The mission of the Natural Resources Law Center is to *promote sustainability in the rapidly changing American West by informing and influencing natural resource laws, policies, and decisions*.

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TABLE OF CONTENTS

Acknowledgements

Coalbed Methane Development in the Intermountain West: A Primer
Gary Bryner 1

Coalbed Methane Development in the Intermountain West: Case Studies
Coalbed Methane in the San Juan Basin of Colorado and New Mexico
Catherine Cullicott, Carolyn Dunmire, Jerry Brown, and Chris Calwell, Ecos Consulting 51

Coalbed Methane Development in Wyoming's Powder River Basin
Diana Hulme, The Institute for Environment and Natural Resources, University of Wyoming 86

Coalbed Methane Development in the Intermountain West: Conference Proceedings

Keynote Addresses

Rebecca Watson, Assistant Secretary for Lands and Minerals, U.S. Department of the Interior 107

John Watts, Consultant, Senate Energy and Natural Resources Committee 112

Session I: Background and Overview

An Overview of CBM Exploration and Production
Steve de Albuquerque 117

Coalbed Methane in The Intermountain West: Yesterday, Today and Tomorrow
Matthew R. Silverman 125

The Hydrology Of Coalbed Methane Reservoirs and the Interplay of Gas, Water, and Coal In CBM Production
Leslie Nogaret 133

Federal, State, and Local Regulatory Framework for Permitting of CBM Development
Kate Zimmerman 139

CBM and Public Wildlands: How Much and at What Cost?
Pete Morton, Chris Weller, and Janice Thompson 156

Powder River Basin Coalbed Methane Financial Model 175
W. Thomas Goerold

Waste or Wast*ed*? – Rethinking the Regulation of Coalbed Methane Byproduct Water in the Rocky Mountains
Thomas F. Darin 187

Session II: The San Juan Basin

Overview of CBM issues in the San Juan Basin
Catherine Cullicott 217

Best CBM Drilling, Completion, Production Technologies, and Management Practices
Dennis Carlton 220

CBM Development and Water Issues
Dave Brown 222

CBM Development on the Southern Ute Reservation
Bob Zahradnik 228

CBM Development from the County Perspective
Josh Joswick 233

Impacts of CBM Development on Communities
Gwen Lachelt 236

CBM Development on Public Lands
Walt Brown 238

Session III: The Powder River Basin

Overview of CBM Issues in the Powder River Basin
Diana Hulme 243

The Geology and Production Characteristics of the Powder River and other CBM Basins in Wyoming
Lance Cook 245

A Review of CBM Development in the Powder River and other Wyoming Basins
Don Likwartz 251

CBM Water Management: Challenges, Solutions, and Opportunities
Mike Day 257

Developing CBM in the Powder River Basin
William T. Brown, Jr. 272

CBM Development from the Perspective of Wyoming Counties
Mickey Steward. 277

Air Quality and CBM Development
Bob Yuhnke 280

CBM Development, Ranching, and Agriculture
Nancy Sullivan and Jill Morrison 285

BLM Environmental Analysis and CBM Development on Federal Lands
Richard Zander 289

Session IV: Concluding Comments and Observations

Ayn Schmit, Coalbed Methane Coordinator, U.S. EPA Region 8 297

Michael Reisner, Northern Plains Resource Council, Montana 299

Mark Pearson, San Juan Citizens Alliance 300

Peter Dea, President & CEO, Western Gas Resources 302

Mark Sexton, Chairman, President, and CEO, Evergreen Corporation 304

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Gary Bryner
Project director
June 2002

COALBED METHANE DEVELOPMENT IN THE INTERMOUNTAIN WEST:

PRIMER

Coalbed methane is one of the most important and valuable natural resources in the Western United States. The natural gas that results from CBM development is the cleanest burning fossil fuel, and the extensive domestic supply makes it a central element of the national goal of a secure supply of energy. Demand for natural gas will continue to grow and CBM will play an increasingly larger role in meeting that demand. CBM production has expanded tremendously over the past decade, and the rapidity with which development has expanded has resulted in stresses and tension in affected communities. Development of this important energy resource must be balanced with a number of other important goals of protecting water, land, and other resources in the West. The primary purposes of the report are to: provide an overview of where CBM resources are located and how they are extracted, provide some background for understanding the issues surrounding CBM development and the role that it plays in the nation's energy policy, review the public policies affecting the production of CBM, assess the major issues that have arisen in the West concerning CBM development and its impact on local communities and other natural resources, examine lessons that might be learned from different basins and that might be applied elsewhere, and suggest some basic principles and practical steps that might serve to address some of the conflicts that have arisen in CBM basins and that might be applied to shape future development in other basins.

GARY BRYNER, *Natural Resources Law Center, University of Colorado School of Law*

Overview

Coalbed methane (CBM) is a form of natural gas that is trapped within coal seams and held in place by hydraulic pressure. The gas is adsorbed to the internal surfaces of the coal; when wells are drilled that extract the water holding the gas in place, the methane eventually flows through fractures to the well and is captured for use. Coalbed methane extraction began as an effort to reduce the threat of methane explosions in coal mines, and has been produced in commercial quantities since 1981. CBM development in the United States has grown rapidly from a few dozen wells in the 1980s to some 14,000 wells in 2000. In 1989, the United States produced 91 billion cubic feet of coalbed methane; ten years later, the total produced had grown to nearly 1.3 trillion cubic feet, representing seven percent of the total natural gas production in the United States.[1]

Some 56 percent of the total CBM production in the United States has come from the Rocky Mountains. The San Juan basin in Southern Colorado/Northern New Mexico has been the major source of CBM. Development began in 1988 and rapidly expanded by the end of the 1990s. Production has now begun to decline and companies are trying to maintain output by more intensive development. The Powder River Basin in Northeast Wyoming is the fastest growing CBM play. In 1997, the basin produced 54 million cubic feet of gas/day from 360 wells. Four years later, 5,854 wells were producing 656 million cubic feet/day. CBM resources are also being developed in the Uinta Basin in Eastern Utah, the Raton Basin in south-central Colorado, and the Piceance Basin in northwest Colorado, and major expansions of coalbed development are expected in Montana, the Green River basin in Wyoming, and perhaps other areas in the West. Colorado, New Mexico, Utah, and Wyoming may contain as much as 47 trillion cubic feet of coalbed methane, one third of the total estimated recoverable amount in the United States. According to the US Geological Survey, the United States may contain more than 700 trillion cubic feet (Tcf) of coalbed methane in place, with more than 100 Tcf economically recoverable with existing technology.[2]

The tremendous and rapid growth in coalbed methane development has posed daunting challenges for the communities in which it has occurred. The construction of new roads, pipelines, compressors, and other facilities have transformed landscapes. Air and noise pollution have become sources of conflict. Some land owners possess only surface rights; government agencies have leased the subsurface mineral rights to companies, and those rights clash with the interests of some ranchers, farmers, homeowners, and others who seek different kinds of land uses. Just as difficult as land use issues have been conflicts over the water produced from CBM development. CBM development may affect underground water quantity and contaminate aquifers, underground water supply may be diminished as dewatering occurs, groundwater may be contaminated by mineral-laden discharged water, and local ecosystems may be adversely affected by the surface release of large quantities of water. Produced water may also be a valuable source of fresh water in arid regions.

CBM development is a major issue facing federal land agencies, state governments, county commissions, energy companies, and citizens throughout the Intermountain West. Another major challenge is that of governance—how to coordinate the efforts of federal, tribal, state, and local governments that have varying interests and responsibilities for regulating CBM production.

This primer seeks to contribute to public discussion and policy making for CBM development by providing a non-technical, accessible, reference tool that explains what CBM is, examines and compares the experience of CBM development throughout the mountain West, explores options for resolving conflicts and improving policies that govern CBM development, and identifies lessons that can be learned from different areas that might help other regions better deal with the challenges posed by development. The sections of the primer focus on four major questions.

First, what is CBM, where is it located, and how is it developed? This section provides background and context for framing the issues surrounding CBM development, including the nature of CBM, its role in meeting national energy needs; the location of major CBM resources in the Interior West, including the relationship of reserves to private and public lands, including split estates and sensitive public lands, such as wilderness study areas, National Forest roadless areas, and national monuments; and the role of CBM in national energy policy.

Second, what are the problems, conflicts, and challenges associated with CBM development? Section two examines the environmental and other impacts associated with CBM development, particularly the impacts of production and distribution of CBM on local landscapes and residents and the conflicts between competing land uses and users, and the impact of CBM extraction on water quality and quantity.

Third, how is CBM development regulated? This section examines current public policies governing CBM development, including Federal clean water, natural gas, and other laws and regulations; Federal tax incentives and its implications for CBM development; state regulatory programs; and local land use, zoning, and other regulatory programs in the Intermountain states where CBM development is occurring.

Fourth, how can conflicts surrounding CBM development be reduced? This section focuses on suggestions that have been made to minimize the environmental and other impacts of CBM extraction and actions that communities, governments, and companies might take to reduce conflicts over land use and water impacts from development.

I. What is CBM, where is it located, and how is it developed?

What is coalbed methane?

Coalbed methane is a form of natural gas that is trapped within coal seams. Coalbed gas is primarily made up of methane (typically 95 percent), with varying amounts of heavier fractions and, in some cases, traces of carbon dioxide. Coals have a tremendous amount of surface area and can hold massive quantities of methane. Since coalbeds have large internal surfaces, they can store six to seven times more gas than the equivalent volume of rock in a conventional gas reservoir. [3] Coal varies considerably in terms of its chemical composition, its permeability, and other characteristics. Some kinds of organic matter are more suited to produce CBM than are others. Permeability is a key characteristic, since the coalbed must allow the gas to move once the water pressure is reduced. The gas in higher rank coals is produced as heat and pressure transform organic material in the coal; gas in low rank coals results from the decomposition of organic matter by bacteria. Figure 1 provides a simplified view of how CBM is formed.

Coalbeds are both the source of the gas that is generated and the storage reservoir once it is produced.[4] Gas

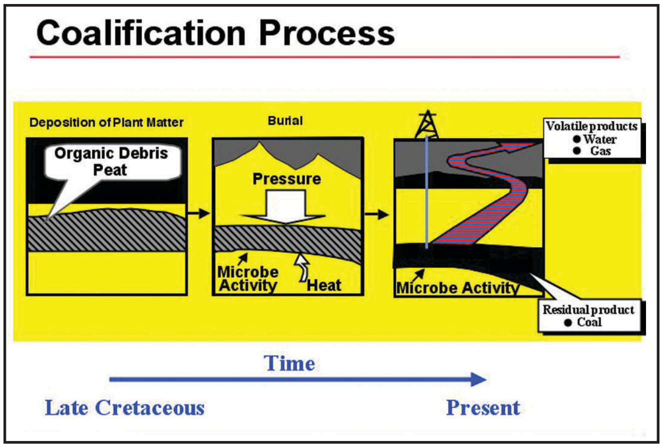

FIGURE 1 *Source: William T. Brown, NRLC coalbed methane conference, April 4–5, 2002.*

molecules adhere to the surface of the coal. Most of the coalbed methane is stored within the molecular structure of the coal; some is stored in the fractures or cleats of the coal or dissolved in the water trapped in the fractures. Coals can generally generate more gas than they can absorb and store. Basins that contain 500–600 standard cubic feet (SCF) of methane per ton are considered to be "very favorable for commercial coalbed gas production," as long as there is sufficient reservoir permeability and rate of desorption. Some coals have generated more than 8,000 SCF of methane per ton of coal. [5] The most productive coalbeds are highly permeable, saturated with gas, and fractured.[6]

Coalbed methane is produced either through chemical reactions or bacterial action. Chemical action occurs over time as heat and pressure are applied to coal in a sedimentary basin. Bacteria that obtain nutrition from coal produce methane as a by-product.[7] Methane attaches to the surface areas of coal and throughout fractures, and is held in place by water pressure. When the water is released, the gas flows through the fractures into a well bore or migrates to the surface. Figure 2 illustrates the different kinds of coal, the production of coalbed methane, and the kinds of coal found in the major CBM basins in the West.

Most coals contain methane, but it cannot be economically extracted unless there are open fractures that provide the pathway for the desorbed gas to flow to the well. Methane remains in a coalbed as long as the water table is higher than the coal.[8] These cleats and fractures are typically saturated with water, and the coal must be dewatered (usually pumped out) before the gas will flow.[9] Some coals never produce methane if they cannot be dewatered economically. Some coal beds may produce gas but be too deep to feasibility drill to release the gas. CBM wells are typically no more than 5000' in depth, although some deeper wells have been drilled to extract the gas. The deeper the coalbed, the less the volume of water in the fractures, but the more saline it becomes. The volume of gas typically increases with coal rank, how far underground the coalbed is located, and the reservoir pressure.[10]

As the fracture system produces water, the adsorptive capacity of the coals is exceeded, pressure falls, and the gas trapped in the coal matrix begins to desorb and move to the empty spaces in the fracture system. The gas remains stored in nearby non-coal reservoirs until it is extracted.[11] Drilling dewaters the coal and accelerates the desorption process. Drilling initially produces water primarily; gas production eventually increases and water

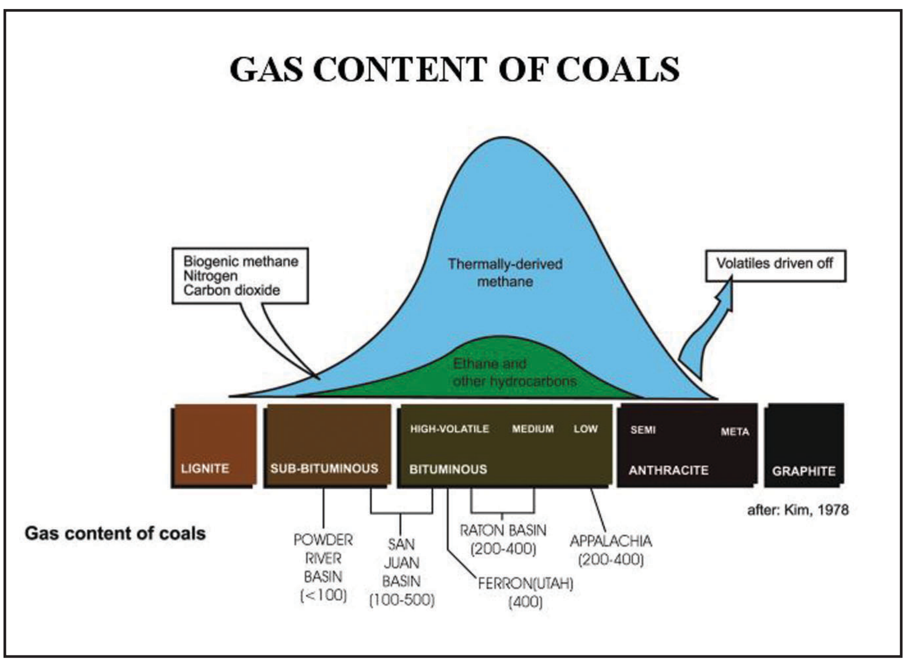

FIGURE 2 *Source: William T. Brown, NRLC coalbed methane conference, April 4–5, 2002.*

production declines. Some wells do not produce any water and begin producing gas immediately, depending on the nature of the fracture system. Once the gas is released, it is free of sulfur and usually of sufficient quality to be directly pumped into pipelines.[12]

What role does CBM play in U.S. Energy Policy?

Oil and natural gas are the dominant fuels in the U.S. energy supply, providing 62 percent of the total energy supply.[13] Natural gas provides 24 percent of the energy used in the United States and 27 percent of total domestic production.[14] The United States produces 85% of the gas it uses and imports the rest from Canada. Natural gas is used to produce 16 percent of the electricity generated in the United States, and the fastest growing use of natural gas is to produce electricity.[15] It is also used for space and water heating, cooking, fueling industrial processes, vehicle fuel, and other purposes. Natural gas prices have fluctuated considerably in recent years, affecting incentives to explore for new reserves. Prices were stable throughout the late 1980s and 1990s, and low prices in 1998 and 1999 resulted in cutbacks in exploration. In 2000, prices quadrupled, reaching an all-time high of $9.98 per million Btus in December 2000, and exploratory activity expanded accordingly.[16] Figure 3 charts the growth in natural gas and other fuels in the United States.

The average household uses about 50,000 cubic feet of natural gas each year. One trillion (1,000,000,000,000) cubic feet of natural gas is enough to meet residential needs for about 75 days. The balance of the natural gas used each year fuels electricity production and industrial and commercial operations. Demand for natural gas is currently growing at about 1 Tcf per year.[17] The Bush administration's national energy policy projects that the United States will need about 50 percent more natural gas to meet demand in 2020 and that demand will eventually outstrip domestic supply, requiring increased imports of natural gas from Canada and elsewhere.[18] The U.S. Department of Energy (DOE) on which the national energy policy projections is based suggests that natural gas use will increase between 2000 and 2020 from 22.8 to 34.7 Trillion cubic feet (Tcf); another estimate suggested consumption will climb to 31 Tcf by 2015.[19] Others project an even more rapid increase in consumption. Many executives of natural gas companies believe that by 2007 the market for gas will reach 30 Tcf.[20]

Domestic production of natural gas is expected to increase from 19.3 Tcf in 2000 to 29.0 Tcf in 2020, resulting in increased natural gas imports. According to a DOE report,

> *the most significant long-term challenge relating to natural gas is whether adequate supplies can be provided to meet sharply increased projected demand at reasonable prices. If supplies are not adequate, the high natural gas prices experienced over the past year could become a continuing problem, with consequent impacts on electricity prices, home heating bills, and the cost of industrial production. . . . To meet this long-term challenge, the United States not only needs to boost production, but also must ensure that the natural gas pipeline network is expanded to the extent necessary.*[21]

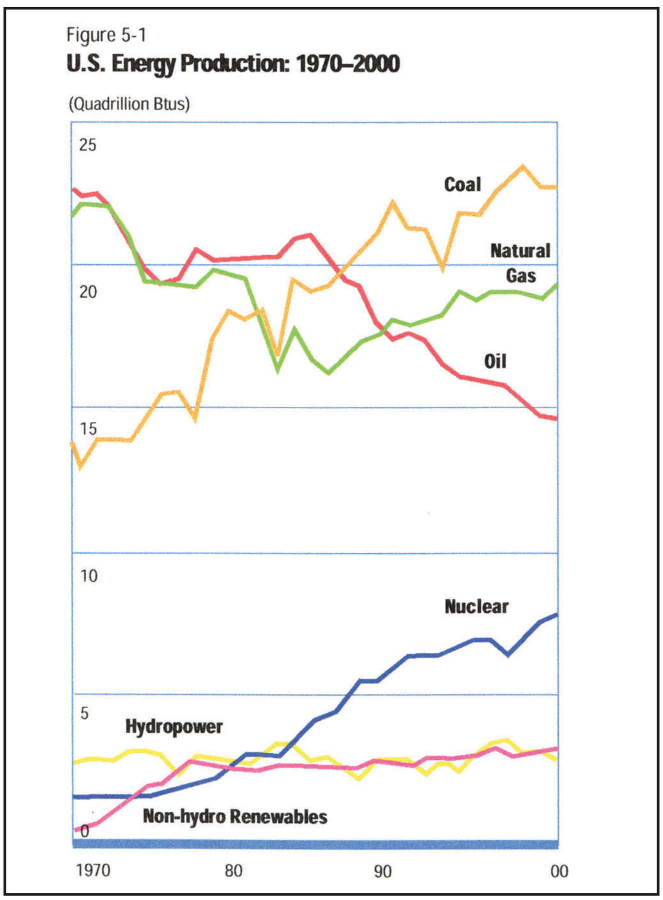

FIGURE 3 *Source: National Energy Policy Development Group, National Energy Policy, 5-1.*

Natural gas, including coalbed methane, and other domestically-produced energy sources play a major role in the Bush administration's energy policy. The administration's National Energy Policy and other policy statements all emphasize expanding U.S. sources of fossil fuels. The report includes 105 specific recommendations, including forty-two suggestions for policies to promote conservation, efficiency, and renewable energy sources and thirty-five that deal with expanding supplies of fossil fuels. The report, however, clearly emphasizes and gives priority to expanding the supply of traditional energy sources by opening new lands for exploration, streamlining the permitting process, easing regulatory requirements, and enlarging the nation's energy infrastructure. It summarizes the energy challenge this way:

Even with improved efficiency, the United States will need more energy supply. . . .The shortfall between projected energy supply and demand in 2020 is nearly 50 percent. That shortfall can be made up in only three ways: import more energy; improve energy efficiency even more than expected; and increase domestic energy supply.[22]

The Bush national energy plan argues that in the near term, increase in natural gas production will come from "unconventional sources" in the Rocky Mountain and other regions, and includes a number of recommendations that affect natural gas and CBM development. The plan:[23]

- Calls on federal agencies to promote enhanced recovery of oil and gas from existing wells, encourage oil and gas technology through public-private partnerships, reduce impediments to federal oil and gas leases, and reduce royalties and create other financial incentives to encourage environmentally sound offshore oil and gas development.
- Recommends additional oil and gas development in the National Petroleum Reserve in Alaska and the opening of an area (called section 1002) in the Arctic National Wildlife Refuge for exploration.
- Calls for streamlining the regulatory process, providing "greater regulatory certainty" for power plant operators, and reducing the time and cost involved in licensing hydroelectric power plants.
- Urges continued development of clean coal technology through a permanent extension of the research and development tax credit and investing $2 billion in research and development over ten years.
- Suggests the President issue an executive order to "rationalize permitting for energy production in an environmentally sound manner" and federal agencies "expedite permits and other federal actions necessary for energy-related project approvals."24
- Suggests the Interior Department reassess decisions it has made to withdraw certain lands from energy exploration and development, and to simplify its leasing policy so that more oil and natural gas are produced, including in the Outer Continental Shelf.
- Urges Congress to resolve the legal status of eleven million acres of BLM lands and 1.8 million acres managed by the Fish and Wildlife Service that have been designated by the agencies as wilderness study areas, and to determine which lands could be opened up to energy development.

The Bush administration's national energy policy, the energy legislation currently before Congress (passed by the House in 2001 and and Senate in the spring of 2002), and the importance of energy in the American economy and the foreign policy consequences of our reliance on imported oil all raise important and difficult policy questions that have profound implications for the American West. Energy development clashes with other values of preservation of wild lands, protection of ecoystems and wildlife habitat, and recreational and aesthetic interests, and conflicts are inevitable as people throughout the West have greatly differing views about what should happen on public and private lands. Coalbed methane is no different from that of other natural resources, in that respect, but the rapid pace of development in areas has compressed and magnified these conflicts.

How is CBM produced?

CBM was first noticed as a problem in coal mining, when fires or explosions of methane gas threatened miners. To reduce the risk of explosions, coalmine methane has been vented during mining operations. Some companies began capturing coalbed methane as a valuable resource and later, as attention came to be focused on methane as a potent greenhouse gas, coalmine methane production has been pursued as a way to help reduce the threat of climate change.

There have been some legal disputes over ownership of coalmine and coalbed methane. In *Amoco Production Company v Southern Ute Indian Tribe*, 526 U.S. 865 (1999), the Supreme Court ruled that CBM is not included in the meaning of coal; CBM is part of the gas estate not the coal estate. The Court indicated that coal companies can vent the gas while mining, but that the right to vent the gas does not imply ownership of it. The ruling is not binding on state law and private contracts. Oil and gas rights, including coalbed methane rights, are generally more senior than coal mining rights, and CBM companies may seek injunctions to ensure mining operations do not adversely affect methane extraction. In some cases, coal companies have bought out CBM leases so mining can continue unobstructed. In other cases, they complain that their operations are being held up unfairly by CBM owners who buy up gas rights and then sell them at above market prices.[25]

In 1980, Congress enacted a tax credit to encourage domestic production from unconventional sources, including CBM. Referred to as the Section 29 tax credit (section 29 of the 1980 Crude Oil Windfall Profit Tax Act), the provision has two limits: the gas must be sold to an unrelated party, and the credit only applies to wells placed in service before Dec 31, 1992. The tax credit, worth $3 barrel of oil or Btu equivalent, expired on December 31, 2000 and the tax credit is modified and extended in both the House and Senate energy bills that the two chambers passed in 2001 and 2002, respectively, and are the subject of a conference committee convened in May 2002.

CBM has been produced in commercial quantities since 1981.[26] CBM development in the United States grew rapidly from a few dozen wells in the 1980s to nearly 6,000 wells producing 1.5 Bcf by 1992. Despite the tax credit no longer being available for new wells after that time, production skyrocketed; the Gas Research Technology Institute reported in 2000 that 14,000 wells produced 1.5 Tcf of gas, representing seven percent of the total gas production in the United States.[27] In 1989, the United States produced 91 Bcf of coalbed methane. Ten years later, the total produced had grown to nearly 1.3 Tcf.[28] Figures for CBM production in the state of Colorado illustrate the rapid growth of development in the state. In 1990, CBM wells in the state produced 27 Bcf of methane; by 1995, they produced 240 Bcf; and their output steadily increased throughout the rest of the decade, reaching 417 Bcf in 2000.[29]

How does CBM compare with other forms of natural gas?

Methane is a major component of natural gas, and coalbed methane can be used in the same way as conventional gas. Conventional gas is formed in shale and limestone formations; pressure and temperature combine to transform organic matter into hydrocarbons. The gas migrates upward until trapped by a geologic fault or fold and rests in this reservoir rock until it is discovered, drilled, and extracted. The location and extent of conventional gas typically requires exploratory drilling since the location of reservoirs is not apparent from the surface.[30]

Coalbed methane is sometimes compared with another unconventional gas—"tight" gas—that is found at much deeper depths and in low permeability sandstone. Companies must use hydraulic fracturing, where they inject a fluid into a rock formation that causes cracking, in order to release gas from tight Cretaceous sands.[31] Fracturing is also used in some CBM plays to increase production, as explained below.

Coalbed methane differs from other gas reservoirs in several ways:[32]

- CBM is stored in an adsorbed state on the surface of the coal;
- Before CBM can be produced in significant quantities, the average reservoir pressure must be reduced; and
- Water is usually present in the reservoir and is normally co-produced with the CBM.[33]

The competitiveness of coalbed methane with conventional natural gas is a function of four primary variables: the rates of gas production, the production costs, markets, and economies of scale.[34]

- The rate and volume of gas production from CBM wells vary considerably. Low gas producers yield about 50 thousand cubic feet per day; high yield wells—"sweet spots" in basins produce 5 million cubic feet/day.
- Since coalbed methane wells are typically shallow (less than 4,000 feet) and on land, well costs are low to moderate in comparison with conventional natural gas.

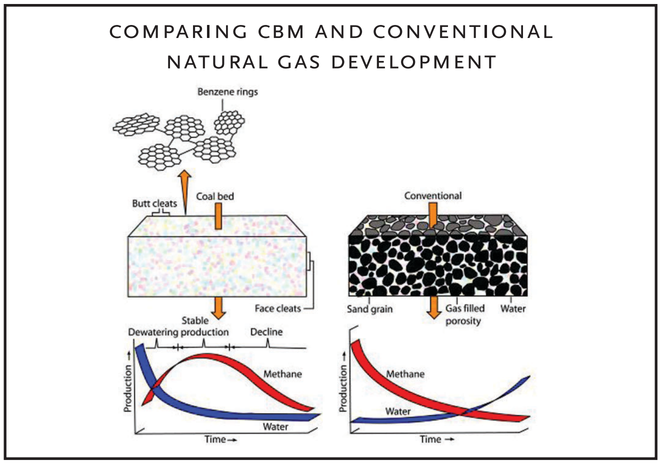

FIGURE 4 *Source: William T. Brown, NRLC coalbed methane conference, April 4–5, 2002*

- The distance between the producing wells and consumers also shapes the economics of CBM development. The market price, minus transportation and compression costs, equal the wellhead net back price. In some areas, the transportation costs may be as great as the wellhead net back price.
- CBM development needs to reach a critical volume of production in order to be economically viable. Costs include gas treatment, compression, transportation, geologic and engineering services, and field operations. The minimum threshold for a viable project varies depends on a variety of factors, but one estimate is that a new, remote basin requires at least 400 wells or 200 billion cubic feet of production to be viable.

In conventional wells, gas production peaks early and then declines over time, and water production eventually increases, the opposite of CBM extraction. The figure below depicts the stages in production of both kinds of wells. For CBM wells, large quantities of water are produced during the initial phase, then water volume declines as the pressure of the reservoir falls. The actual shape of the production curve is a function of production techniques (well spacing, reservoir permeability, reservoir pressure, and water saturation), and varies considerably by reservoir. In some basins, peak gas production occurs in three or more years. The length of time required to produce peak gas production increases in low permeability reservoirs and increased well density.[35] Since CBM wells generally produce gas at lower rates than conventional gas wells, the cost of water disposal in CBM development is significant relative to that of conventional development. Further, CBM development cannot simply be shut off when prices fall, since the coal may refill with water: "you don't start and stop wells in response to short-term price swings."[36] Figure 4 compares CBM and conventional natural gas development and the differences in the volumes of water produced over time. One of the most important characteristics of CBM development is the relatively short span of time wells produce gas. Wells typically produce gas for 7–10 years, and basins may be relatively quickly pumped and then abandoned.

Where are CBM resources located?

Development of CBM resources has been concentrated in the West, South, and, to a lesser extent, the Midwest. Figure 5 is a map that identifies the major CBM plays in the United States.

Some 56 percent of the total CBM production in the United States has come from the Rocky Mountains. Colorado, New Mexico, Utah, and Wyoming may contain as much as 47 trillion cubic feet of coalbed methane, one third to one-half of the total estimated recoverable reserves in the United States. The San Juan basin in southern Colorado/northern New Mexico has been the major source of CBM. Development began in 1988 and rapidly expanded by the end of the 1990s. Production has now leveled off and companies are trying to maintain

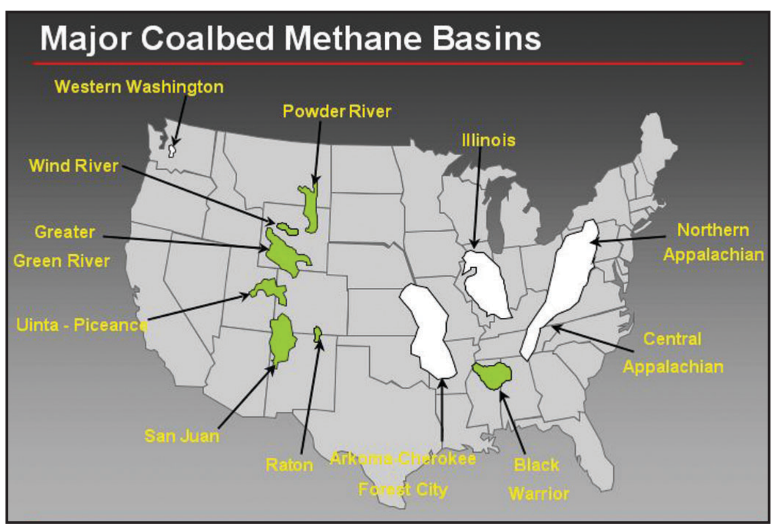

FIGURE 5 *Source: Steve de Albuquerque, NRLC coalbed methane conference, April 4–5, 2002*

output by more intensive development. The Powder River Basin in northwest Wyoming is the area of CBM production that is growing the most rapidly. In 1997, the basin produced 54 million cubic feet of gas/day from 360 wells. Four years later, 5,854 wells were producing 656 million cubic feet/day. CBM resources are also being developed in the Uinta Basin in eastern Utah, the Raton Basin in south-central Colorado, and the Piceance Basin in northwest Colorado, and major expansions of coalbed development are expected in Montana, the Green River basin in Wyoming, and perhaps other areas in the West.

The Potential Gas Committee estimated in 1991 that the four states contained a "most likely recoverable resource" ("probable, possible, and speculative") of coalbed methane of 47.2 Tcf. That amount represents about one-third of the estimated 145 Tcf in the United States.[37] In addition to those reserves, the Gas Research Institute estimates that between 87 and 110 Tcf may exist but is yet undiscovered. Another 1,000 Tcf of methane may also be located in Alaska.[38]

A more recent estimate looked at national reserves. The National Petroleum Council reported in 1999 that the United States' "natural resource base" in the lower 48 states was 1,466 trillion cubic feet; an additional 25 Tcf may be located in the Prudhoe Bay area in Alaska. According to Matt Silverman, CBM resources in the Rocky Mountain states are as follows: About 7 Tcf of CBM has been produced; 11 Tcf are the proved reserves that remain, and another 42 Tcf are economically recoverable reserves. Finally, the total resource base may be some 536 Tcf.[39] Estimates vary considerably, based on differing assumptions and differences between discovered resources and those that are economically or technically extractable.

Figure 6 is a map of the major coal-bearing regions of the Rocky Mountain states; figures for the estimated coalbed gas-in-place, in Tcf, are indicated in parentheses.

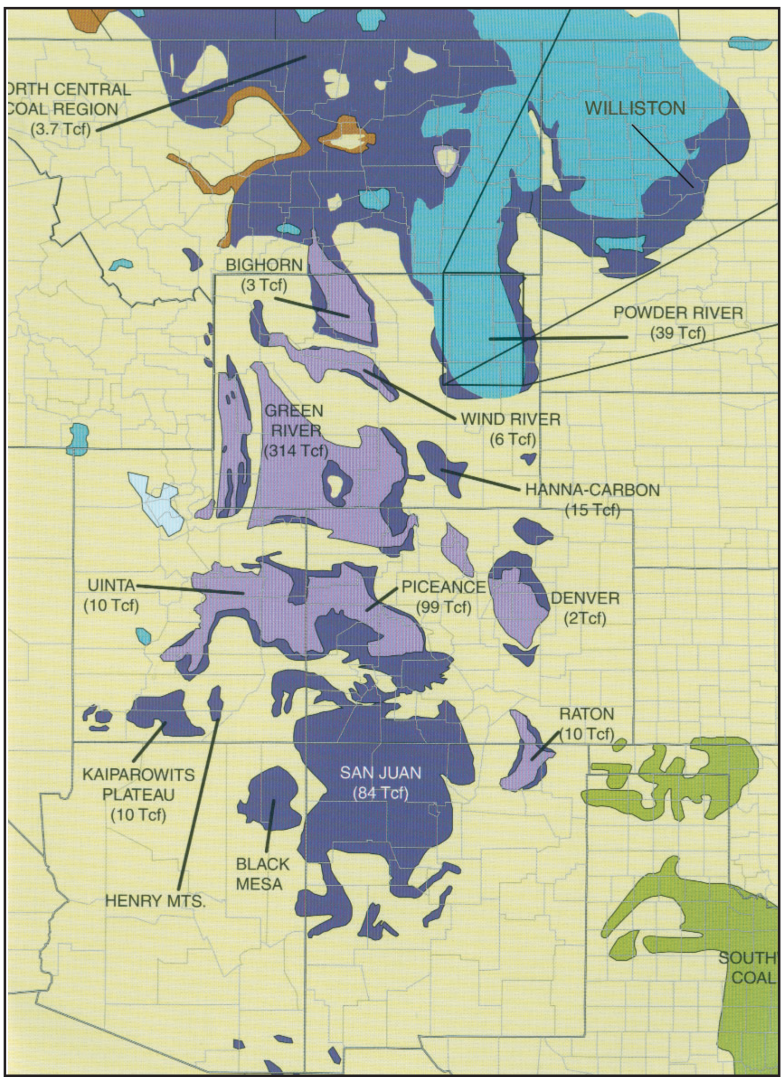

FIGURE 6 *Coalbed methane basisns of the Rocky Mountains*
Source: Matthew R. Silverman, NRLC conference, April 4–5, 2002

How do CBM basins compare?

The major CBM basins in the West include the following:

- Colorado/New Mexico:
  —San Juan Basin (most mature basin 80% of U.S. production)
  —Raton Basin (production for several years)
  —Piceance Basin (potential development)
- Colorado/Utah
  —Piceance (emerging area of development)
  —Uinta Basin (production for several years)
- Wyoming/Montana
  —Powder River Basin (fastest growing area)
- Colorado/Wyoming
  —Green River Basin (potential development)
- There is also potential CBM development in the Denver Basin, Colorado, and in Alaska.

Each coalbed methane basin is unique. Each poses a different set of exploration and development challenges and produces a distinctive set of impacts on surrounding communities and ecosystems. Some basins have reached their peak in production while others are in the early stages of development. In some areas, the water that is produced is of high quality and ready to be used for a variety of human, agricultural, ranching, and other purposes; in other areas, water quality is poor and must be treated or re-injected. According to an engineer with Schlumberger-Holditch Reservoir Technologies, "The one thing coalbed methane plays in the U.S. have in common is that they are all different. You have to consider the complete package of coal characteristics, regional geology, and infrastructure . . . you can't get locked into one mindset."[40] The economics of each basin also varies: some basins may not look profitable at first, but innovative technologies are developed that make development feasible. The Powder River Basin, for example, was originally believed to be unsuited for CBM development, but companies experimented with various production and extraction techniques until development became feasible. Table 1 summarizes the main characteristics of CBM basins in the United States.

COALBED METHANE PLAY CHARACTERISTICS

Table 1 comparison of coalbed methane plays

Basin	States	Producing Wells (1996)	Cummulative CBM Prod. in mmcf (1981–1996)	typical Net Coal Thickness (ft)	Typical Gas Content (scf/ton)	Typical Well Spacing (acres)	Avg. Prod. (mcfd/well)	Est. Finding Cost ($/mcf)
San Juan	CO, NM	3,036	3,857	70	430	320	2,000	0.11
Black Warrior	AL, MS	2,739	728	25	350	80	100	.25
Central Appalachian	WV, VA, KY, TN	814	121	16	na	80	120	na
Piceance	CO	123	36	80	768	40	140	1.23
Powder River	WY, MT	193	17	75	30	80	250	0.25
Uinta	UT	72	14	24	400	160	690	0.25
Raton	CO, NM	59	8	35	300	160	300	0.18

Source: Karl Hart, "Coalbed Methane Trends," Hart Energy Publications, *PTTC Network News, 2nd quarter, 2000.*

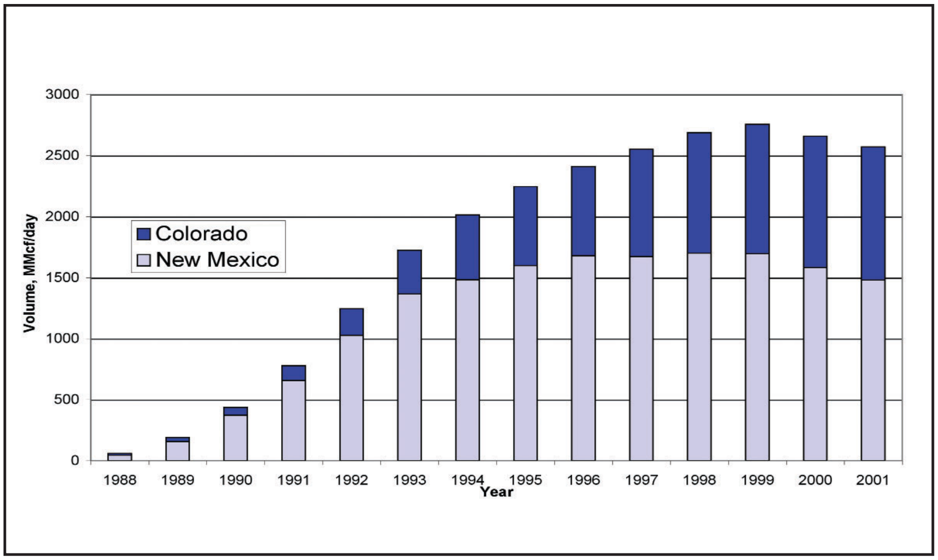

FIGURE 7, *CBM production from the San Juan Basin*
Source: Catherine Cullicott, Carolyn Dunmire, Jerry Brown, Chris Calwell, Ecos Consulting, Coalbed Methane in the San Juan Basin of Colorado and New Mexico.

THE SAN JUAN BASIN—COLORADO/NEW MEXICO

The San Juan basin has been the major source of CBM in the United States. The first recorded CBM well was drilled in 1951, but the first coalbed methane discovery well was drilled in 1976. Development began in 1988 and rapidly expanded to 2.7 Bcf/day by 1999. By 2002, there were some 4,50 active CBM wells in the basin. Production is no longer increasing and companies are trying to maintain output by focusing on enlarging gathering facilities, upgrading production equipment, installing pumping units and wellhead compression, recavitating producing wells, experimenting with secondary recovery efforts, and downspacing from 320-acre units. Typical wells in the San Juan Basin produce a total of from 7–12 Bcf, and many produce several million cubic feet each day. [41] In 2000, the San Juan Basin produced 0.78 Tcf of gas, 4% of total U.S. natural gas production and 80% of its CBM production, valued at $2.5 billion.[42] The BLM projects that 12,500 new oil, gas, and CBM wells will be drilled in the San Juan Basin over the next 20 years. Infill drilling—drilling wells more densely, at every 160 acres rather than 320 acres—has already begun. Figure 7 depicts the evolution of CBM production in the San Juan Basin in Colorado and New Mexico.

Estimates of the total CBM resource available in the San Juan vary greatly. The US Geological Survey's 1995 estimate suggested some 7.53 Tcf while others project 50 Tcf and higher. [43] According to Matt Silverman, there are 84 Tcf of CBM gas in place in the San Juan Basin and 8.5 Tcf of the 12 Tcf recoverable gas has already been extracted. [44]

The BLM and USFS are preparing an EIS in response to industry proposals to open new areas to drilling, and the draft EIS is expected to be released in the summer of 2002. The agencies are considering five options for expanded drilling: all five proposals call for increasing the density of drilling to one well per 160 acres, and all but one call for expanding drilling into the HD Mountains, a Forest Service roadless area.[45]

Coalbed methane development on the Southern Ute Indian Reservation has taken place for more than a decade and generated significant resources for the tribe. CBM development began in the early 1990s. In 1989, the Tribe's net worth was $39,000,000; by 2002, it had grown to $1,200,000,000.[46]

THE POWDER RIVER BASIN—WYOMING

The Powder River Basin is the fastest growing CBM play in the United States. The vast coal deposits of Wyoming contain massive quantities of methane gas and the Powder River Basin is one of the thickest accumulations of coal in the world.[47] In Wyoming, the first CBM wells were drilled in 1986. Companies drilled 10–55 wells/year through 1995, then 253 in 1996 to 4,502 in 2000 and 4,232 in 2001; 13,700 wells had been drilled by 2001. Production has climbed from about 1 Bcf in 1993 to 9 Bcf in 1996 to 251 Bcf in 2001.[48] In 1997, the basin produced 54 million cubic feet of gas/day from 360 wells. By 2001, 5,854 wells were producing 656 million cubic feet/day. Some 400 Bcf had been recovered since drilling began and the Wyoming Geological Survey estimates total recoverable resources at 25.1 Tcf (about the total U.S. demand for natural gas for one year) and a production level by 2010 of 3 Bcf/day.[49] Other estimates range from less than 10 to more than 20 Tcf.[50] Matt Silverman suggests that the total CBM resource in place in the basin is 40 Tcf, with at least 10 Tcf and likely more that is recoverable.[51] Industry representatives estimate that the eight million acre basin will eventually have 50,000–100,000 producing wells.[52]

Coals in the Powder River Basin are very permeable, shallow, and thick, and the low gas content and low pressure were initially seen as barriers to development. The initial wells drilled and completed produced large quantities of water but little gas. As companies shifted to drilling more shallow wells, production increased significantly. The low drilling costs (as low as $35,000 per well, and taking two to three days to drill and complete) and high water quality that allowed it to be discharged on the surface encouraged development. The Powder River basin has become so promising that it has attracted dozens and dozens of operators, both large and small. One industry official explained the popularity as a result of the certainty about development: "It's a fantastic play, and the technical risk is very low. We know the resource is there, we know what the capital costs are going to be."[53] The play is attractive to independent companies since "it has very low geologic risk, and the financial engineering opportunities that are created by that risk profile are not found anywhere else in the natural gas business." [54]

Development costs are described as low: finding costs are in the range of 30 to 40 cents per thousand cubic feet, and the play is profitable even at prices of $2/mcf.

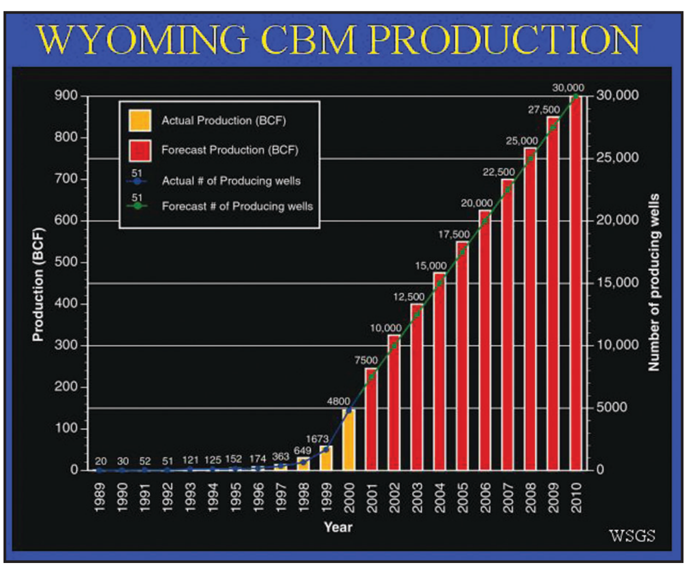

FIGURE 8, *CBM production in Wyoming*
Source: Matthew Silverman, NRLC CBM conference April 4–5, 2002.

But the wells are not huge money-makers: "the per-well recoveries are fairly low {and} high operating costs, mainly from pumping the well and managing the water once it reaches the surface, are ongoing challenges."[55]

By 2000, some 40 companies were working in the area, including Pennaco Energy and Lance Oil and Gas, two of the largest producers of CBM in the basin. A group of oil and gas companies have proposed drilling some 39,400 new wells and accompanying roads, pipelines, and electrical utilities, and compressors in an 8,000,000 acre parcel of private and federal lands. As the CBM play moves west, more and more of the gas lies under lands owned by the Federal government.[56] Before new drilling can take place on these lands, the BLM must complete an environmental impact statement. The draft EIS was released in January 2002.[57] The Powder River EIS assesses the proposal to develop 51,444 new CBM and 3,200 conventional oil and gas wells in a 12,500 square mile area.

Powder River Basin coal ranges from 200 to 2,500 feet below the surface, and most CBM drilling is at the 200–1,200 foot range. Wells typically take from three to six days to complete. Wyoming law provides for 40-acre spacing, but rules issued in March 2001 for units in the northeast and southwest part of the Powder River Basin specified 80-acre units. The CBM wells are projected to produce 3.6 Bcf at maximum production.[58] Wyoming also includes the following other CBM basins: [59]

Washakie Basin: Coal is 5–20 feet thick, at 300–3,000 feet of depth, wells take 5–15 days to complete, hydraulic fracturing may be required, spacing is at 40–80 acres.
Hanna Basin: Coal is 20–50 feet thick, at 3,400–4,500 feet depth, wells take 15 days to complete.
Green River Basin: Wells are 2,500–3,000 feet deep, 80-acre spacing; water is reinjected at 6,700 feet.
Wind River: The basin's CBM resources were estimated in 1995 to be 0.43 Tcf.

Figure 8 charts the dramatic increase in Wyoming CBM production:

POWDER RIVER BASIN—MONTANA

Montana has placed a moratorium on new drilling in its portion of the Powder River basin, and the BLM is preparing an environmental review of the area.[60] Industry officials are optimistic about development in Montana: "In a year's time, after the EIS is complete, CBM could be quicker and easier in Montana than in Wyoming." The proposal being examined in the EIS calls for 20,000 wells, producing 1.5 Tcf per year.[61] One estimate suggests the Montana region of the PRB contains 4.5 Tcf of coalbed methane.[62] Another estimate suggests a total resource in place of 10 Tcf, with half of that recoverable. [63]

THE RATON BASIN—COLORADO/NEW MEXICO

The Raton basin straddles the Colorado-New Mexico border. The Gas Research Institute estimated its recoverable CBM resources at 3.7 Tcf. Others suggest the basin may contain 10 Tcf of resource and 3.5–4.0 Tcf of recoverable CBM.[64] By the end of 2000, some 100 Bcf had been produced. The basin's coal, in comparison with the Powder River Basin, is thin, relatively deep, not particularly permeable, and distributed throughout a wide sedimentary section.[65] Evergreen Resources, Inc., has been the leader in developing the play. By 2001 it had some 675 wells on 200,000 acres that produced about 120 Mcf/day, and planned to drill during that year another 1,000 wells. One third of the wells are expected to be increased density wells (adding a fifth well in a section); one third will be shallower wells; and one-third will extend the field. The average recoverable reserves of these three wells ranges from 1 to 1.6 Bcf per well. The average well costs $400,000; 60 percent of that goes to drilling, completing, and equipping; gathering, gas collection, and compression make up the remaining 40 percent.[66]

The Raton contains two coal bearing formations: Evergreen Company's production has largely been from the Vermejo formation coals (between 450 and 3,500 feet), but it believes that the shallower Raton formation coal seams are also promising. Evergreen is a vertically integrated company. It has compressor stations, owns its own water trucks, has its own pipeline and hydraulic fracturing crews, and operates a low-pressure gathering system that extends for several hundred miles.[67] About half the water it produces goes into surface impoundments and percolates into the ground; 40 percent is discharged onto the surface or is given to local ranchers; and 10 percent is reinjected into formations 2,000 to 3,000 feet below the coals. [68] Devon Energy and El Paso Energy Corp. acquired PennzEnergy and Sonat Exploration and may jointly develop CBM reserves in the Vermejo Ranch property in New Mexico.[69]

THE UINTA BASIN—UTAH/COLORADO

The Uinta Basin CBM play is located on the west side of the San Rafael Swell, at the Southwest edge of the Uinta basin. By the end of 2000, a total of 190 Bcf of gas had been produced and gas was flowing in 2001 at about 250 Mcf/day. Total recoverable reserves in the Ferron are more than 2 Tcf. The largest producing area is Drunkards Wash, where Phillips Petroleum has 350 wells spread over 170,000 acres that produce 210 Mcf/day. The company planned to drill 85 new wells in 2001 and 110 in 2002. Typical wells are drilled at a 160 acre spacing, 1,100 to 4,000 feet deep, and fracturing is used to free up the gas. The average well cost is $330,000. Water is not potable, and some 65,000 barrels per day is reinjected into the Navajo sandstone. River Gas Corporation has some 200 producing wells and plans to develop 400 more. River Gas' operations are in a remote plateau. To save costs, the company installed an automated system that only requires a minimal staff in a remote station. The system includes a "radio system for communicating well data and remote control commands, electronic gas measurement to eliminate chart recorders, and a supervisory control and data acquisition (SCADA) system to manage the operation."[70] Texaco and Anadarko are also operating in the basin.[71]

DENVER BASIN

The Denver Basin in Eastern Colorado contains an estimated 2 Tcf of CBM. Development has been hindered by a lack of data on the extent of the resource and the nature of the gas reservoirs. The two major coal bearing formations are also surrounded by four Denver basin aquifers, raising questions about the extent to which the aquifers and coals are connected hydraulically and what the impacts of CBM development would be on the water.[72]

OTHER BASINS

The Black Warrior Basin, in Alabama, has been the most productive CBM basin outside the Rockies. According to one summary, "relatively limited commercial exploitation of CBM has taken place in other basins, but that is changing." Some production has occurred in the Appalachian basin in Pennsylvania (30 wells in 2000), West Virginia (36 wells), and southwestern Virginia

(1321 wells). Alaska contains nearly half of the total U.S. coal reserves, and studies have found that coals in Northern Alaska's Colville Basin, the Yukon Basin and the Chignik Basin of the Alaskan Peninsula have the highest CBM production potential. Some have suggested that CBM produced in Alaska will likely only be for used for local consumption, while others believe that a gas pipeline may be built from the Prudhoe Basin to the lower 48 states.[73]

II. What are the conflicts, problems, and challenges associated with CBM development?

There are three consequences of CBM development that are responsible for most of the conflicts: the large quantities of water produced during extraction, split estates and the impact of extraction on the owners of surface lands, and development of CBM resources on public lands that might also be reserved for other purposes. These three topics are discussed in detail below. Since methane is a greenhouse gas, CBM development also relates to the threat of climate change and that issue is briefly addressed at the end of this section.

CBM development and water

The amount of water produced during the CBM production process is staggering and represents a major challenge. In the Colorado portion of the San Juan Basin, approximately 1,200 wells have produced nearly 36 billion gallons of water to date.[74] In the Wyoming portion of the Powder River Basin, it is estimated that in the next 15 years, approximately 51,000 wells will have produced over 1.4 trillion gallons of water.[75]

The cleats and fractures in coal are typically saturated with water, and the coal must be dewatered (usually pumped out) before the gas will flow.[76] Some coals never produce methane if they cannot be dewatered economically. As the fracture system produces water, the adsorptive capacity of the coals is exceeded, pressure falls, and the gas trapped in the coal matrix begins to desorb and move to the empty spaces in the fracture system. The gas remains stored in nearby non-coal reservoirs until it is extracted.[77] Drilling dewaters the coal and accelerates the desorption process. The deeper the coalbed, the less the volume of water in the fractures, but the more saline it becomes.[78] The volume of gas typically increases with coal rank, how far underground the coalbed is located, and the reservoir pressure.[79] Initially, drilling primarily produces water; gas production eventually increases and water production declines. Occasionally, wells do not produce any water and begin producing gas immediately, depending on the nature of the fracture system.[80]

When the CBM is extracted, the water must be separated, the gas is sent to pipes, and the water is dumped into ponds or injected back into the ground. In order to develop the resource, companies must first pump large quantities of water from the ground, about 12,000 gallons a day on average for each well, to release the methane. Discharged water that is of high quality, as is the case in many areas in the Powder River Basin, may be used by ranchers to water stock or to irrigate crops. Water that is not useable for irrigation or watering stock may be reinjected into underground regions.[81] Given the scarcity of water in the West, virtually any production of water that is not put to beneficial use or that might affect water quality or water supply and rights is controversial. The development of CBM sometime pits energy developers against ranchers and other water users. CBM development raises several issues surrounding its impacts on:

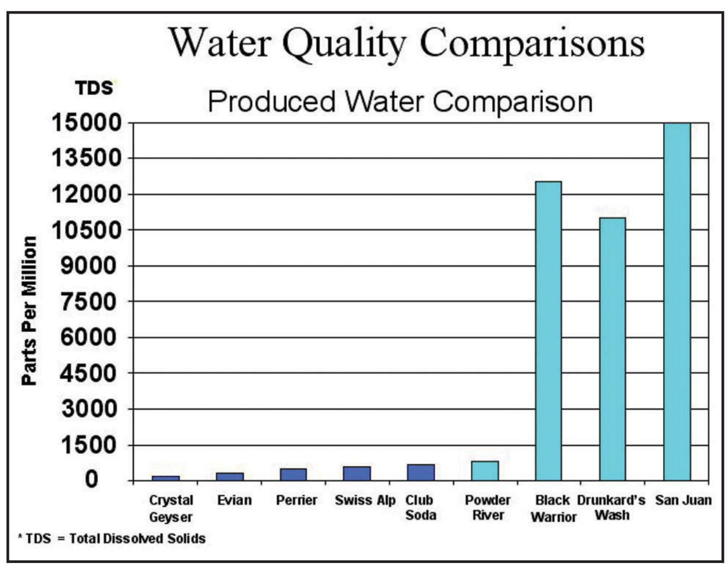

FIGURE 9 *Source: Lance Cook, "Geology of CBM in Wyoming," NRLC CBM conference April 4–5, 2002.*

- underground water quantity and the possibility that drilling or fracturing fluids contaminate aquifers with water of lower quality;
- water rights and underground water supplies that may be diminished as dewatering occurs;
- groundwater that may be contaminated by discharged water that is polluted; and
- aquatic areas, stream beds, and local ecosystems that are unaccustomed to receiving such large volumes of water.

Water quality indicators vary across and even within basins, depending on the depth of the methane, geology, and environment of the deposition. The major elements of CBM water quality include:

- total dissolved solids (salts)
- pH and temperature
- major cations (positively charged ions)—sodium, potassium, magnesium, calcium
- major anions (negatively charged ions)—chlorine, sulfate, hydrogen carbonate
- trace elements—iron, manganese, barium, chromium, arsenic, selenium, and mercury
- organics—hydrocarbons, additives.[82]

Water quality varies tremendously across basins, as figure 9 illustrates (note that the figure also compares CBM produced water with different brands of bottled water):

Because of differences in water quality, CBM-produced water is dealt with differently across the major basins:[83]

San Juan:	99.9% of produced water is injected
Uinta:	97% injected, 3% evaporation
Powder River:	99.9% surface discharge
Black Warrior:	100% surface discharge
Raton Basin:	
Colorado:	70% surface, 28% injected
New Mexico:	100% injected

Even if water quality is high, salts may concentrate during evaporation or may overwhelm the semi-arid environment, inundating vegetation and causing erosion.

The options for dealing with the large quantities of water released include the following (costs generally increase as one moves down the list):[84]

- Traditional surface discharge: water is allowed to travel downstream and be absorbed or evaporate as it moves;
- Irrigation: water released to agricultural areas;
- Treatment: water is treated to improve quality;
- Containment with reservoirs: water is piped to a surface impoundment where it is absorbed or evaporates, or may be used to water cattle;
- Atomization: water evaporates more quickly than normal through the use of misters placed in surface impoundments.
- Shallow injection or aquifer recharge: water is pumped into freshwater aquifers;
- Deep injection: salty water is typically reinjected deep into the ground.[85]

The volume of produced water in the major basins also varies considerably, as Table 2 illustrates:

TABLE 2. AVERAGE WATER PRODUCTION WATER/GAS

BASIN	STATE	No. of WELLS	BBL/DAY/WELL	BBL/MCF
Black Warrior	Alabama	2,917	58	0.55
Powder River	Wyoming	4,454	275	2.17
Raton	Colorado	459	266	1.34
San Juan	CO/NM	3,089	25	0.031
Unita	Utah	393	215	0.42

SOURCE: *C.A. Rice and T.T. Bartos, "Nature and Characteristics of Water Co-Produced with Coalbed Methane with Emphasis on the Powder River Basin" USGS CD.*

SAN JUAN BASIN

The average CBM well in the San Juan basin produces 25 barrels or 1,050 gallons of water a day, a ratio of 0.031 gallons of water/thousand cubic feet of gas. The 4,208 CBM wells produce on average 4.42 million gallons of water a day or 13.6 acre feet.[86] Because of poor quality, virtually all produced water in the San Juan is reinjected. The threat of water contamination is one of the major complaints of local residents surrounding CBM development:

Some residents report that in some areas, their drinking water has been contaminated by methane or by hydraulic fracturing;[87] BP Amoco purchased four homes and leveled them as part of the settlement of a lawsuit after owners charged the company with responsibility for methane in their basements and water wells.[88]

Residents have complained that drilling reduces the water levels of residents' and ranchers' wells as aquifer rock is fractured and water escapes.[89]

Some residents emphasize that while drilling is not directly responsible for the natural seepage of hydrogen sulfide into rivers, it may amplify the natural seepage, and point to signs along the Animas River, a popular kayaking and river running area, that warn of harmful levels of hydrogen sulfide seeping from the ground into the water.[90]

Water storage pits are another source of contention. Dehydrator/separator pits are required to be lined. Residents have complained that companies do not always comply with these requirements.[91]

Industry representatives disagree that CBM development significantly impacts water quality and quantity, although they acknowledge there have been occasional problems. According to one BP official, "different companies have different standards," but there has been improvement over the years in the impacts on water quality.[92] According to a BP official, CBM wells are 2–3,000 feet deep, while drinking water wells are only 200–400 feet deep. CBM well bores are encased in steel and cement 50 feet below the lowest water table to ensure no contamination of aquifers occurs. When BP began drilling at one well in each 160 acre plot, company officials tested water quality near the new wells before and after drilling commenced. Since biogenic-produced methane is found at shallower depths and thermogenic gas at deeper levels, companies can conduct isotopic analyses that fingerprints the gas and allows analysts to trace its origins and learn whether the methane is a result of natural migration or a result of drilling. The Colorado Oil and Gas Commission requires additional testing if methane is found in domestic drinking water wells, and methane has been found in 12 percent of those wells. [93]

The impact of CBM drilling on local water supplies has been very contentious in other areas such as the Raton Basin. Residents of Cokedale, in Las Animas County, protested coalbed methane drilling of one hundred wells that produce twenty-four million gallons of waste water a month, because they feared the water will contaminate the shallow wells that residents depend on, and the dispute resulted in lawsuits and countersuits.[94] The issue of water contamination is critical. The EPA is expected to release a report in the summer of 2002 on CBM contamination of water. If the report concludes that contamination has occurred, it will be difficult for development to continue until more detailed studies are completed.[95]

POWDER RIVER BASIN

The average flow of water from a CBM well in Wyoming is 12–15 gallons/minute.[96] In contrast to the San Juan basin, much of the produced water in Wyoming may be useable for a variety of purposes. A major challenge has been managing in a semiarid landscape the tremendous amount of produced water. CBM wells in Wyoming produce on average 150 barrels of water a day over a 7? year life-time.[97] The rate of water production during initial stages of development range from 400–800 barrels/day to 1,000–1,500 barrels/day in deeper wells.[98] More than 1.28 million barrels of water were produced each day from CBM extraction in 2000.[99] The average production rate of oil per well, after dewatering, is a much smaller amount than in the San Juan.[100]

Critics of CBM development argue that the amount of water withdrawn from CBM production will greatly lower the aquifer levels in Wyoming. They warn that by 2010, surface discharge of produced water will reach 1 billion gallons a day. Data from coal mine permits and plans suggest that it will take 800–1,500 years following reclamation to recharge the coal aquifer and argue that, despite the differences between coal mining and CBM extraction, CBM development poses the same kind of threat to the region's long-term water supply.[101]

The draft environmental impact statement (DEIS) for the next round of development in the Powder River Basin suggests that the drawdown of the Fort Union Coal Aquifer under all alternatives will be from 300–1,200 feet and 10–250 feet for the Deep Wasatch Sands. For the Shallow Wasatch Sands, drawdown projections range from 1–50 feet in areas of thin cover and –1 to –50 feet in areas of impoundments and creeks receiving produced water. Peak drawdown will likely occur between 2006 and 2009, and the aquifers will, according to the DEIS, recover to within 95 percent "over the next hundred years or so."[102]

Just as controversial as impacts on the region's aquifers have been the consequences of the produced water from CBM extraction. The quality of produced water varies across the Powder River Basin. In general, water quality is highest in the southeast, and diminishes to the West and North, where total dissolved solids increase.[103] A USGS study concluded that total dissolved solids (TDS) range from 370 to 1940 mg/L, with a mean of 840 mg/L; the national drinking water standard for potable water is 500 mg/L. TDS levels increase as sampling wells moved North and West.[104]

Discharges into the Tongue and Powder Rivers have been particularly contentious. The water there is generally of sufficiently high quality for drinking water and watering stock, but the produced water is not as good as in the Tongue River, so no discharge permits can be issued.[105] In other areas, the water can be discharged into the Belle Fouche and Cheyenne Rivers and Caballo Creek.[106] While the water is suitable for cattle, there are insufficient cattle to use the produced water. Surface disposal is a challenge as it may result in erosion when discharged into drainages or inundate vegetation. Even though water quality is good, salts may concentrate during evaporation and harm soils.[107]

Some local residents believe domestic and stock water wells are drying up or becoming contaminated, and that discharge of water is causing erosion and soil damage.[108] Others have reported that domestic well lids have been blown off by gas pressure, methane has been found in their water wells, and they have seen companies continue to discharge water after they have received notices of violations.[109] Stock reservoirs have been created, and while some ranchers have wanted the water source, others do not since that takes land out of production.[110] Ranchers are faced with soils damaged by the salts and metals remaining after evaporation, less grass is available for cattle, clay soils become hard pan, and dead cottonwood trees, dead grass, and weeds result from the discharge of produced water that destroys native vegetation.[111]

Given the aridity of the West, the region's water is at least as valuable as its natural gas. One of the most important challenges surrounding CBM development is finding beneficial uses for the produced water. One industry consulting hydrologist emphasized many beneficial uses for produced water—livestock, dust control, industrial, fish and wildlife, recreation, irrigation, and aquifer recharge. He summarized water management options in the Powder River in these terms:[112]

- Discharge to surface streams—acceptable on the Eastern part of the basin; erosion controls are needed but treatment is not; shallow groundwater recharge occurs, and there may be downstream impacts; iron and manganese may need to be removed;
- Impoundment—problems of limited locations, need for erosion controls; few isolated instances of this, the volume is often too low to cause problems;
- Injection—not economic or practical; no evidence of contamination of drinking water, it is often better quality; no toxins; it would reduce water quality of the Tongue River but not others.

CBM development and conflicts with other land uses

Just as contentious as water has been conflicts between local residents and energy companies over land use. CBM development impacts rural lands in several ways. The construction of roads, drill pads, water disposal sites and related facilities and the operation of these facilities may conflict with livestock operations and farming. Noise from pumps, compressors, and traffic may disturb residents and wildlife. Air pollution problems include health effects of fine particles and reduced visibility. CBM development has disrupted areas that were previously isolated from development or valued for undisturbed vistas and solitude. In contrast, in other communities where conventional gas development or coal mining has already occurred, new CBM projects often produce relatively little incremental impact.

Many of the conflicts are rooted in laws that were enacted to promote the development of the West by opening lands to settlers but reserving mineral rights to the Federal government. Most of the land disposition statutes enacted by Congress in the late 19th and early 20th centuries reserved the mineral estate to the United States. The Stockraising Homestead Act of 1916, for example, reserved to the United States "all the coal and other minerals" under the federal lands sold to settlers.[113] The Taylor Grazing Act of 1934 similarly reserved "all minerals to the United States" for federal lands that were exchanged for private lands in order to consolidate BLM grazing districts.[114]

Much CBM development is occurring on split estates—areas where those who own the surface rights of land are not the same as those who own the subsurface mineral rights. Some surface owners have been able to negotiate with energy companies payments for damage to their lands or even a share of the proceeds from development. But conflicts have occurred when residents have purchased surface rights to settle in quiet, undeveloped rural settings or in residential areas, and not realized that those who own the subsurface rights must be given access to the land to develop those rights. Landowners have been forced to allow drilling on lands they assume would be used for grazing or hunting. This is not a problem unique to CBM, but the rapid pace and magnitude of development appears to have intensified conflicts.

The socio-economic impacts of coalbed methane development are similar to those resulting from development of conventional gas. Development produces new jobs, new income, and new revenues for governments from taxes and royalties. It also increases demand for new public services and housing and increases traffic, air pollution (from construction as well as traffic and other sources once construction is completed), noise, and congestion. One difference between CBM and conventional gas that has exacerbated tension is that drilling and construction typically proceeds much more quickly for CBM than for conventional gas. CBM wells may only take a few days to drill and a few more to complete, whereas conventional wells may take 45–60 days to drill and complete. CBM development may rapidly transform a rural community into an energy production area with pipelines, compressors, and other facilities, while the transformation resulting from conventional gas development will likely proceed more slowly. As a result, CBM projects may place more strain on communities than conventional projects because of the speed of development.[115]

THE SAN JUAN BASIN

While most of the San Juan basin is located in New Mexico, conflicts seem to be more pronounced in Colorado. Tax policy differences between the two states are one factor. In New Mexico, oil and gas taxes directly fund educational programs, and that connection helps strengthen support for drilling. In Colorado, oil and gas revenues are not so closely identified with funding for such programs. [116] Perhaps even more important are differences in land use between the San Juan basin in Southern Colorado and Northern New Mexico. The Durango area has become a recreational, residential, retirement community, in contrast with New Mexico, which is still largely an energy production region. Expansion of CBM development in La Plata County clashes with strongly held expectations for protection of roadless areas, vistas, and residential areas.[117] Many people moved into the area because of the solitude, quiet, vistas, and rural landscape, and believe CBM development threatens those characteristics of the land and diminishes their property values. Proposals to intensify drilling density have generated particular opposition in the affected communities.[118]

Other land use conflicts pit preservationists against developers. Some roads are closed for the winter to protect wildlife habitat, but if CBM development occurs in the area, companies get can get a waiver to use the road to get to their sites. [119] There are some roadless areas that include old growth Ponderosa pines that companies would like to open for drilling but are treasured areas for preservationists.[120] Ranches, retirement homes, and roadless areas do not easily coexist with extensive energy development infrastructure. Some residents feel that the long-term goals of sustainability and community are threatened by short-term energy development. The anger and frustration felt by some local residents is palpable, as they accuse companies of failing to comply with the law and arrogantly dismissing residents' complaints and lament the discounting by governments and by energy companies of the personal, anecdotal problems that local landowners report because they are not part of formal scientific studies.[121]

Jim Baca, former director of the BLM and former mayor of Albuquerque, said in a tour of western states sponsored by The Wilderness Society that CBM development in the San Juan Basin "has absolutely destroyed whole landscapes there and quality of life for people." Baca warned that the BLM lacks the resources or staff to deal with the greatly expanded workload due to CBM development, and that as a result, the agency is not inspecting wells in the San Juan area and water is not being properly contained and wells aren't properly maintained. He suggested the agency will need a massive infusion of funds in order to adequately manage CBM development.[122]

THE POWDER RIVER BASIN

As is true of other basins, CBM development brings many benefits to the Powder River Basin. It is less invasive than other forms of non-renewable energy development like coal mining, and it has brought tax revenues, business, employment, and other important economic benefits. Deputy Secretary of the Interior Steve Griles said in a March 2002 speech that energy development in Wyoming is a blueprint for the rest of the nation: "It is restoring the environment and it is allowing us to have both healthy, sound environment and the recovery of energy that fuels this great country and the economy we have." He rejected criticism of coal and CBM development in particular as damaging to the environment: "It's just not a fair representation . . . I looked at coalbed methane development here in and around Gillette. When it is done correct and right, the impact on the environment can be positive." [123]

Local residents, however, have complained about noise, particulate emissions from vehicles and traffic, wind-generated dust, emissions from compressors, reduced visibility, fragmentation of habitat by roads, noxious weeds, increased human damage to fragile ecosystems, loss of privacy, and diminished quality of life. Visibility on Native American reservations and protected federal is threatened, and CBM development appears to have contributed to the problem. Fine particles affect visibility and also pose the greatest threat to human health. Fine particles have increased by 50 percent and average concentrations in the area average 12 micrograms/cubic meter.[124] Larger particles, measured as PM10, are less deadly, but still a health threat for those with asthma and other respiratory diseases. Noise levels provoked one resident to fire 17 shots at a compressor. Others complained of companies leaving garbage and the loss of scenery, solitude, and wildlife.[125]

Landowners argue that CBM development challenges their ability to manage their land in a sustainable fashion. They report that they were not given the option to not sign development agreements, not notified when subsurface minerals were leased, that surface use agreements were not required, that eminent domain was used to install pipelines, and that communications towers have been installed without their permission, that there is a lack of planning for infrastructure needs, a failure to deal with threatened and endangered species, no planning to protect air quality, that little information on development is given to land owners, and bonding is inadequate and some orphan wells have resulted. For these residents, such insults do not just represent damage to their lands and the wasting of scarce and precious water, but are rooted in a sense of powerlessness and a violation of property rights. They view some CBM companies as irresponsible, and complain of signed agreements that are not honored, such as violating royalty agreements by companies that subtract expenses before calculating payments. They feel powerless to protect their lands and ensure their sustainability.[126]

Issues in reducing surface impacts

While split estates have been a major issue in the San Juan and Powder River basins, future CBM development may face a different set of challenges. Issues of overlapping governance will always be a concern as federal, state, and local government boundary conflicts permeate the West. The Bureau of Land Management will play a major role in determining the scope, speed, and impacts of CBM development on public lands and the process of updating resource management plans and preparing environmental impact statements for large scale leasing will be a major task of the agency. CBM development will bump up against other public values, such as protecting habitat and migration routes for wildlife and preserving biodiversity, and insulating recreational lands from the impacts of resource extraction. BLM's resource management plans are largely out of date and some 160 plans will need to be revised during the next ten years.[127]

As discussed below, the failure to have up to date and comprehensive management plans and environmental assessments may block CBM development affecting public lands and federal mineral resources.

For the existing CBM basins, the conflicts between surface and mineral owners are often intense. The BLM requires, under Secretarial Order No. 1, that mineral leaseholders provide evidence that they have entered into good faith negotiations with surface owners before they can receive an approval for a permit to develop.[128] Ranchers, farmers, and others complain that some gas companies fail to consult with them and explore ways to minimize surface impacts. BP officials have argued that reducing visual and noise impacts of drilling and recovery has not been a priority for companies, since their operations are typically not located in inhabited areas. They have begun to develop equipment and practices that reduce impacts. One option is to use a pneumatic pump that pumps without an engine, produces no noise, and is only about 10–15 feet tall (conventional pumps may be 30–40 feet tall). But pneumatic pumps may not work well when large volumes of water are extracted in the process; an alternative is the progressive cavity pump, smaller than traditional pumps (only about 7 feet tall) but requires an engine. Engines can be equipped with a muffler much as in a motor vehicle. Well pads are typically one acre in size, and must be sufficiently large to accommodate drilling equipment, but that size may be reduced as technology improves.[129]

Another option is to place sound barriers, formed with sound insulation, above and on the sides of engines. Noise, traffic, and dust from operators driving to monitor production can be reduced through automated monitoring systems. These systems can be solar powered. J.M. Huber officials have camouflaged wells from nearby residents by building a ridge of dirt and planting trees on the ridge. Companies have also replaced controllers on wells in order to reduce leaking methane and thereby reducing greenhouse gas emissions.[130] At least one company is developing a diagnostic device for assessing the concentration of CBM in a coal seam that uses a slender tube with sensors that produce immediate data on coal conditions. If reservoir assessments can be improved, that will decrease the likelihood that a company will pump out a large volume of groundwater and then discover that there is insufficient recoverable methane to make the process worthwhile.[131]

The Northern Plains Resource Council was organized in 1971 by ranchers to fight coal strip-mining and the group played a key role in getting mining reclamation legislation enacted in Montana in 1973 that served as a model for the 1977 federal strip-mining law. It negotiated in 2000 a "good neighbor agreement" with the Stillwater Mining Company that included more strict water protection standards than provided by law and included other safeguards. In 2001, it published a booklet giving recommendations for how CBM development should take place in the state.[132] And it has launched lawsuits. One suit against the state board of oil and gas conservation board was settled when the agency agreed to conduct an environmental impact assessment of CBM before issuing permits. Another suit against the BLM is pending.[133] The council's call for responsible CBM development includes six provisions: [134]

- Effective monitoring of coalbed methane development and active enforcement of existing laws to protect private property rights, Montana citizens, and Montana's natural resources,
- Surface owner consent, surface use agreements, and reimbursement of attorney fees to help landowners better protect their property rights,
- Use of aquifer recharge, clustered development, mufflers for compressor stations, and other low-impact, best-available technologies to minimize impacts on underground water reserves, rivers and streams, and surface resources,
- Collection of thorough fish, wildlife, and plant inventories before development proceeds to protect habitat, followed by phased-in development to diffuse impacts over time,
- Meaningful public involvement in the decision-making process,
- Complete reclamation of all disturbed areas and bonding that protects Montana taxpayers from all cleanup liability costs.

These and other ideas for reducing conflicts surrounding CBM development are discussed in Section IV, below.

CBM development and public lands

While the development of CBM on private lands has been very contentious in many areas, conflict surrounding CBM development on public lands has also been controversial. As indicated earlier, a major thrust of the Bush administration's national energy plan is to expand development of energy resources on public lands. Congressional Republicans have also vowed to open public lands to energy development. Developing resources on public lands is a major theme of the House energy bill passed in 2001. House Resources Committee chair Jim Hansen (R-UT) said in introducing a March 2001 hearing, "[i]t's time for a course correction in the management of our public lands. It's ironic that we are faced with an energy crisis while we have abundant reserves of oil, coal, natural gas and hydro-electricity locked up in our public lands and waters."[135]

The Senate energy bill proceeded much more slowly, and much of the debate focused on energy development in the Arctic National Wildlife Refuge.[136] In April, 2002, the Senate defeated an amendment to the energy bill to open ANWR to drilling.[137] The House passed a similar provision and the House-Senate energy conference committee was slated to begin negotiating a compromise bill in June. The House bill favors incentives for expanding fossil fuel and nuclear power production, while the Senate version emphasizes conservation and alternative energy sources.[138]

While the national energy policy debate continues, the Bush administration is accelerating plans to develop oil and gas resources on federal lands in the West. Deputy Secretary of the Interior Steve Griles said in a March 2002 speech that energy development in Wyoming is serving as a blueprint for the rest of the country and that the objective of the president's plan is to "have a steady increase in the use of fossil fuel, and at the same time ratcheting down any type of environmental impact."[139] The BLM is reducing the time it takes companies to apply for drilling permits by one-third in order to increase development.[140] In March 2002, Peter Culp, BLM's assistant director for minerals and resource protection said that oil and gas companies can expect speedier drilling approvals, easier access to petroleum deposits, reduced royalty payments, and fewer environmental restrictions as part of the Bush administration's national energy plan. He indicated that the BLM would also expedite reviews of oil and gas resources in the Powder River and San Juan basins.[141] The BLM is also conducting a new study of how much oil and gas might be available in BLM lands in the lower 48 states, expected to be completed in 2002; the study will be used by the BLM to find ways to expedite exploration and "evaluate potentially overly restrictive impediments to determine if alternative methods are available."[142]

State officials have been just as adamant in arguing for the development of energy on public lands. Montana Governor Judy Martz has complained that the Clinton administration had tried to "lock up the West" and prohibit the development of the region's resources, claiming that "we have seen our ability to responsibly develop those resources grind to a halt. . . ."[143] Wyoming Governor Jim Geringer claims that "Wyoming's energy potential could completely replace the entire OPEC production for the next forty-one years."[144]

Controversy swirls around a number of issues, including the methods used to assess resources. Environmental resource economists like Pete Morton have suggested only reserves that are economically viable be counted.[145] Wyoming Congresswoman Barbara Cubin counters that the economic viability test discourages exploratory development that might discover resources, such as the state's Jonah Gas field.[146]

There is little agreement concerning the role public lands have played in energy development. Representative Hansen, for example, argues that domestic natural gas production has steadily declined since 1973.[147] But natural gas production on public lands has increased, while production on private lands has fallen. A Natural Resources Defense Council report found that energy production on public lands steadily increased between 1988 and 1998. During those years, oil production on public lands grew by 39 percent, natural gas by 26 percent, and coal by more than 20 percent. [148] The Department of the Interior reported in January 2001 on the production of oil, gas, and coal from offshore and onshore Federal and Indian lands: the contribution of oil and gas production on federal lands grew from thirteen percent of total domestic production in 1992 to twenty-five percent in 1999.[149] Some industry officials, such as Ed Porter of the American Petroleum Institute, have acknowledged that natural gas production had increased, but argue for expanded drilling on public lands to capture the remaining resources.[150]

Two key issues at the heart of these disagreements over energy development and public lands are the volume of natural gas resources available and their location. As indicated above, the National Petroleum Council reported in 1999 that the United States' "natural resource base" of natural gas (not just CBM) in the lower 48 states was 1,466 trillion cubic feet. While current consumption is about 22 Tcf/year, that is projected to increase to 31 Tcf by 2015.[151] The Council also concluded that some 105 Tcf of this resource base was off limits to development: 29 Tcf in the Rocky Mountain states and 76 Tcf because of restrictions on off-shore development. A representative of The Wilderness Society, in a hearing before the House Resources Committee, suggested that in addition to the 105 Tcf, an additional nine Tcf of gas would not be available as a result of the Forest Service's roadless protection initiative, making 115 Tcf unavailable. If that figure is subtracted from the resource base of 1,466 Tcf, the amount of resource available is 1,351 Tcf. At the projected consumption rate of 31 Tcf per year several years from now, the resource would last 40 years, assuming consumption did not grow. As a result, he argued, we need not feel pressure to move into these environmentally sensitive areas in order to expand natural gas production.[152]

The National Petroleum Council also estimated that some 108 Tcf of natural gas resource in the Rocky Mountain region are available with restrictions. Although these areas can be leased, these restrictions are aimed at protecting sensitive wildlife and habitat areas. The BLM imposes three different kinds of stipulations that affect CBM and other natural gas development:

Standard stipulations that place limits on operations, such as prohibiting development within 500 feet of surface water or riparian areas and are typically applied to all oil and gas leases;

Seasonal or other special stipulations that prohibit activities during specified time periods when suggested by the Fish and Wildlife Service or others to protect nesting, calving, and other seasonal habitat use;

No surface occupancy stipulations that prohibit operations directly over a leased area and require directional drilling to protect underground mining operations, archaeological sites, caves, steep slopes, campsites, or wildlife habitat. [153]

A Wilderness Society analysis of CBM and public land, using USGS data, concludes that there is between 500–943 Bcf of coalbed methane in the roadless areas of the Rocky Mountain States. If these Forest Service lands were opened for drilling, and the economically recoverable CBM were made available, that would increase America's natural gas reserves by only one-tenth of one percent. It cited a USGS report that concluded there is no economically recoverable CBM within any national monument. The analysis emphasized the importance of focusing on economically extractable reserves, rather than technically recoverable resources. If technically recoverable resources are used, this overestimates the value of resources that may be inaccessible due to public land protection policies and may contribute to pressure to open those lands to development when the economically recoverable resources are quite modest.[154]

There are numerous examples of conflicts between developing energy resources and preserving protected public lands that illustrate the challenges confronting CBM and other energy development in the West and will require careful planning, environmental assessments, and other analyses. A draft report from the Interior Department circulated in April 2001 recommended that millions of acres of lands that had been managed by the Clinton administration as protected areas be opened for energy development. The report urged Congress to decide which of the 17 million acres in 11 western states that have been protected as wilderness study areas (WSA) should be designated as wilderness and which should be opened to development. It also recommends that the Forest Service modify forest plans to allow for more energy development.[155] In 1997, in order to protect its jagged peaks and diverse wildlife, the Clinton administration Forest Service banned oil and gas drilling for ten to fifteen years in that portion of the Lewis and Clark National Forest that is part of the Overthrust Belt, a resource-rich mineral formation that primarily traverses Montana, Idaho, and Wyoming.[156] Interior Secretary Gale Norton said in early 2001 that the Overthrust Belt was one of the areas "that would be studied as part of an across-the-board look at energy resources."[157]

In Wyoming, 94 percent of the state's eighteen million acres of public lands are open to development.

Within the 6 percent of protected area is the 600,000-acre Jack Morrow Hills that is part of the Red Desert. Former Interior Secretary Babbitt toured the area in the late 1990s and would have suggested it for designation as a national monument, but the Wyoming congressional delegation in 1950 had pressed Congress to pass an amendment to the Antiquities Act prohibiting presidents from declaring national monuments in the state without congressional approval.[158] The BLM developed a plan to reopen some lands to oil and gas development, but in December 2000, Secretary Babbitt ordered the agency to come up with a new plan that gave top priority to conservation.[159] Similar disputes have arisen elsewhere in the state, such as in the Bridger-Teton National Forest in northwest Wyoming. In a December 2000 draft environmental impact statement, the forest supervisor announced that oil and gas drilling would not be allowed on some 370,000 acres near the Gros Ventre Wilderness Area southwest of Jackson Hole.[160]

Industry groups first proposed drilling in 1996, and the forest plan provided for drilling in the area. More than seven thousand people submitted comments on the proposal; 85 percent of the respondents opposed development, according to preservationists.[161] Environmentalists have successfully blocked development to protect wetlands and forage for elk, bear, coyotes, wolves, and other wildlife, several blue ribbon trout streams, and four rivers eligible for National Wild and Scenic River designation. In addition, migratory patterns of wildlife from Yellowstone National Park would be threatened by the development.[162] The EPA's position is that the area "is an important buffer between wilderness areas and developed private lands," and represents essential protection for endangered species habitat. Development groups charge the Forest Service with trying to create a de facto wilderness area.[163]

CBM and other energy development on public lands in the West pose daunting dilemmas for policy makers and for affected communities and companies. Some argue that the analysis, though difficult, involves an assessment of costs and benefits, while others reject any effort to quantify variables like solitude, open vistas, and habitat protection. In Wyoming, the BLM had argued that it was possible to balance oil and gas development with preservation of the desert elk herd in the area, and other proponents of drilling argued that the benefits of energy development far outweighed the environmental costs. Energy company executives argued that "we respect the issue of preserving the value of place, but oil and gas drilling will have no impact whatsoever on that value . . . ."[164]

Others argue that energy development on public lands often requires choices between preservation or extraction. The editors of the Great Falls, Montana, Tribune wrote, in response to the debate over energy development in ANWR, the Rocky Mountain Front, and the Missouri Breaks Monument; "We've long opposed drilling in those places, saying the benefits of doing so are far outweighed by the environmental and recreational benefits of not doing so."[165] Conservationists argue that 90 percent of BLM lands are available for energy and other resource development, and the last ten percent, much of which has been proposed for wilderness designation, should be protected. "We don't need to drill the last ten percent," said former BLM director Jim Baca.[166]

Others agree that in some landscapes, the issue is a choice between one or the other, rather than a balancing of both: "It gets down to, do you want cheap oil and gas, or do you want Yellowstone?"[167] An official of Questar, a natural gas company operating in the area, focused the debate by saying " [y]ou can't have Wyoming be a pristine, untouched area and still be a major natural gas producer."[168] Richard Fineberg, an environmental consultant, argues that the concept of wilderness "is immutable. It is like perfection—there are no degrees to it. [Energy] development in a wilderness, no matter how sensitive, changes the very nature of it. It means it's no longer wilderness."[169] Said another, "It's almost like the original temptation. We have this incredibly beautiful place that we can either leave alone or go in and grab the apple."[170]

Public lands play a critical role supplying energy and other natural resources, but also in providing recreation, habitat, and ecosystem services such as improving air and water quality. As CBM development moves into new areas, the BLM faces the challenge of protecting habitat, migration routes for big game, and a host of other environmental goals that are part of the purposes of public lands. The Bush administration has emphasized the importance of increasing domestic production of energy sources, and much of that development will take place on public lands.[171] But principles of compromise, collaboration, communication, balance, and stewardship suggest that development needs to be carefully structured in order to ensure that environmental protection and energy production goals are pursued together.

Environmental impact statements are a key vehicle for assessing the interaction of preservation and development goals. Controversy swirled around the BLM's draft EIS for the Powder River Basin in Montana and Wyoming that was released in February 2002 when EPA officials in Region 8 indicated they would give the study the lowest possible ranking it gives. EPA's concerns were primarily about water quality issues and the impacts of discharged water on the environment and irrigation.[172] The agency faulted the BLM for not examining options for preventing harm from the water, for differences between the Montana and Wyoming studies' analyses of the same water issues, for failing to resolve issues dividing the two states as well as the Northern Cheyenne and Crow tribes, and for inadequate assessment of the effect of development on air quality.[173]

The EPA also found the Montana EIS "environmentally objectionable due to the lack of specifically identified, economically and technically feasible water-management practices that are adequate to assure attainment of water quality standards under the Clean Water Act," and was even more critical of the Wyoming EIS, suggesting that while the Montana document could be remedied, the Wyoming study may need to be scrapped.[174] EPA and BLM officials began meeting to try to resolve the differences, and EPA's views might be altered as they are reviewed at agency headquarters. Interior Department Deputy Secretary J. Steven Griles protested to EPA Deputy Administrator Linda Fisher that the criticisms were misdirected, but then distanced himself from the issue because of his past involvement in the Powder River Basin representing gas companies.[175] In May, 2002, the EPA's Denver office released its assessment of the environmental impact statements, giving the lowest possible rating as had been proposed in the draft letter, and focusing particularly on the water quality issues in the Tongue and Belle Fourche Rivers, but also arguing that environmental safeguards could be devised so that the BLM could approve new development by the fall of 2002.[176]

CBM and the threat of climate change

The development of CBM may contribute to reducing the threat of global climate change. Methane is one of the most important greenhouse gases, more than 20 times as potent as the equivalent volume of carbon dioxide in trapping radiated energy and contributing to the threat of disruptive climate change. One-third of the methane released into the atmosphere is related to energy production and transportation. Fugitive methane emissions occur during the production of natural gas and emissions are expected to increase as natural gas production expands, even though the average rate of emissions per unit of production is declining. Coal-related methane emissions are expected to decline as technologies for the recovery of vented methane improve. Expanded CBM development could actually result in decreased methane releases if methane that would be otherwise vented through coal mining is captured through coalmine methane recovery, carefully transported to ensure minimal loss, and then used to produce energy.[177]

CBM production could also reduce greenhouse gas concentrations in the atmosphere by serving as a sink for carbon dioxide. The adsorption of carbon dioxide molecules by coal stimulates the desorption of methane and thus enhances its production. Carbon dioxide injected into coal seams for secondary recovery of methane drawn from power plant waste streams, for example, is as a consequence not released into the atmosphere where it otherwise would act as a greenhouse gas.[178]

While the United States has not ratified an international agreement that mandates reductions in greenhouse gases, some local governments and businesses have committed to reduce their greenhouse gas emissions. Part of the strategy developed by these companies is to achieve emission reduction goals through emissions trading programs. Divisions generate emission credits through instituting changes in materials or process, and by efficiency improvements that reduce emissions. The companies then allow the divisions to meet their goals by buying and selling these emission credits, and by purchasing carbon credits from agricultural sequestration, tree planting, and other activities. The revenue from marketing these credits might create additional incentives for injecting carbon dioxide into CBM formations.[179] The role that CO_2 injection might play in enhancing CBM production is not well documented and its promise is unclear but likely modes. Natural gas use produces CO2 and contributes to the threat of climate change. But some companies are collecting data from pilot projects on the role of CO_2 in enhancing CBM production.[180]

III. How is cbm development regulated? [181]

Federal regulation

The Mineral Leasing Act of 1920 (MLA) provides the current framework for approval and management of CBM activity on federal lands. Federal agencies' policies regarding fluid minerals are adopted pursuant to MLA. Lands managed by the BLM, U.S. Forest Service and other lands owned by the United States are open to CBM production under MLA. BLM is the principal agency responsible for managing the mineral estate on all federal lands. The Federal Land Policy and Management Act (FLPMA) also governs BLM management of federal lands. The National Forest Management Act (NFMA) governs development in national forests. Multiple layers of decisions precede drilling on public lands, including land use plans, leasing decisions, and the Plan of Development (POD)/Application for Permit to Drill (APD).

Land use plans

CBM and other development on federal lands must conform with BLM Resource Management Plans and Forest Service Land and Resource Management Plans. BLM Land Use Plans or Resource Management Plans (RMPs) are developed in accordance with section 202 of FLPMA. Forest Service Land and Resource Management Plans (LRMPs) are issued pursuant to NFMA. Land Use Plans should include a discussion of anticipated land uses, including mineral extraction. Implementation of plans trigger the requirements provided in the National Environmental Policy Act (NEPA) and the agencies must conduct an environmental assessment that may require a formal environmental impact statement (EIS). In the EIS, the agency must predict "reasonably foreseeable" development that will result from opening lands to mineral development. Further, the land use plan should reflect the agency's determination as to where and how development will occur. Because CBM development has been so rapid and recent, most plans did not anticipate or discuss the impacts of this level of CBM development, if CBM development was discussed at all.

Leasing

The Federal Onshore Oil and Gas Leasing Reform Act (FOOGLRA) of 1987 requires competitive bids for leases on federal lands. Standard lease terms include application of federal environmental laws and additional measures to minimize adverse impacts, and can include special or supplemental stipulations. The National Environmental Policy Act (NEPA) applies to leasing decision, although there is some debate whether environmental assessments or full environmental impact statements are required and federal courts have issued inconsistent opinions on the issue. BLM may provide NEPA analysis for leasing decisions in RMPs, but most RMPs did not anticipate the levels of CBM development. The Forest Service engages in a two tier leasing analysis under FOOGLRA: analysis of all lands under its jurisdiction available for leasing, and leasing decision for specified lands. Standard Lease Terms (SLTs) give the lessee the right to use the leased land to explore, drill, extract, remove and dispose of oil and gas deposits under the land. Additional measures may be added to mitigate adverse impacts to the surface.[182]

Leasing disputes may play a major role in the Powder River Basin and perhaps other areas as well. In April 2002, the Interior Board of Land Appeals ruled, in response to a challenge by the Wyoming Outdoor and Powder River Basin Resource Councils of three CBM leases in the Powder River Basin issued by the BLM, that the agency had failed to perform adequate environmental reviews before issuing the leases.[183] The board found that two BLM studies on which the agency relied in making leasing decisions, a 1985 BLM resource management plan that did not consider CBM development impacts, and a draft environmental impact statement on CBM development, as "insufficient to provide the requisite pres-leasing NEPA analysis for the sale parcels in question." While the decisions only applied to three leases, they appear to be similar to many more and the decision could bring to a halt thousands of CBM leases until the BLM can revise its environmental assessments. In addition to stopping existing leases, the decision puts into question whether the analysis the BLM is doing in anticipation of approving thousands of new leases would meet the board's criteria. The IBLA opinion concluded that *not only does the record amply demonstrate that the magnitude of water production from CBM extraction in the Powder River Basin creates unique problems and the CBM development and transportation present critical air quality issues not adequately addressed in the RMP/EIS, but BLM has also acknowledged the inadequacy of the RMP/EIS as far as the analysis of CBM issues is concerned.* [184]

As a result, the BLM could not rely on that document to satisfy its obligations under NEPA. The decision may have major impacts on CBM development, depending on whether the councils appeal more decisions, the Secretary of the Interior reverses the Board's finding, gas companies sue the board in federal court, or the BLM decides to place a moratorium on leases until environmental assessments can be completed.[185]

Plan of development/application for permit to drill

The application for permit to drill (APD) includes a plan of operations that outlines the nature of surface impacts. The Forest Service emphasizes protection of resources and general reclamation principles. Onsite inspections may trigger revision of APD or conditions of approval. APDs are submitted directly to BLM, which then distributes the APD to any affected surface management agency. Under revised BLM and Forest Service regulations, both a "drilling plan" and a "surface use plan of operations" must be developed. Neither BLM nor FS rules contain specific terms and conditions governing surface reclamation, although FS does set out some general principles. Prior to approving the APD, the BLM must verify that the required performance bond is in place. In some cases, the APD review is preceded by an application for a plan of development (POD). PODs are required when a field of oil or gas is to be developed rather than one well. PODs give the BLM the opportunity to assess the cumulative impacts of development and to consider ways to reduce impacts such as requiring companies to consolidate their infrastructure.

BLM's surface use planning addresses an extensive set of issues, including existing roads, proposed roads, location of existing and proposed wells and facilities, location and type of water supply, construction materials to be used, methods for handling waste disposal, ancillary facilities, wellsite layout, plans for surface reclamation, type of water discharge, discharge points, reservoirs/containment pits, road crossings, culverts, erosion control measures, discharge rate, downstream concerns, water management plans, and water quality maintenance and monitoring. An interdisciplinary team of geologists, engineers, biologists, archaeologists, hydrologists, and others review the plans, conduct on-site investigations, and conduct post-inspection monitoring.[186]

Clean water laws

Under the Federal Clean Water Act, as administered by states, CBM development is governed by water quality standards to protect designated uses of water. Standards include pollution limits, anti-degradation requirements beyond water quality standards, and total maximum daily loads—maximum daily pollutant discharges that are assigned to point and non point sources to ensure total pollution levels are not exceeded. Developers must receive a National Pollution Discharge Elimination System (NPDES) permit if they are discharging produced water into surface waters of the state. State Water Quality Standards and Effluent Limitations also apply to CBM, but there currently are no technology-based effluent standards for CBM discharges. Permits must still impose effluent limitations that will ensure that State Water Quality Standards are not violated. There is little agreement on what they should be. In Wyoming, for example, there are no numeric standards for sodium absorption ratio (SAR); state officials require that CBM-produced water does not degrade designated uses of surface water. Montana has numeric standards for some waters downstream, so Wyoming sources are required to comply, and the two states have negotiated an agreement.

Under Section 401 of the Clean Water Act, applicants must receive certification from the State where the discharge originates stating that their activities will comply with the Clean Water Act; state requirements become part of the federal permit and are enforceable by either BLM or Forest Service. Under Section 404, parties must get 404 permits for any activities that may result in the placement of fill into the waters of the United States

The Federal Safe Drinking Water Act (SDWA) governs re-injection of water produced from CBM extraction. No underground injection is allowed without a permit.

Part C of the SDWA is designed to protect underground resources of drinking water by issuing permits for any underground injections of fluids. There are five classes of injection wells under these regulations, which are classified by the type of fluid injected and the area where the fluid is injected. With CBM, most re-injection is done into Class II wells. Class II wells cover fluids that are either brought to the surface in connection with oil and gas development or are used to enhance the recovery of oil and gas. The EPA is studying the environmental risks associated with hydraulic fracturing used to facilitate methane recovery for underground sources of drinking water in response to complaints that CBM development has compromised water quality in some drinking wells.

Hydraulic fracturing or fracing has been the subject of significant litigation. In *Legal Environmental Assistance Foundation (LEAF) v. EPA*[187], plaintiffs claimed that the nearby use of hydraulic fracturing to extract CBM polluted their well waters and should have been regulated under the SDWA. The court held that fracing fluids fell within the SDWA's definition of "underground injection," stating that "the process of hydraulic fracturing obviously falls within this definition, as it involves subsurface emplacement of fluids by forcing them into cracks in the ground through a well."[188] Accordingly, the court granted the petition for review and remanded the matter to EPA. In July of 2000, EPA published a notice in the *Federal Register* indicating that it is undertaking a nationwide study to the evaluate the environmental risks of fracing to underground sources of drinking water.[189] A final report has not been completed. The LEAF decision may pose significant implications for CBM development in western states as well. For example, although the Wyoming Department of Environmental Quality (WDEQ) has an approved UIC program, WDEQ does not regulate the underground injection of hydraulic fracing fluids.

Other federal laws

CBM development on tribal lands is governed by the Omnibus Indian Mineral Leasing Act of 1938[190] and the Indian Mineral Development Act of 1982.[191] Energy development on tribal lands is subject to a dual legal system of federal and tribal law. These acts require the Bureau of Indian Affairs to authorize energy leases. NEPA review applies to these decisions. Under other laws, qualifying tribes can act as states in enforcing environmental laws, and tribes may regulate their lands more stringently than federal minimum standards and may regulate in areas not covered by federal laws or programs.

Other Federal laws are applicable to CBM development. The Endangered Species Act requires all federal agencies to Ainsure that any action authorized, funded or carried out by such agency . . . is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of habitat of such species@[192] Agencies must consult with either the United States Fish and Wildlife Service (USFWS) or the National Marine Fisheries Service (NMFS) when any activity they authorize, fund, or carry out could affect listed species.[193] The Surface Mining Control and Reclamation Act includes provisions to water from coal mining operations that might serve as a model for CBM regulation. Underground coal mining permits must include actions to "minimize the disturbances of the prevailing hydrologic balance at the minesite and in associated offsite areas and to the quantity of water in surface ground water systems." Using the "best technology current available," companies are required to "minimize disturbances and adverse impacts of the operation on fish, wildlife, and related environmental values, and achieve enhancement of such resources where practicable."[194] Federal officials are to monitor operations to ensure compliance and to require monitoring of aquifers.[195]

State regulation

State "conservation statutes" created oil and gas commissions and boards. They were originally authorized to establish drilling units and provide for the location of permitted wells. These laws were typically enacted for three purposes: (1) To protect the opportunity of all owners to share in oil and gas production, (2) To prevent waste of the resource, and (3) To avoid drilling unnecessary wells. Their responsibilities have expanded to include the regulating of drilling, casing, plugging and the abandonment of wells. In some states, the commissions or boards may be authorized to protect the rights of surface owners. Specific state statutory provisions differ in terms of the charge they give to oil and gas commissions:[196]

- Colorado: the Oil and Gas Conservation Commission is to encourage production and prevent and mitigate adverse environmental impacts. Its original function was Ato foster, encourage, and promote the development, production and utilization@ of oil and gas. COGCC focused on increasing production by preventing waste;[197] in 1994, its mandate was expanded to Aprevent and mitigate significant adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations@[198] and to Ainvestigate, prevent, monitor, or mitigate conditions that threaten to cause, or that actually cause, a significant adverse environmental impact.@[199]

- Montana: the Board of Oil and Gas Conservation (MBOGC) was established in 1953 with the passage of the Montana Oil and Gas Conservation Act. No oil or gas exploration, development, production, or disposal well may be drilled until MBOGC issues a drilling permit. MBOGC's mandate is (1) to prevent waste of oil and gas resources; (2) to encourage maximum efficient recovery of the resource; and (3) to protect the right of each owner to recover its fair share of the oil and gas underlying its lands.[200] MBOGC can also take measures to prevent contamination of or damage to surrounding land caused by drilling operations, such as regulating the disposal of produced salt water and the disposal of oil field wastes.[201] Montana also has a state environmental policy act requiring its state agencies to complete environmental analyses similar to those required under NEPA.[202]
- New Mexico: The Oil Conservation Commission and the Oil Conservation Division of the Energy, Minerals and Natural Resources Department regulate the conservation of oil and gas and the disposition of wastes resulting from oil and gas operations, including the protection of public health and the environment.[203]
- Utah: The Board of Oil, Gas and Mining[204] and its related technical and administrative agency, the Division of Oil, Gas and Mining[205] regulate drilling, testing, equipping, completing, operating, producing, and plugging wells; spacing and location of wells; and disposal of salt water and field wastes.[206] Board rules require operators to "take all reasonable precautions to avoid polluting lands, streams, reservoirs, natural drainage ways, and underground water.@ [207] Board rules encourage the development of Asurface use agreements@ with landowners but do not adopt statewide standards of reclamation.[208]
- Wyoming: The Oil and Gas Commission (WOGCC) has the authority to require drilling, casing, and plugging of wells in order to prevent escape of oil or gas, the furnishing of a reasonable bond limited to plugging each dry or abandoned well, and monitoring of well performance.[209] It can also regulate, for conservation purposes, the drilling, producing and plugging of wells, the shooting and chemical treatment of wells, well spacing, disposal of salt water and drilling fluids "uniquely associated" with gas exploration and development, and the contamination or waste of underground water.[210] The Commission has a duty to prevent the waste of natural gas and to keep it from polluting or damaging crops, vegetation, livestock, and wildlife.[211] WOGCC rules provide that, "[t]he owner or operator shall not pollute streams, underground water, or unreasonably damage or occupy the surface of the leased premises or other lands."[212]

Local regulation

County regulation of CBM development has been accepted in some areas and been contentious in others. County regulations may place limits on operations; require special use, building, and road permits; and require companies to paint production tanks and keep sites weed-free. Colorado's La Plata and Las Animas Counties have enacted regulations that require consideration of noise levels, impacts on air and water quality, vibration and odor levels, fire protection, access requirements, visual impacts, impacts to wildlife and public safety. Conflicts have occurred between the county and developers and between the county and state officials.

La Plata County was the first to regulate CBM development and its regulations were challenged by gas companies as pre-empted by state or federal laws. The county first adopted regulations affecting CBM development in 1991. Industry challenged the regulations in court and the county's authority was upheld. It issued new regulations in 1995 providing that surface owners be able to determine, within a window specified by the OGCC, the specific areas on their land where drilling could take place. It was again sued, and this time the court struck down the regulations. County officials have emphasized that their goal is to address the impacts of development on communities and not to block CBM production.[213]

Of particular importance to county officials is the objective of equating the surface and mineral estates so landowners can help shape the location and nature of extractive activities that affect their lands, and these officials have proposed that companies be required to negotiate surface use agreements before drilling begins. Industry representatives argue that they already provide those agreements before drilling, while others claim that such requirements are too onerous and will drive industry out of the state.[214] The county challenged an Oil and Gas Conservation Commission rule that strengthened the Commission's power over county regulation of oil and gas development.[215]

In February 2002, J.M. Huber filed a lawsuit against La Plata County Commissioners, charging they had exceeded their jurisdiction and abused their discretion when they denied Huber's request for a reconsideration of a drilling permit condition. The company also asked for and was granted a hearing before the Colorado Oil and Gas Conservation Commission. The condition required the company to install a low-profile or alternative pump and use an electric motor at its Bellflower gas well east of Durango. The company argued the decision was outside the jurisdiction of the county and was within the purview of the state OGCC, and that complying with the county's directive "will cause waste as prohibited (by state regulations) since it will significantly inhibit or limit production from the well." County officials, local residents, and Huber representatives had met during the summer of 2001 to negotiate noise and visual mitigation steps the company would take in operating the well, but were unable to come to agreement.[216]

La Plata County regulations issued in 1998 require permits for drilling to be processed within seven days. The process typically begins with the company identifying a new site, visiting the site to discuss the proposal, and formulating an agreement with the land owner. If an agreement is reached, the company then submits an application for a drilling permit to the county and to the COGCC. The county and commission may attach conditions to the permit, and that process can take up to a month. Once the permit is approved, a pre-construction notice is sent to the surface owner from 1–14 days before construction begins. A permit is good for up to one year; if not used by the end of that period, a new permit is required. As much as two month's time may pass between the time the surface agreement is negotiated and the construction and drilling are completed.[217]

On July 11, 2000, the COGCC approved infill well applications that provided for one well every 160 acres instead of the standard 320 acre spacing. It also issued an order imposing new requirements on companies drilling for CBM in La Plata County, in response to residents' concerns with noise, gas seepage, and impacts on the local landscape. By August 27th, BP had filed 10 applications to drill with the county and five had been approved. County planning officials reported that "for the most part, we're on the same page" with the state commission. [218] The state's general conditions require companies to take the following actions: [219]

- Request a COGCC hearing to apply for new drilling sites located within 1/2 mile of the Fruitland Outcrop,[220]
- Identify all plugged and abandoned wells near each new well site,
- Submit drilling plans to the COGCC.

Surface mitigation requirements include the following:

- Curtail drilling during wildlife "seasonal" times,
- Install electric motors "where practicable" to reduce noise levels,
- Water roads to control dust,
- Use plugged or abandoned well sites when possible to reduce new wells.

Companies are also required to ensure they don't contaminate drinking water by:

- taking periodic sampling of water from wells located within 1/2 mile of each new well, and
- testing the water wells before drilling occurs, one year after drilling is completed, and twice more within the next six years.[221]

If a proposed CBM well site is near a subdivision:

- the COGCC director or staff member must make an on-site inspection,
- an on-site inspection is required if an agreement with the surface owner is not reached.

An attorney for the San Juan Citizen's Alliance asserted that the state's requirements failed to address noise, visual impact, and other serious issues, and the COGCC director observed that the regulations do not address other issues such as noise, decline in property values, compensation to land owners, and problems with private agreements between land owners and gas companies. [222]

Surface land owners have argued that their rights were not protected by the regulations. In July 2000, landowners in La Plata County filed a class action suit against 13 companies, claiming they were not minimizing surface impacts. If the plaintiffs prevail, companies will be required to use smaller well pads and pumping units whenever possible. [223] The litigation was based on a 1997 Colorado Supreme Court ruling that gas companies must minimize adverse, unnecessary impacts on surface lands.[224] That same year, J.M. Huber applied for a drilling permit in a housing development with lots of ten acres or less. After numerous hearings with county officials and 12 public meetings at the well site with residents, the company and county agreed on 13 conditions for drilling, including an electric pump rather than a more noisy gas-powered pump to run the pump jack within six months of when the well starting producing, burying power lines, and using a smaller pump jack. The company subsequently concluded that those conditions would cost tens or perhaps hundreds of thousands of dollars, and decided not to install the electric pump. The company concluded that the permit conditions made the company operate less efficiently and profitably, and asked the county to reconsider whether it had the authority to impose such conditions. The company's attorney suggested that the county was "regulating down-hole production and sound," contrary to court rulings that the state oil and gas conservation commission alone had that authority. Local residents countered with demands that the county hold the company to conditions it had agreed to.[225] In February, 2002, the company sued the county commissioners and petitioned the COGCC, charging that the county had "exceeded its jurisdiction and abused its discretion" when it denied the company's request in January 2002 to reconsider the drilling permit conditions.[226]

The Colorado Supreme Court's *Gerrity Oil & Gas Corp. v. Magness*[227] opinion has been widely discussed in the context of CBM development, and warrants a brief note here. The issues before the court dealt with a claim of trespass in a split estate. The court explained that,

> *Severed mineral rights lack value unless they can be developed. For this reason, the owner of a severed mineral estate or lessee is privileged to access the surface and "use that portion of the surface estate that is reasonably necessary to develop the severed mineral interest." The right to use the surface as is reasonably necessary, known as the rule of reasonable surface use, does not include the right to destroy, interfere with or damage the surface owner's correlative rights to the surface.*
>
> *In this sense, the right of access to the mineral estate is in the nature of an implied easement, since it entitles the holder to a limited right to use the land in order to reach and extract the minerals. As the owner of property subject to the easement, the surface owner " 'continues to enjoy all the rights and benefits of proprietorship consistent with the burden of the easement.' " The surface owner thus continues to enjoy the right to use the entire surface of the land as long as such use does not preclude exercise of the lessee's privilege*. [citations omitted]
>
> *Although we have referred to the mineral estate as the dominant estate and the surface estate as the servient estate, our cases have consistently emphasized that both estates must exercise their rights in a manner consistent with the other. Hence, in a practical sense, both estates are mutually dominant and mutually servient because each is burdened with the rights of the other*. [citations omitted]
>
> *The fact that neither the surface owner nor the severed mineral rights holder has any absolute right to exclude the other from the surface may create tension between competing surface uses. "The broad principle by which these tensions are to be resolved is that each owner must have due regard for the rights of the other in making use of the estate in question." This "due regard" concept requires mineral rights holders to accommodate surface owners to the fullest extent possible consistent with their right to develop the mineral estate. How much accommodation is necessary will, of course, vary depending on surface uses and on the alternatives available to the mineral rights holder for exploitation of the underlying mineral estate. However, when the operations of a lessee or other holder of mineral rights would preclude or impair uses by the surface owner, and when reasonable alternatives are available to the lessee, the doctrine of reasonable surface use requires the lessee to adopt an alternative means*. [citations omitted].

Communities in other states may have general regulations that impact CBM development, but have not yet enacted regulations that directly address CBM. In Montana, local regulation is allowed if it ensures effective utilization of resources. In New Mexico, it is likely to be upheld if it only deals with issues traditionally within the jurisdiction of county government. In Utah, counties are precluded from regulating in areas of state law, where the oil and gas board is given exclusive authority, but it is likely to be permissible for counties to regulate traffic, noise, and compatibility with surrounding activity.

In Wyoming, counties can regulate land use but can't prevent use necessary to the extraction or production of mineral resources. Wyoming counties have hired a coalbed methane coordinator to help resolve problems. A memorandum of understanding between the state, five county commissions, and two conservation districts is in place to help coordinate the efforts of the various agencies and to facilitate the flow of information. The coordinator has emphasized the need for consistency in regulation across the basin, the importance of impact funding early in development before tax revenues are received, mitigation funds contributed by all companies, more research and data on development and its impacts, and more amenities for communities affected by development.[228]

State water law

Most of the discussion of CBM and water focuses on water quality, but there are many questions about how CBM development affects water rights. The Rocky Mountain states have all adopted the prior appropriation approach to water law. Under prior appropriation, ownership of land does not result in ownership of water, but water rights are created when water is diverted and used or appropriated for a beneficial purpose. The main provisions of prior appropriation include the following. [229]

First, appropriated waters need not be used on riparian lands; they may be used any place and need not remain in the originating watershed. The water right is the amount of water put to a beneficial use; there are no limits to the quantity used such as reasonable use, but state statutes typically require right-holders to show that all the water will be beneficially used and not wasted;

- Appropriators are typically required to use a reasonably efficient means of diversion,
- Seniors may not transfer their rights to another or change diversion, purpose of use, or place of use if that harms the rights of juniors,
  —Since about half of the water diverted for agriculture typically returns to the hydrologic cycle, the return flow may be used by other right-holders, and senior right-holders may not adversely affect the return flow; junior right-holders are entitled to the stream conditions that existed at the time they received their appropriation.

Second, the date of the original appropriation established the water right priority date; the holder of the oldest or most senior priority right is entitled to delivery of the full right; junior right-holders are entitled to whatever water is available after senior rights-holders have withdrawn their water;

- All right-holders are ranked according to the dates of their appropriation and each is either junior or senior to all other right-holders,
- If downstream senior right-holders "call" their water, upstream juniors must allow sufficient water to flow past their diversion to meet the rights of seniors.

Third, rights are acquired by use and may be lost by non-use;

- Abandonment occurs when the right-holder intends to relinquish the water right,
  —the burden of proof lies with those who seek to demonstrate that the right holder has abandoned the water right,
  —a period of non-use creates a rebuttable presumption that the right has been abandoned, and the right-holder may then provide evidence of the intent to retain the right.
- Forfeiture does not require the intent to abandon, but may occur when there is non-use for the specified period of time or the diversion construction does not occur.

Fourth, water rights are "perfected" when an applicant receives a certificate or decree from the state water engineer or court recognizing that the water is being put to beneficial use and belongs to the applicant;

- Most states require rights-holders to apply for a permit,
  —All affected parties must be given notice and a hearing must be held to determine whether the criteria for establishing a right have been met,

—The construction of the diversion facilities must occur within a specified time period, and

—The water must be put to a beneficial use.

- Colorado does not issue permits, but, instead, uses a water court system to adjudicate rights; priority is established when the applicant
  —Decides to put the water to beneficial use, and
  —Makes an "open, overt physical demonstration of the intent" that gives notice to third parties.
- Colorado also allows for "conditional decrees" that reserve water for future use; the priority of the right is that of the date of the decree;
  —Applicants must demonstrate that there is a "substantial probability" that the water project "can and will" be completed within a reasonable time,
  —A court must determine whether there is sufficient water available for the proposed diversion.

Fifth, beneficial use generally includes domestic, municipal, industrial, commercial, agricultural, hydropower production, stockwatering, and mining; recreation, fish and wildlife maintenance, and preservation of environmental and aesthetic values have also been defined as beneficial use;

- If water use is deemed beneficial, it cannot be defeated by a more junior claim that water will be put to a more beneficial use,
- However, a right-holder may lose that right if the means of diversion or the use is found to be wasteful,
- The public trust doctrine also places some limits on uses of water to protect environment and recreational interests of the public.

Sixth, water rights are passed to new land owners when land is conveyed unless the grantor expressly reserves those rights, and water rights may be transferred separately from the land if allowed by state law;

Finally, the prior appropriation doctrine is primarily applicable to surface waters. Water that occurs as a result of human labor, such as transbasin diversions, is not subject to appropriation but belongs to those responsible for producing it.

In Colorado, Utah, New Mexico and Montana, water produced from coalbed methane operations is generally defined as byproduct water. Although Wyoming also exempts byproduct water from oil and gas operation from its groundwater permitting system, coalbed methane water does not fall into the exemption, and operators must obtain a groundwater permit from the state engineer and put the byproduct water to a beneficial use.[230]

Colorado water law

Under Colorado law, operators are not required to apply for a permit from the state engineer when withdrawing non-tributary water unless that water will be put to a beneficial use.[231] If the produced water is put to a beneficial use, the state engineer must ensure that it will not cause "material injury to the vested water rights of others."[232] If injury will result, the permit must contain mitigation measure to avoid injury. In Colorado, a reduction of hydrostatic pressure level or water level is not considered a material injury.[233]

The Colorado Oil and Gas Conservation Commission (COGCC) has jurisdiction over produced water, which appears to fall under its definition of "exploration and production waste."[234] COGCC Rule 907 covers the management of "E&P" waste, and it dictates how produced water shall be managed and disposed. Under the rule, if produced water is placed in a pit, it must first be treated to prevent crude oil and condensate from polluting the pit.[235] The rule also contains a number of disposal options including reinjection into a Class II well, evaporation or percolation in a permitted lined or unlined pit, disposal at commercial facilities or through road-spreading, or discharge into the waters of the state.[236] All of these provisions require the operator to receive the proper permits before undertaking any of these activities. The produced water may also be reused to aid in enhanced recovery, drilling or other uses as long as the use follows established water quality standards and water rights.[237] Finally, the rule allows for the water to be used by the surface owner as an alternative domestic water supply that cannot be traded or sold.[238] When water is used in such a manner, it is not considered an implicit admission by the operator that his or her activities are impacting existing water wells.

New mexico water law

New Mexico law classifies water used in the "prospecting, mining . . . or drilling operations designed to discover or develop the natural resources of the state" as a beneficial use, and in certain instances, mine operators must obtain permits to withdraw water.[239] However the state engineer does not have authority over aquifers found at 2500 feet or further below the ground surface that contain nonpotable water.[240] In most instances, coalbed methane wells operating in New Mexico fall under this provision, and thus are not permitted by the state engineer. The Oil Conservation Division of the Energy, Minerals and Natural Resources Department has jurisdiction over "water produced or used in connection with the drilling for or production of oil and gas."[241] The division may regulate surface and subsurface disposal of the water in such a manner as to protect fresh water sources.[242] Particular methods include the use of lined pits and below grade tanks to store produced water,[243] and requirements calling for the prevention and abatement of water pollution so that "all ground water . . . which has a background concentration of 10,000mg/L or less of TDS" is either remediated or protected for beneficial uses.[244] The division also regulates the subsurface injection of produced water into reservoirs.[245]

New Mexico law also contains provisions crafted to protect existing water rights while at the same time promoting mineral development in the state.[246] Under the Mine Dewatering Act, any operator who wishes to appropriate water for a beneficial use or to dewater a mine is given the right to replace the appropriations of existing water rights which may be impacted.[247] The cost to replace the water is solely the responsibility of the operator, who must make an application with the state engineer to replace water.[248] Although an appropriation of water may be made under this act, simply dewatering a mine does not establish water rights for the applicant.[249] The state engineer may only approve an application under this statute if he is satisfied that the plan of replacement will prevent the impairment of affected waters.[250] In approving a plan of replacement, the state engineer must consider the characteristics of the aquifer, present withdrawals on the aquifer and their effects on water levels and water quality, the impact of the mine dewatering on the aquifer, and the "present and future discharge from, recharge to and storage of water in the aquifer."[251]

Utah water law

While Utah also has a groundwater appropriations system,[252] jurisdiction over byproduct water rests with the Utah Board and Division of Oil, Gas and Mining.[253] However, in certain circumstances, the state engineer may issue a temporary water right to put byproduct water resulting from mining development to a beneficial use, but only occurs once the water has been diverted from its underground source.[254] The Division has developed various rules that pertain to the disposal of "salt water and oil field wastes," which include coalbed methane water.[255] Operators may use lined pits,[256] or unlined pits if the disposed water does not have a TDS content higher than ground water that could be affected or other objectionable constituents such as chlorides, sulfates, pH, oil, grease, heavy metals or aromatic hydrocarbons.[257] Unlined pits may also be used when "all, or a substantial part of the produced water is being used for beneficial purposes such as irrigation, and livestock or wildlife watering" and an analysis of the water shows that it can be used for those purposes.[258] Finally, unlined pits may also be used when the amount of disposed water does not exceed five barrels per day.[259] Operators may also opt for subsurface disposal into Class II injection wells under the state UIC program.[260]

Montana water law

Montana is the only Western state that addresses coalbed methane wells directly in its statutes. Under Montana law, groundwater may not be wasted, although in certain situations, including the management, discharge, or reinjection of coalbed methane water, the withdrawal and use of groundwater will not be considered waste.[261] Coalbed methane operators have three management options for the groundwater that is produced from their wells. They may (1) use the water for irrigation, stock water or other beneficial uses, (2) reinject the water into an "acceptable subsurface strata or aquifer" according to the applicable laws, or (3) discharge the water to surface waters or the surface upon obtaining an NPDES permit.[262] While Montana law mandates that no groundwater shall be wasted, the methods of disposal available for coalbed methane produced water are not considered "wasteful" under the law. However, even though the quality of coalbed methane water in Montana is quite good, the sodium absorption ratio (SAR) of the water still may be too high to allow the water to be used for irrigation. Likewise, allowing the byproduct water to be lost down stream or possibly reinjected into aquifers containing a lower quality of water may result in the byproduct water being wasted in fact. Coalbed methane operators are required to notify any other appropriators whose rights may be harmed by the withdrawal of water from aquifers due to coalbed methane development.[263] Furthermore, the operators must offer mitigation agreements to those appropriators whose wells are within one mile of a coalbed methane well or within one half of a mile of any well adversely affected by a coalbed methane well.[264]

Montana law also allows for the designation of controlled groundwater areas. These are areas where groundwater withdrawals exceed the recharge rate of the aquifers within the designated area or are likely to exceed the recharge rate in the future.[265] In order to withdraw and appropriate water from designated groundwater areas, one must obtain a permit showing that the withdrawal will take water that is available, that existing uses will be protected, and that the water will be put to a beneficial use.[266] The Powder River Basin was designated a controlled groundwater area in 1999, meaning that coalbed methane operators are required to obtain permits to withdraw water from the basin. It is questionable whether operators can meet the permit requirements of controlled groundwater areas when the amount of water taken from coalbed methane operations is, to some extent, uncontrolled in an area where the amount of appropriations is already taxing the available resources.

Wyoming water law

Although Wyoming water law contains provisions that deal with byproduct water appropriations, they do not apply to coalbed methane produced water.[267] Instead, the state engineer retains jurisdiction over produced water from coalbed methane wells, and as such, operators are required to obtain groundwater appropriation permits.[268] According to Wyoming water law, applications to appropriate groundwater "shall be granted as a matter of purpose, if the proposed use is beneficial and, if the state engineer finds that the proposed means of diversion and construction are adequate."[269] However, the state engineer may also deny the application if he finds that it would not be in the public's water interest.[270] Beneficial uses of water are outlined in Wyoming water law, and are ranked according to preferences.[271]

The emphasis placed on putting appropriated groundwater to a beneficial use and preventing waste presented problems for initial coalbed methane applicants. On original "Application for Permit to Appropriate Ground Water" forms, appropriators were required to specify the use to which the water would be put. Operators often checked the "miscellaneous" box and stated that the water was used to produce coalbed methane. Present forms now have an individual box for coalbed methane operators to check.[272] Apparently, the state engineer now considers the production of water in connection to coalbed methane development alone a beneficial use of ground water.

While coalbed methane produced water varies in quality across the region, it does not generally approach the poor quality of conventional oil and gas byproduct water, which can reach TDS levels five to ten times that of the worst coalbed methane water, and in some cases is of relatively high quality. Regulating coalbed methane-produced water under the traditional oil and gas regulations runs the risk of wasting a potentially important source of water. Given the value of the water which many believe is at least as valuable as the gas, if not more so, state legislatures may decide to fashion provisions expressly aimed at defining who owns CBM produced water and what should happen to it.

A variety of theories have been suggested for governing the withdrawal and use of groundwater in CBM development. (1) States could declare the owner of surface lands the owner of all the water under it as part of the soil; most states have rejected this approach since it provides no recourse when land owners deplete or contaminate groundwater. (2) States may allow landowners to withdraw reasonable amounts of water as long as that use is connected to the beneficial enjoyment of the land. (3) California provides for withdrawals from a common aquifer equal to the proportion of ownership of the land above the aquifer, in recognition that withdrawals by one land owner affect the water available to other land owners. (4) States may employ tort law to hold liable those whose withdrawal of water harms neighboring land owners, is beyond a reasonable share of water use, or affects surface water in ways adverse to right-holders of that water. (5) States may apply prior appropriations principles, but since senior right-holders might drain an aquifer, states may limit the protection provided for seniors through principles such as "unreasonable interference," where the "lowering of the water table is not per se an unreasonable impairment of senior rights." [273]

States may require permits for water withdrawal to protect water rights and water quality. Permits may specify that withdrawals do not exceed recharge rates or adversely affect groundwater rights. Permits may regulate withdrawals of groundwater in areas where surface and groundwater are interconnected in order to protect the senior water rights from junior well owners whose pumping may diminish surface water. In Colorado, juniors may pump underground sources if they augment surface right-holders with supplemental water to offset any loss in surface water from groundwater removal. To protect water quality, states may require that wells do not draw contaminants into an aquifer. If such contamination occurs, landowners may pursue tort claims against those who have contaminated their groundwater. If they have no water appropriation rights, landowners may still pursue nuisance claims if contamination unreasonably interferes with their use and enjoyment of the land above the aquifer.[274]

CBM development and pending national legislation in 2002

Both Houses of Congress have passed major energy bills and concerns about energy prices, energy imports and national security, and other energy issues are likely to lead to legislation in 2002.[275] While the national debate has focused on other issues, such as opening the Arctic National Wildlife Refuge and increasing fuel efficiency requirements, some proposals address coalbed methane development, and the future of these CBM-related provisions are linked to the prospects for passage of the broader bills. The following proposals for legislation affecting CBM development are currently before Congress:[276]

Conflicts between coal and CBM development: In response to conflicts between coal and coalbed methane companies, members of Congress introduced H.R. 2952/ S. 675, the Powder River Basin Resource Development Act, which sets up a process to resolve conflicts between coal and CBM development; coal companies are complaining that coal development is a more valuable lease and they are being held up by CBM development, in response to the *Amoco v. Southern Ute* ruling. The proposal would establish a dispute resolution process; if negotiations fail, the parties file a petition in court and the court will decide which resource is of the greater value and give development rights to it. The less valuable lease will be suspended, typically the CBM lease, and damages awarded to the CBM company. The coal company will get a royalty credit to reimburse them for the payment they make to the CBM company, and as a result the federal government would lose royalty payments and will also reimburse the state for any loss of its CBM royalties.

Environmental impacts of CBM development: Section 607 of the Senate's energy bill, S 617, orders a National Academy of Sciences study of the effects of CBM development on surface and water resources (in the May 2002 Senate energy bill). The NAS would have 18 months to study issues such as water disposal, impacts on groundwater supplies, surface impacts, and possible mitigation associated with CBM production. The Secretary of Interior would then be required to respond to the study and make recommendations for legal or policy changes she feels are required as a result of the study.

Tax credits: Both the House and Senate energy bills would extends and modify the section 29 tax credit for nonconventional fuels. The current tax credit ends January 1, 2003; the House bill would extent it through January 1, 2007; the Senate version would only extend it for three years. The bills also authorize increased spending for permitting processing and inspections and enforcement.

Hydraulic fracturing: As indicated above, the EPA is expected to release sometime in 2002 a draft report on the impacts of hydraulic fracturing during CBM production on underground drinking water sources. If the EPA reports little or no harm the study will end; if harm is shown, there will be multiyear field studies. A provision in the Senate energy bill requires the EPA to complete a study on fracturing within 24 months of enactment, and the National Academy of Science to review the study within nine months

While there has been some discussion of legislation to address surface use agreements, no bills are currently being considered. The oil and gas industry is strongly opposed to the requirement, and ranchers and other land owners are adamantly in favor of legislation, and members of Congress have been unable to broker an agreement so far. There may be some possibility for administrative changes, such as BLM encouragement of more surface agreements, and possible incentives for companies and surface owners to negotiate agreements.

IV. How can conflicts surrounding CBM development be reduced?

Findings and conclusions

From the perspective of many landowners, government officials, and energy companies, coalbed methane development is a great success. It is a source of jobs, income, corporate profits, tax revenues, royalty payments, and other benefits. Many companies are trying to work with local residents to minimize impacts and reduce conflicts. Some company officials argued that there are no real problems with CBM development, and it may be that the majority of companies and community members are satisfied with the way development has unfolded and the public policies that are in place. The strong statements of concern offered at the NRLC conference in April, as well as those that have regularly appeared in other meetings and in media stories, are, however, compelling evidence that some problems have occurred.

Given the great number of companies developing CBM resources, it is likely that some companies are better than others in working out problems and conflicts. It is not surprising that the rapidity of CBM development has resulted in unwanted impacts on and polarization and division across communities and local residents. Nor is it surprising that land owners, ranchers, and recreationists clash with energy companies who all envision very different uses of the same land or that conservationists and developers do not see eye-to-eye over whether roadless areas and wild lands should remain untouched by roads, pumps, pipelines, and power lines. Nevertheless, a review of the issues discussed in this report suggests the following conclusions about CBM development and associated problems.

1. Coalbed methane is an important and valuable resource in meeting the nation's energy demand. CBM is a growing component of the natural gas that is produced in the United States each year, and demand for natural gas to generate electricity is expanding rapidly because it is a secure, domestic source of energy and is the cleanest burning fossil fuel. CBM is a particularly valuable resource in the Western United States and is an important source of income and jobs to westerners and revenue to local, state, and national governments.
2. A unique challenge posed by CBM development is the speed in which change is occurring. Parties are forced to deal with issues of produced water, conflicts between landowners and those who lease mineral rights, impacts of development on communities, demands for governmental and regulatory services, and other issues in a very compact time frame.
3. As is true with other forms of energy production, there have been numerous conflicts between local land owners and energy companies over the impacts of development on other uses of land, noise, and property values. These are a result of split estates and division of ownership of the land and underlying resources; the lack in some cases of the formulation, implementation, and enforcement of adequate surface use agreements; impacts from development on lands owned by one landowner that spill over to adjacent landowners that are not addressed by agreements; disputes over the calculation of royalties; and other differences. Some companies have developed better relations with surface land owners than others.
4. Like other forms of economic activity, CBM development poses challenges for local communities that must absorb increased traffic, noise, air pollution, demands on housing and public services, and other consequences of growth. Impact fees, property taxes, royalties, and other financial resources can help communities cope with growth, but the consequences of growth may come much faster than the eventual flow of funds. Local governments bear the brunt of dealing with the consequences of growth but may lack the resources and authority to address them effectively. Depending on state law, local governments may or may not benefit directly from royalties or severance taxes derived from development.
5. Governance in the United States is fragmented, overlapping, and complex. Natural resources, watersheds, and ecosystems implicated in energy development ignore state and other governmental boundaries.

Governance is particularly complicated in the West by large parcels of public lands and reservations that add additional layers of sovereignty and governmental authority. Federal, state, and local governments all have some regulatory authority over CBM development and a major challenge for energy companies, landowners, and other concerned citizens is negotiating this complex structure of jurisdictions whose policy making efforts are often uncoordinated and inconsistent. Most agencies lack the finances and staff to meet all the demands on them for expeditious processing of applications, timely and comprehensive assessment of environmental impacts, monitoring and enforcement of agreements, and long-term planning.

6. Given the aridity of the West, dealing with the impact of CBM development on water is a tremendous challenge. While there is considerable uncertainty concerning the impact of CBM development on water quality, some residents are convinced that development at least exacerbates the natural seepage of methane into drinking water sources if not directly contaminating aquifers. Produced water can inundate desert ecosystems and damage fragile soils, cause erosion, and pollute cleaner bodies of water. Perhaps most importantly, water is so valuable and scarce that any activity that seems to waste it is problematic.
7. Despite some progress in bringing energy companies and land owners together to resolve differences, considerable efforts at public education and communication, and experience all parties are gaining in understanding and addressing the impacts of CBM development, conflicts and pressures will likely continue as the density of development increases and new lands are opened to development. In some areas, parties may be able to strike a balance between energy extraction and grazing, between economic incentives for development and impact fees and taxes, between government regulation and market forces, and between water used for energy production and for other purposes. In other areas, such as wilderness study and roadless areas, development may be precluded by commitments to preservationist values. Major challenges include identifying lands that should not be leased or developed, examining how we can promote domestic energy and provide for other land uses, and devising analytic tools and frameworks for helping decision makers to clarify and make appropriate choices.
8. As of the writing of this report, in May 2002, the future of CBM development is uncertain. Because of its plentiful supply and clean-burning characteristics, demand for natural gas will continue to grow. But legal challenges may slow development. As explained above, the Department of Interior's Board of Land Appeals decision in April 2002 that the BLM did not perform adequate environmental reviews before issuing three leases in Wyoming may be reversed by the Secretary of the Interior, expanded to vacate thousands of leases in the basin, and/or be challenged through lengthy litigation. Current production in some areas may be halted until the BLM prepares additional environmental analyses and new resource management plans. Disputes over the BLM's environmental impact statements for CBM in Montana and Wyoming may delay the completion of the analyses that are required before a new round of leases can be approved and CBM development expands.

Principles for assessing options for CBM development

As is true for other natural resource issues in the West, there is no consensus over the problems surrounding coal-bed methane development. Ranchers, farmers, wilderness advocates, county commissioners, company executives, air and water quality regulators, oil and gas commissioners, governors, federal agency officials, and others differ in their diagnoses of the causes of the controversies that have swirled around CBM development and possible remedies. There is, however, strong support throughout the West for bringing together parties to increase communication, generate innovative alternatives for solving problems, and build support for implementing solutions. A variety of rationales, assumptions, and ideas have contributed to these efforts to find new ways to resolve natural resource conflicts, and include the following underlying principles:

SUSTAINABILITY. The idea of sustainability provides a useful lens for assessing the rapidity of CBM development and for examining possible responses. Sustainability emphasizes the interaction of ecological, economic, social, cultural, and other values, so that no one set of values, such as environmental or economic factors, can alone determine policy. The methodology of sustainability builds on the idea of ecosystem services, but goes beyond to include several other additional criteria for assessing policy choices, including pollution prevention rather than treating emissions, sustainable yield of renewable resources, the precautionary principle and preservation of ecological values in the face of uncertainty, true-cost pricing that internalizes environmental costs in market exchanges, the development of economic indicators and measures that reflect depletion of natural resources, considerations of equity and distribution, and preservation of ecological conditions and options for future generations. Sustainability focuses on comprehensive solutions that reflect the interconnections of ecology. It respects the maxim, "everything is connected to everything else," that is at the heart of ecology.

An important feature of sustainability is its integration of ecological protection and economic activity with social equity and political empowerment. Political participation is a key ingredient in ensuring that decisions affecting economic and environmental conditions be made more inclusive. Sustainability is not an ecological concept alone, but also one of social justice, inclusion, fairness, community well being, and political engagement. These social and political values are important and valued in their own right as well as because they contribute to ecological protection. It requires fairness in the distribution of benefits and burdens, a perpetual resource base and ecological services, and a social system that secures the interests of all persons. Sustainability is bound up with notions of strong democracy, participation, community, and those social characteristics are fostered through a scale of personal interaction. So too is a commitment to a land ethic. As Aldo Leopold defined the land ethic, sounding much like a proponent of sustainable communities, "An ethic, ecologically, is a limitation on freedom of action in the struggle for existence. . . . All ethics so far evolved rest upon a single premise: that the individual is a member of a community of interdependent parts. . . . The land ethic simply enlarges the boundaries of the community to include soils, water, plants, and animals, or collectively: the land."[277]

There is ongoing debate over how to define and implement the goal of sustainability and apply it in contexts such as developing fossil fuels and other nonrenewable resources. For some, sustainability means that development and growth continue with some balancing of economic and environmental values, while others give primacy to ecological health and place severe constraints on economic activity.[278] Despite global agreements that appeal to sustainability, the concept is inextricably intertwined with the idea of community, and the most thriving examples of sustainability seem to be in that context. Dale Jamieson, for example, argues that, at the local level, sustainable works in the negative: we can agree when local land practices are not sustainable:

> *In many specific contexts the language of sustainability can be made more useful by focusing on what is unsustainable rather than on a positive definition of sustainability. Often people who would initially disagree about what sustainability is can agree about when something is unsustainable. Ranchers and environmentalists (for example) may agree that eroded, denuded land is unsustainable, even if they disagree about what it would be like for the land to be sustainable.*[279]

The idea of sustainability suggests a number of principles that might illuminate the choices surrounding CBM and other forms of energy development:

- Ensure sustainable yield of resources
- Integrate ecological, economic, and community values
- Secure inter- and intra-generational equity and fairness
- Prevent problems rather than treat their impacts
- Conserve ecosystem services in the face of uncertainty
- Promote community, local empowerment/responsibility
- Develop true-cost prices that internalize all costs

COLLABORATIVE DECISION MAKING. The idea of sustainability is intertwined with community-based, collaborative decision making as a process for making sustainable policies. Collaboration seeks to avoid the conflict, litigation, and other problems that have plagued other planning processes, and provide a forum for government officials from different levels of government and overlapping jurisdictions to work together. Various forms of collaborative processes are likely to be used by communities as they develop plans and policies for making CBM development more sustainable. Proponents argue that successful collaborative processes involve the interests or stakeholders who are most affected by decisions, empower local environmental protection groups to advocate for broad environmental values in local decisions, ensure that all interests have adequate resources to represent their views and participate effectively, allow agencies to facilitate participation among stakeholders and develop plans responsive to their concerns, within the constraints of national laws and policies, reduce conflict among stakeholders, generate opportunities to find innovative, and low cost solutions, and promote partnerships between agencies and stakeholders that promote implementation and foster problem solving and learning by experience.[280]

One critical issue here is determining the goal of collaboration: is it to produce actual decisions and plans that governmental authorities simply adopt, or to assist decision makers in discharging their responsibilities? The more collaborative groups are seen as advisory, the less of a concern there is about displacing agency authority. But the more decision-making power collaborative groups have, the more opportunities there are to capture the advantages of collaboration. Collaborative groups have arisen in response to the inadequacies of traditional, agency-based decision making, so there are strong incentives to find new processes and structures.[281]

There are significant challenges involved in devising effective collaborative efforts. The processes may exclude national stakeholders' views and weaken national environmental commitments. They fragment decision making and reduce the power of national planning efforts. Critics warn they inevitably benefit industry interests that are typically better funded than conservation groups and they fail to encourage agencies to make the often difficult decisions mandated by environmental laws. Collaborative efforts must respond to the concern that the efforts de-legitimize the conflict that is sometimes required to move away from unsustainable use of resources and toward their preservation and co-opt the strength of environmentalism as a force rooted in broad public support. Such efforts may increase the costs and time required to make decisions, and win-win solutions will not always be possible as natural resources become increasingly scarce and preservation values fundamentally collide with commodity interests.[282] Part of the evolution of natural resource policy making will be the development of new ways of bringing members of a community together to devise plans that will meet sustainability goals and will generate strong commitments to comply with the difficult choices to be made. While each landscape is different, lessons from one area can be shared with others. Open and inclusive processes that encourage broad participation, initiatives that capitalize on a sense of place and landscape, and agreements that clearly meet or exceed the protections required in natural resource laws are some of the keys to constructive collaboration.[283]

CBM development in the West will inevitably expand as demand for natural gas continues to grow. Companies will continue to operate in areas where resources are already being developed and conflicts may diminish in some areas as combatants become weary or irresponsible companies go out of business. Future CBM plays may pose new conflicts over protecting sensitive lands. The challenge is to manage development in ways that promote ecological, economic, and community sustainability. The interest expressed by many companies in building community and protecting local environments can combine with everyone's interest in reducing conflict. CBM development can be the basis of collaborative efforts that reduce conflicts, resolve problems, and ensure that energy production continues in a more sustainable fashion. Consensus-based decision making suggests the following general principles that can guide CBM decisions:

- Recognize the importance of place-based decision making and a land ethic
- Ensure the participation of all affected interests
- Integrate overlapping government jurisdictions
- Develop partnerships for designing and implementing solutions
- Learn from experience and engage in intelligent trial-and-error
- Employ adaptive management techniques and approaches.

