43, Section 1701 (43 USC 1701) states that it is the policy of the United States to manage public lands under the principles of multiple use and sustained yield. Land use plans and planning decisions provide the basis for every land action undertaken by the BLM, but many have been prepared without considering natural gas resource potential. If a land use plan is out of date with respect to anticipating the cumulative impacts of gas development, substantial delays in the permitting of new wells can occur as a new environmental analysis (typically an environmental assessment [EA] or environmental impact statement [EIS]) is completed and the plan updated. Today, many land use plans need to be updated to recognize the use of the land for natural gas development before additional development can occur.

TCF Affected: 120.3

2.1.5 Lease Stipulations

Two categories of restrictions limit access to onshore public lands. Some lands, such as Wilderness Areas and areas with specific geological attributes or unique or significant natural or cultural resources, are completely off limits because of statutory, Executive Order, or other administrative requirements. Other lands, while technically available for development, are subject to stipulations imposed by the BLM or the FS to implement statutory or regulatory requirements. Some of these stipulations, which can affect large geographic areas, can prevent development without providing obvious commensurate environmental benefits (Rubin 2001). Combinations of individual stipulations applied to the same area can effectively prevent access to key natural gas resources (Russell 2000). The EIA has estimated that federal lease stipulations increase development costs by 6% and add 2 years to development schedules (EIA 2001b). Operators report a growth in stipulations and note that when land managers impose a stipulation in one area, there is a tendency to impose the same stipulation in surrounding areas (Martin 1997).

TCF Affected: 108

2.1.6 Monument Designations

The Antiquities Act of 1906 allows the President, at his discretion, to declare by public proclamation, historic landmarks and historic and prehistoric structures owned or controlled by the government of the United States. Between 1996 and 2001, the Administration, under the authority of the Antiquities Act, designated 19 new national monuments and expanded 3 others. The 22 designations collectively cover about 5.6 million acres of federal land, much of which may contain natural gas resources; however, this land is off limits to development.

TCF Affected: 1

2.1.7 OCS Moratoria — Atlantic Ocean

Moratoria deny access to broad areas of natural gas reserves and resources. Major natural resources have been discovered off the Canadian Coast, and this resource potential could extend southward. The moratoria were implemented primarily because of past oil spills; however, they also constrain natural gas E&P.

TCF Affected: 28.0

2.1.8 OCS Moratoria — Eastern Gulf of Mexico

Moratoria covering most of the eastern part of the Gulf of Mexico deny access to broad areas of natural gas reserves and resources. They were implemented primarily because of past oil spills; however, they also constrain natural gas E&P.

TCF Affected: 11.3

2.1.9 OCS Moratoria — West Coast

Moratoria deny access to broad areas of natural gas reserves and resources. They were implemented primarily because of past oil spills; however, they also constrain natural gas E&P. On the West Coast, recent legal action has also limited production on existing leases.

TCF Affected: 18.9

2.1.10 Permit Restrictions

Once leasing access has been obtained and a permit to drill has been issued, restrictions in the permit may be so severe that access is effectively prohibited. These federal and state restrictions can be site- or BLM- or FS-Office-specific.

TCF Affected: 86.6

2.1.11 Bans on Great Lakes Drilling

Recently enacted state and federal temporary and permanent drilling bans in the Great Lakes have effectively stopped exploration and new production of natural gas in the Great Lakes.

TCF Affected: 1.1

2.1.12 Roadless Rule

On January 12, 2001, the USDA's FS promulgated a rule that prohibits road construction in inventoried roadless areas (IRAs) on National Forest System (NFS) lands. These areas compose about one-third of the NFS, or about 58.5 million acres. The Roadless Rule denies access to approximately 11 TCF of potential natural gas resources in the Rocky Mountain region. The rule has been subject to numerous lawsuits and may be revised to allow for an assessment of impacts and the ability to build roads on a more local, forest-by-forest level.

TCF Affected: 11

2.1.13 Wilderness Areas

The FLPMA charged the BLM with identifying and managing lands as potential Wilderness Areas. As required by law, the BLM completed the inventory in 1991 and submitted its recommendations to the President, who endorsed and submitted them to Congress. However, of the roughly 26.5 million acres identified as Wilderness Study Areas (WSAs), Congress has yet to make decisions on 16.3 million acres. In addition, since 1991, some western states, for example, Colorado and Utah, have "reinventoried" potential Wilderness Areas, adding more acres to those that are managed as, although not officially designated as, WSAs. Until Congress acts, all of these areas — both Wilderness Areas and Wilderness Study Areas — will continue to be off limits to gas (and oil) leasing, even though they may contain substantial resources.

TCF Affected: 9

2.1.14 Ocean Policy

The U.S. Commission on Ocean Policy, established under the Oceans Act of 2000, is charged with developing recommendations to submit to the President on a coordinated and comprehensive national policy for oceans and coastal areas. Draft recommendations include the establishment of an Ocean Policy Framework and expanded authorities to address the use of ocean and coastal resources. It is too early to estimate the impacts of such broad

recommendations and their implementation on offshore natural gas exploration, production, and development.

TCF Affected: Not estimated.

2.2 ISSUES LIKELY TO PRODUCE DELAYS

2.2.1 CBM-Produced Water Management

Regulations are being written to address the potential impacts of discharging or disposing of produced water generated during CBM exploration, production, and development. There are significant unknowns regarding the actual impacts of produced water, and many of the regulations may be costly to implement, resulting in delayed or reduced production.

TCF Affected: 74

2.2.2 Drilling Permits

Once the BLM has issued a gas lease on federal land, no drilling can occur until the BLM issues a permit to drill. In the gas-rich basins of the Rocky Mountain region, backlogs for permits to drill and right-of-ways (ROWs) are growing. Many Resource Management Plans (RMPs) are outdated, and revisions, which often require additional environmental analyses, are required before gas leasing or development can occur. Insufficient staffing, combined with the number of plans needing updating and the recent increase in permit applications spurred by gas price increases, compounds the delays. Citizens' suits also contribute to permitting delays. These delays will be particularly important for CBM.

TCF Affected: 311.2

2.2.3 Essential Fish Habitat

EFH regulations issued in 2002 require assessments and consultations that can duplicate the environmental requirements of other federal agencies. This duplication can delay leasing or permitting decisions, because federal agencies undertaking activities that could adversely affect EFH (e.g., permitting) must prepare EFH assessments, undertake consultation with the National Marine Fisheries Service (NMFS), and, in some cases, implement mitigation strategies that could add further costs and delays.

TCF Affected: 174.5

2.2.4 Fracturing Operations

Hydraulic fracturing is a process producers use to increase the flow of natural gas (and oil) from rocks whose natural permeability does not allow the gas to reach the well bore at sufficient rates. It is commonly used to release methane from coal beds, where the gas is held in the rock by hydraulic pressure. During fracturing, a fluid (usually a water-sand mixture) is pumped into the reservoir to split the rock and create drainage pathways. Typically, it is a one-time practice. The NPC estimates that 60 to 80% of all the wells drilled in the next decade to meet natural gas demand will require fracturing. The practice is controversial, with environmentalists arguing that it needs more regulation. Federal or increased state regulation could delay gas production or make it uneconomical, thereby reducing the amount available at reasonable prices (Stewart 2001).

TCF Affected: 293

2.2.5 Nationwide Permits

Section 404 of the Clean Water Act (CWA) requires that any activities that result in the discharge of dredged or fill material into waters of the United States (which include most wetlands) must be approved via a permit issued by the COE. Obtaining an individual permit can take a year or more (Bleichfeld et al. 2001). To reduce the burden caused by permitting many small, inconsequential projects, the COE has established nearly 40 general, or NWP, for categories of activities that will have minimal adverse effects on the environment. The processing time for activities approved under a general permit averages about 14 days (Copeland 1999). Recent regulatory changes have limited the activities covered by NWPs, meaning that more gas-related activities will require individual permits. Also, recent court cases and other actions have resulted in changes to the definitions of wetlands, meaning that the scope of activities and areas requiring a permit have been in a state of flux, which has led to additional delays caused by conflicting definitional interpretations.

TCF Affected: Not estimated.

2.2.6 NEPA Integration and Lawsuits

NEPA requires federal agencies to evaluate the human and environmental impacts of federal activities and projects, including leasing and other activities on federal lands. Various levels of jurisdiction and decision making under the law often produce unnecessary project delays. Also, NEPA-related lawsuits can lead to the preparation of “appeal-proof” documentation, which can further delay project review and approval.

TCF Affected: 464.5

2.2.7 Pipeline Certification

According to the Interstate Natural Gas Association of America (INGAA), about 200 major new pipeline construction projects (valued at about \$2.5 billion per year) will be required over the next 10 years to support projected natural gas demands. The lead time to obtain permission to build new pipeline facilities can be lengthy. The Federal Energy Regulatory Commission (FERC) must approve all new pipelines and expansions to existing interstate pipelines. The process requires approvals from numerous federal, state, and local agencies that have little incentive to work together to approve applications in a timely manner (INGAA 2001). For interstate pipelines, the INGAA estimates that it takes an average of 4 years to obtain approvals to construct a new natural gas pipeline.

TCF Affected: 23.3

2.2.8 Pipeline Safety (Integrity Management)

Recent natural gas pipeline incidents involving loss of life and property, a perceived lack of effectiveness on the part of the federal agency charged with implementing statutory mandates regarding pipeline safety, and the realization that increased gas demands can only be met with increased pipeline capacity have contributed to increased natural gas pipeline safety requirements. Federal-level safety, or integrity management, standards for natural gas transmission pipelines are being written that could increase costs and result in temporary supply disruptions. In addition, states can issue regulations more stringent than the federal regulations for intrastate pipelines.

TCF Affected: Not estimated.

2.2.9 Wetlands Mitigation

Recent COE regulations and guidance for mitigating impacts to wetlands have taken a watershed approach, which allows case-specific exemptions to the one-for-one mitigation-to-impact requirement and expands options for conducting mitigation. Environmental opposition may result in a review and rethinking of these revisions, which could increase the time and money associated with obtaining permits and implementing strategies to mitigate impacts to wetlands caused by natural gas E&P, development, transportation, and construction activities.

TCF Affected: Not estimated.

2.3 ISSUES LIKELY TO INCREASE COSTS

2.3.1 Cooling-Water Intake Structures

Section 316(b) of the CWA requires that cooling-water intake structures reflect the best technology available for minimizing adverse environmental impacts. The EPA is developing national regulations to implement these requirements. It has issued final Phase I regulations for new power plants and manufacturing facilities and final Phase II regulations for existing power plants. The EPA published proposed Phase III regulations for existing manufacturing facilities, including oil and gas extraction facilities, and for new offshore oil and gas extraction facilities in November 2004. Final Phase III regulations must be published by June 2006. The impacts of the final 316(b) Phase III regulations on oil and gas production are not known at this time.

TCF Affected: Not estimated.

2.3.2 Electronic Reporting and Record-Keeping Requirements

On August 31, 2001, the EPA published its proposed Cross-Media Electronic Reporting and Record-Keeping Rule (CROMERRR), which describes conditions under which the EPA would “allow” submission of electronic documents and maintenance of electronic records to satisfy federal EPA reporting and record-keeping requirements. The rule is touted as voluntary, but any entity that reports or maintains records electronically would have to follow certain requirements, which could include installation of costly new systems incompatible with current electronic data management systems. The American Petroleum Institute (API) estimated that the financial impact of the proposed rule on the petroleum industry was comparable to what the industry spent on Y2K, or about \$1 billion.

TCF Affected: Not estimated.

2.3.3 Lack of Incentives to Go beyond Compliance

Permitting and regulatory processes generally lack incentives for companies to provide environmental protection beyond standard operating practices. Proposals that would provide environmental protections beyond legal requirements and proposals that could provide equal protection at lower costs have been rejected by local, state, and federal authorities. Such rejections constrain environmental progress and preclude opportunities to reduce costs. They can also discourage natural gas operators who may otherwise be willing to take voluntary action in the E&P areas, where additional regulations, expected in response to increased activity and attendant environmental impact, would add to the workload of already burdened regulatory staff, further exacerbating production delays.

TCF Affected: 86.6

2.3.4 Louisiana E&P Waste Disposal Regulations

Amendments to the State of Louisiana's E&P waste storage and disposal rules passed on November 20, 2001, may increase costs and delay natural gas E&P schedules in the state. Louisiana is the first state to adopt such regulations, and because many oil and gas states follow Louisiana's lead, the requirements may set precedents for other states, with attendant costs for natural gas E&P operations.

TCF Affected: Not estimated.

2.3.5 Maximum Achievable Control Technology

MACT rules regulate emissions of hazardous air pollutants (HAPs) from stationary and mobile sources. Final MACT rules exist for oil and gas production facilities and for natural gas transmission and storage facilities. Recently, the EPA signed final MACT rules for turbines, process heaters, and reciprocating internal combustion engines, which may affect gas operations. Compliance with these rules, for example, a 95% reduction in emissions at major sources, could impact the economics of natural gas operations.

TCF Affected: Not estimated.

2.3.6 Mercury Discharge Regulations

Discharges of mercury-containing drilling muds from gas (and oil) drilling operations in the Gulf of Mexico have generated concern that such mercury may convert to toxic methylmercury, which can accumulate in the food chain and poison fish. Such concerns may expand to other onshore and offshore geographical areas, leading to strengthened or new mercury regulations.

TCF Affected: Not estimated.

2.3.7 NO_x Prevention of Significant Deterioration Increment Consumption

An increasingly important air quality issue that can affect natural gas production in the West is the potential for new regulations to limit NO_x emissions. The Air Quality Act limits emissions in Prevention of Significant Deterioration (PSD) areas, most of which exist in the West, where the number of combustion sources that create such emissions is growing. Many of these combustion sources are from oil and gas drilling, and particularly CBM drilling, which is expected to increase significantly over the next few years.

TCF Affected: Not estimated.

2.3.8 Noise Regulations

As E&P and transportation of natural gas increase in response to increased demand, the number of drilling rigs, processing plants, and pipelines will also increase. These increases will require additional equipment, particularly compressors and drills, both of which generate high levels of noise. To date, most drilling and producing operations and pipelines have been located away from population centers, so that noise has not been a major issue. However, as thousands of wells are drilled (particularly for CBM in the West) and as new pipelines are built, noise is expected to become an issue that could lead to regulation, and subsequently higher operating and transportation costs. Noise also affects wildlife, and its effect on otherwise quiet areas will continue to be a subject of concern and potential regulation.

TCF Affected: Not estimated.

2.3.9 Nonroad Diesel Rule

Section 213(a) of the Clean Air Act (CAA) requires that the EPA regulate emissions of nonroad engines and equipment. The EPA has issued some nonroad diesel emission standards and plans to issue more, with a new proposal in the spring of 2003 and final rules by the summer of 2004. Nonroad diesel engines are used in natural gas E&P and in gas processing operations. Increased costs of these engines because of stricter emissions controls, when added to other environmental costs, could affect some operations and limit gas development.

TCF Affected: Not estimated.

2.3.10 Ocean Discharge Criteria

Proposed amendments to existing rules implementing the ocean protection provisions of Section 403 of the CWA would strengthen existing ocean discharge criteria. These criteria must be considered in the issuance of individual or general National Pollutant Discharge Elimination System (NPDES) permits for offshore facilities. The proposal would designate "Healthy Ocean Waters" (waters beyond 3 mi offshore), and these waters would be protected by both a narrative statement of water quality and pollutant-specific numeric criteria and would be subject to an antidegradation policy. The proposal would also establish "Special Ocean Sites (SOSs)," where new and significantly expanded discharges would be prohibited.

TCF Affected: Not estimated.

2.3.11 Particulate Matter Regulations

In 1997, the EPA promulgated National Ambient Air Quality Standards (NAAQS) for fine particulate matter (PM_{2.5}, particulate matter with a mean aerodynamic diameter of 2.5 μm or less). The EPA is considering updating that standard, and some states are implementing stricter

regulations. Many diesel-powered engines used at CBM production sites emit PM, and if those emissions were further restricted, more costly new, alternative, or refitted power sources might be required. Depending on the type of regulation, limits on particulate emissions from diesel and gasoline engines could slow the development of CBM.

TCF Affected: 7.2

2.3.12 Pipeline Gathering Line Definition

The Pipeline Safety Act of 1992 requires the U.S. Department of Transportation (DOT) to define the term “gathering line” and to consider the merits of revising pipeline safety regulations for such lines. The issue is complex, and the current definition, adopted in 1970, lacks clarity. The definition could require more lines and facilities to become subject to the federal gas pipeline regulations, which could be costly for small operators and could affect upstream gas flows.

TCF Affected: Not estimated.

2.3.13 Regional Haze Rule

In July 1999, the EPA promulgated final regional haze regulations for protecting visibility in national parks and Wilderness Areas. These rules require states to establish goals for improving visibility in these areas and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment (e.g., sulfur dioxide [SO₂], NO_x, and particulates). The goal is to reduce visibility impairment in these areas to natural levels by 2065.

TCF Affected: Not estimated.

2.3.14 Spill Prevention Control and Countermeasures

On July 17, 2002, the EPA issued a final rule that amended the spill prevention, control, and countermeasures requirements originally promulgated in 1974 under the EPA’s Oil Pollution Prevention regulations in the *Code of Federal Regulations*, Title 40, Part 112 (40 CFR Part 112). While the expanded scope and relatively short compliance deadlines of the new rule would primarily affect oil production and operations, natural gas drilling and production operations would also be affected, potentially causing some small operators to leave the business, and limiting the ability to rework some existing properties to extract additional gas resources.

TCF Affected: Not estimated.

2.3.15 Standards for Decommissioning or Closing Wells

As gas production from a producing well diminishes or becomes uneconomical, the well must be decommissioned or closed according to the regulations set forth by the appropriate state environmental regulatory agency or oil and gas commission. Typically, these regulations specify contaminant-specific concentrations that cannot be exceeded after closure is complete. These concentrations can vary from state to state, and they are usually set on the basis of technology, background concentration, or other non-risk-based measures. Thus, they can be overly protective and costly to implement, without providing significant gains in environmental or human-health protection.

TCF Affected: Not estimated.

2.3.16 Storm Water Construction Permits

The EPA has proposed extending the deadline for obtaining storm water permits under the CWA by 2 years, from March 10, 2003, to March 10, 2005, to determine the appropriate NPDES requirements, if any, for constructing oil and gas E&P facilities of 1 to 5 acres. If all oil and gas and E&P facilities of 1 to 5 acres were required to obtain such permits, as originally proposed in 1999, the costs and delays to oil and gas production could reduce the number of wells drilled and the amount of gas produced.

TCF Affected: 5.75 per year

2.3.17 TMDL Regulations Targeting Oil and Gas Wells

Gas (and oil) wells may be targeted for TMDL limits because large point sources are already regulated, and technical and political factors argue against imposing limits on large nonpoint sources such as agricultural lands. Also, proposed changes to the TMDL rule could limit the use of nationwide construction permits under Section 404 of the CWA.

TCF Affected: Not estimated.

3 ISSUE DISCUSSIONS

This section provides additional detail and discussion for the environmental policy and regulatory constraints summarized in Chapter 2. For each issue, the following information, where available, is presented:

- *Summary.* Brief summary of the issue.
- *Source of constraint.* The constraint can arise from statutes; regulations written to implement a statute; Executive Orders; or from agency implementation of the regulation, statute, or order.
- *Impact.* The impact of the constraint can be one or more of the following: lack of access (unavailability of gas), delays, or increased costs.
- *Phase.* The constraint can affect one or more of the following phases of the natural gas production cycle: exploration, production, or transportation.
- *Category.* The constraint can affect one or more categories of activity, including access, leasing, permitting, and operations.
- *Estimated affected natural gas resources.* Estimates of the amount of gas affected by the constraint, in TCF, were derived from information collected by other sources, such as the USGS and the MMS.
- *Estimate type.* Because not all estimates are reported in the same terms, the type of estimate is identified. Most frequently, the estimates are reported as technically recoverable resources; however, sometimes estimates are reported as economically recoverable amounts or in other terms used by the organization preparing the estimates.
- *Estimate date.* The date of the estimate of the TCF affected.
- *Estimate reference.* The source of the TCF affected estimate.
- *Estimate comments.* Notes that help explain the TCF estimates.
- *Statutory/regulatory citation.* The specific source of the constraint, which can include specific statutes, regulations, proposed regulations, Presidential Memos, etc.
- *Lead player(s).* The agency or other player that has control over the constraint can include various federal regulatory agencies (e.g., EPA, BLM, COE), states, the President, or Congress.

- *Issue discussion.* A discussion of the nature of the constraint, how it evolved, its status, and other information relevant to understanding the constraint. The discussion includes references.

Table 1 lists each constraint, grouped by source of constraint, and identifies lead player(s), category(ies), and production cycle phase(s). Table 2 lists the constraints, grouped by type of impact, and indicates the estimated TCF affected, and the estimate type, date, and reference. Many of these issues have multiple impacts; to prevent duplication in presentation, constraints are grouped according to the impact deemed to be the most significant. The data for each constraint are stored in a Microsoft® Access database to facilitate updating and sorting according to various criteria.

TABLE 1 Environmental Regulatory Constraints, by Source of Constraint^a

Source of Constraint	Constraint	Lead Player	Category	Phase
Statutory/ regulatory/agency implementation	CZMA consistency provisions	NOAA	Access, leasing, permitting	E&P, transportation
Statutory	Bans on Great Lakes drilling	COE, states	Access, leasing	E&P
	Wilderness Areas	BLM	Access	Exploration
Regulatory	CBM-produced water management	EPA, states	Permitting	Production
	Cooling-water intake structures	EPA	Permitting	Production
	Electronic reporting and record-keeping requirements	EPA	Operations	Production
	Fracturing operations	EPA, states	Operations	Production
	Lack of incentives to go beyond compliance	BLM	Permitting	Production
	Louisiana E&P Waste Disposal Regulations	State	Operations	Production
	MACT rules	EPA	Operations	Production, transportation
	Mercury discharge regulations	EPA	Permitting	E&P
	Nationwide permits	COE	Permitting	Production, transportation
	NEPA integration and lawsuits	States, BLM, FERC	Access, leasing, permitting	E&P, transportation
	NO _x PSD increment consumption	EPA, states	Permitting	Production
Noise regulations	States, local governments, BLM	Operations	Production, transportation	

TABLE 1 (Cont.)

Source of Constraint	Constraint	Lead Player	Category	Phase
Regulatory (Cont.)	Nonroad Diesel Rule	EPA	Operations	E&P
	Ocean discharge criteria	EPA	Permitting	Production
	Particulate matter regulations	EPA, states	Permitting	Production
	Pipeline gathering line definition	OPS	Operations	Production, transportation
	Pipeline safety (integrity management)	OPS	Operations	Transportation
	Regional haze rule	States, EPA	Operations	Production
	Roadless Rule	FS	Access	Exploration
	Spill prevention control and countermeasures	EPA	Permitting	Production
	Standards for decommissioning or closing wells	States	Operations	Production
	Storm water construction permits	EPA	Permitting	E&P
	TMDL regulations targeting oil and gas wells	EPA	Permitting	E&P
Presidential, statutory	Wetlands mitigation	COE, states	Permitting, operations	Production, transportation
	OCS Moratoria — Atlantic Ocean	President, Congress	Access, leasing	E&P
	OCS Moratoria — Eastern Gulf of Mexico	President, Congress	Access, leasing	E&P
Presidential	OCS Moratoria — West Coast	President, Congress	Access, leasing	E&P
	Monument designations	President	Access	Exploration
Agency implementation	Ocean policy	President, Congress	Access, leasing, permitting, operations	E&P, transportation
	Drilling permits	BLM	Permitting	Production
	ESA	USFWS	Access, leasing, permitting, operations	E&P
	Essential fish habitat	NMFS	Permitting	E&P, transportation
	Forest Service restrictions	FS	Access	Production

TABLE 1 (Cont.)

Source of Constraint	Constraint	Lead Player	Category	Phase
Agency implementation (Cont.)	Outdated BLM land use plans	BLM	Leasing, permitting	E&P
	Lease stipulations	BLM, FS	Leasing	Production
	Permit restrictions	BLM	Access	E&P
	Pipeline certification	FERC, others	Permitting	Transportation

^a BLM = Bureau of Land Management; CBM = coal bed methane; CZMA = Coastal Zone Management Act; COE = U.S. Army Corps of Engineers; E&P = exploration and production; EPA = U.S. Environmental Protection Agency; ESA = Endangered Species Act; FERC = Federal Energy Regulatory Commission; FS = USDA Forest Service; MACT = maximum achievable control technology; NEPA = National Environmental Policy Act of 1969; NMFS = National Marine Fisheries Service; NOAA = National Oceanic and Atmospheric Administration; NO_x = nitrogen oxides; OCS = Outer Continental Shelf; OPS = Office of Pipeline Safety; PSD = Prevention of Significant Deterioration; TMDL = total maximum daily load; USFWS = U.S. Fish and Wildlife Service.

