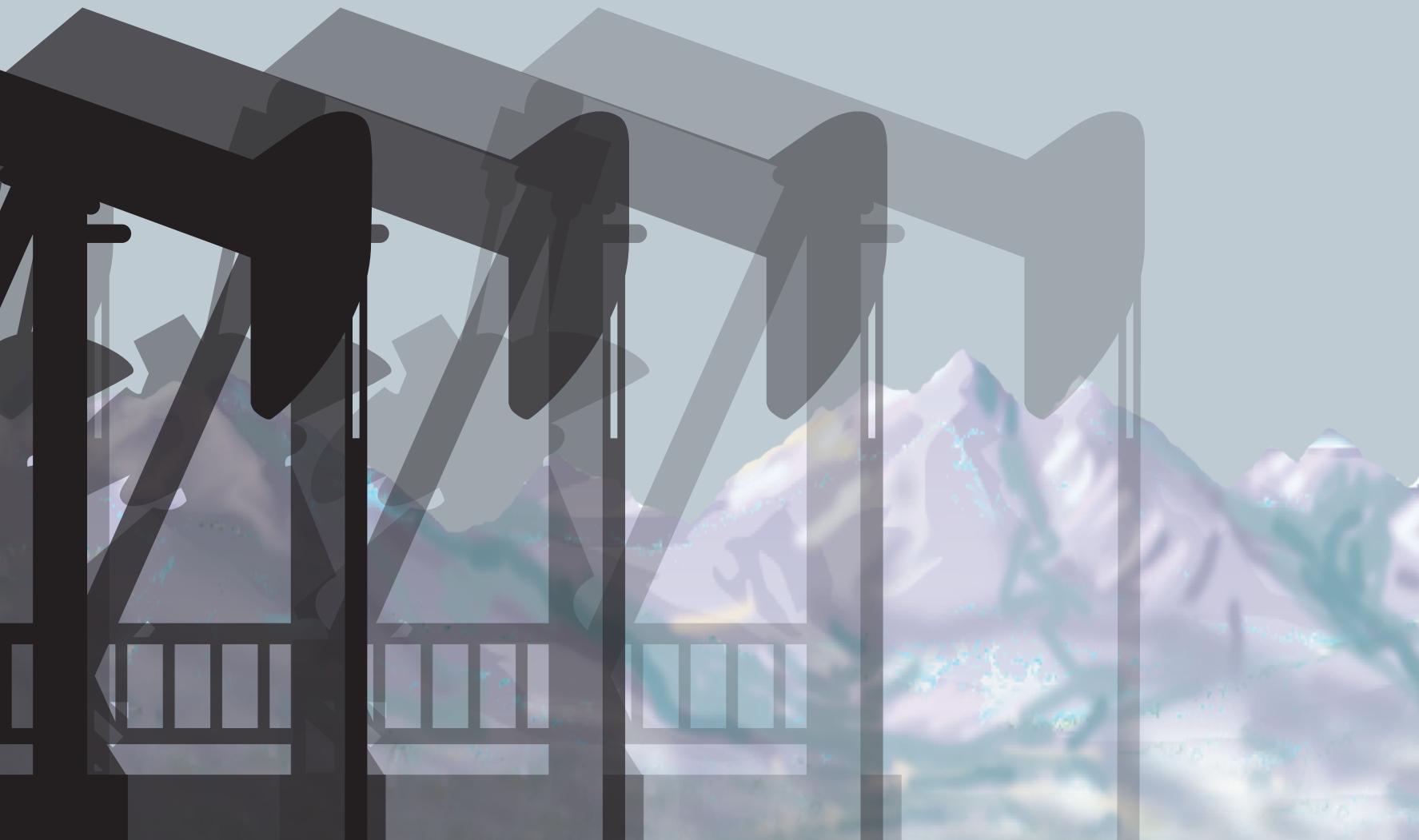
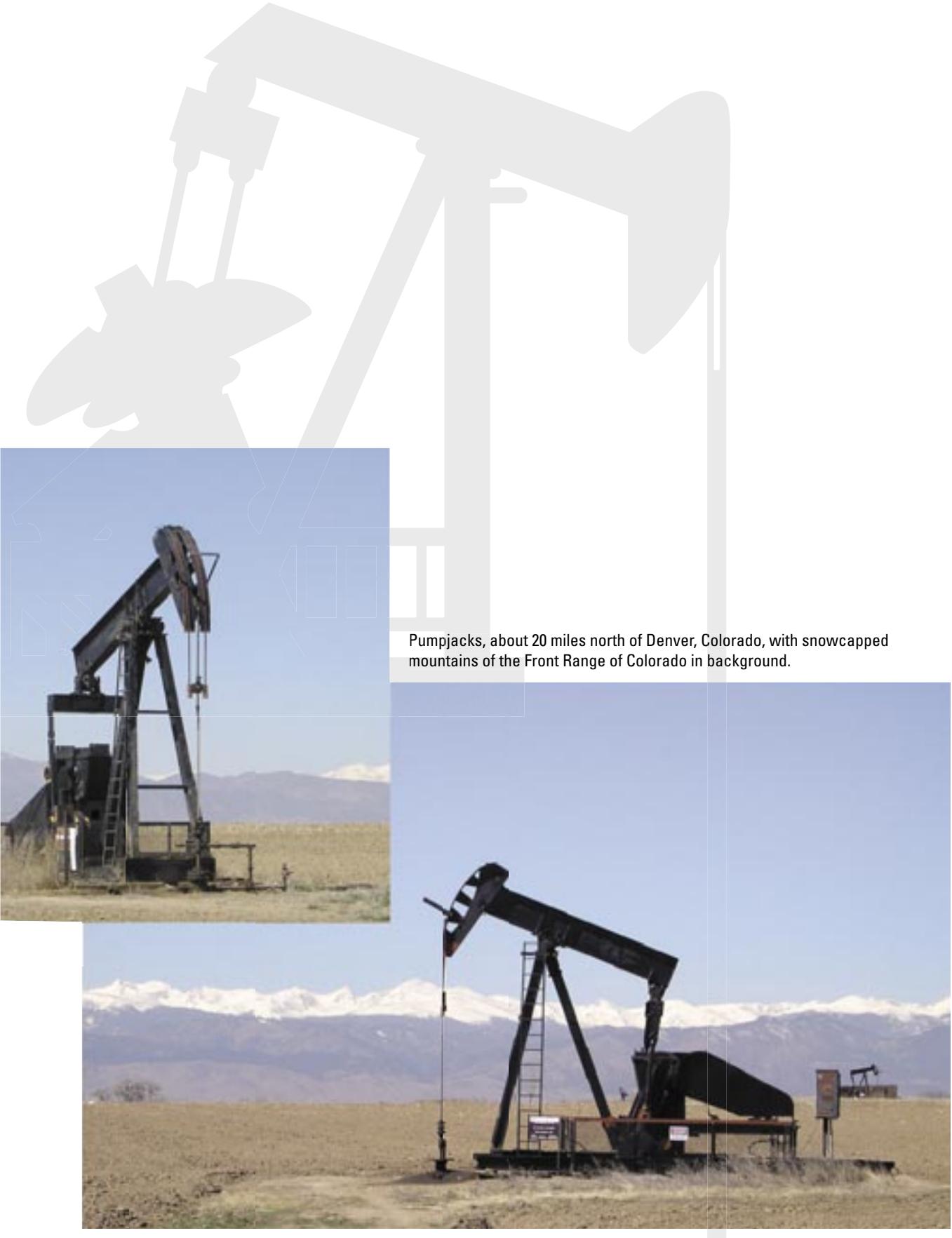


Energy Resource Studies, Northern Front Range, Colorado



Professional Paper 1698



Pumpjacks, about 20 miles north of Denver, Colorado, with snowcapped mountains of the Front Range of Colorado in background.

Energy Resource Studies, Northern Front Range, Colorado

Edited by Neil S. Fishman

Chapter A

Overview of Studies Related to Energy Resources, Northern Front Range of Colorado

By Neil S. Fishman

Chapter B

Oil and Gas Exploration and Development along the Front Range in the Denver Basin of Colorado, Nebraska, and Wyoming

By Debra K. Higley and Dave O. Cox

Chapter C

A Model for Determining Potential Areas of Future Oil and Gas Development, Greater Wattenberg Area, Front Range of Colorado

By Troy Cook

Chapter D

Origin of Saline Soils in the Front Range Area North of Denver, Colorado

By James K. Otton, Robert A. Zielinski, and Craig A. Johnson

Chapter E

Effects of the Oil, Natural Gas, and Coal Production Infrastructure on the Availability of Aggregate Resources and Other Land Uses, Northern Front Range of Colorado

By Neil S. Fishman, William H. Langer, Curtt L. Coppage, and David W. Siple

Chapter F

Coal in the Front Range Urban Corridor—An Overview of Coal Geology, Coal Production, and Coal-Bed Methane Potential in Selected Areas of the Denver Basin, Colorado, and the Potential Effects of Historical Coal Mining on Development and Land-Use Planning

By Stephen B. Roberts

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Units of Measurement and Abbreviations used in this volume

API	American Petroleum Institute
bbl	barrel
BBO	billion barrels of oil
BCFG	billion cubic feet of gas
BO	barrels of oil
BOPD	barrels of oil per day
BTU	British Thermal Unit
BWCF	Boulder-Weld Coal Field
CFG	cubic feet of gas
CGS	Colorado Geological Survey
CIMRP	Colorado Inactive Mine Reclamation Program
cm	centimeter
°C	degrees Celsius
DEM	digital elevation model
EUR	estimated ultimate recovery
°F	degrees Fahrenheit
ft	foot
ft ³ /ton	cubic feet per ton
FRIRP	Front Range Infrastructure Resources Project
gal	gallon
GIS	geographic information system
GOR	gas oil ratio
GRI	Gas Research Institute
GWA	greater Wattenberg area
in	inch
km	kilometer
km ²	square kilometer
lb	pound
LULC	land use land cover
m	meter
µm	micrometer
Ma	mega-annum (million years)
MBO	thousand barrels of oil
MCF	thousand cubic feet
mD	millidarcy
mi	mile
mi ²	square mile
mL	milliliter
mm	millimeter
MMBNGL	million barrels of natural gas liquids
MMBO	million barrels of oil
MMBW	million barrels of water
MMCF	million cubic feet
MMCFC	million cubic feet of gas
µS/cm	microsiemens per centimeter
OSM	Office of Surface Mining
psia	pounds per square inch—atmosphere
R _o	mean random vitrinite reflectance
scf	standard cubic feet
TCF	trillion cubic feet
TCFG	trillion cubic feet of gas
TOC	total organic carbon
TTI	time-temperature index
USGS	U.S. Geological Survey
WFZ	wrench fault zone
yd ³	cubic yard



Overview of Studies Related to Energy Resources, Northern Front Range of Colorado

By Neil S. Fishman

Chapter A of
Energy Resource Studies, Northern Front Range, Colorado

Edited by Neil S. Fishman

Professional Paper 1698

**U.S. Department of the Interior
U.S. Geological Survey**

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Overview of Studies Related to Energy Resources, Northern Front Range of Colorado

By Neil S. Fishman

Introduction

The infrastructure of a populated area, including roads, airports, water and energy transmission and distribution facilities, and sewage treatment plants, is critical to the vitality and sustainability of the area. Construction of new and ongoing maintenance of existing infrastructure both require large volumes of natural resources such as energy (oil, natural gas, and coal), construction aggregate (stone, sand, and gravel), and water. However, sufficient natural resources may not always be available for ready use due to (1) scarcity of local sources, (2) inaccessibility (for example, gravel cannot be mined from under a housing subdivision), (3) unsuitability of the resource (for example, polluted ground water may be unfit for domestic use), or (4) land use or legal restrictions limiting access to local sources. Should local sources of these natural resources either be unavailable or not used, then costs incurred to construct and maintain an area's infrastructure through use of more distant supplies will be greater than they would be if local sources were used. Thus, the ability to explore for and develop local accumulations of natural resources for use in infrastructure construction and maintenance, in large part a function of accessibility to the resources, is of particular interest and benefit to areas of significant population growth or where growth is expected. The challenge for communities is to adequately factor maintenance and growth of the area's infrastructure into comprehensive land-use planning efforts and to consider how changes in land-use designation can influence the availability of these vital natural resources.

The U.S. Geological Survey's Front Range Infrastructure Resources Project (FRIRP) was designed, with direct input from stakeholders (see following section), to advance our understanding of the location and characteristics of accumulations of energy, construction aggregate, and water—herein termed infrastructure resources—in the plains immediately east of the northern part of the Front Range in Colorado (fig. 1). The project study area, approximately 2,200 square miles (mi^2), extends from the metropolitan Denver area north to Fort Collins, and from the mountain front eastward for about 40 miles (fig. 1). The study area is in the western part

of the Denver Basin (defined by Matusczak, 1973), a large (about 70,000 mi^2) sedimentary basin in northeastern Colorado, southeastern Wyoming, and western Nebraska (fig. 2). The basin is a structurally asymmetric foreland basin with a steeply dipping western flank and gently dipping eastern flank (fig. 3), and the basin axis lies beneath part of Denver. The basin formed adjacent to the Front Range during the Laramide orogeny, approximately 71 to 50 Ma, although most downwarping probably occurred between 64 and 50 Ma (Weimer, 1996).

The FRIRP study area was selected for two primary reasons. First, this area has undergone substantial population growth over the last 30 years, with the attendant need for infrastructure resources. The population is expected to increase by as much as 1 million people within the next 25 years (Denver Regional Council of Governments, 1999). Not surprisingly, the need for infrastructure resources will correspondingly grow as the existing infrastructure requires maintenance and new construction is undertaken. Second, the northern part of the Front Range of Colorado was chosen for this study because urban and commercial development has encroached upon some areas that are supplying or have historically supplied infrastructure resources. Furthermore, urban growth is projected for areas that currently produce infrastructure resources or have the potential to do so. Thus, the project study area was a natural laboratory to consider the interplay between population growth and its effects on the availability of infrastructure resources.

Stakeholder Involvement

An important project goal is to deliver to decisionmakers and other stakeholders the scientific findings of the project in a form that is both understandable and readily usable, assuming that integration of project findings could lead to more informed decisionmaking by planners, developers, and other interested groups and institutions. To that end, direct stakeholder participation was solicited by project managers, which led to stakeholder involvement from initial project planning through its completion. Stakeholders, including governmental (city, county, and State) planning officials and representatives from both industry and academia, were invited

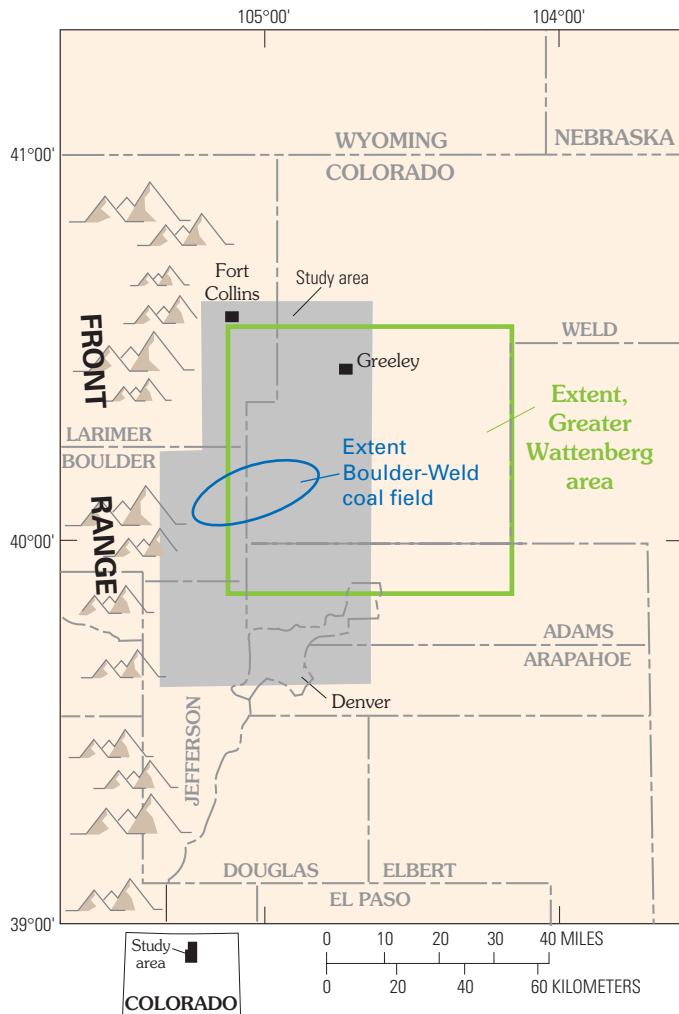


Figure 1. Location of the Front Range Infrastructure Resources Project study area (gray) in the urban corridor adjacent to the northern part of the Front Range of Colorado. Also shown are the extents of the greater Wattenberg area and Boulder-Weld coal field.

to evaluate and critique the original project design before its formal acceptance by U.S. Geological Survey management. Direct feedback from stakeholders led to modifications of the project design so as to better address expressed needs. Ongoing communication with stakeholders was achieved through several mechanisms, including (1) the project Web site, (2) periodic publication and distribution of project highlights, (3) a stakeholder's meeting (fig. 4) in November 1998 to present preliminary findings (U.S. Geological Survey, 1998), and (4) publication of the results of various studies conducted by FRIRP scientists on infrastructure resources in the Front Range (Knepper, 2001). A field trip to the project study area to discuss project findings and a formal USGS publication (Knepper and others, 2001) marked the final direct interaction between stakeholders and project members, although additional publications, such as this one, continue to be published to convey the detailed results of project work.