Sustainability and collaboration are reinforced by the Western Governors Association and others who have embraced principles of balance and stewardship in environmental policy making that is reflected in a concept labeled "enlibra." Enlibra, a hybrid term from Latin words, is a set of principles aimed at promoting solutions to natural resource conflicts that avoid litigation, torn communities, and natural resource wars.[284] The governors endorsed the idea as governing principles in 1997 and have held two summits in the West in order to encourage use of enlibra in addressing problems of population growth, developing natural resources, providing for economic growth in new service industries, adjusting to the globalization of markets and competitiveness, controlling more diverse and diffused sources of pollution, changing land use patterns, and new technologies.[285] Enlibra builds on collaborative efforts the governors developed in the 1990s that are reflected in the Park City Principles for Water Management, the High Plains Partnership, the Grand Canyon Visibility Transport Commission, the Oregon Plan for Salmon and Watersheds, the Texas Regional Water Supply Planning Process, Trails and Recreational Access for Alaska, and the Wyoming Open Lands Initiative. These efforts reflect "strong commitment from state and local government, vested local support, and federal collaboration."[286] Enlibra embraces the following eight principles:

- National standards, neighborhood solutions—assign responsibilities at the right level, give flexibility to non-federal governments, and provide accountability
- Collaboration, not polarization—use collaborative processes to break down barriers and find solutions
- Reward results, not programs—move to a performance-based system that encourages problem solving, not just compliance with programs
- Science for facts, process for priorities—separate subjective choices from objective data gathering and seek agreement on facts and uncertainties before framing choices
- Markets before mandates—pursue market-based approaches and economic incentives whenever appropriate
- Change a heart, change a nation—support environmental understanding and education about stewardship
- Recognition of benefits and costs—make sure all decisions affecting infrastructure, development, and environment are fully informed by life-cycle costs and economic externalities
- Solutions transcend political boundaries—use appropriate geographic boundaries to identify the full range of affected interests and facilitate solutions to environmental problems.[287]

The Bush administration has embraced the principles of enlibra. The White House Council on Environmental Quality co-hosted the Western Governors' Association's enlibra summit, and EPA administrator Christie Whitman and Interior Secretary Gale Norton both endorsed its principles in speeches given at the meeting. Administrator Whitman's National Environmental Performance Partnership System emphasizes collaboration between federal and state governments in setting priorities and defining roles. Secretary Norton's "4 Cs"—"communication, cooperation, and consultation in the service of conservation"—is another reflection of these principles.[288] They are rooted in a decades-long effort to redefine federalism and refine the relationship between federal, state, and local governments in natural resources and other policy making arenas that have been given labels like cooperative federalism, new federalism, and policy devolution.[289]

Proponents of these principles of collaboration and conservation will need to be responsive to the fears of environmentalists that devolution to state and local policy making will weaken compliance with national environmental standards and require battles for conservation that were won at the national level be re-fought in each state. An important strength of the environmental movement lies in its ability to tap into broad public interest in protecting the environment and in the aggressive use of the courts to ensure national laws are implemented faithfully, and that they are disadvantaged in other forums. The participation of environmentalists in policy making efforts sponsored by the administration, western governors, and others will likely require a strong commitment to the principles of balance and fairness.

Recommendations for the governance of CBM development

While there are some differences between these prescriptions for policy making, they share a common core of ideas:

- solutions to problems need to engage a wide range of affected interests in their design and implementation,
- national environmental standards need to be pursued in light of local conditions,
- fragmented governmental jurisdictions need to coordinate their efforts,
- policy makers need to balance competing interests and values such as preservation and resource extraction, and

- the interests of future generations need to be reflected in decision making.

The widespread commitment to these principles for managing the West's natural resources and preserving its unique environment is, of course, not a reflection of a consensus over how to deal with CBM development and a host of other issues. Not everyone embraces the principles and some are quite skeptical of their utility in bringing Westerners together in ways that adequately protect national values and environmental quality. If one begins, for example, with the view that the most pressing public purpose is extracting energy resources as quickly as possible to help reduce vulnerability to imported sources of energy, these principles will likely be viewed as a diversion. But they reflect the common view, at least at the level of basic commitments, of a wide range of interests. Applying them to the problems and challenges surrounding CBM may help illuminate possible solutions as well as some of the strengths and weaknesses of these principles of sustainability, collaboration, enlibra, and cooperation in guiding energy policy in the West.

Workshops in existing CBM basins

The active support of and participation in problem solving forums requires sacrifices of time and resources on the part of all parties. Environmental and community group volunteers will need to find time to participate in proceedings, as will industry executives and government officials. While those investments may be costly in the short-run, they may prevent and reduce conflict in the long-run. Environmental groups do not give up their ability to seek remedies in court, but may defer such efforts until more collaborative forums are supported first. Energy companies will be required to take more time initially to meet with land owners and others and lay the foundation for obtaining drilling and water discharge permits, but that investment can result in fewer conflicts, problems, and delays in the future.

Since the problems and conflicts surrounding CBM development differ considerably by basin, it makes sense that people in each basin work together to design and implement solutions. A series of workshops could provide a forum for those interested in CBM development in each basin to produce recommendations and guidelines to governments, companies, and residents concerning many of the most contentious issues surrounding CBM development. Such collaborative efforts seem to be most promising when they are characterized by clear and discrete tasks to be accomplished within a limited time frame, strong leadership and commitment by affected interests, and adequate resources to support the analyses required and ensure the participation of all interests. These workshops could draw upon the expansive materials already available, including environmental impact statements, reports, and studies as well as commission additional research that may be needed. Participants might include representatives from the BLM and other federal agencies, state oil and gas commissions and boards, state air and water quality agencies, county commissions and planning boards, other governmental bodies, as well as citizen and industry representatives.

The first forum could be convened as a pilot project to work out the details of who would participate, how commissioned research would be funded, what kinds of recommendations and guidelines might be produced, and how the forum would be structured. The agenda for these workshops could include the following questions set out below. A separate workshop could be convened for each issue, or a workshop could take on two or three issues.

1. How can the rights and interests of surface and mineral owners be balanced?

Stewardship, sustainability, and collaboration all require that those who own and live on the land play a major role in determining how development occurs. If landowners cannot help shape the surface impacts of CBM development then they will simply not be viable partners in ensuring the sustainability of the western landscape. Their participation in determining the location of pumps, compressors, pipelines, and roads need not be a threat to the ability of companies to extract the gas profitably, and there needs to be a balance between the needs of companies and land owners. Established mineral law generally emphasizes the rights of those who hold leases to extract minerals, and companies could stand firm on this superiority issue. But harmonizing surface and mineral owner rights is an essential element of reducing the conflict surrounding CBM development and balancing resource extraction with other uses of the land. The Supreme Court of Colorado ruled in 1997 that the rights of mineral and surface owners must be exercised in a manner consistent with each other: "Both estates are mutually dominant and mutually servient because each is burdened with the rights of the other."[290] Other states could choose to embrace a similar view. Some suggestions for ways of improving cooperation and reducing conflict between surface owners and companies that could be discussed in CBM workshops include:

- Require consultation and encourage surface owner agreements on split estate lands before issuing drilling permits and effectively enforce this requirement and monitor compliance
  - —Some companies report that they already require such agreements before drilling begins;
  - —Companies can give land owners options for different ways to locate development and allow them to choose the option that minimizes conflict with other uses of their land;
- Provide an ombudsperson or expedited dispute resolution process to address problems with surface owner agreements;
- Create incentives for companies to work closely with landowners through royalty credits, awards and recognition, and other efforts;
- Assess the need for legislative changes in oil and gas laws to better reflect the balance between land owner and mineral development rights.

2. How can the true costs of resource development be provided for?

The costs of leases, royalty or severance taxes, exploration, extraction, and transportation are reflected in the price at which gas is sold. But other costs of development, including the surface land owner's financial, opportunity, aesthetic, and other costs of the development of CBM resources are often not represented in those prices. Competitive pressures between CBM and other sources of natural gas plays, and between natural gas and other energy sources, create powerful incentives to externalize costs, and the commitments of companies to ensure that prices include more of the real cost of production is essential. CBM workshops might explore several options for better internalizing the costs and benefits of CBM development, including the following:

- Compensate split estate landowners for surface access, mitigation of impacts, damages, and loss of property values resulting from gas development with mineral lease revenues and royalties;
- Require adequate reclamation bonding or create an escrow fund from lease and royalty revenues to ensure the implementation of reclamation agreements.

3. How can the process of issuing permits and enforcing permits and other legal requirements be improved?

Enforcement of permit stipulations, relevant laws, and other legal requirements is important in recognizing the efforts of responsible companies and in creating clear incentives for compliance. Both industry and community representatives emphasize the need for effective enforcement. Effective enforcement helps ensure that all companies are required to incorporate the costs of balanced and environmentally sensitive development in the prices they charge and some firms are not able to undercut their competition by reducing environmental protections. Effective enforcement is a regular refrain of community groups who want to ensure that standards are applied consistently and fairly. Ideas for improving permitting and enforcement efforts of federal and state agencies include the following:

- Secure additional funding for processing, issuing, and enforcing permits, through permit fees on applications as occurs in other environmental permitting (Clean Air Act operating permits, for example), royalty payments, and other sources;
- Ensure companies that are not acting responsibly are identified and sanctioned for noncompliance with relevant laws and regulations;
- Create incentives for companies to comply with permit requirements through self-audits and other innovations that allow conscientious companies to demonstrate compliance and government agencies to focus enforcement resources on problem companies.

4. How can the interests of counties to regulate the impacts of CBM development be better integrated with state and federal agency regulation of CBM development?

Counties are at the front lines of efforts to deal with the impacts of CBM development and they need the legal and financial resources to address those impacts and to be able to coordinate energy and other forms of economic development with zoning and other land use planning efforts. State laws give responsibility to oil and gas commissions to regulate resource extraction and typically emphasize efficient production of resources and minimization of waste, and may not provide much guidance for how the impacts of extractive activities should be addressed. In some areas, county and state official appear to be working together with minimal problems, while in a few areas, conflicts between state and county officials are a major issue. State agencies should work with counties to develop clear statements of authority concerning the governance of CBM. Workshops could seek to devise guidelines for coordinating the efforts of county, state, and federal agencies that could address the following questions:

- How can state oil and gas commissions and environmental quality agencies and counties harmonize their regulatory concerns and cooperate in regulatory activities?
- How can companies work with counties in coordinating the development of CBM infrastructure among themselves to reduce the number and extent of facilities? Contractual obligations, technological differences, and other factors place limits on sharing infrastructure, but some reduction in impacts is likely.
- What state-county relationships have worked in particular areas and how can successful models be adapted elsewhere?

5. How can ecosystem- or watershed-level planning and coordination for CBM development take place?

Each CBM basin poses a unique set of challenges in governing development, but one commonality is the complex, overlapping, and fragmented framework of governance. Specific regulatory authority is given to a variety of government agencies and those jurisdictions do not reflect the landscape, watersheds, and other factors shaped by development. A workshop involving all relevant agencies and citizen and industry representatives could bring participants together to produce guidelines to:

- Create ecosystem or watershed planning efforts and regional air quality planning processes to ensure that CBM-related decisions are integrated with other land use and development decisions;
- Create forums to coordinate CBM permitting and other regulatory decisions to streamline the time required to make decisions, facilitate public participation in regulatory decisions, and increase communication among decision makers.

6. How can water quality and supply be best protected?

There is clear consensus that water quality must be protected during CBM development, and no consensus over how serious a problem this is. As indicated above, governments can assuage concerns by more effective enforcement of permitting requirements for drilling and for disposal of water. A workshop could bring parties together to:

- Formulate plans to produce accurate baselines for water quality and quantity;
- Review compliance with testing and monitoring requirements and regularly assess those requirements to see if they should be strengthened.

7. How can beneficial use of produced water be fostered?

Water is such a valuable commodity that all parties involved in CBM development should renew their efforts to find ways to ensure that produced water is used beneficially. Suggestions for workshops include the following:

- Clarify legal ownership of produced water
- Develop guidelines and processes to ensure that surface owners are involved in decisions concerning the discharge of water onto their lands;

- Develop a research program to carefully trace what happens to produced water and what its impacts are on surface ecosystems and groundwater.

8. How can effective reclamation be secured in permitting and bonding?

Reclamation is not currently the most pressing CBM development-related issue, but the fear of inadequate future reclamation is undoubtedly a concern of those who seek to slow down CBM development. Given the relatively short life-span of CBM wells, the adequacy of reclamation policies will soon be tested as fields mature. Some of the recommendations discussed above address reclamation, but because of the importance of ensuring that reclamation contributes to the sustainability and stewardship of lands in the West, a workshop could develop specific recommendations on how to:

- Ensure surface owners are involved in reclamation planning through surface use agreements;
- Ensure adequate reclamation requirements are included in permits and adequate reclamation bonds are posted as part of the permitting process.

9. Where should CBM development be prohibited?

In most areas, CBM development and other land uses can be balanced. In a few areas, the choice is either to protect them as undeveloped or to allow some development. The vast majority of public lands are available for resource extraction, and lands where no development has yet occurred contain only a small fraction of total CBM reserves. Wilderness study areas, roadless areas, and other protected lands may contain valid leases and the rights and interests of leaseholders need to be preserved. One of the most difficult challenges for a CBM workshop would be to develop recommendations for placing limits on development, compensating leaseholders fairly if they are not able to exercise their leases, and minimizing impacts of development affecting protected areas. A workshop could address the following questions:

- In what places where there are CBM reserves, such as a roadless areas, wilderness study areas, and national monuments and wildlife reserves, should development not take place? How should such decisions be made?
- How can CBM development take place with a minimum of environmental impact in or near these ecologically sensitive areas?
- How can lease holder rights be protected in areas where it is determined that development should not occur?
- How can the broad commitment to collaboration, communication, and conservation ensure that development of new CBM resources is more carefully and systematic planned and adverse impacts minimized?
- How can the BLM apply principles of adaptive management to planning and leasing actions affecting CBM so that development is balanced with protection of habitat, wildlife corridors, and other environmental values?

10. How can we promote conservation and efficient use of natural gas?

Demand for natural gas is increasing and will continue to do so. Satisfying that demand exclusively through increased production will make it very difficult to balance extraction with other values affected by development. The more efficient the use of natural gas and more effective efforts to conserve its use are, the less pressure there will be on increasing well density and developing new areas. In addition to conservation and efficiency in the use of natural gas, collecting methane that would otherwise escape in the process of mining prevents the waste of an important resource and reduces emissions of a very potent greenhouse gas. While conservation and efficiency efforts are not directly part of CBM development, and may not be in the short-term interest of gas companies, all parties should be interested in the sustainability of natural gas as a transition fuel until even cleaner, renewable energy sources are more widely developed. A workshop might address the following questions:

- How can the amount of methane vented in coal mining and conventional gas operations be reduced?
- How can methane extraction be balanced with conservation and efficiency efforts and the promotion of renewable resources in order to reduce pressures for development on sensitive lands, ranching and agriculture, and other values?

Lessons for emerging basins

The Powder River Basin in Montana, the Green River Basin in Wyoming, and other areas are poised to begin major development of CBM resources. Federal, state, and local government officials, energy companies, and local residents could join in a CBM summit before development occurs to examine the lessons learned in areas where CBM development has already occurred. The results of the workshops suggested above could also be valuable not only to the basins with large-scale existing development, but also to these potential sites. These lessons, indicated by the NRLC April CBM conference, suggest the following agenda for such summits:

- A comprehensive inventory of the location of likely CBM wells and base line data on underground and surface water quality, wildlife and soils, and other important resources likely to be affected;
- A framework of governance to clarify governing authority and ensure the permitting and other regulatory decisions are coordinated;
- A set of guidelines for best operating and management practices for companies from cradle-to-grave CBM operations, landowner/gas company relations, and other issues;
- A plan to ensure adequate funding of the impacts of development on communities, funding of the issuance and monitoring of permits, funding of reclamation, and other costs of development;
- A plan to ensure protection of water quality and beneficial use of produced water.

Notes

1. Vito Nuccio, "Geological Overview of Coalbed Methane" U.S. Geological Survey, Open File Report 01-235 (2001).

2. US Geological Survey, "Coal-Bed Methane: Potential and Concerns" USGS Fact Sheet FS 123-00, October 2000.

3. U.S. Geological Survey, Energy Resource Surveys Program, USGS Fact sheet FS-019-97, "Coalbed Methane—An Untapped Energy Resources and an Environmental Concern" (n.d.). Others suggest that, at similar depths and pressures, coal beds contain from two to four times as much gas as contained in conventional gas reservoirs. J.E. McElhiney, G.W. Paul, G.B.C.Young, and J.A. McCartney, "Reservoir Engineering Aspects of Coalbed Methane" American Association of Petroleum Geologists, "coal-sourced gas: a reprint archive of AAPG articles on coal-sourced hydrocarbons (n.d.) at 361.

4. Karl Lang, "Coalbed Methane Trends," Hart Energy Publications Excerpts in PTTC Network News, 2nd Quarter 2000.

5. D. Keith Murray, "Coalbed Methane Reservoir Evaluation and Completion Technology," in New Mexico Bureau of Mines and Mineral Resources, *Atlas of Major Rocky Mountain Gas Reservoirs, 1993*, at 188.

6. Permeability is measured in units called a Darcy; Powder River coal, for example, often has a permeability of greater than 1 Darcy, which means the coalbeds are quite productive and gas is relatively easily extracted. Lance Cook, "Geology of CBM in Wyoming," NRLC CBM conference, April 4–5, 2002.

7. Gene Whitney, U.S. Geological Survey, testimony before the Subcommittee on Energy and Mineral Resources, Committee on Resources, U.S. House of Representatives (September 6, 2001).

8. Vito Nuccio, *supra* note 1.

9. D. Keith Murray, *supra* note 5, at 188.

10. U.S. Geological Survey, *supra,* note 3.

11. D. Keith Murray, *supra* note 5, at 188.

12. *Id.*

13. National Energy Policy Development Group, "National Energy Policy: Reliable, Affordable, and Environmentally Sound Energy for America's Future" (2001): 5–3

14. *Id.,* at 1–7.

15. Gene Whitney, U.S. Geological Survey, testimony before the Subcommittee on Energy and Mineral Resources, Committee on Resources, U.S. House of Representatives (September 6, 2001).

16. National Energy Policy Development Group, *supra* note 13, at 1–8, 5–18, 5–19.

17. Catherine Cullicott, Carolyn Dunmire, Jerry Brown, Chris Calwell, Ecos Consulting, Coalbed Methane in the San Juan Basin of Colorado and New Mexico (2002):12.

18. National Energy Policy Development Group, *supra* note 13, at 5–3.

19. National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand* (1999).

20. Mark Hand, "The Golden Age: How Long Will It Last?" *Public Utilities Fortnightly* (March 1, 2002): 12.

21. National Energy Policy Development Group, *supra* note 13, at 1–8.

22. *Id.,* 1–4.

23. The provisions that follow are listed in National Energy Policy Development Group, Appendix One, Summary of Recommendations, Chapter Five, Energy for a New Century: Increasing Domestic Energy Supplies, unless otherwise noted.

24. National Energy Policy Development Group, Chapter Three, Protecting America's Environment: Sustaining the Nation's Health and Environment, *supra* note 13.

25. John Watts, keynote address, NRLC CBM conference, April 4–5, 2002.

26. Richard A. Schraufnagel, "Coalbed Methane Production" AAPG, *supra* note 3, at 341.

27. Peggy Williams, "Western Coalbed Methane," *oilandgasin-vestor.com* (November 2001): 34.

28. Vito Nuccio, *spura* note 1.

29. Data provide by Richard Griebling, Colorado Oil and Gas Conservation Commission, November 2001.

30. For more on how CBM compares with other forms of natural gas, see Catherine Cullicott et al., *supra* note 17.

31. Andrew Kelly, "Rockies Seen as Key to U.S. Natural Gas Growth," Reuters (October 25, 2001) http//dailynews.yahoo.com/htx/nm/20011025/sc/energy_gaspackage . . . 10/25/01.

32. The composition of CBM and natural gas in the Powder River Basin differs:

	CBM	Natural Gas
Carbon dioxide	1.1%	1.8%
Nitrogen	0.1	2.1
Ethane	0.1	12.4
Methane	98.6	73.9

See William T. Brown, "Development of Powder River Basin, WY CBM Production" NRLC CBM conference, April 4–5, 2002.

33. Richard A. Schraufnagel, "Coalbed Methane Production" AAPG, *supra* note 3, at 341.

34. The four points that follow are taken from Vello A. Kuusraa, and Charles M. Boyer, II, "Economic and Parametric Analysis of Coalbed Methane" AAPG, *supra* note 3, at 373–74.

35. Richard A. Schraufnagel, "Coalbed Methane Production" AAPG, *supra* note 3, at 342–43.

36. Quoted in Peggy Williams, *supra* note 27, at 38.

37. D. Keith Murray, "Coalbed Methane [CBM] in the Rocky Mountains—Overview," in New Mexico Bureau of Mines and Mineral Resources, *Atlas of Major Rocky Mountain Gas Reservoirs, 1993*, at 165.

38. Karl Lang, *supra* note 4.

39. Matthew Silverman, NRLC CBM conference, April 4–5 2002.

40. Mike Zubler, quoted in Karl Lang, *supra* note 4. .

41. Peggy Williams, *supra* note 27, at 34.

42. Catherine Cullicott, *supra* note 17. .

43. *Id.*.

44. Matthew Silverman, NRLC CBM conference, April 4–5 2002.

45. Catherine Cullicott, ECOS consulting, meeting, February 27, 2002.

46. Bob Zahradnik, "Coalbed Methane Development on the Southern Ute Indian Reservation" NRLC CBM conference April 4–5, 2002.

47. William T. Brown, NRLC CBM conference, April 4–5, 2002.

48. Don Likwarz, NRLC CBM conference, April 4–5, 2002.

49. Terry McCarthy, *Plumbing the Pasture*, *Time*, July 16, 2001, at 22.

50. Institute for Environment and Natural Resources, University of Wyoming, "Coalbed Methane Development in Wyoming's Powder River Basin."

51. Matthew Silverman, NRLC CBM conference, April 4–5 2002.

52. McCarthy, *supra* note 49, at 22.

53. Williams, *supra* note 27, at 38.

54. *Id.,* at 41.

55. *Id.,* at 38.

56. *Id.* at 36.

57. U.S. Department of the Interior, Bureau of Land Management, Wyoming State Office, "Draft Environmental Impact Statement and Draft Planning Amendments for the Powder River Basin Oil and Gas Project" (January 2002): ix.

58. Don Likwarz, NRLC conference, April 4–5, 2002.

59. *Id.*

60. Todd Wilkinson, "Wyoming Weighs the Price of Prosperity," *The Christian Science Monitor* November 13, 2000, at 2.

61. Williams, *supra* note 27, at 42.

62. Institute for Environment and Natural Resources, *supra* note 50.

63. Matthew Silverman, NRLC CBM conference, April 4–5 2002.

64. *Id.*

65. Williams, *supra* note 27, at 42.

66. *Id.* at 43. Another company operating in the basin, Devon Energy, reported typical costs for wells of 1,200 to 2,800 in depth of $350,000. Reserves average 1.25 to 1.75 Bcf per well, and finding and development costs are in the range of 35–40 centers per Mcf. Id., at 44.

67. *Id.,* at 42–43.

68. *Id.*, at 43.

69. Lang, *supra* note 4. .

70. *Id.*

71. Williams, *supra* note 27, at 45.

72. Laura L. Wray, Nicole V. Koenig, and John P. Seidle, "Can Coalbed Methane and Aquifer Development Co-Exist?" *Outcrop* (Newsletter of the Rocky Mountain Association of Geologists) (December, 2001): 1.

73. Lang, *supra* note 4.

74. Colorado Oil and Gas Conservation Commission, Statistic (Visited June 3, 2002) <http://oil-gas.state.co.us/statistic.html.

75. U.S. Department of Interior, Bureau of Land Management, Draft Environmental Impact Statement and Draft Planning Amendment for the Powder River Basin Oil and Gas Project, Vol. 1, at 2–24.

76. D. Keith Murray, *supra* note 5, at 188.

77. *Id*.

78. Vito Nuccio, *supra* note 1.

79. U.S. Geological Survey, Energy Resource Surveys Program, *supra* note 3.

80. D. Keith Murray, *supra* note 5, at 188.

81. *Id*.

82. C.A. Rice and T.T. Bartos, "Nature and Characteristics of Water Co-Produced with Coalbed Methane with emphasis on the Powder River Basin" *supra* note 1.

83. Steve de Albuquerque, NRLC CBM conference, April 4–5, 2002

84. Rice and Bartos, *supra* note 82.

85. Williams, *supra* note 27, at 43.

86. Catherine Cullicott, et al., *supra* note 17.

87. Gwen Lachelt, NRLC conference, April 4–5, 2002.

88. Judy Pasternak, Coal-bed Methane Puts Basic Needs of Water, Energy at Odds," *Los Angeles Times* (March 27, 2001), available at http://www.ogap.org/resources/latimes_cbm.htm.

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90. Judy Pasternak, *supra* note 88.

91. Catherine Cullicott, ECOS Consulting, February 27, 2002.

92. Dave Brown, NRLC conference, April 4–5, 2002.

93. *Id.*

94. Stuart Steers, "Look Out Below! When a Denver Gas Company Started Drilling Wells in Las Animas County, it Brought Bad Feelings to the Surface*," Westword* (Denver, Colo.), Nov. 12, 1998, *available at* http://www.westword.com/issues/1998-11-12/feature.html/1/index.html (visited Nov. 18, 2001).

95. Adam Keller, Planning Office, La Plata County, meeting, February 28, 2002.

96. Institute for Environment and Natural Resources, *supra* note 50.

97. Lance Cook, NRLC CBM conference, April 4–5, 2002.

98. Don Likwarz, NRLC CBM conference, April 4–5, 2002.

99. C.A. Rice, M.S. Ellis, and J.H. Bullock, Jr., "Water co-produced with coalbed methane in the Powder River Basin, Wyoming: preliminary compositional data" USGS Open File Report 00-372 (2000). 1.

100. Williams, *supra* note 27, at 34.

101. Thomas F. Darin and Amy W. Beattie, "Debunking the Natural Gas 'Clean Energy' Myth: Coalbed Methane in Wyoming's Powder River Basin," 31 *ELR* 10566 (May 2001): 10575-76.

102. U.S. Department of the Interior, Bureau of Land Management, Wyoming State Office, "Draft Environmental Impact Statement and Draft Planning Amendment for the Powder River Basin Oil and Gas Project" (January 202): xxiv, 4–12.

103. Mike Day, NRLC CBM conference, April 4–5, 2002.

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105. Mike Day, NRLC conference, April 4–5, 2002.

106. Williams, *supra* note 27, at 43.

107. Wilkinson, *supra* note 60.

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109. Jill Morrison, NRLC CBM conference, April 4–5. 2002.

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114. U.S.C. 315g(c); the Taylor act was repealed in 1976. See Laitos, 333.

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118. *Id.*

119. Catherine Cullicott, ECOS Consulting, meeting, February 27, 2002.

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176. Ellen Nakashima, "Wyo. Drilling Project Gets Failing Grade from EPA," *Washington Post* (May 17, 2002). http://www.washington-post.com/ac2/wp-dyn/A30380-2002May16?language=printer.

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179. *Id.*

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181. This section is based on Kate Zimmerman, NRLC CBM conference, April 4–5, 2002.

182. For more on FOOGLRA, see Kate Zimmerman, NRLC conference, April 4–5, 2002.

183. Wyoming Outdoor Council, 156 IBLA 347 (April 26, 2002).

184. The opinion is available at http://plnfpr.com/landnews.htm; the quotes in this paragraph are from p. 9 of the file.

185. According to one report, reversal by the secretary is unlikely. See Ellen Nakashima, "Ruling Could Delay Wyo. Gas Exploration," *The Washington Post* (May 1, 2002): A23.

186. Walt Brown, NRLC CBM conference, April 4–5, 2002.

187. F.3d 1467.

188. *Id*. at 1474–75.

189. *Fed. Reg*. 45774-75 (July 25, 2000).

190. U.S.C. '' 396a-396g.

191. *Id*. '' 2101-2108.

192. U.S.C. ' 1536(a)(2).

193. *Id.*

194. U.S.C. ' 1266(b)(9) and (11).

195. *Id.*, ' 267(b)(2).

196. For more on state regulation, see Kate Zimmerman, NRLC CBM conference, April 4–5, 2002, from which the following paragraphs on state commissions and boards is extracted.

197. Colo. Sess. Laws 250.

198. COLO. REV. STAT. ' 34-60-106(2)(d).

199. COLO. REV. STAT. ' 34-60-124(4).

200. MONT. CODE ANN. ' 82-11-101.

201. MBOGC regulations are located in Title 36, Chapter 22 of the Administrative Rules of Montana.

202. MONT. CODE ANN. ' 75-1-201.

203. N. M. STAT. ANN. '' 70-2-1 through 70-2-38, 19 N.M. ADMIN. CODE tit. 19, ' 15.1.12.

204. UTAH. CODE ANN. ' 40-6-4..

205. *Id.* ' 40-6-15.

206. *Id.* ' 40-6-5(3).

207. UTAH ADMIN. CODE R649-3-15:

208. UTAH ADMIN. CODE R649-3-34.

209. WYO. STAT. ' 30-5-103(a), 30-5-104(d)(i). Bonding requirements cover only plugging. They do not address reclamation.

210. *Id*. ' 30-5-104(d)(ii).

211. *Id*. ' 30-5-121.

212. WOGCC Rules ch. 4, ' 1(ff).

213. Josh Joswick, La Plata County commissioner, NRLC CBM conference, April 4–5, 2002.

214. *Id.* Josh Joswick, La Plata County commissioner, presentation, Oil and Gas Accountability Project, Energy Summit (Denver, April 6, 2002).

215. Counties issue permits for each well that specifies what mitigation activities are required. If there is a conflict between county per-

mits and Commission standards, the Commission standards are to be binding, but the new regulation makes that provision more explicit and more definitive than counties believe is legal under state law. Interview, Adam Keller, Planning Office, La Plata County, February 28, 2002.

216. Bob Schober, "Producer alleges commissioners 'exceeded jurisdiction,' *The Durango Herald* (February 28, 2002): 1A.

217. Shirena Trujillo, "New rules for wells aimed to address landowners' concerns," *The Durango Herald* (August 27, 2000): http://199.45.202.146/OILGAS/1news2988.htm.

218. Adam Keller, La Plata County planner, quoted in *id.* .

219. *Id.*

220. The Fruitland Outcrop is where the Fruitland coal formation reaches the surface; it runs from northeast of Bayfield down to the Southeast, eventually crossing the state line almost due South of Pagosa Springs.

221. Before these regulations were issued, testing of nearby water wells was voluntary.

222. Travis Stills, San Juan Citizens Alliance, and Rich Griebling, GOCGG director, cited in Shirena Trujillo, *supra* note 191.

223. *Id.*

224. Electa Draper, "Gas drilling company says La Plata's rules too tough," *Denver Post* (January 23, 2002): www.denverpost.com/Stories/0,1002,53%7E352494,00.html.

225. *Id.*

226. Bob Schober, "Producer alleges commissioners 'exceeded jurisdiction.' *The Durango Herald* (February 28, 2002):1A.

227. P.2d 913 (Colo. 1997).

228. Mickey Steward, NRLC CBM conference, April 4–5, 2002.

229. The following bulleted points are taken from the discussion of water law in Jan G. Laitos, *Natural Resources Law* (St. Paul, MN: West Group, 2002): 384–99,

230. This discussion of water law is based on a memo written by Jennifer Kemp, Natural Resource Law Center, June 2002..

231. COLO. REV. STAT. § 37-90-137(7)(a).

232. COLO. REV. STAT. § 37-90-137(7)(b).

233. *Id.*

234. COLO. REV. STAT. § 34-60-103(4.5): "'Exploration and Production Waste' means those wastes that are generated during the drilling of and production from oil and gas wells or during primary field operations and that are exempt from regulation as hazardous wastes under" RCRA.

235. COGCC Rules, Exploration and Waste Management, § 907(c)(1).

236. COGCC Rules, Exploration and Waste Management, § 907(c)(2).

237. COGCC Rules, Exploration and Waste Management, § 907(c)(3)

238. COGCC Rules, Exploration and Waste Management, S 907(c)(4).

239. N.M STAT. ANN. § 72-12-1.

240. N.M. STAT. ANN. § 72-12-25.

241. N.M. STAT. ANN § 70-2-12.

242. *Id.*; *See also* N.M. Reg. § 19.15.1.13.

243. N.M. Reg. § 19.15.1.18.

244. N.M. Reg. § 19.15.1.19.

245. N.M. Reg. § 19.15.9.701.

246. N.M. STAT. ANN. §72-12A-2.

247. N.M. STAT ANN. §72-12A-4.

248. *Id.*

249. N.M. STAT. ANN. §72-12A-5A.

250. N.M. STAT. ANN. § 72-12A-7C.

251. N.M. STAT. ANN. § 72-12A-8.

252. *See* UTAH CODE ANN. § 73-3-1 et seq.

253. UTAH CODE ANN. § 40-6-5(3)(d).

254. UTAH CODE ANN. § 73-3-8(2).

255. UTAH ADMIN. CODE R649-9-1.1.

256. UTAH ADMIN. CODE R649-9-3.1 to 3.2.

257. UTAH ADMIN. CODE R649-9-4.2.

258. UTAH ADMIN. CODE R649-9-4.3.

259. UTAH ADMIN. CODE R649-9-4.4.

260. UTAH ADMIN. CODE R649-5-2.

261. MONT. CODE ANN. § 85-2-505(e).

262. MONT. CODE ANN. § 85-2-521.

263. *Id.* at § 85-2-521(e).

264. *Id.*

265. MONT. CODE ANN. § 85-2-506.

266. MONT. CODE ANN. § 85-2-508

267. WYO. STAT. §§ 41-3-903, 41-3-904.

268. WYO. STAT. § 41-3-905.

269. WYO. STAT. § 41-3-931.

270. *Id.*

271. WYO. STAT. § 41-3-102(b), by application of WYO. STAT. 41-3-906. The statute itself states:

(b) Preferred water uses shall have preference rights in the following order:

(i) Water for drinking purposes for both man and beast;

(ii) Water for municipal purposes;

(iii) Water for the use of steam engines and for general railway use, water for culinary, laundry, bathing, refrigerating, . . . for steam and hot water heating plants, and steam power plants; and

(iv) Industrial purposes.

272. Wyoming State Engineer's Office, Form U.W. 5 (revised as of March 1995).

273. Laitos, *supra* note 229, at 407–09.

274. *Id., at* 410–11.

275. H.R. 4 was passed on August 20, 2001; S 517 (H.R. 4, amended) on April 25, 2002; members of the conference committee were named on April 25, 2002. See Rebecca Adams, "Daschle Must Make Fast Shuffle To Get ANWR Opponents on Panel, *CQ Weekly* (May 4, 2002): 1133.

276. This section is based on John Watts, NRLC CBM conference, April 4–5, 2002.

277. Aldo Leopold, *A Sand County Almanac* (New York: Ballantyne Books, 1966): 238–39.

278. For a thoughtful critique and defense of sustainability, see Thomas Prough, Robert Costanza, and Herman Daly, *The Local Politics of Global Sustainability* (Washington, DC: Island Press, 2000).

279. Dale Jamieson, "Sustainability and Beyond," NRLC Public Land Policy Discussion Paper Series (PL02) (Boulder CO: Natural Resources Law Center, 1996): 12.

280. For a helpful overview and assessment of the functioning of consensus-based groups, see Douglas S. Kenney, "Arguing About Consensus: Examining the Case Against Western Watershed Initiatives and Other Collaborative Groups Active in Natural Resource Management" (Boulder CO: Natural Resources Law Center, University of Colorado School of Law, 2000).

281. *Id.*

282. For a discussion of the challenges facing collaborative efforts and how they might be addressed, see Julia M. Wondolleck and Steven L. Yaffee, *Making Collaboration Work: Lessons from Innovation in Natural Resource Management* (Washington, DC: Island Press, 2000).

283. Barb Cestero, *Beyond the Hundredth Meeting: A Field Guide to Collaboratvie Conservation on the West's Public Lands* (Tucson, AZ: Sonoran Institute, 1999).

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286. Western Governors' Association, "Enlibra," www.westgov.org/wga/initiatives/enlibra/default.htm

287. Western Governors' Association, Policy Resolution 99-013, "Principles for Environmental Management in the West" (June 15, 1999) www.westgov.org/wga/policy/99/990113.htm.

288. Western Governors' Association, *supra* note 259; see also Rebecca Watson, NRLC CBM conference April 4–5, 2002.

289. See Denise Scheberle, *Federalism and Environmental Policy: Trust and the Politics of Implementation* (Washington, DC: Georgetown University Press, 1997).

290. Gerrity Oil and Gas Corp. v. Magness, 946 P.2d 913 (Colorado 1997).

COALBED METHANE DEVELOPMENT IN THE INTERMOUNTAIN WEST: CASE STUDIES

Coalbed methane resources are primarily found in several intermountain states as well as in the Midwest and South. Each CBM basin reflects a different set of environmental, production, and regulatory issues. Surface land owner/subsurface mineral owner relationships, the volume and location of gas, the characteristics of water produced during extraction, state and local legal requirements, and other issues vary considerably. Case studies allow an in-depth exploration of these issues, but if the studies are structured similarly, they also allow for some cross-basin observations. The two case studies presented below examine in detail the San Juan Basin in Colorado and New Mexico and the Powder River Basin in Wyoming and Montana using a similar framework so the analyses and results can be compared and contrasted. The San Juan is a mature, well-developed CBM play that has been the leading source of CBM in the nation. In the San Juan region in Colorado, much of the tension has centered on conflicts between developing energy resources and preserving lands for residential use, recreation, roadless areas, and other goals, and possible impacts of development on drinking water quality. In contrast, the Powder River region is still in the early stages of development and is rapidly growing. Tension has resulted from a different set of conflicts over competing uses of the land, including energy development and ranching, and over the impacts of the produced water on local ecosystems and watersheds. Each case study provides an overview of the basin, a review of its energy and other resources, and an assessment of the tradeoffs between CBM development and important public values.

COALBED METHANE IN THE SAN JUAN BASIN OF COLORADO AND NEW MEXICO

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Summary

The San Juan Basin is a historic oil and gas producing province in the Four Corners region of Colorado and New Mexico. In the 1980s a combination of tax credits and new technologies led to the development of a new resource in the Basin, coalbed methane. In the past 14 years production has increased exponentially in both the Colorado and New Mexico portions of the Basin, and legislation in both states is moving forward in both states to double the density of wells. This proposed infill drilling has prompted local Bureau of Land Management offices to initiate a series of Environmental Impact Statements/Resource Management Plans, two in Colorado and one in New Mexico. This infill drilling could potentially double the number of coalbed methane wells in the Basin over the next 20 years, with at least 4000 more wells being drilled in that time. This is in addition to the already 25,000 total oil, gas, and coalbed methane wells in the Basin, and the expected 12,500 more in the next 20 years. The San Juan Basin has already produced approximately 8.9 trillion cubic feet (tcf) of coalbed methane, and contains an estimated 10–30 more tcf of technically recoverable coalbed methane resource (4–12 tcf economically recoverable at today's gas prices). The most frequently cited "gas-in-place" resource of the San Juan Basin is 50 tcf.

This level of growth in development has significant impacts to the land and communities, but the picture is further complicated by the nature of the governance in the Basin. The San Juan Basin spans two states, three BLM districts, two national forests, four Indian reservations, and six counties, plus private land, two wilderness areas, a National Historic Park and a National Monument. Each level of government has its own regulations affecting the oil and gas industry, which affects the final impacts to the land of the development.

Thirteen different issues/resources with the potential to be impacted by coalbed methane development in the San Juan Basin, including surface and groundwater impacts, split estate lands, communities, effects at the outcrop, and a Forest Service roadless area, further complicate the picture. Each impact can vary in intensity depending on how well planned and executed the devel-

opment is, which depends in large part on the company that does the development. Approximately 90 different companies have coalbed methane operations in the San Juan Basin, and while some, such as BP, win awards for environmental stewardship, others are repeatedly fined for breaking environmental regulations.

Although there is no doubt that the coalbed methane resource of the San Juan Basin will continue to be developed, it is the hope of area residents (ranchers, hunters, recreationalists, and the environmental community, among others) that the energy resource will be developed in a manner that minimizes impacts to the non-energy resources of the area.

I: SAN JUAN BASIN OVERVIEW

Introduction

The San Juan Basin is a major oil and gas-producing province located in the southeastern corner of the Colorado Plateau in Colorado and New Mexico (Figure 1). Oil and gas production has been occurring in the San Juan Basin since the 1920s. Until the last 20 years, this production has tapped conventional oil and gas resources. However in 1976, Amoco drilled a well that would change the focus of oil and gas development to a new resource,

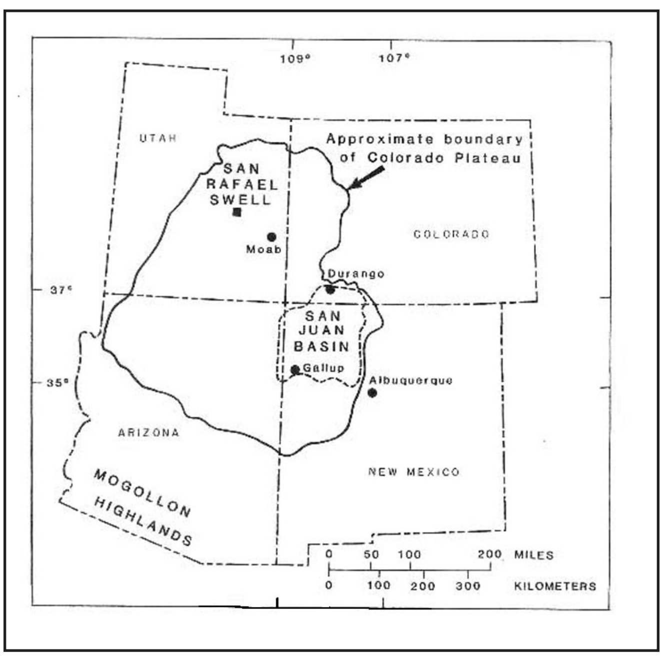

FIGURE 1 *Location map showing the San Juan Basin and Colorado Plateau.*[1]

coalbed methane. This chapter presents an overview of issues surrounding coalbed methane development in the San Juan Basin, starting with a brief introduction to coalbed methane as a resource.

Coalbed Methane, the Resource

Introduction

Much has been written about coalbed methane in recent years. There is increased interest in natural gas generally, because it burns more cleanly than oil or coal. There are abundant reserves of it available within the U.S. and Canada, avoiding the energy security concerns that plague oil. Perhaps most importantly, it is versatile. It can be burned directly onsite at homes and businesses for space heating and water heating, used directly by power plants for generating electricity, and offers significant promise as a transportation fuel (either directly or as a means of producing hydrogen for fuel cells). Methane is the major component of natural gas, so coalbed methane can be used in the same manner as so-called "conventional" natural gas. The recent development of technology specifically aimed at recovering methane from coal seams has led to a boom in production of coalbed methane over the past 15 years. Figure 2 shows areas of the country where this boom in development is occurring. The issues and impacts of developing this resource will be discussed further in Section 2.

CONVENTIONAL NATURAL GAS

Coalbed methane is considered to be an unconventional resource because it is neither formed nor extracted in the same manner as conventional oil and gas. Conventional oil and gas form from source oceanic rocks (shale, limestone) that contain a high percentage of organic (carbon-containing) material originating from microscopic sea creatures. When this organic matter is subjected to the right increased pressure/temperature conditions (referred to commonly as the oil window), liquid and gaseous hydrocarbons are generated. These hydrocarbons are less dense and more buoyant than the surrounding rocks, and therefore migrate upward until they are trapped by some sort of geologic feature such as a fault or fold. They are then stored in the rock (known as the "reservoir rock") under the trap. The oil and gas are trapped in pore spaces within the reservoir rock. This combination of source rock, reservoir

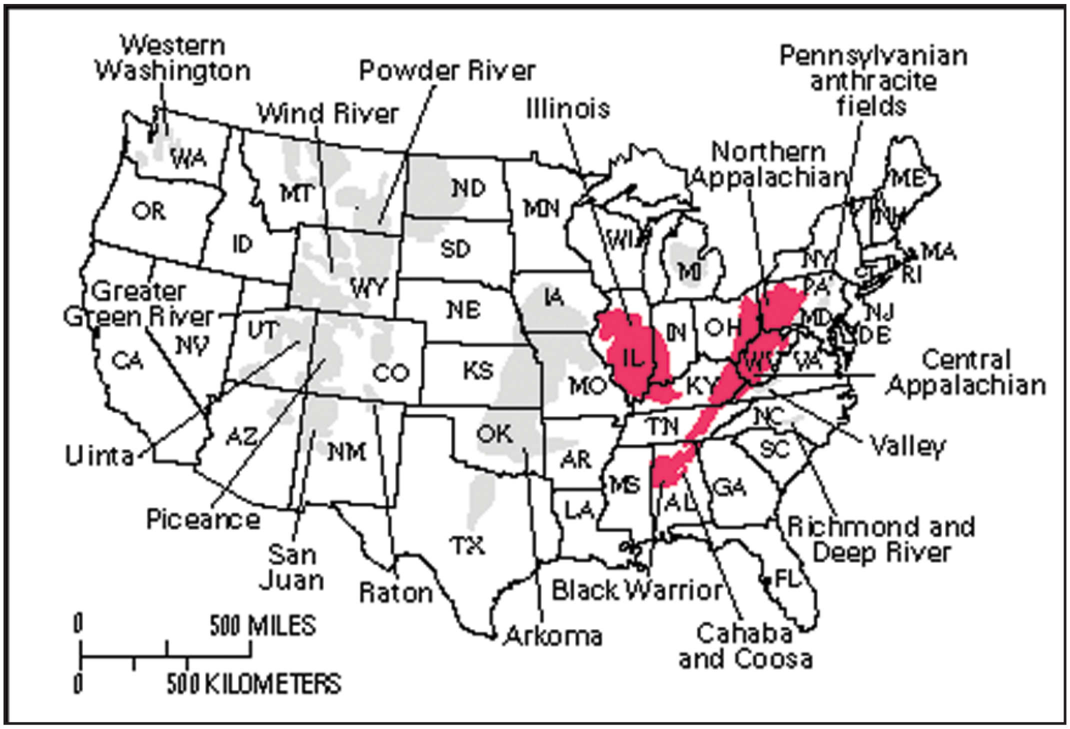

FIGURE 2 *Areas within the U.S. with coalbed methane development and/or potential.*[2] *Areas colored red are basins that emit significant amounts of coalbed methane to the air as a result of coal mining.*

rock, and trap rock is necessary in order for a conventional oil and gas deposit to exist. Because the traps are not generally discernable from the surface, complex exploration strategies are utilized by production companies, including seismic, gravity, and magnetic surveys.

COALBED METHANE

Coalbed methane deposits differ from conventional oil and gas deposits in several ways. Coal-bed gas is present in all coal beds and is formed by biochemical and physical processes during the conversion of accumulated plant material into coal. First, the coal is both the source rock and reservoir rock of the methane, and water within the coal seam is the trap. Second, the coal that generates the methane formed in swampy areas on land, so the source of the organic matter is plant material rather than animal material. Third, when the plant material is subjected to increased heat and pressure (diagenesis), the organic material undergoes chemical and physical changes and turns into coal without moving from the original point of deposition, except for compaction. On average it takes about ten feet of peat/original plant material to form one foot of coal.[3] The methane within the coal is generated by either microbial (biogenic) or thermal (thermogenic) processes shortly after burial and throughout the diagenesis that results from further burial.[4] Fourth, the methane is not just occupying pore spaces within the coal, but is in fact adsorbed or accumulated on the surface of the coal. Water contained in fractures (cleats) in the coal exerts enough pressure on the coal to keep the methane in place. This means that when the coal seam is tapped with a well, gas will generally not flow until after the water has been removed from the coal seam. Removal of the water releases pressure on the coal, and if the coal is sufficiently fractured, release of the water pressure allows the methane to escape (Figure 3). As more water is removed, more methane desorbs (releases) from the coal (Figure 4). According to the USGS, one short ton of coal can produce as much as 46,000 cubic feet of methane.[5] Coal can hold two to three times as much gas in place as conventional sandstone reservoirs.[6] The San Juan Basin coals contain approximately 100 to 500 cubic feet of gas per ton of coal,[7] in different seams throughout the Fruitland Formation.

San Juan basin—geologic setting

The San Juan Basin is a major gas and oil-producing province located in the southeastern corner of the Colorado Plateau (Figure 1). The basin has an elliptical shape, and at its longest is about 100 miles (north-south) by 90 mile (east-west), covering an area of about 7,100 square miles (4.54 million acres).[9] The San Juan Basin is a large bowl in the bedrock that was filled up over the past 500 million years with more than 14,000[10] feet of

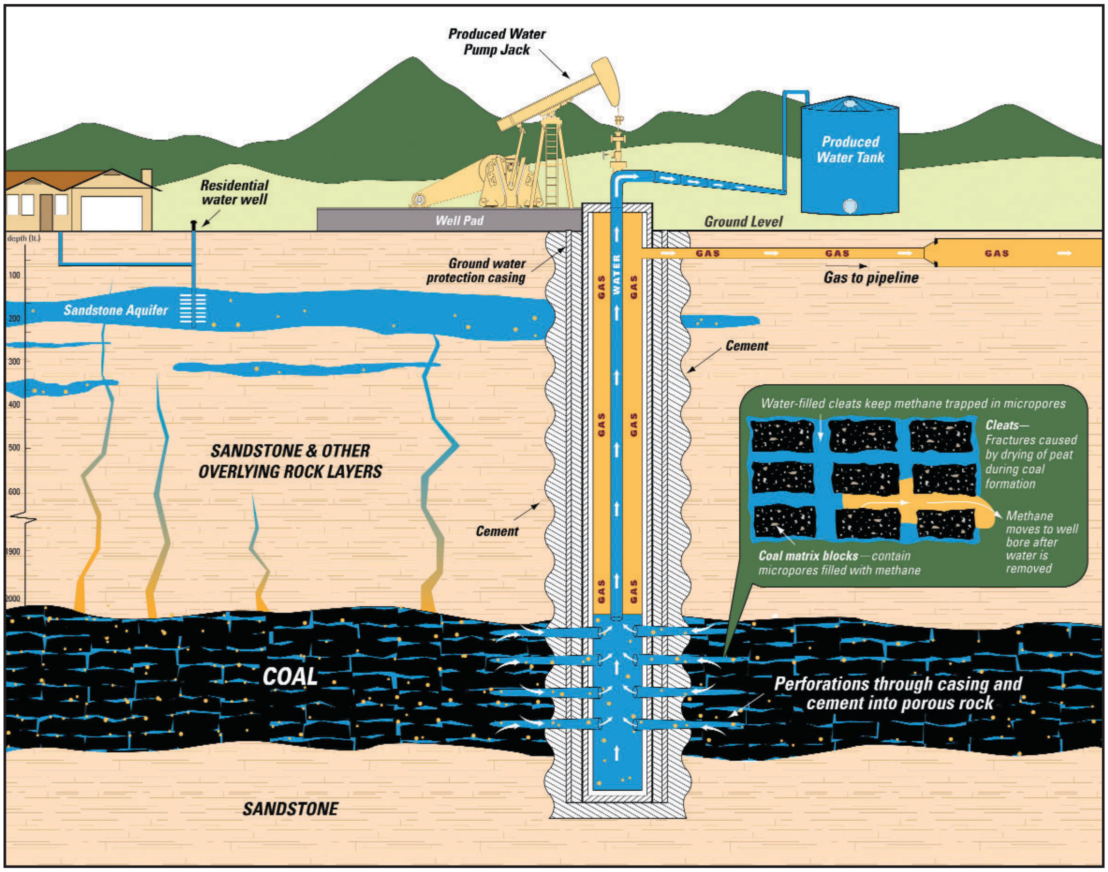

FIGURE 3 *overleaf: Illustration of a hypothetical coalbed methane well, showing detail of coal seam, how water removal causes gas release, gas transport pipes, and aboveground well site equipment (produced water pumpjack, produced water tank).*

sedimentary rocks such as sandstone, limestone, shale, and coal. Extractable accumulations of hydrocarbons exist at many different depths in the San Juan Basin, including conventional gas and oil in the Mesa Verde Group at over 5,000 feet deep, and conventional gas in the Dakota Formation at over 8,000 feet deep.[11] Coalbed methane occurs in two different formations within the San Juan Basin, the Fruitland Formation, with average depth 2,000 feet, and the deeper, older Menafee Formation within the Mesa Verde Group.

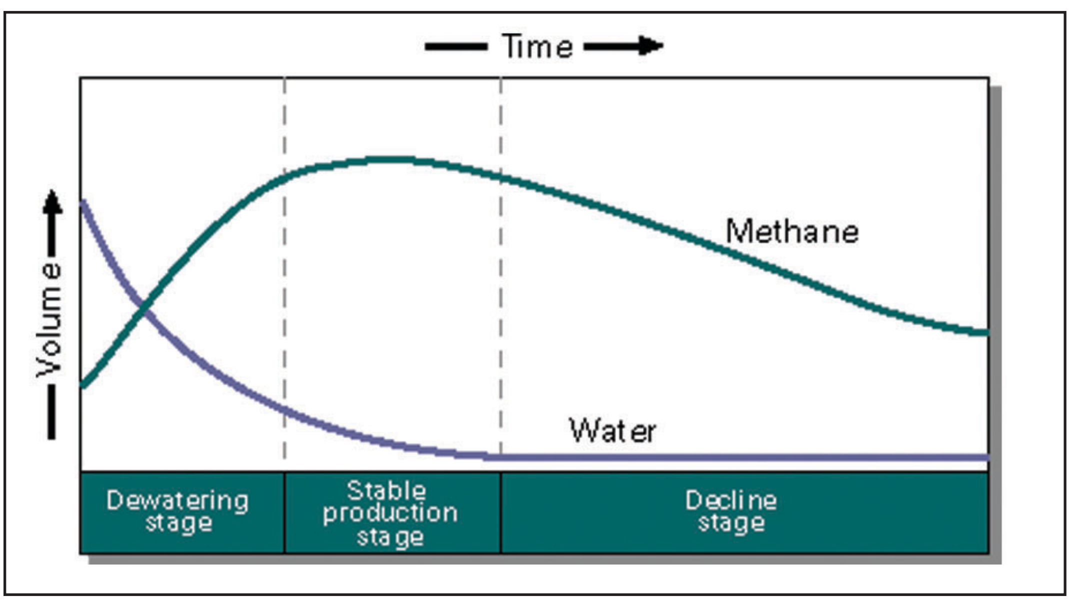

FIGURE 4: *Water and gas production versus time for a typical coalbed methane well.*[8]

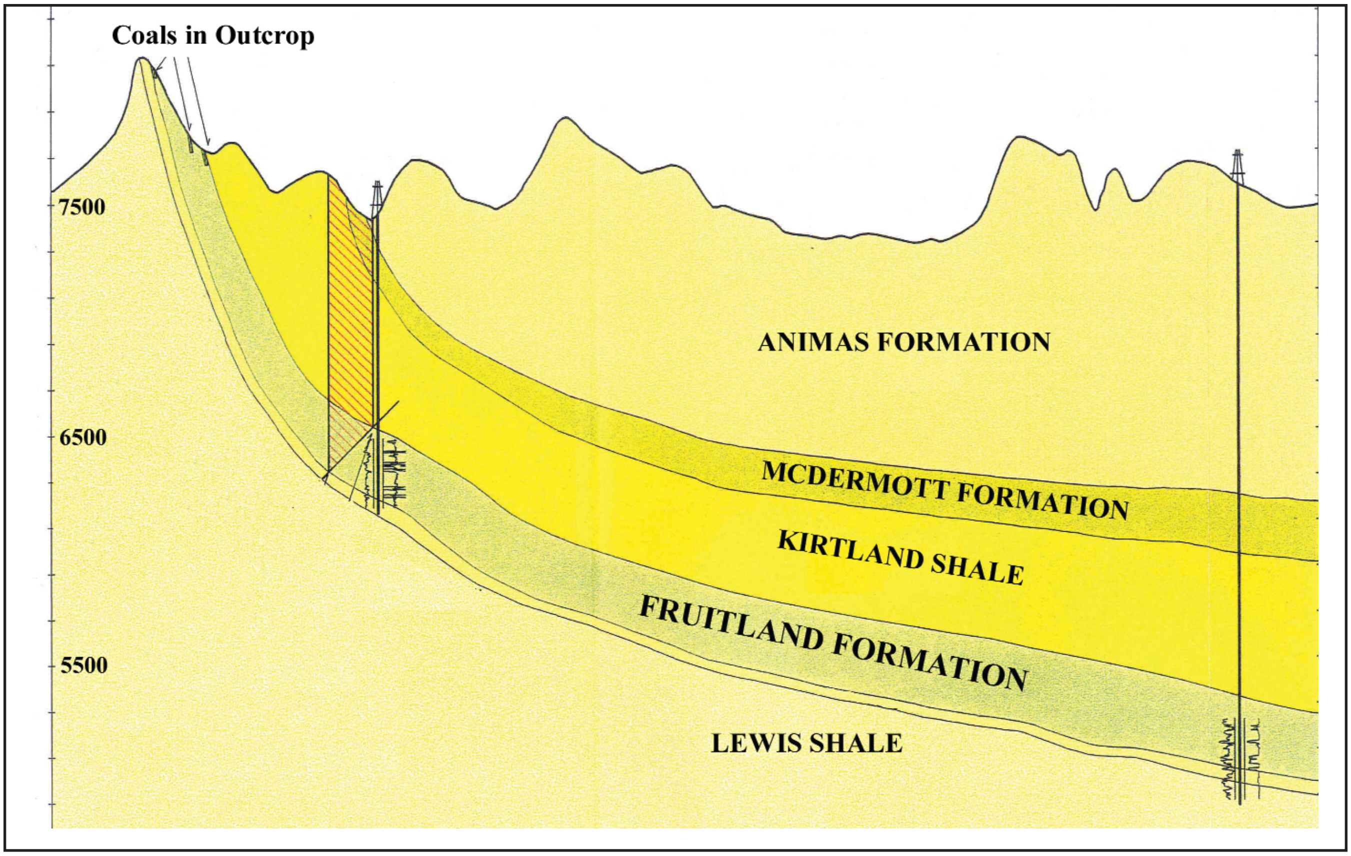

FIGURE 5 *Cross section through Hogback Monocline along Pine River, La Plata County, Colorado, showing the Fruitland Formation at depth below the ground surface and the fold that warps the formation up to the surface. Vertical scale exaggerated five times relative to horizontal scale.*[15]

The vast majority of the coalbed methane resource currently being developed in the San Juan Basin is contained within the Cretaceous Fruitland Formation. The organic plant material that formed the coal was deposited in swamps that flourished for millions of years. In the time since the plant material was deposited, the western interior of North America has undergone a series of mountain building and other tectonic events during which the basin itself was formed, the Hogback Monocline, which delineates the northern and western edges of the Basin, was formed,[12] and the Colorado Plateau, containing the San Juan Basin, was uplifted as a coherent block.[13] Additional sedimentary rocks were deposited on top of the Fruitland during this time period.

Within the San Juan Basin, the Fruitland crops out (*i.e.* is exposed at the surface) around the periphery of the basin and at its deepest is a little more than 4,000 feet below the surface in several areas in the northeast part.[14] The Hogback Monocline fold (Figure 5) warps the Fruitland from depths of greater than 3,000 feet to the surface over a horizontal distance of, in many cases, fewer than five miles. Since the methane is produced directly from the coal, it is found exactly where coal is found. The outcrop of the Fruitland marks the limits of coalbed methane production from the Fruitland Formation in the San Juan Basin, so no coal bed methane wells are found beyond it. Figure 6 shows the outline of the outcrop of the Fruitland Formation relative to towns, roads, and county and state lines. Also shown on Figure 6 are the over 25,000 wells (oil, conventional gas, and coalbed methane) that were drilled in the San Juan Basin between 1921 and 1995.

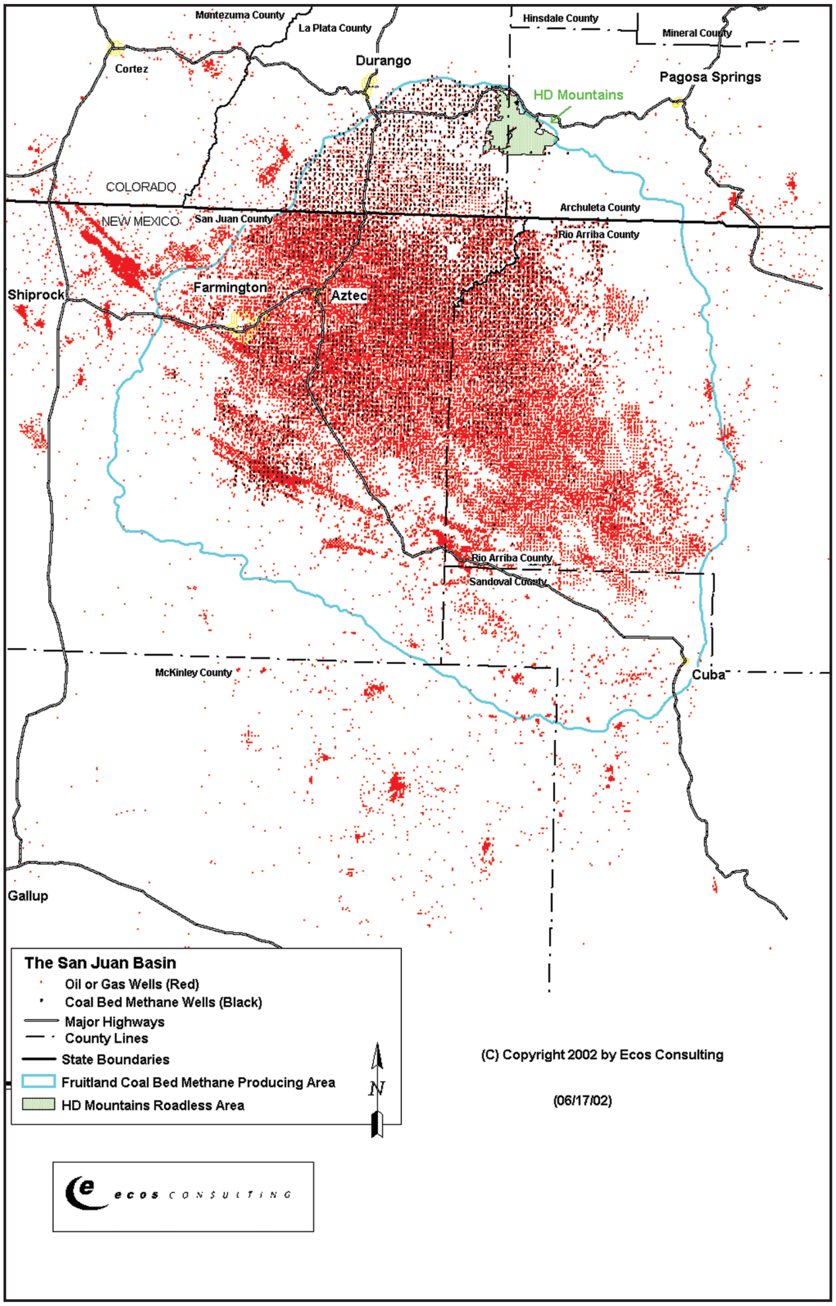

FIGURE 6 *Map of San Juan Basin, showing towns, roads, and county and state lines. The red dots are some of the 25,000 conventional oil and gas wells that were drilled in the San Juan Basin up through 1995, and the black dots are coalbed methane wells drilled in the same time period*

San juan basin—non-energy resources

The Basin's non-energy resources are extensive and varied, spanning a variety of national forests, wilderness areas, national parks, national monuments, state parks, and reservations (table 1).

Coalbed Methane Development in the San Juan Basin—History

The Fruitland Formation of the San Juan Basin contains more than 200 billion tons of coal,[16] ,[17] with an estimated 50 trillion cubic feet (tcf) of gas stored within the coal itself.[18] In the early years of coal mining in the Basin, methane in the coal was considered a hazardous nuisance because of explosions, fires, gas seeps, and contamination of water wells.[19]

The development of coalbed methane in the Fruitland Formation of the Northern San Juan Basin in Colorado began in earnest in the late 1980s,[20] however, natural gas from a coal seam may have been tapped as long as 100 years ago. The first recorded coalbed methane well was drilled in 1951 when the Stanolind Oil and Gas Company drilled into the Fruitland Formation just outside of Ignacio, Colorado.[21] For the next 20 years, though, drilling targeted shallow gas within Fruitland Formation sandstones (see Figure 3) rather than the Fruitland coals. In 1977, Amoco, the successor to Stanolind, drilled what is considered to be the CBM discovery well for the San Juan Basin, Amoco Cahn Gas Com No. 1, just south of the state line in New Mexico.[22]

The most prolific well in the region to date is Amoco's Gardner A-1 well, which has produced over 20 billion cubic feet of gas. Cumulative production of coalbed methane to date from the San Juan Basin is about 8.9 trillion cubic feet.[23]

TABLE 1 NON—ENERGY RESOURCES IN THE SAN JUAN BASIN

Type of Resource	Examples
Environmental	San Juan National Forest, Colorado HD Mountains roadless area, Colorado Carson National Forest, New Mexico Bisti / De-Na-Zin Wilderness, New Mexico San Juan River Watershed (Upper Colorado River Drainage)— San Juan, Animas, La Plata, Los Pinos, and Chaco Rivers, Largo Canyon, Colorado and New Mexico
Archaeological/ Cultural	Chaco Culture National Historic Park, New Mexico Aztec Ruin National Monument, New Mexico Salmon Ruins and Heritage Park, New Mexico Southern Ute Indian Reservation, Colorado Ute Mountain Indian Reservation, Colorado Jicarilla Apache Reservation, New Mexico Navajo Indian Reservation
Recreational	Angel Peak National Recreation Site, New Mexico Bisti Wilderness, New Mexico Navajo Lake State Park, New Mexico
Biological	Bald eagles, elk, mule deer, black bear, rare plants in HD Mountains roadless area and other portions of San Juan Basin in Colorado. Southwest Willow Flycatcher—threatened and endangered bird species.

WHAT IS A TCF?

1 trillion (1,000,000,000,000) cubic feet of natural gas is a quantity that can be difficult to comprehend. Total U.S. consumption of natural gas in 2000 was approximately 22 tcf, according to the U.S. Department of Energy's *Natural Gas Annual 2000.* In the residential sector, natural gas is used primarily for cooking and space and water heating. Average annual residential usage is about 50,000 cubic feet per household, so 1 tcf of natural gas is enough to meet the nation's residential gas needs for approximately 75 days. At present rates of growth in demand, U.S. natural gas consumption is expected to exceed 30 tcf in 2011, according to the U.S. Department of Energy's *Annual Energy Outlook 2000–2015*. So, simply put, 1 tcf is approximately the annual growth in U.S. demand for natural gas.

COALBED METHANE PRODUCTION IN THE SAN JUAN BASIN—CURRENT STATUS

The growth in production of coalbed methane from the San Juan Basin in the past 14 years has been tremendous, as shown in Figure 7 and Figure 8, below. There are currently 2,850 coalbed methane wells in the New Mexico portion of the San Juan Basin and 1,200 wells in the Colorado portion, on lands underlain by federal minerals alone.[24] There are an additional 158 wells in the New Mexico portion of the San Juan Basin on leases owned by non-federal mineral rights holders.[25] Production through coal seam gas processing plants averaged 1.835 billion cubic feet per day (bcf/d) for the year 2000. Gas from the San Juan Basin was delivered to El Paso Natural Gas, Transwestern, and PNM (Public Service Company of

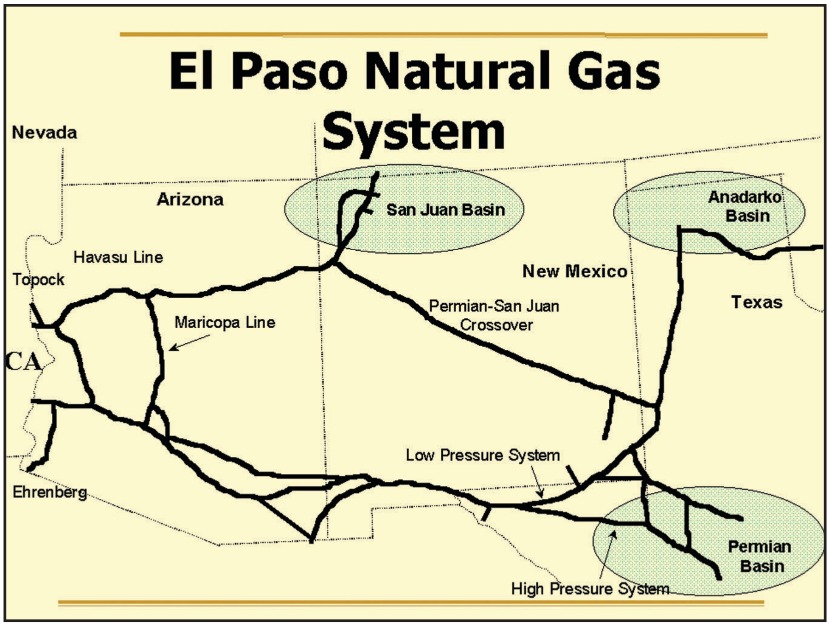

FIGURE 7 *El Paso Natural Gas southwest pipeline system, showing San Juan Basin and other southwestern basins.*

New Mexico) at a rate of 3.764 bcf/d.[26] They, in turn, operate pipelines that gather gas from other basins in the southwest and route the gas to markets in California (Figure 7). The San Juan Basin is California's largest single supplier of natural gas.[27]

In the past 13 years, coalbed methane production has increased by a factor of 34 in the New Mexico portion of the Basin[28] (see Figure 8), and that growth is expected to continue. Figure 8 shows the exponential growth of coalbed methane production in the San Juan Basin for the years 1988 through 2001. Production from the New Mexico portion of the basin was steady for the years 1996–1999, and has declined slightly since then. Production from the Colorado portion of the basin has

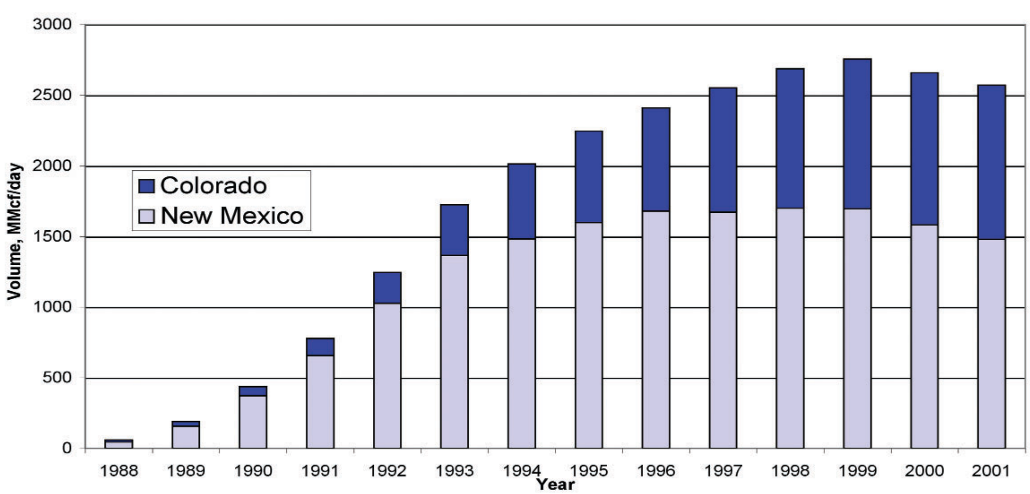

FIGURE 8 *Coalbed methane production in the San Juan Basin, New Mexico and Colorado, 1988–2001, in million cubic feet per day (MMcf/d).*[29]

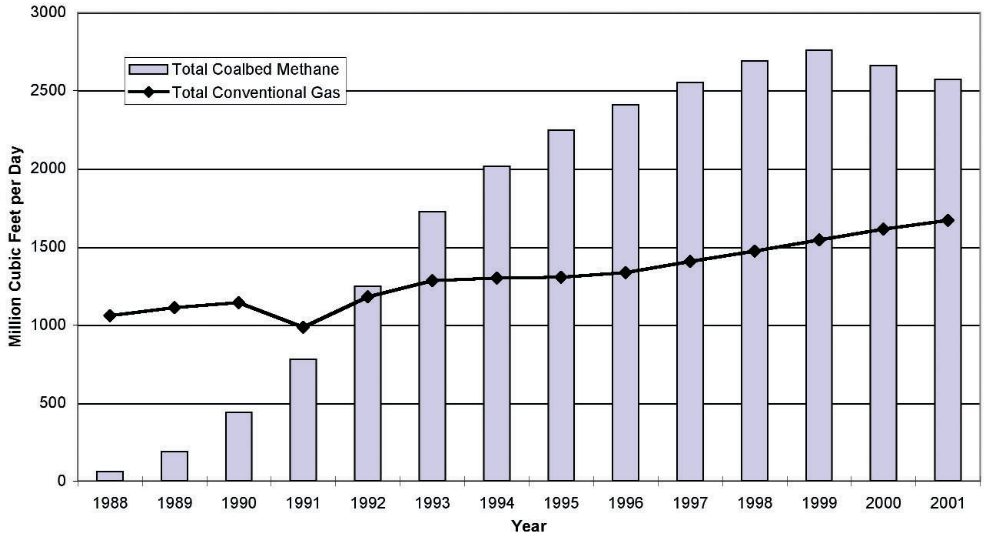

FIGURE 9 *Coalbed methane and conventional natural gas production in the San Juan Basin, New Mexico and Colorado, 1988–2001, in million cubic feet per day (MMcf/d).*[34]

remained steady for the past three years (1999–2001). Based on the shape of the curve in Figure 8, overall production in the Basin peaked in 1999 and has been slowly decreasing since then.

Figure 9 shows both coalbed methane and conventional gas during the same time period. In Colorado, the volume of coalbed methane produced has been more than ten times the volume of conventional natural gas produced for the past five years. In New Mexico, the volume of coalbed methane produced was more than the volume of natural gas produced for the years 1993 to 1999.30 In 2000, the volumes were nearly the same, and in 2001, the volume of conventional gas produced exceeded the volume of coalbed methane produced.[31]

The current takeaway capacity of the basin is 4 bcf/d. In 2000 the San Juan Basin produced 0.78 tcf, which was 4% of the United States total natural gas production, and 3% of United States total natural gas consumption.[32] The San Juan Basin produces the majority of coalbed methane in the country compared with other basins. The total value of resources removed from the San Juan Basin in 2000 was $2.5 billion, of which 12.5%, or $325 million, was the Federal Royalty.[33] The majority of coalbed methane produced in the basin has been produced in the New Mexico portion, but the Colorado portion is now more than half the amount that New Mexico produces. New Mexico's portion of 2000 coalbed methane produced was 45% of total New Mexico natural gas production (See Figure 8).

This rapid expansion of development likely would not have occurred without the advent of the Section 29 Tax Credits in 1987. The "Section 29" refers to Section 29 of the *Crude Oil Windfall Profit Tax Act*, signed by President Carter in 1980, which was enacted with the intent to tax a fair share of the added revenues enjoyed by oil companies as a result of high prices.[35] Section 29 of the act "included a tax credit for the production of alternative, or non-conventional, fuels designed to encourage the domestic development of alternative energy supplies."[36] At the time, it was expected that the taxes on crude oil would help support the development of alternative energy sources.[37]

Coalbed methane wells, as an unconventional source of natural gas, qualified for this credit. The credit varies based on market prices, but is approximately $1 per thousand cubic feet of gas (Mcf). The credit was initially applied to wells drilled in the time period 1988–1990, but was extended through 1992. There was concern within the industry that the expiration of the credit would mean a slowdown of the industry. However, it has remained profitable for companies to continue coalbed methane development in the intervening 10 years, and drilling of new coalbed methane wells has continued, albeit at a slower pace than before 1992 (Figure 10). Indeed, the coalbed methane industry in both Colorado

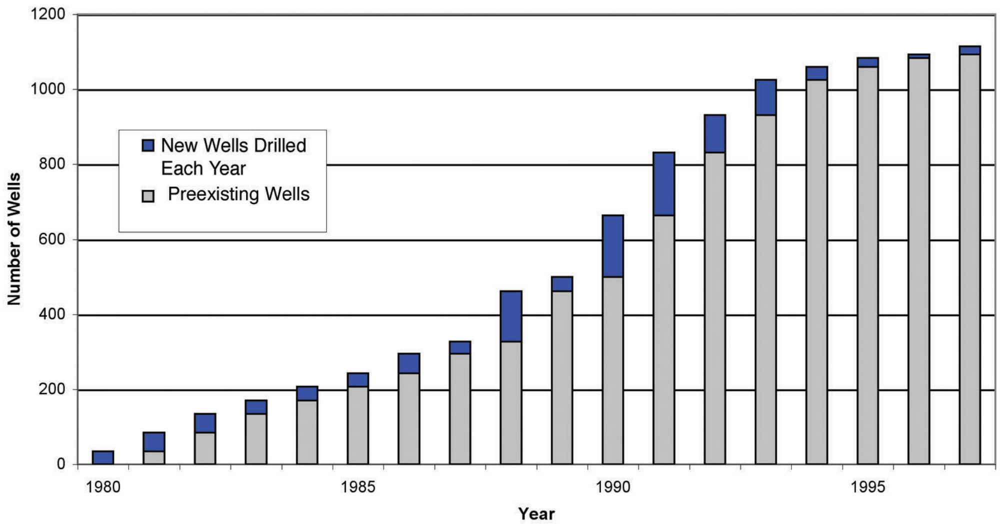

FIGURE 10 *Coalbed methane wells drilled in the La Plata County, Colorado, portion of the San Juan Basin, 1980–1997,*[40] *showing new wells drilled each year and cumulative number of wells drilled.*

and New Mexico wants to double the density of coalbed methane wells over the next 10 years. The Section 29 tax credit was good for ten years after the drilling date, which means that there are some wells today that are still garnering this credit with today's average gas price of $2.25/Mcf.[38] The current version of the House of Representatives' Energy Plan, H.R. 4, includes reinstating the Section 29 tax credit for coalbed methane.[39]

Coalbed methane production in the San Juan Basin—future

Introduction

The Farmington Field office of the BLM anticipates approximately 12,500 total new wells (oil, gas, and coalbed methane) to be drilled in the San Juan Basin over the next 20 years, with 3,000 new coalbed methane expected in just the New Mexico portion of the Basin.[41] Approximately 10,000 of these wells are expected to be drilled on lands with federally administered mineral rights.[42] The wells will be drilled on a combination of leases with currently producing wells through infill drilling, and on currently undeveloped leases. Infill drilling, installing wells on 160 acre instead of 320 acre spacing, is already occurring in portions of the Basin in Colorado, and the process will be discussed for the New Mexico portion of the Basin at a meeting this summer in Santa Fe.[43] There are currently three environmental impact statements underway that will determine what future coalbed methane development

TABLE 2 ENVIRONMENTAL IMPACT STATEMENTS CURRENTLY UNDERWAY IN THE SAN JUAN BASIN, NEW MEXICO AND COLORADO

Name of EIS Project	Area Covered
• Northern San Juan Basin Coalbed Methane Environmental Impact Statement	• Colorado portion of San Juan Basin, north of Southern Ute Indian Tribe Reservation
• Southern Ute Environmental Impact Statement	• Colorado portion of San Juan Basin on Southern Ute Indian Tribe Reservation
• Farmington Area Resource Management Plan	• New Mexico portion of San Juan Basin

will look like in the San Juan Basin (Table 2). Each EIS is summarized briefly below.

Northern San Juan Basin Coalbed Methane Environmental Impact Statement

The Colorado portion of the San Juan Basin north of the Southern Ute Reservation has been managed under an earlier resource management plan, with the exception of the HD Mountains Roadless Area, which has been managed according to a 1992 EIS. The oil and gas industry's request for infill drilling[44] of coalbed methane wells, doubling the density of wells from one well per 320 acres to two wells per 320 acres, has prompted the current environmental review. Five alternatives addressing six different land status categories were initially proposed by both the USFS/BLM and an industry working group. These range from a minimum of 118 wells to a maximum of 523 wells. Since the EIS scoping meetings, held in January 2002, and as a direct result of comments made by the public at these meetings, the BLM is developing additional alternatives.[45] This has pushed back the originally scheduled draft EIS publishing date from March to July, 2002. No preferred development alternative is available at this time.

Southern Ute Environmental Impact Statement

The Southern Ute EIS is still "in progress", as it has been for many years. The EIS was initially undertaken to evaluate "how best can oil and gas development revenues continue to be received and maximized for benefiting the Southern Ute Indian Tribe while at the same time protecting Tribal lands and the environment from injurious impacts."[46] Infill drilling has already been approved for portions of the reservation, and up to 500 more coalbed methane wells are possible on reservation lands.

Farmington Area Resource Management Plan

The New Mexico portion of the San Juan Basin contains the majority of the land in the basin, and 4 million acres of that land are managed by the Farmington Field Office of the Bureau of Land Management. In August 2000, a notice of intent to conduct the Resource Management Plan (RMP) was posted in the Federal Register. This undertaking is a revision of the current RMP, and is being done to "establish land use management policy for multiple resource uses on approximately 1.5 million acres of public land and 2.26 million acres of federal mineral resources in the Farmington Field Office[47]" including coalbed methane as well as conventional oil and gas. As part of this process, a 20-year Reasonable Foreseeable Development (RFD) scenario was developed for the BLM by the New Mexico Bureau of Geology and Mineral Resources. The RFD scenario anticipates another 12,461 total wells (oil, conventional gas, coalbed methane) to be drilled in the New Mexico portion of the San Juan Basin in the next 20 years, with an associated 3600 miles of new pipelines and up to 300 new compressor stations required as part of this development, impacting a total of 11,600 acres.[48] Of those wells, it is estimated that approximately 3000 will be coalbed methane wells, or approximately 150 new coalbed methane wells are expected to be drilled each year for the next 20 years.

Role of Associated Governments in Deciding What Future Development Will Look Like in the San Juan Basin

There are five layers of government that have jurisdiction in the larger San Juan Basin area: federal, tribal, state, county, and town. Within the Basin are two states, three BLM districts, two National Forests, four Indian Reservations, and six counties, plus private land, two wilderness areas, a National Historic Park and a National Monument. Each plays a role in the coalbed methane discussion, as shown in the table on the next page.

TABLE 3: GOVERNMENTS WITH JURISDICTION OVER LAND IN THE SAN JUAN BASIN

Type	Government Name		Jurisdiction	Function
U.S. Federal	United States Bureau of Land Management	Colorado	Public land in Colorado *north of the Southern Ute Indian Reservation?*	Administer subsurface mineral rights. Oversee EIS process. Conduct lease sales. Regulate drilling through APD.
		New Mexico	4 million subsurface acres with federal minerals	Administer subsurface mineral rights. Oversee EIS process. Conduct lease sales. Regulate drilling through APD.
	United States Forest Service	Colorado	San Juan National Forest	Identify Forest Service land suitable. for oil and gas leasing. Ensure proposed development proceeds. consistently with forest RMP.
		New Mexico	Carson National Forest	Identify Forest Service land suitable . for oil and gas leasing. Ensure proposed development proceeds. consistently with forest RMP.
Tribal	Southern Ute Indian Tribe, Colorado		Southern Ute Indian Tribal Lands	Red Willow Production Company operates 200 wells on tribal land. Red Cedar Gathering operates gather ing pipeline on tribal land. Regulates other companies operating on tribal land.
	Ute Mountain Ute Indian Tribe, Colorado		Ute Mountain Ute Tribal Lands	
	Jicarilla Apache Tribe, New Mexico		Jicarilla Apache Tribal Lands	
	Navajo Nation, New Mexico		Navajo Nation Lands	

TABLE 3: GOVERNMENTS WITH JURISDICTION OVER LAND IN THE SAN JUAN BASIN, CONTINUED

Type	Government Name	Jurisdiction	Function
State	Colorado Oil and Gas Conservation Commission	Colorado state lands, direct regulation of development	Promotes responsible development of Colorado's oil and gas natural resources. Approved infill drilling process.
		Federal, private, Indian lands	Approved infill drilling process and well locations.
	New Mexico Oil Conservation Division, District 3	McKinley, Rio Arriba, Sandoval, and San Juan Counties	Permitting, well data, inspection, and enforcement actions
County	Archuleta County, Colorado	County land	Developing county rules for oil and gas development
	La Plata County, Colorado	County land	Supports local control of land use through county regulations. Currently producing a report discussing impacts to the county from oil and gas development. Intercedes on behalf of residents impacted by development.
	Rio Arriba County, New Mexico	County land	No role in oil and gas development within the county.
	Sandoval County, New Mexico	County land	No role in oil and gas development within the county.
	San Juan County, New Mexico	County land. Largest percentage of basin within San Juan County	No role in oil and gas development within the county.
City/Town	City of Bayfield, Colorado	City land	Active with residents, industry in well placement decisions within town limits.
	Town of Ignacio, Colorado	Town land	No development within town. However, there are many wells are drilled right outside the town limits, and the town is impacted in several ways by the surrounding development.

TABLE 3: GOVERNMENTS WITH JURISDICTION OVER LAND IN THE SAN JUAN BASIN, CONTINUED

Type	Government Name	Jurisdiction	Function
State			
City/Town	City of Aztec, New Mexico	City land	Recently passed City Ordinance 2001-272, updating the city's rules for oil and gas wells in order to "facilitate the development of oil and gas resources within the incorporated area of the city while mitigating potential land use conflicts between development and existing or planned land uses." Applications to drill are made to the municipality, and the Community Development Department issues recommendations for approval or denial.
	City of Bloomfield, New Mexico	City land	The city has a permitting process for drilling of wells. The city council does final review of applications then approves the application for permit to drill, and the company may proceed with the drilling. Once the well is drilled, the New Mexico Oil Conservation Division does all monitoring.
	City of Farmington, New Mexico	City land	Requires a special use permit prior to drilling, which is a zoning action that requires a public hearing. The company applies to the city clerk's office for the drilling permit and puts up bonds. The zoning review process checks for compliance with standards for minimum separation between structures, rights-of-way, water, etc., and may require mitigation measures, but all wells are approved.

II: San Juan Basin Resources

San Juan Basin Estimated Coalbed Methane Resource

Introduction

Estimates of the coalbed methane resource in the San Juan Basin vary widely, depending on both the source and type of the estimate. Energy resource estimates come in several forms, presented here in order of decreasing volume. Largest is an estimate of "gas-in-place", which is simply the theoretical amount of gas that the formation is physically capable of holding. Second is the amount of that gas that is recoverable using current technology, or the "technically recoverable resource". Finally, even if the gas is technologically recoverable, it might not be economic to extract, so the final category is economically recoverable. The amount economically recoverable depends on the current price of gas. For coalbed methane, about 30 percent of the technically recoverable gas is economically recoverable if gas is priced at $2 per thousand cubic feet (Mcf). If gas is priced at $3.34 per Mcf, the economically recoverable amount increases to slightly more than 50 percent.[49]

Estimates

Gas-in-place

The energy resource number most frequently cited for the San Juan Basin is 50 tcf of gas within the Fruitland Formation alone,[50] a number that has been used to describe the San Juan Basin "resource" of coalbed methane for the past 15 years.[51] This number refers to gas-in-place only (Figure 11). In addition, the gas-in-place estimates for the older, deeper, Menafee Formation range from 34–38 tcf,[52] giving a total Basin gas-in-place estimate of 84–88 tcf. The 84 tcf resource estimate is also cited by the Petroleum Technology Transfer Council.[53]

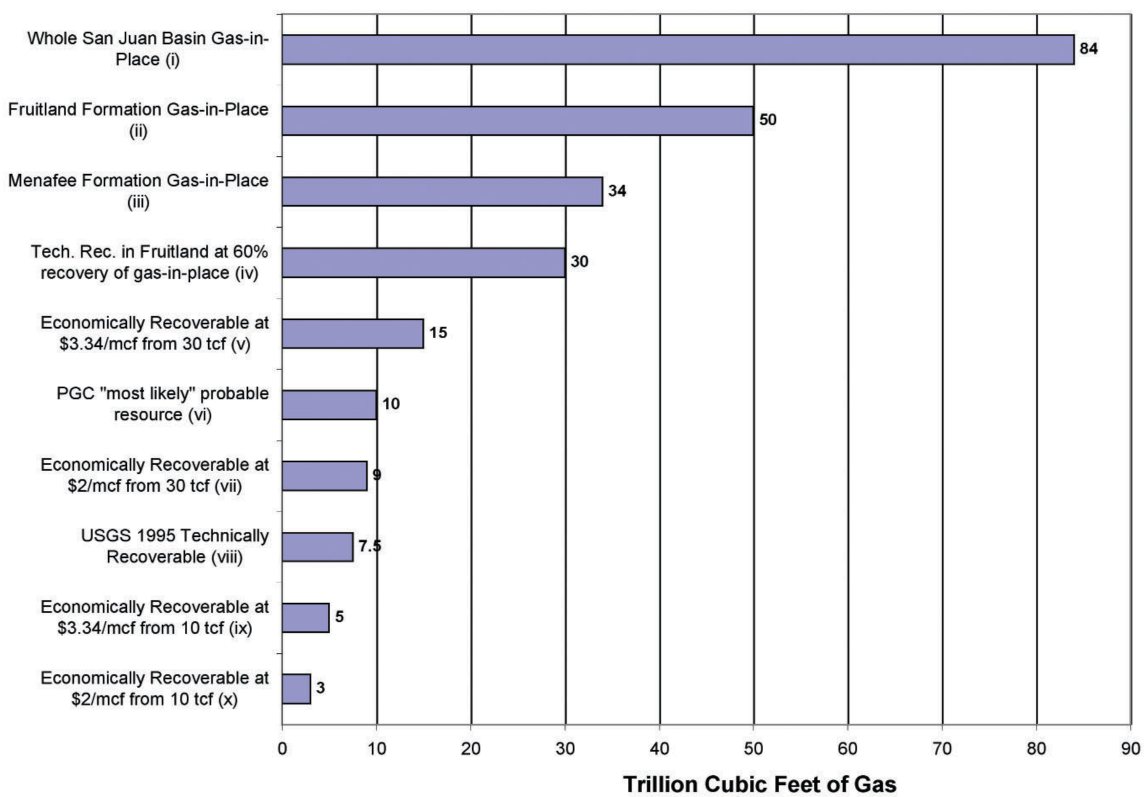

FIGURE 11 *Estimates of gas-in-place, technically recoverable, and economically recoverable coalbed methane resources of the San Juan Basin.*[57]

Technically recoverable

In 1995, the United States Geological Survey estimated the mean technically recoverable amount of coalbed methane in the San Juan Basin at 7.53 tcf.[54] In 2000, the Potential Gas Committee (PGC) estimated the "Probable Resources" of coalbed methane in the San Juan Basin at 10.24 tcf.[55] This category may be reasonably compared with technically recoverable numbers. Therefore, in the intervening five years since the USGS report, the estimated technically recoverable amount of coalbed methane in the San Juan Basin has increased by 36%. However, one source indicates a possible recovery factor of gas-in-place of over 60% when using new technologies,[56] giving a technically recoverable amount for the Fruitland Formation of over 30 tcf.

Economically Recoverable

Using the PGC technically recoverable volume of 10.24 tcf and applying the above-mentioned economically recoverable amounts, the San Juan Basin holds between 3.1 tcf (at $2/mcf) and 5.12 tcf (at $3.34/mcf) of economically recoverable coalbed methane. Using the 30 tcf technically recoverable estimate cited above gives economically recoverable amounts of between 9 tcf and 15 tcf, respectively. Assuming gas prices remain over $3/mcf, the actual economically recoverable amount of coalbed methane in the San Juan Basin may be expected to be between 5 tcf and 15 tcf, or approximately 10 tcf.

Issues surrounding coalbed methane development in the San Juan basin:

Introduction

The Northern San Juan Basin Coalbed Methane EIS Proposal dated January 16, 2002, listed the following issues surrounding coalbed methane development: property values, noise, visual impacts, tax revenues, water depletions, surface and groundwater impacts, gas seepage into domestic water wells, dying vegetation at Fruitland outcrop, impacts to wildlife, roadless area in HD's, archaeological resources, and air quality. Additional issues include split estate lands, tax credits, royalties, impacts to rangeland, and effects at the outcrop. These issues largely are Basin-wide, and some or all will be addressed in each of the three Environmental Impact Statements. All are discussed below.

FIGURE 12 *Photograph of coalbed methane well and associated infrastructure in the Colorado portion of the San Juan Basin.*

Split estate lands

The term "split estate" refers to land with one owner of the surface and a different owner of the subsurface mineral rights. This situation may arise when an owner sells only the surface land and keeps the subsurface mineral rights. Likewise, it may originate from the time when the land was originally homesteaded and the claimant did not make the trip to the state capital to claim the subsurface mineral rights, which were retained by the government or claimed by other individuals. These competing rights can often lead to conflicts when gas development companies place wells on or adjacent to residential property (Figure 13). Often the surface owner has little say in the process, and can end up with a potentially very noisy well very close to their house (see below). Some production companies are voluntarily developing "surface use agreements" with landowners in order to minimize conflict and impacts and maximize cooperation with regards to well and road siting. Some landowners end up with improved roads and free domestic gas as part of these deals. Others may end up with diminished property values[58] and little if any compensation from industry. One La Plata County, Colorado landowner expressed particular concern to the Durango Herald about a gas company's reluctance to follow its permit requirements for development on his land: "'It's obvious all they're doing is for the bucks,' he said. 'I stand to benefit from the extraction, but I'd just as soon give the money back.' "[59]

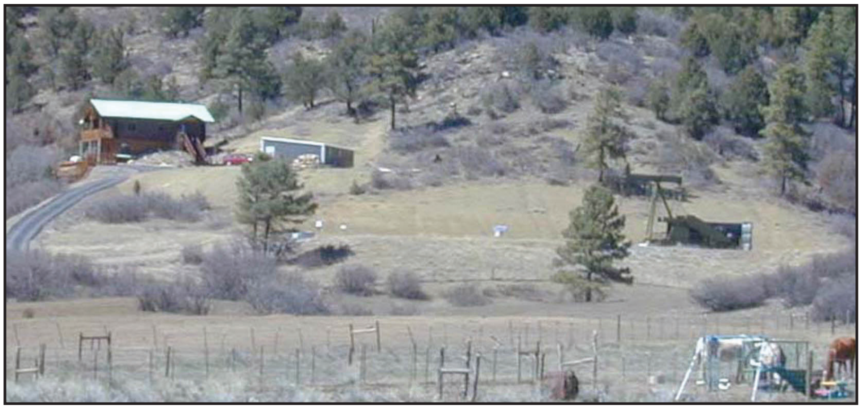

FIGURE 13 *Photograph of pumpjack and well adjacent to home, Colorado portion of San Juan Basin.*

Property values

Coalbed methane wells drilled on or adjacent to private land can reduce property values and render land difficult to sell. The development can turn once rural areas into industrial zones. Noise from associated equipment (see below) can heavily impact the residents of the property. In addition, roads, pipeline rights-of-way, power line rights-of-way, and other infrastructure surrounding private land can heavily impact resale value.

noise

Noise is a major concern in areas with coalbed methane development. This noise comes initially from the heavy equipment used to create roads and drill pads, continues at very high levels during drilling and well completion, and becomes a permanent part of the landscape with the installation of pipelines, compressors, pumpjacks, and with the large amount of vehicle traffic needed for routine maintenance. Some noise mitigation measures can be put into place on a well-by-well basis, depending on surface use agreements and applicable government regulations. The Colorado Oil and Gas Conservation Commission (COGCC) has noise regulations in place,[60] however, "currently there are no federal noise standards for oil and gas equipment."[61] The BLM is considering adopting decibel standards, especially near homes[62] and regularly visited archaeological sites in the New Mexico portion of the San Juan Basin.[63]

Lack of regulation can lead to noise levels that can drive people from their homes and change the local atmosphere from rural to industrial. One landowner in Aztec, New Mexico, describes one noise effect of coalbed methane development as the "compressor nightmare...compressors run night and day. Their constant roar interrupts sleeping and dinner. The companies could muffle the sound if they want, but they never agree to spend the little extra money it would take to make people's lives easier."[64] With regards to a proposed compressor adjacent to her property, one La Plata County, Colorado landowner commented, "I'm just concerned that having this kind of noise behind my home ... would be quite impossible to live with."[65]

Recently in La Plata County, the JM Huber Corporation sought a waiver to noise reduction requirements that were written in to their original 2000 drilling permit, which required that the company used electricity to power any motors needed after the initial six months of drilling. Residents of the subdivision containing the well commented that "the gasoline engine powering the pump was excessively noisy," however company officials stated that measurements taken at the site fall within COGCC standards, and baffles were added to further reduce noise impact.[66] La Plata County denied the waiver, and Huber was directed to install an electric motor pump on the site.

In some cases, however, the wells can be fairly unobtrusive and not very loud once completed, depending on whether compressors and/or pumpjacks are needed. In La Plata County, BP proposed to add compressors to six gas wells, and offered to mitigate the noise with barriers and other measures.[67]

visual impacts

The visual and aesthetic contrast between a bare well pad, its associated heavy equipment, and the surrounding forest can be stark indeed. Even in the desert, vegetation is stripped away, leaving just bare dirt and equipment. Equally dramatic contrasts can result in residential areas, since even the best paint job cannot cause wellhead equipment to "blend in" with homes, trees, and yards (Figure 14). The "footprint" of such development extends significantly beyond the well pad as well, with roads being cut and pipelines buried to join the wells together. Temporary impacts can be even more profound, as truck

FIGURE 14 *Photograph of a well pad with a pumpjack carved into a forest, Colorado.*[68]

FIGURE 16 *Photograph of trash on well pad, New Mexico portion of San Juan Basin.*

traffic dramatically increases on rural roads, and massive drill rigs and associated equipment dominate the skyline during well drilling, completion, and workover (the process of redrilling the well to stimulate additional production) (see Figure 15).

It is also clear from some existing coal bed methane wells that the land near well pads can often become degraded, with discarded well fittings, beer cans, fire rings, etc. (Figure 16). It appears, in fact, that the initial decision to allow drilling literally "paves the way" for even greater impacts to the area in the future. This effect has the potential to be particularly devastating in areas such as the HD Mountains roadless area, compromising the pristine quality of the area that made it worth protecting in the first place.

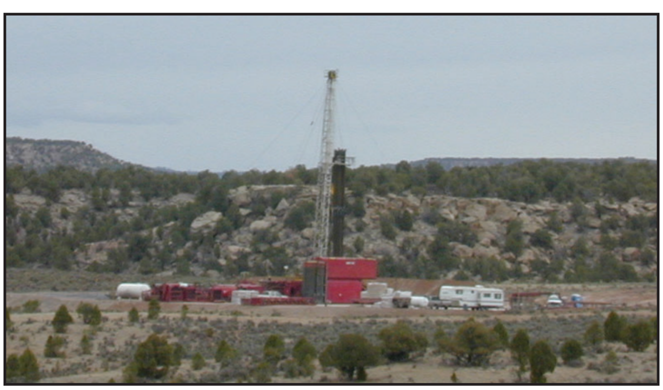

FIGURE 15 *Photograph of drilling rig, San Juan Basin, northern New Mexico.*

TAX REVENUES/ROYALTIES

In addition to gas production companies, many other entities make money off of coalbed methane development. La Plata County, Colorado, got 42.7% of its property tax revenues from the industry in 2001, a total of 11.7% of total county revenues.[69] The percentage of revenue that the county gets from development has been steadily increasing as the number of coalbed methane wells increases (Figure 17). The federal government received $211 million from coalbed methane development royalties (12% of revenues) in 2000 from coalbed methane development on federally owned mineral leases in just the New Mexico portion of the San Juan Basin alone.[70] In addition, private subsurface mineral owners get royalties from development, although the industry in the past few months has been challenging the amount of royalties they have to pay private citizens.

Taxes and royalties generated by oil and gas production are a major source of revenue for government and schools in New Mexico. Total natural gas production in New Mexico is in the range of 1.5 trillion cubic feet (tcf) per year.[72] The value of this gas fluctuates with price. For example in 2002, the average gas price is forecasted to be $2.50 per mcf (thousand cubic feet).[73] Therefore, the total value of natural gas production (assuming 1.5 tcf) will be on the order of $3.75 billion. The total tax rate on natural gas for school tax, severance tax, conservation tax, and ad valorem taxes on production and equipment is about 7.38% of gross sales value.[74] Therefore, the estimated State tax revenues from natural gas production in

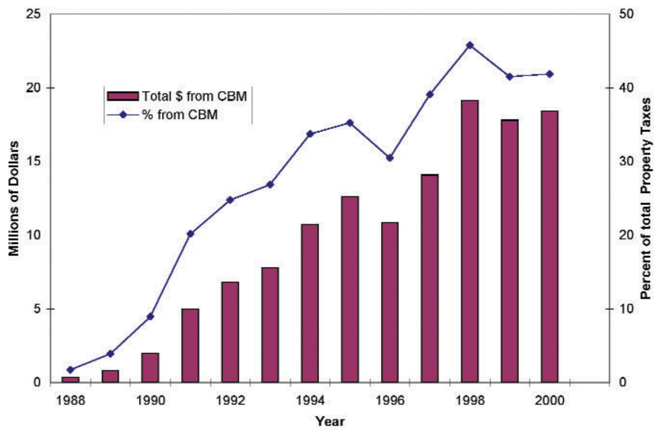

FIGURE 17 *La Plata County property tax revenues from coalbed methane development, dollar amount and as percent of total property taxes, 1988–2000.*[71]

2002 will be on the order of $275 million. In general, the taxes generated by revenues from natural gas production contribute about 5 to 6% of the total general fund revenues in New Mexico.[75] In addition to tax revenues, New Mexico gains revenue from royalties, lease payments, and bonuses paid by oil and gas companies operating on State and Federal lands.

Private subsurface mineral owners also get royalties from development, although the industry in the past few months has been challenging the amount of royalties they have to pay royalty owners. A July 2001 Colorado Supreme Court decision said that royalty owners should only "bear that portion of the cost of bringing oil and gas to the surface and not to a buyer."[76] A bill in the Colorado legislature earlier this year would have overturned this ruling, passing along industry's costs of bringing oil and gas to buyers to royalty owners, thereby reducing their royalty payments, which average about 12% of the sale of the minerals.[77] Many lawmakers on both sides of the aisle felt the bill was necessary because without it, "producers bear all the risk and cost of finding gas and drilling wells" and that producers "deserve to profit."[78] Those opposing the bill, also from both sides of the aisle, say that the bill "could be devastating for farmers and ranchers who are barely holding on economically. 'There are 10,000 royalty owners, half farmers and ranchers that need these royalty incomes...we're talking about potentially hurting thousands of royalty owners to potentially help a few small producers, whom we may not even be helping.' "[79] The bill was passed by the Senate in February, 2002,[80] and was extremely controversial, leading to editorials,[81] letters to the editor, and royalty owner complaints to the state.[82] The result, for now, was the shelving of the regulation, which will be reconsidered during next year's legislative session.[83]

Water issues—water depletions, surface and groundwater impacts

Water is the single biggest issue in coalbed methane development, and it is the issue that separates development of this resource from development of conventional resources. Water quantity and water quality can be affected by any number of the steps in CBM development. During drilling of CBM wells, aquifers are crossed by the borehole. Any time an aquifer is breached, cross-contamination may occur. In some instances a surface casing is driven into the ground and filled with concrete before drilling begins in order to form a seal around the borehole in an attempt to minimize contamination of surface aquifers.[84] However, there is no requirement for this degree of protection. Drilling fluids (also known as "mud"[85]) and other rig wastes are often stored in unlined pits (Figure 17), which can allow infiltration of contaminants directly to groundwater. Drilling fluids are necessary for lubricating the drill bit, preventing friction and preventing the drill bit from getting stuck in the hole. According to industry sources, these fluids may be made up of a combination of natural clays, water, caustic soda, and possibly barite,[86] and may contain significant amounts of suspended solids, emulsified water or oil.[87] However, testimony discussed below states that only non-toxic substances and fresh water are used for drilling fluids in the San Juan Basin.

After drilling, completion methods vary. "Open hole" completions contain a pipe which is perforated at the levels of the coal seams, but the area of the borehole surrounding the pipe is not filled with concrete. An open hole allows communication between aquifers, even when the aquifers have historically been separated by a non-permeable layer such as shale, because now an open hole exists between the two. If the space surrounding the pipe is filled with concrete, aquifers are much more protected from cross contamination.

During well stimulation, two different practices are used which can impact groundwater, hydraulic fracturing ("fracing", pronounced "fracking") and cavitation.

Fracing is the process of increasing formation permeability by injecting fluids at high pressures to cause the rocks to break. Some kind of solid material, usually sand, is injected with the fluid in order to hold open the newly created fractures. Most of the fracing liquid is recovered after the operation is complete, but at least in one documented instance, the materials proposed for use in fracing are toxic, including benzene, polycyclic aromatic hydrocarbons, ethylbenzene, toluene, xylenes, napthalene, methanol, sodium hydroxide, and MTBE.[88] In another case, sworn testimony that fracing and drilling fluids used in coalbed methane development in the Fruitland Formation contained only fresh water and non-toxic additives was presented before the Colorado Oil and Gas Conservation Commission.[89] The environmental community contends that large amounts of anecdotal evidence indicate that fracing has negatively impacted citizen's drinking water wells,[90] but the oil and gas industry responds that they've always done things this way, and that studies have shown there are no impacts to water supplies from hydraulic fracturing.[91] The United States Environmental Protection Agency is seeking to resolve this controversy by conducting its own "Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water",[92] which is currently underway.

Cavitation is the process of creating cavities in the coal seam. The well in this case is an open hole completed in the coal seam, and compressors pump air or foam into the well to pressurize the coal.[93] A valve is then opened, which depressurizes the well, causing a vacuum that breaks up the coal and surrounding rock so that gas can flow through the resulting fractures.[94] The cavitation process "creates a jet engine-like noise that lasts anywhere from a few minutes to 15 minutes and is done several times before the well is completed. Bits of rock or coal mixed with water often spew out of the wellhead. Cavitation is a similar phenomenon to opening a shaken pop bottle, only on a much larger scale. Environmental and safety precautions are required during the process."[95] During cavitation, the rock is fractured under high pressure, which can cause fractures that allow water migration into other aquifers. In addition, if the formation is pressurized using foams, contaminants can be introduced into the groundwater.

FIGURE 18 *Photograph of unlined reserve pit at recently completed coalbed methane well, New Mexico portion of San Juan Basin. Black stain on dirt berm is from spray out of hole during cavitation (see below).*

Once the well is drilled and fracing or cavitation is completed, production begins. The wellhead is connected by pipeline to a distribution network, and a pumpjack is installed to begin removing water from the coal seam. Some wells require very little water removal to release the gas from the coal, and other wells produce water at rates of up to 2000 barrels of water per day.[96] The average in the San Juan Basin as a whole is 25 barrels per day, at a ratio of 0.013 gallons of water per every thousand cubic feet of gas produced.[97] One barrel equals 42 gallons, so the average well in the San Juan Basin produces 1050 gallons of water each day. For the 4,208 coalbed methane wells in the San Juan Basin, this adds up to 4.42 million gallons of water produced from the Fruitland Formation Coal in the San Juan Basin *every day*. This nearly 600,000 cubic feet of water is equal to 13.6 acre-feet of water per day.

This produced water is in many cases as salty as the ocean, and therefore disposal of this water can be problematic. Total dissolved solids (tds) is a measure of the "saltiness" of the water, or the amount of dissolved sodium, calcium, chloride, and other elements. The tds of produced water results from a combination of factors: the depth of the coal beds; the type of the rocks surrounding the coal beds; the amount of time the rock and water are in contact; and the origin of the water entering the coal beds (*i.e.* is it fresh rainwater recharge or from another aquifer hosted in rock with a high calcium carbonate content).[98] In the San Juan Basin, the majority of the produced water has a total dissolved solids value of 2,000 parts per million (ppm) to over 20,000 ppm. For reference, drinking water must contain less than 500 ppm tds, and seawater averages 35,000 ppm tds.[99]

Four methods of handling produced water are typically used today. One is storing produced water in large tanks onsite, which requires regular visits from water trucks, which pump the water from the tanks to the truck, and then transport the water to a wastewater treatment facility. Second, produced water may be reinjected into deep aquifers. Reinjection requires an aquifer with enough volume to hold the injected water and no communication with the ground surface or other aquifers. Third, produced water can be stored in onsite impoundments for evaporation. Finally, in some instances where the produced water has a low enough salinity, a permit may be issued for surface discharge. In the Colorado portion of the San Juan Basin, a controversial surface discharge permit was issued by the state, which would have allowed the JM Huber Corporation to discharge of up to 576,000 gallons of wastewater containing the equivalent of *8 tons* of table salt *daily* from two gas wells.[100] The original permit would have allowed the dumping of this water into an irrigation ditch that drains directly into the Florida River, which then crosses into the Southern Ute Indian Reservation.[101] The state has admitted it erred in granting the original permit because they did not take into consideration the proper water standards for disposal, and has revoked the permit.

Problems exist with all of these disposal methods. Produced water often leaks from storage tanks, which are required to have a dirt containment berm surrounding them. The berms are often breached themselves, in which case the produced water flow can flow out of the berm and across the ground surface, as shown in Figure 19.[102] The white material outside the berm consists of salts that have precipitated from produced water spills that overtopped the berm. A rancher in the New Mexico portion of the San Juan Basin, a member of a BLM/rancher working group formed to address the impacts of gas development on grazing leases on BLM lands in New Mexico, says that at least 75% of the produced water tank berms on his BLM grazing lease show salt stains from produced water spills.[103] In addition, several spills that have escaped the berms have permanently impacted the surrounding soil, rendering it unfit to grow forage for his cattle. Finally, this rancher has expressed concern about what happens when the well's lifespan is over and the area is reclaimed—is the salt-encrusted dirt considered waste to be hauled off and treated, or will it remain in situ, forever barren of vegetation?

Reinjection of produced water can introduce saline water into deeper aquifers that may contain fresher water. Often, an area with coalbed methane development does not have aquifers meeting the requirements for reinjection within the area. This is the case in the Powder River Basin. Or, if aquifers with the right characteristics are present, they might be in communication (*i.e.* water flows freely between them) with the coalbed aquifer. If the reinjection is <u>re</u>watering the coal seam while pumps are <u>de</u>watering the coal seam, the process becomes self-defeating. In addition, pressurizing deep aquifers may cause unforeseen problems at the surface miles away from the actual injection point. One example is occurring in La Plata County, Colorado, where water is being injected into the Entrada Formation at considerable depth in the San Juan Basin.[104] However, the Entrada is folded upward at the northern end of the basin and comes to the surface north of Durango, Colorado. Where it comes to the surface new water seeps are occurring, most likely from the extra pressure in the formation caused by produced water injection at depth.

FIGURE 19 *Photograph of produced water spill next to produced water tank. White is salts precipitated from produced water. Photo courtesy T. Blancett.*

Surface impoundments also have problems. First, a surface impoundment requires digging up an even larger area of ground than was required by the well pad. In the Powder River Basin these ponds may reach areas as great as five acres.[105] Second, depending on water quality, these ponds must be lined. As a result, disposal happens only by evaporation, and the water in the ponds gets successively more saline as evaporation proceeds. Wildlife or livestock drinking this water can become sick or even die from the saltiness. Third, as with any artificial impoundment, breaches or leaks can occur, spreading the salty water over the land surface and impacting both surface and groundwater supplies (see Figure 18). However, successful experimental testing by Amoco in the San Juan Basin using surface impoundments to treat produced water by using the natural freeze-thaw/evaporation process may lead to commercial use in reducing the volume of produced water requiring disposal.[106]

Finally, assuming the water quality is good enough, produced water can be discharged onto the ground surface. This causes problems with erosion of stream channels, flooding of low-lying areas, and other downstream effects. But, there can be beneficial uses to surface use and/or discharge of good quality produced water, including irrigation, livestock watering, creation of ponds for recreation or wetlands for habitat, dust suppression on roads,[107] and emergency firefighting.[108] One landowner in the La Plata County, Colorado, portion of the San Juan Basin (which contains the "freshest" water in the basin) even filed for and obtained the right from Water Court to use produced water for irrigation.[109] However, these benefits last only as long as the well remains in production. The majority of water in the San Juan Basin, however, is too salty for surface use. In La Plata County, more than 90 percent of produced water from oil and gas production is disposed of or used for enhanced recovery by underground injection.[110] Some of the remaining produced water is disposed of in evaporation pits, which are regulated, permitted and checked by the Colorado Oil and Gas Conservation Commission,[111] while some is pumped into produced water holding tanks and trucked to disposal facilities.[112]

GAS SEEPAGE INTO DOMESTIC WATER WELLS

Anecdotal evidence suggests that improperly sealed gas wells can allow gas to escape into shallow aquifers that are used for domestic well supplies. Documented evidence for coalbed methane production allowing the release of methane in domestic water wells occurred in the Colorado portion of the San Juan Basin in the early 1990s.[113] Older, conventional gas wells that had been completed open hole were blamed for a series of methane seeps. The explanation that was finally developed is that dewatering the Fruitland coal seam for coalbed methane development dewatered the coal seams within the open holes of the conventional wells, allowing methane to escape both up the wells into shallow aquifers and along the formation to where the formation outcrops at the surface, filling basements and other enclosed structures with explosive levels of methane. Once this problem was identified, the conventional wells were recased and recemented, and other wells were plugged. Currently, a large scale monitoring program is in place to test well integrity and local water wells.[114] A Bradenhead valve exists on each gas well to monitor gas pressure in the wellbore, and the valve pressure is recorded every year. If there is any pressure, it is assumed to be from gas that has not been collected into the pipe. More than five pounds of pressure in a critical area, or twenty five pounds of pressure in a noncritical area, requires additional study of wellbore integrity.[115]

In addition, local water wells are tested before any coalbed methane wells are drilled in the area, then are tested one year after drilling, and at 3 year intervals after that, and the results are shared with the well owner. Methane concentrations greater than 2 milligrams per liter require additional chemical analysis to determine the source of the methane contamination.[116]

EFFECTS AT THE OUTCROP—DYING VEGETATION AT THE FRUITLAND OUTCROP, GAS SEEPS, COAL SEAM FIRES

"The Outcrop" refers to the area where the Fruitland Formation is exposed at the surface, which defines the outline of the coalbed methane-producing portion of the San Juan Basin. It is thought that dewatering the coal seam at depth is producing unforeseen effects where the coal outcrops at the surface. This includes gas seeps that may be causing vegetation to die off, and fires in the coalbeds at the surface. The BLM states that "exacerbation of these seeps and fires appears to be increasing as coalbed methane gas extraction increases and large-scale withdrawal of coalbed produced water intensifies."[117] Some industry representatives dismiss these concerns as being unrelated to coalbed methane development,[118] while others agree that dewatering the coal seam does exacerbate fires.[119] The environmental community contends that anecdotal evidence should be considered when planning for expansion of development.[120] Five under-

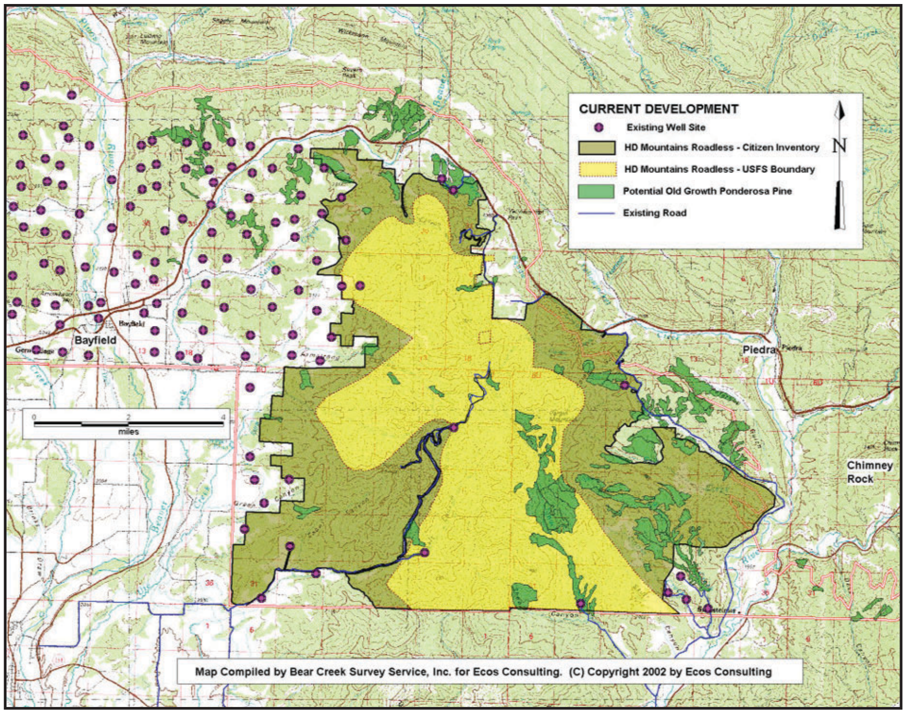

FIGURE 20 *HD Mountains roadless area, current development, showing originally inventoried roadless area, surrounding inventoried roadless area, old growth Ponderosa pine, and current oil and gas development (purple dots). Note town of Bayfield, Colorado, to west of HD Mountains.*

ground fires are currently burning on the Southern Ute Indian Reservation where Fruitland coal seams are exposed at the surface, but they are not currently a threat to public safety.[121]

HD MOUNTAINS ROADLESS AREA

The HD Mountains is a 39,000 acre roadless area in the extreme northeastern portion of the San Juan Basin in Colorado. The coalbed methane industry wishes to extract gas from the roadless portion of the HD Mountains region by drilling up to 100 new wells, and various citizen groups favor designation of the HD Mountains as a Roadless Wilderness. Current coalbed methane production in the HD Mountains area is limited to about two dozen wells that exist on land immediately adjacent to the roadless area or along two preexisting roads within the roadless area (see Figure 20). The roadless area is currently leased by three different gas companies, and as the situation stands now, industry has the right to develop the leases if they can demonstrate they are not violating the current laws,[122] pending the results of the Northern San Juan Basin EIS. Figures 20 and 21 (foldout maps) show the current and proposed development in the HD Mountains.

The HD Mountains contain some of the last remaining stands of unlogged, old-growth ponderosa pine in the San Juan Mountains.[123] The 6,193 acre Ignacio Creek area of the HD Mountains has been proposed as a Research Natural Area because of its pristine condition.[124] The HD Mountains are used by many different groups of recreational users, including hikers, horseback riders, hunters,[125] and mountain bikers. The bulk of the roadless area can be reached by the roads that currently exist along the edges. Plus, there is an existing trail system in the Sauls Creek area that was developed by the Columbine Ranger District. The scenic beauty of the old growth forest and quiet solitude of so much land uncrossed by roads are a major draw to recreationalists.

IMPACTS ON WILDLIFE

Roads and other development cause destruction of habitat as well as habitat fragmentation, which occurs when roads and other infrastructure are introduced into an area. Remaining habitat scattered in isolated patches, which increases edge to area ratio and leads to the loss of "core area", or prime species habitat.[126] Specific edge effects for forest environment fragments include "micro-habitat alterations, increased wind, more direct sun, dryer conditions (soil), more dramatic fluctuations in temperature, hotter midday, cooler at night."[127] Habitat fragmentation also favors certain species (i.e. deer, raccoons, skunks, blue jays) over others, and allows access to forest interior by edge species.[128] In addition, development affects wildlife migration routes.

The HD Mountains provide prime habitat for bald eagles, mule deer, elk, turkey, bear and the rare Mexican spotted owl.[129] The HDs are so important as winter range for wildlife that the United States Forest Service closes the few publically accessible roads during the winter

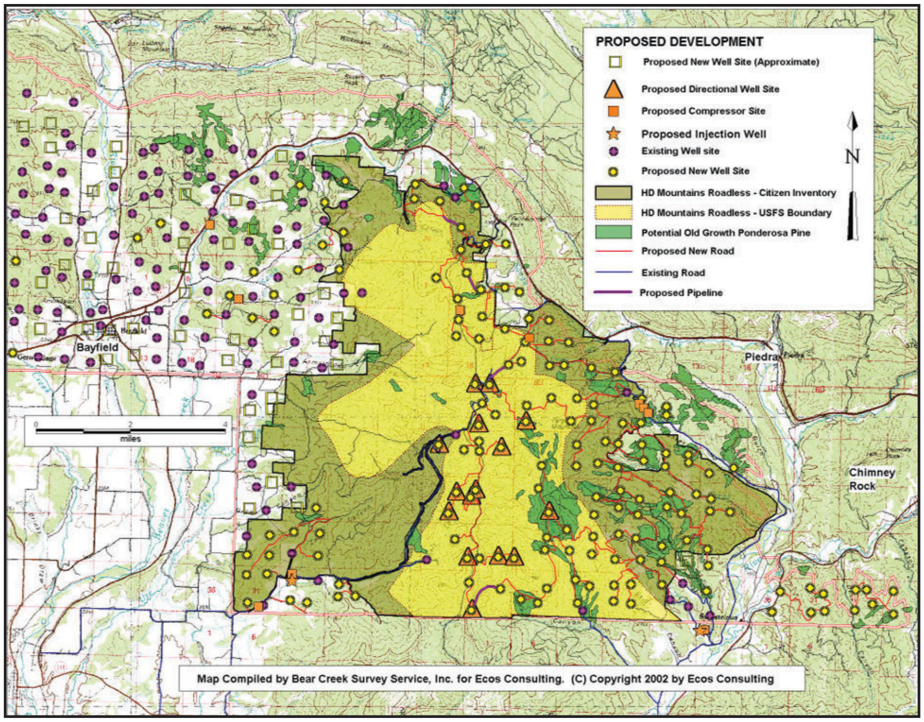

FIGURE 21 *HD Mountains roadless area, proposed development, showing original inventoried roadlesss area, surrounding inventoried roadless area, old growth Ponderosa pine, and current (purple dots) and proposed oil and gas development (yellow dots, lines, triangles, squares).*

so that the winter range is not disturbed.[130] The HD Mountains are a main elk and deer migration habitat, and drilling will "disrupt the migration and scatter the herds,"[131] which is of great concern to hunters and others concerned about the effects of development on wildlife.

ARCHAEOLOGICAL RESOURCES

Areas of archaeological significance exist in several places in the San Juan Basin. The Spring Creek Archaeological District encompasses the majority of the HD Mountains Roadless Area in Colorado. The district was listed on the National Register of Historic Places (NRHP) on May 21, 1983.[132] The roadless portion of the HD Mountains contains at least 100 ancient, undamaged pre-Puebloan cultural sites.[133] The NRHP designation

provides recognition that a property is significant to the Nation, the State, or the community and assures that Federal agencies consider the historic values of the property in the planning for Federal or Federally assisted projects. In addition, listing in the National Register ensures that significant archeological resources become part of a national memory.[134]

In addition, the HD Mountains are sacred to the Southern Ute Indian Tribe, and in fact extend southward on to the SUIT reservation. The tribal council has voted in the past not to allow development in their portion of the HDs in order to protect the resource.[135]

In the New Mexico portion of the San Juan Basin are three areas with set aside to protect archaeological resources: Chaco Culture National Historic Park, Aztec Ruins National Monument, and Salmon Ruins & Heritage Park. Aztec Ruins was listed in the NRHP in 1966. Aztec Ruins is considered to be an outlier to the Chaco Canyon culture, and on December 8, 1987, the United Nations Educational, Scientific, and Cultural Organization designated Chaco Culture National Historic Park as a World Heritage Center, and included Aztec Ruins as a star in the Chaco outlier constellation.[136] In addition to these protections, measures to reduce noise around other highly visited archaeological sites are currently in progress.[137]

FIGURE 22 *Photograph of ruin in Owl Creek, Utah, similar to those found in the San Juan Basin.*

rangeland impacts

BLM lands in the New Mexico portion of the San Juan Basin are extensively leased for grazing, and some families have held their leases for several generations. These ranchers are in favor of multiple use of the land, however, many have found themselves in the unlikely position of siding with the environmental community when it comes to coalbed methane development on their grazing leases. Increased development threatens the health of the land as well as the health of their cattle. As more well pads are cut, more surface vegetation is destroyed. A typical well pad with associated connecting roads and pipelines can destroy three acres of forage,[138] and if this acreage is not properly reseeded, it can be particularly devastating to ranchers during drought years, and can lead to the need to overgraze other areas of the lease. In addition, improperly fenced produced water berms or reserve pits can give cattle access to drink polluted water (Figure 23). If a cow is found dead near one of these, the onus is on the rancher to prove that the cow died because of drinking the polluted water, adding additional expense to often marginal ranching operations.

air quality

Coalbed methane development impacts air quality in several ways. Higher levels of particulate matter are released when increased road building and well pad construction strips off protective topsoil, leaving bare dirt exposed to wind. Vehicle traffic on these roads contributes further to particulate emissions (see Figure 24). Emissions from vehicles and diesel powered generators also affect the air quality surrounding coalbed methane developments. The combined effects of these emissions can affect both the local and regional air quality and visibility, and may impact nearby areas that have protected airsheds, such as Indian reservations and National Parks.

New technology and best practices

introduction

The exploitation of coalbed methane as a resource has depended on the continuing development of new technologies to manage the issues unique to coalbed methane development. These technologies include different drilling options that allow multiple wells from a single pad, draining a larger area with less surface disturbance. However, before a well is drilled, the coalbed methane companies can take steps to reduce surface impact (and development costs) by minimizing the number of dry holes drilled. There are also procedures during the production phase that can reduce the impact to the surface and surrounding communities.

exploration and development best practices

The surface impact of coalbed methane development can be minimized at any step from the initial selection of a drill site, through drilling and well stimulation, to regular operation and maintenance. Best practices for selecting drilling targets include a detailed study of the area's geology using a combination of gravity and magnetic (geophysical) surveys, study of satellite images, and detailed study of the field geology in order to minimize

FIGURE 23 *Photograph of cow in poorly fenced, unlined reserve pit, BLM land, northern New Mexico. Photo courtesy T. Blancett.*

FIGURE 24 *Drill rig near Carlsbad, New Mexico. Blowing dust is from vehicles driving on well pad and connecting roads.*

the drilling of dry holes and the unnecessary clearing of well pads and roadways.[139] The field geology study includes studying coal at the surface to discern what might happen at depth; mapping fracture patterns; and knowing the microgeology of the coal seams, including gas content, using cores and surface samples. Once the drill site is selected, steps can be taken to mitigate surface disturbance during different phases of development. The initial clearing needs to be larger than the final well pad due to the amount of equipment required. As described above, best practices used during well drilling and stimulation can help minimize impacts to surface and ground water. Once the well is drilled, portions of the pad can be reclaimed and reseeded to help keep the bare dirt from blowing away and to contribute to grazing fodder. Trash and other drilling debris should be hauled away at this time. Any waste/reserve pits should be securely fenced and closed according to the stipulations in the application for permit to drill.

Several steps can be taken during production to reduce the impact on the surrounding land. Companies can use satellite telemetry to monitor well production, rather than having a worker visit the site every day. On site management of produced water, rather than offsite disposal, also reduces truck traffic to the well site. Compressor noise can be mitigated using barrier and other muffling devices. Equipment can be fenced to prevent people and animals from accessing onsite hazards.

DIRECTIONAL DRILLING

Directional drilling refers to an advanced drilling technique that deviates from the straight and vertical. According to the US Department of Energy (DOE), oil and gas wells have traditionally been drilled vertically at depths of a few thousand feet to as deep as 5 miles. Depending on subsurface geology, technological advances now allow wells to deviate from strictly vertical orientation by anywhere from a few degrees to completely horizontal, or inverted toward the surface.[140] The three categories of advanced drilling technologies recognized by DOE are directional, horizontal, and multilateral. These three techniques are illustrated in Figure 25. According to DOE, "directional and horizontal drilling enable producers to reach reservoirs that are not located directly beneath the drilling rig, a capability that is particularly useful in avoiding sensitive surface and subsurface environmental features. New methods and technologies allow industry to produce resources far beneath sensitive environments and scenic vistas in Louisiana wetlands, California wildlife habitats and beaches, Rocky Mountain pine forests, and recreational areas on the Texas Gulf Coast."[141]

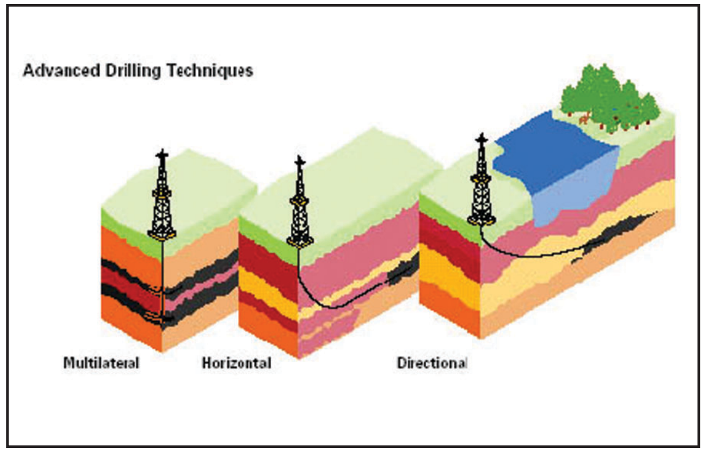

FIGURE 25 *Schematics showing advanced drilling techniques: directional, horizontal, and multilateral.*[142]

In addition to enabling producers to dig beneath sensitive surface areas to reach remote reservoirs of oil and gas, horizontal drilling has been shown to increase resource recovery. DOE estimated that horizontal drilling could increase reserves in the US by 100 billion barrels of oil equivalent because the average production ratio is 3.2 to 1 for horizontal wells compared with vertical, while the average costs ratio is 2 to 1.[143] A horizontal well may produce at rates several times greater than a vertical well because it has an increased chance of intersecting natural fractures and increasing drainage of the nearby well.[144] Figure 26 shows how horizontal drilling can increase production by tapping into several producing regions at once.

Advances in directional drilling now allow extraordinarily precise control of drilling direction. Multiple wells directed at targets several miles distant can be drilled from a single location.[146] According to the National Petroleum Council, "More recent efforts in other parts of the world have extended the drilling reach to 5–6 miles.[147]

In multi-lateral drilling, multiple offshoots or laterals can radiate in different directions or contact resources at different depths from a single vertical wellbore.[148] Figure 27 shows an example of multi-lateral directional drilling being done in the Alpine Field in Alaska. According to DOE, this "21st Century Technology" will allow for

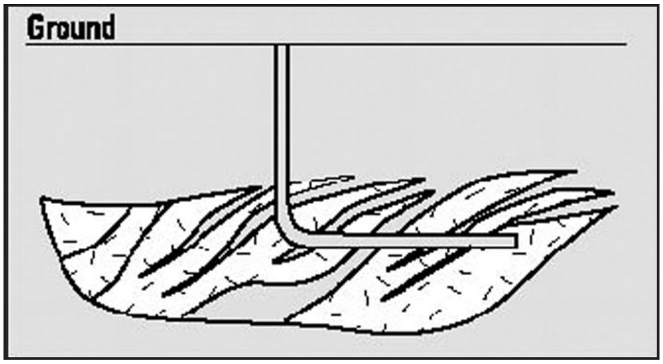

FIGURE 26 *Example of horizontal well tapping into several producing reservoirs in a complex field where producing strata and non-producing strata interweave.*[145]

smaller surface production pads and larger areas explored under the earth.[149] Using directional drilling technology, it is possible to develop nearly 80 square miles of subsurface area from a single 2-acre drill site.[150]

According to DOE, the environmental benefits of directional drilling include:

- Fewer wells
- Lower waste volume
- Protection of sensitive environments.[151]

FEASIBILITY AND CURRENT APPLICATIONS OF DIRECTIONAL DRILLING

Despite the present Administration's enthusiasm for directional drilling as a future energy solution, it seems to be more widely embraced and practiced by industry in other regions than in the San Juan Basin. Directional drilling is most commonly used when environmental concerns, space constraints, or other resource interests prevent vertical drilling from being implemented. When directional drilling has been proposed as a means of meeting No Surface Occupancy stipulations, such as in the HD Mountains, oil and gas producers often claim that directional drilling is too costly or infeasible in these locations. For example, the La Plata (County, Colorado) Energy Council, an oil and gas industry group says:

> *There are limits to the degree that the well bore can deviate from the vertical and to the horizontal distance from the well surface site. Moreover, the limit of horizontal distance is affected by many factors, including the depth and the characteristics of the rock formations to be penetrated. The considerable additional costs and increased risks of directional drilling must also be factored into the decision whether to utilize this technology.*
>
> *Additional time to drill and complete well construction and increases in long-term maintenance activity sometimes necessary in a directionally drilled well, are surface impacts seriously considered before using this technology. Directional drilling can significantly increase well construction time, which includes drilling — turning a week's activity into a month or more. Increased long-term maintenance may result in frequent and repeated use of construction equipment, such as rigs, and associated noise at a directionally drilled well site. Further, it may be necessary to use additional equipment to draw gas out of a directionally drilled well, such as a pump jack. Thus, while directional drilling might appear to be less intrusive, in some cases the opposite will be true.*[153]

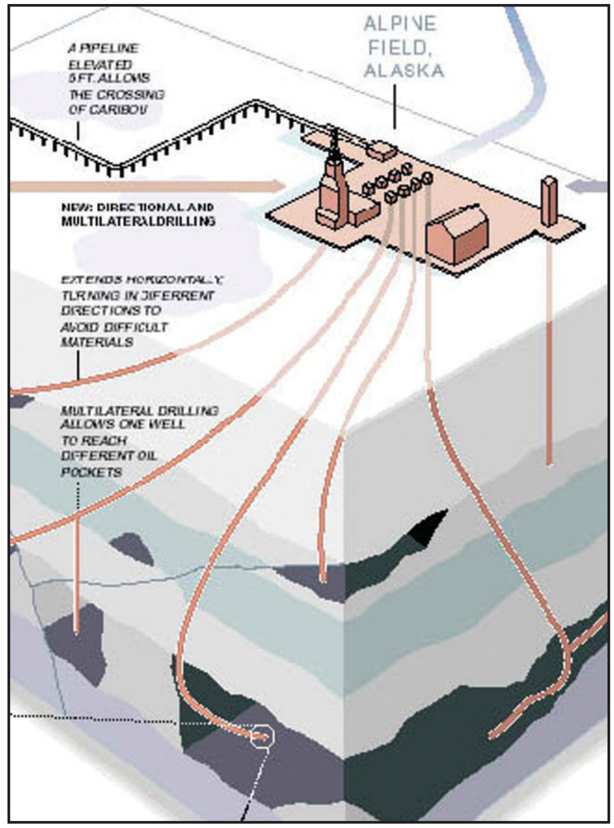

FIGURE 27 *Schematic of the Alpine Field, Alaska, located about 60 miles west of the Trans-Alaska pipeline, showing multilateral drilling allowing one well to reach different pockets of oil.*[152]

However, directional drilling is becoming more common throughout the US. According to DOE, "At any given time, horizontal drilling accounts for 5 to 8% of U.S. land well count."[154] BLM managers for the San

Juan and Permian Basins report that directional drilling has been completed in both of the basins. Bill Papich, PR Director for BLM office that manages oil and gas development in the San Juan Basin, reports that there has been directional drilling done near Navajo Reservoir and under the towns of Farmington and Aztec, New Mexico.[155] In addition, horizontal drilling is currently being used for coalbed methane production in the San Juan Basin. Meridian Oil, Inc., used horizontal drilling to reach a coal bed methane resource in the Fruitland Formation. The completed well produced at a rate of 7 million cubic feet per day, as opposed to the average conventional rate of 1.05 million cubic feet per day.[156] CDX Technologies is also using horizontal drilling for coalbed methane development in the San Juan Basin. Their "Pinnate" technology allows them to drain areas as large as 1000 acres from one main well bore on a well pad smaller than is required by conventional wells. However due to limitations currently in place from the Colorado Oil and Gas Conservation Commission and infrastructure capacity, CDX's one horizontally drilled well in La Plata County is currently draining just 320 acres.[157] Additionally, a new way of developing coalbed methane has been proposed by the Omega Oil Company in Gillette, Wyoming, for their leases in the Powder River Basin.[158] From a single 7-acre pad, they propose to drill a vertical shaft to the coal seam and then drill horizontally in order to drain 8,500 acres of the coalbed. This approach would drain the same acreage as 220 conventional surface wells in the Powder River Basin, or 53 wells in the HD Mountains, half of the total number proposed. A few locations of this type of development, if located just outside the exterior boundary of the roadless area, could tap much if not all of the entire roadless area without requiring any new roads. Industry officials, however, plan to start development using conventional vertical wells, and expect that directional drilling might be necessary to deplete the coalbed methane resource in the HD Mountains.