TABLE 2 Environmental Regulatory Constraints and Estimated Amounts of Gas Affected^a

Issue Impact	Constraint	TCF Affected	TCF Type	TCF Date	TCF Reference
Unavailable gas, delay, cost	Ocean policy	Not estimated	NA	NA	NA
	Lease stipulations	108	Undeveloped gas resources	01/1998	NPC (1999)
Unavailable gas, delay	CZMA consistency provisions	362.2	Undiscovered conventionally recoverable resources	01/1999	MMS (2000)
	ESA	Not estimated	NA	NA	NA
	Outdated BLM land use plans	120.3	Technically recoverable	01/2003	DOI (2003)
Unavailable gas	Forest Service restrictions	10–30	Natural gas resources	01/2001	Fisher (2001)
	Monument designations	1	Technically recoverable	01/1995	Wilderness Society (2002)
	OCS Moratoria — Atlantic Ocean	28.0	Technically recoverable	01/2000	EIA (2001b)
	OCS Moratoria — Eastern Gulf of Mexico	11.3	Technically recoverable	01/2000	EIA (2001b)

TABLE 2 (Cont.)

Issue Impact	Issue	TCF Affected	TCF Type	TCF Date	TCF Reference
Unavailable gas (Cont.)	OCS Moratoria — West Coast	18.9	Technically recoverable	01/2000	EIA (2001b)
	Permit restrictions	86.6	Technically recoverable	01/2003	DOI (2003)
	Bans on Great Lakes drilling	1.1	Possible and probable reserves	09/2001	Shirley (2001)
	Roadless Rule	11	Technically recoverable	11/2000	Eppink (2000)
	Wilderness Areas	9	Technically recoverable	01/2003	DOI (2003)
Delay, cost	CBM-produced water management	74	Technically recoverable	01/1998	NPC (1999)
	Fracturing operations	293	Unproved technically recoverable	01/2000	EIA (2001b)
	Pipeline safety (integrity management)	Not estimated	NA	NA	NA
	Wetlands mitigation	Not estimated	NA	NA	NA
Delay	Drilling permits	311.2	Assessed additional resources	01/1998	NPC (1999)
	Essential fish habitat	174.5	Technically recoverable	01/2000	EIA (2001b)
	Nationwide permits	Not estimated	NA	NA	NA
	NEPA integration and lawsuits	464.5	Technically recoverable	01/2000	EIA (2001a)
	Pipeline certification	23.3	Annual gas consumption	01/2003	EIA (2003)
Cost	Cooling-water intake structures	Not estimated	NA	NA	NA
	Electronic reporting and record-keeping requirements	Not estimated	NA	NA	NA
	Lack of incentives to go beyond compliance	86.6	Technically recoverable	01/2003	DOI (2003)
	Louisiana E&P waste disposal regulations	Not estimated	NA	NA	NA
	MACT rules	Not estimated	NA	NA	NA
	Mercury discharge regulations	Not estimated	NA	NA	NA

TABLE 2 (Cont.)

Issue Impact	Issue	TCF Affected	TCF Type	TCF Date	TCF Reference
Cost (Cont.)	NO _x PSD increment consumption	Not estimated	NA	NA	NA
	Noise regulations	Not estimated	NA	NA	NA
	Nonroad Diesel Rule	Not estimated	NA	NA	NA
	Ocean discharge criteria	Not estimated	NA	NA	NA
	Particulate matter regulations	7.2	Technically recoverable	01/1995	Whitney (2001)
	Pipeline gathering line definition	Not estimated	NA	NA	NA
	Regional haze rule	Not estimated	NA	NA	NA
	Spill prevention control and countermeasures	Not estimated	NA	NA	NA
	Standards for decommissioning or closing wells	Not estimated	NA	NA	NA
	Storm water construction permits	5.75 per year	Economically recoverable	09/2002	Texas Alliance of Energy Producers (2003)
TMDL regulations targeting oil and gas wells	Not estimated	NA	NA	NA	

^a Abbreviations: BLM = Bureau of Land Management; CBM = coal bed methane; CZMA = Coastal Zone Management Act; E&P = exploration and production; DOI = U.S. Department of the Interior; EIA = Energy Information Administration; ESA = Endangered Species Act; MACT = maximum achievable control technology; MMS = Minerals Management Service; NA = not applicable; NEPA = National Environmental Policy Act of 1969; NO_x = nitrogen oxides; NPC = National Petroleum Council; OCS = Outer Continental Shelf; PSD = Prevention of Significant Deterioration; TCF = trillion cubic feet; TMDL = total maximum daily load.

3.1 ISSUES LIKELY TO LIMIT ACCESS

3.1.1 Coastal Zone Management Act Consistency Provisions

Summary: The CZMA requires that each federal agency activity within or outside the coastal zone that affects any land or water use or natural resource of the coastal zone must be undertaken in a manner consistent “to the maximum extent practicable” with the enforcement policies of approved state CMPs. Nonfederal applicants for federal licenses or permits must comply with

state CMP enforcement policies. Federal approvals may not be granted until the state concurs, or, if the state objects, until the Secretary of the Department of Commerce, on appeal by the applicant, overrides the state's CMP objections. These provisions have caused duplications and costly delays to federal leasing and production activities. Also, once a lease has been obtained, the CZMA can still limit/prevent exploration, development, and production for that lease. (See related issue, OCS Moratoria — West Coast.)

Source of Constraint: Statutory, regulatory, agency implementation

Impact: Unavailable gas, delay

Phase: E&P, transportation

Category: Access, leasing, permitting

Estimated affected natural gas resources (TCF): 362.2

Estimate type: Undiscovered conventionally recoverable resources

Estimate date: 01/1999 **Estimate reference:** MMS (2000)

Estimate comments: This estimate is MMS's mean estimate for all OCS areas. The low estimate is 292.1 TCF, and the high estimate is 468.6 TCF. The breakdown for mean estimates is as follows: Alaska, 122.6; Atlantic, 28.0; Gulf of Mexico, 192.7; Pacific, 18.9. Note that the specific example of OCS Lease Sale 181 in Florida prevented drilling for an estimated 1.45 TCF because of the downsizing of the lease area in July 2001.

Statutory/regulatory citation: CZMA (Section 307, 16 USC 1456); CZMA Federal Consistency Regulations, Final Rule, *Federal Register*, Volume 65, page 77124 (65 FR 77124), December 8, 2000, and Proposed Rule (68 FR 34851), June 11, 2003

Lead player: NOAA

Issue discussion: The CZMA created a national program to encourage states to manage and balance competing uses of, and impacts on, coastal resources. The oil and gas industry suggests that over the years, the law has been used to stall or halt offshore development by using loosely worded passages in the law that require a "seemingly endless loop of permit approvals" (Fry 2001). A coastal state with a federally approved CMP can block or delay offshore E&P plans by claiming that the federal lessee's activity will have some effect on resources in the coastal zone. If the lessee's activity will have an effect, the activity must be consistent with the state's CMP. The coastal zone itself generally extends only 3 mi offshore, except for the Gulf of Mexico off Texas and Florida, where it extends 9 mi. However, the "effects test" can extend a state's reach to greater distances.

The MMS issues OCS mineral leases under the authority of the Outer Continental Shelf Lands Act (OCSLA; 43 USC 1331 et seq). Under the OCSLA, an OCS lessee prepares a Plan of

Exploration (POE) as part of the exploration stage of lease activity. If recoverable resources are found, the lessee may then submit to the MMS a Plan of Development and Production (POD) to continue on to the production stage. In filing either plan, the OCSLA stipulates that the OCS lessee will certify that its activities will be consistent with the CMP of any affected state that has such an approved program. (43 USC 1340(c) addresses applying CZMA certification requirements to POEs; 43 USC 1351(h) addresses applying the requirement to PODs.)

Under the CZMA consistency provisions, a federal agency is prohibited from granting any further permits to conduct activities under a POE or POD unless the state has concurred that such activities are consistent with its approved CMP. If the state does not concur, the lessee faces considerable delay in appeal before the Secretary of Commerce, which can “override” the state’s objection. In recent years, a number of states, including North Carolina, California, and Florida, have used their consistency determination authorities to limit oil and gas leasing, exploration, and development. The Secretary of Commerce has upheld certain controversial state CZMA objections, thus thwarting further OCS development. Even in instances where the Secretary has overridden the state’s objection, appeals involving OCS activity have taken from 16 months to 4 years from the state’s initial objection to the final override decision (Wyman 2001).

Chief risks associated with current CZMA implementation include escalating compliance costs resulting from unexpected interpretations of vague policies in state CMPs, delays caused by lengthy appeals before the Department of Commerce, and the risk of losing lease rights without compensation when a state authority changes a plan requirement (Young 2001). Existing challenges take an average of 2 years to review (Inside EPA 2001c). A 1996 amendment to the CZMA, adding 16 USC Section 1465 (appeals to the Secretary), was designed to expedite the override decision-making process. But lengthy agency commenting continues to draw out appeals (Wyman 2001).

Other issues include the policy of allowing states to conduct consistency reviews of activities outside their own geographic boundaries; delays caused by lack of coordination among federal agencies in processing permits for OCS activities, and delays involving separate state consistency reviews for those permits; state requirements for multiple information requests with the related use of “lack of information” to deny consistency certifications; and lengthy appeals processes, exacerbated by overlong agency commenting and by the Department of Commerce’s requirement that the decision-making period not begin until after the Administrative Record is “closed” (Wyman 2001).

OCS Lease Sale 181. An example of how the CZMA can restrict drilling and production of natural gas is OCS Lease Sale 181. Federal OCS Lease Sale 181, in the Eastern Gulf of Mexico Planning Area, off the coast of Florida, was scheduled for December 2001. In the early to mid-1990s, the MMS had comprehensive consultations with Alabama, Florida, and other coastal states about leasing in the eastern Gulf of Mexico. Both Alabama and Florida expressed concerns and requested that the leasing not occur within certain distances of their shores (15 mi for Alabama and 100 mi for Florida.) MMS designed Lease Sale 181 to meet these criteria and placed it on the current 5-year schedule. Subsequently, Congress ratified the MMS decision through the appropriations process. (The lease area is not subject to the OCS moratorium.) Industry then began to accumulate seismic data, review geological trends, and conduct

preliminary engineering studies in anticipation of the sale. Florida tried to block the sale on environmental grounds, even though the lease sale had existing infrastructure that could be used with a minimum amount of turnaround time. The lease was also near one of the most rapidly growing population areas in the United States, and many argued that the streamlined development of Lease Sale 181's gas resources could prevent energy supply and delivery disruptions in the area (Fry 2001).

On June 21, 2001, the U.S. House of Representatives approved an amendment to House Resolution (H.R.) 2217, the Interior Appropriations bill that bars the spending of funds to execute a final lease agreement for oil or gas in Area 181 before April 1, 2002, effectively blocking the sale of Lease 181. On July 2, 2001, the Bush Administration announced that Secretary of the Interior, Gale Norton, would seek to allow drilling on 1.47 million acres (256 leases) of Lease Sale 181, about one-fourth of the original acreage of 5.9 million acres (1,033 leases) first proposed for leasing by the Clinton Administration in 1997. The revised area is estimated to contain 1.25 TCF of natural gas, whereas the original site holds an estimated 2.7 TCF (Ferullo 2001a).

The original sale area also contained acreage near infrastructure and in moderate water depths, allowing for 1- to 2-year projects. The revised sale area is farther from existing infrastructure and in ultra-deepwater depths, requiring projects with cycle times of 4 to 10 years. The revised sale area eliminates all acreage in less than 6,500-ft depths, with most of the available acreage in depths greater than 7,000 ft. Thus, the sale is an ultra-deepwater sale, where state-of-the-art development tools are required. There may be limited equipment to drill and produce in these waters in the near term (Young 2001).

The lease sale for the modified OCS Lease Sale 181 was conducted in December 2001. Ninety-five of the 256 available leases were sold, and the remaining leases in the scaled-back OCS 181 lease will be auctioned as part of the 2002–2007 5-year plan (MMS 2002a). These auctions, which will cover about 0.8 million acres, are scheduled to occur in December 2003 (Lease Sale 189) and March 2005 (Lease Sale 197). Both are currently in the NEPA process. A draft EIS was issued in November 2002, and a final EIS is expected in June 2003. Consistency determinations will be made roughly 5 months before each sale has been prepared (MMS 2002b). Drilling in areas sold in the December 2001 reduced area could begin within 2 to 10 years, but the remaining 4.4 million acres (1.45 TCF) of the original OCS Lease 181 would not become available for leasing until at least 2007.

Destin Dome. The Destin Dome area is another example where the CZMA functioned to prohibit drilling. Between 1984 and 1989, the MMS sold drilling rights to 11 parts of the Destin Dome area for about \$20 million. However, Florida rejected the development and production plan submitted by the lessees, saying that the plan would not be consistent with the state's CMP. Neither the EPA nor the NOAA would issue the permits required for drilling; each argued that it needed clearance from the other before it could issue its own permit (Inside EPA 2001b). The oil company lessees appealed to the Department of Commerce to overturn Florida's objections, but action was never taken. On May 29, 2002, the President announced that the U.S. Department of the Interior (DOI) would pay \$115 million to buy back the Destin Dome oil and gas leases to settle the legal dispute and appease state and local officials who objected to energy exploration in

the state. The settlement covered the costs for leasing, exploration, and gas in the ground that they would be unable to sell. The estimated amount of these resources varies from 0.7 TCF (DOI estimate) to 2.6 TCF (DOE estimate) (Ferguson 2002). A representative of the Natural Gas Supply Association stated that the Destin Dome area is one of the largest fields in the Gulf of Mexico.

Regulatory issues. Recent changes made to the implementing regulations could limit or delay gas (and oil) exploration and development. On December 8, 2000, the NOAA published final rules revising the regulations implementing the federal consistency provisions of the CZMA. (The regulations had been in place since 1979, and the NOAA needed to update them to reflect changes made to the federal consistency provisions in Section 307 resulting from the Coastal Zone Protection Act of 1996 and the Coastal Zone Act Reauthorization Amendments of 1990.) Sections 930.120 through 930.131 of 15 CFR describe the procedures for appeals to the Secretary of Commerce for reviews of consistency decisions related to national security interests. Before the changes, 15 CFR 930.121 required that a successful appeal must include the specific finding that “[t]he challenged activity furthers one of the national objectives or purposes of the [CZMA].” However, the new CZMA rules have added the requirement that the challenged activity must further the national interest requirements in a “significant or substantial” manner. According to testimony before the House Resources Committee, Subcommittee on Fisheries Conservation, Wildlife, and Oceans, this change to the “national interest” criterion could have substantial detrimental impacts. The preamble to the December 8, 2000 rule cites examples of activities that significantly or substantially further the national interest as the siting of energy facilities or OCS oil and gas development (DOC 2000).

While these examples give OCS lessees some comfort regarding the new criterion’s application to OCS development, they do not provide the same level of comfort for exploration. The distinction is significant, as demonstrated by recent override decisions by the Secretary of Commerce. For example, the Secretary’s POE and NPDES permit override decisions in a North Carolina leasing project, the Manteo project, specifically found, contrary to longstanding Secretarial precedent, that the drilling of an exploration well in an important frontier OCS area would only provide a “minimal contribution” to the national interest. Emphasizing that the Manteo POE had indicated that there was a 10% chance of actually finding mineral reserves (which, in the industry, is a solid chance for even conservative decision making), the Secretary found that the supposedly small chance of exploratory success diminished the Manteo project’s contribution to the national interest. Therefore, it is possible that the Secretary of Commerce could use the new override criterion to reject the importance of OCS exploratory activity in frontier areas (Wyman 2001).

The December 8 rule also provided for the review and preclusion of a federal action (e.g., a leasing or permitting decision) based on a state’s objection, even if that state was not the one in which the activity would occur. According to 15 CFR 930.151, states can object to an activity on the basis of any “reasonably foreseeable” direct or indirect effect resulting from a federal action occurring in the state or on any coastal use or resource of another state that has a federally approved management plan.

One of the recommendations of the NEPDG in its National Energy Policy of May 2001 was for the Department of Interior and Commerce to “re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf” (NEPDG 2001). On June 11, 2003, the NOAA published a proposed rule to address these CZMA-related recommendations. The proposal seeks to clarify some sections of and provide greater transparency and predictability to the federal consistency regulations (NOAA 2003).

3.1.2 Endangered Species Act

Summary: The ESA can limit access to gas resources and cause delays in permitting on both federal and private lands. Court-interpreted definitions have expanded the scope of what is considered a “take” under the ESA to include habitat modification, such as clearing or similar development, which often occurs with natural gas E&P. Similarly, the USFWS, an implementing agency for the ESA, often treats sensitive species as requiring the same or similar protections as species that are actually listed as endangered or threatened.

Source of Constraint: Agency implementation

Impact: Unavailable gas, delay

Phase: E&P

Category: Access, leasing, permitting, operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: ESA (16 USC 1531 et seq.)

Lead player: USFWS

Issue discussion: Under the ESA, the USFWS or the NMFS lists certain plant and animal species as endangered or threatened, depending on their assessed risk of extinction. The ESA prohibits the “take” of an endangered species. The definition of take, which includes, among other things, harming, harassing, or pursuing, has been interpreted broadly. For example, in 1995, the Supreme Court determined that significant habitat modification, which could include clearing or development, was a reasonable interpretation of the term “harm.” Once a species is listed, the USFWS is to designate critical habitat for that species, and federal agencies must avoid “adverse modification” to these areas. Section 7 of the ESA requires any federal actions that may affect a listed species to ensure that those actions are “not likely to jeopardize the continued existence” of any endangered or threatened species, nor to adversely modify critical habitat. Federal agencies must consult with the Secretary of Interior or Commerce for such actions, and if the Secretary finds that an action would jeopardize a listed species, he or she must

suggest alternatives. Until the consultation process is completed, agencies are limited in what they may approve.

The designation of critical habitat can have significant cost and schedule impacts on gas development. For example, in comments on the July 2002 rule designating critical habitat for wintering piping plovers, one petroleum company estimated that the critical habitat designation could cause natural gas project delays resulting from Section 7 consultations of 6 months to 2 years. It also estimated that the net present value cost of the designation over 30 years would be \$261 million to \$979 million to the local economy (USFWS 2001).

Failure to conduct Section 7 consultations can lead to legal action. In November 2001, for example, environmental groups sued the FS and the BLM for issuing leases encompassing grizzly bear habitat in the Shoshone National Forest without conducting formal consultation with the USFWS regarding the impacts of such leasing on the habitat (DEN 2001).

Although critical habitat issues are important, the broad interpretation of the law by its implementing agencies means that the mere listing of a species can have nearly as much of an impact as a critical habitat designation. A Congressional Research Study found that “as a practical matter, critical habitat has not been designated for many listed species because the USFWS regards listing as providing the bulk of species protection, while critical habitat adds only a marginal increment” (Buck and Corn 2001). In February 2002, the USFWS proposed listing three species of snails and one species of amphipod as endangered in the Roswell Basin of Southeastern New Mexico. The proposal noted that oil and gas extraction activities in the area were potential threats to these species and that stipulations on permits to drill may be necessary to protect aquatic habitat from contamination or degradation (USFWS 2002).

The Cooperating Industries Forum has also reported a tendency among BLM and FS land managers to apply the same stringent standards that apply to listed species to “watch,” “candidate,” or “sensitive” species. Substantial acreage can be set aside for wildlife species that are considered sensitive, and, therefore, given the same status as listed species, delaying projects for months. Also, drilling operations can be delayed to allow surveys to be conducted during narrow windows in the spring or summer when plants are in bloom (DuVall 1997).

The BLM has acknowledged that ESA consultations can delay the permitting process. On April 25, 2001, Peter Culp, Assistant Director of Minerals, Realty, and Resource Protection at the BLM, noted that although the BLM is coordinating with other federal agencies, there is room for much improvement. ESA consultations and similar coordination issues can cause the BLM to miss the 30-day processing time applications to drill (Culp 2001).

ESA requirements can potentially affect all gas resources in lands that are designated critical habitat or where listed or even sensitive species are present.

3.1.3 Forest Service Restrictions

Summary: Forest Service restrictions contained in RODs for development of natural gas resources in three areas — Beaverhead National Forest, Helena National Forest, and Lewis and Clark National Forest — are limiting the ability to access and produce natural gas.

Source of Constraint: Agency implementation

Impact: Unavailable gas

Phase: Production

Category: Access

Estimated affected natural gas resources (TCF): 10 to 30

Estimate type: Natural gas resources

Estimate date: 01/2001 **Estimate reference:** Fisher (2001)

Estimate comments: 10 to 30 TCF in three national forests (Beaverhead, Helena, and Lewis and Clark)

Statutory/regulatory citation: National Forest Management Act; Forest Service Plans

Lead player: FS

Issue discussion: RODs issued by the FS have restricted access to potentially rich natural gas areas in the NFS. Combined, three recent decisions cover 5,009,453 acres of national forest. Of these, 3,738,095 acres (75%) are legally available, but only 440,600 acres (94% of which are in the Beaverhead National Forest) are available with standard lease terms. In testimony presented to the House Resources Committee in 2001, the Montana Petroleum Association indicated that the combined decisions have potentially cost 10 to 30 TCF in natural gas production. The statement also reported that the FS's decision to disallow further oil and gas exploration on the Rocky Mountain Front was based "primarily on the will of the people (Fisher 2001). The three decisions and their impacts are highlighted below.

- In 1996, the FS issued a ROD for the EIS for the Beaverhead National Forest. Of the 1,636,900 total acres, 76% are administratively available. However, of these, 22% have no surface occupancy (NSO) restrictions, 35% have controlled surface use (CSU) or timing limitations (TLs), and the remainder (19% of the total) have BLM standard lease terms (Fisher 2001).
- In 1997, a ROD was issued for 1,862,453 acres in the Rocky Mountain Division and the Jefferson Division of the Lewis and Clark National Forest. Of the 67% that are administratively available, none are available with

standard lease terms. The administratively available lands have the following designations: no lease offered (19.1%), NSO (19.5%), CSU (21.1%), CSU/TL (7.3%) (Fisher 2001).

- In 1998, a ROD was issued for the Helena National Forest covering roughly 997,700 acres. Of these, 85.52% were found to be administratively available; however, of these, only 2.48% (24,700 acres) are available with standard lease terms. The remainder are designated as follows: 185,100 acres (18.6%), discretionary unavailable; 384,700 acres (38.6%) NSO; and 258,700 acres (25.9%) CSU/TL (Fisher 2001).

The greatest concern for the industry following these FS decisions is the perceived threat to resource development and basic access, particularly the no-lease decision in the Lewis and Clark Forest (Fisher 2001). According to the FS, the Rocky Mountain Division of the Lewis and Clark Forest in the Montana Thrust Belt has the potential to contain a minimum of 2 and up to 11 TCF of gas. The Montana Thrust Belt is rated third in the country for potential conventional gas reserves and second for potential deep gas reserves. Montana's overthrust province may hold 20 TCF or more of CBM, but is currently inaccessible because of recent FS decisions (Fisher 2001). Independent producers testifying at another House Resources Committee hearing stated that under the current circumstances and attitudes of the government, these reserves would not be explored and produced. There have been no FS leases in Montana since 1981. Under the preferred alternative for the Lewis and Clark Forest in the draft EIS, the area would remain open for leasing. These leases, however, would be so severely restricted in stipulations, including NSO, that for all practical purposes the 1.2 million acres have been taken out of play (Nance 1997). In July 2002, the chairman of the Independent Petroleum Association of America (IPAA) testified before the House Resources Committee that the forest manager for the Lewis and Clark National Forest concluded that natural gas development was inconsistent with the development of the forest because it violated "a sense of place" and prohibited new leasing. There is no administrative mechanism to appeal such a judgment despite there being no such basis for denying the use of this multiple use federal land. Court action to overturn the decision failed because the courts concluded that the decision was within the discretion of the forest manager (True 2002).

A similar concern came to fruition in Wyoming in the recently released Preferred Alternative for the Bridger-Teton Forest. The FS decision to adopt a "no lease" policy (even after a 10-year process to prepare the Bridger-Teton Land and RMP) disregards the science and planning that underlie the document. This decision places another 370,000 acres in a "de facto" wilderness classification and more resources off limits (Fisher 2001).

3.1.4 Outdated BLM Land Use Plans

Summary: The FLPMA established land use planning requirements on federal lands, and 43 USC 1701(a)(7) states that it is the policy of the United States to manage public lands under the principles of multiple use and sustained yield. Land use plans and planning decisions provide the basis for every land action undertaken by the BLM, but many have been prepared without

considering natural gas resource potential. If the land use plan is out of date with respect to anticipating the cumulative impacts of gas development, substantial delays in the permitting of new wells can occur as a new environmental analysis (typically an EA or EIS) is completed and the plan updated. Today, many land use plans need to be updated to recognize the use of the land for natural gas development before additional development can occur.