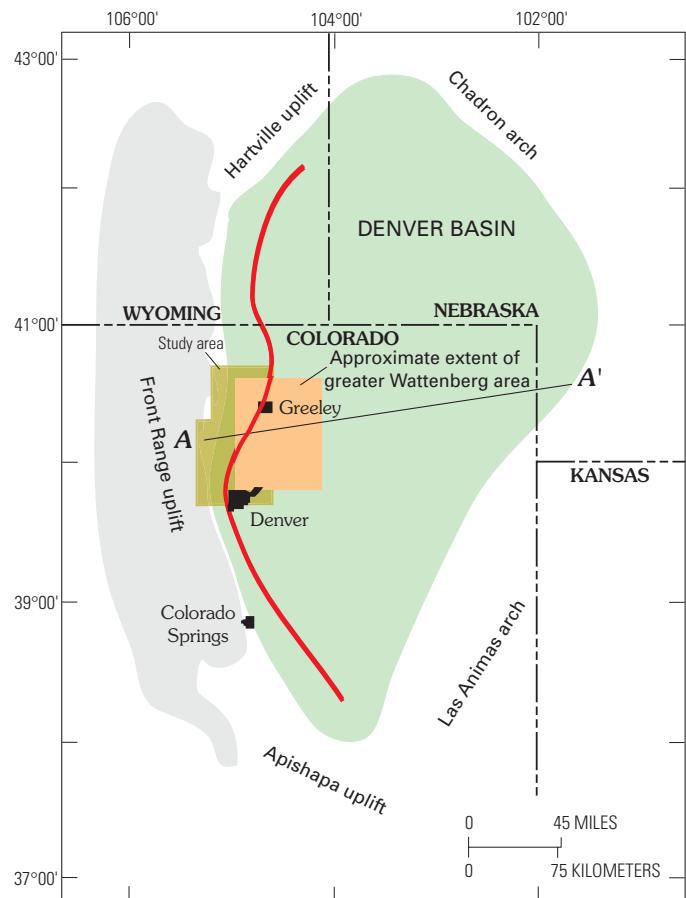


Figure 2. Approximate extent of the Denver Basin and bounding structural features. Also shown (in red) is the approximate location of the subsurface structural axis of the basin. Cross section A-A' shown in figure 3. Extent of basin based on structure contours on top of the Precambrian basement rocks (modified from Matuszcak, 1973).

Scope of this Volume

This volume contains five chapters that address various aspects of energy resources in the region (oil, natural gas, coal, coal-bed methane), as well as some of the environmental and land-use implications resulting from the exploration, development, and production of such resources. Specifically, efforts were focused on (1) reviewing the oil, natural gas, coal, and potential coal-bed methane resources in the study area and surrounding region (Higley and Cox, this volume; Roberts, this volume); (2) evaluating the potential for future exploration and production of oil and natural gas in the region (Cook, this volume); (3) assessing the relation between elevated soil salinities and waters produced along with oil and natural gas (Otton and others, this volume); and (4) determining the effects of energy resource production on the availability of aggregate resources and other land uses (Fishman and others, this volume).

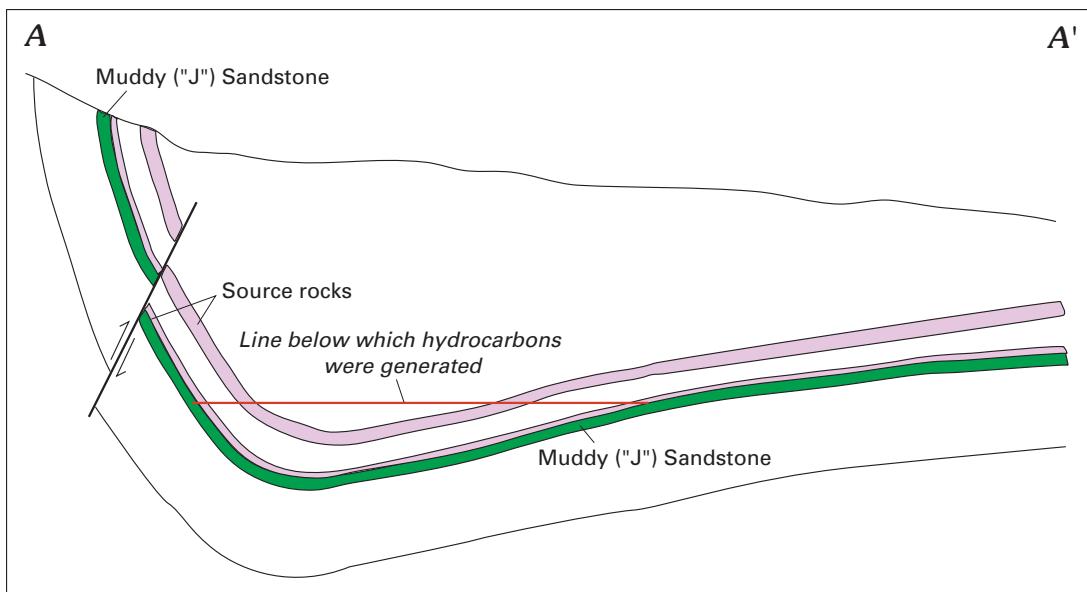


Figure 3. Schematic cross section of sedimentary rocks in the Denver Basin along line A–A' (see figure 2 for location). Note steeply dipping rocks on the western flank and their shallow dip on the eastern flank. Muddy ("J") Sandstone, one of the more prolific producers of oil and gas in the Denver Basin, is the reservoir rock (shown schematically) for petroleum generated by overlying source rocks (modified from Weimer, 1996).



Figure 4. Project scientists discuss preliminary project results with stakeholders at a mid-project meeting, November 1, 1998. Photograph taken by W.H. Langer, U.S. Geological Survey, Denver, Colorado.

Energy Resources in the Northern Front Range

The following two sections provide a brief overview of the geology and history of energy resource production in the northern part of the Front Range region of Colorado. This overview is intended as a general orientation and not an exhaustive description of the geology and energy resources of the region. For more details, the reader is referred to the technical chapters in this volume.

Petroleum Resources

Although petroleum was first produced along the Front Range more than 130 years ago (Higley and Cox, this volume), and significant drilling and production occurred in the 1950s and 1960s, most of the discoveries and production in the region have occurred since about 1970. Post-1970 production has been concentrated in what has become known as the greater Wattenberg area (GWA), an area defined by the Colorado Oil and Gas Conservation Commission (an agency of the State of Colorado) for regulatory purposes to ensure the responsible development of petroleum resources. The FRIRP study area encompasses approximately the western one-half of the GWA (fig. 1). There are more than 7,000 wells that produce oil and (or) gas in the study area, and permitting continues for drilling new wells, particularly in Weld County and to a lesser degree in Adams County. Production through 1999 from wells within the study area has exceeded 2.15 trillion cubic feet of gas and more than 245 million barrels of oil (D.K. Higley, U.S. Geological Survey, unpub. data, 2003). Accessibility to local markets in the Front Range region, coupled with the sheer volume of contained petroleum, has made the GWA an important energy-producing province in Colorado. Indeed, of the 96 individual oil and (or) gas fields that exist within the project study area, four oil and two gas fields are among the 25 largest oil and gas fields in Colorado in terms of cumulative production (Higley and Cox, this volume).

Rocks of Cretaceous age serve as both reservoir and source rocks for much of the petroleum produced in the GWA, although there is some production also from Permian rocks. The dominant Cretaceous reservoir rocks include (1) Muddy (“J”) Sandstone of the Dakota Group; (2) other sandstones in the Dakota Group, including the Plainview Sandstone Member of the South Platte Formation (“Dakota” of drillers) and Lytle Formation (“Lakota” of drillers); (3) “D” sandstone of the Graneros Shale; (4) Codell Sandstone Member of the Carlile Shale; (5) Niobrara Formation; and (6) Terry “Sussex” Sandstone, Hygiene “Shannon” Sandstone, and Sharon Springs Members of the Pierre Shale (see fig. 5). Within the study area, oil is the principal resource produced from the Cretaceous Terry Sandstone Member and the Permian Lyons Sandstone, whereas either oil or natural gas, or both, have

been produced from the other formations of Cretaceous age (Higley and Cox, this volume). Source rocks for most of the petroleum in the GWA include the Cretaceous Mowry, Graneros, and Carlile Shales and the Greenhorn Limestone (fig. 5) (Weimer, 1996; Higley and Cox, this volume). The Skull Creek Shale (fig. 5) also may have served as a source rock, although to a lesser degree than the others (Higley and Cox, this volume).

Because much of the western part of the GWA overlaps an area in the northern Front Range region that has recently undergone substantial urban expansion and is expected to experience much additional urban growth in the next few decades, a more complete understanding of the volume and distribution of undeveloped petroleum resources was an important project goal. Determining the remaining oil and gas resources, number of wells (existing and new) that might be required to extract these resources, geographical areas of potential discoveries, and possible timeframe for resource depletion were emphasized. In the chapter titled “Oil and Gas Exploration and Development Along the Front Range in the Denver Basin of Colorado, Nebraska, and Wyoming,” Higley and Cox (this volume) review the history of petroleum exploration and production in the Front Range region back to 1862 and provide an overview of its petroleum geology. Recently, as an extension of work done on this project, a geologically based assessment of undiscovered petroleum resources, which represents an estimation of the endowment of petroleum within the entire Denver Basin, was performed for all of the major petroleum systems in the Denver Basin, as well as for hypothetical accumulations of oil in Pennsylvanian rocks and coal-bed methane in Cretaceous and Tertiary rocks (Higley, 2003; Higley and others, 2003). An understanding of the regional geologic framework, also an outgrowth of the FRIRP studies, proved critical in assessing the undiscovered energy resources in the region as well as in evaluating the region for areas that are potential targets for new exploration and production.

Although the assessment of undiscovered resources in a region is important, it is performed at a scale that may be too coarse to adequately address the needs and interests of such disparate stakeholders as petroleum production companies, municipalities, and developers. These stakeholders are keenly interested in knowing more closely where prospective oil and gas development could take place within the study area because this information bears on possible future land-use conflicts. Building on the work of Higley and Cox (this volume), Cook (this volume), in the chapter titled “A Model for Determining Potential Areas of Future Oil and Gas Development, Wattenberg Field, Front Range of Colorado,” presents the results of a study undertaken to determine the potential (high, moderate, or low) for future oil and gas development, particularly from Cretaceous rocks. Several steps were required in formulation of the model, the first of which was to calculate the initial volume of oil and gas likely to be present in the various Cretaceous petroleum reservoirs. The estimated volume of ultimately recoverable oil and gas was

NORTHERN FRONT RANGE, OUTCROP				ADJACENT DENVER BASIN							
QUAT.	Undifferentiated alluvial deposits			Undifferentiated alluvial deposits							
TERTIARY											
	Undifferentiated boulder & gravel deposits										
				Castle Rock Conglomerate							
	Denver Formation			Dawson-Denver Formations							
	Arapahoe Formation			Arapahoe Formation							
	Laramie Formation			Laramie Formation							
	Fox Hills Sandstone			Fox Hills Sandstone							
	Pierre Shale	Richard Sandstone Mbr.		Pierre Shale	Terry "Sussex" Ss. Member						
		Terry Sandstone Mbr.			Hygiene "Shannon" Ss. Member						
		Hygiene Sandstone Mbr.			Sharon Springs Member						
		Smoky Hill Shale Mbr.			Smoky Hill Shale Member						
	Niobrara Formation	Fort Hays Limestone Mbr.		Niobrara Formation	Fort Hays Limestone Member						
		Codell Sandstone Mbr.			Codell Sandstone Member						
		Carlile Shale			Carlile Shale						
		Greenhorn Limestone			Greenhorn Limestone						
	Graneros Shale				Graneros Shale		"D" sandstone				
	Mowry Shale				Mowry Shale equivalent						
	Dakota Group	South	North								
		Upper members, South Platte Formation		Muddy ("J") Sandstone							
		Skull Creek Shale		Skull Creek Shale							
		Plainview Ss. Member	Plainview Formation	"Dakota" of drillers							
	Lytle Formation				"Lakota" of drillers						
JURASSIC	Morrison Formation				Morrison Formation						
	Ralston Creek Formation										
	Sundance Formation				Older Jurassic rocks may be present						
TRI.	Jelm Formation				Jelm Formation						
	Lykins Formation				Lykins Formation						
	Lyons Sandstone				Lyons Sandstone						
	Owl Canyon Formation				Owl Canyon Formation						
	Ingleside Formation				Ingleside Formation						
PENNSYL-VANIAN	Fountain Formation				Fountain Formation						
MISS.					Mississippian rocks						
DEV.					Devonian rocks						
SIL.					Ordovician rocks						
ORD.					Cambrian rocks						
CAM.											
PRE-CAM.	Metamorphic and intrusive rocks										

Figure 5. Generalized stratigraphic columns showing units exposed in outcrops along the northern part of the Front Range of Colorado and units in the subsurface in the Denver Basin, immediately to the east in the project study area. Shaded intervals represent periods of erosion or nondeposition. Formations labeled in green are the most important petroleum (oil and (or) gas) reservoir rocks, those labeled in purple are source rocks for the petroleum, and those labeled in red have produced coal or lignite. Ss., sandstone; Fm., formation; Mbr., member; PRECAM., Precambrian; CAM., Cambrian; ORD., Ordovician; SIL., Silurian; DEV., Devonian; MISS., Mississippian; TRI., Triassic; QUAT., Quaternary. Sources of stratigraphic nomenclature include MacKenzie, 1971; Pipiringos and O'Sullivan, 1976; Irwin, 1977; Colton, 1978; Kirkham and Ladwig, 1979; Tweto, 1979; Trimble and Machette, 1979; Bryant and others, 1981; Hansen and Crosby, 1982; Braddock and others, 1988; Braddock and others, 1989; and Madole and others, 1998.

determined from production data and then subtracted from the initial volume of petroleum in the rocks to estimate the volume of petroleum that might be accessible from new wells or by undertaking a program of “recompleting” existing wells into additional reservoir rocks. Any future drilling or recompletion of existing wells assumes there is economically producible petroleum remaining in the rocks. Finally, Cretaceous formations within the region were ranked from low to high for their potential for future petroleum development. Plots showing the areal distribution of potential for future petroleum development reveal that most areas of moderate to high potential are concentrated between Denver and Greeley, in much of the same area for which future urban growth is expected.

The typically saline water produced along with petroleum can be voluminous and requires proper handling and disposal to ensure minimal adverse environmental effects. The juxtaposition of saline soils with oil-production facilities at some sites in the study area, identified through reconnaissance field investigations at the start of the project, led to questions regarding the significance of produced waters in the formation of saline soils around or near some petroleum production sites. Otton and others (this volume) report on detailed mapping and mineralogic studies that address the origin of the saline soils as well as the nature and composition of contained salts. Their research indicates that saline soils containing largely sulfate-bearing minerals are in specific geomorphic and hydrologic settings, particularly where ground water enriched in dissolved solids is close to the soil surface for part of the year (Otton and others, this volume). The distribution of the saline soils and the isotopic composition of saline minerals indicate that salts may have originated from outcrops of the Pierre Shale (fig. 5) in the region. Although Otton and others (this volume) identified some sites where saline soils surround or are near oil-production facilities, including large tanks used to store produced waters, at only two sites did their studies reveal that a portion of the saline minerals (chloride-dominant minerals) in the soils may have been derived from produced waters. Thus, much of the observed saline soil mineralization in the study area appears to have originated by natural processes, locally enhanced by irrigation practices, rather than by leakage of saline waters from oil-production facilities.

The effects of petroleum production are not limited to environmental concerns, but such production may well preclude use of the land for other purposes, including urban and commercial development, farming, and notably, extraction of aggregate resources (sand, gravel, and crushed stone). With more than 7,000 oil and (or) gas wells currently producing within the study area, and with large deposits of aggregate also being mined within the same area, it is not surprising that numerous examples exist where oil and (or) gas wells have been established over economically viable aggregate deposits. In the chapter titled “Effects of the Oil, Natural Gas, and Coal Production Infrastructure on the Availability of Aggregate Resources and Other Land Uses, Northern Front Range of Colorado,” Fishman and others (this volume) evaluate the effects of oil and (or) gas production on the availability of

aggregate resources. At two sites that were studied in detail, the presence of energy-production equipment precludes production of a large portion of the available aggregate resources. As the need for more resources (energy and aggregate) grows to keep pace with future demands, conflicts between aggregate production and oil and gas operations may become more common (Fishman and others, this volume). However, petroleum-production companies, aggregate-production companies, developers, and farmers are increasing efforts to mitigate conflict and promote good relations.

Coal Resources

Coal was first produced along the Front Range in the early 1860s in the southwestern part of the Boulder-Weld coal field (BWCF) in Boulder and Weld Counties (fig. 1). In the northern part of the Front Range, within the project study area, coal was mined continuously for more than 100 years until closure of the last mine in 1979 (Kirkham and Ladwig, 1980). In addition to the BWCF, coal was also produced in Jefferson and Douglas Counties in the northern part of the Front Range (Kirkham and Ladwig, 1980; Roberts, this volume). Focus in this volume, however, has been on the coal mines in the BWCF because of the wealth of data concerning the extent and depth of mining available for the more than 130 mines in it. Furthermore, coal produced from the BWCF totaled approximately 107 million short tons, which represents more than 82 percent of all of the coal mined throughout the Front Range region (Kirkham and Ladwig, 1980; Tremain and others, 1996). Although no longer mined, interest in coal for this study stemmed from the effects of past coal mining, including mining-related subsidence and coal-mine fires, and, notably, the potential for coal-bed methane resources (Roberts, this volume).

The Cretaceous Laramie Formation (fig. 5) is the dominant coal-producing unit in the study area (Kirkham and Ladwig, 1979; Roberts and Kirschbaum, 1995; Weimer, 1996), with only minor production of lignite from the overlying Tertiary Denver Formation (fig. 5). Laramie Formation coal ranges from subbituminous B to subbituminous C in rank, has a sulfur content of generally less than 1 percent (Kirkham and Ladwig, 1979), and was used locally for both domestic and industrial purposes, as well as in the numerous mining towns and camps in the nearby mountains (Tremain and others, 1996).

Most of the abandoned mines in the BWCF are in those parts of Boulder and Weld Counties that have either recently undergone urban growth or are slated for development during the next few decades. Rather than focusing research efforts on understanding the volume and distribution of remaining coal resources and the potential for future mining in the BWCF, emphasis in the FRIRP was on post-mining land-use effects and on the potential for extraction of methane from coal remaining in the subsurface in the region. Roberts (this volume), in the chapter titled “Coal in the Front Range Urban

Corridor—An Overview of Coal Geology, Coal Production, and Coal-Bed Methane Potential in Selected Areas of the Denver Basin, Colorado, and the Potential Effects of Historical Coal Mining on Development and Land-Use Planning,” presents a structural and geologic framework for the Denver Basin and the Laramie Formation, respectively, that bears directly on coal resources in the region. The geologic framework provides the foundation for evaluation of the coal-bed methane potential of the Laramie Formation, which is also discussed in Roberts’ (this volume) chapter. The geologic framework is also important when considering the post-mining effects on land use in the region because depth to coal and the nature of the rocks overlying mined areas figure prominently in the potential for subsidence and coal-mine fires (Roberts, this volume). Study results of coal-bed methane potential of the Laramie Formation and post-mining environmental effects provide planners, developers, and natural gas operators with information needed for future land-use considerations.