The feasibility of directional drilling depends on several factors including:[159]

- TYPE OF ROCK: The Austin Chalk field has been the site of over 90% of the onshore horizontal rig count since the late 1980s and still accounts for the majority of horizontal permits and rig activity in the US today. About 30% of all U.S. reserves are in carbonate formations.[160]
- TYPE OF WELL: Up until recently, most directional drilling was completed for oil wells. However, with the increase in gas drilling activity and the advent of coal bed methane recovery, the number of directionally drilled gas wells is increasing each year.
- FLEXIBILITY OF DRILL PIPE: the radius of the curve that can be drilled is determined in part by the flexibility of the drill pipe. For tight radius drilling, short sections of straight pipe must be used. A new options is flexible coiled piping which eliminates joints and allows for tight radius drilling.
- TRAINED PERSONNEL: Directional drilling is made possible by the convergence of several technologies in exploration and drilling including new diamond drill bits, computer drill control and laser guidance systems, and skilled personnel to implement all of these new technologies. The greatest barrier to directional drilling at the moment is the availability of trained personnel to operate all of these new technologies.

COST OF DIRECTIONAL DRILLING

Directional drilling can cost anywhere from 25% to 300% more than a vertical well to drill and complete.[161] However, these additional costs can offset by higher production rates and lower waste removal and reclamation costs. Furthermore, directional or multilateral drilling could eliminate costs to drill, maintain, and reclaim additional wells. Drilling expenditures for gas wells and horizontal wells in 2000 are shown in Table 3.[162] This table shows that horizontal wells averaged twice the cost of gas wells, but only 35% more per foot drilled. According to API, "advances in technology have made horizontally drilled wells a viable option for field development. Horizontal wells can improve productivity, enhance reservoir maintenance, or produce reservoirs which would be uneconomical with vertical wells."[163]

One example of the estimated cost premium for directional drilling in Colorado was reported by Barrett Resources Corporation. Barrett requested permission to increase well density in a natural gas field in Garfield County in western Colorado. Opponents including landowners and county officials suggested directional drilling as an alternative to drilling new wells. Ted

TABLE 3: API JOINT ASSOCIATION SURVEY OF DRILLING EXPENDITURES SUMMARY TABLE—2000			
	Conventional Gas Well	Horizontal Well	Horizontal: Conventional
Average depth	5,470 feet	6,842 feet	1.25: 1
Average cost/well	$756,939/well	$1,300,000/well	1.72 : 1
Average cost/foot	$139/foot	$190/foot	1.37 : 1

Brown, Barrett's manager of engineering reported that the average cost to drill a vertical well in that location was $1 million. Directional wells would cost as much as $150,000 more to drill. Requiring 58 new wells, which collectively could produce about 96 billion cubic feet of natural gas, to be drilled directionally would add about $8.7 million in project costs.[164]

Overall, directional drilling is touted as the 21st century method of drilling, especially when it is combined with 3-D seismic surveying. Costs for directional drilling are being reduced as it is being applied more frequently and more drillers are becoming familiar with the new technologies. The basis for the environmental benefits of oil and gas production as reported by DOE are advanced drilling and production techniques.[165] Many of the technological and cost barriers (if the full cost of production is considered) have been eliminated for directional drilling. Oil and gas industry reluctance to use directional drilling is primarily based on the increased drilling cost which must be borne by the wildcatter or production company. In order to overcome this barrier, the full field production cost must be evaluated. This evaluation will likely show that the increased drilling cost will be offset by increased production efficiency, reduced well maintenance, and a fewer number of wells being drilled, maintained, and reclaimed. Over the life of the field, directional drilling may actually be less expensive than drilling, maintaining, and reclaiming additional wells and well-sites.

NO2/CO2 ENHANCED RECOVERY

The injection of carbon dioxide and/or nitrogen into coalbed methane reservoirs can greatly enhance gas recovery, from 30% to 400% above expected returns.[166] This technology can increase methane production rates up to six-fold, and increase "producible gas reserves" up to two-fold.[167] The injected gas displaces the methane in the coal, and some consider this to be the "ultimate methodology for extraction of this valuable resource."[168] In fact, "coalbed methane reservoirs that might otherwise not be economical to develop under conventional production operations could become fully developed."[169]

Recovery of additional gas from the same well prolongs useful well life, reducing the need to drill additional wells in order to deplete the resource. Enhanced recovery via injection of gases has been tested in the San Juan Basin and found to be economically and technically feasible.[170] Using carbon dioxide for enhanced recovery has the additional advantage of disposing of a greenhouse gas with "virtually permanent storage capacity."[171]

III: SAN JUAN BASIN COALBED METHANE DEVELOPMENT—SUMMARY OF TRADEOFFS

WHAT WE'VE LEARNED FROM HISTORY

The San Juan Basin is considered to be the "Granddaddy" coalbed methane basin. The first development started in the Basin in the late 1980's, and many of the technological advances that have spurred the further rapid development of other basins were initially tested and developed in the San Juan Basin. This includes understanding how methane is stored in coal, that removing water from the coal allows the gas to escape, and the role that natural fractures play in this process.[172] However, with new technology and understanding of the geology of coalbed methane leading rapid growth in well numbers, coalbed methane development has "raised a number of issues relating to the environment, permitting, and ownership."[173] Some of these issues have been easily resolved, while others still need to be addressed on a well-by-well basis.

One ongoing problem in the New Mexico portion of the San Juan Basin has been the lack of proper funding for BLM inspectors. According to former BLM Director Jim Baca, "inadequate staffing has made it difficult to inspect wells in the San Juan area and the number of wells out of compliance is astounding. Wells are not being properly maintained and water is not being properly contained."[174] This problem has only gotten worse as the number of wells has increased.

What are the current tradeoffs?

The tradeoffs of current coalbed methane development have been addressed throughout this paper. There is a delicate balance between protection of the non-energy resources development of the coalbed methane resource. There are many resources that have the potential to be negatively impacted by coalbed methane development, but there are also financial incentives rewarding development.

Based on government and industry predictions, what is the future scenario?

Based on scenarios developed during the various EIS processes in different portions of the San Juan Basin, it is reasonable to expect that approximately 4000 more coalbed methane wells will be drilled in the Basin within the next 20 years. These wells would tap into a resource most often cited as 50 tcf of gas-in-place, which will most likely yield approximately 10 tcf given current technological and economic conditions (as discussed in Chapter 2). The takeaway capacity of the Basin, coalbed methane and conventional natural gas, will remain at approximately 4 bcf/day, most of which will continue to supply California's natural gas needs. With this continued and expanded development, it is the hope of area residents (ranchers, hunters, recreationalists, and the environmental community, among others) that the energy resource will be developed in a manner that minimizes impacts to the non-energy resources of the area, meaning using "best practices" in all stages of exploration, development, and production. This also means having a regulatory structure and staff in place with the resources to ensure compliance with environmental regulations.

Notes

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2. http://energy.usgs.gov/factsheets/Coalbed/map.html

3. Travis Brown, Geological Consultant to the J.M. Huber Company, "Developing Coalbed Methane in the Powder River Basin", presented at presented at the Natural Resources Law Center Coalbed Methane Conference, Denver, Colorado, April 5, 2002.

4. Dallegge, T. A., and Barker, C. E., 2000, *Chapter L—"*Coal-Bed Methane Gas-In-Place Resource Estimates Using Sorption Isotherms and Burial History Reconstruction: An Example from the Ferron Sandstone Member of the Mancos Shale, Utah", *in* Kirschbaum, M. A., Roberts, L. N. R., and Biewick, L. R. H., editors, 2000, *National Coal Resource Assessment: Geologic Assessment of Coal in the Colorado Plateau: Arizona, Colorado, New Mexico, and Utah*. USGS Professional Paper 1625-B, Disc 1, page L4.

5. Dallegge, T. A., and Barker, C. E., page L4. Ecos Consulting calculations suggest numbers substantially smaller.

6. http://www.dgslaw.com/articles/274185.html

7. Travis Brown, April 5, 2002

8. http://energy.usgs.gov/factsheets/Coalbed/graph.html

9. square mile = 640 acres

10. Fassett, J. E., 2000, *Chapter Q—"*Geology and Coal Resources of the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado", *in* Kirschbaum, M. A., Roberts, L. N. R., and Biewick, L. R. H., editors, 2000, *National Coal Resource Assessment: Geologic Assessment of Coal in the Colorado Plateau: Arizona, Colorado, New Mexico, and Utah*. USGS Professional Paper 1625-B, Disc 1.

page Q5.

11. http://cogccweb.state.co.us/ facilities search. Data are for La Plata County portion of the San Juan Basin only.

12. http://oil-gas.state.co.us/Library/blm/Background/geoseting.htm

13. Laubach, S. E., and Tremain, C. M., 1994, "Tectonic Setting of the San Juan Basin", *in* Ayers, W. B., and Kaiser, W. R., 1994, *Coalbed Methane in the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado*, New Mexico Bureau of Mines and Mineral Resources, Bulleting 146, page 9.

14. Fassett, page Q1.

15. Cross section from case files of March 2000 infill drilling hearings, modified from figure created by Geologic Data Systems, Exhibit number 26, Cause No. 112, Docket No. 004-AW-05 and 06, La Plata and Archuleta Counties/Ignacio Blanco Field.

16. Wray, Laura L., 2002, *Geologic Mapping and Subsurface Well Log Correlations of the Late Cretaceous Fruitland Formation Coal Beds and Carbonaceous Shales – the Stratigraphic Mapping Component of the 3M Project, San Juan Basin, La Plata County, Colorado*, Colorado Geological Survey, Denver, Colorado, Open File Report 00-18, page 4.

17. The vast majority of the Fruitland Formation coal is buried too deeply to be recovered with current technology. If it could be recovered, it would be enough for approximately 185 years of US consumption at the current consumption rate of 1.08 billion tons per year (http://www.eia.doe.gov/cneaf/coal/quarterly/html/t38p01p1.html). Current U.S. recoverable coal reserves at producing mines is 18.34 short tons (1 short ton = 2000 pounds). The U.S. has a demonstrated reserve base of coal, potentially recoverable with current technology, of 507.2 billion short tons

(http://www.eia.doe.gov/cneaf/coal/cia/html/t33p01p1.html), about 280 billion tons of which are considered recoverable reserves (ftp://ftp.eia.doe.gov/pub/pdf/international/0484(2002).pdf figure 57, page 72).

18. As of December 31, 2000, U.S. operators had 177,427 billion cubic feet of dry natural gas reserves. Of that, 5.9% is in Colorado, and 9.8% is in New Mexico. Of the total U.S. proved reserve, 15,708 billion cubic feet, or 9%, is from coalbed methane. (http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/current/pdf/ch4.pdf page 1 and 8).

19. Wray, Laura L., 2002, *Geologic Mapping and Subsurface Well Log Correlations of the Late Cretaceous Fruitland Formation Coal Beds and Carbonaceous Shales – the Stratigraphic Mapping Component of the 3M Project, San Juan Basin, La Plata County, Colorado*, Colorado Geological Survey, Denver, Colorado, Open File Report 00-18, page 4.

20. http://oil-gas.state.co.us/blm_sjb.htm

21. Colorado Geological Survey, 2000, page 8.

22. Colorado Geological Survey, 2000, page 9.

23. http://octane.nmt.edu/news/newsletter/2000/June/SanJuan_GasProd.asp

24. Bill Papich, BLM Public Information Officer, Farmington, New Mexico, Office, personal communication, April 3, 2002.

25. Steve, New Mexico Oil Conservation Division, Aztec, NM, personal communication, April 3, 2002.

26. Mahan, G. C., 2002b, "Reviewing Recent San Juan Basin Natural Gas Production", in *Energy: A Quarterly Guide to Oil and Gas and the Power Industries in the Four Corners*, Four Corners Business Journal, February 2002, p. 13.

27. Four Corners Business Journal Editors, 2002, "San Juan Basin Information and Fact Sheet", in *Energy: A Quarterly Guide to Oil and Gas and the Power Industries in the Four Corners,* Four Corners Business Journal, February 2002, p. 19.

28. Mahan, 2002b, page 13.

29. http://octane.nmt.edu/news/newsletter/2000/June/SanJuan_GasProd.asp

30. http://octane.nmt.edu/news/newsletter/2000/June/SanJuan_GasProd.asp

31. http://octane.nmt.edu/news/newsletter/2000/June/SanJuan_GasProd.asp

32. Four Corners Business Journal Editors, 2002.

33. Four Corners Business Journal Editors, 2002.

34. http://octane.nmt.edu/news/newsletter/2000/June/SanJuan_GasProd.asp

35. http://www.irs.gov/pub/irs-soi/98excise.pdf, page 1.

36. http://www.unt.edu/ipa/vol18no1.htm

37. http://www.epa.gov/coalbed/pdf/pol003.pdf, page 2.

38. tp://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_monthly/current/pdf/table_04.pdf

39. http://www.worc.org/stopassault.html

40. http://oil-gas.state.co.us/blm_sjb.htm Appendix C, Chart 6.

41. Bill Papich, April 3, 2002.

42. Four Corners Business Journal Editors, 2002, page 19.

43. Bill Papich, BLM Public Information Officer, Farmington Field Office, personal communication, April 3, 2002.

44. A note on terminology: "Infill Drilling" vs. "Downspacing": The current EIS is taking place because of the oil and gas industry's wish to change the number of wells per each 1 square mile, or section, from two to four. Each section contains 640 acres, so often this is expressed as a change from one well per 320 acres to two wells per 320 acres, or one well per 160 acres. However, there are two different ways that this process is being described by various groups—"Downspacing" and "Infill Drilling"—and some clarification is needed. According to Mike Weems (personal communication, January 29, 2002) of the Colorado Oil and Gas Conservation Commission (COGCC), the correct way to express what is being proposed is Infill Drilling. This term implies that drilling is occurring within the same lease as a previous well, keeping the divisions in order, and the "piece of the pie" within the drilling unit remains the same. Downspacing means cutting a drilling unit into smaller pieces. Based on royalty interests, it is important that this process is referred to as infill drilling.

45. Walt Brown, BLM, personal communication, March 29, 2002.

46. http://www.epa.gov/docs/fedrgstr/EPA-IMPACT/1995/September/Day-15/pr-1304.html

47. http://www.epa.gov/fedrgstr/EPA-IMPACT/2000/August/Day-30/i22119.htm

48. Engler, 2001, pages 7, 10.

49. http://resourcescommittee.house.gov/107cong/forests/2001apr04/morton.htm

50. http://www.ziffenergy.com/news/comment/2000-08/article08.asp; Colorado Geological Survey, 2000, page 4; http://energy.cr.usgs.gov/1995OGData/Cbm/CBM.pdf, page 22.

51. http://www.dgslaw.com/articles/273977.html

52. http://energy.cr.usgs.gov/1995OGData/Cbm/CBM.pdf, page 22.

53. http://www.mines.edu/research/PTTC/newsletter/volume4/v4n1p3.html

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55. Potential Gas Committee, 2001, "Potential Supply of Natural Gas—2000: Rocky Mountain Area", *in* Decker, Michael K., 2001, *Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee*

December 31, 2000, page 131. Published by the Potential Gas Agency, Colorado School of Mines, Golden, Colorado.

56. http://www.ziffenergy.com/news/comment/2000-08/article08.asp

57. Figure 11, Sources of Estimates:

i. http://www.mines.edu/research/PTTC/newsletter/volume4/v4n1p3.html

ii. http://www.ziffenergy.com/news/comment/2000-08/article08.asp

iii. http://energy.cr.usgs.gov/1995OGData/Cbm/CBM.pdf, page 22

iv. http://www.ziffenergy.com/news/comment/2000-08/article08.asp

v. Uses above 30 tcf estimate and applies economically recoverable percentage at $3.34/mcf

vi. Potential Gas Committee 2000 "most likely" probable resource. From Potential Gas Committee, 2001, "Potential Supply of Natural Gas—2000: Rocky Mountain Area", *in* Decker, Michael K., 2001, *Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee December 31, 2000*, page 131. Published by the Potential Gas Agency, Colorado School of Mines, Golden, Colorado.

vii. Uses above 30 tcf estimate and applies economically recoverable percentage at $2.00/mcf

viii. USGS 1995 Technically Recoverable amount for entire San Juan Basin. From Rice, D. D., and Finn, T. M., 1996, Coal-Bed Gas Plays, in Gautier, D. L., Dolton, G. L., Takashi, K. I., and Varnes, K. L., *editors*, 1996, 1995 National Assessment of United States Oil and Gas Resources—Results, Methodology, and Supporting Data, USGS Digital Data Series DDS-30, Release 2, resource estimates pages.

ix. Uses PGC 10.24 tcf estimate and applies economically recoverable percentage at $3.34/mcf

x. Uses PGC 10.24 tcf estimate and applies economically recoverable percentage at $2.00/mcf

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COALBED METHANE DEVELOPMENT IN WYOMING'S POWDER RIVER BASIN

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I. Introduction

The western United States abounds with natural resources. People are drawn to the scenic vistas, diverse wildlife, clean air, clean water, and recreational opportunities. People have also been lured by the economic potential of the vast mineral resources that reside in the West. The early Euroamerican settlers came to the West and used coal for heat. Coal consumption began to dominate the energy scene in the second half of the 1800's with the advent of the transcontinental railroad. Later, coal use became overshadowed by the discovery of crude oil, which carried the nation through two world wars in the mid 1900's. The environmental movement of the early 1970's saw a shift back to coal, but to cleaner burning low sulfur coal that is found in parts of the West. Uranium was also mined in the West in the 1940's through the late 1970's for nuclear power generation of electricity and for the military.

Natural gas is another energy source produced in the West throughout most of the 20th century. Natural gas has become the fossil fuel of choice in the United States in the last two decades, as it burns cleaner than oil or coal. While there have been some significant discoveries of conventional natural gas fields in Wyoming and Montana in the recent years, a new energy source has emerged. Technology has finally allowed for the economic extraction of coalbed methane (CBM).

It has been known for centuries that methane gas is found in association with coal, but until the 1970's, CBM was considered more of a safety hazard than a potential energy source. The huge coal deposits found in Montana, Wyoming, Colorado, New Mexico and Utah have become new energy reservoirs for the United States, not only for the coal, but also for the methane associated with it. While development of this resource has benefits for the country as a whole, it does not come without impacts to the western environment, the communities and the culture in the areas where it is produced.

The Powder River Basin (PRB), located in northeastern Wyoming and stretching north into southeastern Montana, has become recognized as the premier provider of low sulfur coal, and has contributed oil and gas resources for the United States' energy needs. But since the mid-1980's, the focus of mineral production in the PRB has turned from coal to CBM. Since the first CBM well was tapped in Wyoming's PRB in 1986, the industry has boomed in Wyoming, but development has occurred to a much lesser extent in Montana due to regulatory constraints imposed by the state.

This case study will discuss the issues surrounding CBM development in the Powder River Basin, primarily focusing on the more aggressive development that has occurred in Wyoming. The first section will describe the environment and mineral resources in the area of development, relying heavily on the resource information provided in Chapter 3 of the Bureau of Land Management, Draft Environmental Impact Statement for the Powder River Basin Oil and Gas Project, January, 2002,[1] and Chapter 3 of the Montana Statewide Draft Oil and Gas Environmental Impact Statement and Amendment of the Powder River Basin and Billings Resource Management Plans, January, 2002.[2] The second section will examine the energy potential of CBM, the net energy value and cost-benefit of the resource, the environmental and socioeconomic issues surrounding CBM development in the PRB, the trade-off between the environment and the mineral resource value, and technological advances in CBM development that have the potential to minimize impacts to the environment. The last section will examine lessons learned from the development to date, and the potential for future development.

Environmental resources

Geography[1]

The PRB is a rolling upland plain, extending 220 miles from north to south across eastern Wyoming and Montana, and is generally less than 95 miles wide from east to west. The topography is relatively flat, but is broken up by hills, buttes and mesas. The PRB is bordered by the Big Horn

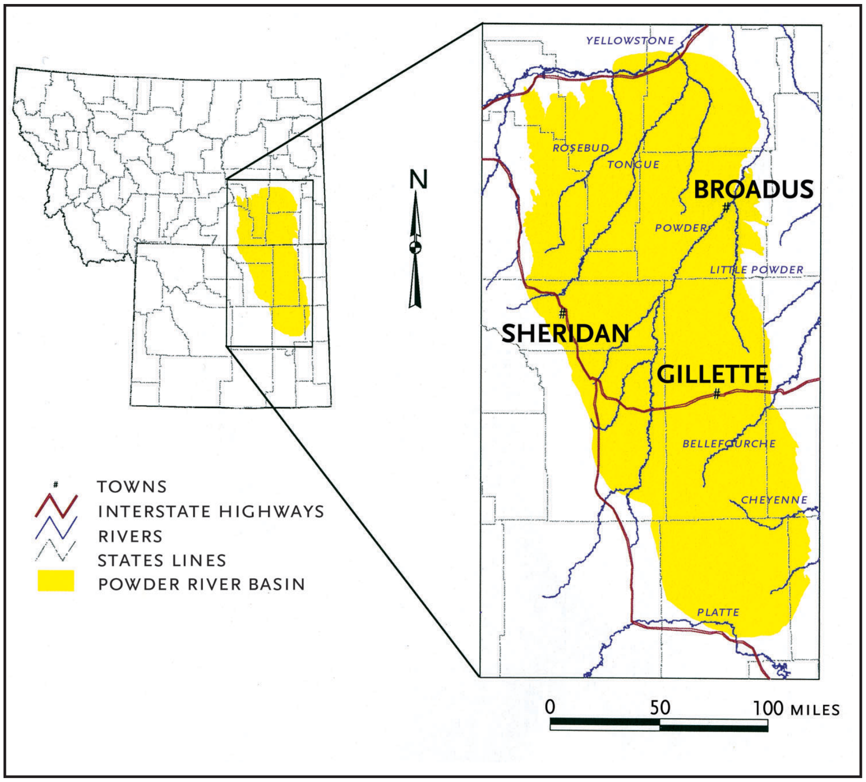

FIGURE 1 *The Powder River Basin in Wyoming and Montana showing major towns and rivers (produced by Scott Lieske, University of Wyoming, Department of Agriculture and Applied Economics, 2002).*

Mountain range to the west; the Black Hills to the east; and the Casper Arch, Laramie Range, and Hartville Uplift to the south. Elevation in the PRB ranges from 3,000 to 5,000 feet above mean sea level. The basin is drained to the north and east by six major rivers that all contribute to the Missouri River System: the Tongue River, Powder River, Little Powder River, Yellowstone River, Belle Fourche River and Cheyenne River (Figure 1).

The climate in the region is arid, receiving an average of 14 inches per year of precipitation. The average daily temperature ranges from a low of 5–10 degrees Fahrenheit (°F) to a high of 30–35 °F in mid-winter, and lows of 55–60 °F to highs of 80–85 °F in mid-summer. Prevailing winds are from the southwest at an average annual speed of 15 miles per hour. Wind speeds tend to peak in late morning and afternoon and usually become calm in the evening due to cooling temperatures.

Water

SURFACE WATER

Wyoming's PRB can be divided up into 18 sub-watersheds, including the mountainous and plains regions of the PRB. Streambeds in the mountainous areas are primarily recharged by snowmelt and those in the plains region are largely influenced by runoff as a result of heavy rainstorms. Stream flows are typically highest in May, June, and July and lowest January through March. Stream infiltration, evaporation, and evapotranspiration rates are higher in the plains areas of the PRB, especially during the summer months.

Surface water quality varies across the PRB. Lowland waters tend to be high in sodium sulfate whereas waters in higher elevations are often high in calcium bicarbonate. Surface water quality in the PRB is affected by irrigation return flows, runoff from erosive soils and other natural background conditions. This results in surface waters with elevated concentrations of total dissolved solids (TDS). TDS represents the sum of all dissolved constituents in a water sample and is often used as an overall indicator of water quality. The drinking water standard for TDS is 500 mg/L. Most surface waters in the PRB exceed this level, ranging from 500–2500 milligrams per liter (mg/L) TDS.

PRB surface waters tend to have a high sodium absorption ratio (SAR). SAR represents the proportion of sodium ions to calcium and magnesium ions in water. Water with a high SAR can impact the structure of certain soils through sodium accumulation and negatively affect vegetative growth. The SAR value of water becomes important when the water is going to be discharged onto the ground or used for irrigation. In these cases, the character of the soil has to be considered in relation to the SAR of the water. The soils in the PRB tend to have a high clay content that reacts negatively with high SAR waters and caution must be used when considering the use of this type of water for crop irrigation.

GROUNDWATER

Groundwater in the PRB is part of the Northern Great Plains Aquifer System. There is an alluvial unconfined aquifer exposed to the surface throughout much of the PRB, and underlying layers of aquifers separated by complete or partial confining layers. The underlying aquifers, such as the Wasatch, Fort Union and Tullock formations, are located primarily in sandstones and coals, which offer substantial water storage. These are also the aquifers that have been tapped for CBM.

Groundwater quality varies across the PRB and between aquifers. The alluvial aquifer has varying concentrations of total dissolved solids (TDS), with values ranging from 106 to 6,600 mg/L. The high TDS values are typically attributed to excess sodium and sulfate ions. In general, waters within unconfined portions of the coal aquifer are calcium-magnesium-sulfate types and those within confined portions of the aquifer are sodium bicarbonate types. Groundwater samples from confined aquifers show an average TDS of 740 mg/L and average bicarbonate and sodium concentrations of 850 and 240 mg/L, respectively.

Alluvial groundwater in the PRB is typically not suitable for drinking water. It's marginal for irrigation but acceptable for use by livestock and wildlife. Domestic water wells in the PRB are generally less than 500 feet deep and produce from the Fort Union or Wasatch aquifers, the same aquifers where CBM is produced.

Air

Air pollutants in the PRB are generated from mobile and stationary sources. Pollutants from mobile sources, such as gasoline and diesel fired automobiles, trucks, and trains include nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM) and sulfur dioxide (SO_2). PM is also generated from vehicle traffic on unpaved roads and from wind. Stationary sources and their pollutants in the PRB include: PM from surface coal mining; NOx, SO_2 and PM from coal fired power plants; and NOx, SO_2, CO and VOC from gas fired compressor stations and gas processing plants. Pollutants from these stationary sources are generated in isolated areas. The flat topography and moderate to high winds in the PRB aid in the dispersion of these pollutants.

Visibility, defined as the distance one can see and the ability to perceive color, contrast and detail, can be impacted by meteorological conditions and air pollutants.[1] Visibility in the PRB is considered good, but there may be localized areas of poor visibility depending on wind speeds and industrial activity.

Soil[1]

The soil in the PRB is generally low in organic matter and tends to be alkaline. Agricultural crops are difficult to grow without irrigation. Some localized areas of the PRB around the confluence of the Powder River, the South Fork of the Powder River, and along the Belle Fourche River contain high salinity soils while other areas have clay type soils. When water with a high SAR is introduced to these soils, vegetative growth can become impaired, inhibiting water uptake by plants. The revegetation potential is poor in disturbed areas containing these types of soils.

Vegetation[1]

FIGURE 2 *Ute ladies' tresses orchid. Source: www.google.com.*

Most of the vegetative ground cover in the PRB consists of shortgrass and mixed-grass prairie and sagebrush shrubland. There are areas of coniferous forest on the extreme east and west fringes of the PRB and riparian areas are found along major streams and water bodies.

THREATENED AND ENDANGERED SPECIES

As mandated by the Endangered Species Act (ESA), the United States Fish and Wildlife Service (USFWS), is charged with identifying and protecting threatened and endangered plant and animal species. The ESA defines an endangered species as any species that is in danger of extinction throughout all or a significant portion of its range. The ESA defines a threatened species as any



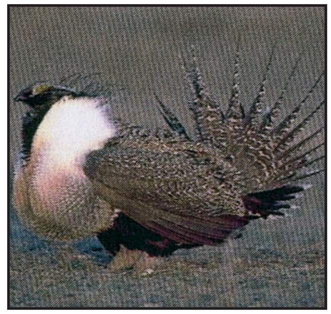

FIGURE 3 *Male pronghorn Source: www.google.com.*
FIGURE 4 *Male mule deer Source: www.google.com.*
FIGURE 5. *Male sage grouse Source: www.google.com.*

species that is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.

The Ute ladies'-tresses is the only plant species on the threatened list that is found in the PRB (Figure 2). This plant is a perennial herb that flowers from late July to September and is found in moist, sub-irrigated valley floors.

Wildlife[1]

The shortgrass and mixed-grass prairie habitat supports a variety of terrestrial and aquatic wildlife. Terrestrial species include big game animals such as pronghorn, deer, and elk; predators such as coyote, fox, eagles, and hawks; upland and migratory game birds such as sage grouse, ducks and geese; and a variety of other birds and rodents. Aquatic species include various species of trout, bass, catfish, perch and chub. Figures 3–5 show some of the wildlife common to the PRB.

Threatened, endangered or sensitive species

The Wyoming PRB Draft EIS issued in January 2002 listed the sturgeon chub (Figure 6) as the only animal species considered to be endangered in the PRB. Since issuance of the Draft EIS, the Wyoming State Engineer's Office has stated that additional sturgeon chub populations have been found in Montana and the species has now been given "status 1" by the Wyoming Game and Fish Department, meaning the populations are restricted or declining and extirpation is possible (personal communication with S. Lowry, May 2, 2002). The Preble's jumping mouse and bald eagle are listed as threatened species, and candidate species for listing in the PRB include the black-tailed prairie dog and mountain plover.

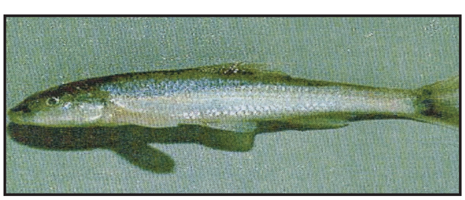

FIGURE 6. *Sturgeon chub, from the North Dakota Game and Fish Dept., 2002*

Historical resources

Paleontologic resources[1]

Scientifically significant paleontologic resources, including vertebrate, invertebrate, plant, and trace fossils are thought to occur within the PRB, especially in the Pumpkin Buttes area, located in southwestern Campbell County, Wyoming. However, much of the PRB has not been extensively explored for fossils and the potential exists for future finds.

Cultural history[1]

Prior to Euroamerican settlement, many Native American tribes passed through or temporarily settled in the PRB to take advantage of the vast herds of bison. About 200 years ago, European explorers and fur traders entered the area and established the Rocky Mountain Fur Trade in what is now Fort Laramie, Wyoming. The fur trade declined in the 1830's and emigrant trails were developed in the southern portion of the PRB. The discovery of gold in Montana in the 1860's, and in the Black Hills in the 1870's, created increased conflicts between tribes and prospectors who were trying to move through the PRB to find their fortunes.

Sheep and cattle ranching moved into the PRB with the passage of the Homestead Act of 1862. This act also granted subsurface mineral rights to the homesteader. Subsequent homestead acts, passed in 1909 and 1916, allowed for larger tract homestead entries, but partially or entirely reserved federal mineral rights while granting surface rights to the patent. This created what is known as a "split estate," or an area of contrasting surface and mineral ownership. In most cases, the surface is private and the minerals are federal.

Throughout most of the 1900's, mining and mineral extraction became an important element in the regional economy. The large shallow deposits of coal in the eastern PRB has brought surface coal mining to the region in addition to oil and gas development.

Mineral resources

The PRB is one of the major mineral development areas in North America. Oil, gas, coal, uranium and CBM are the primary mineral resources found there.

Coal[1,2]

The PRB contains some of the largest accumulations of low sulfur sub-bituminous coal in the world. Thick coal deposits occur at or near the surface along the eastern boundary of the PRB, in a north-south trend west of the towns of Gillette and Wright, Wyoming and in the northwestern portion of the PRB. Wyoming has been the largest producer of coal in the United States for over ten years, with the PRB producing over 80% of the state's coal (http://lmi.state.wy.us). Currently, there are 17 surface coal mines in operation in the eastern portion of the PRB in Wyoming (www.wma-minelife.com). The primary coal seam that is mined is the Wyodak seam, which is 100 feet thick on average.

The state of Montana has the largest reserves of low sulfur coal in the United States. There are five active mines in the PRB of Montana near the towns of Decker and Colstrip.

Oil and gas (non-cbm)[1,2]

Conventional oil and gas development became significant in the southwestern portion of the PRB in the Salt Creek and Teapot Dome areas of Wyoming in the 1950's and 1960's. Oil production from this area peaked at 160 million barrels in the early 1970's and has been steadily declining since. Oil has been produced to a lesser extent in the southern, central and northeast areas of the PRB, but production is in decline there as well. Currently, there are approximately 2,546 productive conventional gas wells operating in the Wyoming portion of the PRB.

The Montana PRB only produces small amounts of oil at the eastern edge of the basin and very small amounts of conventional natural gas from shallow reservoirs. The majority of the oil in Montana is produced in the Williston Basin, located in northeast Montana.

Uranium[1,2]

Uranium deposits are located in the southern PRB in Wyoming. In the 1950's and 1960's, 55 different small surface uranium mines removed over 36,000 tons of ore. Many of these mines remain abandoned. Until recently, two in-situ leach mines were in operation in the southern and southwestern part of the PRB.

Small deposits of uranium are found in Montana's PRB but it has not been commercially mined in Montana.

Coalbed methane

Coalbed methane is natural gas (methane) that is produced in underground coal seams by either biological or thermogenic processes. During the decay and pressurization of plant matter, methanogenic bacteria break down the matter and produce methane as a by-product. Methane is also generated when underground coal seams undergo excessive heat and pressure. If possible, the methane will escape or migrate to the surface through large fractures in the formation. It is also stored or trapped in coal beds as either free gas in tiny pores or cleats in the coal, as dissolved gas in water within the coal, as adsorbed gas on coal surfaces or as absorbed gas within coal molecules. There is estimated to be 25 trillion cubic feet of recoverable CBM in the Wyoming PRB[1] and 4.5 tcf in the Montana PRB.[2]

Other minerals[1,2]

Other mineral resources mined in the Wyoming and Montana PRB include aggregate used in construction, clinker or deposits of burned coal, sand and gravel, clay for brick and tile manufacturing, bentonite, limestone, and gypsum.

Land use

Land ownership[1]

Land ownership in the state of Wyoming is 47.7% federally owned, 42.8% privately owned, 6.2% state or locally owned, and 3.3% tribally owned.[3] As Figure 7 shows, most of the federally owned land occurs in the western half of the state and the vast majority of private land ownership is located in the eastern part of the state, including the PRB. However, during settlement of the PRB under the homestead acts of 1909 and 1916, minerals were partially or entirely reserved for the federal government and surface rights were granted to the patent. This created what is known as a split estate, or areas of contrasting surface and mineral ownership. In split estate, the surface is private and the minerals are federal. Even though CBM is associated with coal seams, it is managed by the federal government as an oil and gas right and not a coal right.

Surface land ownership in Montana's PRB is 65% privately owned, 20% federally owned, 10% tribally owned and the remaining 5% belonging to the state.[2] Figure 8 shows the surface ownership for the Montana PRB.

Federal oil and gas, including CBM rights for the Wyoming and Montana PRB are shown in Figure 9. Federal oil and gas ownership constitutes 63% of the total oil and gas ownership in the Wyoming PRB.[4] and less than 50% in Montana.

Land uses

The BLM, USFS, and State of Wyoming manage land in the PRB along with private landowners. The primary use of private land in the PRB is agricultural rangeland, and the majority of the BLM and USFS land in the PRB is leased for grazing. Extensive surface coal mines are located on the eastern side of the PRB in Wyoming. There are areas of urban and residential land use that are primarily concentrated in or immediately adjacent to incorporated areas. The PRB is also traversed by underground gas

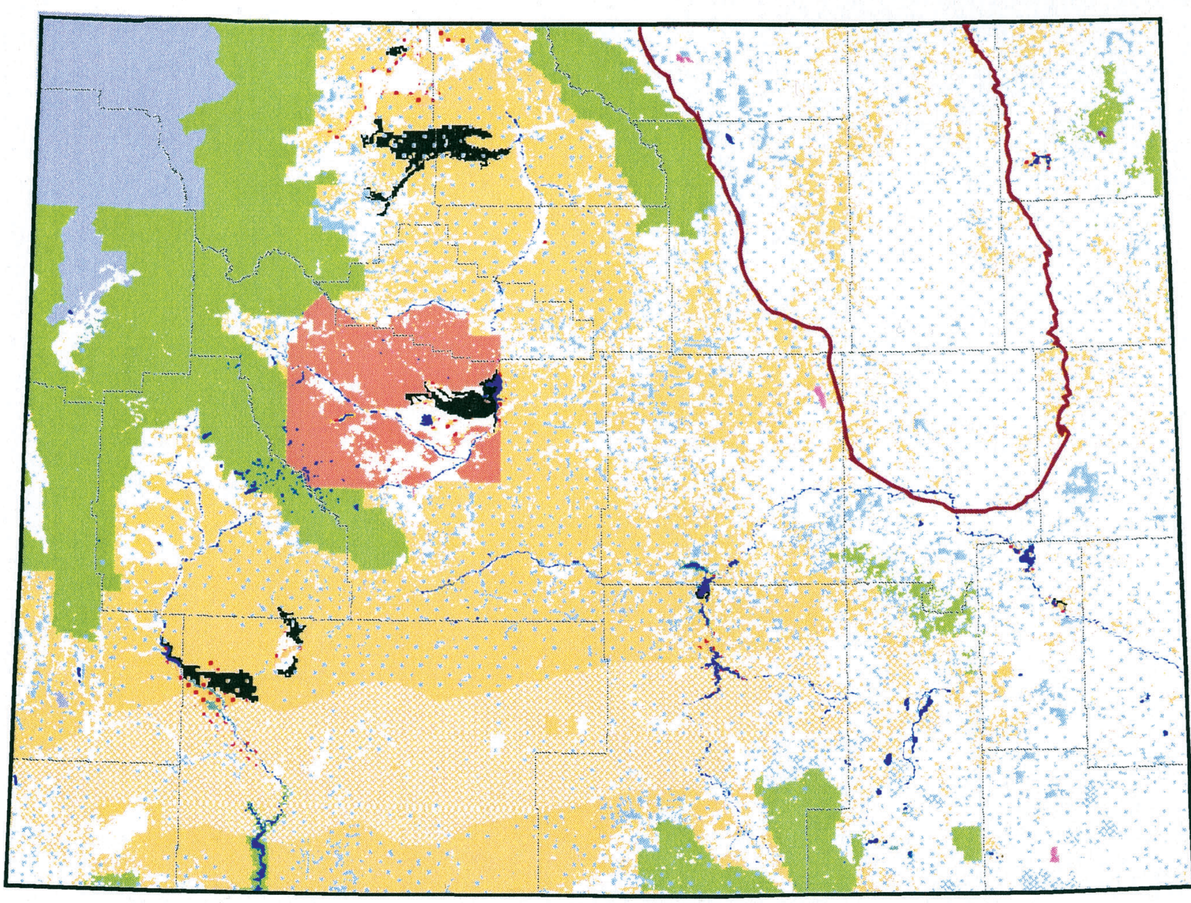

FIGURE 7 *Bureau of Land Management map of suface ownership. Source: University of Wyoming, Wyoming Geographic Information Science Center Data Clearinghouse website, http://wygisc.uwyo.edu/clearinghouse.*

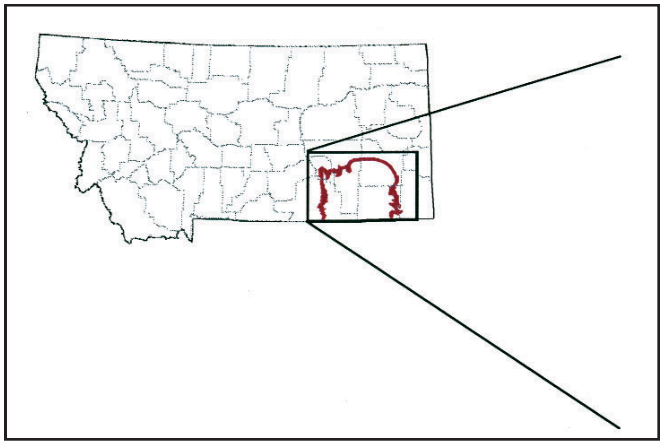

FIGURE 8 *Bureau of Land Management surface ownership map for the Montana PRB. Source: Montana State Library website, 2002, http://nris.state.mt.us/gis/datalist.htm.*

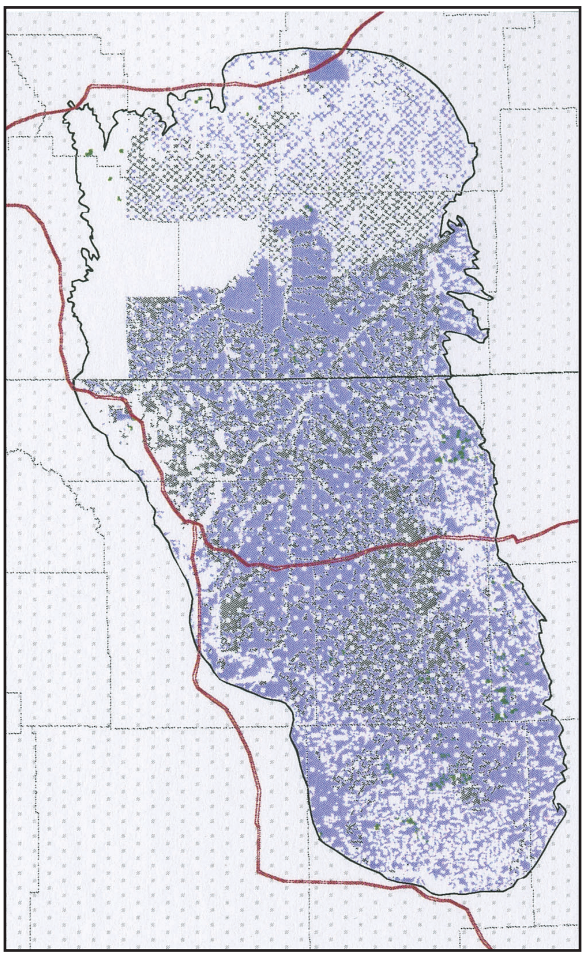

FIGURE 9. *United States Geological Survey map showing federal oil and gas, and coal ownership in the Montana and Wyoming PRB. (From the USGS website, 2002, http://dss1.er.usgs.gov/download/info_prb.htm.)*

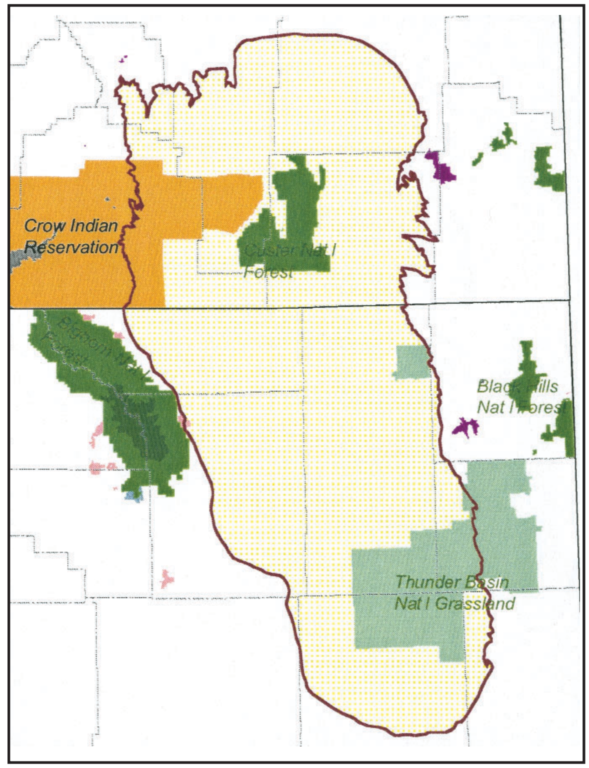

FIGURE 10 *Points of interest and recreational lands in the Montana and Wyoming PRB. Source: University of Wyoming, Wyoming Geographic Information Science Center Data Clearinghouse website, http://wygisc.uwyo.edu/clearinghouse and the Montana State Library website, http://nris.state.mt.us/gis/datalist.htm.*

pipelines and other utilities, and by above-ground transportation corridors for vehicles and trains.

Recreation areas are limited in the PRB as more than 75% of the land is privately owned. However, the PRB does have attractions such as the Thunder Basin National Grassland, several state historic sites, and the historic Bozeman Trail. The majority of the recreation opportunities are located in the Big Horn Mountains that border the PRB on the west and the Black Hills area, including Devil's Tower National Monument, to the east. There are no wilderness areas in the PRB, but the Cloud Peak Wilderness area is located to the west in the Big Horn Mountains. Figure 10 shows the recreational lands and other points of interest in the Montana and Wyoming PRB.

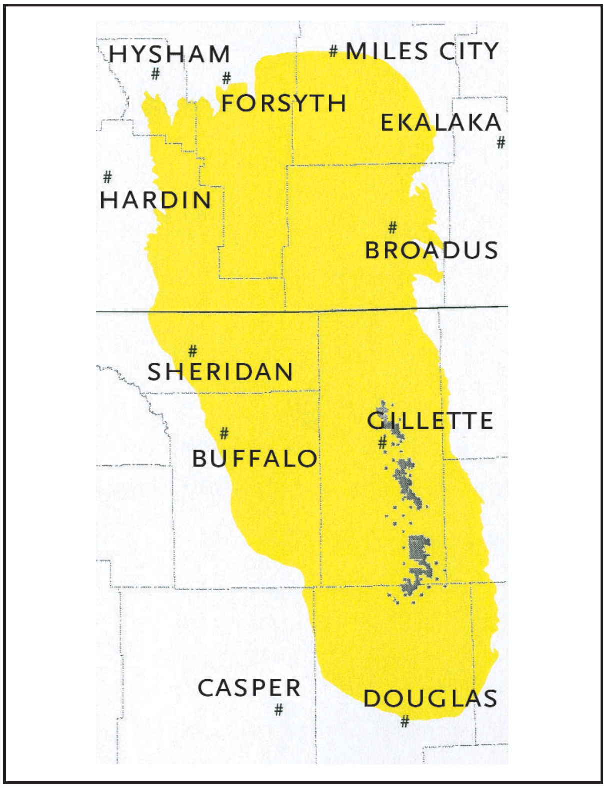

FIGURE 11 *County lines and county seats in the Montana and Wyoming PRB. Source: University of Wyoming, Wyoming Geographic Information Science Center Data Clearinghouse website, http://wygisc.uwyo.edu/clearinghouse and the Montana State Library website, http://nris.state.mt.us/gis/datalist.htm.*

Socioeconomics[1,2]

Figure 11 shows the counties and county seats in the Montana and Wyoming PRB. The total population of the Wyoming counties is 79,385 people, or 16% of the total population of the state of Wyoming. Most of the population is concentrated in the incorporated areas. The 2000 census showed that the total population increased by 12.7% from 1990–2000 on average in the Wyoming counties.

The employment sectors that dominate the Wyoming counties are mining, local government, retail trade, and services. Mining is the primary employment sector in Campbell and Converse counties, local government employs the most people in Johnson County and jobs in the service industry dominate Sheridan County. The mining industry tends to pay the highest wages and agriculture the lowest.

Demographics show that the majority of the population in the Wyoming counties is white, between the ages of 25–44 years old, and earns an average annual income of $33,000. These counties experience a poverty rate slightly higher than the state average of 12%.

The Montana counties located in the PRB include Big Horn, Carter, Custer, Powder River, and Rosebud. The PRB area of Montana experienced only 1.5% population growth during the 2000 census period.

Primary employment sectors in Montana's PRB are services, retail, government and agriculture. Mining was only a significant employment sector in Rosebud County where the surface coal mines are located.

Over 90% of the population in the Montana PRB is white and 6.6% of the population is Native American. The average poverty rate for the area is 17%, over 2% higher than the state average. The average per capita income in the PRB is $17,700 compared to the state average of $21,200.

II. Issues and trade-offs of CBM development in the PRB

This section of the case study will discuss the following economic, environmental, and social issues surrounding CBM development in the PRB:

- Review of the energy potential of the CBM resource
- The net energy available from the development and the net cost benefit
- The environmental and societal trade-offs associated with CBM development
- Techniques being used to minimize environmental impact
- Opportunities for the use of new technologies to minimize environmental impacts

Energy potential of CBM in the PRB

Production of CBM

As previously described, CBM is found in coal seams, which also contain CBM but also large volumes of water that trap the adsorbed CBM under pressure. CBM is produced from wells similar to those used for conventional natural gas, but before CBM will flow from a well, the water must first be removed to depressurize the formation.

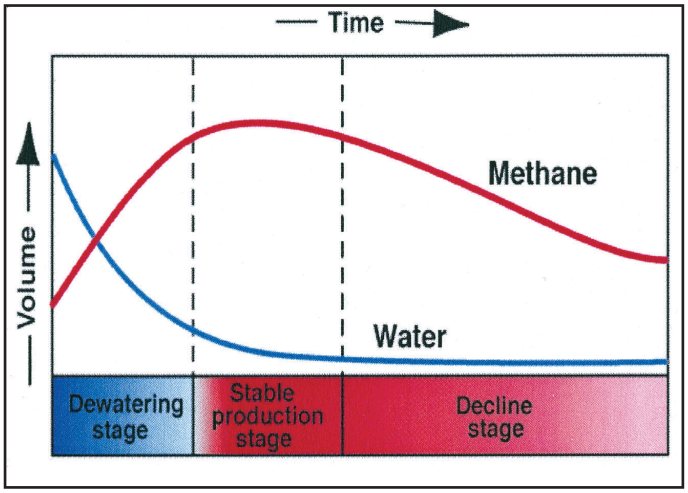

FIGURE 12 *Typical CBM/Water production curve. Source: Wyoming State Geological Survey, 2001.*

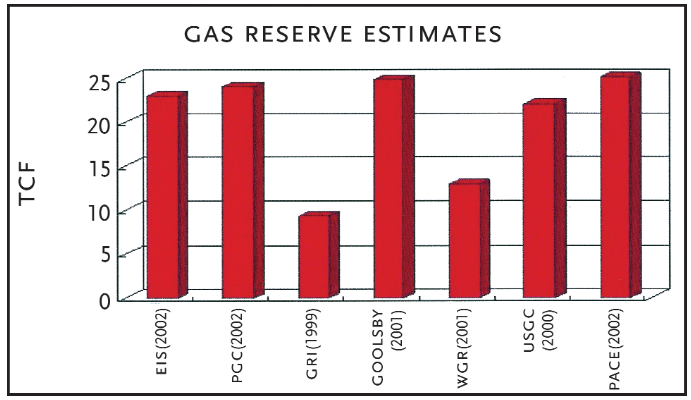

FIGURE 14 *Estimates of CBM reserves from different sources. Source: Wyoming State Geological Survey, 2002.*

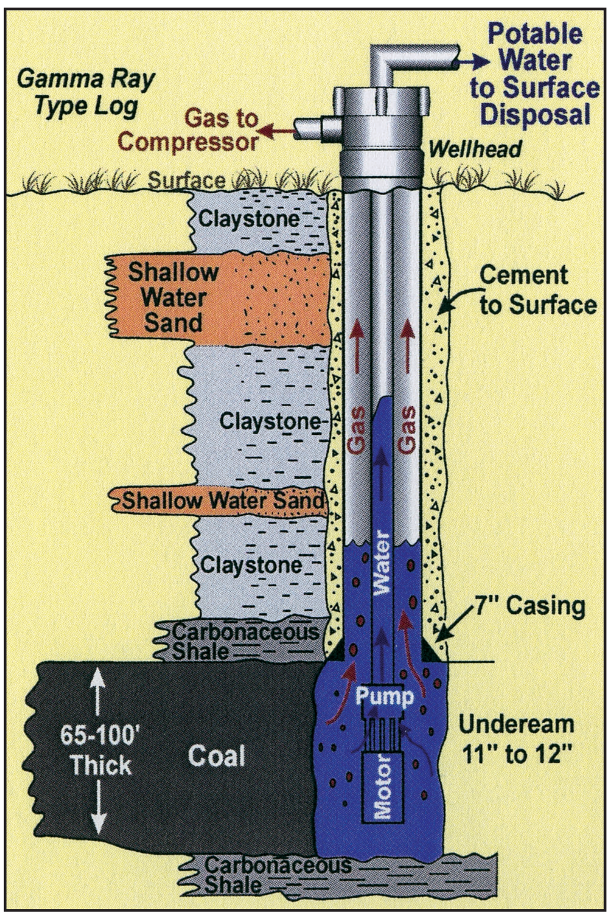

FIGURE 13. *Schematic of typical CBM well. (From the Wyoming State Geological Survey, 2002)*

As a result, large quantities of groundwater are produced as a by-product of CBM development. Upon start up of a CBM well, there is an initial flow of water, followed by a spike in gas flow as the hydrostatic pressure is diminished. Produced water volume and gas flow will decrease over time as shown in Figure 12.

CBM wells have been relatively easy to construct in the PRB. The initial CBM development has taken place in shallow coal seams, which allows for wells to be drilled in a day with truck-mounted rigs. The wells are constructed to allow water to flow to an outlet for discharge while allowing CBM flow into a different header for gathering. A typical CBM well schematic is shown in Figure 13.

Estimated recoverable CBM reserve in the PRB

There have been several estimates of CBM reserves in the PRB. Figure 14 shows estimated reserve values from several government and industry sources. Most of the estimates are comparable and show an average value between 20–25 trillion cubic feet (tcf) of recoverable CBM. According to the Wyoming State Geological Survey, these estimates are typically based on coal seams that are greater than 20 feet thick, an assumed recovery factor of 67%, coal seam permeability of approximately one darcy, and a production area of 3.4 million acres.[5]

The average life span of a CBM well is 7.5 years. Over that time, a typical CBM well will produce an average of 150 barrels per day of water and 310 tcf per day of gas.[5] The 1999 summary report from the National Petroleum Council estimates the natural gas demand for the United

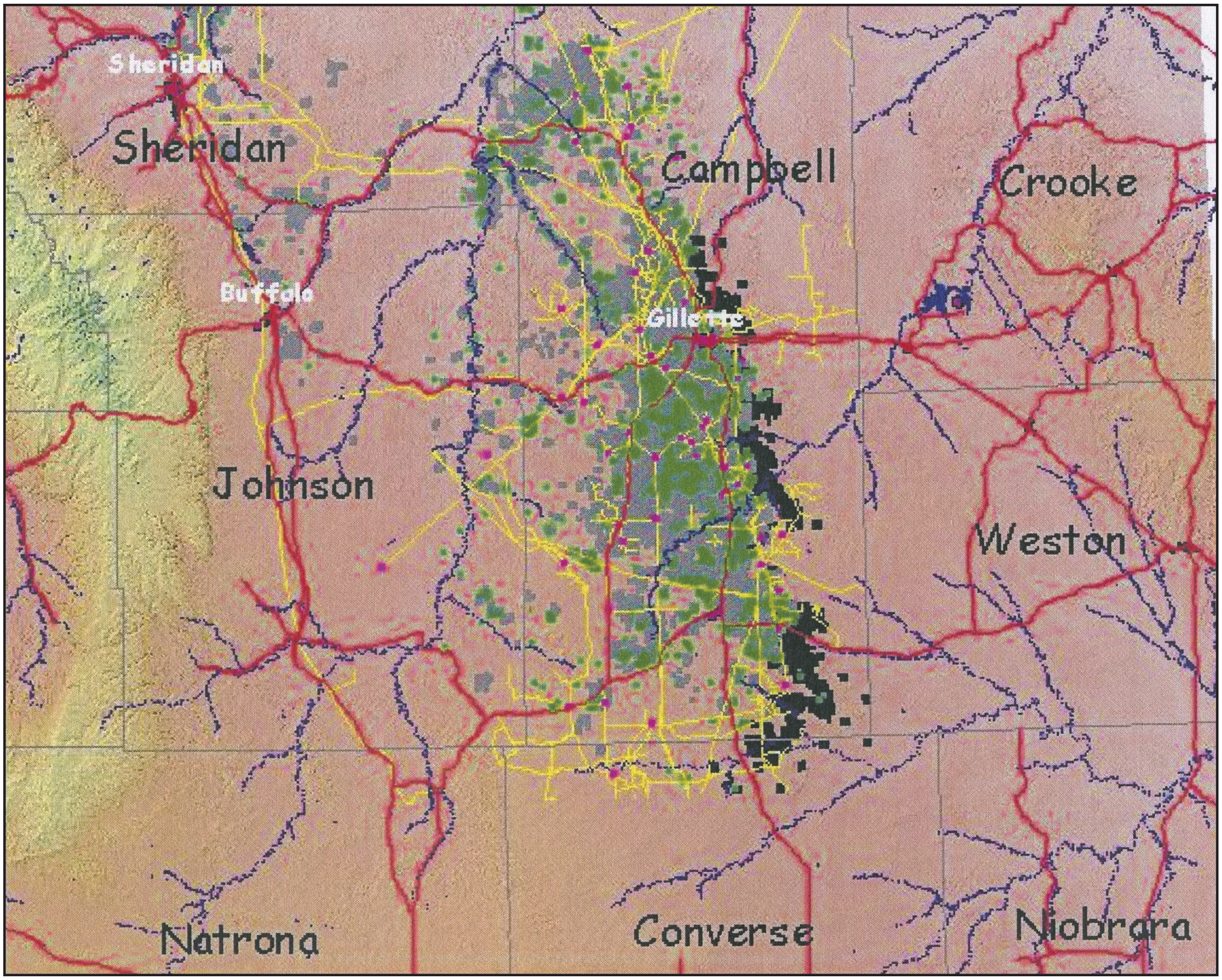

FIGURE 15 *CBM Production in the Wyoming PRB (produced by Scott Lieske, Department of Applied Agriculture and Economics, University of Wyoming, April 2002).*

States will be 24 tcf, meaning the Wyoming PRB has enough gas to supply one year of the nation's current gas demand.[6] The Montana BLM estimates that there are 4.5 tcf of recoverable CBM reserves for the Montana PRB.[2] The Gas Technology Institute estimates 17.7 tcf of recoverable CBM from the entire state of Montana (personal communication with C. Lawson, Montana BLM, May 7, 2002).

Current cbm development in the wyoming prb

Figure 15 shows the producing wells, compressor stations, and pipelines in the Wyoming PRB from CBM development. At the time of this publication, there are an estimated 12,100 producing wells in Wyoming's PRB and over 5,800 wells permitted to be drilled. (From the Wyoming Oil and Gas Conservation Commission website, http://www.wogcc.state.wy.us) As Figure 15 shows, most of the development to date is located in eastern Campbell County around the town of Gillette. The first wells that were installed were required to be spaced at one for every 40 acres. Recent changes in regulations now require that wells be spaced at one for every 80 acres.

Net energy available and net cost benefit of CBM

Energy cost/benefit

CBM promises to be a significant source of energy for the nation, but it takes energy to produce energy. The estimated 25 tcf of CBM reserves in the PRB convert to 25 quadrillion British thermal units (Btu) of energy, assuming a CBM heat value of 1000 Btu per standard cubic foot of gas (Btu/scf) (personal communication with C. Schlichtemeier, Wyoming Air Quality Division, May 2, 2002). Approximately 2% (0.5 quadrillion Btu) of the total CBM produced at the well is used to fuel other associated production equipment, including compressor engines and micro-turbines (http://wogcc.state.wy.us). Some other production energy demands include the following:

- Fuel for drilling rigs
- Fuel for trenching and ground clearing equipment for underground utilities, roads and compressor stations
- Construction of discharge water retention ponds
- Fuel for diesel fired generators

Even with the energy inputs, there is a substantial net gain of Btu's from CBM production. It would be interesting to further investigate the energy inputs on a Btu basis to determine how much energy is expended in production of this energy resource.

Cost/benefit analysis

The economic benefits of CBM development are many. Federal and state governments collect severance taxes and the county receives ad valorem tax revenue from the industry. The development brings jobs to the area and increased labor income. Additional population results in an increase in the number of people paying property and sales taxes. There is an increase in the costs to the government to provide services for the additional population, but the revenue exceeds this cost.

The Department of Agriculture and Applied Economics at the University of Wyoming, is conducting a study on the local benefits and costs of 17 years of CBM development in the PRB. The study assumed installation of 39,372 CBM wells and took the cost of the value of the lost water, recreation losses, and government costs into account. Preliminary results show that CBM development in Campbell, Converse, Johnson and Sheridan Counties for the next 17 years has a net benefit of $688.5 million dollars. However, the analysis assumes that all reclamation and mitigation costs are carried by state and federal governments and the value of the water is $275 per acre foot. The conclusion is that CBM is inexpensive to produce and results in a net economic gain to the counties, the state, and federal government.[7]

Environmental and societal trade-offs of CBM development

The previous section illustrates the energy and economic benefits of CBM development. However, CBM production does not occur without some disruption to the landscape, the wildlife and the people that live in the development area. This section will weigh the economic benefits of CBM against the major environmental and societal impacts of the industry to the PRB.

Environmental impacts

Water

Without a doubt, the most notable environmental concern associated with CBM development centers around water quality and quantity. The PRB is an arid region where effort is taken to conserve water for people, livestock and crops. CBM development has brought

Table 1: Approximate concentrations of total dissolved solids (ppm TDS)[5]

Bottled Water	CBM Product Water	
Crystal Geyser ~ 200	Wyoming PRB ~	800
Perrier ~ 500	Black Warrior Basin, AL ~	12,500
Club Soda ~ 750	San Juan Basin, CO ~	15,000

groundwater to the surface, but it has been a blessing for some and a curse for others.

WATER QUALITY

Water quality from CBM production varies with depth and region across the PRB. In general, water produced on the eastern side of the PRB is of good quality with respect to drinking water standards, but TDS concentrations tend to be higher on the west side of the basin. The city of Gillette in Campbell County gathers CBM product water to supplement their municipal water supply. Many ranchers use water from these same aquifers as stock water. A comparison of parts per million (ppm) TDS values between produced water from other CBM developments in Colorado, Utah, and New Mexico, and even to bottled water, show the water from the PRB is good quality drinking water. In some areas, the water may be questionable as a potable water source, but it is more than adequate for stock water.

CBM product water quality becomes problematic when the water is used for irrigation. The soils in the PRB have a high clay and sodium content. Produced water from the PRB also tends to have a high sodium concentration relative to other ions. The combination of clay soils and high sodium concentrations in both the soil and the water hampers vegetative growth. Sodium accumulates in the root zone of clay soils and inhibits the ability of plants to take in water. Continued application of high sodium water can inhibit native plant growth, create hardpan areas in the soil, and allow for invasion of salt tolerant species of weeds.

Produced water from CBM wells that is discharged into a common drainage can have a negative impact on the quality of the stream. The Wyoming Department of Environmental Quality, Water Quality Division (WWQD) issues permits for surface discharge of CBM product water. These permits are issued under the State's National Pollutant Discharge and Elimination System (NPDES) program. The discharged water must meet certain standards for designated constituents prior to discharge into any existing stream or ephemeral drainage. In some cases, the produced water must be treated, usually by retention in a settling pond, prior to discharge.

Early in the development of CBM in the Wyoming PRB, the state issued numerous NPDES permits to facilitate development, but did not consider the potential cumulative impact of multiple discharges into the same waterway. A specific example of the problems this caused is the case of the Powder River, which was listed sixth in the American Rivers publication, "America's Most Endangered Rivers of 2002."[8] The Powder and Little Powder Rivers flow north from Wyoming into Montana. As the state of Wyoming continued to issue NPDES permits for discharge into the Powder and Little Powder Rivers, salinity levels continued to increase. The state of Montana became concerned that they would not be able to discharge CBM product water into the Powder River and still be able to comply with federal standards for total maximum daily loads (TMDLs).

In September of 2001, Montana and Wyoming signed a memorandum of cooperation whereby Wyoming would be allowed to proceed with CBM development and issuance of discharge permits, but must ensure the protection of the downstream users in Montana.[9] As CBM development proceeds in Montana, the two states will continue to monitor the water quality of the Powder River Drainage.

WATER QUANTITY

With CBM development, water quality issues seem to get the most attention, but mismanagement of water quantity has created serious long-term environmental problems as well. According to the Wyoming Oil and Gas Conservation Commission, the average flow of water from a Wyoming PRB CBM well is between 12–15 gallons per minute (gpm) (From the Wyoming Oil and Gas Conservation Commission website, http://www.wogcc.state.wy.us). Produced water volume will decrease over time as the hydraulic pressure is relieved in the aquifer and the gas continues to flow. A typical water production curve over the life of an average CBM well in the Wyoming PRB was shown in Figure 12. Even with the decline in water production over time, aquifer drawdown or depletion becomes a concern considering that more than 50,000 CBM wells are expected to be installed in the Wyoming PRB by the year 2010.[4]

Since the PRB began to experience large scale CBM development, there have been accounts of ranchers blaming CBM production for their stock and domestic wells going dry. Ranchers worry that the water is being wasted and that aquifers will take hundreds or thousands of years to recharge, especially when the PRB has experienced drought conditions in recent years.

FIGURE 16 *Stream channel erosion from CBM discharge water. Source: Powder River Basin Resource Council website, 2002, http://www.powderriverbasin.org.*

The primary method of CBM water disposal in Wyoming's PRB is surface discharge. Many people in Wyoming are critical of a perceived wasting of water in a region where water is a precious commodity. Some CBM developers have built retention ponds to store produced water and provide it to ranchers for stock water and in some cases, irrigation. However, most of the produced water is lost down a drainage, or by infiltration into the ground or to evaporation.

Flooding and erosion have also been concerns in the PRB. As produced water is discharged into channels that normally experience low or periodic flows, erosion can occur, causing changes in stream morphology, mobilization of metals, and transportation of silt and sediment downstream (Figure 16). However, not all discharged water flows downstream. There is a certain amount of infiltration back into the ground that takes place. The BLM's PRB Draft Environmental Impact Statement estimates an average infiltration rate of 80%[1], but the percentage varies depending on soil conditions, the amount of vegetative cover, and water flow rate.

As the CBM development in the PRB proceeds, it appears that public pressure has encouraged consideration of better management and uses for produced water. The City of Gillette has added produced water to their municipal water supply. Some ranchers have benefited from the water and used if for their livestock and irrigation where appropriate. Developers have used produced water mixed with magnesium chloride as a dust suppressant on access roads. The water can also have benefits for wildlife as a source of drinking water and for creating wetland and riparian habitat.

Air

It is true that CBM burns cleaner than other fossil fuels, which is an important factor for energy consumers around the country. However, on the production side, CBM development contributes to air pollution. Below is a list of emission sources from CBM development. These emission sources combined with emissions from coal mines and gas processing plants, contribute to deterioration of air quality and visibility in the PRB.

- Particulate matter (PM) from vehicles and heavy equipment traveling on unpaved roads and from wind blowing across areas of disturbed land
- Oxides of nitrogen (NOx) from compressor engines, diesel fired generators and vehicle tailpipes
- Carbon monoxide (CO) from compressor engines, diesel fired generators and vehicle tailpipes
- Sulfur dioxide (SO_2) from diesel fired generators, vehicles and heavy equipment
- Formaldehyde from lean burn compressor engines

According to the Wyoming Air Quality Division (WAQD), which has primacy for implementation of the Clean Air Act in Wyoming, particulate emissions from industrial sources are a growing concern. Recent monitoring

FIGURE 17 *Aerial view of the road network associated with CBM development in the PRB. Source: Coalbed Methane Coordination Coalition website, http://www.cbmcc.vcn.com, 2002.*

has shown periodic exceedences of the 24-hour national and state ambient air quality standard for particulate matter less than 10 microns in diameter (PM-10). Exposure to PM-10 poses increased health risks to people and animals, as these smaller particles are able to penetrate deep into the lungs and cause respiratory problems.

Particulate emissions can be controlled using dust suppression. In some areas, CBM product water is used as a dust suppressant on unpaved roads and areas prone to wind erosion. Magnesium chloride is another common dust suppressant that is widely used. However, controlling dust in the PRB is prohibitively time consuming and costly due to the arid climate, persistent winds, the hundreds of miles of unpaved roads across the PRB. Figure 17 shows an example of the extensive road system that CBM development has created in the PRB and the effort that would be involved to continually keep roads wetted down to control dust.

In addition to potential health impacts, PM-10 is also a major contributor to visibility impairment. Most of the visibility issues associated with CBM development tend to be localized and short term. Visibility is locally impaired if an unpaved road experiences heavy traffic flow or if it is excessively windy. Regional visibility can also be impacted by PM-10 that does not deposit back on the ground but gets trapped in the atmosphere. Visibility may not be impaired in the immediate area, but in regions downwind of the activity.

Compressor engines primarily emit NOx and CO. Figure 18 shows a typical compressor station. Lean burn engine technology has been able to lower NOx emissions from compressor engines, but at the expense of increased CO emissions and generation of formaldehyde emissions. The WAQD requires review of best available control technology (BACT) for construction of new, and modification of existing compressor engines. Depending on the size of the engine, BACT would require a lean burn engine to reduce NOx emissions and the addition of oxidation catalysts to reduce CO and formaldehyde emissions. These requirements are necessary considering the number of compressors required for CBM transmission. The WAQD estimates that 3700 engines are operating in the PRB and they emit an estimated 26,000 tons per year of NOx (personal communication with Chad Schlichtemeier, WAQD, May 2, 2002). The WAQD has indicated concerned with approaching the ambient air quality standard for NOx considering the cumulative emissions from compressor engines, gas plants and proposed coal-fired power plants in the area.

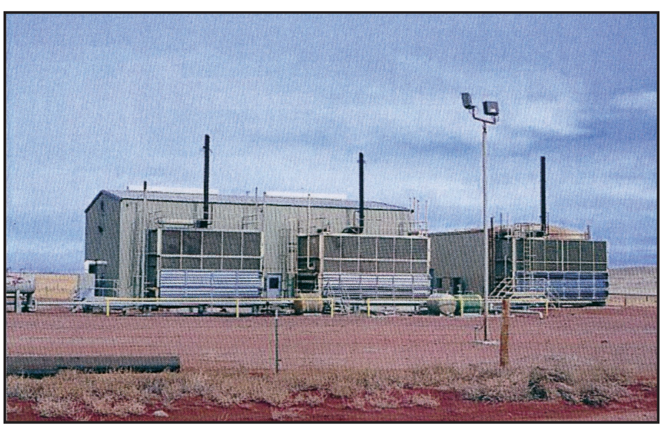

FIGURE 18 *Typical CBM compressor station. Source: Wyoming State Geological Survey, 2001.*

Some remote areas of the PRB do not have electrical service and until service can be provided, power is supplied to these sites by portable diesel-fired generators. These generators are small in size, but are not efficient combustion sources. Depending on the make and model of generator, deisel fired generators can emit over seven times as much NOx as a compressor engine based on grams of NOx per horsepower-hour. At any one time, there may be more than 400 diesel-fired generators operating in the PRB.[1] Diesel-fired generators also emit SO_2, a by-product of the sulfur contained in the diesel fuel. The SO_2 contribution from these generators does not have a significant impact due to the temporary nature of the generators and the national trend toward lower sulfur concentrations in diesel fuel.

Noise

Air pollutants are not the only concern with compressor engines. Conflicts have arisen between CBM transmission companies and local residents over excess noise and vibrations from compressor engines. In March, 2001, a rancher shot at a nearby compressor engine seven times with a high power rifle after his persistent complaints to the company about noise from the engines were ignored.[10] In an area where residents are accustom to a quiet environment, the constant whine from a bank of large compressor engines can be a nuisance. Since that episode, industry has been working on noise-proofing engines and working with residents on siting of the engines.

Methane Seepage

Depressurization of CBM containing formations by the removal of water allows the gas to become mobile in the sub-surface. Obviously, the preferred path of the migrating methane is into a CBM well bore, but methane, like water, will take the path of least resistance. Sub-surface faults allow the methane to migrate laterally and come to the surface where possible. Migrating methane has been an issue since CBM development began and it has serious implications. Methane has been known to find its way into crawl spaces or basements of homes and into stock or domestic water wells. Because methane is colorless, odorless, and highly flammable, methane seepage can be dangerous. Figure 21 shows the impact of methane migration on a domestic water well in the PRB. Methane infiltration into domestic wells usually results in the developer drilling a new well for the landowner. Sub-surface methane migration is difficult to control making it a serious safety issue.

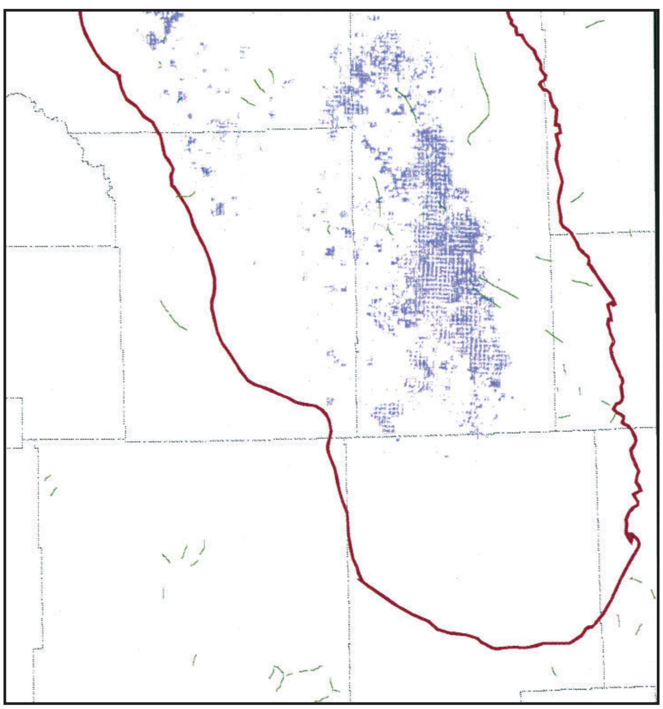

FIGURE 19 *Antelope migration routes and existing CBM well development (developed by Scott Lieske and Dennis Feeney, University of Wyoming, Department of Agriculture and Applied Economics, 2002).*

Wildlife

There are over 180 wildlife species that make their home in the PRB.[11] CBM development impacts wildlife habitat and increases the amount of human contact. Discharge of produced water into rivers and streams alters the habitat for aquatic species and waterfowl. Most of the disturbance to wildlife habitat occurs during installation of wells, power lines, pipelines, and compressor stations; and during construction of retention ponds and access roads. Even though areas are reclaimed where possible and human activity is reduced after the wells and accompanying infrastructure are in place, wildlife is still impacted.

CBM impacts include habitat fragmentation due to roads (see Figure 17), well pads and compressor stations; increased human activity and noise; increased traffic; decline in prey species due to habitat changes; and obstruction of flight paths by utility lines. Migrating species, such as elk and pronghorn are affected by the presence of roads across migration routes, critical winter range and birthing areas. Figure 19 shows the migration routes for antelope superimposed on existing CBM development. The map shows that most of the existing development does not significantly interfere with migration routes, but future development may. The incidence of collisions with vehicles increases for these species and also for rabbits, prairie dogs and birds. Ground disturbance reduces habitat for burrowing species and upland birds, which can cause a decline in their numbers and in turn, a decline in food source for predators.

Fish and other aquatic species can be impacted by the increase in sediment caused by erosion. Some CBM product water contains concentrations of sodium, bicarbonate, arsenic, barium and selenium above levels found in ambient water, which can have an impact on water chemistry and the aquatic ecosystem. Toxic metals like selenium, can concentrate in retention ponds that hold CBM product water. Selenium bioaccumulates and becomes concentrated higher in the food chain. Waterfowl and shorebirds can experience reproductive impairment and even death from consuming insects or vegetation that have accumulated selenium.[12]

Soil and vegetation

Impacts to vegetation occur from ground disturbance and from CBM discharge water degrading the soil. Clearing native vegetation and topsoil for roads, well pads and compressor stations can change the vegetation in those localized areas. Late successional vegetation will not return to the disturbed area for years, allowing for more opportunistic plant species to invade the area. More often than not, the invasive plant species are noxious weeds that, once established, will spread throughout the native vegetation.

When high sodium CBM product water is released onto the clay soils found in the PRB, vegetation can be negatively impacted. The positively charged sodium ions from the water become bound to the negatively charged clay particles in the soil. As more and more sodium ions bind to the clay, water is excluded from the system. This makes water unavailable to plant root systems and the vegetation dies. For this reason, produced CBM water is not usually suitable for crop irrigation.

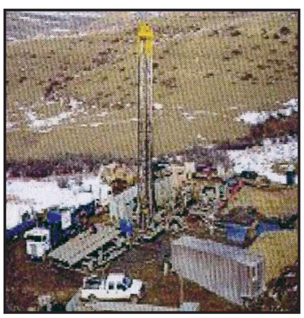

FIGURE 20 *Road constructed across a drainage. Source: Powder River Basin Resource Council website, 2002, http://powderriverbasin.org.*

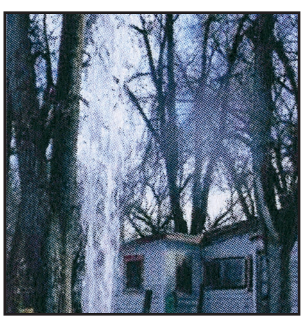

FIGURE 21 *Methane see page into a domestic water well. Source: Powder River Basin Resource Council website, 2002, http://powderriverbasin.org.*

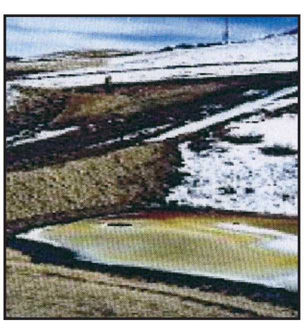

FIGURE 22 *Well pad on a ranch. Source: Powder River Basin Resource Council website, 2002, http://powderriverbasin.org.*

Societal impacts

split estate

Just as water is probably the most talked about environmental issue, split estate is likely the most prominent societal conflict in the PRB CBM development. As discussed earlier, split estate was created as a result of the Stock Raising Homestead Act of 1916, which severed mineral rights from the surface and reserved some or all of the minerals for the federal government. The act was meant to reduce the incidence of prior homestead abuses, but in recent times, it has created a whole new set of problems.[4] In the Wyoming PRB, the BLM administers 10% of the land surface, but controls over 50% of the natural gas reserves, meaning over half of the landowners in Wyoming's PRB are subject to split estate.[4]

The development of CBM as an energy source for the nation is important for meeting consumer demand. Some ranchers who own the mineral estate have seen financial windfalls that, in some cases, has saved their ranches or allowed them to give up ranching all together. Ranchers that own mineral rights also have complete autonomy in deciding how the development will occur on their land. Conversely, ranchers that are severed from the mineral estate have less control over the extraction process and realize less financial gain.

The BLM leases out the minerals in a competitive bidding process. The Stock Raising Homestead Act of 1916 provides for a right of entry for the mineral lessee.[4] This means the surface owner has little or no control over when or where the mineral lessee will develop the mineral. In the early stages of CBM development in the PRB, developers rushed to take advantage of the high gas prices creating rapid change in lifestyle for ranchers and landowners. Some landowners saw roads, dams, power lines and reservoirs built on their land with little regard for the land or their ranching operations. Some ranchers reported dried up stock wells and flooding, erosion, and impacts to vegetation once CBM development started. The land was disturbed by the construction of new roads, well pads, and water impoundments. There have been accounts of methane contamination in domestic water wells and of methane seepage into houses. Figures 20–22 show some of the damage done to private land by CBM development.

Landowners can and should insist on a surface agreement and bond with developers as early in the development process as possible. Most of the damage created on private land by CBM occurred early in the development when there was a "gold rush" mentality to grab some of the CBM wealth. The booming development caught many ranchers by surprise and unfortunately, some ranchers became the guinea pigs for others that would soon see development on their land. The ranching lifestyle requires one be adept at veterinary medicine, business, accounting, farming, plumbing, etc; basically a Jack-of-all-trades. CBM development required landowners to quickly become experts in mineral law and gas development as well. The trade-offs of split estate can be summarized as production of an energy source for the nation and disruption of lifestyle and livelihood for some of the local people.

BOOM ECONOMY

Wyoming has seen its share of booms, all of them mineral related. In the last 50 years, Wyoming has seen the oil boom at Teapot Dome in the 1950's and the oil, gas, uranium, and coal booms of the 1970's and 1980's. As those booms faded, the late 1980's and early to mid-1990's were economically depressed times for Wyoming while surrounding states were seeing immense economic growth in the technology sector. Wyoming's primary revenue source has always been and still is mineral production. In the 1990's, energy was cheap and Wyoming suffered. At the end of the 1990's California was experiencing severe electrical shortages, the price of gasoline was rising, and the nation seemed on the verge of another energy crisis.

CBM production began in the mid-1980's but with the impending energy crisis in 1999-2000, CBM development took off. Wyoming found itself in the midst of yet another boom. The boom made itself evident in the state's economy almost immediately. In 1999, the state of Wyoming's budget projection showed a $200 million dollar shortfall. One year later, in 2000, the state's budget projected a $700 million dollar surplus. In a state that had been losing people and jobs, and had a stagnant economy, the CBM boom was a blessing. The state continued staunch support for more methane development. The increased revenue to the state allowed for pay raises for teachers and state employees, and for repair of dilapidated school buildings.

At that time, the price for CBM was around $10.00/thousand cubic feet (mcf) and the gas was easy to get out of the ground. This brought developers to the area in droves with as many as 80 different companies developing CBM as fast as they could. Some of these companies developed with little regard for the people and environment in the area. As the development has progressed, larger corporations have bought out the leases of smaller companies, decreasing the number of operators in the PRB. The development has appeared to become more uniform as fewer companies own more of the leases. Large corporate buy-outs tend to increase the consistency of operational and management practices.

In the last couple of years, the price of CBM has dropped to $2.00–$3.00/mcf, but another 50,000 wells are proposed for the PRB in the next ten years beyond the approximately12,000 wells that are currently in production. At this time, the average life expectancy of a CBM well is seven years. If the last of the proposed 50,000 CBM wells is installed by 2015, production will cease around the year 2022. This gives the state of Wyoming 20 years to decide how to make the benefits of this boom last.

Other areas of Wyoming are gearing up for CBM development in the near future. Coal fields in the Hanna Basin, Green River Basin and Wind River Basin may see CBM development in the next 5–10 years.[5] Gas in these areas will be more expensive to produce since it is deeper and the produced water is of poorer quality than that in the PRB and may require treatment prior to discharge.

A famous bumper sticker seen around Wyoming reads, "God, please let there be one more boom and I promise not to [throw] it away this time." The CBM boom has enabled Wyoming to hurl itself out of economic depression, but for how long and at what cost to the local communities and the environment?

CBM DEVELOPMENT ON STATE LANDS

As shown in Figure 7, 6.2% of the land in Wyoming is owned by the state. The state of Wyoming does not have a state environmental policy act, which has allowed for rapid CBM development on state lands. The state of Wyoming adopted the slogan "Go Blue" as an enticement for developers to produce CBM on state lands, which are typically colored blue on most land ownership maps. The rapid CBM development on state lands created some concern for the federal government who is restricted from developing their minerals on federal lands until the requirements of the National Environmental Policy Act (NEPA) are completed. The flow of CBM in the subsurface has no regard for man-made boundaries, which has allowed developers on state land to pull CBM out from under federal lands. Therefore, in some instances, the state has been able to develop CBM on state land without delay and pull potential CBM revenues away from the federal government. This issue has been resolved by imposing well placement restrictions in relation to land and mineral ownership boundaries.

CHALLENGES TO LOCAL GOVERNMENTS

Virtually everyone in the PRB has likely been impacted in some way by CBM development. The monetary benefits of the development to the state, counties and municipalities cannot be denied, however; money can't solve all problems.

The 1990's saw a 14.7% increase in population in Campbell County, Wyoming.[3] The booming CBM development in Wyoming's PRB brought a new demographic of people to the area, most of whom settled in and around the town of Gillette in Campbell County. The CBM workers tend to be men between the ages of 25–44 who are transient and will stay in the area as long as there is work. Not all workers bring their families with them. The influx of workers has resulted in increased labor income and support of the service industry in Campbell County, but has brought problems, too.

Providing services for the population growth has been a challenge. The municipalities have had to keep up with the increased demand for water, sewer, and refuse disposal. The counties have had to allocate more funds to road maintenance due to the increase in industrial traffic. Schools have seen increasing enrollment and larger class sizes. Adequate housing for the additional people has been a problem and most workers end up staying in motel rooms. Property values have risen due to housing shortages. The branches of law enforcement in Gillette and Campbell County have seen an increase in domestic disputes, drunk driving, assault and petty crime although there has been no perceptible change in violent crimes in the area.[1] The jails are often full as a result.

To help the counties cope with these rapid changes, the Coalbed Methane Coordination Coalition was formed. The Coalition is governed by a joint powers board consisting of commissioners from five counties, representatives from two conservation districts, a representative from the State of Wyoming, and a representative from the methane operators. The Coalition hired a coordinator and assistant coordinator to be responsible for obtaining information and facilitating its flow to and from the coalbed methane coalition joint powers board and to interested and affected stakeholders. The goal of the coalition as a whole is effective information transfer for rational development of coalbed methane. The Coalition has been instrumental in helping individuals and the counties cope with the development (From the CBMCC website, 2002, http://www.cbmcc.vcn.com). Some of the duties of the Coalition include:

- Presentation of statistics and explanatory information to the public
- Landowner complaints
- Regulatory issues
- Streamlining processes for entering into production (permitting and water handling)
- Investigating methods for optimizing resource production and recovery and minimizing negative impacts

QUALITY OF LIFE

The real trade-offs have come down to changes in quality of life brought about by CBM development. As previously discussed, the ranchers that don't own minerals have seen what CBM development has done to their land and livelihood. The quiet rural setting they have known for most of their lives, even for generations, has turned into a light industrial zone in some areas. On the other hand, ranchers that own rights to CBM have seen financial relief and may received monthly royalty checks ranging from $10,000–$40,000.

The abundant wildlife, clean environment and scenic vistas are a major draw for people coming to Wyoming. CBM development has changed the look of the PRB and compromised wildlife habitat, air and water quality, and the scenery.

Those directly impacted by CBM development may not appreciate the way the play has proceeded, but most of the state of Wyoming has benefited financially. The revenues generated by CBM have improved the quality of life for many Wyoming residents in the form of pay raises for government employees and for those in education. The American Federation of Teachers (AFT) 1998 salary survey ranked Wyoming 44th in the nation for teacher salaries (from the AFT website, 2002, http://www.aft.org/research/survey/tables/tableI-1.htm.). It has been difficult for the state to retain good teachers and government employees because of low pay. CBM revenue has allowed Wyoming to start paying competitive salaries to these sectors. Overall, CBM revenues have allowed for more funds to be spent on education and much needed school facility improvements.

Development techniques that minimize environmental impact

In the PRB, developers are using techniques to minimize impacts to the environment and to lower production costs. Most techniques used today are aimed at minimizing surface disturbance. Some of these practices are discussed below.

Remote monitoring of wells and compressors

Monitoring of wells and compressor stations can be done from remote locations by telemetry. Operators can now obtain operational data from a central stationary location, reducing the number of trips to the well sites and compressor stations. Remote monitoring of wells and compressor helps the environment by reducing emissions from field vehicles and minimizing impacts to wildlife while saving the producer money and employee time. Access roads are traveled less, reducing vehicle generated dust and requiring less maintenance than well-traveled roads. Remote monitoring can immediately alert crews to problems on site, minimizing equipment down time.

Methane fired microturbines to power well pumps

Each CBM well is equipped with an electric down-hole pump to remove water and gas. Traditionally, power was provided at a new well site by a skid mounted diesel fired generator until power lines could be brought to the site. These generators are noisy and sources of air pollutants. Recently, industry has been using skid mounted CBM fired microturbines to generate electricity that can power four to six well pumps at a time. The microturbines are quiet and emit far less pollution than diesel fired generators. New well sites may still rely on diesel-fired generators until the well begins to produce enough methane to fire the microturbine. Since the generators and microturbines are skid mounted, replacement of a diesel generator with a microturbine is straightforward (personal communication with R. Cool, WOGCC and T Dall, Williams Companies, May 6, 2002).

Well clustering and equipment siting

In some locations of the PRB, wells are installed in a cluster of two or three wells with each well drilled into a different depth coal seam. Centralization of wells and compression sites requires fewer miles of access road and less land disturbance.

Burying power lines

CBM development requires miles and miles of power lines to operate pumps and compressor stations. To date, 5,300 miles of aboveground power lines have been installed for CBM development (From the Powder River Basin Resource Council website, 2002, http://www.powderriverbasin.org). If these lines were installed underground and in conjunction with pipeline corridors, it would decrease the amount of land disturbance, minimize visual impacts, and eliminate collisions between birds and power lines.

Opportunities for the use of new technologies to minimize environmental impacts

Directional drilling

Directional drilling has been used for conventional oil and gas production for several years. If this technique could be used successfully to complete CBM wells, wells could be clustered together and recover gas from the same area as several wells set on 40–80 acre spacing. This would decrease the amount of ground disturbance, reduce the miles of access roads needed, and allow for consolidation of produced water.

Directional drilling is being evaluated in the PRB, but has not been tried in the field. There are problems with the undulating topography of the coal seams and being able to stay within the seam. Also, it may be difficult to get gas and water to flow with a horizontal well due to the relatively shallow well depths (personal communication with R. Cool, WOGCC and T. Dall, Williams Companies, May 6, 2002).

Wind and/or solar powered well pumps

There has been discussion about using wind or solar energy to power well pumps. With the persistent wind and 200+ days of sunshine per year in the PRB, this could be feasible. Wind or solar powered well pumps would eliminate the need for power lines, reduce air pollution and would allow more methane to go to sales as opposed to fuel for a microturbine.

Research on wells that could produce CBM without as much water

Research is underway at a major university to design a CBM well that will efficiently produce gas without producing the large quantities of water (statement from T. Brown, Western Research Institute, 2002, Western Governors' Association Environmental Summit II, Salt Lake City, UT). Information about this research is limited at this time.

Industry agreement of best management practices

Although best management practices are not considered a technological advancement, unified use of specified practices to minimize impacts to the environment could minimize conflicts between developers and landowners and reduce impacts to the environment.

III summary

CBM has become a controversial development that has far reaching impacts for the nation, the environment and the people that live with the development. This section reviews the gains, losses, lessons learned, and what the future holds.

What is being gained?

The primary gain from CBM production has been energy for the nation and money for developers, the state of Wyoming and those ranchers who own minerals under their land. Estimates indicate that PRB CBM reserves are sufficient to meet the entire nation's gas supply for one year.[6] The state of Wyoming has been able to come out of an economic slump with the revenues that CBM has generated. Development of CBM in the West decreases the nation's dependence on foreign energy. Produced water in some areas of the PRB has been put to use for municipal water supply and stock water.

What is being lost?

CBM development has taken a toll on the environment of the PRB. Below are some statistics listed on the Powder River Basin Resource Council website relating to environmental impacts: (http://www.powderriverbasin.org)

Since development began, the following has occurred:

- 17,000 miles of new roads, enough to cover the distance from New York to Los Angeles six times.
- 20,000 miles of pipeline have been laid
- 5,300 miles of aboveground power lines
- 200,000 acres of disturbed soil and vegetation
- 500–1,200 produced water discharge points have been established
- 1800–4000 produced water retention ponds have been built
- 1.4 trillion gallons of water are estimated to be lost over the life of the development. This is enough water to support the state of Wyoming for 30 years.

Lessons learned

Conversations with industry, environmentalists, state agency personnel and landowners have echoed similar sentiments on lessons learned from CBM development in the PRB to date. If time could be reversed, and people knew 15 years ago what they know now, here are some recommendations of what should be done:

- Gather baseline data on surface water quality and quantity; groundwater quality and quantity; air quality; soil chemistry; and vegetation and wildlife surveys.
- Make baseline information and monitoring data available in a central location accessible by industry, government agencies, and the public.
- Establish and enforce best management practices for industry before allowing development
- Notify those ranchers affected by split estate about impending development and assist them in collaborating with industry on how the land should be developed.
- Closely monitor the development for impacts on the environment and change development practices when necessary (adaptive management).
- Establish a state fund with a portion of the revenues generated by CBM that can be used to mitigate environmental impacts and personal damages.

What does the future hold?

CBM development will continue as long as there is a demand for clean burning gas. Other areas of Wyoming are being explored for CBM development and Montana is getting ready to begin development of its resource. Those who are disenchanted with CBM development do not seem to be against gas production, but would like to see it proceed with caution and respect for the residents of the area and the environment. The recent decline in gas prices has caused the development to slow down. This could be an opportunity for industry, landowners and government to take time to resolve past conflicts and move forward with the development in a manner that will not only provide an energy resource, but also satisfy the needs of the people that have sacrificed their way of life for the benefit of the nation.

Notes

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COALBED METHANE DEVELOPMENT IN THE INTERMOUNTAIN WEST: CONFERENCE PROCEEDINGS, KEYNOTE ADDRESSES

On April 4-5, 2002, the Natural Resources Law Center, along with co-sponsors the Institute for Environment and Natural Resources at the University of Wyoming and the Pendergast Sarni Group, and with funding from the William and Flora Hewlett Foundation, convened a conference in Denver at the Brown Palace/Comfort Inn Conference Center. The goal of the conference was to examine issues regarding the development of coalbed methane in Colorado, Utah, Montana, New Mexico, and Wyoming, and to provide a balanced, open, neutral forum for discussion among stakeholders and others interested in CBM development. Topics addressed at the conference include the potential CBM gas resource in the intermountain area, the regulatory framework in which development occurs, the potential overlap between environmentally sensitive lands and gas development, the economics of CBM production, the environmental and socio-economic impacts associated with CBM, best management practices that are being or could be used by industry leaders to balance development and resource protection, and other issues involved in balancing CBM development, ranching and agriculture, residential development, environmental preservation, and other interests. The sessions were recorded and the transcripts of the presentations, along with selected slides, are reproduced below. Some of the presentations were revised for publication, to include citations and additional material not presented at the conference. All speakers were provided a copy of the draft transcription and invited to make changes and corrections.

KEYNOTE ADDRESS

REBECCA WATSON, *Assistant Secretary for Lands and Minerals, U.S. Department of the Interior*

Thank you for inviting me to participate in your conference. I want to begin by complimenting Jim Martin and the Natural Resource Law Center for organizing, and the William and Flora Hewlett Foundation, for supporting this forum. These forums perform a valuable service to the public to educate and provide an opportunity for discussion.

I'm always glad to be in Denver, Colorado. As you can tell from Jim's recital of my "dry details," I spent a lot of time here as a student, and then I returned to Denver after spending ten years practicing law in the great state of Wyoming. I practiced law in Denver for two years before I moved to Washington, D.C. to go into the first Bush administration to handle energy policy issues as an attorney at the Department of Energy. From Washington, D.C., I moved back to Montana to practice law for 6 years. I must be a "glutton for punishment," because I decided to leave beautiful Montana to go back "inside the Beltway." I now have the responsibility of the very challenging job of Assistant Secretary for Land and Minerals Management administering the Bureau of Land Management, Office of Surface Mining and Minerals Management Service at the Department of the Interior. I've been on the job for less than two months, but have learned that each of the bureaus I administer have a lot of controversy and challenge, but also a lot of interesting public policy issues. And, particularly, for me as a Westerner, I appreciate that these bureaus play a very important role in rural communities and their quality of life. I know firsthand that many of the policy decisions that we make in Washington, D.C. have a significant impact on your communities and the states here in the West. Under Secretary Norton's leadership we are committed to listening to you. I welcome this opportunity to be with you in person so you can tell me your concerns first-hand.

I'm honored to serve President Bush at this time in our history. Our national priorities have never been so clear as they are now—national security and a strong economy without sacrifice of the values important to all Americans. As stewards of public lands, we need to decide what role can or should the public land and public resources play to address these priorities?

One of the questions that the BLM is seeking to address is: How do we balance the national demand for energy security and the needs of the West for economic development with our desire to conserve public land resources over the long-term? The BLM manages 262 million acres of public land in the fast-growing West. The demographics of the West are changing, and that has changed the mission of the agency. We need to balance the nation's needs and our responsibility as stewards to conserve the public lands. I don't think there is any simple answer to this question, but as a first principle we look to congressional direction in law.

Congress, under our Constitution, has the authority over the public lands, and they have delegated their management authority to the Bureau of Land Management and the U. S. Forest Service in a series of laws. These laws direct multiple use of public lands—conservation and development. Secretary Norton and I believe in multiple use, and we think that you can balance the multiple use mandate and aesthetic, environmental and recreational demands in a way that provides for long-term sustainability of our public resources. And we're committed to seeing that that happens.

A second guiding principle for this administration is what Secretary Norton calls the "new environmentalism." It involves what we have named the Four C's: Communication, Cooperation, and Consultation all in the service of Conservation. I know this may sound like "D.C. speak" or just some good "buzz words," but I'm personally committed to seeing that we make the four C's a reality. At its heart is the Secretary's belief that we must involve the people who live on, work on, and love the land. The Four C's represent a way to find consensus and common ground. It means a lot to me to see all of you here—government, conservationists, ranchers—those of us in the administration like Kit Kimball, who's in the audience, who are coming to events like this, getting out onto the land, and listening to what people have to say; all people, all perspectives, to try to get people to work together to move forward on some of these issues.

The Four C's and Why I Came to Washington

As I mentioned, I've been an attorney in Wyoming and Montana and Colorado. I've spent the last 23, 24 years primarily representing natural resource industries and ranchers. Over the years I became increasingly distressed at the type of dialogue we were having about the public lands, the sound bites, the hyperbole, the constant litigation, and it didn't seem to me to be a productive way to resolve some of these disputes. Courts are involved more than ever in how the public lands are managed. The Federal land use planning processes have really, in large measure, been derailed or hijacked through constant rounds of litigation, and it's difficult to manage public lands under those circumstances. This concern is one of the two reasons why I left my home on the Little Blackfoot River to go back inside the Beltway. I wanted to see if we could have a different dialogue on public land issues—a way to take into account people's strong feelings on both sides and resolve them in a way that works better than litigation. And that's why I'm excited to be in this position to have the opportunity for collaboration and consensus under the four C's concept. I think that it is a new way to address these issues. It's not any easier, but maybe more productive to work through these issues together because I believe in the end we'll have a better product.

The second reason I came to Washington, is my concern over what I see as the end result of all of this litigation and controversy for the rural West. Denver is an anomaly, Boise, some of our bigger western cities, but if you go to eastern Washington, eastern Oregon, Montana, you will see people struggling to survive. You see people in Montana living on $21,000 a year, families working two and three jobs. They have no time for their family, they have no time for their community. And I worry about those western communities. I was attracted to the West not only for its landscapes, but also because of its people. These people are a product of the West's rural communities—places with a sense of community, caring, and a unique way of life. Those rural western communities are part of our country's diversity and I believe they are of value to us as a Nation. I returned to Washington to try to manage public lands and public resources in a way that will foster long-term sustainable economic health in the rural communities.

The Administration's Energy Policy

I want to talk next about the Administration's Energy Policy, and then I'll talk about the subject matter of your conference, coalbed natural gas. A secure energy supply is one of our Nation's most critical concerns. The President and the House of Representatives led the way a year ago when the President prepared his National Energy Policy and the House acted by developing energy legislation. The Senate is now poised to act on its version of an energy bill.

Even though we've become more efficient in the way we use energy, the demand for energy to fuel our economy keeps growing. The Energy Policy looks out over 20 years, and sees that in 20 years our demand for energy is going to increase, particularly for natural gas, in response to demands of the Clean Air Act and people's desire for cleaner air. A lot of electricity is now generated by natural gas, and we need to have a steady and secure supply of natural gas for the security of our economy. Production and conservation are two key ways to address demand for energy. The Energy Policy seeks to address both sides of this equation although my remarks today will focus on domestic production.

The BLM is working on more than 40 specific tasks under the National Energy Policy to meet these projected needs, and together the three bureaus that I supervise have some 66 tasks out of the 120. Right now, the BLM manages 700 million acres of Federally-owned mineral estate. In 2001, the public lands produced more than one-third of the nation's coal, 11 percent of its natural gas, and five percent of its oil, as well as significant energy from renewable sources. So today the public lands are playing a big role in energy production.

The President's Energy Policy provides us with a direction for our energy future, geared at finding reliable domestic supplies of energy. Although we produce significant domestic energy, we still have a lot of energy coming in from places like Iraq and other places in the Middle East and Venezuela, the stability of which supply is certainly something that's on all of our minds as we read the newspaper. The President's Energy Policy proposes a variety of ways to improve the supply of domestic energy. I will highlight a few significant supply proposals: reducing unnecessary impediments to production; increasing resource recovery through economic incentives; responsible expansion on Alaska's North Slope; ensuring access to renewable energy; and transmission.

It's one thing to produce energy, but if you can't move the energy to where it is needed, it doesn't do anybody any good. Energy infrastructure and transmission are key components of the Energy Policy. There's a strong need for improvement in that area particularly after the lessons learned during the California electricity crisis last summer. There simply was no way to move power to get it to California, even though there was abundant power that could have been supplied from elsewhere.

Finally, the Energy Policy also encourages more effective coordination with the other regulatory agencies in how some of the review processes that have to take place before you can take any federal action are conducted.

BLM's role in energy policy

The BLM will play a significant role in implementing these provisions of the President's Energy Policy. First, the President's 2003 budget proposes new support for energy-related activities. This will allow BLM to better handle gas permitting, step up oil and gas compliance inspections by 25 percent, and process 400 more energy rights-of-way.

Second, the BLM has also taken some other specific actions mandated by Congress in the Energy Policy Conservation Act. The EPCA studies are a cooperative effort by the BLM, the U.S. Geological Survey, the Forest Service and the Department of Energy to review impediments to Federal oil and gas exploration, particularly in five critical western basins. The public and Congress should have initial results of that study in April, and the full report later this fall.

Third, as to Alaska, BLM is looking at completing the re-permitting of the Trans-Alaska Pipeline System by 2003 to keep that oil flowing into the lower 48 states.

Fourth, on the issue of transmission, it's estimated that about 90 percent of all oil and gas pipelines and electric transmission rights-of-way depend, to one degree or another, on access on Federal lands. In 2001 alone, BLM processed more than 3300 rights-of-way actions, and we see that demand growing as we try to bring our energy infrastructure up to the needs of the 21st century.

Lastly, thorough and efficient processing of applications for permits to drill (APDs) federal minerals are an important part of increasing access to energy. Over the last few years, that process has become more challenging. There's the inherent complexity of the process, litigation, and something that maybe a lot of people in the private sector may not be aware of, the loss of experienced employees from the growing "elderly" state of our BLM employees (not Colorado State Director Ann Morgan, she's the picture of youth and vitality!), but it's a real problem.

I was on a panel the other day with Mark Rey, Under Secretary at the Department of Agriculture, and he related that the average age at the U. S. Forest Service is 45. I know the statistics at the BLM are similar. He added that about a third of the U.S. Forest employees will reach retirement age in the next five years. BLM's the same way. There's a huge workload turnover on the horizon and not a lot of young people coming into government service. The compensation isn't that great and the frustration level is high. So that's a real workload problem, and it's going to place a huge demand on the agencies to work better with less people.

COALBED METHANE

The last thing I want to talk about is coalbed natural gas. Coalbed methane is a significant new source of clean burning natural gas. As I said before, the demand for natural gas for electricity is high. Coalbed methane production has some positive environmental benefits because of the fact that it is not only clean burning like all natural gas, but also because its production removes a very detrimental greenhouse gas from the environment. According to EPA, methane is 20 times more potent than CO_2 in producing the greenhouse effect.

However, coalbed methane does not come without certain challenges. The environmental issues and challenges raised by the production of coalbed methane (CBM) are what we need to address in order to produce and use this domestic energy in a way that minimizes long-term negative environmental impacts. Impacts to water quality and water quantity from the production of CBM, topics I addressed in a lengthy article for the 2001 Rocky Mountain Mineral Law Institute, are the key environmental issue raised by coalbed methane production. Another issue BLM is addressing is its policies and practices as they relate to the conflict between the production of coalbed methane and coal production. That conflict is something that we have to address, particularly in the Powder River Basin.

A third issue surrounding CBM production is the level of cooperation and coordination between Federal, State and local government and interested external groups. The management of coalbed methane involves many agencies: in the Federal government—EPA, the Bureau of Land Management, the Fish and Wildlife Service, Army Corps of Engineers—; in the State government—state departments of environmental quality, state engineers or other agencies regulating water quantity, Boards or Commissions of oil and gas; and in Tribal governments—entities that manage tribal lands and water quality. Over the last ten years, as you know from your conference this morning, indeed since 1996, some 10,000 CBM wells have been drilled in the Wyoming portion of the Powder River Basin. From 1997 to 2000, the production of coalbed methane increased by 100 percent. In Montana, the industry predicts about 10,000 wells over some ten years. We believe a good, coordinated working relationship among these agencies is necessary to effectively manage this resource development in the way the public expects and demands.

In regards to the conflict between coal and coalbed methane, last October, Wyoming Representative Cubin held a hearing on a bill that put forward a way to handle that conflict. The department, at that time, testified in support of the intent of that bill to balance and promote the production of both resources, since about 45 percent of the oil and gas that was targeted is under Federal ownership. The department is currently reviewing a new draft of an expanded BLM policy on this issue. A few things will guide the BLM's policy. One is to protect the rights of the lessee under the terms of the lease and the Mineral Leasing Act, and particularly those concerning conservation of natural resources. A second is to optimize the recovery of both resources. A third is to minimize the impacts on local communities.

I think there are good opportunities to produce these two energy sources without undue conflict. For a coal operator, methane is a safety hazard, yet the coalbed resources are considered valuable by the mineral owner. I think we can find a way to develop both these resources in an efficient manner. One of the early cases I worked on as a young lawyer in Wyoming involved a similar conflict between oil and gas production and coal where we were successful in negotiating a way to produce both resources without conflict.

BLM is also looking at CBM water related issues—the impacts of the production of coalbed natural gas on water quality and water quantity. The impact of CBM produced water on surface water, groundwater, and surface lands and the requirements of the Clean Water Act's antidegradation policy, and TMDL requirement are some of the many water related issues to be addressed in NEPA analyses. Water handling and treatment alternatives are a key to minimizing impacts. But again, you get back to the complexities inherent in a divided regulatory regime over water: primarily, the states exercising their primacy under the Clean Water Act (CWA) over water quality with EPA oversight. You also see the tribes implementing their own CWA water quality standards. Water quantity is controlled by several different state entities. In Montana, for example, in addition to the State Department of Natural Resource and Conservation, a technical advisory committee has been established to look at CBM water quantity issues to ensure that adequate safeguards are in place.

Regulation of impacts to water from natural gas production is handled by a lot of different state, federal and tribal agencies, and I don't think that is something that can or should be changed by BLM or Congress. What is important is that it be coordinated so that everyone is headed in the same direction—the production of CBM in a way that protects the environment and other existing uses. The water quality of coalbed methane water varies greatly between the basins. The quality and quantity of methane gas in these areas also varies greatly. The economics are different, and I think that's important to keep in mind as we look at managing coalbed methane in New Mexico, Colorado, Wyoming and Montana. I know western people are interested in managing this water in a way so that it can have value. Certainly in eastern Montana, water is a very valuable resource; additional good quality water can provide for better crops, healthier livestock and a better economy. In some cases, the water is of good quality for humans, livestock and crops. In other areas, it presents challenges for use in irrigation and in still others it is unusable for any purpose.

The Montana CBM EIS's preferred alternative seeks to prevent undue degradation of water quality and diminution of water quantity. The Montana DEIS preferred alternative would require operators to develop Water Management Plans to address replacement of impacted water prior to any exploration or development. The preferred alternative directs that the first preferred water management tool is beneficial use of the water. Water from CBM production would be managed on a site-specific basis and would specifically be coordinated with the desires of the surface owner.

One other CBM-related issue that came up during the debate on the energy bill, which we followed at the Department of Interior, is the relationship of the surface owner to the CBM mineral owner. This issue arises particularly in the case of those surface owners that don't own the mineral estate. Right now, mineral law of long standing provides that the mineral estate is the dominant estate—the production of the mineral estate takes priority over the surface uses. Of course, this is not without limit—state laws provide for surface use damage payments and other laws—environmental and common law nuisance can protect surface owners from inappropriate use of the surface. And, at the Department of the Interior, Secretarial Order No. 1 requires that a mineral developer present proof that good faith negotiations for the surface owner's consent to mineral development were conducted prior to the grant of an APD.

There is a concern among surface owners that these existing protections are not adequate. And some of these surface owners came to Washington last month looking for a stronger surface owner consent or a veto over CBM development in the Senate Energy Bill. Various other ideas addressing this concern were discussed during the debate all implicitly asking the question, is established mineral law where we as a society want it to be in the 21st century? Are there changes that need to be made to recognize that surface owners, as well as CBM development are an important part of these western communities? How do we balance these issues? I think that's something all of us in this room need to take a look at, and that's something we're looking at the Department of Interior in a review of Secretarial Order No. 1 and its implementation to ensure that operators work responsibly with surface owners to minimize their development impacts to surface uses.

Finally, the last thing I want to mention is BLM's resource management plans. These plans are out of date. They were written some time ago, back before the huge explosion in population in the West. We need to update these plans and we're involved in a massive effort to do just that. We have 21 plans we've identified as time-sensitive plans, and those plans generally fit in with the Energy Policy and deal with coalbed methane and other energy development. These plans are supposed to be concluded within the next two to three years. However, over the next 10 years, all 160 resource management plans will be revised. So that's a massive effort that the BLM is taking.

I want to conclude by just reiterating the fact that the Department of Interior plays a big role in the development of the energy policy and we're proud of that role. We in the Bush Administration believe that we need to have an energy policy. I think September 11th, the instability in Venezuela and the war in the Middle East, highlight the inherent risks that exist by an over dependence on foreign sources of energy and a corresponding inadequate domestic energy supply. Certainly, as a country, we can and should address this in a series of actions. We can develop domestic resources, we can conserve and use our resources more efficiently, and we can work with our international partners to develop their resources as well, to provide for an enhanced level of energy security.

I want you to know we're going to have an open door at the Department of Interior. I want to meet with you. Come in, that's what I'm there for, to serve the public. We had an administration meeting in February right before I came to Washington with the President and the Vice President, Secretary of State Colin Powell, and other members of the cabinet and sub-cabinet at the historic State Department Reception Rooms. You can imagine it was pretty awesome for this person from Montana to be there. I took away two pieces of guidance I want to share with you. President Bush said to us that "We had one Boss," and I expected him to say he was the boss, but he rightly said, "that Boss is the people." His direction to us is to focus on the people and policies that are directed at better serving the people.

The other thing the President said that I took to heart is that if, we see something working right and good in government, we should laud it and grow it, but if there's something that isn't working, that's broken, then let's fix it. That's good advice. I think that there's a lot that we have going on in government that is good, but there's always room for improvement, and that's what we hope to do in our time in the Administration.

Finally, I think that partnerships with the public are very important. That's something that the President, Secretary Norton and I want to do more of. We're proposing in the 2003 budget additional funds to support state and local government conservation projects that improve the health of the land. The Cooperative Conservation Initiative would provide $100 million in challenge grants to landowners, conservation groups and local and state governments for conservation projects. This would help us better serve the public and breathe life into the Four C's.

I thank you for your attention.

KEYNOTE ADDRESS

JOHN WATTS, *Counsel, Energy and Natural Resources Committee, U.S. Senate*

I want to start just by thanking the Natural Resources Law Center and the other sponsors of the conference. I have learned a great deal this morning and yesterday. It's sort of obligatory for speakers to say this, but I really mean it. I've learned a great deal. The talks have been very informative and from a whole range of different perspectives, and I've really learned a lot. I also appreciate my conversations with you all apart from the regular proceedings.

I also want to start out by saying that it struck me that the amount of information we've learned has been really impressive. And I want to tell a story about how it hasn't always been that way with the Bureau of Land Management (BLM) and other public agencies. In my former life, as I mentioned, I was an attorney in the Department of Justice, and I tried cases involving the BLM and the public lands. At Justice, I had a colleague who had a case which he loved to tell about back in the old days when BLM was first trying to figure out what environmental impact statements were and how to do EISs and the various land use plans that were being done. My colleague was assigned to defend an EIS. And he was a bit concerned because some of the previous EIS defenses hadn't fared too well in court. So he said to BLM, "I'm a little concerned, do you have any good analysis here?" They said, "Don't worry, we have a new analytical technique that absolutely confirms that the environment is fine. It's called "ocular reconnaissance." So my colleague strode into court with his "ocular reconnaissance" defense. He started to explain why this was such a great thing. The judge would have none of it, however. He cut off my colleague and said, "So you mean they just eyeball it?" Needless to say, the case did not go very well.

I am going to try to speak fairly briefly. You may have noticed that usually when people say they're going to speak very briefly, they end up talking even more about the subject, which is typically long enough to begin with. But I'm going to try not to follow that track. What I'm going to talk about is legislation, potential legislation out there right now regarding various issues regarding coalbed methane. The five areas include some of what you already heard about.

One, which Assistant Secretary Watson mentioned yesterday, is conflicts between coal development and coalbed methane development. A second is the study of the environmental impacts of coalbed methane. Third is tax credits. Fourth is hydraulic fracturing. And fifth is surface use agreements and enforcement of coalbed methane leases. One general point before I go into the details of each of these issues: Four of five topics are tied to the energy bill. Some of you may be aware that the House passed an energy bill last year, and the Senate is now debating an energy bill. Most of the possible legislation is on coalbed methane tied to the energy bill, which means that whether or not the legislation actually is enacted will depend upon whether the energy bill is enacted.

I know folks in this room have a wide range of feelings about the energy bill. What I'm going to say about the energy bill is that it's likely to pass the Senate without a provision regarding the Arctic National Wildlife Refuge in it. And at that point that it passes the Senate, it will go to conference between the Senate and the House. And that will be a difficult conference, because the House bill is very different from the Senate bill. It's the $64,000 question or, more accurately, the multibillion dollar question: What happens then? Most possible coalbed methane legislation will require passage of this energy bill to become law. So I'm going to go through now the five topics identified as to what coalbed methane legislation is pending.

The first is this issue of conflict between coal development and coalbed methane development. This issue is most prominent in the Powder River Basin. There's also a similar conflict in the New Mexico portion of the San Juan Basin. The problem from the coal company's perspective is that the coal companies generally have junior leases and the senior leases contain the coalbed methane rights. You saw some of this in the powerpoint slides. The coal is essentially being plowed. The coal face is moving along in a straight line, and there will be coalbed methane wells in the path of the coal mine. And because the oil and gas lessees have senior rights, the coal companies can't simply move on through venting the methane as they pass. Instead, they can be sued. And the coalbed methane lessees can get a preliminary injunction in court to require the coal companies to essentially swerve around the coalbed methane wells.

As a result, there have been some negotiations where coal companies have paid to buy out the coalbed methane lessees. Now, there are two views of what's happening here. You heard yesterday about the Supreme Court's decision in the Amoco versus the Southern Ute case, which determined that the coalbed methane was owned by the gas company, not the coal lessee. The Supreme Court envisioned that conflicts between the owners of the coal and the coalbed methane would be resolved through negotiation. And the oil and gas lessee's perspective is that's what has happened. They have conducted negotiations, and they will acknowledge they're in a good market position, but they would say that there's no problem. Essentially, everything that's happening is according to the way the Supreme Court envisioned it. The coal companies see it differently.

There was a western character, I believe his name was Black Bart, who in the 19th century would wait around, and he knew the stagecoach's path and when it was coming, and he would hold it up. And that was based on his knowledge of the schedule. The coal companies believe that they are being held up in a similar way by the owners of coalbed methane, in that the coalbed methane lessees know the schedule of when the coal is going to get to certain spots. In this view, they are buying up the coalbed methane rights and then holding up the coal companies for prices which are a lot more than the market value of the coalbed methane.

The bills pending now which are mentioned here on my outline, they're two very similar bills. One is by Senator Enzi, and the other by Representative Cubin. Both of them set up a process whereby if there is potential conflict between the resources, one of the parties will notify the other. They'll try to negotiate. If they can't agree, then they file a petition with the court, and the court will make a determination of which of the resources is of greater value. This is always going to be the coal, because for a specific unit of area, coal will always have a greater value. The Court will then suspend the less valuable coalbed methane lease, allowing the coal company to plow on through. Then there will be an evaluation process with three experts, who will value the loss of income and consequential damages to the coalbed methane lessee. And then, very importantly, there will be a royalty credit for the coal companies so that they get reimbursed for what they had to pay the coalbed methane owners. And finally, the federal government will ensure that the State gets its portion of the royalty credit. Thus, the Federal government will lose several ways. It will lose the royalties that it would have gotten, and it also will end up paying the royalties to the State.

Those are the bills that are out there. Senator Bingaman, who I work for, has a statement on record expressing opposition to these bills as drafted. He has expressed several different concerns. First of all, this is just one example of a common problem of conflict between users of the public land. He is concerned that if there's going to be an attempt to resolve this conflict, that we use established eminent domain law; that we follow a regular process, not create some special process. Also, Senator Bingaman said he's concerned about the Federal government paying a credit and then also having to pay the state. The state shares in the benefits of coalbed methane development, so the state should also share in paying for any solution. So that's Senator's Bingaman's position on this issue. Where this legislation stands now is that we are waiting to hear back from the parties involved as to whether they can agree to this approach. So we're sort of on hold with this legislation.

The final thing I want to say about it is that I want to emphasize the point that Assistant Secretary Watson made, which is that if you responsibly develop both resources, the public benefits. You avoid venting coalbed methane gas into the atmosphere, and both energy sources are used. And the government gets its royalties from all the resources. I'm glad to hear that BLM is attempting to revise its instruction memorandum to encourage the development of both resources.

My second issue is the environmental impacts of coalbed methane development. There is a provision in the Senate version of the energy bill which would require the National Academy of Sciences to prepare a study over an 18-month period on the impacts to the surface and water resources of coalbed methane development. The study would focus on some of the questions that we heard discussed at length this morning regarding how to dispose of the water, what the impacts are of water disposal, possible groundwater depletion issues, other surface issues and impacts, and what mitigation measures can improve or reduce those impacts. The way the bill is set up, the National Academy of Sciences will have 18 months to do this study. The results will then be publicly available and transmitted to the Secretary of the Interior, and she would then have to respond to the National Academy of Science's findings to indicate whether she agreed or disagreed with them and also whether she recommended to Congress any changes in law or policy based on the results of the study. So the idea is to do a broad study by the independent National Academy of Sciences. You then have the Secretary of the Interior responding to the study and the public also having a chance to respond. This provision is not in the House version of the energy bill, but it's possible that it will be in the final version of the energy bill following conference. That's the second issue.

The third issue is tax credits. And I'll start out by saying I'm not an expert on this issue, but I can tell you briefly what is out there regarding tax credits. There's an existing tax credit for production of wells from a nonconventional source. The amount of the tax credit is three dollars per barrel of oil or Btu equivalent. That tax credit would be modified and extended in both the Senate and House versions of the energy bill. The tax credit would include production of gas or methane gas from coalbeds. The House version of the energy bill could extend that credit from the date of enactment through January 1, 2007. So that if a well is drilled or a facility placed in service, the operator of a coalbed methane well could get this tax credit, three dollars per barrel; and in addition, earlier drilled wells could also get a tax credit for the same four-year period. The Senate finance committee marked up a similar provision with a three-year expansion of this tax credit, which is expected to be inserted into the energy bill as an amendment to the energy bill either this week or next during the remaining debate on the energy bill. So that's the basic status of the tax credit issue.

My next issue is hydraulic fracturing, and before I get into the legislation, I would like to say that I was very interested in yesterday afternoon's discussion. I like the idea that was expressed that industry and the relevant agencies should share whatever data they have with the public, because I think that will help. And I wanted to let people who are concerned about hydraulic fracturing know that a source of information on that issue is likely to be publicly available soon, which is this EPA study. The EPA is doing a potentially multiphase study of the impacts of hydraulic fracturing to underground sources of drinking water. The EPA will shortly be completing the first phase in their study, which is a review of existing literature and on the potential contamination of underground sources of drinking water from hydraulic fracturing. The EPA has been undertaking a fairly rigorous process for this study. They received public comments on its design last year. More recently, they have prepared a draft of the study, which they submitted for a scientific peer review.

When I last heard from them about this issue, EPA was planning to release the draft study in April. Now, I don't know if they're going to make that schedule, but it should be available within the next couple of months. Public comment on these draft study results will follow, and EPA will then make a final determination after receiving the public comments. If EPA determines that there is clearly little or no harm from coalbed methane, then they will stop the study at this point. If they determine that there is a real potential for harm, then they'll continue, and they'll go out and do field studies, which could be a multimillion dollar, multiyear process. The main point is, if you're concerned about the potential impacts of hydraulic fracturing on underground sources of drinking water, then you should look for that study, because that's probably going to be the best source that is available to date.

Just from the spirit of sharing what information I have about information concerning impacts from hydraulic fracturing, there was a survey done in 1998 by the Groundwater Protection Council, which is an organization of State Oil and Gas Commissions and also State agencies responsible for protecting drinking water. And in that study, there were 13 State agencies that responded to the survey who indicated that they had coalbed methane production in their states. And of those 13 State agencies, none of them reported any verified instances where hydraulic fracturing in coalbed methane had contaminated underground sources of drinking water. That survey has been criticized as incomplete, in that it was simply an instance of what information had been reported to State agencies; and that, potentially, something could have happened that wasn't reported to State agencies. EPA acknowledged the survey was done and is asking for public comment on any additional instances where drinking water has been contaminated. So EPA's current study may well close any gaps in the Groundwater Protection Council survey.

There is one other issue I would like to address. It was stated yesterday that there are hazardous constituents in hydraulic fracturing fluids, and it is true that there sometimes are chemicals such as benzene and zylene, in fracturing fluids. However, from what I have been able to gather, those constituents are generally or almost always associated with fracturing in deeper formations such as those containing oil. There are no reported cases where the very low concentration of these chemical constituents has migrated up to drinking water aquifers from the generally deeper oil or gas bearing formations. So, as far as I know, there is no evidence that these chemical constituents in fracturing fluids have contaminated drinking water sources.

I think this process of information gathering on this issue is important. What's currently in the Senate energy bill is a provision which Senator Bingham, my boss, sponsored which requires the EPA to do a study of hydraulic fracturing's potential effects on underground sources of drinking water. And the basic idea of this provision is that we should examine whether this is a problem that would require Federal regulation on top of the existing state regulation of hydraulic fracturing. And the way this provision would work is that the EPA would have 24 months to do a study. The Natural Academy of Sciences would then have nine months to review the EPA study. And then there would be a several month period for EPA to determine whether or not there was a need for regulation of hydraulic fracturing under the Safe Drinking Water Act (SDWA). During the period of the study, state programs would remain in place. And state programs, as you heard yesterday, already protect underground sources of drinking water through a variety of ways, including casing around the well bore where it goes through an underground source of drinking water. The tate regulations remain in place, and for Federal regulation, the status quo would be maintained.

If there's one state that's required to regulate hydraulic fracturing under the SDWA, it's Alabama as a result of the 11th circuit decision in *Legal*

Environmental Assistance Foundation v. United States Environmental Protection Agency, 118 F.3d 1467 (1997). Alabama would still have to regulate hydraulic fracturing under the SDWA during the study. Other states are not currently required to regulate hydraulic fracturing, and they would not be required to regulate it under the Safe Drinking Water Act during the study. And the EPA would retain its emergency powers to regulate homes to drinking water that immediately threatens the public health. Even without this provision of the energy bill, states are unlikely to voluntarily regulate hydraulic fracturing under the SDWA. If a lawsuit were filed to try to force them to do so, it probably would take about 12 to 18 months to get a decision, perhaps longer, and then even if the State lost, it would probably be given – if Alabama's experience with their previous litigation is any model – another year to develop regulations. So even without this provision of the energy bill, states probably would not regulate hydraulic fracturing under the SDWA for the next two to three years, which is roughly the same amount of time as the EPA study.

I'm about to violate my comment that I was going to speak briefly. So I will now move onto surface use agreements. Surface use agreements are a difficult issue. There's currently not any legislation out there on this topic. There is, however, legislation on a related topic, which is inspection and enforcement of oil and gas leases including coalbed methane leases. The Senate energy bill currently includes an increased authorization of appropriations for the aggregate of permit processing and increased inspection and enforcement of oil and gas leases. It's likely that this provision is going to be amended to break out a separate increased authorization for inspection and enforcement in particular. There are a number of places, including the New Mexico and San Juan Basin, where the agency is currently quite deficient in the number of folks it has to do inspection and enforcement, and we want to correct this situation.

Let me say a few more words about surface use agreements. First of all, I want to thank Jill Morrison for her moving presentation of the issues facing the ranching community on split estate lands. You have to be pretty unfeeling to not sympathize with what a lot of ranchers are going through. And it's because I take the ranchers' concerns seriously that I want to be straightforward about my perception of the situation on Capitol Hill on this issue. I don't think in the near term it's likely that any legislation will require surface use agreements. Under existing law, the Stock-Raising Homestead Act of 1916 currently gives the oil and gas lessee three options for dealing with surface users. One is to obtain their consent for surface operations. Second is to obtain a damage agreement concerning any damage of the surface use. And third, as a final choice, to post a good and sufficient bond of at least $1,000. You would have to change this provision of law to require surface use agreements on split estate lands.

This is a difficult issue because it pits the environmental community and the ranching community against the oil and gas community, and the oil and gas industry is very strongly mobilized. I know because I've heard from them. And western senators generally want very much to support both groups—both the ranching community and the oil and gas industry. And so I think in the near term it's going to be difficult to get a major change in the law. However, that's the bad news. The good news is that you heard from Assistant Secretary Watson yesterday that she felt that it was time to reexamine this issue. And I know that my boss, Senator Bingaman, wants to improve the situation, as does Senator Baucus. And this is something that I and others are going to be working on over the next few months and longer if necessary. There was legislation that had circulated which would have encouraged surface use agreements and required BLM to develop procedures for making them work better and also require BLM to report back with suggestions and improvements. And from what I understand, the ranching community did not support this legislation because they believed it did not go far enough.

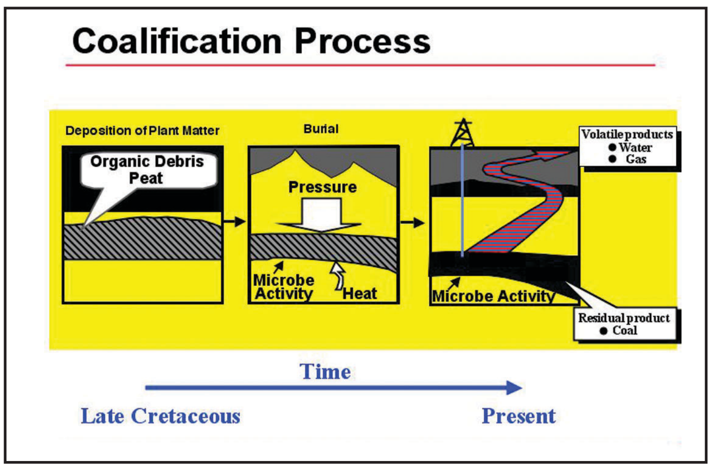
But there's a chance to address this administratively, I think, because a number of key parties believe this is an important issue. There is a chance for BLM to start working with other interested parties to make effective surface use agreements happen more often and perhaps to develop model surface use agreements to address the issues that concern the ranching community. There is a chance to work it into the process, perhaps to provide incentives for oil and gas lessees to sign surface use agreements. There's a chance, I think, for people to think creatively about this issue and for there to be some progress made.

I think I will stop with that. And just say, once again, thank you all very much for what I've learned from you, which has been a great deal over the past few days.

an overview of cbm exploration and production

steve de albuquerque, *EHS Manager, Phillips Petroleum*

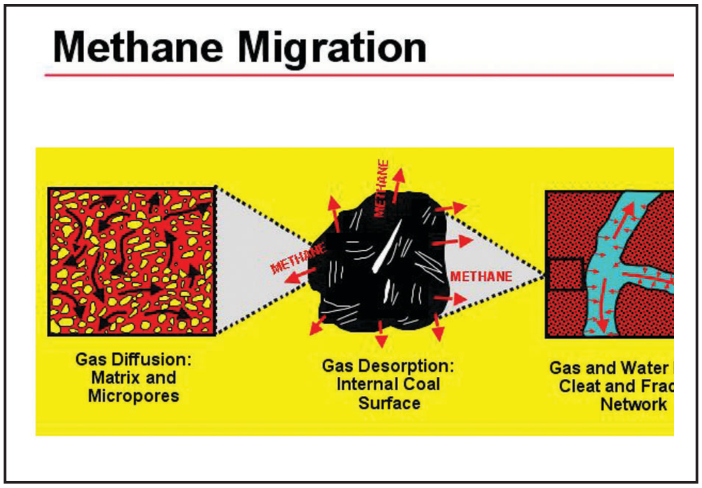
I'll give you a little background of what coalbed methane really is from a geologic perspective. I'll give you a little bit of developmental history on the coalbed methane basins, specifically in the U.S., that are currently being developed today. I want to take you through a life cycle of a coalbed methane project, and then talk a little bit about development issues that we've all heard so much about in the last three or four years. I'll talk a little bit about produced water management, since that has some controversy surrounding it. Then coalbed methane water characterization, and then talk about water resource values as it's related to fresh water resources in the development of coalbed methane. And then I'm going to talk a little bit, to close, on focusing on what's going on in the basin today.



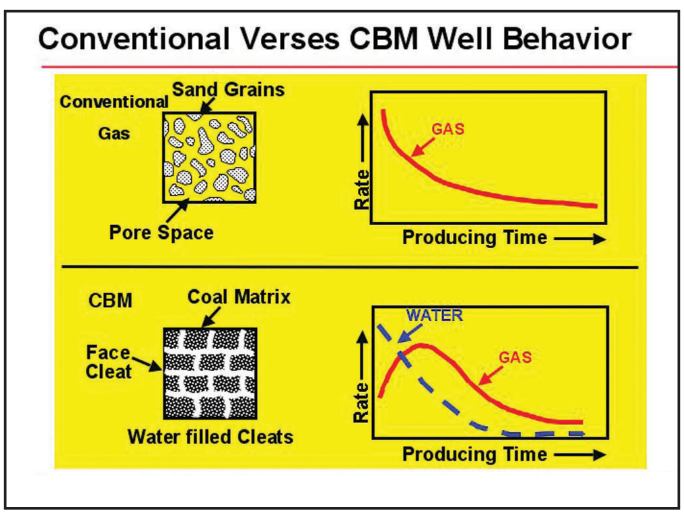
What is coalbed methane? Simply put, it's a CH4 for natural gas. It's formed within coal seams as a result of the coalification process. What's the coalification process? Think about a big landfill in natural decay or a compost pile. You have natural plant material deposited in there that's been buried within the earth, and as things get buried within the earth, you increase temperature and pressure. It's kind of like a pressure cooker. And as you increase that temperature and pressure, the organic material begins to decay. So, in a cartoon sense, let's look at this real quick. About 78 million years ago, you had organic heat deposits laid down with sediments deposited over the top. There are different environments for CBM throughout the West. Through geologic time, the stuff gets buried.

Again, pressure and temperature increase, you begin to get bichromial activity in a very simplistic sense of methane in coal formed in the substrips. What did that look like in the Powder River Basin back in the Paleocene? If you think about the Atlantic Coast plain in the Carolinas today, that would go back in geologic time to when the coal deposits were beginning to form.

How does coalbed methane work? Before I go through this slide, let me just give you a very simplistic explanation. Keep in mind that this is quite simplistic. You have a bottle of club soda that you can buy at any grocery store. Club soda is sodium bicarbonate water. That's exactly what coalbed methane water is, pretty much, sodium bicarbonate water. When you open that bottle of club soda, what happens? You see the bubbles come out very quickly. Well, in a sense, that's how coalbed methane is developed and brought to the surface. You have a well that we put into the ground. We begin to pump the well. We pump water out of the well. We have a hydrostatic head on the aquifer, which lowers the pressure on the aquifer. As you lower the pressure in the aquifer, the gas begins to rise. This goes into the coal face and then into the fracture and cleat system, and hopefully goes into your well. In a very simplistic sense, that's how it works, just think of a bottle of club soda.

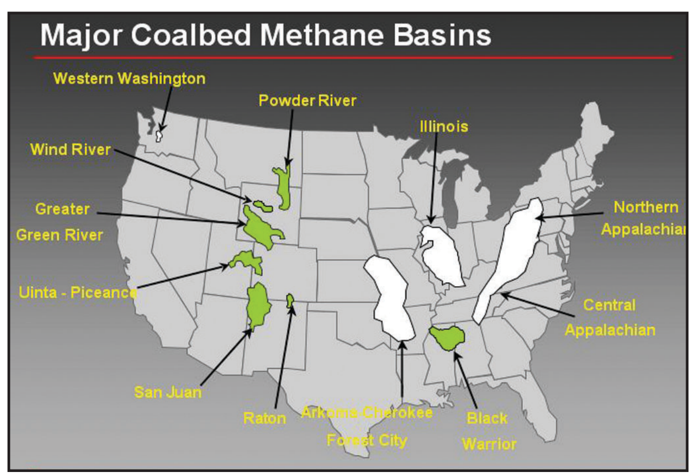


Think of a gas well. I'm going into a sandstone reservoir, and hopefully we get gas immediately. But as you go through time, gas begins to play off in a conventional well. The difference is that the gas that has migrated into that sand stone reservoir was not sourced in the reservoir; whereas in coalbed methane the gas that is sourced is part of the coal. In the cleat system and the fracture, initially you get a lot of water. That's the blue line on the bottom. As you begin to lower the pressure in the coal aquifer, you begin to get gas, and then it will mirror a conventional well and play out as the gas content drops in the coal.



Typically, people vented methane gas from coal mines as a safety measure. Natural gas is an explosion hazard, it can be a health risk, and even today, people vent enormous amounts of methane gas from coal mines simply as a safety measure. It's kind of interesting that coal companies oftentimes have no right to that gas, and the only outlet they have for that gas is to vent it through the atmosphere. In the post-1974 energy crisis, people began to investigate producing coalbed methane as part of this coal mine. But at the time, gas prices precluded technology development. It just didn't happen. In the early 1980s, we saw spiking gas prices. Technology had advanced and development pursued in Tuscalusa, Alabama to the north and to the eastern side of Tuscalusa. We see the first commercial gas sale in about 1980. That's the Black Warrior Basin, in the Alabama portion of the Warrior Basin. There is potential, and people are beginning to explore now in the northern and central regions of the Appalachian Basin, and we have people looking quite hard at the Illinois Basin.

Actually, that's three different basins that I've depicted as one around northeastern Oklahoma and southern Kansas. Western Washington basin, south of Seattle, actually has a plain up there. They're beginning to produce some water. There's the Greater Green River Basin and the Uinta Basin in here. And then you have the granddaddy of them all, in terms of oil and gas content, which is the San Juan Basin, to date; and they probably will for a while. On the western edge of the basin, you're beginning to see a little bit of activity. We have a field outside the San Juan. It's been probably one of the most prolific coal plays in the U.S. And, of course, the Powder River Basin, which is where all the activity is today. And then, the Raton. The Raton has been active for a few years with quite good success. And then the final basin that I have up here is the Wind River Basin.