Source of Constraint: Agency implementation

Impact: Unavailable gas, delay

Phase: E&P

Category: Leasing, permitting

Estimated affected natural gas resources (TCF): 120.3

Estimate type: Technically recoverable

Estimate date: 01/2003 **Estimate reference:** DOI (2003)

Estimate comments: Theoretically, gas under all BLM lands that are not yet leased or are leased but do not have permits to drill would be affected. These lands include potentially significant CBM resources. Estimates were calculated by subtracting currently leased acreage from total BLM acreage in Colorado, Montana, New Mexico, Utah, and Wyoming, and multiplying by the average TCF per acre derived from DOI (2003), p. xv, Table ES-1.

Statutory/regulatory citation: FLPMA (43 USC 1701, et seq.)

Lead player: BLM

Issue discussion: BLM has been preparing land use plans since the 1960s. In 2000, the BLM had 162 plans covering nearly 264 million acres of public lands and 758 million acres of mineral estate (BLM 2000). Some of the BLM's land use plans are current, but others date to the mid-1970s and do not meet the requirements of current BLM program requirements. Plans were developed to guide management for a 10- to 20-year period (Colorado BLM 2001), and they did not forecast the dramatic and accelerated changes that are now occurring in the West. Thus, the average life span (or period of usefulness) of these plans has diminished to 7 years. In the Powder River Basin in northeastern Wyoming, for example, the land use plan has been updated twice in the past 2 years and is currently being updated for a third time (Smith 2001). In the Buffalo, Wyoming, Field Office, thousands of permits are not being accepted by the BLM because of limitations of the RMPs for the area. This is because the reasonably foreseeable development estimates of future development failed to recognize the interest in developing CBM (Rubin 2001).

Most plans need updating to reflect current conditions and statutory requirements; they must also be adaptable to changing conditions and demands. The BLM's land use plans (RMPs)

take about 3 years to complete. The process whereby land managers rewrite or amend land use plans has become cumbersome and detailed, resulting in marked delays in decision making; in addition, the time to rewrite or amend an RMP has increased from about 1 year to an average of 3 years (Smith 2001). Funding for land use planning has compounded the problem. From a typical budget of \$10 million in the early 1990s, the planning budget reached a historic low of \$6.6 million in 2000. The planning organization of the BLM is being rebuilt to handle the workload of eliminating the backlog and preventing future backlogs. In 2001, the BLM's planning budget increased to \$25.8 million, and budget increases have followed in every year since; in 2004, \$48 million was appropriated for land use planning.

3.1.5 Lease Stipulations

Summary: Two categories of restrictions limit access to onshore public lands. Some lands, such as Wilderness Areas and areas with specific geological attributes or unique or significant natural or cultural resources, are completely off limits because of statutory, Executive Order, or other administrative requirements. Other lands, while technically available for development, are subject to stipulations imposed by the BLM or the FS to implement statutory or regulatory requirements. Some of these stipulations, which can affect large geographic areas, can prevent development without providing obvious commensurate environmental benefit (Rubin 2001). Combinations of individual stipulations applied to the same area can effectively prevent access to key natural gas resources (Russell 2000). The EIA has estimated that federal lease stipulations increase development costs by 6% and add 2 years to development schedules (EIA 2001b). Operators report a growth in stipulations and note that when land managers impose a stipulation in one area, there is a tendency to impose the same stipulation in surrounding areas (Martin 1997).

Source of Constraint: Agency implementation

Impact: Unavailable gas, delay, cost

Phase: Production

Category: Leasing

Estimated affected natural gas resources (TCF): 108

Estimate type: Undeveloped gas resources

Estimate date: 01/1998 **Estimate reference:** NPC (1999)

Estimate comments: The affected 108 TCF consist of proven reserves and unproven resources on public lands available for leasing but governed by nonstandard lease stipulations in the Rocky Mountain states. This represents nearly one-third of the total 340 TCF of unproven resources in the area. An additional 29 TCF in national parks, national monuments, and Wilderness Areas are completely unavailable for development, and about 203 TCF are subject to standard lease terms

(NPC 1999). The Energy Policy and Conservation Act (EPCA) Report (DOI, USDA, and DOE 2003) presented results on the nature and extent of leasing restrictions in five specific areas within the Rocky Mountain region. It concluded that of the 138.5 TCF of technically recoverable resources on federal lands in the five areas, 36.0 TCF were subject to nonstandard leasing restrictions, 86.6 were subject to standard leasing stipulations, and 15.9 were completely unavailable for leasing.

Statutory/regulatory citation: FLPMA, Resource Management

Lead players: BLM, FS

Issue discussion: Lease stipulations are derived from RMPs (BLM) and Forest Plans (FS). Categories of lease stipulations imposed on federal lands include the following:

- “Standard stipulations” or “standard lease terms.” These are provisions within standard federal oil and gas leases regarding the conduct of operations or conditions of approval given at the permitting stage. These include prohibitions against surface occupancy within 500 ft of surface water and or riparian areas; on slopes exceeding 25% gradient; construction when soil is saturated; or within 1/4 mi of an occupied dwelling. These are generally applied to all BLM oil and gas leases.
- “Seasonal” or other “Special” stipulations. These prohibit mineral exploration and/or development activities for specific periods, in, for example, sage-grouse nesting areas, hawk nesting areas, or calving habitat for wild ungulate species. These are often imposed at the request of state wildlife officials or the USFWS to protect sensitive species.
- NSO leases prohibit operations directly on the surface overlaying a leased federal tract to protect some other resource that may be in conflict with surface oil and gas operations, for example, underground mining operations, archeological sites, caves, steep slopes, campsites, or important wildlife habitat. These leases may be accessed from another location via directional drilling.

The following examples illustrate the severity and impact of lease stipulations.

Short drilling windows. The layering of wildlife protection and other environmental restrictions in part of the year limits periods in which drilling can occur. Deep wells that require more time to drill than the allowed drilling window will either not be drilled, or must be drilled in inefficient phases over more than 1 year (Hackett 2001).

Impact of restrictions. The NPC estimates that 137 TCF of natural gas resources under federal lands in the Rocky Mountains are either off limits to exploration or heavily restricted. This amount, which does not include the 11 TCF placed off limits by the FS Roadless Rule, is 48% of the natural gas resources on federal land in this region. Independent oil and gas

producers, who drill more than 85% of the wells in the United States and produce nearly two-thirds of America's natural gas, resist doing business on many federal lands because of the lack of access, uncertainty of permits, and costly regulations (Nance 1997). Surveys conducted by the IPAA indicate that independents are not increasing their activities on federal lands even though government reports, supported by private and industry studies, indicate that one of the last frontiers for unexplored onshore oil and gas reserves lies beneath public lands.

Onerous restrictions over large areas. In testimony before the House Committee on Resources Subcommittee on Energy and Mineral Resources on April 25, 2001, Mark Murphy, representing the IPAA and the National Stripper Well Association, stated that federal land managers generally impose excessively onerous restrictions on large geographic areas. He cited an example of a BLM-imposed moratorium on operations on 380,000 acres of land in southeastern New Mexico from April through June to avoid disruptions to prairie chicken mating, referred to as the "booming" season. After industry insisted on a scientific study of the issue, the BLM indicated that it may reduce the area to 196,000 acres. Mr. Murphy stated that industry does not object to reasonable restrictions in areas where species are "truly being affected" by its activities; industry does object; however, to "unfounded restrictions on overly broad geographic areas" (Murphy 2001).

Lack of agency guidance/authority of individual land managers. The decisions of a single individual within a land management office can cost thousands or millions of dollars and lead to supply disruptions. As reported in April 25, 2001 testimony, federal land managers have not been given clear instructions for considering the impacts of their actions on energy development. Each land manager must assign his or her own value to the importance of energy development on a case-by-case basis, and the effect of such decisions on energy supply is not necessarily considered. Mixed messages and a lack of accountability have led to a focus on the process of land management practices, with limited regard for their outcome (Stanley 2001). In Southwestern Lea County, New Mexico, for example, a local BLM geologist is requiring operators to set an additional 700 to 800 ft of surface casing (which is estimated to cost an additional \$30,000 to \$40,000 per well) to protect water zones in the area. However, there is no proof that such zones exist, and the New Mexico regulatory agency charged with protecting groundwater has neither stated a similar concern nor proposed modifying its long-standing surface casing requirements (Murphy 2001).

3.1.6 Monument Designations

Summary: The Antiquities Act of 1906 allows the President, at his discretion, to declare by public proclamation, historic landmarks and historic and prehistoric structures owned or controlled by the government of the United States. Between 1996 and 2001, the Administration, under the authority of the Antiquities Act, designated 19 new national monuments and expanded 3 others. The 22 designations collectively cover about 5.6 million acres of federal land, much of which may contain natural gas resources; this land, however, is off limits to development.

Source of Constraint: Presidential

Impact: Unavailable gas

Phase: Exploration

Category: Access

Estimated affected natural gas resources (TCF): 1

Estimate type: Technically recoverable

Estimate date: 01/1995 **Estimate reference:** Wilderness Society (2002)

Estimate comments: The Wilderness Society estimates that the amount of economically recoverable gas in five selected national monuments, based on USGS low- and high-price scenarios for gas, is 0.27 to 0.42 TCF, representing 21 to 42% of the technically recoverable gas in these national monuments.

Statutory/regulatory citation: Antiquities Act of 1906 (16 USC 431, et seq.)

Lead player: President

Issue discussion: The USGS estimates that of the 22 national monuments designated or expanded, 5 have significant hydrocarbon potential. These are the California Coastal National Monument, Canyons of the Ancients National Monument in Colorado, Carrizo Plain National Monument in California, Hanaford Reach National Monument in Washington, and Upper Missouri River Breaks National Monument in Montana (Lorenzetti 2001). Although the national monument designation only prohibits new leases and does not affect existing leases, operators are concerned that the designations will nonetheless affect existing leases. For example, according to testimony presented to the House Committee on Resources on March 7, 2001, the newly designated Canyons of the Ancients National Monument in southwestern Colorado encompasses McElmo Dome, a significant source of natural gas used for advanced oil and gas recovery in Colorado, New Mexico, and Texas. Of the 183,000 acres within the monument's boundary, nearly 155,000 have active federal leases, 141,000 of which are held by production or are included in four federal production units. When the monument was designated, the BLM proposed stringent surface use restrictions on 79,000 acres, including a NSO stipulation. Oil and gas companies are concerned that given "BLM's predilection for restricting access," the RMP to be developed for the monument will create even more uncertainty for production (Stanley 2001).

The designation also provides an avenue for legislative restrictions. For example, in June 2001, the House passed a DOI spending bill that banned drilling in national monuments.

As with other blanket bans to leasing access, the monument designations do not consider the ability of natural gas operators to apply technologies and drilling practices that minimize harm to the environment or that land managers could designate specific areas in which drilling should be banned, as opposed to banning leasing of all covered areas. Some observers note that

the designations have locked up large areas, when, according to the Antiquities Act, the smallest amount of acreage possible should have been designated.

3.1.7 OCS Moratoria — Atlantic Ocean

Summary: Moratoria deny access to broad areas of natural gas reserves and resources. Major natural resources have been discovered off the Canadian Coast, and this resource potential could extend southward. The moratoria were implemented primarily because of past oil spills; however, they also constrain natural gas E&P.

Source of Constraint: Presidential, statutory

Impact: Unavailable gas

Phase: E&P

Category: Access, leasing

Estimated affected natural gas resources (TCF): 28.0

Estimate type: Technically recoverable

Estimate date: 01/2000 **Estimate reference:** EIA (2001b)

Estimate comments: Estimates are for undiscovered technically recoverable resources. The EIA notes that the estimates come from the MMS's *Outer Continental Shelf Petroleum Assessment, 2000*, and are mean estimates with values adjusted to reflect 1999 new field discoveries.

Statutory/regulatory citation: OCSLA (43 USC 1331, et seq.); Presidential Memo (06/12/1998)

Lead players: President, Congress

Issue discussion: In June 1990, President George H.W. Bush, acting under the authority of the OCSLA (43 USC 1341(a)), issued a directive to withdraw three general areas from new leasing and development until the year 2000. These areas included the West Coast, the southeastern coast of Florida, and the North Atlantic Coast. In August 1992, President Bush issued a memorandum to the Secretary of the Interior confirming his 1990 directive as implemented in the 5-year OCS Oil and Gas Program for 1992–1997. These regions of the OCS were included in President Clinton's broader 1998 Executive Order forbidding leasing of most of the OCS in the contiguous United States until 2012. That order prohibits the Secretary of the Interior from leasing off the East and West Coasts, in the North Aleutian Basin in Alaska, and in most of the eastern Gulf of Mexico prior to June 30, 2012.

Even assuming that application of advanced technology results in substantial increases in natural gas production, it is difficult to see how future U.S. demand for natural gas will be met without production from OCS areas currently under moratoria. One of the more promising frontier areas is the North Atlantic OCS. Major discoveries have been made off the coast of Canada at Sable Island and Panuke. The former is now in production. The estimated undiscovered natural gas potential off the east coast of Canada is 63 TCF. This gas play may continue south into U.S. waters. OCS oil production has impacts that gas production does not, and the Atlantic resources are viewed primarily as gas (not oil). Advances in technology and knowledge have changed the baseline used to deny access to OCS lands. Innovative technologies have revolutionized the means of finding and producing natural gas so that disturbances to the environment are minimal and temporary. For example, three-dimensional (3-D) seismic processes that analyze geological structures with greater precision and directional and horizontal drilling technologies that allow a variety of productive reservoirs to be accessed from one location mean that more gas can be produced with fewer wells. A 1999 DOE report, *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology*, states that "...innovative E&P approaches are making a difference to the environment. With advanced technologies, the oil and gas industry can pinpoint resources more accurately, extract them more efficiently and with less surface disturbance, minimize associated wastes, and, ultimately, restore sites to original or better condition....[The industry] has integrated an environmental ethic into its business and culture and operations...[and] has come to recognize that high environmental standards and responsible development are good business..." (DOE 1999).

The TCF estimates are based on little or no historical exploration and could be greater if exploration were allowed. The NPC (1999) estimated that as of January 1, 1998, 31 TCF were affected by the moratoria.

3.1.8 OCS Moratoria — Eastern Gulf of Mexico

Summary: Moratoria covering most of the eastern part of the Gulf of Mexico deny access to broad areas of natural gas reserves and resources. They were implemented primarily because of past oil spills; however, they also constrain natural gas E&P.

Source of Constraint: Presidential, statutory

Impact: Unavailable gas

Phase: E&P

Category: Access, leasing

Estimated affected natural gas resources (TCF): 11.3

Estimate type: Technically recoverable

Estimate date: 01/2000 **Estimate reference:** EIA (2001b)

Estimate comments: Estimates are for undiscovered technically recoverable resources and assume that OCS Lease Sale 181 (estimated to contain 1 TCF) occurs. If OSC Lease Sale 181 is not fully leased, the restricted estimate would be 12.3 TCF. The EIA notes that the estimates come from the MMS's *Outer Continental Shelf Petroleum Assessment, 2000*, and are mean estimates with values adjusted to reflect 1999 new field discoveries.

Statutory/regulatory citation: Presidential memos, directives

Lead players: President, Congress

Issue discussion: In June 1990, President George H.W. Bush, acting under the authority of the OCSLA (43 USC 1341(a)) issued a directive to withdraw three general areas from new leasing and development until the year 2000. These areas included the southeastern coast of Florida. In August 1992, President Bush issued a memorandum to the Secretary of the Interior confirming his 1990 directive as implemented in the 5-year OCS Oil and Gas Program for 1992–1997. These regions of the OCS were included in President Clinton's broader 1998 Executive Order forbidding leasing of most of the OCS in the contiguous United States until 2012. That order prohibits the Secretary of the Interior from leasing, among other areas, most of the eastern Gulf of Mexico prior to June 30, 2012.

Analyses conducted by the NPC, EIA, and Gas Research Institute (GRI) project that natural gas demand will increase from 21 TCF in 1998 to 30 to 32 TCF by 2015. To meet projected 2015 demand, the NPC analysis envisions that the Gulf of Mexico will produce about 8 TCF of natural gas in 2015, a 33% increase from current production. However, on March 15, 2001, an MMS representative testified before the House Subcommittee on Energy and Mineral Resources that the Service had serious concerns regarding the ability of the Gulf of Mexico to meet this projected growth rate. Data recently published by the MMS indicate an optimistic natural gas production for the Gulf peaking in 2002 at about 5.2 TCF (Condit 2001). Even assuming that application of advanced technology results in substantial increases in natural gas production, it is difficult to see how future U.S. demand for natural gas will be met without production from OCS areas currently under moratoria.

OCS oil production has impacts that gas production does not, and the Eastern Gulf resources are viewed primarily as gas (not oil). Advances in technology and knowledge have changed the baseline used to deny access to OCS lands. The API states that technology has revolutionized how natural gas is found and produced, resulting in minimal and temporary disturbances to the environment. "We can produce more gas with fewer wells thanks to 3-D seismic processes that analyze geological structures with greater precision and directional and horizontal drilling technology that allows a variety of productive reservoirs to be accessed from one location" (API 2000). DOE's 1999 report states that "...innovative E&P approaches are making a difference to the environment. With advanced technologies, the oil and gas industry can pinpoint resources more accurately, extract them more efficiently and with less surface disturbance, minimize associated wastes, and, ultimately, restore sites to original or better condition....[The industry] has integrated an environmental ethic into its business and culture and operations...[and] has come to recognize that high environmental standards and responsible development are good business...." (DOE 1999).

On May 16, 2001, U.S. representatives from Florida and California introduced resolutions to oppose any new offshore drilling in areas currently under development moratoria. Also on May 16, 2001, Representative Lois Capps (D-CA) reintroduced the Coastal States Protection Act, which would place a federal moratorium on new offshore oil development along coasts where existing state moratoria are in effect (Najor 2001).

The 1999 NPC study reports affected TCF estimates due to moratoria to be 24 TCF or roughly one-half of the estimated 49 TCF of undiscovered technically recoverable resources, which include proven reserves (6 TCF) and unproven resources (43 TCF). The EIA estimate of 11.3 TCF is as of 2000 and assumes that the estimated 1 TCF in Lease Sale 181 would be accessible. If Lease Sale 181 is not allowed, the total TCF affected by moratoria in the eastern gulf would be 12.3 TCF.

The TCF estimates are based on little or no historical exploration and could be greater if exploration was allowed. In the western and central Gulf of Mexico areas, estimates have significantly increased after exploration (Young 2001).

Estimated total undiscovered, technically recoverable natural gas resources as of January 1, 2000, in the entire lower 48 OCS consists of 233.7 TCF. The currently inaccessible portion of the total amounts to 58.2 TCF, with 18.9 TCF in the Pacific, 28.0 TCF in the Atlantic, and 11.3 TCF in the eastern Gulf of Mexico. The remaining 175.5 TCF of fully accessible lower 48 OCS resources are located almost entirely in the western and central Gulf of Mexico, with 1 TCF in the eastern Gulf of Mexico (EIA 2001b).

3.1.9 OCS Moratoria — West Coast

Summary: Moratoria deny access to broad areas of natural gas reserves and resources. They were implemented primarily because of past oil spills; however, they also constrain natural gas E&P. On the West Coast, recent legal action has also limited production on existing leases.

Source of Constraint: Presidential, statutory

Impact: Unavailable gas

Phase: E&P

Category: Access, leasing

Estimated affected natural gas resources (TCF): 18.9

Estimate type: Technically recoverable

Estimate date: 01/2000 **Estimate reference:** EIA (2001b)

Estimate comments: Estimates are for undiscovered technically recoverable resources. The EIA notes that the estimates come from the MMS's *Outer Continental Shelf Petroleum Assessment, 2000*, and are mean estimates with values adjusted to reflect 1999 new field discoveries.

Statutory/regulatory citation: OCSLA, Presidential Memo (06/12/1998)

Lead players: President, Congress

Issue discussion: The OCSLA specifies the conditions under which the Secretary of the Interior, through the MMS, grants the rights to explore for, develop, and produce oil and gas. It issues leases every 5 years, and over the years, the MMS has extended the life of the 5-year leases by granting "suspensions" to their termination dates. Moratoria were first enacted in the fiscal year (FY) 1982 Interior Department Appropriations Act (Pub. L. 97-100) for leasing off central and northern California. In June 1990, President George H.W. Bush, acting under the authority of the OCSLA (43 USC 1331, et seq.), issued a directive to withdraw three general areas from new leasing and development until the year 2000. These areas included the West Coast, the southeastern coast of Florida, and the North Atlantic Coast. In August 1992, President Bush issued a memorandum to the Secretary of the Interior confirming his 1990 directive as implemented in the 5-year OCS Oil and Gas Program for 1992–1997. These regions of the OCS were included in President Clinton's broader 1998 executive order forbidding leasing of most of the OCS in the contiguous United States until 2012. That order prohibits the Secretary of Interior from leasing off the East and West Coasts, in the North Aleutian Basin in Alaska, and in most of the eastern Gulf of Mexico prior to June 30, 2012.

In addition to the moratorium on E&P, recent legal actions have limited production on existing federal oil and gas leases off the coast of California. Between 1968 and 1984, the MMS issued 36 leases off the central coast for exploration of new deposits of gas (and oil). Valued at \$1.25 billion, the leases are estimated to contain about 0.5 TCF of gas (and a billion barrels of crude oil). Not subject to the OCS leasing ban Congress includes annually in the Interior appropriations bill, these are the only leases along the entire West Coast that could be developed until 2012, when the leasing moratoria expire. In November 1999, as they were about to expire, the Clinton administration granted "suspensions" to extend the leases. The orders accompanying the extension required the oil and gas companies to complete, and allowed the state to review, studies before drilling could occur. However, the State of California sued, arguing that the leases were outdated because of stricter state laws and that the state had a right under NEPA and the CZMA to review the leases for consistency with state laws, and that the review should be at the beginning of the process, not at the end.

In June 2001, the U.S. District Court for the Northern District of California ruled in favor of the state. It said that the DOI illegally extended the leases because it did not give the state the opportunity to determine if development of the leases was consistent with the California CMP and ordered the leases terminated pending an environmental impact study. In the summer of 2002, the Bush administration appealed the district court's decision, arguing that extending a lease was not the same as issuing it, and therefore did not require the same level of state involvement. In December 2002, a three-judge appellate court panel denied the appeal. It stated that because the leases were issued prior to the 1990 amendments to the CZMA, that they had

never been reviewed by the state; it also affirmed the lower court's finding that the MMS violated NEPA because it failed to consider the environmental impacts of developing the leases. In January 2002, the DOI challenged the ruling. In May 2002, after the Bush administration announced that the government was paying oil companies to drop drilling plans in the Destin Dome area of the Gulf of Mexico, California officials urged the administration to retire the California leases in a similar way (Whetzel 2002a). On June 7, the Secretary of the Interior rejected the request, explaining that the situations were different and that litigation was underway (Whetzel 2002b). The FY 2003 DOI appropriations bill includes language that would ban drilling on the 36 leases as well (Holly 2002).

Even assuming that application of advanced technology results in substantial increases in natural gas production, it is difficult to see how future U.S. demand for natural gas will be met without production from OCS areas currently under moratoria, such as the Southern California planning area.

The TCF estimates are based on little or no historical exploration and could be greater if exploration were allowed. In the western and central Gulf of Mexico areas, estimates have significantly increased after exploration (Young 2001).

3.1.10 Permit Restrictions

Summary: Once leasing access has been obtained and a permit to drill has been issued, restrictions in the permit may be so severe that access is effectively prohibited. These federal and state restrictions can be site- or BLM- or FS-Office-specific.

Source of Constraint: Agency implementation

Impact: Unavailable gas

Phase: E&P

Category: Access

Estimated affected natural gas resources (TCF): 86.6

Estimate type: Technically recoverable

Estimate date: 01/2003 **Estimate reference:** DOI, USDA, and DOE (2003)

Estimate comments: Estimated to be the amount of gas in areas inventoried and reported by the interagency study of oil and gas resources in five U.S. basins that are available for lease under standard lease terms (DOI, USDA, and DOE 2003, p. 3-5). This is an estimate; the Interagency EPCA study does not address restrictions after a permit has been issued.

Statutory/regulatory citation: FLPMA

Lead player: BLM

Issue discussion: Permitting constraints that can limit development include overlying habitat management plans that prevent production and restrictions over unnecessarily large geographic areas that are not based on science. For example, the BLM imposed a moratorium on operations on 380,000 acres in Southeastern New Mexico from April through June of each year to avoid disrupting the prairie chicken mating season. Citing a lack of scientific evidence that field operations disrupt the mating season, industry requested a scientific study of the issue. Because of the study, the BLM is considering reducing the acreage subject to the moratorium to 196,000 acres. In another example, a local New Mexico operator had begun leasing and exploration near Roswell, New Mexico, in the 1980s, obtained permits to drill, and began producing in 1997. The operator then requested, and 11 months later obtained, drilling permits for additional confirmation wells; however, the BLM conditioned the approval with onerous stipulations, which meant that the approval to produce was not granted. Similarly, although planning documents deem certain lands as accessible, in reality they are not, because of restrictions, such as a requirement to use horizontal or directional drilling for depths for which such drilling is physically impossible. Also, BLM geologists can, without scientific proof that drilling may contaminate water zones, determine that operators must set hundreds of additional feet of surface casing and at an estimated incremental cost of \$30,000 to \$40,000 per well (Murphy 2001).