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Oil and Gas Exploration and Development along the Front Range in the Denver Basin of Colorado, Nebraska, and Wyoming

By Debra K. Higley and Dave O. Cox

Chapter B of
Energy Resource Studies, Northern Front Range, Colorado

Edited by Neil S. Fishman

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Oil and Gas Exploration and Development along the Front Range in the Denver Basin of Colorado, Nebraska, and Wyoming

By Debra K. Higley and Dave O. Cox

Abstract

More than 1.05 billion barrels of oil and 3.67 trillion cubic feet of natural gas have been produced from wells across the Denver Basin. Of this, 245 million barrels of oil and 2.15 trillion cubic feet of natural gas are from wells within the Front Range Urban Corridor; this totals about 23 percent of the oil and 58 percent of the gas produced in the basin. The urban corridor, located adjacent to and east of the Rocky Mountains in the Colorado and Wyoming portions of the basin, is as much as 40 miles (64 kilometers) wide and encompasses Denver, Colorado, Cheyenne, Wyoming, and other population centers.

The area has an extensive petroleum exploration history. The first oil well in the Denver Basin was completed in 1881 in the Florence field, the oldest continuously working oil field in the United States. More than 52,000 wells have been drilled for oil and (or) gas in the basin, and more than 29,000 of these are within the urban corridor. The basin contains more than 1,500 oil and (or) gas fields, 96 of which are within the corridor. Currently producing sandstone reservoirs range in age from Paleozoic through Cretaceous. Depths of production vary from less than 900 feet (270 meters) at the Florence field in Fremont County to about 9,000 feet (2,700 meters) at the Pierce field in Weld County.

Introduction

The Denver Basin encompasses more than 70,000 square miles (mi^2) (180,000 square kilometers [km^2]) in eastern Colorado, southeastern Wyoming, and southwestern Nebraska. It is bounded on the west by the Front Range of the Rocky Mountains, on the northwest by the Hartville uplift, on the northeast by the Chadron arch, on the southeast by the Las Animas arch, and on the southwest by the Apishapa uplift. The Front Range Infrastructure Resources Project (FRIRP) that was conducted within the basin extends from north of Cheyenne, Wyo., to south of Colorado Springs, Colo.; the

predominantly Precambrian-age rocks of the Rocky Mountains form the western edge, and it is approximately bounded on the east by the eastern limit of Douglas County, at about 104.6 degrees longitude. Oil and gas wells across the northern two-thirds of the Denver Basin are shown in figure 1. The stratigraphic column (fig. 2) shows ages and names of formations, including marking those that produce oil and (or) gas, as well as the primary hydrocarbon source rocks*. A glossary follows the selected references and presents definitions and explanations for some of the geologic and petroleum terms that may be unfamiliar to some readers of this paper. Defined words are indicated by an asterisk (*).

The Denver Basin is an asymmetrical Laramide-age foreland-style structural basin that is approximately oval, stretched north to south, with a steeply dipping western flank and a gently dipping eastern flank. Greatest thickness of sedimentary rocks is along the axis of the Denver Basin, which is a north-south-trending line that approximately connects Denver and Cheyenne (fig. 1). West of the axis, formations dip down steeply eastward; the change in elevation can be more than 9,000 feet (ft) (2,700 meters [m]) in the space of several miles. Precambrian* rocks form the basement of the Denver Basin, are as deep as 13,000 ft (4,000 m) below the ground surface and have been dated at about 1.6 billion years old (Weimer, 1996). Nearly 70 percent of the thickness of sedimentary rocks that overlie Precambrian rocks within the basin are sandstones, shales, and limestones of Cretaceous age (144 to 67 million years old) (Hemborg, 1993a-d).

West of the basin axis, outcrops of east-dipping strata form prominent ridges that parallel the mountain front (fig. 3). The Laramide orogeny began about 67.5 million years ago (Ma) and ended about 50 Ma (Tweto, 1975). This was the major tectonic event that folded these originally flat-lying rocks, formed the current structure of the basin, and uplifted the Rocky Mountains to the west. Amount of uplift is highly variable; estimates are as much as 25,600 ft (7,800 m) in the Mount Evans area of the Rocky Mountains, south of Highway I-70 (Bryant and Naeser, 1980) (west of area in figure 1). Between 1,000 ft (300 m) and 6,500 ft (1,910 m) of Tertiary and older strata were removed by erosion in the central Front

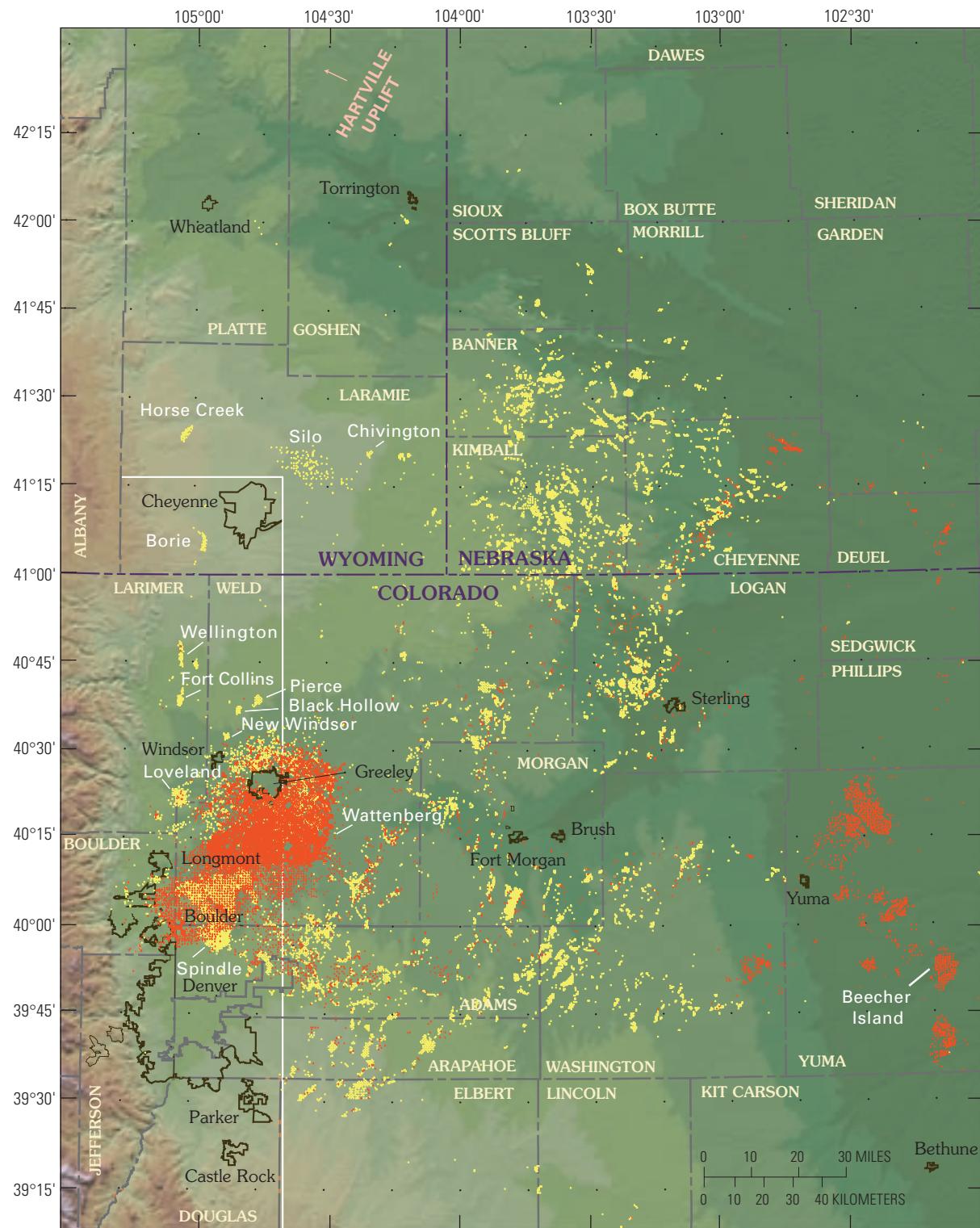


Figure 1. The northern two-thirds of the Denver Basin of Colorado, Nebraska, and Wyoming. Shown are oil (yellow-green), oil and gas (blue), and gas (red) wells across the basin. Major fields within the Front Range area are labeled (white text). The white line shows the northern and eastern boundaries of the study area. Western boundary is the approximate eastern limit of Precambrian rock exposures in the Rocky Mountain foothills. Vertical scales of the underlying digital elevation model (DEM) are 30 and 90 meters.

NORTHERN FRONT RANGE, OUTCROP			ADJACENT DENVER BASIN				
QUAT.	Undifferentiated alluvial deposits		Undifferentiated alluvial deposits				
TERTIARY	Undifferentiated boulder & gravel deposits						
	<i>Denver Formation</i>			Castle Rock Conglomerate			
	Arapahoe Formation			Dawson-Denver Formations			
	<i>Laramie Formation</i>			<i>Laramie Formation</i>			
	Fox Hills Sandstone			Fox Hills Sandstone			
	Pierre Shale	Richard Sandstone Mbr.		Pierre Shale	Terry "Sussex" Ss. Member		
		Terry Sandstone Mbr.			Hygiene "Shannon" Ss. Member		
		Hygiene Sandstone Mbr.			Sharon Springs Member		
	Smoky Hill Shale Mbr.			Smoky Hill Shale Member			
	Niobrara Formation	Fort Hays Limestone Mbr.		Niobrara Formation	Fort Hays Limestone Member		
		Codell Sandstone Mbr.			Codell Sandstone Member		
		Carlile Shale			Carlile Shale		
	Greenhorn Limestone			Greenhorn Limestone			
	Graneros Shale			Graneros Shale "D" sandstone			
	Mowry Shale			Mowry Shale equivalent			
	Dakota Group	South	North				
		Upper members, South Platte Formation		Muddy ("J") Sandstone			
		Plainview Ss. Member		Skull Creek Shale			
		Lytle Formation		"Dakota" of drillers			
JURASSIC	Morrison Formation			"Lakota" of drillers			
	Ralston Creek Formation						
	Sundance Formation			Morrison Formation			
TRI.	Jelm Formation			Older Jurassic rocks may be present			
	Lykins Formation						
	Lyons Sandstone			Lykins Formation			
	Owl Canyon Formation			Lyons Sandstone			
	Ingleside Formation			Owl Canyon Formation			
	Fountain Formation			Ingleside Formation			
PENNSYL-VANIAN							
MISS.				Fountain Formation			
DEV.				Mississippian rocks			
SIL.				Devonian rocks			
ORD.				Ordovician rocks			
CAM.				Cambrian rocks			
PRE-CAM.	Metamorphic and intrusive rocks						

Figure 2. Stratigraphic section of rock units in outcrop and the adjacent Denver Basin. Light blue zones are periods of erosion or nondeposition. Green text marks formations that produce oil and (or) gas. Red text marks formations that have the potential to produce coal-bed methane. Hydrocarbon source rocks are marked with purple text. Question marks label unclear boundaries. Sources of information include Hoyt (1963), Momper (1963), Irwin (1976), Sonnenberg and Weimer (1981), Higley and Schmoker (1989), Hjellming (1993), and MacLachlan and others (1996).

Range area (Higley and Schmoker, 1989; L.C. Price, oral commun., 1991). Rocks and sediments now exposed across the surface of the Denver Basin are of Tertiary age (less than 66 million years old). They represent redistribution of sediments that were eroded from the Rocky Mountains and redistributed in the subsiding Denver Basin.

Oil and Gas Exploration in the Front Range Area

Oil and gas are produced primarily from Cretaceous rocks across the Denver Basin; several fields produce from Paleozoic formations, and there is some potential of gas from coals of the lower Tertiary and uppermost Cretaceous Denver and Laramie Formations (fig. 2). Depths of production for the conventional* oil and gas reservoirs range from about 3,000 to more than 8,000 ft (900 to 2,400 m); shallower production is from unconventional* reservoirs, such as the Florence field, and those that produce biogenic gas*. Four oil and two gas fields in the urban corridor are among the 25 largest oil and gas fields in Colorado in terms of cumulative production; these are the Florence, Pierce, Spindle, and Wellington oil

fields and the Hamber and Wattenberg gas fields. More than 1.05 billion barrels* of oil (BBO) and 3.67 trillion cubic feet of gas (TCFG) have been produced from the basin; about 23 percent of the oil and 58 percent of the gas in the basin have been produced from fields within the Front Range Urban Corridor; this totals 245 million barrels* of oil (MMBO) and 2.15 TCFG. Petroleum production information, well location, and producing formations are derived from referenced publications, the Nehring and Associates (NRG) database (through 1994), the 1998 Oil and Gas Statistics of the Colorado Oil and Gas Commission combined with their Web site data (through July of 2001), and IHS Energy's Petroleum Information/Dwights Well History Control System (WHCS) and Production Data on CD-ROM databases (through 1999).

The Denver Basin contains about 1,500 oil and (or) gas fields, concentrated along a northeast-trending band from Denver into the panhandle of southwestern Nebraska (fig. 1). Ninety-six of these fields are within the boundaries of the FRIRP study area. Intensive exploration and development drilling began in 1950; from 1950 to 1966 the basin was the most actively explored province in the Rocky Mountains (Hemborg, 1993a-d). More than 52,000 wells have been drilled, and 29,000 of these are within the urban corridor. Drilling is focused in the central part of the Denver Basin and

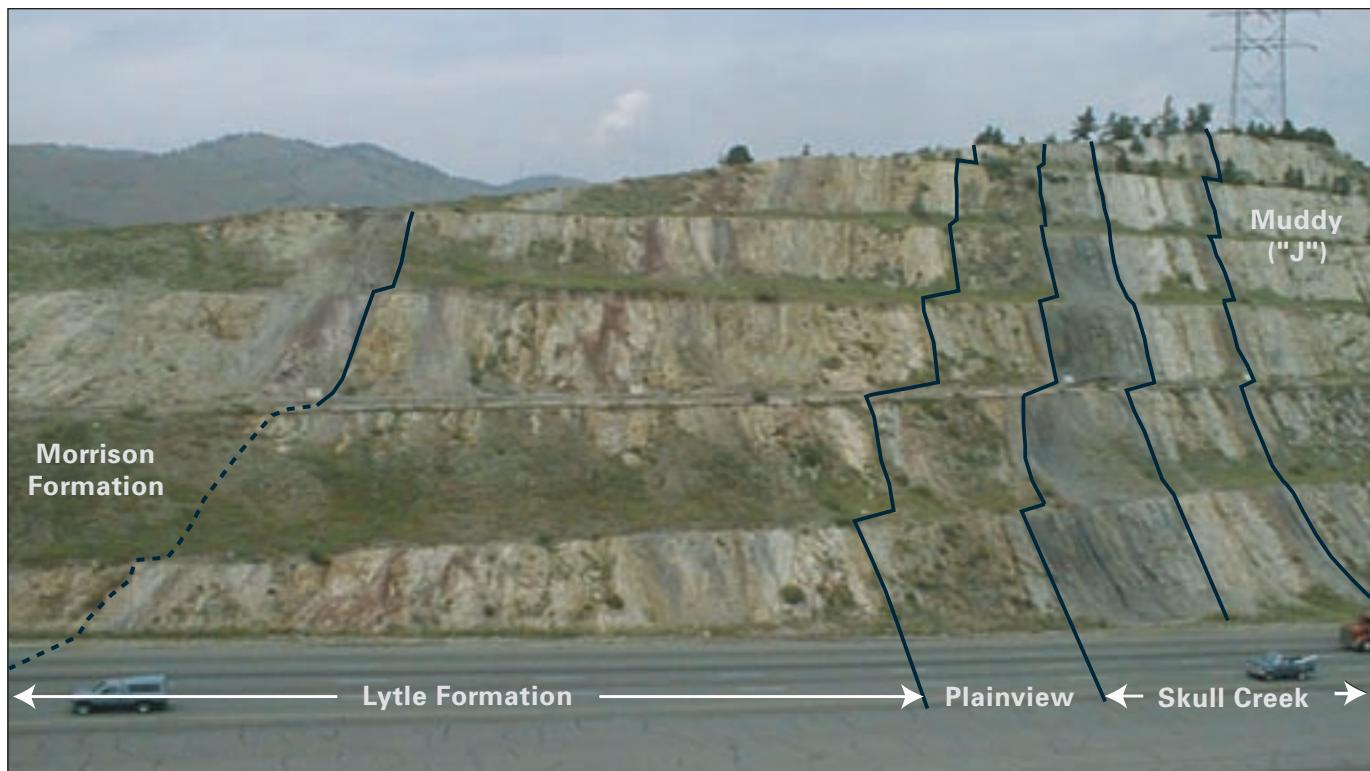


Figure 3. View looking north at an outcrop of Cretaceous (Lytle, Plainview, Skull Creek, Muddy ("J") and Jurassic (Morrison) Formations. Location is a road cut along Interstate 70, west of Denver, approximately 10 miles (16 kilometers) east of the Rocky Mountains, the foothills of which are shown on the left, above the outcrop. These tan and reddish sandstone and gray shale beds were originally deposited flat lying in marine and nonmarine environments and were thrust upward during growth of the Rocky Mountains and associated bounding faults. The oldest rocks are to the left. Black lines that are dashed where inferred bound the labeled formations. Boundaries are as drawn by LeRoy and Weimer (1971) and Weimer (1996).

within the corridor; there is limited exploration and (or) development in the northwestern and southern parts of the basin.