Let's talk about the lifecycle of a coalbed methane project. There are three main phases in the lifecycle project. The reason I'm telling you this is because it is quite different. You start off with identifying and evaluating and acquiring acreage. You go in and you actually drill a couple of core holes. And you get—you send some of that data to the the lab, and they do what's called absorption/desorption testing on the coal. Basically, you come up with the gas content and a rate of absorption so that you get coal permeability. How permeable is the coal and at what depth does the coal exist; and that would give you an indication of the release gas. The rule of thumb is if the coal's less than 5,000 feet, the way technology exists today, you can drill. If coal is deeper than 5,000 feet, and I know people are pushing this theory as we speak, but I suspect through time you will see people begin to look at deeper coals. Well, if the core data looks good, we take it to pilot phase. Let's install a few wells. And you see if you can depress to get the gas to desorb from the coal. And in the final phase, that's when you really know you have a project. And then you can begin expanding the wells out from the central dewatering point.

CBM: CONCERNS AND ISSUES

- Split estate: Surface verses mineral
- Genuine concern for wilderness, scenic areas, wildlife, and associated habitat
- Legitimate complaints —bad actors
- NIMBY
- Nuisance issues:
  - — Noise
  - — Traffic/Road dust
- Produced water quality and associated management
- Spurious issues
  - — Land subsidence
  - — Underground coal fires
  - — Groundwater contamination in the Powder River Basin

Let's talk about coalbed methane concerns and issues. The main one I see in the West today is a split estate with federal versus mineral. That creates a lot of inherent conflicts initially, right off the bat. If you could go back in time and fix something, it would probably change a lot of conflicts that we see today. You have a lot of genuine concerns. Your concern for wilderness, scenic areas, wildlife, and habitat out there. Most of the perspective coalbed methane areas are in the western U.S. today, and these are full of scenic areas of, areas of wilderness potential, and several types of species. You have, where existing coalbed methane method operations occur, you have legitimate complaints. Unfortunately, my opinion is that there's a minority few people who actually have tarnished an industry. You know, my opinion is that the sky is not falling with coalbed methane, quite frankly, and I do feel that there are some bad actors out there and legitimate complaints associated with bad actors that, in a sense, have tarnished the industry.

Simply put, you have people that just don't want this kind of thing in their backyard. It's very scenic, and they're very concerned about coalbed methane development in their area. Then you have your standard nuisance issues. Noise; people who live in a rural area are used to hearing the wind, and now they hear a hum from an engine or a compressor, and they're not used to that, and they don't like it. You also have traffic, increased traffic. This creates road dust and is a nuisance issue for landowners in the area. The main concern that I'll probably spend most of my time talking about today is produced water quality. What is the water quality from the coal seams and how do we manage it?

There are three things about coalbed methane that are very similar to gas: They produce gas, you drill a well, and they produce water. Outside of all that, CBM is fairly unique compared to conventional oil and gas. The only thing they really have in common are purely those three things. Then you have some issues that I don't think are founded as a legitimate complaints. You hear people saying things about land subsidence. That's just—this hasn't happened. Underground coal fires. I hear about this all the time, and that's just not true. Doesn't happen. It hasn't happened.

There are concerns about groundwater contamination and about CBM development and the stigmas associated with it. The Powder River Basin is actually quite good. There are some issues that you need to watch, and I'll talk about this in a minute. But quite frankly it recharges the aquifer system in the alluvial, and if you look at the water quality, if you look at the facts, the detailed water quality, the coal versus the..., you'll very quickly come to the decision that the water quality is recharging and improves the water quality. So when I hear about surface discharges, it just blows me away, because the fact is that it is a valuable resource, it's a good resource, and we should tap it as a valuable resource and treat it as such. Well, let's talk about mitigation and gas development. You build roads, we disturb the surface. There's no way around that. Oil and gas companies and mineral owners have a valid and existing right to produce that resource. But before you do that, you need to step back to look at where you're working, and you need to understand and respect existing land uses. And projects will fit in the contention of existing land uses and how to respect what's going on out there and do it in a way that's going to be low impact and operate in a manner that allows both existing land uses to continue and your operation to continue without controversy.

Like I said, oil and gas is development. There is land disturbance. We do build roads. We do build pipelines. What you want to do is try to maximize well spacing. To do this, you have to have a pretty good understanding of what the coal influences from a given well are going to be. That way, you have to drill less wells, and it's more cost effective to the company. It's less land disturbance. You want to try to minimize the size and number of well pads. Real wells disturb a lot of ground. I sit and I work with my drilling guys day in and day out to try to get them to shift the paradigm through so I can move my trucks around. The fact is that those guys can operate in a smaller area, and we tend to work out the details and make it work.

So what I try to do with my drilling group is work on a paradigm-thinking shift, as we did 20, 30 years ago. We just need to minimize size and numbers. And then that follows right into minimize the number of roads, pipelines, and the infrastructure that we have. And this is a big one—minimize impact to wildlife and habitat. I don't think there's any doubt that when you drill, you do have habitat impact and you do impact the wildlife. That has a long-term negative effect on the species of habitat; big game, mule, deer, and elk in the Rockies and Alberta and then Canada. So we're very interested in wildlife interaction with oil and gas and what the impacts are. But again, it goes back to minimizing your footprints, in a sense, and understanding what species are in your area. Before we go in and do any development at Phillips, we send a surveyor in to consider where raptor nests are and things like that. We know where the sensitive areas are. But we can plan, like I said, we plan and execute our development around these areas. Quite frankly, we operate in Utah, and it's the second largest concentration of North American . . . outside of Idaho, the birds of prey area. We've studied in detail the oil and gas impacts on raptor nesting, specifically, for about ten years now and have a pretty good data set. We've probably had to shy away from about 600 wells because of raptor issues, but the raptor population has increased. We tend to think that the cycle really driving them is based on what we're seeing today.

Visual impacts. People don't like to look at pumping units. People in the West, when they build their retirement homes and look out over the vista, they don't want to see that. Technology has advanced now, and there are low-profile pumps that you wouldn't know what you were looking at if you drove by. A lot of people I can take to the Powder on tours and I'll drive down and say, let me know when you see the first well, and we'll pass 300 wells before they even know what they're looking at. The fact is, it's very low-profile. They're small boxes blended into the landscape. Noise is a big one, too. Again, I mentioned noise earlier as a nuisance. The fact is, people don't like to hear noise in rural environments, and you need to be sensitive to that. You can, through interior design and control, design something that makes less noise than they did a few years ago.

Whatever you do on a CBM project, you really want to consider water seriously and how you manage that water. Well, what is the issue with produced water management? The fact of the matter is we have to produce ground water. That's the whole physical component to get the gas out. The question becomes: Now that I have this water, what do I do? And there's not going to be one answer that solves all the water problems. You're going to have an integrated approach, and this is true across the United States, quite frankly. Well, what is the water management approach? You need to figure out how much water you'll use when you do the pilot phase of the project.

Quality, and this is the driving force right here, water quality will define water management. If you don't take anything else away from here, take this away. Water quality will define your options. You have to ask this question, once you determine what you're going to do with that water, whether surface discharge, or livestock use? You have to ask the question, where is that water going? And I'm thinking surface discharge right now; is it okay to be there? Because the last thing that you want to do is create some unintended consequence for a landowner downstream. So you really need to understand your quality, what's downstream of you, and you need to look at the project's economics.

Let me give you a quick little overview here. I could take the produced water from Utah, it's fairly salty. So if I took that produced water and put it in the Powder River Basin today, it's greater than 1,000 TDS, they probably never would have drilled one well in the Powder River Basin. So the economics of water management work into your economics of your project development to make a real project. And then resource values. Again, this is a proven true resource. Let's look at surface discharge considerations, because that is such a controversial issue in a lot of places.

SURFACE DISCHARGE CONSIDERATIONS

- Water volume:
  - — Erosion
  - — Flooding
  - — Stream channel morphology
  - — Stream channel conveyance loss
- Water quality:
  - — State water quality standards
  - — Downstream water use
  - — Coal seam water characterization

You look at two things. First thing is water volume; how much water are you going to have. You also have to regulate the volume of discharge. They only regulate as it affects water quality. But you still need to think about the water you're discharging. Are you going to cause erosion or unintended consequences? Are you going to cause downstream flooding? Are you going to do something that follows you? Are you going to make impacts in a negative way or positive way? What about stream channel morphology? And have you considered stream channel conveyance laws? And what do I mean by that? If you just discharge water on the surface, three or four things are going to happen. A little bit is going to evaporate or you're going to have infiltration into the subsurface, generally speaking. Evaporation, on the other hand, sends the water up into the atmosphere, but it concentrates the salt. And then you have the uptake of water by plants and streams along the channels. So you need to think about what's happening along that conveyance and discharge.

Water quality. Water quality is mostly regulated by the states. States have their own water quality standards, and they have two types of standards: the numerical standards that you won't discharge more than X parts; and then they have the narrative standards which really deal with agricultural uses. Are you going to have fish populations, for example, in the water that you discharge? So you need think about that.

You need to think about downstream water use as it pertains to your water quality. And you define that water quality by characterizing the coal seam of water. Well, what do we do when we characterize water? If you recall characteristics of the water, salinity is an early indicator. SAR is only a clay soil issue.

CBM PRODUCED WATER CHARACTERIZATION

- Major characteristics:
  - — pH, temperature, electrical conductivity
  - — Salinity (TDS), TSS, hardness, alkalinity
  - — Sodium Adsorption Ratio (SAR)
  - — Stream channel conveyance loss
- Inorganics:
  - — Major cations and anions
  - — Metals
  - — Radionuclides
- Organics:
  - — Volatiles and semivolatiles

So the thing you really want to understand is what your ratio is. We look at inorganics, major cations and anions of the water. We look at metals; have they presented a problem for receptors in the stream or people downstream? Then we look at radionuclides, because we don't want to do thing without understanding the consequences of what we do. The third thing we look at is organics. Volatiles and semivolatiles, like things you find in petroleum gasoline. You typically don't see these in coalbed waters. Exceptions vary that do produce minimal amounts of crude oil because of the geological setting. But those are more the exception to the rule. But you still want to scrap your water.

What we hear most about in the Powder is irrigation water quality. And irrigation water quality is defined using two parameters. The first one is salinity, how salty is the water. The second one is sodicity. And that's the amount of sodium in a water relative to calcium and magnesium. What's the problem with sodicity? Sodicity, basically, is made up of solids which dissolve in the water. Total salts equals salinity, which equal TDS. Just for your information, seawater is about 30,000 TDS. Conventional oil wells can produce all the way up to 100,000 parts. Heavy water from a conventional well will range anywhere from 500 up to 20–30,000, depending on where you are geologically. I'm not going to go through all those. And we measure this in the field or lab using it as a gross indicator of salinity.

This is what we use in the Powder. What's the problem with salinity? You know, you spill water from a conventional well and the plants die. And my operations guys come to me and say, you know, we killed the grass because we had a water spill. And they say, you know, that salt must have been toxic to the plants. The fact of the matter is that, no, it wasn't toxic to the plants. The plants can't get the water. Plants take up water using osmosis, osmotic potential. It's a pull on water by the salts. What happens is that the salts in the soil compete with the plants for the water. There's water there, but the plants can't get it because there's so many ions and cations in there that it won't release the water. What happens is you have drought stress in salty soil. There's plants there that just can't get the water.

The second issue: What's the problem with sodium? Well, excess sodium can destroy clay soil structure. Soils can be sand, clay, or somewhere in between. They're not all the same. Sodium will cause soil dispersion. In a good soil, it's a well-aggregated, clumpy-type dirt that floats past that dirt, that subsurface, and into the roots. When you have excess sodium, that tends to repel the plays and the negatively charged sites on the edges of the clay and cause dispersion, and inhibit soil drainage and infiltration. And again, it's a relative proportion of the sodium, that's how we measure it, to calcium and/or magnesium and bring down the SAR. So there are things you can do to juggle the water quality to make it less of an impact to a clay soil. Well, based on that water quality, you will decide to do one of probably five or six things with your water. You can inject it into a Class II conventional salt water disposal well as part of an oil and gas product, but you would never get that resource back. So you need to look at your water quality, and if it's fresh enough, you really need to think about where it's going to be lost.

SALTS AND SALINITY

- Solids forming ions when dissolved
- Total salts= Salinity = TDS
- Na^+, K^+, Mg^{2+}, Ca^{2+}, CO_3^{2-}, HCO_3^-, SO_4^{2-}, Cl^-, NO_3^-
- Measured by electrical conductivity (EC)

SODIUM AND SODICITY

- Na^+
  - — Excess sodium can destroy clayey soil structure
  - — Causes soil dispersion
  - — Inhibits soil drainage
  - — Inhibits infiltration
- Sodicity
  - — Relative proportion of Na^+ to Ca^{2+} and Mg^{2+}
- Sodicity measured by:
  - — Sodium adsorption ratio (SAR)

SODIUM AND SODICITY

- Injection
  - — Disposal
  - — Freshwater aquifer restoration
- Surface discharge
  - — Downstream water uses?
- Evaporation of FTE® (freeze-thaw)
- Treatment:
  - — Reverse osmosis
  - — Chemical amendment
- Beneficial use:
  - — Ranching/Livestock/Irrigation
  - — Municipal water supply/Industrial supply
  - — Wildlife habitat enhancement or restoration
- Novel approaches??

The second thing you could do is freshwater aquifer restoration, where you go into a zone that's fresh enough or with good enough water quality to dispose of it. The problem with that is that it's not able to take that much water. And in the Powder, we have formations in the shallow zones, and it just can't handle the amount of water that we would produce in the Powder. We can discharge water on the surface if, in fact, the water quality is good enough to do that. But you need think about downstream. We can evaporate the water. In Utah, we have seven injection wells and one really big evaporation pond. I don't really like evaporation because you have to manage it, but that is one thing you can do with it.

We can treat it by reverse osmosis or chemical amendment. Even if that costs the oil company less than ten cents a barrel to treat, it's not going to happen because remember I talked about project economics. That cuts into the lifting cost of the gas and makes it less cost effective to produce that gas. Or we can find a beneficial use for that water. And I know there's probably going to be a lot of discussion about this in the next couple days. But, you know, water in the West is actually a precious resource. It may be more valuable to the Westerners than natural gas is to a gas company. We need to capture this resource. I really think we need to do that. And yes, in fact, irrigation can occur with some of these coalbed waters. Municipal water supply. Pennco was recharging a certain zone in the City of Gillette's drinking water, and they were able to do that from that zone for a long time. So you can possibly look at that. You can use it for industrial supply, or you can use it for wildlife enhancement or restoration.

You know, Phillips is on the board of directors of . . . which is a wildlife habitat restoration enhancement organization that looks at habitats from the Cascades to the Rockies in the various states. We deal with the one thing they look at, most of is water, freshwater. It's hard for me to imagine that freshwater on the ground is not a benefit to wildlife. I see that in the Powder every day. The fact is, it is a life blood of wildlife and if we can capture it again, the value of that water, we want to do that. And then there's things out there that we simply haven't looked at yet or nobody's come up with yet.

Let me give you a range of salinities for you to keep in mind. This is based on Phillip's experience. Produced water is about 1,000. Remember, I said seawater is 30,000. You can see the minimum and the maximum there, so there's quite a range. It's actually getting quite fresh; fresh enough to service. So my low number there is probably not low enough. In the Black Warrior, it's 700 to 37,000, which is right there at seawater.

CBM PRODUCED WATER SALINITY

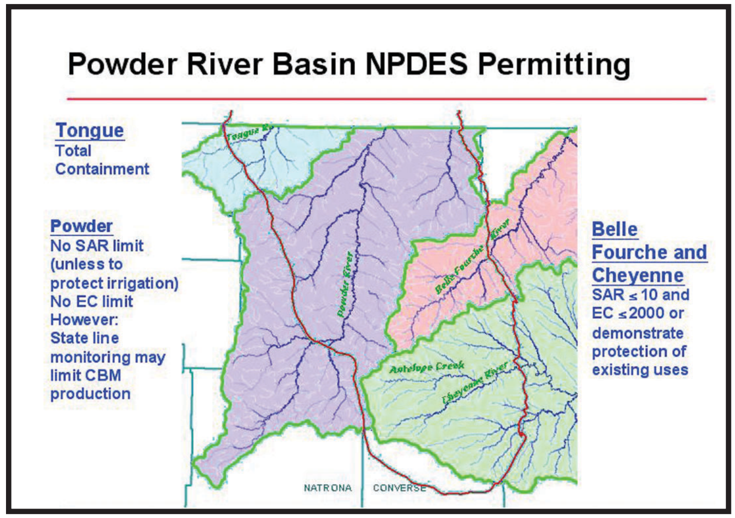
	ave	min - max
San Juan	15,600	(7,000–20,000)
Black Warrior	12,500	(700–37,400)
Western Uinta	11,00	(6,400–19,600)
W. Powder River	1,500	(1,000–2,500)
E. Powder River	1,000	(800–2,000)
NW Colorado	2,000	(650–5,200)

I'll talk a little bit about how we manage surface discharge. Keep in mind that we're going into something about the size of the Mississippi River. So there is surface discharge at that point. In the Western Uinta Basin, we're about 11,000. The Powder on the western side of the basin is a little bit poorer quality. Then the east, which is shown here at the bottom, is okay. With all of these salinities, we have salinities that are about 450, and we're able to surface discharge that. There are a few permits that people are working on at the fringe of the basin now. In the San Juan Basin, there's almost 100 percent Class II injection. In the West Uinta, there's 97 percent Class II injection, and we evaporate about 3 percent. Powder River, almost 100 percent of it is surface discharge. Black Warrior Basin is 100 percent surface discharge. Tuscaloosa and the Raton, in the Colorado side, about 70 percent of it is surface discharged and the other amounts of that is injected in a Class II well, a salt water well. On the New Mexico side, on Ted Turner's ranch—he has coalbed methane on his ranch—100 percent of it is injected. In the Sand Wash, about half is surface discharge and the other half is injected.

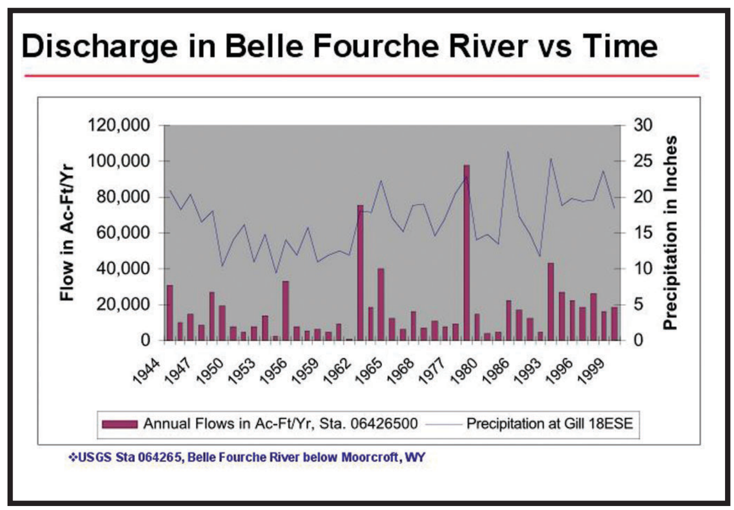
CBM PRODUCED WATER MANAGEMENT

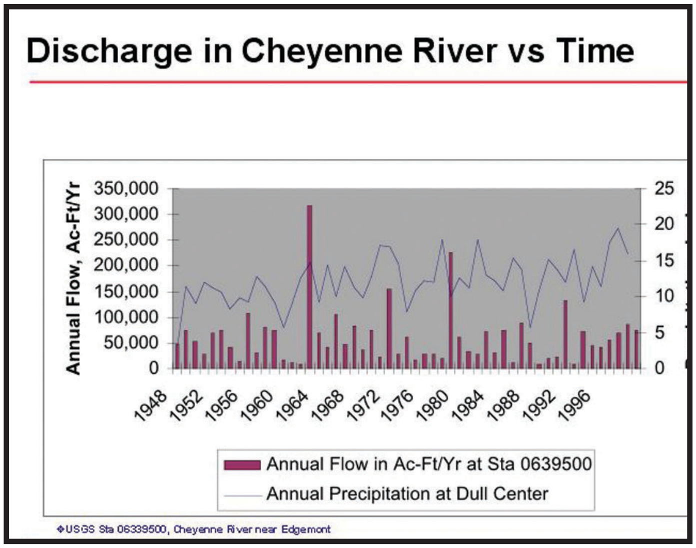
San Juan		Class II injection	99.9%
Western Uinta		Class II injection	97%
		Evaporation	3%
Powder River		Surface discharge	99.9%
Black Warrior		Surface discharge	100%
Raton	CO =	Surface discharge	72%
		Class II injection	28%
	NM =	Class II injection	100%
Sand Wash		Class II injection	50%
		Surface discharge	50%

Let's look at the Powder. Here you have northeastern Wyoming outlined in red, and I'll give you a quick overview of what's going on permit-wise. This is the northwest part of the basin. There is a high quality irrigation river in that portion of Wyoming. Up in Montana, there is really good quality water. Let's go to the Powder River itself. There are no SAR limits, but there's an agreement with Montana to monitor at the state line. This may limit coalbed methane production. Then Wyoming will have to implement requirements upstream.



Look at the Belle Fourche and the Cheyenne River. Let me just talk quickly in closing here about these northeastern Wyoming rivers. In the Belle Fourche River, there are probably 100s plus, maybe thousands of coalbed wells discharged. If you look at the blue line and you look at the stream gauge, they correlate quite well with precipitation.





In fact, if you look at 1993 to 1999, you see the stream flow. This is at the same time we're seeing hundreds of coalbed wells coming online. Well, they organized sending the water to South Dakota and Montana. But look at the hydrographs. The hydrographs don't lie. Where is the water? The water is infiltrating, and it is, in fact, not leaving the state of Wyoming. I'm sure there's some of that that does get through to the Belle Fourche River in northeastern Wyoming from coalbed methane. Okay. If you look Caballo Creek and Highway 59, that's where the core areas are, and that's U.S. Geological Survey gaming station and there might be that much water crossing that.

This is a picture of the Belle Fourche down at Moorcroft. I could jump across the Belle Fourche here. Hundreds of coalbed methane wells contribute to coal mines that are discharging to the Cheyenne River. In fact, you see the same kind of trend. Wildhorse Creek in Arvada, Wyoming has 32,000 barrels a day. They're discharging somewhere upstream at this location. Where's the water? It's not there.

BELLE FOURCHE RIVER AT MOORCROFT, WY

In summary, I want you to take away from this that all CBM projects are not alike. Your water quality will define your approach, and your water management economics may determine if you have a coalbed methane project or not. And if there is a value net water resource, by all means you have to capture it. Water's too precious in the West not to. And it's not going to be a one size fits all. It's going to be an integrated approach on your operation.

Thank you.

COALBED METHANE IN THE ROCKY MOUNTAIN REGION: YESTERDAY, TODAY AND TOMORROW

MATTHEW R. SILVERMAN, *Consulting Petroleum Geologist*

Coalbed methane (CBM) resources are important in a number of different places in the Rockies. This paper is intended to provide a broad, geographic background on where those resources are and where they may be in the future.

Just a dangerous waste product a few decades ago, CBM now represents about seven percent of the natural gas production in the United States. Most of the country's gas, of course, comes from conventional gas production, but that seven percent is very important. It represents about 1.3 trillion cubic feet (TCF) of gas per annum, coming from about 15,000 coalbed methane wells. Most of those CBM wells are in the Rockies.

Today, those CBM resources are focused in four basins (Figure 1). The most important area in terms of production is the San Juan Basin of New Mexico and Colorado.

The other key producing basins in the region are the Powder River Basin in Wyoming and Montana, the Uinta Basin in Utah and Colorado, and the Raton Basin in Colorado and New Mexico. The CBM resources in each of these basins are summarized below.

Importantly, each of these basins is located in more than one state. Each of the basins is unique, and its coalbed methane resources are distinctive, but the basins share a number of characteristics. They are all interstate areas, and they will all require interstate solutions to

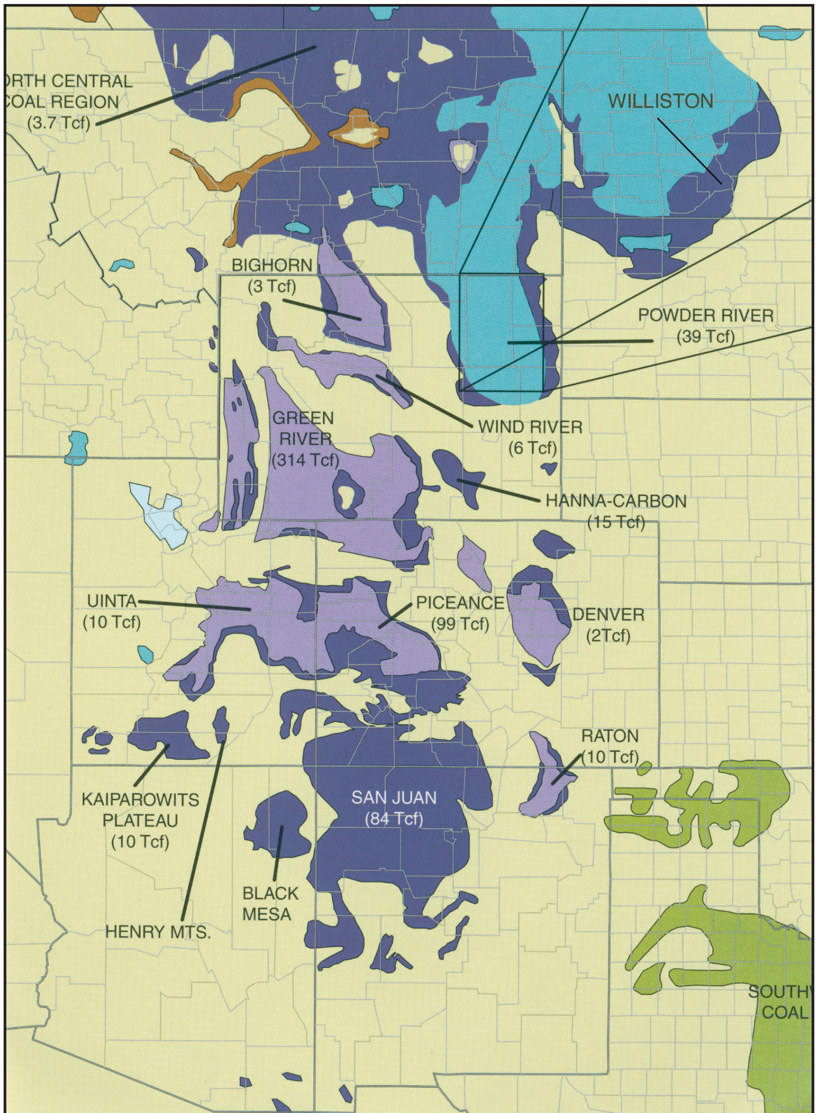


FIGURE 1 *Coalbed methane basins of the Rocky Mountain region, after GTI, 2001; and Wood and Bour, 1988. The map is color-coded by the age of the coals that produce, or may produce, coalbed methane. The light blue areas represent Tertiary coals, which are the youngest coals in the Rockies. The lavender color represents Tertiary to Cretaceous coals, and purple represents Cretaceous age coals. The small areas in brown are Cretaceous-Jurassic, the oldest of the CBM coals in the Rockies. (Permo-Pennsylvanian coals in Texas and western Oklahoma are also shown.) The numbers in parentheses represent estimated resources of coalbed gas-in-place.*

what are interstate problems. They share problems related to the environment, water quality issues, Federal access issues. They also share the requirement for resolving the infrastructure problems related to production, transportation, water management and local impacts. These are all issues that are common across essentially all coalbed methane basins.

Figure 2 provides a historical perspective, going back a little over ten years. Over the past decade, New Mexico, shown here in yellow, has been the dominant state. This CBM gas, of course, is from the San Juan Basin. But in the last few years, production has really come on strong from the Colorado portion of the San Juan Basin and from the Raton Basin, as well. Alabama has made a significant portion of the country's coalbed methane production and so have a few other states that are shown here as "Others". A very large portion of this production labeled "Others" comes from Wyoming, and that volume has grown dramatically in just a few years.

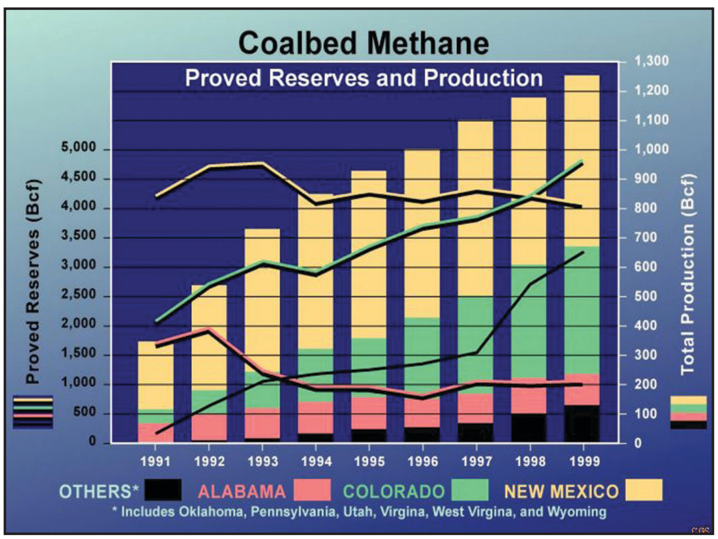


FIGURE 2 *Coalbed methane proved reserves and production (courtesy Colorado Geological Survey). The bars represent coalbed methane production and the lines represent CBM reserves.*

Two of the things that petroleum geologists and engineers are concerned with are: 1) the volume of gas that is in-place in any reservoir, including a CBM reservoir, and 2) how much of that is recoverable. Those are often two very different numbers, as Figures 3 and 4 illustrate.

Within the Rockies (Figure 3), over 50 percent of the coalbed methane gas in-place is in the Green River Basin. A lot of that is not recoverable by today's methods, because it is deep, and because of economics, environmental considerations, access restrictions and other reasons. But this huge number provides a sense of the total size of the resource base. The Piceance Basin and the San Juan Basin also have very significant pieces of the pie. The other basins in the Rockies play a smaller role in terms of the resource base.

ESTIMATED ROCKIES CBM IN PLACE

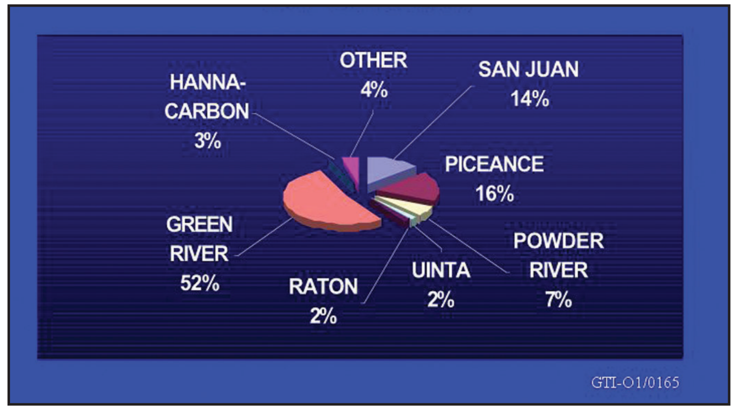


FIGURE 3 *Estimated Rockies CBM in place. Estimates were derived from a variety of sources, principally GTI-01/0165.*

Figure 4 shows the estimated volumes of recoverable coalbed methane, and this is a very different picture. The Powder River Basin takes the biggest piece of the pie at 43 percent of the coalbed methane that is *recoverable under current technical and economic conditions*. Again, the San Juan Basin and the Uinta-Piceance Basin play a big part in recoverable reserves as well.

ESTIMATED ROCKIES RECOVERABLE CBM

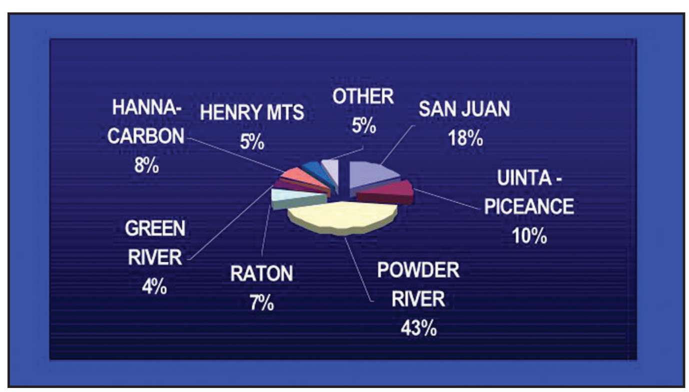


FIGURE 4 *Estimated Rockies recoverable CBM. Estimates were derived principally from the potential gas committee, 2000, as given in GTI-01/0165.*

Key producing basins

SAN JUAN BASIN

The San Juan Basin (Figure 1) has an estimated 84 trillion cubic feet of coalbed methane gas in-place. The San Juan Basin has been and continues to be the world's number one area for CBM production. But the San Juan is now in a relatively mature stage of development for CBM. Coalbed methane production has probably peaked there, and, while the basin is still very active, the focus of new drilling and new activity has now gone elsewhere.

Of the basin's estimated 84 trillion cubic feet of CBM in-place, about 12 TCF is recoverable. Almost 8.5 trillion cubic feet of CBM has already been produced (IHS, 2002). The San Juan Basin represents 80 percent of all the CBM production in the United States, and is currently making about 75 percent of all the CBM gas in the country. The reasons for that include the presence of thick, rich coals with high permeability and a play that has been extensively developed. Among the top operators in the basin, in terms of both historic production and total well permits, are well established, very large to super-major oil companies, including Burlington, Amoco (now BP) and Phillips.

Table 1 compares the San Juan Basin with three of the other key CBM basins in the Rockies. Typical production per well per day in the San Juan Basin is relatively high, often 2 million cubic feet (MMCF) per day. This is ten times what is being produced per well in the Powder River Basin and four times greater than the Uinta Basin, where rates are typically 200 to 500 thousand cubic feet (MCF) per day. There is much tighter spacing in the Powder River Basin than in the other basins, reflecting the shallow depths and low per-well recoveries.

The typical depths for CBM wells In the San Juan Basin are 2,000 to 3,000 feet; whereas, in the Powder River Basin, over 10,000 much shallower wells have been drilled. In the Uinta and Raton Basins, well depths vary greatly, but typically, they are much deeper than the wells in the Powder River Basin. Coals are thickest in the Powder River and San Juan Basins, and richest (measured in standard cubic feet of gas per ton of coal) in the San Juan and Uinta Basins. Finding costs for CBM reserves in the San Juan Basin have been less than half those in the Powder River and Uinta Basins, and about 60% of those in the Raton Basin.

	SAN JUAN BASIN	POWDER RIVER BASIN	UINTA BASIN	RATON BASIN
Daily production/well	2,000 MCF	200 MCF	500 MCF	300 MCF
Spacing (acres)	320/160	80	160	160
Number of wells	3,500–4,000	+10,000	450	800–1,000
Typical well depth (ft)	2,000–3,000	300–700	1,000–4,000	500–3,500
Net coal thickness (ft)	70	75	24	35
Gas content (scf/ton)	430	60	400	300
Finding cost ($/MCF)	0.11	0.25	0.25	0.18

Table 1. Comparison of key producing basins, after GTI and McMichael et al., 2001.

POWDER RIVER BASIN

In terms of well permitting, current drilling, and the growth in production, the Powder River Basin is the most active coalbed methane play in the Rockies. Figure 5 illustrates the CBM basins of Wyoming, including the Powder River Basin in the northeastern part of the state. CBM targets which are shallower than 5,000 feet are shown in red. This depth is a traditional cut-off, above which, coalbed methane targets are thought to be currently viable. Shallow coalbed methane plays are present in the Powder River Basin, of course, and in the Wind River Basin, shallow portions of the Hanna Basin and the Big Horn Basin, and a couple of places in the Green

River Basin. Deeper targets (shown in orange) represent a resource base for the future. Those targets are present in a number of areas, but the key for the future is the huge, deep coalbed methane potential in the Green River Basin. If this becomes economically viable and technically feasible, it could dwarf everything else that is being done in the region.

WYOMING CBM TARGETS

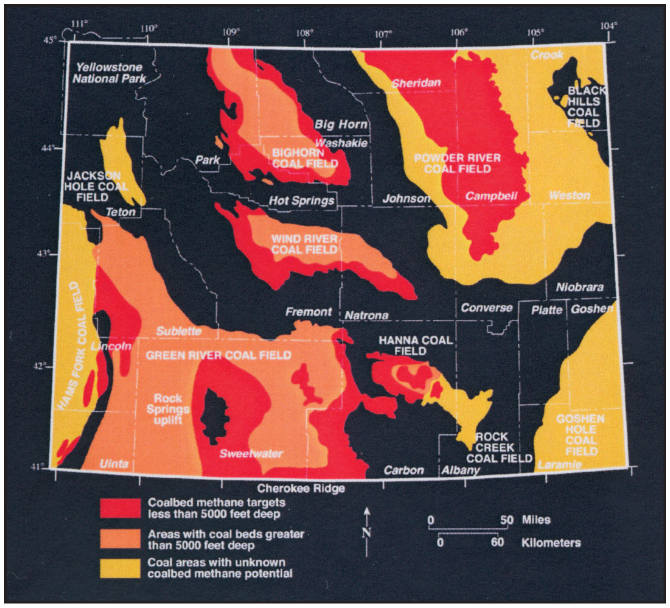


FIGURE 5 *Wyoming coalbed methane potential includes the producing Powder River Basin and several other basins, some with targets deeper than 5,000 feet (courtesy Wyoming State Geological Survey).*

Historical and projected growth in CBM development in Wyoming is shown in Figure 6. Most of this growth is projected to come from the Powder River Basin. Before five years ago, there was essentially no CBM production in the Powder River Basin, but the basin has now produced about 400 billion cubic feet of coalbed methane. Figure 6 illustrates how that production is projected by the Wyoming State Geological Survey to ramp up over the next 20 years. The number of producing wells has also grown explosively here since the mid 1990s and is projected to grow at a very high pace over the next five years, as well.

WYOMING CBM PRODUCTION

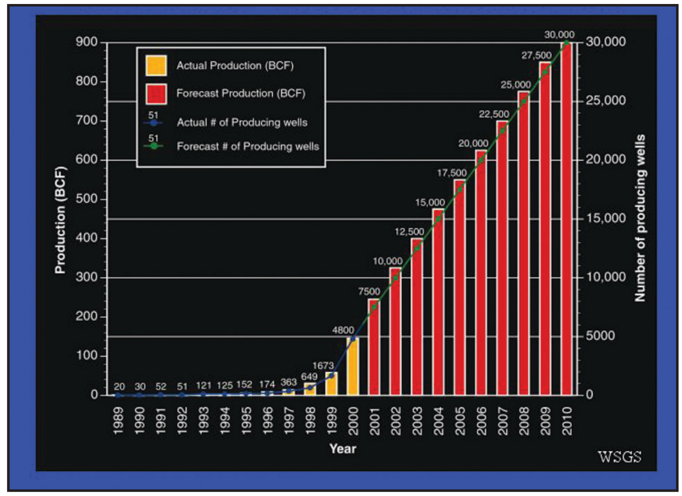


FIGURE 6 *Actual and projected growth in Wyoming coalbed methane production and producing well count (courtesy Wyoming State Geological Survey).*

This is a developing resource and also a developing problem that concerns people throughout the region today. Much of the impact has been felt in the eastern part of the basin near Gillette in an established coalbed methane fairway. Drilling has now been extended to the western part of the basin near Buffalo and Sheridan. Due to governmental restrictions, activity in the promising northern part of the basin in Montana has moved forward less rapidly.

Published estimates suggest the presence of at least 40 trillion cubic feet of gas in-place in the Powder River Basin, and approximately 10 TCF is thought to be recoverable. As more pilot projects are undertaken and more data are gathered, these numbers have been revised upward several times. We may expect to see future upward revisions as well. The Powder River Basin has a relatively low gas content per ton of coal, but the coals are thick, shallow and permeable. The basin enjoys very large CBM resources because the thick coals have a huge areal extent. The favorable economics are related in part to low costs associated with shallow drilling and permeable reservoirs that do not require expensive fracture treatment.

The list of top operators in the Powder River Basin includes some of the industry's established independents like Devon and J. M. Huber, as well as companies that have traditionally been midstream or transportation companies like Western Gas and Williams. Companies ranging from smaller majors, like Marathon, to some regional independents are represented, also. Many of these strong positions in Powder River Basin CBM (and in other CBM plays) were created by recent acquisitions.

UINTA BASIN

The prolific Ferron coalbed methane play in east-central Utah (Figures 1 and 7) is the third largest CBM play in the Rockies. The volume of estimated CBM resources in-place in the Uinta Basin is about 10 TCF, of which roughly half is thought to be recoverable. The play is currently producing about 300 MMCF of gas per day, of which roughly 250 MMCF comes from the Drunkard's Wash Field. Approximately 300 billion cubic feet (BCF) of gas has been produced from this basin since the early 1990s (Lyons, 2002).

Gas content in the coals in some parts of the Uinta Basin rivals that in the San Juan Basin. Per well recoveries are relatively high in the northern part of the play where well control and the pipeline infrastructure have been located. Over 400 wells are producing, but published estimates suggest the play could ultimately support eight times this many CBM wells. Top operators in the Uinta Basin include major oil companies and large independents such as ChevronTexaco, Phillips, and Anadarko.

RATON BASIN

The Raton Basin in southeastern Colorado and northeastern New Mexico (Figure 1) is fourth in terms of CBM production in the Rockies. There are over 10 trillion cubic feet of gas in-place in the Raton Basin, and about 3.5 to 4 trillion cubic feet of that gas is considered recoverable. Cumulative CBM production is about 130 BCF (IHS, 2002). Although these are big numbers, the Raton Basin's production so far represents less than two percent of the gas that has been produced in the San Juan Basin. The Raton Basin's current production is about 110 MMCF of gas per day. This total comprises about three percent of all of the coalbed methane gas that is being produced in the United States.

Ten years ago, coalbed methane gas represented approximately 10 or 15 percent of all of the gas being produced in Colorado. Now, utilization of this important resource has increased dramatically. Coalbed methane now represents more than half of the gas being produced in the state, and most of this growth comes from CBM from the Raton and San Juan Basins. The top operator in the Raton Basin by far, is Evergreen, which is the dominant company, especially on Colorado's side. The other key companies include Devon, El Paso, Williams, and other independents.

New coalbed methane resources

FUTURE SOURCES OF CBM

Parke A. Dickey said, "We usually find oil in new places with old ideas. Sometimes, also, we find oil in an old place with a new idea, but we seldom find much oil in an old place with an old idea. Several times in the past we have thought that we were running out of oil, whereas actually we were only running out of ideas." The same is true for gas, including coalbed methane.

In the coming years, CBM production will be generated from a number of new ideas, sources and areas (Figure 1), including the following:

- New Economics
- New Plays and/or Areas in Producing Basins
- New Technologies
- Deep Plays
- New Basins

First, new economics could mean not just higher prices for the producers, but as new pipelines come into the Rockies, new markets are developed. Markets in the future will become available for gas that has been stranded, and CBM resources will be used locally and subregionally for electric power generation.

Second, a key method by which people have traditionally found oil and gas is by exploring in new plays or new areas in producing basins. The Powder River and San Juan Basins, for example, have been traditional conventional gas producing areas for many years. In the last decade or two, both have become very important coalbed methane producers, generating huge volumes of new resources.

Third, new technologies that will be important for CBM development include exploration and evaluation techniques, horizontal and slant-drilling, multiple-seam and thin-zone completions, enhanced fracturing methodologies, and advances in water treatment, disposal and re-injection. All of these will be called upon to enable new coalbed methane resources to be brought to life.

Fourth, we also will have new production from deep plays in which huge gas resources are stored throughout the Rockies. These will be developed in the future as technological advances and market conditions permit. Finally, we can expect to see coalbed methane produced from new basins, in other words, basins that are not producing now at all, as in western Washington, for example.

TECHNOLOGY

The Uinta Basin provides an example (Lyons, 2002) in which application of seismic technology has made a positive difference in the reserves base and in project economics. New advances in geophysical techniques will also play a vital role in the development of coalbed methane resources in the future. Near the top of the seismic line (Figure 7), two gas wells with poor production are labeled in red. An excellent producer is labeled in blue. The significance is that the seismic line shows the presence of prominent faulting in the CBM interval. Black vertical lines in the center of the seismic data panel show the faults. Generally speaking, faulting and associated folding produce fractures, and fractures may yield higher permeability. Higher permeability results in wells that produce more efficiently. Use of this technology leads to the identification of sweet spots, relatively small areas of higher production. By focusing on the sweet spots, operators may be able to drill fewer wells and still drain the same volume of gas. This tends to result in better profitability <u>and</u> in less surface disturbance. Seismic in this area helped not just to identify faults and predict a high-productivity fairway, but also to:

- Map the extent of the producing coals more precisely
- Understand coal facies changes
- Improve the interpretation in sparsely drilled areas
- Assess other formations for water disposal or hydrocarbons production

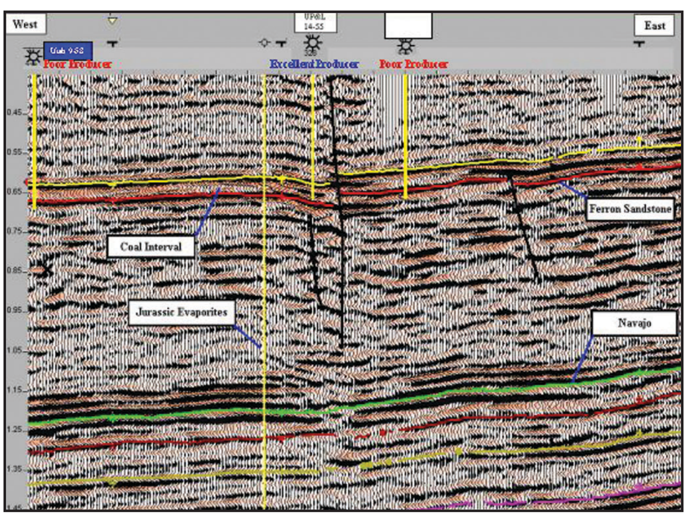


FIGURE 7 *Buzzard Bench seismic line 4, showing the relationship of faulting to a narrow fairway of higher production, Uinta Basin, Utah (after Lyons, 2002).*

DEEP COALBED METHANE

An example from which we may begin to see the potential of deep CBM production is offered by the Piceance Basin of Colorado and Utah (Figure 1). In the Piceance Basin, approximately 99 trillion cubic feet of coalbed methane gas is in-place. Of that, 84 TCF is in deep coalbeds, that is, coalbeds deeper than 5,000 feet. One example of deep CBM production there is the White River Dome Field, which is producing coalbed methane from depths of 5,000 to 8,000 feet. Sixteen wells drilled in the late 1980s and early 1990s cut 25 to 85 feet of net coal, with gas contents measured at 547–621 scf/ton. This field has produced over 10 BCF of coalbed methane (Murray and Perlman, 2002).

Other examples of basins with deep CBM potential (SPE 26196, GTI-01/0165) include:

- The Green River Basin, in which only 48 of the 314 trillion cubic feet of gas resources is estimated to be actually in coals that are shallower than 6,000 feet.
- The Uinta Basin, where a majority of the CBM resources are thought to be deep.
- The Tertiary basins of western Washington, in which 50–80% of the estimated 24 TCF of CBM in-place is below 5,000 feet.
- The San Juan Basin, in which 17 trillion cubic feet of CBM is estimated to be reservoired in Menefee coals that are deeper than 5,000 feet.
- Alberta, Canada, where at least 50 TCF is present in coals from 5,000 to 11,000 feet deep.

NEW PLAYS IN PRODUCING BASINS

A final example of potential future CBM sources is the Williston Basin of North Dakota and Montana (Figure 1). There, the U.S. Geological Survey (Ellis et al., 1999) has mapped the presence of coals near the heart of the traditional oil and gas play (Figure 8, for example). These coals are considered prospective for coalbed methane.

Coals in both the Williston Basin and the Powder River Basin are from the Tertiary Fort Union Formation. The Williston Basin's coals are relatively low rank and have produced biogenic gas, as in the Powder River

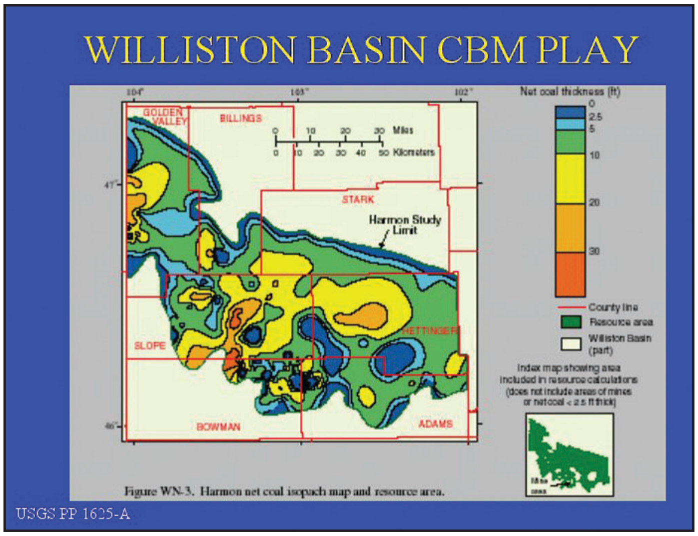


FIGURE 8 *Net isopach map of the Harmon coal, Williston Basin, North Dakota (from Ellis et al., 1999).*

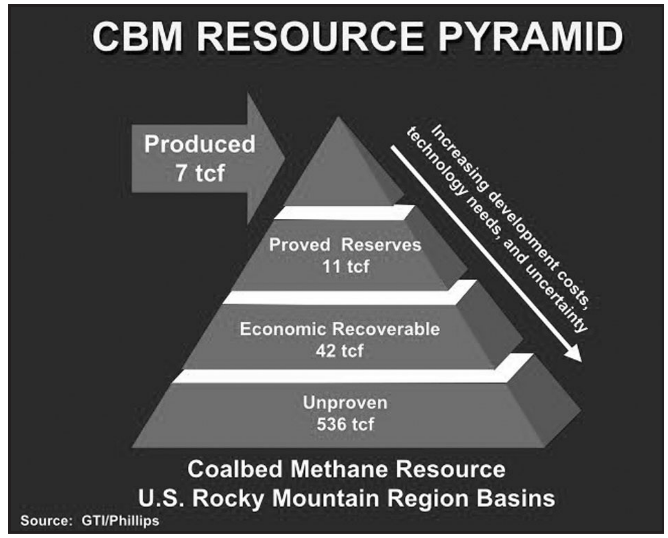


FIGURE 9 *Coalbed methane resources pyramid for the Rocky Mountain region, after Bowles, 2001, from GTI. The 42-TCF level reflects the resources that are considered technically feasible and economically viable today. The pyramid is actually broader at the base than represented here.*

Basin. They are 20 to 50 feet thick and continuous over a large mapped area. Fifteen years ago, many people said that no coalbed methane play in the Powder River Basin would ever work because of the low gas content of the coals. Now, we can all see the enormous size of the resource base that has been developed there. The question is open: Is there a CBM play in the Williston Basin?

Conclusions

Figure 9 is the coalbed methane resources pyramid for the Rockies. The volume of 7 TCF at the apex of the pyramid suggests the amount of coalbed methane gas that has been produced so far, although actual numbers are somewhat higher. This is the gas that has proven easiest to find and produce, and includes the most highly economic resources. Below this is a level of proved reserves at about 11 TCF. As one looks down the pyramid, the volume increases dramatically to where the total resource base may be as much as 536 trillion cubic feet of coalbed methane in the Rockies. However, costs increase, the requirements for new technology increase, the environmental considerations increase, and the uncertainty also increases, all in the same direction towards the base of the pyramid.

Therefore, the future level of coalbed methane production in the Rockies may ultimately approach the huge numbers at the bottom portion of the pyramid. But this entire volume of gas at the pyramid's base is unlikely to be produced. It is essential to keep in mind all of these difficult factors that must be dealt with before these resources can be brought to the market.

Acknowledgments

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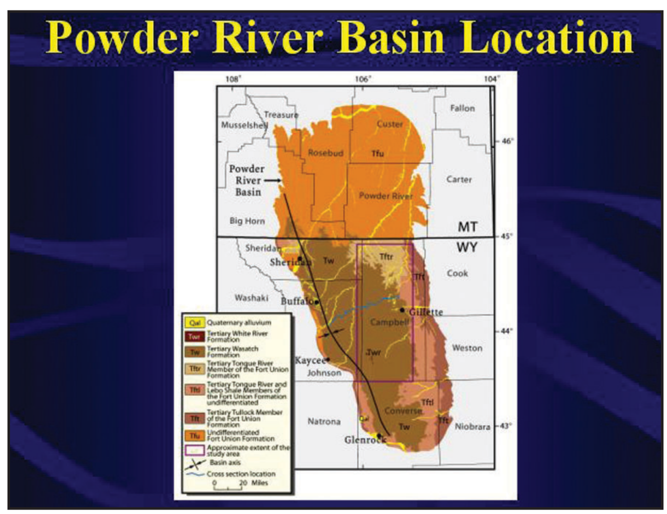
THE HYDROLOGY OF COALBED METHANE RESERVOIRS AND THE INTERPLAY OF GAS, WATER, AND COAL IN CBM PRODUCTION

LESLIE NOGARET, *Engineer-Hydrologist, SI International/Pendergast Sarni Group*

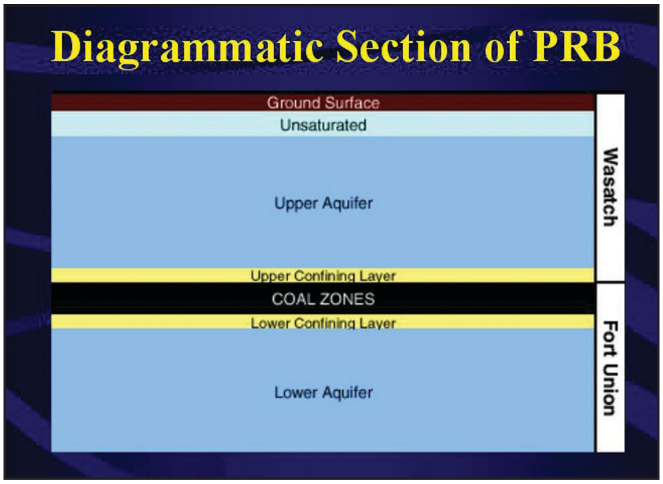
I'm going to give a very general overview of the hydro geology of coalbed methane reservoirs. This general overview is meant to be more technical in nature. I'm not going to discuss permitting or anything to do with legal issues. An outline of my talk is as follows: A review of coalbed methane production mechanisms, then I'll launch into the hydrogeology, and finally, I'll finish with a little bit of simulation.

First, an introduction. Some of these statistics may be a little dated. They were published in 2000, but you'll get a general sense of trends. Gas from coalbed methane accounts for 7.5 percent of U.S. gas production, and recoverable resources are estimated to be 141 Tcf. The Powder River Basin, as we have seen already, has been one of the most active areas for coalbed methane production since 1997. And the Powder River Basin is going to be a topic of discussion tomorrow. So for these two reasons, I'm going to draw on the Powder River for some of the examples throughout my talk.

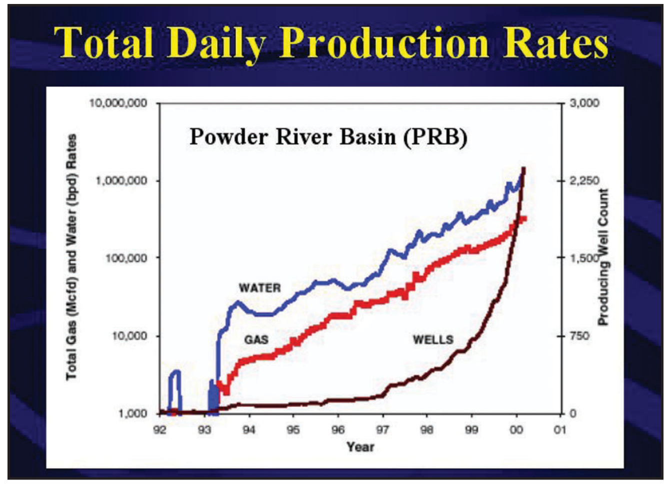
Once again, here's the location of the Powder River Basin in Wyoming and Montana. On the left, you can



FROM *Rice, C.A., M.S. Willis, and J.H.Bullock, Jr., Water coproduced with coalbed methane in the Powder River Basin, Wyoming: Preliminary compositinal data, USGS Open-file report 00-372,2000.*



FROM *Onsager, P.R., and D.O. Cox, Aquifer controls on coalbed methane development in the Powder River Basin, Wyoming, SPE 63090, 2000.*



FROM *Onsager, P.R., and D.O. Cox, Aquifer controls on coalbed methane development in the Powder River Basin, Wyoming, SPE 63090, 2000.*

see the basin axis. If we were to take a vertical cross-section through this basin we would get the following, (see slide above). This is a very general schematic view of a vertical cross-section of the Powder River. You can see that the coal zones are located predominantly in the Fort Union formation.

Note the two confining layers overlaying and underlying the coal. These are layers of lower permeability. This is very general because the confining layers are present in some areas of the basin and not in others. Overlaying and underlaying these confining layers are aquifers. And you'll notice that the upper aquifer actually extends up the unsaturated zone, which extends to the surface. The boundary between the unsaturated zone and the upper aquifer represents the water table. Below the water table, water saturation is 100%, and above it, water saturation decreases and air saturation increases toward the ground surface. There are two things I'd like you to remember from this slide. One is the presence or lack of these confining layers around the basin; and the other thing to note is the possible communication from the surface through the unsaturated zone to the upper aquifer.

The next slide shows a few statistics of the Powder River Basin. There were 270 wells in March of 1997. This grew to nearly 2,500 by March of 2000. 15 to 17,000 wells are projected for the next 20 to 30 years. Methane production increased from 35,000 to 333,000 Mcf per day from 1997 to 2000. And water production increased from 130,000 to 1.28 million barrels per day during that same time period.

This slide shows these statistics in graphical form. The left axis is gas and water rate, and this axis is actually logarithmic in scale. And the X axis is time. So the water and gas rates you see increase exponentially. The producing well count is shown on the right axis, and the number of wells is shown by the brown curve. You can see the number of wells is also increasing exponentially.

Next I'm going to briefly review the coalbed methane production mechanism we saw in Steve's talk earlier. During coalification, methane-rich gas is generated and stored in the coal matrix, and it's actually adhered onto the surface of the coal. We call this adsorption. Due to the large internal surface area of the coal, it can store six to seven times the amount of gas stored in a conventional reservoir of equal rock volume. Water permeates the coal, and the pressure of this water holds the methane adsorbed to this coal. To produce methane we need to produce water to lower the pressure and desorb that methane from the coal. Once it's desorbed, the methane can diffuse through the matrix to the cleats, where it flows to the wellbore and can be produced.

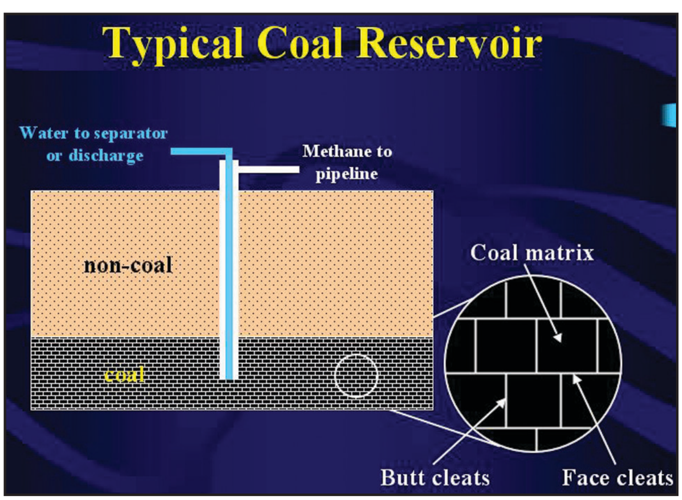
Our next slide shows this process in a schematic, where we have a coalbed overlain by a non-coal unit. This non-coal unit could be an aquifer or a shale or silt. And then we have our natural fracture system, or cleats. We have two types of cleats, the face cleats and butt cleats. The face cleats are aligned along the direction of maximum com-

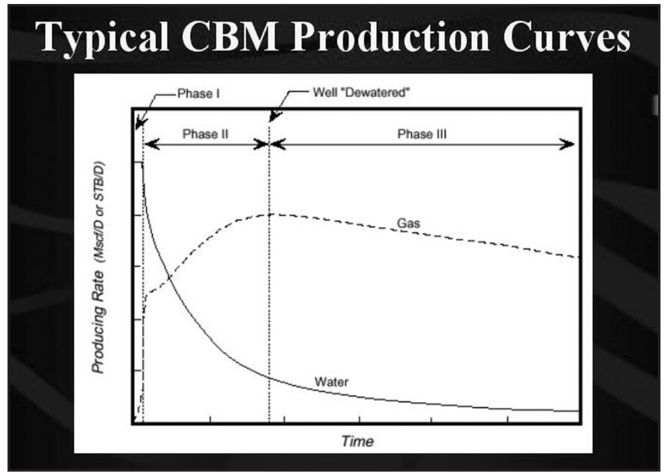
CBM PRODUCTION MECHANISM

- During coalification, methane-rich gas is generated and stored in coal matrix ->adsorption
- Large internal surface area of coal means it can store 6–7 times the gas stored in a conventional reservoir of equal rock volume
- Water permeates coal, and its pressure traps methane within the coal
- Water must be produced to lower pressure and desorb methane.
- Methane diffuses through coal matrix to cleats, where it flows to the wellbore and is produced

pressive stress. And the butt cleats are perpendicular to this. If we drill a well here and permeate the coal and start producing water, the methane will diffuse through the matrix to the cleat system where it can be produced.

The slide in the next column shows a typical coalbed methane production curve, which we've also seen today already. This is rate versus time; water production is the solid line, gas production is the dotted line. In general, coalbed methane production can be divided into three phases. The first phase is characterized by a high water rate and a very low gas rate. Gas rates can be inclining or declining, depending on relative permeability. The boundary between phases one and two is when we've reached our minimum bottom hole pressure in the well, and we have also reached our desorption pressure. At this point, water rate starts to decrease, and we really see an increase in our methane rate. At the end of phase two, water rate is pretty low. Phase three, therefore, is characterized by a decline in gas rate that looks like that for conventional gas reservoirs and very low water rates.





FROM *GRI, A Guide to Coalbed Methane Reservoir Engineering, 1996.*

There are two things I'd like for you to note from this slide: First, I'd like you to remember this slide and take it into consideration, because I'll show some examples of production later on that don't look like this.Seond, note the fact that we really have most of our water production in phase one. As we drill more wells, total water production will increase, but total water production for the basin is likely to decrease if no new wells are drilled.

RESERVOIR HYDROGEOLOGY

- Cleats
- Fractures and faults
- Structure
- Stratigraphy
- Leakance
- Flushing
- Re-injection
- The coal is an aquifer itself!

Finally, I'm going to get into hydrogeology now. I've separated the hydrogeology into three zones of interest. One is the coalbed methane reservoir itself; the second is surface hydrology; and then third is the interaction between these two zones. So first, for the reservoir, the following features can affect the hydrogeology in the coalbed methane reservoir:

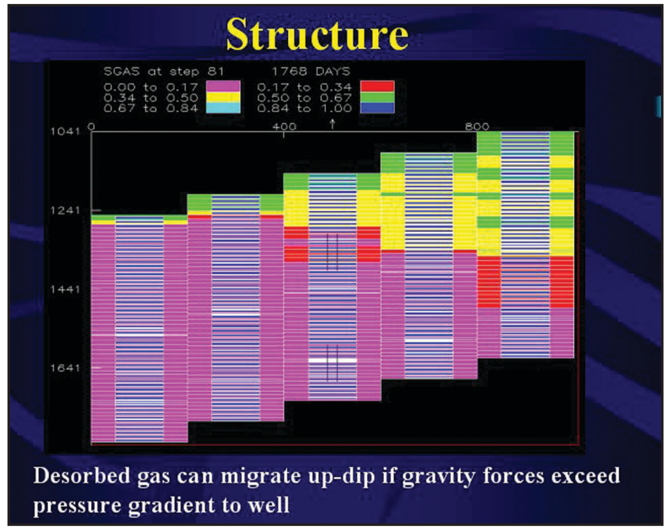
- Cleats; larger scale cleats, or fractures, and faults
- Structure
- Stratigraphy
- Leakance—this is leakance into the coalbed methane reservoir
- Flushing of water through the coalbed methane reservoir
- Reinjection, which was discussed in detail this morning

One thing that I'd like you to remember throughout the rest of the presentation is that the coalbed is actually an aquifer itself.

So first the cleats. The cleats are formed during coalification due to shrinkage. In general, increased depth closes these cleats, which is why we look for relatively shallow reservoirs. Cleat permeability in the Powder River Basin ranges from 100 millidarcies to one Darcy. This is a great permeability, corresponding to a well-cleated system. But there are pros and cons for good cleating. The pros are that good cleating leads to high permeability and rapid localized dewatering and methane desorption. The cons are that the water may move laterally over large distances, which would require the need for small well spacing.

Next, fractures and faults. The main issue to be concerned with fractures and faults is that they may connect to a neighboring aquifer or to the surface, which would provide an influx of water via recharge which would make the dewatering difficult.

The next influence on hydrology is structure. Recharge may occur if a coalbed outcrops at the surface, which makes dewatering difficult. Another issue to think about is if the coalbed is dipping. And this draws on the fact that the coal is an aquifer itself. The coalbed has two phases. Gravity is going to dictate how these two phases, water and gas, like to segregate. If the coalbed is dipping, care must be taken to place wells in locations in the coalbed reservoir to optimally extract desorbed gas. The next slide shows this schematically. This slide shows a numerical model of a vertical cross section of a coalbed reservoir. The model is five blocks across and over 100 blocks deep. For this example, we have actually eight coal seams interbedded with sands, silts and shales. The deepest coal seam was at the bottom of this cross section. The vertical black lines in the middle block represent the well. The colors are gas saturation, pink is low and green is high.

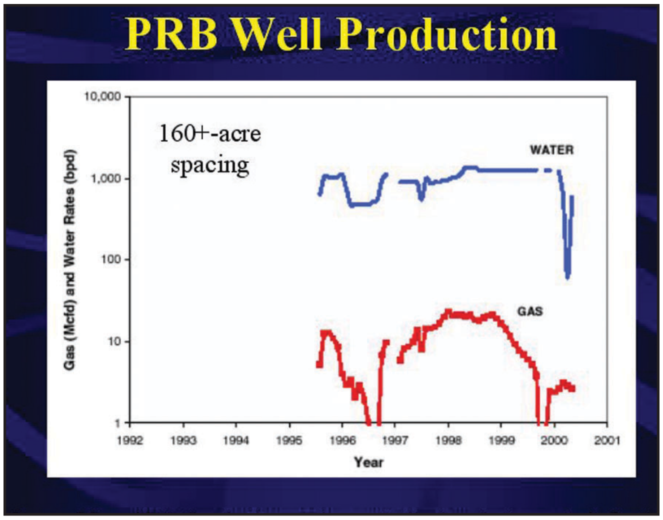


Note that the potential for the gas to migrate to the well due to the pressures gradient was overcome by the potential for the gas to migrate vertically due to gravity. In this study, we recommended to complete wells in an upper interval, perhaps a coal that was thinner and not as attractive, in order to collect the desorbed gas.

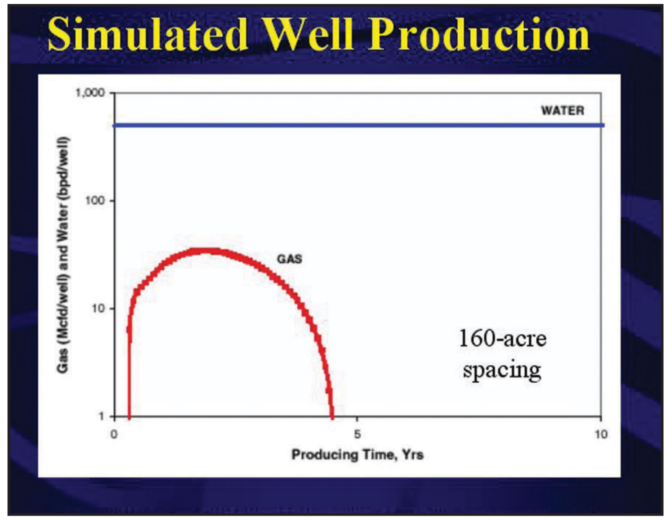
Stratigraphy is another influence on hydrogeology. Desorbed gas could migrate to an overlying aquifer if gravity forces exceed the pressure gradient to the well. If there's communication with aquifers, dewatering is difficult. If there is no communication, due to the presence of confining layers, we must take care that we don't penetrate into neighboring aquifers with hydraulic fractures.

Leakance is another influence on hydrogeology. Leakance was presented elsewhere by Onsager and Cox, who showed that if aquifers are well-connected to the coal, leakance can be high, and this can lead to a steady-state pressure environment that deters dewatering efforts. What that basically means is water influx into the coal is as fast as water production from the coal. They gave examples for the Powder River Basin, because they looked at some of the production profiles for the Powder and they did not look like the profile I showed you previously. One end result was that they found the higher the leakance, the tighter the well spacing required to dewater the coal and desorb the gas.

I'm going to show you just one example of one of those production profiles. This slide shows Powder River well production on 160-acre spacing. The y axis is rate and the x axis is time. Water is shown in blue, and gas is red. This slide is unlike the typical production profile I



FROM *Onsager, P.R., and D.O. Cox, Aquifer controls on coalbed methane development in the Powder River Basin, Wyoming, SPE 63090, 2000.*



FROM *Onsager, P.R., and D.O. Cox, Aquifer controls on coalbed methane development in the Powder River Basin, Wyoming, SPE 63090, 2000.*

showed earlier, where water rate had a steep decline. Here we see a constant water rate. This is because the water that influxes from the aquifer recharges the water that is produced from the coal. The gas rate also looks different from what we saw before, although it has some decline. The peak gas rate is about 10 to 30 Mcf per day. The typical production profile in the previous slide had a higher peak gas rate. Note that in this example, the incline is steep and so is the decline. This is because the methane was not able to desorb efficiently due to the pressure support provided by leakance. Onsager and Cox were able to model this behavior using a simulator, and their results are shown on the next slide. You can see that they reproduced the constant water rate and the increase in methane rate to a maximum of 10 to 30 Mcf per day, followed by a steep decline.

Flushing is another influence on hydrogeology. This is merely a hypothesis at this point, presented by Professor Mark Bustin at the University of British Columbia. He has hypothesized that groundwater can flush methane from coal over geologic time, due to a dissolution process in the coal. This hypothesis could be possible, even with the relatively low solubility of methane in water. This can explain some situations where the coalbeds have been undersaturated.

Lastly, this is something to do with hydrogeology that was discussed in detail earlier, and I'm merely touching on it here—the issue of reinjection. Care must be taken so that a reinjection zone does not communicate with the coal, because pressure support makes dewatering difficult. Some other issues to do with reinjection are as follows: plugging of injection wells must be avoided. Suspended solids must be removed, and precipitation of dissolved solids must be avoided. One way we can do that is to maintain a low pH, which prevents precipitation of iron, the most common plugging agent, and manganese. Lastly, water compatibility issues are important in reinjection. High sulfate water should not be mixed with water containing appreciable amounts of barium and strontium. And again, low pH prevents formation of calcium scale.

The next zone of interest in hydrogeology is the surface. We saw a presentation this morning that went into this in more detail. This is surface hydrology, and here again the issue is really disposal of produced water. There are two issues, which are water quantity and quality. As I mentioned earlier, there were 1.28 million barrels per day of produced water in the Powder River, and that was in 2000.

Water quality issues include the composition of the produced water, which influences how to dispose of it. In a coalbed methane reservoir, composition is controlled by the association of water with the gas phase, which contains carbon dioxide and methane. Produced water typically contains sodium, bicarbonate, and chloride. It's generally low in sulfate, and the total dissolved solids will often increase with depth. This is another reason why shallow coalbed methane reservoirs are desirable. The total dissolved solids in the Powder River Basin ranges from 370 to nearly 2,000 milligrams per liter with a mean of 840. For a comparison, potable water is 500 milligrams per liter, seawater is 35,000. So this is fairly fresh water. Powder River Basin TDS increases from the south to the north in the basin and from east to west. And this increase was found to be due to water/rock interaction along the flow path or changes in composition of the ash content of the coal.

The last zone of interest is the zone that links the previous two zones, and that's surface-to-reservoir. Examples of surface-to-reservoir communication are as follows:

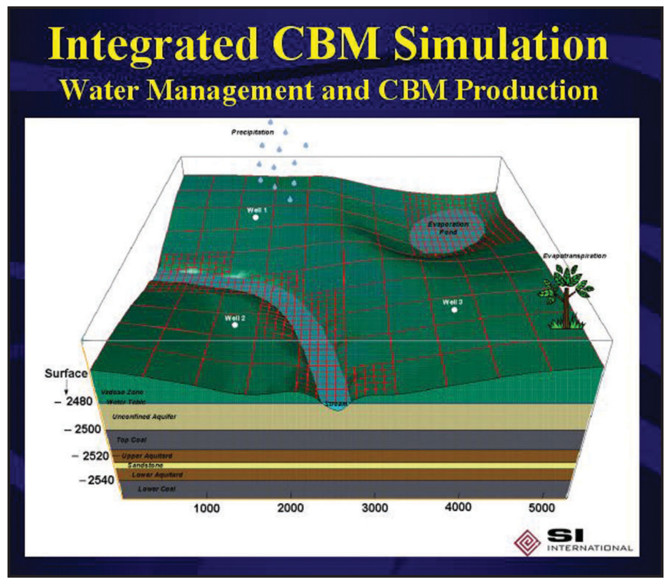
- Communication from the surface to the unsaturated sone to aquifer to the coal.
- A shallow coal with no confining layers.
- Fractures and faults connecting coal to the surface or near-surface.
- A dipping coalbed that outcrops at the surface.

If you recall the vertical cross section of the Powder River Basin, communication from the surface to the coal could be an issue.

My last topic is simulation. I merely present this because simulation is a useful tool to understand current production and forecast future production. It's also a way that we can link the two worlds I've kind of talked about, hydrology and the production of methane. The requirements for coalbed methane simulation are, multiphase water and methane production, dual porosity, a desorption isotherm, matrix diffusion of methane, and the transfer of methane from matrix to fracture.

Now, is a groundwater simulator appropriate for coalbed methane problems? Although a ground water simulator can represent water management very well, it may not be appropriate to handle multiphase flow, dual porosity, or both. And if a ground water simulator does have a desorption isotherm, it's not the appropriate type of function. Adsorbed gas should be a function of pressure, not concentration, but the isotherms in groundwater simulators are adsorbed concentration versus concentration in solution. Are petroleum simulators compatible for coalbed methane? Although a petroleum industry simulator may have all the requirments for CBM, it may not be able to handle the water management problem. It does not handle near-surface hydrogeology or disposal of produced water.

The next slide shows something that we propose that may link hydrology and the coalbed methane reservoir. The coal is the gray layers. The aquitards are the confining layers. An unconfined aquifer stretches up to the water table near the surface. A confined aquifer is located between the aquitards. This confined aquifer, shown as a sandstone, may interact with the coal seams depending on the extent to which these aquitards are continuous layers. Surface features integral to disposal of produced water, such as a stream and an evaporation pond, are also shown. Other sources and sinks such as precipitation and evapotranspiration, can be represented. In this integrated CBM simulation approach we can represent both surface



water disposal and issues related with the CBM reservoir including hydrogeology and methane production. Such an integrated approach may be a useful methodology to. examine fields such as the Powder River Basin where water management and CBM issues may be linked.

My conclusions are as follows: Coalbed methane is growing as a source for natural gas. The amount of produced water will increase as the number of wells increases. The hydrogeology is complex and can involve interaction of water in the cleats with the coal, interaction of neighboring aquifers with the coal, surface disposal of produced water, and interaction of produced water with the subsurface. Simulation can be a useful tool to investigate production and water management. And lastly, a method was developed that can provide coalbed methane and water management simulation in one package.

Thank you.

Federal, State, and Local Regulatory Framework for Permitting of CBM Development

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Coal Bed Methane (CBM) production has exploded upon the landscapes of mineral-rich Western states. Regulatory agencies with responsibility to preserve and protect natural resources both above and below the surface are scrambling to find effective measures for ensuring both the development of this valuable resource and the protection of other values placed at risk by such development.

Few of these agencies, however, have plans or programs specifically designed to address the special concerns posed by CBM production. Perhaps, the best example of the game of "catch-up" being played by land use management and regulatory agencies is in the Powder River Basin (PRB) where industry proposals now forecast the development of more than 50,000 CBM wells.

Thousands of those new wells will be on federal lands. This level of CBM development, however, was never addressed by the agencies charged with managing Wyoming's federal lands in either land use plans or environmental analyses.[1] The Bureau of Land Management (BLM) and the Forest Service (FS) are now preparing a new environmental impact statement (EIS) on CBM development in the PRB, but the draft EIS avows that the agencies' ability to limit or control CBM activity in the Basin is limited.

Oil and gas leases already have been issued. The underlying federal leases were issued based upon development scenarios for more "conventional" oil and gas operations, not CBM, but, the agencies acknowledge, it is just too late to revisit the issue of whether full-field CBM production is appropriate for lands in the PRB. According to BLM, an oil and gas lease grants the lessee the "right and privilege to drill for, mine, extract, remove, and dispose of all oil and gas deposits" in the lease lands, "subject to the terms and conditions incorporated in the lease."[2] "Once the land is leased, BLM no longer has the authority to preclude surface-disturbing activity, even if the environmental impact of such activity is substantial.[3]

In the State of Montana, where downstream impacts of CBM development in the PRB are being felt, a moratorium on the issuance of new CBM well permits is in place pending completion of a new statewide EIS. The draft was released in January 2002 as a joint effort of BLM and the State of Montana. It acknowledges that neither entity was prepared for the CBM deluge.[4]

The purpose of this article is to explore the regulatory framework currently in place governing CBM production on federal, state, and private lands in five states of the interior West: Colorado, Montana, New Mexico, Utah, and Wyoming.[5] The article begins with a discussion of the special land use and management rules that apply to government lands. The discussion then shifts to the state and local land use and environmental protection provisions applicable to CBM production on both public and private lands.

Federal lands

The current framework for approval and management of CBM activity on federal lands is governed by the agencies' fluid minerals[6] policies adopted pursuant to the Mineral Leasing Act of 1920 (MLA).[7] Lands managed by BLM, those of the National Forest System, as well as other lands owned by the United States, are available for CBM production under MLA.[8] BLM is the principal agency responsible for managing the mineral estate on all federal lands. Its lands and those of FS have been most impacted by CBM development thus far. Therefore, this discussion will focus on the regulatory structures of BLM and FS.

Multiple decisions regarding the availability of lands for leasing and the conditions of mineral production precede drilling for any type of natural gas on the federal mineral estate of BLM and FS. First, land use plans are developed in accordance with Federal Land Policy and Management Act (FLPMA)[9] and the National Forest

Management Act (NFMA).[10] Those land use plans should include a discussion of the impacts of anticipated land uses, including mineral extraction.[11] Second, an operator must lease the mineral estate from BLM in order to acquire the legal right to explore and develop any natural gas reserves. Third, the operator seeking to develop a field of natural gas (including CBM) wells, must file a plan of operations or Plan of Development (POD) with the BLM.[12] Finally, an operator must, for each well or group of wells, file an Application for Permit to Drill (APD) which must be approved by BLM and FS, if National Forest System lands are involved.

Each of these four stages requires compliance with the National Environmental Policy Act (NEPA)[13] including an assessment of reasonable alternatives and mitigation measures. However, the range of available alternatives and mitigation measures shrinks at each stage of this NEPA review. Once lands use plans are adopted and leases issued, the federal land management agencies lose the flexibility to deny mineral development or substantially lessen its impacts.

1. Land use planning

a. BLM land use plans

FLPMA Section 202 requires BLM to establish "land use plans," more commonly known as Resource Management Plans (RMPs),[14] and requires BLM to "manage the public lands under principles of multiple use and sustained yield in accordance with the land use plans developed."[15] An RMP establishes land uses, resource uses, resource goals and objectives, and the management practices necessary to meet FLPMA's multiple use objectives.[16] FLPMA regulations provide that the implementation of an RMP "is considered a major Federal action significantly affecting the quality of the human environment."[17] Thus, the RMP planning process triggers NEPA and requires the drafting of an EIS.

Pursuant to BLM>s current policy, that EIS should include a discussion of the potential environmental impacts that might result from future oil and gas activity within the resource area.[18] In order to do so, the agency is required to predict the "reasonably foreseeable development" that would flow from a decision to make lands available for fluid minerals production. The RMP should then reflect BLM's determination as to where oil and gas activity is appropriate and under what conditions that activity should be conducted.

FLMPA then requires all government actions that affect land governed by an RMP to conform to the RMP. Implementing regulations state that "[a]ll future resource management authorizations and actions, as well as budget or other action proposals to higher levels in the [BLM] and [the Department of the Interior], and subsequent more detailed or specific planning, shall conform to the approved [RMP]."[19] Conformity "means that a resource management action . . . be specifically provided for in the plan, or if not specifically mentioned, . . . be clearly consistent with the terms, conditions, and decisions of the approved plan or plan amendment."[20]

Pursuant to FLPMA and its implementing regulations, CBM production on BLM lands should only occur where such activities are consistent with the applicable land use plan. Unfortunately, in the PRB and elsewhere, BLM's RMPs often contain little or no discussion of CBM development. RMP decisions to make lands available for mineral leasing frequently were based upon reasonably foreseeable development scenarios for "conventional" oil and gas. BLM's continued reliance on these outdated RMPs remains a source of controversy for the agency.[21]

b. FS land use plans

Like RMPs, the Land and Resource Management Plans (LRMPs) prepared by FS pursuant to NFMA are supposed to delineate land uses and resource uses.[22] LRMPs also are binding on future FS management decisions. FS regulations specifically require that "all site-specific decisions, including authorized uses of land, must be consistent" with the applicable LRMP.[23] However, many LRMPs contain little or no information on any fluid minerals activities. In 1991, FS itself concluded that the majority of completed forest plans and accompanying EISs do not contain adequate information upon which to base oil and gas leasing decisions.[24] Since 1991, FS has been including a mineral leasing analysis in its scheduled revisions of LRMPs.[25] Until completion of revised LRMPs, however, FS has determined that the forest plan itself does not have to address any kind of mineral development in order for FS to conclude than CBM production is consistent with the plan's land management goals.[26]

2. Leasing

Between 35 and 40 million acres of federal land (onshore) currently are under lease for oil and gas development.[27] Pursuant to MLA, as amended by the Federal Onshore Oil and Gas Leasing Reform Act of 1987 (FOOGLRA)[28], leases on lands where the United States owns the oil and gas rights are offered competitively via oral auction at least quarterly. Their maximum size is 2,560 acres and the minimum bid is $2.00 per acre.

a. lease provisions

The Standard Lease Terms (SLTs) provide the lessee the right to use the leased land as needed to explore for, drill for, extract, remove, and dispose of oil and gas deposits under the leased lands.[29] This right is not unlimited. Federal environmental protection laws, such as the Clean Water Act (CWA)[30], Endangered Species Act (ESA)[31], and National Historic Preservation Act (NHPA)[32], apply to all lands and are included in the standard lease stipulations. If threatened or endangered species, objects of historic, cultural, or scientific value, or substantial unanticipated environmental effects are encountered during construction, all work affecting the resource can be halted. Surface-disturbing activities that would destroy or harm these species or objects are prohibited under the terms of all federal leases.[33]

SLTs also provide for some additional measures to minimize adverse impacts to surface resources. These include modifications to the siting or design of facilities, timing of operation, and specification of interim and final reclamation measures. SLTs, however, cannot require the lessee to relocate drilling rigs or supporting facilities by more than 200 meters, require that operations be sited off the leasehold, or prohibit new surface-disturbing operations for more than 60 days each year. The lease requires that the lessee meet stipulation conditions or avoid activities within all, or an identified part, of the leasehold.[34]

SLTs can be modified by special or supplemental stipulations attached to the lease.[35] Additional special stipulations can be developed specifically to meet resource concerns that cannot be mitigated by existing stipulations.[36]

b. nepa and leasing

According to the Supreme Court of the United States, NEPA sets forth a "national policy which will encourage productive and enjoyable harmony between man and his environment [and will] promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man."[37] NEPA, however, neither establishes substantive environmental standards, nor prescribes a regulatory program;[38] instead, it merely requires federal agencies to take a "hard look" at the environmental consequences of "major federal action[s] significantly affecting the quality of the human environment."[39]

Where an action qualifies as a "major federal action" having a significant impact on the human environment, NEPA dictates that the federal agency must prepare an environmental impact statement that enumerates:

- (i) the environmental impact of the proposed action,
- (ii) any adverse environmental effects which cannot be avoided should the proposal be implemented,
- (iii) alternatives to the proposed action,
- (iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
- (v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.[40]

If an agency is unsure of whether it must draft an EIS, it may prepare an environmental assessment (EA).[41] Based upon the EA's analysis and conclusions about the significance of the impacts of the proposed project, an agency must either issue a finding of no significant impact (FONSI)[42], thereby terminating the NEPA process, or prepare an EIS [43].

Two circuit courts of appeals have held that by conveying to the lessee some right to occupy the surface at the time of lease issuance, BLM has irretrievably and irreversibly committed federal resources resulting in a significant impact on the human environment and requiring preparation of an EIS.[44] There is a split in the circuits, however, with the United States Court of Appeals for the Tenth Circuit holding in *Park County Resource Council, Inc. v. U.S. Department of Agriculture*[45] that leasing alone poses no significant impact on the environment.[46] Although it has been suggested that these cases are reconcilable on their specific facts[47], they clearly represent distinctly different approaches to balancing the need for an early environmental analysis while the agency's full range of options are still open versus delaying the environmental analysis until the potential impacts can be more accurately predicted.

This schizophrenia concerning NEPA compliance prior to lease issuance persists, unresolved by BLM and FS. In response to the decisions in *Park County, Conner,* and *Sierra Club v. Peterson,* BLM issued Information Bulletin No. 92-198 announcing that: "[t]he simple rule coming out of the Conner v. Burford case is that we will comply with NEPA and ESA prior to leasing."[48] Notably, the IB fails to state whether that compliance will take the form of an EIS or an EA.

In theory, completion of a pre-leasing EIS has been integrated into BLM's resource management planning process.[49] The EIS prepared with the RMP is intended to satisfy NEPA requirements for issuing fluid mineral leases.[50] In practice, few of BLM's land use plans contain a detailed discussion of the potential environmental impacts resulting from mineral development. In the early 1990's, BLM completed a number of amendments to its existing land use plans intended to provide the necessary NEPA analysis to support oil and gas leasing decisions on BLM lands. Many of these plan amendments, however, projected only minimal levels of CBM exploration.[51]

c. Forest Service Compliance with NEPA Prior to Leasing

In FOOGLRA, Congress for the first time legislatively recognized that FS should play a significant role in oil and gas management decisions within the National Forests and expressly defined that role. While BLM is still primarily responsible for managing the federal mineral estate, FS has been delegated significant responsibilities for lease issuance and management of lease activities.[52] Specifically, FOOGLRA prohibits BLM from issuing leases on National Forest lands reserved from the public domain over the objection of FS.[53]

In regulations implementing FOOGLRA, FS established a two-tiered leasing analysis scheme as the basis for making its leasing consent decisions. First, FS conducts a "leasing analysis," which analyzes all lands under its jurisdiction that are legally available for leasing to determine which of those lands will be administratively available for leasing.[54] This leasing analysis may occur as part of a forest plan or through an independent study.[55] It identifies: (i) areas open to leasing without stipulations, (ii) areas open to leasing with stipulations, and (iii) areas administratively or legally closed to leasing.[56] In its leasing analysis, FS considers alternative availability scenarios, projects the reasonably foreseeable post-leasing activity under each alternative, and analyzes the reasonably foreseeable impact of each activity.[57] However, because a decision to make lands administratively available does not commit FS to authorize BLM to issue leases on those lands,[58] an EIS is not required.[59]

According to FS, the decision to commit to lease issuance is made in the second tier of analysis when FS makes a "leasing decision for specified lands."[60] Before consenting to lease issuance, FS confirms that an adequate NEPA analysis has been conducted and that lease issuance is consistent with the applicable forest plan.[61] FS ensures that appropriate stipulations, as determined in the leasing analysis, are included in the lease and, except where the lease is subject to an NSO stipulation, ensures that mineral operations are allowed somewhere on the lease.[62] Where sufficient NEPA documentation to support a leasing decision has not been prepared, FS conducts an additional environmental analysis. FS purposefully has refrained, however, from prescribing whether an EA or EIS will be prepared, concluding that the determination is to be made on a case-by-case basis.[63]

2. Drill permits

After land and resources are allocated in a land use plan and a particular parcel is leased, the final stage prior to drilling a CBM well is approval of an APD. NEPA review at this stage normally is limited to site-specific considerations not previously addressed in broader NEPA documents.[64]

The APD is submitted directly to BLM which distributes the APD to any affected surface management agency.[65] Prior to the enactment of FOOGLRA, BLM specified that an APD include a drilling plan which described both surface and subsurface components. The revised BLM regulations and FS regulations separate these into a "drilling plan" and a "surface use plan of operations,"[66] and describe generally the contents of each.[67] FS includes in its regulations a list of very general requirements for the protection of various resources, such as wildlife and wetlands.[68] Despite FOOGLRA's emphasis on the importance of reclamation, neither BLM nor FS rules contain specific terms and conditions governing surface reclamation[69], although FS does set out some general principles.[70]

Prior to approval of an APD, BLM will verify that the required performance bond is in place. In FOOGLRA, Congress directed the adoption of "such standards as may be necessary to ensure that an adequate bond . . . will be established prior to commencement of surface-disturbing activities on any lease, to ensure the complete and timely reclamation of the lease tract, and the restoration of any lands or surface waters adversely affected by lease operations after the abandonment or cessation of oil and gas operations on the lease."[71] BLM concluded that its existing minimum bond levels were adequate to comply with the congressional directive in FOOGLRA.[72] After proposing full-cost bonding, FS agreed with BLM's approach in its final regulations.[73]

BLM and FS may conduct an on-site inspection prior to issuance of an APD. One purpose of the on-site inspection is to identify the environmental consequences associated with drilling in a particular location. The on-site inspection could include surveys for cultural resources or threatened or endangered species. After the on-site inspection, the APD may be revised or site-specific mitigation may be added as Conditions of Approval to the APD, consistent with the applicable lease terms, for the protection of surface or subsurface resource values near the proposed activity. These may include adjusting the proposed locations of the well sites, roads, and pipelines; identifying the construction methods to be employed; and identifying reclamation standards for the lands.

3. Plans of development

In some instances, APD review is preceded by approval of a POD.[74] If an operator intends to develop a field of oil or gas rather than an individual well, BLM must review and approve a POD. Since CBM production normally requires many wells, POD approval is often necessary. NEPA review at the POD stage affords BLM an opportunity to examine the cumulative impacts of gas field production. At this stage, BLM can require, for example, consolidation of the infrastructure associated with CBM production. The roads, the gas and water pipelines, and the waste disposal facilities for multiple drilling rigs can be limited to specific areas or corridors on the lease. By doing so, BLM can reduce the industrial footprint on the landscape.

Application of other federal statutes

1. Endangered species act

ESA Section 7 requires that all federal agencies "insure that any action authorized, funded or carried out by such agency . . . is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of habitat of such species."[75] To satisfy this requirement, all federal agencies must consult with either the United States Fish and Wildlife Service (USFWS) or the National Marine Fisheries Service (NMFS) when any activity they authorize, fund, or carry out could affect listed species.[76] Once consultation has been initiated, the agency must not make any irreversible or irretrievable commitment of resources.[77] If a determination is made that proposed mineral operations will jeopardize an endangered or threatened species or its habitat, those operations must be halted or modified to avoid the harm.

In *Conner v. Burford*[78], the United States Court of Appeals for the Ninth Circuit required the Forest Service to include in mineral leases a prohibition on substantial development pending issuance of an adequate biological opinion.[79] USFWS regulations essentially now codify that approach.[80] ESA review is required at every stage of agency decision-making regarding CBM production.

2. The clean water act

Pursuant to section 313 of the Clean Water Act[81], federal agencies are required to ensure that their actions will not result in violations of state water quality standards (WQSs). In order to meet that obligation, federal agencies must address specifically compliance with those standards in agency decision documents.[82] Any BLM or FS decision regarding CBM production should include a discussion of state WQSs and adopt measures to ensure that the standards will be met.

A. SECTION 401

Section 401(a) of the CWA requires that any applicant for a federal license or permit which may result in any discharge into waters of the United States must provide to the permitting agency a certification from the state in which the discharge originates that any discharge will comply with applicable provisions of the CWA.[83] Without such certification, the applicant is ineligible to receive the license or permit.[84] A state certification may include "any . . . appropriate requirement of State law."[85] Although state law determines what requirements may be "appropriate" in a CBM APD, any requirements imposed by state certifications become permit conditions enforceable by BLM or FS. [86]

Section 401(a)(2) further provides that: "[u]pon receipt of such application and certification the . . . permitting agency shall immediately notify the {Environmental Protection Agency region} Administrator. . . . Whenever such a discharge may affect . .. the quality of the waters of any other State, the Administrator . . . shall so notify such other State, the . . . permitting agency, and the applicant."[87] This provision allows the "other state" to assess whether the discharge will affect the quality of its waters and object to any such discharge.[88] This provision may play an important role in areas where CBM discharges impact downstream states.[89]

B. SECTION 404

Activities that would impact waters of the United States from the placement of fill materials, such as road and/or pipeline construction across "navigable streams" or discharge structures in such streams, require compliance with the wetlands provisions of CWA Section 404.[90] A 404 permit must be issued by the Army Corps of Engineers.[91]

3. National historic preservation act

NHPA represents an effort to protect and preserve areas of historical and cultural significance. It provides authority for the National Register of Historic Places, a listing of historic sites and objects of national, state, or local significance. NHPA then requires that any federally–authorized undertaking must take into account the effect of the activity on any property listed or eligible for listing on the National Register.[92]

NHPA mandates that federal agencies seek information as appropriate, from consulting parties, other individuals, and organizations likely to have knowledge of, or concerns with, historic properties in the areas, and identify issues relating to the potential effects on historic properties; and gather information from Indian tribes to assist in identifying properties, included those located off tribal lands, which may be of religious and cultural significance to them.[93] The recommendations received as a result of this consultation, however, are advisory only.

So, while NHPA Section 106 is an effective tool in focusing attention on federal agency actions affecting historic or cultural resources, it does not prevent federal agencies from taking actions that ultimately harm those resources. NHPA Section 106 only requires that federal agencies comply with certain procedural requirements before issuing a lease or APD. It will not prevent BLM from issuing an APD that entails destroying cultural or historic resources. It does, however, require the agency to identify historic resources and explore alternative measures, in consultation with the State Historic Preservation Officer (SHPO) and others, that may mitigate or avoid whatever harm the project may have.[94]

According to BLM, avoidance of eligible sites is the preferred mitigation method.[95] However, "[w]here eligible sites cannot be avoided, adverse effects can be mitigated by implementation of approved data recovery treatment plans."[96]

Tribal lands

Leasing of unallotted or tribal lands on reservations is done pursuant to one of two acts: the Omnibus Indian Mineral Leasing Act of 1938[97] and the Indian Mineral Development Act of 1982.[98] Both require authorization from the Secretary of Interior via the Bureau of Indian Affairs (BIA) prior to lease issuance.[99] Because resource development on Indian lands generally requires federal agency participation, CBM production on the reservation is subject to a dual legal structure of federal and tribal law.[100] For example, NEPA compliance is required before BIA can approve a contract or lease for mineral operations on reservation lands. The consultation provisions of ESA Section 7 also apply to such undertakings in the vast majority of cases.

State lands

The western states own and manage an enormous amount of land. State lands in Colorado, Montana, New Mexico, Utah, and Wyoming are available for CBM production pursuant to leases issued by the state land boards.[101] The vast majority of these lands are grant lands.[102] These lands are managed according to the principle that they must be used to produce income for the grant fund for which they were given. Although some have questioned whether the principle is as strict as most western states interpret it[103], it remains the principle to which most state grant land managers adhere.[104] Nevertheless, the mineral leasing policies of several states indicate that CBM production on state lands are subject to conditions intended to provide some protection for environmental resources.[105]

State permitting requirements

Prior to commencing CBM operations on federal, state or privately owned lands, permits from state regulatory agencies must be obtained governing the locations of drilling facilities and the control of any pollutants associated with production.

1. State drilling permits

All of the states under consideration have adopted so-called "conservation" statutes. These acts originally were enacted to protect the opportunity of all owners to share in oil and gas production and prevent waste of the resource.[106] To accomplish these goals, the acts created oil and gas commissions[107] and authorized them to establish drilling units and provide for the location of permitted wells.[108] Over the years, the commissions' responsibilities have expanded. In most states, the commissions now have the authority to regulate the drilling, casing, plugging, and abandonment of wells. The commission may also be authorized to protect the rights of surface owners.[109] In 1984, the Colorado Oil and Gas Commission (COGCC) was directed to promulgate rules to protect the health, safety, and welfare of the general public with respect to oil and gas wells.[110] Ten years later, COGCC was charged to adopt measures to protect environmental resources.[111]

The state oil and gas commissions all require permits to drill that set out spacing requirements for drill pads, regulate disposal of wastes created by oil and gas operations (including injection of produced water), describe the standards for abandonment (including reclamation), and establish bonds.[112]

a. Colorado Oil and Gas Conservation Commission

The oil and gas industry in Colorado has been subject to state regulations since the 1915 creation of the office of the State Oil Inspector.[113] In 1951, the Oil and Gas Conservation Act established the Colorado Oil and Gas Conservation Commission.[114] Its original function was "to foster, encourage, and promote the development, production and utilization" of oil and gas.[115] COGCC focused on increasing production by preventing waste.[116]

In 1994, Senate Bill 94-177 refocused the power of COGCC expanding its directives beyond simply encouraging production.[117] COGCC must now "prevent and mitigate significant adverse environmental impacts on any air, water, soil, or biological resource resulting from oil and gas operations."[118] The Act gives COGCC the authority to "investigate, prevent, monitor, or mitigate conditions that threaten to cause, or that actually cause, a significant adverse environmental impact."[119]

Since 1994, COGCC has enacted regulations regarding water quality standards, practice and procedure, reclamation, safety, and financial security requirements.[120]

b. Montana

The Montana Board of Oil and Gas Conservation (MBOGC) was established in 1953 with the passage of the Montana Oil and Gas Conservation Act.[121] The Board consists of seven members, three of whom must be from the oil and gas industry, and two of whom must be landowners residing in oil- or gas-producing counties in the state.[122] Under Montana law, no oil or gas exploration, development, production, or disposal well may be drilled until MBOGC issues a drilling permit. The powers and duties of MBOGC in regulating oil and gas activities are defined in MONT. CODE ANN. ' 82-11-111. MBOGC serves three primary purposes: (1) to prevent waste of oil and gas resources; (2) to encourage maximum efficient recovery of the resource; and (3) to protect the right of each owner to recover its fair share of the oil and gas underlying its lands. In addition, MBOGC can take measures to prevent contamination of or damage to surrounding land caused by drilling operations. These measures include, but are not limited to, regulating the disposal of produced salt water and the disposal of oil field wastes.[123]

Montana has a state environmental policy act requiring its state agencies to complete environmental analyses similar to those required under NEPA.[124] Currently there is a moratorium on CBM development in Montana pending completion of an state environmental impact statement pursuant to Montana's "Little NEPA."[125]

C. NEW MEXICO OIL CONSERVATION DIVISION

N. M. STAT. ANN. '' 70-2-1 through 70-2-38 set forth the Oil and Gas Act which grants the Oil Conservation Commission and the Oil Conservation Division of the Energy, Minerals and Natural Resources Department authority over all matters relating to the conservation of oil and gas and the disposition of wastes resulting from oil and gas operations, including the protection of public health and the environment.[126]

D. UTAH BOARD OF OIL, GAS AND MINING

In Utah, regulation of oil and gas operations falls to the Utah Board of Oil, Gas and Mining[127] and its related technical and administrative agency, the Division of Oil, Gas and Mining.[128] The Board's powers include regulation and enforcement of operations related to drilling, testing, equipping, completing, operating, producing, and plugging wells; spacing and location of wells; and disposal of salt water and field wastes.[129] Pursuant to Rule 649-3-15: {t]he operator shall take all reasonable precautions to avoid polluting lands, streams, reservoirs, natural drainage ways, and underground water." The Board's rules encourage the development of "surface use agreements" with landowners but do not adopt statewide standards of reclamation.[130]

E. WYOMING OIL AND GAS CONSERVATION COMMISSION

The Wyoming Oil and Gas Commission (WOGCC) is comprised of the governor, the director of the office of state lands and investments, the state geologist, and two additional members from the public appointed by the governor.[131] WOGCC has the authority to require drilling, casing, and plugging of wells in order to prevent escape of oil or gas, the furnishing of a reasonable bond limited to plugging each dry or abandoned well, and monitoring of well performance.[132] WOGCC has the authority to regulate, for conservation purposes, the drilling, producing and plugging of wells, the shooting and chemical treatment of wells, well spacing, disposal of salt water and drilling fluids "uniquely associated" with gas exploration and development, and the contamination or waste of underground water.[133]

In addition, WOGCC has a duty to prevent the waste of natural gas and to keep it from polluting or damaging crops, vegetation, livestock, and wildlife.[134] WOGCC rules mandate that, "[t]he owner or operator shall not pollute streams, underground water, or unreasonably damage or occupy the surface of the leased premises or other lands."[135]

2. WATER DISPOSAL

Unlike conventional oil and gas operations, CBM production involves pumping large volumes of water from the ground in order to release the pressure that is trapping the methane in the coal seam. There are two primary methods of disposing of this water: surface discharge and injection.

Both of these disposal methods require additional permitting by state regulatory agencies. Surface discharges are subject to regulation under the Clean Water Act. Injection in governed by the Safe Drinking Water Act.

A. CWA

In 1972 Congress passed CWA[136] "to restore and maintain the chemical, physical, and biological integrity of the Nation's waters."[137] To achieve these goals, Congress mandated two key initiatives: 1) development of national, technology based effluent standards and treatment requirements for major categories of polluting activities; 2) adoption of water quality standards for rivers and lakes to protect actual and potential stream uses such as fishing and swimming. This approach was intended to provide two layers of protection for the nation's waters. Dischargers not only have to apply the requisite pollution control technology to meet technology-based limits but also have to provide whatever further treatment is necessary to meet in-stream water quality standards.

The state WQSs have several components, including water quality criteria designed to protect specific uses, anti-degradation provisions to protect the existing clean condition of state waters, and measures to restore polluted waters.

Water quality criteria are intended to protect designated uses, such as drinking water, agriculture, or cold water fisheries.[138] Water quality criteria can consist of numeric pollution limits (for example, "five micrograms of selenium per liter of water"), or narrative standards (for example, "no odor").[139] Where a water body has more than one designated use, the most stringent applicable criteria control.[140]

In addition to designated uses and water quality criteria, state standards must include anti-degradation requirements.[141] Anti-degradation rules require protection beyond water quality criteria. For example, where a river has quality better than that necessary to support fishable/swimmable uses, anti-degradation policy may preclude a new discharger from causing any lowering of in-stream water quality, even if such lowering of quality would not cause water quality criteria to be violated.[142]

Finally, the Act requires states to identify those waters for which technology-based limitations have not been sufficient to produce compliance with WQSs.[143] For such "water quality limited" waters, states must develop "total maximum daily loads" (TMDLs) for each pollutant for which standards are being violated.[144] The TMDL sets a maximum amount of the pollutant that the water body can receive daily without violating WQSs.[145] States must assign portions of the load to point and non-point sources along the water-body, limiting the allowed contribution from each category so as to ensure that standards will be attained and maintained.[146] Once all of the TMDL is assigned or "used up," no further discharges of the affected pollutant are allowed.[147]

To ensure that all components of state WQSs are achieved, CWA establishes the National Pollutant Discharge Elimination System ("NPDES"), under which it is illegal to discharge pollutants from a point source without a permit complying with the Act.[148] Any NPDES permit issued by a state must contain effluent limitations sufficiently stringent to ensure that WQSs will not be violated by the discharge.[149] Effluent limits must protect numeric and narrative water quality criteria and ensure compliance with anti-degradation requirements and any applicable TMDLs.[150] Where interstate waters may be affected, effluent limits must be sufficiently stringent to prevent violation of water quality standards in downstream states.[151]

CBM AND CWA

CWA regulations provide that "there shall be no discharge of waste water pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (i.e. produced water, drilling muds, drill cuttings, and produced sand)" without an NPDES permit.[152] CBM operations, due to the water produced and discharged by each well, require issuance of state NPDES permits.[153] While there are no technology-based effluent standards for CBM dischargers,[154] NPDES permits for CBM operations must impose effluent limitations sufficient to ensure that state WQSs will not be violated.

There is, however, little agreement on what those effluent limitations should be. The primary water quality concern for CBM production is the amount of salts contained in produced water. This level of salts often is measured by the sodium absorption ratio (SAR). In some states, such as Wyoming, there are no numeric standards for SAR in meeting water quality standards. Under current regulations in Wyoming, narrative guidelines typically say only that the SAR of CBM-produced water cannot degrade designated uses of surface water.[155] Montana has numeric water quality criteria for SAR in some watersheds, including many of those in the PRB.[156] Since the Montana watersheds are downstream, Wyoming's NPDES permits in the PRB must ensure compliance with Montana's WQSs. Montana and Wyoming currently are attempting to resolve the differences in their treatment of CBM discharges. The two states have entered into an interim memorandum of cooperation.[157]

B. THE SDWA

I. INJECTION OF PRODUCED WATER

The purpose of SDWA is to regulate contaminants in drinking water. Part C of the Safe Drinking Water Act establishes a regulatory program intended to ensure protection of underground sources of drinking water.[158] SDWA prohibits any underground injection unless authorized by permit or rule.[159] Regulations define five classes of injection wells according to the type of fluid they inject and where the fluid is injected.[160] CBM operations may require issuance of SDWA permits for Class II injection wells. Class II wells inject fluids either brought to the surface in connection with oil and gas operations or used to enhance recovery of oil or natural gas.[161] Colorado, Montana, New Mexico, Utah, and Wyoming all have primacy under SDWA Section 1425[162] to regulate Class II underground injection control (UIC) facilities. In these states, the issuance of Class II permits is regulated by the oil and gas commissions.[163] In general, operators are required to:

site the wells in a location that is free of faults and other adverse geological features;

drill to a depth that allows the injection into formations that do not contain water that can potentially be used as a source of drinking water;

use an injection pipe that has multiple layers for containment of potentially contaminating injection fluids; and monitor to ensure the integrity of the well.[164]

The primary objective of Class II injection wells is to isolate the produced water from any future use. The regulations governing Class II wells were designed to address the problem of extremely briny water extracted during conventional oil and gas operations. CBM, however, produces much more water than conventional oil and gas. Moreover, CBM-produced water is sometimes suitable in quality for agricultural or domestic use. It has been suggested that some CBM water should be re-injected into usable aquifers in order to avoid dewatering ground water aquifers impacted by CBM operations. Re-injection of produced water into usable aquifers would require compliance with more stringent regulations under SDWA governing Class V wells.

Thus far, BLM has rejected re-injection of CBM-produced water as an option for water disposal. The Montana Draft EIS summarily rejects any alternatives that would have required re-injection stating that such measures would be "counter productive."[165]

ii. Hydraulic Fracturing

Hydraulic fracturing (fracing) is utilized by CBM drillers to pump fluids into the coal seams to fracture the coal, to facilitate methane extraction.[166] In *Legal Environmental Assistance Foundation (LEAF) v. EPA*[167], plaintiffs claimed that the nearby use of hydraulic fracturing to extract CBM polluted their well waters and should have been regulated under the SDWA. Plaintiffs petitioned EPA to withdraw approval of Alabama's UIC program for exempting fracing from the SDWA's regulatory scheme. EPA refused to conduct a hearing on the petition, contending that fracing did not fall within the regulatory definition of underground injection. Plaintiffs appealed EPA's decision to the United States Court of Appeals for the Eleventh Circuit.

The court reversed EPA's decision. The court held that fracing fluids clearing fell within the SDWA's definition of "underground injection," stating that "the process of hydraulic fracturing obviously falls within this definition, as it involves subsurface emplacement of fluids by forcing them into cracks in the ground through a well."[168] Accordingly, the court granted the petition for review and remanded the matter to EPA.

In July of 2000, EPA published a notice in the *Federal Register* indicating that it is undertaking a nationwide study to the evaluate the environmental risks of fracing to underground sources of drinking water.[169] A final report has not been completed.

The LEAF decision may pose significant implications for CBM development in western states as well. For example, although the Wyoming Department of Environmental Quality (WDEQ) has an approved UIC program, WDEQ does not regulate the underground injection of hydraulic fracing fluids.

Local regulation of cbm

CBM operations must also comply with any applicable city or county ordinances governing their activities. Many communities, pursuant to local land use authority, have adopted regulations that may bear on CBM production. These regulations fall into two general categories: zoning and conditions of use. Zoning regulations designate those areas of the city or county that are open to CBM and other oil and gas facilities. Conditions of use place restrictions on the manner in which such facilities must operate.

Most local regulations accommodate oil and gas production in industrial and agricultural zones, requiring only that operators obtain special use, building, and road permits; paint production tanks; and keep the site weed-free.[170] Few local governments have adopted ordinances specific to CBM operations. However, some communities, in areas heavily impacted by CBM production, have attempted to improve their oversight of such operations.[171] Local land use regulations recently adopted in Las Animas County, Colorado, for example, required consideration of "noise levels, impacts on air and water quality, vibration and odor levels, fire protection and access requirements, visual impacts, wildlife impacts, and public safety."[172]

The central legal question concerning local regulation of CBM is whether these provisions are pre-empted by state and federal activities[173] in the field. The answer to this question varies from state to state depending on applicable law and regulation. The most extensive legal debate on this issue currently is taking place in the State of Colorado.

1. Colorado

In 1992, before the changes made in the Conservation Act by S.B. 94-177, the Colorado Supreme Court looked at the issue of state pre-emption of local government oil and gas production regulations in two cases. In *Board of County Comm'rs of La Plata County v. Bowen/Edwards Associates, Inc.*[174], operators challenged the county permit system that required an oil and gas facility to demonstrate the ability to comply with county regulations as to noise and nuisance mitigation measures, visual standards, wildlife mitigation, surface disturbance standards, and setback requirements. The Court first determined that both the County Planning Code[175] and the Local Government Land Use Control Enabling Act[176] gave La Plata County the authority to regulate land use aspects of oil and gas operations. It found that the Conservation Act did not explicitly pre-empt the land use authority of the county[177] nor did the "purpose and scope" of the Act demonstrate an implied intent to occupy the field of oil and gas regulation[178]. Finally, the Court examined whether an "operational conflict" existed between the state and local regulations. An operational conflict can arise "where the effectuation of a local interest would materially impede or destroy the state interest."[179] The Court remanded the case to the district court for further findings regarding whether such a conflict existed stating that "any determination that there exists an operational conflict . . . must be resolved on an ad hoc basis under a fully developed evidentiary record."[180]

In *Voss v. Lundvall Brothers, Inc.*[181], the Colorado Supreme Court analyzed a Greeley zoning ordinance that banned all oil and gas drilling within the city. The analysis in *Voss* was different than that in *Bowen/Edwards* because of Greeley's status as a "home rule" city.[182] Colorado's home rule cities hold a special constitutional status. Their authority to regulate land use issues within their territorial boundaries supercedes conflicting state statutes. However, if the matter is of purely state concern, state law governs. State statutes and home rule regulations can co-exist if the matter is of mixed local and state concern and there is no conflict with the state statute. The Court found that the regulation of oil and gas operations is one of mixed concern.[183] Noting that oil and gas pools are not confined by jurisdictional boundaries, the Court found that Greeley's total ban on drilling "materially impeded" significant state goals.[184] The Court noted that the decision was specific to a total ban on drilling and was not meant to imply that home rule cities were completely pre-empted from enacting regulations applicable to oil and gas production.

In 1994, the Colorado General Assembly expanded the mission of COGCC but recoiled from declaring that the legislature intended to pre-empt local regulation of oil and gas production. Instead, the legislature attached the following statement to S.B. 94-177: "[t]he General Assembly declares that the purpose of this act is to address the regulatory and enforcement authority of the Colorado Oil and Gas Conservation Commission and that nothing in this act shall be construed to affect the existing land use authority of local governmental entities."[185]

In 1996, La Plata County enacted new regulations governing certain aspects of the surface location of oil and gas wells. The Colorado Oil and Gas Association, the Colorado Petroleum Association, and COGCC immediately challenged the regulations, asserting that they were pre-empted by state law. The Colorado District Court for La Plata County disagreed, holding that "nothing in [S.B. 94-177] was intended to overrule *Voss* and *Bowen/Edwards* or delegate the land use authority historically delegated to local governments to [COGCC]."[186]

Following the decision in *La Plata County*, Las Animas County adopted similar regulations. COGCC amended its rule regarding permits to drill stating that: "[t]he permit-to-drill shall be binding with respect to any conflicting local governmental permit or land use approval."[187] Both Las Animas County's regulations and the COGCC rule have become the subject of legal challenges.[188]

2. Local regulation in Montana, New Mexico, Utah, and Wyoming

The adoption of comprehensive land use regulations governing oil and gas activity in La Plata and Las Animas Counties was precipitated by a proliferation of CBM development in Colorado. Thus far, however, the expansion of CBM production elsewhere has not resulted in the same kind of restrictive local regulation or the same legal battle over the application of local ordinances. There are no reported cases in the states of Montana, New Mexico, Utah, or Wyoming specifically addressing whether local regulation of oil and gas is pre-empted by state law. As CBM production extends its reach across the West, however, more cities and counties may decide that additional local regulation is appropriate and more legal challenges to the enforceability of such regulation undoubtedly will follow.

a. Montana

All counties and municipalities in the State of Montana have been granted expressly the power to adopt such local ordinances and zoning regulations necessary to promote the general welfare of their citizens. However, part of the zoning enabling legislation provides that "[n]o resolution or rule adopted pursuant to the provisions of this part . . . shall prevent the complete use, development, or recovery of any mineral, forest or agricultural resource by the owner thereof."[189] In interpreting this provision of state law, Montana courts have held that it does not preclude all local regulation of mineral processing or extraction, however, land use and zoning ordinances must provide that mineral resources can be effectively utilized.[190]

Based upon its land use and zoning authority, Gallatin County, Montana recently rejected issuance of a conditional use permit that would have allowed J.M. Huber to drill an exploratory CBM well east of Bozeman in the Bridger Canyon Zoning District.[191] Denial of Huber's permit currently is the subject of a legal challenge in federal court.

b. New Mexico

New Mexico courts consistently have upheld county and municipal authority to enact zoning and land use ordinances that are reasonably related to the promotion of the health, safety, and general welfare of their citizens.[192] In looking at whether adoption of a comprehensive act regulating other mineral operations pre-empted local ordinances, the New Mexico Supreme Court concluded that where neither the Act nor the regulations contain any mention of development issues with which local governments are traditionally concerned, such as traffic congestion, increased noise, compatibility of the use with the use made of surrounding lands, appropriate distribution of land use and development, and the effect of the activity on surrounding property values, state law does not pre-empt local regulation.[193]

c. Utah

The legislature has conferred upon cities and counties the authority to enact all measures necessary to promote the general health, safety, morals, and welfare of their citizens.[194] However, local governments are without authority to pass any ordinance prohibited by, or in conflict with, state statutory law.[195] An ordinance "is invalid if it intrudes into an area which the Legislature has pre-empted by comprehensive legislation intended to blanket a particular field."[196] The Utah Oil and Gas Conservation Act of 1983 states that one of its purposes is "to provide exclusive state authority over oil ad gas exploration and development as regulated under the provisions of this chapter. . . ."[197] It is unlikely, however, that exclusive state authority extends to matters of purely local concern such as traffic congestion, noise, and compatibility with surrounding uses.

d. Wyoming

Deep in the belly of the PRB, Johnson County, Wyoming has no comprehensive land use plan. In Converse County, mineral extraction is exempted from local regulations.[198] The City of Gillette's zoning regulations define oil, gas and mineral exploration and production activities as "permitted uses" within the agricultural or heavy industrial districts within the city.[199]

All Wyoming cities and counties are free to apply their zoning and planning authority under various provisions of Wyoming law.[200] The extent of that authority, however, may not be the same for cities and counties. Counties may "regulate and restrict the location and use of buildings and structures and the use, condition of use or occupancy of lands for residence, recreation, agriculture, industry, commerce, public use and other purposes in the unincorporated area of a county."[201] However, "no zoning resolution or plan shall prevent any use or occupancy necessary to the extraction or production of mineral resources."[202]

Conclusion

The operation of CBM facilities, whether located on federal, state, tribal or private lands, requires the authorization and oversight of numerous regulatory agencies. Drill permits must be issued by state and federal agencies. Permits for disposal of waste water and other pollutants must be obtained from federal or state departments of environmental quality. The facilities must be in compliance with city or county land use regulations designed to protect local environmental amenities. Few of these agencies, however, have plans or programs specifically designed to address the special concerns posed by CBM production. There are serious questions as to whether the regulatory programs in place to govern "conventional" oil and gas are adequate to address the environmental impacts associated with CBM production. Certainly the level of CBM development currently proposed was unanticipated. The amount of land that will be disturbed and the volume of water that will be dumped were never contemplated It remains to be seen whether the regulatory structure discussed here will prove adequate to the challenge now before it.

Notes

1. BLM, Draft Environmental Impact Statement for Oil and Gas Production in the Powder River Basin (PRB Draft EIS) (February 2002), 1–3 .

2. Leases within the PRB contain various stipulations concerning surface disturbance, surface occupancy, limited surface area, and timing restrictions. In addition, the lease stipulations provide for the imposition of such reasonable conditions, not inconsistent with the purposes for which the lease was issued, as the BLM or FS may require to protect the surface of the leased lands and the environment. None of these stipulations, however, would empower BLM or FS to deny all development activity because of environmental concerns. *See* 43 C.F.R. § 3101.1–2.

3. PRB Draft EIS at 2–51.

4. For example, BLM's 1994 *Oil and Gas Amendment of the Billings, Powder River, and South Dakota RMPs* supported only "limited [CBM] exploration and development" and included no "analysis for full-scale CBM development." BLM & Montana Dep't of Envt'l Quality, Draft Environmental Impact Statement for Oil and Gas Production in Montana (Montana Draft EIS) (January 2002), 1–1.

5. This article does not address water rights or air quality issues. Those issues are discussed in other papers in this volume.

6. For the past decade, CBM production has been encumbered by confusion over whether CBM is part and parcel of the coal seam or a separate fluid mineral like conventional natural gas. That issue on certain federal mineral estates was resolved by the United States Supreme Court in *Amoco Production Co. v. Southern Ute Indian Tribe*, 526 U.S. 865 (1999). At issue in the case were approximately 20 million acres of land patented under the Coal Lands Acts of 1909 and 1910. 30 U.S.C. § 81; 30 U.S.C. §§ 83–85. These patents conveyed the surface estate and all underlying minerals to the patentee except the "coal" which the United States reserved. Southern Ute involved a 1938 transfer by the United States to the tribe of title to reserved lands, including lands patented under the 1909 and 1910 Acts. The issue in *Southern Ute* was whether the reservation of "coal" to the United States upon granting the land patents included CBM, thereby conveying the CBM rights to the Southern Ute Tribe in the 1938 conveyances, or if the CBM rights went to Amoco, the holder of a valid oil and gas lease. The Court, finding that "coal is coal" and "gas is gas," held that the reservation of "coal" under the Coal Lands Acts of 1909 and 1910 did not include CBM, overruling a Tenth Circuit decision holding that it did.

7. 30 U.S.C. §§ 181–287 (1994). This law removed coal, oil, gas, oil shale, and four chemical minerals from the location system of the General Mining Law and provided that they could be obtained from federal lands only by leasing. The United States Supreme Court has often affirmed that the federal government has broad discretion whether or not to grant mineral leases. *See, e.g., Udall v. Tallman*, 380 U.S. 989 (1965).

8. Oil and gas operations can also take place on other federal land types—wildlife refuges, national seashores, and in limited areas in the National Park System. 43 C.F.R. § 3100.0-3(g)(4). Federal lands next to active oil and gas development, even those not normally available for other types of private commercial activity, may be leased if federal oil and gas reserves could be drained by operations on adjacent lands. *See* 43 C.F.R. § 3100.0-3(d).

Recent amendments to the National Wildlife Refuge Act placed additional limits on the availability of Refuge System lands for uses other than wildlife such as oil and gas operations. Such uses may be prohibited not only when incompatible with the National Wildlife Refuge System mission, but also when they would interfere with wildlife-dependent recreational uses. 16 U.S.C. § 668dd.

9. 43 U.S.C. §§ 1701–82.

10. 16 U.S.C. §§ 1600–14.

11. Congress enacted FLPMA to provide BLM with comprehensive statutory guidance for administering the public lands. FLPMA defines public land as "any land owned by the United States within the several States and administered by the Secretary of the Interior through the [BLM], without regard to how the United States acquired ownership." 43 U.S.C. § 1702(e).

12. Since the issuance of the Record of Decision (ROD) for production in the Wyodak resource area, BLM has been requiring that CBM projects be sub-

mitted as Plans of Development (POD). PRB Draft EIS at 1–7. A POD is a group of wells and their supporting infrastructure (e.g., roads, pipelines, power lines, water discharge points, booster stations, and compressor stations) for a given geographic area or sub-watershed.

13. 42 U.S.C. §§ 4321-4370b.

14. 43 U.S.C. § 1712(a).

15. *Id.* § 1732(a).

16. 43 C.F.R. § 1601.0-5(k) (1)-(8).

17. *Id*. § 1601.0-6.

18. BLM HANDBOOK No. 1624-1. For a discussion of the potential environmental impacts that should be addressed by NEPA documents, see *Preserving Our Public Lands* authored by Thomas F. Darin and Travis Sills in 2002. Copies are available from the Wyoming Outdoor Council.

19. *Id.* § 1610.5-3(a).

20. *Id*. § 1601.0-5(b).

21. The Interior Board of Land Appeals recently ruled that BLM may not rely on RMPs and other environmental addressing only the impacts of conventional oil and gas to support CBM activities. *Wyoming Outdoor Council, et al.,* 156 IBLA 347 (2002).

22. 36 C.F.R. § 219.7.

23. *Id*. § 219.10.

24. United States General Accounting Office, FEDERAL LAND MANAGEMENT: BETTER OIL AND GAS INFORMATION NEEDED TO SUPPORT LAND USE DECISIONS (1990) at 36–37.

25. *See, e.g.,* FS, Draft Environmental Impact Statement for the Proposed Revised Rio Grande National Forest Land and Resource Management Plan (1995) at 1–8.

26. 36 C.F.R. § 228.102(d); *see also* 55 *Fed. Reg.* 10, 423, 10,430 (March 24, 1990).

27. See BLM, 2000 Public Land Statistics at Tables 3–13 to 3–15.

28. Pub. L. No. 100-203, 101 Stat. 1330-256 (1987).

29. The standard lease terms are contained in Form 3100-11, Offer to Lease and Lease for Oil and Gas, United States Department of the Interior, BLM, June 1988 or later addition.

30. 33 U.S.C. §§ 1251–1387.

31. 16 U.S.C. §§ 1531–44.

32. 16 U.S.C. §§ 470–470j.

33. The agencies commonly use Lease Notices (LNs) or Notices to Lessees (NTLs) to identify the potential for the occurrence of these protected resources on any given lease. For example, BLM applies two LNs to leases in the PRB. PRB Draft EIS at 5–6.

34. All leases are subject to regulations and formal orders of the Secretaries of the Interior and Agriculture in effect at the time of issuance.

35. 43 C.F.R. § 3101.1-2-3101.1-4.

36. These special stipulations include:

No Surface Occupancy (NSO)—Neither exploration nor production facilities are permitted on the leasehold.

Controlled Surface Use (CSU)—Surface occupancy and use are permitted but are restricted to mitigate effects to particular resources. The CSU stipulation provides for mitigation measures that would not normally be met by relocating the drilling site the 200 meters provided by SLTs.

Timing Limitations (TL) — Construction activities are restricted or prohibited during certain periods to protect resources. The TL stipulation provides for mitigation measures that would not normally be met by delaying surface-disturbing operations for the 60 days provided by SLTs.

37. 42 U.S.C. § 4331.

38. *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332 (1989).

39. 42 U.S.C. § 4332(2)(C).

40. *Id*.

41. 40 C.F.R. §§ 1501.3, 1508.9, 1507.3.

42. *Id*. § 1508.13.

43. *Id.* § 1502.1.

44. *Sierra Club v. Peterson,* 717 F.2d 1409 (D.C. Cir. 1983); *Conner v. Burford*, 848 F.2d 1441 (9th Cir. 1988).

45. F.2d 609 (10th Cir. 1987).

46. Colorado, New Mexico, Utah, and Wyoming fall within the jurisdiction of the Tenth Circuit.

47. *See, e.g.,* Mansfield, Through the Forest of Onshore Oil and Gas Leasing Controversy Toward a Paradigm of Meaningful NEPA Compliance, 24 LAND & WATER L. REV. 85 (1989).

48. BLM, Information Bulletin No. 92-198 (1992) at 1.

49. BLM's handbook on oil and gas leasing states that "[e]ligible lands are available for leasing when all statutory requirements and reviews, including compliance with [NEPA] have been met. The BLM objective is to place reliance on land-use planning and associated NEPA analyses, conducted in accordance with the supplemental program guidance for energy and mineral resources (see .. . Handbook 1624-1)." BLM HANDBOOK No. H-3101-1 at 1.

50. BLM HANDBOOK No. H-1624-1 at I.B.2.

51. *See, e.g.,* BLM, Oil and Gas Amendment of the Billings, Powder River, and South Dakota Resource Management Plans (1994):

The Reasonable Foreseeable Development projections can accommodate the drilling of test wells and initial small-scale development of CBM. The extension of the nonconventional fuels tax credit for wells drilled before December 31, 1993, should generate some activity in the planning area. This amendment does not contain either a hydrologic analysis of the RFD area or an environmental study of the impacts of building major pipeline systems.

52. Prior to FOOGLRA, FS took the position that it had "no statutory responsibility for issuing or supervising prospecting permits or leases" on National Forest lands reserved from the public domain. FOREST SERVICE MANUAL § 2822.04 (1990).

53. 30 U.S.C. § 226(h). The BLM regulations broaden FS' role by providing that FS consent is required for leasing on all national forest lands regardless of

whether the lands are acquired or reserved from the public domain. 43 C.F.R. §§ 3101.7-1, 3101.7-2(b). Although FOOGLRA would seem to allow BLM to go forward with leasing proposals when FS simply fails to act on lease proposals, the BLM regulations require affirmative consent from FS. 43 C.F.R. § 3101.7-1.

54. 36 C.F.R. § 228.102.

55. *Fed. Reg.* at 10,429.

56. 36 C.F.R. § 228.102(c).

57. 36 C.F.R. § 228.102(c)(21)-(4).

58. 55 *Fed. Reg.* at 10,428.

59. If there is a conflict between the rights conveyed by an oil and gas lease and a subsequently adopted LRMP, FS may choose to enforce the new forest plan, recognizing that this may subject the government to appropriate legal action by the lessee, or FS may choose to enforce the forest plan that was in effect when the lease was issued. 55 *Fed. Reg*. at 10,435.

60. 36 C.F.R. § 228.102(e).

61. 36 C.F.R § 228.102(e)(1). If the proposal is inconsistent with the forest plan, the plan must be amended or FS must deny leasing consent. 55 *Fed. Reg.* at 10,430. FS may also determine that lease issuance would be inappropriate even though it would be consistent with the forest plan. *Id.*

62. 36 C.F.R. §§ 228.102(e)(2) and (3).

63. *See* 55 *Fed. Reg.* at 10,426, 10,431.

64. APD NEPA documents are often "tiered" to EISs or EAs prepared in conjunction with land use planning or lease issuance. Tiering is used by an agency when the impacts covered by a proposed decision have been addressed in a prior NEPA document. Tiering is only appropriate when, "[a] current proposed action previously was proposed and analyzed (or is part of an earlier proposal that was analyzed); resource conditions have not changed; and there is no suggestion by the public of a significant new and appropriate alternative." BLM, Instruction Memorandum No. 99-149 (1999) at 1.

65. 55 *Fed. Reg*. 22814, 22,832–33 (June 17, 1988).

66. 43 C.F.R. § 3162.3-1(d); 36 C.F.R. § 228.106(a).

67. For example, a BLM surface use plan of operations shall include "the road and drillpad location, details of pad construction, methods for containment and disposal of waste material, plans for reclamation of the surface. . . ." 43 C.F.R. § 3162.3-1(f). FS requires similar information. *See* 36 C.F.R. § 228 Appendix A to Subpart E.

68. 36 C.F.R. § 228.108.

69. FOOGLRA mandates regulation of surface disturbance and directs that BLM and FS "shall determine reclamation and other actions in the interest of conservation of surface resources." 30 U.S.C. § 226(g).

70. 36 C.F.R. § 228.108(g). In response to a comment on this point, BLM noted in the rulemaking preamble that reclamation standards are more properly addressed on a site-specific basis. 53 *Fed. Reg*. at 22,832.

71. 30 U.S.C. § 226(g).

72. 53 *Fed. Reg.* at 22,821. Current bond requirements are as follows: $10,000 per lease, 43 C.F.R. § 3104.2; $25,000 covering all lease and operations in any one state, *id.* § 3104.3(a); or $150,000 covering all leases and operations nationwide, *id.* § 3104.3(b).

73. 36 C.F.R.. § 228.109. FS does authorize a bond increase or separate bonds if the agency concludes that the existing BLM bond will not ensure complete and timely reclamation. 36 C.F.R. § 228.109(a).

74. Exploratory APDs may precede POD approval.

75. 16 U.S.C. § 1536(a)(2).

76. *Id.*

77. *Id.* § 1536(d).

78. 848 F.2d 1441 (9th Cir. 1988), *cert. denied*, 489 U.S. 1012 (1989).

79. *Id*. at 1455.

80. 50 C.F.R. § 402.14(k).

81. 33 U.S.C. § 1323.

82. *See National Wildlife Federation v. U.S. Army Corps of Eng'rs,* 132 F. Supp. 876 (D. Ore. 2001).

83. 33 U.S.C. § 1341(a)

84. *Id*.

85. *Id*. § 1341(d)

86. *Id*.

87. 33 U.S.C. § 1341(a)(2).

88. *Id*.

89. *See* Montana Draft EIS at 4–29.

90. 33 U.S.C. § 1344.

91. General Permit No. 404 covers such "fill" activities. *See* 33 C.F.R. Part 320; 40 C.F.R. Part 230.

92. 16 U.S.C. § 470(f).

93. 36 C.F.R. §§ 800.5, 800.6. BLM issuance of an oil and gas lease is an undertaking within the meaning of NHPA. BLM Director Opinion No. M 36928 (November 24, 1980). BLM approval of an APD is a federal undertaking within the meaning of NHPA. Solicitor's Opinion, Legal Responsibilities of BLM for Oil and Gas Leasing and Operations on Split Estate Lands, April 1988.

94. *See* 36 C.F.R. Part 800.

95. PRB Draft EIS at 4–226.

96. *Id.*

97. 25 U.S.C. §§ 396a–396g.

98. *Id*. §§ 2101–2108.

99. The 1982 Act was intended to provide increased flexibility for the tribes to conduct their own lease negotiations.

100. Although states have actively sought environmental jurisdiction over the reservations, these efforts have been largely rebuffed by EPA and the courts. *See, e.g., Washington v. EPA*, 752 F.2d 1465, 1469–70 (9th Cir.1985) (upholding EPA's refusal to permit state regulatory program to operate on Indian lands). *See generally* Judith V. Royster & Rory Snow Arrow Fausett, Control of the Reservation Environment: Tribal Primacy, Federal Delegation, and the Limits of State Intrusion, 64 WASH. L. REV. 581 (1989) (providing detailed information on jurisdictional conflicts over environmental regulation); Charles F. Wilkinson, Cross-Jurisdictional Conflicts: An Analysis of Legitimate State Interests on Federal and Indian Lands, 2 UCLA J. ENVTL.L. LAW & POL'Y 145 (1982).

101. *See, e.g.,* MONT. ADMIN. R. 36.25.103 (2001); UTAH ADMIN. CODE R652-20-100 (2001); WY ADC LAND LC Ch. 6 § 5 (2001).

102. Every state entering the Union since 1803 has received lands from the federal government for the support of public schools. For example, the 1875 Enabling Act for the Territory of Colorado, 18 Stat. 474 (1875), authorizing the admission of Colorado as a state provided that two sections of every township would be granted for the support of common schools.

103. Sally K. Fairfax et al., The School Trust Laws: A Fresh Look at Conventional Wisdom, 22 ENVTL. L. REV. 797 (1992).

104. A letter produced by the State of Wyoming Office of State Lands and Investments, *see* Letter from Harold D. Kemp, Assistant Director, Wyoming Office of State Lands and Investments, to Wyoming Coal Bed Methane Operators (November 18, 1999), unabashedly encourages CBM development on state sections (marked on state land status maps with blue shading). The letter informs producers that due to higher permitting costs for federal wells, and the application of NEPA and other laws, CBM operators can obtain a better return on investment if they drill on largely unregulated state sections. *Id*. The letter asks CBM operators "to take another look at the blue squares" on the Wyoming Land Status Map, and "fill them in" with CBM wells in order to "get the biggest bang for your drilling buck." *Id.*

105. Colorado has amended the provisions of its Constitution with respect to grant lands, eliminating the requirement that the state manage these lands "in such a manner as will secure the maximum possible amount therefore" and substituting an obligation to "produce reasonable and consistent income over time." Colorado Const. art. 9, § 10. *See Branson School Dist. RE-82 v. Romer*, 161 F.3d 619 (10th Cir. 1998) (upholding the amendment). Colorado has also created a "Stewardship Trust" of 300,000 acres that must be managed to "protect and enhance the beauty, natural values, open space, and wildlife habitat thereof." *Id.* In Montana, the Trust Land Management Division's Minerals Management Bureau must comply with the Montana Environmental Policy Act (MEPA), MONT. CODE ANN. §§ 82-11-701 to 306, before issuing oil and gas leases. *See also* UTAH ADMIN. CODE R652-20-2200 (3)(a), (b); R850-20-2200(3)(a), (b) (Utah rules authorizing the inclusion in state leases of provisions requiring surveys for biologic and cultural resources and mitigation of adverse impacts).

106. *See, e.g.,* COLO. REV. STAT. § 34-60-116(1).

107. COLO. REV. STAT. § 34-60-104.

108. COLO. REV. STAT. §§ 34-60-116(1), 43-60-116(3).

109. *See, e.g.,* COLO. REV. STAT. §§ 34-60-106(1)(c), 34-60-106(3.5).

110. COLO. REV. STAT. §§ 34-60-107(10), 43-6-107(11).

111. COLO. REV. STAT. § 34-60-106(2)(d).

112. The amount the bonds is often linked to the depth of the wells. *See, e.g.*, N.M. ADMIN. CODE tit. 19, § 15.3.101 (2001); UTAH ADMIN. CODE R649-3-1, WOGCC Rules, ch.2, § 4 (2001).

113. 1915 Colo. Sess. Laws 367.

114. 1951 Colo. Sess. Laws 250.

115. *Id.*

116. *Id.*

117. COLO. REV. STAT. § 34-60-102(1).

118. COLO. REV. STAT. § 34-60-106(2)(d).

119. COLO. REV. STAT. § 34-60-124(4).

120. *See, e.g.,* COGCC Rules 324A, 701, 703, 1001–04 (2001).

121. MONT. CODE ANN. § 82-11-101.

122. MONT. CODE ANN. § 2-15-3303.

123. MBOGC regulations are located in Title 36, Chapter 22 of the Administrative Rules of Montana.

124. MONT. CODE ANN. § 75-1-201.

125. Montana Draft EIS at 1–1.

126. 19 N.M. ADMIN. CODE tit. 19, § 15.1.12.

127. UTAH. CODE ANN. § 40-6-4.

128. *Id.* § 40-6-15.

129. *Id.* § 40-6-5(3).

130. UTAH ADMIN. CODE R649-3-34.

131. WYO. STAT. § 30-5-103(a).

132. *Id*. § 30-5-104(d)(i). Bonding requirements cover only plugging. They do not address reclamation.

133. *Id*. § 30-5-104(d)(ii).

134. *Id*. § 30-5-121.

135. WOGCC Rules ch. 4, § 1(ff).

136. 33 U.S.C. §§ 1251-401.

137. 33 U.S.C. § 1251(a).