3.1.11 Bans on Great Lakes Drilling

Summary: Recently enacted state and federal temporary and permanent drilling bans in the Great Lakes have effectively stopped exploration and new production of natural gas in the Great Lakes.

Source of Constraint: Statutory

Impact: Unavailable gas

Phase: E&P

Category: Access, leasing

Estimated affected natural gas resources (TCF): 1.1

Estimate type: Possible and probable reserves

Estimate date: 09/2001 **Estimate reference:** Shirley (2001)

Estimate comments: Consists of 0.4 TCF possible and 0.6 TCF probable reserves in Ohio's portion of Lake Erie alone (Shirley 2001).

Statutory/regulatory citation: The Energy and Water Development Appropriations Act, 2002 (H.R. 2311) (Pub. L. 107-66); Michigan H.B. 5118, 2002

Lead players: COE, states

Issue discussion: None of the Great Lakes states allow drilling from offshore rigs on the water. Ontario, Canada, however, allows directional drilling under the Great Lakes and has about 500 natural gas wells on the bottom of Lake Erie. While it prohibits offshore drilling, Michigan is the only state in the United States that has leased directionally drilled wells under the Great Lakes. Between 1979 and 1997, 13 oil and gas wells were drilled directionally; 7 of these wells are producing and have safe operating records. In 1997, public opposition arose when a company proposed to drill three new wells. At the governor's request, a suspension of drilling was issued and the Michigan Environmental Science Board reviewed the issue. It reported that environmental risks associated with directional drilling were minimal and did not recommend banning drilling under the lakes. Rather, it recommended certain restrictions such as a 1,500-ft setback from the shoreline, and prohibiting wells in sensitive coastal environments. The Michigan Department of Natural Resources implemented the regulations, and in July, the governor recommended lifting the ban on directional drilling. In September 2001, the state lifted the 4-year suspension and began to move forward on four lease sales for directional drilling. A Michigan Senator (Debbie Stabenow) tried to convince state officials to ban future oil and gas drilling. In early 2002, both houses of the Michigan state legislature passed H.B. 5118, which prohibits new slant drilling beneath the Great Lakes except in cases of a state energy emergency. The governor opposed the bill, but it became law without his signature on April 5, 2002. Ms. Stabenow also introduced federal legislation to amend the Energy and Water Appropriations Bill of 2002, to include a 2-year ban on drilling in the Great Lakes (Taylor 2002).

In October, both houses passed the bill, with the amendment, and on November 12, 2002, the President signed the legislation. The Energy and Water Development Appropriations Act, 2002 (H.R. 2311) (107 Pub. L. 66), implements a 2-year drilling ban until September 30, 2003, in the Great Lakes. The ban includes both directional and offshore drilling. It also instructs the COE to conduct and submit to Congress a study that examines the known and potential environmental effects of oil and gas drilling activity in the Great Lakes. At the conclusion of the study, Congress could extend the moratorium or lift it if the analysis shows that oil and gas could be extracted from the Great Lakes without endangering the freshwater supplies or compromising the lakes' importance to the economic well-being of the region and the nation (National Driller 2001).

An official from the Michigan Department of Environmental Quality notes that under Michigan law, the leases issued to date have provided \$15 million, which the state uses to buy and maintain parks; if the drilling ban were lifted, an additional \$100 million in state revenues for these purposes would be generated (Heartland Institute 2001). Drilling bans may be implemented without acknowledgment of the safety of existing offshore producing wells in Michigan (Greenwire 2001).

3.1.12 Roadless Rule

Summary: On January 12, 2001, the FS promulgated a rule that prohibits road construction in IRAs on NFS lands. These areas compose about one-third of the NFS, or about 58.5 million acres (FS 2001). The Roadless Rule denies access to approximately 11 TCF of potential natural gas resources in the Rocky Mountain region. The rule has been subject to numerous lawsuits and may be revised to allow for assessment of impacts and the ability to build roads on a more local, forest-by-forest level.

Source of Constraint: Regulatory

Impact: Unavailable gas

Phase: Exploration

Category: Access

Estimated affected natural gas resources (TCF): 11

Estimate type: Technically recoverable

Estimate date: 11/2000 **Estimate reference:** Eppink (2000)

Estimate comments: Within the IRAs, natural gas resources are concentrated in four provinces/basins: the Uinta/Piceance (3.9 TCF), the Wyoming Thrust Belt (3.2 TCF), Southwestern Wyoming (2.0 TCF), and the Montana Thrust Belt (1.6 TCF). The range of total resources affected by the Roadless Rule is 3.5 to 23.1 TCF.

Statutory/regulatory citation: 66 FR 3244, January 12, 2001, Final Rule and ROD, Special Areas; Roadless Area Conservation

Lead player: FS

Issue discussion: Multiple-use federal lands, such as FS lands, contain unexplored, as yet, nonproducing gas resources that will be important for meeting projected natural gas demands. Although the Roadless Rule does not affect existing leases, it will prevent expansion of existing leases and exploration and development of new leases on FS lands that require road construction or reconstruction in IRAs (Phillips 2001). According to a study prepared for DOE, the Roadless Rule will prevent access for E&P of an estimated 3.5 to 23.1 TCF of yet undiscovered gas in the FS's IRAs (Eppink 2000). Of the mean estimate of 11 TCF underlying roadless areas, 1.9 TCF are under no access lands, 2.4 TCF are under access-restricted lands, and 7.0 TCF are under lands with standard lease terms. As a result, implementation of the Roadless Rule would add 9.4 TCF to that considered to be "no access" in the 1999 NPC study (Eppink 2000) and raise the NPC's estimates at 29 TCF for natural gas resources closed to development to 38 TCF (NPC 1999). The rule, which covers all IRAs with a "one-size fits all" approach, ignores requirements of The National Forest Management Act for the FS to manage the NFS areas

outside designated Wilderness Areas with full consideration of resource values. (The FLPMA has the same requirements for BLM-managed lands.) The rule also appears to ignore the fact that prior to leasing, an EA or EIS must be conducted that will consider the impacts of any required road building on the environment. According to the API, because of the distribution of the natural gas resources within the Rocky Mountain region, access to roughly 83% of the affected gas resources could have been preserved by a reduction of less than 0.5% in the roadless acreage (Rubin 2001).

In February 2001, the Bush Administration reviewed the rule and allowed it to proceed, with the goal of revising it later to consider local needs and access issues. The rule was to become effective on May 12, 2001. On May 4, 2001, the USDA announced that it would examine whether it would amend the rule, since it was intended as a temporary ban on building new roads within the 58.5 million acres until the FS developed revisions based on local, forest-by-forest input. On May 10, 2001, a federal judge in Idaho issued an injunction blocking the rule, stating that it violated NEPA, did not allow for sufficient public participation, and would harm local economies. Environmental groups appealed the decision to the Ninth Circuit Court. On July 10, 2001, the FS announced that it was reopening the rule for public comment. On December 12, 2002, a three-judge panel of the Ninth Circuit Court found that the Idaho judge erred when granting the injunction, and it remanded the case for trial on whether the rule violates NEPA or the Administrative Procedure Act. With the injunction lifted, the Roadless Rule went into effect, and nine lawsuits in seven other states proceeded (Ferullo 2002). On June 9, 2003, the FS announced that it would propose a rule allowing state governors to seek exceptions to the Roadless Rule for “exceptional circumstances,” which would include road-building activities to protect human health and safety, wildfire protection and habitat restoration, maintenance of dams and other existing facilities, and to make technical corrections to boundary adjustments. The rule is expected to be proposed in the fall of 2003 and made final by the end of 2003 (Ferullo 2003).

3.1.13 Wilderness Areas

Summary: Under the FLPMA, the BLM was charged with identifying and managing lands as potential Wilderness Areas. As required by the law, the BLM completed the inventory in 1991 and submitted its recommendations to the President, who endorsed and submitted them to Congress. However, of the roughly 26.5 million acres identified as WSAs, Congress has yet to make decisions on 16.3 million acres. In addition, since 1991, some western states, for example, Colorado and Utah, have “reinventoried” potential Wilderness Areas, adding more acres to those that are managed as, although not officially designated as, WSAs. Until Congress acts, all of these areas — both Wilderness Areas and WSAs — will continue to be off limits to gas (and oil) leasing, even though they may contain substantial resources.

Source of Constraint: Statutory

Impact: Unavailable gas

Phase: Exploration

Category: Access

Estimated affected natural gas resources (TCF): 9

Estimate type: Technically recoverable

Estimate date: 01/2003 **Estimate reference:** DOI (2003)

Estimate comments: The estimate is for five Rocky Mountain areas studied in the EPCA report (DOI, USDA, and DOE 2003) and includes TCF unavailable for leasing because of national park, national monument, or wilderness designation. (The EPCA report does not break out TCF unavailable due to Wilderness Area designations. The estimate does not include TCF in WSAs, which are treated as Wilderness Areas, pending final designation.)

Statutory/regulatory citation: FLPMA (16 USC 1712 and 1782); Wilderness Act of 1964 (16 USC 1131, et seq.)

Lead player: BLM

Issue discussion: The Wilderness Act of 1964 established a National Wilderness Preservation System to protect wilderness lands for future use and enjoyment and preserve their wilderness character. The Wilderness Act required that the National Park Service, the FS, and the USFWS determine the number of acres under their respective jurisdictions that met the wilderness criteria, also defined in the act. The agencies were required to recommend to Congress those areas believed to be appropriate for wilderness designation. Until Congress acted to either designate a WSA as a Wilderness Area or allow it to revert to its prior status, the agencies were to manage and protect the wilderness character of those lands, which put them off limits for leasing. In 1976, Congress passed the FLPMA, which, among other things, extended the Wilderness Area designation process to the BLM. Under the law, the BLM had 15 years to conduct its inventory and make its recommendations to Congress. Between 1977 and 1980, the BLM identified more than 700 WSAs covering roughly 26.5 million acres. These areas were placed under BLM's Interim Management Policy to be managed to protect their wilderness values pending final action by Congress (Hatfield 2002). Between 1980 and 1991, the BLM studied its WSAs and in 1991, transmitted its recommendation to the President, which was that 9.7 million acres of BLM-managed public lands in 330 units were suitable for inclusion in the National Wilderness Preservation System. (Subsequent congressional actions reduced the remaining acreage recommended as suitable to approximately 6.5 million acres.) The President endorsed the recommendations and submitted them to Congress. However, Congress has yet to act on 16.3 million of the WSA acres, thereby preventing them from being leased.

In addition, the BLM has "reinventoried" lands in Utah and Colorado for additional Wilderness Areas. In Utah, the BLM identified 800,000 acres as WSAs by 1980. Appeals by environmentalists to the DOI Board of Land Appeals led the BLM to declare 3.2 million acres in Utah as WSAs, of which the BLM recommended 1.9 million acres for Congress to designate as Wilderness Areas. In 1986, a citizen-based study recommended 5.7 million acres to be designated as wilderness in Utah. In 1996, the Secretary of the Interior, at the behest of the Chair

of the House Subcommittee on National Parks and Public Lands, ordered the BLM to verify these findings (Utah Wilderness Coalition 2000). In February 1999, the BLM released its results, which found that 5.8 million acres met the criteria. Since then, a subsequent citizens' reinventory identified an additional 2.6 million acres that were on lands not reviewed by the BLM. If the BLM offers leases on any of the 2.6 million acres in the new citizens' inventory, the Southern Utah Wilderness Alliance has vowed to continue protesting every lease offered within the proposal (McHarg and Thomas 1999).

In Colorado, the BLM also identified 800,000 acres as WSAs, and in 1991, recommended that Congress designate 388,000 acres as wilderness. In 1994, citizens' groups released a Citizens' Wilderness Proposal that recommended 1.3 million acres of BLM lands for wilderness designation. The BLM agreed to stop issuing oil and gas leases in citizen-proposed areas pending further review, and in 1996, agreed that 120,000 acres within the citizen-proposed areas possessed wilderness values. In 1999, citizens began to identify additional lands and added 300,000 more acres. The Sierra Club and others have advocated designating and reinventorying additional lands in Wyoming as wilderness lands (Tipton 1997).

Oil companies and state and federal lawmakers have challenged the legality of the BLM conducting reinventories on lands already surveyed under the FLPMA; the lack of public involvement in these citizens' surveys; and the treatment of the citizen-proposed lands as WSAs, which denies access to gas resources. In 2002, Representative C.L. Otter (R-ID) introduced a bill (H.R. 4620) that would accelerate the wilderness designation process by requiring the release of WSAs after 10 years, or when the Secretary of the Interior or Agriculture determines them as not being suitable.

3.1.14 Ocean Policy

Summary: The U.S. Commission on Ocean Policy, established under the Oceans Act of 2000, is charged with developing recommendations to submit to the President on a coordinated and comprehensive national policy for oceans and coastal areas. Preliminary recommendations include the establishment of an ocean policy framework and expanded authorities to address the use and stewardship of ocean and coastal resources. It is too early to estimate the impacts of the new policy and its ramifications on offshore natural gas E&P, but the development and implementation of specific recommendations will be important to follow.

Source of Constraint: Presidential

Impact: Unavailable gas, delay, cost (possible)

Phase: E&P, transportation

Category: Access, leasing, permitting, operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: Oceans Act of 2000 (33 USC 857-19)

Lead players: President, Congress

Issue discussion: Congress passed the Oceans Act of 2000 on July 25, 2000, and the President signed it into law on August 7, 2000. The law established a commission, which, in coordination with the states, a scientific advisory panel, and the public, is required to establish findings and develop a National Oceans Report that makes recommendations to the President and Congress on ocean and coastal issues and on a coordinated and comprehensive national ocean policy. The President is to respond to these recommendations in a “National Ocean Policy” to be submitted to Congress. The report is to assess the cumulative effect of federal laws; examine the supply and demand for ocean and coastal resources; review the relationships between federal, state, and local governments and the private sector and the effectiveness of existing federal interagency policy coordination; and recommend modifications to federal laws and/or federal agency structures.

The commission held its first meeting in September 2001, and subsequently heard from 440 presenters in 10 cities over 11 months. After completing its fact-finding phase in October 2002, it entered its deliberative phase, which will continue into early 2003. At the November 2002 meeting, the commission discussed various policy options to address key issues associated with developing a comprehensive and coordinated national ocean policy. Some of the options discussed may have significant impacts for natural gas development in the offshore and coastal areas. For example, the draft options report listed a number of guiding principles that include, among others, sustainability, participatory governance (all stakeholders are an integral part of the decision-making process), ecosystem-based management, and the precautionary approach. The precautionary approach requires that where threat of serious or irreversible damage exists, the lack of full scientific certainty should not be used as a reason for postponing action to prevent environmental degradation. The draft also noted the importance of habitat protection and restoration, encouraging greater use of land conservancies in coastal management, and the need to reverse trends in biodiversity reduction (Ocean Commission 2002).

Because the ocean policy has not yet been established, no TCF estimates can be made. However, the policy could affect both offshore and coastal natural gas production.

3.2 ISSUES LIKELY TO PRODUCE DELAYS

3.2.1 CBM-Produced Water Management

Summary: Regulations are being written to address the potential impacts of discharging or disposing of produced water generated during CBM production. There are significant unknowns regarding the actual impacts of produced water, and many of the regulations may be costly to implement, resulting in delayed or reduced production.

Source of Constraint: Regulatory

Impact: Delay, cost

Phase: Production

Category: Permitting

Estimated affected natural gas resources (TCF): 74

Estimate type: Technically recoverable

Estimate date: 01/1998 **Estimate reference:** NPC (1999)

Estimate comments: Could affect all CBM resources. The estimate is from the 1999 NPC study and includes all technically recoverable resources in the lower 48 states.

Statutory/regulatory citation: Federal Water Pollution Control Act (FWPCA) (33 USC 1251, et seq.), generally known as the Clean Water Act (CWA); state regulations

Lead players: EPA, states

Issue discussion: Large volumes of CBM-produced water are pumped to the surface to release gas trapped in coal seams. This produced water is discharged to the land surface and to surface water, stored in evaporation ponds, used for stock or wildlife watering, reinfiltrated, injected back into the aquifer, or treated for various uses. CBM-produced water can affect the receiving environment. For example, because it can contain concentrations of chemicals higher than those of the receiving waters, it can lead to soils becoming dispersed, less permeable, and more prone to erosion. Also, high levels of soil salinity can reduce crop yields, and hydrologic changes resulting from CBM operations may adversely affect fisheries. The USFWS has expressed concern that CBM-produced water can contain selenium levels that are toxic to birds and fish (Baltz 2002a). However, the cumulative effects of CBM-produced water on fisheries, crops, and other environmental resources, and the factors that influence those effects, are not well understood.

Regulations exist and are being developed to address the potential problems associated with CBM-produced water. For example, in the Powder River Basin Controlled Groundwater Area, CBM operators must follow standards for drilling, completing, testing, and production of CBM wells adopted by the Board of Oil and Gas Conservation. The Montana Department of Environmental Quality (MDEQ) has prepared a General Discharge Permit for CBM-Produced Water, the purpose of which is to authorize discharges of CBM-produced water to specially constructed impoundments (holding ponds) for the specific beneficial use of livestock or wildlife watering. (Irrigation of agricultural fields or rangeland with CBM-produced water is not considered a beneficial use.) Applicants must submit chemical analyses of more than 20 constituents in the proposed discharge, monitor the produced water for various parameters, and cease discharging if impoundment waters exceed upper bound criteria.

Montana currently approves CBM production on a well-specific basis using a narrative standard aimed at protecting public health and safety. However, the one permit issued has been the subject of three lawsuits (Beattie 2002). The MDEQ states that current CBM drilling practices likely produce water with a salinity level “well above almost all” current levels in the four rivers that traverse Montana’s portion of the Powder River Basin. Thus, the department has new numeric limits that are likely to be stricter than current controls. Implementing any of the proposed numeric caps could directly impact the number of CBM wells approved not only in Montana, but also in the upstream areas of Wyoming, where most of the CBM activity is located. The draft EIS for the Wyoming portion of the Powder River Basin projected that 50,000 wells would be developed in the Wyoming portion of the basin by 2010. Montana expects to receive applications for 20,000 wells in the near future, and regulators say they need firm, across-the-board limits.

Wyoming, which also uses narrative standards, has also begun discussing the development of numeric standards for pollutants discharged to surface water to address concerns of nearby states whose waters may be affected by CBM-produced water discharges (Compton 2001).

The EPA has not promulgated national-level effluent limit guidelines under the CWA specifically for CBM operations; EPA Region 8, however, has started to develop effluent limitations that represent the Best Available Technology Economically Achievable for CBM-produced waters. This information could form the basis for other states as they establish NPDES permits. The Rocky Mountain states, where the bulk of the near-term CBM drilling activity is projected to occur, have been delegated the authority to write their own NPDES permits under the CWA.

Individual permits and decision documents also contain environmental requirements intended to mitigate potential impacts. For example, RODs can specify that CBM-produced water must be treated or stored to ensure that pollutant constituents in rivers will not be elevated beyond current baseline levels at the state line. RODs could also require dispersal of CBM-produced water in the upper reaches of drainages via the installation of stock tanks or transport of the produced water to distant discharge points to avoid sensitive soils, agricultural areas, or areas of potential accelerated erosion.

There are numerous unknowns about the effects of produced water, and developing such regulations requires a sound understanding of the science, transport and fate mechanisms, and interactions among various constituents that may not be available to state regulators. Many of these requirements may increase costs to the point that the pace of development could be slowed and the amount of production reduced. Also, as the number of applications increases (the NPC forecasts that a significant portion of the natural gas demand will be met by CBM), the backlog of applications will slow production. One CBM expert testified before a House Committee investigating CBM development that the severe restrictions being faced for discharge permits have caused operators to reduce the drilling pace. In some areas it takes 4 to 6 months to obtain permits, and it is estimated that more than 1,000 currently drilled wells are waiting for NPDES permits. These wells could represent more than 250 MMCF of gas per day in production (George 2001).

3.2.2 Drilling Permits

Summary: Once the BLM has issued a gas lease on federal land, no drilling can occur until the BLM issues a permit to drill. In the gas-rich basins of the Rocky Mountain region, backlogs for permits to drill and ROWs are growing. Many RMPs are outdated, and revisions, which often require additional environmental analyses, are required before gas leasing or development can occur. Insufficient staffing, combined with the number of plans needing updating and the recent increase in permit applications spurred by gas price increases, compounds the delays. Citizens' suits also contribute to permitting delays. These delays will be particularly important for CBM.

Source of Constraint: Agency implementation

Impact: Delay

Phase: Production

Category: Permitting

Estimated affected natural gas resources (TCF): 311.2

Estimate type: Assessed additional resources

Estimate date: 01/1998 **Estimate reference:** NPC (1999)

Estimate comments: Rocky Mountain region resources that can be leased. According to the 1999 NPC report, there are 340.5 TCF in the Rocky Mountain region; of this, 29.3 TCF are unavailable because no access is allowed. The remaining 203.3 TCF are subject to standard lease terms or are "high-cost" resources (108 TCF). Note that the amount could be higher, since drilling permit delays can also apply in non-Rocky Mountain states, such as Ohio.

Statutory/regulatory citation: FLPMA; State (Montana Environmental Protection Act [MEPA])

Lead player: BLM

Issue discussion: The BLM uses a staged decision-making process to accommodate the speculative and costly nature of gas (and oil) exploration and development. The stages generally include (1) determination of lands available for leasing (after evaluation using the BLM's multiple-use planning process according to procedures outlined by NEPA and FLPMA); (2) authorization for leasing on specific lands; (3) application and approval of permit to drill (APD); and (4) analysis of field development, if oil and gas are discovered. The BLM is required to process the APD within a 30- or 35-day period or advise the applicant of the reasons for the delay or disapproval. The Assistant Director of the BLM's Minerals, Realty, and Resource Protection Division suggests that the BLM meets the 30-day standard about 25% of the time, and the average is likely around 60 to 120 days (Culp 2001). (For operations on NFS lands, the BLM must obtain the consent of the FS before approving APDs.) Because most of the area available

for development has limited access for only 6 months of the year, a 1-month delay may result in a 1-year delay before wells can be drilled and natural gas is produced (Watford 2001). Companies exploring for natural gas on a southwestern Wyoming federal lease have very short windows in which to drill wells because of surface use and seasonal restrictions. If the BLM has not processed the permits in time to meet the window of opportunity, the company will have to release the drilling rig they have contracted and wait another year before drilling (Stanley 2001).

Recent Public Lands Advocacy and IPAA surveys found that APDs are delayed by up to 7 months when no additional environmental analysis is needed, and can take several years to approve when such analysis is required. Applications for ROWs are also delayed, causing supply bottlenecks, where gathering lines and pipelines cannot be installed (Smith 2001). The time required for well permitting and drilling on private land is 3 months, while the time required for well permitting and drilling on federal land ranges from 1 to 3 years (Stanley 2001).

Permitting backlogs have slowed supply to market in most of the active Rocky Mountain basins (e.g., Green River, Uinta, Powder, Piceance, San Juan, Williston) (Smith 2001). An internal 1996 BLM study identified factors contributing to delays in processing APDs that included the following: conflicting priorities, poor understanding of national APD priorities, conflicting resource demands, unclear directives or guidance, insufficient agency resources, and poor or inadequate BLM and FS planning documents. (See related issue, outdated BLM land use plans.)

BLM staffing has not kept pace with increased leasing activity in the West. The fluid mineral program staff has shrunk from 1,800 employees in the mid-1980s to 695 in 2001 (Smith 2001). In the Rawlins, Wyoming, BLM Field Office, thousands of applications for permits to drill await action because of manpower shortages (Rubin 2001). A related issue is that staffing reflects field office priorities, and many may not be focused on energy; state offices have little influence over the field offices (Smith 2001). The FS may have worse staffing problems than the BLM. It takes the FS a minimum of 6 months to permit a single well, as opposed to 30 to 45 days for the BLM (Stanley 2001).

Lack of coordination between state and federal agencies and within federal agencies also contributes to delays. It is difficult to reconcile the missions of various agencies when some are multiple-use land management agencies (BLM, FS) and others are single-purpose agencies (EPA, USFWS) whose focus is not on balancing multiple uses on public lands. Also, other agencies (USGS, DOE) have information on energy trends, which, if shared with the other agencies, could help land managers plan for future development activity (Smith 2001). The BLM has manuals for land use planning and processing APDs, but different interpretations occur among the various field offices (Culp 2001). In the Monongahela National Forest in West Virginia, for example, inconsistency in the directives given by FS specialists in the preparation of an EA caused 10 revisions over a 2-year period. Some revised drafts duplicated previous drafts that had been rejected by FS personnel (Hackett 2001). In the Wayne National Forest in Ohio, a small oil and gas producer applied for a permit from the BLM to drill a development well on a federal lease tract in February 2000. Since then, the producer has waited while the FS has conducted an EA to account for new information, if any, regarding endangered species and the relationship of that information to the Forest Plan. The producer already operates

two other wells on the property, and continuous operations have existed in the area since 1860. While waiting for the federal process to issue a permit, the requisite permits issued by the State of Ohio have been issued and expired (Stewart 2001).