Permian Lyons Sandstone

Paleozoic-age rocks in the Denver Basin are exposed in the Hartville uplift area (southeastern Wyoming, fig. 1) and along the western margin of the basin; outcrop areas include the Flatirons, west of Boulder, Roxborough State Park, southwest of Denver, and the Red Rocks Amphitheater, west of Denver. Paleozoic reservoirs are located in the northern one-half of the basin, with oil production from the Permian Lyons Sandstone within the urban corridor. Across the basin, oil is produced primarily from carbonates of the Admire Group and the informally named Wykert sandstone interval of the Council Grove Group, which is part of the Lower Permian Wolfcampian series (fig. 2). Minor amounts of oil also are produced from Pennsylvanian-age sandstone, limestone, and dolomite in the Nebraska panhandle and far eastern flank of the basin. Prospective reservoir depths are about 4,000 to 13,000 ft (1,200 to 4,000 m) in sandstone-limestone-dolomite sequences of Desmoinesian, Missourian, and Virgilian ages. In the southeastern Denver Basin and Las Animas uplift, Paleozoic production is mainly from the Pennsylvanian Morrow Sandstone.

Across the Denver Basin, 187 wells have recorded production from Paleozoic-age rocks. Sixty-seven of these are within the urban corridor and produce mainly oil from the Permian Lyons Sandstone (fig. 2). Corresponding oil fields are Baxter Lake, Berthoud, Black Hollow, Douglas Lake, Fort Collins, Lake Canal, Loveland, New Windsor, and Pierce (fig. 4). All of these fields are located north and northeast of Boulder in Larimer and Weld Counties. Also shown in figure 4 are structure contours drawn on the top of the Lyons Sandstone and a series of right lateral, mostly vertical, wrench faults* that were identified by Stone (1969) and Weimer (1996). Weimer (1996) mapped these wrench faults as offsetting the Muddy ("J") and underlying formations.

In 1905, N.M. Fenneman named the Lyons Sandstone for the prominent red quartz sandstone formation that is exposed near the town of Lyons, Colo. (Oldham, 1996) and is a common building stone used for rock walls, facings on buildings, and flagstone for walkways and patios. Many older buildings in downtown Denver have facings from large blocks of the sandstone, and some older sidewalks are composed of flagstone. Oil was first discovered in the Lyons in 1953 in the Black Hollow (fig. 4) and Keota fields. The Keota field, not shown in figure 4, lies east of the urban corridor and along a northeastern extension of the Windsor wrench fault zone (WFZ) in northeastern Weld County; the field has produced more than 1.27 MMBO and 0.60 billion cubic feet of gas (BCFG). The Pierce field (Clark and Rold, 1961c) and the New Windsor field (Clark and Rold, 1961b) were discovered in 1955 and 1957, respectively. The Pierce and Black Hollow fields terminate southward against the north side of the

Windsor WFZ, whereas the Windsor field lies south of the fault. The Windsor WFZ, like the parallel Colorado Mineral Belt that is located in the mountains to the west (Tweto and Sims, 1963), was first activated during Precambrian time (Stone, 1985). Probable eastern extensions of the mineral belt are the Johnstown and Lafayette WFZs. Both the northeast-trending Windsor wrench and the north- to northwest-trending faults associated with the Pierce and Black Hollow anticlines were thought to be the result of compressional forces during the Laramide orogeny (Stone, 1985). The faults at Pierce and Black Hollow appear to have caused only minor vertical separation of the rocks (probably less than 100 ft [30 m]) with displacement of the Precambrian basement being more obvious on seismic sections for the Black Hollow feature, although still not entirely definitive (Stone, 1985).

The three fields with cumulative production greater than 1 MMBO from the Lyons Sandstone are Black Hollow (10.8 MMBO, 0.330 million cubic feet of gas (MMCFG), Lake Canal (2.7 MMBO, 0 CFG), and Pierce (11.5 MMBO, 0.500 MMCFG). Reported Paleozoic production in these and other fields is commonly commingled with that of overlying Cretaceous reservoirs. Oil in the Black Hollow field is produced from the Permian Lyons and the Upper Cretaceous Niobrara Formation and the Codell Member of the Carlile Shale (fig. 2). The New Windsor field also has production from the Upper Cretaceous Terry ("Sussex") and Hygiene ("Shannon") Members of the Pierre Shale as well as the Codell Sandstone. Hydrocarbons in this field are stratigraphically* trapped (Clark and Rold, 1961b); however, a structural* trapping element is indicated by a northeast-trending anticlinal axis across the middle of the field.

Primary traps for Paleozoic production along the Rocky Mountain Front Range are mainly small anticlines near the western margin of the basin. Potential hydrocarbon traps in Paleozoic strata, particularly in the Hartville uplift area (fig. 1), may have originated in part during a deformational period represented by the Ancestral Rocky Mountains* that were uplifted slightly west of, and oriented more northwest-southeast than, the present Rocky Mountains during Pennsylvanian time (Mallory, 1972). An "events" chart, which illustrates time of deposition of petroleum source*, reservoir, overburden, and reservoir seal rocks and the subsequent generation, migration, and accumulation of gas, shows that geologic structures formed at that time are thought to have also influenced the development of trapping conditions for hydrocarbons in the Permian Lyons Sandstone (fig. 5).

The Lyons Sandstone, which ranges in thickness from 0 to more than 200 ft (60 m), marks one of the more significant lithologic facies changes within strata of Leonardian (Early Permian) and Guadalupian (Early to Late Permian) ages in the Denver Basin; uplift and erosion of the Ancestral Rocky Mountains to the west provided the source of sediments (Oldham, 1996). The Lyons Sandstone along the Front Range was deposited in eolian* and shallow water environments.

Although structural* traps were formed along the corridor during the Laramide orogeny and possibly earlier during

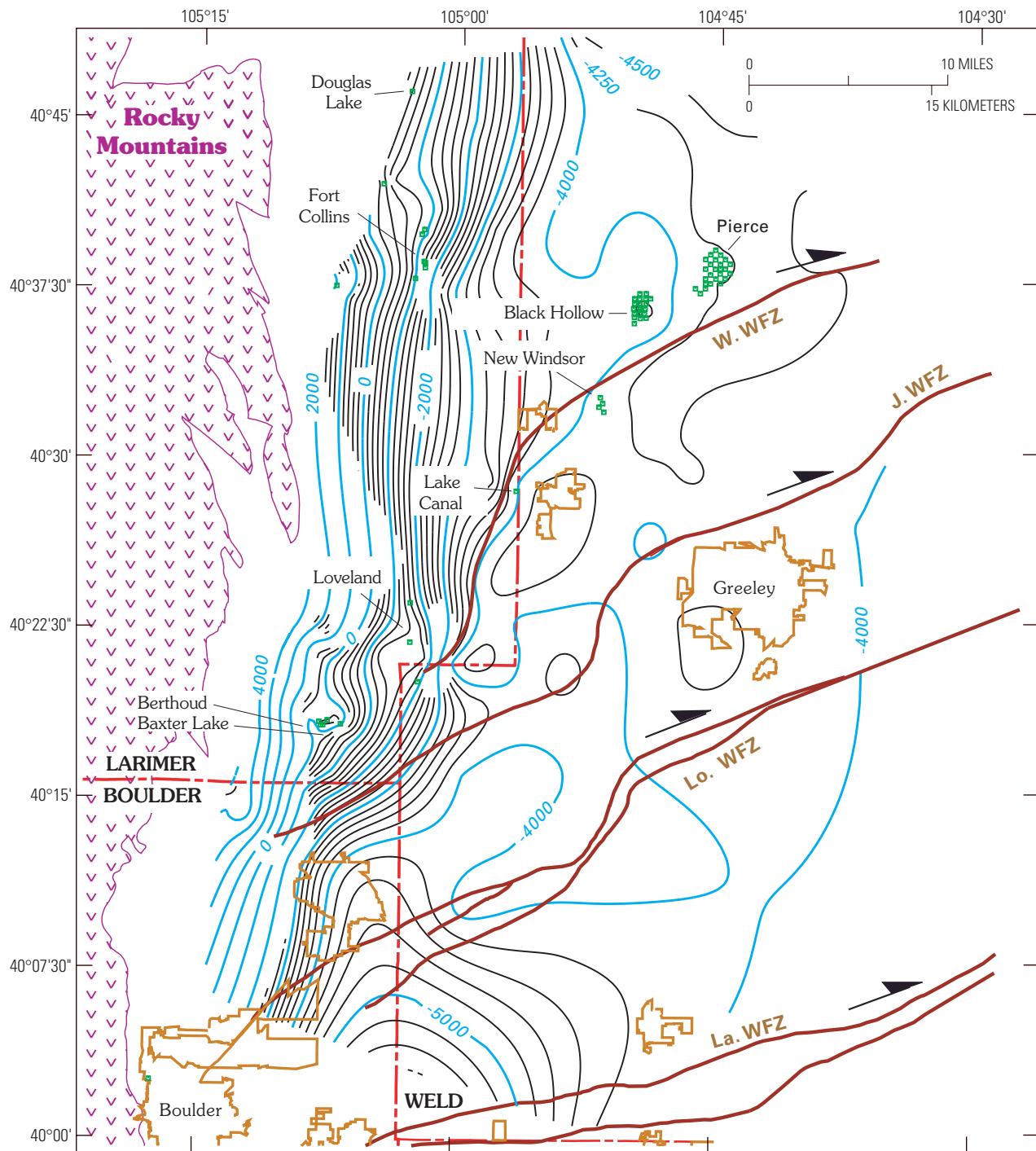


Figure 4. Elevation in feet relative to sea level on the top of the Permian Lyons Sandstone in the Front Range Urban Corridor. Contour interval is 250 feet (76 meters). Producing oil wells (green) are shown for the labeled fields. Labeled wrench faults are Windsor (W. WFZ), Johnstown (J. WFZ), Longmont (Lo. WFZ), and Lafayette (La. WFZ); arrows indicate direction of lateral movement.

Late Paleozoic time, potential source* rocks were not buried deep enough to generate hydrocarbons until early to middle or even late Tertiary time (fig. 5). Principal source rocks in the Denver Basin are Upper Cretaceous shales (fig. 2), but the oils generated by those strata differ in composition from the oil produced in the Lyons Sandstone (Clayton and Swetland,

1980), thus indicating that another source was involved. No potential source rocks of either Permian or Pennsylvanian age are known in the areas of Lyons production. Clayton (1992, 1999) and Clayton and others (1992) indicate that organic-rich black shale of Paleozoic age (Middle Pennsylvanian) is present only in the northern and eastern parts of the Denver Basin

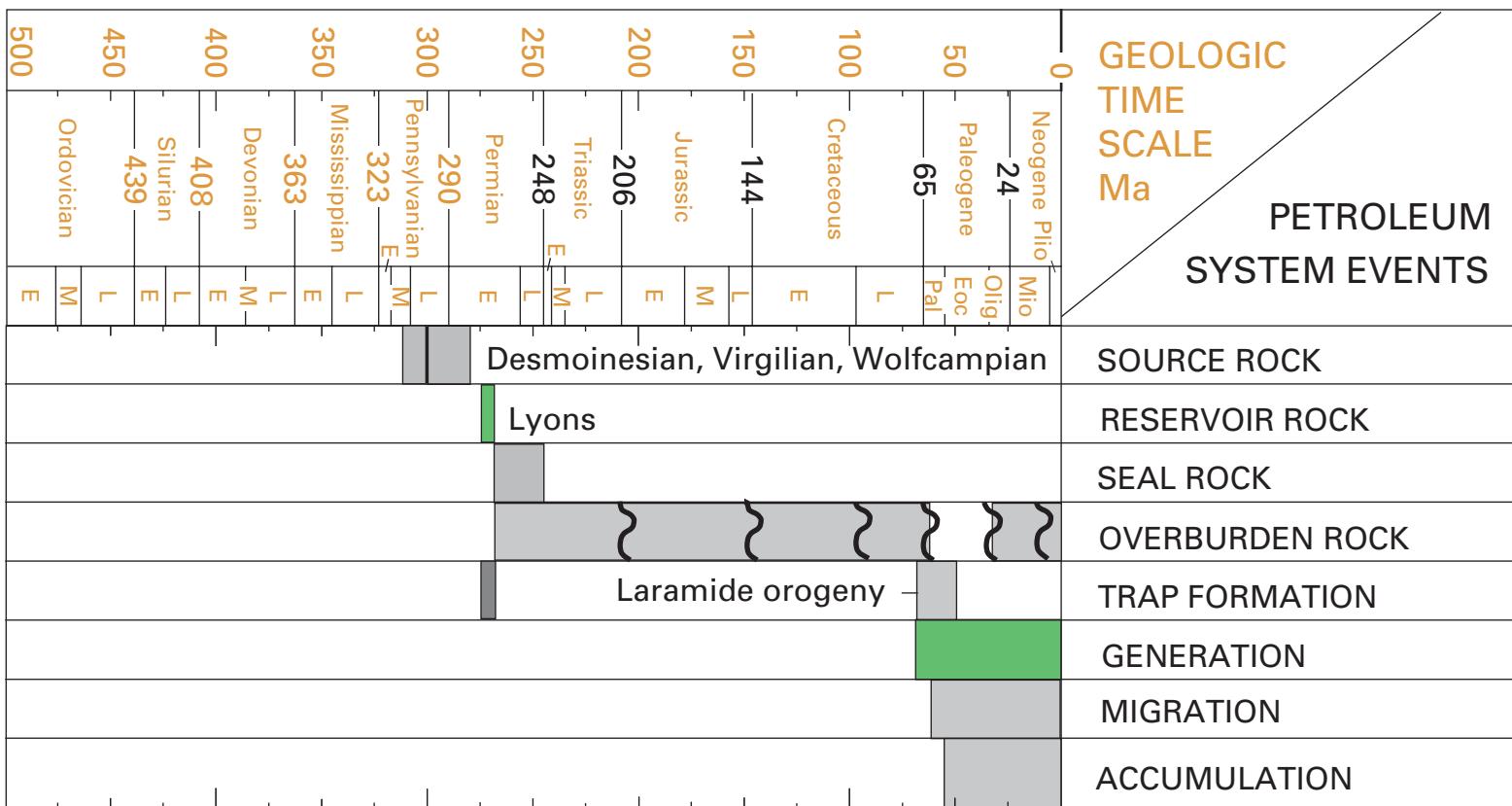


Figure 5. Geologic events chart for the Permian Lyons Sandstone. Gray and green mark times of primary events. Dark gray within the trap formation category indicates the time interval for development of stratigraphic traps. Wavy black lines are times of probable unconformities. Abbreviations for Tertiary epochs: Pal, Paleocene; Eoc, Eocene; Olig, Oligocene; Mio, Miocene; Plio, Pliocene. Sources of information include Obradovich and Cobban (1975), Tweto (1975, 1980), Irwin (1976), Kauffman (1977), MacMillan (1980), Trimble (1980), Tainter (1984), Weimer (1984, 1996), Sonnenberg (1985), Higley and Gautier (1988), Oldham (1996), and Rall (1996).

and along a trend that extends from northeast of the Wattenberg field to the Nebraska panhandle. They postulate that these are a potential, but unverified, source of hydrocarbons for the Lyons Sandstone.

Cretaceous "D" and Muddy ("J") Sandstones

Conventional Reservoirs

Most exploration in the Denver Basin has focused on the Lower Cretaceous Muddy ("J") Sandstone (fig. 2). The "J" sandstone is an informal economic term for the Muddy Sandstone. The "D" sandstone overlies the Muddy ("J") Sandstone and production is often reported commingled with the "J". More than 700 MMBO, 980 BCFG, and 68 million barrels of natural gas liquids (MMBNGL) have been produced from these sandstones in 355 fields across the basin. This is more than 67 percent of the oil and 47 percent of gas production in the basin. Cumulative production for the "D" sandstone alone exceeds 170 MMBO, 590 BCFG (Hemborg, 1993d), and 270 million barrels of water (MMBW) from some 1,600 wells. Depths of production for these conventional oil and gas fields range from about 3,000 ft to more than 8,000 ft (900 to 2,400 m). Approximately 39,000 wells reach total depth either in or below these formations; 9,800 of these are oil and (or) gas productive from the "D" sandstone and (or) Muddy ("J") Sandstone (Petroleum Information/Dwights, 1999a).

The Wellington field in Laramie County was discovered in 1923 by Union Oil Company of California and was the first Muddy ("J") Sandstone production in the Denver Basin (Hemborg, 1993a) (fig. 1). Approximately 8.19 MMBO, 19.0 BCFG, and 28.7 MMBW have been produced from a north-south-trending anticline (Colorado Oil and Gas Conservation Commission through 1999; Petroleum Information/Dwights production data through 1999). This anticline is about 7.5 miles (12 km) long and 1.5 miles (2.4 km) wide. Depth to the top of the Muddy ("J") Sandstone is approximately 4,500 ft (1,400 m). Average reservoir thickness is 25 ft (7.6 m), oil gravity ranges from 33° to 39° API*, and oil composition is about 0.16 percent sulfur (Mott, 1961). Hydrocarbon source rocks are marine shales of the overlying Mowry and Graneros Shales; vitrinite reflectance* (R_O) values for core and outcrop samples are about 0.5 percent to 0.6 percent R_O in the field area (fig. 6) (Higley, 1988). These R_O values indicate shales are immature to marginally mature for oil generation based on extrapolation between samples from outcrops and deeper core. Some migration of oil into the reservoir from greater depths in the basin probably occurred.

The "D" sandstone underlies most of the eastern flank of the basin; its approximate western limit is indicated by the extent of drilling shown in figure 6. Only the westernmost "D" sandstone wells were drilled within the Front Range Urban Corridor. The Muddy ("J") Sandstone crops out along the western margin of the basin in a prominent hogback of tan-colored sandstone. Figure 7 shows a creek- and road-cut

through the hogback of mostly valley-fill (river-deposited) sandstones that are part of the Horsetooth Member of the Muddy ("J") Sandstone. The sandstone overlies the gray Skull Creek Shale, which was deposited offshore within the Cretaceous epicontinental seaway* that covered much of what is now the central United States. The gray shale outcrop on the left side of figure 7 is the marine Mowry Shale, which overlies the Muddy ("J") Sandstone and, combined with the overlying Graneros Shale (fig. 2), are the major hydrocarbon source rocks in the basin. Yellow and black vertical stripes on the rock result from chemical interactions on a natural oil seep with ground water and the air through a process of biodegradation, which is biologic breakdown of the oil by microorganisms that results in the oil being "eaten" and the formation of a thin surface coat of yellow sulfur minerals and thin black tar stripes and smudges. This process is most visible (and smelly) on a warm day in the afternoon, when the outcrop is in sunlight.