138. 33 U.S.C. § 1313(c)(2)(A); 40 C.F.R. § 131.11(a)(1).

139. 33 U.S.C. § 1314(a).

140. 40 C.F.R. § 131.11(a)(1).

141. 40 C.F.R. § 131.12.

142. 40 C.F.R. § 131.12(a)(2).

143. 33 U.S.C. § 1313(d)(1)(A).

144. 33 U.S.C. § 1313(d)(1)(C).

145. *Id.*

146. 40 C.F.R. § 130.7.

147. 33 U.S.C. § 1313(d)(1)(C). A court order currently prohibits Montana from issuing any new NPDES permits or renewals that would increase permitted discharges until all necessary TMDLs are established. *Friends of the Wild Swan, Inc. v. U.S.E.P.A.*, 130 F.Supp.2d 1204 (D. Mont. 2000). In areas impacted by CBM development in the PRB, additional operations may be delayed unless non-discharging options are employed. Montana Draft EIS at HYD-8.

148. 33 U.S.C. §§ 1311(a), 1342.

149. *Id*.

150. 33 U.S.C. § 1342(a)(1); *see also PUD No. 1 of Jefferson County v. Washington Dep't of Ecology*, 114 S. Ct. 1900, 1910–11 (1994).

151. *See Arkansas v. Oklahoma*, 503 U.S. 91, 104–6 (1992).

152. 40 C.F.R. § 435.32.

153. 33 U.S.C. §§ 1251–1387. Section 301 of the Act makes "the discharge of any pollutant by any person . . . unlawful." *Id.* 1311(a). Section 402 allows for the discharge of a pollutant by permit as long as existing water quality uses are not impaired. *Id*. § 1342(a). "Discharge" is defined as the addition of any pollutant from a "point source." 40 C.F.R. § 122.2. "Point Source" in turn is defined to include any "discernable, confined, and discrete conveyance, including but not limited to, any pipe. . . . " *Id*. "Pollutant" is defined as "dredged spoil, solid

waste, . . . and industrial, municipal, and agricultural waste discharged into water." *Id*. CBM water with dissolved solids and minerals contains pollutants.

It is important to note that some state CWA programs provide for a general permit for certain oil and gas operations. *See, e.g.,* Montana Draft EIS at HYD-13.

154. Under CWA Section 402, EPA is preparing a technical and economic analysis to assess disposal options for water that is produced as part of the CBM extraction process. This analysis will support the determination of effluent limitations that represent Best Available Technology Economically Achievable (BACT) for CBM produced waters. Montana Draft EIS at 1–10.

155. *See* PRB Draft EIS at 4–43.

156. Montana Draft EIS at 4–29.

157. *Id*. at HYD-9 to HYD-11.

158. 42 U.S.C. § 300hh-8.

159. 40 C.F.R. § 145.11(a)(5).

160. 40 C.F.R. § 144.6.

161. *Id*. § 144.6(b).

162. 42 U.S.C. § 300h-4.

163. Injections of other fluids or injections into drinking water aquifers normally are permitted by state departments of environmental quality. *See, e.g.,* 56 *Fed. Reg*. 9408-22 (March 6, 1991).

164. SDWA prohibits EPA from prescribing requirements that interfere or impede the underground injection of brine or other fluids that are brought to the surface in connection with oil and gas production unless the requirements are essential to assure that injection will not endanger an underground source of drinking water. 42 U.S.C. § 300(h)(b)(2).

165. Montana Draft EIS at 2–2.

166. *See Legal Env'l. Assistance Foundation v. EPA*, 118 F.3d 1467, 1470 (11th Cir. 1997) (*quoting* Thomas E. Sexton & Frank Hinkle, State Oil and Gas Board, Oil and Gas Report 8B: Alabama's Coalbed Gas Industry, at 12–15 (1985)).

167. 118 F.3d 1467.

168. *Id*. at 1474–75.

169. 65 *Fed. Reg*. 45774-75 (July 25, 2000).

170. *See, e.g.,* City of Gillette, Wyoming Land Use Regulations.

171. *See, e.g.,* Oil and Gas Regulations of Las Animas County, Colorado as originally adopted in 2001.

172. *Id.* § 1.10(b).

173. Zoning regulations, for example, are not applicable to CBM facilities located on federal lands within the boundaries of a city or county planning area. *See California Coastal Comm'n v. Granite Rock Co.*, 480 U.S. 572, 587 (1987).

174. 830 P.2d 1045 (Colo. 1992).

175. COLO. REV. STAT. § 30-28-101.

176. COLO. REV. STAT. § 29-20-101.

177. 830 P.2d at 1057.

178. *Id*. at 1058.

179. *Id.*

180. *Id*. at 1060.

181. 830 P.2d 1061 (Colo. 1992).

182. A home rule city is created by and obtains powers directly from the state constitution. The Home Rule Amendment gives such cities the "right of self-government in both local and municipal matters," Colo. Const., art. 20, § 6, and provides that a city ordinance "shall supercede within the territorial limits" a state law when there is a conflict, *id.* If a matter is of purely local concern, the authority of the home rule city to regulate the issue supercedes any state authority.

183. 830 P.2d at 1067.

184. *Id.* at 1068.

185. COLO. REV. STAT. § 34-60-102.

186. *Colorado Oil and Gas Assoc. v. Bd. of County Comm'rs of La Plata County,* 98-CV-429, (March 2, 2001).

187. COGCC Rule 303(a).

188. Legal challenges to Las Animas County's oil and gas regulations were recently settled. The County agreed to amend its regulations significantly. E-mail conversation with Gwen Lachelt, Oil and Gas Accountability Project (May 14, 2002).

189. MONT. CODE ANN. § 76-2-209 (applicable to county zoning). The chapter on municipal planning contains a nearly identical provision, MONT. CODE ANN. § 76-1-113, which states that "[n]othing in this chapter shall be deemed to authorize an ordinance, resolution, or rule that would prevent the complete use, development, or recovery of any mineral, forest, or agricultural resource by the owner thereof."

190. *Missoula County v. American Asphalt, Inc.*, 701 P.2d 990 (1985).

191. *Bozeman Chronicle* (January 12, 2002). Elsewhere in the County, however, outside the zoning district, local authorities have no control over CBM activities.

192. *Battaglini v. Town of Red River*, 669 P.2d 1082 (N.M. 1983); *Temple Baptist Church v. City of Albuquerque*, 646 P.2d 565 (N.M. 1982).

193. *See, e.g., San Pedro Mining Corp. v. Bd. of County Comm'rs of Sante Fe County*, 909 P.2d 754 (N.M. 1996).

194. UTAH. CODE ANN. §§ 10-8-84, 17-5-77.

195. *State of Utah v. Hutchinson*, 624 P.2d 1116, 1121 (Utah 1980).

196. *Id.*

197. UTAH. CODE ANN. § 40-6-1.

198. Converse County Land Use Plan.

199. City of Gillette Land Use Regulations.

200. WYO. STAT. §§ 15-1-601, 18-5-201.

201. *See River Springs, L.L.C. v. Bd. of County Comm'rs of the Teton County*, 899 P.2d 1329 (Wyo. 1995).

202. WYO. STAT. § 18-5-201.

COALBED METHANE AND PUBLIC WILDLANDS: HOW MUCH AND AT WHAT COST?[1]

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The Wilderness Society is a 175,000-member national conservation group that focuses specifically on public land management issues. The Wilderness Society's research department has been actively involved in the analysis of energy policy, including a GIS mapping assessment of the oil and gas potential of national forest roadless areas and national monuments managed by the Bureau of Land Management (BLM). Our results were presented in congressional testimony in spring 2001 (http://www.wilderness.org/newsroom/rls051701.htm). In April 2002 we presented additional analysis and recommendations to Congress on methods for assessing the oil and gas potential of western public lands (see www.wilderness.org/eyewash/legislation.htm). The specific results for coal-bed methane presented in this paper derive directly from the energy research completed by The Wilderness Society since January 2001.

Our paper begins with background terminology in order to establish economically recoverable energy resources as the policy-relevant measure for evaluating coal-bed methane (CBM) development scenarios. We provide estimates on the amount of CBM located in public wildlands, focusing on roadless areas on our national forest and BLM-managed national monuments, followed by an examination of the economic costs from CBM extraction—costs that typically are excluded from economic analyses. We close the paper with a short discussion on access to energy resources on public land and the relationship between economic costs and the sustainable scale of CBM development, and end with recommendations on the appropriate use of taxpayer subsidies in our emerging energy policy.

Background

We begin by noting the distinction between discovered and undiscovered resources. If resources are discovered and if they're economical to extract, they are classified as reserves. Gas reserves are, by definition, profitable to extract (Attanasi 1998). At this point, most of the political debate by the oil and gas industry and the Bush administration has been about access to undiscovered oil and gas, rather than access to already discovered oil and gas in reserve. Currently in reserve and in growth of those reserves, we have about 22 years of gas supply for the U.S. That means that, without drilling another exploratory well, we could be completely dependent on our domestic gas reserves for 23 years. With investments in conservation and efficiency, our expected gas reserves could last twice as long.

The scientists at the U.S.Geological Survey (USGS) also classify gas as conventional or unconventional based on the technology used during extraction. Conventional gas is gas that can be extracted using conventional technology, while unconventional gas cannot be produced with conventional technology. An energy policy that relies heavily on subsidies to accelerate production of unconventional gas may be pushing this gas out to market before "environmentally friendly" technology can be fully developed. The two main unconventional gases are coalbed methane and continuous-type gas also called tight sands gas. While this conference focuses on coalbed methane, it is important to remember the current push to drill for tight gas, the other unconventional gas. The USGS estimates that there is approximately five times more tight gas in the west than coalbed methane, and the dense drilling pattern required to extract tight gas has its own significant environmental impacts. It is therefore vital, when examining environmental impacts at multiple spatial scales, that the cumulative impacts from all forms of energy production be fully accounted for in the analysis.

Mean estimates of economically recoverable CBM is the policy-relevant measure

When estimating quantities of undiscovered resources, the USGS makes a distinction between technically recoverable gas-oil and economically recoverable gas-oil (Figure 1). The gas in place estimated by USGS to be recoverable without regard to profit or extraction costs is termed technically recoverable gas. When the costs of production and a 12% profit margin are included, the USGS derives an estimate for economically recoverable gas. When discussing roadless area, monument or wilderness protection, or, for that, matter leasing stipulations designed to protect the environment, the opportunity cost of that protection is the amount of gas-oil estimated by the USGS to be economically recoverable.

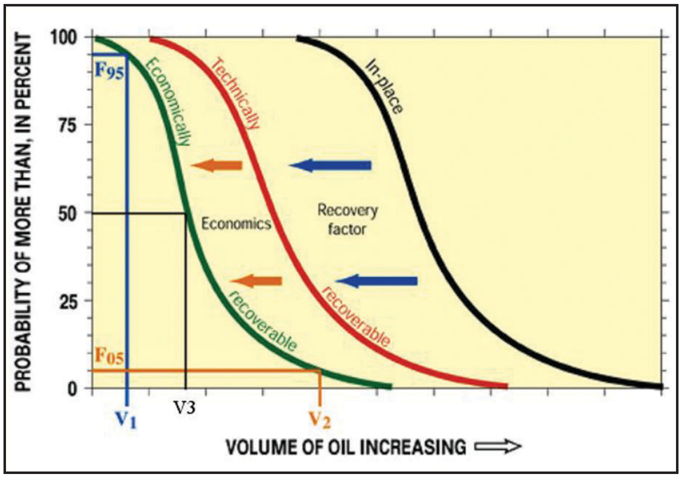


FIGURE 1 *Oil volumes and probabilities for estimating undiscovered quantities. There is a 95% chance of at least volume V1 of economically recoverable oil, a 50% chance of at least V3, and a 5% chance of at least V2 of economically recoverable oil. Source: USGS, 2001.*

The opportunity cost of a policy or action equals the *net benefits* foregone as a consequence of that policy or action. One of the common mistakes made when evaluating regulations or decisions to limit access is the use of gross revenues when estimating opportunity costs, rather than net revenues. The energy opportunity costs of the roadless policy or leasing stipulations should equal the net economic benefits of the oil or gas foregone. This is consistent with economic theory. The use of technically recoverable oil-gas, rather than economically recoverable, is similar to the incorrect use of gross revenues, rather than net revenues, when evaluating policies.

When economic criteria are considered, the amount of recoverable oil and gas drops significantly. In the Rockies, USGS scientists (Attanasi 1998) estimates that, at prices of $2.00 and $3.34 per thousand cubic feet (MCF), between 34 and 77 percent of the technically recoverable coalbed methane is profitable to extract. Similar financial constraints apply to coal bed methane (CBM) located more than 5000 feet underground (Silverman 2002). CBM located 10,000 feet underneath a roadless area or national monument would therefore have an opportunity cost of zero–regardless of whether the area remains roadless. The San Juan Basin holds approximately 84 TCF of gas in place, but only 14 percent, or about 12 TCF, is economically viable to extract (Silverman 2002). In the Upper Green River basin of Wyoming and Colorado, 90 percent of the gas is tight sands gas located in low permeability geologic strata. Scientists at the USGS (Attanasi 1998) estimate that only 7 to 15 percent of the tight gas is economical to recover–underscoring the need to rely on economically viable gas in land management and policy decisions (LaTourrette et al. 2002).

Unfortunately, some officials in the Bureau of Land Management continue to use technically recoverable gas in planning and decision documents. The recent Green River Study (2001) ignored economics and used technically recoverable criteria when examining undiscovered resources that may be potentially off-limits. The report therefore overestimated the oil and gas potential of these western public lands and the gas-oil potentially inaccessible. It is inappropriate to estimate potential CBM jobs based on technically recoverable gas. Planning documents that use technically recoverable in economic impact studies will overestimate the job potential from CBM drilling alternatives. Similarly, when estimating revenues to state or county governments, it is inappropriate to base those revenue projections on technically recoverable gas, as it will overestimate potential revenues.

The Congressional Research Service (2000) has recommended that economically recoverable resources be the basis of policy analysis. If economic constraints on production are ignored, the assessments will overestimate the quantity of oil or gas potentially off-limits. *To reiterate, if the oil-gas is not economically viable to extract, there are no adverse impacts on supply or prices from lease stipulations designed to protect wildlife, archaeological sites, recreation sites and other public resources.* Since policymakers should be concerned about the actual impacts—not the hypothetical impacts, the economically recoverable resource, as estimated by USGS, is the policy-relevant and economically correct measure of the opportunity costs of leasing stipulations, monument designation and roadless area protection.

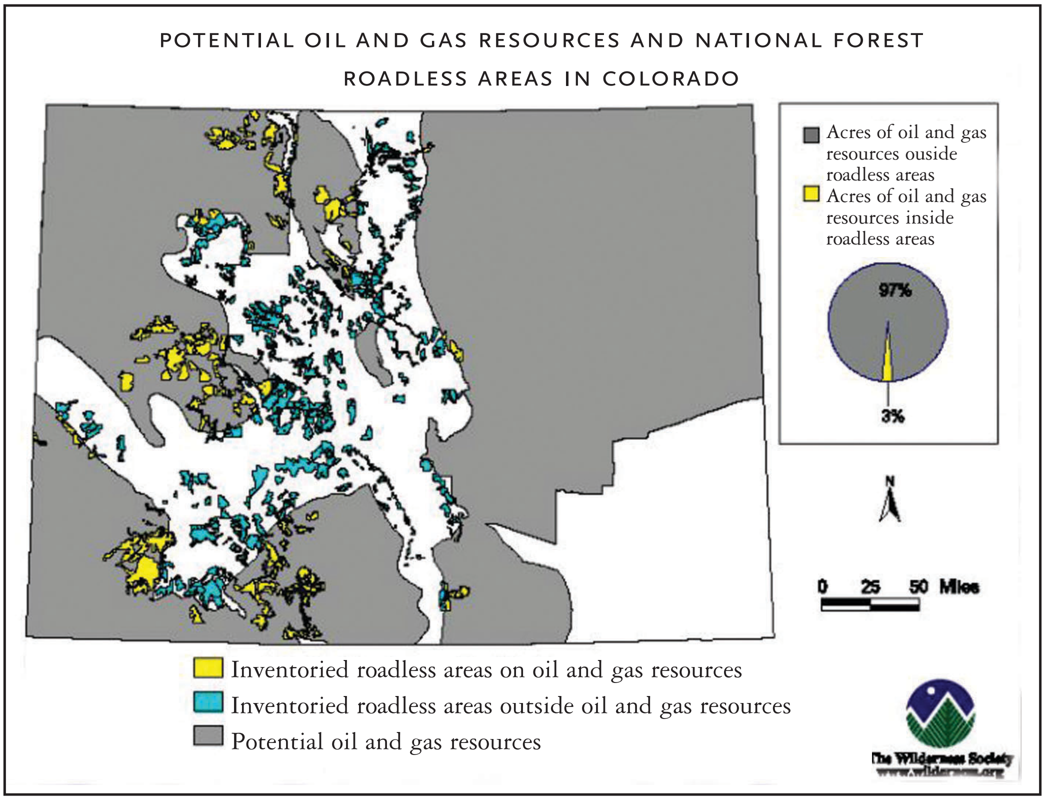
When discussing undiscovered resources, it is also important to recognize the significant uncertainty that comes with the USGS estimates. On the Y-axis of Figure 1 we have probabilities—anywhere from a 95 percent probability of V—1, a 50 percent probability of V—3, to a 5 percent probability of V—2. The Wilderness Society recommends using the mean estimate of economically recoverable oil or gas. This figure represents the best, unbiased estimate of the expected value of the economically recoverable gas–which, as discussed, correctly represents the opportunity cost of environmental protection.

One of the reasons why the environmental community and the oil and gas industry might be citing different estimates of oil and gas has to do with the chosen probability. Some pro-drilling advocates tend to cite the five-percent probability. While we support the use of mean estimates, we express considerable skepticism when it comes to quantities of undiscovered oil or gas estimated with only a five-percent probability. Estimates with just a five-percent probability can be expected to be wrong 19 out of 20 times. Predictions that are wrong 19 out of 20 times are rarely relevant in policy debates. To emphasize this point, consider the following example. If an environmental group ran a computer model that estimated global temperatures would increase 15 degrees in the next 10 years if we keep emitting carbon dioxide at current rates, but the model prediction was wrong 19 out of 20 times—would anyone take the estimate seriously? Would decision-makers, scientists, or the press give the estimate any credibility? Pro-drilling forces would certainly scoff at the scare tactics and pseudo-science behind a dire environmental prediction that may be correct only five percent of the time. With this in mind, we believe that quantities of oil and gas, estimated with just a five-percent probability, should be heavily discounted, if not ignored, by decision-makers.

Coalbed methane and public wildlands: how much?

The Wilderness Society was initially concerned about the energy potential of two major land designations: national forest roadless areas, and national monuments managed by the Bureau of Land Management (BLM) and designated by former President Clinton using the Antiquities Act. To address our concerns, we utilized USGS data and completed a GIS overlay analysis of oil and gas plays with roadless area and monument boundaries. In grey (Map 1), we have merged all the oil and gas plays in Colorado into one layer. This gives you an idea of the land in Colorado that has oil and gas potential. The other GIS layer on this map includes roadless areas, shown in two colors. In yellow are the national forest roadless areas that have oil and gas potential, while in blue are the roadless areas without oil and gas potential. As this map shows, national forest roadless areas account for only three percent of the land in Colorado with oil and gas potential. We have similar estimates and maps for all Rocky Mountain States located on our web site at www.wilderness.org/eyewash/legislation.htm.

With respect to the amount of economically recoverable coal-bed methane in roadless areas of the Rockies, we used USGS data to estimate that national forest roadless areas in the Rocky Mountains contain somewhere between 500 and 943 *billion* cubic feet of undiscovered coal-bed methane gas. Most of the CBM is in Colorado—predominantly located in roadless areas on the San Juan National Forest (Table 1). There's a little bit of roadless CBM located in Utah, mostly in the Uinta Basin. Now, to put this amount of CBM gas in perspective, if we were to drill for CBM in these roadless areas, the economically recoverable CBM would increase America's expected gas reserves by only one tenth of one percent (0.1%). In terms of the length of time this gas would be able to meet U.S. demand, CBM in national forest roadless areas of the Rockies would meet our demand for about 15 days. There is simply not a huge pot of "CBM gold" out there in our roadless areas. When all forms of energy are counted, economically recoverable oil in these roadless areas would meet total US oil consumption for approximately 21–29 days, while the economically recoverable gas would meet total US gas consumption for approximately 2 –3 months. Obviously, this gas will be produced over a much longer period of time, but this estimate provides a metric on the relative amount of economically recoverable gas-oil in national forest roadless areas.



MAP 1 *Potential oil and gas resources and roadless areas. In grey we have merged all the oil and gas plays to show the land in Colorado that has oil and gas potential. In yellow are the national forest roadless areas that have oil and gas potential, while in blue are the roadless areas without oil and gas potential. National forest roadless areas account for only 3% of the land in Colorado with oil and gas potential. Source Data: Map and pie chart obtained from the U.S. Forest Service and the U.S. Geological Survey.*

TABLE 1. ECONOMICALLY RECOVERABLE COAL-BED METHANE IN NATIONAL FOREST ROADLESS AREAS

State	Coal-Bed Methane (billion cubic feet)
Colorado	429–801
Utah	70–141
Wyoming	0.27–0.46
New Mexico	0.1–0.13
Montana	None
North Dakota	None
TOTAL	500–943

NOTE: Based on analysis of USGS data.

We repeated our oil and gas analysis for the 15 national monuments managed by the BLM (Table 2). In terms of the length of time this gas would be able to meet U.S. demand, all types gas in these monuments would meet our demand for about 7 days. We did not break out estimates for coal-bed methane because according to the USGS, there is no coal-bed methane in any of our national monuments. Some pro-drilling advocates may argue that the Grand Staircase–Escalante National Monument contains coal and hence CBM. We, however, agree with the USGS. If in fact the gas does exist, it is unlikely to be economically viable to bring to market. The CBM has, just as Kaiparowits Plateau coal has, very high transportation costs associated with bringing a resource in a remote area to market.

TABLE 2. ECONOMICALLY RECOVERABLE OIL AND GAS IN THE NEW BUREAU OF LAND MANAGEMENT (BLM) NATIONAL MONUMENTS

Monument	Economically recoverable oil as a portion of total U.S. consumption	Economically recoverable gas as a portion of total U.S. consumption
Agua Fria, NM	0	0
California Coastal, CA	13 days	5 days
Canyons of Ancients, CO	3 hrs	3 hrs
Carrizo Plain, CA	2 days	19 hrs
Cascade Siskiyou, OR	0	0
Craters of the Moon, ID	0	0
Grand Canyon–Parashant, AZ	16 mins	Less than 1 min
Grand Staircase–Escalante, UT	4 hrs	1 hr
Ironwood Forest, AZ	0	0
Kasha-Katuwe Tenet Rocks, NM	Less than 1 min	Less than 1 min
Pompey's Pillar, MT	Less than 1 min	Less than 1 min
Santa Rosa and San Jacinto Mts., CA	0	0
Sonoran Desert, AZ	0	0
Upper Missouri River Breaks, MT	1 hr	15 hrs
Vermillion Cliffs, AZ	10 mins	8 mins
Totals	**15 days, 12 hrs, 28 mins**	**7 days, 2 hrs, 11 mins**

NOTE: Data for oil and gas were obtained from the United States Geological Survey (1995). Our estimates utilized USGS mean value estimates of economically recoverable oil and gas because they provide the best unbiased estimate of the expected value of oil and gas resources. Economically recoverable oil and gas amounts were estimated with prices of $30/barrel of oil and $3.34/thousand cubic feet of gas.

Coal-bed methane and public wildlands: the uncounted economic costs

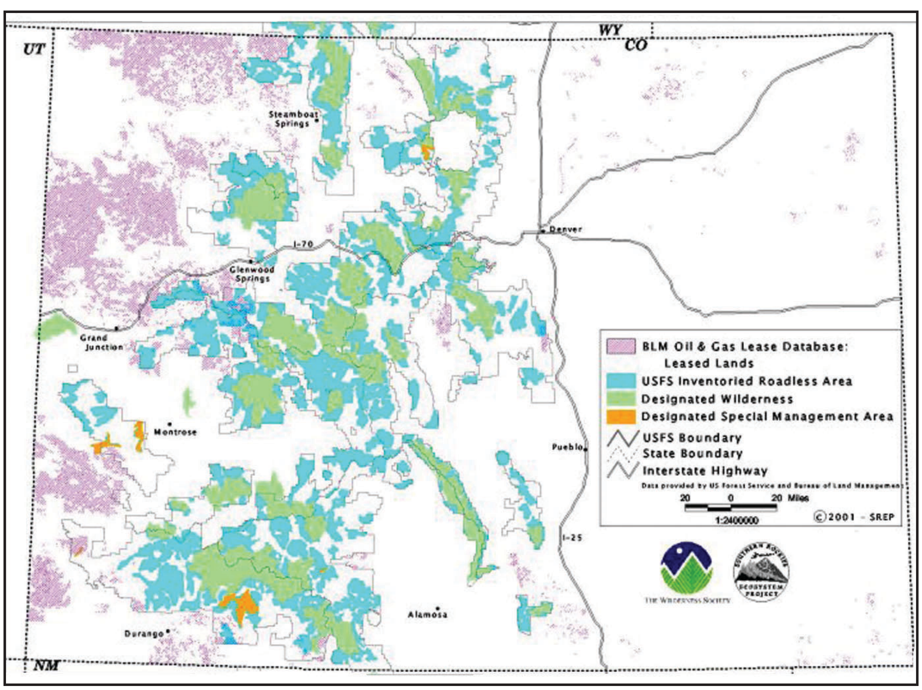
While the benefits of drilling for coalbed methane in these remote areas are relatively small, the benefits of conserving wild areas are significant. To account for the full array of goods and services generated by wildlands, economists have derived the total economic valuation framework (Krutilla 1967, Randall and Stoll 1983; Peterson and Sorg 1987; Loomis and Walsh 1992). A total economic valuation framework is the appropriate measure when comparing wilderness benefits to its opportunity costs in terms of energy resources foregone.

When evaluating CBM drilling in wildlands, the potential energy benefits from drilling should be compared to the known opportunity costs in terms of wildland benefits lost or forgone. To examine this issue, we transformed the seven benefit categories outlined by Morton (1999) into cost categories (i.e., categories of foregone wildland benefits; see Table 3). While many of these costs are difficult to estimate, academic and federal agency economists have made great advances in developing methods to value non-market costs and benefits. Included in Table 3 are methods available for estimating the economic costs, driving home the point that these costs are quantifiable and should be included in the economic calculus. Many heretofore unquantifiable wildland benefits and costs are now quantifiable and available to agency officials responsible for developing the policies and procedures for guiding public land management. (Table 3 next page).

economic costs to hunters, anglers and other direct users

The first economic cost category includes the foregone benefits associated with the direct use of an area. Obviously, gas wells and waste pits are likely to negatively impact the recreational experience of many users, including hikers, hunters, and anglers. The direct use economic costs therefore include the decline in the utility of the recreational experience resulting from oil and gas drilling. Given the importance of public land for outdoor recreation, the lost of foregone recreation benefits could be significant.

Map 2 illustrates national forest roadless areas in relationship to wilderness areas in Colorado. Designated wilderness areas are shown in green while the adjacent roadless areas are shown in blue. Across the west, national forest roadless areas are, in general, adjacent to our wilderness areas and, in particular, adjacent to some of America's best-loved wilderness areas. Our public roadless areas, if left alone, are capable of sustaining the view-



oil and gas leases and usfs inventoried roadless areas in COLorado

map 2. *Designated wilderness areas are shown in green while the adjacent roadless areas are shown in blue. Our public roadless areas, if left alone, are capable of sustaining the viewsheds and quality recreational experience for current and future visitors to our wilderness areas. In purple hatchmarks are the current leases for gas. Currently, only 2% of national forest roadless areas in Colorado are under lease even though these lands have been open for leasing for over 60 years, during which there was little or no interest from industry.*

TABLE 3. THE ECONOMIC COSTS OF MINING, OIL, AND GAS EXTRACTION		
COST CATEGORY	DESCRIPTION OF POTENTIAL COST	METHODS FOR ESTIMATING COST
DIRECT USE	Decline in quality of recreation, including hunting, fishing, hiking, biking, and horseback riding. Loss of productive land for grazing and farming.	Travel cost, contingent valuation surveys.
COMMUNITY	Air, water, and noise pollution negatively impacts quality of life for area residents, with potential decline in the number of retirees and households with non-labor income and loss of educated workforce, with negative impacts on non-recreation business. Decline in recreation visits and return visits negatively impact recreation businesses. Socio-economic costs of boom-bust cycles.	Surveys of residents and businesses. Averting expenditure methods for estimating costs of mitigating health and noise impacts. Change in recreation visitation, expenditures, and business income. Documenting migration patterns.
SCIENCE	Oil and gas extraction in roadless areas reduces value of area for study of natural ecosystems and as an experimential control for adaptive ecosystem management.	Change in management costs, loss of information from natural studies foregone.
OFF-SITE	Air, water, and noise pollution decrease quality of life for local residents and decrease quality of recreation experiences for downstream and downwind visitors. Haze and drilling rigs in viewsheds reduce quality of scenic lanscapes, driving for pleasure, and other recreation activities and negatively impacts adjacent property values. Groundwater discharge can negatively impact adjacent habitat, property, and crop yields, while depleting aquifers and wells.	Contingent valuation surveys, hedonic pricing analysis of property values, preventive expenditures, well replacement costs, restoration and environmental mitigation costs, direct impact analysis of the change in crop yields and revenues.
BIODIVERSITY	Air, water, and noise pollution can negatively impact fish and wildlife species. Groundwater discharged changes hydrological regimes, with negative impacts on riparian areas and species. Road and drill site construction displaces and fragments wildlife habitat.	Replacement costs, restoration and environmental mitigation costs.
ECOSYSTEM SERVICES	Discharging groundwater negatively impacts aquifer recharge and wetland water filtration services. Road and drill site construction increases erosion, causing a decline in watershed protection services.	Change in productivity, replacement costs, increased water treatment costs, preventive expenditures.
PASSIVE USE	Roads, drilling rigs, and pipelines in roadless areas result in the decline in passive use benefits for natural environments.	Contingent valuation surveys, opportunity costs of not utilizing future information on the health, safety, and environmental impacts of oil and gas drilling.

Source: Morton 2001

sheds and quality recreational experience for current and future visitors to our wilderness areas. In addition, these roadless areas play an important ecological role by providing wildlife habitat and migratory corridors between roadless and wilderness areas. Also shown on this map in purple hatchmarks are the current leases for gas. Currently, only 2% of national forest roadless areas in Colorado are under lease even though these lands have been open for leasing for over 60 years, during which there was little or no interest from industry.

Economic costs to communities

The second economic cost category includes the socioeconomic costs to communities from promoting the boom and bust cycles associated with oil and gas extraction. Take for example, Colorado's oil shale boom and bust from the early 1980s (Figure 2). As you can see, oil, gas and mining had an employment boom in the '80s before a big bust and downward slide for the last 20 years. In Colorado, oil, gas, and mining employment currently accounts for less than 0.5% (one-half of one percent) of total employment (*www.wilderness.org/newsroom/colorado_090600.htm*). It's interesting to note that at the peak of the boom, the oil, gas and mining industries only accounted for about three percent of the employment in the state of Colorado. Similar extractive-based boom and bust employment cycles can be found in most other western states. The current emphasis on rapid oil and gas exploration by the Bush administration is pushing rural communities into another boom-bust cycle, and there are indications that the bust is already here.

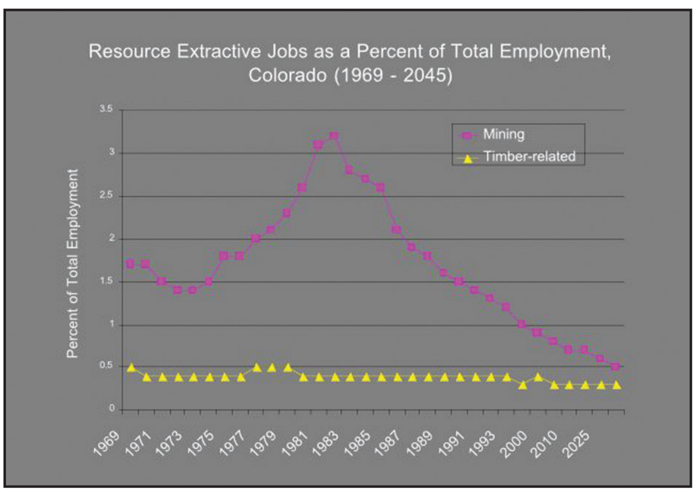


FIGURE 2 *Resource extraction employment as a percent of total employment in Colorado (1969–2045). Mining employment rose to 3.2% of total employment in 1981 before decreasing to 0.9% in 1997. Employment in the timber-related industries (includes lumber and wood products manufacturing and paper products) experienced a steady decline from 0.5% of total employment in 1969 to 0.3% in 1997. Source: Bureau of Economic Analysis, U.S. Dept. of Commerce, 2000.*

As recent employment data from western states are released, you will likely see a bump up in oil and gas employment corresponding to the 2001 spike in gas prices—followed by a drop in employment as gas prices have plummeted. In New Mexico, between November of last year and February of this year, the oil and gas industry laid off 900 workers (New Mexico Department of Labor 2002). In Wyoming, from September 2001 through February of 2002, the oil and gas industry laid off 1,500 workers, representing 12 percent of the industry's work force (Wyoming Department of Employment Research and Planning 2002).

These figures provide some evidence that the CBM bust has started as a result of the recent drop in gas prices. The recent job losses illustrate the economic instability and lack of local control associated with promoting rapid energy development. Communities have little control over the local economy because they have absolutely no control over global commodity prices. When prices drop, companies abandon wells, lay off workers, and leave the communities high and dry to suffer the economic consequences.

The current boom-bust cycle has generated significant costs to communities in the Powder River Basin of Wyoming–costs that must be considered by public agencies rapidly promoting energy development. Many landowners are spending thousands of dollars on attorneys in order to negotiate a surface damage agreement to protect their property (i.e. the split estate problem). Other landowners have seen dramatic declines in property values. The City of Gillete has experienced a 12 to 15 percent increase in truck traffic plus a 26 percent increase in traffic violations between 1999 and 2000 (Pederson Planning Consultants 2001). As a result, the expected life of city streets has decreased, while road operation and maintenance costs have increased. Dust from poorly constructed access roads causes health problems with horses, reduces the grass available for cattle, and negatively impacts air quality and visibility. County officials and residents area concerned that they will have to pay for clean up and restorations costs as the bonds posted by CBM companies for plugging and abandoning a well are inadequate.

As a result of recent coal-bed methane boom, Campbell County has seen an increase in larceny, traffic accidents, destruction of private property, family violence, and child abuse–resulting in the county spending money to add 36 cells to its existing jail. The fire department has seen a 40 percent increase in emergency calls between 1997 and 2000 (Pederson Planning Consultants 2001). Similar trends have occurred in other counties in the Powder River Basin. There has also been a shift in the labor force. County workers have left for CBM jobs, resulting in instability in the labor force and making it more difficult to hire public workers (e.g. policemen, firemen) at a time where the counties and cities are stretched thin to handle the increased work load. *The accelerated energy development has left many counties and communities unable to pay for or finance the increase in public service costs*. We have every reason to believe that similar costs and burdens will be placed on other communities where public and private land is threatened by energy development. The socio-economic risks and costs associated with expedited energy development must be fully accounted for as part of the NEPA process involved with current push for energy development in the west.

An historic emphasis on promoting resource extraction industries has resulted in repetitious cycles of socio-economic distress for rural communities in the west. Resource extractive workers tend to get stuck in a vicious cycle of relatively high paying jobs with frequent layoffs and unemployment. This cycle is what Freudenburg (1992), a sociologist, calls the "intermittent positive reinforcement regime," one of the most effective of all behavioral reinforcements (Freudenburg and Gramling 1994). While resource extractive workers develop high skills, such skills are not readily transferable to other jobs, and the workers become overspecialized (Freudenburg and Gramling, 1994). Investment in education and job retraining is low because "the potential return on their investment in their education is either too low or too uncertain to justify sacrifice (Humphrey et al. 1993). The resultant pattern of "rational under-investment" in the development of skill and other forms of human capital can result in reduced economic competitiveness in resource-dependent communities.

Thankfully, in the last 15 years, the economies of the Rocky Mountain States have diversified, and resource extraction makes up an even smaller part of the economy. For many of these states and communities, service jobs, retirees, recreation, and hunting are the mainstays of the economy. In the new economy, public wildlands play a direct role in sustaining the recreation and tourism businesses, and wildlands play an indirect role in attracting non-recreational businesses and retirees to western states. There is a growing body of literature suggesting that the future diversification of rural western economies is dependent on the ecological and amenity services provided by public lands in the west (Power 1996, Rasker 1995, Haynes and Horne 1997). These services (e.g. watershed protection, wildlife habitat, and scenic vistas) improve the quality of life for a trained and educated workforce, which in turn, can attract new businesses and capital to communities. The natural amenities from public land provide communities with a comparative advantage over other rural areas in diversifying their economies. It is therefore important to recognize and analyze the potential negative impacts of oil and gas exploration on public land amenities and hence the economy as a whole, including the service and recreation industries, as well as on retirees and other households with investment income.

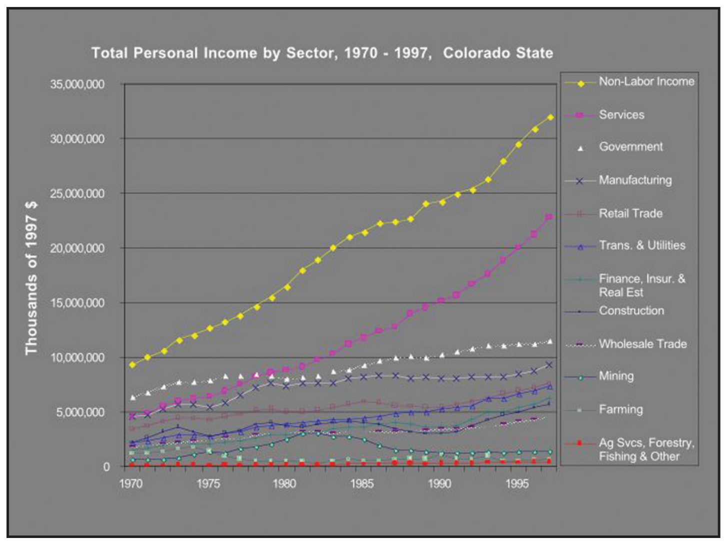


FIGURE 3 *Components of total personal income (TPI) in Colorado (1970–1997). Non-labor income, the largest component of TPI, has steadily increased in importance since 1970 and is followed by service and government.*

As Figure 3 shows, the number one component of personal income in Colorado and other western states is nonlabor income, which includes investment income, dividends and rent, and retirement income. The contribution of nonlabor income in the Rocky Mountain States ranges from 26 percent of total personal income in Colorado to 39 percent of total personal income in Montana, making it a significant component of our western economy. In fact, if retirees and investment income were classified as an industry, it would be the number one industry in most western states, and it is largely based on sustaining our environment and quality of life. It is therefore important to fully evaluate the negative

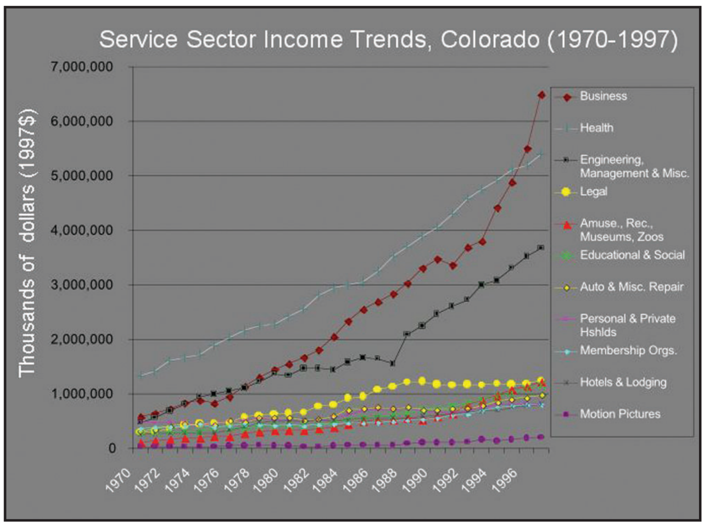


FIGURE 4 *Personal income earned from the service sector in Colorado (1970–1997). Business services were the largest and fastest growing component of the service sector between 1970 and 1997, followed by health, engineering, management, and miscellaneous services.*

impacts of a rapid expansion of coalbed methane production on a region's amenities and, hence, the potential negative impacts on retiree and investment income. As one industry speaker mentioned, on occasion his company drills gas wells on ranchettes owned by retired couples. If the drill rig goes in, despite objections of the landowner, and causes the couple's quality of life to decrease, they might move and take a significant chunk of a county or state's total personal income with them.

In addition to retirees, amenity development is bringing new workers and service businesses to the west. In Colorado, as with other western states, the service sector is the number two component of our economy. Jobs in the service sector are often mischaracterized as those of burger flippers and maids. However as Figure 4 illustrates, some of the fastest growing jobs in the service sector are high paying jobs in business, health, and engineering services. These jobs are increasing, in part, because people are moving to Colorado and New Mexico and Montana and Wyoming because they are nice places to live.

Many economists believe that amenity development has changed the dynamics of regional economic development. In the past, workers moved to where the jobs were; now, businesses and jobs are moving to locations that have a high quality workforce in place. With computers and the Internet, service workers can live wherever they want, and most workers want to live in a nice place with a clean environment. Sustaining our environment and quality of life is, therefore, a prerequisite to sustaining our economy. If CBM development degrades our environment and decreases our quality of life, however, workers may move someplace else and businesses will follow. The bottom line is that we need to carefully assess the net impacts of CBM development on our economy, taking into consideration the potential negative impacts of coalbed methane extraction on other, perhaps more important, sectors of the western economy.

SCIENTIFIC AND OFF-SITE ECONOMIC COSTS

A third economic cost category includes the scientific costs in terms of the decline in natural areas for research. Natural areas are important for studying natural processes and for providing reference conditions to help guide adaptive ecosystem management outside natural areas. Economic costs that occur off the site comprise the fourth cost category. Off-site costs include air pollution and the negative impacts on human health from fine particulates, visual impacts from the haze will reduce the quality of life for local residents and decrease recreational experiences for visitors to regional parks and wilderness, increased water treatment costs for downstream users, and potential negative impacts on property values.

Many of the off-site costs are a result of the water discharged during CBM development. The amount of water discharged from CBM wells in Wyoming has skyrocketed in recent years, increasing from approximately 98 million gallons (300 acre feet) per year in 1992, to 5.5 billion gallons (17,000 acre feet) per year in 1999 (Wyoming State Engineer's Office cited in Darin 2000). The surge in water flow has resulted in erosion in ephemeral stream channels and sediment downstream in the main river channel. The water discharged from oil and gas wells is highly saline with a very high sodium absorption ratio (SAR)–a ratio that affects how water interacts with soil. Water with a high SAR can permanently change chemical composition of soils, reducing water permeability and thereby decreasing native plant and irrigated crop productivity. These off-site impacts have the potential to increase water treatment costs for communities and homeowners downstream, cause a decline in range productivity, and increased crop costs for downstream farmers.

THE ECONOMIC COSTS TO BIODIVERSITY AND ECOSYSTEM SERVICES

The increased water production facilitates the spread of noxious weeds that replace native species unable to survive the unnaturally high flow of water and the saturated soil. The spread of noxious weeds, when combined with the loss and fragmentation of wildlife habitat by drill pads, waste pits and roads, negatively impact biodiversity, the fifth economic cost category. Roads are a number one source of sediment in a forest or rangeland. If we allow more poorly constructed roads to be built in search of CBM, we will have more sediment in our streams. Photo 1, from an overflight of the Upper Green River Basin in Wyoming, gives you an idea of the road fragmentation and the density of drilling necessary to extract tight sands gas. So, once again, although this conference is on CBM, when discussing the impacts of CBM development, we need to keep in mind the cumulative impacts from all forms of energy development and resource extraction.

PHOTO 1 *Overflight photo of habitat lost and fragmented as a result of the roads and drill pads from drilling for tight sands gas in the Upper Green River Basin of Wyoming. Photo credit: Peter Aengst.*

The sixth economic cost category includes the loss or decline in ecosystem services such as aquifer recharge, wetland function, and watershed protection. Roadless areas protect private property from floods and lowers water treatment and reservoir maintenance costs for downstream communities. Watershed protection is an important role for public lands because wildlands contain the headwaters of many of America's rivers, and controlling development, road construction and hence erosion on private lands is more difficult due to concerns over private property rights. The national forests are well suited for this important ecosystem service as the EPA estimates that 3,400 public drinking water systems are located in watersheds containing National Forest System

TABLE 4. NATIONAL FOREST ROADLESS AREAS WITH HIGH LANDSLIDE SUSCEPTIBILITY FOR SELECT STATES

STATE	ACRES OF ROADLESS AREAS WITH HIGH RISK OF LANDSLIDES*	PERCENT OF FS ROADLESS AREAS WITH HIGH SUSCEPTIBILITY TO LANDSLIDES
Colorado	1,146,000	33
Wyoming	645,000	21
Montana	564,000	15
Utah	492,000	14

NOTE: This is a conservative estimate of roadless acres classified as highly susceptible to landslides, as these totals did not consider the 21 million acres in roadless acres allocated to prescriptions that do not allow road construction and reconstruction, some of which may have high susceptibility to landslides (USDA FS Watershed Specialist Report, 2000).

land, and about 60 million people live in those 3,400 communities (Sedell and others 2000).

In addition to keeping sediment from access roads and drill sites out of community water sources, roadless areas protect communities from sediment produced by mass wasting (e.g. landslides). Mass wasting from landslides and debris flows is a key source of sediment, particularly in western forests, and many of the roadless areas are at high risk from landslides. In Colorado and Wyoming, for example, over 1,146,000 and 645,000 acres of roadless areas, respectively, have high susceptibility to landslides (Table 4). While landslides are a natural process, management activities like road construction and logging accelerate the incidence of mass wasting by several orders of magnitude (LaFayette, 2000). For example, a joint FS and BLM study in Oregon and Washington found that of 1290 slides reviewed in 41 subwatersheds, 52% were related to roads, 31% to timber harvest, and 17% to natural forest (USDA Forest Service 1996). The Forest Service concluded that the Roadless Area Conservation Rule "would have a considerable beneficial effect on water quality, particularly in Regions 1 and 4."

The rapid development of CBM also jeopardizes acquifer recharge. As Figure 5 shows, there has been a huge increase in coalbed methane permits in Wyoming, more drilling, in fact, than several environmental documents predicted or even addressed. To be conservative, before any

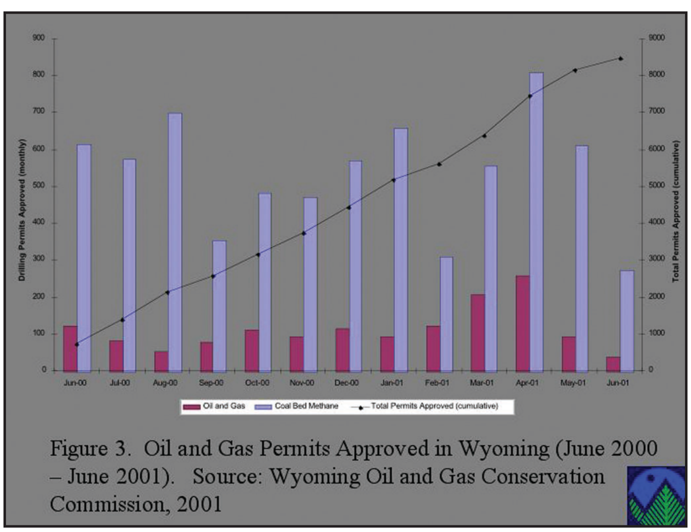


FIGURE 5 *Oil and gas permits approved in Wyoming (June 2000–June 2001). Source: Wyoming Oil and Gas Conservation Commission, 2001.*

more CBM drilling is phased in, the public needs a more complete understanding of the cumulative impacts of drilling and de-watering on ecosystem services such as aquifer recharge. If there is one resource more valuable than oil and gas in the west it is water. So we urge conservative decision-makers to display some caution and stick to their conservative principles with respect to our water resources specifically and our natural resources generally.

WILDLAND PASSIVE USE BENEFITS LOST OR FOREGONE

The last cost category includes the loss of passive use benefits from CBM development. Economists and the courts have recognized that wildlands generate substantial passive use benefits, including option, existence and bequest values (Clawson and Knetsch 1966; Walsh and Loomis 1989). Option value is like an insurance premium that people are willing to pay over and above their expected recreation benefits to maintain the option, for themselves or for their children, of visiting wildlands in the future (Weisbrod 1964; Krutilla 1967). Existence value is the psychic value a person enjoys from just knowing that a wildlands exist—regardless of whether the person will ever visit an area (Krutilla and Fisher 1985). Bequest value represents what the current generation might be willing to pay to bequest wildlands to future generations. Researchers have found that the passive use benefits of wildlands are typically greater than the other benefits included in the total economic valuation framework (Walsh and others 1984; Walsh and Loomis 1989; Walsh and others 1996). If CBM development occurs in roadless areas or national monuments, for example, these passive use values will be lost or seriously compromised.

Discussion and conclusions

Based on our analysis of USGS data, it is clear that drilling public wildlands in the west will do little to affect our energy future. We should, therefore, not assume that extracting energy resources is the highest and best use of our public lands–because in many cases it is not. Public lands provide greater benefits to society when left in their wild and roadless condition for current and future generations to enjoy. The marginal benefits from wildland conservation are, in most cases, much greater than the marginal costs in the form of the undiscovered, economically recoverable energy resources foregone

As the RAND report (LaTourrette et al. 2002) correctly points out, much of the potentially restricted oil and gas resources in the west would never be developed because they are inaccessible for other reasons. *The oil and gas leasing stipulations that dictate where, how, and when exploratory drilling may be conducted in order to protect wildlife and the environment are not, in many cases, binding constraints on energy production.* Economics, terrain and technology may in fact play more important roles in determining the "economically viable resource."

When examining the economically viable resource, it is important to recognize the cumulative and increasing economic costs associated with increasing the scale of production beyond the "sustainable scale." While increasing the scale of production typically decreases the financial costs to a producer (i.e. economies of scale), larger scale projects will, in general, increase the non-market economic and community costs, resulting in what we will call the "diseconomies of scale." The socio-economic and environmental constraints on the scale of oil and gas production should limit development of recoverable CBM resources to a more sustainable scale based on the assimilative capacity of the ecosystem and community

While CBM development on a small scale may have limited negative impact on communities and ecosystems, as the scale of production increases, the ability of those systems to assimilate the impacts is jeopardized. For example, as the scale of coal-bed methane increased in the Powder River Basin of Wyoming, the increase in traffic, crime and immigrants overwhelmed the capacity and budgets of communities and counties for handling these problems. While the CBM may be financially recoverable, local community concerns over the cumulative negative impacts from future production will increase the economic costs and may prevent additional development (i.e. increasing the scale of development) from actually occurring.

Similarly, the cumulative negative impacts of CBM production on clean air and clean water may be a constraining factor on the scale of production—irrespective of whether the CBM is financially or technically feasible to extract. The amount of CBM wells drilled in Wyoming have increased dramatically resulting in the surface disposal of thousands of gallons of water with a very high sodium absorption ratio. *To be sustainable and to maintain water quality, the increase in SAR water should not exceed the SAR assimilative capacity of the regional river systems.* As the scale of CBM production increases, it is more likely that the cumulative quantities of SAR water will exceed the assimilative capacity of regional watersheds. The SAR assimilative capacity of the regional watershed should therefore be used to help define a sustainable scale of CBM development.

Similar scale arguments can be made with respect to the negative impacts of CBM production on air quality. Based on an analysis by Bob Yunke of the Environmental Defense Fund (2002), the total emissions associated with developing the more than 50,000 wells expected in the Powder River will exceed Clean Air Act limits in the surrounding Class I airsheds (Northern Cheyenne Reservation in Montana and the Badlands National Park in South Dakota). As a result of CBM development in the Powder River, there could be a 60 percent decrease in visibility in the Badlands on peak air pollution day. The loss of clear skies will reduce the quality of life for local residents and decrease the quality of the recreational experiences in nearby wilderness areas and national parks–all of which will translate to negative economic impacts on local communities.

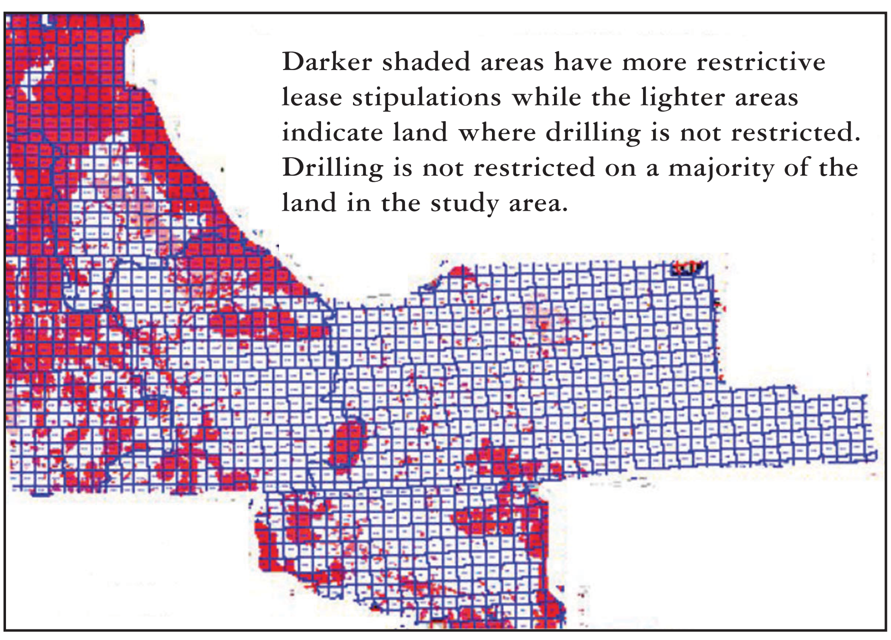
To summarize, the assimilative capacity of communities and ecosystems represent binding constraints on the scale of oil and gas production that should limit future production, even though the oil-gas may be financially feasible for a corporation to produce. Cumulative impacts and constraints on the scale of production should therefore be considered when assessing economically viable resource and when fully accounting for the economic costs of CBM development.

To help address the sustainable scale issue, we recommend that public agencies and private companies immediately begin to scientifically collect, monitor and analyze the cumulative impacts of CBM development from the watershed and landscape perspective–a perspective that should include both public and private lands. We firmly believe it is vital that the public fully understand the potentially irreversible, cumulative environmental impacts from energy development in the Rocky Mountains–impacts on our aquifers, our air and water quality, wildlife species and cropland productivity—before we allow industry to increase the scale of CBM production by phasing in more development.

We also recommend that the BLM increase the bonding requirements for companies drilling for oil and gas on public lands. History has shown that the costs of restoring abandoned drill pads have been greater than the bonds posted. Increasing bonding requirements will provide taxpayers with assurance that there will be sufficient money to pay for the damages to their public land from CBM development. Increasing environmental bonding requirements can reduce the need for regulation and represents a cost-effective method for internalizing the environmental costs into energy production decisions. If, in fact, as one industry official trumpeted at the CBM Conference, CBM development produces "clean water," then increasing the bonding requirements should not be much of an added burden to the "good actors" in industry. If the water is clean and the damages are minimal, companies will get their bonds back. Increased bonding requirements will also help weed out those "bad actors" whom many in industry seem concerned about, yet no one seems to know.

While some industry officials at the CBM Conference questioned the integrity of many of the claims made by the environmental community, from our perspective, integrity begins with companies accepting responsibility for their own actions. Integrity requires CBM companies to accept responsibility for the cumulative negative impacts that CBM development has had on the environment and communities. Integrity begins with monitoring the cumulative environmental impacts of your company's actions, and ends with providing sufficient bonding to pay for the damages caused by such actions. Denying environmental problems or calling them "spurious" is neither credible nor helpful in promoting a dialogue with integrity.

Switching to the issue of access, we do not believe lack of access is a problem. Rather, we believe that industry has too much access to public land. Consider, for example, the road access problem. The national forests contain 383,000 miles of official roads and 52,000 miles of user-created roads–and these are conservative estimates. We have more roads than we can maintain. The Forest Service alone has an $8.4 billion backlog of deferred road maintenance and improvements. Currently the national forest budget can only pay for maintaining 18 percent of the roads. The BLM has similar road problems. Since we cannot maintain the roads we already have on our public lands, why build any more? A taxpayer question worth pursuing is: if we allow more roads to be built to access coal-bed methane or other energy resources, who is going to pay to close or maintain the roads? Also, who is going to pay the costs to maintain the energy infrastructure (e.g. holding ponds, pipelines, etc.) if and when the economic bust comes? We already



DRILLING OPPORTUNITIES IN THE GREATER GREEN RIVER STUDY AREA

MAP 3 *Drilling opportunities in each township (indicated with blue squares) in the DOE Green River Study Area for the Base Case analysis. The red shade toward the northwest indicates more protective lease stipulations for crucial elk winter range, raptor habitat, and sage grouse nest sites near the Wind River Range and the Bridger-Teton wilderness complex southeast of Yellowstone and Grand Teton National Parks. The lighter areas indicate land where drilling is not restricted and shows that industry has access to a majority of the landscape in the Green River Basin.Source: Dept. of Energy may 2001*

TABLE 5. BLM ACREAGE BY OIL AND GAS STIPULATIONS (1995)				
STATE	STANDARD STIPULATIONS (% OF TOTAL)	SEASONAL AND OTHER STIPULATIONS (% OF TOTAL)	NO SURFACE OCCUPANCY (% OF TOTAL)	OFF-LIMITS (% OF TOTAL)
Colorado	45	46	5	4
Montana	58	38	2	2
New Mexico	84	10	1	5
Utah	64	26	6	4
Wyoming	49	46	3	3
5-State Total	**61**	**32**	**3**	**4**

SOURCE: Bureau of Land Management, 1995

have thousands of abandoned wells scarring public land and threatening human health; why drill more?

With respect to regional access to energy resources in the Rocky Mountains, the BLM is currently examining access to oil and gas as required by the Energy Policy and Conservation Act of 1999. The BLM will focus on five basins in the Rocky Mountains: the Powder River, the Montana Overthrust Belt, the San Juan Basin, the Uinta-Piceance Basin, and the Upper Green River Basin. Final reports for these five basins will be completed by November 2002.

Map 3 is from the Department of Energy's recent Green River study (2001). While critical of the report (www.wilderness.org/newsroom/pdf/doe_greenriver_071001.pdf), this interesting map illustrates drilling opportunities in southwestern Wyoming and the northwestern corner of Colorado. The lighter areas indicate land where drilling is not restricted and shows that industry has access to a majority of the landscape in the Upper Green River Basin. This result is consistent with BLM data (1995) in Table 5 indicating that more than 95 percent of the public estate managed by the BLM in Wyoming is open to leasing. Most of the potentially restrictive leasing stipulations in the Upper Green River Basin are on the Bridger-Teton National Forest moving north up the Wind River and Gros Ventre ranges toward Yellowstone National Park and south toward Grand Tetons—plus leasing stipulations protecting places such as Flaming Gorge National Recreation Area in Wyoming and Steamboat Lake State Park in Colorado.

This map highlights two things: One, industry has access to a majority of the land out there; and two, when you examine access to oil and gas, you need to take a landscape perspective and include both private and public land. The ecological impacts from energy extraction cannot be separated across ownership boundaries and neither should the resources. A strict focus on public land will underestimate the full access industry has to gas and oil in a region–and this would be especially true in the Powder River Basin, where most of the landscape is privately owned.

It is important to recognize that while leasing stipulations might reduce access to oil and gas, they help conserve the other multiple uses enjoyed by the public on their land. Seasonal closures, necessary to protect raptor nest sites and critical elk habitat, for example, conserve the wildlife and other multiple uses under which public land is managed. Legislative intent and public sentiment indicate that public lands should not be for the exclusive use of the oil and gas industry. The oil and gas industry already has too much access to public lands; they certainly do not need any more.

The current fixation on access to undiscovered resources in remote wildlands overestimates the importance of undiscovered resources in reducing market instability and reducing the energy prices paid by

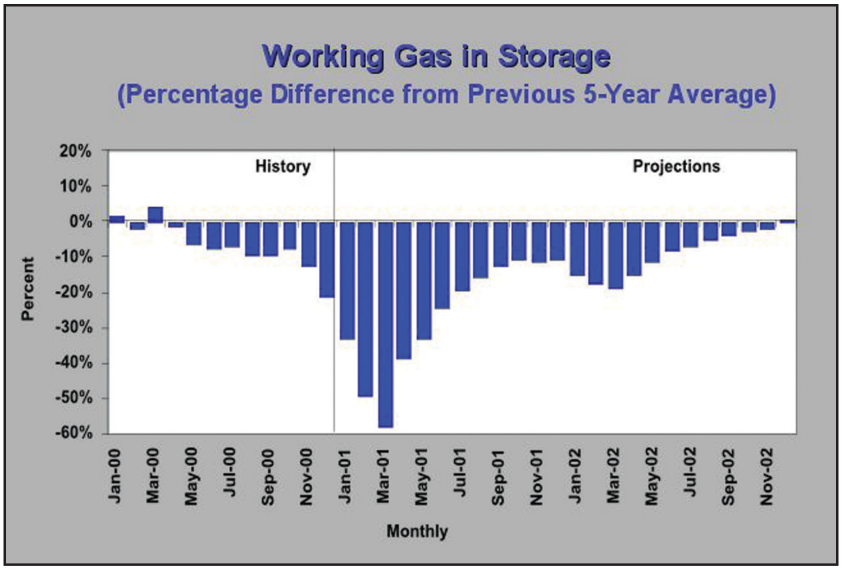


FIGURE 6 *During the last half of 2000 and the first half of 2001, gas inventories were at historic lows.*

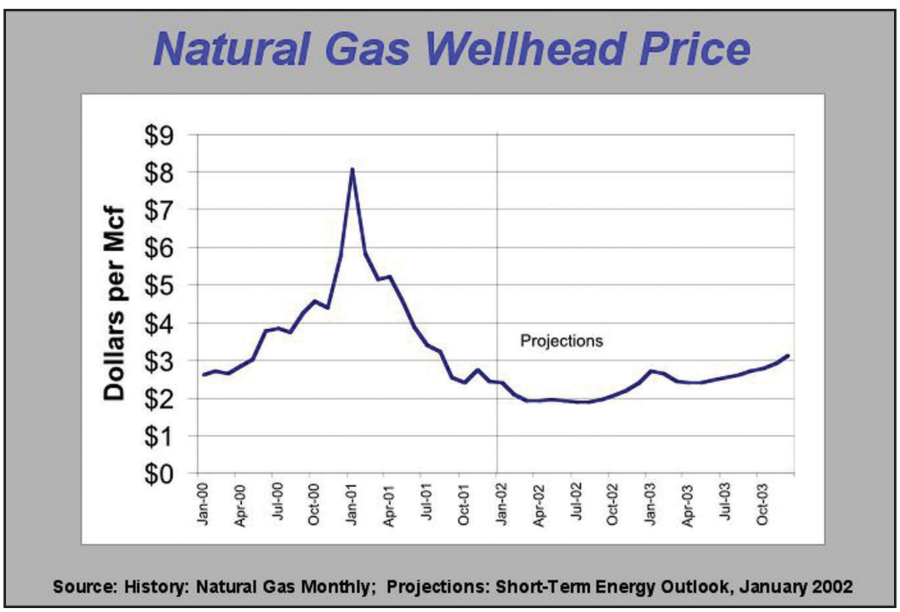


FIGURE 7 *Very low levels of working gas in storage contributed to the price spike.*

consumers (Morton 2002). Decision-makers concerned about high energy prices and price volatility (the main components of the energy "crisis") would be better served by focusing on transporting gas from existing reserves into short-term storage. The shortage in underground storage was perhaps the dominant causal factor in the spike in gas prices, the market instability, and the ephemeral energy crisis of 2001.

The amount of gas in underground storage is a major supply factor influencing short-term market price and market instability (DOE 2001). With relatively inelastic demand for energy in the short-term, lower levels of working gas in storage (short-term supply) will, in general, lead to higher energy prices. Figures 6 and 7 clearly illustrate the recent inverse relationship between gas in storage and gas prices—the lower the storage levels the

TABLE 6. COMPARISON OF TAXPAYER SUBSIDIES-INCENTIVES FOR OIL AND GAS DRILLING IN SENATE AND HOUSE VERSIONS OF THE 2002 ENERGY BILL

Energy Bill Subsidy-Incentive	House Bill (H.R. 4)	Senate Bill (S. 517)
Tax incentives	$1.1 billion	$3.2 billion
Tax credits	$2.8 billion	$1.4 billion
Royalty relief	$7.4 billion	n/a
Deep water technology.	$3.0 billion	n/a
Royalty-in-kind	$1.4 billion	n/a
Total	**$15.7 billion**	**$4.6 billion**

source: U.S. PIRG, 2002

higher the price. From January 2000 through September 2001, working gas in storage was significantly below the 5-year average, resulting in the increased price volatility, which is reflected in the spike in natural gas wellhead price. Gas inventories were not the only inventories that were low; similar inventory shortages occurred in all the major energy markets.[2]

An energy policy requiring industry to maintain a higher minimum underground storage level will reduce price volatility and the cause of high energy costs for consumers and businesses. In contrast, an energy policy subsidizing drilling public wildlands will do little to address the root causes of the 2001 "energy crisis", nor will it reduce the energy costs for families–despite claims to the contrary made by industry officials.

We believe that taxpayer subsidies to corporations for drilling marginal gas and oil wells in our public wildland are misdirected (Table 6). These subsidies are not needed and are part of a shortsighted energy policy based on the quixotic pursuit of energy independence via more domestic drilling. Of particular concern for communities impacted by CBM development is the $2.8 and $1.4 billion in tax credits included in the House and Senate bills, respectively. This incentive extends and modifies the tax credit for companies extracting CBM and tight sand gas. Additional subsidies for CBM drilling, in addition to running counter to the "free market" philosophies of the Bush administration, will be like pouring gasoline on a fire already burning out of control.

With respect to oil, regardless of whether there are subsidies, high access to resources, or high investment in drilling technology, the downward trend in America's crude oil production will continue. In other words, we have already discovered the best reserves America had to offer. *Of the 4.6 million oil wells worldwide, 3.4 million have been drilled in the U.S and a majority of America's wells were dry wells (Udall and Andrews 2002)*. Why subsidize the drilling of more dry wells? Rather than propping up old industries and sacrificing America's remaining wildlands, taxpayer subsidies would be far better spent promoting new markets in alternative energy, efficiency and conservation.

Adopting an energy policy based on energy efficiency and conservation will reduce air pollution, cut transportation and home heating bills for families, and lower the capital and operating costs for businesses. If we lower the energy required to produce America's goods and services, we become more competitive in the global market place, and we reduce the chance that constraints on expanding our energy supply will constrain our economic growth.

There are also more jobs associated with investing in alternative energy, conservation and efficiency. Oil and gas corporations are capital intensive and have low employment multipliers. In contrast, industries involved in carrying out energy conservation measures—manufacturers of electrical, wind, and solar equipment and the construction jobs associated with home or office weatherization programs—are labor intensive and have high employment multipliers. Labor intensive businesses with higher multipliers generate more jobs per dollar invested by producers, consumers, or the government. For example, an energy policy that provides $1 million in tax relief to encourage consumer investment in energy efficiency will generate more jobs than a policy providing the same tax relief to oil and gas corporations for drilling marginal wells.

In addition to the direct jobs created via investments in energy conservation, such investments indirectly create thousands of additional jobs by directly reducing the energy bills of families. Lower energy bills free up consumer spending, which represents two-thirds of our economy. The re-spending of the savings from lower energy bills creates additional income and jobs in industries, services, and suppliers in which the savings are spent. Most of this spending will occur in relatively labor-intensive industries.

A 1996 Department of Energy study examining the benefits to Colorado from accelerating investments in energy efficiency and renewable energy concludes that Colorado would have a net gain of 8,400 jobs, consumers would save $1.2 billion from lower energy bills, and everyone would enjoy cleaner air as air pollution would be reduced by 133,000 tons. The cleaner environment in turn improves the quality of life for local residents—maintaining Colorado's comparative economic advantage by retaining a talented workforce that attracts new businesses to the state.

Paying energy bills represent a significant leakage of financial resources from a local economy. Economists for the State of Nebraska estimate that 80 percent of every dollar spent on utility bills leaves the community and the state. Energy conservation benefits communities by sealing the economic "leaks," thus keeping local money circulating longer in the local economy. Similar benefits can accrue to state, cities, and small communities that promote energy conservation. Quite simply, the inefficient use of energy unnecessarily raises the cost of living and doing business in an area. State, local, or national policies that promote energy conservation and efficiency will lower energy costs, stimulate job creation, and improve the quality of life for local residents—a win-win-win situation. In contrast, energy policies that subsidize CBM development are not needed, will exacerbate boom and bust economic cycles, and will likely decrease the quality of life for many local residents.

Acknowledgements

We would like to acknowledge the technical assistance of T.J. Brown in generating the estimates for coal-bed methane, and Cherie Staples for editorial comments on an early version of this paper. All errors remain our own responsibility.

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ENDNOTES

1. Paper presented at the Coalbed Methane Conference, University of Colorado Natural Resources Law Center, April 4&5, 2002, Denver, CO.

2. In late 2000 and early 2001, the short-term inventories of major fuels were significantly below normal ranges, contributing to higher prices and hence the perception of an energy "crisis." An energy plan focused on drilling wildlands does nothing to remedy the causes of the recent energy crisis. A question for further investigation: What were the circumstances that allowed inventories—short-term storage levels—of all major energy markets, to be at such low levels during late 2000 and early 2001?

POWDER RIVER BASIN COALBED METHANE FINANCIAL MODEL (PRB-CBM-FM)

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I. Objectives and structure of this study

This paper is a revision of a preliminary financial analysis of Powder River Basin (PRB) Coalbed Methane (CBM) operators. A previous paper was given before the University of Colorado Natural Resources Law Center conference on April 4, 2001. The ultimate objective of this and possible subsequent papers is to (1) construct representative models of different CBM operations throughout the PRB region, (2) examine costs of different water disposal options, and (3) compare the results of this financial model with other cost estimates from the U.S. EPA, the CBM industry, conservation groups, and other sources, and (4) construct a series of different project scenarios that will accurately illustrate the financial impact of a multitude of possible regulatory and other project actions. The resulting financial model, as described in this paper is termed the Powder River Basin Coalbed Methane Financial Model (PRB-CBM-FM).

Subsequent sections of this paper discuss data sources, financial model methodology, financial model assumptions, characteristics of different modeled PRB CBM regions, model results, conclusions, references, and finally, an appendix shows selected portions of the model.

II. Data sources

Five major sources supplied data that were used to evaluate the costs and project structure of CBM operations throughout the Powder River Basin. They are: (1) A report by Morgan Stanley Dean Witter Research on Coal Bed Methane (4/10/00) (Morgan Stanley Dean Witter, 2000); (2) Several descriptive documents from the U.S. EPA on their website that give some economic parameters, assumptions, and basic proposed EPA financial model structures and scenarios (EPA, 2002); (3) A Report by Brian Hodgson of Marathon Oil that lays out in detail the costs of a number of water treatment scenarios for PRB CBM wells (Hodgson, 2001); (4) Two reports that were commissioned by the EPA that surveyed the PRB CBM operators on many economic aspects of CBM operations in that region. The first report (ERGa) was later revised and updated by a subsequent report (ERGb); Finally (5) Ron W. Pritchett, a hydrologist commissioned by one of the PRB CBM operators, prepared a report that exhaustively examined the geologic formations—from shallow to deep—to find possible candidate formations that would be able to receive quantities of water produced during the CBM de-watering and gas-production process and the costs associated with filling them with produced water (Pritchett, 2001).

III. Methodology

The financial model used in this study (PRB-CBM-FM) is based on a class of financial models called discounted cashflow (DCF) models. DCF models are probably the most commonly used tools used by companies, stock researchers, and others to evaluate the financial viability of different projects (as well as different scenarios within projects). It is very likely that most or all of the CBM operators in the Powder River Basin use DCF models to evaluate different coalbed methane project scenarios.

A DCF model implicitly recognizes the time value of money—a cost or revenue that occurs now is given more weight than a similar cost or revenue that occurs in the future. The further into the future that a cost or revenue occurs, the less the weight given to it by a DCF model. The basis for this differential weighting is explained by the observation that, for example, a dollar invested today will be worth more in five years than a dollar invested next year. So—a dollar in-hand today is worth more than a dollar in-hand tomorrow. Thus, the costs and revenues that occur today have a greater impact on overall project profitability than costs and revenues that occur further out into the future.

Another useful feature of a DCF model is that it can compare projects and scenarios that have very different patterns of costs and expenditures and evaluate them all on a common footing. For example, Project A may require that an investor pay $500 today to start a project that will return $150 in each of the next four years and $25 for each of the succeeding two years. Alternatively, Project B may need investments of $300 in each of the next two years that would yield returns of $125 in each of the following six years. Which project is the most attractive? DCF models assign weights, based on the timing of the costs and revenues. A discount rate, based primarily on what the firm must pay to acquire investment funds, is used to calculate the weightings of the costs and revenues. Then, a DCF model can look at the entire proposed project and calculate the "life-of-project" or annualized values for each of the project's cost or revenue categories.

In the above example, a DCF analysis could calculate annualized values for the revenue streams for each of the different projects. Also, one could use a DCF model to obtain annualized values for the cost streams. Even though they contain different values in different years, the annualized values for Project A can be directly compared to those of Project B. With a DCF analysis tool one can then critically evaluate the likely total financial viability of different projects, and can also compare different cost and revenue components to help determine the causes of different project financial viabilities.

IV. Assumptions

A. REGIONAL GAS FIELDS MODELED—Two different regions are modeled by PRB-CBM-FM—the Eastern Region, and the Northern Region. These geographic sections are represented by the Fairway North, and Northern Production Area model scenarios, respectively. Collectively, these two regions host the large majority of PRB CBM production. This model assumes that all PRB projects occur in Wyoming. Montana PRB projects may show slightly different results.

B. SCALE AND DURATION—The financial model described in this paper is constructed at the well level. That is, costs, revenues, and profits are calculated as they are produced from a single well. PRB CBM operators usually configure CBM operations so that a series of wells from contiguous regions tie into a single node (or "pod"). These pods then feed their gas into successively higher-pressured pipelines. Ultimately the gas produced from the PRB CBM is transported to gas marketing sites from Wyoming to Louisiana. These marketing sites then distribute the gas to the final end users (or to storage). PRB-CBM-FM model base cases assume that each well operates for 9 years. An alternative financial model scenario allows one to use a 15 year CBM well life.

C. REVENUES—Revenues in the PRB-CBM-FM are modeled starting with an assumed price for gas delivered to a site in Louisiana called Henry Hub. Working backwards from the Henry Hub price, the PRB-CBM-FM deducts costs for (1) transportation from Cheyenne Hub (WY) to Henry Hub (LA), (2) "shrinkage" and fuel costs for powering the compressors that compress and transport gas from the wellhead and through various pipelines, and (3) adjustments for differences of the BTU content and impurities of the PRB CBM gas, as measured against national natural gas standards.

D. COSTS—Costs are broken down as follows: (1) capital costs of constructing a well and the pro-rata portion of a pod (excluding water-disposal facilities); (2) capital costs of constructing the water disposal facilities; (3) costs of operating a well (excluding water-disposal facilities); (4) costs of operating water-disposal facilities; (5) costs of leasing land and payment of royalty rights to owners of the CBM; (6) severance tax payments to the State of Wyoming; (7) payment of incomes taxes to the U.S. Government and the State of Wyoming.

Collectively, with one exception, these are all of the costs that a typical PRB CBM operator will face during the CBM production process. In this preliminary stage of modeling, final reclamation costs are not calculated. Because the actual length of operations at a given CBM facility is based on changing costs and revenues that occur during the CBM operations, the actual shut-down date of each well is difficult to calculate. Also, under current law and practice, reclamation costs for these types of facilities are typically not large and therefore do not have a significant impact on overall profitability of CBM wells.

E. PROFITS—PRB CBM profits are calculated by subtracting project costs from project revenues during each year of operation. A convention of DCF models is that the discount rate (cost of obtaining investment funds for each firm) is considered to define a "normal profit." In this instance and in most economic applications, a normal profit is the minimum expected profit that is expected from CBM firms operating in the PRB. So, in addition to representing the firm's cost of obtaining investment funds, the discount rate also represents a firm's expected (or "normal") profit. In the PRB-CBM-FM I have used a discount rate of 10 percent.

Thus, if a firm earns a return on investment (ROI) of 10 percent, it has earned a normal profit. In this financial model, if a firm earns in excess of 10 percent, the excess is called an "above-normal" profit. One can think of the 10 percent rate as being a benchmark—if a project earns 10 percent or more, it fully covers the cost of obtaining the investment funds and can be considered a profitable project. Conversely, a project yielding an ROI of less than 10 percent is unprofitable because obtaining investment funds costs the firm 10 percent per annum.

F. SELECTED GAS FIELD CHARACTERISTICS—Selected characteristics of the two gas fields are: (A) ultimate gas production in 9-year life: 0.418 billion cubic feet (bcf)—Northern), and 0.364 bcf (East), (B) ultimate water production: 343,000 barrels—Northern), and 854,000 barrels—East), (C) well depth: 850 feet—Northern), 1000 feet—East), (D) well and pro-rata pod costs: $98,500—Northern), $95,000—East), (E) base case gas decline rate: 13 percent per annum—Northern and East), (F) base case water decline rate: 50 percent per annum—Northern and East), and (G) number of wells per pod: 8—Northern and East).

G. WATER DISPOSAL FACILITIES MODELED—At this time the PRB-CBM-FM model features six different water disposal technologies (1) surface water disposal (data from ERGb), (2) shallow injection (data from ERGb), (3) deep injection (data from ERGb), (4) shallow injection (data from Hodgson), (5) deep injection (10% of produced water) combined with surface treatment (90% of produced water) (data from Pritchett), and (6) reverse osmosis (80% of produced water) combined with shallow disposal (20% of produced water) (data from Hodgson). Technical details pertaining to these water disposal techniques are beyond the scope of this paper. For additional details please refer to the referenced source of each water disposal technique.

V. Results

Two broad classes of scenarios were analyzed for each base case in the PRB-CBM-FM—(1) current gas price, and (2) breakeven gas price. The current gas price case uses a recent value for the Henry Hub (LA) gas price ($3.61 thousand cubic feet [Mcf]) as an indicator of the profitability of each region's projects with the six different water disposal variants. The breakeven gas price varies the gas price needed for each region's projects to reach a 10 percent return on investment (ROI). A 10 percent ROI is considered the minimum rate of return needed for a project to be considered profitable.

By comparing the different ROIs returned by each region's projects under the current gas price scenarios, one can find the impact on overall project profitability of each of the six different water disposal options. One can find out the individual impact of any water disposal technique, or any other cost or revenue category on project profitability. If a project exceeds a 10 percent ROI, one can also calculate the "above-normal" profits that the project generates.

One might assume that all above-normal profits would be available for other purposes. For example, if under a particular scenario a project ROI is 15 percent, the additional profits above a "normal profit" of 10 percent might be available to pay for a more expensive water disposal technique.

TABLE 1. RETURN ON INVESTMENT (ROI), PRB EAST REGION, BASE CASE ASSUMPTIONS, CURRENT GAS PRICE

WATER DISPOSAL TECHNIQUES	RETURN ON INVESTMENT	"ABOVE-NORMAL" PROFITS (NPV)
1. Surface disposal (ERG data)	44 %	$ 158,414
2. Shallow injection (ERG data)	38	137,735
3. Deep injection (ERG data)	21	71,117
4. Shallow injection (Hodgson data)	36	139,152
5. Deep injection + surface treatment (Pritchett data)	25	95,510
6. Reverse osmosis + shallow injection (Hodgson data)	27	104,822

SOURCE: PRB-CBM-FM model runs. See individual references for additional details.

A. CURRENT GAS PRICE SCENARIO—Appendix A of this report shows PRB-CBM-FM (a) assumption section, (b) water disposal cost section, and (c) results section. Examples of these model elements are shown for an East region model run for a scenario embodying base case assumptions, current gas price, and surface water disposal.

Selected results of the East region model runs are shown in Table 1.

Table 1 assumes that each of these East PRB projects receives $3.61 per Mcf of gas produced. This gas price is relatively high by historical standards—although gas prices in 2001 reached levels more than double that value. Note that all projects exceeded a 10 percent ROI. And, as expected, the most profitable project used surface disposal techniques for produced water (project 1). PRB East model projects handle significantly more water than PRB Northern projects.

The 44 percent ROI for the surface water disposal indicates that "above-normal" profits of $158,414 exist (as expressed in present-day dollars or "net present value [NPV]). Expressed another way, if $158,414 in revenues was removed from the surface water project, the overall ROI of the project would drop to 10 percent. Or, expressed another way, if the project were required to use more expensive water disposal techniques, as much as $158,414 would be available for additional remediation, while still allowing for a minimum ROI of 10 percent.

Note that the least profitable project (project 3) uses deep injection water disposal techniques and results in an ROI of 21 percent and above-normal profits of $71,117. Comparing project 1 with project 3 shows that the net effect of using deep injection costs an additional $87,297 and lowers the ROI from 44 to 21 percent.

Other water disposal techniques fall in between these two extremes. In order of decreasing profitability, the projects use (A) surface disposal, (B) shallow injection (ERG data), (C) shallow injection (Hodgson data), (D) reverse osmosis + shallow injection (Hodgson data), (E) deep injection + surface treatment (Pritchett data), and (F) deep injection (ERG data).

Table 2 shows results for Northern PRB projects. PRB Northern project model runs show a very similar

TABLE 2. RETURN ON INVESTMENT (ROI), PRB NORTHERN REGION, BASE CASE ASSUMPTIONS, CURRENT GAS PRICE		
WATER DISPOSAL TECHNIQUES	RETURN ON INVESTMENT	"ABOVE-NORMAL" PROFITS (NPV)
1. Surface disposal (ERG data)	38 %	$ 123,543
2. Shallow injection (ERG data)	36	114,344
3. Deep injection (ERG data)	20	59,099
4. Shallow injection (Hodgson data)	23	75,040
5. Deep injection + surface treatment (Pritchett data)	22	70,982
6. Reverse osmosis + shallow injection (Hodgson data)	31	104,269

SOURCE: PRB-CBM-FM model scenarios. See individual references for additional details.

pattern to PRB East projects. The span of ROIs is smaller (20–38 percent for PRB Northern versus 21–44 percent for PRB East), but the profitability ranking of each water disposal technique is virtually identical. The only difference is that PRB Northern project 6 (reverse osmosis + shallow injection) is the third most profitable technique whereas PRB East project 4 (shallow injection) is the third most profitable technique.

Above-normal profits in the PRB Northern region projects range from $70,982 to $123,543 as compared to $59,099 to $123,543 for PRB East projects. Thus, under the current gas price scenario, PRB Northern projects are typically from 17 to 22 percent less profitable than analogous PRB East projects.

1. Cost breakdown

a. PRB East, current gas price, surface water disposal (ERG data)

Figure 1 shows the breakdown of costs for a PRB East Region, Base Case, using surface disposal (water disposal option 1). Costs are shown as annualized values per Mcf of gas sold.

Revenues from each marketed Mcf of gas assume a recent Henry Hub gas price of $3.61. After losing gas lost from "shrinkage", and gas used to power pipeline compressors, revenues received amount to $3.31 per produced Mcf of gas, over the life of the project.

Cost calculations shown in Figure 1, starting with the 12 o'clock position, show the capital costs of building the well (exclusive of water disposal facilities) that amount to $0.44 per Mcf. Capital costs for constructing facilities for surface water disposal are negligible—they actually round down to $0.00. Operating costs of the methane well (lifting costs) (exclusive of water disposal) are $0.41 per Mcf. Water disposal operating costs amount to $0.012 per Mcf.

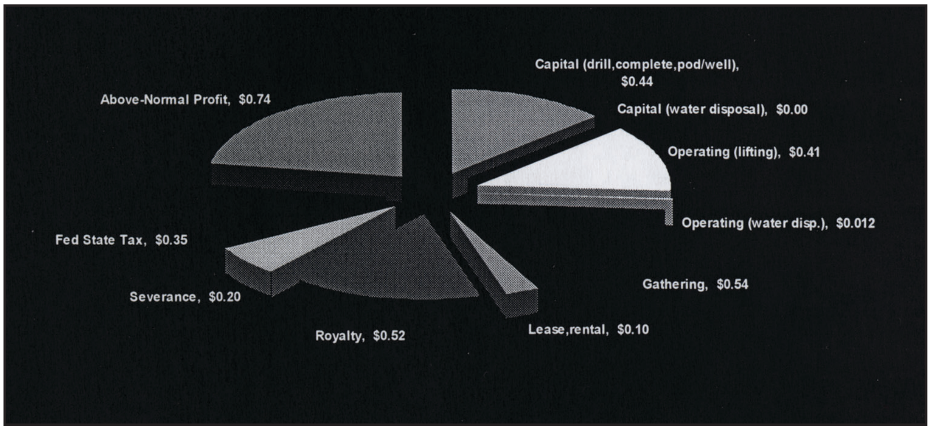

FIGURE 1 *Cost breakdown of PRB East, current gas price ($3.61), surface water disposal. Source: PRB-CBM-FM model.*

Gathering costs are shown in the four o'clock position in Figure 1. These costs are associated with collecting produced gas from individual wells, transporting them to pods, and ultimately to successively larger pipelines. PRB East gathering costs in this scenario amount to $0.54 per Mcf.

Payments to the owners of the mineral and surface rights by coalbed methane operators total $0.62 per Mcf. Mineral severance taxes paid to the state of Wyoming and income taxes paid to Wyoming and the Federal Government total $0.55 per Mcf.

The final "piece of the pie", shown at the 10 o'clock position, is "above-normal profits." As explained previously in the text, above-normal profits are monies earned in excess of the assumed "normal" return on investment of 10 percent. In the scenario shown in Figure 1, above-normal profits amount to $0.74 per Mcf. Examined another way, if $0.74 per Mcf were removed from the project, the return on investment would drop from 44 percent to 10 percent.

B. PRB EAST, CURRENT GAS PRICE, DEEP INJECTION WATER DISPOSAL (ERG DATA)

Figure 2 shows an almost identical PRB East project scenario—all assumptions remain the same as those shown in Figure 1 except that deep injection is used as a water disposal technique rather than surface water techniques (water disposal option 3 instead of water disposal option 1). This scenario represents the most costly water disposal option that is modeled in this study.

Return on investment drops from 44 to 21 percent due to the additional costs of deep injection of produced water. The revenues earned by the project on each increment of gas remain the same as those shown in scenario described in Figure 1.

Costs of building the well and operating the well (exclusive of water disposal capital and operating costs) also remain the same—at $0.44 and $0.41 per Mcf, respectively.

But compared with the negligible capital costs incurred with surface disposal of water, deep injection capital costs amount to $0.29 per Mcf (according to data collected from the PRB industry by ERG representatives). And, deep injection operating costs amount to $0.285 per Mcf. The costs for disposing produced water by deep injection—$0.575 per Mcf, show an increase of more than 4000 percent compared with the $0.012 cost of using surface water disposal methods.

Gathering costs, surface and mineral payments, and severance taxes are identical in Figures 1 and 2. Lower profits levels, caused by deep injection of produced water, reduced the Wyoming and Federal income taxes by 43 percent—from $0.35 to $0.20 per Mcf. And, the above-normal profit decreased 55 percent—from $0.74 to $0.33 per Mcf.

B. BREAKEVEN GAS PRICE SCENARIOS—Table 3 depicts the gas price needed to yield an ROI of 10 percent for

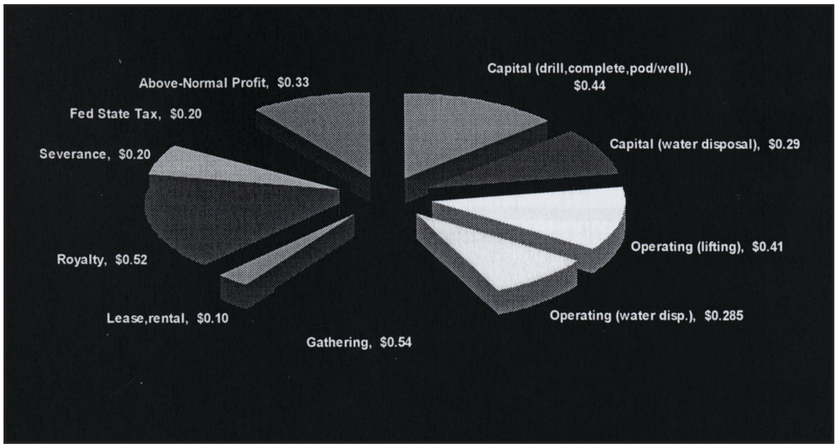

FIGURE 2 *Cost breakdown of PRB East, current gas price ($3.61), deep injection (ERG data). Source: PRB-CBM-FM model.*

TABLE 3. BREAKEVEN GAS PRICE SCENARIO, BASE CASE ASSUMPTIONS, SELECTED PRB EAST AND PRB NORTHERN PROJECTS

WATER DISPOSAL TECHNIQUES	PROJECT LOCATION	BREAKEVEN HENRY HUB (LA) GAS PRICE ($2002/MCF)
1. Surface disposal (ERG data)	PRB East	$2.25
3. Deep injection (ERG data)	PRB East	2.98
1. Surface disposal (ERG data)	PRB Northern	2.47
3. Deep injection (ERG data)	PRB Northern	3.05

SOURCE: PRB-CBM-FM model runs. See individual references for additional details.

the most- and the least-profitable water disposal techniques for both PRB East and PRB Northern projects.

Interpreting the data in Table 3 shows that the Henry Hub (LA) gas prices needed to breakeven for all water disposal techniques ranges from $2.25 to $3.05—a range of $0.80 per Mcf. PRB Northern projects require a gas prices of from $0.22 (surface water disposal) to $0.07 (deep injection [ERG data]) more than analogous PRB East projects. Thus, the regional differences in water disposal techniques range tend to be relatively small. And, the cost differences between disposal techniques in all regions is about $0.80 per Mcf—about 22 percent of the current gas price of $3.61.

VI. Conclusions

Five major conclusions come from financial modeling using two regions to represent the large majority of current PRB CBM production. (1) Six water disposal techniques were modeled: (a) surface water disposal (ERG data), (b) shallow injection (ERG data), (c) deep injection (ERG data), (d) shallow injection (Hodgson data), (e) deep injection (10% of produced water) combined with surface treatment (90% of produced water) (Pritchett data), and (f) reverse osmosis (80% of produced water) combined with shallow disposal (20% of produced water) (Pritchett data). (2) Using a current gas price of $3.61

per Mcf, all water disposal techniques in all regions were profitable and yielded ROIs ranging from 20 to 44 percent that represent above-normal profits of about $59,000 to about $158,000 (NPV). (3) Regional variations between PRB East and PRB Northern regions were not large ($0.07 to $0.20 per Mcf). (4) Surface water disposal was the least costly option and deep injection the most costly, for both regions. Additionally, (5) Pritchett data shows that deep injection of 10 percent combined with surface treatment of 90 percent of produced water was significantly less costly than injecting all produced water. This produced-water-disposal technique shows promise because it minimizes the quantity of water that needs to be injected into costly deep wells and can produce significant amounts of drinking-water-quality water for beneficial consumption.

The Powder River Basin Coalbed Methane Financial Model (PRB-CBM-FM) described in this paper is a "work-in-progress." Feedback from government, industry, conservation, and other public and private sources will help to refine the assumptions, scenarios, and conclusions of this financial modeling effort.

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appendix a: powder river basin coalbed methane financial model, prb east region, showing the (a) assumptions section, (b) water disposal options section, and (c) results section

a1. assumptions section

assumptions		
east (fairway north) model		
NYMEX Henry Hub Current Gas Price ($2002/Mcf)	$	3.61
Basis Differential (Cost of Transportation of Rocky Mountain Gas to Marketing Hub [$/Mcf])	$	0.30
BTU Cost Adjustment ($/Mcf as BTU Adjustment Cost)	$	-
Shrinkage/Compression/Field Use (%)		7.75%
Netback to Wellhead ($2002/Mcf)	$	2.81
WY Severance Tax (% of Sales) (1st 2 Years @ 2% if <=360 Mcf/Day)		6.0%
Percentage Depletion Allowance (%)		15%
Depletion Type (0=Percentage Depletion, 1=Cost Depletion)		0
Federal Income Tax Rate (%)		34%
WY Income Tax Rate (% of Taxable Income)		6.6%
Water Disposal (0=Surf. Dish., 1=Sh. Inj, 2=Deep Inj., 3=Sh. Inj.2, 4=Deep Inj.+S.T., 5=RO + Sh. Inj.)		0
Independent Operator (60% Costs Expensed, 1=Indep. Prod. {yes}, 0=Integ. Prod. {no}		0
Federal or Private Royalty (0=Private, 1=Federal, 2=Weighted Average)		2
PRB CBM Barrel of Oil Equivalent Multiplier (Mcf/Bbl)		5.56
Real Discount Rate		10%

EAST (FAIRWAY NORTH) CHARACTERISTICS

Avg. Well Depth (Feet)		1,000
Peak Gas Production (Mcf/Day)		170
Avg. Water Production (Bbl/Day)		
Peak Water Production (Bbl/Day)		750
Avg. Water Production Volume (GPM)		
Peak Water Production Volume (GPM)		22
Avg. Water Pump Prior to Production (Months)		12
Avg. Time to Reach Peak Gas Production (Months)		12
First Gas Production % of Peak (% of Peak Gas Production)		75%
Ultimate Gas Recoveries (Bcf/Well)		0.2–0.4
Typical Gas Decline Rates/Well (%/Year)		13%
Typical Water Decline Rates/Well (%/Year)		30%
Average Life of Well (Years)		9
Avg. Drilling and Completions Cost/Well	$	95,000
Additional Production Infrastructure Costs	$	-
Avg. Total Well + Pro Rata Production Costs (Avg.)	$	
		95,000
Gathering Fees per Mcf (Includes Treatment + Transportation to Cheyenne Hub) ($/Mcf)	$	0.50
Gas Lifting Costs per Month ($/Month)	$	1,500
Land Costs ($, Assuming 80-Acre Lease)	$	32,000
Private Royalties (%)		20.0%
Federal Royalties (%)		12.5%
Weighted Average Royalty Rate (%)		15.65%
Number of Wells per Pad		8

A2. WATER DISPOSAL OPTIONS SECTION

WATER DISPOSAL OPTIONS		
OPTION 0		
Capital - Surface Water Disposal ($) (Source: ERG, 1/02)	$	300
O & M - Surface Water Disposal ($/BW) (Source: ERG, 1/02)	$	0.0040
OPTION 1		
Capital - Shallow Injection ($) (Source: ERG, 1/02)	$	6,250
O & M - Shallow Injection ($/BW) (Source: ERG, 1/02)	$	0.0450
OPTION 2		
Capital - Deep Injection ($) (Source: ERG, 1/02)	$	62,500
O & M - Deep Injection ($/BW) (Source: ERG, 1/02)	$	0.0950
OPTION 3		
Capital - Shallow Disposal Well ($/BW Capacity) (Source: Marathon Oil)	$	28.57
O & M - New Shallow Disposal Well ($/BW) (Source: Marathon Oil)	$	0.014
Piping Per Well (Miles) (Source: EPA)		0.06
Piping Cost ($/Ft.) (Source: EPA)	$	-
OPTION 4		
Capital - 11,200-Foot Injection Well/25 Wells	$	58,480
Capital - 10% Deep Injection + 90% Surface Treatment ($/BW Daily Capacity) (Source: Caribou)	$	9.75
Capital - 10% Deep Injection + 90% Surface Treatment ($/BW Daily Capacity) (Source: Caribou)	$	6,384
O & M - 10% Deep Injection + 90% Surface Treatment ($/BW) (Source: Caribou)	$	0.0400
OPTION 5		
Capital - Reverse Osmosis + WDW (20%) ($/BW Capacity) (Source: Marathon Oil)	$	77.14
O & M - Reverse Osmosis + WDW (20%) ($/BW) (Source: Marathon Oil)	$	0.033

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A3. RESULTS SECTION

9-YEAR PROJECT RESULTS			
CATEGORY	M 2002 DOLLARS	NPV M 2002 DOLLARS	ANNUALIZED 2002 DOLLARS PER MCF
COSTS ITEMS			
Drilling, Completion, Pro Rata Prod. Capital Costs	$ 95,000	$ 95,000	$ 0.44
Chosen Additional Water Disposal Capital Cost	$ 300	$ 300	$ 0.00
Gas Lifting Cost	$ 144,000	$ 87,299	$ 0.41
Chosen Additional Water Disposal Operating Cost	$ 3,415	$ 2,571	$ 0.012
Gathering Cost	$ 181,859	$ 116,213	$ 0.54
Land Rental & Lease Cost	$ 32,000	$ 20,477	$ 0.10
Royalty Cost	$ 173,809	$ 111,069	$ 0.52
Severance Tax Cost	$ 66,636	$ 42,582	$ 0.20
Intangible Drilling Cost	$ 40,026	$ 40,026	$ 0.19
Depreciation (Capitalized Drilling Cost)	$ 55,274	$ 36,250	$ 0.17
Depletion Allowance	$ 166,590	$ 106,456	$ 0.50
Federal Income Tax Cost	$ 102,770	$ 63,462	$ 0.30
State Income Tax Cost	$ 19,950	$ 12,319	$ 0.06
COST TOTAL	**$ 819,739**	**$ 551,290**	**$ 2.57**
REVENUE ITEMS			
Gross Revenue	$ 1,313,018	$ 839,055	$ 3.91
BTU Adjustment	$ -	$ -	$ -
Shrinkage, Compression, Field Use Cost	$ (101,759)	$ (65,027)	$ (0.30)
Basis Differential (Rocky Mountain Gas Price Differential)	$ (100,659)	$ (64,324)	$ (0.30)
REVENUE TOTAL	**$ 1,110,601**	**$ 709,705**	**$ 3.31**
ABOVE-NORMAL PROFIT	**$ 290,862**	**$ 158,414**	**$ 0.74**
		IRR	44%

Waste or Wasted? Rethinking the Regulation of Coalbed Methane Byproduct Water in the Rocky Mountains: A Comparative Analysis of Approaches to CBM Produced Water Quantity Legal Issues in Utah, New Mexico, Colorado, Montana and Wyoming

Thomas F. Darin[†*]

"If state ownership is to be anything but a delusion, if it is to be more than nominal, there must be the same authority and control over streams and over diversion of water as is now exercised by the general government over the occupation and settlement of public lands. No diversion or appropriation should be permitted, therefore, until . . . the beneficial character of the proposed use established. Such oversight and precaution is necessary for the proper protection of public interest . . . and in order that controversies growing out of extravagant and injurious claims may be avoided."[1]

I. Introduction

Coalbed methane—the natural gas derived from water-saturated underground coal seams—has risen from relative obscurity in the early 1990s to the most talked about and hyped energy resource in the West. As of the mid-1980s coalbed methane (CBM) was widely regarded as a hazardous byproduct of coal mining—it was not considered a resource in and of itself. That, of course, has changed. The water pumped out of the aquifers necessary to liberate the natural gas from coal seams—much of it drinkable—will total in the trillions of gallons in the Rocky Mountain states of Utah, New Mexico, Colorado, Montana and Wyoming. Largely disposed of pursuant to historic statutes for oil and gas byproduct water that assumes the water to be "waste" given the typical low-quality conventional oil and gas brine water, these states are more accurately wasting this valuable and scarce resource in the West.

Touted as the hottest natural gas play by investment brokers in 1999,[2] CBM production has flown off the charts, making that prediction in 1999 actually somewhat modest. As a nation, we now consume approximately 22 trillion cubic feet (TCF) each year.[3] By 2020, the Department of Energy predicts our country will consume 34 TCF on an annual basis, close to a 60% increase.[4] The Rocky Mountain region consists of over 240 TCF of technically recoverable natural gas reserves, comprised mostly of tight sands (160 TCF) and CBM (40 TCF).[5] More recently, however, Rebecca Watson, Asst. Secretary of Interior for Land and Minerals Management, reported that as of 2000, the U.S. had 177 TCF of proven natural gas reserves, estimating that CBM comprises *over* 50% of that total.[6] CBM now comprises 6% to 7.5% of the U.S. production of natural gas and is expected to rise significantly over the next decades to 7 TCF by 2010, or 25% or more of the predicted U.S. consumption.[7]

The San Juan Basin spanning from northwest New Mexico to southwest Colorado, is the nation's leading producer of CBM.[8] That is expected to change in the near future. Currently, the Bureau of Land Management is considering proposals to tap into 39 trillion cubic feet (TCF) of reserves in the Powder River Basin, spanning from northeast Wyoming into southeast Montana. The numbers are astronomical—at peak production, for example, the Wyoming PRB play is expected to top 3.6 billion cubic feet *per day*, and produce over 25 TCF for the life of the project. Equally off-the-charts are the environmental impacts to do so—Montana is projecting as many as 26,000 wells in the PRB, while estimates in Wyoming range from 51,000 to 80,000 to a "high scenario" of 139,000 wells. In short, nothing of this magnitude has ever been proposed, let alone studied, in the history of the Department of Interior when it comes to federal onshore oil and gas wells. In fact, the current total of all such wells is 59,000—*nationwide*.[9] CBM wells in just one Basin in the West will more than double that.

These are not the only examples: CBM can be found virtually everywhere there is coal, and coal formations are prevalent in the Interior Rockies. Other major CBM plays to be discussed in this article include the Uinta Basin in Utah and Colorado (10 TCF of CBM reserves), the Piceance Basin in Colorado (99 TCF), the Raton Basin in Colorado and northeastern New Mexico (10 TCF), the San Juan Basin in New Mexico and Colorado (84 TCF) and the big unknown—the 314 TCF of in place CBM reserves in the Greater Green River Basin in southwest Wyoming and northern Colorado.[10] One may not be surprised to learn that industry literally *circled* each one of these areas on a map of the western United

States as key areas of interest for oil gas exploration, in working with the Bureau of Land Management.[11] Also not surprising is that each of one these areas is a key component of the Bush administration's National Energy Policy and subject to fast-tracking, expediting and streamlining of leasing and drilling permit approvals.[12] This article addresses these water quantity legal issues for CBM extraction in the five western states where CBM is now becoming the dominant oil and gas play: Utah, New Mexico, Colorado, Montana and Wyoming. Part II will provide a general summary of the groundwater regulatory approaches used by these states concerning CBM byproduct water. Part III will provide a brief overview of the CBM extraction process, focusing on the unique attribute that is garnering all of the attention due to the problems it causes: the massive dewatering of underground coal aquifers to allow the methane to freely vent to the surface. Part IV will provide an overview of western groundwater law and particularly the key exemption for oil and gas byproduct water. Part V will focus on the regulation of CBM produced water in Utah, New Mexico and Colorado, where, perhaps due to much lower quality than elsewhere, the handling of CBM water aligns more closely to byproduct water codes that presume this water to be waste (and therefore, not put to any beneficial use). Next, Part VI will focus on Montana's approach to this issue in the Powder River Basin. Part VII discusses Wyoming's unique approach to this issue, with an emphasis on possible state constitutional and statutory violations. Indeed, the needed reform is equally applicable to Montana, and may very well be relevant to future plays in the other three states as CBM plays develop. Part VIII will conclude by calling for reform in Wyoming and Montana—again, given the much higher quality of the produced water in these states—in how they approach the water quantity issue to provide a better solution to CBM byproduct water so that the trillions of gallons of water are not ultimately wasted and denied from future generations.

II. Overview of CBM water quantity issues and regulatory approaches

CBM production adds a new element to environmental hazards associated with natural gas drilling—to be sure, it has the roads, pipelines, powerlines, well pads, compressor facilities, central management facilities and other infrastructure associated with conventional natural gas wells—it also deals with the produced water that accompanies CBM extraction (discussed below in Part III).[13] A couple of examples demonstrate the magnitude we are talking about—the Montana production for the PRB estimates at the high end 3 trillion gallons of water pumped from underground coal aquifers and disposed on the surface; Wyoming estimates up to 1.4 trillion gallons over the life of the project. Put simply, these numbers are staggering. And while industry and state and local governments have spent countless hours tallying up the dollars the CBM boom will bring in, to date, no one has bothered to put a price tag on the value of the wasted water.

Up until now, much of the CBM debate over the water impacts this development brings—what to do with all of this water once it reaches the surface—has largely dealt with the water quality issue. High in salinity and total dissolved solids, much of this water is of little value for long-term irrigation—in short, it's most practical use is watering a few livestock. This ignores, however, that much of the water in place is suitable for drinking water, and is a resource many folks living in the areas of Wyoming and Montana are concerned about losing, especially in light of the fact that it can take up to hundreds of years before adequate recharge can take place. As such, its greatest value may be its reservation and storage underground, where future generations can bring it to the surface, treat it (depending on the intended use) and then put it to a beneficial use. Put simply, in the semi to arid West, water is gold and this point has never been more poignant than the summer of 2002, as the region enters its fifth straight season of drought, the worst in recent years:

It's not even summer and we're in bust times. Montana is a federal drought disaster area, and the governors of Colorado, Wyoming and Arizona have asked the Bush administration for the designation; Utah and Nevada are in states of water emergency. . . . Wildlife experts expect heavy death tolls, and farmers expect wilted crops.[14]

This reason alone calls into question the waste/disposal without consumptive use of billions of gallons of water in the West from the dewatering process that coincides with CBM production. In Wyoming, numerous aquifers that supply drinking water will not be adequately recharged for hundreds of years.[15] Hardly any of this water is being beneficially used (save for watering a few livestock and very limited irrigation possibilities), and given the quantity and quality we are dealing with, what is not used should be considered for injection back into the ground for future retrieval. In Wyoming and Montana, however, that is not being done, and the simplest answer as to why is that no one is requiring this of industry.

This article takes a focus that has not received the brunt of attention on the CBM water issue: water *quantity* legal issues. Of course, as we'll soon discover, every state's approach to the water *quantity* issue is invariably linked to the *quality* of this water. A shorter way of saying this is that where the water is of questionable (or very poor) quality, no one cares much if it is wasted. Much of the produced legal literature on the CBM issue has focused on different issues associated with CBM production.[16] Overlooked in the debate until this point are serious questions concerning how certain exemptions from permitting under the western ground water appropriation law fit—or more accurately does not fit—the CBM model. This is particularly true where the water—of the plays mentioned, primarily the Powder River Basin—has quality that varies *significantly* from the traditional brine associated with deep conventional gas wells.

As will be discussed, western groundwater law evolved on many tenets, but two are key here: one, as water is a precious resource in the semi to arid West, it should not be wasted; and two, given that groundwater should not be wasted, if diverted from the ground, it must be put to a "beneficial use." Of course, and this should surprise no one, western groundwater law made special exceptions for byproduct water associated with the mining industry—primarily with fluid minerals (usually oil and gas). In other words, preventing "waste" and requiring the diverted groundwater to be put to a beneficial use were concepts not applied to this industry so as not to impede settlement of the West. This may have made sense with traditional (or conventional) oil and gas byproduct water from deep formations where the byproduct water is mostly unusable salty brine. In fact, most current CBM produced water in Colorado, Utah and New Mexico is of such questionable quality that it perhaps fits the waste exception model.[17]

Things are different, though, in Wyoming and Montana where the water quality (in total dissolved solids at least) is much better. Until recently, Montana state law prohibited the waste of groundwater. Because much of the water cannot be used for irrigation and can only be used to water a few livestock, the rest (expected to be in the trillions of gallons) is evaporated or left to flow out of the state. This probably constituted waste under the old law. In 2001, however, the Montana legislature resolved this issue by declaring CBM water handling of this sort not to constitute waste.

Wyoming's approach to CBM byproduct water is unique compared to the other states mentioned. It is the *only* state that requires the water to receive a beneficial use permit from the State Engineer at the point of diversion from the underground reservoir. As will be discussed, this model has problems because only a fraction of the water can itself be beneficially used—the rest is wasted in violation of Wyoming law. It should be noted that "beneficial use" in western water law has never been defined as using the byproduct water to allow gas or oil to flow to the surface—rather, the beneficial use must always be the use that the water itself is put to.[18]

Of course, there is another option in Wyoming—to follow the byproduct water code section that, similar to Utah, New Mexico and Colorado, does not require any permit for the diversion of water when associated with oil and gas development. In Wyoming, as these states, this statutory provision considers this water "waste," and after initial diversion, if someone wants to put it to beneficial use, *only then* is a State Engineer permit required. Perhaps this is a better approach in Wyoming: assume that all of the water is waste (which transfers jurisdiction of handling the water to the Wyoming Oil and Gas Conservation Commission), and then, where appropriate for irrigation, drinking or stock watering, put a small fraction of the water through the beneficial use permitting process. Of course, this model is problematic—although much of the water is not suitable for long term irrigation, it is *much* different than the type of oil and gas byproduct water contemplated when the Wyoming byproduct statute was passed. In other words, it should not, perhaps, be considered and treated as waste, when it could be stored for distant generations for potable drinking water or for future desalinization treatment to be put to other uses. The TDS, salinity and sodium content is about 1/10 that of deep, conventional oil and gas byproduct water for which the groundwater "waste" exceptions were most likely intended.

III. The coalbed methane extraction process

The CBM extraction process will be briefly described in this article.[19] In general, CBM can be found anywhere there is coal, meaning that the potential resource is widespread throughout the United States.[20] CBM is natural gas trapped in coal seams, formed over millions of years in the coalification process, whereby plant material was slowly converted to coal. The natural gas or methane is a byproduct of the process of decomposing organic material. The methane is adsorbed to coal particulates in underground coal seams that also serve as aquifers. The methane is held to these particulates by the water pressure; in short, the coal seams have to be "dewatered" to different degrees to depressurize the coal seam, and allow the methane to vent freely through the well bore, to be captured and transported to market.

The United States Geological Survey summarizes the dewatering process as follows:

The coalification process, whereby plant material is progressively converted to coal, generates large quantities of methane-rich gas, which are stored within the coal. The presence of this gas has been long-recognized due to explosions and outbursts associated with underground coal mining. Only recently has coal been recognized as a reservoir rock as well as a source rock, thus representing an enormous undeveloped "unconventional" energy resource. But production of coalbed methane is accompanied by significant environmental challenges, including prevention of unintended loss of methane to the atmosphere during underground mining, and disposal of large quantities of water, sometimes saline, that are unavoidably produced with the gas.[21]

This dewatering process is at the heart of most of the environmental concerns at the center of the ongoing CBM debate. In Wyoming for example, each well is currently averaging 15,000 to 20,000 gallons of produced byproduct water per day. In essence, therefore, each CBM well should be properly viewed as two wells: a natural gas well and a water well. In fact, this unique feature of CBM production caused the Colorado Bureau of Land Management to describe the unconventional CBM resource extraction as "radically different," than tradition conventional deep natural gas.[22] This extraction process naturally lends CBM wells to being regulated under different approaches to appropriating, beneficially using and handling these massive volumes of water pursuant to western groundwater law.[23]

IV. An overview of western groundwater law and oil and gas extraction

Groundwater provides for one-half of the drinking water sources in the United States, and worldwide, groundwater comprises 95% of all freshwater sources, excluding glaciers.[24] In Utah, for example, groundwater is relied upon by approximately 63% of the population for consumptive use.[25] Accordingly, western groundwater law is premised, much like surface water law, on avoiding waste of water resources in a region that is long on land and generally short on water.[26]

Western groundwater law is primarily governed by the doctrine of prior appropriation.[27] The central tenets of the prior appropriation system award priority water rights to first-in-time users who divert groundwater to a "beneficial use."[28] The prior appropriation doctrine is primarily in place to establish a system of determining senior rights when there are competing or conflicting uses; presumably requiring groundwater diversions to be put to a beneficial use addresses a non-conflict concern as well—when put to a beneficial use, water is assumed in western water law to not constitute waste of this all important resource.[29] The prior appropriation system affords water rights to ensure protection of a user's original means and amount of diversion and to establish a system to address allocation between competing users when shortages occur.[30]

To bring some form of order to an appropriation system that naturally is vulnerable to the unpredictable nuances of underground hydrology, most western states, including Utah, New Mexico, Colorado, Montana and Wyoming, have developed a permit and adjudication system to groundwater rights. Upon the initial diversion of the groundwater, a permit is sought, usually from the state engineer, establishing the priority date, nature of beneficial use and amount of withdrawal.[31]

In the settling of the West and, of concern here, mining for oil and gas reserves, an exception evolved from the above prior appropriation scheme. Until recently, byproduct water associated with oil and gas extraction was typically a very salty brine solution of little use. Accordingly, oil and gas "byproduct" water did not involve the concept of preventing "waste"—it was considered waste already, and as a corollary, no one wanted this water, meaning no problems arose concerning "scarcity" and competing uses for it.[32] Deep conventional oil and gas wells range from 3,000 to 20,000 feet in depth, and the associated byproduct water was readily exempted from the normal concepts of water rights, prior appropriation and beneficial use. On top of poor quality, a lot of conventional gas production produced relatively low quantities of water. As such, the primary focus was not on preserving and establishing a system to account for competing uses of this unwanted water, but rather, how to best dispose of this byproduct waste.

The U.S. Environmental Protection Agency reports that conventional oil and gas produced water is the largest volume waste generated in the United States—between 1985 and 1995, for example, byproduct water from oil and gas production ranged from 15 to 21 billion gallons per year.[33] Total dissolved solids (TDS) are a fairly good barometer of water quality (apart from hard metals, arsenic, chemicals, etc.) and examples of traditional (conventional) oil and gas byproduct water are used here. EPA provided sample oil and gas well data from formations in Pennsylvania: 28 oil samples averaged 58,000 TDS (in mg/L or ppm) and 15 samples from produced gas brine ranged from 139,000 to 360,000 TDS.[34] For comparison purposes, EPA has set a recommended (but not binding) drinking water limit on TDS at 500 ppm,[35] although levels up to 2,000 TDS are considered borderline for human consumption for those not on salt-restricted diets.[36] As a further comparison, seawater averages 35,000 ppm TDS[37] and a bottle of Perrier is close to 500.[38]

Bringing the conventional oil and gas byproduct water quality sampling closer to home, a random sampling of the following deep oil and gas wells now producing in Wyoming reveals the following:

WYOMING CONVENTIONAL NATURAL GAS BYPRODUCT WATER TDS[39]

FORMATION	FIELD	WELL DEPTH (FT)	TDS (PPM)
KF/KD	Bruff	12,322	3,859
Almond	Continental Divide	13,100	5,719
Frontier	Bruff	12,962	8,917
Fort Union	Muddy Ridge	12,750	15,563
Mesaverde	Red Desert	9,600	18,730
Frontier 2	Storm Shelter	11,151	21,114
Muddy-Dakota	Cherokee Creek	8,500	31,898
Madison	Whitney Canyon–Carter Creek	17,300	38,497
Fort Union	Muddy Ridge	7,523	58,659
Entrada	Brady	12,413	104,613

WYOMING CONVENTIONAL OIL BYPRODUCT WATER TDS

FORMATION	FIELD	WELL DEPTH (FT)	TDS (PPM)
Frontier	Borie	8,660	668
KFU	Wildcat Creek	6,805	3,729
KMD-KD	Graham Reservoir	16,161	6,978
Fort Union	Wild Rose	9,885	12,304
Minnelusa	Lance Creek	5,407	14,200
PML "B"	Wolf Draw	7,410	14,700
Teapot	Mikes Draw	7,600	17,000
PML "B"	Tanner	9,100	21,100
PML "A"	Dry Gulch	10,663	30,900
PML "B"	Ditto Lake	9,750	53,400
Nugget	Dry Piney	11,198	60,510
Nugget	Dry Piney	11,428	65,492
PML "B"	Bronco	8,599	89,500
Nugget	Brady	11,935	92,944

Looking at some of the typical quality of this conventional oil and gas byproduct water, therefore, it becomes readily apparent that it was considered "waste" and not a part of (or excepted from) the western groundwater prior appropriation/beneficial use system. In short, no one in their right mind wanted the majority of this water.

Before the advent of coalbed methane, perhaps this exemption made sense. These assumptions justifying this exemption, however, largely evaporate when CBM enters the picture. In Montana and Wyoming, for example, massive quantities of water—to the tune of 15,000 to 20,000 gallons of water per day, per well, are pumped from the ground to liberate the methane. Moreover, almost all of the produced CBM water in these two states is potable, suitable for livestock watering, and in rare circumstances, appropriate for irrigation. For illustration purposes, a few examples of Wyoming and Montana produced CBM water are provided for comparison.

WYOMING PRB CBM BYPRODUCT WATER TDS[35]

DRAINAGE	SAMPLES	MIN. TDS (PPM)	MAX. TDS (PPM)	AVG. TDS (PPM)
Upper Powder River	124	214	7,210	1,884
Middle Powder River	12	2,300	3,830	2,977
Little Powder River	147	495	8,810	1,170
Antelope Creek	1	698	698	698
Upper Cheyenne River	9	323	677	402
Upper Belle Fourche River	189	2	1,790	770

*Avg. WY PRB CBM well depth: 200-600feet[41]
*Avg. WY PRB CBM byproduct water TDS: 2,128 ppm.[36]

MONTANA PRB CBM BYPRODUCT WATER TDS[37]

FORMATION	TDS (IN PPM AS AVERAGED OVER FIVE COUNTIES)
Judith	2,100
Hell Creek/Fox Hills	1,148
Fort Union	1,892
Quaternary Alluvium	2,014

*Avg. MT PRB CBM well depth: 300 to 1,000feet[41]
*Avg. MT PRB CBM byproduct water TDS: 1,500 to 2,800 ppm.[38]

The point here is simple: much of CBM produced water is drinkable, most all of it is suitable for stock watering and a small percentage can be used to irrigate. This water fits into neither the western prior appropriation groundwater model, nor the exception—not all of it can be beneficially used (meaning billions of gallons are wasted) and hardly any of it constitutes the "waste" water typically associated with conventional oil and gas byproduct brine. In short, the assumptions underlying treating all oil and gas byproduct water under the "waste" exception, do not hold water, so to speak, when considering much of western CBM production. A new approach fitting for this new extraction method needs to be developed.

V. Regulation of coalbed methane produced water in Utah, New Mexico and Colorado

Utah, New Mexico and Colorado are being discussed in one section largely because the current CBM production in the major fields share two things in common: low water quantity per well produced as a byproduct and, compared to Wyoming and Montana at least, the relatively low quality of this water. In general, each of these states has a groundwater code based on the prior appropriation doctrine—requiring beneficial use permits for each diversion. However, as will be discussed, each state also exempts oil and gas byproduct water from these provisions, with the jurisdiction of handling the produced water with the state oil and gas board. With TDS between 10,000 and 20,000, however, this water is much cleaner than that associated with the average conventional oil and gas well. That this water may be later treated and put to a beneficial use, or that future CBM plays in these states may enter areas with cleaner water, further calls into question whether CBM byproduct water should be simply discarded and treated as waste under these states' water quantity regulatory systems. The water's greatest value may be leaving it in a retrievable reservoir for future treatment, use and consumption.

A. Utah

1. Utah CBM production

The major CBM play in Utah is the Uinta basin, located in the northeast portion of the state. The Uinta basin has 10 TCF of CBM, with the estimated recoverable reserves now at less than 2 TCF, an estimate that changes over time, that is usually related to ongoing drilling operations.[46] Presently, there are approximately 646 producing CBM wells tapped into the Ferron sands, about 3,000 to 4,500 feet below ground.[47] Water production averages 150 barrels (6,300) gallons per day, or 4.4 gallons per minute (gpm), although some wells produce water as high as 40 gpm.[48] The cumulative water production through November of 2001 for the life of the existing wells is 5.8 billion gallons.[49] Most if not all of the water is being injected into disposal aquifers (not meant for future retrieval) as TDS can range from 15,000 to 20,000 ppm, averaging 12,000 ppm.[50] The Utah Bureau of Land Management Price Field Office managing the federal lands in this area has two environmental studies predicting 1,000 total CBM wells in Carbon and Emery counties over the next 10 years.[51] Assuming 1,000 total wells, the anticipated loss of groundwater calculates to 2 billion gallons per year.[52]

2. Utah oil and gas byproduct water regulation

The Utah Constitution provides that, "All existing rights to the use of any of the waters in this state for any useful or beneficial purpose, are hereby recognized and confirmed."[53] This is the only mention of water in the state constitution, which stresses that water diversions are to be for beneficial purposes.

The Utah water code states that, "All waters in this state, whether above or under the ground are hereby declared to be the property of the public" and that "[b]eneficial use shall be the basis, the measure and the limit of all rights to the use of water."[54] Authority for the appropriation of all ground and surface water in Utah is vested in the state engineer, who has the power to prevent waste or loss of groundwater.[55] In Utah, rights to groundwater can only be acquired through the water code and each appropriation "must be for some useful and beneficial purpose.[56] Any application to appropriate groundwater for mining development may be approved for a specific period of time from when the water is put to a beneficial use until the primary purpose of the application is achieved.[57]

None of these provisions, however, are followed for oil and gas byproduct water in Utah. Instead, "the disposal of salt water and oil field wastes"—including water associated with natural gas development—is under the jurisdiction of the Utah Board and Division of Oil, Gas and Mining.[58] The DOGM has implemented rules to handle the byproduct water to "regulate . . . the disposal of these wastes in a manner which protects the environment, limits liability to producers, and minimizes the volume of waste."[59] Methods of handling the water are lined pits,[60] unlined pits (surface reservoirs) if the disposed water's TDS are not higher than any groundwater that could be affected,[61] unlined pits if all or a substantial portion of the water is being used for a beneficial purpose such as irrigation or livestock watering,[62] unlined pits if the produced water is less than 5 barrels per day,[63] or via Class II injection wells into disposal aquifers that do not contain suitable drinking water.[64] Most CBM produced water is currently being disposed of via injection wells.[65]

Accordingly, there is no inquiry or requirement as to whether the diverted groundwater itself is being beneficially used. Importantly, the Utah oil and gas code provision bypassing the water code requirements, passed in 1953, only contemplated conventional oil and gas development, and the associated brine. As no one wanted the water associated with that type of development, with its quality being so low that it was inconceivable to be put to a beneficial use, this exception to the Utah prior appropriation water code requirements probably made sense. With present CBM produced water TDS averaging 12,000 ppm, and (relatively) low water yields, this treatment perhaps makes sense today. Nonetheless, apparently no inquiry has been made as to whether a majority of this water could be injected for future retrieval purposes (with possible treatment first), and in the future, the water quality of new Utah CBM plays may vary to the point where the mid-20th century assumptions about the volume and quality of the produced water do not justify treatment of CBM byproduct water under this antiquated exception.

B. New Mexico

1. New Mexico CBM production

The big CBM play in New Mexico is its portion of the San Juan basin in the northwest corner of the state. Currently, the San Juan basin is the largest producing CBM field in the U.S., and with its 2,849 CBM wells, is currently producing approximately 547 BCF (or over 1/2 TCF) per year.[66] Cumulatively, the Fruitland coal formation in this area has produced between 5 and 6 TCF of CBM.[67] To date, data for 2,849 wells provides that 134.5 million barrels (or 5.6 billion gallons) of byproduct water have been produced, yielding an average of .3 gpm per well (making water production quantity very similar to deep conventional gas—this is about 11 barrels per day).[68] The TDS in this water are generally higher than the Uinta basin, averaging 15,000 ppm.[69]

With a total of 5,072 CBM wells expected in the New Mexico San Juan basin in the next 20 years,[70] a fair estimate of total produced water is 10 billion gallons.[71]

2. New Mexico Oil and Gas Byproduct Water Regulation

The New Mexico constitution provides that, "All existing rights to the use of any waters in this state for any useful or beneficial purpose are hereby recognized and confirmed."[72] There is no specific constitutional provision applying to groundwater, although for all water, "Beneficial use shall be the basis, the measure and the limit of the right to the use."[73]

The New Mexico water code makes it explicit that underground water is "declared to be public water[] and to belong to the public and to be subject to appropriation for beneficial use."[74] As in Utah, "Beneficial use is the basis, the measure and the limit to the right to use of the [groundwater]."[75] If a person wishes to appropriate groundwater, he must submit a permit to the New Mexico state engineer, stating the beneficial purpose, the amount to be used and other particulars.[76] Importantly, there is a public interest review provision before the state engineer can grant the permit application, he must find that the proposed diversion is not contrary to the conservation of water within the state and is also not detrimental to the public welfare of citizens in New Mexico.[77] It is unlawful for any person (including corporations) to begin the drilling of a well for water from an underground source that has been determined to be reasonably ascertainable, without a valid, existing permit from the state engineer.[78] In New Mexico, when there is drilling below 2,500 feet and the water is nonpotable (defined as 1,000 ppm TDS or higher) (both of which apply to CBM drilling), these areas are, by law, "nonascertainable" and not subject to permit requirements.[79]

Of course, even without the 2,500 and nonpotable exception for needing a state engineer permit, New Mexico, similar to Utah, places the regulatory jurisdiction of "the disposition of water produced . . . with the drilling . . . of oil or gas" with the state oil conservation division.[80] In addition, New Mexico has a "Mine Dewatering Act," as part of its water code, which states a legislative finding that the diversion of water to permit mineral production is in the public interest and the, "existing principles of prior appropriation, beneficial use and impairment of water rights, when applied to the diversion of water to mineral production, may cause severe economic hardship and impact to persons engaged in mineral production."[81] While "mine dewatering," is defined to include the diversion and discharge of groundwater developed by mining activities by means of depressurizing wells,[82] no reported case has explicitly held the Act applicable to oil and gas production. Although CBM production is technically a form of mining, and dewatering is explicitly involved to depressurize wells, the Mine Dewatering Act most likely does not apply to CBM production, but rather to traditional hard rock and gravel types of mining.[83]

As stated, oil and gas byproduct water in New Mexico falls under the control and jurisdiction of the Oil Conservation Division (NMOCD). Operators must conduct their business in a manner that will prevent the contamination of fresh waters.[84] After 1986, lined pits must be used for produced water and operators must abate pollution of groundwater having TDS of 10,000 ppm or less, so as to be protected as domestic, industrial or agricultural water supply.[85] Currently, almost all CBM produced water is handled by disposal injection,[86] which is strictly regulated by the NMOCD.[87] The Division has special rules applicable to the disposal of oil and gas wastes in San Juan county, generally proscribing unlined pits to protect fresh waters having less than 10,000 ppm TDS.[88]

New Mexico, similar to Utah, vests jurisdiction of oil and gas byproduct water with the state oil conservation division. In short, because of the high TDS values of this water, it is exempted from traditional groundwater appropriation requirements of beneficial use—in fact, the Mine Dewatering Act makes it implicit that such byproduct waters in and of themselves, are not a traditional "beneficial use."[89] Rather, these waters are considered and treated as waste. As some of this water is from reservoirs above 2,500 feet and may be potable, there is a present conflict as to whether the state engineer is unlawfully neglecting jurisdiction over some of this water. In addition, as future CBM plays in New Mexico develop—particularly in the Raton basin—it is arguable that treating and handling this water as waste does not fit the assumptions normally associated with deep conventional gas byproduct water and that CBM produced water of better quality should be regulated differently.

C. Colorado

1. Colorado CBM Production

CBM production in Colorado is occurring in primarily two basins: the San Juan and Raton.[90] The San Juan basin is the most "prolific CBM basin in the world," estimated to have 50 TCF in place and recoverable reserves at 6 TCF.[91] Presently, there are approximately 1,200 wells producing in the basin, with an additional 960 wells planned in the foreseeable future.[92] Average water production is initially 5.8 gpm with a lifetime average of 2.7 gpm.[93] To date, CBM produced water has exceeded 36 billion gallons of water from 1998 through 2001,[94] and water quality can vary from 20,000 ppm TDS in the southern portion of the basin to 500 ppm (potable) near the outcrops.[95] If there is such a thing of an average TDS (given different depths, aquifer characteristics and aquifer recharge influences), it is around 10,000 ppm (with most drilling depths around 5,000 feet) and nearly all of the water is handled by disposal injection.[96]

The other major producing basin in Colorado is the Raton. It currently has 821 producing wells, with an expected total of 1,293 in the next several years.[97] Beyond that, BLM is predicting another 1,000 to 2,000 wells in the next 10 years[98] to capture an estimated 6 TCF of recoverable CBM reserves.[99] To date, 7.1 billion gallons of water have been produced,[100] with TDS averaging 2,500 ppm.[101]

2. COLORADO OIL AND GAS BYPRODUCT WATER REGULATION

The Colorado constitution only addresses water appropriation, beneficial use and priority provisions as they apply to "natural streams."[102] Groundwater is addressed in Colorado by the 1965 Ground Water Management Act.[103] A critical initial determination in Colorado is whether the groundwater diversion is from a designated groundwater basin and whether the diversion is from a tributary or non-tributary source.[104] If in a designated groundwater basin, a person seeking to appropriate water must put it to a beneficial use and have an application approved by the Ground Water Commission.[105] If outside a designated groundwater basin, and non-tributary, a permit from the state engineer is required.[106] Non-tributary groundwater is not considered part of the "natural stream" that brings Colorado's Constitution into play for "natural streams" or surface waters; in general, it is subject to regulation by the Colorado legislature according to surface ownership, well construction or adjudication and authorized withdrawals based upon supply and surface acreage ownership.[107]

Of course, not to be inconsistent with her sister states, Colorado too exempts oil and gas byproduct water from state engineer regulation:

> In the case of dewatering of geologic formations by removing non-tributary ground water to facilitate or permit mining of minerals:
>
> (a) No well permit shall be required unless the non-tributary ground water being removed will be beneficially used; and
>
> (b) . . . . The state engineer shall allow the rate of withdrawal stated by the applicant to be necessary to dewater the mine; except that, if the state engineer finds that the proposed dewatering will cause material injury to the vested water rights of others, the applicant may propose, and the permit shall contain, terms and conditions which will prevent such injury. The reduction of hydrostatic pressure level or water level alone does not constitute material injury.[108]

Critical considerations here are that for the exception to apply, the groundwater basin must not be designated (this would seemingly invoke 37-90-107) and the groundwater source being non-tributary.[109] Noteworthy is that no permit is required unless, after diversion, the water is to be put to beneficial use, suggesting that the *initial diversion from the ground itself* is not a beneficial use of the water.

CBM water production in Colorado—particularly where the tapped coal aquifer is depleting surface streams[110]—certainly casts doubt about a decent percentage of the regulatory oversight. Presently, all CBM water is treated under the mine dewatering nontributary groundwater exception, which divests jurisdiction to the Colorado Oil and Gas Conservation Commission for handling. Regarding produced water, it is mandatory that the water be treated prior to placement in a pit (lined or unlined) to prevent crude oil and condensate contamination.[111] The rules allow five types of byproduct water handling: (1) injection into a Class II Safe Drinking Water Act disposal well; (2) evaporation/percolation in a properly lined or unlined pit; (3) disposal at permitted commercial facilities; (4) roadspreading on leased roads (to control fugitive dust) when less than 5,000 ppm TDS (with approval by the surface owner); and (5) discharging into state waters with a Clean Water Act 402 permit.[112]

Once out of the ground, one could obtain a beneficial use permit for the byproduct water.[113]

In sum, therefore, much like Utah and New Mexico, Colorado presumes this water to be waste and treats it as such. Problems persist with this permitting structure as CBM wells tapped into aquifers hydrologically linked to surface waters are most likely tributary groundwater sources to which the byproduct exception does not apply. That distinction, of course, would result in a major change concerning which state agency has control over permitting and regulating the byproduct water, and brings the prior appropriation and beneficial use requirements into play. Even if not tapped into tributary groundwater supplies, the exception for non-tributary groundwater and mine dewatering was most likely based on deep conventional oil and gas brine water—in parts of the San Juan basin where TDS approach 500 ppm TDS and the Raton basin where the average is 2,500 ppm TDS, the assumptions justifying the exception do not apply to water of this higher quality. Obviously, treating all CBM byproduct water in Colorado as "waste" under the COGCC rules is allowing potentially billions of gallons of water that could be used for a beneficial purpose—either now or in future times of scarcity—to be carelessly discarded and wasted.

VI. Regulation of coalbed methane produced water in Montana

A. Montana CBM production

The major CBM interest in Montana at the present time is in its portion of the Powder River Basin. Currently, there are 247 producing wells in the Decker Field that over 20 months of production have yielded nearly 1.8 billion gallons of byproduct water.[114] In the Montana PRB, estimates for recoverable CBM reserves range up to 17.7 TCF, with an expected 10,000 to 26,000 new CBM wells to be producing by 2020.[115] Average water production for each of these wells could reach 10 gpm, with possibly 3 trillion gallons depleted over the lifetime of the 20 year project.[116] The quality of this water to date ranges from 1,148 to 2,100 ppm TDS.[117] Of particular concern is the permanent loss of water—the Upper Tongue watershed spanning 600,000 acres could lose 60% of its available groundwater; water level recovery (recharge) in all aquifers is likely to take "*hundreds of years*."[118] Groundwater resources (e.g., existing wells) could be affected within 14 miles of existing CBM fields and within the Montana PRB there are nearly 10,000 existing groundwater rights that could be affected.[119] That groundwater quantity conflicts will occur is perhaps the only surety as this project moves forward.

B. Montana oil and gas byproduct water regulation

Montana's constitution regarding water rights states, "All surface, underground, flood, and atmospheric waters within the boundaries of the state are the property of the state for the use of its people and are subject to appropriation for beneficial uses as provided by law."[120] Of course, amended in 1972, Montana's constitution has the resource protection trump card: "All persons are born free and have certain inalienable rights. They include the right to a clean and healthful environment."[121] Importantly, "The state and each person shall maintain and improve a clean and healthful environment in Montana for present and future generations."[122]

Similar to Utah, New Mexico, Colorado and Wyoming, Montana's water code[123] appears to have an oil and gas byproduct exception to its groundwater appropriation requirements.[124] In Montana, however, that it not the major regulatory issue. Troublesome for the CBM industry was that the Montana groundwater code prohibited waste of this precious resource: "Waste and contamination of ground water prohibited. . . . No ground water may be wasted."[125] That all changed, however, in 2001 when this preventing waste provision was specifically amended to address CBM byproduct water quantity issues.[126] As the Montana water code now reads, the "the management, discharge, or reinjection of ground water produced in association with a coal bed methane well in accordance with 85-2-521(2)(b) through (2)(d)" may not be construed as waste.[127]

The Montana legislature established the criteria for handling CBM byproduct water. There are three alternatives for handling the predicted billions of gallons of produced water each year: (1) using the it for irrigation or stock water or for other beneficial uses; (2) injecting the water into an acceptable subsurface strata or aquifer pursuant to applicable law; or (3) discharging it to the surface or surface waters subject to the section 402 of the Clean Water Act.[128] This appears to be an answer to the problem, except that: (1) due to high sodium content, sodicity or the sodium adsorption ratio (SAR), of this water, most of it is not suitable for long-term irrigation;[129] or discharging it into a waterway, or left to percolate in above-ground reservoirs. may lead to Clean Water Act violations;[130] and just a fraction of the water can be used by livestock.[131] In short, despite the 2001 amendment, the water, in fact, will be wasted—either by evaporation or to downstream surface waters. Accordingly, there is a strong case to be made that the "waste" exception for CBM produced water in Montana violates the of the inalienable constitutional right for Montana citizens to enjoy a clean and healthful environment—particularly for future generations given the lengthy aquifer recharge scenarios at play.

That is not the only problem facing CBM byproduct water regulation in Montana. The other key issue deals with the ramifications of designating a controlled groundwater area. The water code authorizes the designation of a controlled groundwater area when, pertinent here: (1) the groundwater withdrawals are in excess of recharge to the aquifer or aquifers within the ground water area; or (2) that excessive groundwater withdrawals are very likely to occur in the near future because of consistent and significant increases in withdrawals from within the groundwater area.[132] In December of 1999, the Montana Department of Natural Resources and Conservation designated most of the entire Montana Powder River Basin as a control area, finding: (1) excessive groundwater withdrawals are very likely to occur in the near future in a water-scarce area; and (2) the public health, safety and welfare provision requires that these withdrawals be monitored to protect existing beneficial uses.[133] The designation requires water well mitigation contracts, strict monitoring and data collection to assess impacts.[134]

That seemingly solves the problem, except designating a groundwater control area in Montana brings us full circle: once designated, all operators need a permit to appropriate, and three conditions for that permit that are pertinent here are that there is water available, the operator protect existing uses and the proposed use of the water is a beneficial use.[135] And, as stated, *very little* of the hundreds of billions of gallons of water produced each year will be beneficially used: irrigation is problematic for most of this water long-term, there are only so many cows in Montana and only so many roads to soak. Montana's legislature has made it clear that the secondary effect of allowing CBM to vent to the surface is not a beneficial use of the water itself.[136] It seems like every time Montana takes a step forward in addressing these problems, it comes full circle to still facing the problems it thought it had solved.