Citizens' suits can also contribute to permitting delays. Opponents to projects often use environmental laws to delay or block permits. For example, in Montana, citizen advocates and agency officials can challenge a permit under the MEPA's EIS requirements clause. Inappropriate use of MEPA adds an extra level of authority to block permits, when its only purpose is to provide requirements for EIS preparation (Inside EPA 2001a).

Timely permitting of gas wells on federal lands is critical because long-term sustainable gas production can only be achieved through the orderly development of frontier areas such as those in the Rockies. Improved permitting processes are needed for industry to meet the growing demand (Smith 2001).

3.2.3 Essential Fish Habitat

Summary: EFH regulations issued in 2002 require assessments and consultations that can duplicate the environmental requirements of other federal agencies. This duplication can delay leasing or permitting decisions, because federal agencies undertaking activities that could adversely affect EFH (e.g., permitting) must prepare EFH assessments; undertake consultation with the NMFS; and, in some cases, implement mitigation strategies that could add further costs and delays.

Source of Constraint: Agency implementation

Impact: Delay

Phase: E&P, transportation

Category: Permitting

Estimated affected natural gas resources (TCF): 174.5

Estimate type: Technically recoverable

Estimate date: 01/2000 **Estimate reference:** EIA (2001b)

Estimate comments: The Entire Gulf of Mexico is considered an EFH; it is conceivable that all the gas in this area could be subject to permitting delays. The EIA estimated, using the MMS's *Outer Continental Shelf Petroleum Assessment, 2000*, that the western gulf holds 74.2 TCF and that the central gulf holds 100.3 TCF. These areas are not restricted by leasing moratoria and are thus theoretically accessible, but would be subject to the NMFS regulations that could limit actual E&P.

Statutory/regulatory citation: 67 FR 2343-2383, January 17, 2002, Final Rule, codified at 50 CFR Part 600; Magnuson-Stevens Fishery Conservation and Management Act (16 USC 1801 et seq., as reauthorized on October 11, 1996)

Lead player: NMFS

Issue discussion: The Magnuson-Stevens Fishery Conservation and Management Act of 1976 provided a national framework for conserving and managing U.S. fishery resources. The 1996 amendments, known as the Sustainable Fisheries Act, added provisions, which, among other things, require fishery management plans to identify as EFH those areas that fish need for their basic life functions. EFH regulations, which are implemented by the NMFS, are intended to promote the protection, conservation, and enhancement of EFH. These regulations require assessments and consultations that can duplicate the environmental requirements of other agencies, including the COE, the EPA, and the MMS. This duplication can lead to costly delays in leasing or permitting decisions because federal agencies undertaking activities that could adversely affect EFH (e.g., permitting) must prepare EFH assessments; undertake consultation with the NMFS; and, in some cases, implement mitigation strategies that could add further costs and delays. The implementing legislation calls for consultations and coordination but does not require the written assessments and conservation recommendations called for by the regulations. Agency coordination activities required by the regulations can divert federal agency staff from normal permitting and operational duties. Also, disagreements between the NMFS and another agency will require time to settle, and potential mitigation costs can further delay leasing and permitting decisions.

The act established eight fishery management councils and required them to “describe and identify essential fish habitat” and “encourage the conservation and enhancement of such habitat.” The law requires the Secretary of Commerce to establish requirements to assist councils in identifying EFH and to coordinate with and provide information to other federal agencies to further and enhance the conservation of fisheries.

The NMFS, within the NOAA within the Department of Commerce, issued final regulations to implement these provisions in January 2002. The NMFS regulations are controversial. Development entailed 5 separate public comment periods, 20 public meetings and workshops, and receipt of about 3,300 written comments. The regulations tend to go beyond the act’s requirements. For example, the regulations require fishery councils to interpret information collected for determining EFH in “a risk-averse fashion to ensure adequate areas are identified as EFH for managed species.” This approach is not based on science and does not consider economic, social, and perhaps other environmental issues, meaning that cost-effective decisions are not assured. Further, it can lead to the establishment of so many EFHs that those truly needing protection may not be addressed. EFH include essentially the entire Gulf of Mexico, adjacent wetlands, and inland areas along waterways.

The regulations also require a consultation process on any EFH that could be adversely affected by federal agency actions. Agency actions can include permitting, leasing, renewals, reviews, and emergency actions. The consultation process is similar to that required for the ESA; once it is determined that an agency action may adversely affect EFH, consultation is mandatory.

The consultation process requires that the federal agency prepare a written EFH assessment and that the NMFS provide conservation recommendations. Such recommendations can include measures to avoid, minimize, mitigate, or otherwise offset adverse effects on EFH. For example, the NMFS could recommend not drilling during certain months when winter flounder are spawning and eggs are developing. The interaction of multiple stipulations could significantly shorten the drilling windows in some areas. Federal agencies must also prepare written responses to the conservation recommendations provided by the NMFS. The regulations allow the NMFS to request additional time to review federal agency actions that are contrary to NMFS recommendations. In many cases, there is significant overlap between EFHs and areas covered by other environmental programs that regulate the natural gas industry, including the COE's wetlands programs, CMP requirements, and MMS and EPA impact assessment requirements. Often individual agencies, including the NMFS, have consultation privileges on the regulatory activities of other agencies, for example, on COE Section 404 wetlands permits. States also have their own regulatory programs that overlap with the EFH consultation requirements. The additional federal agency and NMFS requirements for EFH may unnecessarily burden oil and gas leasing and permitting activities, which are already heavily regulated in the Gulf of Mexico and other offshore areas. Leases could be delayed, denied, or otherwise restrict natural gas production in the Gulf.

3.2.4 Fracturing Operations

Summary: Hydraulic fracturing is a process producers use to increase the flow of natural gas (and oil) from rocks whose natural permeability does not allow the gas to reach the wellbore at sufficient rates. It is commonly used to release methane from coal beds, where the gas is held in the rock by hydraulic pressure. During fracturing, a fluid (usually a water-sand mixture) is pumped into the reservoir to split the rock and create drainage pathways. Typically, it is a one-time practice. The NPC estimates that 60 to 80% of all the wells drilled in the next decade to meet natural gas demand will require fracturing. The practice is controversial, with environmentalists arguing that it needs more regulation. Federal or increased state regulation could delay gas production or make it uneconomical, thereby reducing the amount available at reasonable prices (Stewart 2001).

Source of Constraint: Regulatory

Impact: Delay, cost

Phase: Production

Category: Operations

Estimated affected natural gas resources (TCF): 293

Estimate type: Unproved technically recoverable

Estimate date: 01/2000 **Estimate reference:** EIA (2001b)

Estimate comments: The Rocky Mountain region contains approximately 293 TCF of unproved technically recoverable natural gas resources. Most of these resources, however, need to be subjected to a significant degree of stimulation (e.g., hydraulic fracturing). The estimate has not been adjusted to reflect the resources that are inaccessible due to access restrictions. According to the EIA, 202 TCF are accessible in the Rocky Mountain region, with lease stipulations or under standard lease terms.

Statutory/regulatory citation: Safe Drinking Water Act (SDWA), Underground Injection Program

Lead players: EPA, states

Issue discussion: When Congress enacted the SDWA in 1974, the states had already developed extensive underground injection control (UIC) programs to manage liquid wastes from oil and gas operations and the reinjection of produced water. In 1980, recognizing that a federal program could not provide the flexibility needed to deal with varying circumstances in different states, and that the existing state programs were well structured, Congress modified the SDWA, giving primacy to the state programs. In 1994, the Legal Environmental Assistance Foundation (LEAF), arguing that the fracturing fluid interacted with groundwater supplies and contaminated nearby drinking water sources, sued the EPA to regulate hydraulic fracturing for CBM development under the UIC program. The EPA rejected LEAF's claim, arguing that Congress never intended UIC to cover hydraulic fracturing. LEAF appealed to the 11th Circuit Court. In 1997, the 11th Circuit Court found that the plain language of the statute could include hydraulic fracturing as underground injection, and that hydraulic fracturing of coal beds in Alabama must be regulated under the SDWA as underground injection. The EPA then required Alabama to develop a UIC regulation, which the state subsequently did. In 1999, the EPA approved the revisions. According to the IOGCC, the mandated changes have increased costs to the state by about \$300,000 per year, and the requirement that operators use federally certified drinking water for fracturing has significantly increased their costs (IOGCC 2001a). (Such water must be purchased and trucked to the well development operations [Stewart 2001].) LEAF then filed a second case, arguing that the EPA violated SDWA requirements when it approved Alabama's UIC program. LEAF stated that the EPA should have required the State of Alabama to regulate hydraulic fracturing under Section 1422 of the SDWA, a provision with strict requirements, rather than allowing the state to regulate the process under the more flexible Section 1425 (Inside EPA 2002b). The court decision prompted the EPA to conduct a nationwide study of the impacts of hydraulic fracturing on underground sources of drinking water. Although the EPA was under no legal requirement to issue a national standard for hydraulic fracturing, it planned to use the results of the study to determine if it should do so.

On December 21, 2002, the 11th Circuit Court, in the second LEAF case, held that (1) the EPA's decision to use the approval route under Section 1425 was based on a permissible construction of the statute; (2) the EPA's decision to classify hydraulic fracturing of coal beds to produce methane as a "Class II-like underground injection activity" was inconsistent with the EPA's well classification scheme; and (3) the Alabama UIC program regulating hydraulic fracturing of coal beds complied with the requirements of the SDWA. The court remanded the case to the EPA to determine if Alabama's revised UIC program complied with the requirements

for Class II wells. LEAF then petitioned for a rehearing by the full 11th Circuit Court, arguing that the court did not adequately enforce a statutory requirement that all applicants seeking to inject underground fluids as part of the hydraulic fracturing process must first prove that their processes will not affect human health (Inside EPA 2002a). In March 2001, the 11th Circuit Court denied LEAF's petition for a rehearing. On June 12, 2002, LEAF petitioned its case to the Supreme Court; on October 21, 2002, however, the Supreme Court declined to hear the challenge.

In 2004, LEAF filed a petition directing the EPA to determine immediately whether Alabama's revised UIC program complied with the requirements for Class II wells. The EPA argued that the petition should be denied in light of the Agency's reasonable progress and schedule toward reaching a final determination.

In June 2004, the EPA published the final version of its hydraulic fracturing study (EPA 2004a). During its study, the EPA reviewed more than 200 peer-reviewed publications, interviewed roughly 50 state and local government agency employees, and communicated with about 40 citizens concerned that CBM production had affected their drinking water wells. The EPA also searched for confirmed incidents of drinking water well damage. After reviewing this information, the EPA concluded that the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to underground sources of drinking water and does not warrant additional study. On July 15, 2004, the EPA published a notice in the *Federal Register* announcing its final determination that "the hydraulic fracturing portion of the state's [Alabama] UIC program relating to coalbed methane production, which was approved under Section 1425 of the SDWA, complies with the requirements for Class II wells within the context of Section 1425's approval criteria" (EPA 2004b).

The controversy over the regulation of hydraulic fracturing continues, and it is possible that additional suits over the fracturing issue could be filed in federal courts. Because of the "plain language" finding of the original LEAF case, these subsequent suits could lead to federally imposed regulations in those states where such cases are filed (Stewart 2001). Regulations that would require the use of drinking water as the fluid could increase the price of gas and thereby reduce supply (Russell 2000).

3.2.5 Nationwide Permits

Summary: Section 404 of the CWA requires that any activities that result in the discharge of dredged or fill material into waters of the United States (which include most wetlands) must be approved via a permit issued by the COE. Obtaining an individual permit can take 1 year or more (Bleichfeld et al. 2001). To reduce the burden caused by permitting many small, inconsequential projects, the COE has established nearly 40 general, or NWP, for categories of activities that will have minimal adverse effects on the environment. The processing time for activities approved under a general permit averages about 14 days (Copeland 1999). Recent regulatory changes have limited the activities covered by NWPs, meaning that more gas-related activities will require individual permits. Also, recent court cases and other actions have resulted in changes to the definitions of wetlands; thus the scope of activities and areas requiring a permit

has been in a state of flux, leading to additional delays caused by conflicting definitional interpretations.

Source of Constraint: Regulatory

Impact: Delay

Phase: Production, transportation

Category: Permitting

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CWA (Section 404, 33 USC 1344); 33 CFR Part 330

Lead player: COE

Issue discussion: Two key issues have the potential to increase the number of permits and the permitting times required to gain approval to develop natural-gas-related projects (e.g., drilling platforms, pipelines) in wetlands. The first is the recent elimination of NWP 26, and the second is the definition of water bodies that will require permits. NWP 26 was a general permit established by the COE in 1977 that authorized discharges in headwaters or isolated waters (nontidal waters with a flow rate of less than 5 ft³/s, or nontidal waters that are neither part of nor adjacent to a surface water system). Headwaters and isolated waters can be difficult to identify as wetlands because they may be dry for much of the year or lack the types of vegetation commonly associated with wetlands. Unlike other NWPs, NWP 26 did not restrict nor authorize specific activities, such as minor dredging or bank stabilization. Instead, it authorized discharges to certain types of waters on the basis of acreage and lack of hydrologic connection to navigable waters. Environmental groups had long been concerned that NWP 26 was overly broad, subject to abuse by applicants through segmenting of projects, and responsible for large amounts of unmonitored wetland losses. Industry groups viewed NWP 26 as an important mechanism for minimizing regulatory burdens on small businesses and other permit applicants, and as a means of limiting development delays and associated costs.

On March 9, 2001, the COE issued final regulations that included the elimination of NWP 26 (COE 2000). The rules “replaced” NWP 26 with five new NWPs. However, many activities formerly authorized by NWP 26 are not covered by any of the new or existing permits, so that individual permits must now be obtained. (NWP 26 permits composed between one-quarter and one-third of all NWPs authorized annually, and 90% of all NWP 26 actions involved areas of less than 3 acres (Copeland 1999). On August 9, 2001, the COE issued a proposal to reissue all existing NWPs, general conditions, and definitions, with some modifications (COE 2001). On January 15, 2002, the COE issued its final rule, which incorporated the more than 2,000 comments it received in response to the proposal (COE 2002). The five new NWPs established in the final rule to replace NWP 26 cover only a limited portion of the range of activities formerly covered by NWP 26. The most broadly applicable new permit was NWP 39. This permit authorizes many of the activities previously authorized by NWP 26. It

authorizes fills for the construction or expansion of certain building foundations or pads, but specifically excludes oil and gas wells from coverage. The final rules also made substantial changes to NWP 12 (utility crossings, including pipelines), subjecting such crossings to new size, notice, and geographical restrictions. These changes lowered the threshold for NWP approvals from 3 acres to 1/2 acre, reduced the preconstruction notification and mitigation threshold for NWP activities from 3/10 to 1/10 of 1 acre, and limited the use of NWPs within floodplains and in critical waters. Because of these changes, projects that would have previously qualified for approval under an NWP are now subject to the more time-consuming and costly individual permit process.

In addition to these complex and restrictive new NWP limits and conditions, the 35 COE District Offices are preparing supplemental regional conditions that will be imposed on various NWPs in states and regions. Gas operations in different regions or states, will thus be required to comply with varying regional NWP conditions applicable to each region. Estimates of the additional costs to comply with the new restrictions range from \$32 million to \$300 million per year (Miller 2001). In addition, the delays are expected to be significant, as the COE is required to process many more individual permits. The COE's cost analysis of the proposal to issue five new and modify six existing NWPs to replace NWP 26, estimated that the number of individual permit applications would increase by 4,656 annually (50% over current amount), the direct compliance costs to the regulated community would increase by about \$48 million annually, and the time to process the permits would increase by three to four times (Institute for Water Resources 2000). The analysis did not estimate indirect costs.

The second issue, the definition of federal water bodies, is significant because the COE definition determines what activities will require a permit. It can lead to prohibitions on activities that pose a threat to the water bodies or to permit conditions that require a permittee to undertake projects to mitigate environmental damage. On October 11, 2001, a COE district office expanded its definition of water bodies that fall under the jurisdiction of its NWP program when it stated that a nearby streambed that fills with water only in certain times of the year would now come under the review of the COE. This definition could force all COE district offices to accept additional streambeds, as under federal jurisdiction, thereby significantly expanding the scope of areas requiring permits. This action came after the U.S. Supreme Court ruled in *Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers* to limit the COE's authority to regulate isolated wetlands. This ruling has required the COE and the EPA to redefine what constitutes a water of the United States that comes under federal control. The discussion of the Spill Prevention Control and Countermeasures constraint (Section 3.3.14) contains more information on the definition of waters of the United States.

Changes to the NWP system and to the definition of waters requiring permits would delay gas production and distribution from facilities in wetlands that require permits; amounts of potentially affected TCF were not estimated.

3.2.6 NEPA Integration and Lawsuits

Summary: NEPA requires federal agencies to evaluate the human and environmental impacts of federal activities and projects, including leasing and other activities on federal lands. Various levels of jurisdiction and decision making under the law often produce unnecessary project delays. Also, NEPA-related lawsuits can lead to the preparation of “appeal-proof” documentation, which can further delay project review and approval.

Source of Constraint: Regulatory

Impact: Delay

Phase: E&P, transportation

Category: Access, leasing, permitting

Estimated affected natural gas resources (TCF): 464.5

Estimate type: Technically recoverable

Estimate date: 01/2000 **Estimate reference:** EIA (2001a)

Estimate comments: All natural gas resources will theoretically go through at least one NEPA review, and most, if not all, will go through a pipeline that requires a NEPA assessment. This TCF estimate is for all accessible, technically recoverable onshore and offshore resources.

Statutory/regulatory citation: NEPA (42 USC 4321 et seq.); ESA; state; local

Lead players: States, BLM, FERC

Issue discussion: NEPA integration concerns often relate not so much to the law itself, but to federal agency implementation of the law. Delays and inefficient expenditures of resources and capital often result from the following:

- Inadequate integration of NEPA compliance with other federal, state, and local permitting requirements, particularly ESA and National Historic Preservation Act (NHPA) requirements;
- Overlapping and inconsistent federal, state, and local permitting and mitigation requirements;
- Inadequate communication and coordination among participating agencies and the use of inconsistent procedures and data elements across responsible agencies;

- Lack of clarity in the roles and responsibilities of participating agencies;
- Decisions made on the basis of data that are not accurate, objective, or relevant;
- Duplicate environmental documentation;
- Limited use of categorical exclusions even when previous analyses would cover such exclusions; and
- NEPA-related lawsuits and the threat of additional suits, which can lead agencies to prepare lengthy, time-consuming, and costly EISs and EAs that go beyond the basic requirements.

In announcing an interagency agreement to improve coordination and cooperation on the permitting of natural gas transmission pipelines, the Chairman of the Council on Environmental Quality (CEQ) stated in October 2002, that one of the largest constraints to expanding the use of clean-burning natural gas relates to production and pipeline constraints. For pipeline projects, FERC is required to certify construction and operation of interstate natural gas pipelines, and numerous agencies can be involved in the review process.

For many pipeline projects, the various federal, state, and local compliance efforts are completed independently, leading to inconsistent conclusions and requirements, schedule and cost delays, and inefficiencies. For example, NHPA or ESA compliance assessments may require the use of one pipeline routing, while the NEPA compliance assessment could require a different routing. Even though CEQ regulations require timely coordination by federal agencies in dealing with interagency issues (40 CFR 1501.6) and avoiding duplication in tribal, state, county, and local procedures (40 CFR 1506.2), duplication and lack of coordination often occur. CEQ regulations require integration of analyses required by other laws into a single analysis (CEQ 1997). Although all interested parties are to become involved early and remain involved until solutions are found, sometimes such coordination does not occur.

Agencies have different (and conflicting) timetables, requirements, and statutory missions. For example, according to testimony provided by Wyoming Governor Jim Geringer, the BLM had been developing an EA for an additional 2,500 permits for CBM wells in Wyoming's Powder River Basin. Following its approved procedures, the BLM had completed its work and given assurances to leaseholders that the additional permits would be available by March 1, 2001. At the last moment, the USFWS reported that it had not completed its required assessment of impacts and would delay the issuance of permits. The lack of coordination and cooperation between two divisions within the single Department (of Interior) delays access to much-needed natural gas supplies. "Federal activity is primarily focused on process rather than results, and there is no accountability for improper decisions" (Geringer 2001).

Litigation associated with NEPA implementation has resulted in allowing the courts to determine the intent of NEPA and requirements for compliance. Environmental and other groups and individuals have accused federal agencies of failing to comply with NEPA requirements by

issuing leases and other approvals without proper NEPA review. To respond to or avoid challenges to their NEPA activities, federal agencies have gone beyond statutory NEPA requirements and prepared “appeal-proof” EISs and EAs. These, in turn, require time-consuming, overly broad studies, inventories, and analyses, which result in lengthy, cumbersome documents that require lengthy review periods, further delaying the NEPA process (Moseley 2002). “The move toward immunizing decisions from challenges and away from gathering scientific evidence on which to base a decision is beginning to erode the utility of the NEPA process” (Hopkins 2002).

An example of such a lawsuit is *Southern Utah Wilderness Alliance v. Norton*, December 6, 2001. In this case, the National Resources Defense Council and the Southern Utah Wilderness Alliance filed suit in the U.S. District Court for the District of Columbia charging that the BLM failed to conduct critical EAs before issuing 12 leases (in September 2001) that cover 10,500 acres in Utah’s Redrock Canyon region. The lawsuit alleged that the BLM failed to fully evaluate and disclose the impacts of the leases and asked the court to force the BLM to conduct an environmental review and rescind the leases until the study was completed. The environmental groups said that the BLM’s determination of NEPA adequacy was flawed; they conceded, however, that prior to actual drilling, the BLM requires more extensive environmental impact analyses (Ferullo 2001b; Beattie 2001). The plaintiffs stated that they plan to challenge BLM activities in other regions, such as Wyoming’s Red Desert-Bridger Teton National Forest that may also be in violation of environmental laws (Beattie 2001).

A more recent case could further increase the pressure for additional study as a part of NEPA compliance. On October 15, 2002, the DOI’s Board of Land Appeals upheld an April 26, 2002, ruling that the BLM erred in issuing three CBM permits for Wyoming without conducting sufficient NEPA analysis. The April ruling found that the sale of the three leases was illegal because the BLM failed to update a 17-year-old EIS that authorized continued gas and oil development in lands near Buffalo, Wyoming. The board said that although the Buffalo RMP and EIS addressed general oil and gas exploration, production, and development, it did not specifically address CBM extraction and development. The affirmation of the April ruling could be used to challenge existing and pending CBM leases in the Powder River Basin, as those leases were granted under the same Buffalo RMP/EIS (Baltz 2002c).

3.2.7 Pipeline Certification

Summary: According to the Interstate Natural Gas Association of America (INGAA), about 200 major new pipeline construction projects (valued at about \$2.5 billion per year) will be required over the next 10 years to support projected natural gas demands. The lead time to obtain permission to build new pipeline facilities can be lengthy. FERC must approve all new and expansions to existing interstate pipelines. The process requires approvals from numerous federal, state, and local agencies that have little incentive to work together to approve applications in a timely manner (INGAA 2001). For interstate pipelines, INGAA estimates that it takes an average of 4 years to obtain approvals to construct a new natural gas pipeline.

Source of Constraint: Agency implementation

Impact: Delay

Phase: Transportation

Category: Permitting

Estimated affected natural gas resources (TCF): 23.3

Estimate type: Annual gas consumption

Estimate date: 01/2003 **Estimate reference:** EIA (2003)

Estimate comments: All projected natural gas not already in system. Projected annual increases in consumption over the next 10 years; assumes gas consumed goes through pipelines.

Statutory/regulatory citation: Natural Gas Act of 1938 (15 USC 717); NEPA (42 USC 4321, et seq.)

Lead players: FERC, others

Issue discussion: The interstate pipeline approval process involves numerous agencies. FERC is usually the lead agency because it must approve interstate pipeline projects under the Natural Gas Act. FERC must determine (under NEPA) whether an EA or a full EIS is necessary. FERC must also evaluate the effect of the proposed project on cultural and historic properties and on threatened and endangered species. The COE issues permits for major water crossings under the CWA, Section 404. The USFWS may need to issue a “biological opinion” and a statement on incidental takes of protected species under the ESA, Section 7. The EPA evaluates projected air emissions. State agencies are responsible for issuing erosion and sediment permits, hydrostatic test water acquisition and discharge permits, and for approving stream and river crossings, threatened and endangered species preservation, air emissions, and noise. Local agencies must approve building and road crossing permits.