"D" sandstone production is scattered across the basin in 378 oil and gas fields (Hemborg, 1993d), including minor production along the eastern margin of the Wattenberg field; this production is commonly reported commingled with the underlying Muddy ("J") Sandstone. Figure 6 also includes vitrinite reflectance (Higley, 1988; and unpublished data of Higley) contours of the hydrocarbon source rocks for Lower Cretaceous reservoirs. These source rocks (fig. 2) are thermally mature for oil generation at R_O values of about 0.6 percent. Production outside the 0.6-percent R_O boundary is largely due to lateral migration and trapping of oil and gas along valley fill and other porous and permeable sandstones of the "D" and Muddy ("J").

Sediments that compose the "D" sandstone were originally sourced from the east and grade westward into marine shales, terminating against the marine Graneros Shale (fig. 2) near the middle of the Wattenberg field, which is approximately delineated by the 0.9-percent R_O contour in figure 6. Depth to production ranges from about 4,000 ft (1,200 m) in east-central Washington County to 8,200 ft (2,500 m) in northwest Elbert County (fig. 1) (Hemborg, 1993d). The "D" sandstone is as much as 90 ft (27 m) thick and has two types of sandstones that are designated D-1 and D-2 members; the D-2 is a widespread, very fine to fine-grained sandstone that was deposited in shoal-water delta environments (Weimer and others, 1997). The unconformably overlying D-1, the primary reservoir facies, is a fine- to medium-grained sandstone with shales and siltstones that were deposited in narrow valley fills (Weimer and others, 1997). Primary trapping mechanisms in the field and across the basin are stratigraphic (Martin, 1965), mainly pinch-outs of the valley-fill sandstones against low-permeability mudstones and cemented sandstones. Wattenberg also has a structural component, with hydrocarbons being trapped in segregated blocks bounded by internal faults.

Elevations on the top of the Muddy ("J") Sandstone are shown in figure 8. The steeply dipping western flank of the basin is well illustrated by the rapid change in contour spacing, and the offsets along the five right-lateral wrench faults

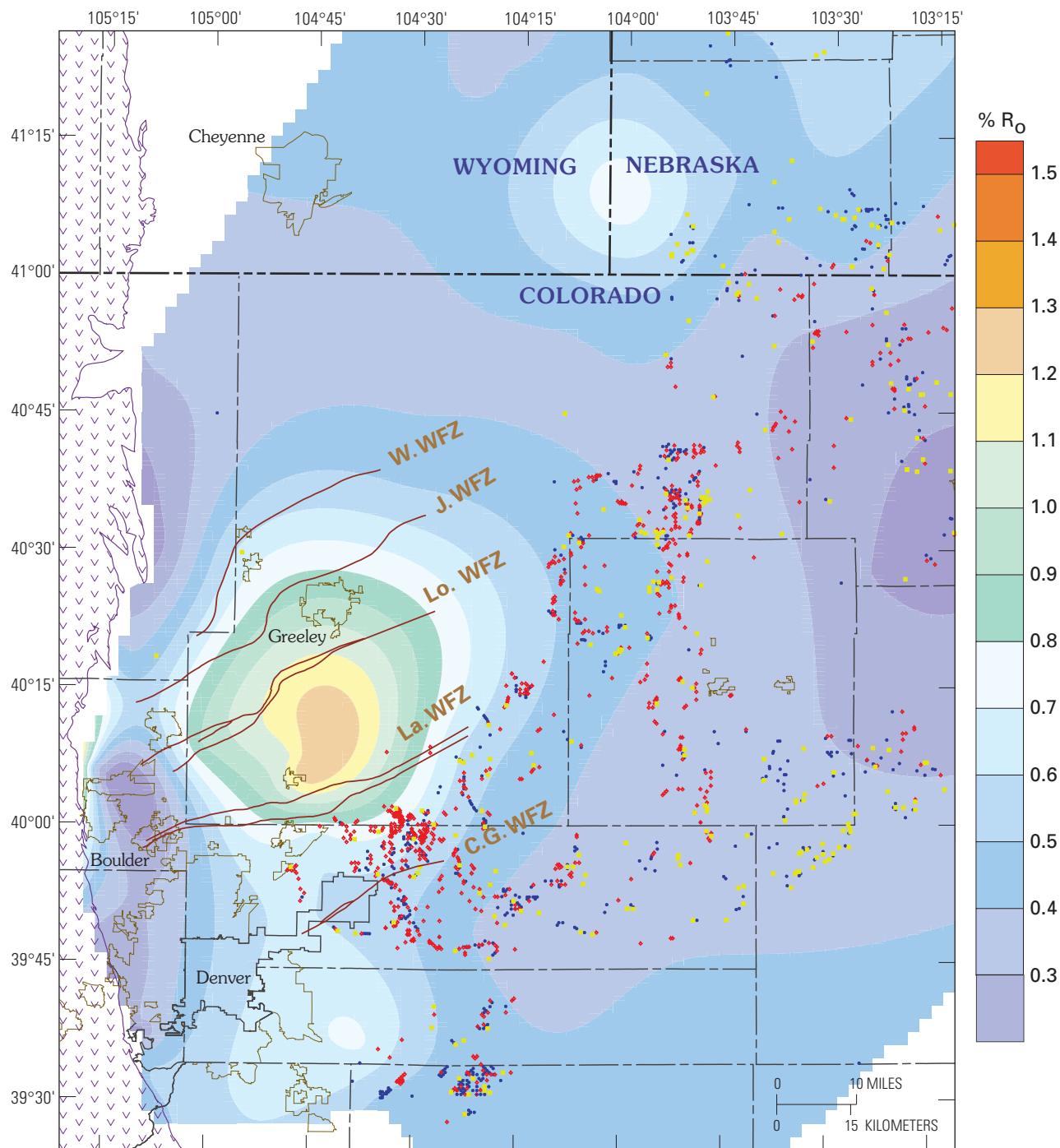


Figure 6. Distribution of oil (yellow), gas (red), and oil and gas (blue) wells that produce from the Lower Cretaceous "D" sandstone across the Denver Basin. Classifications for "D" sandstone wells are based on Petroleum Information/Dwights (1999b) production histories. Color-fill contours are vitrinite reflectance contours (percent R_O) for the Graneros, Huntsman, Mowry, and Skull Creek Shale source rocks (Higley, 1988; and unpublished data of Higley). The Wattenberg gas field is approximately outlined by an R_O of 0.9 percent; 0.6 percent R_O is the approximate lower limit for oil generation. Shown are locations of the Windsor (W. WFZ), Johnstown (J. WFZ), Longmont (Lo. WFZ), Lafayette (La. WFZ), and Cherry Gulch (C.G. WFZ) wrench faults.

that cut the Cretaceous section and extend into basement rocks are readily observed. Erslev and Wiechelman (1997) indicated that northeast-trending faults in adjacent Front Range

basement exposures are poorly represented; this suggests that areas where basement-involved strike-slip faulting is important are primarily localized to the basin.



Figure 7. View looking north-northwest at an outcrop of mostly valley-fill (river-deposited) sandstones of the Lower Cretaceous Horsetooth Member of the Muddy ("J") Sandstone (bounding arrows) and underlying gray marine shales of the Skull Creek Shale. Location is along Turkey Creek and Hampden Road (Highway 285), several miles east of the Rocky Mountain front. Vertical yellow and black streaks on the Mowry Shale outcrop to the left are the result of chemical reactions associated with this natural oil seep.

Figure 9 is a thin-section photomicrograph of a sample of fine- to medium-grained valley-fill sandstone from a section of core of the Horsetooth Member of the Muddy ("J") Sandstone located in the Kachina field, Washington County (fig. 1). The black blob is oil that is trapped within the (blue) pore space. The spotty white "particles" within other pores are kaolinite, a variety of clay, which resulted from dissolution of feldspar grains, probably during chemical processes associated with hydrocarbon generation and migration. The sand grains are cemented together by early diagenetic (relatively soon following deposition) quartz (white) and later calcite (pinkish pore filling). The large blocky pore in the center of the photograph resulted mainly from dissolution of feldspar and quartz grains. Permeability (connections between pores) is occluded (filled) by the kaolinite and by calcite and quartz cements.

The mainly nearshore marine, deltaic, and valley-fill sandstone reservoirs of the Muddy ("J") Sandstone (fig. 2) were deposited from about 99 to 97 Ma during a regression of the Cretaceous epicontinental seaway* (Kauffman, 1977; Obradovich and Cobban, 1975; Weimer, 1984; Weimer and others, 1986). The overlying "D" sandstone was largely deposited as valley fill and as deltaic sandstones adjacent to the seaway. Primary trapping mechanisms in most fields across the basin are stratigraphic, either facies changes or updip pinch-outs of the porous and permeable reservoir sandstones against low-permeability shales. Other trap types are structural or a combination of stratigraphic and structural. Trap formation along the western margin of the basin during Paleocene and Eocene time (fig. 10) was associated with folding and faulting associated with the Laramide orogeny.

Figure 10 is an events chart for the "D" and Muddy ("J") Sandstone. Seal rocks for the "D" sandstone and Muddy ("J")

Sandstone reservoirs are primarily the overlying and relatively impermeable Mowry, Huntsman, and Graneros Shales. The Huntsman Shale, which is a source rock for the "D" sandstone, has generally lower total organic carbon (TOC) contents, greater amounts of silt, and lesser levels of thermal maturation than the Mowry and Graneros (Higley and others, 1992). The Skull Creek Shale, located below the Muddy ("J") Sandstone, may also be a source rock; lower TOC values and a mix of types II and III kerogen may make it more gas prone.

The burial history chart of the Muddy ("J") Sandstone in the Wattenberg field (fig. 11) integrates major depositional and structural events across the Denver Basin to show changes in the rock record through time. The information is derived from the No. 1 G.W. Stieber gas well within the Wattenberg field (fig. 1), in sec.* 24, T.*1 N., R.* 67 W. Also shown are time-temperature indices (TTI) lines that were calculated using a constant geothermal gradient* of 2.55°F/100-ft burial depth. This is the approximate average current temperature gradient within the Wattenberg field as determined from Meyer and McGee (1985); the gradient outside the field area is about 2.0°F/100 ft. It is unlikely these present gradients are representative of those from the past. Estimated onset of oil generation is at a TTI of 10 (vitrinite reflectance R_o 0.6 percent); generation of thermogenic gas occurs at a TTI of about 160 (R_o 1.3 percent). There is a poor correlation between R_o and TTI values at this well, inasmuch as the measured R_o is 1.14 percent for Mowry and Graneros Shales samples from core of this well, and the calculated maximum TTI of 350 correlates to an R_o of 1.6 percent. One interpretation for this discrepancy is that the "cooking event" and associated high heat flow was a relatively recent event. Another is that most of the sampled shales have a mix of terrestrial and marine organic matter,

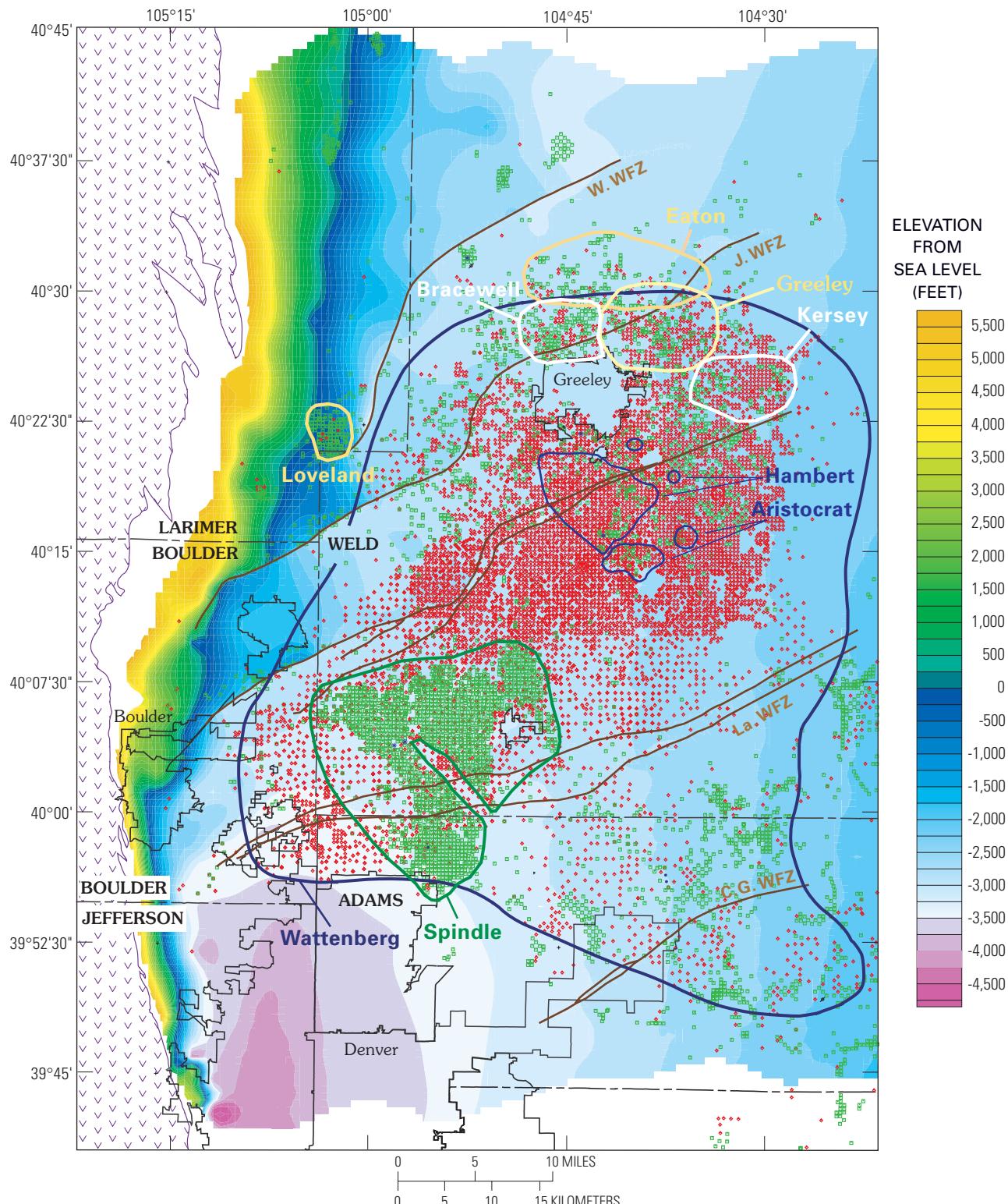


Figure 8. Locations of oil and (or) gas wells within a portion of the Front Range Urban Corridor. Oil wells are green, gas wells are red dots, and oil and gas wells have blue symbols. Color-filled contours are elevation relative to sea level on the top of the Lower Cretaceous Muddy ("J") Sandstone. Contour interval is 250 feet; contours are offset relative to Windsor (W. WFZ), Johnstown (J. WFZ), Longmont (Lo. WFZ), Lafayette (La. WFZ), and Cherry Gulch (C.G. WFZ) wrench faults. The eastern and western termini of these faults are not mapped. Contours show the steeply dipping western flank and gently dipping eastern flank of the Denver Basin. Fields mentioned in the text have labeled boundaries.

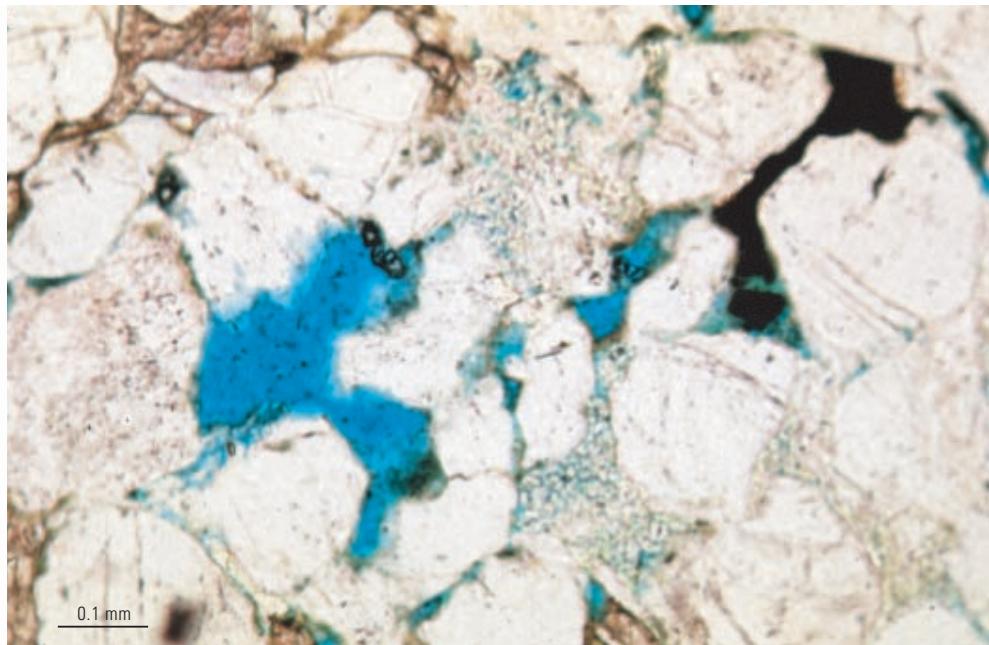


Figure 9. Thin section photomicrograph of a fine- to medium-grained sandstone in the Horsetooth Member of the Muddy (“J”) Sandstone, Kachina field, Washington County. Image is transmitted light. Black pore-filling is oil, blue pore-filling is epoxy. Quartz (white) grains have quartz overgrowths. Kaolinite (white “popcorn” in pores near the oil) occludes porosity and permeability, as does calcite cement (pink pore filling). Mottled large grain in middle left side is a mudstone rip-up clast. Core depth is 4,284 feet (1,306 meters), in the B-1 Sheetz well.

and this mix of macerals, with their associated different levels of light reflectance, influences the calculated vitrinite reflectance values. Included in the model is a minimum of 1,400 ft (430 m) of overburden (Tertiary strata) that was subsequently eroded, but as much as 4,000 ft (1,200 m) of additional upper Tertiary strata may also have been removed by erosion (Higley and Schmoker, 1989). This late-stage deposition and erosion, however, would have caused only a slight increase on calculated final TTI values. Onset of oil generation using the TTI calculations was about 70 Ma, just prior to the onset of the Laramide orogeny at about 67.5 Ma; but the probable onset is 65 Ma, following deposition of 6,400 ft (1,900 m) of the Pierre Shale. Gas generation (red line in fig. 11) probably started at 40 to 20 Ma during another time period of increased igneous activity in the basin (Higley and Schmoker, 1989).