Summing up Montana's approach to CBM byproduct water quantity—it's a mess. Trillions of gallons of water that can water livestock and for most people is drinkable (for those not on salt-restricted diets), and certainly if treated, can be used for crop irrigation—will mostly be lost down gradient to the Powder River drainage, the Yellowstone River and ultimately the Gulf of Mexico. Sure, in 2001 the legislature declared that not to be waste, but that seems a target for a Montana constitutional challenge, particularly since aquifer recharge is admitted to take hundreds of years. Joint jurisdiction over the produced water with the Department of Natural Resources and the MBOGC makes sense as the DNC has admittedly more expertise with hydrogeologic issues and preserving existing water rights, but the inescapable CBM catch-22 there is that to appropriate this water, *all* of it must be put to a beneficial use. And put simply, it is not and cannot be used when all gushing out at once in the amounts of billions of gallons. In the end, most of this (relatively) moderate quality water will be lost for hundreds of years.

VII. Regulation of coalbed methane produced water in Wyoming

A. Wyoming CBM production

On the bright side for Montana is that its regulation of CBM byproduct water is not as problematic as Wyoming's. Despite the problems in Montana, the legislature did act to specifically address the problem by amending the water code (while conveniently rewriting the "shall not waste" provision) and did act to designate the entire basin as a control area. In the meantime, Wyoming, presently with 9,100 producing wells, 13,250 wells drilled and coming on line, and an additional 6,549 wells permitted and waiting to be drilled, is forecasting 51,000 CBM wells to be operating and producing gas and water by 2010.[137] The most frightening aspect about this projection is that it is actually *conservative*—BLM predicts under its "high scenario" as many as 80,000 total wells by 2010 and as many as 139,000 wells in total to extract Wyoming's 25 TCF of recoverable CBM reserves.[138]

To date, the cumulative produced water to the surface has been 53 billion gallons.[139] In Wyoming, CBM wells discharge water at an average rate of 9.5 gpm over their productive life. When all 51,000 wells are producing, this will amount to nearly 700 million gallons drawn from aquifers and discharged each *day*, and 255 billion gallons produced and discharged each year at peak production. BLM predicts a total groundwater loss of 1.4 trillion gallons over the life of the project,[140] but if calculated the way MT BLM did, the total loss of groundwater amounts to 5 trillion gallons.[141] Either way, the lost water quantity is simply staggering. The two primary ways of handling the water in Wyoming include: dumping it on the ground, untreated and/or excavating up to 4,000 (new) surface reservoirs, with bore holes drilled in the bottom, as percolation/infiltration reservoirs (also called pits).[142] Both methods lead to one result: the absolute waste of almost all of this water.

The quantity of this water ranges in TDS depending on sub-watershed in the Powder River Basin. In general, by the particular coal seams and targeted depth of wells in each sub-watershed, TDS vary from 402 to 698; 770; 1,170; 1,884 and 2,977 ppm.[143] Therefore, for most of these sub-watersheds that will see the bulk of production, the quality makes it drinkable and suitable for livestock irrigation. The problem is that when deluged with billions of gallons of water each year, there just are not enough cows and people to consumptively make use of the water before it ends up flowing into Montana or South Dakota. While the oil and gas industry and the state of Wyoming have spent countless hours tabulating the projected revenue from the produced natural gas, no one has bothered to put a price tag on the trillions of gallons of water that will be lost. Aquifers will take decades to recover to 75% of capacity, with 95% recharge, in BLM's words, "over the next hundred years or so."[144] All existing wells within 10 to 12 miles of CBM development will be affected by aquifer drawdown (and with 51,000 wells, that means a significant portion of the 8 million acre Wyoming Powder River Basin), possibly affecting the 26,946 existing water wells in the area.[145] As in Montana, the only sure bet as this project moves along is massive conflict between competing water users.[146]

B. Wyoming Oil and Gas Byproduct Water Regulation

1. Wyoming State Engineer Regulatory Structure

The Wyoming Constitution provides that, "Control of Water: Water being essential to industrial prosperity, of limited amount, and easy of diversion from its natural channels, its control must be in the state, which, in providing for its use, shall equally guard all the various interests involved."[147] It is unclear whether this provision applies to groundwater—the phrase "natural channels" may refer only to surface hydrology. The next provision applies to all waters of Wyoming: "Priority of appropriation for beneficial uses shall give the better right. No appropriation shall be denied except when such denial is demanded by the public interests."[148] Accordingly, it is arguable that the Wyoming state engineer has a constitutional duty to equally guard all of the various water interests affected by CBM dewatering, and certainly there is a public interest review requirement for these groundwater diversions.[149] The concept of public interest review and the public trust—applicable to all states that hold all of the water in trust for its citizens—will be discussed in further detail below.

Wyoming's groundwater code is based on the prior appropriation doctrine: "A water right is a right to use the water of the state, when such use has been acquired by the beneficial application of water under the laws of the state relating thereto, and in conformity with the rules and regulations dependent thereon. Beneficial use shall be the basis, the measure and limit of the right to use water at all times."[150] Jurisdiction over water use and rights is vested with the Wyoming state engineer, which requires a permit for groundwater diversions.[151] Groundwater appropriation permits "shall be granted as a matter of course, if the proposed use is beneficial and, if the state engineer finds that the proposed means of diversion and construction are adequate."[152] However, the important constitutional concept of public interest review specifically applies to groundwater, "If the state engineer finds that to grant the application as a matter of course, would not be in public's water interest, then he may deny the application subject to review at the next meeting of the state board of control."[153]

Wyoming's groundwater law follows a system of preferred uses.[154] Importantly, in the current CBM context, it is noteworthy that underground water appropriations for stock or domestic use "shall have a preferred right over the rights for *all other uses*, regardless of their dates of priority."[155] Water rights have preference rights in the following order: (1) drinking water for man and animals; (2) municipal purposes; (3) steam engines and cooking, laundry and bathing; and (4) industrial purposes (which would include mine dewatering).[156]

Wyoming, unlike any other western state, places CBM water quantity jurisdiction within the state engineer. This model does not fit CBM production for primarily one reason: just like in Montana, only a small percentage of this water can be beneficially used itself and, as a result, the rest is wasted. An interesting side note is that Wyoming did not need to follow this path; it too has the byproduct provision in the oil and gas statute vesting jurisdiction with the state oil and gas commission, which oversees the "[d]isposal of salt water . . . which [is] uniquely associated with exploration and production operations."[157] Rather, the state engineer assumed jurisdiction over the initial diversion from the ground, given that early wells produced so much water, without any gas, for long periods of time.[158]

The state engineer rules for groundwater provide that permits are required for all diversions of water from an underground source.[159] Importantly, "All three types of water rights are limited to the beneficial used being made. The state engineer may deny or modify an application for permit if he determines that the granting of an application would be injurious in some respect."[160] Of equal importance is the following duty of the Wyoming state engineer, "The ground waters of the State of Wyoming are the property of the state. The Wyoming state engineer is charged with the administration of the rights to use this ground water. It is his responsibility to provide for the orderly development of the resource and to *protect it against waste* and contamination."[161]

Obtaining a groundwater right in Wyoming is a two-step procedure: the permit approval process and them adjudication of the permit to perfect the right.[162]

2. A BRIEF HISTORY OF CBM PRODUCED WATER REGULATION

The first drop of CBM produced water occurred in Wyoming in 1989.[163] The "Application for Permit to Appropriate Ground Water Form" did not address CBM production; for that matter, in the "Use" category of the permit application, there has never been a box that described "oil and gas byproduct water" as a beneficial use. Rather, at the time of the first few CBM wells, under "use" there were the following categories: domestic, stock watering, irrigation, municipal, industrial and miscellaneous. As none of these uses fit CBM production (save a small fraction for stock watering), operators checked the "Miscellaneous" box, describing the beneficial use as, "Well produces water in conjunction with coalbed methane gas production."[164] By 1994, when CBM water production reached 520 million gallons annually, the same form was revised. "Miscellaneous" now read, "Any use of water not defined under previous definitions such as . . . mine dewatering, [and] mineral/oil exploration drilling."[165] Within a year, the form was revised again to create a new beneficial use category, "Coal Bed Methane—Water produced in production of coal bed methane gas."[166]

3. PROBLEMS ARISING WITH CBM WATER QUANTITY REGULATION

The resulting regulatory system for handling the quantity has resulted in a state agency shell game of sorts. The produced water is not injected back underground, instead, it is disposed of onto the surface. For discharges that reach surface of the waters of the U.S., the Wyoming Department of Environmental Quality has jurisdiction as Wyoming has section 402 primacy under the Clean Water Act. Beginning in early 2000, WDEQ was presented with "new" information, known to soil scientists since the 1950s, about the sodium content of this water and possible violations of Wyoming water quality standards in terms of impairment of agriculture uses of existing surface waters.[167] At that time, due to CWA concerns, operators began to intensify efforts to build and excavate reservoirs or stock ponds to hold the water. Generally, the state engineer permits all of these reservoirs, and presently there are approximately 400 of them in the Powder River Basin to handle CBM produced water.[168] As stated above, that number is expected to climb by an additional 4,000 reservoirs in the next decade.

Quickly, however, there evolved a new set of problems, as several of these reservoirs were built in ephemeral drainages, requiring section 404 permits under the CWA. In addition, some Wyoming ranchers, many of which adapted to the little precipitation (but of very high quality) that flowed down these drainages during snow melt and infrequent storm events, found themselves with impeded water flows. In some cases, there was the difficult decision: receive little or no water due to the blocked drainage upstream (because of the CBM water impoundment) or receive released CBM reservoir water that some considered undesirable compared to the high quality run-off that occurred naturally.[169] The shell game can be explained as follows: (1) the Wyoming state engineer was concerned with quantity from the well and reservoir construction; (2) the WDEQ was concerned with the quality of CBM water, but not existing water rights (which include a right to quantity and quality); and (3) the Wyoming Oil and Gas Conservation Commission (WOGCC) was concerned with well construction, location, spacing and safety. Currently, however, there are proactive steps by the Wyoming agencies to address some of these issues.[170]

4. PROBLEMS ARISING WITH COMPETING USES—INTERFERENCE

Another set of problems emerged with water wells going dry that were tapped into the same (or nearby) aquifers as CBM wells.[171] The Wyoming groundwater code provides for handling complaints of interference—generally, upon complaint of the operator of a stock or domestic well, the state engineer can order the interfering appropriator to cease or reduce withdrawals of water or furnish a new supply of water to the complainant.[172] A complaint requires a filing fee of $100.00 and triggers a state engineer investigation.[173]

Two problems persist for the affected landowner. First, "It is an express condition of each underground water permit that the right of the appropriator does not include the right to have the water level or artesian pressure at the appropriator's point of diversion maintained at any level or pressure higher than that required for maximum beneficial use of the water in the source of supply."[174] Conflicts are certain given that and that many CBM wells are tapped into the same aquifers in which there are over 20,000 pre-existing groundwater rights and BLM's admissions that the reduction in hydraulic head within coal aquifers in the PRB, "likely would reduce or eliminate artesian flow in water wells" and that "[a]rtesian flow in wells likely would not recover until hydraulic head in the coal aquifer recovers sufficiently following CBM development."[175] And, as noted, this recovery process will takes decades and possibly over a hundred years.[176] Second, establishing "who's at fault" in groundwater depletion scenarios is a difficult matter of proof, and if the state engineer cannot prove conclusively the interference, the landowner may be out of luck.[177]

5. THE BENEFICIAL USE MODEL—PERSISTING PROBLEMS

The current model of treating each CBM water diversion as a beneficial use has a few problems. First, as in Montana, very little of the water itself is actually beneficially used. The Powder River Basin has a total of 500,000 cattle and sheep. One cow (or seven sheep) drinks/drink about 14.5 gallons per day. At peak production of 51,000 wells at 9.5 gpm, this will amount to nearly 700 millions gallons per day. At this rate, for this use alone to account for all of the produced water, the Powder River Basin would be overrun with over 45 million cows or 325 million sheep.[178] True, the water is drinkable, but pre-CBM development, drinking water needs were met in the Basin, meaning that none of this water is likely to be used for drinking purposes. That leaves irrigation, which due to sodium and salinity issues, is problematic due to soil dispersion and long-term salt accumulation. As stated, a principal argument here is that, despite the state engineer forms, the beneficial use of the water is not the secondary effect of the gas being depressurized. If that were the case, the 1979 form the state engineer developed would have specifically listed oil and gas byproduct water as a beneficial use—it did not, because, like other states, this water, at that time, was treated as "waste" and not under the administration of the state engineer.

Secondly, vesting control over this water in the state engineer brings in constitutional questions such as equally guarding the various interests and denying diversions when in the public interest. To date, there has not been this public interest review. Lastly, given that little of this water is in fact beneficially used, by allowing diversion in the amounts of billions of gallons per year of water that could be stored and eventually used by future generations, the state engineer is not preventing this water from being wasted.[179]

6. AN ALTERNATIVE MODEL: WYOMING'S OIL AND GAS BYPRODUCT WATER PROVISION

Interestingly, similar to the other states discussed herein, Wyoming does have a provision in its water code that addresses oil and gas byproduct water.[180] In Wyoming, byproduct water is defined as, "water which has not been put to prior beneficial use, and which is a by-product of some non water-related economic activity. . . . By-product water includes, but is not limited to, water resulting from the operation of oil well separator systems or mining activities such as dewatering of mines."[181] In turn, the code deals with the issue of whether someone wants to put the water to a beneficial use *after* it is diverted from the ground, suggesting that the primary first diversion from the underground aquifer is itself, not beneficial.[182] In Wyoming, traditional deep oil and gas byproduct water is treated in this fashion, with no beneficial use permit required by the state engineer.[183]

One way of comparing/contrasting the two models is to examine the different water handling controls if the byproduct water provision had been applied in Wyoming to CBM extraction. Important to remember throughout this discussion is the key distinction between the legal regulatory framework applying to first taking the water out of the ground (the initial diversion) and the much different question of how that water is handled once out of the ground. These are two completely separate regulatory issues. In Wyoming, for example, the following discussion concerning the second phase (how to handle the water once out of the ground) sheds light on, and calls into question, Wyoming's justifications that the beneficial use model fits the initial diversion (first phase).

For example, if the byproduct provision and/or the oil and gas statute provision on oil and gas brine had been applied, as in other states, jurisdiction over handling the water would vest with the state oil and gas commission—the Wyoming Oil and Gas Conservation Commission. Indeed, for the surface reservoirs or pits, WOGCC has stricter standards in place than are currently being required by the Wyoming state engineer's office. For example, all such pits must be designed to prevent leakage and contamination of any freshwater source, when they are located near "an area with a high potential for communication between the pit contents and surface water or shallow groundwater."[184] They must be lined when near "shallow groundwater" or "groundwater recharge areas."[185] As many of the proposed and existing CBM water retention pits fit these descriptions, the regulation of the pit aspect by WOGCC might mean tougher standards. And if lined, they would not fit their intended purpose of handling millions of gallons of byproduct water, because evaporation alone (as opposed to the current method of designing them to bleed into the water table) would be insufficient to handle the quantity of water. The result would be overflowing pits in a matter of months.[186]

Besides these practical problems, treating CBM water as "byproduct" waste is not in the best interest of Wyoming citizens. WOGCC, even with its proposed rulemaking, speaks primarily of how to dispose of the water, and to be praised, how to protect aquifers and surface waters. However, the fundamental problems persist under this model with the result that still *no* agency in Wyoming will be regulating the waste of the water resource or the preservation of the same for future use. Lined pits and proper siting of CBM byproduct reservoirs water may address some issues, but not the fundamental one discussed herein of preventing trillions of gallons of fairly decent quality water (depending on the intended use) from being wasted for decades or centuries. Accordingly, neither the state engineer's beneficial use regulatory model, nor the handling of this water as oil and gas byproduct waste are appropriate models for the very different nature of CBM byproduct water in Wyoming.[187]

7. THE PUBLIC INTEREST

What is certain, despite the regulatory uncertainties in Wyoming, is that there never has been a formal public interest review conducted by the state engineer. This failure is legally problematic given the following in Wyoming:

(1) The state constitution provides that the state shall equally guard all various water interests;[188]

(2) The state constitution provides that water appropriations should be denied when against the public interest;[189]

(3) The groundwater code specifically provides that appropriations not in the "public's water interest" may be denied;[190]
(4) The groundwater code further provides that the state engineer may condition permits based upon the public interest;[191]
(5) The water of the state is held in trust for the public;[192]
(6) The state engineer's rules provide for denying a groundwater appropriation permit when not in the "public interest"; and
(7) The state engineer's rules on groundwater require the agency to protect it against waste.[193]

Despite all of these public interest duties and responsibilities, CBM produced water permitting evolved without formal rulemaking by the state engineer, public input or participation or a written record. Rather, the groundwater appropriation forms evolved by including CBM produced water as miscellaneous use to eventually having its own "box" to be checked on the permit form. Given the scarcity of the resource, the competing water rights involved, the quality of this water as compared to conventional oil and gas brine, and moreover, the quantities involved (hundreds of billions of gallons of water each year), the people of Wyoming deserve this public interest review. Equally important is that the law requires it.

In the case of *Rissler & McMurry v. Environmental Quality Council*,[194] at issue was the designation of Bessemer Mountain as "very rare and uncommon" by the Wyoming Environmental Quality Council. The EQC made this determination after public notice and a hearing, but the decision was challenged for the lack of objective criteria on which such determinations would be made. In setting aside the designation as arbitrary and capricious, the Wyoming Supreme Court held:

[T]he EQC cannot classify lands within the state as "very rare or uncommon' without first establishing by regulation the criteria and factors which will set the standard for that classification. We are satisfied that, in the absence of such a regulatory standard, the phrase, 'very rare or uncommon' it too amorphous to permit judicial review of the action of the EQC. Consequently, any such classification is inherently arbitrary and capricious.[195]

In the very same category is the vague concept regarding determining what is in the "public interest" (and for that matter, "beneficial use") when it comes to groundwater diversions. In the present context, public interest rises to the constitutional level (as well as statutory and administrative rules), whereas the duty on the agency in *Rissler & McMurry* was statutory. In addition, the facts in *Rissler & McMurry* demonstrated public notice and hearing before the determination, something not done by the state engineer in deciding whether some or all of the CBM dewatering is in the public interest. Accordingly, the state engineer has conducted little if any formal public interest review, and is legally required (and has been) through a formal Administrative Procedure Act rulemaking, to develop, establish and apply public interest criteria, through public notice and involvement, before approving these permits. As they stand now, without *any* such criteria in place, all state engineer CBM dewatering permits are arguably arbitrary and capricious.[196]

8. Wyoming summary

Wyoming is unique in its permitting each CBM gas well as a beneficial use groundwater well. Many problems persist with the concepts of beneficial use, constitutional duties and with the fact that no agency in Wyoming is addressing the water quantity waste issue. Indeed, the multi-agency wrangling and in some cases abdication of responsibility, as illustrated herein, has led to a vicious cycle of mind-numbing circular reasoning in Wyoming that will assuredly provide an ample new market for Bayer and Tylenol to penetrate. Neither the current model of appropriation permits nor the alternative byproduct approach addresses the groundwater waste issue or the important issue concerning the preservation of this scarce resource. Equally troublesome are the lack of established criteria for the state engineer to conduct the required public interest review and the fact that no such review is taking place. The only sure thing moving forward with CBM production in Wyoming is more and tougher questions that will demand careful and well-considered regulatory answers.

VIII. Conclusion

Coalbed methane and the hundreds of trillion cubic feet of potential reserves in the Rocky Mountains is obviously one of the major, if not biggest threats, to the environment and natural resources in this region. The Wyoming Powder River Basin alone projects 17,000 miles of new roads, 20,000 miles of new pipelines, 5,300 miles of new overhead powerlines and over 200,000 acres of surface disturbance by 2017.[197] Beyond these traditional impacts associated with but one of the proposed CBM projects in the West are the impacts, both below and above ground concerning the trillions of gallons of water depleted from aquifers to allow the natural gas to vent to the surface to be captured.

While each state varies on handling the byproduct water, the basic premise of this Article is that the assumptions in each state that underlie treating this water as waste are based on statutes diverting jurisdiction to state oil and gas commissions, that contemplated the brine associated with conventional deep oil and gas drilling. In other words, the assumptions in place for treating byproduct water as "waste" never considered CBM development. These statutes were passed in Utah, New Mexico, Colorado, Montana and Wyoming in the 1950s and early 1960s, when the associated water was deep oil and gas produced brine water—with TDS in some cases at 100,000 ppm, or nearly triple that of seawater. CBM production did not start until the late 1980s, with the real boom occurring in the mid-1990s, long after these models were developed. CBM byproduct water across the West varies in quality; however, as illustrated, the quality in many cases makes it suitable for drinking, livestock watering, and if treated, for other uses. Put simply, these outdated models for handling oil and gas byproduct water do not fit CBM production and the associated byproduct water. In the process of handling and assuming *all* of this water to be "waste," these states are in fact in the process of actually "wasting" a valuable resource. Wyoming's problems include not only the wasting of this resource, but also issues germane to its unique approach in permitting each CBM well as a beneficial use water well with jurisdiction under the state engineer. All five states face potential legal problems with the concepts of public interest review and the public trust doctrine.

Without question, as our country makes the transition to renewable and alternative forms of energy, the natural gas from CBM production is an important fuel source in the interim. Industry and the states have adequately voiced the economic benefits of this extraction. What is missing from the debate, and hopefully articulated here, is that critically important water resources in the arid West are also at stake in this development. The challenge lying ahead is for each state to rethink how it deals with produced CBM water in a manner that best serves the purposes of western appropriation water law—protecting competing uses, preserving water for future generations and requiring water to be put to (or at least preserved for) beneficial uses so that this resource is not ultimately wasted and discarded.

Notes

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CBM is an "unconventional" extraction method for natural gas and growth of CBM plays in the U.S. in the 1990s was partially spurred by tax credits for such sources. See Darin and Beatie, infra note 16 at 10573, n. 58 (describing the role of IRS code Section 29 tax credits for wells drilled between 1980 and 1992, with the tax break for industry to expire in 2002). Under the new administration, section 29 tax credits are back on the table. The House energy bill, passed in July of 2001, and now in conference with the Senate energy bill, would extend the credit to new wells drilled before 2007 and continue the credit for old wells through 2007. See House Resolution 4, § 3306(a) (2001). If this provision becomes law, one can only expect CBM production to receive even more heightened focus. This massive subsidy is estimated to be approximately $20 billion in unneeded corporate welfare to an already thriving industry over the next decade. See Marianne Lavelle, High-Octane Help for the Not So Needy, U.S. News & World Rep., Feb. 26, 2001, at 46.

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10. David G. Hill et al, of the Gas Research Institute, Changing Perceptions Regarding the Size and Production Potential of Coalbed Methane Resources (March 27, 2000), available at the Strategic Research Institute, 333 7th Ave., New York, NY 10001-5004. The SRI website is: *http://srinstitute.com*. See also Schraufnagel and Schafer, Major U.S. Coal-Bed Methane Resources (1996) (similar figures for each basin).

11. U.S. Dept. of Interior, Bureau of Land Management, 2002 Budget Justifications 1–18 (2001).

12. Oil and gas production on federal lands is now BLM's "Number one priority." Recently, BLM announced that to one western state BLM office that "when an oil and as lease parcel or when an APD [drilling permit request] comes in the door, that this work is their No. 1 priority." See U.S. Dept. of Interior, Information Bulletin UT 2002-008 (Jan. 2002) (after BLM D.C. completed a review of the Utah BLM's oil and gas programs, the Utah BLM office was strongly criticized for allowing Endangered Species Act consultation to delay leasing decisions and for slowing down leasing for oil and gas pending the inventories of nominated wilderness study areas). On May 18, 2001, President Bush signed Executive Order 13,212, providing that, "For energy-related projects, agencies shall expedite their review of permits or take other actions as necessary to accelerate the completion of such projects." Exec. Order 13,212, 66 Fed Reg. 28,357, § 2 (2001). Since that time, the Dept. of Interior and BLM have taken measures to aggressively implement the National Energy Policy, including developing an energy office within BLM and requiring personnel to complete statements of adverse energy impacts when taking an action that could impede energy production. In addition, BLM developed a list of time sensitive land use plans (called resource management plans) to be placed on a "high priority" fast track for amendment to allow for significantly higher levels of oil, gas and particularly CBM development. See U.S. Dept. of Interior, Instruction Memorandum No. 2002-081, Time Sensitive Plans, National Planning Support Team and Action Plan for Time Sensitive Plans (Feb. 4, 2002) (listing 21 planning projects as time sensitive and high priority, including amending the land use plans for the BLM field offices administering public lands within the Wyoming and Montana Powder River Basin, San Juan Basin in New Mexico, Raton Basin in Colorado and Uinta Basin in Utah).

13. Also unique to CBM extraction are the energy requirements necessary to power not just booster compressors and larger compressor facilities, but also submersible water pumps in each CBM well to facilitate bringing the water to the surface. In Wyoming, this power is supplied from thousands of diesel generators, gas-fired generators and, currently, three proposed coal-fired power plants—all of this fossil fuel power generation, being used, ironically, to liberate yet another fossil fuel. To this date, no state or federal agency has conducted a cost benefit analysis concerning the net BTU gain when obtaining CBM by using all of these power sources.

14. Paul Tolme, Water Worries, Newsweek at 11 (May 13, 2002).

15. U.S. Dept. of Interior, Bureau of Land Management, Draft Environmental Impact Statement and Draft Planning Amendment for the Powder River Basin Oil and Gas Project, Vol. 1, 4-12, 4-23 (Jan. 2002) [hereinafter, "BLM, BLM, WY PRB DEIS"]

16. See Thomas F. Darin and Amy W. Beatie, Debunking the Natural Gas "Clean Energy" Myth: Coalbed Methane in Wyoming's Powder River Basin, 31 Envtl. L. Rpt. 10566 (2001) (discussing history of CBM, environmental impacts, CBM permitting processes; BLM CBM regulatory legal issues; Clean Water Act concerns; Safe Drinking Water Act problems; state agency regulatory problems and nuisance and trespass possibilities); M. Kristeen Hand and Kyle R. Smith, The Deluge: Potential Solutions to Emerging Conflicts Regarding On-lease and Off-lease Surface Damage Caused by Coal Bed Methane Production, 1 Wyo. L. Rev. 661 (2001) (analyzing CBM surface disturbance and water impacts as affecting surface estate owners); Kathy Jean Flaherty, Quandary or Quest: Problems of Developing Coalbed Methane as an Energy Resource, 15 J. Nat. Resources & Envtl. L. 73 (1999–2000) (discussing the competing interests in developing coal resources and CBM); Amy Callard, Southern Ute Indian Tribe v. Amoco Production Company: A Conflict Over What Killed the Canary, 33 Tulsa L.J. 909 (1999); Markus G. Puder, Did the Eleventh Circuit Crack "FRAC"?—Hydraulic Fracturing After the Court's Landmark LEAF Decision, 18 Va. Envtl. L.J. 508 (1999) (discussing the ramification's of the 11th Circuit's decision that required EPA to regulate the production

stimulation practice of injecting fracturing fluids into coal seams to enhance recovery).

17. As new CBM plays are discovered in these regions, the water quality and quantity are surely subject to vary; therefore, as new CBM plays are discovered where the quality and quantity of the byproduct water approach that of Montana and Wyoming, the calls for state regulatory reform in this Article would apply equally to those situations.

18. This notion is supported by the fact that Utah, New Mexico, Colorado, Montana and Wyoming all have placed oil and gas produced water under the jurisdiction of the state oil and gas commissions—and not requiring a beneficial use permit for the point of first diversion (this holds true for all conventional oil and gas byproduct water in these states). In other words, if the "beneficial use" of the water was actually the secondary effect of allowing the gas or oil to be mined, then there would not be a need to except this water from the traditional requirements of receiving a beneficial use permit from the state engineer. The mere existence of the exception, therefore, strongly implies that the water itself is not being put to a beneficial use. These concepts are more thoroughly discussed infra.

19. For a more thorough discussion, see, e.g., Darin and Beatie, supra note 16, at 10572–10574 (notes 51–82).

20. See Hill, supra note 10, and accompanying text, for major CBM plays in the western United States.

21. U.S. Geological Survey, USGS Fact Sheet FS-019-97, "Coalbed Methane—An Untapped Energy Resource and an Environmental Concern," (1997).

22. U.S. Dept. of the Interior, Colorado Bureau of Land Management, Notice to Lessees (NTL) 88-2, 1 (Dec. 3, 1998). Recently, the Department of Interior Board of Land Appeals affirmed this principle, holding that underlying environmental studies for deep conventional gas were insufficient to allow leasing and production of CBM—due to its unique and different environmental impacts. Wyoming Outdoor Council, 156 IBLA 347 (2002). In general, deep, conventional gas averages 5 to 10 barrels of water per day (1 barrel equals 42 gallons) whereas, in Wyoming for example, CBM water production averages 500 barrels per day (per well) and can easily exceed, in some instances, 2,000 barrels per day. See., e.g., U.S. Dept. of Interior, Wyoming Bureau of Land Management, Draft Environmental Impact Statement—Jonah Field II Natural Gas Project 2-14 (July 1997) (average produced water from conventional natural gas field between .5 and 10 barrels per day); Darin and Beatie, supra note 16, at 10575 n. 90, 91 and accompanying text (average CBM production per well in Wyoming at 15 gallons per minute (equating to 514 barrels per day; with some wells at 85 gpm, or over 2,900 barrels per day). Due to these differences, CBM wells are in fact different than conventional gas wells, as they contain a separate handling and separation system to deal with the significantly different water quantities. In Wyoming, BLM recognized as early as 1990 that its land use plans for oil and gas did not account for or even mention (let alone study and analyze) these unique attributes of CBM production. See, e.g., U.S. Dept. of Interior, Wyoming Bureau of Land Management, Decision MM-7, Plan Change 2 1 (1990) (in discussing the Buffalo land use plan (RMP) covering the Powder River Basin, Program Leader Richard Zander stated, "RMP did not cover this non-traditional type of oil and gas activity."); U.S. Dept. of Interior, Wyoming Bureau of Land Management, Coal Bed Methane Environmental Assessment 3 (March 1990) ("The Buffalo RMP did not address the removal of large quantities of water in its evaluation of oil and gas development.").

23. Other regulatory issues not addressed herein are water quality issues and Clean Water Act discharge permits, reinjection of produced water pursuant to the Underground Injection Control program of the Safe Drinking Water Act, regulation of drilling operations by state oil and gas conservation commissions, and the federal leasing, project approval and permitting of CBM wells. Each one of those topics is an article unto itself—see generally, however, Darin and Beatie, supra note 16, at 10594–97 (CWA issues discussed in context of CBM development); 10597–98 (discussing the Safe Drinking Water Act). In addition, byproduct water typically associated with oil and gas production has been exempted from regulation under the Resource Conservation and Recovery Act, 42 U.S.C. §§ 6901–6991 (1984); see generally Richard Ottinger, Strengthening of the Resource Conservation and Recovery Act in 1984: The Original Loopholes, the Amendments, and the Political Factors Behind Their Passage, 3 Pace. Envtl. L. Rev. 1, 10–11, n. 49 (1985).

24. Linda Malone, The Necessary Interrelationship Between Land Use and Preservation of Groundwater Resources, 9 UCLA J. Envtl. L.& Pol'y 1, 1–2 (1990).

25. Michele Engel, Water Quality Control: The Reality of Priority in Utah Groundwater Management, 1992 Utah. L. Rev. 491, 495 (1992).

26. See generally John W. Anderson and John L. Davis, Water and Mineral Development Conflicts, 32 Rocky Mtn. Min. L. Instit. 9-1, 9-27 (1986) ("The foundation upon which western water law rests is the economical use of water and the suppression of waste.").

27. J. David Aiken, Ground Water Mining Law and Policy, 53 U. Col. L. Rev. 505, 510 (1982).

28. Malone, supra note 24, at 8–10. See Frank J. Trelease, Law, Water and People: The Role of Water Law in Conserving Natural Resources in the West, 18 Wyo. L.J. 3, 4–5 (1963) (the two cardinal principles of the prior appropriation system are, "that beneficial use of water, not land ownership, is the basis of the right to use water, and the priority of use, not equality of right, is the basis of the division of water between appropriators when there is not enough for all."). Utah, New Mexico, Colorado, Montana and Wyoming are prior appropriation groundwater law states. Id. See also Aiken, supra note 27, at 510 n.23. Other groundwater law approaches include absolute ownership (or "English rule" where every landowner has an absolute right to withdraw any and all groundwater), reasonable use (or "American rule" where groundwater withdrawals are limited to what a landowner can reasonably use based upon the amount and type of use) and correlative rights (where landowners overlying the same water source have equal rights, and in periods of scarcity, water is apportioned with respect to land surface acreage). See generally Malone, supra note 24, at 5–8; Aiken, supra note 27, at 511; Engel, supra note 25, at 499–500. See generally Wells A. Hutchins, Trends in the Statutory Law of Ground Water in the Western States, 34 Tex. L. Instit. 158 (1955) and Charles E. Corker, Inadequacy of the Present Law to Protect, Conserve and Develop Groundwater Use, 25 Rocky Mtn. Min. L. Instit. 23-1 (1979) (both providing

excellent overviews of the prior appropriation doctrine as applied to western groundwater). Not discussed in this article is the possible application to reserved federal water rights, recently held by the Arizona Supreme Court to apply to groundwater. In areas such as the Powder River Basin in Wyoming and Montana, where the federal government has reserved millions of acres of mineral estate under homesteading laws, it has not been addressed whether the federal government has any implied reservation—and therefore control—over groundwater diversions with massive CBM dewatering of aquifers. See generally E. Brendan Shane, Water Rights and Gila River III: The Winters Doctrine Goes Underground, 4 U. Denv. Water L. Rev. 397 (2001). In all five states discussed herein, it is presumed that the states have regulatory control over groundwater withdrawals involving public lands administered by the Bureau of Land Management. This, in fact, is most likely appropriate given that the government to have a reserved right, must own the surface in question, whereas in the Wyoming Powder River Basin, for example, nearly 4 million acres are private surface/federal mineral (split-estate). See U.S. Dept. of Interior, Wyoming Bureau of Land Management, Buffalo Resource Management Plan Draft Environmental Impact Statement 84 (1984).

29. See George W. Pring and Karen A. Tomb, License to Waste: Legal Barriers to Conservation and Efficient Use of Water in the West, 25 Rocky Mtn. Min. L. Instit. 25-1, 25-17-18 (1979) ("If water is not beneficially used, it is waste. There exists in all prior appropriation states either a duty not to commit waste or a duty to use water beneficially.").

30. Aiken, supra note 27, at 510.

31. In New Mexico, for example, all groundwater is owned by the state in trust for its citizens, and one must seek a permit from the state engineer, demonstrating beneficial use, to obtain a water right. Robert A. McCleskey, Maybe Oil and Water Should Mix—At Least in Texas Law: An Analysis of Current Problems with Texas Groundwater Law and How Established Oil and gas Law Could Provide Appropriate Solutions, 1 Tex. Wesleyan L. Rev. 207, 222 (1994). See generally Malone, supra note 24, at 12–14. Each of these five western states' approaches to the permitting and adjudication of groundwater rights will be discussed infra in more detail.

32. See, e.g., A. Dan Tarlock, Law of Water Rights and Resources § 6.03[3] (5th ed. 1993) (byproduct water from secondary oil and gas recovery traditionally exempted from groundwater appropriation requirements);

33. U.S. Environmental Protection Agency, Profile of the Oil and Gas Extraction Industry 52 (Oct. 2000). [hereinafter, "EPA, Profile Oil and Gas"].

34. EPA, Profile Oil and Gas, supra note 33, at 54–55.

35. C.F.R. § 143.3 (EPA's National Secondary Drinking Water Regulations). Wyoming's groundwater numeric standard for TDS relating to domestic uses is 500 ppm. See Wyoming Dept. of Envtl. Quality, Quality Standards for Wyoming's Groundwaters, Ch. VIII, Table 1.

36. See, e.g., Jim Bauder, Montana State University Soil and Water Quality Specialist, Coalbed Methane Gas and Montana Water Quality 2 (2000) (TDS up to samples showing 1,727 ppm acceptable for human consumption for those not on salt-restricted diets).

37. USGS, CBM WATER, supra note 7, at 1. USGS further notes that drinking water is recommended to be no higher than 500 ppm TDS and the beneficial use for stock ponds is from 1,000 to 2,000 ppm TDS.

38. Lance Cook, Wyoming State Geologist, Geology of CBM in Wyoming 16 (April 4, 2002).

39. All data for these two charts was obtained on May 7, 2002, from the Wyoming Oil and Gas Conservation Commission's website available at *http://wogcc.state.wy.us*.

40. BLM, WY PRB DEIS, supra note 15, at 3–7.

41. Interview with Lance Cook, Wyoming State Geologist, June 14, 2002. Cook stated that as of June 2002 there are approximately 8,200 producing CBM wells in the Powder River Basin (with over 14,000 drilled) and almost all of the current producing wells are within the 200 to 600 foot depth. As the CBM play in the Basin spreads west and deeper formations are targeted, drilling depths can reach over 2,000 feet deep, in addition to the shallower wells.

42. BLM, WY PRB DEIS, supra note 15, at 3–4.

43. U.S. Dept. of Interior, Bureau of Land Management, Statewide Draft Oil and Gas Environmental Impact Statement and Amendment of the Powder River and Billings Resource Management Plans, 3–28 (Jan. 2002) [hereinafter, "BLM, MT PRB DEIS"].

44. BLM, MT PRB DEIS, supra note 43, at 3–25–26.

45. BLM, MT PRB DEIS, supra note 43, at 3–21.

46. Personal communication with David Tabet, Utah Geological Survey (April 1, 2002). [hereinafter, "Tabet communication"]. Two key formations are the Drunkards Wash and Blackhawk, with operators saying each 160-acre well sit could produce 1.8 billion cubic feet (BCF) to 2.4 BCF, respectively. In 2000, the DOE Energy Information Administration listed proved CBM reserves for Utah and the Uinta basin at 1.59 TCF based on a total of 494 producing wells at the time. Id.

47. Tabet communication, supra note 46.

48. Interview with John Baza, Associate Director, Oil and Gas and Gil Hunt, Technical Services Manager, Utah Division of Oil, Gas and Mining (April 1, 2002). [hereinafter, "Baza interview"]

49. Baza interview, supra note 48.

50. Baza interview, supra note 48.

51. Interview with Floyd Johnson, Asst. Field Manager, Utah Bureau of Land Management Price Field Office (April 1, 2002).

52. As stated, estimated recoverable reserves in the Uinta basin are now less than 2 TCF at 1.59 TCF. Tabet communication, supra note 46. However, as one learns when following CBM over time, the recoverable TCF number is a constantly moving target—it generally takes test wells and full plans of development with years of production to gather data on how much methane can be recovered based on existing technology and current economics. Other areas of future CBM interest in Utah include: Nelson formation coals in the eastern Uinta basin (of the Sego coalfield); the Dakota sandstone coals in southern Utah (of the Alton-Kolob coalfields); the Frontier and Adaville formation coals in northern Utah (in the western Henrys Fork coalfield); and the Straight Cliffs formation coals in southern Utah (of the Kaiparowits plateau coalfield). Id. The 1,000 CBM well figure for Utah, therefore,

may change radically over time. Therefore, as different coal formations are tapped, so too will produced CBM water quantity and quality.

53. Utah Const. of 1895, art. XVII, § 1.

54. Utah Code Ann. §§ 73-1-1; 73-1-3. See generally Engel, supra note 25, at 503–07.

55. Utah Code Ann. § 73-2-1(3)(a); (3)(b)(iii)(B).

56. Utah Code Ann. § 73-3-1. The requirements for obtaining a groundwater appropriation permit are in section 73-3-2 and the state engineer shall approve an application if: (a) there is in unappropriated water in the proposed source; (b) the proposed use will not impair existing rights or interfere with the more beneficial use of the water; (c) the proposed plan is physically and economically feasible; (d) the applicant has the financial ability to complete the proposed works; and (e) the application was filed in good faith and not for purposes of speculation or monopoly. Utah Code Ann. § 73-3-8(1).

57. Utah Code Ann. § 73-3-8(2).

58. Utah Code Ann. § 40-6-5(3)(d) (first enacted in 1953). For a discussion concerning conflicts in Utah between prior appropriation groundwater rights and traditional mining water diversions, see Edward W. Clyde, Mineral Rights Versus Water Rights, 2 Natural Resources Law 299–328 (1969). Clyde observed that water associated with mineral production constitutes waste of a valuable resource in semi-arid Utah. Id. at 302.

59. Utah ADC R649-9-1.1, "Waste Management and Disposal; Oil and Gas."

60. Utah ADC R649-9-3.1 and 2.

61. Utah ADC R649-9-3.4.2.

62. Utah ADC R649-9-3.4.3.

63. Utah ADC R649-9-3.4.4.

64. Utah ADC R649-5-2.1.

65. Baza interview, supra note 48.

66. EIA, Rocky Mountains, supra note 4, at 1. Currently, there are 2,849 producing CBM wells in New Mexico, all within the New Mexico BLM Farmington Field Office resource area. Interview with David Mankevich, New Mexico Bureau of Land Management Farmington Field Office (April 1, 2002) [hereinafter "Mankevich interview"]. But see Personal Communication with Steven Hayden, New Mexico Oil Conservation Division (April 3, 2002) [hereinafter, "Hayden communication"] (stating the active producing wells in this area totals 3,005). For the entire San Juan basin spanning into southwestern Colorado, there are 4,050 producing CBM wells at this time. Mankevich interview, supra note 66.

67. Hayden communication, supra note 66.

68. Hayden communication, supra note 66 (total cumulative water production from 1989 to 2002 at 134.5 million barrels).

69. Cook, supra note 38, at "Water Quality Comparisons"

70. Mankevich interview, supra note 66 (2,849 existing wells plus 2,223 expected in the next 20 years).

71. CBM production is also occurring in very small quantities in the Raton basin in northeast New Mexico; however, no data was obtainable concerning ongoing production, produced water or reasonably foreseeable development scenarios. Indeed, the New Mexico Raton basin CBM play will probably be comparable to the Raton basin CBM development ongoing across the border in Colorado. The Colorado Raton basin CBM play is discussed infra.

72. New Mexico Const. of 1911, art. XVI, § 1.

73. New Mexico Const. of 1911, art. XVI, § 3. The constitutional provision on waters of the state being owned by the public and subject to appropriation for beneficial use, applies only to surface waters. New Mexico Const. of 1911, art. XVI, § 2.

74. N.M. Stat. Ann. § 72-12-1.

75. N.M. Stat. Ann. § 72-12-2. Traditional mine dewatering is not defined as a "beneficial use" in New Mexico. One author has pointed out the anomaly therefore that a mining company—much like a CBM company today—can waste water by dewatering a mine and dumping it down an arroyo (all legally and without the need for a permit), while if that same water is put to a beneficial use, the strict permit requirements must be met. See Barbara G. Stephenson and Albert E. Utton, The Challenge of Mine Dewatering to Western Water Law and the New Mexico Response, 15 Land and Water L. Rev. 445, 453–54 (1980). The article also provides a brief overview of groundwater appropriation regulatory systems in Wyoming, Colorado, Montana and Utah. Id. at 458– 70.

76. N.M. Stat. Ann. § 72-12-3.

77. N.M. Stat. Ann. § 72-12-3.E.

78. N.M. Stat. Ann. § 72-12-12.

79. N.M. Stat. Ann. § 72-12-25. According to the New Mexico Energy, Minerals and Natural Resources Department, some of the current New Mexico CBM production is above 2,500 feet (or is below 2,500 feet and can be potable). To date, the New Mexico state engineer has declined to exercise any jurisdiction over these groundwater diversions. Personal Communication with Stephen C. Ross, Asst. General Counsel, New Mexico MNRD (April 1, 2002). See also Bliss v. Dority, 225 P.2d 1007, 1011 (N.M. 1950) (state engineer has jurisdiction only on groundwater with reasonably ascertainable boundaries, and the state engineer is vested with the discretion to define those underground waters). The court also held that the New Mexico prior appropriation groundwater act was constitutional. Bliss, 225 P.2d at 1012. An interesting case on groundwater diversions for oil and gas is Mathers v. Texaco, 421 P.2d 771 (N.M. 1966). In Mathers, the Mexico Supreme Court discussed the requirements that all groundwater diverters—even those for oil—had to receive a state engineer beneficial use permit when appropriating from a declared underground basin. This suggests that all byproduct water should be permitted through the state engineer. A key distinction is that the water needing a beneficial use permit in Mathers was used in oil field flooding—it was not byproduct water. Mathers, 421 P.2d at 773. This suggests that for oil and gas production, water is only considered a "beneficial use" when it is being used to facilitate production subsequent to its initial diversion from the ground (as opposed to merely being pumped out of the ground as a byproduct of production) In the latter instance, western water law has treated this as byproduct waste and the water itself, not a beneficial use. As will be discussed infra this concept has important application to Wyoming's treatment of CBM byproduct water.

80. N.M. Stat. Ann. § 70-2-12.B(15) (first enacted in 1953).

81. N.M. Stat. Ann. § 72-12A-2.A(2), (3).

82. N.M. Stat. Ann. § 72-12A-3.B.

83. See Personal Communication with Frank Chavez, Oil and Gas Inspector, District 3, New Mexico Oil Conservation Division (May 12, 2002) (stating that the NMOCD has jurisdiction over "produced water" pursuant to its rules and regulations and the Mine Dewatering Act does not apply); see also Lawrence J. Wolfe and Jennifer G. Hager, Wyoming's Groundwater Laws: Quantity and Quality Regulation, 24 U. Wyo. L. Rev. 39, 65, 66 (1989) (discussing the Act as specifically to mines, and oil and gas byproduct water is discussed separately).

84. N.M. Reg. § 19.15.1.13.

85. N.M. Reg. § 19.15.1.18;.19. For surface reservoirs, those are strictly regulated as waste management facilities, subject to detailed plans demonstrating no contamination of water sources. N.M. Reg. § 19.15.9.711.

86. Mankevich interview, supra note 66.

87. N.M. Reg. § 19.15.9.701.A.1. All salt water disposal is required to be in a zone having TDS exceeding 10,000 ppm, meaning that this is disposal, and not retrieval injection. In other words, the water is permanently lost for whatever beneficial purposes it could serve in the future. N.M. Reg. § 19.15.9.701.E(2).

88. N.M. Reg. § 19.15.S.7.1(b); S.9.1(a).

89. See Charles T. DuMars, New Mexico Water Law: An Overview and Discussion of Current Issues, 22 Nat. Res. J. 1045, 1045 (1982) ("The common theme to all [prior appropriation] states is that beneficial use means application of water to a lawful purpose which is use to the appropriator and at the same time is a use consistent with the general public interest in having water utilized to its maximum."). DuMars further states that the requirement of putting water to a beneficial use is because "Water is a precious commodity and in scarce supply." Id. at 1046.

90. The Colorado portion of the Uinta basin as well as the Piceance basin in Colorado have high CBM reserves, but little if any CBM production is now occurring in those areas. They are certainly targets for future development however.

91. U.S. Dept. of Interior, Bureau of Land Management, Draft Environmental Impact Statement: Oil and Gas Development on the Southern Ute Indian Reservation 3-47 (Oct. 2000). [hereinafter, "BLM, SUIT DEIS"].

92. Interview with Jim Powers, Colorado Bureau of Land Management, San Juan Field Office (April 1, 2002).

93. BLM, SUIT DEIS, supra note 91, at 4–98.

94. This data is available on the Colorado Oil and Gas Conservation Commission's website, *http://oil-gas.state.co.us/statistics.html*.

95. BLM, SUIT DEIS, supra note 91, at 3–65

96. Interview with Helen Mary Johnson, Minerals Staff Chief, Colorado Bureau of Land Management, San Juan Field Office (May 9, 2002).

97. Personal Communication with Tom Morrissey, East of Huajatolla Citizens Alliance (March 31, 2002). [hereinafter, "Morrissey communication"].

98. U.S. Dept. of Interior, Bureau of Land Management, Environmental Assessment Record: Minerals—Raton Basin Coal Bed Methane Development 16 (Sept. 2001). [hereinafter, "BLM, Raton Basin EA"].

99. Morrissey communication, supra note 97.

100. Morrissey communication, supra note 97.

101. BLM, Raton Basin EA, supra note 98, at 37.

102. Colo. Const. of 1876, art. XVI. §§ 5,6.

103. Colo. Rev. Stat. §§ 37-90-101-143 (1997). See Upper Black Squirrel Creek Ground Water Management Dist. v. Goss, 993 P.2d 1177 (Colo. 2000) (en banc).

104. Goss, 993 P.2d at 1182.

105. Colo. Rev. Stat. § 37-90-107(1).

106. Colo. Rev. Stat. § 37-90-137(4).

107. See generally Justice Gregory Hobbs, Colorado Water Law: An Historical Overview, 1 U. Denv. Water. L. Rev. 1, 21 (1997).

108. Colo. Rev. Stat. § 37-90-137(7)(a), (b) (first enacted in 1963).

109. Scores of questions and concerns abound here, probably worthy of a separate article. First, Colo. Rev. Stat. § 37-90-107 speaks of appropriating water from a designated basin for a beneficial use—does that include mine dewatering for oil and gas? Second, 37-90-137(7) only speaks to tributary v. non-tributary—perhaps this exception applies to designated groundwater basins that are non-tributary. Third, the whole issue of tributary v. non-tributary—particularly as over some temporal scale, all surface and groundwater is invariably intertwined—is far from black and white. In the case of CBM, for example, where drilling may occur in depths of 1,000 to 2,000 feet, the coal aquifers may be defined as tributary—and therefore not allowing this exception. An important study on this issue was recently concluded in the San Juan basin Fruitland formation. The study researched the connection between massive dewatering of the Fruitland coal aquifers and the effect on surface waters, concluding:

CBM development will deplete a maximum of 140 ac-ft/yr of surface flows from the Animas, Pine and Florida rivers by the year 2050. A further depletion of 15 to 60 ac-ft/yr can be expected for the Piedra River, given the similar hydrogeologic characteristics and assuming the future level of CBM development in the area near the Piedra River will be the same as that experienced in La Plata County. As of 2001, approximately 65 ac-ft/yr are being depleted from surface waters. Depletions will continue to increase as long as CBM production occurs, although most of the impacts will occur within the next 30 to 50 years. [Dave Cox et al., San Juan Basin Ground Water Modeling Study: Ground Water—Surface Water Interactions Between Fruitland Coalbed Methane Development and Rivers 5 (Oct. 2001)]

This certainly raises the specter that CBM byproduct water may be in some instances so linked to surface hydrology as to constitute tributary groundwater. On this point, non-tributary groundwater is defined as, "groundwater, located outside the boundaries of any designated groundwater basins, . . . the withdrawal of which will not, within one hundred years, deplete the flow of a natural stream, . . . at an annual rate of greater than one-tenth of one percent of the annual rate of withdrawal." Colo. Rev. Stat. § 37-90-103(10.5). "Tributary groundwater" means water in an unconsolidated alluvial aquifer of sand, gravel, and other sedimentary material and all other waters hydraulically connected thereto which can influence the rate or direction of movement of the water in that alluvial aquifer or natural stream. Colo. Rev. Stat. § 37-92-103(11) (emphasis added). For a thorough discussion of these concepts, see American Water Development Inc. v. City of Alamosa, 874 P.2d 352

(Colo. 1994) (en banc). Tributary and non-tributary was once again at issue in Bayou Land Co. v. Talley, 924 P.2d 136 (Colo. 1996) (en banc). An interesting consideration in the CBM context is that the right to extract non-tributary groundwater not in a designated basin is incident to land ownership. Bayou Land Co., 924 P.2d at 145. In the mineral context, there is usually a conveyance of the mineral (here, oil and gas) rights, but not necessarily the surface interest, raising at least a question concerning an operator's right to divert billions of gallons of groundwater attached to the surface estate.

110. Cox, supra note 109, at 5.

111. COGCC Rules, Exploration and Waste Management, § 907(c)(1).

112. COGCC Rules, Exploration and Waste Management, § 907(c)(2)(A)-(E).

113. COGCC Rules, Exploration and Waste Management, § 907(c)(2)(E).

114. The 1.8 billion gallons was calculated as of February 2002 by data available on the Montana Board of Oil and Gas Conservation, *http://www.bogc.dnrc.state.mt.us/OnlineData.htm*, See also ALL Consulting, Water Resources Technical Report: Montana Statewide Oil and gas Environmental Impact Statement and Amendment of the Powder River and Billings Resource Management Plans 12 (June 2002) (1.4 billion gallons for 200 wells producing measured in April 2001).

115. BLM, MT PRB DEIS, supra note 43, at Minerals Appendix, MIN-5, MIN-22.

116. ALL Consulting, supra note 114, at 7 n.2, n.3.

117. ALL Consulting, supra note 114, at 34.

118. BLM, MT PRB DEIS, supra note 43, at 4–36, 4–37 (emphasis added).

119. BLM, MT PRB DEIS, supra note 43, at 4–36, 3–28.

120. Mont. Const., art. IX, § 3(3).

121. Mont. Const., art. II, § 3.

122. Mont. Const., art. IX, § 1(1). These provisions were given teeth in the landmark case, Montana Environmental Information Center v. Dept. of Envtl. Quality, 988 P.2d 1236 (Mont. 1999). In MEIC, the Montana Supreme Court held that a 1995 amendment to the Montana Water Quality Act that exempted a class of water discharges from any nondegradation review, where the water discharges in question would have added arsenic to a receiving water above its baseline quality, violated the plaintiffs' rights to a clean and healthful environment. MEIC, 988 P.2d at 1249.

123. Montana's groundwater appropriation statute is similar to other western states. The permit, priority rights and beneficial use requirements can be found in Mont. Code. Ann. §§ 85-2-501-520.

124. See e.g., Mont. Code. Ann. § 82-11-111(2)(a) (first enacted in 1953) (jurisdiction over regulating disposal of oil and gas byproduct water is vested with the MBOGC). The mere fact that Utah, New Mexico, Colorado and Montana all leave this byproduct water to the handling of state oil and gas commissions underscores the point that the water itself is not considered a beneficial use—otherwise, the control over diverting the water would reside with the state engineer. In an interview with Tom Richmond, Administrator, Montana Board of Oil and Gas Conservation, it was confirmed that traditional oil and gas byproduct water is "under the prior jurisdiction of the MBOGC." Interview with Tom Richmond, May 10, 2002. This is consistent with Montana's administrative rules that place the control of this water with the Board. If the water is 15,000 ppm TDS or less, disposal may be disposed of "in any manner that does not degrade surface waters or groundwater or cause harm to soils." Mont. ARM § 36.22.1226(1). If above that threshold, disposal must be pursuant to a Class II UIC injection well or board-approved lined or unlined pits. Id. at § 36.22.1226(2)(a), (3). Montana has strict regulations that apply to these above-ground reservoirs (pits) for high TDS produced water to protect the water table, requiring the pits to be lined with an impermeable layer. Id. at § 36.22.1227(1), (2)(b). Because of the more specific statutory 2001 amendment addressing CBM water, these provisions are considered not to apply in this context. Richmond Interview.

125. Mont. Code. Ann. § 85-2-505(1).

126. House Bill 573, Allow oil and gas board to permit certain coal bed methane gas wells, 2001 Montana Legislative Session, codified at Mont. Code Ann. § 85-2-505(1)(e) (2001).

127. Mont. Code. Ann. § 85-2-505(1)(e) (2001).

128. Mont. Code. Ann. § 85-2-521(2)(a)-(c) (2001). In addition, "Prior to the development of a coalbed methane well that involves the production of ground water from an aquifer that is a source of supply for appropriation rights or permits to appropriate under this chapter, the developer of the coal bed methane well shall notify and offer a reasonable mitigation agreement to each appropriator of water who holds an appropriation right." Mont. Code. Ann. § 85-2-521(3)(a) (2001). Noteworthy is that the Montana legislature, following traditional notions of water being required to be put to a useful purpose itself to fit under the groundwater prior appropriation doctrine, did not declare the liberation of the methane natural gas to be a beneficial use. If that had been the legislative finding (that liberating the methane was the beneficial use), then there would have been no need to declare the billions of gallons of byproduct water each year as no constituting "waste."

129. This topic, like many others in this paper, is scientifically complex. See generally Larry Munn, Coalbed Methane Product Water Quality Issues (August 16, 2000); Larry Munn, Water on the Land in the PRB (August 22, 2000); Larry Munn, Coal Bed Methane Product Water and Wyoming Agriculture (Oct. 12, 2000); Jim Bauder, Montana State University Soil and Water Quality Specialist, Coal Bed Methane (CBM)—Manna, Mania or Maiming! (2000) (reporting an average SAR value of 34.8 for CBM discharge wells in Montana—40 times the SAR value of .79 in the Montana portion of the Tongue River; with total dissolved solids 4 times that of the Tongue River); Jim Bauder, Some Guidelines About CBM Discharge Water Use (2000) (concluding that almost without exception, CBM discharge water in unsuitable for crop irrigation); Robert Mitchell, MT BLM soils scientist, Limiting Effects to the Tongue River Watershed from CBM Discharge Waters, at 5 (2000) (recommending an upper limit for EC and SAR values of 1.2 dS/m and 3, respectively, "to ensure a healthy aquatic system [with] limited effects for crop irrigation."). See also U.S. Dept. of Agriculture, Agricultural Handbook 60: Diagnosis and Improvement of Saline and Alkali Soils 71 (L.A. Richards ed., 1954). But see California Fertilizer Association, Western Fertilizer Handbook 41 (8th ed. 1995) (<.7 electrical conductivity (an alternative way of expressing the different measure of TDS) poses no restriction on use for irrigated crops; .7 to 3.0 poses a slight to

moderate restriction on use; and 3.0 places a severe restriction). For a thorough overview of CBM water quality in the Powder River Basin and agricultural impacts, see Darin and Beatie, supra note 16, at 10576–77 and accompanying notes.

130. Because of likely Clean Water Act violations due to the TDS and SAR values of produced CBM water in Wyoming, EPA has ranked the current draft EIS an "EU-3"—the worst possible environmental ranking EPA can give. "EU" means that the project, as proposed, would yield unsatisfactory impacts from a human health and public welfare point of view; "3" requires the agency, here, BLM, to start again with a new draft EIS to explore the full range of alternatives and mitigation options it failed to do the first time around. One key impact concerned the SAR and TDS values of the produced water, which as discharged "would make the Tongue River and the Belle Fourche River unsuitable for irrigation." Likewise, there was no analysis as to how to mitigate this problem. Letter from Jack W. McGraw, Acting Regional Administrator, Environmental Protection Agency, Region VIII to Al Pierson, State Director, Wyoming Bureau of Land Management 2 (April 2002). See also Northern Plains Resource Council, Inc. v. Mont. Dept. of Envtl. Quality, In re: NPDES Permit No. MT-0030457 (Mont. Bd. of Envtl. Review, filed July 14, 2000) (appealing validity of NPDES permit issued by the Montana Department of Environmental Quality); Northern Plains Resource Council, Inc. v. Redstone Gas Partners, LLC, No. CV-00-110-M (D. Mont., amended complaint filed June 26, 2000) (action alleging violations of the Clean Water Act as defendants were discharging CBM wastewater without section 402 NPDES permits).

131. The average cow or heifer consumes approximately 14.5 gallons of water per day in the month of July. Paul Q Guyer, Water Requirements for Beef Cattle (G77-372-A), Institute of Agriculture and Natural Resources, University of Nebraska-Lincoln 2 (1977), available at *http://www.ianr.unl.edu/pubs/beef/g372.htm*. At peak production in Montana of over 300 million gallons per day (using 10 gpm for 26,000 wells), it is clear that only a few cows/sheep will beneficially use this water.

One proposed beneficial use of the discharged CBM water being advanced is that it can partially recharge near surface aquifers. This beneficial use theory seems circular in logic: the CBM dewatering process is what depletes the aquifers in the first place, so at best some of this water returning to an aquifer is recycling a portion of the water, not "beneficially" using it. In other words, it is a nonsequitur to advance that a small percentage of water is being beneficially used by replacing itself. Put yet another way—it is not plausible that taking the water out of the aquifer is a beneficial use in the first instance (as argued in Wyoming) and a portion of the water returning to the aquifer is also a beneficial use of the very same water. That accounting (or double-counting) rings bells of Enronomics.

132. Mont. Code Ann. § 85-2-506(2)(a)-(b) (2001).

133. In the Matter of the Designation of the Powder River Basin Controlled Groundwater Area, Final Order, Mont. Dept. of Natural Resources and Conservation 3 (Dec. 1999) [hereinafter, "In Re PRB Controlled Groundwater Area Order"].

134. Id. at 5–7. By statute, designating a controlled ground water area wherein oil or gas wells produce saline water confers production of the water "under the prior jurisdiction of the board of oil and gas conservation." Mont. Code. Ann. § 85-2-510 (2001). The DNR recognized this fact in its December 1999 order, but because "water rights matters and hydrogeologic issues are not within the ordinary technical expertise and area of concern to the Board," DNR adopted joint jurisdiction with the Board by adopting is own rules for appropriations in the area, discussed above. In Re PRB Controlled Groundwater Area Order, supra note 133, at 3–4. Simultaneously, the MBOGC adopted its own rules for handling CBM exploration, concerning well spacing (generally one well per section or 640 acres), drilling and casing requirements, public notice requirement for spacing exemptions, provisions concerning providing notice to existing water right holders, water well mitigation agreements and other issues. See In the Matter of the Board's Own Motion for an Order Establishing Coal Bed Methane Operating Practices within the Powder River Basin Controlled Groundwater Area in Big Horn, Powder River, Rosebud, Treasure and Custer Counties, Montana, Montana Board of Oil and Gas Conservation (Order 99-99) (Dec. 9, 1999).

135. Mont. Code Ann. §§ 85-2-508; 2-311 (2001).

136. Strong support against the argument that the so-called "beneficial use" of CBM water is the secondary effect that dewatering allows the methane to vent to the surface comes from the Montana legislature itself. "Waste" of groundwater includes "the application of water to anything but a beneficial use." Mont. Code. Ann. § 85-2-102(19) (2001) (emphasis added). If the beneficial use was this secondary effect, the legislature would not needed to declare it non-waste. In turn, "beneficial use" is defined, among other things, as a "use of water for the benefit of the appropriator . . . including . . . mining." Mont. Code. Ann. § 85-2-102(2)(a) (2001). If "mining" meant byproduct water associated with oil and gas, as opposed to the probable meaning of using water to mine (e.g., using in mine tailing ponds or the water used to actually drill an oil or gas well), then it would be considered a beneficial use, and therefore, not "waste." In other words, there would have been no need to amend Montana's water code if the "CBM byproduct water is a beneficial use because it allows for gas production" theory was correct. Therefore, with the 2001 amendment specifically declaring CBM byproduct water not to be "waste," the legislature established that the consequence of massive dewatering—allowing the methane to be captured—is not, in and of itself, a beneficial use. The point here is not to highlight a case of circular reasoning; rather, the legal consequences are significant—taking away this theory of beneficial use for the byproduct water means that the Montana ground water control area statute is being violated, as very little of the water is actually being put to a beneficial use as defined by the Montana legislature.

137. Personal Communication with Don Likwartz, Chairman, Wyoming Oil and Gas Conservation Commission (May 10, 2002). The WOGCC permits approximately 40 CBM wells for the PRB every single business day. The WY PRB DEIS provides that there are 12,000 drilled CBM wells 39,000 new wells by 2010 for a total of 51,000. See BLM, WY PRB DEIS, supra note 15, at xvi. This in addition to 3,200 new oil wells in the basin to be drilled in the same time frame. Id.

138. BLM, WY PRB DEIS, supra note 15, at Appendix A-2 (re-forecasting once again the recoverable CBM reserves to be 28 TCF).

139. This figure was obtained on April 1, 2002, from data provided on the Wyoming Oil and Gas Commission's website, *http://wogcc.state.wy.us/coalbedchart.cfm*.

140. BLM, WY PRB DEIS, supra note 15, at 2–24.

141. See ALL Consulting, supra note 114, at 7 n.2. The math is: 9.5 gpm X 60 minutes/hour X 24hours/day X 365 days/year X 20 years. This equals 5 trillion gallons.

142. BLM, WY PRB DEIS, supra note 15, at xxiii.

143. BLM, WY PRB DEIS, supra note 15, at 3–7.

144. BLM, WY PRB DEIS, supra note 15, at 4–12.

145. BLM, WY PRB DEIS, supra note 15, at 4–11, 3–13.

146. As the Wyoming Powder River Basin CBM project is the largest CBM field contemplated in the United States, and by far the largest natural gas project ever considered for approval by the Department of Interior, it is the Wyoming focus of this article. Other major CBM plays in Wyoming include south central Wyoming, where there is currently an EIS underway to study 3,880 wells near the Atlantic Rim. See U.S. Dept. of Interior, Bureau of Land Management, Notice of Intent to Prepare an Environmental Impact Statement and Conduct Scoping for the Atlantic Rim Coalbed Methane Project, Carbon County; and to Amend the Great Divide Resource Management Plan, 66 Fed. Reg. 33975-76 (June 26, 2001). Water quality in that area can be gleaned from the Hanna Draw CBM project, where TDS range from 982 to 2,420 ppm averaging close to 1,000 ppm; these wells are tapped into the Hanna No. 2 coal seam at depths from 4,000 to 6,000 feet. U.S. Dept. of Interior, Wyoming Bureau of Land Management, Rawlins Field Office, Environmental Assessment for the Hanna Draw Coalbed Methane Exploration Project, Carbon County, Wyoming 89–91 (Jan. 2002). The big unknown for Wyoming at the present time is the Greater Green River Basin, which holds 314 TCF of CBM reserves. The Atlantic Rim project is proposed on the southeastern part of that basin and in the northeast portion, just miles from the Bridger-Teton National Forest is the Big Piney CBM project, which has 5 exploratory wells. See U.S. Dept. of Interior, Wyoming Bureau of Land Management, Pinedale Field Office, Environmental Assessment for Infinity Oil and Gas of Wyoming, Inc.'s Coalbed Methane Pilot Test Project 34–37 (Oct. 2000) (TDS ranging from 2,230 to 3,160 ppm at depths of 2,500 to 3,400 feet (targeting the Mesaverde coals)). That water is being disposed of by injection wells to a disposal aquifer at a depth of 3,300 feet. Id. at 20. After initial production, the operator now plans on expanding that particular project to full field development of 125 CBM wells. Rob Shaul, Company Drilling Pilot Coal Bed Methane Wells West of Big Piney, Pinedale Roundup, Nov. 1, 2001, at 1, 12. The economics are different in the Greater Green River Basin, as target depths average 3,000 feet, compared to CBM wells drilled to depths of 200 to 1,000 feet in the PRB. Depending on how much of the 314 TCF of CBM reserves in the Greater Green River Basin prove to be recoverable, the CBM play in southwestern Wyoming has the unthinkable possibility of literally dwarfing the current 51,000 well project proposed for the PRB's 39 TCF of CBM reserves, 25 TCF of which are presently considered recoverable.

147. Wyo. Const. of 1889, art 1, § 31.

148. Wyo. Const. of 1889, art 8, § 3.

149. For an excellent overview of Wyoming groundwater law, see Wolfe and Hager, supra note 83. Wolfe and Hager note that due to minimal use of groundwater when Wyoming gained statehood, the state constitution may not have intended these provisions to apply. Id. at 42. This question remains an uncertainty.

150. Wyo. Stat. Ann. § 41-3-101.

151. Wyo. Stat. Ann. § 41-3-905.

152. Wyo. Stat. Ann. § 41-3-931.

153. Wyo. Stat. Ann. § 41-3-931.

154. Wyo. Stat. Ann. § 41-3-906.

155. Wyo. Stat. Ann. § 41-3-907 (emphasis added).

156. Wyo. Stat. Ann. § 41-3-102(b), by application of Wyo. Stat. Ann. § 41-3-906. See Wolfe and Hager, supra note 83, at 53–54.

157. Wyo. Stat. Ann. § 30-5-104(d)(ii)(D).

158. Interview with Dick Stockdale, Wyoming Deputy State Engineer (May 8, 2002).

159. Wyoming State Engineer Rules, Ch. I, Wyoming Water Administration, § 5 ("A permit to drill a water well must be obtained from the State Engineer. Upon the completion of a well, beneficial use of the water, and preparation of a proper form, proofs are presented to the State Board of Control for adjudication. The statutes give authority to the State Engineer to resolve disputes involving interference between ground water appropriations or between surface water and ground water appropriations."). See also Wyoming State Engineer Rules, Ch. I, Wyoming Water Administration, § 4.a. ("A Wyoming water right is a right to use the water of the state when it has been applied to a beneficial use as defined by law and its appropriation has been made in conformance with the applicable rules and regulations."); Wyoming State Engineer Rules, Ch. I, Purpose of Standards, § 2.a. (requiring permit from state engineer to appropriate groundwater).

160. Wyoming State Engineer Rules, Ch. I, Wyoming Water Administration, § 4.c.

161. Wyoming State Engineer Rules, Ch. I, Purpose of Standards, § 1.

162. First, a permit is submitted for appropriation pursuant to Wyo. Stat. Ann. § 41-3-905. Then, "as a matter of course," when the proposed use is beneficial and the diversion is within the public interest, the state engineer approves the permit. Wyo. Stat. Ann. § 41-3-931. Then next step is formal adjudication, pursuant to Wyo. Stat. Ann. § 41-3-935(a), (b), involving a statement of completion of the well, submission of proof of appropriation and establishing beneficial use. The more detailed requirements and procedures are within the rules. See generally Wyoming State Engineer Rules, Ch. III, Instructions for Preparing Ground Water Forms, §§ 1-5; Wyoming State Engineer Rules, Ch. V, Map and Survey Requirements for Maps to Accompany Proof of Appropriation and Beneficial use of Ground Water, §§ 1-15; Wyoming State Engineer Rules, Ch. IV, Adjudication of Proofs, §§ 2-3 (permit application, statement of completion, proof of appropriation and beneficial use of ground water, public notice requirements before adjudication, final adjudication and certificate of appropriation for recording the adjudicated right in the appropriate county recorders office procedures); Wyoming State Engineer Rules, Ch. II, Procedures and General Instructions for Obtaining a Ground Water Right, §§ 1-14. The process is also well described by Wolfe and Hager, supra note 83, at 48–53.

Obtaining a water right has two separate parts—permit and adjudication. Wyoming's Deputy State Engineer explained the permit process as three steps: (1) applying for a permit; (2) developing and submitting a statement of completion; and (3) submission of proof of appropriation and beneficial use. Stockdale interview, supra note 158. This allows for permit issuance, which provides the basis for adjudication. This second part (adjudication) involves: (1) submitting the proper form; (2) providing a map of the area; (3) a state engineer field inspection, including measuring static levels of the target aquifer; (4) public notification procedures with any opportunity for protest; (5) approval by the Board of Control; and (6) recordation of the water right certificate with the county recorder. The adjudication process serves to fix five things: priority date, location, quantity, type of use and point of use. Id. Virtually none of the CBM operators (all needing to have state engineer permits) have their rights adjudicated; however, once a permit has been properly approved, the Wyoming State Engineer considers a water right to attach, receiving full protection. Id.

163. Wyoming State Engineer's Office, Ground Water Production From Coal Bed Methane Wells 1 (Feb. 28, 2000).

164. Wyoming State Engineer's Office, Form U.W. 5 (revised as of May 1979).

165. Wyoming State Engineer's Office, Form U.W. 5 (revised as of March 1994).

166. Wyoming State Engineer's Office, Form U.W. 5 (revised as of March 1995). The latest revision of the form, revised in March of 1999, remains the same.

167. For a more detailed discussion of these issues under the CWA, see Darin and Beatie, supra note 16, at 10594–96.

168. This information was obtained from Jody Hopkins (now Pring), Senior Analyst, Surface Water Division, Wyoming State Engineer's Office and is current as of October 2001. (The 400 reservoir figure was calculated by extracting the subset of permitted stock reservoirs after November of 1999—when the WSEO started seeing stock reservoir permits for CBM retention in larger numbers—from all permitted reservoirs for the PRB counties of Johnson, Campbell and Sheridan.) The state engineer permits reservoirs in Wyoming (in addition to other agencies for CBM produced water purposes). Most of the 400 existing reservoirs for CBM water are permitted as "stock reservoirs," which must have a capacity of 20 acre-feet or less, with the dam fill height not to exceed 20 feet. See Wyoming State Engineer Rules, Ch. V "Reservoirs," § 6.

169. See Swartz v. Beach, No. 02 CV 044B (D. Wyo. filed March 2002) (landowner complaint filed due to upstream reservoir blocking natural flow and releasing CBM water harmful to soils and vegetation, based on theories of nuisance, trespass, the Clean Water Act and constitutional takings).

170. These are just some of the issues. As mentioned above, the PRB in Wyoming is slated for at least another 4,000 reservoirs or pits—most of which will be unlined and with drilled bore holes into the bottom to facilitate infiltration. Not addressed by anyone at this point is whether these pits, which are designed to concentrate contaminants through evaporation, then bleed into the water table, require Safe Drinking Water Act permits (as they may well indeed be considered an "injection well,") or a separate section 402 CWA permit at the bottom of the pit, as these drilled holes are a point source of pollution. There is strong evidence that there is a hydrologic between the water table into which these reservoirs intentionally leak and nearby surface waters. EPA, for example, notes that the reservoirs are designed for "optimum infiltration" and where surface reservoirs are located near or in stream channels, including ephemeral drainages, or in places close to the water table, they will have "a high probability of connection with surface waters." Letter from Stephen S. Tuber, Director, Water Programs, EPA Region 8 to Gary Beach, Administrator, Water Quality Division, Wyoming Dept. of Environmental Quality, March 15, 2002, at 1–2.

The manner in which these reservoirs are built or excavated when in ephemeral drainages (or "on channel") are permitted under section 404 of the CWA. See, e.g., Wyoming Outdoor Council v. Army Corps of Engineers, No. 1:02 CV 0077 HKK (D. D.C., filed Jan. 2002) (challenging a general permit for on-channel reservoirs for CBM water production in Wyoming). The regulatory haze does not end there—under Wyoming Environmental Quality, ponds used to handle industrial byproduct water require strict permit requirements from the WDEQ, yet another agency that needs to be involved in the permitting process. See 60-Day Notice of Intent to Sue, from Wyoming Outdoor Council to Dennis Hemmer, Administrator, WDEQ (March 18, 2002) (notifying of intent to sue as WDEQ has failed to permit aboveground reservoirs pursuant to Wyo. Stat. Ann. § 35-11-301(a)(iii), which requires permits for "disposal systems" or "treatment works" capable of causing or contributing to pollution). The key factual allegation is that WDEQ admits these reservoirs are designed to bleed CBM water into the alluvial aquifer, which can contribute to water pollution. Two matters are important here: first, the reservoir permitting Bermuda triangle in Wyoming is based on a term of art that byproduct water is labeled "waste"—this is at the disposal stage of analysis; second, while there is focus by agencies on handling the water once it is first diverted from the ground, that is a much different analysis than whether the primary issue of this Article of what is legally required when this water is first appropriated from underground (the initial diversion), with a primary emphasis on western groundwater appropriation law, beneficial use, public interest and preventing waste. No agency is addressing these latter concerns.

171. Through 2001, industry has drilled approximately 45 replacement wells for affected landowners, either voluntary or pursuant to surface use agreements. In 2002, a few more have been drilled, making the cumulative total close to 50. Interview with Dick Stockdale, Wyoming Deputy State Engineer (June 10, 2002).

172. Wyo. Stat. Ann. § 41-3-911(a).

173. Wyo. Stat. Ann. § 41-3-911(b). See also Wyoming State Engineer Rules, Ch. I, General Information, § 17:

> Any appropriator of either surface or ground water may file a written complaint alleging interference with his water right by a later priority ground water right. Complaints are to be filed with the State Engineer and must set out in detail the facts pertinent to the situation, Each complaint is to be accompanied by a fee of $100 to help defray the cost of the investigation, Upon receiving the complaint and fee, the State Engineer shall undertake an investigation to determine if the alleged interference does exist. Following the investigation, the State Engineer will issue a

report stating his findings and suggestions on various means of stopping, rectifying or ameliorating the interference or damage.

To date, however, no one in Wyoming has filed an official interference complaint along with the $100.00 filing fee. Stockdale interview, supra note 171. Perhaps one reason to explain this is that industry has voluntary agreed to drill or re-drill approximately 45 replacement wells for affected landowners. Id.

174. Wyo. Stat. Ann. § 41-3-933. This provision is generally interpreted to mean someone with a groundwater permit is not guaranteed any right to water level in his well. The phrase, "higher than that required for maximum beneficial use," however, implies a right to have the water at a level for the original appropriator's beneficial use (just not higher), and that a junior appropriator from the same source can be denied groundwater withdrawals interfering with that use pursuant to Wyo. Stat. Ann. § 41-3-911.

175. BLM, WY PRB DEIS, supra note 15, at 4–29.

176. BLM, WY PRB DEIS, supra note 15, at 4–11–12; 4–23. .

177. See Wolfe and Hager, supra note 83, at 62–64 (discussing interference procedures, and that after the state engineer's investigation and findings, a dissatisfied well owner can appeal, with the burden of proof on the landowner on reversing the state engineer. As a general rule, however, at this point, "whoever has the burden of proof in a groundwater case, loses."). See also Willadsen v. Christopulos, 731 P.2d. 1181, 1184 (Wyo. 1987) (holding that senior groundwater right holders had to show state engineer's "no interference" finding was erroneous by a "preponderance" of the evidence). An excellent discussion of the many legal and factual issues surrounding groundwater right interference claims in the context of mine dewatering is found in Joseph Novak, The Legal Dilemma in Dewatering Mines, 17 Rocky Mtn. Min. L. Instit. 657 (1972).

178. In the present debate, it should be noted that EPA has developed effluent limitation guidelines (ELGs) associated with oil and gas production. In general, applying best available control technologies to onshore operations: "there shall be no discharge of waster water pollutants [including produced water] into navigable waters from any source associated with production, field exploration, drilling, well completion or well treatment." 40 C.F.R. § 435.32. A subpart of the ELGs, however, applies to situations in which produced water has a use in agriculture or wildlife watering. To fit this exception, however, only that amount that is "actually put to such use during periods of discharge," may be released to surface waters of the U.S. See 40 C.F.R. §§ 435.50; .51(c). This underscores the point that even EPA, if allowing a discharge of the byproduct water at all, limits it to actual beneficial use for livestock and wildlife, suggesting the rest (and most of the water in the Wyoming/Montana CBM example) would be wasted and not appropriate for discharge to the surface waters. In 2001, EPA took the position that these ELGs for onshore oil and gas, developed in 1995, were not intended for CBM byproduct water, and initiated a new study to appropriate discharge conditions and parameters. See EPA Region 8 "Best Professional Judgment" (BPJ) Determination of Effluent Limitations That Represent Best Available Technology Economically Achievable (BAT) for Coalbed Methane (CBM) Activities; Announcement of Meeting, 66 Fed. Reg. 46,455 (Environmental Protection Agency, 2001).

179. The provisions regarding public interest review and preventing waste apply to any model used—whether the beneficial use permitting system in place or the "waste" byproduct exception currently not being used in Wyoming. In short, these mandatory duties do not disappear when one regulatory regime is used in place of another.

Similar to Montana, the Wyoming groundwater code provides for designation of a groundwater control area. The board of control may designate a control area for the following reasons:

(i) The use of underground water is approaching a use equal to the current recharge rate;

(ii) Ground water levels are declining or have declined excessively;

(iii) Conflicts between users are occurring or are foreseeable; or

(iv) The waste of water is occurring or may occur;

Wyo. Stat. Ann. § 41-3-912(a). Arguably, given the above information in the current draft EIS for 51,000 or more wells by 2010, and particularly given the admissions concerning recharge rate, groundwater declines and likely conflicts, each one of these four separate criteria has been or will be met in Wyoming's PRB. Moreover, whenever the state engineer has "information leading him to believe that any underground water district or subdistrict should become a control area," he "shall" report to the board of control all information on the subject in order that the board may act on the matter. Wyo. Stat. Ann. § 41-3-912(b). Despite this mandatory duty, it appears that no such information has been provided to the board of control for the Powder River Basin. Wyo. Stat. Ann. § 41-3-915 provides the corrective controls the state engineer would have upon such a designation in order to preserve groundwater resources, protect senior rights and provide for competing uses.

180. The Wyoming state engineer, however, did not apply the byproduct provision to CBM water. This is explained due to the CBM production process, where, initially, the state engineer observed large amounts of water being diverted—for up to a year—with no gas production. Without simultaneous gas production, and in order to monitor groundwater depletion to protect existing rights, the state engineer, from the onset, required a beneficial use permit. Stockdale interview, supra note 158.

181. Wyo. Stat. Ann. § 41-3-903 (1973, with historical reference to Wyo. Stat. Ann. § 41-121.2(1957)).

182. Wyo. Stat. Ann. § 41-3-904. The office of the Wyoming state engineer disagrees with this notion and contends that "beneficial use" is achieved by the secondary effect of allowing the methane to be depressurized to vent for capture. Stockdale interview, supra note 158. This interpretation is belied not only by the byproduct water provision itself (by addressing how one might acquire a beneficial use permit once the water is diverted, arguably the legislature intended that the initial diversion itself was not a beneficial use), but also the definition of "byproduct" water. If byproduct water is defined as not having been put to a prior beneficial use, and the only possible event before being applied to the ground surface is the act of first diverting it from its natural underground reservoir, by the statute, it has "not been put to a prior beneficial use." Wyo. Stat. Ann. § 41-3-903. In other words, the definition itself indicates that the initial act of diversion is itself not beneficial.

183. Stockdale interview, supra note 158, 171. For example, the deep gas fields in southwest Wyoming near Pinedale that do produce byproduct water, do not need a beneficial use permit for the initial diversion. Once out of the ground, however, and someone would like to put the water to a beneficial use, the Wyoming byproduct statutory provision applies for permitting. Stockdale interview, supra note 171. This treatment of conventional oil and gas byproduct water is consistent with the argument advanced in this Article that the initial diversion of oil and gas byproduct water is not, in and of itself, a beneficial use of the water.

184. Wyoming Oil and Gas Conservation Commission Rules and Regulations, ch. 4, § (v).

185. Wyoming Oil and Gas Conservation Commission Rules and Regulations, ch. 4, § (x).

186. Presently, WOGCC is amending its rules for placement of retention pits in "critical" areas to address CBM water handling. Critical areas will include: locations within one-quarter mile of water supplies, areas where groundwater is less then 20 feet from the surface, locations within 500 feet of wetlands, ponds, lakes or perennial drainages within a floodplain. Wyoming Oil and Gas Conservation Commission, Proposed Rule Changes for May 14, 2002 Hearing, Ch. 1, § 2(jj) (Docket 148-2002) (March 2002). Because of the potential for direct communication with shallow groundwater resources of the state, "application for approval of construction of percolation pits for containment and discharge of water produced in association with coalbed methane gas in the Powder River Basin must be accompanied by a review of the groundwater issues by the Department of Environmental Quality. With the DEQ's concurrence, and if the proposed construction meets with requirements of the Commission's rules, the application may be granted." Id. at proposed ch. 4, § (r)(ii). Importantly, all pits for CBM water proposed in a critical area will be required to be lined. If operators cannot demonstrate pits in shallow sands or aquifers will not adversely affect water resources of the state, as approved by WDEQ, then they will be denied approval. Id. at proposed ch. 4, § (w). While these proposed changes are taking steps to address some of the quantity problems, they certainly raise two obvious questions: first, WOGCC rules on water retention normally come into play when it, and not the state engineer, has jurisdiction over oil and gas water—suggesting that this water is not under the state engineer's authority and not, therefore, a beneficial use; second, with all of the lining that will be required, industry will either have to drill tens of thousands of pits (infiltration being taken away) or find another way to handle the billions of gallons of water each year. At odds with the Wyoming state engineer's assertion that it has jurisdiction over this water, in proceeding with this rulemaking, WOGCC is claiming authority pursuant to its jurisdiction over "Disposal of salt water . . . which [is] uniquely associated with exploration and production operations." Wyo. Stat. Ann. § 30-5-104(d)(ii)(D). The point here is that WOGCC's assertion of jurisdiction over this water itself contradicts the position of the Wyoming state engineer, which claims this not to be oil and gas disposal water.

Further frustrating matters is that WDEQ and WOGCC are not sure who has regulatory authority over the produced water when stored in pits. See Letter from Dennis Hemmer, Director of Wyoming Department of Environmental Quality to Don Likwartz, Supervisor, Wyoming Oil and Gas Conservation Commission 1, Jan. 10, 2002, (in discussing detention ponds that will intentionally seep into the alluvial aquifer, Hemmer states, "We have had discussions about who should permit these ponds when they allow seepage from the bottom of the pond."). Hemmer concluded, "it is my suggestion that your office should cover these facilities under your permit since they are produced water treatment ponds associated with Oil and Gas operation." Id. This clearly indicates that two agencies, WDEQ and WOGCC, consider the water quality jurisdiction to fall under the WOGCC and its control over, "[d]isposal of salt water . . . which [is] uniquely associated with exploration and production operations." This byproduct water, in turn, is regulated and assumed to be waste, which conflicts with the state engineer's assertion that this water is being beneficially used. The water quantity regulatory issue in Wyoming therefore, is intertwined in a bureaucratic web of competing jurisdictional claims that undoubtedly cast a cloud of confusion over the entire matter. WDEQ even has completed a general permit for "off-channel" (in upland areas and not in or connected to natural drainages or alluvial aquifers) CBM reservoirs. See Wyoming Dept. of Envtl. Quality, Authorization to Discharge Produced Water from CBM Coal Bed Methane Wells into Off-Channel Containment Units (April 19, 2002). While bi (WOGCC and WSEO) or even tri (WOGCC/WSEO/WDEQ) jurisdiction over surface retention pits is feasible—the whole competing jurisdictional issue undermines the state engineer's position that this water is all being beneficially used. This is demonstrated by both WDEQ and WOGCC focusing on two things: disposal of the water and trying to prevent surface water contamination; in other words, all the focus on getting rid of this water casts serious doubt as to whether much of it is being beneficially used.

If the multi-tiered jurisdiction in Wyoming over the water once it is out of the ground seems confusing—keeping in mind that the state engineer's office is the only agency with control over the initial diversion from the groundwater aquifer (the major focus of this article)—it is because it is confusing. Don Likwartz, Chairman of the WOGCC recently stated that jurisdiction of the produced water in above ground reservoirs (or retention pits) "doesn't fit any of them [the jurisdiction of the WSEO, WDEQ or WOGCC], that is the problem." Adam Rankin, New Water Permits for Methane Must Follow Murky Trail: Three State Agencies are Involved in Quicker Permitting Process, Gillette News-Record, May 13, 2002, at 1. Generally, WDEQ will only permit an off-channel reservoir (meaning not in a waterway—including ephemeral draws/drainages) when the operator can show the water from the pits will not enter surface waters (via infiltration), and importantly, only if beneficially used. If not for a beneficial use, then jurisdiction is with the WOGCC, to basically handle the water as waste. Id. Again, if the state engineer is not involved in permitting the latter reservoirs, as there is no beneficial use of the water, this seriously undermines the agency's position that the water, itself, upon initial diversion from the ground, is being beneficially used.

187. See also Wolfe and Hager, supra note 83, at 64–66 (observing that the basic principle of western water law is that water not be wasted, noting that Wyoming statutes are silent on whether mine dewatering is itself a beneficial use of the water. The authors specifically questioned whether a permit from the state engineer is

needed for mine dewatering and, written in 1989 when the first CBM wells were permitted, further noted that there was confusion over whether to obtain a state engineer or WOGCC permit for the byproduct water, or both).

188. Wyo. Const. of 1889, art 1, § 31.

189. Wyo. Const. of 1889, art 8, § 3.

190. Wyo. Stat. Ann. § 41-3-931.

191. Wyo. Stat. Ann. § 41-3-933.

192. Wyoming State Engineer Rules, Ch. I, Wyoming Water Administration, § 4.a.

193. Wyoming State Engineer Rules, Ch. I, Purpose of Standards, § 1.

194. P.2d 450 (Wyo. 1993).

195. Rissler & McMurry, 856 P.2d at 453.

196. For an excellent overview of the requirements of public interest review and water rights, see Douglas L. Grant, Public Interest Review of Water Right Allocation and Transfer in the West: Recognition of Public Values, 19 Ariz. St. L.J. 681, 685, 689 (1987) (noting that "public interest" is undefined in Wyoming and that states with similar statutes include factors such as effects on game and fish, public health, recreational opportunities and access to navigable waters when considering the impact of a proposed appropriation on the public interest).

Of course, any discussion of public interest review necessarily brings in the closely related concept of the state of Wyoming holding and administrating this water in the public trust. States like Wyoming that own the water do so in trust for her citizen's—this is the public trust doctrine. In 1983, California extended the doctrine to include water in the landmark case of National Audubon Soc'y v. Superior Court of Alpine County, 658 P.2d 709 (Cal. 1983). Importantly, extending the public trust doctrine to water rights and consumption allows a challenge to water use based on environmental concerns. Under this doctrine, a state has an "affirmative duty . . . to protect the people's common heritage of streams, lakes and marshlands." National Audubon, 658 P.2d at 724. If adopted in Wyoming and extended to groundwater diversions, given the massive extraction in the trillions of gallons of water expected in the CBM extraction process, the public trust doctrine may serve as a key protection for the Powder River Basin's existing water resources. For an overview of the public trust doctrine as applied to water, see Roderick E. Walston, The Public Trust and Water Rights: National Audubon Society v. Superior Court, 22 Land and Water L.Rev. 701 (1987); Charles F. Wilkinson, Aldo Leopold and Western Water Law: Thinking Perpendicular to the Prior Appropriation Doctrine, 24 Land and Water L.Rev. 1, 35–36 (1989).

197. BLM, WY PRB DEIS, supra note 15, at xxiii.

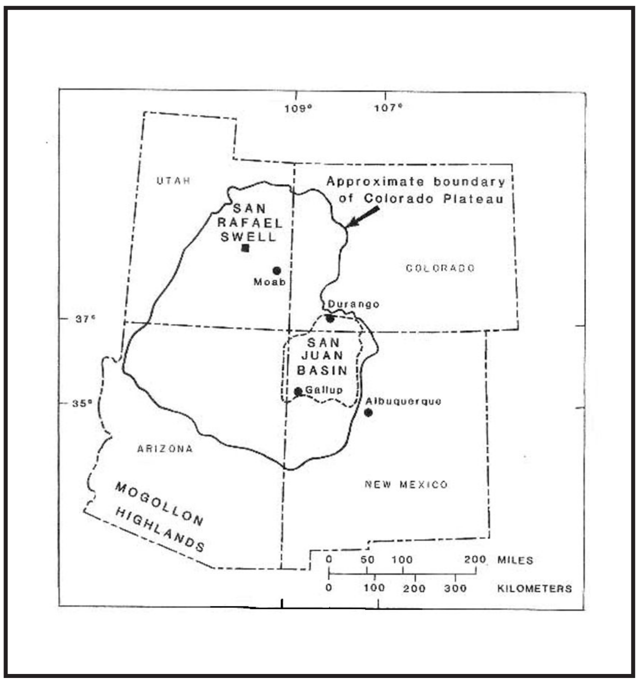
COALBED METHANE DEVELOPMENT IN THE INTERMOUNTAIN WEST: CONFERENCE PROCEEDINGS, SESSION 2: THE SAN JUAN BASIN

OVERVIEW OF CBM ISSUES IN THE SAN JUAN BASIN

CATHERINE CULLICOTT, *Geologist, Ecos Consulting*

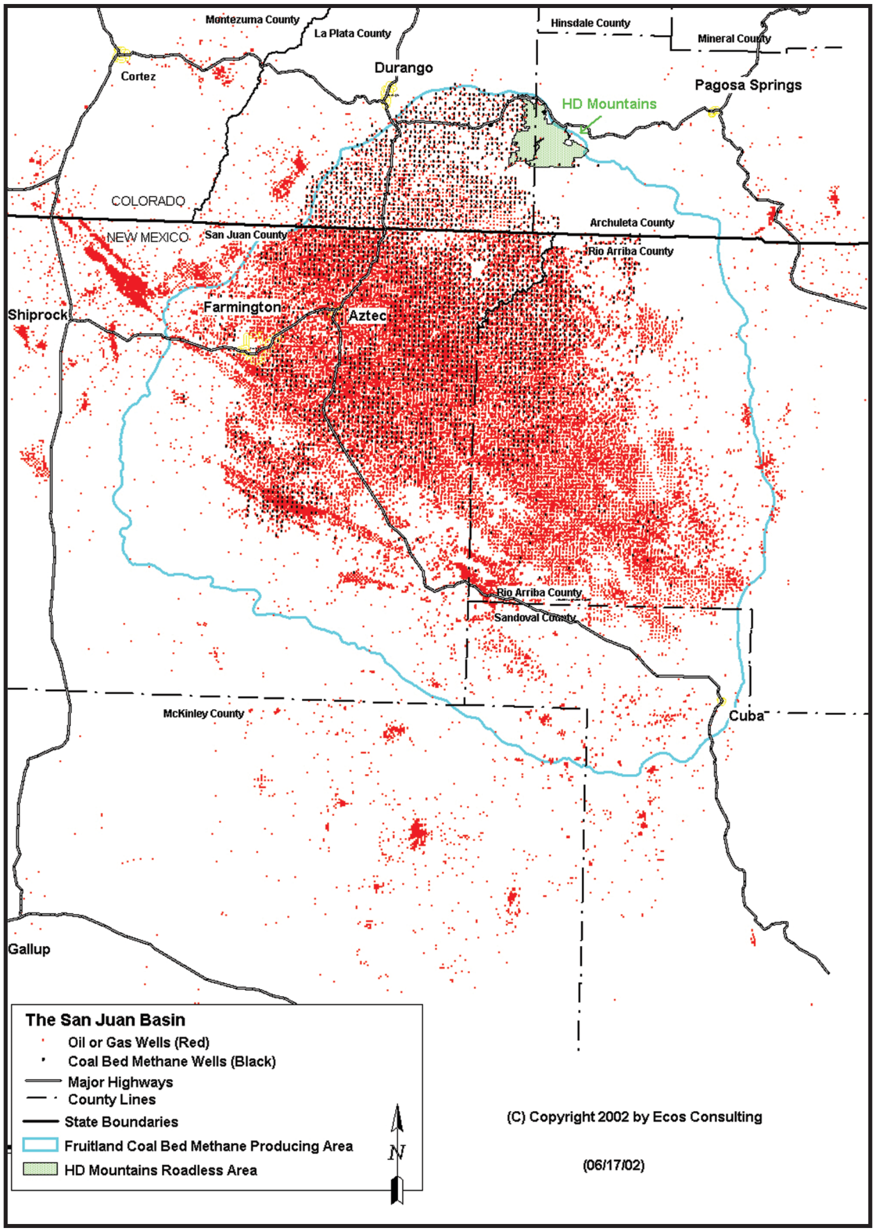
The San Juan Basin is located in the central/eastern portion of the Colorado plateau. It is a historic gas and oil province; in the 1920s, oil wells and coal activities occurred around the edges of the basin, and there were fires and explosions and all kinds of problems with nuisance methane gas. And it wasn't until much later that the first coalbed methane beds were drilled. Here is a map of the Four Corners region.

A map on the next page outlines in the faint blue line the outcrop of the San Juan Basin. The coal formation is actually Cretaceous in age. It was formed, as we saw in a slide in this morning's session, that showed the Western United States with this interior seaway through the middle of it. We had a series of inter-bedded, inter-layered swamps—plant material with various influxes of river material, some sand tones and shales—interlayered along the western edge of the seaway. Over time, it became buried and incorporated into the San Juan Basin structures. Around the edge, particularly in here, the coal is exposed in uplifts. Once you get across the blue line, there's no more Fruitland coal and no more coalbed methane development. One dot is a section that contains a well. And at least one well and could be oil, could be gas, could be coalbed methane. One dot could represent as many as 10 to 15 wells.



There are currently 21,000 wells just in the New Mexico part of the basin. One of the speakers this morning pointed out all of these basins seem to cross state lines. There's no one nice easy jurisdiction to them. So when the San Juan Basin is talked about, it's important to remember this state line here. We have the Colorado portion of the basin and then the San Juan Basin proper down here. This is just an example from the La Plata County only portion of the San Juan Basin in Colorado. It's just showing the new wells drilled each year, and then it's cumulative, as well, by showing pre-existing wells. And this just shows growth from 1980 to 1997 of coalbed methane wells drilled just in one part of the San Juan Basin. As a gentleman I spoke with the other day at the Farmington field office said, "Well, you folks are up in Colorado. It's down here where all the action is." That's mostly true, because in New Mexico there's about 21,000 active wells, and those are all types; conventional oil, conventional gas, as well as coalbed methane. There are currently about 4,050 producing coalbed methane wells today in the Colorado part of the San Juan Basin. And the first of the wells, the coalbed methane discovery well, was drilled in 1976. But as we have heard and will continue to hear, these wells didn't come about in earnest until the late 1980s.

The following figure graphs this kind of growth. Notice in particular the years in the early 90s, late 80s, when the Section 29 tax credits came in, when there is a roughly one dollar for production. And the last of these



wells, the ones drilled in '92, are still getting the last of their section 29 credits this year.

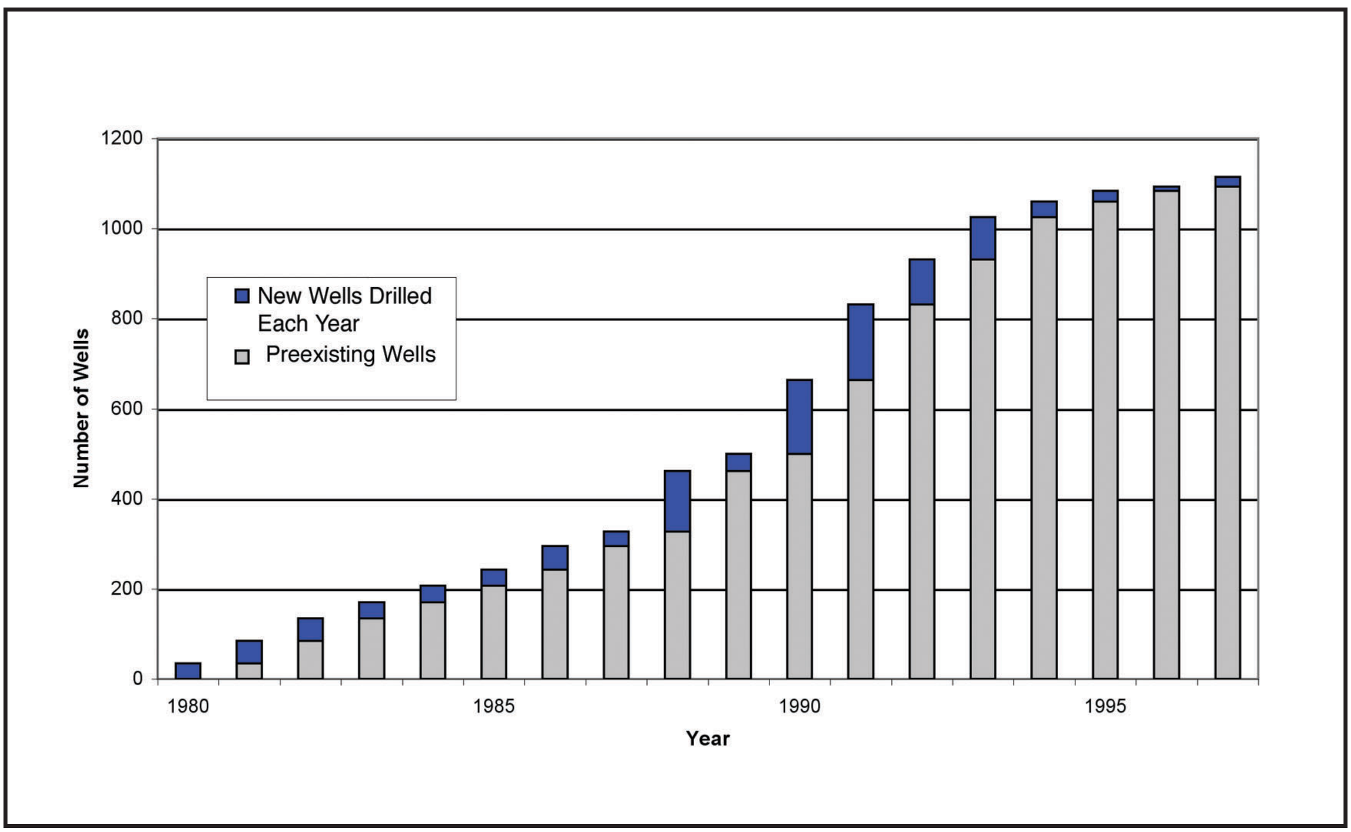
These wells in the San Juan Basin produced just over three quarters of a trillion CF in 2000. And that is four percent of U.S. total natural gas production, just from this one basin. So the earlier speakers who said this is the granddaddy of them all, that's what they're talking about. As other basins come along, this will become a smaller percentage, but until recently, there's been that type of development. And then there's the question of, where does this chart go from here? Is it going to keep going up? Is it going to go back down?

One of the speakers this morning said the San Juan Basin might be dead the terms of jobs. I think in this case, we couldn't be here having this conversation right now. Currently, it's predicted that in the current San Juan Basin, 15,000 more wells are going to be drilled. In the New Mexico portion alone, they're expecting at least 3,000 wells over the next 20 years, at least 150 coalbed methane wells in the San Juan Basin alone per year over the next two years. Expansion of production, infill drilling is going on in Colorado right now. It's already been approved to go from 320 acres for one well to one well per 160 acres. So eventually, it will be doubling well density. It's on the books in New Mexico as well. There will be a meeting in June in Santa Fe on changing the spacing there from one well per 320 acres and one well per 160 acres. Energy consumption of natural gas in 2001 is projected at 33 trillion cubic feet. So it's going up by 50 percent here over the next 14 years or so.

We've already heard about groundwater, surface water, noise, air quality, impacts to wildlife, visual effects. Some of these effects are specific to the outcrop—again, around the blue edges of that drawing. And those include methane seeps, fire, depth education, methane in the drinking water, community and social impacts, impacts on property values, split estate—, if somebody owns a surface, somebody else owns the sub surface miaeral rights.

A lot of people make a lot of money off of this development. That's definitely a driving factor in it. If you consider the San Juan Basin, the total value of all resources removed in 2000, the total value is $2.5 billion. Of that, federal royalties were $325 million. So we're talking about a lot of money that makes a lot of people interested.

Finally, up in my neck of the woods, we have a real interesting situation where we've got a federally recognized roadless area that is now the subject of development. That is, as far as I know, the first time a case like this has happened, where there was land that was set aside at one point and has now since reverted back to being open for development. And, as I'm sure you'll hear, this causes quite a stir on this as well. So that's an overview. We're going to hit on most of these topics in this part of the session of the conference. We'll certainly hear about more of these issues tomorrow. But as you've heard and will continue to hear, the overall issues are similar, it's just the specifics that differ.



BEST CBM DILLING, COMPLETION, PRODUCTION, TECHNOLOGIES, AND MANAGEMENT PRACTICES

DENNIS CARLTON, *Senior VP, Exploration and Operations, Evergreen Resources, Inc., President, Evergreen Operating Corporation, Denver*

I am also a geologist, so this presentation is somewhat skewed to a geologic standpoint. No one has tried to really take a look at the basics of the best practices in coalbed methane. And please understand that this is a presentation really targeted toward the Raton Basin. As you've all heard, each basin has its own characteristics for completions, production techniques, and the Raton Basin is no different. This was Evergreen's primary production, and this presentation is targeted for just the Raton Basin. [Slides presented at the conference are not available].

Evergreen is a public company, and we're focused on coalbed methane opportunities throughout the Rocky Mountains, primarily. And we're a little bit different from most companies, in that we're integrated. We do everything internally, from building locations to cleaning the wells, producing, installing the gas gathering system to marketing the gas to putting the molecules of gas in the pipeline. We also have a couple of projects in the UK and in Alaska, which are just beginning. The intent here is to show that we are vertically integrated. And to be able to have our own completion techniques has really helped in the quality control in the Raton Basin. This is a diagram that you've probably all seen with all the coalbed methane basins. No presentation would be complete without it.

So the Raton Basin is out here to the South. This is the estimated recoverable—excuse me, estimated resources. And this is the Raton Basin, the city of Trinidad, Walsenburg, New Mexico, I-25 comes around, makes a loop around. Evergreen is about 275 acres from the basin. The Spanish Peaks lie right here. The deepest part of the basin is to the north and comes down like this. Other operators, Barrett/Williams, I guess Williams now, Devon in El Paso. The field was discovered in 1993, based on our exploratory wells. Currently in the basin, there are 805 gas wells drilled, of which 743 wells are producing. We're just starting to develop the Raton at this point in time. Total production is about 132 million cubic feet a day. And that's approximately a one to one ratio. We produce anywhere from one barrel of water, from small amounts of water, to as much as 1,000 barrels of water. Total sales in the basin right now is about 120 million a day from Evergreen's operations. The intent of this is to try to give you a whirlwind view of how we select drill sites and the best technology.

We go out and kick the rocks, because what we see on the surface can be translated to depth. We do a series of maps, and we also look at the microgeology under the microscope. We just completed a magnetic survey of 21,000 kilometers in an attempt to understand the base and structure, primarily the leaf structure and also the water limits throughout the basin. This is a satellite image of the Raton Basin. The same basics; here's the Spanish Peaks, Sangre De Cristo Mountains, Trinidad Reservoir, and the state line is down here. We use aerial photography to try to identify fracture trends, and we also use aerial photography to look for drainage patterns, anomalies, and thus, permeability in the coals themselves. So we start from the macro and work to the micro. This interesting photo shows a stress agitation anomaly, which equates to the hot spot within the basin itself. We think the hot spot is going to be associated with the . . . or the Spanish Peaks down to the south. And this the same basic photograph of a smaller area using the infrared high area photography.

We have a complicating factor in the Raton Basin, in that we have intrusions in the form of vertical and horizontal silts. They eliminate the actual coal seams that we're trying to produce. Little bit of the structural geology. This doesn't quite fit, but what we look at on the surface, these coals, for instance, here, are actually lower most Raton, and approximately six miles to the north would be producing out of those same coals. So we study the coals on the surface to try to understand what's going to happen at depth. Something that's important to the coalbed methane success story is permeability. And one way of mapping or trying to understand permeability is to look for fracture trends. So wherever possible, we try to map the intensity of fractures on the surface. This is a vertical cut, but we map by the intensity of the permeability of depth. This is the same view, just in a horizontal view. Minor stress direction. Keep in mind, we're doing all this geologic work with the intent of trying to pick the best drillable locations. We even look at the sedimentary geology and the non-coalbearing strata to determine what happens at different depths.

So you can imagine drilling here and saying, oops, not a good place to drill. But 50 feet away we have a good area. We look at the coal geology, as an outcrop mostly, along Highway 12. This is one-meter thick coal, if you look at the microgeology of the actual coal seams. This scale is a pocketknife scale. We try to understand the gas contents by measuring the gas contents in both cores and in samples. I mentioned before that the Raton Basin was somewhat unusual, in that we have igneous protrusions which seem to be both good news and bad news. They can induce fracturing, but on the other hand, this is a situation where about 100 feet of coal has been totally eliminated by an igneous intrusion called a dike; and then likewise, intrusion of the coal seam over here has totally eliminated the coal itself. As with other operators in the basin and other operators in the basin, we use the typical gamma ray to identify the coal seams.

In the San Juan Basin, we operate where we have multiple thin seams, anywhere from as thin as two to a maximum of about 10 feet in the Powder River Basin. So we have a multiple seam to deal with, and it's complicated in that factor. We have a very, very low formation pressure we have to deal with. This is an example of the subsurface mapping. We take all of the log data and try to map the structure and also the thickness of the coals or the isopach. This is where total thickness of the coals are going to be the best penetrated. The correlation of the coal seams is somewhat challenging in the Raton Basin.

And finally, we look at the microgeology under the microscope. Once we have selected a drill site, we try to evaluate the surface for disturbance. We try to locate wells so they have the least amount of visual impact. Here is another example. This is a county road in the country. There's the well site. This is the different phases of drilling techniques. All of our wells in the Raton Basin are phased for completion. So we have basically surface casing and conductor pipe, and then production casing sends it all the way back to the surface and the producing formations at depth. And then inside the casing we have a string of tubing and rods.

We use an air drilling technique using an air compression hammer. Rates of penetration are very, very rapid. Typical wells are drilled and cased to depths of 2500 feet. We run casing and logs in about 36 hours. This is a picture of the percussion or hammer bit assembly. This is the actual drill rig. This is the actual drill bit, and this is basically a down hole jackhammer. It does regulate very slowly, this being the bit. It essentially chips away at the depth. And we use air instead of mud to bring the samples to the surface, mainly to prevent damage to the formations. We cut cores in several wells to try to keep up on the contents, permeability, and measurements, and also to give us an idea of ash contents so we can calculate recoverable reserves. This is a close-up of the coal. Some coals require hydraulic fracture stimulation to reach economic levels of production. We have a high quality nitrogen foamed fracturing fluid, which is something that looks like a shaving cream, which goes down the hole, carrying the sands and creating the actual crack at that depth.

We're on the forefront of developing a technique called a coil tubing unit. So, it's a $1.65 million machine that allows us to frac every single coal seam. This is a little cartoon of drilling a well. The well comes down, intersects the coal seams, and we shoot perforations through the pipe. The rig is brought in, and this is a visual account of how we isolate the individual coal seam and the coal mixed with sand and fluid and foam. It's the same exact thing. So we have good penetration of the coals and for the frac job. This is what it looks like, in theory. We use what's called a progressing cavity pump to actually produce the well, versus an insert pump. It looks like an Archimede's spiral. I'm sure everybody's seen this type of curve also. This is a typical coalbed methane well, if there is such a thing. It has increasing methane content, production through time, with decreases in the water.

Same picture of an electrically driven gas meter. This stays like a motor on top of the well here, and the same thing, that's a perpetual motion machine, a gas-driven unit. And then where we have a noise considerations, we put the gas drive inside of the house. This is the progressing cavity pump. It's about 20 feet long in most cases, and looks like an Archimedes' spiral. This is inside the pump. This is the roter, this is the stay, which is just opposite of the Archimedes. So when the pump turns, it actually brings the fluid and anything else to the surface. Typical production unit, very simple.

Two-phase gas and water sprayer. Gas comes out the side of the operator. It goes through a meter room, which in this case has an electronic metering device. So when our guy is in here, he downloads data which is accumulated every second. So he has all kinds of information. Water data, temperature, pressures and it's recorded. He takes all that data and e-mails it to Denver every single day for all 750 wells. Because our system is—our formation is very, very under pressure, we have a very large pipe in place which takes gas of the basin. Then we have an infrastructure pipe throughout the field going to eight compressor stations. And this is a pipe that's over eight inches in diameter. Typical gathering construction crew along the highway. And this is what the right-of-way looks like when it revegetated. This one is contained within a building. That particular unit is 3,000 horse powered—it moves about 10.8 million cubic feet a day. All the compressor stations have emergency shut down for high pressure, high temperature. It's a system that shuts off the computers and then phones automatically to the field office, which sends a signal to about 15 different maintenance guys to come fix the compressor.

Water management is, of course, one of our key issues. Water quality. We test the water from COGCC earthen pits. We offer the chance to home owners to have their water wells sampled, and we give them water quality data. We test the water from the producing wells also. Colorado Department of Health, we test all the permitted outfall points.

Surface water, there's a program where we have a data base of water, samples from all the rivers and also the Trinidad reservoir. We test water using an independent laboratory, so it puts some distance between the operator and the Department of Heath and Environment. With only 700, 800 wells in production, we have well over 20,000 data points of water collected. With our current operations, we have 640 pits that are permitted with the Oil and Gas Commission and 678 out of the Colorado Department of Health and Environment. We have seven active disposal wells; two wells are being completed right at the moment. As I mentioned before, we have independent companies who collect data for us so that we have a good data base to work from.

Thank you.

CBM DEVELOPMENT AND WATER ISSUES

DAVE BROWN, *Environmental Specialist, BP*

I was assigned the topic of CBM development and water issues in the San Juan Basin of Colorado. I'm going to talk about this today because that's where a lot of water issues are occurring right now in terms of people's concerns.

First, here is a brief overview of BP for those who may have lost track. BP is a multinational company formed as a result of recent mergers involving BP, Amoco, ARCO, Vastar, and Castrol. So those of you who are familiar with Amoco, that's who BP is now. BP is the largest oil and gas producer in the United States, so we're quite involved here in the lower 48 states and in Alaska in terms of energy supply in the U.S.

In Colorado, we are the biggest natural gas producer, and we market quality fuels at retail service stations. The gasoline BP markets in Colorado is the same Amoco product as we've always sold.

In La Plata County, we operate 900 natural gas wells, and we have 114 employees who live and work in the area. So we have a lot of folks committed to producing natural gas in the most environmentally responsible manner possible. What I want to discuss is the potential

WHO ARE WE?

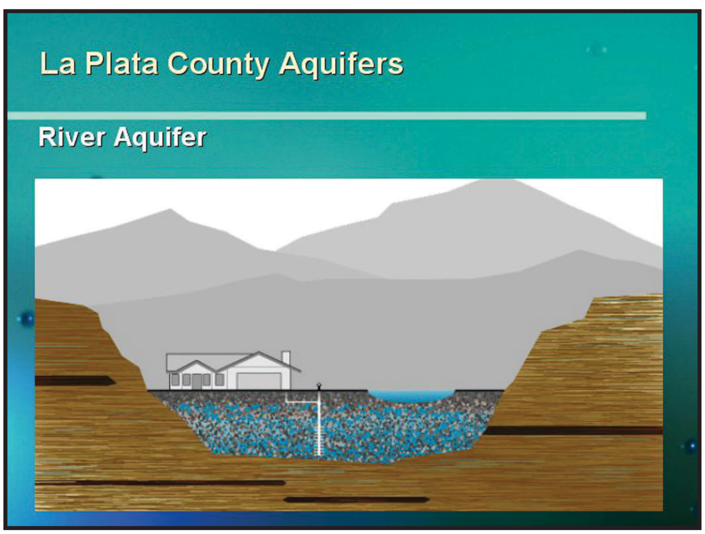
- BP has merged with Amoco, ARCO, Vastar, and Castrol.
- In the U.S. BP is the largest producer of oil and gas based upon offshore, Alaska, and the lower 48 states.
- In Colorado BP is the largest natural gas producer, and we market quality fuels at retail service stations.
- In La Plata County we operate 900 natural gas wells supported by 114 employees.

impacts to groundwater and the preventative actions. There's some other issues going on, but that is one that stands out.

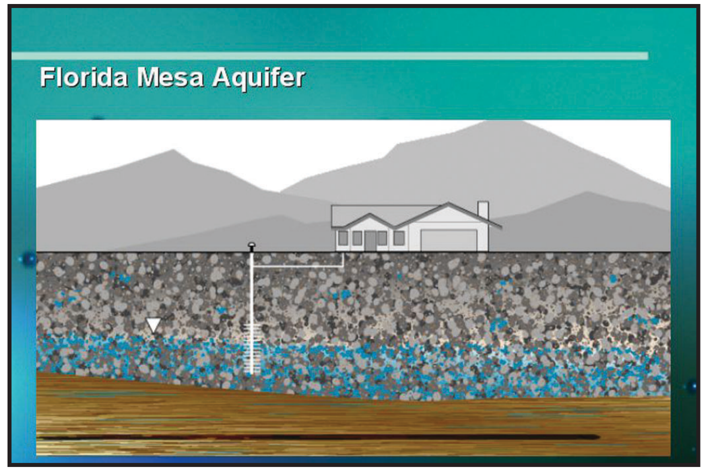
I've been working in this area since we got started in the late 80s, and the one issue that keeps coming up is: What are the impacts from coalbed methane development? And, you know, I heard that in '87, and we're hearing it now. It's an ongoing concern we address on a daily basis.

What I want to give you are some background and tell you how and what kinds of things are being done to protect those shallow aquifers. I want to give you a comparison about where those shallow aquifers are and where we produce the natural gas. And then I want to talk about some preventative actions and talk about well construction. Dennis got into that a little bit. We also have a water well testing program similar to Raton Basin, so I'm going to get into a little bit more detail about that.

I picked the three main types of aquifers where people get their water from, in the general area where coalbed methane development is occurring. The first example is called a river aquifer. These slides show that loose gravels have been deposited over time. This is an aquifer that has unlimited water, and its quality is based on how good the water is in the river. So this is a very good, high-yielding type of water.

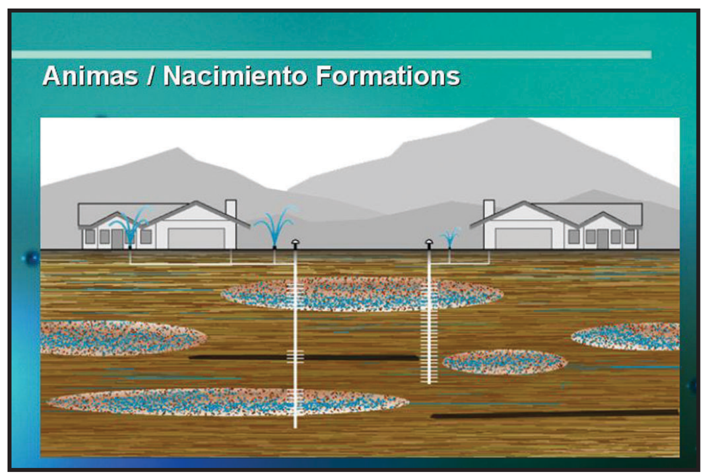


This is the Florida Mesa Aquifer. This encompasses a very large area with the gravels loosely deposited over time. This aquifer is mainly recharged by irrigation.

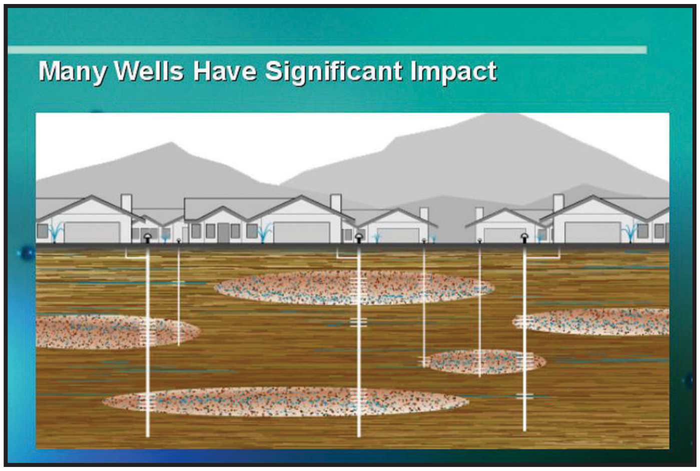


This is an agricultural mesa with a lot of that type of activity going on.

This aquifer is more complicated. This is the Animas and Nacimiento aquifer. What you have are shale and sandstone with subsurface lenses of more permeable material where water has collected over time. The difficulty with this aquifer is the fact that once the water is used up, it's not going to be replaced very quickly.



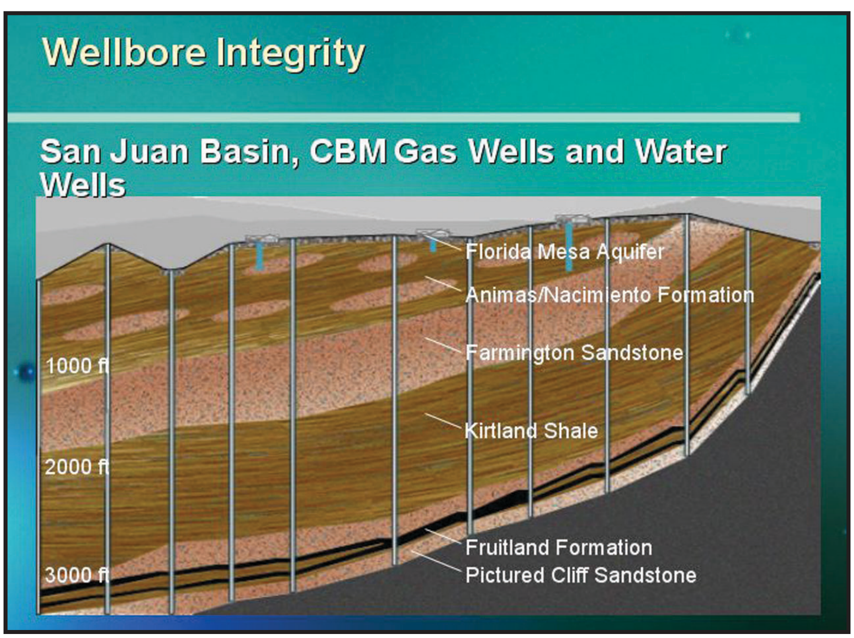
In fact, it's going to be a long time, possibly hundreds of years. The water is recharged mainly from precipitation. The previous aquifer, Florida Mesa Aquifer, is recharged by irrigation and the first aquifer, River Aquifer, is recharged from the leaking of the river to the aquifer. Now, this is when it really gets tough, because what's happening is, if you get development going on in that area where you have the Animas and Nacimiento aquifers, you can really stress or overuse the aquifer to the point that it's going to dry up.



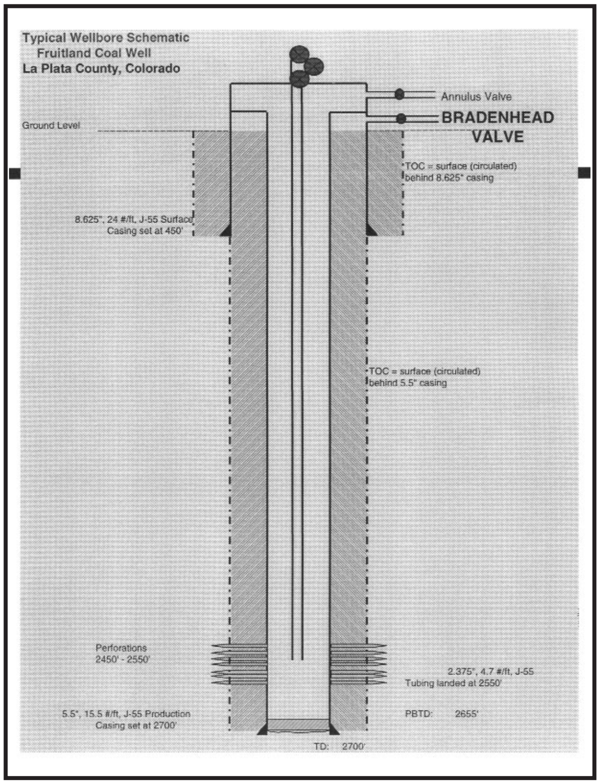
Again, it's going to be a long time before it's replenished. So that's the reason why water management, in terms of these particular types of aquifers, is very important in educating the users that you don't want to overuse these aquifers. I'm going to put this in perspective now. This is a cartoon, but it is to scale. This is the Fruitland formation here where the coalbed methane is produced. This is northern part of the San Juan Basin, and this is to the New Mexico state line. I just showed you these aquifers on the slide, and what we're trying to show here are the coalbed methane wells. These are depicted by the tubular looking features on the slide. We'll talk about this in more detail.

These coalbed methane wells are constructed in such a way that there is no way, or shouldn't be a way, for these wells to communicate with shallow drinking water aquifers. And I'll show you how we're doing that in a second, but it's important to note that the distance between the shallow aquifers and the Fruitland formation in this case can range from 1,500 to 2,000 feet in depth. So there's quite a bit of geological separation, which forms a seal that prevents any movement of fluids from down here, Fruitland formation, in the productive natural gas interval to where the drinking water aquifers exist. So I'm just trying to give you a sense of that. We talked about those aquifers. And again, water wells can vary in depth, with the deepest I found being 400 feet, which is depicted on the slide. Most, though, are in the 100 to 200 feet range on depth.

Now, I want to talk about the wellbore construction. Dennis touched on it with his slides. We'll look at this and see what's going on here in terms of how wellbores are constructed. I'm also here to talk about this from a historical perspective. There was a time where there was some drinking water aquifer contamination from subsurface leaks from conventional natural gas wells. We'll talk about what caused that and what was done to fix it. The next slide is of the surface and the wellbore we drill. This is this upper part of the hole. This is what we call our surface casing. Surface casing is set at a depth of 450 feet for this



example. How we determine the depth to set surface casing is by researching the State Engineer records for a depth of the nearest water well. Then we set surface casing 50 feet deeper than the depth of the nearest water well.

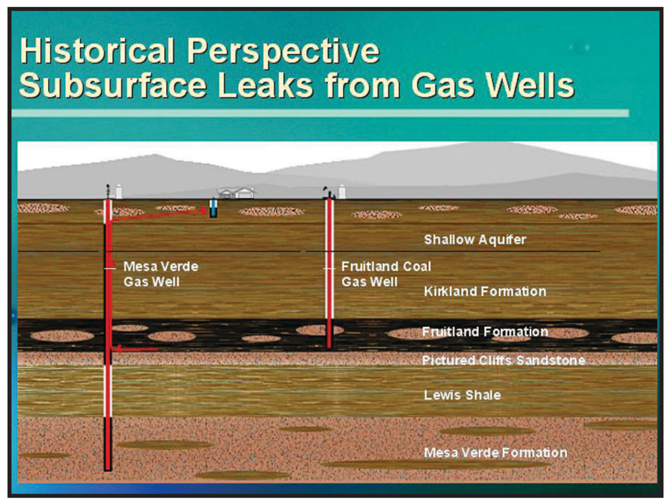


Then we pump cement down the bottom and up the backside to surface to get the seal between this wellbore and the casing, which fills the annulus. Again, these drinking water aquifers I spoke about before are up in here (pointing to the upper part of slide above the surface casing).

As I mentioned, the deepest drinking water aquifers are up in here (the upper portion of the slide above the surface casing). So at this point, we have two levels of protection. Steel casing and then the cement that encases it. Now, the next stage, we go ahead and drill the well to total depth, which in this case, is approximately 2,700 feet.

The casing is run inside this particular wellbore, and then cement is pumped down the bottom and back up to the surface to seal the annular space between the wellbore and the casing. So now we're up in this area (pointing to upper part of slide above the surface casing) where the drinking water aquifers are being used. Now, there are actually four layers of protection, two strings of casing with both sets cemented into place. Then tubing is run and the casing is perforated across the coal formation (pointing at the bottom of the slide where the perforations are shown). This is the Bradenhead valve (pointing to the wellhead configuration at the top of the slide), which monitors pressure between the surface casing and the long string or production casing. We'll talk about more shortly.

Now, let's look at the history of what happened when there were problems from natural gas development and water wells. Back in the 1950s and 60s, there were conventional wells being drilled. The practice in those days was to not cement the section above here, leaving a portion of annulus behind the long string uncemented.



In other words, that annular space was open in that portion of the long string or production casing. There was really never a problem with this practice for a long time. But when the Fruitland development started in the 1980s, they began dewatering the Fruitland which in turn allowed, in very isolated cases, for gas to migrate up the backside of the casing, and if conditions were right, for gas to make its way to a water well. Despite the rarity of this event, programs were developed to prevent a reoccurrence.

Now, I want to talk about that Bradenhead Valve. Again, it exists at the surface but monitors pressure that could indicate gas migrating between the surface casing and the production or long string of casing. If that condition existed, an option is to perforate the casing and pump cement behind the casing to seal the open annular space so that it resembles the same type of current wellbore construction used for Fruitland wells. What we basically have then is a cased and cemented well from the surface all the way to total depth. It is important to note that those wells that needed to have this type of corrective action taken have been identified and the wellbores have been remediated. So this problem has been addressed.

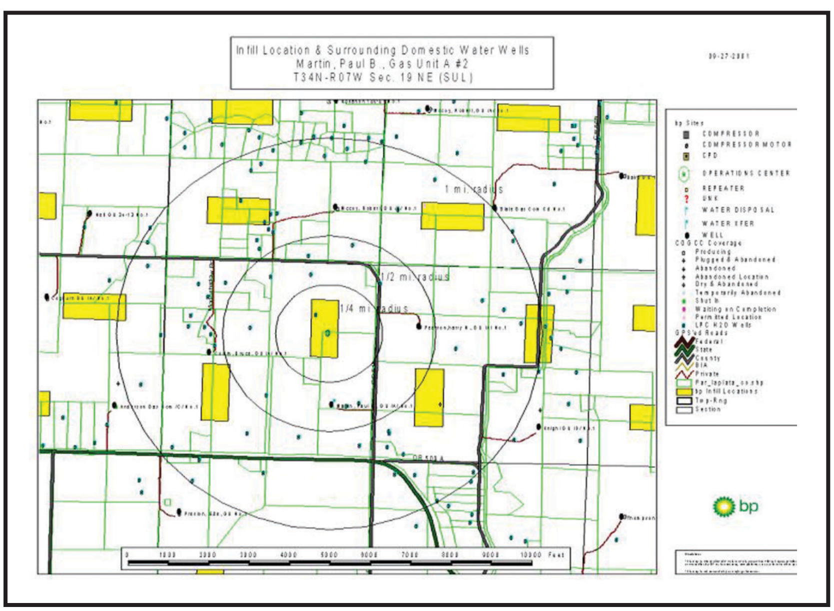
Remember the conventional well we just saw? Every year, we go out and check the Bradenhead valves on conventional wells to determine if there's any pressure on it. There are areas that are designated as "critical" which means there are a concentrated number of water wells in the vicinity. In those cases, you're only allowed five pounds on the Bradenhead. For coalbed methane wells, we test them when they're completed and then every other year after that. Just to give you an idea, we did over 900 Bradenhead tests in 2001. So we were very busy with this program last year. But we also recognized that, even with the Bradenhead program, many people were not convinced their wells were not being affected by coalbed methane development.

Despite explanations of proper wellbore construction and monitoring using Bradenhead testing, many people were still saying, "I'm still not convinced that my water well is not being affected." We felt strongly about that and we listened. What was developed, as part of the infill order for 160 acre density for CBM wells, was a program whereby the industry would test the two closest water wells within a quarter of a mile of new proposed coalbed methane well.

WATER WELL TESTING

- Infill order requires water well testing
- Originally included in industry's health, safety, and welfare plan
- Test two closest water wells within 1/4 mile of:
  - Conventional gas well, or if none
  - Proposed CBM well, or
  - Extend radius to 1/2 mile if no water well within 1/4 miles.

What is done for this program is as follows: If you have a coalbed well proposed in a designated 160 acre spacing window, and there's also a conventional gas well within a quarter mile radius of a proposed Fruitland coalbed well, you select the nearest two water wells within a quarter of a mile of the conventional well and possibly out to a half a mile. But if there's no conventional gas well within a quarter of a mile of a new coalbed methane well, then you select the nearest water well no more than one-half mile from the proposed coalbed methane well. I believe there's only been a couple of cases of new CBM wells where we have not found at least one water well to test. These are the infill windows (pointing to yellow shaded areas). We checked the Colorado State Engineer's records to identify all of the water wells shown on this map.



Looking at this particular site, here is the proposed gas well. Here is the water well selected (pointing to the map). In this case, selecting that particular water well was a slamdunk because it is so close to the new coalbed methane well. We try and select the wells on opposite sides of the proposed new coalbed methane well, which in this case was this well right there (pointing to a water well). So in this case, these two water wells are on opposite sides of the proposed coalbed well.

Here is the water well test procedure. First, there are prescribed analytical parameters that are based upon the infill order. We use a third party contract water tester to sample the water wells. We have to collect samples from the water well before the drilling starts on the nearby coalbed methane well. We also conduct post-tests from the water well within one year after the coalbed methane well is completed. Ideally we try to sample within eight to nine months after completion of the new gas well, but at least within a year. After that, we test a given water well at three and six-year intervals as required in the COGCC infill order. There is another important aspect of this testing program. We share the results with the well owners with an explanation about water quality. This is very constructive. They are now aware of aspects about their water well and water quality that they may not have known before.

WATER WELL TEST PROCEDURE

- Prescribed analytical parameters
- Pre-test before drilling
- Post-test after drilling within one year
- Post-tests at three- and six-year intervals
- Share results with water well owner
- Methane levels > 2 mg/L require isotopic analysis

Where you have that exchange of information, it has been valuable, particularly for local residents. Some post-tests have been completed recently and those results would essentially demonstrate if any changes in the water quality from their water well has occurred after drilling the new coalbed methane well. We have seen virtually no change in the post-tests from the pre-tests in the water wells that have been sampled pursuant to this program.

We've heard a lot about the potential for natural gas in the San Juan Basin, but there's also a lot of shallow methane gas that is naturally occurring in this basin. Under the infill order—and I know this doesn't mean a lot to some people—if you have two milligrams per liter of dissolved methane in a water well sample, you're required to obtain an isotopic analysis. An isotopic analysis can differentiate between shallow naturally occurring biogenic methane and deeper thermogenic methane. I'll just give you some statistics here. We have sampled more than 300 domestic water wells so far in this program. 55 percent of those had some level of dissolved methane. I want to point out one thing: We go really, really low on our methane detection levels, 0.0004 mg/L to be specific. This is a very low detection level. Anything over that level is part of the 55% number. Due to the number of ongoing samples taken, the percentage changes almost daily. However, I checked it today, and we're down to less than 50 percent now of the water wells with dissolved methane over 0.0004 mg/L. However, any concentrations greater than 2.0 mg/L requires an isotopic analysis of the water. We do this so an understanding about the source of the methane gas in a water well can be made. Is it from a shallow biogenic source, or is it coming from thermogenic sources that could be associated with deeper production of natural gas? Isotopes are very valuable in terms of determining the source of the methane.

METHANE IN GROUNDWATER FACTS

- >300 domestic water wells sampled
- >55% w/dissolved methane, 12% > 2mg/L
- Biogenic vs. thermogenic methane
  - Biogenic D bacterially generated
  - Thermogenic D deeper derived, associated with natural gas development
  - All isotope results from wells > 2mg/L have been of a biogenic source
- Isotopic analysis of both methane and CO_2 and compositional analysis are needed to distinguish Fruitland gas

Here is a very important point from our testing program so far. All the isotopic results in water wells that are greater than two milligrams per liter have been biogenic or from shallow naturally occurring sources of methane and not associated with coalbed methane development. What I want to point out is that the isotopic analysis needs to look not just at methane, but also the carbon component of the CO2 since it will provide additional information about the source of the methane. Using isotopes allows "fingerprinting" to identify thermogenic methane vs. biogenic methane. This is something that has proven to be very valuable.

In summary, I think one of the things that should be pursued is public education about hydrology and how water wells function. That was done in La Plata County last year. A copy of the booklet that was handed out at the public information sessions last year in La Plata County is here and I would be glad to share these with anybody who wants one. This pamphlet was put together by two local consultants with input from five different agencies located in La Plata County. It's called, "How Well Do You Know Your Water Well?" It's pretty neat. Our third party water contractor delivers this informative pamphlet to the water well owners and reviews the water well testing procedure with them.

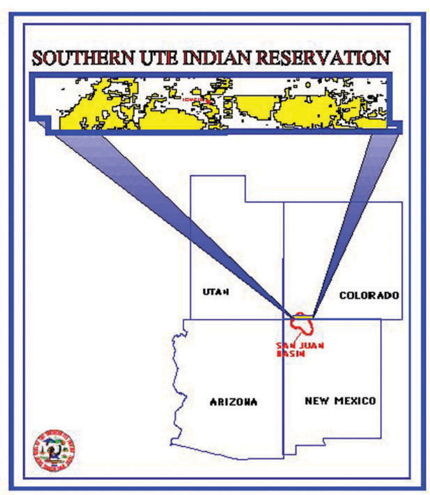
Another summary item is proper wellbore construction techniques. Something that will continue to be emphasized is continuing the use of the best techniques for wellbore construction and monitoring. This will ensure that wellbore integrity stands the test of time. We will also continue to baseline and post-test water wells that are selected for sampling as required under the infill order. And finally, isotopes are extremely valuable in terms of understanding what the source of gas is in water wells where it exists.

Thank you.