In most cases, the approval steps include the following: (1) the applicant gathers and submits information to the agency; (2) the agency performs a preliminary assessment of the project and may seek comment from other government entities and the public; (3) the agency issues a final analysis; and (4) the agency considers the analysis in making its decision on whether to issue a permit (or certificate). A study by the INGAA Foundation found that both pipeline applicants and agency reviewers experience problems coordinating the environmental permitting process. The study found that federal agencies often have inconsistent information on the project review process, possibly arising from the different personnel interfacing with the applicant (INGAA 1999). A related issue pertains to the handling of plan modifications subsequent to the approval of the EA or EIS. After EA or EIS approvals, unexpected field conditions or opportunities to further reduce impacts and costs can require that the plans be modified. Often, in such situations, the pipeline company, the FERC-designated environmental

coordinator, and the cooperating agencies reach an on-scene agreement. However, without the clear authority to approve a change in plans, field personnel may decide to implement a less desirable option, if such an option would require no further approvals (INGAA 1999). Interstate pipeline operators believe the environmental regulatory review of new pipeline proposals should be streamlined and coordinated to reduce the excessive delays now experienced and to facilitate permitting for new pipeline projects. There has been some activity at the federal level to expedite certification and permitting, but much of the problem is at the state and local levels, where reviews and approvals must also occur (AGA 2000).

The majority of individual permits required for infrastructure expansion are state and local. Although state and local regulations are necessary and add oversight, only a few states effectively coordinate the natural gas pipeline permitting process, and state and local regulatory activities can add months or years to the time required to build a pipeline. Also, state and local regulations sometimes overlap, as do requirements across different state agencies (IOGCC/NARUC 2001).

The NPC report projects a need for more than 38,000 mi of new transmission lines and 263,000 mi of new distribution lines to meet future natural gas demands. These increases will exacerbate existing pipeline permitting delays (NPC 1999).

3.2.8 Pipeline Safety (Integrity Management)

Summary: Recent natural gas pipeline incidents involving loss of life and property, a perceived lack of effectiveness on the part of the federal agency charged with implementing statutory mandates regarding pipeline safety, and the realization that increased gas demands can only be met with increased pipeline capacity have contributed to increased natural gas pipeline safety requirements. Federal-level safety, or integrity management, standards for natural gas transmission pipelines are being written that could increase costs and result in temporary supply disruptions. In addition, states can issue regulations more stringent than the federal regulations for intrastate pipelines.

Source of Constraint: Regulatory

Impact: Delay, cost

Phase: Transportation

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: The Pipeline Safety Improvement Act of 2002 (H.R. 3609); 49 USC 60101, et seq., “High Consequence Areas for Gas Transmission Pipelines,” Final Rule (67 FR 50824), August 6, 2002; “Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),” Final Rule (68 FR 69778), December 15, 2003

Lead players: DOT, Research and Special Programs Administration (RSPA), Office of Pipeline Safety (OPS)

Issue discussion: INGAA estimates that by 2015, nearly 50,000 mi of new transmission lines will need to be built to meet the projected demands for natural gas in the United States. Currently, there are about 180,000 such miles (Boss 2002). Over the past 7 years, the OPS has investigated cost-effective ways of improving the safety, security, and reliability of natural gas pipelines, and over the past 3 years, Congress has been trying to reauthorize existing pipeline safety legislation and further increase the safety of pipelines. The OPS has undertaken a two-part rulemaking procedure that (1) defines high consequence areas (HCAs), or areas where the consequence of a gas pipeline accident could cause considerable harm to people or property, and (2) sets requirements to improve the integrity of interstate gas transmission pipelines located in these HCAs. On August 6, 2002, the OPS issued the final HCA rule.

On November 15, 2002, Congress passed the Pipeline Safety Improvement Act (H.R. 3609), and on December 17, 2002, President Bush signed the legislation. Among other things, the new law (49 USC 60109) mandates safety inspections for pipelines in HCAs to prevent leaks and ruptures within the next 10 years and reinspections within 7 years, stiffens penalties for violations, increases state oversight, and establishes a permit streamlining program. It uses a risk-based approach to target more problematic pipelines for inspection within the first 5 years. On December 15, 2003, the OPS issued final integrity management regulations for gas transmission lines in HCAs (DOT 2003).

Both the legislation and the rule contain prescriptive requirements, the implementation of which could increase prices, or even cause supply or delivery problems. Specific areas of concern include the following: the new law allows the DOT to require operators to take corrective action, including repairing and replacing equipment, if there is a potential safety-related condition (Section 7). While much of the bill uses risk as a criterion for action, this provision gives the Secretary much more latitude in what can be required of operators. The law also requires the DOT to study and report to Congress on preserving environmental resources with regard to pipeline ROWs to determine ways to address and prevent hazards and risks to the public, pipeline workers, and the environment, and to address how to best preserve environmental resources in conjunction with maintaining ROWs (Section 11).

The inspection schedules in the rule are tight, and the need for smaller operators to implement new inspection programs could delay delivery if finite resources are directed toward such implementation and away from delivery. Making lines piggyback, conducting the actual tests and retests, and addressing needed repairs will remove pipelines from service for periods ranging from a few days for an inline inspection test, to 30 days or more for installing necessary fittings and pipe modifications. The lack of flexibility in integrity management requirements and the “one-size fits all approach” for all pipelines regardless of size may preclude the use of more cost-effective integrity management measures that would limit supply disruptions. Projected natural gas demand increases, which will add strain to the systems, can be expected to exacerbate the effects of inspection-induced delays.

Potentially all gas that goes through interstate transmission lines located in HCAs could be affected by the pipeline safety requirements. However, no specific estimates of the amounts of gas affected are available.

3.2.9 Wetlands Mitigation

Summary: Recent COE regulation and guidance for mitigating impacts to wetlands has taken a watershed approach, which allows case-specific exemptions to the one-for-one mitigation-to-impact requirement and expands options for conducting mitigation. Environmental opposition may result in a review and rethinking of these revisions, which could increase the time and money associated with obtaining permits and implementing strategies to mitigate impacts to wetlands caused by natural gas E&P, development, transportation, and construction activities.

Source of Constraint: Regulatory

Impact: Delay, cost

Phase: Production, transportation

Category: Permitting, operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CWA (Section 404, 33 USC 1344); 67 FR 2020, January 15, 2002; U.S. Corps of Engineers Regulatory Guidance Letter 01-1, October 31, 2001

Lead players: COE, states

Issue discussion: Section 404(a) of the CWA (FWPCA, 33 USC 1344(a)) authorizes the COE to issue permits regulating the discharge of dredged or fill material into the waters of the United States, including wetlands. Typically, the permit requires mitigation to offset the impacts. A June 2001 National Academy of Sciences Report criticized the COE's mitigation approach, citing failures of mitigation projects and other problems. On October 31, 2001, the COE issued Guidance Letter 01-1 to improve mitigation conditions required in COE permits. The guidance adopts a watershed management approach that includes provisions for compensatory mitigation such as off-site mitigation and case-by-case exceptions to a one-for-one functional replacement. The guidance is designed to improve mitigation consistency across districts. On January 15, 2002, the COE modified its General Condition 19, which addresses mitigation for NWPs, or general permits. This modification also takes a watershed approach, and although it adheres to the "no-net-loss" of wetlands policy by requiring a one-for-one mitigation for wetlands impacts at the district level, exceptions can be made on a case-specific basis. A variety of mitigation approaches, including mitigation banking, are allowed. Environmentalists, the EPA, and the USFWS have raised concerns about the revisions; some view these revised mitigation policies as moving away from the "no-net-loss" policy and as loosening the standards. Legal action may be taken against the COE, with the argument that the COE has insufficient data to make a

determination that the programs revisions will result in a minimal impact on the environment (Inside EPA 2002c).

Natural gas production and transportation may be facilitated by the COE's revisions to mitigation policies, since they allow for case-by-case exceptions to the one-for-one mitigation requirements and since they expand the actions that qualify for compensatory mitigation. Attempts to retract the provisions or to have states implement more stringent legislation and regulations could cause delays to projects or increased costs for more costly mitigation approaches. Wetlands issues, regulations, and policies are constantly undergoing discussion and review by Congress, the COE, environmental groups, and others. Wetlands-related actions stemming from these discussions could delay access to natural gas or increase costs of obtaining the gas. Estimates of the number of potentially affected TCF are not available, but gas at any exploration, production, or transportation facility that needs a wetlands permit could be affected.

3.3 ISSUES LIKELY TO INCREASE COSTS

3.3.1 Cooling-Water Intake Structures

Summary: Section 316(b) of the CWA requires that cooling-water intake structures reflect the best technology available for minimizing adverse environmental impacts. The EPA is developing national regulations to implement these requirements. It has issued final Phase I and II regulations for existing power plants and for new power plants and manufacturing facilities. The EPA published proposed Phase III regulations for existing manufacturing facilities, including oil and gas extraction facilities, and for new offshore oil and gas extraction facilities in November 2004. Final Phase III regulations must be published by June 2006. Impacts of the final 316(b) Phase III regulations on oil and gas production are not known at this time.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Permitting

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CWA, Section 316(b); 69 FR 68444-68565, November 24, 2004

Lead player: EPA

Issue discussion: For several years, the 316(b) requirements have been implemented on a site-by-site basis, without federal standards. Following settlement of a lawsuit, the EPA is now developing national regulations in three phases: Phase I for new facilities, Phase II for existing

electric utilities that use large amounts of cooling water, and Phase III for electric utilities using smaller amounts of cooling water and other industries, which include existing and new offshore and coastal oil and gas extraction facilities. These extraction facilities typically use cooling systems for their engines and brakes.

Entities affected by the 316(b) rules use cooling-water intake structures to withdraw water for cooling purposes and have, or are required to have, a NPDES permit issued under Section 402 of the CWA (33 USC 1342). The regulations apply to the intake of water and not the discharge. Major goals of the regulations are to minimize impingement, which occurs when fish and other aquatic life are trapped against cooling-water intake screens, and entrainment, which occurs when aquatic organisms, eggs, and larvae are drawn into a cooling system through the heat exchanger and then pumped back out. Cooling water intake requirements are performance standards implemented through NPDES permits, which are based on the best technology available to minimize impingement and entrainment.

The EPA published proposed “Phase I” regulations for cooling-water intake structures at certain new industrial facilities on July 20, 2000, and final Phase I regulations on November 9, 2001. It published proposed “Phase II” regulations for approximately 550 existing electric power generating plants on February 28, 2002, and final Phase II regulations on July 9, 2004. It published proposed “Phase III” regulations for certain existing industrial facilities, including oil and gas extraction facilities, and for new offshore oil and gas extraction facilities on November 24, 2004. The EPA must publish final Phase III rules by June 1, 2006.

Preliminary EPA information indicated that about 200 offshore oil and gas platforms and mobile drilling units could be subject to the Phase III regulations (EPA 2002c). The EPA estimated that the final Phase I regulations for new electricity-generating facilities would affect 121 facilities to be built over the next 10 years and cost about \$48 million per year (EPA 2001a). The U.S. Coast Guard estimated that retrofits for drill ships and semisubmersibles that use “seachests” as the cooling-water intake structure could cost approximately \$8 million to \$10 million and require several weeks to months for dry-docking operations. The Independent Association of Drilling Contractors reported that the cost of converting a jack-up modular offshore drilling unit from sea water cooling to closed-loop air cooling is roughly \$1.2 million and requires a six-month lead time to obtain the required equipment (EPA 2001b). Impacts to the scheduling of offshore drilling rigs, such as the downtime needed for retrofitting, could adversely affect the availability of natural gas to consumers.

The proposed Phase III requirements published in November (EPA 2004g) would apply to existing facilities that withdraw more than 50 million gal/day of water; existing facilities that withdraw less than 50 million gal/day would continue to be subject to 316(b) permit conditions established on a case-by-case, best professional judgment basis. Because few, if any, existing offshore oil and gas extraction facilities withdraw more than 50 million gal/day, compliance with the proposed rule is not expected to generate significant impacts for existing facilities. However, the proposed Phase III regulations also establish requirements for new offshore oil and gas extraction facilities. (The EPA had specifically excluded these facilities from the scope of the Phase I new facility regulations so that it could collect additional data on them.) According to the proposed rule, new offshore and coastal oil and gas extraction facilities with cooling-water intake

structures that have a design intake flow of greater than 2 million gal/day to withdraw from waters of the United States would be subject to the rule's requirements. Impacts of the proposed rule and of the eventual final rule on new oil and gas offshore extraction facilities are not known.

3.3.2 Electronic Reporting and Record-Keeping Requirements

Summary: On August 31, 2001, the EPA's Office of Environmental Information published its proposed CROMERRR, which describes conditions under which the EPA would "allow" submission of electronic documents and maintenance of electronic records to satisfy federal EPA reporting and record-keeping requirements (EPA 2001f). The rule is touted as voluntary, but any entity that reports or maintains records electronically would have to follow certain requirements, which could require the installation of costly new systems incompatible with current electronic data management systems. The API estimated that the financial impact of the proposed rule on the petroleum industry alone would be comparable to what the industry spent on Y2K — about \$1 billion.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: 66 FR 46162, August 31, 2001

Lead player: EPA

Issue discussion: The EPA's apparent intent in proposing this rule was to remove existing regulatory obstacles to electronic reporting and record keeping across EPA programs to comply with the requirements of the Paperwork Reduction Act by the deadline of October 2003. However, the proposal, as written, goes beyond those requirements and is burdensome. The proposal would impose mandatory, extensive, and difficult-to-implement requirements on essentially all environmental records at all facilities subject to environmental regulation. The EPA received more than 180 comments on the proposal, most of which were directed toward the record-keeping requirements, finding them to be overly burdensome, not voluntary, and too prescriptive. For example, a given facility may have dozens of different data collection systems that would have to be evaluated and set up to meet the CROMERRR criteria. As of June 2002, the EPA was considering decoupling the record-keeping portions of the rule from the reporting portions, thus allowing for timely compliance with the Paperwork Reduction Act for reporting, but postponing the record-keeping portions to a later date.

The rule would probably be most costly for small producers. Although it would not directly affect gas production, it could be an additional economic burden that some, especially small, operators could not afford. Added to other regulatory burdens, this rule could put some small operators at risk.

3.3.3 Lack of Incentives to Go beyond Compliance

Summary: Permitting and regulatory processes generally lack incentives for companies to provide environmental protection beyond standard operating practices. Proposals that would provide environmental protection beyond legal requirements and proposals that could provide equal protection at lower costs have been rejected by local, state, and federal authorities. Such rejections constrain environmental progress and preclude opportunities to reduce costs. They can also discourage natural gas operators who may otherwise be willing to take voluntary action in the E&P areas, where additional regulations, expected in response to increased activity and attendant environmental impact, will add to the workload of already burdened regulatory staff, further exacerbating production delays.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Permitting

Estimated affected natural gas resources (TCF): 86.6

Estimate type: Technically recoverable

Estimate date: 01/2003 **Estimate reference:** DOI (2003)

Estimate comments: Estimated to be the amount of gas in EPCA I areas that are available for lease under standard lease terms. This estimate is based on the assumption that the lack of incentives applies to any federal land. It could also apply to state and private lands and could apply in other areas in addition to the Rocky Mountain region.

Statutory/regulatory citation: FLPMA; Mineral Leasing Act (30 USC 209)

Lead player: BLM

Issue discussion: Operators have suggested mitigation approaches regarding habitat protection, but they are typically not allowed because of “department policy” (Watford 2001). An example of a missed opportunity for going beyond compliance was described to the House Resources Subcommittee on Energy and Minerals on April 25, 2001, by the president of Ultra Petroleum Corporation, an independent E&P company with core operations in Wyoming. Ultra Petroleum

had proposed such an approach during the preparation of an EIS for gas drilling operations in the Pinedale Anticline in Wyoming. In this case, discussions with the BLM and the Wyoming State Game and Fish Department indicated that some of the greatest benefits to the affected wildlife would come from protecting habitat in areas away from the proposed project area (i.e., other critical wintering areas or riparian areas that had a high probability of being subdivided and therefore of having a greater adverse impact on the species than oil and gas development). Ultra offered to establish an “off-site” mitigation fund whereby the BLM and the State of Wyoming could spend industry dollars, on a per-well-drilled basis, to mitigate impacts to affected species in the locations that would render the greatest environmental protection for the dollars spent, even if those locations were outside the project boundary. However, the BLM stated that a DOI solicitor’s opinion and department policy prohibited any off-site mitigation, regardless of the potential environmental benefit (Watford 2001).

In another example, on the basis of information produced during the NEPA process, which showed that reducing disturbance to the surface and the habitat was one of the best ways to minimize the significant impacts from operations, Ultra analyzed the option of drilling several wells directionally from the same pad. Because the cost of directional drilling is significantly higher than that of drilling a traditional well bore, Ultra sought a legal interpretation to determine if royalty rate reductions could be applied for the voluntary use of directional drilling. According to the Mineral Leasing Act (30 USC Section 209), the Secretary of the Interior is authorized to grant reductions in production royalties as follows: “The Secretary of the Interior, for the purpose of encouraging the greatest recovery of . . . oil, gas . . . and in the interest of conservation of natural resources is authorized to . . . reduce the rental, or minimum royalty on an entire leasehold, or on any tract or portion thereof segregated for royalty purposes, whenever in his judgment it is necessary to do so in order to promote development, or whenever in his judgment the leases cannot be successfully operated under the terms therein provided.” The BLM responded, however, that the DOI solicitor had issued an opinion prohibiting the department’s ability to utilize an ecoroyalty relief program as an incentive for such environmental protection. “It appears that capitalizing on or creating incentives in the marketplace or within the bureaucracy to better ease or quicken the NEPA process is grossly neglected by the Federal Government and that valuable opportunities for improvement are foregone” (Watford 2001).

3.3.4 Louisiana E&P Waste Disposal Regulations

Summary: Amendments to the State of Louisiana’s E&P waste storage and disposal rules passed on November 20, 2001 may increase costs and delay natural gas E&P schedules in the state. Louisiana is the first state to adopt such regulations, and because many oil and gas states follow Louisiana’s lead, the requirements may set precedents for other states, with attendant costs for natural gas E&P operations.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: Louisiana Statewide Order No. 29-B, AC 43:XIX, Subpart 1, Chapter 5 (501 et seq.)

Lead player: State

Issue discussion: On November 20, 2001, a new rule, Statewide Order No. 29-B, took effect in Louisiana. The rule responds to citizen complaints since 1984 in Grand Bois, Louisiana, where a local land-treatment facility handled gas plant wastes that allegedly caused health and pollution problems. Among other things, the amendments require generators to characterize the E&P wastes they generate, set maximum permissible limits on the benzene concentration in gas plant wastes, and increase the sizes of buffer zones near waste facilities. The rules result from a comprehensive waste evaluation and health risk analysis of oil field wastes managed at commercial facilities. Waste generators are responsible for proper handling and transportation of E&P waste taken off site for storage, treatment, or disposal. The fiscal and economic impact statement accompanying the proposed rule estimated impacts to the regulated community of \$940,000 or higher for costs to dispose of gas plant wastes. Comments on the proposed rule indicated that the costs would be much higher — on the order of \$5 million to commercial facilities — and that the provisions for design criteria for commercial facilities (Section 509 A) would be “virtually impossible to comply with and could cause the closure of many facilities.” Other comments suggested that the one-time costs, per disposal company, for such items as injection wells, retention basins, and levees, would be \$6,600,000; operating costs and lost revenue were estimated at \$1,600,000 per year (Louisiana Docket IMD-01-11-2001). Presumably, these costs would be passed along to the natural gas operators. A requirement that an independent consultant or laboratory (third party) perform the sampling would also add to operator costs. Whether the impacts would be enough to limit production, particularly for smaller operators, is not known.

Risk-based regulations can lead to rules that are generally fair and science-based, because they tend to reflect actual events and consider both the degree of hazard as well as the likelihood of the hazard occurring. In contrast, some regulations reflect only the hazard or potential for hazard without considering the likelihood of the hazard occurring. However, the benefits of using a risk-based approach can be lost if the assumptions are overly conservative and if the risk assessment assumes these overly conservative assumptions in all cases. A risk-based evaluation of E&P wastes was used to develop the new Louisiana rules. However, some commenters noted that the series of overly conservative assumptions used in developing the rules could never occur in actual operations, and that taken together, they not only compound the conservatism of the results but can set an improper precedent for developing other risk-based regulations.

The new rules also require public notification requirements for routine operational changes, which could delay production with little if any environmental benefit. For example, the

newly adopted revisions require that any application to recomplete a Class II commercial disposal well into a new disposal zone must be advertised in the legal ad section of the official state journal and in the official parish journal where the facility is located. According to comments filed on the proposed rule, recompletion of an existing injection well into a new disposal zone typically becomes necessary based on something discovered during a well workover. The public notice provision will require that the operator dismiss the workover rig from the site, submit the application, and advertise as required. Since there is no defined public comment period, the length of time allotted for comments is unknown. At a minimum, it would likely be 15 days, during which time the well would be shut in and the rig moved off site. If the application is approved after the allotted public comment period, the rig must be remobilized and the well reworked. Before the new rules were implemented, the procedure had been to handle the application administratively, with relatively little delay. The final rule retained the public notification requirement citing federal EPA requirements.

The E&P waste disposal regulation could affect all gas produced in the State of Louisiana. Although it would not prohibit or limit access, it could increase production costs. Combined with other regulatory actions that could increase costs, the rule could reduce the incentive for some producers to continue or start operations.

3.3.5 Maximum Achievable Control Technology (MACT)

Summary: MACT rules regulate emissions of HAPs from stationary and mobile sources. Final MACT rules exist for oil and gas production facilities and for natural gas transmission and storage facilities. Recently, the EPA has signed final MACT rules for turbines, process heaters, and reciprocating internal combustion engines, which may affect gas operations. Compliance with these rules, for example, a 95% reduction in emissions at major sources, could impact the economics of natural gas operations.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production, transportation

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CAA (Section 112(d), 42 USC 7412 (d)); Final MACT rules

Lead player: EPA

Issue discussion: The EPA has estimated relatively small economic and energy impacts associated with implementation of the production, transmission, and storage rules. However, the potential impacts of additional MACT regulations on future natural gas and CBM operations are

uncertain. The sources affected by the recently signed MACT rules — turbines, process heaters, and reciprocating internal combustion engines — are used in natural gas production and transmission. The degree of impact depends, to a large degree, on whether sources are considered major or not. A major source is defined as any stationary source or group of stationary sources located within a contiguous area and under common control with the potential to emit 10 tons per year or more of any HAP, or 25 tons per year or more of any combination of HAPs. To determine whether a gas production facility is a major source, HAP emissions from combustion turbines, reciprocating internal combustion engines, glycol dehydrators, and tanks that have the potential for flash emissions will be aggregated (EPA 2002a).

Although combustion turbines and reciprocating internal combustion engines are efficient combustion devices, products of incomplete combustion form HAPs, including formaldehyde. Combustion turbines are used at compressor stations, and internal combustion engines are necessary for producing and processing natural gas and transporting it to market. A large turbine or reciprocating internal combustion engine could emit about 10 tons per year of combined HAPs, with formaldehyde accounting for about half of the HAP emissions. Combustion turbines are used to maintain pressure in gas pipelines, and the EPA estimates that there are about 8,000 existing turbines in the United States, ranging in size from 1 to 200 MW (1 MW equals about 1,200 hp). The EPA estimates that about 20% of the existing and new turbines will be located at major sites. In addition to adding controls, covered sources would be required to monitor HAP emissions.

On June 15, 2004, the EPA issued final MACT standards for reciprocating internal combustion engines (EPA 2004c). These rules are expected to affect natural gas transmission, natural gas production, and natural gas liquids production. On February 26, 2004, the EPA signed final MACT rules for process heaters and boilers (not yet published). These rules apply to, among other sectors, natural gas extraction operations. On March 5, 2004, the EPA issued final MACT standards for stationary combustion turbines (EPA 2004d). Among other activities, these rules will affect natural gas transmission, natural gas production, and natural gas liquids production.

Because the EPA rules only apply to major sources, they are not expected to affect small producers, who typically are the most susceptible to economic impact (i.e., they may have to close operations). However, as more gas is produced and shipped, the size of the affected sources may increase, bringing more of them under control. Also, the HAP requirements in some states, such as Oklahoma, are more stringent than the federal requirements. Some state minor source requirements can burden small operators who lack the personnel and expertise to determine compliance with a state's air emission requirements and must hire consultants to make these determinations. While the MACT rules are not expected to prevent gas from being produced or shipped, they could increase costs.

3.3.6 Mercury Discharge Regulations

Summary: Discharges of mercury-containing drilling muds from gas (and oil) drilling operations in the Gulf of Mexico have generated concern that such mercury may convert to toxic

methylmercury, which can accumulate in the food chain and poison fish. Such concerns may expand to other onshore and offshore geographical areas, leading to strengthened or new mercury regulations.