Unconventional Reservoirs (Wattenberg Field)

Producing formations in the Wattenberg field (figs. 1, 4) are classified as “tight” (low permeability) for the Muddy (“J”) Sandstone, as well as the Niobrara and Codell reservoirs; the field is categorized as a low-permeability basin-center gas field. The first well drilled in the field was completed in 1970. Within the field boundaries, oil and gas are produced from the Lytle Formation, Plainview Sandstone, Muddy (“J”) Sandstone, “D” sandstone, Codell Sandstone Member of the Carlile Shale, Niobrara Formation, and the Hygiene (“Shannon”) Sandstone Member and Terry (“Sussex”) Sandstone Member of the Pierre Shale (fig. 2). Approximately 1.75 TCFG, 76.4 MMBO, and 15.7 MMBW have been produced from all formations; this is based on analysis of production data from the Colorado Oil and Gas Conservation Commission (through 1999) and Petroleum Information/Dwights (through 1999).

The field has more than 6,800 oil and (or) gas wells and 990 abandoned wells (Lawson and Hemborg, 1999; McKinney, 1993). The Petroleum Information/Dwights databases (through 1999) listed 9,328 leases for a total of 11,371 wells, but this included numerous duplicate and triplicate listings of wells. Much of the production, particularly for Niobrara and Codell wells, is reported on a lease basis. Average spacing for these wells and for those in shallower formations is 40 acres, which commonly increases the number of wells per lease. Most Muddy (“J”) Sandstone production, which averages 160-acre spacing, is reported for single wells in a lease. Of all the oil and gas leases in Wattenberg, 96.2 percent have producing wells (Colorado Oil and Gas Commission well data through 1996, Petroleum Information/Dwights WHCS database through 1999).

The Lower Cretaceous Muddy (“J”) Sandstone is the primary producing formation in the Wattenberg field; there are more than 1,900 producing wells and 336 dry and abandoned holes. Natural gas is concentrated along the axis of the Denver Basin. Trapping mechanisms are a complex intermixture of diagenesis*, lateral facies change, and vertical and lateral movement along right-lateral wrench fault* systems (fig. 8). More than 779 BCFG, 8.4 MMBO, and 6.6 MMBW have been produced from the Muddy (“J”) Sandstone in the Wattenberg field; the estimated ultimate recovery (EUR) of 1.27 TCFG was determined from geologic and engineering analysis of the production history of 1,680 Muddy (“J”) Sandstone wells; remaining field life is estimated to be more than 30 years (Higley and others, 2003). Muddy (“J”) Sandstone average gas characteristics in the field include a heating value of 1,139 British Thermal Units (BTU)* per 1,000 standard cubic feet (scf), specific gravity of 0.682, and composition of 82.6 percent methane, 10.1 percent ethane, 2.7 percent propane, 0.3 percent pentane, and 2.6 percent carbon dioxide (Hemborg,

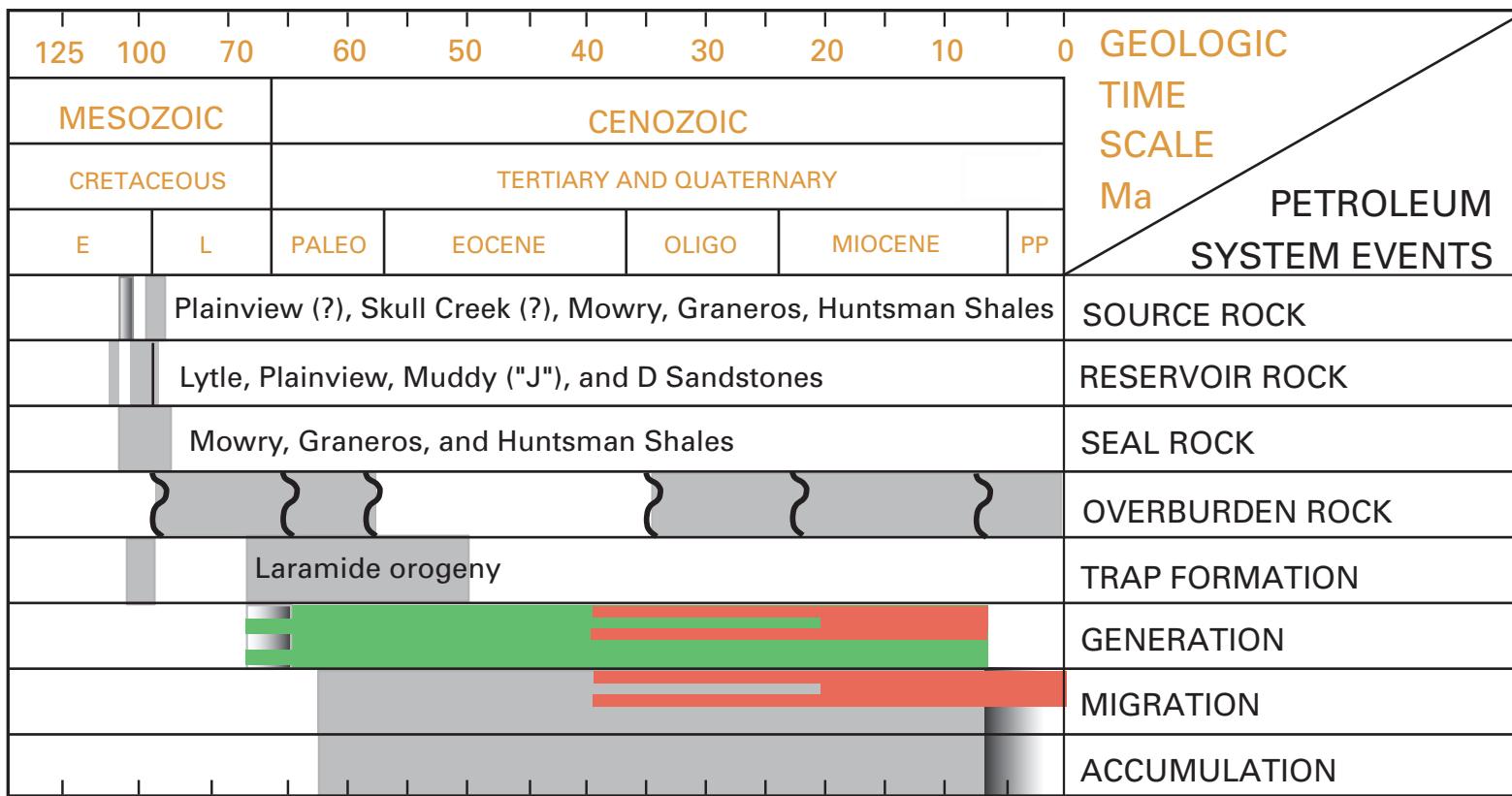


Figure 10. Geologic events chart for the Cretaceous "D" and Muddy ("J") Sandstones in the Front Range Urban Corridor, Denver Basin. Gray intervals mark times of primary events; gradients show possible times of events. Green and red are respective times of generation of oil and gas from the Mowry and Graneros Shales that are the principal hydrocarbon source rocks. Wavy black lines indicate ages of probable unconformities. Abbreviations: E, Early; L, Late; Paleo, Paleocene; Oligo, Oligocene; PP, Pliocene and Pleistocene. Sources of information are Obradovich and Cobban (1975), Tweto (1975, 1980), Irwin (1976), Kauffman (1977), MacMillan (1980), Trimble (1980), Zoback and Zoback (1980), Tainter (1984), Weimer (1984, 1996), Higley and Gautier (1988), Crysdale and Barker (1990), and Higley and others (1992).

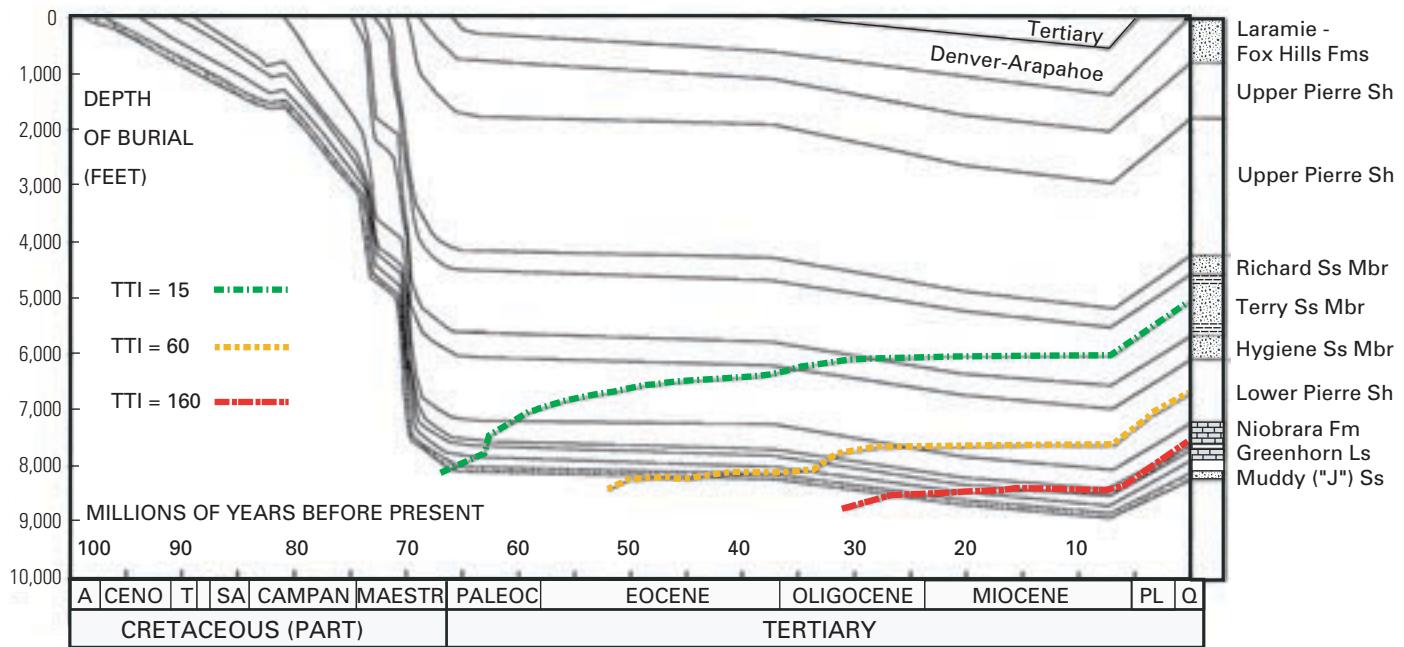


Figure 11. Burial history reconstruction of the Lower Cretaceous Muddy ("J") Sandstone in the No. 1 G.W. Steiber Unit gas well, Wattenberg field. Time-temperature indices (TTI) were determined using a constant geothermal gradient of $2.55^{\circ}\text{F}/100\text{-foot}$ burial depth. The model includes a conservative estimate of 1,400 feet (430 meters) of deposition and subsequent erosion of upper Tertiary sediments. As much as 4,000 feet (1,200 meters) of additional upper Tertiary strata may have been deposited and then removed during the last 7 million years (Higley and Schmoker, 1989). Data based on examination of wells logs in the Wattenberg field and surrounding area supplemented by the following references: Brown (1943), Obradovich and Cobban (1975), Tweto (1975, 1980), Irwin (1976), Kauffman (1977), Trimble (1980), Zoback and Zoback (1980), Porter and Weimer (1982), Tainter (1984), Weimer (1984, 1996), Meyer and McGee (1985), Weimer and others (1986), Cobban, oral communication (1988), and formation tops from the Petroleum Information WHCS database (1999).

1993a). Median gas-oil ratio (GOR) is 95.5 MCF/BO for Muddy ("J") Sandstone production across the field.

The primary reservoir rocks in Wattenberg field are very fine to fine-grained, massive to tabular-bedded to burrowed, upward-coarsening sandstones of the Fort Collins Member of the Muddy ("J") Sandstone (fig. 2). Oil and gas are also produced from the unconformably overlying Horsetooth Member (fig. 2); this production is concentrated near the southern border of the field, south of the Lafayette WFZ, and is primarily from porous and permeable, fine- to medium-grained sandstones that were deposited in valley-fill environments.

Additional new production will result from development of reservoirs in the Lower Cretaceous Plainview Sandstone Member of the South Platte Formation and the Lytle Formation of the Dakota Group. No production values are available for these formations, mainly because Muddy ("J")/Plainview/Lytle production is generally all reported as commingled Dakota production. The Plainview is located about 200 ft (60 m) stratigraphically below the Muddy ("J") Sandstone within the field and about 90 ft (27 m) below at the Turkey Creek outcrops (figs. 2, 3). Because of the short additional drilling depths, most production is from new wells or from deepening wells that originally bottomed in the Muddy ("J").

Lytle Formation exposures at Turkey Creek, west of Denver, are mainly varicolored mudstones, fine- to coarse-grained sandstones, and conglomerates of fluvial origin; the unconformably overlying Plainview Member (figs. 2,3) is composed of very fine- to medium-grained sandstones of coastal plain swamp and tidal flat and channel environments (Weimer, 1996).

As elsewhere in the Denver Basin, the primary source rocks for oil and gas for the Muddy ("J") and "D" in the Wattenberg field area are the overlying Mowry and Graneros Shales (fig. 2) (Clayton and Swetland, 1980). The Huntsman and Skull Creek Shales also may have contributed some hydrocarbons. A dark gray shale that is located at the base of the Plainview Formation is also a potential, but as yet untested, source for the Lytle and Plainview (John Ladd, oral commun., 2000; Ladd, 2001). Average TOC is about 2.5 weight percent for the Graneros and Mowry Shales in the basin (Higley and others, 1996); the Mowry and Graneros generally have greater TOC than the Skull Creek Shale. Vitrinite reflectance values within the field (fig. 6) are as much as R_o 1.51 percent. This exceeds the estimated minimum cutoff by Waples (1980) of R_o 1.35 percent for thermogenic gas, which results from breakdown of precursor oils and is generated from

hydrocarbon source rocks. Gas may have been generated at a lower R_o than this because of the mix of gas-prone type III terrigenous vitrinite macerals (organic matter) with the type II macerals from mostly marine environments. Greatest levels of thermal maturation are along the basin axis between Greeley and Denver (fig. 6); but north of Greeley the trend of greatest levels of thermal maturity turns northeast toward the Nebraska panhandle. Relatively low levels of thermal maturation in the basin near Cheyenne, Wyo., combined with scattered oil wells and the absence of gas wells (fig. 1) decrease the possibilities of finding another basin-center gas field here.

Upper Cretaceous Niobrara Formation and Codell Sandstone Member of the Carlile Shale

More than 72.1 MMBO and 678 BCFG have been produced from the Niobrara Formation and Codell Sandstone Member of the Carlile Shale in the west-central part of the Denver Basin; of these amounts, 50.8 MMBO and 588 BCFG are from the Niobrara and Codell in the Wattenberg field (Petroleum Information/Dwights production data through 1999), representing approximately 67 percent of the total oil and 34 percent of the total gas production for the field. Actual contribution to total production from these formations is probably somewhat greater because the listed volumes of produced Niobrara and (or) Codell oil and gas excludes that which is reported commingled with "D" and (or) Muddy ("J") sandstones.

Most Niobrara/Codell production from the Spindle field (fig. 1) is reported commingled with that of the overlying Terry ("Sussex") and Hygiene ("Shannon") Sandstones of the Pierre Shale (fig. 2), the primary reservoirs in the field. Minimum cumulative production through 1996 from leases that list only Niobrara and Codell production is 14,526 BO and 47,043 MCFG; maximum cumulative from all leases that include Niobrara/Codell production is 226,188 BO and 2,045 MMCFG (modified from Lawson and Hemborg, 1999). Field cumulative (through 1998) is 56.84 MMBO and 278.5 BCFG (Colorado Oil and Gas Commission well data through 1998). Codell production is limited to areas of the basin north of Denver to about the Wyoming State line; Niobrara production includes biogenic gas in several fields close to the Colorado-Kansas border, in western Kansas, and in the Nebraska panhandle. These were not added to the above production figures.

Fields that produce from the Codell Sandstone Member and contain reserves greater than 6 BCFG include Bracewell, Eaton, Greeley, Kersey, and Wattenberg. The Hamber and Loveland fields (fig. 8) have smaller Codell reserves. Productive depths in the urban corridor area range from about 4,000 to 8,000 ft (1,200 to 2,400 m); 6,850 ft (2,090 m) is the average depth of production for the formation in the seven fields. Thickness of reservoir sandstones ranges from 22 to 35 ft (6.7 to 11 m) for five of the seven fields, including Wattenberg (Weimer and Sonnenberg, 1983).

The Niobrara contributes 15 to 25 percent and the Codell 75 to 85 percent of the petroleum produced from a typical Niobrara-Codell well, such as the Robert Gerrity-OCUMA II C31-15, in sec. 31, T. 14 N., R. 64 W. (Hemborg, 1993b). Additional characteristics of a typical well include specific gravity of 0.60 and gas content of 76.2 percent methane, 13.7 percent ethane, 5.5 percent propane, 2.6 percent butane, 1.0 percent carbon dioxide, 0.2 percent nitrogen, and a trace of argon and helium (Hemborg, 1993b). Heat content of the gas is 1,283 BTU/scf (Hemborg, 1993b) and averages 1,350 BTU/scf for the field (Cox, 1998). Initial average API gravity is 45° for the Codell oil (Higley and Schmoker, 1989). Water saturation of the reservoir is 40 to 60 percent (Cox, 1998).