CBM DEVELOPMENT ON THE SOUTHERN UTE RESERVATION

BOB ZAHRADNIK, *Southern Ute Growth Fund*

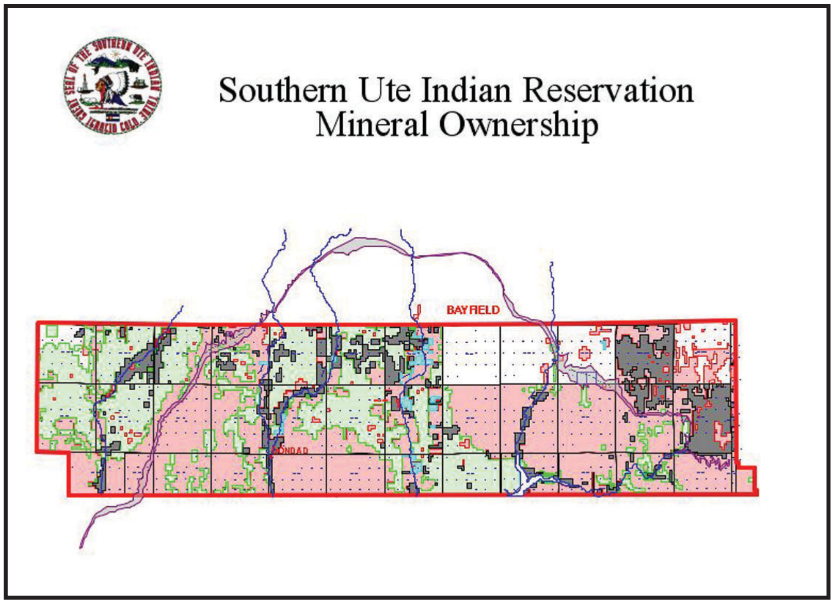
The Southern Ute Indian Tribe is a small tribe. They have approximately 1,000 square miles, about 700,000 acres. It's a 70 by 15 mile strip on the Colorado/New Mexico border here. Just to put this in perspective, the original deal with the Federal Court would be one million acres. It's been reduced to about 700,000.



The tribe controls about half of that. The land is a victim of something called the Allotment Act, which was put into place by the Federal Court and the people of southwestern Colorado. The tribe is hung up within the exterior boundaries of the reservation. The red here is tribal acreage, so you see it has extremely interesting jurisdictional problems and a lot of government.

The red part is basically desert. This part is a waterless plateau. This part, where we have another big tract of land, is extremely rugged, mountainous terrain. So the tribe was left with this. Until 1982, development of energy on Indian land was controlled completely by the Federal government. After that, the tribe was then actually allowed to talk to oil companies about development on their land. They weren't allowed to negotiate before then. Leasing on these lands began in 1949 and then basically we stopped in the 50s. And the tribes, therefore, had very little to do with that process. And the tribe in the 70s was faced with the prospect of living with deals the Federal government had cut.

So they were handed this situation they had to deal with. However, the tribe did support this in 1951 the



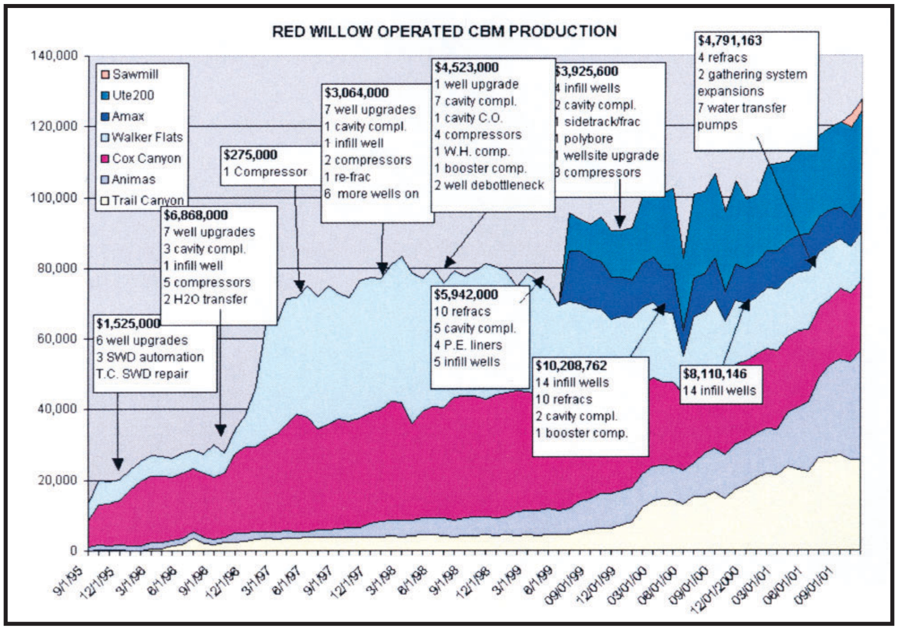
first gas was found on the reservation. The tribe was going out to hold a dance on this location because they were so desperate for cash and were an extremely poor tribe. And were very hopeful they would find something. But in 1966, field gas production peaked at 38 million cubic feet per year, and you'll see later, in about 2001, the coalbed methane production peaked at 400 million cubic feet of gas per year. So all these sands and things left us with a resource with ten times our productive capacity.

In the mid 1970s, the tribe took the first step in taking control of its resources by auditing the USGS to see that they were living up to the lease agreements. Not surprisingly, they were doing an awful job. In 1980, they hired their own technical people to start taking control of that process and issued a severance tax. In 1984, the Energy Division was reorganized. In 1987, we cut our first agreement, which was the first time the tribe was able to negotiate, and closed the agreement with an energy company. Up till then, it was always handled by the Bureau of Indian affairs.

1991 marks a paradigm shift for the tribe. They were directed towards being a better governmental manager. We were now making sure oil companies lived up to their deal, and we educated ourselves so we could understand what was going on on the tribe's reservoir. In 1991, we went out and attempted to buy some wells that were for sale. That was the first time we really thought seriously about doing that. We were unsuccessful. We also filed a suit which led to about a nine-year odessy, and we signed some MOUs with the state BLM and the BIA to make the checkerboarded jurisdictional map manageable. And to make sure of that, we've worked very cooperatively with the state since then. From 1991 to '93, we negotiated various coalbed methane ownership settlements. In '92, the council approved the Red Willow business plan for a acquiring acreage and acquiring leases and construction. We bought 18 wells from Conoco for $3.1 million.

In 1994, we were very active. We completed a trade with ARCO for wells. We hired an operation staff. In 1994, we got our butts kicked. We bought a little gathering company from the Public Service Company of Colorado. It's now called Red Cedar. And we have a joint venture with a company called Stephens. In 1994, we reached 130 billion cubic feet of gas per year. So we're already at four or five times what we were producing.

In 1995, we sold our Royalty Section 29 tax credits to allow negotiations to buy out a bankrupt company. We spent 18 months in Federal Court. We took over McKenzie construction in about nine months. In 1995, we signed an agreement with El Paso and KN Energy to build a treating station out on the extreme western portion of the reservation. We entered into a joint venture with McKenzie, and we stepped up our ownership in the gathering company of Red Cedar to 40 percent. Red Willow has exceeded 80 million cubic feet per day. The Tenth Circuit Court reverses the Federal District Court's decision on coalbed methane ownership, and we contracted



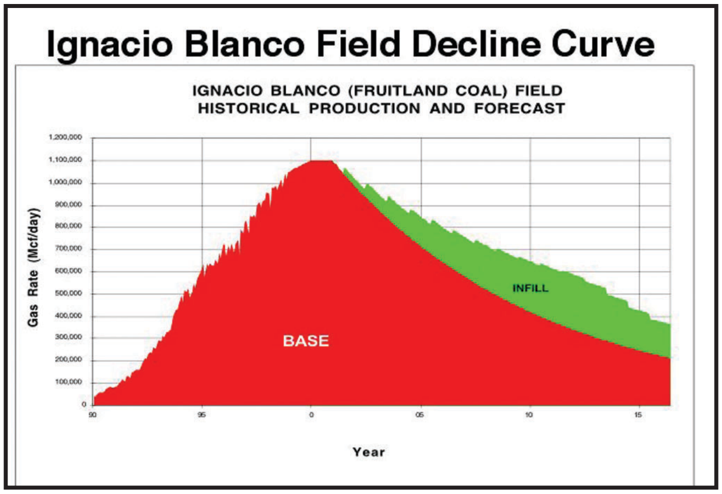
for a second plan in our agreement with El Paso and KN Energy.

In 1998, by this point, ownership with Red Cedar had increased to 51 percent. Red Cedar's output and was exceeding 600 million cubic feet of gas per day, four times what it was when we bought the company. In 1999, the Growth Fund from the tribe was established. This is the business fund of the tribe in assets and cash. The point is to go out and aggressively return on the tribe's money. There's a parallel fund, which is essentially an endowment that provides the income that runs the tribal government. There was an out-of-court settlement regarding coalbed methane ownership with Amoco and others, and the Supreme Court ruled against us. So it was fortunate timing that we worked it in that order.

In 1999, we dealt with our interest in the settlement wells. We purchased Cedar Ridge there for $53 million for additional coalbed methane wells on the reservation. We drilled five infill wells in Trail Canyon in 1999. The interesting thing about this is how conservative the tribe's business plan was for this well. We started the plan in February of '92. We acquired 18 wells in January of '93. We did not drill a well till 1999. We sold the tax credits for Red Cedar to El Paso. When El Paso left the reservation, we rolled that into Red Cedar. Production now exceeded 100 million cubic feet of gas per day. We continued to optimize and expand the production of the wells. We continued to produce over 10 million cubic feet per day in a drilling program with a public company. And we beat all our goals. We continued to buy back the leases that the BIA issued in the 50s and parts of those leases were within the exterior Ute.

We acquired interest in the Williston and small gas plans in Paradox Basin, and we began talking about working with other tribes so we could share some of our capitol, which we now had in abundance. In 2002, we sold our South Texas investments and implemented a 140,000 seismic option with the Indian tribe. And we were going to be starting operations there in the immediate future. We continued to acquire interests on the reservation. Yesterday, we closed our first Canadian acquisition. This shows the Ignacio Blanco field curve design. This is what we're looking at here. As you can see, prior to 1990, there was virtually no production, but at this point in 2001, 2002, production peaks at a little over 1.1 million cubic feet per year. The decline starts here. The declines flatten a little bit here, and this is what we're projecting for the 160 acre joint program. To show you how important this was to the tribe, the level of business at this time—we're getting a lot of money from the coalbed methane development besides just the additional royalty that comes from things we've bought. We've discounted the present value of that infill to the right. That infill property is $600 million.

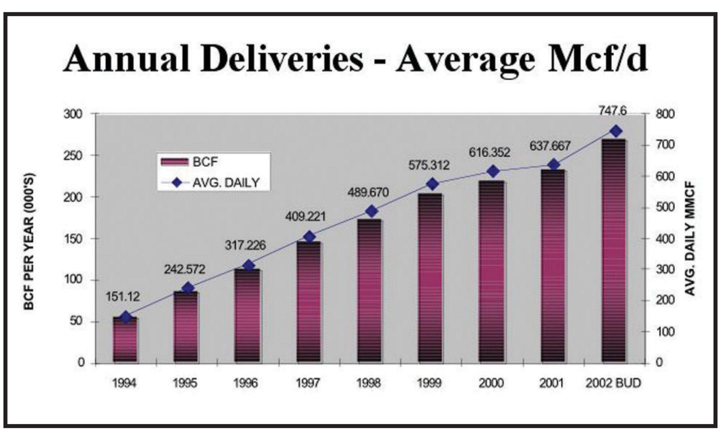
This is an interesting slide. The yellow line is the conventional gas, which is the northern portion of the

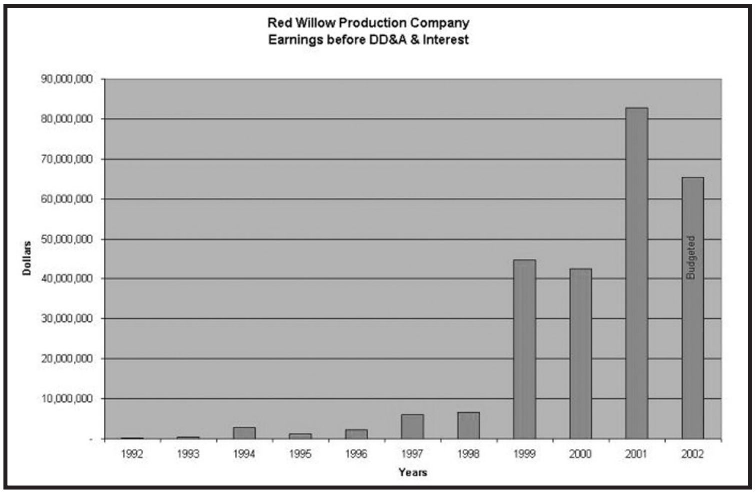


San Juan Basin. It was just bouncing along. People were drilling wells and finding new things for years and years. In 1988, '89, coalbed methane gas started being found. And you can see how it's changed the field. In '89, the tribe, with farsighted leadership and reserve, was finally bringing in money. Excluding the tribe's trust asset, the tribe's net worth was $1.2 billion. They're now a tribe that is more financially secure than any other Indian tribe throughout the Rockies.

We find the Ute situation unique, that they are financially secure. Other tribes are pretty much living from hand to mouth. Even tribes with billions of dollars of resources under their reservations do not have this kind of financial security. The reason for this is: This tribe has a very rational system of government, and the tribal membership is elected by very progressive, farsighted leaders that were willing to stay with the course of these resources for the tribe's benefit. They invested $8 million in an energy company in 1992. That was about a year's revenue for the tribe, and it was a big risk that they took. But they took that are risk, and they stayed with it. The tribal government has been very patient and this is the rule.

Red Willow expanded its business in our original Conoco acquisition. This is a well count slide, and the red is the number of wells that we operate. A little over 600 today. We have interest in wells we don't operate of about 400 wells. These are the results in the data: Last year, we brought in the $83 billion with Red Willow alone. The tribes had a very aggressive capital expansion program to do that. Look at the programs here in 1999:

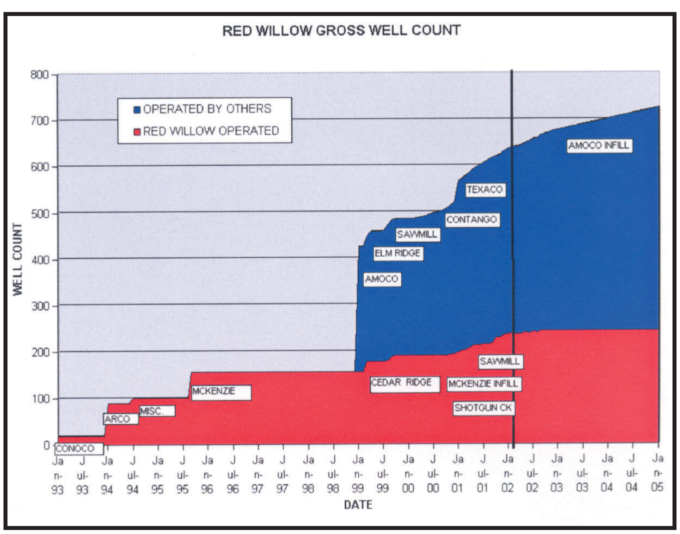




Asset Comparison 1994 versus 2001

	1994	2000
Miles of Pipe	220	725
Compressor Stations	3 Stations	20 Stations
Compressor Units	6 Units	56 Units
Installed Horsepower	21,000 HP	> 70,000 HP
• Arkansas Loop	13,200 HP	13,200 HP
• Field	7,800 HP	61,500 HP
CO2 Processing Plants		
• Arkansas Loop	+100,000 MCFD	260,000 MCFD
• Capote	0 MCFD	70,000 MCFD
Wells Connected	>300	> 700
Total Gas on System	>130,000 MCFD	> 700,000 MCF/D

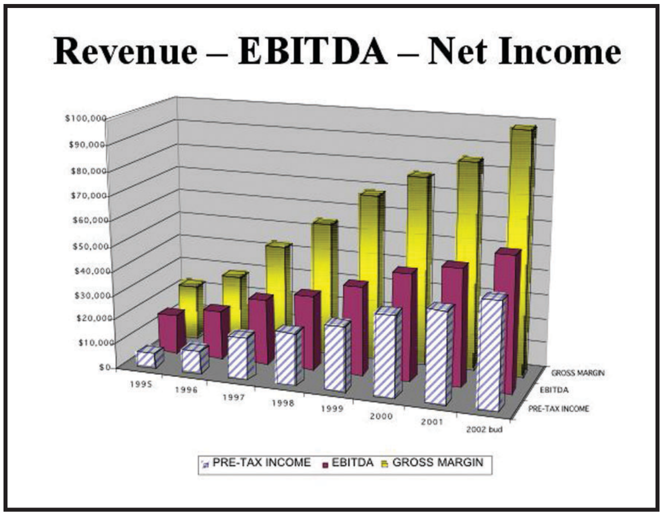
4 million, 3 million, 5 million. The tribe has very, very aggressively attacked this resource. They managed—we feel we managed that reservoir about as well as anybody



in the basin. The tribe now owns 51 percent of the company. In '94, it was a joint venture with Stephens. In 1996, ownership was up to 40 percent and gradually stepped up to 51 percent. As you can see, it's a success story. 151 million a day to 747. One percent of the U.S. gas supply flows through our pipe.

Now, major capital expenses. Of the profits from Red Cedar—we're back into Red Cedar—and these are the results in earnings. EBITA this year is projected at $65 million. The tribe made clear early on that we would have to work very diligently if they intended to be there 500 years from now. They've been there for 500 years.

We've worked with several governmental committees, including helping accounting provide technical support of the Pine River investigative team. In '96, we started the largest EIS ever completed on an Indian reservation. In '99, we were one of the founding members of the 3M study and provided funding to the reservoir. From



'95 to date, we've been very active in seep monitoring of the outcrop along 22 miles of outcrop within the reservation. Bottom line for the tribe is: We've spent close to $10 million on monitoring, studying, simulating, and trying to ensure that there's no impact to the environment.

The tribe's got a higher credit rating than Canada, Colorado, or Denver. What does that mean to the membership? The day a tribal member turns 60, he recieves money from the Elder's Pension. Each and every tribal member receives this. Ten percent of the profits in the growth are distributed between 26 and 59-year-olds. Any tribal member that wants to go to college gets a full scholarship plus a substantial allowance for living expenses. The tribe got tired of fighting with the schools and finally said, well, we'll start our own school, and they built it. So, by aggressively managing this, the benefit to the tribe is maximized to be financially secure forever.

That's the bottom line. And that's a result, again, of farsighted and extremely competent leadership on the part of the tribe.

CBM DEVELOPMENT FROM THE COUNTY PERSPECTIVE

JOSH JOSWICK, *Commissioner, LaPlata County*

I'm going to give a virtual power point presentation, which some of you may recognize as just a regular old talk. I'm Josh Joswick. Some of you I know, and some of you I don't. I want to tell to you a little something about the job of County Commissioner and about La Plata County and give another view of coalbed methane development in our area.

In La Plata County, we have three county commissioners, and primarily our job is to administer the county's budget. And that means we fund everything from our sheriff's department to the fairgrounds, social services to our planning department. This is my tenth year as County Commissioner, and in that time I have developed a very strong respect for local government.

And I realize now that most of all, my real job is to fix things, and that is, if I can, to make things right for people who come to me with problems. And that happens on a daily basis. La Plata County is the home of 44,000 extremely well-governed people. We're situated in southwest Colorado, as you've seen repeatedly in here.

We're located about 330 miles from Denver. As we have heard, it sits atop the northern boundary of the Fruitland Formation, perhaps the largest repository for coalbed methane in the United States. Now, these two facts are the basis for La Plata County's concerns and how the county government became involved in dealing with coalbed methane development.

One premise I'd like you to remember is that La Plata County maintains that land use is a matter of local control, and the surface aspects of coalbed methane development falls within its purview. The first coalbed methane development began back in the mid to late 1980's at 320 acre spacing, and we were at ground zero when the coalbed methane experiment came out of the laboratory and hit the real world.

Nobody was really sure what would happen when production began. La Plata County is where they found out. Coalbed methane development began because of the tax credits. At that time, coalbed methane was classified as an unconventional fuel and thereby qualified for the tax credits. The consequences of this act would not be simple; in fact, they would be downright confusing.

Although it was federal action that spurred the development, development would not occur on just federal land. There were essentially three classes of land on which coalbed methane development would occur: on federal land, private land, and the land on the sovereign nation of the Southern Ute Indian Tribe.

This meant that oversite and regulation of exploration and drilling was split between the Bureau of Land Management, the BLM, on federal and tribal land; and the Colorado Oil and Gas Conservation Commission, the COGCC, on private land. Now, the impacts of drilling do not recognize political boundaries. So this bifurcation of regulatory authority would prove to be troubling.

And also, on private land, the ownership of the surface and mineral estates was quite often split. This meant that the surface owner might not own the minerals underlying his property. The split estate aspect of this project would prove to be one of the most complicating.

It is important to understand that the State of Colorado is an industry-friendly state. Its governor is the former head of the Rocky Mountain Oil and Gas Association. Its COGCC is predominantly comprised of people with ties to the oil and gas industry. Their task is to promote the development of Colorado's oil and gas natural resources. And they take their charge very seriously and pursue it with great vigor.

It is also important to understand that La Plata County is a resident-friendly county. In the early 1990s, around the time coalbed methane development was beginning in earnest, La Plata County was discovered by the outside world. That residential boom that began back then is still with us.

By their very natures, industrial and residential development simply are not compatible. And much of the drilling took place where this residential boom was occurring. And there was a conflict. And because coalbed methane development has a greater impact on the community than does the production of tight sand gas, it did not take long for residents to start feeling that impact.

County roads, designed as farm-to-market roads, were being blown apart by heavy truck traffic. Because of this increased traffic on our gravel roads, air quality suffered. Drinking water aquifers were being contaminated and depleted. There were vegetation die-offs because of gas seeps at the Fruitland Formation's outcrop.

Pump jacks were put into neighborhoods, and the county had no ability to deal with something as basic as regulating noise that was coming from this equipment. Because of the lack of any substantive response from either the BLM or the COGCC, people looked to county government to help them with their problems.

Coalbed methane was affecting their lives, it was affecting their homes, it was affecting their property values, and their security. Coalbed methane development does not occur in a bubble. It occurs where people live.

It occurs in subdivisions. The COGCC and the BLM, their regulations deal with the technical aspects of extraction. They do not address the problems people were facing back then. In La Plata County regulations do address these problems. And that set the stage for the drafting of our land use regulations, which we adopted in 1991. I would like to read a little something from the Purpose of Article, which is prefaces these regulations: "This article is enacted to protect and promote the health, safety, morals, convenience, order, prosperity, or general welfare of the present and future residents of the county. It is the county's intent by enacting this article to facilitate the development of oil and gas resources within the unincorporated areas of the county while mitigating potential land use conflicts between such development and existing, as well as planned land uses."

And generally, these regulations require operators to go through our land use process for both minor and major facilities, that is, wells and compressor stations. They deal with things like setbacks from residences, how you locate facilities within subdivisions, noise mitigation, how you should access county roads, and weed control. That's in general.

In specific, what happened was the enactment of these regulations got us sued. The lawsuit was *Bowen v. Edwards*, which went to the Colorado Supreme Court. And essentially, the Court upheld the county's rights to exercise their land use authority as it pertains to the development of oil and gas, so long as the exercise of that authority does not create an operational conflict with COGCCs rules and regulations.

That rule rankled the industry and the state to no end, because as far as we could tell, we were the first county to ever do anything like that. There were dire forecasts from the industry that because of the onerous nature of these regulations, the industry would be forced out of La Plata County.

You have to understand, oil and gas production accounts for approximately 50 percent of our property tax. So these were significant, albeit empty threats. More than 2,000 coalbed methane wells have been drilled under those regulations, none have been denied. And as we speak, drilling continues. It's where the gas is. That's where they're going to go.

In 1995, La Plata began the process of revising and adding to our regulations. And the question that was asked repeatedly by the industry and the state was: Why are you doing this? You have something in place already. The answer was that we knew that the next round of drilling at 160-acre spacing was coming, and we wanted to take what we had learned from the first round of drilling and adapt our regulations to fix the problems before they happened at 160-acre spacing.

And over the next 18 months that it took the task force to draft regulations, the county was told repeatedly by both the industry and the state that this effort was unnecessary because there was nothing on the radar screen about downspacing. Less than six months after the regulations were adopted, the State of Colorado joined the Colorado Oil and Gas Association in a lawsuit against La Plata County. Less than six months after the regulations were adopted, the first application for 160-acre spacing was processed by the COGCC. It is that kind of collusion and deception that has created the atmosphere that currently exists in La Plata County toward both the state and the industry.

Now, the most important regulation to come out of that round of rulemaking was what we refer to as the Surface Owner Discretion regulation, which said: "The surface owner shall determine the location of an oil and gas well on their property, provided the location lies within the COGCC determined drilling window, is a legally authorized approved drilling location under COGCC statute and regulation and is in general conformance with the standards outline in this section."

Not surprisingly, that got us sued. And despite the imminently reasonable concept behind it, that a surface owner should be able to say where things go on his property, the Court found against us. But even that finding supported the concept of what we wanted to do, in terms of the surface owner. What it did not support was the process that we used to accomplish this. What does that mean? And that is that the Court felt that we had given to the surface owner that authority which is more rightfully that of the counties. So what we did was we redrafted the regulation to accommodate the Court's concern, and it is currently our code.

Of all the myths associated with the development of the resource, the dominance of the mineral estate is perhaps the most widely accepted and the one that most stands in the way of people being treated equitably. What we have attempted to do in all of this is to equate the states. We feel that our effort is supported by the Colorado Supreme Court when it said in *Gerrity v. Magness*: "Although we, the Supreme Court, have referred to the mineral estate as the dominant estate and the surface estate as the servient estate, our cases have consistently emphasized that both states must exercise their rights in a manner consistent with the other. Hence, in a practical sense, both estates are mutually dominant and mutually servient because each is burdened with the rights of the other."

As I said before, La Plata County is over 300 miles from Denver, and while that generally works in our favor, when dealing with legislative matters, it definitely puts us at a disadvantage. The oil and gas industry has one of the strongest lobbies in the state and is present in the legislature on a daily basis to advance their position. And by God, I will give them that.

Consequently, the range and depth of legislative understanding of the oil and gas issue generally runs in the veins of: Gas clean, gas cheap, gas good. The myths that any regulation, and especially local regulation, is detrimental to the industry. The myth that local regulation will drive the industry from the state. The myth that local regulation is driving up the cost of gas and will result in people starving to death in the dark.

Those myths are propagated daily, and like anything, if repeated often enough, become general common knowledge. It is a constant source of amazement to me to listen to good, solid conservative legislators, advocates for personal freedom, believers that government should be as close to the people as possible, for these same people not to support the idea of local control when it comes to this issue.

Having gotten little or no support from the COGCC, people have repeatedly turned to the Colorado legislature for help. Efforts to reconfigure the composition of the COGCC to make it less a puppet of the industry, efforts to bring the rights of the surface owners up to the same level as those of the mineral estate, efforts to compensate surface owners for damages to their property incurred by drilling operations. All of those have been defeated.

Now, I will say that things have improved since 1991. We have better operators down there, we have better relations than we did back then, but there is still a lot of work to be done. And I will credit a lot of that to what we have done locally. It is very difficult to fight a fight when you're 300 miles away from the battleground.

It is much easier to level the playing field at home, in our effort to get fair treatment for surface owners as the development of resources continues. That is what we are trying to do. And that is where La Plata County has had our successes. And that is where we will continue to make sure that our people have a voice in the future of their community.

Thank you very much.

IMPACTS OF CBM DEVELOPMENT ON COMMUNITIES

GWEN LACHELT, *Oil and Gas Accountability Project*

I am with the Oil and Gas Accountability project, and our mission is to work with communities throughout the Rocky Mountain West and throughout the country to reduce the problems caused by oil and gas development. We've worked on oil and gas issues now since 1988, when Amoco, now BP, I believe, announced plans to build 1,000 coalbed methane wells on the south side of the Powder River Basin. I'd like to state up front that I'm not an attorney. I'm not a geologist or petroleum engineer or land use expert. My experience comes from working directly with people who are directly affected by coalbed methane development in particular, oil and gas issues in general. I've been working at the local, state, and national levels since '88 through various reform initiatives. And I'm going to focus my communication both on the physical impacts on the environment and the effect this impact has had on people and families. Certainly, there are economic benefits, as Bob Zahradnik stated earlier, but I'm going to leave that discussion to those folks.

This is where coalbed methane development is occurring right now. {The 35mm slides shown at the conference are not available here}. If you take a look at this map, you can see where the reserves of coalbed methane are. And actually, there have probably been additional reserves discovered since this map was produced. The San Juan Basin is in the southwestern portion of Colorado, with the majority of it being in New Mexico. We believe that coalbed methane development poses a serious environmental threat to the Rocky Mountain West. Regions of Colorado and New Mexico and Wyoming have been serving as America's guinea pig, you if you will, from the development of coalbed methane. As you've heard in other presentations, massive amounts of ground water must be pumped from underground aquifers. Coal seams are to simulate production in a web of roads, constructed to deliver the product to market. Let's go into the San Juan Basin.

Thousands of coalbed methane wells have been drilled and have profoundly altered our landscape. In coalbed methane wells, the density is every 160 acres. As new regions across the west begin to experience coalbed methane development, tribal groups are pointing to the San Juan Basin and saying that they don't want their communities to be nightmare stories of being able to light their tapwater on fire from methane contamination, caused by the dewatering of the coal formation. Stories like these haunt residents in these regions that are looking at potential coalbed methane development. Reports of methane contamination and new methane seeps continue to be reported in the county in toxic levels. Toxic levels of hydrogen sulfide have driven some families their homes. Several residents' homes have become uninhabitable from these contaminations. And torn-down homes are now commonplace, especially in areas where the coal seams outcrop at the surface. Companies have received state and federal approval to double the density of allowable wells in the San Juan Basin.

Just to give you some idea, here is a pit for oil and gas waste during drilling. Here is a smoking drilling rig near a home. Pretty typical drilling tower. And as you can see here, a single well can punch miles of road into the middle of undisturbed land, destroying wildlife habitat in the area. Drilling and completion is a really loud and smelly process. A bright and intensely lit drilling rig and crew works about 24 hours a day for weeks on end. Trucks and heavy equipment come and go constantly, and many family are literally driven from their homes during the drilling period. Here's a truck. This is a good example of a hydraulic fracturing operation.

This is a stimulation technique that they use to get oil and gas out faster. Hydraulics is one technique. Fluids are injected under the seams to create new fractures for the gas to escape through. Injection is another technique where explosives are detonated underground for hazardous chemicals to get into ground water. This is a production waste pit. And if you're unaware, a number of exploration—I mean, in general, exploration and production waste are exempt from regulation under the nation's waste law. This is a sign near the Animas river in town near one of our new middle schools where hydrogen sulfide is seeping into the river.

In full-field development, this is a picture of the area I mentioned previously in Colorado's Grand. . . . Here's some collector pipelines. Once you hit full-field development, you just, you have collector pipelines, compressors, dehydrators; in central facilities, transport pipelines. And these—this is a development that turns previously rural areas literally into industrial zones. This still doesn't mean that oil and gas shouldn't happen, but with all these impacts, it certainly means the oil and gas industry needs to go back to the drawing board and figure out how to do that. This type of development is not appropriate where it has a negative affect on people, water, air, land, and wildlife. With this lack of information, it makes sense for companies to fully disclose the impacts before proceeding.

The impacts on families who live in rural subdivisions and ranches has been tremendous. Many report sleepless nights and concern for their health and also the loss of quality of life due to constant noise from nearby facilities and constantly having the oil and gas industry on their land on a fairly frequent basis. One man I know, who developed cancer, is very suspicious of the water he drank from his tap after a nearby fracturing association. He called one day a couple of years ago and reported that his water had actually turned black after a hydraulic fracturing investigation. Many are concerned for the safety of their children on roads with very heavy truck traffic and unfenced well sites with with jacks and toxic pits. Many are concerned with their property values. For many, our home is our largest investment. A lot of these people want to sell their homes to move out of the gas patch, and they're fearful that their homes won't be sold because of nearby gas and oil drilling. And then there's the ranchers. Many fear that coalbed methane development will force them off the land and finally—and this is not an exhaustive list—but people are growing increasingly frustrated at the lack of response they receive from state and federal agencies.

Many simply feel shut out in public decision making processes. As pressure to drill is at any cost, decisions are made that directly affect our lives and the public lands that we hold so dearly. Some people who have decided to speak out have actually been faced with various sorts of SLAPP suits from oil and gas companies and federal agencies that are trying to squelch their voices. So there's been many, many impacts; not just to the land, but to people who are just trying to live normal lives. And just one more note: A rancher that we work with on the New Mexico side is losing about eight to ten cattle a year from drinking out of toxic pits that are unfenced at well sites. And one of our battle cries has been to talk about the fact that coalbed methane is not a clean fuel. And as we struggle to meet America's energy demands and reduce air pollution, coalbed methane is constantly being promoted by the oil and gas industry as a clean alternative fuel.

At a worldwide oil and gas symposium two years ago in Denver, speakers announced plans for accelerated development of this so-called environmentally friendly fuel that would offer tax credits for coalbed methane development and roll back environmental safeguards to pave the way for increased oil and gas development on public, private, and tribal lands throughout the country.

As stated in the 1993 Greenpeace report, and I quote, "nonpolluted fuel is either to minimize or completely ignore its total fuel cycle impacts, beginning with initial size of its surveys, drilling production, processing, and distribution, all the way through to the final combustion process." Protecting areas is a priority for my organization and many of the community organizations that are represented in this room today. And we believe that there's just simply a whole lot at stake.

Thanks.

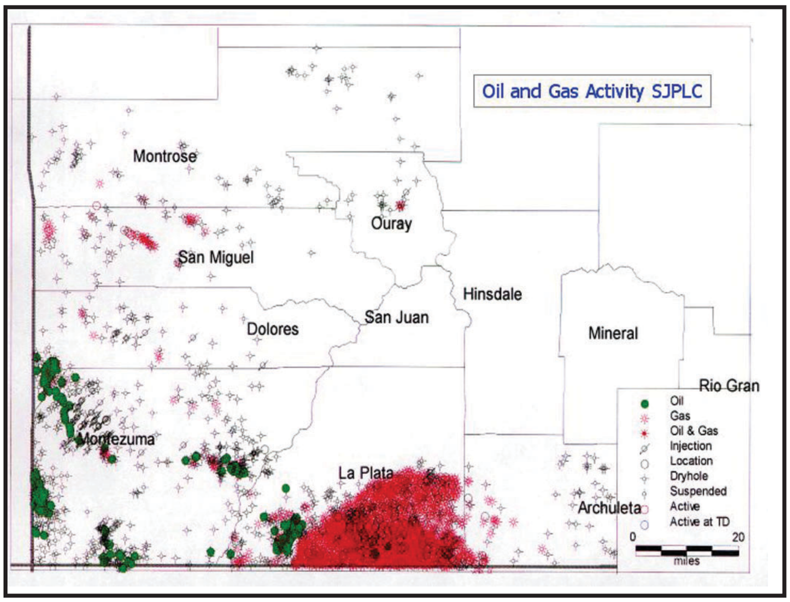
CBM DEVELOPMENT OF PUBLIC LANDS

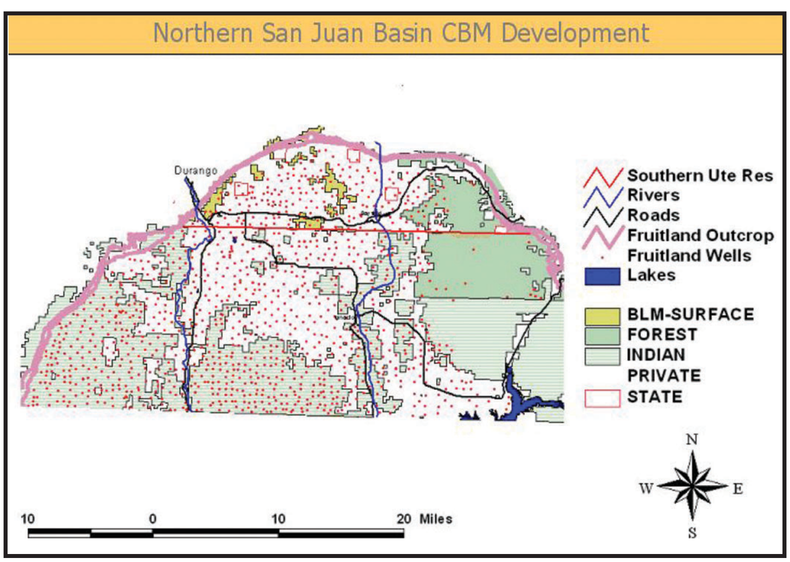
WALT BROWN, *EIS Team Leader, Forest Service/BLM Durango*

My presentation is on two ongoing Environmental Impact Statements for continued coalbed methane development in the Colorado portion of the San Juan Basin. This map shows oil and gas existing activity in the southwest corner of the state. In the red, red is oil and gas wells. As you can see, there's a few spread out around the countryside there. But by far and away, the most activity is in the Colorado portion of the San Juan Basin and La Junta County. When we zoom in, you can see the red dots come apart, and you can see the existing oil and gas wells.

This is the Southern Ute Indian Reservation here. This is what we call the Northern Basin EIS study area. And this is relatively undisturbed forest area land. And the HD Mountains are in that eastern part of the northeast San Juan Basin.

To date, there's about 1,200 existing conventional wells in the Northern Basin. There's about 1,300





coalbed methane wells there, and then about 300 proposed conventional wells and about 700 proposed coalbed methane wells.

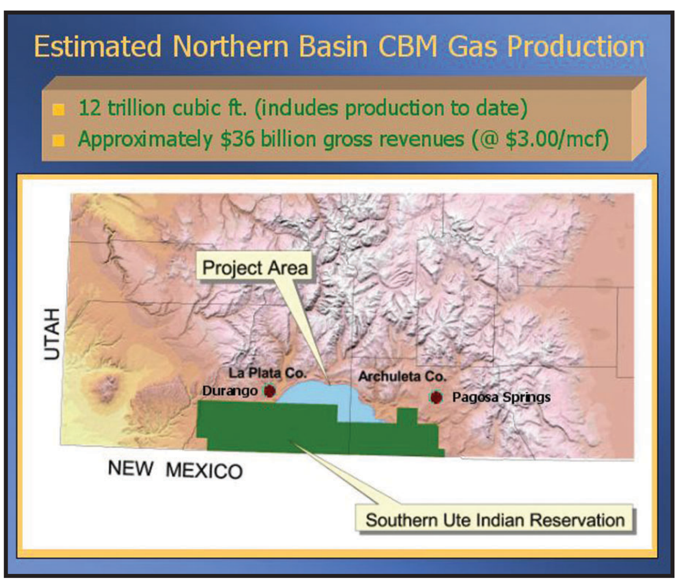
So as people have talked about all day long, there's a lot of interest in the San Juan Basin. There's some big

EXISITING AND PROPOSED WELLS IN NORTHERN SAN JUAN BASIN*

	Exisiting Conventional	Existing CBM	Proposed Conventional	Proposed CBM
SUIT EIS Area	1200	1000	269	367
NSJB EIS Area	20	300	20	300
Totals	1220	1300	289	667

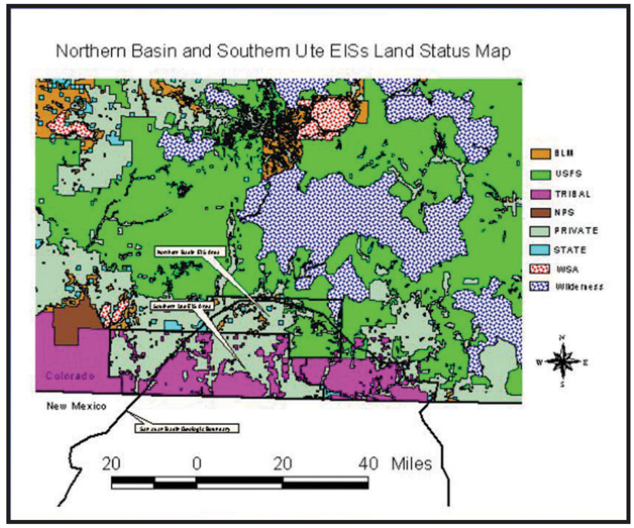
*Approximate

reserve numbers, perhaps 12 trillion recoverable cubic feet in this part of the world, which means some big dollars in gas revenues. This map also shows the relationship between the Northern Basin EIS area and the Southern Ute Indian Reservation.



While we're working on these two EISs, the permitting of oil and gas activities are guided by the interim criteria. We're not processing anymore applications in region A or C, which is a mile and a half buffer zone. Also, in region E, which is primarily forestland, we are not permitting applications until the Northern Basin EIS is completed.

In region D, we're continuing to process well applications, but only after making sure that there are no new impacts to hydrologic or gas seepage-type issues. In



region B, which is the Southern Ute Indian Reservation, we are processing APDs. However, these APDs may be issued with Conditions of Approval for data collections for the EISs.

So now, I'd like to get into a little more detail on the two EISs. The first one we'll talk about is the Southern Ute Indian Reservation EIS. This shows you some of the complex demographics of the area. This is the Northern Basin study area. It's kind of hard to see this here. But I'd like you to look at both this level and when you get down closer to the ground. Southern Ute Indian Reservation is about half tribal lands and about half private lands. This is Mesa Verde National Park, this is the Weminuche wilderness, and this is the outline of the San Juan Basin.

The Southern Ute EIS is a programmatic EIS, analyzing the potential impacts of future oil and gas development on approximately 200,000 acres of tribal land within a 421,000 acre study area. Most of the study area is already substantially developed for coalbed methane production and the Southern Ute EIS is a cooperative effort by the tribe, the BLM, and the BIA.

Background of the Southern Ute EIS

In September of 1995, a notice was filed in Federal Register to prepare the EIS, due to the scope of potential oil and gas developments and infill requests and orders. In May of 2000, the BLM issued a Fruitland Coal Seams infill development order for federal oil and gas mineral estates held in trust within the exterior boundaries of the Southern Ute Indian Reservation. This allowed up to four wells per section for improvement and development within the Southern Ute Indian Reservation. Following that, in July of 2000, COGCC issues their order allowing infill development on state and private leases within the exterior boundaries of the Southern Ute Indian Reservation. In March of 2001, the draft EIS was issued with a 30-day public comment period. We received about 300 comments. And then we got hung up in the Cobell lawsuit for about three months—it referred to individual tribal allotment data—and we had to work with our solicitors and lawyers to get permission to work on the EIS again, but we are. Issues have been identified in the Southern Ute EIS, and those are: impacts of property values, noise impacts, aesthetic impacts, water depletion issues, surface and groundwater quality and quantity issues, gas seepage into domestic water wells, dying vegetation along the Fruitland outcrop, impacts to wildlife, impacts to archaeological resources, and air quality impacts.

We are analyzing three alternatives in the Southern Ute EIS. Alternative one is the no action alternative and represents the continuation of present management and of exploration and development at rates that are similar to recent drilling and development activity rates. A total of 210 wells would be developed, including both conventional and coalbed methane wells. Alternative two is the infill development alternative. And this considers the drilling of two wells per 320-acre spacing unit or of four wells per section throughout most of the tribal lands on the study area. In this alternative, 636 wells are being analyzed. Alternative three: enhanced coalbed methane recovery is the agency and tribal-preferred alternative. This includes all the developments included within alternative two, plus recovery techniques; that is, the injection of nitrogen, carbon dioxide, or other fluids into the Fruitland formation to improve recoveries of coalbed methane. So it has the same number of wells as alternative two and an additional 70 injection wells to improve the recoveries of those 636 wells. So this alternative has 706 wells.

The current EIS schedule: We're hoping to have the final EIS out on the street in late May of this year. That would be followed by a 30-day public comment period, and a Record of Decision issued in late July of this year.

Background of the Northern San Juan Basin EIS

I'd like to talk a little bit now about the Northern San Juan Basin coalbed methane development EIS. Refer to the land status map, above, and keep in mind the unique demographics. The main difference for these two different EISs is that this is tribal land with some private land, and this is private land with some public land. There's a lot of private land, but it's a distinct area from the Southern Ute Indian Reservation. The land status within the Northern Basin EIS study area is very complex. There's six different categories, at least, of land. It's about 45 percent private, about 37 percent national forest land, about 7 percent private surface and federal mineral, 5 percent BLM land, 4 percent State, and then 2 percent in this interesting category of federal surface and private mineral, to make up this 125,000-acre study area.

Surface/Mineral Ownership in Project Area *

Jurisdiction	%	Acreage
Private land	45	56,250
National Forest land	37	47,370
Private surface/ Federal mineral	7	8,570
BLM land	5	6,660
State land	4	4,460
Federal surface/ Private mineral	2	2,030
TOTAL:	100	125,340

* Almost 50% of the subsurface mineral estate in the project area is administered by the BLM

Another way to look at some of these land status combinations is that almost 50 percent of the subsurface mineral estate in the project is administered by the BLM.

The Northern Basin EIS started in April of 2000. There was a notice filed in Federal Register to prepare an EIS, due to the scope of industry development intentions and the infill discussions that were ongoing. In

NSJB EIS—CURRENT SCHEDULE	
Draft EIS publication	June 2002
Public comment period on Draft EIS	June–August 2002
Final EIS publication	November 2002
Governor's review and public comment period on final EIS	Nov–Jan 2003
ROD publication	Early 2003

April through July of 2000, the COGCC held their hearings on the spacing requests to down space from one to two wells for 320 acres in the San Juan Basin north of the Ute line in La Plata County. In May of 2000, the BLM issues an infill development order on federal lands in the San Juan Basin north of the Ute line in La Plata County, allowing up to four wells per section. In June of 2000, the United States Forest Service and the BLM conduct public scoping of the industry proposal to drill 160 new CBM wells in La Plata County. Then in July, COGCC issues an order allowing infill development on state and private leases north of the Southern Ute Indian Reservation.

In the spring of 2001, we got a revised proposed action from the industry proposing to drill 300 CBM wells, including the intention to infill to a density of four wells per section in portions of the HD Mountains in the Eastern study area. In July of 2001, gas companies submit details of a development plan for the leases in the HDs. And then in January, we held additional public meetings in Durango and Bayfield to present the revised proposed action of 300 wells and alternatives and to continue scoping. The EIS procedures that we work with: The first thing we have to do is determine the scope of issue, then we prepare and issue a draft, analyze a draft, prepare a final, issue the final, and reach and record a decision. Right now, we're in step two. We've sorted through about 2,000 comment letters that were received during the last round of scoping. We're preparing the revised scoping summary and addressing all pertinent issues identified to date as we're preparing this draft EIS. We're currently looking at five alternatives, but we are taking a hard look at another alternative based on the extensive response from the public on that issue.

Issues associated with the Northern San Juan Basin, in no particular order, similar to Southern Ute, are: property values, noise, aesthetics, tax revenues, water depletions, surface and groundwater quality and quantity impacts, gas seepage into domestic water wells, dying vegetation along the Fruitland outcrop, wildlife impacts, impacts to archeological resources, air quality impacts, and impacts to the HD Mountains inventoried roadless areas, and resource values in the HD Mountains.

Alternative one is the "no federal action" alternative. There would be no new development on federal lands or federal minerals in this alternative.

Alternative number two is to continue the current direction under the existing federal plans and permits. Under this alternative, about 200 wells would be developed. An additional 0–20 wells would be developed on BLM land, 100 on private surface and private mineral land, and 65 on Forest Service land.

Alternative three is "industry proposed action." What they're proposing—you get ranges in well numbers. So you can have a range of wells, but you get up to 18 on BLM surface and federal mineral. You end up with about 300 total wells under the industry's proposed action.

Alternative four is the "maximum development" alternative, which considers the maximum number of wells, and that number is about 523. Alternative number five is "no new development in HD Mountain area." And I can spend a little bit of time talking about the HD Mountains. There's a chronology of the decisions that have led to where we are today.

The USGS identified the HDs as having high potential for oil and gas development back in the early 70s. Then in the 70s and early 80s, large portions of the HDs are leased to oil gas operators. Slightly after that and overlapping a little bit, there was a roadless area review evaluation, RARE II, which identified about 20,000 acres in the HD's roadless areas. In the 1979 RARE II decision, it classified the HDs as an "inventoried roadless area" and recommended the area remain non-wilderness. And in 1980, the Colorado Wilderness Act did not include the HD roadless area based on that decision. Previous NSO stipulations on some of these older leases were rescinded.

In 1983, the San Juan National Forest Plan was approved. The ROD reaffirmed HDs availability for multiple uses. In 1992, there was an EIS for development of coalbed methane in the HDs, up to 95 wells. And the

ROD permits 16 wells. In 1999, President Clinton directs the Forest Service to develop regulations for protection for inventoried roadless areas. In January of 2001, there is a final roadless conservation area rule, which is currently the subject of eight lawsuits, which prohibits new road activities in inventoried roadless areas on national forests, except, among other things, where a road is needed in conjunction with the continuation, extension, or renewal of a mineral lease on lands under lease. The Northern San Juan Basin EIS will determine and address how each alternative would impact the environment, and how and to what degree impacts can be mitigated. It will evaluate development alternatives across jurisdictions and evaluate direct and indirect impacts. It will evaluate cumulative impacts and identify environmental protection measures for implementation on federal lands. And it will evaluate the impacts specific to the HD's RARE II area. It will not make spacing decisions or make CBM development decisions on private lands or private mineral estates.

Two records of decision will be issued at the end of this process; one for the BLM, and one for the Forest Service. These records of decision will be based upon EIS findings, outlining and explaining the decisions, describing all the alternatives considered. They will be describing which alternatives are environmentally preferable, disclose facts considered in making the decision, explain adopted mitigation measures and describe monitoring programs, and include decisions on APDs filed during the preparation period. The current schedule for the EIS: We're working toward having a draft out on the street in June of this year. There will be a public comment period on the draft from about June till August. The final EIS could be published in November of 2002. This is followed by another 90-day public comment period in 2003. Then, early 2003, we're looking at publication of the Record of Decision for this document.

Thank you.

COALBED METHANE DEVELOPMENT IN THE INTERMOUNTAIN WEST: CONFERENCE PROCEEDINGS, SESSION 3: THE POWDER RIVER BASIN

OVERVIEW OF CBM ISSUES IN THE POWDER RIVER BASIN

DIANA HULME, *Institute For Environment and Natural Resources, University of Wyoming*

I am going to give you an overview of the coalbed methane issues in the Powder Basin. First, I'd like to give specific thanks to Paul Rau, who's a research specialist with the Wyoming Geographic Information Science Center at the University of Wyoming, and also to Dennis Feeney, who's also a research scientist in the Department of Agriculture and Applied Economics at the University of Wyoming. They helped me put this presentation together. And also to the Wyoming State Geologic Survey, who allowed me to pilfer some of their data.

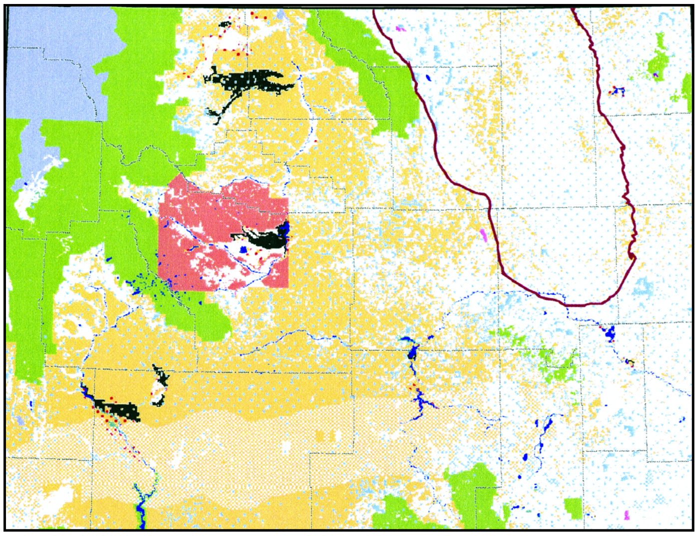
I'd like to orient everybody as to where the Powder River Basin is. The state of Wyoming is the other square state located north of the other square state of Colorado. And the Powder River Basin area is bordered on the west by the Big Horn Mountains and on the east a little bit by the start of the Black Hills. The town of Gillette is basically the focal point and the hub for a lot of development in the state of Wyoming. It's located in Campbell County, Wyoming. Lots of coal there, which means lots of coalbed methane.

The terrain of the Powder River Basin is very flat; it's grassland prairie. The climate is very dry. The average annual precipitation is about 14 inches. The average wind speed in this area is about 15 miles per hour, so it blows. You can see development starting to push more towards the West and starting in the Sheridan area.

My slides are going to take us on a little journey. [The animation shown at the conference is not available here]. I'm going to take you through a computer-generated 3D fly over of the part of the Powder River Basin where coalbed methane development is at its heaviest [slides not available here]. We're going to start northeast of the town of Gillette and move south down Highway 59 here. And we're going to make a right and go to the west at this intersection, and go north back up along Highway 50. It's over a 100 mile journey. There are some coalbed methane wells within the boundaries of the coal mine, and there we'll move into the town of Gillette. There's even some wells within the city of Gillette as well. We're heading south on Highway 59. Well spacing started out at 40 acres and I think new wells are going in at 80 acre spacing. So around Gillette, primarily, 40-acre spacing was that rule at that time, I think. Now we're coming up to the town of Wright, Wyoming. There are a lot of proposed wells for this area. Now we're heading to the west. Not much development out here yet. There are some proposed wells, but not a lot going on in this part. You can see quite a few pipelines to the south here and some proposed wells and some compressor stations; quite a few, actually. Now, at this junction, we're going to turn back to the north. A lot of proposed wells are off to the west. We're going up Highway 50 now, finishing on a loop. I looked on the 2000 census data and figured out, at least at this point in time, there's one coalbed methane well for each household in Campbell County. So everybody can claim one, or each household can anyway. We're coming back around as we come into the town of Gillette. That gives you an aerial perspective of kind of what the terrain is like for the area and how heavy the development is in that particular part of the state.

I'm going to briefly talk about some of the issues with coalbed methane development in the Powder River Basin. These include water issues, air quality, land, effects on wildlife and vegetation, agricultural, and socioeconomic impacts. We heard yesterday that probably one of the main conflicts that has evolved with the coalbed methane project is that of split estate. This is a land ownership map of the state of Wyoming. Again, the Powder River Basin is up in this area. The kind of tan color indicates land owned by the BLM. Green is Forest Service, blue is Yellowstone National Park and Grand Teton National Park. The Wind River Indian reservation here, and state land is the very light turquoise color. There are sections of state land scattered throughout. The white indicates private land, at least for surface ownership. You can see the eastern part of the state is primarily private land. But in contrast, this is just a close-up of the Powder River Basin, Sheridan beings over here and this is the Wyoming/South Dakota border on the right. The pink color indicates federal subsurface mineral ownership of all the minerals. You can see that most of private surface land is under federal mineral ownership. This isn't an issue for just a few people, it's pretty widespread.

LAND OWNERSHIP IN THE WYOMING POWDER RIVER BASIN



Coalbed methane is basically a coin with two sides. There are good things about it, and there are some bad things about it. And I think depending on whom you talk to and what you're talking about, you can think of things for both cases. For water issues, we heard a lot about this yesterday and we'll probably hear more about it today. In some areas of the basin, the produced water is a good source of stock water and even potable water for the town of Gillette. Water discharged to the surface, which most of it is in Wyoming, can create wetland habitat for wildlife. It's also a good source of irrigation water if the water and soil conditions permit that.

Some of the downsides are state disputes over the discharge of poor quality water into interstate streams. Case in point, the Powder River; we'll talk more about that as well. There were some conflicts between the states of Wyoming and Montana on water quality issues with the Powder River. There's been concern over depletion of groundwater aquifers due to the removal of water. There are issues with soil and stream bank erosion due to discharge into streams that generally don't see that much water. Again, the Powder River being an arid area, the ground isn't used to that much water, so it's susceptible to erosion. Poor water quality may require the producer to do some treatment before discharge, so that's an added expense to them. High sodic water combined with certain soil types can inhibit vegetative growth.

We heard some about air quality yesterday too, and that coalbed methane is a clean fuel. It does burn cleaner than other types of fossil fuels, such as coals and oils. I would say that coalbed methane is probably a cleaner fuel down at the end of the pipeline, but on the production side there are some air quality impacts. It's a clean fuel at its destination but not where it's generated usually. Some of the negative effects are, and, again, the arid climate plays into this quite a bit, you see fugitive particulate emissions from vehicle traffic, vehicles traveling quickly at high speeds on unpaved roads. There's wind dust. Any time a land is disturbed, it will kick up dust without a problem. You'll see nitrogen oxide emissions and formaldehyde emissions from gas—fired compressor engines. You'll see the nitrogen oxide and sulfur dioxide from temporary diesel—fired generators, which are used at sites before electricity or wires are brought into the site for power. All the activity brings in more vehicles, a lot of them diesel—fired. All of these factors together can result in an impact regionally on visibility in the area.

The upside of coalbed methane development here is that it's not as evasive as other forms of mineral extraction, and not, probably as invasive as conventional oil and gas development because well pads don't need to be as big. The water produced can increase the fertility in the area. But again, on the downside, and some of these are repetitive, but it goes to show you that these are some of the key issues. If the poorer quality waters that are higher in salt are put on certain kinds of soil, it can bind it up for vegetative growth. You'll see topsoil loss where the land is disturbed up in this area, and there are just visual land and scenic impacts. I've heard some people say that the prairie has been turned into a light industrial zone. That's the scene they have to look at now.

For wildlife and the vegetation, some of the produced water can create wetland habitat. Some people have thought since the water production decreases as the play moves on, what may have been a wetland habitat will eventually dry up again and then there won't be, so it's probably a temporary wetland. And coalbed methane development, once the well is in, there's not a lot of attention that needs to be paid to it. And I think the wildlife tends to come back into the area once everything is set in place. Downside is that there are a lot of roads associated with coalbed methane development, which disrupts the wildlife habitat.

There is some increased pressure on threatened and endangered species and increased human contact with wildlife. And there are some issues with the spread of noxious weeds overtaking native growth. The agricultural industry—for some ranchers it's just been a blessing. They've seen some water improvements for stock and irrigation and seen an increase in personal income. On the downside of this, for other ranchers, the development has intruded on their ranching operations and they feel a loss of privacy and a change in their lifestyle. A change in things for the reasons they live out there and the things they do, their day-to-day lives.

And finally, socioeconomic impacts. It's lots of money. Wyoming is very much based on mineral production which includes coalbed methane. These mineral extractions have brought the majority of the revenue into communities in the state and Wyoming, and it provides education and other services that the state needs. It also, in the local areas such as the town of Gillette, which is the hub for minerals, brings people in and money in and obviously creates jobs. The downside is that it has created rapid population growth. The community is unable to keep up with some infrastructure demands, such as maintaining county roads due to increased traffic, even the roads in town. There are problems providing room in schools, hospitals, housing, and lodging. From what I understand, it's difficult to find a motel room up there, because a lot of people coming into town to work, that's where they stay. So room is limited in motels and also the "cross-bar" motel—the jail. Transient population—people are there for a certain period of time. They come and go. When their job is over, they leave. Increase in crime, increase in people, people having to live in adverse conditions. There are also issues with safety of some of their workers.

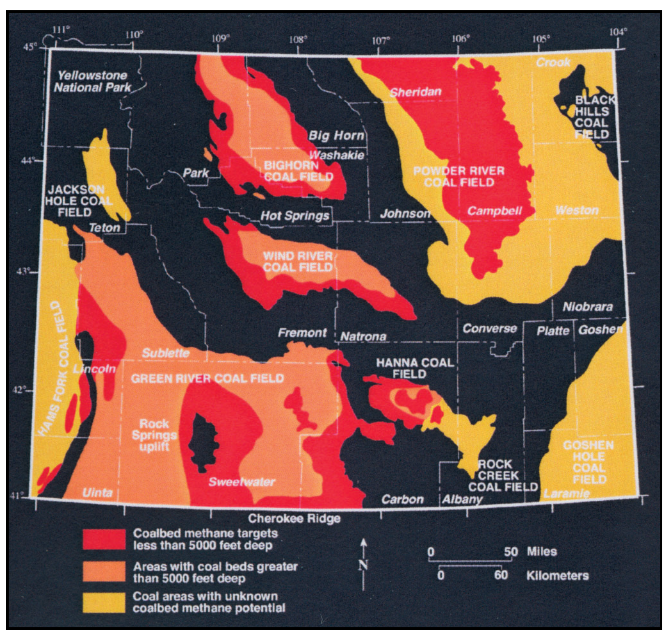
That is just a broad overview to set the stage. Our speakers will give a lot more detail on each of these issues.

THE GEOLOGY AND PRODUCTION CHARACTERISTICS OF THE POWDER RIVER AND OTHER CBM BASINS IN WYOMING

LANCE COOK, *Wyoming State Geologist*

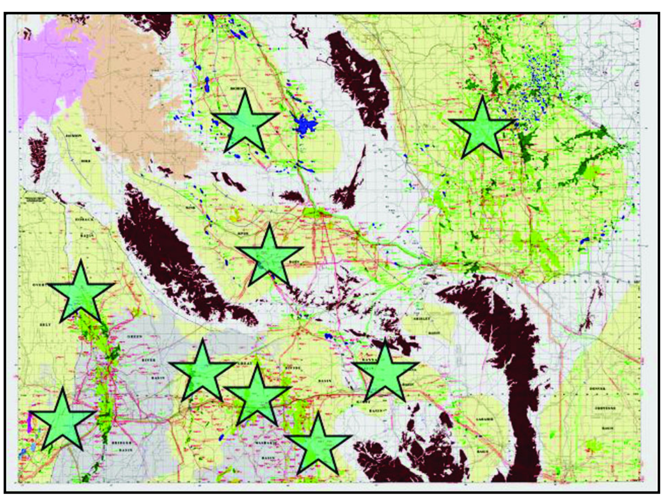
Good morning. Thank you for the opportunity to be here. I'm going to talk more about the subsurface than anything else and try and give you an idea of what the geology and the production characteristics of the coalbed methane reservoirs in Wyoming are like. And I'll do a little bit of comparison and contrast with what's been described in the San Juan Basin from yesterday. So we'll talk about where coalbed methane may occur in the state of Wyoming. We'll take a look a little bit at some of the Powder River Basin geology and the production characteristics. And we'll talk a little bit about this strange gas reservoir that seems to occur in conjunction with an aquifer.

This is a slide showing coalbed methane potential around the state of Wyoming. The Powder River Basin, as you see here, is a large area. This is coalbed methane production shallower than 5,000 feet. The coalbed methane areas with beds greater than 5,000 feet are shown here. And the areas with unknown coalbed methane potential are in these areas here.

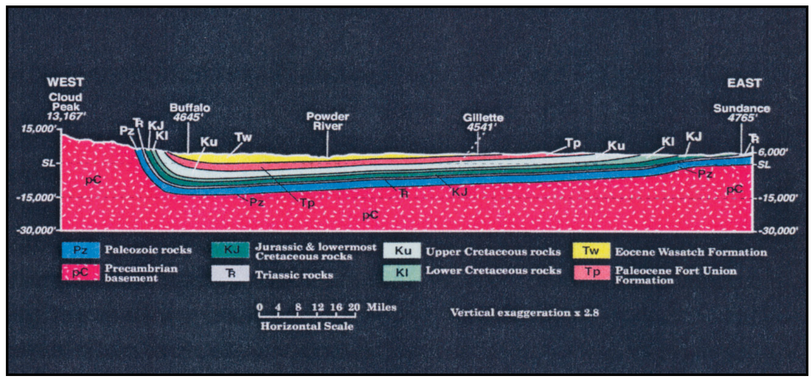


The next slide shows where the potential is outside of the Powder River Basin. There are a couple of projects going on right now. We have the Atlantic Rim, where there's an environmental impact statement going on right now. The vision is about 3,800 wells or 3,000 wells, something in that neighborhood. There's some private projects being drilled in that area, and we should have some results this summer or fall from those reports. We show coalbed methane potential in the Wamsutter Arch areas in the upper Cretaceous coals, and potential off to the north and to the lower corners. We have had a coalbed methane pilot project in the overthrust. I just heard the other day that that looks like it's probably going to be unsuccessful. No big surprise there. The geology is very complex in that area, and the area is pretty small. There's a pilot project going on at Big Piney, and some of the wells were drilled there this fall and winter. And there will be some initial drilling this spring and they'll get into production this summer. We have some projects going on in the Wind River Basin, and we have potential in the Big Horn Basin, being one of the larger unknowns right now. There is a coal field in the Big Horn Basin. Nobody's really done any work on it yet. People have looked at it and studies are being done, but nothing is publicly available right now.

HIGH CBM POTENTIAL AREAS

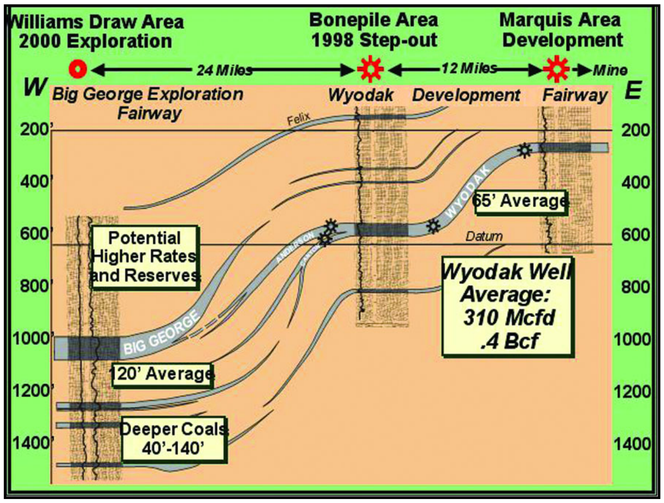


Next is a cross section, east to west across the Powder River Basin. The Powder River Basin is an asymmetric basin. There's a little bit more complexity on the west side. There's a thrust fault that brims the Big Horn Range on the west side and creates thrust faults. The coal section that produces in the Powder River Basin is in the Fort Union formation. It's in the brown or tan color here. So it crops out just to the east of Gillette. We have coal at the surface. It dips steadily into the basin at about one to one and a half degrees. We have the basin low or syncline just in front of the Big Horn Mountains, and then the beds dip up steeply to the surface. We've had development primarily in the shallow areas just alongside and west of the outcrop. And we've had development over on the west side of the basin, just east of the outcrop. We have had little development thus far in the deeper part of the basin, although we know that's where most of the impact probably is, in the deeper part of the basin.



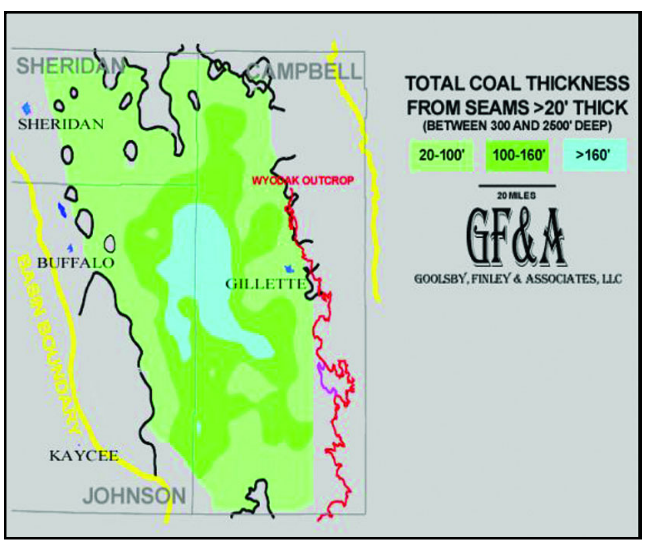
This is a schematic cross-section across part of the basin running from an area very close to the coal mines that were in the Marquis area. Here is one of the first areas that was developed in the basin, going to the Campbell/Johnson County line. This is called the Big George area. There are coal seams in the range of 100 to 200 feet in thickness, single coal seams. It's a very lucrative area in terms of a gas resource. In between, you can see the Bonepile Area, which was drilled in '98 and represented about a 12 mile step-out from the original development that we had. The Wyodak coal in here does not connect, you'll notice, to the Big George. We know that the Big George is set geologically higher than the rock columns of the Wyodak coals. So what we have is a series of major coal seams in the basin that are thick and fairly continuous over several miles, but they are not connected, necessarily, to other coal seams deeper in the basin.

COALBED METHANE STRUCTURAL CROSS SECTION POWDER RIVER BASIN



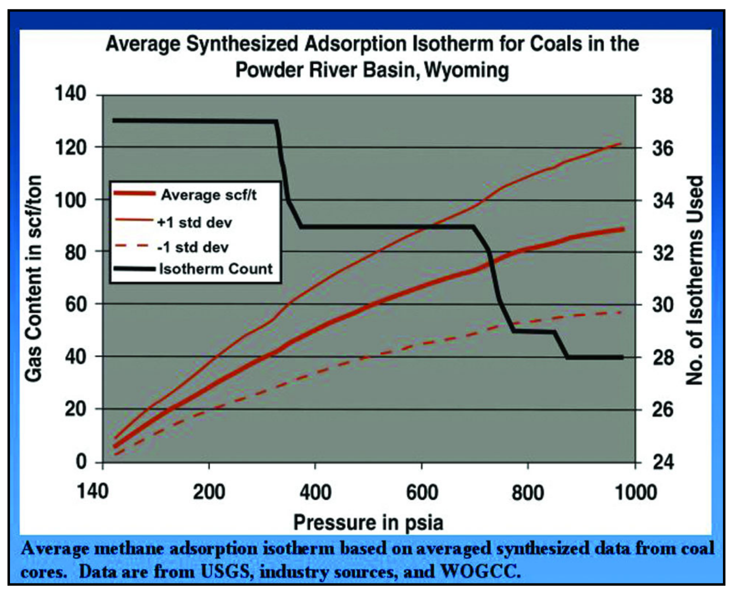
In the next slide, the blue color here represents aggregate coal seam thickness using coal seams greater than 20 feet thick. That's right here along the Johnson/Campbell County Line. That's the Big George area right there. This represents coal seam thickness greater than 160 feet of aggregated coal. And the darker green is 100 to 160 feet. And these lighter areas are 20 to 100 feet thick.

THICK COAL SEQUENCES



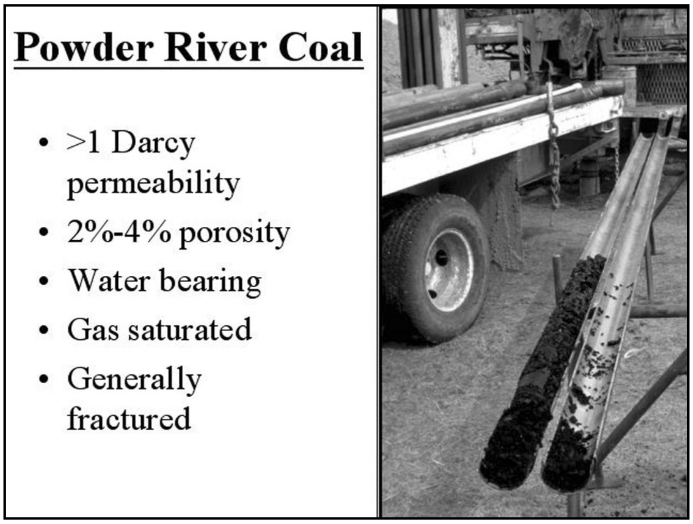
Powder River Basin coals are thick, but they have to be thick to make up for the fact that there's low saturation. The gas is stored in the coals via adsorption. This was touched on yesterday. The analogy in coalbed methane has been drawn that it's like popping the top on a bottle of soda, and that's really not right. It's an effective analogy, but it's not correct. The coal is physically located on the surface of a microfractured system called a cleat, and the process is called adsorption. It is the adherence of the gas molecules to the surface of the solids with which they are in contract. This is right out of the AGI glossary. So that gas is really physically situated on the surface of the fractures within the coal. Now, we go out in the industry, take a coal core, take it back to the laboratory and start to analyze that coal core to determine how much gas can that particular coal physically store on this microfractured surface. And that's what this curve shows.

This slide is about adsorption, or desorption, actually. Well, this is an adsorption isotherm for the coals in the Powder River Basin, using an aggregate of about 37 different cores from work around the basin. This is work done by, primarily, the USGS and the BLM. You can see a reservoir pressure of about 600 PSIA and about 65 cubic feet per ton. Those are low numbers. Typical San Juan Basin numbers are in the range of 300 to 400 standard cubic feet per ton. This makes up for its low gas content in thickness.



Average methane adsorption isotherm based on averaged synthesized data from coal cores. Data are from USGS, industry sources, and WOGCC.

This is a photograph of a core as it comes out of the well. You can see that this is rubblized. It's heavily and intensively fractured. That's a very dominant characteristic of the Powder River Basin coals. Permeability in the coals is measured in terms of millidarcies. The coal in the Powder River Basin has greater than one darcy, or a thousand millidarcies of permeability. Yesterday you were hearing about a few millidarcies. In some cases, those permeabilities have been shown to be over two darcies or 2,000 millidarcies. So we have huge permeability. That's what allows this low gas saturation in coal to produce gas. The coal is water-bearing. Once you get a mile or two away from the outcrop, the coal is saturated with water.



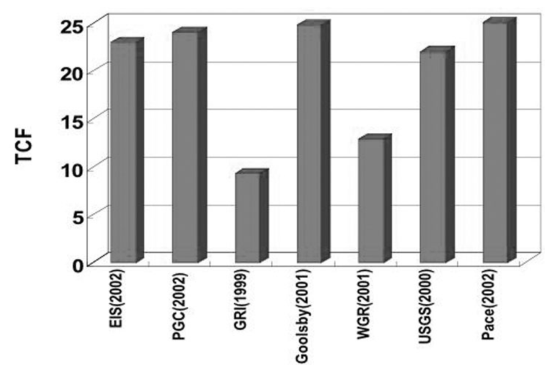
The coal is gas saturated. You saw that adsorption isotherm. That adsorption isotherm, once you know the reservoir pressure, accurately describes the amount of gas in the coal. If there were less gas in the coal, you would have to decrease the pressure even greater, and we don't find that to be the way. In almost all instances, the coal has as much gas stored in it as it can hold. That gas is biogenic gas, which is created by bacterial action. The coal is almost always fractured. There have been a few wells in the basin that did not tie into a fracture. Those are the exception. The rule is an average of about a darcy permeability.

Resource estimates: In the early '90s, '91, '92, if we were only working on the basis of economically recoverable resources, the Powder River Basin would have been given zero dollars of gas value resources. That's not an accurate way to describe a resource. You have to go in and look at the resource in the ground and then trust human ingenuity and technology to get that resource. Nobody's smart enough to know all of the variables and all of the factors to say with certainty in the future whether a resource will be producible or not. We've gone from not having a recognized resource, economically, and we know in the Powder River Basin, we have somewhere between 20 and 25 trillion cubic feet of economically recoverable gas. The estimates that are lower were produced by the Gas Research Institute in 1999 who were not looking at a resource number. They were actually looking at a reserve number. Same with Western Gas Resources. They were looking at a slightly different measurement than we were. Pace Energy Services, U.S. Geological Survey, the Goolsby Study, Potential Gas Committee, and the BLM's Environmental Impact Statement where the resource estimate was done by their Reservoir Management Group, and all of them picked this number between 20 and 25 trillion cubic feet. The gas estimates vary, but they're very close. When the resource estimates are actually all looking at the same thing, they're very close together at around 25 TCF recoverable.

RESOURCE ESTIMATES

• *Gas estimates vary among different organizations. When comparing "apples to oranges" the estimates are quite close in many cases.*

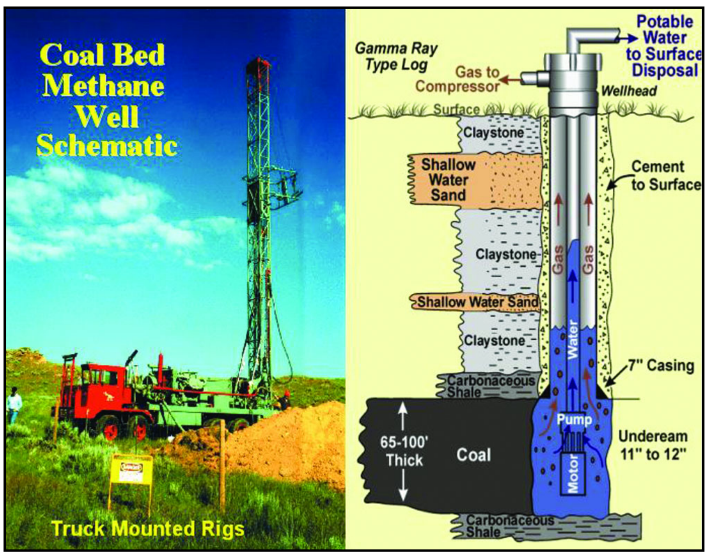
GAS RESERVE ESTIMATES



Well schematics: Wells are drilled differently in the basin. Surface casing is set and cemented in place. We go in, we under-ream for an open hole completion into a coal seam, and then we set a submersible pump and a simple sprayer to spray the water and the gas. It's a very low-technology completion, although there is some technology that goes into the monitors.

Gas production forecast: This is from a study that was recently done by Pace Global Energy Sources and is even more recent than the analysis that the BLM has put into their study. We're assuming a base price of $2.50 for gas, and we're at about 4.5 billion cubic feet a day. I still think that this is aggressive. I honestly think we're going to end up more in the range of three BCF per day, but we'll have to wait and see. Nobody's smart enough to predict future gas prices.

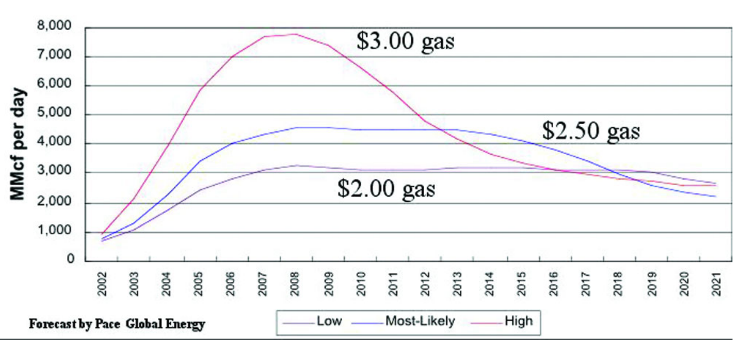
Reservoir simulation model: We saw some modeling work yesterday that showed nontypical coalbed methane curves. Some of those reservoir models were the early analysis done on data that was not appropriate for modeling. They were from wells that were unbounded. So you're basically trying to model an open system with widely differing well profiles in terms of water production and gas production. It's not until you aggregate a large number of wells that you're able to generate curves like this that fits the classical coalbed methane curves. So you have to work with them on a statistical basis.



GAS PRODUCTION

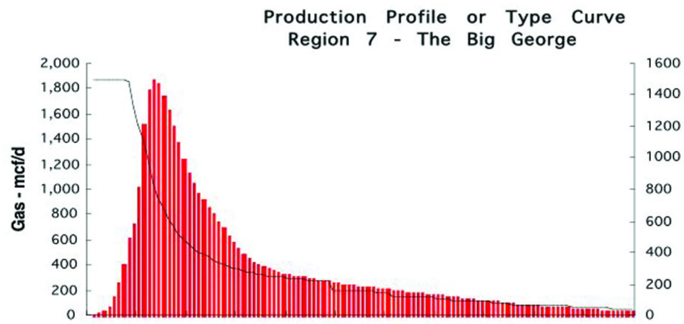
• *Gas production peaks at 4.6 Bcf/d in 2009 in the most likely scenario.*

CBM GAS PRODUCTION FORECASTS BY SCENARIO



RESERVOIR SIMULATION MODEL

- *While individual wells may have differing curves, well populations have well-defined production profiles.*

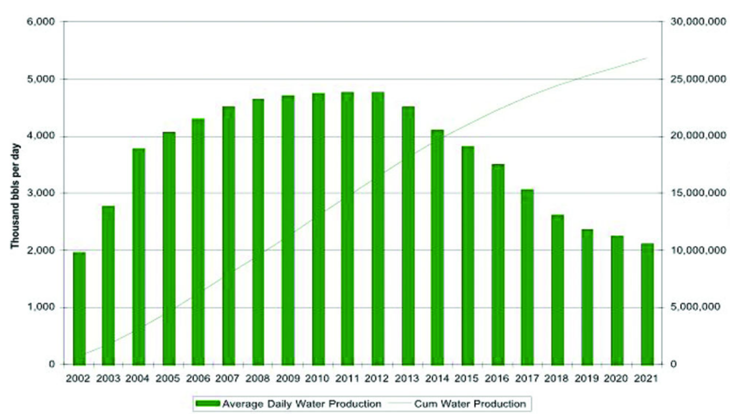


Cumulative water production: This is based on that medium-priced scenario that we saw on gas production. Cumulative water production here shows something in the range of 25 billion barrels per day estimated to be produced by the year 2021.

WATER PRODUCTION

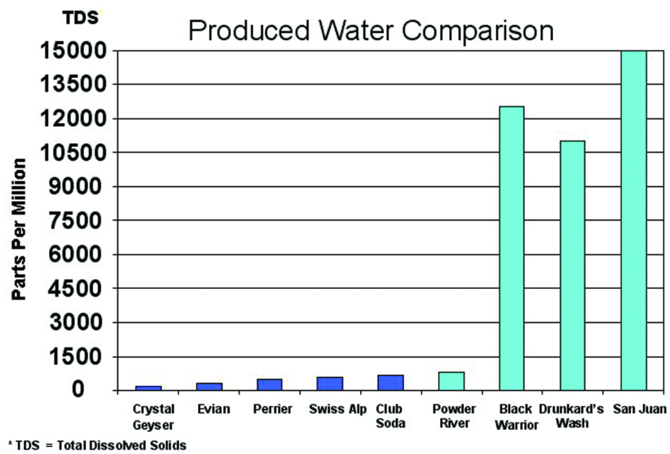
- *The average water production per day per well is 150 barrels during a typical 7-year life.*

WATER PRODUCTION FOR ALL REGIONS "MOST LIKELY SCENARIO"



Finally, water quality comparison. I need to make something very clear and make sure you understand this. A lot of people refer to the produced water in the Powder River Basin as saline water. The Powder River Basin's coal water averages around 1,000 to 800 parts per million. As you move to the western parts of the basin, that number gets up close to 1,000 parts per million. Little bit less in some places, more in others. There's club soda and crystal geyser. By comparison, water is about 13,000 parts per million in the Black Warrior. Drunkard's Wash is about 11,000 parts per million. San Juan Basin, 15,000 parts per million.

WATER QUALITY COMPARISONS



This water is very different from other coalbed methane waters. It is low salinity. What it has is a peculiar chemistry. It is sodic water. A very high amount of the total dissolved solids in this water is due to sodium. We have almost no calcium and also no magnesium. It's because of that peculiar water chemistry, and only because of that, that we have a conflict between the use of the water for irrigation and the soil types. Clay-rich soils are probably about the worst kind of soil you can have for that. Nonetheless, this water meets drinking water standards, fit for human conception. And in many cases, the water is superior in quality coming out of the coal seams than it is for shallow water coming out of the Wasatch Formation.

Thank you.

A REVIEW OF CBM DEVELOPMENT IN THE POWDER RIVER AND OTHER WYOMING BASINS

DON LIKWARZ, *Director, Wyoming State Oil and Gas Conservation Commission*

Thank you very much. I'm glad to be here this morn ing. We thought it would make more sense if Lance got up first and set the stage. I'll get into the details. I'm known as "Mr. Facts" because I have all the data. We have a really good web site that's updated on a daily basis electronically, so some of the data is brand new, and some of it is two or three weeks old. So it won't agree with some of the information you heard over the last few days. Again, I may be repeating some things, but I'm trying to make sure you come away with some of the key points.

As Lance said, this is totally different than any other large coalbed methane development taking place. It works because the depth of the coals is shallow. It starts at about 200 feet from the surface just west of those strip mines that were shown on some of the information this morning, and it's moving west at about two to three miles a year. And this is what we call the fairway. Where most of the producing wells are at right now is about 15 miles from the west—from the mines out about 15 miles west—and about 55 miles north to south. So about a 1,500 square mile area. We are now also moving northward to the Sheridan area where there are a couple of pilot projects going on, and then up along the Powder and Little Powder towards the Montana/Wyoming state line.

Most of the drilling, to date, probably averages about 950 feet deep. As a result, using the small truck-mounted water rigs, it takes about three to six days to drill and complete these wells from start to finish. As we also mentioned earlier, in the state of Wyoming, statutory spacing is 40 acres, but in March of 2001, the Oil and Gas Commission had a rule making where they changed the spacing to 80 acres for one well in the northwest and southwest quarter; and that's what now applies through the rest of the Powder River Basin. Main targets are very thick, I'm not going to go into detail. They are completed open hole, and they are not stimulated. They don't need any type of acid treatments or fractures, not with one or two darcies of permeability. So again, it's different from the San Juan Basin and the Black Warrior Basin in that regard.

We are seeing a few operators now use commingled production, but typically this takes a thicker coal at the bottom, which is completed open-hole, and then they perforate the coals above it. They're going to have to use more of that technology on the fringes of the basin, because of the thin coal stringers. Initial water rates run between about 400 to 800 barrels of water per day; that's equal to about 12 to 25 gallons per minute. But as we go west into the deeper coals, like the Big George that Lance pointed out to you, we're seeing rates of 1,000 to 1,500 barrels of water per day. Gas production typically is from 150 up to 500 thousand cubic feet per day, although we have seen some wells at 1 to 2 million CF per day. The reserves are running about 250 to 500 million cubic feet. They're not big wells, but because we have so many of them, that makes up for the type of wells that you have down in the San Juan Basin, for example.

Lance showed one slide that said the average life is about seven and a half years. Some of these coals are going to be produced in four years, some are going to go as long as ten, but the average that we have in the EIS and this study came up with seven and a half years. When we first started doing this in March of 1998, we had 300 wells. We didn't know what a well decline curve looked like because we didn't have enough data points. Some of those wells had been on production for 10 or 12 years, but they had been drilled unbounded. In some wells, they drained 160 acres. They were, in all cases, limited by the amount of take away capacity for pipelines, so it was limited production. We really didn't know what a curve should look like.

POWDER RIVER BASIN CBM

- Depth to coals 200'–2500' but most drilling 200'–1200' to date.
- Takes 3–6 days to drill & complete wells using small water well rigs with diverters.
- 40 acre statutory spacing changed to vertical 80 acre units in NE and SW in 03-01 rulemaking.
- Main target thick coals (50'–150') completed with under-reamed open holes. Casing set at top of coal. No stimulation required.
- Some operators using commingling with bottom coal completed open hole & 1–2 upper coals perforated.
- Initial produced water rates 400–800 BWPD in Fairway but have seen 1000–1500 BWPD in deeper wells in Basin center. Max. gas rates 150–500 MCFD.
- Reserves of 250–500 MMCF recovered in 4–10 years (avg. 7 years).

The Powder River Basin environmental impact statement: Not a lot of detail because Richard Zander will be covering this, but it began in June of 2000 with three scoping meetings. We've learned from some of the problems that they had in the San Juan Basin, so the Governor asked if we could become a cooperating agency with the BLM on their EISs. They made that offer, we accepted it, and Lance and I have been either lead or co-lead on three EISs so far. That allows us to be part of the interdisciplinary team, which actually selects the various alternatives that are studied. In the case of the Powder River Basin EIS, we went a step further. A number of counties had asked to be a cooperating agency on the EIS, but the BLM said that wasn't something they were prepared to do at that point. So we helped create a joint powers board and all of the counties affected—Sheridan, Johnson, Campbell, and Converse, plus Carbon County, who's going to see some activity down in southern Wyoming in Atlantic Rim—got together and became a cooperating agency through us and participated from the start. It's key to get those local people involved as soon as you can.

PRB EIS

- Process began June 2000
- 51,444 CBM/3,200 oil and gas wells
- 12,500 square mile area or 8 million acres. All of Campbell, Sheridan and Johnson Counties & N of Converse County
- 3.6 BCFD maximum production
- Minerals 54% Federal land, 37% Fee and 9% State
- Surface 14% Federal land, 77% Fee and 9% State
- 3rd Qtr. 2002 approval
- Held scoping meetings in 4 cities 6-00
- BLM stopped accepting APD's 08-11-00 after reaching 5890 cap in Wyodak EIS

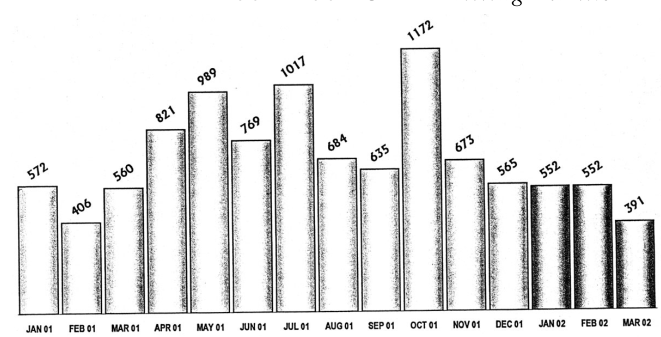
The other thing I want to point out, when BLM does one of these NEPA documents, they have to suspend permitting in that area. However, these documents have to look at the effects of wells on all the minerals. The State and fee minerals have to be in there as well so you can look at all air and water impacts. But while the BLM has to shut down permitting, my agency continues to issue permits on the other two minerals. As a result, this creates a situation where Federal minerals are being drained. If you recall some of those pictures from earlier, the individual ownerships are interspersed, so that it is almost a checkerboard. So a lot of the Federal acreage is surrounded on all four sides by State and fee wells. This has created another problem for them. Richard can confirm this, but I understand that this is the largest environmental impact statement that's been done by the Bureau of Land Management. The Wyadak EIS that was completed in November of '99 looked at 5,900 wells.

The study is assuming that we will drill 51,444 wells over about a ten-year period, but we also are looking at 3,200 conventional oil and gas wells on 12,500 square miles or 8 million acres. The area that's been developed, to date, is probably between 1,500 and 1,800 square miles. Maybe 10 percent of the acreage has been under development. Mineral ownership is 54 percent Federal, but only 14 percent surface. There's a 40 percent difference there. So the fee or private ownership, while it's only 37 percent of the minerals, becomes 77 percent of the surface. That 40 percent, I guarantee you, has caused all the difficulties and problems we've had to wrestle with. Maximum production in the EIS is 3 to 6 billion CF per day. In December, we produced a little over 800 million CF per day, so this would be an increase of four and a half times what we had last year. To further put that in perspective, the entire state of Wyoming from all sources of natural gas is 4.5 billion cubic feet per day. We're anticipating a record of decision some time in 2002.

I'm skipping past some pilots. I was at one point going to go through the seven or eight pilots in southern Wyoming. They will be in the proceedings [see last page].

Drilling permits. So for this year, we've issued 1,500, about 40 less than last year. But in the year 2001, 8,863 coalbed methane permits were issued by my organization. That's 24 every single day of the year and 35 on a workday basis. That was up 40 percent from the year before, which was up 25 percent from the year before. And on March 28th, we issued our 25,000th well permit. I'll point a couple of other things out here. We've issued 25,000 permits, but only 25 percent on Federal acreage, when they should have 54 percent. The first coalbed methane wells were drilled in 1986, but it took some companies a long time to stay with it and figure out how to make it work. Drilling really didn't pick up until the last part of '93. This play has never used any of those gas and oil unconventional reservoir Federal tax credits.

WYOMING OIL AND GAS CONSERVATION COMMISSION *2001–2002 CBM Drilling Permits*

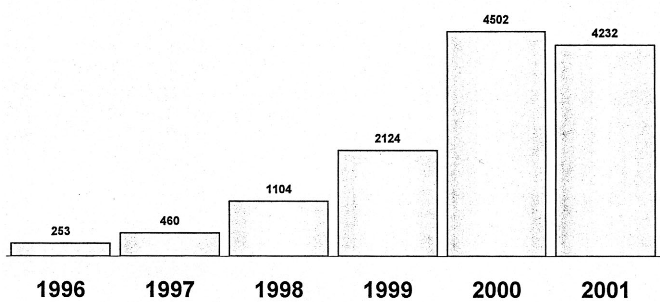


In 1996, we got up to 253 wells. We'd only had 300 wells drilled prior to that time. In 2000, 4,502, but it's slightly smaller in 2001. We had 87 rigs in 2001 in deeper coals, and it was taking slightly longer to drill the wells. 13,700 wells have been drilled to date, and again, only 20-some percent of those are on Federal acres. And last week we had about 40 rigs operating. The rigs use a three or four-man crew, and most of these rigs only work daylight hours, they don't work 24 hours.

2001–2002 CBM DRILLING PERMITS

- Issued 1495 APD's in 3 mon. '02 vs. 1538 in '01=-43 (3%). Avg. 15/day (21/workday).
- Issued 8,863 in '01 vs. 6,311 in '00 = +2,552 (40%). Avg. 24/day (34/workday).
- Year 2000 = 6,311 vs. 5,109 in '99 (+24%) Avg. 17 CBM Apd's/day (25/workday). Hired 2 temps in Oct. '99 to handle increased workload.
- Total of 3,267 issued prior 13 yrs.

WYOMING OIL AND GAS CONSERVATION COMMISSION *CBM Wells Drilled*



CBM WELLS DRILLED

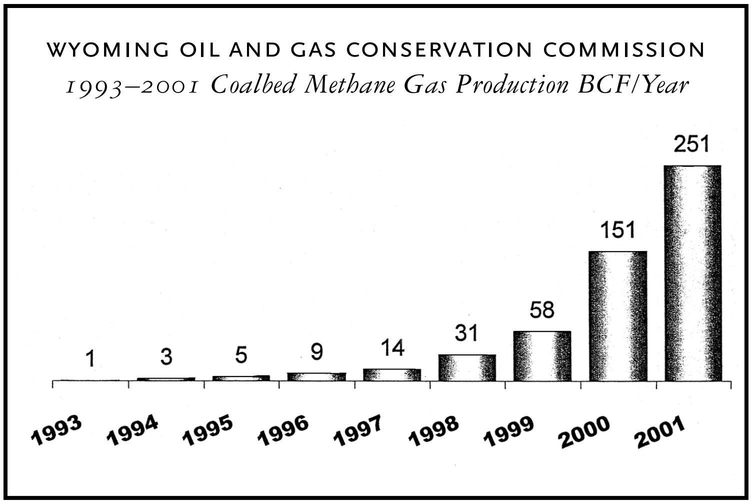
- First wells drilled in 1986. Drilled 10–55 wells/year through '95 to 4,502 in '00. = 312 wells total.
- Rapid increase from 253 in '96 to 4,502 in '00.
- 4,232 drilled in '01 = 6% (270) < '00 = 12/day.
- 13,700 total wells drilled, but 800 P & A'd. Current rate 8/day.
- 62 of 237 rigs operating with 3–4 man crews.

The gas production slide shown here is for the past nine years because we had small amounts, less than one billion CF per year, up through '92. Since that time, production has increased at an average rate of 100 percent. Last year, our increase was 67 percent per year. Over the past year, we've produced at a rate of about 100 MCF per day per well. The production so far has been 74 and a half percent from fee or private minerals, 17 and a half percent from Federal, and 8 percent from State, accounting for about 15 and a half percent of the total state production.

Water rates: similar to gas slide. Although it hasn't been increasing quite as rapidly as the gas, about 81 percent per year, but last year it only went up 36 percent. What we're seeing in the Powder River Basin, water production generally drops 50 percent within 12 to 18 months of initial production.

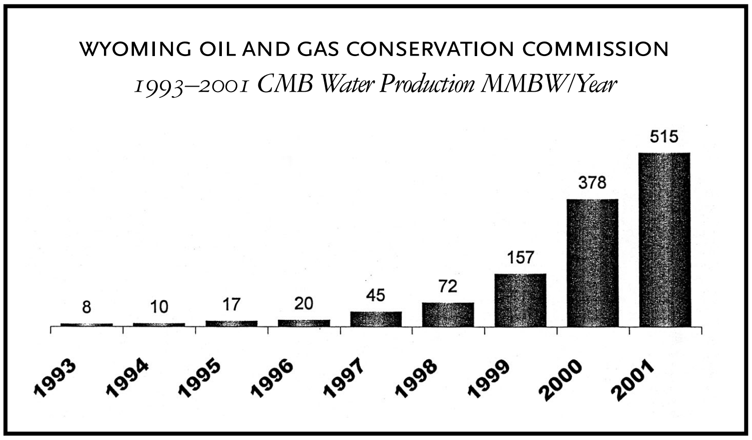
We have partial dewatering of the coals, and the gas starts coming in at excellent rates, again, due to the excellent permeabilities. Then last year the 515 million barrels per year was an increase to about 1.4 million barrels of water per day, but it's been on decline since April, and it had an increase of only 36 percent from the prior year. Gas production was twice that rate. That's about 182 acre feet a day, 92 cubic feet per second, and about six and a half gallons a minute. A typical hose in the backyard is 25 gallons a minute, and the rate in December was down to 5.2 gallons per minute. So it's dropping off very rapidly. Even though we're adding wells on production, the base is so big that the water rate is declining.

I have one more slide, on coalbed methane water issues. I want to make a couple points there. It's complicated in Wyoming because not one agency has all of the responsibility for the water production. You first have to get a permit from the State Engineer to give you an allocation to use that water. So every coalbed methane well has to have a State Engineer's permit. Every water well drilled by the individual landowners is supposed to have one of those permits too, but we found out that generally wasn't the case. Then, if you're going to discharge that water, unless it goes directly into a reservoir, you have to have a discharge permit from the Department of Environmental Quality. You also have to come to me, in some cases, if you're not going to reinject in the shallower zones and the BLM gets involved. There's a lot of coordination, that's why we formed the Governor's CBM Work Group in January of 1999. We then got together with the Bureau of Land Management, all the county commissioners, conservation districts, and some of the royalty owners. We next got the agricultural groups involved, and they used some coordinated resource management plans. You get all the state holders involved and



COAL BED METHANE GAS PRODUCTION

- '87 prod. 0.4 BCF and ranged between 0.7 and 1.1 BCF from '88 to '92.
- Prod. incr. avg. 100%/yr since then.
- '01 Prod. of 687 MMCFD is 1.67 x 412 MMCFD in '00 and = 100 MCFD/well. Cum. gas 526 BCF. Now largest gas fields in Wyoming (15.6% of total).



COAL BED METHANE WATER PRODUCTION

- Prod. 0.5–3.4 MMBW '89–'92.
- Water prod. incr. avg. 81%/yr since then.
- '01 prod. 515.3 MMBW (1,412,000 BWPD) and 136% > '00 (182 acre-ft/day, 92 CFS or 6.5 GPM). Cum. through 12-01 of 1.231 BBW= 9.0 GPM vs.12 used in EIS and = 158,616 acre-feet.

try to come up with some agreements on how to handle the water. We then started studying individual drainages with all the operator's development plans, rather than one company in isolation.

CBM WATER ISSUES

- Involves 3 state agencies and BLM so coordination required. Mostly good quality water in Fairway.
- WOGCC permitted and bonded 38 large pits (1–5 acres): 25 in Sheridan, 3 in Johnson, 6 in Campbell, and 4 in Carbon. Where DEQ not issuing NPDES Permits.
- Re-inject split with DEQ. WOGCC only issued 24 permits as CBM water has to go into zone with poorer water quality (5–10,000 PPMTDS).
- Water well agreements offered to landowners. Permit all water wells and do baseline survey.

There are some areas where you can't get a discharge permit right now. As a result, the Oil and Gas Commission has permitted 38 large pits. They're one to five acres in size. We also have been bonding the pits to ensure they'll be closed without us having to do that for them. 25 of them are in the Sheridan and northern Campbell areas, because there are no discharge permits in the area, these are on the Powder River, and four of them are down in Carbon County.

Reinjection: I keep hearing that; let's use reinjection. You don't want to do that under the class two program that I was delegated under the EPA, because you're going to take what's good quality water—and I agree with Lance—especially in the areas close to the mines where you're going into the Belle Fourche River, that's excellent water. A lot of the people have been using the same water from the same coals for drinking water and certainly for livestock water. If you do it through me, the disposal zone has to be at five to 10,000 parts per million. You will not be able to use it for anything. I maintain that this valuable water resource would be ruined.

Most of the reinjection has been done under DEQ, under their class five program. Since the water is going into similar water quality reservoirs. But I can tell you of the 18 of them they've tried, only one has worked, and that's the one going into the city of Gilette's water supply. The shallow aquifers will take only a small amount of water before pressuring up, and we won't allow anybody to fracture out of zone where they have those aquifers, so they have not worked in the Powder River Basin.

In areas where we have the higher SARs, higher TDS, there wasn't conventional oil and gas. So it's going to be a problem. They're going to have to come up with some type of treatment—maybe chemicals or more pits through me, but it's going to cost more. The costs that we see are usually double what you saw yesterday in the information that was presented. We are doing some injection down in southern Wyoming because they're not going to be able to use surface discharge there. Anything that drains into the Colorado River or the Green River is restricted among the various states and also Mexico. So that water is going to have to be reinjected or put into pits that are permitted through my agency. We have water well agreements issued to the land owners. This is a BLM requirement. We strongly urge every operator, some two or three person outfits, independents, and a couple of majors to do this. We've asked them to give that water well agreement to everybody. What it says is if a coalbed methane well is drilled within a half mile of your well, affects your well, and water drops off, the operator has to either repair it or replace it.

Data on other pilot projects:

Washakie Basin CBM

- Atlantic Rim EIS for 3880 Wells in W. Carbon Cty began 8-'01. BLM allowing 200 wells to be drld on 9 pods during 2 yr period.
- 4 coals 5–20 ft. thick at 300–3000 ft. depth. 5–15 days drlg & compl. Most wells cased & perfed & will frac if req'd. Mixture of 40 & 80 acre spacing
- 130 APD's issued, 24 prod. & 2 inj. wells drld & 1 Prod using submersible pumps.
- Est. 100–1800 BWPD/well with 380–1300 TDS & 3–47 SAR into off channel reservoirs or reinj. into Deep Creek & Cherokee Sands at 4100–4500 ft.
- 46 well Pipeline Pilot in E. Sweetwater Cty Prod 3–5 Almond & Lance coals at 2500–2900 ft. 40 acre spacing.
- 20 APD's issued, 10 wells drld & 5 prod. 10–625 MCFD, 15–65 BWPD, & 20–175 BCPD using rod pumps. SDS not perfed but coals fraced.
- 2 Inj. wells drld to Fox Hills at 1500 ft.
- Rock Ridge Pilot (Greasewood Wash) in Sweetwater Cty began with 3 wells on 160 acre spacing in 4th Qtr '97. 6 wells on 40 acre spacing added late '00.
- Prod. 10–90 MCFD (15% CO2) & 150–500 BWPD from 5–7, thin (7–10 ft.), low "K" R.S. coals at 3800–4500 Ft. using PCP's. Also prod. 4 BOPD.
- 3000–4000 TDS water reinj. into 1 Ericson well at 5500 ft. & 1 Nugget well at 10,500 ft. Gas being vented.

Hanna Basin CBM

- 9 wells drld at Hanna Draw Pilot in Carbon Cty at the same location as Metfuel's 3 well pilot in '90. EA ROD due for 16 more wells.
- 3 coals 20–50 ft. thick at 3400–4500 ft. 15 day wells using conventional rigs. Unstimulated, cased hole compls. With PCP's.
- Prod. 1–2 MCFD & 50–1350 BWPD/well. Gas vented. 2400 TDS water into 2 WOGCC off channel pits & 1 SEO pond.
- Seminoe Road Pilot in Carbon Cty .Will have 18 CBM wells on 160 acre spacing from Almond and Allen Ridge coals.
- Conventional rigs drilled 6000 ft. wells in 15–18 days. Unstimulated, cased hole compls with rod pumps.
- 6 wells on Prod. 4th Qtr-'01 making 300–600 BWPD with 1300–2000 *TDS* S 25 SAR discharging into ephemeral stream draining into Seminoe Reservoir .

Green River Basin CBM

- Blake Hollow Pilot in Uinta Cty has 4 Prod in Evanston coal at 2500–3000 ft. on 80 acre spacing.
- Using PCPs to produce 3–17 MCFD & 135–255 BWPD. Gas being vented.
- Reinj. _________ water into Frontier at 6700 ft.
- 1st. Qtr . '02 Riley Ridge Pilot in Sublette Cty has 5 spot on 108 acre spacing. Took 10–15 days to drill & compl. 2500–3500 ft. wells into thin Mv coal.
- Est. Prod. 200 MCFD/well using Rod pumps.
- Est. 2–500 BWPD/well with 2000–3200 TDS & low SAR will be reinj. into Mv at 4100 ft.

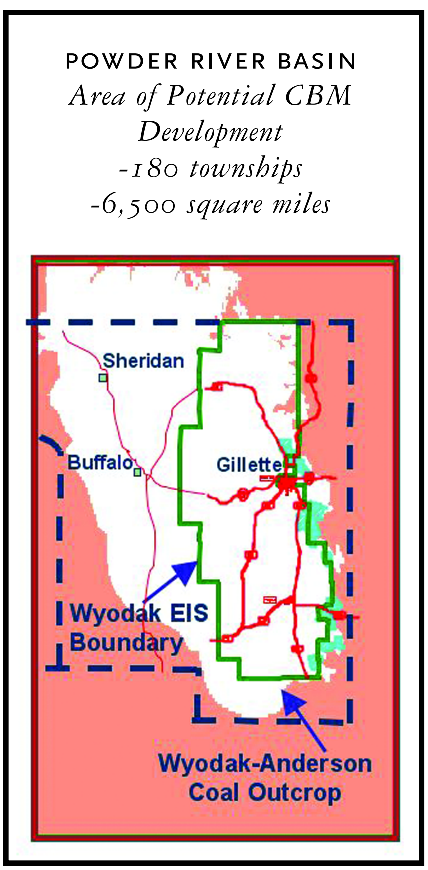
MIKE DAY, *Applied Hydrology Associates*

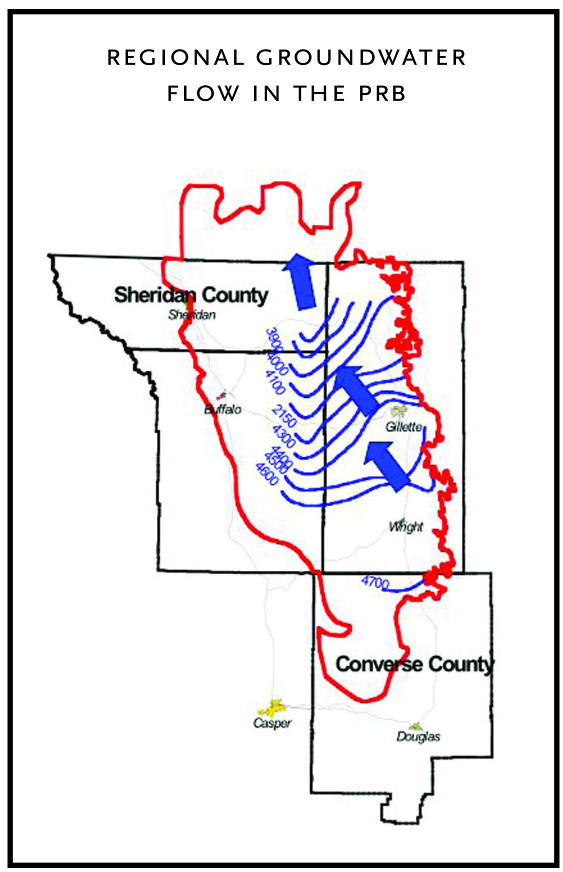
I appreciate the opportunity to be here this morning. I would like to share my personal opinions about the potential hydrologic impacts of coalbed methane development in the Powder River Basin. I want to emphasize that I'm not here representing any individual entity today. I'm here representing myself and presenting my own opinions. My talk this morning is really going to focus on the challenges of producing this very valuable energy resource in a responsible manner. In my opinion, we do have the engineering solutions to manage produced CBM water responsibly. I also feel that there are opportunities that perhaps are not recognized to increase the beneficial use of produced water. While I will be talking about the potential hydrologic impacts from the projected coalbed methane development in the Powder River Basin, I'd also like to emphasize the water management techniques that are being used, or that could be used, to minimize impacts, and the opportunities to increase beneficial use of produced water. There has been a lot of rhetoric regarding water issues associated with the Powder River Basin development. For example, the quality of the produced CBM water being characterized as very saline. I'd like to address some of those misconceptions that have been put out there toward the end of my talk.

The proposed CBM development in the Powder River Basin covers a very large area encompassing over 180 townships and over 6,500 square miles.

The slide below shows a very simple sketch of the regional groundwater flow in the Powder River Basin. Most of the recharge occurs along the eastern margins of the basin. Groundwater flow from this area generally tends to be towards the North and Northwest towards the Yellowstone River regional discharge area.

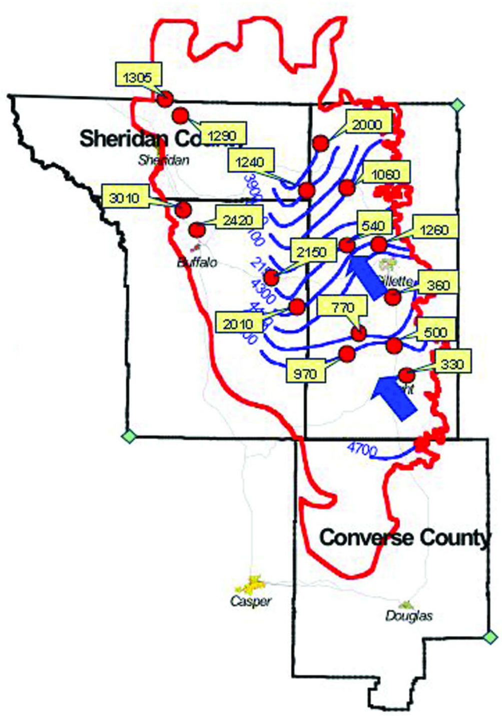
As we move along the regional groundwater flow path, in very general terms, the salinity (measured in terms of total dissolved solids) tends to increase towards the discharge areas. However, the salinity values are generally not very high. The highest values that we find are in the





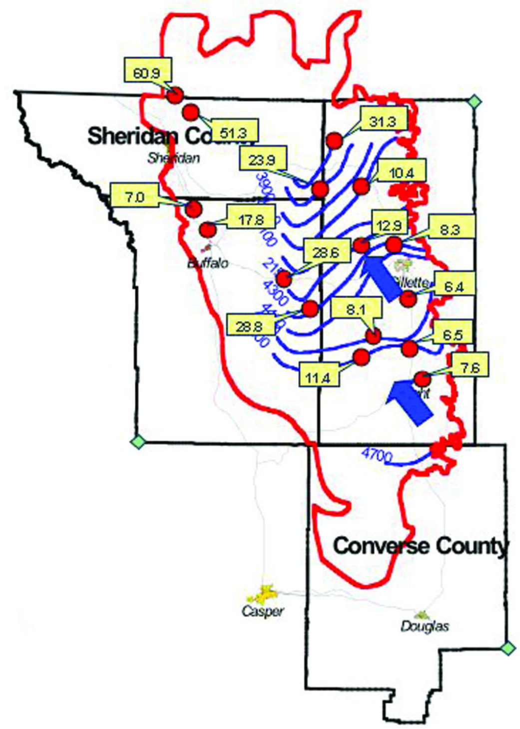
2,000 milligram per liter range. CBM water is good quality water, generally speaking. In many cases, good enough for drinking water. This slide shows a comparison of total dissolved solids in CBM wells with adjacent surface waters. The salinity of CBM water in the vicinity of the Powder River and the Little Powder River is very comparable with the salinity of the surface water in those rivers. Surface water in the Belle Fourche and the Cheyenne River tends to be more saline than adjacent CBM water. The Tongue River has very good quality water because it derives most of its runoff from snowmelt in the Big Horn Mountains. Clearly, water derived from the coal is much poorer quality than the Tongue River surface water, which is why there are no discharge permits issued in Wyoming for CBM water discharge to the Tongue River.

TOTAL DISSOLVED SOLIDS IN CBM WELLS AND SURFACE WATERS



The other trend that we see in the regional groundwater is the increase of sodium content along the flow line. The sodium adsorption ratio, or SAR, is essentially the ratio of sodium content to magnesium and calcium content. The higher the sodium, the less amenable it is for irrigation use, particularly in areas of clay soils. As we move along the regional groundwater flowpath, we find that the sodium content increases. So we do find some high SAR values in the northern parts of the Basin. The SAR of the CBM produced water has been a major issue, particularly as development has moved from the Eastern to the Western side of the Basin. It's the sodic content of produced CBM water that has stimulated the concern with regard to discharge to surface waters that are, or potentially could be, used for irrigation.

SAR IN CBM WELLS AND SURFACE WATERS



The main hydrologic issues that I hear people express concerns about are: Loss of groundwater resource, impacts on shallow groundwater and streams, and impacts to people using groundwater in the basin.

The next slide shows the projected EIS water production. The EIS assumes about a 20-year development timeframe. What this graph shows is that the projected CBM development is going to potentially produce a very large quantity of water. However, much of this produced water does not end up as surface water flow because of the water management techniques used. Much of the produced CBM

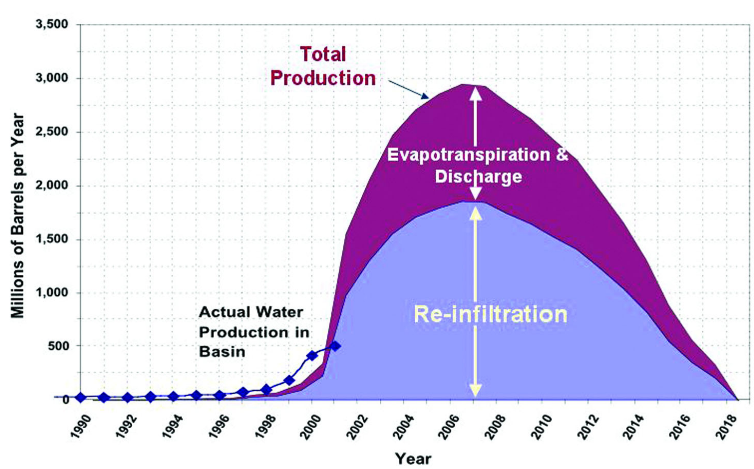
HYDROLOGIC ISSUES ASSOCIATED WITH CBM DEVELOPMENT

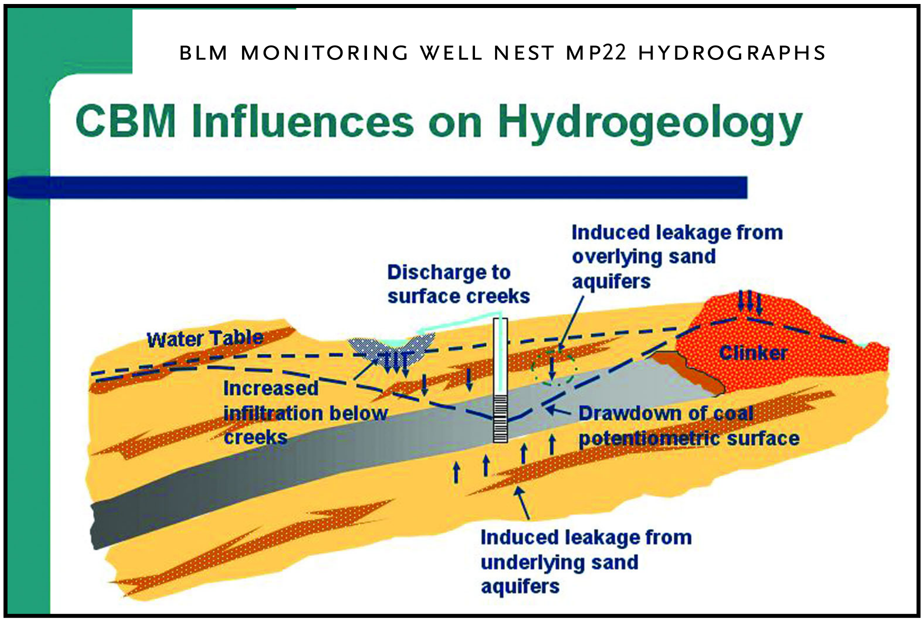
- Loss of groundwater resource
  - Concern over waste of groundwater resource
  - Low natural recharge to groundwater aquifers
  - How much of discharged water re-infiltrates?
  - How long will it take to recharge depleted coal aquifers?
- Impacts on shallow groundwater and streams
  - Direct discharge of produced CBM water
  - Seepage of CBM water stored in ponds and reservoirs
  - Will there be any water quality impacts to alluvial water?
- Impacts on existing groundwater users
  - Users of coal aquifers that are developed for CBM
  - Users of aquifers above and below target coals

water reinfiltrates back into the groundwater system, either naturally along stream channels or in impoundments. In my opinion, re-infiltration of CBM water into shallow aquifers should be encouraged because this process preserves the groundwater resource. Actual CBM production to date is also shown on the graph. If you compare actual water production with projected water production, it can be seen that, at least early in the development, projections are running a little high compared to the past year's actual production. This difference is primarily because the actual number of wells put into production last year was less than used in the predictive analysis.

What happens when we pump the coals? Pumping reduces the water pressure in the coals. Depressurization of the coal by pumping has the effect of increasing vertical hydraulic gradients and consequently increasing leakage

EIS PROJECTED CBM WATER PRODUCTION AND RECHARGE

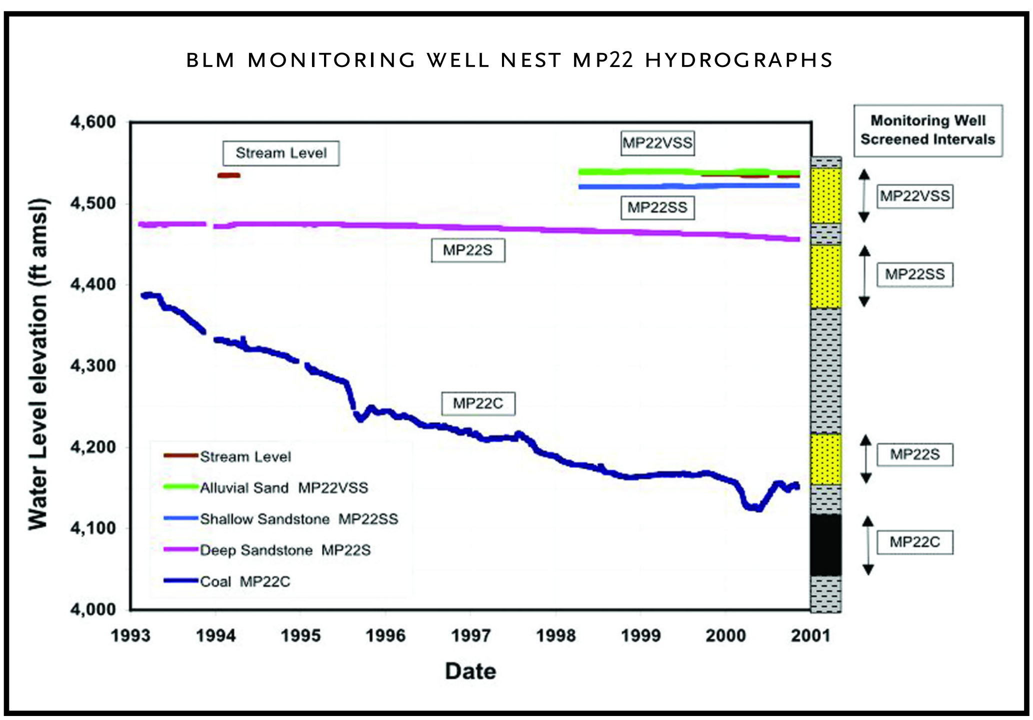




BLM MONITORING WELL NEST MP22 HYDROGRAPHS

into the coal from overlying and underlying aquifers. The vertical permeability of the units separating the coal from these units is the major factor determining the extent of leakage and the potential impact to the adjacent aquifers.

One aspect that we evaluate when we assess impacts of CBM development is the potential effects on shallow aquifers. This is a concern for the people that use these aquifers. One of the best ways to evaluate potential impacts is to look at the effects of actual CBM developments that have been operating for some time. In the developed coalbed methane area, the BLM has established several "nests" of monitoring wells, with wells completed in different zones. This slide shows one such nest with a well completed in the coal, a well completed in the sand immediately above the coal, and wells completed in two shallow sands. You can see the effects of CBM develop-



BLM MONITORING WELL NEST MP22 HYDROGRAPHS ment in the water level in the coal. The water level has been drawn down about 300 feet as a result of pumping of water and production of gas in the coal. The water level in the well completed in the sand only 40 feet above the produced coal, shows very little impact from CBM development. There is a slight decrease in water level of about 10 to 20 feet starting in about 1999. This area has had active CBM development for about eight years so this monitoring well data gives us very good information about the potential impacts on overlying aquifers resulting from extended CBM operations. This is not an isolated example. The monitoring conducted by the BLM to date has not shown any evidence that CBM depressurization of the coal has significantly affected shallower aquifer water levels. There is leakage into the depressurized coals from these sands, but not to the extent that major impacts are seen in terms of loss of resources in the sands.

I'd like to discuss the pros and cons of some of the management options that are being use at the present time in the Powder River Basin. There are four primary water management options being used currently. The most common option — at least in the early days of development on the Eastern side of the Basin — is discharge to surface streams. The CBM water quality on the Eastern side of the Basin is certainly good enough that for this water management option to be practical and environmentally sound. Discharge points for CBM produced water are typically constructed with erosion controls. Most water discharges are not treated, except for minimal passive treatment to precipitate iron and manganese. However, additional treatment of water prior to discharge could be performed if deemed necessary and appropriate.

WATER MANAGEMENT OPTIONS

- Discharge to surface streams
    - Erosion controls
    - Treatment/No treatment
- Impoundment
    - Lined/Unlined
- Injection
    - Shallow/Deep
- Land application

The second major management water management technique consists of discharging CBM produced water to impoundments that can be either lined or unlined.

Injection is another water management technique that has been used in a few locations in the Powder River Basin. Injection is used extensively for CBM water management in the San Juan Basin and also in the Raton Basin because of much lower water production rates and much poorer water quality compared with the Powder River Basin. In general, injection is not a very economic or practical way of handling the relatively large quantities of water that are typically produced in the Powder River Basin. Injection has only been used in the PRB where unique conditions provide the opportunity for this option to be feasible. For example, pumping of deeper Fort Union aquifers by the city of Gillette over the past 20 years or so has lowered the pressure in these aquifers locally by as much as 600 feet. These aquifers have relatively high transmissivity and the low head allows injection of CBM water at reasonable rates to be feasible.

The last water management technique that is currently being used in limited locations in the PRB is land application of CBM produced water. Surface discharge and infiltration pits are the two water management techniques that are currently most commonly used in the PRB. They are also the techniques that stimulate the most controversy and discussion.

When selecting a water management approach in any given area there are a number of factors that have to be considered. The overall volume produced and how the production rate will vary over the life of the well will have an influence on the choice of water management approach. It is important to examine the quality of the produced water and its suitability for beneficial uses in

SELECTION OF WATER MANAGEMENT METHOD

- Nature of produced water
    - Volume and decline
    - Suitability for beneficial uses
    - Quality
- Regulatory constraints
- Landowner constraints
- Cost

the area. Also, regulatory requirements, landowner constraints, and costs have to be considered.

CBM produced water is suitable for a number of beneficial uses because the water is typically of good quality. CBM water produced anywhere in the PRB is suitable for livestock. Industrial use is currently limited to dust control. The water is suitable for fish and wildlife. Irrigation use is limited to areas where the CBM water has salinity and SAR values that are appropriate for irrigation use. In areas of predominantly clay soils, there may be limited possibilities to use coal bed methane water for irrigation. One beneficial use of coalbed methane water that is largely overlooked or not recognized, is for recharge of shallow groundwater. Shallow groundwater in the Powder River Basin generally has fairly poor quality. The CBM water is of far better quality for most purposes. In my opinion, the use of coalbed methane water to recharge shallow aquifers should be encouraged and recognized as a real beneficial use. The last beneficial use for CBM water is recreational: ponds and wetlands, duck habitat, and fishing. There are a number of recreational uses that could be constructed to use CBM water but this has not occurred primarily because of the expected relatively short duration of CBM water availability.

BENEFICIAL USES

- Livestock
- Industrial
- Fish and wildlife
- Irrigation
- Aquifer recharge and storage
- Recreation

WATER QUALITY COMPARISON

PARAMETER	UNITS	TYPICAL PRB CBM WATER	TYPICAL RATON BASIN CBM WATER	LIVESTOCK	IRRIGATION CRITERIA	PRIMARY DRINKING WATER	SECONDARY DRINKING WATER
Chloride	mg/L	5 to 38	10 to 1330 (Avg 419)				250
TDS	mg/L	471 to 2350	922 to 4350 (Avg 2082)	5000	varies with crop		500
Arsenic	ug/L	<0.1 to 1.3	ND	200 to 500	100	10	
Barium	ug/L	100 to 2000				2000	
Boron	ug/L	70 to 150	50 to 2100 (Avg 386)	5000	750 to 6000		
Fluoride	ug/L	200 to 2000		2000 to 3000		4000	
Fe, diss.	ug/L	<30 to 1400	150 to 15400 (Avg 1712)		5000		300
Mn, diss.	ug/L	<10 to 100	10 to 63 (Avg 33)		200		50
Selenium	ug/L	<5	ND	50 to 100	20	50	
Trace Metals	ug/L	ND	ND				
SAR		5 to 35	2 to 61	N/A	varies with soil and SC		

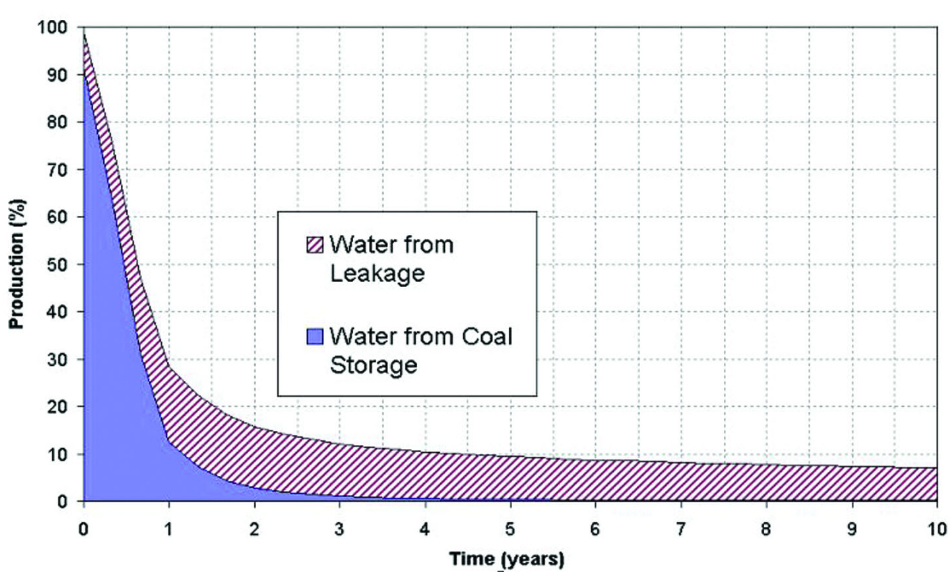
This slide shows a comparison of typical CBM water quality to various standards. I want to emphasize the fact that CBM water has relatively good quality. Chloride concentrations in CBM water usually meets drinking water standards, and certainly do not exceed livestock standards. Arsenic and barium concentrations typically are less than drinking water standards. Iron and manganese can exceed drinking water standards, but they tend to be precipitated using passive oxygenation techniques prior to discharge. SAR, varies widely within the Powder River Basin. SAR can be a issue with respect to water use for irrigation depending on the type of soil and also the salinity of the water.

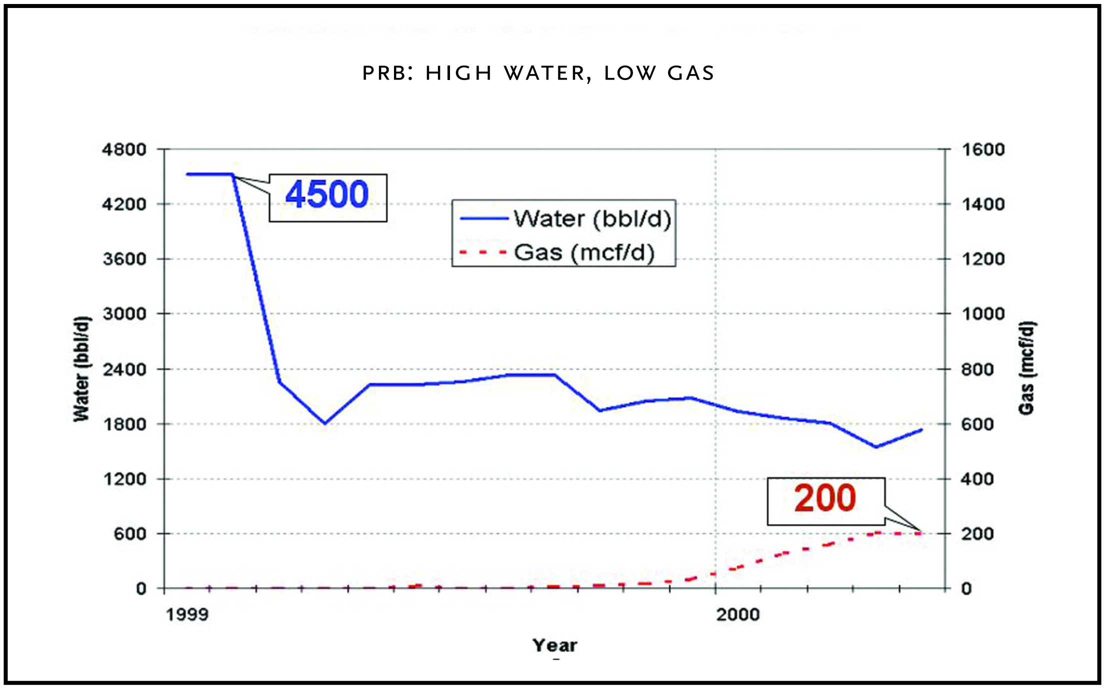
Generally, the life of a CBM production well is estimated to range from 7 to 15 years. Average production rates can vary initially from up to 100 gallons a minute to as low as 10 gallons per minute. Typically, wells experience a very rapid decline in production rate, particularly in the first year. Initially, the water pumped from the well is derived from storage in the coal, but over time this storage component decreases and the major source of the pumped water becomes leakage into the coal from

PUMPING RATES

- Decline with time
  - Storage: Approaches 0 after 1 year
  - Leakage
- Life span of a well?
- Average production rate?

COAL WATER PRODUCTION DECLINE



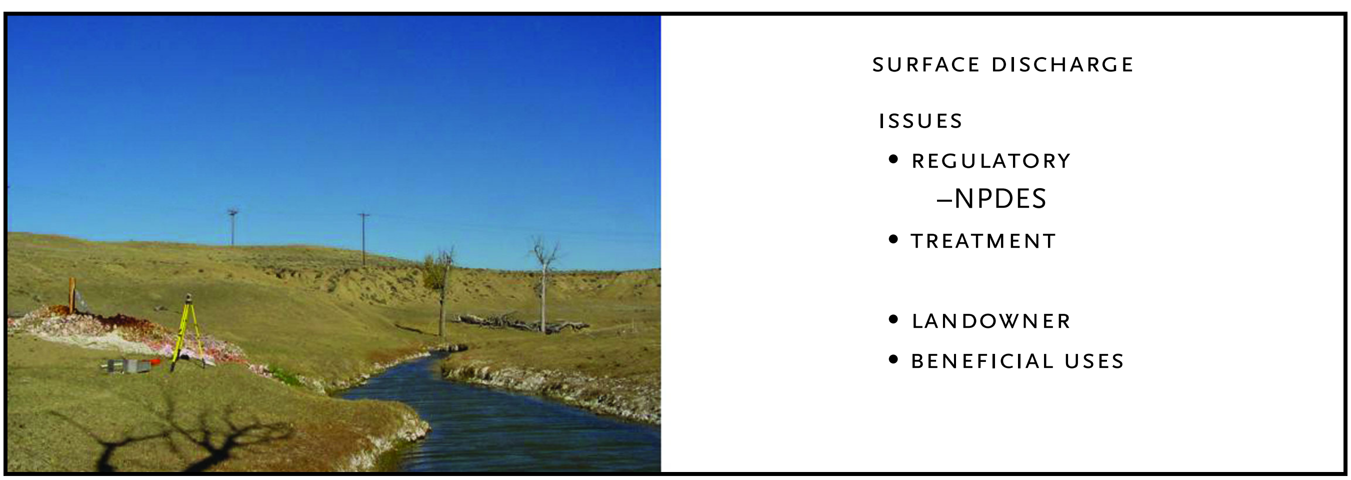


above and below the coal seam. As a result, the production rate from a well tends to flatten off very quickly.

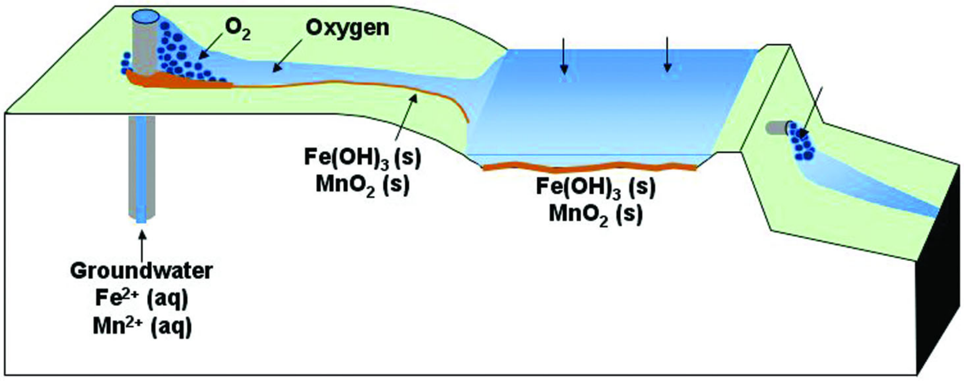
Above is a typical production graph from a high production well. The graph shows a very rapid decline and then a leveling off in water production rate.

There are a number of issues associated with discharge of CBM produced water to surface streams. Discharge is regulated under the NPDES program, so that the idea that coalbed methane operators can discharge into any creek they want is incorrect. In most cases, surface water discharge issues are associated with surface landowners, particularly those located downstream from the discharge point.

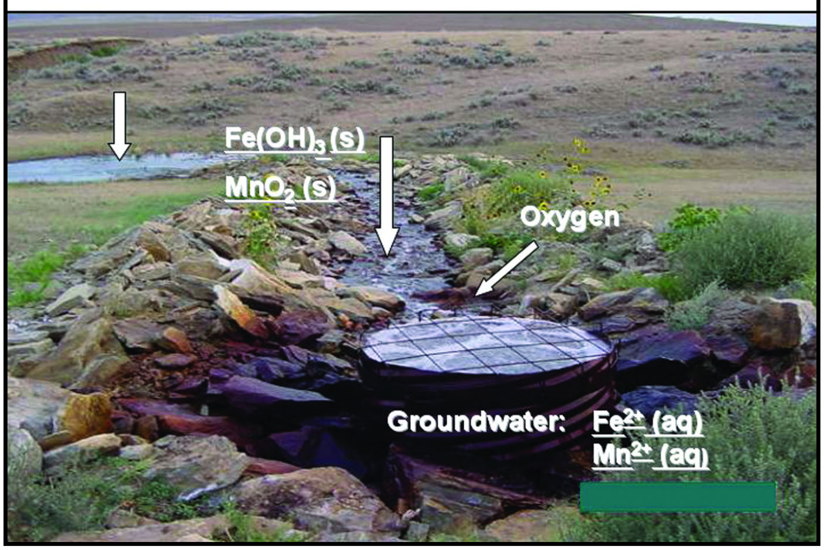
There are some fairly simple techniques that can be used to remove iron and manganese from discharge water. These slides show the concept and construction

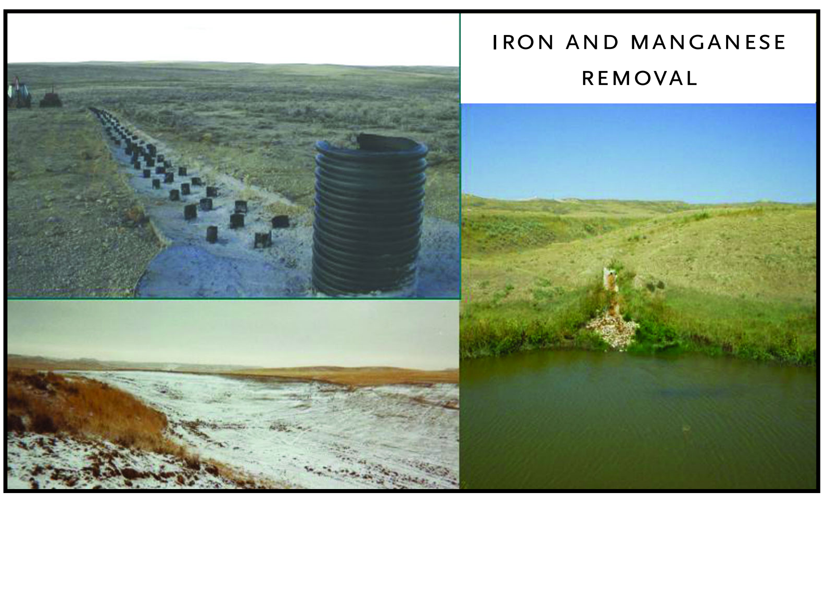


IRON AND MANGANESE REMOVAL



IRON AND MANGANESE REMOVAL



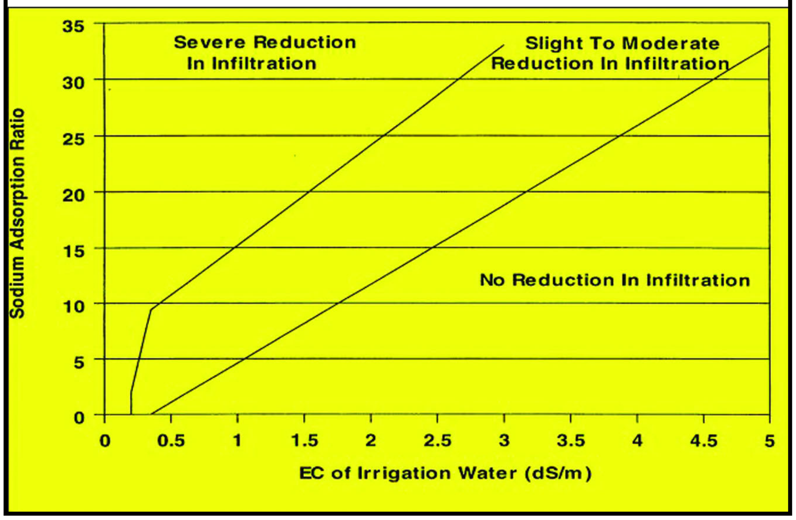


IRON AND MANGANESE REMOVAL

of some typical systems. The water is discharged across a rocky area that promotes aeration of the water so that iron and manganese precipitate out.