Source of Constraint: Regulatory

Impact: Cost

Phase: E&P

Category: Permitting

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: NPDES permits, possible new federal or state regulations, federal interagency task force

Lead player: EPA

Issue discussion: Recent newspaper articles in Mobile, Alabama, and New Orleans, Louisiana, have cited studies by the MMS suggesting that oil and gas rigs in the Gulf “amount to islands of intense mercury contamination,” which could spread to fish attracted to drilling rigs for feeding (Rains 2002). The articles state that the contamination results from the discharge of barite-containing muds used to cool and lubricate drill bits during initial exploration, rather than from ongoing operations. Barite often has high mercury concentrations. When certain microscopic organisms ingest mercury, methylmercury, a potent neurotoxin, is formed. The article reports that hundreds of thousands of pounds of mercury could have been released around the 4,000 rigs drilled in the Gulf over the past several decades. Federal regulations require a permit for the discharge of all barite-containing drilling muds in U.S. waters. These permitted discharges must contain less than 1 part per million (ppm) of mercury, and no discharges are allowed within 3 mi of the shore. According to the articles, however, more than 1,000 lb of mercury could still be legally discharged from the 1,200 new wells projected to be drilled annually.

The IOGCC notes that while the articles are aimed at off-shore Gulf of Mexico drilling platforms, it “may be only a small step” to make such claims about other regional offshore or onshore oil and gas operations (Carl 2002).

The MMS responded to the articles, stating that it provided misinformation and that studies supported by the MMS, EPA, and DOE have demonstrated that mercury around drilling platforms does not result in mercury levels in marine organisms living near the platforms that are greater than those for marine organisms living far from the platforms (Querques 2002).

In May 2002, the White House announced the formation of an interagency federal task force to determine whether mercury discharges in the Gulf and other areas pose a threat. EPA regional sources stated that the EPA could change its permitting regulations for discharges if

further study indicates that mercury is being converted to methylmercury. The State of California is also pursuing additional regulations, with legislation introduced to launch a state task force to evaluate the effects of mercury from drilling rigs (Superfund Report 2002).

Regulations could affect gas from wells that are drilled using mercury-containing muds or that produce mercury-containing cuttings. The regulations could potentially affect any new wells drilled in the Gulf of Mexico, and perhaps in other onshore and offshore areas. Additional regulations that would require the hauling of the drilling muds to shore or the use of alternative formulations could significantly increase drilling costs, with the possibility that the increased costs could limit natural gas drilling operations.

3.3.7 NO_x Prevention of Significant Deterioration Increment Consumption

Summary: An increasingly important air quality issue that can affect natural gas production in the West is the potential for new regulations to limit NO_x emissions. The Air Quality Act limits emissions in PSD areas, most of which exist in the West, where the number of combustion sources that create such emissions is growing. Many of these combustion sources are from oil and gas drilling, and particularly CBM drilling, which is expected to increase significantly over the next few years.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Permitting

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CAA, PSD Regulations (40 CFR 51.166 and 52.21)

Lead players: EPA, states

Issue discussion: State and NAAQS set upper limits for specific air pollutant concentrations, including NO_x. The New Source Review PSD program is designed to limit the incremental increase of specific air pollution concentrations (e.g., NO_x) above a legally defined baseline level, depending on the classification of the location. Class I areas have more stringent limits than Class II and Class III areas. Western governors and state environmental agencies have recognized that the increased growth of combustion sources in their states is leading to increased emissions of criteria air pollutants. Many are concerned that growing releases of NO_x associated with increased drilling operations could affect state compliance with the PSD NO_x increment, even though most individual sources alone would be too small to trigger the PSD increment. The Wyoming Air Quality Division is “processing thousands of permits for compressor engines, and there is no end in sight” (Easton and McVehil 2001). To determine how much of the NO_x

increment is being used, the Wyoming Department of Environmental Quality is conducting a large-scale study of emission sources in the Powder River Basin, including oil and gas development in addition to the more traditional NO_x sources of mining and mineral processing. Because the state already requires Best Available Control Technology in permits for all but insignificant sources, a finding that suggests a high consumption of the NO_x increment could mean much more aggressive source control. If the Wyoming study indicates excessive increment consumption, the EPA is likely to dictate the next steps, which could include limits on combustion sources or lower emission limits. These requirements would slow the rate of natural gas development in those states where the PSD limits are being met (Easton and McVehil 2001).

At a meeting of the Western Governors' Association, the cochair of the Western Regional Air Partnership (WRAP) Program stated that NO_x emissions will most likely be the next major area of concern, and other participants noted the importance of assessing nonutility sources (e.g., oil and gas producers) (Baltz 2002b). (WRAP is an organization of 13 states, 9 tribes, and 3 federal agencies established to address air quality issues in the western states.)

The West is not the only area for which NO_x emissions from natural gas operations are of concern. In 1988, a gas pipeline company installed four new engines at a compressor station in Illinois. In 1996, a state environmental inspection discovered that the engines were emitting NO_x at levels that triggered control requirements under the PSD program and fined the company \$1.0 million. (The state environmental agency had proposed a \$2.2 million penalty for the violation, but the pollution control board lowered it [Bologna 2001].)

As E&P drilling increases and as more pipelines are built to move the gas, the need to maintain low levels of NO_x emissions could limit the production and delivery of gas. Also, the process for developing new E&P and pipeline operations can be expected to lengthen as more sources apply for permits.

Potentially all new gas being developed, produced, or transported in PSD areas could be affected by NO_x limitations, but neither the specific PSD areas nor the TCF resources within them have been estimated.

3.3.8 Noise Regulations

Summary: As E&P and transportation of natural gas increase in response to increased demand, the number of drilling rigs, processing plants, and pipelines will also increase. These increases will require additional equipment, particularly compressors and drilling equipment, both of which generate high levels of noise. To date, most drilling and producing operations and pipelines have been located away from population centers, so that noise has not been a major issue. However, as thousands of wells are drilled (particularly for CBM in the West) and as new pipelines are built, noise is expected to become an issue that could lead to regulation and subsequently higher operating and transportation costs. Noise also affects wildlife, and its effect on otherwise quiet areas will continue to be a subject of concern and potential regulation.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production, transportation

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: County ordinances, proposed state legislation

Lead players: States, local governments, BLM

Issue discussion: Noise from gas operations, particularly compressors at pipelines and increasingly from CBM operations, has generated concern and action by local residents. Some areas have implemented regulations or introduced legislation to limit noise and others may follow, especially as the numbers of wells and pipelines increases. This emerging issue is most likely to be the subject of local or site-specific regulations that may prove costly, as operators are required to develop quieter equipment or increase the use of muffling techniques.

Pipeline compressor stations contain three to four compressors. Noise from this equipment can be heard up to 5 mi away. Anecdotal evidence indicates that pipeline compressors can disrupt nearby residents' lifestyles, leading to cease-and-desist orders being filed against pipeline companies and proposed regulations to limit noise. Members of the State of Wyoming's Coal Bed Methane Coordination Coalition, which consists of five counties and two conservation districts in Wyoming where CBM development is occurring, state that they would consider supporting noise regulations for pipeline compressors (Billings Gazette 2001). In Michigan, legislation has been introduced to reduce noise and nighttime nuisance by allowing counties to adopt ordinances that regulate hours during which gas, oil, brine, or any other substance can be transported to or from a gas (or oil) well (Stoneman 1995). The State of Arkansas is holding hearings on compressor noise and is studying the impact of compressor noise on the environment.

During CBM development, short-term noise impacts (2 to 5 days) result from drilling operations (rig operation, trucks, and other equipment). As development continues, additional compressor sites are required. These compressors are generally powered by large natural gas engines capable of producing high-decibel noise levels. The following examples illustrate the types of noise restrictions that can be expected in the future. Certain Colorado counties have compressor noise regulations that include installing mufflers, additional sound insulation or berms to prevent noise pollution, and location restrictions (Morrison 2002). Residents in other counties have begun circulating petitions requesting action to require controls to reduce noise from compressor stations. Noise regulations may be adapted not only to reduce impacts on humans, but also on wildlife. The ROD for the Hanna Draw Coal Bed Methane Exploration Project in Wyoming states that the BLM may require noise levels to be no greater than 10 dB(A) above background levels at greater sage-grouse leks. It also states that the BLM may require compressor engines to be enclosed in a building and located at least 600 ft from sensitive receptors or sensitive resource areas (BLM 2002).

Noise abatement regulations could increase costs to the point where prices are affected. It is also possible that schedules could be delayed if noise-sensitive habitat areas must be located as part of the permitting process. Noise regulations could potentially affect all new CBM wells and pipeline operations.

3.3.9 Nonroad Diesel Rule

Summary: Section 213(a) of the CAA requires that the EPA regulate emissions of nonroad engines and equipment. The EPA has issued some nonroad diesel emission standards and plans to issue more, with a new proposal in the spring of 2003 and final rules by the summer of 2004. Nonroad diesel engines are used in natural gas E&P and in gas processing operations. Increased costs of these engines because of stricter emissions controls, when added to other environmental costs, could affect some operations and limit gas development.

Source of Constraint: Regulatory

Impact: Cost

Phase: E&P

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CAA (Section 213 (a), 42 USC 7547(a)); Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel, Final Rule (69 FR 38957), June 29, 2004

Lead player: EPA

Issue discussion: Until relatively recently, emissions from nonroad diesel engines have not been regulated. On October 23, 1998, the EPA issued final emission standards for nonroad compression ignition (diesel) engines for engines over 50 hp (EPA 1998). In the preamble to that rule, the EPA stated that pursuant to the CAA, the agency was undertaking a technology review to determine whether more stringent standards are now feasible and to promulgate such standards if the findings are positive. The technology review will reassess the standards for NO_x and hydrocarbons and will set the next phase of PM standards for engines rated at 50 to 750 hp. In June 2002, the EPA announced that it would work closely with the Office of Management and Budget (OMB) and other experts and interested stakeholders in developing a nonroad diesel rule that could go beyond the requirements finalized in 1998 (Najor 2002).

In June 2002, the State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials issued a report that found that nonroad engines represent one-third of the motor vehicle industry's fine particulate inventory. The report, *The Dangers of the Dirtiest Diesels: The Health and Welfare Impacts of Nonroad Heavy-Duty*

Diesel Engines and Fuels (Walsh 2002), also found that the disparity between onroad and nonroad PM emissions will grow as vehicles and engines comply with the EPA's recently adopted onroad heavy-duty diesel engines and fuel rules, which are to be phased in during 2006 to 2007. On September 3, 2002, the EPA released a report, *Health Assessment Document of Diesel Engine Exhaust* (EPA 2002b), which is the first comprehensive review of the potential health effects from ambient exposure to diesel engine exhaust. The study, which took 10 years to complete, is intended to be used as a tool in evaluating regulatory needs under the CAA. The report concluded that diesel exhaust contains large quantities of NO_x, SO₂, HAPs, and PM, and that the health impacts from these air pollutants include increased potential for lung cancer and exacerbated allergies and asthma symptoms.

On May 23, 2003, the EPA proposed to control emissions of air pollutants for nonroad diesel engines (EPA 2003a). The rule would apply to new diesel engines used in most types of construction and industrial equipment, including oil and gas field machinery and equipment. It would require such engines to be equipped with state-of-the-art emission control systems that would reduce PM emissions by 90% and NO_x emissions by 95%. Implementation would be phased in between 2008 and 2014. The rule is aimed at the manufacturers of nonroad diesel engines, but since it may result in increased costs for new engines and diesel engines are widely used in onshore and offshore E&P operations, it could lead to increased costs for the industry. Those costs, in combination with other increased costs and demands, could result in supply availability problems, especially for small producers. The EPA issued a final rule in 2004 (EPA 2004e).

The nonroad diesel engine rule could affect E&P for offshore and onshore wells using new diesel-powered engines; the number of TCF affected (by increased costs) was not estimated.

3.3.10 Ocean Discharge Criteria

Summary: Proposed amendments to existing rules implementing the ocean protection provisions of Section 403 of the CWA would strengthen existing ocean discharge criteria. These criteria must be considered in the issuance of individual or general NPDES permits for offshore facilities. The proposal would designate "Healthy Ocean Waters" (waters beyond 3 mi offshore), and these waters would be protected by both a narrative statement of water quality and pollutant-specific numeric criteria and would be subject to an antidegradation policy. The rule would also establish SOSs, where new and significantly expanded discharges would be prohibited.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Permitting

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: Prepublication Proposed Rule (EPA 2001d); Executive Order 13158; CWA (Section 403, 33 USC 1343), Ocean Discharge Criteria

Lead player: EPA

Issue discussion: Under the CWA, point-source discharges to waters of the United States must have a NPDES permit. The NPDES permit requires compliance with technology- and water-quality-based treatment standards. In addition, discharges to the territorial seas and beyond must comply with Section 403 of the CWA and meet additional requirements intended to ensure that sensitive ecological communities are protected.

In 1980, the EPA developed Ocean Discharge Guidelines (40 CFR Part 125, Subpart M [45 FR 65942], October 3, 1980), which specify the factors (ecological, social, and economic) for permit writers to consider when evaluating the impact of a discharge on the marine environment.

On May 26, 2000, then President Clinton issued Executive Order 13158, “Marine Protected Areas,” which, among other things, required the EPA to “expeditiously propose new science-based regulations, as necessary, to ensure appropriate levels of protection for the marine environment.”

On January 19, 2001, then EPA Administrator Carol Browner signed the prepublication version of the proposed rule to amend existing regulations implementing Section 403 of the CWA, the ocean discharge criteria (EPA 2001d). On January 20, the EPA withdrew the proposal from the *Federal Register* to give the new EPA Administrator an opportunity to review it. The proposal would establish baseline water quality standards for ocean waters beyond 3 mi offshore, designated as “Healthy Ocean Waters.” Healthy ocean waters would be protected by both a narrative statement of water quality and pollutant-specific numeric criteria. Discharge permits for these waters issued or reissued after the effective date would need to comply with new water quality standards and an antidegradation policy. The rule would strengthen permit requirements to discharge to any ocean waters by requiring permit requesters to consider alternative disposal sites, and would require that no discharge permit be issued unless sufficient information exists to evaluate the impacts of the proposed discharge. The rule would also establish a new class of waters, SOSs, considered to be of outstanding value and within which new discharges and significant expansions (20% or greater increase in loadings) of existing discharges would generally be prohibited. The rule identifies four such areas and establishes a process for identifying and establishing additional SOSs. The rule would apply to any facility or activity where there is a discharge of a pollutant from a point source into ocean waters — that is, facilities that have or need an NPDES permit. It would apply both to individual permits and to general permits controlling discharges from oil and gas exploration, development, and production operations. The EPA estimates that 2,761 entities are covered under oil and gas general permits (EPA 2001d).

Ocean discharge requirements could have significant cost and schedule impacts on natural gas exploration and development projects. It is possible that some permits for offshore facilities could be denied. Amounts of potentially affected natural gas cannot be estimated until the EPA discusses or proposes actual requirements. The EPA has been “tweaking” the proposal and plans to send a revised proposal to OMB for review by the end of February 2002. OMB will have a 90-day review period. The May 2003 Regulatory Agenda indicated that the EPA had withdrawn the rule and plans no further action (EPA 2003b).

3.3.11 Particulate Matter Regulations

Summary: In 1997, the EPA promulgated NAAQS for fine particulate matter (PM_{2.5}). The EPA is considering updating that standard, and some states are implementing stricter regulations. Many diesel-powered engines used at CBM production sites emit PM, and if those emissions were further restricted, more costly new, alternative, or refitted power sources might be required. Depending on the type of regulation, limits on particulate emissions from diesel and gasoline engines could slow the development of CBM.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Permitting

Estimated affected natural gas resources (TCF): 7.2

Estimate type: Technically recoverable

Estimate date: 01/1995 **Estimate reference:** Whitney (2001)

Estimate comments: The estimate is for technically recoverable CBM in the Rocky Mountain region. Any regulations that require the use of equipment and technologies to prevent exceeding NAAQS particulate standards could limit production in this area.

Statutory/regulatory citation: CAA; NAAQS; state regulations

Lead players: EPA, states

Issue discussion: PM consists of solid particles and liquid droplets found in the air. Particulates less than 2.5 µm in diameter (PM_{2.5}) are referred to as “fine” particles, and sources include fuel combustion from motor vehicles, power generation, and industrial facilities. They can also be formed when combustion gases are chemically transformed into particles. Particulates larger than 2.5 µm in diameter are referred to as coarse particulates. Sources of coarse particulates include

wind-blown dust, vehicles traveling on unpaved roads, materials handling, and crushing and grinding operations.

Nonattainment areas are geographic areas that do not meet the NAAQS for one or more of the criteria air pollutants, including particulates. As CBM and other natural gas resources are developed, the potential for increased particulate emissions grows, and with it the potential to push areas into nonattainment status, which could result in limiting emissions sources. Increased natural gas development and particularly CBM development, in areas not served by existing infrastructures, often leads to greater use of diesel-powered generators, new road construction, and new pipeline construction, all of which increase the generation of particulates and can affect visibility. Wyoming and Montana may begin regulating sources to prevent areas from becoming nonattainment, and such regulations could limit natural gas resource development in the Rocky Mountain region (Easton and McVehil 2001).

In 1997, the EPA added two new PM_{2.5} standards: 15 µg/m³ for the annual standard and 65 µg/m³ for the 24-hour standard, which is designed to allow for unusual occasional daily spikes. The EPA is collecting data on PM_{2.5} concentrations and is expected to designate areas that do not meet the new PM_{2.5} standards as nonattainment. It may also propose new standards that may be more stringent than the existing standards, because new research indicates that there is no threshold below which serious health effects are not seen; measurable health impacts have occurred at concentrations as low as 2 µg/m³. New standards are not expected before the spring of 2004, as the criteria document for PM is being revised and must undergo additional review before standards can be set.

Even without the EPA standard, states can issue standards that may affect natural gas production. For example, the Wyoming Department of Environmental Quality is investigating diesel-powered generators used during CBM production. The state recently became aware that about 300 portable diesel generators are used in drilling, and the emissions from so many generators could exceed state or federal standards. It is likely, that with increased CBM development, the number of such generators, along with the particulate emissions they release, is likely to increase. In June 2002, the California Air Resources Board approved a new annual average limit of 12 µg/m³ for PM_{2.5} (3 µg/m³ lower than the federal standard) and new standards for PM.

3.3.12 Pipeline Gathering Line Definition

Summary: The Pipeline Safety Act of 1992 requires the DOT to define the term “gathering line” and to consider the merits of revising pipeline safety regulations for such lines. The issue is complex, and the current definition, adopted in 1970, lacks clarity. The definition could require more lines and facilities to become subject to the federal gas pipeline regulations, which could be costly for small operators and could affect upstream gas flows.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production, transportation

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: Pipeline Safety Act of 1992 (1996 Amendments) (49 USC 601)

Lead player: OPS

Issue discussion: Since 1974, the DOT's OPS has been working to clarify the definition of a gas "gathering line" to distinguish it from a transmission line and a distribution line, as the various lines are subject to different jurisdictions and regulatory requirements, with gathering lines being subject to less stringent requirements. In 1970, a definition was adopted as part of the Natural Gas Pipeline Safety Act of 1968. In 1974 and 1991, the OPS proposed rules to revise and clarify this definition, since it was interpreted inconsistently. In the 1996 amendments to the Pipeline Safety Act of 1992, Congress directed the DOT to define the term gathering line. In March 1999, the DOT issued a request for public input on whether and how to modify the definition of a gas gathering line and the regulatory status of such lines. The DOT was to have issued a new proposal for the definition by December 2002, but as of this writing, the original 1970 definition remains in effect.

The number and nature of lines included in the definition will affect the number of facilities that will be subject to federal pipeline safety standards. These standards are being developed for interstate transmission lines and will require risk analysis, periodic inspections and reinspections, and corrective action where necessary. These regulations may be very costly for small lines in remote areas where there are few risks of human injury from pipeline incidents. Expanding the requirements to rural gathering lines will likely impact marginal wells, because the increased compliance costs will be passed on to marginal well operators through pipeline gathering costs. These increased costs could lead to the plugging and abandonment of a significant number of these wells. Meeting nationwide construction and operating specifications may also be difficult in some cases where gathering lines are used. For example, in comments to the RSPA on the 1991 proposed gathering line definition, one association explained that its gathering lines were constructed to a safe, but different, standard from that required for transmission lines. It referred to the fact that at the request of the FS, many of the gathering lines in Ohio are plastic and were laid above ground to minimize environmental impact on the forest areas.

One definition of a gathering line suggested to the OPS was developed by the National Association of Pipeline Safety Representatives (NAPSR). The API has estimated that the NAPSR definition would reclassify 197,000 mi of existing rural gathering lines as transmission pipelines and could cost the industry \$630 million in implementation costs and \$105 million annually for compliance. An alternative definition, suggested by a coalition of several pipeline organizations, including the API, the Gas Processors Association, the IPAA, and the Appalachian Producer Organizations, is based on the function performed by the pipeline

(Simpson 1999). The OPS is currently evaluating data and information for development of the gathering line definition.

The regulation could affect a significant portion of gas gathering lines and result in increased costs or delays for gas in these lines. The amount of gas that could be affected was not estimated.

3.3.13 Regional Haze Rule

Summary: In July 1999, the EPA promulgated final regional haze regulations for protecting visibility in national parks and Wilderness Areas. These rules require states to establish goals for improving visibility in these areas and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment (e.g., SO₂, NO_x, and particulates). The goal is to reduce visibility impairment in these areas to natural levels by 2065.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CAA (Sections 169A and 169B 42 USC 7491 and 7492); 64 FR 35713, July 1, 1999

Lead players: States, EPA

Issue discussion: The CAA enacted goals for visibility in many areas, and the 1977 CAA Amendments established the following national goal for visibility: to prevent any future and remedy any existing impairment of visibility that results from man-made pollution in mandatory Class I federal areas. (Class I areas include 156 specific national parks, Wilderness Areas, national memorial parks, and international parks.) The amendments also required that the EPA issue regulations to assure “reasonable progress” toward meeting the national goal. According to the EPA’s July 1999 regional haze rule, states must develop new State Implementation Plans (SIPs) to reduce emissions contributing to regional haze, to improve visibility during significant haze pollution episodes, and to protect against degradation even on relatively clean days. SIPs are to require either the installation and operation of best available retrofit technology (BART) for certain sources, or alternative emission reduction programs. States must submit SIPs by 2008, although exact deadlines vary (depending on attainment status for particulates and whether the state is participating in a multistate regional planning effort). Subsequent SIP revisions are required in 2018 and every 10 years thereafter. With each revision, the state is to set new progress goals and strategies (EPA 1999d).

The CAA of 1977 also required the EPA to establish a Visibility Transport Commission for areas affecting the visibility of the Grand Canyon National Park. In 1991, the EPA established the Grand Canyon Visibility Transport Commission (GCVTC), and in 1996, the GCVTC issued a report containing recommendations for protecting visibility at 16 Class I areas on the Colorado Plateau. In its 1999 rule, the EPA allowed the nine transport region states to adopt the national rules promulgated by the EPA or those based on the work of the GCVTC, as well as additional requirements outlined in the rule. These requirements include quantitative emission reduction milestones for SO₂ (EPA 1999a). However, concerns exist regarding the models being used to set these milestones. Similar issues may exist for other regional and state planning bodies. As a result, there are significant concerns about how the states will actually implement the EPA rules, and natural gas operations are likely to be among the sources to which these new requirements will apply.

In general, the national regulations focus on BART, or retrofit technologies, while the GCVTC approach focuses on market trading. States must decide by 2003 which approach they will take. It is unclear at this point which approach would have a greater impact, but both are expected to significantly affect natural gas operations.

The principal man-made sources likely to be subject to emissions reductions are large manufacturing facilities, electric utilities, and mobile sources. However, for western states, where such sources are relatively few, other sources such as natural gas and CBM operations are likely to be targeted. Haze-forming pollutants can travel large distances, and states with no Class I areas are required to consider the effects of their emissions on Class I areas in other states. However, because the prevailing wind direction is from the West, it is not likely that emission reductions in the East would affect visibility impairment in the West, where natural gas production is projected to increase, further increasing the likelihood that emissions from natural gas operations will be targeted for emissions reductions (IOGCC 2001b).

Also, although the primary target is SO₂, if the milestones cannot be reached by reducing SO₂ emissions alone, states must look to other haze-forming pollutants such as NO_x and PM. NO_x in particular is emitted in large quantities from compressor stations and gas processing plants.

In February 2002, industry plaintiffs sued the EPA in the U.S. Court of Appeals for the District of Columbia, arguing that the EPA overreached its authority in issuing the haze regulations. On May 24, 2002, the Court found that the rule's BART provisions were inconsistent with the CAA. It said that the CAA requires states to consider the degree to which visibility will be improved when deciding whether a particular source should install BART controls, but that the rule does not allow states to consider visibility in forcing BART controls. As a result, the court is requiring that the EPA redraft the BART provisions, which used a "group approach" that would have required all sources in a geographical area to have controls rather than allowing states to determine BART requirements on an individual source basis. Nonetheless, the court affirmed the overall regional haze program. Because BART requirements pertain mostly to larger sources built before 1977, the remand is not likely to have a significant impact on natural gas operations. Indeed, if these sources are not required to implement BART,

greater emissions reductions may have to come from other sources, such as natural gas (Doman 2002).

In February 2002, the EPA released a congressionally mandated report on visibility improvements in Class I areas (required every 5 years) that found little progress in visibility improvement. Environmental groups are using this information to urge strong aggressive action to control regional haze (EPA 2001c).