The earliest production from the Carlile Shale was from shallow fractured sandstones and shales in the Boulder field (discovered in 1901), west of the Wattenberg field in Boulder County. More than 800 MBO and 52 MMCFG have been produced from the Carlile Shale and Pierre Shale in the Boulder field (Colorado Oil and Gas Commission, 1998). Because early reporting of oil and gas was inconsistent, actual production is probably greater. The field is located on a fractured south-plunging anticline, and production is associated with fractures that decrease with depth; oil gravity is 39° API (Cary, 1961). Drill depths for current producers range from 110 to 8,425 ft (33 to 2,568 m) and average 2,612 ft (796 m). The next Carlile production was from the Codell Sandstone Member in a wildcat well, Lillie Pallaoro No. 1 in sec. 7, T. 5 S., R. 69 W., that was drilled just southeast of Morrison, Colo., in 1955; depth range to perforations in that well was 8,956 to 8,980 ft (2,730 to 2,737 m) (Hemborg, 1993b). It was located in what became the Soda Lake field, which was abandoned after producing 15,275 BO and 3,820 MCFG (Hemborg, 1993b).

Exploration for basin-centered accumulations of oil and gas in the Niobrara and Codell was slow until the early 1980s, when drilling rates increased as a result of higher oil and gas prices combined with Federal pricing incentives for these "tight" low-permeability reservoirs, the discovery of "sweet spot" areas of greater production, and the economic benefits of commingled production with the underlying Muddy ("J") Sandstone.

The Codell was classified as tight on September 16, 1982, under the Natural Gas Policy Act of 1978. Cox (1998) stated that:

"in May 1998, the Colorado Oil and Gas Conservation Commission issued a ruling that allows up to 10 wells per 320 acres in any of the Cretaceous reservoirs. Thus, currently uneconomic or marginally economic Codell/ Niobrara wells can now be deepened to the Muddy ("J") Sandstone, or can be recompleted in the shallower Terry ("Sussex") Sandstone where it is productive. By not having to prepare a new location and drill and complete the 7,300 feet (average) depth to the Codell/Niobrara, a great cost savings for completing the other zones can be achieved from using existing wells. Of course, if the existing well is owned by one party, while the rights to

develop other zones are owned by other parties, the different groups will have to reach a mutual agreement in order to proceed. A considerable amount of negotiation and bartering is anticipated. In any case, the new ruling is likely to lead to improved uses of existing wells and equipment to develop the oil and gas resources of Colorado."

Thickness of the Niobrara Formation in the Wattenberg field area ranges from 240 to 330 ft (73 to 100 m); production is from four 20- to 30-ft- (6- to 9-m-) thick chalk zones (Hemborg, 1993b). Thickness of the Codell Sandstone Member of the Carlile Shale in the field area ranges from a wedge edge to 25 ft (7.6 m) and averages 15 to 20 ft (4.6 to 6.1 m) (Weimer and Sonnenberg, 1989); average pay thickness for the Codell is 14 to 16 ft (4.3 to 4.8 m) (Hemborg, 1993b).

Hemborg (1993b) reported that Codell porosity in the area is commonly 10 percent or less, primarily due to abundant pore-filling clay, calcite cements, and iron oxide, and that in-place permeability of the Codell is 0.022 millidarcy* (mD). The Codell Sandstone in the Wattenberg field has an average porosity and permeability of 14 percent and 0.1 mD based on core testing (Higley and others, 1996). Niobrara porosity in the area is 10 percent or less, and matrix permeabilities are less than 0.1 mD (Hemborg, 1993b). Typical values of porosity and permeability are 14 percent and 0.05 mD for the Niobrara/Codell wells in the Wattenberg field (Cox, 1998). With these low permeabilities, natural and induced fault and fracture networks are important for production of oil and gas. Hydraulic fracturing* for the Niobrara/Codell wells vary from injecting 70,000 gallons of fluid and 200,000 pounds of sand to 180,000 gallons of fluid and 575,000 pounds of sand (Hemborg, 1993b). Reservoir-drive mechanisms include those involving retrograde condensate behavior as well as solution gas (Hemborg, 1993b). Retrograde condensates occur when the reservoir pressure is decreased through time by production, allowing condensation of hydrocarbons in the reservoir or in the well bore. Figure 12 (Cox, 1998) shows a typical production decline curve for oil and gas in a well that has been hydraulically fractured and produces from the Niobrara/Codell intervals. The large initial production, which results primarily from induced fracturing, is associated with radial flow of oil and gas to the well bore and decreases rapidly through time as the radial flow is replaced by linear flow along existing faults as well as natural and induced fractures.

Niobrara and Codell gas production is less than that of the underlying Muddy ("J") Sandstone. The average Niobrara/Codell well on 40 acres is expected to recover about 130 MMCFG and 11,000 BO, compared to the average Muddy ("J") Sandstone ultimate production of 630 MMCFG on 160 acres (Cox, 1998) (table 1). Values shown in table 1 and displayed in figures 13A–H resulted from aggregating the various Niobrara/Codell leases by township; this was done to determine the average production response within each township. Using a power-law relation, the rate of gas production for each township is a function of the initial rate of production per well and the number of active wells; it was assumed that once

a well began producing, it would continue producing until it became uneconomic (Cox, 1998). Niobrara/Codell production performance was found to follow a power-law decline, with an average exponent of 0.5 for gas (indicative of linear flow) and an average exponent of 0.7 for oil (Cox, 1998).

Figure 13A–H shows distribution and production characteristics of oil and gas across the field. Based on analysis of production histories (Cox, 1998), average initial rate of production per well for the Niobrara and Codell across the area of the Spindle and Wattenberg fields is 155 MMCFG and 26 BO per day; these rates decrease through time such that the daily well production after 1 year is 43 MMCFG and 4.4 BO; average initial gas/oil ratio (GOR) is 5,949 standard cubic feet* per barrel of oil (scf/bbl); the average GOR at 20 years is 11,576 scf/bbl. The Niobrara/Codell analysis indicated the presence of a high gas-production area (330 MMCFG/well) centered on T. 4 N., R. 65 W. (fig. 13A, B, G), with production decreasing rapidly in all directions (Cox, 1998). This high gas-production area is also the region with the greatest GOR values, which increase through time as reservoir pressure decreases and the amount of produced gas increases relative to that of oil (fig. 13E, F). The high oil-producing area (fig. 13C, D, H) appears as a rim around the high gas-producing area, with the maximum reaching 18,000 bbl per well in T. 3 N., R. 67 W. and T. 6 N., R. 66 W.; the high oil-production "rim" adds to the central gas high, leading to the most prospective area being in T. 3–6 N., and R. 64–66 W. (Cox, 1998). Possible geologic reasons for these production highs include (1) greater fracturing and more open-fracture networks near the Longmont WFZ, (2) better grain sorting and lower amounts of matrix clays and muds with associated increased porosity and permeability, and (3) thicker reservoir sandstones of the Codell in this area. Oil and gas are stratigraphically trapped in low-porosity and low-permeability nearshore marine sandstones of the Codell. Reservoir facies of the Niobrara in the field area are mainly fractured sandy limestones and shales; sediment source was from the west, and depositional energy decreased eastward, accompanied by an eastward increase in organic matter content (Longman and others, 1998).

Figure 14 is a geologic events chart that shows important principal stages in the formation of Upper Cretaceous reservoirs, traps, and source rocks with their linked hydrocarbon generation, migration, and accumulation.

Illite/smectite* geothermometry was used to determine that the area thermally mature for hydrocarbon generation in the Niobrara Formation includes the entire Front Range Urban Corridor north of Elbert County, located just south of Denver (fig. 1) (Pollastro, 1992). The eastern boundary of Morgan County (fig. 1) is the approximate eastern limit of Niobrara source rocks that are thermally mature for oil generation (fig. 1) (Pollastro, 1992). Black shales within the Niobrara Formation, some of which are rich in coccoliths* and fecal pellets, are the major hydrocarbon source rocks; shaly beds that overlie the chalky or sandy reservoir intervals are seals (Longman and others, 1998). Organic richness (TOC) in source intervals ranges from less than 1 percent in the

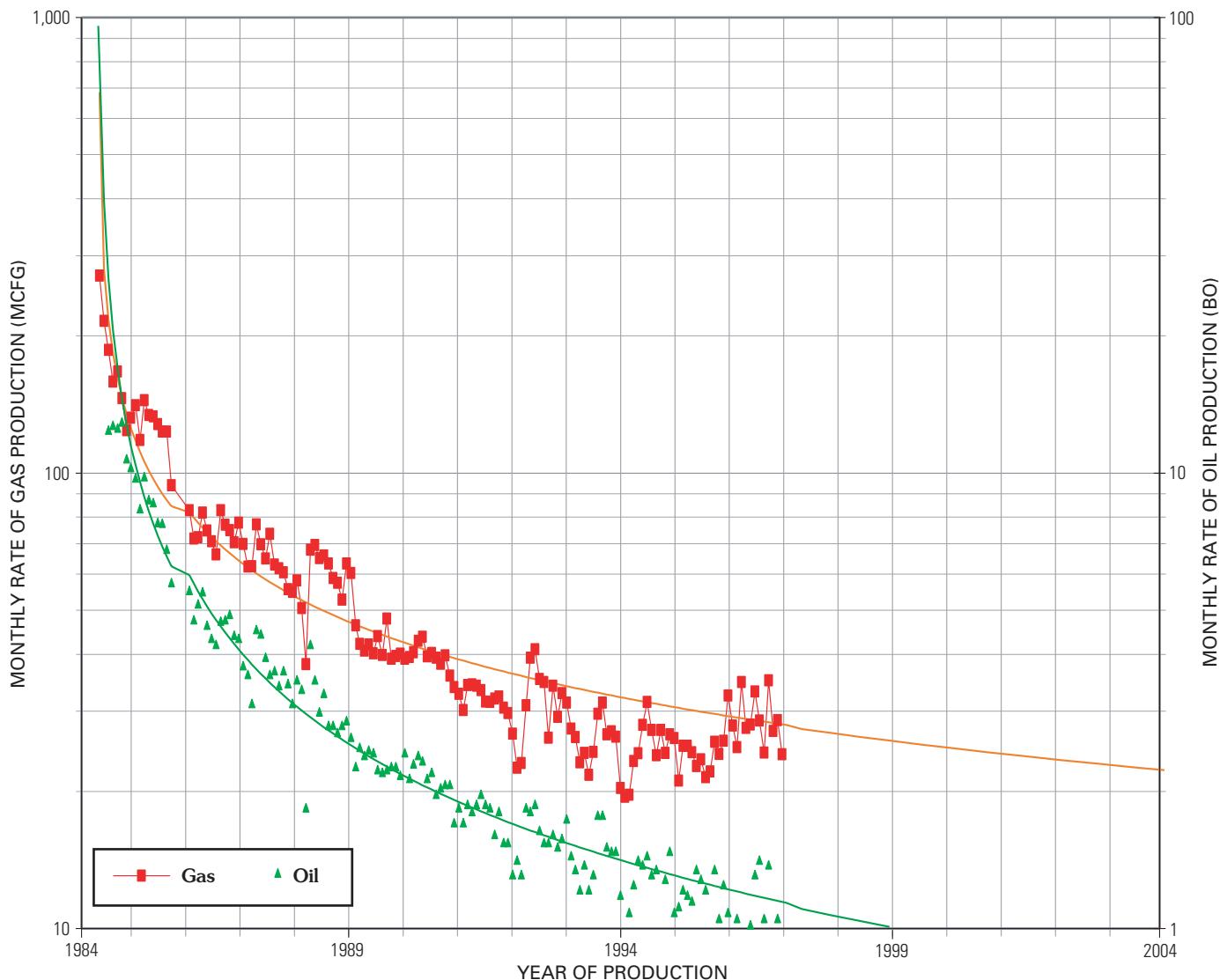


Figure 12. Decline curve of monthly oil and gas production for a typical Niobrara/Codell well in the Wattenberg gas field (Cox, 1998). Vertical scale is thousand cubic feet of gas (MCFG) and barrels of oil (BO).

siliciclastic-rich facies in the western part of the basin to more than 7 percent in the clastic sediment-starved facies along the eastern part of the basin (Longman and others, 1998). Upward migration of hydrocarbons may also have occurred along faults within the field. Underlying Mowry and Graneros Shales, the primary source rocks for Muddy ("J") Sandstone oil and gas, exhibit thermal maturity levels of 0.8 percent R_o or greater in the area (Higley and others, 1996).

Upper Cretaceous Pierre Shale Sandstones

Three oil and gas fields, Spindle, Hambert, and Aristocrat, have each produced more than 5 BCF of associated gas from the Upper Cretaceous Richard, Terry ("Sussex"), and Hygiene ("Shannon") Sandstone Members of the Pierre Shale

(fig. 15). Much of the gas produced from the Pierre Shale sandstones in the Front Range Urban Corridor is reported commingled with deeper formations, such as the Niobrara/Codell and (or) Muddy ("J") Sandstone in the Wattenberg field.

"Sussex" and "Shannon" sandstones are informal names for subsurface units in the Denver Basin; they are formal members of the Pierre Shale in the Powder River Basin of Wyoming. Figure 15 shows producing wells for the Pierre Shale and associated sandstones within the Denver Basin; excluded are the Florence field and a limited number of wells in and near the Chivington field, southeast Wyoming. These fields are shown in figures 16 and 1, respectively. Color-fill contours (fig. 15) are elevations on the top of the Terry ("Sussex") from more than 8,000 wells across the basin (Petroleum Information/Dwights WHCS data through 1998). Basin lows stretch linearly from Denver to Cheyenne, Wyo. Elevation

Table 1. Rates of oil and gas production through time for Niobrara Formation and Codell Sandstone Member of the Carlile Shale wells in townships in the Wattenberg field area (Cox, 1998). Cumulative (Cum) production values are through mid-1997. The 20-year gas and oil forecasts are from 1997. Minimum gas decline rate is 6 percent and minimum oil decline rate is 8 percent. Economic limit to determine life of wells is based on \$500/month operating costs, prices of \$2/MCF of gas and \$16/bbl of oil, 8 percent severance plus added value, and a 75-percent net revenue interest to the leaseholder. Results for townships with fewer than 10 leases are questionable. Those with greater than 100 leases per township are considered to be more significant.

[T, township; R, range; MCF, thousand cubic feet; BO, barrels of oil; GOR, gas-oil ratio; scf, standard cubic feet; bbl, barrel; MMCF, million cubic feet; MBO, thousand barrels of oil.]

Area	No. of leases	Initial gas rate, MCF/day/well	Initial oil rate, BO/day/well	Initial GOR, scf/bbl	20 year-gas forecast, MMCF/well	20-year oil forecast, MBO/well	20-year GOR, scf/bbl	20-year gas equiv., MMCF/well	Cum gas to date, MMCF/T.	Cum oil to date, MBO/T.
T.1S.-R.67W.	14	99	23	4,309	72	9	8,233	125	571	73
T.1S.-R.68W.	33	158	31	5,115	136	13	10,330	215	3,108	353
T.1N.-R.65W.	4	131	33	4,000	113	16	6,888	211	107	18
T.1N.-R.66W.	24	113	21	5,298	85	8	10,218	135	896	111
T.1N.-R.67W.	63	199	20	10,078	173	8	20,444	223	7,282	415
T.1N.-R.68W.	28	191	23	8,280	165	10	16,797	224	3,447	235
T.2N.-R.64W.	8	131	23	5,714	107	11	9,692	174	190	24
T.2N.-R.65W.	45	142	20	7,218	113	8	14,196	161	4,022	315
T.2N.-R.66W.	59	106	26	4,081	78	9	9,038	129	4,645	562
T.2N.-R.67W.	69	133	26	5,072	105	9	11,549	159	7,113	744
T.2N.-R.68W.	30	35	5	7,027	9	1	9,950	14	1,991	178
T.3N.-R.64W.	143	108	23	4,643	85	11	7,775	150	10,292	1,414
T.3N.-R.65W.	289	262	26	10,019	228	13	17,320	306	34,326	2,255
T.3N.-R.66W.	491	205	19	10,610	178	11	15,568	246	51,636	3,984
T.3N.-R.67W.	313	162	36	4,441	140	18	7,677	250	20,321	3,316
T.3N.-R.68W.	32	142	26	5,405	114	9	12,399	169	3,708	340
T.4N.-R.64W.	321	150	27	5,612	128	13	9,652	207	33,791	3,944
T.4N.-R.65W.	460	381	27	13,863	330	14	23,965	413	87,186	4,151
T.4N.-R.66W.	445	195	12	16,941	168	7	24,822	209	74,250	3,130
T.4N.-R.67W.	192	114	26	4,340	89	11	8,473	152	14,844	2,272
T.4N.-R.68W.	30	62	43	1,453	45	14	3,196	129	1,407	429

Table 1. Rates of oil and gas production through time for Niobrara Formation and Codell Sandstone Member of the Carlile Shale wells in townships in the Wattenberg field area (Cox, 1998).—Continued

T.5N.-R.64W.	308	151	31	4,944	131	15	8,547	223	32,804	4,366
T.5N.-R.65W.	315	239	35	6,810	207	13	16,138	284	42,765	3,197
T.5N.-R.66W.	220	224	22	10,362	195	11	17,912	260	26,950	1,757
T.5N.-R.67W.	124	132	40	3,329	109	14	7,735	193	8,906	1,471
T.5N.-R.68W.	20	56	32	1,756	39	12	3,294	109	999	297
<hr/>										
T.6N.-R.63W.	18	85	31	2,740	64	12	5,279	136	988	227
T.6N.-R.64W.	173	120	33	3,633	97	14	7,205	179	13,148	2,065
T.6N.-R.65W.	211	119	36	3,329	99	15	6,631	188	16,318	2,821
T.6N.-R.66W.	210	133	42	3,132	114	18	6,333	222	18,838	3,233
T.6N.-R.67W.	35	48	30	1,608	31	10	2,961	94	1,189	417
T.6N.-R.68W.	1	3	18	192	1	4	291	24	1	6
<hr/>										
T.7N.-R.63W.	3	76	11	7,128	39	3	12,308	59	77	8
T.7N.-R.64W.	17	2	2	1,060	0	0	1,120	1	226	126
T.7N.-R.65W.	26	27	27	1,004	15	9	1,758	66	528	277
T.7N.-R.66W.	20	31	31	1,008	19	10	1,817	80	433	242
T.7N.-R.67W.	1	1	2	455	0	0	481	1	0	0
T.7N.-R.68W.	1	16	5	3,307	3	1	4,282	7	1	0
<hr/>										
Averages	---	155	26	5,949	128	11	11,576	195	---	---
TOTALS	4,796	---	---	---	---	---	---	---	529,303	48,775