The effect of SAR on infiltration rate through soils is a function of the salt content of the water. This graph represents the relationship between SAR, salinity (as measured by electrical conductivity), and effect on infiltration. If water has SAR and electrical conductivity characteristics that plot below the line on the right-hand side of the graph, this indicates that the water will have no adverse effects on infiltration rate.

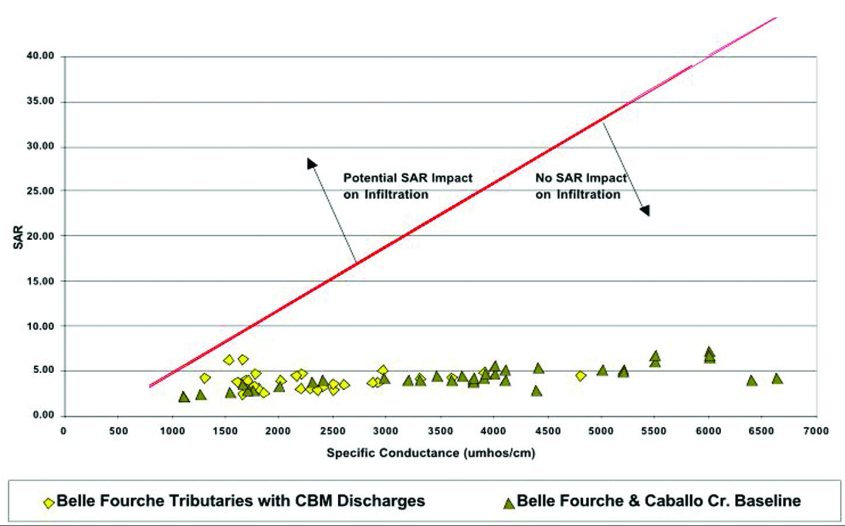
EFFECT OF SAR ON INFILTRATION RATE

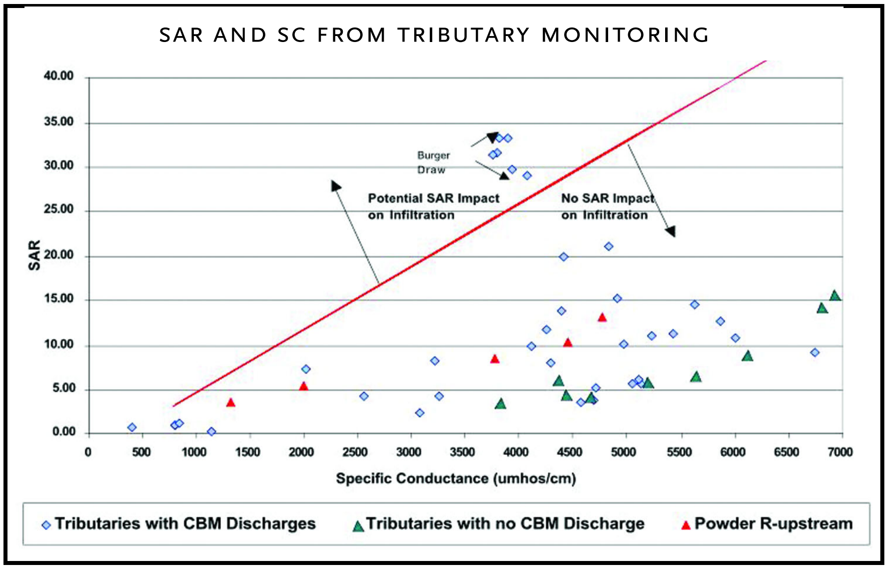


This graph shows the results of SAR and electrical conductivity measurements that have been performed on the water in tributaries to the Belle Fourche River and Caballo Creek drainages, on the Eastern side of the basin. The SAR and electrical conductivity characteristics fall within the area of the graph that indicates no adverse effects on infiltration rate. This indicates that there is generally not a problem with the use of this water for irrigation. The baseline values (measured prior to any CBM water discharge) are very similar to values measured on tributaries that currently receive coalbed methane discharge. This demonstrates that coalbed methane discharge has not measurably affected baseline water quality in these creeks.

A similar plot for the Powder River drainage is shown in the next slide. There is a much wider spread of SAR and specific conductance values in the Powder River drainage. Plotted values for measurements taken in Burger Draw, fall above the line indicating potential SAR effects on infiltration rate. Measurements taken on other tributaries receiving CBM discharge all fall below the line indicating no potential for infiltration effects. Measurements taken upstream from any CBM discharge and measurements taken in tributaries that do not receive CBM discharge tend to be similar to values for tributaries

SAR AND SC FROM TRIBUTARY MONITORING

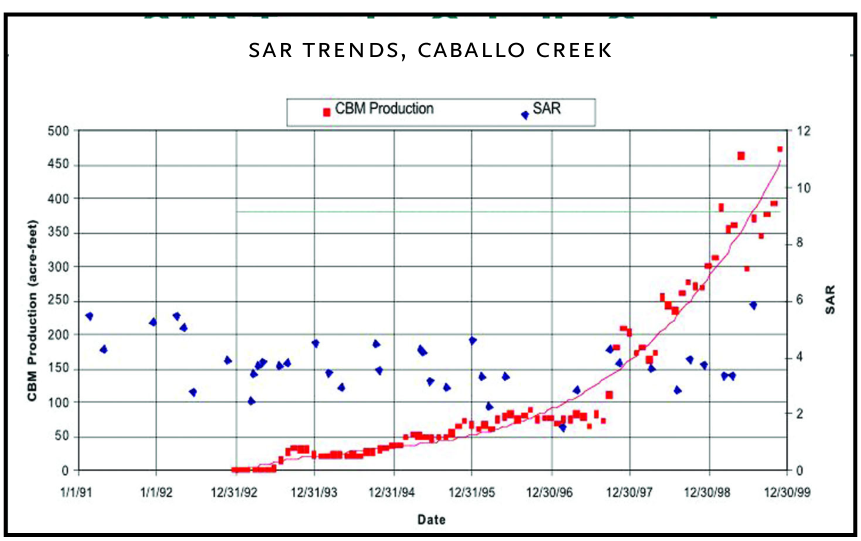


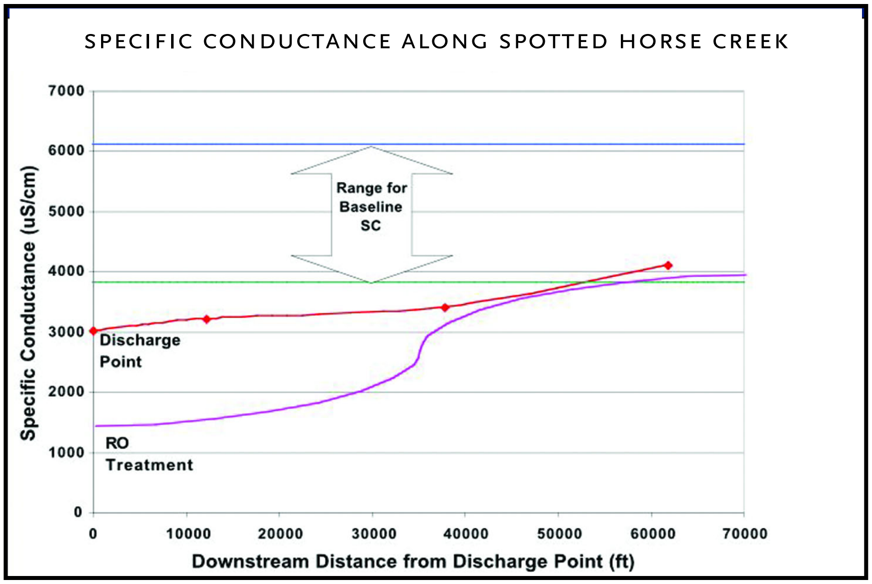


receiving CBM discharge water. With the exception of Burger Draw, CBM discharge has not had a measurable impact on surface water quality in tributaries to the Powder River with respect to potential infiltration rate effects.

The Caballo Creek drainage is an area of the PRB with a long CBM production history. This plot shows how the CBM water production increased over time through year 1999 as this area was developed, then leveled off in year 2000, and started to decline in year 2001. This reflects the cumulative water production decline that is seen in individual wells. The same trend is projected to occur in other areas of the PRB as CBM is developed. The average SAR of the CBM water being produced in the Caballo Creek drainage area is about 9. The SAR of the creek water varies between 2 and 6 but has remained within this range throughout the period of development. It is apparent that the discharge of CBM water into the creek has not had any measurable affect on the SAR of the water in the creek itself.

There are a variety of techniques that can be used to manage irrigation when there is a component of the CBM water that perhaps does not meet quality or SAR criteria. For example, head gates can be installed on spreader dykes to control the amount of water that does not meet criteria. Bypass channels can be constructed to divert unsuitable water around irrigated fields. The timing and amount of CBM releases to surface waters can be managed to control the quality of water used for land application. Unsuitable water can be contained during the irrigation season if necessary.





There is considerable debate about treating CBM water, prior to surface water discharge, to reduce the salinity. However, the baseline salinity of stream water (as measured by specific conductance) based on several samples of natural runoff collected during year 2000 at locations not influenced by CBM discharges, is typically higher than CBM water. For example, data from Spotted Horse Creek indicates a range of specific conductance of between 3,800 and 6,200 uS/cm compared with typical CBM water in this area of 3,000 uS/cm. The natural salinity of the creek water results from rain and snowmelt that forms runoff dissolving ions from the soil materials in the stream channel and the alluvium. This is confirmed by measurements taken of CBM discharge water downstream of the discharge point during dry weather conditions (i.e. the CBM water was the only source of water in the creek) that show that the water increases in salinity, and approaches baseline conditions, as it flows down the creek. If this water was treated to decrease the salinity at the discharge point, in a similar way to rainwater, solution of ions from the soils in the stream channel will probably bring the salinity back to baseline conditions within a few miles of the discharge point.

Surface discharge of CBM water is obviously a very low-cost method of dealing with large volumes of water. A large amount of shallow groundwater recharge has been shown to occur as water flows along the creeks. There are beneficial uses for the discharged water, primarily with respect to livestock and wildlife. On the negative side, there are permitting difficulties associated with surface water discharge in the Powder River Basin, primarily due to potential downstream impacts. If discharges are permitted, there are costs associated with monitoring and potential treatment.

SURFACE DISCHARGE

- Pros
  - Low cost—large volumes
  - Shallow groundwater recharge
  - Beneficial uses
    - Year-round water supply
    - Better distribution for livestock and wildlife
- Cons
  - Permitting delays
  - Downstream impacts
  - Monitoring costs
  - Treatment costs

IMPOUNDMENT/CONTAINMENT

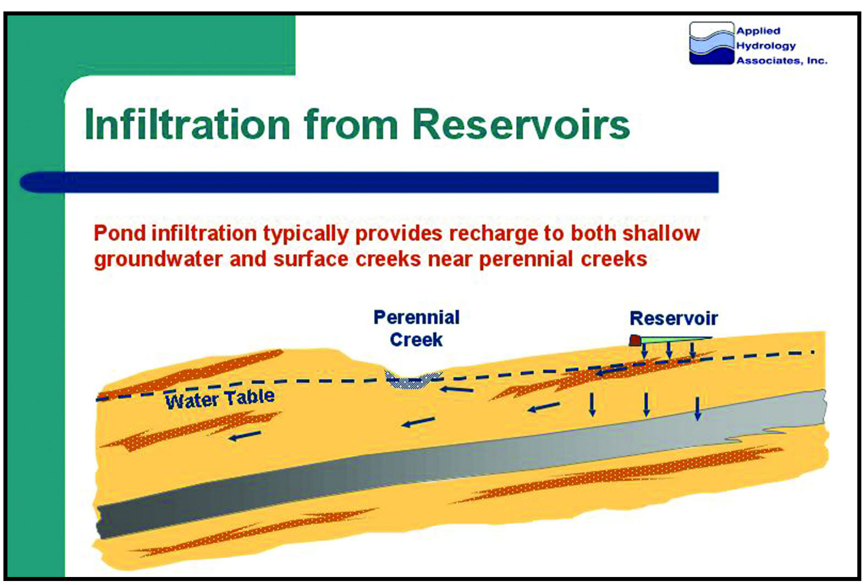
- Containment—WOGCC Pits
- Off channel—No discharge WDEQ Option 1
- Discharging impoundment—WDEQ Option 2

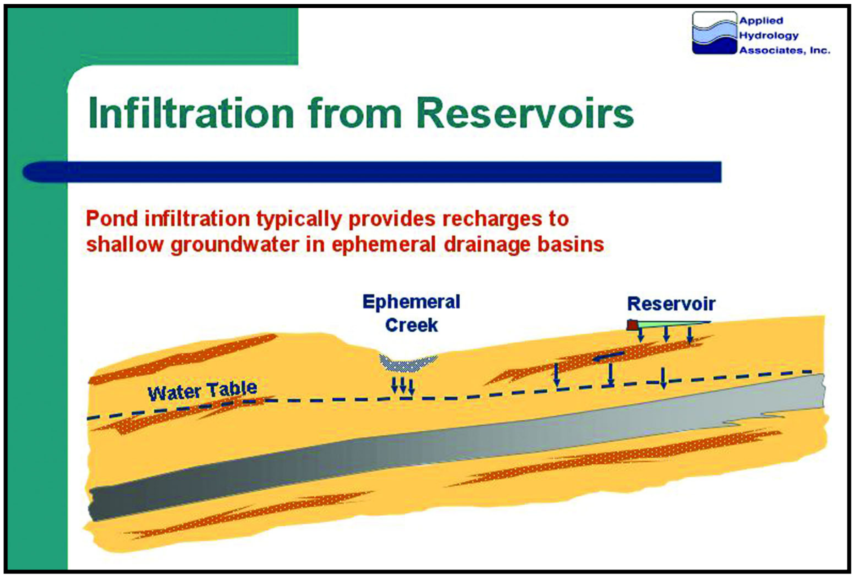
IMPOUNDMENTS
• Pros - Zero surface discharge - Groundwater recharge - Beneficial uses - Permitting - Low operating costs • Cons - Restricted locations - Landowner issues - High capital costs - Reclaimation (off channel)

There are basically three types of impoundments that are currently being permitted in the PRB. Off-channel, no-discharge impoundments are designed so that there will be no uncontrolled surface discharge. The impoundments are unlined to allow recharge to shallow groundwater.

Groundwater recharge is a positive thing, given the good quality of the groundwater that's produced from coals compared to the shallow aquifers. The main downside to these impoundments is the area that they occupy, particularly if there are restricted locations for construction. The use of valuable surface area can be a significant landowner issue depending on the circumstances.

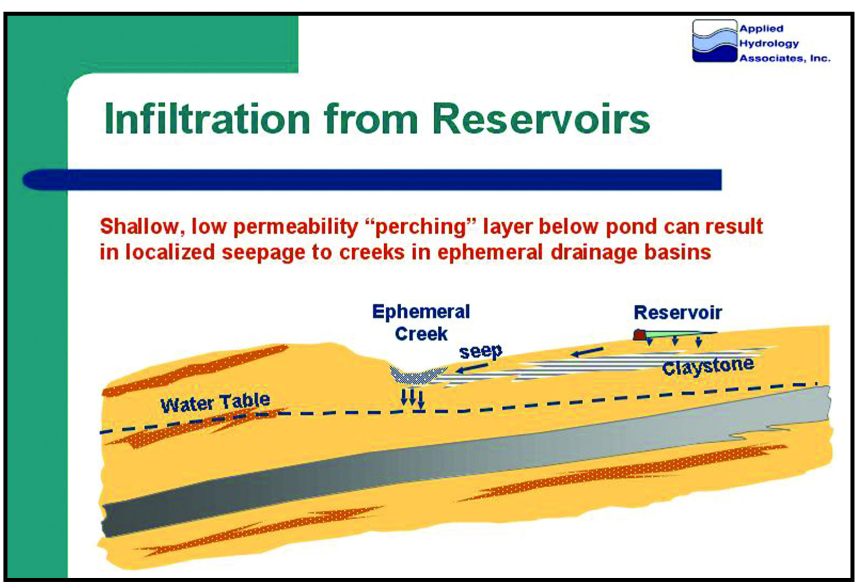
The location of the impoundment influences whether infiltration has the potential to eventually result in surface water discharge. In perennial stream drainages, groundwater naturally discharges to the stream. Infiltration from impoundments located close to perennial streams could raise ground water levels and result in increased discharge to the stream.





Ephemeral streams only flow in response to snowmelt or storm events. The natural groundwater water table is below the stream level. When there is flow in the stream, it tends to recharge the groundwater. Infiltration from impoundments located in ephemeral stream drainages would have to raise the ground water level above the base of the streambed in order to result in any discharge to the stream.

If a shallow, low permeability "perching" layer exists below an impoundment, there is a potential for localized seepage to creeks in ephemeral drainage basins.



MISCONCEPTIONS AND FACTS

- High levels of water production and discharge will cause flooding and erosion.
  - Erosion controls at discharge points
  - Rates vary and decline substantially in year 1
  - Conveyance loss usually >80%
  - Actual surface flows too low to cause significant erosion
- CBM water will contaminate underground sources of drinking water.
  - –Coal water quality typically much better than shallow aquifer quality
  - –CBM water actually used to replenish groundwater supply
  - –Regulations protect the receiving aquifer
  - –No evidence of contamination
- CBM water will turn freshwater streams into continuous brackish streams.
  - –CBM water salinity in PRB often lower than in streams
  - –Must meet stream standards
- CBM water contains toxic levels of arsenic, iron, barium, and manganese.
  - –Usually below stream standards and ambient
  - –Treated before discharge to streams.

CONCLUSIONS

- Techniques are available to effectively manage water production from CBM development in the PRB.
- Opportunities exist for beneficial use of produced water.
- Recharge of shallow groundwater from impoundments and surface streams should be considered positive rather than negative.

I would like to conclude with some comments regarding misconceptions versus facts with respect to CBM hydrologic impacts in the Powder River Basin. A common misconception is that the high levels of water production and discharge are going to cause flooding and erosion. That generally is not the case. There are erosion controls at discharge points. The actual surface flows that result from discharge are very much lower than typical runoff from storm events or spring snowmelt. Erosion from CBM water discharge has not been a significant problem, although there may have been some isolated cases where this has occurred. There is a common misconception that infiltration of coalbed methane water will contaminate underground sources of drinking water. In most cases the CBM water is of much better quality than the shallow groundwater. As indicated earlier, CBM water is actually used to replenish the drinking water aquifer that supplies the city of Gillette. There are regulations to protect situations where the shallow aquifers have better quality water than the CBM water, but there are very few areas in the Powder River Basin where this is the case.

Another misconception is that coalbed methane water is going to turn fresh water streams into brackish streams. Again, this is generally not the case in the Powder River Basin because coalbed methane water salinity is often lower than the streams into which it is discharged. An exception to this general observation is the Tongue River, which has very low salinity. As a result, there is no discharge of CBM water to the Tongue River in Wyoming. The last misconception is that coalbed methane water contains toxic levels of arsenic, iron, barium, and manganese. Water quality data indicate that these trace metals may be detectable, but generally not at concentrations that exceed ambient stream quality or stream standards.

In conclusion, we do have techniques to effectively manage water production from coalbed methane development in the Powder River Basin. There are many opportunities for beneficial use of this water due to its generally good quality. In particular, recharge of shallow aquifers resulting from infiltration of CBM water in streams and impoundments should be considered as a positive beneficial use rather than as a negative impact.

Thank you.

DEVELOPING CBM IN THE POWDER RIVER BASIN

WILLIAM T. BROWN, *Jr., Geological Consultant*

What I will attempt to do today is give you a little bit more philosophical overview from the geologic standpoint of coal and how it's produced and more of the geologic problems involved with that. First of all, I would like to express my appreciate to Jeannie and, in particular, these two people here, Ed Weber and Eric Mitchell, who did a lot of art work and basically put this together.

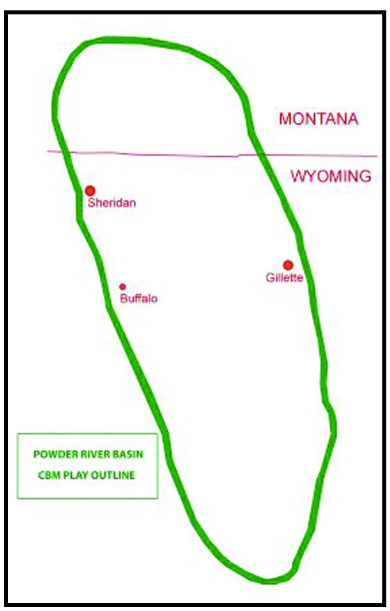
Below is just a very simplified view of the coal outcrop. One thing I'd like to point out is that this line here, which is labeled as a state line, is not a fault line.

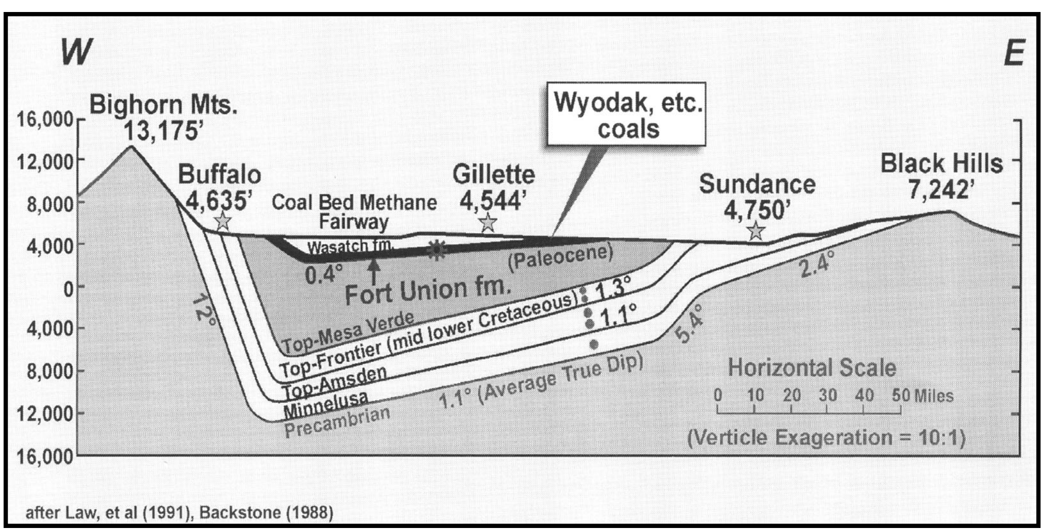
Next is a generalized cross-section from west to east across Powder River Basin.

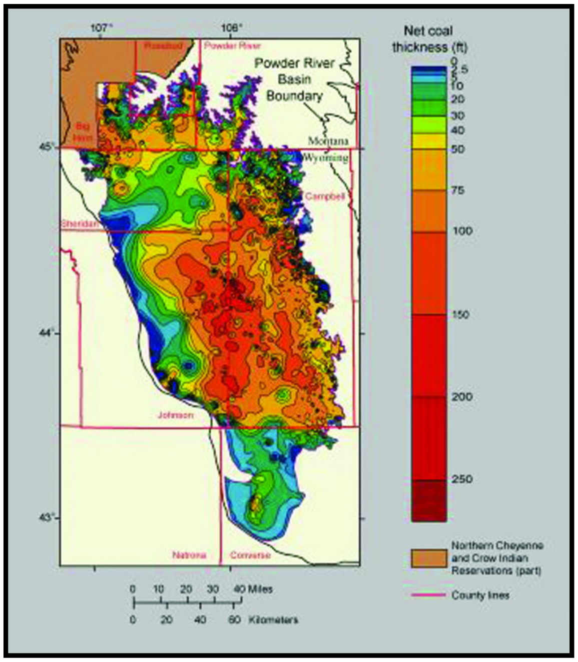
The Fort Union Formation is sitting here. We're looking at the upper part, which has the coal in it. A lot of that coal is actually a combination and merging of at least three different coal seams that split off as you move further west. The Wasatch coals, to date, have not been intensively evaluated in terms of their producibility. They are the coals that are mined in the Sheridan area. One thing I'll point out to people who are not familiar with basic geology, we have in the Powder River Basin one of the thickest coals in world. Around Lake DeSmet, you have about 300 feet of cumulative coal. There's no other place in the world that has that thickness of coal.

This is just a generalized cumulative thickness map of all the coal seams that exist in the basin. As you can see, the thicker coals are out in here. And as you reach the outcrop and mining, you have some very thick coals in that area, about 100 feet in thickness in many cases. As we move out into the basin, where the play is active now, you have multiple coal seams. There will be at least one seam in much of this area that has a 30-foot thickness. A 30-foot seam by itself, that's the least we want to look for to start with. If you have two seams each that are 30-feet thick, what we've done to date is drill two wells.

They're open-hole completed. One of the things that I wanted to basically acquaint you with, again not knowing quite what the demographics of my audience would be, is how coal is formed. Basically, you have a swamp or area of accumulation of organic material that will just pile up on top of itself, bury it, subject it to heat and pressure, and then you get the coal, which is a residual. One thing here that you may not be aware of is that for every foot of coal, you started out with ten feet of organic material. We're looking at 100-foot thick coal. We actually have 1,000 feet of organic material. This is a very unusual situation in terms of coal. But every coal basin I have worked in or looked at is unique.

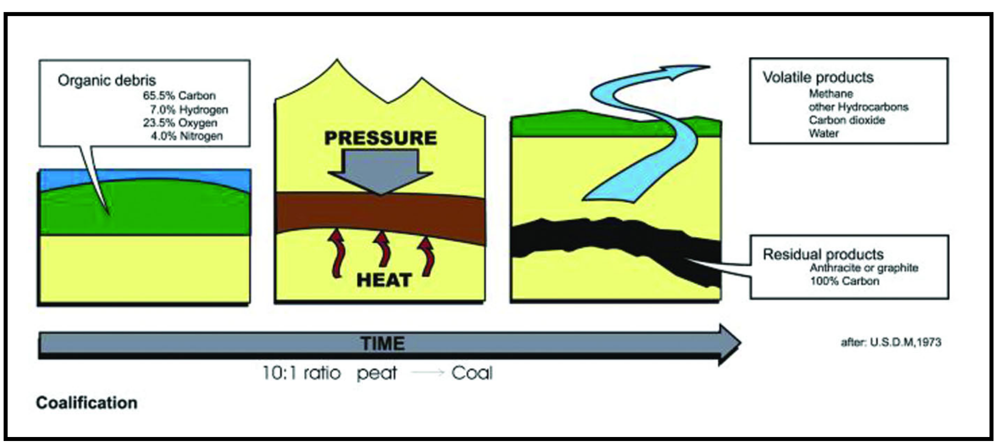




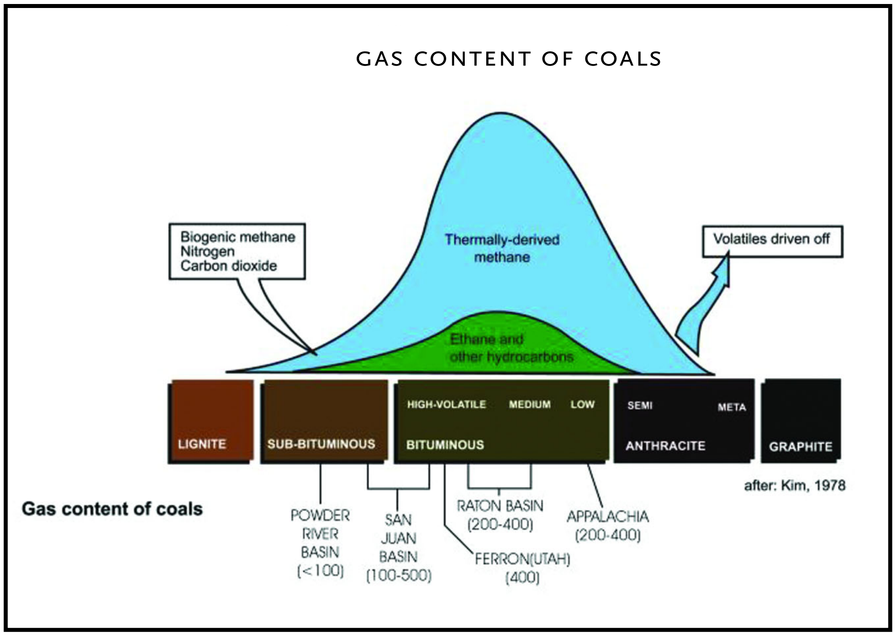


There are different ways to drill. There are different ways the coal is formed. There are different ways to complete wells, and they have different production characteristics. What I've tried to show here are the differences in the types of coal that we're looking at. The Powder River Basin is a sub-bituminous coal, and it's relatively immature. And initially, I did start working in the Powder River Basin, but we were using the San Juan Basin model. We took pressure cores, and our gas contents were in the 20 cubic feet per ton range, which, as you know, compared to the San Juan Basin, if you're looking at 3 or 400 more, it's disappointing. It makes up for it though by being thick. This coal gas is biogenetically created. The process is still going on today.

One of the important supports for the gas generation system is the groundwater. There are instances of coals in the Powder River Basin that are breached on both sides. They do not have water in them. There is no gas in that coal. That happens specifically up in Montana because you're more heavily incised into the section as you move into that area. The Raton Basin and Utah and then Appalachia contain coals of progressively higher rank. In all of these cases, you have wells that are too deep to produce gas at an economic rate.



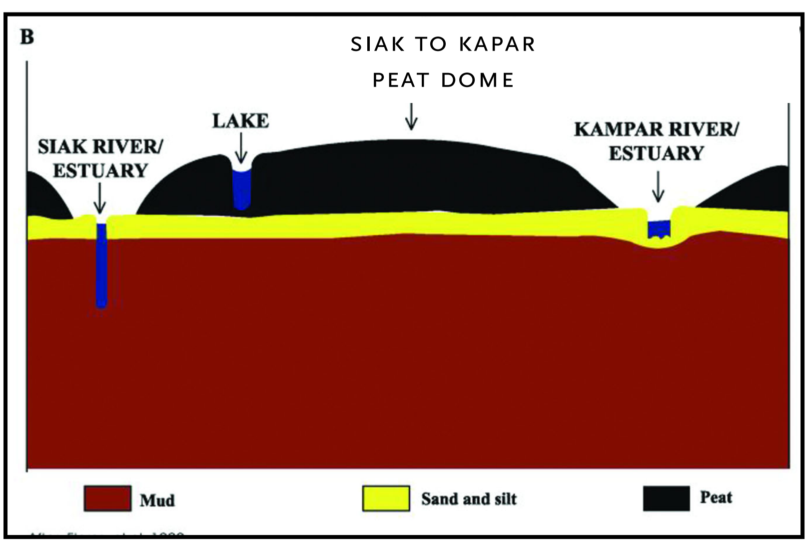
Coalification



The gas content for the coalbed biogenically created gas in the Powder River Basin is primarily methane. There are some other constituents that will come in from time to time. This carbon dioxide, this is actually a little high because the methanogens that will create gas actually consume CO2. CO2 has not been a problem in the basins. You look at the natural gas you get out of a sand reservoir, and you have a large spread of the constituents there. Basically, what we're getting is almost pure methane out of the ground. By the way, if you don't know it, what you burn in your home is pure methane. If it has any of the heavier constituents in it, those are stripped out. And in some a cases, there's propane, or actually liquids, that can be removed from the gas itself. What runs down the street and comes into your home is, in fact, about 100 percent methane. And they put the stinky stuff in there so you know you have gas. It's colorless and doesn't have a smell. This is something intriguing to me as a geologist.

One of the things I have found is, this may be true, that the coal is rarely missing due to stream erosion where the stream channel actually cut the coal. Those are very rare.

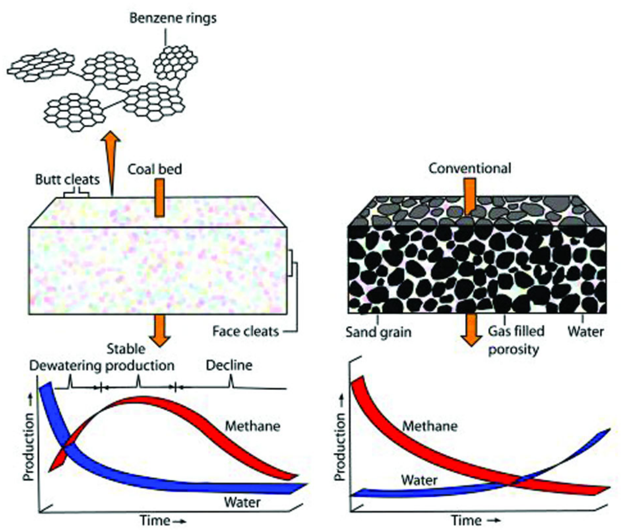
As you know, and I'll go through this quickly, production characterizations versus conventional. You're looking at adsorption taking place in the coal. And the Powder River Basin has some unique qualities with that. You've got the adsorbed gas on the face of a cleat and microcleat in the coal. And as you take the water off, you allow the gas to escape.



This has not been discussed much in the literature—but you have another methane molecule sitting in here by itself. How far this process goes, I don't know. But what we've found consistently from basin to basin is that you get more gas than you originally thought you had. And a lot of things that cause that. But basically, that's generally a rule.

One thing we found at the Powder River Basin is that we do have, because of

PRODUCTION CHARACTERISTICS

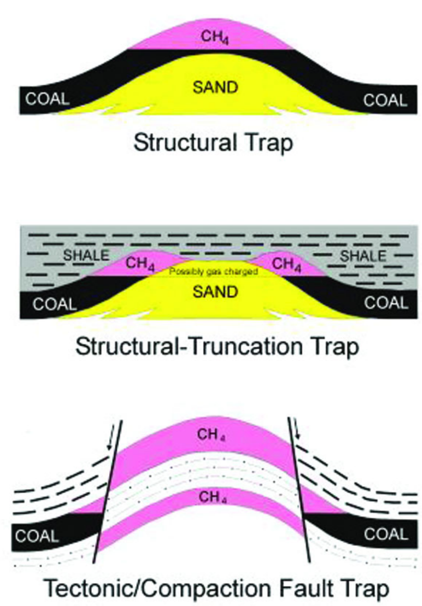


the Powder River Basin, and this is probably true in many other basins, but there are several different types of traps that form here.

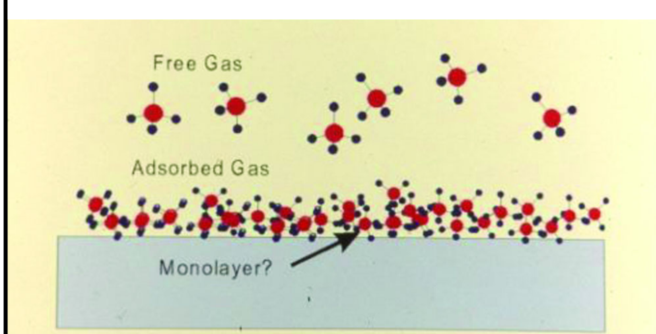
In one case, if you have a sand underneath the coal and the coal is actually draped over the sand due to compaction, you can get a free gas cap in the well. A relatively water-free gas cap, although nothing is water-free. One thing that's not shown well on here is in the Powder River Basin the Fort Union coals are charged with free gas. The sands have very high porosities and very high permeabilities. This production, in many cases, is essentially water-free. Unfortunately, the size of the reservoirs are limited and very difficult to map because of the type of depositional system we're in. So that's not something being chased very dutifully. Then, of course, if you have faulting, you can charge the coal in those sections there. In the area around Sheridan there is faulting. We're talking about hundreds of feet. We do find many instances where there's basically free gas, and there's wells that have blown in that area. There are also other

the type of coal present, some primary porosity. That may, in fact, and in many case is, interconnected to the cleat system. We have not been able to get an accurate measurement because the methodologies that we have for determining this actually destroy the coal. So we get to a point where it's going to blow up on us, which is fun, but we don't get a number out of it. We assume, based on the modeling and reservoir reconstruction, that we're looking at something between 10 to 12 percent primary porosity. That's a significant increase. Also in

CONVENTIONAL TRAPS
IN
SHERIDAN COUNTY, WYOMING



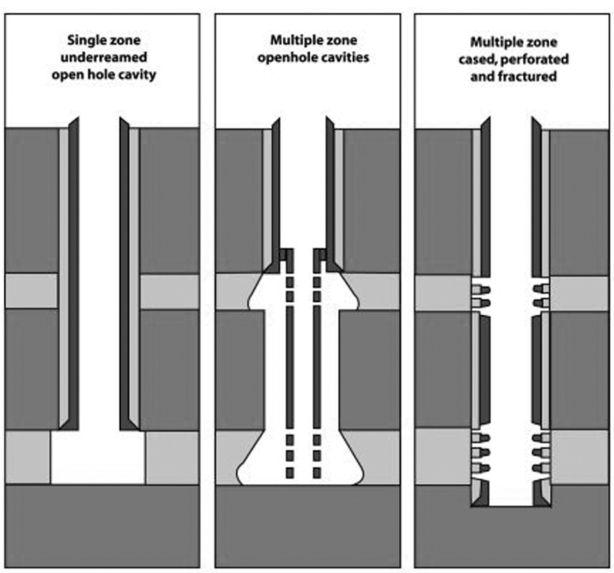
SORBED GAS ON COAL SURFACE



wells that have blown out, in other areas of the basin, but the drillers weren't really equipped to handle the occurrence of free gas.

The type of completion, typically, is open-holed completion, as before. If you have a thinner zone, you don't want to let that go. It may not justify drilling an additional well because of its thickness. So we're looking very actively at multiple zone completions. The mechanical difficulty of this is severe in some cases. We have tried to use plastic pipe, and we end up with a bird's nest that the drillers hate because they have to pull the plastic shavings off by hand. Also, we don't get good adherence with cement. So in many cases, we've gone back to using steel and either drilling it out or perforating it. When you cement across the coal zones, you very often destroy permeability, and it's difficult to get back. The treatment typically used on the wells is, if it's under-reamed, it's injected with water, the same type of water you use for drilling, and then flowed back, which you don't have problems with. And this is really the only stimulation of any type. It's actually called an enhancement. There's nothing to compare it with except trying to fracture a sand without proppant.

COMPLETION PROCEDURES



This is for the environmentalists in the audience. We do have buffalo in the area. There are scenic views.

CBM PRODUCING WELL
AMERICAN BISION RUBBING ON WELL FENCE

When we finish however, this is how things look. We chase out the buffaloes and level the buttes.

CBM WELL WITH ELECTRICAL
SUBMERSIBLE PUMP

This is just a brief comparison of the different basins we're looking at. As you see, the grade and coal in the Powder River Basin in less than in other basins. Gas content is extremely low. Areas in square miles is great. Thicknesses are wonderful. And GIP is very low. (See table on next page).

Thank you.

COALBED CHARACTERISTICS, ROCKY MOUNTAIN BASINS							
Basin	Coal Rank	Gas Content SCF/ton	Area (sq. mi.)	Max. Seam Thick.	Gip (TCF)	Cum. BCF 1998	#CBM Wells
Powder River	Sub-bituminous B	<100	25,800	200'	30	55	1,500
San Juan	Bituminous Med. and low volatile Sub-bituminous	100–500	7,500	40'	50	5,873	>3,000
Raton	Bituminous High volatile C Med. volatile	200–400	2,200	10'	32	38	~225
Utah (Ferron)	Bituminous High volatile B	200–500 (400)	290	10'	5	100	210

CBM DEVELOPMENT FROM THE PERSPECTIVE OF WYOMING COUNTIES

MICKEY STEWARD, *Coalbed Methane Coordination Coalition Coordinator*

I am the coordinator for the Coalbed Methane Coordination Coalition, which is a unique organization developed in Wyoming for a purpose that is different depending on who you talk to. So today, to start my description of the coalbed methane coordination coalition, I brought the memorandum of understanding that created the coalition. The coalition was constructed between the state of Wyoming and a joint powers board that is made up of five county commissioners and two conservation district supervisors. And if I had been smart, when I found out the constituency of the board, I would have known right away that this was a job that was going to have controversy associated with it, because I have five government people and two technical information transfer people, and that accurately reflects the purpose of the Coalbed Methane Coordination Coalition. And let me read to you exactly how we were constituted.

The purpose of this memorandum of understanding is to provide for participation between the parties in addressing coalbed methane issues. The participation will be facilitated through communication, coordination, and cooperation between the State and the board for the common goal of reasonable and responsible coalbed methane development and protection and preservation of water supplies in Wyoming.

The board will employ a coalbed methane coordinator (you can switch that phrase to sacrificial goat). The board will employ a coalbed methane coordinator to facilitate participation including participation in the preparation of the Powder River Basin oil and gas development, environmental issues and environmental assessment.

So we were created for the specific purpose of assisting in the reasonable and responsible development of coalbed methane and also to review the environmental impact statement. We are also unique in that our board has some industry advisors and participants who have been very brave and very helpful in furthering our cause, but early on, we recognized a split role was a difficult one for the industry, legislatively. So, to wholeheartedly support this, we have a very dynamic interaction there.

Let me continue by saying that the responsibilities of the coalition, actually including the board and it's employed contractor, shall compile information and provide that information to promote a better understanding of coalbed methane issues. So that is the essence of the Coalbed Methane Coordination Coalition.

Our five counties, are Campbell, Johnson, Buffalo, Gillette, and Sheridan, which comprise the outlines of the Powder River Basin, which you all have seen in every presentation till mine. I would like to emphasize that we serve a town and country population of about 70,000 people. The project area is 8 million acres, of which about 4 million are actually forecasted to be under development. We also represent a variety of industries. We have a very large coal industry. We have a smaller and not so active uranium industry. The transportation industry, to move the energy out of the basin, and we have the coalbed methane industry. There are, in the four million acres, about 1,000 ranches that vary in size. And each of these constituents has a very different viewpoint and very different goals and objectives.

We also have been sensitive to the fact that given the nature of development, there are numerous transboundary issues affecting conditions at some distance from the originating point of the activity, and we see that both at the state and regional levels. The split estate has been chewed on for a little bit here, and it also comes into play with trasboundary issues. I can tell you, from the involvement of the split estate as well as the number of stakeholders and the number of agencies, it has been a very big challenge to implement the goals of the Coalbed Methane Coalition.

That being said, I feel that we've been extremely active in information transfers, and we've also taken some heat off the government agencies in the sense that I believe a number of people come to our coalition for information first. And we use a process of providing information, looking for information, and then try to direct the questioner in a logical and reasonable direction with their concerns.

One of the things when we think about information transfer, it's important to recognize that we also do quite a bit of interagency information transfer between both agencies and between state, Federal, and local government. And sometimes I feel we do a lot of semi-important tattling, but yet that flow of information is extremely important, given the fragmented responsibilities of the different agencies involved in the coalbed methane development.

We do have a website. Our aspiration is to have as good a website as the State Geologists and the Oil and Gas Conservation Commission, and we do link to those websites. We also do numerous presentations and personal interactions. Since the Coalbed Methane Coordination Coalition started at the beginning of last year, we have had personal interactions with about 5,000 people, either individually or in group settings. We've also had about 4,000 hits on the website, which isn't anything to get real excited about; but on the other hand, we are seeing some utilization of our organization. And we are extremely interested in linking with other sites so people can get a grip on coalbed methane development as well as they can.

I'll pause here for just a minute and remind you, if you don't know, that Wyoming is very big on property rights and individual rights, and we're very pro-development. And we feel that we can be all three of those things and still protect and preserve the multiplicity of resources that we have in our area. This is a very rich area, and I think that's been sufficiently emphasized today. In my role as coordinator, I have to tell you that you must take the philosophy and points of view of numerous people into account as you're trying to move forward. And I can tell you that in the Powder River Basin, with the three larger municipalities that we have, Buffalo, Sheridan, and Gillette, you have three very distinct points of view and you cannot use a one-size- fits-all approach; yet, at the same time, you need a certain degree of consistency in order to move forward in an orderly fashion.

So what we've done for the past year is been a complaint department in some respects, and we've been on a very high learning curve. In fact, I learned a number of new things today in the presentations that were made. And we have also been able to provide some information in our own right. But the direction that we're moving continues to be somewhat schizophrenic. We are information transfer and we are also governors; that is by the nature of our board make up. One of our perplexities has been how to reconcile these two very different yet closely related items. And I want to share with you this morning, then, the direction that the board is taking with the Coalbed Methane Coordination Coalition and then close with a few thoughts on some of the interesting challenges that I personally have seen as the coordinator for this coalition.

The board is making some recommendations as to the direction that they feel things need to go in the Powder River Basin. Their primary recommendation at this point in time is to create or modify the existing joint powers board to clearly distinguish between government and information transfer. This is causing some heartburn among numerous entities, and it makes the job very difficult that that distinction is not clearly made.

The second recommendation is that we need a long-range resource plan for the region as part of the overall energy plan for the state that is currently under development. And the important item with respect to that long-range plan is that we must have rapid response to developing issues. The one hallmark with the Coalbed Methane Coordination Coalition, in addition to the multiplicity of stakeholders, is that things change very quickly.

The third recommendation the board is considering making is that we need to be sure that we incorporate the diversity of stakeholder interest. That's very difficult because there are so many stake-holders, and that means that we all need to be on our best behavior and refrain from the easy to use tendency to demonize what we regard as the opposition. If there was ever a need for collaborative tolerance, the coalbed methane development is certainly it.

We need to create and maintain long-term economic opportunity and quality of life. We need to preserve and enhance the productive capacities of any development that creates new wealth. New wealth is hard to come by. I worked in Denver as a consultant for a year, and what I mainly saw is that we recycled money that somebody else had made for us. And I think the Powder River Basin is a prime example of how money is made by agriculture, by extractive industries, such as the mineral development, and by logging and by things like hunting and recreation. Those are all valuable developments that create new wealth, which we need.

We need to create consistency in management objectives, as they're needed from the very most individual action at the surface use agreement level through the conservation district plan, through city plans, through county plans, the state basin group plans, and the Federal government. There is a certain amount of common ground and consistency that is needed throughout all those types of management exercises in order for us to achieve our protection, enhancement, and management of the landscape.

We need to provide a level playing field. We simultaneously, in the Powder River Basin have the most heavily regulated mineral extraction industry, which is the coal industry and the least regulated—although that's all a question of relatives—industry in the coalbed methane extraction industry; and that is providing us with some real challenges.

We need to develop a means of impact funding in advance of development for resources, particularly the county roads and law enforcement. Coalbed methane development, as well as any agriculture, recreation, or conventional oil and gas that depend on the county roads for their well-being has to be serviced in order to do that, particularly in the counties that have not yet experienced the tax benefits of development. They need some place to go to the bank and get an advance so they can prepare for the services they need to provide.

We need to make accessible a funding source for mitigation as needed. As this development deepens, spreads, and prolongs, we, the CBM industry, cannot be expected to be responsible for all mitigation measures that might be needed. So we need an alternative. We need to accelerate research into optimization of resource extraction and landscape production activity. We must have more data, because more data means less controversy. We need to apply increased amenities for residents without creating an unsupportable future burden for government. We're talking about things like park services and recreational facilities. We need to do that because those people who live in the Powder River Basin are providing a service for the United States, and they are living in what one of their own county commissioners called a barren environment. And we must recall that some of the needs of those residents must be met as part of this development.

So as you can see, the board is moving, is continuing with the information transfer as we've begun. But the board, after 14 months of interaction, has also seen the need for government in certain aspects, and we feel that the Coalbed Methane Coordination Coalition is definitely going to continue its metamorphosis and change. But it's important, I think, to make more clear that differentiation between the government aspect and the information transfer aspect.

Finally, because I can't resist it and my light hasn't turned red yet, water has occupied a lot of our attention in the Powder River Basin. And I'm not in total concurrence with what the gentlemen have said so far this morning. However, I'd like to point out four things. There is a change in the dynamics of the receiving environment that we need to accommodate. We now have short reaches of perennial flows in heretofore, ephemeral and very flashy landscape. We produce no large quantity of water from every well. But from the standpoint of livestock production, we typically produce enough water per well per day for about 500 head of cows when the forage resource in the well area is about five head per day. And so the water needs to be put to even better uses than it has so far been put in order for us to optimize our water resource. And I really like the concept that Mr. Day had about considering the infiltration and recharge an important value from that standpoint. The third point I'd like to make is that water cannot be separated from its receiving environment—as we forecast the benefit and utility of that water that is receiving it. And finally, with respect to the water, I agree with the observation that the salt levels are not high, but some of those salts come and go with drought and heavy rainfall periods, calcium and magnesium particularly, but the sodium tends to accumulate; and that calls for special management techniques.

So, in closing, I'd like to thank you very much for giving me the opportunity of visiting you a little bit. I think Wyoming is on the forefront of a lot of technical issues and a lot of community involvement and industry interaction issues. And it's very harrowing at times, but it's very exhilarating as well. And I have to extend thanks to everyone that's been willing to participate in the coalition. We grow by people supporting us, and we also grow by people being critical of us. And I think that's what we have to see is a partnership, not always necessarily a positive partnership, but a partnership in order to take best advantage of the resources we've been given.

Thank you very much.

AIR QUALITY AND CBM DEVELOPMENT

BOB YUHNKE, *Attorney At Law*

I'm going to begin here with the assumption that none of you have read the air quality review or assessment contained in the EIS, which is the only information that we really have about the air quality impacts of the coalbed methane development. I'm going to make that assumption, in part, because even if you asked for the EIS, you would not get the air quality assessment. You'd have to find the small footnote that refers to the air quality assessment. You don't get it unless you ask for it. And then when you get it, you discover that there's a lot of things that are missing, and we'll talk about some of those things later. But first let me focus on what it does say about what the expected impacts will be.

The Clean Air Act divides the world up into nonatainment areas, which we don't have here—those are areas that violate national health standards and areas that do meet the national health standards, which are in turn divided up into what are called Class II areas and Class I areas. And in this part of the world, the Class I areas consist of these five wilderness areas along the Continental Divide and the Badlands National Park and one of these caves. Another Class I area, by determination of the tribe, is the Northern Cheyenne Reservation, which was made into a Class I area back in the late 1970s. And is a management tool that the tribe adopted to try to protect its air quality from the impacts of coal development which was happening back in that period. That definitely has an impact on what's going on now with regard to the oil and gas development in the project area.

Now, to give you a quick summary of the results of the air quality analysis, what it shows is the most significant impacts from the emissions from this development, which has to be accounted for in the context of all the other development occurring in the region. In other words, the Clean Air Act does not simply focus on the emission from a particular development or particular source, but focuses instead on the cumulative impacts of all of the activities that produce emissions into a region. And the underlying regulatory program of the Clean Air Act that requires this cumulative impact analysis is called Prevention of Significant Deterioration, which was added to the Act back in 1977 for the purpose of trying to protect clean air areas and to prevent them from being deteriorated to the level of the national standards. Partly because even though the national standards, although intended to protect public interest, do not protect against other effects of air emissions.

So the objective was to try to make sure that areas that were already clean did not become as dirty as the national standards would allow. The PSD program requires that you assess the cumulative impacts of growth in a region and to limit the amount of new pollution that's added into those areas. Now, in the Class I areas, here (pointing to wilderness areas along the Continental Divide and in western South Dakota) and on the reservation, the limitations on new pollution that can be added are quite stringent. And the numerical increases in emissions that are allowed in those areas become, usually, the most constraining impact on development, certainly on the increasing of emissions. But there are also limits on pollutants in Class II areas about ten times greater. The limits are about ten times greater than in Class I areas. The Class II areas—and the project area itself is a Class II area—include the wilderness area here, the Cloud Peaks, Emerald Lake.

Another aspect of the Clean Air Act is to protect visibility. Visibility being identified specifically as an important value related to the wilderness experience in wilderness areas and also in the national parks, where the ability to see the natural phenomenon that a park was established to protect is often the most important aspect of

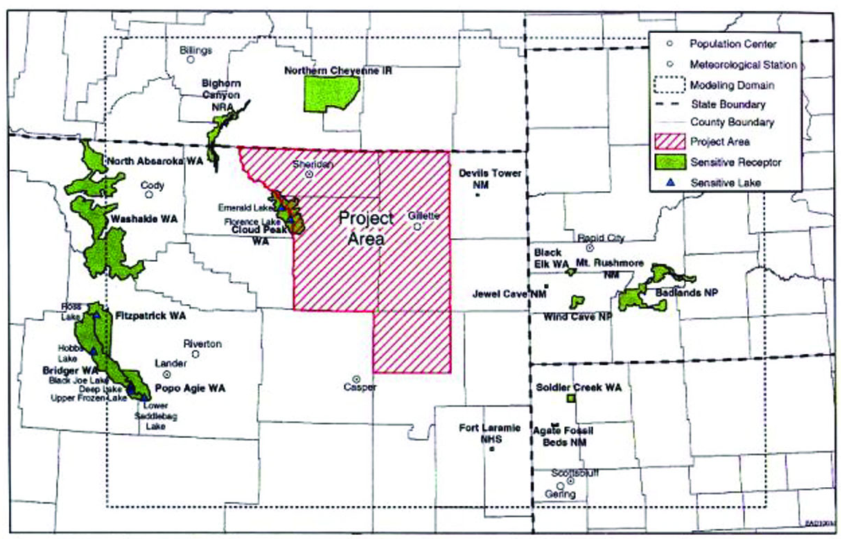


Figure 1-2 Modeling Domain, Project Area, Population Centers, Meteorological Stations, and Sensetive Receptors for the PRBO&G Project

the user experience of a national park. Like if you went to the Grand Canyon and you couldn't see the other side, you would probably be upset about that. And that sometimes happens, largely due to a combination of air pollution and natural conditions. So the Clean Air Act, back in 1977, also added a provision that said that the national goal is to, over time, without setting any particular time limits, to eliminate man-made reductions in visibility in Class I areas. And the EPA has now defined that time period as being, approximately, a 60-year timeframe, starting from two years ago, to reduce the emissions from man-made activities that cause visual impairment in Class I areas. And in addition to that long-term program, there's also a requirement that new activities that will add new pollution into an area, should not deteriorate visibility in designated Class I areas. So what we see from the EIS is that the CBM project emissions and projected normal gas and oil activities in this basin, when combined with the permitted emissions in this area that's defined by the dotted line, which is called the modeling domain. The emissions from sources in that area, combined with the new oil and gas development, will cause some significant impairment in visibility.

The analyses that were performed were in the Devil's Tower and the Class I area, plus some of these other designated Class II areas, to determine what the visibility impairment would be. There was not any assessment of this visibility impact directly within the project area, although one would expect that they would be significantly higher. In the Northern Cheyenne reservation and in Devil's Tower, the highest visibility impairment would be expected. And in those areas, the refined analysis showed what is called a deciview, which is a ten percent change in visibility that would occur at least ten days out of the year as a result of the total emissions from this. There would be approximately a 60 percent reduction in visibility in the reservation and at Devil's Tower. The impacts within the project area would likely be somewhat greater, although that was not assessed. So from the standpoint of people living in this area or using those resources or living on the reservation, this would be a quite observable phenomena. And it would likely be something that people would become quite aware of and not be happy about if you're used to the clear skies that most of us who live in the West love and cherish. And in the Badlands, which is the other Class I area that would most likely be effected by visibility there, it was predicted that for three days out of the year, there would be a 10 percent reduction, and the peak visibility would be a 25 percent reduction on the worst day.

Now, in addition to those impacts on visibility, closely tracking those impacts, would be increases in fine particles. And, in fact, it is the fine particles that are responsible for visibility impairment. Fine particles have the greatest impact on human health. You may have read in the press last week, after three years, a decision from the Court of Appeals in Washington, D.C., from the 1997 fine particle rule making, came down. That standard is 15 micrograms. What the analysis here shows is that final particle concentrations within the project area would increase by approximately 50 percent compared to baseline levels, which would be a 100 percent increase in man-made particles, taking into account the fact that some of them are natural. The EIS predicts fine particles with average 12 micrograms per cubic meter annually, which is low compared to the EPA standard of 15. You also might want to compare it with the proposed new California ARB standard for particles, which is 12, based upon the most recent evidence of the adverse effect of fine particles, which has come out since the EPA proposed its standard in 1996. So those could very well affect human health. And, in fact, 24-hour daily concentrations could be well above the levels that have shown increased mortality in studies. And this may well be the most significant impact, although it would not be prevented by any of the standards that are currently in place.

It's also worthy or important to note that there is no PSD limit on fine particles, because the act required the EPA to set a PSD limit for fine particles. That obligation ripened and expired back in 1999, but the EPA has not done it. Somebody's going to have to sue them to make them do it. And if they set PSD limits for fine particles that was in any way similar to those that were set some 20 years ago for PM10, this increase in fine particle pollution in the area would likely exceed those limits by more than a factor of two. So that, if limits were set for fine particles on the same kind of ratio that was set for PM10, this development might well exceed those limits, at least based on this analysis.

And then finally, for PM10 itself, which is a larger sized particular, which is the difference between fine particles, which are particles less than 4 PM10, which is particles that are between 2 and a half and 10 microns in size, is that the 4PM10 particles appear to be somewhat less deadly in terms of human health. But they still cause significant impacts in terms of adverse health affects. The analysis shows, again, there would be a 37 to 50 percent increase in Class II areas and significant increases in Class I areas. But the largest increase is in the Northern Cheyenne reservation, where over half of the increment allowed under the PSD program would be consumed according to this analysis. This analysis does not show any violations of the PSD increments themselves. So what needs to be focused on are the visibility impacts, which have been demonstrated, and the unacceptable impacts resulting from the relatively high fine particle concentrations. Now, that being said, it's important to understand what the limitations of this study are, and they are considerable.

And, in fact, I think if the EPA took an honest and careful look at this analysis, they might have to conclude that this was an unacceptable analysis from the standpoint of NEPA. One of the most critical deficiencies in this study, and if you could put up my outline, is that it fails to account for the emission inventories that resulted from development between the time that the baselines were set for PSD and the present. The baseline dates for the PSD program is determined when you start counting increases in emissions from new development. Baseline dates for that particular matter and SO2 were set back in 1979, and for nitrogen oxides in 1988. This analysis only looks at emissions from new sources that were permitted after 1995.

So all this development that occurred between 1979 and 1995 has been left out of the analysis all together.

And those sources include some major power plants like Coal Strip. They include the Moon Lake power plant over in northeastern Utah, the Craig Power Plant in northern Colorado. All of these were major sources that consumed some of the allowable emission increase under the PSD program early on in the early 80s. None of that was accounted for in this analysis. And then there has been a lot of oil and gas development in the Green River Basin, none of which has been accounted for in this analysis either. The western boundary of this study area, the Washakie and the three wilderness areas in the Wind River Range, for example, are significantly impacted by emissions from the West and the Southwest. All of that development in the Green River Basin, oil and gas, and the new power plant being proposed for that region, none of that was accounted for in this analysis. So when you start to look at all of the major sources of pollution that were left out of this study, recognizing too that you know the wind doesn't just blow from the East to West. The wind will blow some of the emissions, from time to time, from this area to the West to the wilderness areas along the Continental Divide. And those emissions will add to the emissions from all that has occurred to the West and Southwest of those areas. There are a lot of impacts here that have been ignored. And that also is true with regard to some of the development of the Northern Cheyenne Indian Reservation in Montana and to the east in South Dakota.

So there are a lot of deficiencies in this analysis that they've left out as far as major sources of emissions. In addition, there appears to be a significant mismatch between the estimated emissions from that development itself, based on the fact that the air quality analysis was based upon the assumption that there would be 39,000 wells in the basin. And you heard this morning from the Oil and Gas Commission chairman that the expected number of wells to be developed in this area will exceed 50,000. So that there appears to be at least a 35 percent omission of the total emissions that should have been estimated from this development. So when you put all these things together, what it says is that the total emissions, if they were properly accounted for, could very well be showing violations of the PSD increments. I think I mentioned that I wanted to address the cumulative impacts in increments.

Some of the other issues that have not been addressed, partly because of regulatory failures of the EPA, include the failure to set the PSD increments for fine particles and the failure to respond to a remand from the Court of Appeals in a case challenging the adequacy of the nitrogen oxide increments back in 1990. The EPA, 12 years later, has done nothing, even though the Court told them to revise the increments for nitrogen oxides. That still has to be addressed.

Then finally, a couple of major issues relating to the responsibility of the Secretary of the Interior. The Secretary has a statutory duty to deal with visibility impairment. There is no discussion anywhere in this EIS about how the Secretary will carry out that responsibility. NEPA requires that there be consideration of mitigation measures to mitigate adverse impacts. Here the adverse impacts have been clearly demonstrated. This is no analysis of the mitigation that the Secretary intends to implement to carry out that responsibility to protect against visibility impacts. And there is no discussion of her responsibility to protect the tribal lands, given her responsibility to carry forth the trust responsibilities of the United States to the tribes. And then finally, there are FLPMA requirements that require leasing decisions or permitting decisions by BLM to not allow any violations of air quality standards. And to the extent that we are seeing here, some potential violations of increments, this air quality analysis was not properly done. That draws into question how the BLM will carry out its obligation to address those impacts in that impact statement.

So there are a lot of unanswered questions here and some very important environmental consequences that need to be addressed.

[additional information provided by the speaker follows]

ISSUES REGARDING AIR QUALITY ANALYSIS FOR OIL AND GAS DEVELOPMENT IN THE POWDER RIVER BASIN

I. Emissions inventories—

A. Modeling Analysis Based Only on Recently Permitted Sources:
Emissions from only those new sources permitted since 1995 are included in modeling analysis. Increment consumed by major sources permitted after the PSD baseline dates (1979 for PM10 and SO2; 1988 for NO2) not included in the analysis. Among impacts excluded from analysis are emissions from major power plants including Colestrip (southern MT), New Moon (north-eastern UT), Craig (northern CO). Emissions from existing and planned oil and gas development in Green River Basin, and proposed power plants (eg, Roundup Plant in southern MT) also not accounted for. These sources could significantly increase increment consumption and AQRVs in WAs on the western boundary of the modeling domain, and the N Cheyenne Indian Reservation.

B. Regional Unpermitted Minor Sources, Area Sources, Transportation Emissions Not Included.

C. Mismatch Between Estimated Wells Under Reasonable Development Scenario and Emissions From Well Pads Differ by 100%: RD moderate scenario estimates 81,000 wells in 5 county area over life of the project, with 50,000 wells by 2010. AQ assessment assumes 39,000 wells.

II. Modeling domain too narrow to address cumulative impacts on increments, AQRVs in Class I areas.

A. Wyoming Class I Areas: no assessment of impacts of emissions from sources in SW Wyoming, N Colorado, NE Utah. Could be important for Class I areas along western boundary of modeling domain.
B. South Dakota Class I Areas: no assessment of impacts of emissions from sources east of modeling domain that will also impact AQ and AQRVs in So Dakota Class I areas.
C. Northern Cheyenne Indian Reservation Class I Area: no assessment of emissions from sources north and west of modeling domain that will also impact AQ and AQRVs in NCIR.

III. Clean air act requirements not implemented.

A. PSD Increments for PM 2.5—CAA §166.
Near-field cumulative PM2.5 concentrations will increase annual concentrations by more than 50% to 12 μg/m3. Would likely violate a Class II increment set under §166.
B. PSD Increments for NOx—CAA §166, EDF v. EPA, (D.C. Cir. 1990).
Court remanded NOx increment rulemaking to EPA to set increments for NO3, in addition to NO2, or for total NOx. EPA action on remand is still pending. NO3 concentration might violate Class I increment set under §166.

IV. FLPMA requirements.

A. 43 U.S.C. §1712(c)(8) requires that management plans "provide for compliance with applicable pollution control laws, including State and Federal air, water, noise, or other pollution standards or implementation plans . . . "
B. BLM regulations require that this statutory mandate be implemented by requiring that—

> *Each land use authorization shall contain terms and conditions which shall: (3) Require compliance with air and water quality standards established pursuant to applicable Federal and State law. 43 CFR §2920.7.*

CBM DEVELOPMENT, RANCHING, AND AGRICULTURE

NANCY SORENSON AND JILL MORRISON, *Powder River Basin Resource Council*

NANCY SORENSON

I have lived for the last 29 years on a ranch in the Powder River Basin in northern Wyoming. I was really surprised that Campbell County was totally flat and didn't have any trees at all, because my ranch is bound on the north and west by the Powder River Basin, which is characterized by very steep topography and it's heavily wooded with Ponderosa pine and juniper. The bottoms are a trimmed with box elders, choke cherry, and many other shrubs and things like that. I think I still live in Campbell County, but maybe not. Farming and ranching in the Basin has never been easy. This semi-arid environment only allows so much livestock and so much disturbance before the land stresses to a point that a living cannot be made. While countless others tested the boundaries imposed by nature and packed up and left, my husband's family listened to the land and have persevered for four generations. Where it was once possible to plant a few crops and raise some livestock, anyone who ranches successfully in the Powder River Basin today accepts many limitations imposed by nature, the economy, the environmental and recreational community, and the extractive industries that are predominant in our area.

My family and I have worked hard to improve our ranch each year, not only to make it more productive, but to make it more hospitable to the many native species in our area. We strive for a form of sustainability that takes the long view that whatever we do on our land will not damage the resources to a point that the land cannot recover.

Since 1997, when we were first approached about leasing our minerals for coalbed methane development, our ability to maintain the delicate balance required for our philosophy of sustainability has been sorely tested. And for the first time in our ranching career, which spans 29 years, we have witnessed degradation that I fear is irreversible. We have negotiated and signed 13 separate agreements for various aspects of the coalbed methane play, including oil and gas leases, pipeline right of ways, road rents, and surface damage agreements. In not one of those negotiations did we have an option of not signing. In not one of those agreements were we able to maintain the control we need to assure the long-term sustainability of our ranching operation. Here is why.

In 1997, when we were approached about leasing our 50 percent share of 2,500 acres of oil and gas rights that we own, we said, "No, thank you. We're not ready to do that." The landman simply went on to the nonresident owner of the other 50 percent of those same minerals in Dallas, Texas, and promptly leased them. The land man then called us back and explained that since he now owned the rights to the other 50 percent of our minerals, we could lease our rights or not, but he had the right to develop his minerals. In order to control, to a certain extent, what would happen to our land, we ultimately signed. The cost of this attorney for this first foray into the coalbed methane business was $5,000. The rest of the minerals under our land belonged to the BLM, the State of Wyoming, or other nonresident entities.

As a surface owner, you are not contacted when these minerals are leased. We only hear about it when the industry developer desires to access his minerals. In Wyoming, the surface owner does not have the right to deny access to a mineral developer who owns oil and gas leases under his or her property. In fact, a surface user agreement is not actually required, as these can be settled in the courts, usually to the disadvantage of the landowner. Some pipelines fall under the eminent domain laws. Others fall under the laws that allow development of anything reasonable and necessary to develop the minerals.

In one instance, a company wanted to erect an 80-foot radio tower. Again, we said, "No, thank you." A few months later, a huge concrete footing was poured for that tower, even though we had not signed any agreement for it to be placed on our land. When we notified the company that they were, in effect, trespassing, they hurried to complete the tower without ever calling us back. Then they came to us with an agreement. The company's response as to why they didn't try to obtain permission for installation prior to building it was, "We needed that tower." One representative of the oil industry said to me that he failed to see what was so offensive about coalbed methane development.

To that person and all the others who encroach on our lands, here is a partial list. First of all, lack of respect for the land, for me, for the environment, for history, and for the future. Dishonesty by the landman and the operators and also by the state and BLM who pretend to care about the environment but instead work to expedite development to the detriment of the rights of those on the land.

Denial of property rights. I never understood people who constantly spouted about private property rights. Their opinions and rhetoric seemed extreme to me. I understand a little more now. Simple justice cries out for a law requiring a surface use agreement before any activity takes place on one's land. What we have, in effect, now is a two-tiered system in which the rights of large international corporations whose purpose is profit have more rights than a person who has lived on the land for perhaps his whole life.

Lack of viability. It is becoming more apparent by the day and month that CBM extraction may not be economically or environmentally viable. I have been told by a representative of a company that developed land that adjoins our property that that facility does not seem to have any economically recoverable gas under it. Did they have to destroy beyond recognition 640 acres of land and discharge untold thousands of gallons of water to figure that out? Furthermore, the amount of estimated recoverable gas in the entire Powder River Basin is measly compared to the amount of water that must be discharged and wasted to recover that gas. It's enough water to serve the needs of Wyoming's people for 30 years.

Irresponsibility. Methane companies repeatedly fail to live up to the promises they have made in contracts to landowners and private mineral owners. The surface user has become a policeman to keep the operators from even obvious violations. Verbal agreements with landmen or operators mean nothing, of course. But legally signed agreements do not mean anything to these guys either. Bouncing along over open country roads where access has been denied is common. Illegally discharging water and venting wells are other offenses. Private individuals are commonly cheated out of part of their royalties. A methane company my family is involved with subtracts transportation expenses and the amount of gas they use to fuel their compressors before paying royalties used to support my invalid mother-in-law, even though the contract on the mineral lease and the laws of the State of Wyoming clearly state that they may not do that.

Things are even worse for folks who live near methane development but do not benefit from it. Domestic water wells have dropped or become altered as a result of nearby development. The burden of proof lies with the owners of those wells, not the CBM operator. People near compressor sites must live with the noise and emissions. Individuals near county roads and new roads built for the industry must live with choking dust through most of the summer. High SAR water discharged by the industry damages or destroys trees and hay meadows miles downstream from the site of the discharges.

A lack of adequate planning is, in a way, the key to all the other problems I'm outlining here. Planning needs to take place at all levels. First of all, environmental issues need to, finally, be seriously planned for. One of my greatest concerns is that methane development will cause the addition of species onto the threatened or endangered species lists. They will leave the surface user to alter his or her operation to accommodate such listings.

On a regional level, it is ludicrous that we are drilling all these wells when there is a possibility that there is inadequate pipeline capacity to market the gas. On a local level, it is a constant surprise to me that power lines and other infrastructure are added willy-nilly, as needed, creating an unnecessary clutter of power lines and roads, or that no one has planned for the deterioration of air quality near county roads.

On a private level, I am astonished that an operator cannot tell me before I sign an agreement where or how the water will be discharged, where the power lines will go, or where the compressors will be placed. Often, such decisions are made by people out of Denver or some other central location who has never seen the land. When the land man is pinned down to answer such questions, the answers he gives you have little to do with the reality of what ultimately happens.

A lack of adequate bonding. The Powder River Basin is dotted with orphan oil wells, fields that were developed in the 1960s, '70s, and '80s, and whose owners have decided that it is cheaper to abandon the wells and forfeit the bond than to clean up after themselves. This leaves the taxpayers to foot the bill for this clean-up, if it ever happens. Compared with deep wells, the clutter in a methane project is much greater. Who's going to clean that up? Another landman from a CBM company once asked me, "What can we do to appease you, Ms. Sorenson?"

To him and all the others who may need to know, including our elected representatives, here's the answer: Develop an energy policy that benefits alternative, renewable sources of energy and conservation measures, such as requirements for automobile manufacturers to develop vehicles with higher gas mileage; and show me that development on my land is a necessary part of making progress toward a cleaner, better, and more prosperous society. Then I might be willing to do my part sacrificing my way of life, knowing that our nation is working diligently to solve our energy problems for the long haul.

Like most people in my neighborhood, I do not wish to prevent development of necessary natural resources, but I believe it can be done in a careful and thoughtful manner that will allow for the sustainability that we value so much. These comments reflect the experiences that my family and I have had. They're by no means the worst that has happened to people in our area, nor are they the best. And in many ways, they are very typical. I'd like to conclude my remarks with a comment as to how much I respect Mickey Steward for the work she's doing with the Coalbed Coalition.

I think she's crazy for taking on this impossible job. I do think the coalition itself would have been better served if it had included landowners and members of the environmental committee. Thank you.

Jill Morrison

I live in the Powder River Basin and work there. And I'm going to show you some actual shots of the area and of the development and talk about it. My presentation is not a power point, but it is about power, because that's what this issue is about. It's about producing power, but fundamentally it's about who has the power. And the people who have the power are not the people being affected by the development. The people who have the power are the industry, and that's who's calling the shots here. And I believe it's about an abuse of that power. And I hope that we can begin to work for a truly sustainable development. Because right now, there is nothing sustainable about this development, with the exception of one thing: lawsuits and lawyer's fees. And that is very sustainable.

This is a shot of Powder River Basin [35mm slides shown at the conference are not available here]. On the west side—this is actually Sheridan. The Bighorn Mountains are up here. You can see there is a lot of topographic relief in this part of the basin. The area where it is flat is really south of Gillette. That's where there have been the least problems—the least water quality issue problems—and the least development problems. Another map of Wyoming. And this is from the year 2000. This is about half of the permitted wells that they have now. The pink line is the outline of the project area. Campbell County is the green line. So you've seen that plenty of times today. I do want to point out that, while this development is project over an eight million acre area, the majority of the impacts are really going to be located in about three to maybe four million acres, and we're talking about 50,000 wells over the next 10 years. And this is what it looks like in many areas where new roads are constructed. This was taken in August of last year. This is a state lease up here in the upper part of the screen and if you go on up, it continues as Federal surface. The majority of surface in the Powder River Basin, as you have heard, is private. And this is what private landowners are trying to prevent. And this is what ranchers and people who own the surface are dealing with, the potential destruction of their land. The Powder River is right down here, and those discharges are going into the Powder River. These are wells, roads, and pipelines. This is what it looks like before they were issued a notice of violation for some of these discharges. And this photograph was taken back in, I think, '99. These are the sodic deposits built up on the side. This is the iron staining. That development was initiated by a company called Michiwest and the development is now operated, I believe, by Anadarko.

This slide is northeast of Sheridan. This is a slide of one of these large containment reservoirs. Again, these are not stock watering facilities. This is not for the benefit of livestock. This is for ways to get rid of the CBM discharge water. And in some cases they are actually drilling holes in the bottom of these reservoirs to help speed the infiltration in certain areas. This is a JM Huber field northeast of Sheridan. This is Prairie Dog Creek, which runs into the Tongue River. This is a compressor station in that area, and this is a compressor. This was taken last August. There's another two or three compressors added here. They're probably going to add several more. I've seen up to 20 in one area. And if you once were used to complete solitude, these run 24 hours a day, 7 days a week. They've been described as sounding like a jet engine that never leaves, a freight train that never goes by. And one gentleman described it as, "It drives you to the breaking point."

This reminds me of a story that goes along with an old Warren Zevon song, "Send Lawyers, Guns and Money." This is what is going to be happening in the Powder River Basin. Guns come into the picture in the case of a compressor station because it drove one gentleman to the breaking point. He became so upset at the sound, and frustrated that no one would do anything, he called the sheriff, the county commissioner's, the governor's office, nobody would do anything about the noise. So he allegedly fired 17 shots at a compressor station. That got their attention, and they finally made a few minor modifications to that compressor station, but the noise level is not reduced to what it should be. And it's very miserable to live with that.

This is another ranch south of Sheridan. The operator came in here. They did not save the topsoil, bladed right over the drainages. They came in, made a mess, and left. And it's still sitting there like that. This is the road they bladed in to get this. The landowner has filed a lawsuit against this operator. Garbage, tons and tons of garbage that is thrown on people's land. Ranchers not only become policemen, they become garbage men. I have a list of all the garbage that has been picked up by landowners, and it's a long one. In a place that you care for and that you've done everything to maintain, you don't even throw a single cigarette butt down, and then to have to come and pick up big and little garbage.

This is a drilling mud pit. Drilling fluids are dumped into that pit and then just covered up. Another stock reservoir. The BLM has estimated that the development over the next ten years will require pumping out over four million acre feet. And their primary method of disposal now is putting anywhere from 1,500 up to 2,000 of these containment reservoirs across the Powder River Basin. Many landowners who are involved in ranching do not want this because you can see how much acreage it will take out of production on your ranch. And then, what I didn't hear anybody mention, is what will settle at the bottom of these reservoirs and be left to clean up when they're done. It will be salts and metals, and who is going to clean those up? Is industry going to clean those up? How are they going to be reclaim it? There are no reclamation plans for any of these projects.

This is another reservoir, a natural reservoir that was never full. It's down by the southern part of the basin. It filled in about eight days from 15 coalbed methane wells. They had to berm it up on this side in order to keep the water from flooding out onto the grass. This is how they try to prevent erosion, put all this rock in, but you can see all the dead vegetation here. And this also takes what you use to create an income, your grass, out of production. All this grass is dead and dying, and it's not going to come back because these are clay soils and this is high SAR water, and the two do not mix. This is Spotted Horse Creek. This is on Marge and Bill West's property. This is an ephemeral channel that normally only flows in spring and/or during summer flood events. In this slide all this water is from CBM discharges upstream. It has flowed out over a large area, and the company was issued a notice of violation to stop the discharge, but they were issued the notice of violation on a downstream landowner where the water had not reached. The discharge continued. They appealed the discharge, and they were allowed to continue the discharge. This discharge continued for many, many months. What was left the next year, this is the following fall, in September, all of those cottonwood trees are dead. You can see from the slide that most of them are dead. One area where the CBM water flowed out and froze and sat for many months left a large salt flat. The only thing that would come up in there after Bill tried to move those salts out of there and put some other topsoil down was a weed, fireweed. All along that other property where the road was bladed is now full of weeds that were never there before. Even if you tried to control those weeds, it's hard to get rid of them once they take hold; it's very, very difficult. So you've lost your good grass and had soil disturbed and replaced with weeds.

This slide is a domestic water well. This is an example I've seen around the basin a few times. Not always quite this dramatic. The lid from this water well was blown off by the pressure of gas. There are a couple of fields close to this area, I think Fidelity has one and J.M. Huber has one a little further away. This is a very serious safety issue in the basin, and it is mentioned in the EIS.

Methane will occur in water wells at potentially explosive levels. This is a quote from the BLM DEIS, "In areas within two miles of operational CBM well fields, well houses and basements should be well ventilated and periodically checked for methane gas." I don't know any landowners out there or ranchers who carry methane detectors around, but I know plenty of them who smoke. And I want to know what the industry and the regulators are going to do to prevent these problems.

This is not a great slide, but it's that earlier Huber site when they were constructing those reservoirs. That's from June, 2000. And this is just a further distance from the development scene, the reservoirs. And another shot. There's an overriding issue here: The value of land and property values is not being addressed. It's the issues of wildlife habitat, scenery, solitude, open spaces, these intrinsic values that are not being addressed in the development.

We need industry to work closely with landowners. Landowners need to have the right to say where the facilities are going to be placed. Landowners need to be shielded from liability for accidental damage to drilling equipment and infrastructure. We need to establish a right to negotiate a surface damage agreement for the landowners. We need a collaborative process where we can sit down and the landowners can work with industry and not be bullied and intimidated and forced into what is a nonsustainable development. I think we can do better. I hope we will do better. Because I hope we just don't have the biggest natural gas development, but that we turn it into what could be maybe the best.

Thank you.

BLM ENVIRONMENTAL ANALYSIS AND CBM DEVELOPMENT ON FEDERAL LANDS

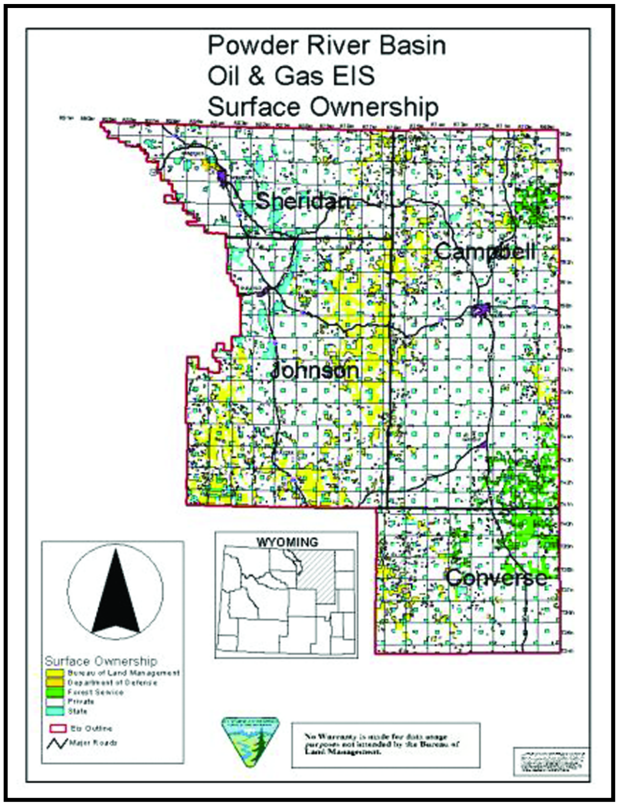
RICHARD ZANDER, *Assistant Field Manager, BLM, Buffalo Field Office*

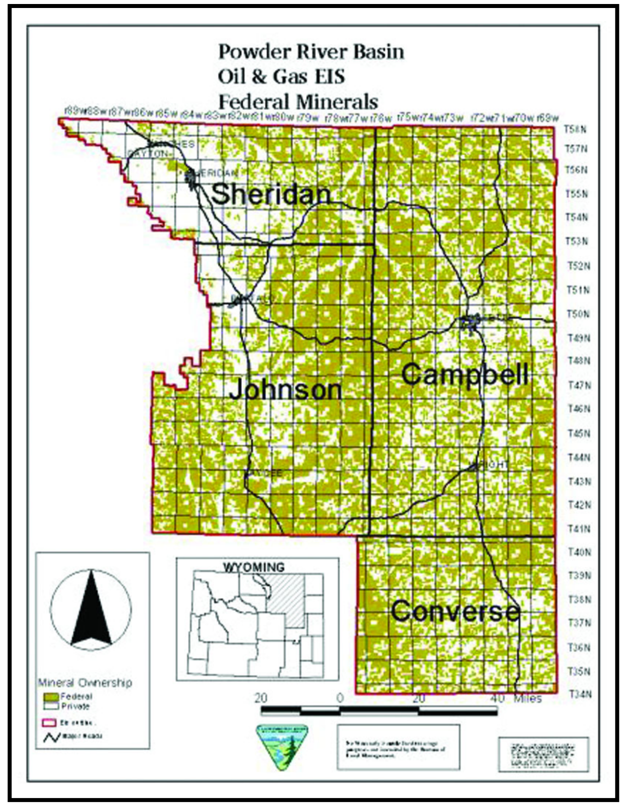
I would like to thank the conference sponsors for inviting me here. We've heard from a variety of speakers about the aspects that govern coalbed methane development—lawyers, hydrologists, etc. I'm going to try to show you what actually happens on the ground in the permitting process. But please be aware that this process only applies to the federal minerals.

As Diana mentioned, I've been in Buffalo for about 17 and a half years, so I've been involved in this play from the very beginning. We had some false starts in the early 80s. D.L. Cook was a developer. We laughed at him. That was about 1985. By 1992, coalbed methane was a reality in the basin. So I have seen the whole play. I would like to thank Don for talking about the EIS today, because actually I'm not going to talk about the EIS. Thank you for filling people in on that. I'm going to talk a little bit about NEPA. How it applies to coalbed methane development on the federal lands and actually what happens with NEPA when we put it down on the ground.

But first off, I need to give you a little bit of history about NEPA. We've heard a lot about this over the last couple of days. In 1862, the Homestead Law was enacted with 160-acre patents, no mineral reservation. In 1909, the Homestead Law was enlarged, allowing 320-acre patents with coal reserved. In 1914, the United States began reserving oil and gas and other minerals. And, of course, the biggest was the Stockraising Homestead Act of 1916, when a lot of the West, especially in the Powder River Basin, was settled. This reserved all minerals. And then in 1920, the Mineral Leasing Act provided for exploration and development of coal, oil, and gas and other minerals by lease issuance.

What does that mean, then, when you put it on the ground? We've seen maps of the basin. This is actually the EIS study area we're looking at here. BLM manages about 10 percent of the surface of the 8 million acres we are looking at in the basin. So, yes, the private surface estate issue is a very big situation for us. What does that mean when we get to minerals? Development will occur while we're complying with NEPA. About 60 percent of the basin in the EIS area is federal mineral ownership. That's the ground you see here on the map. How does NEPA affect oil and gas development? Leasing and development of the mineral is a federal action. Therefore, NEPA would have to analyze federal actions. (maps on next page).





The leasing of the federal minerals was covered under our Resource Management Plan. We have a decision that says we can go ahead and lease. That was done in 1985, and some additional work was done just recently. There are some planning issues being covered in EIS, that's underway right now. Actual development on the federal minerals requires additional analysis, and this applies to public surface or private surface federal minerals. So, the Buffalo Field Office, since 1992, has done a number of umbrella documents to address overall coalbed methane development. We've done five rather large environmental assessments, and we're on our third environmental impact statement.

Just a couple of corrections on errors that I heard this morning. Don stated we are not permitting. Actually, we are not permitting for coalbed methane development except for drainage protection wells. We did an assessment in 2001 which allowed us to protect ourselves from the drainage that was occurring by the private and State development. For the air quality model, we actually are looking at 51,000 wells, not 39,000 wells. 12,000 wells are covered in the baseline.

NEPA is a disclosure document. We have to say what's going to happen. EAs and EISs are designed to develop mitigation stipulations, which are designed to protect the resources or minimize impacts. A site-specific EA is completed at the time of actual development or permitting. Mitigation stipulations are applied site-specifically as part of the EA. There are extensive lists of mitigation stipulations that are present in both the Wyodak EIS Record of Decision and the EIS draft released on oil and gas in the Powder River Basin. There are some notable stipulations which we have developed over time. This, again, is on federal minerals only. Operators are required to offer a water well mitigation agreement to all potentially affected surface owners. That means if your water well is affected, the company will step up and take care of it. It also applies to adjacent surface owners if they will be affected by the development.

Water Management Plans are required of all Plans of Development. An extensive network of groundwater monitoring wells are required to be installed by the industry, but BLM will actually do the monitoring on those wells. Because of relatively low impacts, two track roads have been used for most access needs. The use of corridors to handle roads, buried electrical distribution, gas lines, and water lines is required to the extent feasible to minimize the amount of surface disturbance that we see.

SOME NOTABLE MITIGATION STIPULATIONS WHICH HAVE BEEN DEVELOPED

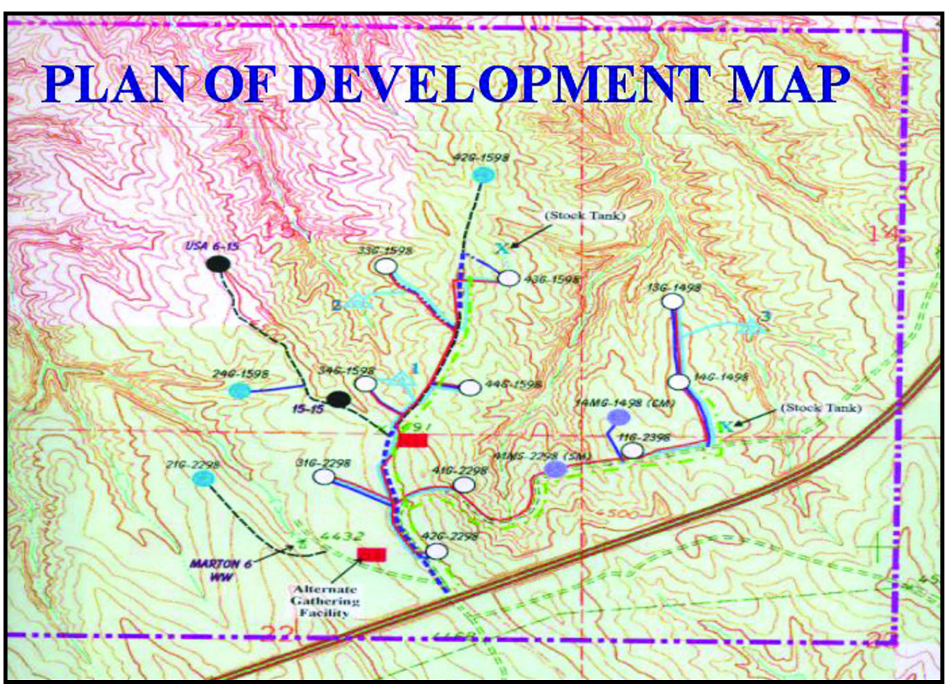
- Operators are required to offer a water well mitigation agreement to all potentially affected surface owners.
- Water management plans are required of all development plans.
- An extensive network of groundwater monitoring wells are required to be installed by industry.
- Because of relatively low impacts, two track roads were allowed for most access needs.
- The use of corridors to handle roads, buried electrical distribution, gas lines, and water lines is required to the extent feasible.

How is permitting handled? This is where the nuts and bolts come in. We develop the project based on what's out on the ground. That includes the topography, soils, vegetation, existing hydrologic systems, land ownership, existing land uses, and exiting improvements out there. This is not done in a vacuum.

What does the Federal Plan of Development consist of? We look at six major points for POD, and this is required of industry as part of the process. Our intent is to try and address cumulative impacts in a reasonable manner. You have to have an application for permit to drill. We look at plats surveys—master drilling plan, master surface use plan, water management plan, and a plan of development or a map showing what your plan of development is going to look like on the ground; how you are going to address the issues that occur on the ground. The master surface use plan covers a lot of area. We also want to look at the existing roads, proposed roads, location of existing wells, where your facilities are going to go, where you're going to get your water supply to drill your wells, what construction materials you're going to use. We look at how you're going to handle your waste disposal out there, and ancillary facilities. You need the well site layouts, how you're going to reclaim it, and surface ownership, as well as other information. The "other information" could include a water well agreement or certification; historical, cultural, and/or paleontological clearances; threatened or endangered species or special habitat; if you need a right-of-way; what stipulations exist on the lease that you have; what existing land uses or improvements are out there. And then the operator, the person who's actually going to develop has to certify that he has a legal right to be on that lease.

CBM PLAN OF DEVELOPMENT

- Applications for permit to drill or deepen (Form 3160-3) for each of up to 32 wells
- Well survey plats
- Master drilling plan
- Master surface use plan
- Water management plan



The water management plan is a another big part of the plan of development that we would require. We know water issues are becoming bigger concerns for everybody, and now we require plans as part of your plan of development. So we want to know what your type of discharge is going to be: Pits, surface, land application, whatever; where your discharge points are going to be; and we want to look at the whole watershed. If you're going to discharge to existing streams, you want to look upstream and downstream; who's above and below you; how much are you going to see coming down that drainage; how many wells are we going to see in the drainage; discharge rate; downstream concerns; water quality; monitoring and maintenance plan; and a map, again, of how your plan will lay on the land.

WATER MANAGEMENT PLANS

- Type of discharge: pits, surface, land application, etc.
- Discharge points (must include entire watershed)
- Reservoirs/containment pits
- Road crossings/culverts
- Erosion control measures
- Maximum number of wells
- Discharge rate
- Downstream concerns
- Water quality
- Monitoring and maintenance plan
- Legible map

BLM specialist reviews which occur on a plan of development are: Legal instruments examiner, geologist, engineer, wildlife biologist, archaeologist, hydrologist. The natural resource specialist is the person that actually puts that plan on the ground and lays it out with the company. Realty specialist, if you need a right-of-way to get to your lease, and then the rangeland management specialist if there is a grazing allotment.

Once we've got a complete submission, we do what's called an on-site. The objectives on that on-site are successful outcome for all parties involved; the company, the landowners, and the BLM. We want to develop environmentally sound projects, which minimize surface disturbance and water impacts out there, maintain land productivity, and maximize land reclamation. And our final objective is to comply with NEPA. Our whole goal is to have less surface disturbance, which equals less impact and less reclamation needs.

SURFACE USE PLAN (13-POINT)

- Existing roads
- Proposed roads
- Location of existing wells
- Location of existing and/or proposed facilities if well is productive
- Location and type of water supply
- Construction materials
- Methods for handling waste disposal
- Ancillary facilities
- Wellsite layout
- Plans for reclamation of the surface
- Surface ownership
- Other information
- Water well agreement/certification
- Historical, cultural, and/or paleontological resources
- Threatened or endangered species and/or special habitat
- Right-of-way needs
- Lease stipulations
- Existing land uses and improvements
- Lessees' or operators' representative and certification

Where do private surface owners fit in the picture? The BLM does a field review of all actions that we permit. The companies are urged to work with those private surface owners. We actually go out on the ground with them. We want the companies to have worked with that surface owner to develop a plan that the landowner is satisfied with. Once we schedule the on-site, that landowner is invited along with us. We address concerns that may exist out there, and we will attempt to accommodate the

WHAT HAPPENS AT AN ON-SITE?

OBJECTIVES

- Successful outcome for all parties involved
  - Company
  - Landowners
  - BLM
- Develop environmentally sound projects
  - Minimize surface disturbance
  - Minimize water impacts
  - Maintain land productivity
  - Maximize land reclamation
- Comply with NEPA

landowner's wishes to the extent that an environmentally sound project can be permitted.

On-site considerations: We look at the location of wells, where your facilities are going to go, pipelines and power routes, access roads, where your water discharge points are. We want them in a well-established drainage area. We use corridors for roads, pipelines, and power lines to minimize disturbance. The less cross-country you do, the more you stay in the corridor, the less disturbance you have, the less you're going to have to reclaim, less dust movement, etc.

WHERE DO PRIVATE SURFACE OWNERS FIT IN THE PICTURE?

- BLM does a field review of all actions we permit.
- The companies are urged to work with the surface owner prior to this field review to settle on an acceptable plan of action.
- The surface owner is invited to the on-site to insure their concerns are addressed. BLM will attempt to accommodate landowner's requests as long as an environmentally safe project can be permitted.

ON-SITE CONSIDERATIONS

- Locating wells
- Locating central gathering/metering facilities
- Locating pipeline and power routes
- Locating access roads
- Locating water discharge points
- Use of corridors for roads, pipelines, and power lines to minimize disturbance

What happens after the on-site? Mitigation stipulations determined at the on-site are applied. The maps are revised to reflect mitigation stipulation; plans are revised. Concurrence with the EIS is verified. A NEPA analysis is done on the plan of development, both what happened in the field and in the office is considered. And then finally, the decision record is issued which puts those stipulations into place.

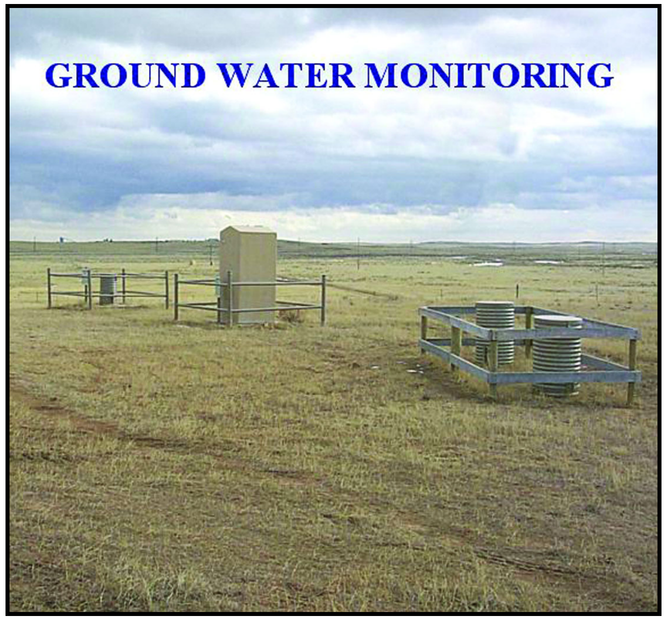
But we don't stop there. Some people think we approve a permit and walk away. That is not the case. There is a lot of work that goes on after a project is permitted. Compliance issues are handled by the engineering technicians; natural resource specialists look at what's going to happen on the surface with that project; and the hydrologists are making sure that water management plans are actually being followed. We're also monitoring what's going on with the groundwater and surface water, air quality, methane soil vapor, and land reclamation. The

WHAT HAPPENS AFTER THE ON-SITE?

- Mitigation determined at the on-site is applied
  - Maps revised
  - Plans revised
- Concurrence with EIS verified
- NEPA analysis documented in EA
- Decision and approval
  - Site-specific conditions and mitigation stipulations
  - Standard conditions and stipulations

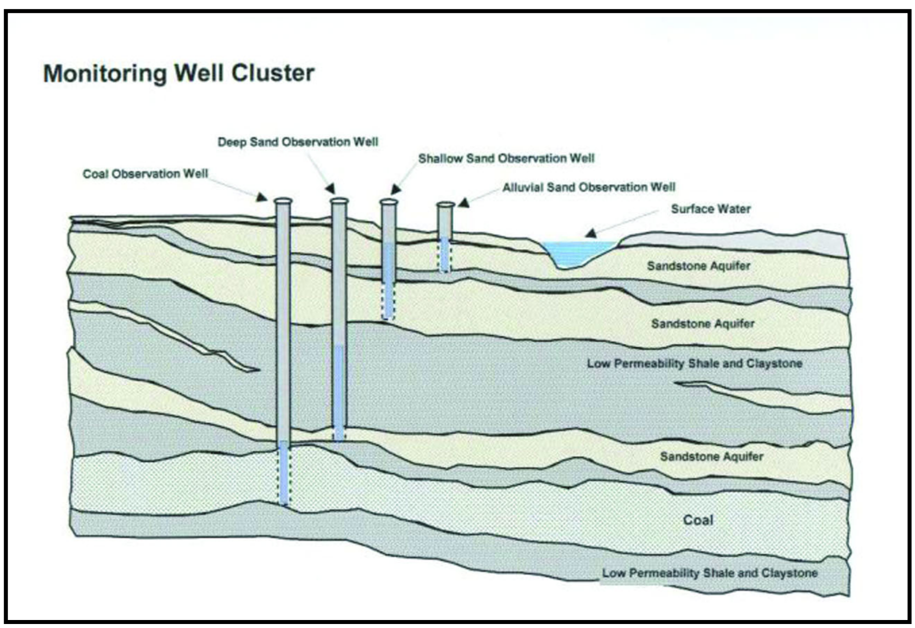
POST-APPROVAL INSPECTIONS AND MONITORING

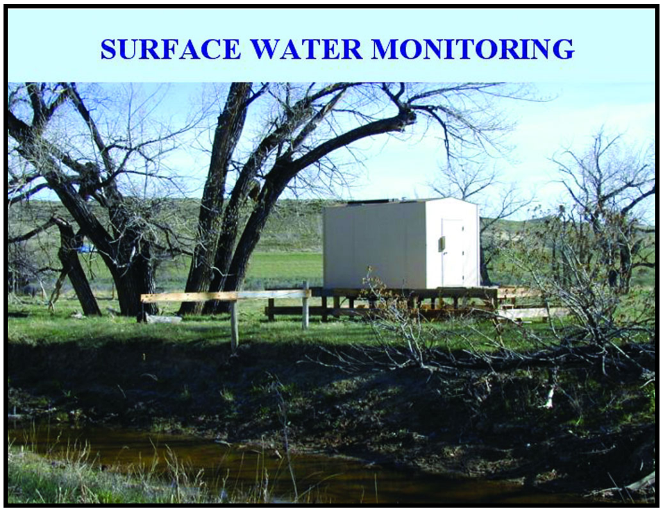
- Compliance issues are handled by:
  - Petroleum engineering technicians
  - Natural resource specialists
  - Hydrologists
- Monitoring
  - Groundwater
  - Surface water
  - Air quality
  - Methane soil vapor
  - Reclamation
- Surface owners are extra eyes for us
- "Cradle to grave"



landowners are extra eyes out there for us. We're looking at the whole situation from start to finish. We have established a groundwater monitoring network. We have about 38 locations scattered throughout the basin right now.

What you see is a series of wells. We actually started out with early concerns about what's going to happen to the coals and the sands above the coal at the first sites of wells we put in. Then, as time went on, we started putting in shallow wells, both for the aquifers and the sands below the aquifers. We were wanting to know what was happening with infiltrating water. Surface water monitoring: We've got gauging stations in place. There were concerns that were voiced, we were going to have all this amount of water coming down these drainages, so we're addressing these potential situations. And then to go along with, that is channel stability. We're out there looking at what's happening on the ground. Our whole intent is to minimize erosion. Most recently, we are having the concerns with containment pits or containment reservoirs or on-channel pits and the quality of





groundwater being put in these pits. We're now putting in a series of shallow infiltration wells as we move onto Federal minerals to look at speed and groundwater movement and water quality.

Other things we're doing: we've got three air quality monitoring stations in the basin along with ones the

mines have in place. We're adding visibility and dust capabilities at these stations. We have to address these issues that have recently come up. Then, over time, we've heard concerns about methane moving through the ground surface. We have also established a network of soil vapor monitoring sites.

So in summary, BLM works to ensure mitigation. We don't just walk away from a permit once it's permitted. We are looking at the mitigation and monitoring design to ensure a sound product to comply with our NEPA documents. When we put mitigation in place, it has to be done right, or our NEPA documents aren't valid. We take our responsibilities very seriously. We coordinate closely with the various state agencies. We are coordinating and cooperating with the state agencies on some of the monitoring that we do. We work closely with the landowners and we try to address concerns the public may have. But the bottom line is, we do not control the whole show out there. We are only about 60 percent of what's going on. Some people would like us to assume responsibility for everything. We can't. We don't have that big of an authority.

Thank you.

COALBED METHANE DEVELOPMENT IN THE INTERMOUNTAIN WEST: CONFERENCE PROCEEDINGS, SESSION 4, CONCLUDING COMMENTS

AYN SCHMIT, *Coalbed Methane Coordinator, U.S. EPA Region 8*

I am here representing the EPA here in Denver; and Region 8 covers the Dakotas, Montana, Wyoming, Utah, and Colorado. I'm the coalbed methane coordinator. I've come to the conclusion that one possible, and perhaps the most likely interpretation, is I'm supposed to know everything, enough to be dangerous. So that's sort of the premise I guess I can operate on here. What I wanted to do is take just a few minutes to talk about a few things that are happening now or they are upcoming in the very near future, not in any detail at all, but then to touch really briefly on them. And then I wanted to talk about the topic of the panel—coalbed methane.

EPA is working—in fact, I've been running back and forth, I mean that quite literally, between my office and . . . concerning the Wyoming and Montana BLM environmental impact statements. As many people have mentioned, those are out there now and the comment periods are coming to a close. Section 309 of the Clean Air Act obligates the EPA to evaluate and rate environmental impact statements done by Federal agencies so that we have sort of a unity in that regard. We were a cooperating agency on the Montana EIS as well. So that's something that will be coming to a close very shortly. We're also preparing a response to a petition that was submitted to the state of Wyoming's delegation. I think I actually saw one of my Wyoming's DEQ colleagues in the audience. So that's something that was submitted. It's been perhaps nine months or so, and so we have done a review of Wyoming's EIS routinely anyway as part of its oversight. So we've prepared a draft report on that program review, and we're working on response to that petition which, by the way, was filed by the Powder River Basin Resource Council. We're also working to finish an analysis of the economic feasibility of different waste water management treatments similar to some presented yesterday. And we're doing that because the EPA interprets that.

Oil and gas agreement limitation guidelines don't apply to coalbed methane development. So EPA's intention is to certainly expect to be in a permit writing role for tribal lands, and we expect to use that so-called best providential judgment analysis in that capacity, but we also hope it will be a useful piece of information for other people out there working on this issue. And then we've been working with the Northern Cheyenne tribe quite a bit lately in their development of numeric and sodium absorption ratio; and they are now, in fact, I think they just mailed their responses and comments. They had a public hearing, and they are now finishing the response to comments. And I would expect that they would take those proposed for adoption some time in the very near future.

On the upcoming front, Montana is in the process—and a number of these things have been alluded to in previous talks—but they're in the process of addressing salinity and SAR. And EPA, typically as developing standards, will enter with the State regarding our perceptions of the approvability of those proposed standards and, in fact, will be until they're approved.
So that process, as many of you know, is playing out. The standards they're looking at also in Wyoming, there is work group that has been convened by the DEQ to advise on possible approaches to SAR and salinity. We expect the tribe to enter into coalbed methane lease agreements in the near future. And again, as mentioned before, that will require both NEPA coverage as well as EPA permitting for water management.

Another thing I just wanted to mention briefly. Just based on a number of things, litigation, the extent of public concerns being raised about permitting, I think EPA is intending to look more closely at permits for coalbed methane discharges in our office site capacity. I think we feel like we've been doing that, to a greater or lesser degree, in the different states. And I think we're going to be asking some questions like, do those permits consistently protect numeric water quality standards, and so forth. I think I've actually lost a page of my talk.

I just wanted to mention those briefly. As far as kind of ideas about where this might go in the future and conclusions based on some of the observations people have made over the last day and a half, I really have to commend the law center for the diversity of the speakers they have. I did a quick tally on the program, and I counted six industry speakers, two from local government, two from state governments, two from federal agencies, six from community and environmental groups, one tribal person, and discovered that I was the lone representative of a federal regulatory agency. And I guess as a representative of an environmental regulatory agency, landscape is going to continue, I think, to be a major factor that shapes the future of coalbed methane development.

In that light, EPA's position has been from the beginning and remains that this resource can be developed in a manner that meets environmental standards. It's really a question of how the collective groups and individuals that are vested in this issue can work together to define that. That sort of brings me to the watershed approach. As Jim mentioned in the introduction, I come from the arena of management of large rivers, and in that arena, there are some very distinct parallels. The same stakeholders are involved and their positions are quite entrenched; but nevertheless, despite the concept of watershed management, this is something that is really beginning to occur elsewhere, and I don't yet see that happening here.

I think a couple of benefits of this, which I'm talking about an ecosystem management approach, which already determines a lot of different terms that get used for similar kind of philosophy, I think. This is one of the benefits to resolving disputes via litigation, and litigation is kind of a high-stakes game. It may not be what you went in thinking was the likely outcome. I think another benefit is that, although it sometimes seems like a lot of time upfront to set the wheels in motion, I think it often is able to go much more smoothly and quickly because of that upfront work. I just want to talk about elements that are common to successful watershed or community-based problem solving efforts. One is the notion of working within natural boundaries. That makes sense given the issue, rather than traditional administrative boundaries. If water is your concern, then working with people on a watershed basis is the only way, I think, that makes sense to defining and solving problems. I think another environmental element is that all of the interests are represented and they're at the table on an equal footing. And the more contention, the more essential it is that that be the case.

I think another ingredient of this type of approach is the notion of goals or outcomes. And probably one that everybody's had a hand in is developing. They might be water quality standards or they might be goals that are derived from those standards. Another element I want to talk about with this is to approve scientific information in a cooperative and transparent way so that you can avoid the potential for very dueling science and stretch what are scarce monitoring resources. And I think that in order for us to be able to make science-based decisions, there's a need for a pretty rapid mobilization around integrating the data that's already out there and developing new data. I think that's something that's best done by people sitting around the table together. You have to be committed to working together for the long haul.

These are complicated problems, and there are a lot of relationship and trust issues. It's not going to happen overnight. So I think there has to be a commitment to working together in a very long-term kind of way. And that commitment has to be understood for something like this to be successful. I think there are some hopeful signs and some initial steps, and maybe the elements of a model are there that we can look at. I think these meetings that have occurred between the two states and the tribes to talk about transboundary issues was hopeful. I think the fact that the state of Montana—this was something I was going to mention earlier—development of TMDLs for the Powder River Basin streams is also a good thing. And I think the TMDL process had the kind of elements of watershed approaches. I think models like the Montana technical working group where you have people that are working on technical issues, coming together on a regular basis so everybody knows and can keep each other updated are great. Technical work is also a good model.

I went to a community meeting down in the Raton Basin a couple of weeks ago that was convened by the CSU cooperative extension that I thought was a really constructive form for people to get information. What's missing is an opportunity for people to interact; it tends to be more talking heads. If you're lucky, there's time for questions and answers, but what I think is needed here is going beyond that and building some forums for real interaction. And it probably makes sense to do that within the individual basins.

Thank you.

Michael Reisner, *Northern Plains Resource Council, Montana*

I work for Northern Plains Resource Council. We are a grassroots organization of conservationists, farmers, and ranchers located in eastern Montana. The last couple of years, our group has come full circle. We started 30 years ago in the coal fights in the 1970s, with the Reclamation and Control Act, which industry said would put them out of business. As far as I know, they're still doing fine. Now, the coalbed methane companies have come to the Powder River Basin. Before talking about where we need to go, I want to talk about where we're at with coalbed methane in Montana. We only have one producing field in Montana. And production is at a 250-well field, tapping federal and private minerals. Because of the Board of Oil and Gas in Montana, we have a moratorium on additional producing wells until EIS is complete.

As we heard yesterday, or earlier today, there are no discharges into the river. One of the problems in Montana, as we heard yesterday, is the water quality of the discharges gets worse as you go from the southwest part of the basin to the northwest part of the basin. For example, the average SAR is 39, and the Tongue River's baseline water quality at the border is somewhere less than one. Contrary to what we heard this morning, there are discharges into the Tongue River. The Fidelity Project began in approximately 1989, where water was discharged into the Tongue River and it's contributing without a permit under the Clean Water Act. When they finally got a permit, they violated that permit 13 separate times in 2000 and 2001. And in addition, in 2001, they discharged over 1,000 gallons of water.

Last summer during the irrigation season, the SAR on the Tongue River immediately below the discharges exceeded three. Above their discharges, it was less than one. So we have discharges from 250 wells. And just to remind everyone that BLM's estimate for the Powder River Basin is 77,000 wells by 2010, 26,000 in Montana, and approximately 51,000 in Wyoming. For this project in November of 2000, approximately 18 months ago, the BLM determined that it deeded on EIS for this project. Despite the fact that some of these wells have been drilled, they have not produced a single NEPA document for this project.

So basically, where do we want to go from here? The first thing we need to do is to address the split estate issue, which we've heard a lot about during the past couple of days. We need to make sure that surface owners above these Federal minerals are protected and to ensure coalbed methane development does not destroy their farm, their ranches, and their way of life. The Powder River Basin is incredible. The BLM owns approximately 10 percent of the surface, but much more of the mineral resources depending on the area you're in. One would think that when the BLM controlled this amount of resourse, based on basic rules of fairness and fair play, they would have made sure to include these farmers and ranchers to participate in those decisions before leasing resources under their farms and ranches. The BLM hasn't done this. They have leased over 380,000 acres in 370-some separate leases with no landowner participation. The BLM isn't giving them the chance to participate and without completing an EIS prior to leasing. This behavior is not only illegal, it's unfair. And another wake up call to industry, it's exacerbated by the split estate problem.

So basically, what do we need to do to remedy this? We need BLM to step up to the plate and give lip service to the four Cs we heard yesterday, and put their money where their mouth is. The BLM needs to develop new lease stipulations, development, and it needs to review and update its existing lease stipulations, most of which are about 15 years old, and modify them, if needed. It needs to even the playing field with public participation, including the surface owners, on the controversial parts. It needs to retroactively put these stipulations on the leases they've issued to reduce the surface mineral/owner tensions, which are only going to build as development moves north in the basin.

The second thing we need to do is to address the damage caused by discharges of untreated waters to the surface waters. Yesterday we heard that . . . percent of the basin is discharged untreated, either to the surface water, ephemeral streams, or into unlined pits which flow north into Montana. So we get those impacts as well. The recently released EISs says as a result of Wyoming discharges the water will be rendered unsuitable for irrigation. . . . It is both unfair and illegal to pass these costs onto downstream water users. The solutions to these are, one, existing and anticipated beneficial uses, and two, soils in the basin. Basin soils are moderate to high susceptibility to salt problems, and they need to protect the most sensitive crops in the watersheds. And third, we need to allocate to meet the TMDLs and divide it between the states of Montana, Wyoming, the Crow Indian Tribe, and the Cheyenne Indian agreement. Fourth, we need to accomplish a reasonable monitoring plan, and it needs to be funded by industry, and we need to start collecting the data now; little, if any, data has been collected for any resource. Finally, discharges should be authorized in an individual MPDS permit not a general discharge permit.

We need to minimize surface impacts. Right now we're talking about 25,000 miles of new road and 47,000 miles of new pipelines in the Powder River Basin. These impacts, among others, will disrupt wildlife populations and result in increased erosion. The solutions to these are: first, where companies are required to share pipelines, where possible, to minimize surface impacts; second...we need to require adequate funding for disturbed lands. That's what the Montana Constitution says. It needs to be guaranteed to restore all the roads, all the well padding and present some unique reclamation concerns and mitigation when we're done. We should not be left with the clean-up bill when development disappears from the basin....The Montana EIS admits that these things and wells are going to be impacted. It wouldn't for some of these resources in heavily impacted areas. Some solutions are to, first, phase in development instead of all at once—that way it would be as development proceeds; second, we need a registered inventory of the groundwater resources and a regional to get that in place today and start collecting baseline data before development proceeds. We need to have water bonding similar to the Surface Reclamation Control Act. And the final bond isn't leased until the aquifers recover. And if the spring or well is impacted, industry must not only replace that resource, but it's got to cover the increased cost of maintaining the increased cost until the aquifer is covered . . .

In Montana, there's an EIS looking at the environmental impacts of 26,000 wells. In Wyoming, the BLM is looking at the impacts of 51,000 wells, and the Federal is right now looking at the proposed grass lands, which is 40 miles long, to service the northern portion of the basin in a totally separate environmental impact statement. The contradictions raised by the BLM . . . when you look at the EISs is fairly staggering. A few examples are, in terms of the produced water by each well, Montana says 2.5 gallons per minute, Wyoming says 1.7 per minute. In terms of the life of the well, Montana says 10 years, Wyoming says 7 years. . . . Coalbed methane development and the geology of the basin does not change magically at the border. The solution is . . . complete EISs for the basin, looking at the EISs of the 77 wells, including connected actions, and they need to address the impacts from projects by the Federal and state agencies.

Thanks.

MARK PEARSON, *San Juan Citizens Alliance*

My presentation doesn't include any graphs, charts, figures, cartoons, tables, or equations; and it doesn't have any photos of drill ranges or mud pits or resting barrels or soil. It only has pictures of places, and it's my place. It's the place of the San Juan Basin, San Juan National Forest. [35mm slides shown at the conference are not available here]. And I think what it highlights is that the discussions we've had the last couple of days come down to a clash of values. And those of us who are residents of the places where the development is targeted value our place. And whether their place is a 40,000 acre roadless area on the forest or a 1,000 acre ranch in the Powder River Basin or a retirement home in LaPlata County, when those places are invaded by industrial development, people have a very strong reaction and it creates a lot of conflicts. All of these pictures you'll see that I'm showing are the before pictures. Industry plans call for 300 new coalbed methane wells and associated roads and compressor stations and injection wells and pipelines and power lines laid on this landscape here, which is a significantly different landscape than perhaps a lot of what we're talking about in the San Juan Basin and in the Powder River Basin.

In the San Juan Basin, we already have 30,000 wells that have been drilled. There's another 12,000 proposed for our basin and the mountains here are the northern fringe of our basin. The 300-odd wells, or the 150 that would actually be in the roadless areas, are a pretty small percentage in this heavily developed basin, and that's where our values will clash, in whether this last bit of the basin needs to be as thoroughly turned into a central industrialized zone as the rest of the basin has. The flagging here marks a proposed well site in the HD mountains. It would clearly convert this grove of Ponderosa pine into a two-and-a-half-acre gravel pad. And those of us who place a high value on the last few remaining big old trees that are left in the San Juan National Forest, would not think that converting this into a gas well is a good idea. The HDs are significant because they're the last old-growth Ponderosa pines left in the San Juans. Most of the San Juans was heavily logged a century ago and all the big trees were taken out because they were accessible and low.

The HDs were essentially protected because they were rugged and inaccessible. A lot of the figures and charts that we've seen today have talked about production of wells or trillions of cubic feet of gas or the value of the tax credits that are generated from this activity or gallons of water that are produced, but very few of them take into account the sort of ecological or ecosystem values that a lot of us have. This is Ignacio Creek. It's the most pristine low elevation watershed in the San Juan National Forest. It's a proposed research area. There's also a proposal for a well pad every 160 acres all the way up this 8- or 10-mile long watershed. Those are two different visions for the future of this place.

How we make the decisions about which future we want to pick will say a lot about us in terms of the places we live; and I think a lot of this view, as someone who lived in Grand Junction through "Black Monday," when Exxon left one day and laid off 2,500 people in the morning when they thought things weren't going to pan out, I don't think we have a lot of faith that the industry is going to build our communities and be long-term community players. They're here for one reason: to extract a resource or to extract a tax credit and then leave.

Now, I think the only solution that we see is to level the playing field. And that is to have decisions about development made in a fashion that allows everyone's interests to be equally accommodated. I think the residents of the basin feel that we're dealing with a very powerful industry too. I think the industry probably feels the playing field is tilted in their favor right now.

The pressure is on the agencies to process permits faster. So local resident control, in the areas in which we're able to take control, and in our part of the world, that's with our LaPlata County Commissioners. And you heard from Commissioner Joswick about the regulations to protect the interests, the health, the safety, and the welfare of the residents of the county, because our local elected officials are most concerned about their constituents and less interested in what the industry, which is based elsewhere, thinks about in terms of protecting the place in which we live. And there are real impacts to real people. I mean, if you're listening to a 3,000 horsepower compressor 24 hours a day, 7 days a week, 365 days a year, it's a big impact; and people want those sort of issues dealt with; and county commissioners are willing to deal with those kinds of issues. This is still in Ignacio Creek. That is an old-growth Ponderosa pine. The Forest Service had never thoroughly inventoried old-growth, and that is one of the issues that will have to be analyzed in the EIS that's coming up.

For those of us who have had to deal with industry, we've chosen to fight those fights at the local level and with the Federal agencies, like the Forest Service, where we think we have a more level playing field and we get a fair shake. That's why, for example, LaPlata County has adopted regulations. Las Animas County has some regulations; I mean, every county involved in the coalbed methane resources in our state of Colorado will be adopting regulations, and they'll probably be different regulations in every place. The industry doesn't like to have to deal with those kind of diversity of regulations, but since that is the place where we have the interest, we will attempt to get satisfaction. But even with that, I mean, every week we have people call our organization that have a concern about the industry, and it invariably relates to what I would call an abuse of power.

And you heard some of that when Nancy Sullivan spoke this morning about dealing with the companies on their ranch. But companies just appear and put in pipelines and scrape land and obtain discharge permits proposing, as we just had in LaPlata County, proposing 576,000 gallons a day of water into a ditch without actually knowing where the ditch went and finding out that actually that's also the water supply for a rural subdivision. There's a company operating right now in Archuleta County without any appropriate county permits, despite State Court decisions to the contrary. So they simply ignore their need to obtain county permits. We have another company that bought leases in the HD Mountains that do not allow for any surface occupancy in their entirety. Those companies are just presuming that those stipulations will waived and they'll just do whatever they please.

In our county, we routinely get sued by the industry. We're sued by the oil and gas association. We're sued by State of Colorado over our authority to regulate surface impacts under the county's land use authorities. Huber just sued our county a couple of weeks ago because they want to back out of an agreement on a compressor in the middle of a rural subdivision. The individual citizens who have spoken out have had lawsuits personally filed against them by companies in order to intimidate and silence them. We have a really interesting situation in our county right now in that La Plata County will probably institute a ban on burning in the next two weeks because of the drought. There was a forest fire that was started last year by a coalbed methane operation on a road south of Durango. We've tried to get the BLM's report on that, but they have thus far turned us down. But in two weeks, our county will ban burning of irrigation ditches by ranchers, but they won't do anything to prohibit gas wells from flaring in the middle of the forest.

Our county doesn't have any ability to regulate that in terms of a fire and protecting against forest fires. Those are the sort of above-the-law situations that really drive people crazy in our part of the world. So unless we find some way that we can level the playing field, this sort of conflict and strife is only going to increase. And I guess I kind of view it as both open and guerilla regulatory warfare. And the industry has found out that we're going to make Federal agencies do as thorough a job as they can, we're going to make it take as long as possible, make it cost as much as it can, and hope to achieve some satisfaction in that fashion. And that is going to increase unless we can figure out a better way to do it. And a better way to do that is for industry to voluntarily give up some of the power that they possess.

I mean, that is perhaps foregoing some level of development in some places. It means accommodating public interest, agreeing to comply with the regulations that apply to every other developer. For example, Wal-mart has to go through a county permitting process and you deal with issues about landscaping and visual impacts, and that's the same regulations that our county has adopted to address traffic and visual impacts from the oil and gas company as well. And it means, you know, more public scrutiny of what the companies are doing. It may mean more public hearings, and it may mean that things take a slight bit longer. But I think in the long run that the companies will get acceptance and less antagonism from the affected residents. So that's it. These are the HD Mountains, and this is a place that will obviously be a focal point of CBM development and national energy in the coming year. These are the sorts of places that inspire us, and you can be sure they're places that are going to generate a lot of scrutiny and public concern.

Thanks.

PETER DEA, *President and CEO, Western Gas Resources*

Good afternoon and thank you, for having me and for holding this event. I thought for my ten minutes I'd take a more macroview of things. Driving down from Evergreen this morning from work, I was trying to contemplate who the audience here would be and going through the list in my mind that Jim Martin sent me. Usually my audience is oil and gas companies, investment banks, and analysts and institutional funds. But then it struck me, I probably have more in common with all of you on a personal lifestyle basis than my typical audience. I like to go kayaking, like Jim Martin, hiking, mountain biking, or skiing. Most of my peers like to golf and I don't golf, so I do not see them on the weekends.

When Jim had first invited me to speak with all of you today, I was asking him about the William Hewlett

Foundation. And I read the issue paper, which is presented by the Rand Corporation, prepared on behalf of the Hewlett Foundation. It's called the new approach, the assessing of gas and oil resources in the intermountain west. It's an interesting perspective.

What I concluded they were saying is that they would prefer there be no gas drilling in the U.S. And largely due to the questions that they had on the economic viability of gas drilling based on their interpretations and assumptions, as well as their questions on the environmental viability of natural gas. Many of their assumptions are erroneous or based on outdated data. And they ignore that Americans have chosen natural gas as the fuel of choice since it is the most environmentally friendly fuel.

Well, as a natural gas guy, you can imagine my reaction. I was put back a bit. I decided to think on it, and I said, maybe this isn't such a bad idea after all. After all, I like to camp in the great outdoors, and if we do halt all the gas drilling in the West, then a lot of us are going to camp out, and I'll volunteer. And the reason for that is, if we have no more gas drilling in the U.S, then many of us would not be able to enjoy the lifestyle that Americans have come to enjoy, including myself. I've spent two full summers—when I was too old to be doing this—camping out, working to put myself through college. I spent two years in Alaska doing field work. I followed that with a summer in Montana doing my thesis on environmental geology. I've kayaked the Grand Canyon twice and numerous other rivers camping weeks at a time. I've also spent well over 200 days on various ski and climbing expeditions, particularly in the arctic, living out of tents. I've also climbed Mt. McKinley, Mt. Logan, and spent 40 days each in Labrador and ANWR camping, while skiing or hiking. I skied 20 days through Yellowstone Park and several other trips.

So, overall, camping out won't be a problem, at least for me and maybe a few of us in this room. But it will be a problem for most people. They really value their lifestyle, and have grown to be very dependent on natural gas and the heat, air conditioning, electricity, and convenience it provides. We in the natural gas industry are merely trying to provide more resources to meet the growing demand for America. So let me put the conclusions of the issue paper in context with the alternatives to natural gas. Taking the conclusions to the extreme: no more gas drilling, no more gas supply for the U.S.; what do we need to do? Well, it's simple—sort of. We need more coal plants, but that means more air pollution. My fellow panelists, Ayn, Mike and Mark, want clean air. And I agree. We could import more oil, but there are questions on domestic security with that. We also have questions and threats on oil spills and wars. The worst environmental disaster ever was the fires of Kuwait, I would maintain.

We can add more nuclear plants, but who wants the nuclear waste in their backyard? Not many hands would go up anywhere in the U.S. Or we could build more dams, on many free flowing rivers.

I did some rough calculations from some energy equivalent data. We can correct the energy needed from the alternatives to clean burning natural gas, assuming we stop providing and drilling for natural gas in the U.S., as the Hewlett Foundation Issue Paper desires. With no natural gas supply, we would have to double our coal consumption. Or we would have to double our oil imports. Or we would have to triple our nuclear plant capacity. Or we would have to build more dams on countless rivers. I haven't quantified the specific number of new dams to replace natural gas. I can tell you this from some energy equivalence data that 300 average gas wells save the next Grand Canyon Dam, when looking at the energy provided over a 20-year period.

So, overall, just in summary, I think it's pretty clear that Americans enjoy and value their lifestyle. We should conserve a whole lot more than we do. I personally think it's a crime we did not pass the CAFE standards a couple of weeks ago. I believe the energy policy in the U.S. should focus more on conservation. But the reality is, as hard as it is to believe, Americans just don't conserve as much as we should. If I asked all of you who uses a personal computer, I bet everybody's hands would go up. Some of you have two or three between your office or at your home. PC's and the internet consume 10 to 13 percent of the electrical demand in the U.S.

The bottom line is: We are using more and more electricity. That electricity is coming, more and more, from clean burning natural gas.

Overall, what Americans want is a clean burning, domestic energy source, one that's abundant and reliable and relatively inexpensive. Natural gas has to be the clean burning fuel of choice. I think we need to stand back and decide whether we should drill or not drill for natural gas, including coalbed methane, and take a look at the broader picture. We need to contemplate where we will get our energy needs if we stop drilling for natural gas. The abundant available alternative sources, such as coal oil, nuclear and hydro, are considerably less environmentally friendly than natural gas. There is good reason America has chosen natural gas as the clean burning fuel of choice for America.

Thank you.

MARK SEXTON, *Chairman, President, and CEO, Evergreen Corporation*

Peter gave everybody, I think, a different energy industry perspective, and I'd like to do the same. What I would like to do is speak to half the people in this room, because the other half has made up their minds. As I look over this room and see who's here, there's plenty of people from groups that talk about responsible development. I see producers here who want to talk about responsible development, but pretty much, they want to drill wells. And they've pretty much made up their minds, and very little we say will change their minds or what anyone else has said. But I applaud Peter for offering the human perspective. The model for doing business is just as offensive to independent natural gas producers in Colorado and in the Rockies here. It's just as offensive to us in the business as it is to you who aren't in the business. And every once in a while I run into one of those classic sort of old style, big cigar chomping, oil and gas guys from Texas that wants to drill the biggest well that's ever been drilled. And believe it or not, I probably find them just about as offensive as you do.

But Peter offered a different perspective. . . . And as Peter said, on a lifestyle issue he and I have different views than other people in industry. Who are those people in industry? I mean, who are those people that run Western Gas Resources? They're all very productive companies; all companies, by the way, that are committed to trying to do it right; and all companies that win awards for their willingness to try to do it right. I heard some presentations that I thought, just don't have the facts right. And what I found troubling, in addition to the fact that I'd like to have policy discussions, I'd like to know what the facts are. How are we supposed to come together on what policies are or what we're supposed to do?

The things I heard attributed to coalbed methane simply aren't true. In my world, coalbed methane is an asset. In my world, the water is an asset. Maybe these are some issues from basin to basin, and there's certainly differences in what we do with the water and what we can do with water, but in my world . . . we want to finally find a way to appreciate that water for the benefit of the community, and we want to work with them to do that. We didn't even want to surface discharge water when he we first started. We had very elaborate plans to put the water back in the ground, which would have been just fine. But instead, ranchers came to us and said, "You know, that water is pretty good water, isn't it?" And I said, "It tastes a little funny, so it's not potable; it's pretty good for an upset stomach, but define good." And they said, "Well, I think that water's good." And I said, "It's better than the water you've been drinking and your father's been drinking." So the ranchers said, "Well, I want to use that for irrigation." So I said, "Well, I'm sorry it won't work, but its very good for wildlife and animals and cattle." And so the ranches wanted the water in a stock pond.

We say, well, okay, we'll do that but we need to get proper permits. We have permits with the Oil and Gas Commission and the Department of Health. And the horror story that developed behind that is: there is no good deed that goes unpunished in these matters, and that's really the way it feels. We gave the water to the ranchers, that's what they wanted. Then, they came back in a Clean Water Act lawsuit where the whole issue appeared to boil down to the fact that nowhere in Colorado had the produced water from an oil or gas operation been so clear as to allow beneficial uses at the surface. It never has been a waste by-product or technically defined as a pollutant, and yet those ranchers are saying, "I want that water," so we gave it to them. We got permits, and we got in trouble for it. And we finally got resolution, not by getting people to agree with what are and are not, but rules by the Department of Health, the Oil and Gas Commission, the EPA, and they still disagreed. Why? Because we've gone through with the Army Corps of Engineers, Colorado Department of

Health, the EPA, and the Oil and Gas Commission and said, what is it, water to the State. They all disagreed because it's interpretive.

So different people interpret it different ways. That's huge when you're trying to do something for someone and one of the agencies comes in and says, "No, actually I wanted to put that water back in the ground, but the ranchers want it." What do you mean? We have recorded discharges from that pond. Well, that's because there are no discharges from the pond, but the pond itself is in waters of the state. It is waters of the state. Have you looked around? Wetland is just a concept down here, what are you talking about. And we said, waters of the state; how is this waters of the state? Finally, we came out with a very precise but technical definition, and we agreed to use it. Turned out we could have satisfied the whole thing by reporting discharges into the pond. Nobody ever said this was a problem with the quality of the water. And those are the sort of things we're dealing with.

So from a CEO's perspective, first of all, I agree with Peter; I don't want to see any more dams. I love to kayak. I've climbed over half the 14,000-foot peaks here. As Peter said, I climbed Mount McKinley. I moved from Alaska to Denver. And I never really thought I'd be in the energy business, but I wanted to go to Alaska. I wanted to kayak rivers there. I wanted to fish. I wanted to climb mountains. Now, I come to Colorado and say, thank God for people with a different attitude about this. But you know what? From what I can tell, not only does every good deed go unpunished, but there's no incentive to be the good guy, because when we sit down and talk, we can't even agree on innocent pacts.

I looked at presentations yesterday that talk about spacing. I'm not aware of coalbed methane wells with hydrogen sulfide. Water quality does change. I hear about toxins. I've been accused of spreading toxic carcinogens throughout Las Animas County, that was the so-called produced water. There have been no toxins for two years. I've heard that drilling takes weeks. Not in the world I live in. Most coalbed methane wells are drilled, the deepest ones you frac them in a day or two, and then you're out again. And as Peter said, what do you want? You have to have the energy. I agree with Peter. We need more conservation. Conservation should be a very important part of this country's energy policy. But guess what? The production's going to grow to meet demand in this country. That's going to 30 trillion cubic feet, regardless of how much conservation, this country requires it because people get more and more PCs, people get more phone lines. . . . Demand is going up and will continue to go up, despite our best efforts at conservation.

What do you want? Do you want more coal plants? I don't. Do you want more dams? I don't. Do you want more nuclear plants? I don't. So whatever industry does, 100 percent of our production is gas, coalbed methane gas, natural gas. There are three major benefits to this: it produces clean gas, clean water, and jobs that weren't there before. The economic benefit to the communities are in the tens of millions of dollars a year. What could we replace this with? A natural gas well to supply 750,000 over a 10-year period requires an area of about half an acre while it's drilled, and a lot smaller since it's been drilled. That's a natural gas well. You get that same kind of power out of wind, which only requires 80 acres. Who wants to be near the wind farm?

Solar? Great idea, but the same set of problems. You need a football field type of right-of-way. You want coal?... Coal technology has been promised. It's right around the corner. Unfortunately, it's three years ago. It's always been right around the corner. I really believe it will exist, and when it does, this country's in great shape because we've got more coal on most seams. We have the Saudi Arabia of coal in the Powder River Basin and places like it. But until that happens, conservation and natural gas is the fuel of the future. And coalbed methane being particularly good, well there's conflicts, of course there's conflicts. And bad manners are always bad manners, regardless of the operation. You have a bad operator, regardless of the regulations and operations, and I'm sorry that there are a few.

I was also the President of the Colorado Oil and Gas Association last year. Peter was the President last year. And the people we deal with don't have the old attitudes; development is possible. If you look at Evergreen's mission statement in our annual reports, if you're going to invest in Evergreen as a shareholder, we're going to make a lot of money; that's the first thing investors want to know. But oh, by the way, we also use environmentally responsible development. Community enrichment and integrity in our business practice is our way, and we believe that solutions are possible, solution.... And when I hear the distortions that are going on, I'm sad on two levels. One is, they don't live in the same world I live in, so things are really a problem; but the second is, how can we sit down and talk about meaningful compromise or meaningful solutions? We were in a litigation with the Las Alamos county commissioners, we initiated it. Both parties wished they had gotten more. So I guess, like all compromises, it must not be good if neither party is satisfied with it. We're going to try to make it worth our while on both sides, and we have that commitment.

What does it feel like to be an energy executive? You send people out to get their jobs done. These are all people that work for a living, have a family. If you had asked me to define myself as a person, Peter says I'm a kayaker; I am; I'm a mountain climber. First, I'm a father; second, I'm a husband. I'm also a thinker. There's a lot of things I want to do. I want to do hiking and climbing, but I do as time allows. So as somebody who cares about the environment,..., who wants to see people do it right, I'm offended by misstatements because as long as the facts aren't right, these concerns will always be valid. If we never agree on what we're supposed to do it about it, these conversations are appropriate, they're necessary. But the truth is the truth; the facts are the facts. Let's have some integrity in the statements we're going to make in the Q and A here.

I'll tell you what it looks like from our perspective. Our people are out there trying to do the best job he can or she is. In fact, our operations manager in the Raton Basin is a Colorado School of Mines graduate engineer, a congresswoman who was a secretary and went back to school. A single mother went back to school, put herself through school, and now she's an operations manager over 160 guys in the Raton Basin.
I said, are there days you feel like a mom? And she said, yes. And you know, that's who we are. These energy companies not some...that doesn't give a damn about you. Well, some are, but most aren't. And there are a few players that are a problem. There are 600 play operators in Colorado; maybe 1 percent are bad actors. You all probably feel you have them all in your backyard.

I'll tell you, there are very few choices. Natural gas is the coal of the future. Colorado and the Rockies are blessed with an abundance of resources, that includes coalbed methane; the by-product of that, water, is valuable. We can find ways to use it. Where we're producing five, six million gallons a day, some goes to the rancher and their stock ponds or we reinject it. Five, six million gallons a day. My God, why are we wasting all that water? And look what it's doing to the environment is the equivalent of about 0.3 inches of rainfall in an area that gets about 10 inches of rain fall. That water goes to the . . . River, although the environmental standards we agreed to assume all of it gets to the . . . River on its lowest flow day . . . You know, if 5 percent gets in, I'd be surprised, and yet that's a standard we agreed to. We're comfortable with it. We're willing to live with it. And it's a good thing for that area.

But there are problems with this water, let's put it in perspective. Let's talk perspective. Let's talk the big picture. Let's have some integrity in this discussion because we're not going away. I heard comments about, you know, the surface estate is co-dominant with the mineral estate. The law says that's not true. But let's assume for a minute it is, that he can't develop it on your land, he has to go somewhere else. If you cooperate with him, you'll probably get a cattle guard, a road, a fixed up driveway, and a better fence. You can tell him you don't want it, but he'll probably put it where you do want it if you give him a chance. But he's trying to obey the Oil and Gas Commission, and they're telling him, get the well drilled and do it the right way, and he just wants to get that well drilled. And if the landowner refuses to talk to him, refuses to work with him, if the county had put up rules that don't make sense for the geology, you're going to see a lot of animosity both ways. It's not needed. They're just people; they're fathers, mothers, they're people just trying to get their job done, and they think they're doing the right thing.

So let's start the discussions by agreeing on the facts, by agreeing that we're all people. And I wish conservation would get us to our goals, but it doesn't. And if you want to see that production, it's going to come, it will come; it's coal, it's a natural gas, and it's going to stay there for the foreseeable future. So people that have natural gas and coalbed methane could be doubly blessed. Some rules have developed. There is some animosity on this issue. LaPlata County appears to have the most animosity with the industry. I just ask everybody to please...try to work together and find a way to work together, but please, let's get some integrity in the conversations.

Thank you very much.