On May 22, 2003, the EPA issued a final rule implementing the WRAP, which applies to nine western states and is intended to reduce SO₂ emissions by more than 40% from 1990 levels. The WRAP plan, or WRAP annex, uses a “nonregulatory” approach, in which participating states would implement measures to reduce SO₂ in order to meet annual milestones (EPA 2003c).

This issue could have significant cost impacts on natural gas operations in the West, possibly limiting production in some areas. Depending on how the states write their implementation plans, potentially large amounts of gas in the West could be at risk.

3.3.14 Spill Prevention Control and Countermeasures

Summary: On July 17, 2002, the EPA issued a final rule that amended the spill prevention, control, and countermeasures requirements, originally promulgated in 1974 under the EPA’s Oil Pollution Prevention regulations at 40 CFR Part 112. While the expanded scope and relatively short compliance deadlines of the new rule will primarily affect oil production and operations, natural gas drilling and production operations will also be affected, potentially causing some small operators to leave the business and limiting the ability to rework some existing properties to extract additional gas resources.

Source of Constraint: Regulatory

Impact: Cost

Phase: Production

Category: Permitting

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CWA (Section 311, 33 USC 1321); 40 CFR 112; 67 FR 47042, July 17, 2002; 69 FR 48794, August 11, 2004

Lead player: EPA

Issue discussion: The July 17, 2002, rule, which applies to onshore and offshore gas E&P facilities, required amended Spill Prevention Control and Countermeasures (SPCC) plans to be

in place by February 17, 2003, and new plans to be in place by August 17, 2003 (EPA 2002d). An SPCC plan is required if a facility could cause a release of oil that would reach navigable waters. According to the IPAA, the terms “navigable waters” and “facility” are confusing to many E&P operators (IPAA 2003).

Some of the reported uncertainty stems from a series of judicial decisions relative to the definitional reach of the term “navigable waters.” In 2001, the U.S. Supreme Court, in *Solid Waste Agency of Northern Cook County (SWANCC) v. United States Army Corps of Engineers*, 531 U.S. 159 (2001), overturned the COE’s assertion of federal jurisdiction over certain isolated wetlands based on the presence of migratory birds. The Court held that the provision of the CWA that requires those who discharge fill material into navigable waters to obtain a permit from the COE does not extend to isolated, abandoned sand and gravel pits with seasonal ponds that provide migratory bird habitats. Chief Justice Rehnquist explained that “[t]he term ‘navigable’ has...the import of showing us what Congress had in mind as its authority for enacting the CWA: its traditional jurisdiction over waters that were or had been navigable in fact or which could reasonably be so made.” Subsequent decisions at the circuit court level suggest conflicting approaches. The Court of Appeals for the Fourth Circuit and the Court of Appeals for the Sixth Circuit affirmed CWA jurisdiction over drainage ditches, intermittent tributaries, and isolated wetlands that have any type of surface water connection to regulated “navigable waters,” no matter how attenuated — *United States v. Deaton*, 332 F.3d 698 (4th Cir. 2003); *United States v. Rapanos*, 339, F.3d 447 (6th Cir. 2003); *Newdunn Associates v. Army Corps of Engineers*, 344 F.3d 407 (4th Cir. 2003). The Court of Appeals for the Fifth Circuit, on the other hand, in cases involving the definition of navigable waters under the Oil Pollution Act, ruled that the SWANCC decision reigned in the historic expansion of the COE’s jurisdiction — *Rice v. Harken Exploration Co.*, 250 F.3d 264 (5th Cir. 2001); *In re Needham*, 354 F.3d 340 (5th Cir. 2003). Because the U.S. Supreme Court has declined petitions to review the decisions by the Fourth and Sixth Circuits, some practitioners suggest that the COE will likely continue asserting jurisdiction over wetlands and other nonnavigable water bodies that are geographically remote from navigable surface waters but that have some hydrologic connection to those waters — through man-made ditches, culverts, and various types of seasonal or intermittent drainages.

On January 15, 2003, the EPA and the COE issued a joint memorandum to provide clarifying guidance regarding the SWANCC decision and to address several of the legal issues that had surfaced since SWANCC (COE and EPA 2003). However, consistent application of that guidance has been questioned (Fuller 2003).

Also on January 15, the EPA and the COE issued an advance notice of proposed rulemaking on the regulatory definition of “Waters of the United States” (COE and EPA 2003). The intent of these agencies was to develop proposed regulations that would “further the public interest by clarifying what waters are subject to CWA jurisdiction and affording full protection to these waters through an appropriate focus of federal and state resources consistent with the CWA.” After receiving more than 125,000 comments on the advance notice, the EPA and the COE announced on December 16, 2003, that they would not pursue the rulemaking.

The uncertainty over the regulatory definition of navigable waters, questions about the guidance, and the conflicting court decisions can affect SPCC plans and any other regulations

that are triggered by actions that affect navigable waters. These include NWRs under the dredge and fill program, storm water construction permits under the NPDES program, and TMDL requirements under water quality standards and implementation plans.

Interpretation of the term “facility” is also a concern with the SPCC rule. According to the IPAA, the EPA estimates that roughly 144,000 oil and gas upstream operations would require SPCC plans. Most producers, however, believe that the SPCC definition of a facility would capture most of the estimated 870,000 producing oil and gas wells in the United States. The IPAA estimates that about 635,000 of these producing wells are stripper wells, which are highly vulnerable to the impact of excessive regulatory costs. It suggests that many of these wells could be shut down if the new SPCC plan requirements are too costly.

Other issues of potential concern to gas E&P operations include the following:

Consideration of costs. Although past interpretations of the SPCC plan requirement allowed operators to consider costs in determining the practicability of meeting the new requirements, the new regulation states that it is not appropriate to allow an owner or operator to consider costs in determining whether the secondary containment requirements can be satisfied. At \$25.00 per barrel, the average marginal well, which produces 15 barrels per day or less, grosses about \$20,000 annually and incurs operating costs of about \$17,400. With estimated SPCC plan costs ranging from \$5,000 to \$20,000, the economic viability of marginal wells becomes of concern (IPAA 2003).

Produced water. According to the new rule, if produced water exhibits an oil sheen, it will be treated as oil and, therefore, included in the threshold to determine if an SPCC plan is required. An SPCC plan is required if more than 1,320 gallons of oil could reasonably be expected to be discharged from the facility to navigable waters. Independent gas operators suggest that even if compliance costs were as low as \$3,000 per plan, this requirement could put some small operators out of business (Holliday 2003).

Newly purchased properties. The rule contains no provision that would allow an operator to buy an existing property and prepare a plan if one is not already in place. An existing property cannot be sold without an SPCC plan after a certain date. As a result, the ability to sell (and buy) oil- and gas-producing properties without existing SPCC plans will diminish, thereby limiting the amount of land acquired by many small independent operators for the purposes of extracting additional gas. The amount of gas for which access is denied by this provision is not known. However, it is estimated that thousands of properties are traded among small independent producers who have developed techniques to increase production at existing properties. Although the new rule may not significantly impact the number of new wells drilled (because the incremental cost of preparing a plan will not be great relative to the overall exploration and drilling costs), in cases where additional wells may be drilled to extract marginal gas from existing fields, the additional cost of preparing an SPCC plan may be enough to preclude the drilling of such wells.

On August 11, 2004, the EPA published a notice in the *Federal Register* extending the compliance date for amended SPCC plans to be in place to February 17, 2006, and stating that new plans be in place by August 18, 2006 (EPA 2004f).

3.3.15 Standards for Decommissioning or Closing Wells

Summary: As gas production from a producing well diminishes or becomes uneconomical, the well must be decommissioned or closed according to the regulations set forth by the appropriate state environmental regulatory agency or oil and gas commission. Typically, these regulations specify contaminant-specific concentrations that cannot be exceeded after closure is complete. These concentrations can vary from state to state, and they are usually set on the basis of technology, background concentration, or other nonrisk-based measures. Thus, they can be overly protective and costly to implement, without providing significant gains in environmental or human-health protection.

Source of Constraint: Regulatory

Impact: Cost

Phase: E&P

Category: Operations

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: State regulations

Lead player: States

Issue discussion: An estimated 400,000 to 600,000 E&P sites exist in the United States, many of which have been operating for 50 to 100 years. During their operations, hydrocarbons, inorganic salts, and drilling fluid constituents may have entered the surface and subsurface soils and groundwater at or near the sites. States generally set contaminant concentration limits for the different media. However, the lack of data on the risks of these contaminants often means that cleanup levels are set on the basis of available technologies, background concentrations, or other measures. As a result, they can often be set lower (more restrictive and costly to meet) than necessary to protect human health and the environment. For example, some states, such as Colorado, Louisiana, and Michigan, set standards for total petroleum hydrocarbons (TPH) in soil at 10,000 mg/kg, while other states, such as Wyoming, have levels as low as 250 mg/kg. Innovative methodologies for determining the risks associated with TPH indicate that TPH action levels of 1,000 mg/kg or less are overly conservative and should be reevaluated (Nakles et al. 1998). Similar studies may indicate similar results for other contaminants. Such findings suggest that the overly conservative, non-risk-based levels should be revised to consider land use and other risk factors to prevent unnecessarily costly remediation efforts that provide no significant environmental benefit. Risk-based concentrations will consider such factors as size

and location of operations (upstream operations can be small scale and remote, thereby posing lower risks than downstream operations that are closer to human population centers) and characteristics of the condensates (lighter hydrocarbons are present upstream, with the heavier hydrocarbons more likely to be found downstream). By using state-of-the-art approaches for risk assessment of contaminants at E&P closure sites, decommissioning standards can be developed that will provide for well closure in a cost-effective manner that results in acceptable risks to human health and the environment. Non-science-based closure requirements alone will likely have little impact on natural gas exploration, production, or transportation. However, for operators at the margin, additional costs because of such requirements, especially if combined with other requirements, could cause certain operators to cease production, thereby reducing the amount of gas produced, or ultimately increasing the price of that gas.

Decommissioning standards indirectly affect industry — if such requirements are too strict, some smaller operations may drop out.

3.3.16 Storm Water Construction Permits

Summary: The EPA has proposed extending the deadline for obtaining storm water permits under the CWA by 2 years, from March 10, 2003, to March 10, 2005, to determine the appropriate NPDES requirements, if any, for constructing oil and gas E&P facilities of 1 to 5 acres. If all oil and gas E&P facilities of 1 to 5 acres were required to obtain such permits, as originally proposed in 1999, the costs and delays to oil and gas production could reduce the number of wells drilled and the amount of gas produced.

Source of Constraint: Regulatory

Impact: Cost

Phase: E&P

Category: Permitting

Estimated affected natural gas resources (TCF): 5.75 per year

Estimate type: Economically recoverable

Estimate date: 09/2002 **Estimate reference:** Texas Alliance of Energy Producers (2003)

Estimate comments: The EPA states that there are 30,000 oil and gas well starts per year, but does not distinguish between gas and oil. At 15,773,600 MCF per day, the annual delayed production would be 5.75×10^9 MCF, or 5.75 TCF.

Statutory/regulatory citation: CWA Section 402 (p) (33 USC 1342(p)); 40 CFR 122.26

Lead player: EPA

Issue discussion: Section 402(p) of the CWA directed the EPA to develop a phased approach for regulating storm water discharges under the NPDES program. In November 1990, the EPA published a final regulation for Phase I of this program, which established permit application requirements for “storm water discharges associated with industrial activity.” Under 40 CFR 122.26(b)(14)(x), construction activities that disturb 5 acres of land and greater are considered “industrial activity.” On December 8, 1999, the EPA published final regulations (EPA 1999b) for Phase II of the storm water program, which covers sites disturbing between 1 acre and 5 acres (40 CFR 122.26(b)(15)(i)). The rule requires that discharges from these sources have permits by March 10, 2003 (40 CFR 122.26(e)(8)).

NPDES permitting authorities are to use existing Phase I permits to guide their development of Phase II permits. As such, expected requirements from applicants would include a Notice of Intent, a storm water pollution prevention plan with appropriate best management practices to minimize discharge of pollutants from the site, and a Notice of Termination. Because gas (and oil) E&P facilities are generally less than 5 acres, they have not been required to obtain storm water construction permits in the past; the Phase II rules would require such facilities to obtain the permits. NPDES permitting authorities can waive the requirements for operators of small construction activities if the site has (EPA-defined) low predicted rainfall potential or if the EPA determines that pollution load allocations are not needed to protect water quality. The EPA acknowledges, however, that many sites would be unable to take advantage of these waivers.

The Texas Independent Producers and Royalty Owners Association (TIPRO) estimates that an average NPDES permit would require at least 6 months to obtain and would include an ESA determination, an NHPA determination, and a site-specific storm water pollution prevention plan (TIPRO 2002). The Texas Alliance of Energy Producers states that most independent producers measure drilling plans in days rather than months, and that many smaller companies will find the new procedures so frustrating and time-consuming that they will not drill many of the wells they had planned (Texas Alliance of Energy Producers 2003). The Alliance also estimates that in the first year of implementation, U.S. natural gas production would decline by 15,773,600 MCF per day, and the number of gas (and oil) wells drilled would decrease to 25,034 from 38,527 in 2001, or by more than a third (Mills 2002). It further states that virtually all drilling sites are larger than 1 acre but smaller than 5 acres, and, therefore, all future drilling locations would be subject to the storm water regulations. The Alliance also estimated that the rules would result in a 70% reduction in drilling for independents and 40% for major companies. The dramatic decline for independents is because “Independents have had their staffs cut to the bone,” do not have specialists that know the “ins and outs” of acquiring a federal permit, and will have to hire consultants to prepare the permit applications, which will increase costs and significantly delay the time before drilling can occur (Texas Alliance of Energy Producers 2003).

In addition to the immediate issues associated with obtaining storm water permits, there is a debate over whether construction activities at oil and gas E&P sites are covered by the exemption in CWA (33 *United States Code Annotated* [USCA] Section 1342(1)(2)), which states that no permit shall be required “for discharges of storm water runoff from mining operations or oil and gas exploration, production, processing, or treatment operations or transmission facilities, composed entirely of flows which are from conveyances . . . used for collecting and conveying precipitation runoff. . . .” Industry maintains that there is no definition or language in the act that

suggests construction activities should be considered separate from the terms exploration and/or production or in the regulations to support the EPA's position that such terms should be narrowly construed (Briggs 2002).

On March 10, 2003, the EPA extended the storm water permit deadline for oil and gas construction activity that disturbs 1 to 5 acres from March 10, 2003, to March 10, 2005. The EPA granted this extension at least in part because of information submitted by DOE and industry that said that each year about 30,000 oil and gas sites could be subject to the regulations (Bruninga 2003). Acknowledging the differences between the nature of construction at oil and gas sites and at residential and commercial property development sites, the EPA plans to determine whether these differences are significant enough to warrant different regulations for oil and gas sites. During the extension period, the EPA plans to analyze and better evaluate the impact of the permit requirements on the oil and gas industry. It will identify appropriate best management practices for preventing contamination of storm water runoff resulting from construction associated with oil and gas exploration, production, processing, or treatment operations or transmission facilities, and assess the applicability of the exemption in the CWA to construction associated with these activities (EPA 2003d). The results of the analysis will help determine the extent to which oil and gas facilities will have to comply with the potentially costly and time-consuming requirements for obtaining storm water permits.

3.3.17 TMDL Regulations Targeting Oil and Gas Wells

Summary: Gas (and oil) wells may be targeted for TMDL limits because large point sources are already regulated, and technical and political factors argue against imposing limits on large nonpoint sources such as agricultural lands. Also, proposed changes to the TMDL rule could limit the use of nationwide construction permits under Section 404 of the CWA.

Source of Constraint: Regulatory

Impact: Cost

Phase: E&P

Category: Permitting

Estimated affected natural gas resources (TCF): Not estimated.

Statutory/regulatory citation: CWA Section 303(d) (33 USC 1313(d)); 40 CFR Part 9; 65 FR 43587 (July 13, 2000)

Lead player: EPA

Issue discussion: Although the EPA's point-source control program for water pollution has been successful, nonpoint source control has been elusive. The EPA's TMDL program is an effort to address nonpoint-source pollution of water bodies. Section 303(d) of the CWA requires states,

territories, and authorized tribes to identify (list) waters that are not meeting water quality standards and to establish pollutant budgets (TMDLs) to restore those waters. A TMDL is the sum of the allowable loads of a single pollutant from all contributing point and nonpoint sources to a given stream segment. The calculation must include a margin of safety to ensure that the water body can be used for its designated purposes. The calculation must also account for seasonal variation in water quality. If a state, territory, or authorized tribal submission is inadequate, the EPA must identify the waters and establish the TMDL. Once a TMDL has been established, the state, territory, or tribe must allocate the TMDL to individual sources.

The gas (and oil) industry may be vulnerable to TMDL allocations. The reason is that for a typical stream, large point sources are likely to be sufficiently controlled, but agricultural and forest nonpoint source control will likely be deferred until technically and politically acceptable control strategies are developed. Thus, small, nonpoint sources, for example, gas (and oil) wells, could become targets, because the construction work they require can generate runoff, even when managed properly (Stewart 2001).

Potential changes to the existing rule could also impact natural gas operations. In August 1999, the EPA proposed changes to the TMDL, and on July 13, 2000, the EPA promulgated a final TMDL rule after considering more than 34,000 comments (EPA 2000). Several parties have since challenged the rule in court. On July 16, 2001, the EPA asked the District of Columbia Circuit Court to hold action for 18 months to allow the agency to review and revise the rule (Woods 2001). On October 12, 2001, the District Court agreed. On October 18, the EPA announced that the effective date for the revisions to the TMDL program published on July 13, 2000, would be April 30, 2003 (EPA 2001e). The effective date had been October 31, 2001. The delay will allow the EPA to incorporate recommendations made by the National Research Council into the TMDLs. In addition, the rule revises the date on which the next list of impaired waters is to be submitted from April 1, 2002, to October 1, 2002. The states and the EPA continue to develop TMDLs under the original rules issued in 1992. As of November 2002, more than 22,000 impaired waters had been reported, and 6,644 TMDLs had been approved nationwide.

According to the American Gas Association (AGA 2000), changes to the existing (1992) TMDL rules proposed in 2000 would have, among other things, expanded the scope of impaired waters by including waters impaired for “unknown causes” (EPA 1999c). Nearly 2000 state CWA 303(d) lists include impaired waters for which the parameter of concern is “unknown.” Many listings with unknown causes may be based on limited observations, faulty assumptions, or outdated information. Expanding the lists could result in increased costs and schedule delays for construction permits for gas utility and pipeline crossings required under Section 404 of the CWA. This is because utilities typically use NWP to obtain streamlined approvals for gas pipeline installation and maintenance projects. The COE proposed changes to the rules for NWPs (COE 1999), which state that under proposed General Condition 26, a project affecting a listed “impaired water” will not qualify for an NWP without an explanation of how the project (excluding mitigation) would not further impair the water body. This condition would apply to NWP 12, which provides streamlined permitting for utility line projects. The COE acknowledges that given the number of waters already listed as impaired, the new condition will “substantially reduce” the availability of NWP 12. Expanding the list to include waters impaired for unknown

causes will further reduce the availability of NWP 12, because it would be impossible to explain how a project may or may not contribute to impairment due to unknown causes.

One industry source reported that although his company had met all the requirements for an NWP (which is less costly and time-consuming than an individual permit), the COE denied the NWP, stating that an individual permit was needed to address “the new antidegradation water quality requirements” (SWS Forum 2001).

4 CONCLUSIONS

Numerous environmental policy and regulatory constraints currently affect natural gas E&P and transportation. Additional constraints may accrue as more environmental regulations are written. The constraints take several forms, including individual laws and regulations that directly affect natural gas access or production. They also include presidential policies and actions taken by implementing agencies. As environmental issues surface, additional regulations are written, and many may potentially constrain domestic natural gas production. The amounts of gas affected by denying or limiting access, delaying permits or production, and increasing costs can be significant. Where constraints overlap, small operators may cease operations, leading to possible further delays and reductions in marginal gas production.

4.1 LEGISLATIVE AND REGULATORY CONSTRAINTS

Specific laws, such as the CZMA, whose consistency provisions can allow states to effectively prohibit development already approved by federal entities, and the ESA, whose court-interpreted definitions extend protected areas, can limit development on both private and federal lands. The Antiquities Act allows the President to designate national monuments on which no exploration or production may occur, even if the lands they overlie contain known natural gas resources. EFH regulations, whose requirements can duplicate those of other federal regulations, can delay leasing or permitting decisions, and the Roadless Rule, which prohibits road construction in roughly one-third (58.5 million acres) of the NFS, denies access to an estimated 11 TCF in the Rocky Mountain region.

4.2 AGENCY ACTIONS

Once Congress passes a law and the responsible agencies have written the implementing regulations, local enforcement agencies can, through their own policies and procedures, delay or prohibit gas production. Federal land management agencies, such as the BLM and the FS, control development on their respective lands through land use planning documents. If these documents do not specifically provide for oil and gas drilling, the agencies can prohibit such drilling until the plans are updated, adding months or years to the time before extraction from a leased site can begin. Similarly, when granting drilling permits, the land management agencies can impose stipulations, which, when added together at a given site, can narrow or effectively close the window of opportunity to drill. Compounding these problems are requirements to gain approval from other federal, state, and local agencies before a permit can be issued. As the number of permit applications grows, the ability to coordinate among the various agencies in a timely fashion diminishes, further increasing delays. This concern is particularly important for interstate natural gas pipelines, which are critical for transporting gas to users. FERC grants certifications to build new pipelines, but only after it has received approval from other federal, state, and local agencies that have environmental jurisdiction.

4.3 LEGAL CONSTRAINTS

The legal system can compound environmental regulatory constraints. When issues cannot be resolved among participating agencies, or when special-interest groups challenge a gas-related activity, legal action can delay projects for months or years. For example, the tendency for organizations to sue over EISs has led agencies to prepare “appeal-proof documentation,” which further delays the approval process.

4.4 CONGRESSIONAL AND PRESIDENTIAL ACTIONS

Typically, laws are developed after congressional debate, and regulations require a prescribed notice and comment period. However, at times, Congress and the President can impose constraints that may not follow the formal procedures designed to allow for the expressing of concerns by all interested parties. These initiatives can significantly decrease access to natural gas. For example, Congress has enacted and presidents have extended offshore drilling moratoria. These actions not only deny the extraction of natural gas, but also deny federal agencies and others the ability to determine the extent of the resources in waters off the coasts of most of the United States. Recently enacted congressional bans on drilling in the Great Lakes and lack of congressional action to determine the status of WSAs precludes the extraction and production of gas in these areas.

4.5 NEW ENVIRONMENTAL REGULATORY CONSTRAINTS

A number of environmental rules are currently under development, and the potential impacts of these rules require active monitoring. For example, the EPA’s “nonroad diesel engine” rule could increase costs for new engines used in natural gas E&P to ensure that they meet the required emissions reductions. The EPA is also writing regional haze rules designed to protect visibility in national parks and Wilderness Areas, which could apply to drilling and production equipment and affect the ability to produce natural gas in a timely and cost-effective manner. The OPS within the DOT is writing rules to ensure “integrity management,” or structural safety of gas transmission lines. The implementation of these rules could disrupt supplies as companies are forced to meet certain inspection deadlines using specific technologies that may not be available when needed. The EPA may require oil and gas E&P facilities covering 1 to 5 acres to obtain storm water permits under the CWA.

State and federal agencies are determining whether and how to address emerging environmental issues, many of which could affect or limit cost-effective production of natural gas. For example, the U.S. Commission on Ocean Policy, established under the Oceans Act of 2000, has developed recommendations that could include new policies and authorities to address the development of ocean resources, potentially including natural gas. Other issues are closer to regulation. For example, some states have written rules to address potential impacts of discharging produced water from CBM operations to the environment. Others may follow, and such actions could severely restrict development of this source of gas, which many believe to be a significant future contributor to the nation’s energy supply. A related issue is the use of

hydraulic fracturing to increase the flow of gas, particularly CBM gas. This practice has been the subject of regulatory and legal action, and further regulatory activity can be expected. Other environmental regulations with potentially significant impacts on natural gas development include regulations for minimizing adverse environmental impacts from cooling-water intake structures at offshore oil and gas platforms; mercury regulations that could affect the use and discharge of mercury-containing drilling muds; and regulations to reduce noise generated by engines, drills, and compressors used in natural gas E&P and transportation.

Some of these constraints can have significant impacts on natural gas production on an individual basis. Others, taken alone, may not have as great an impact, but when combined with other regulations or policies, could be so costly or produce so many delays that many small, independent operators may leave the business. Whether the gas produced by these independents would then be extracted by other, larger firms, at an increased cost to them, or whether the gas would not be produced until prices increased sufficiently to warrant reentry into the market is not known. However, mitigation approaches should be developed to address not only the major impediments, such as access restrictions, but also to address the other regulations and implementing practices so that the ability to extract and distribute the gas to users in a cost-effective and environmentally protective fashion can be maintained, if not increased.

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