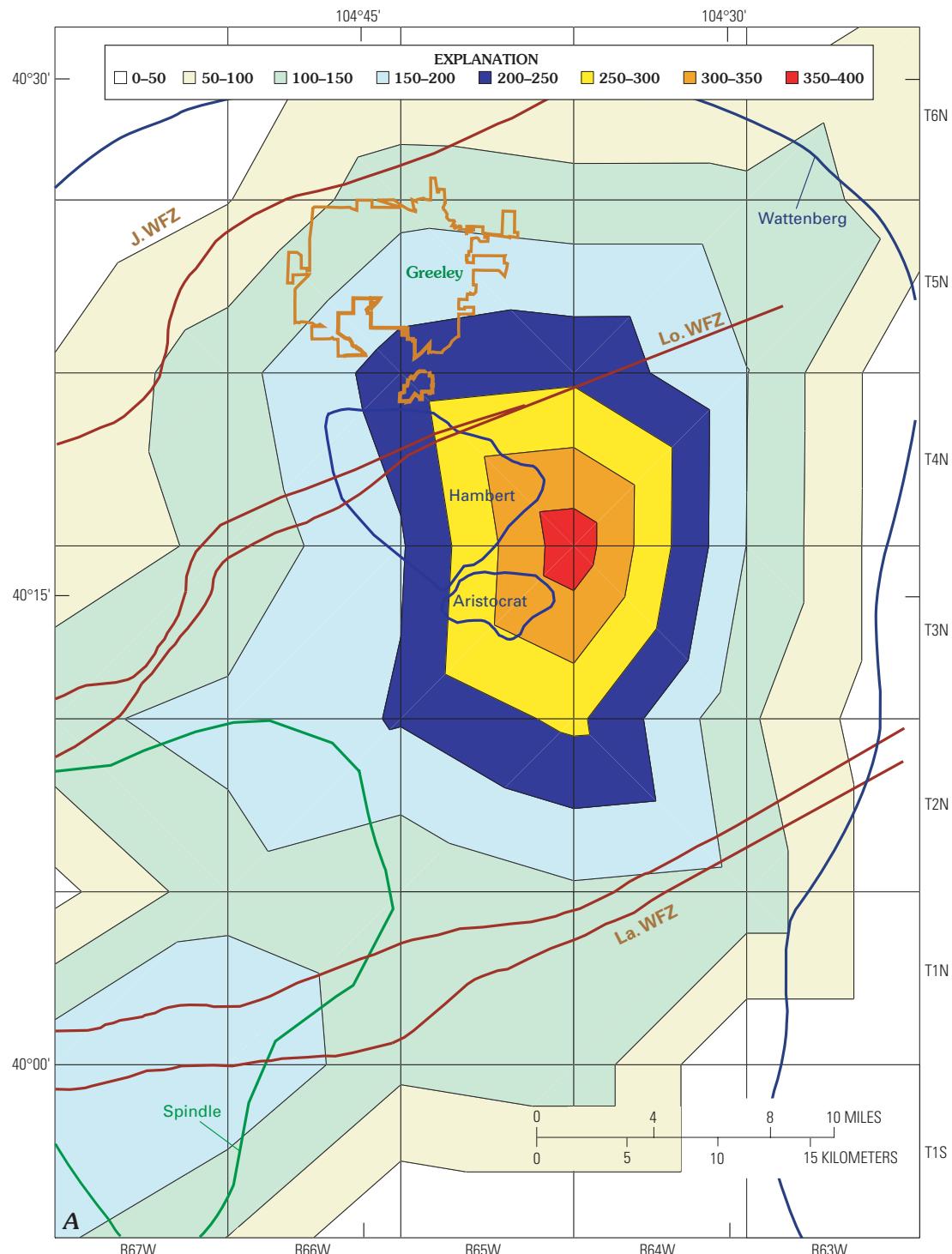
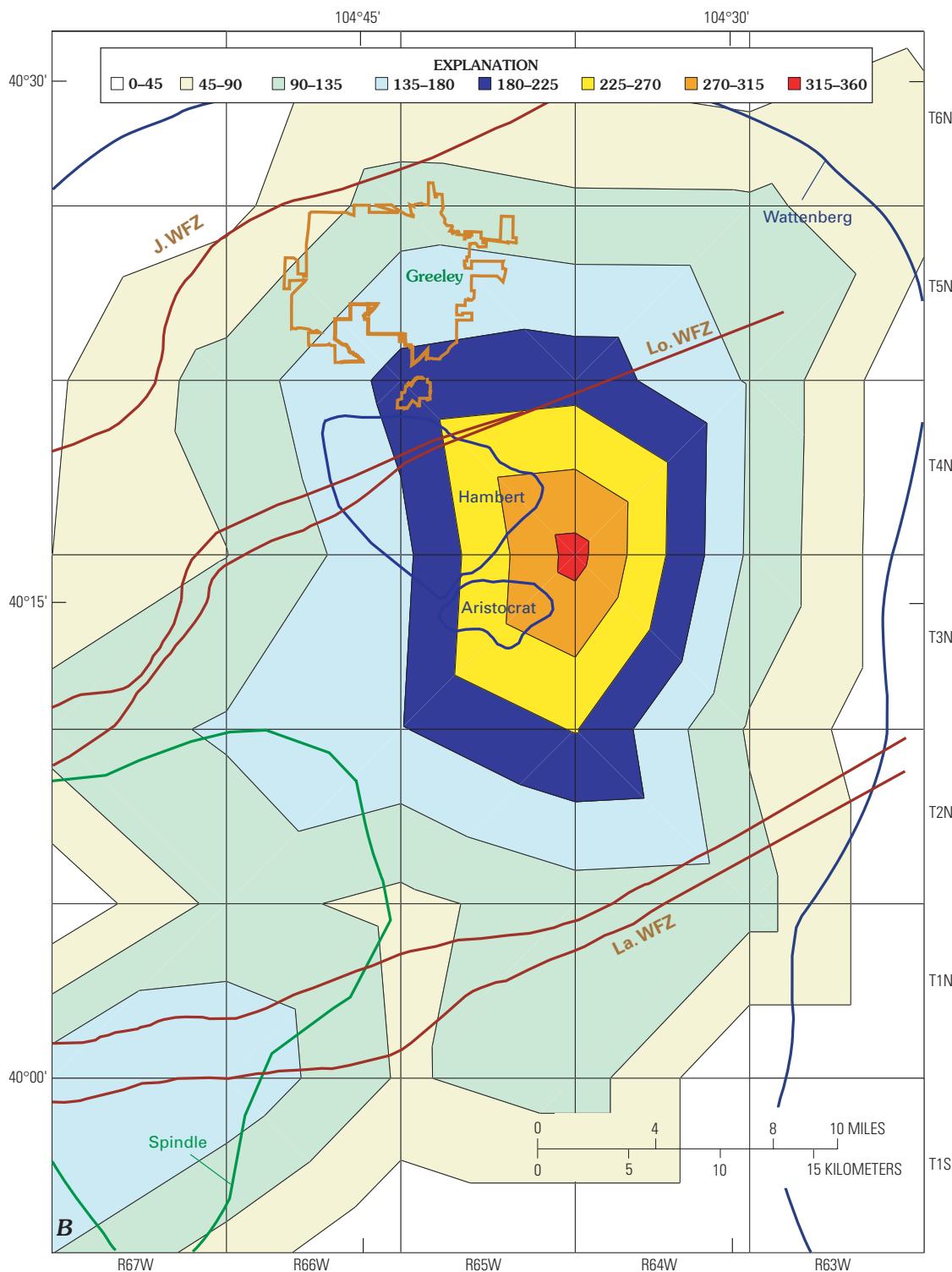
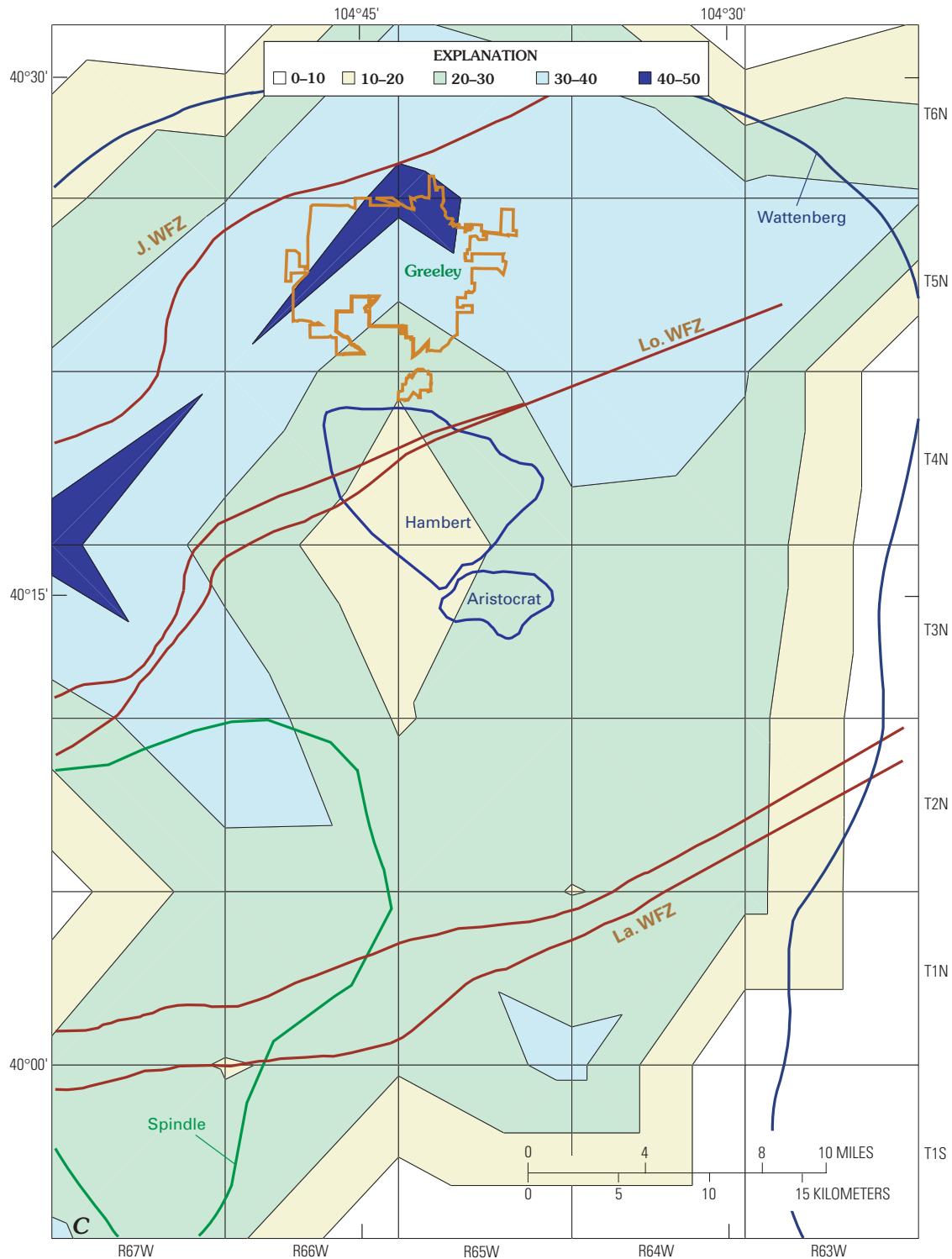


Figure 13A–H (above and following pages). Plots show oil and gas production characteristics of Niobrara/Codell production from the Wattenberg field (Petroleum Information production data through 1997, modified from Cox, 1998). Production values were determined from wells that were aggregated by township across the field; this spacing results in the angular character of lines. Areas of the Wattenberg, Hambert, and Aristocrat fields are outlined in blue; Spindle field is outlined in green. City boundaries and the Lafayette (La. WFZ), Longmont (Lo. WFZ), and Johnstown (J. WFZ) wrench faults are shown in brown. Color-fill contour values are labeled at the top of the figures. (A) Initial rate of gas production (MCFG day/well), (B) 20-year cumulative gas at production (MMCF/well), (C) initial rate of oil production (BO day/well), (D) 20-year cumulative oil production (MBO/well), (E) initial GOR (scf/bbl), (F) GOR at 20 years (scf/bbl), (G) cumulative gas (MMCF/township), and (H) cumulative oil (MBO/township). MCFG, thousand cubic feet of gas; MMCFG, million cubic feet of gas; BO day/well, barrels of oil; MBO, thousand barrels of oil; GOR, gas-to-oil ratio; scf/bbl, standard cubic feet of gas per barrel of oil.



contours shift to the northeast near the western terminus to the Longmont wrench fault zone. The northeastern offset of structural contours here may be the result of movement along these wrench faults during and following deposition of the Pierre Shale. Weimer (1996) noted six different times of wrench fault movement that started with deposition of the Pierre Shale and ended following deposition of the Fox Hills Sandstone.

Cumulative production from the more than 1,400 wells in the Spindle field is more than 56.8 MMBO and 278 BCFG (Colorado Oil and Gas Commission, 1998). More than 97 percent of the field's total oil production and 95 percent of the total gas production is from Terry ("Sussex") and Hygiene ("Shannon") Sandstones (fig. 2). Spindle field accounts for 80 percent of all gas produced from these reservoirs across the Denver Basin (McKinney, 1993). Oil and gas in the

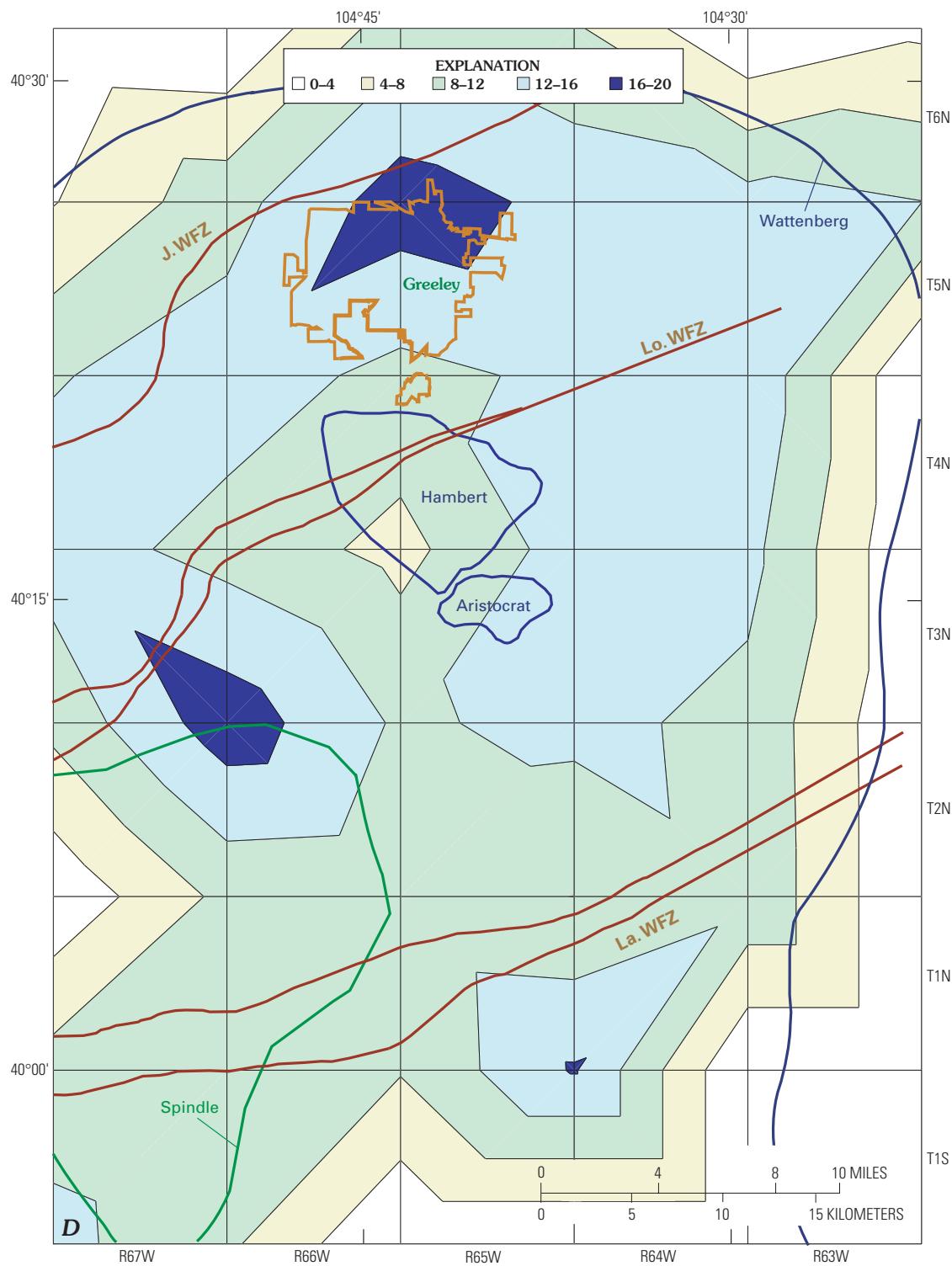


Spindle field are also produced from the Upper Cretaceous Codell Sandstone Member of the Carlile Shale and Niobrara Formation, and several leases list production from Cretaceous Muddy ("J") and "D" sandstones.

Oil and gas from the Spindle, Hambert, and Aristocrat fields are mostly from the Terry ("Sussex") Sandstone Member; monthly gas production from these fields has declined from a peak of more than 1.4 BCF in the late 1970s to 509

MMCF by the end of 1990 (McKinney, 1993). Eighteen other fields in the Denver Basin have collectively produced another 3 MMBO and 10 BCFG from Richard, and (or) Terry ("Sussex") and (or) Hygiene ("Shannon") sandstone.

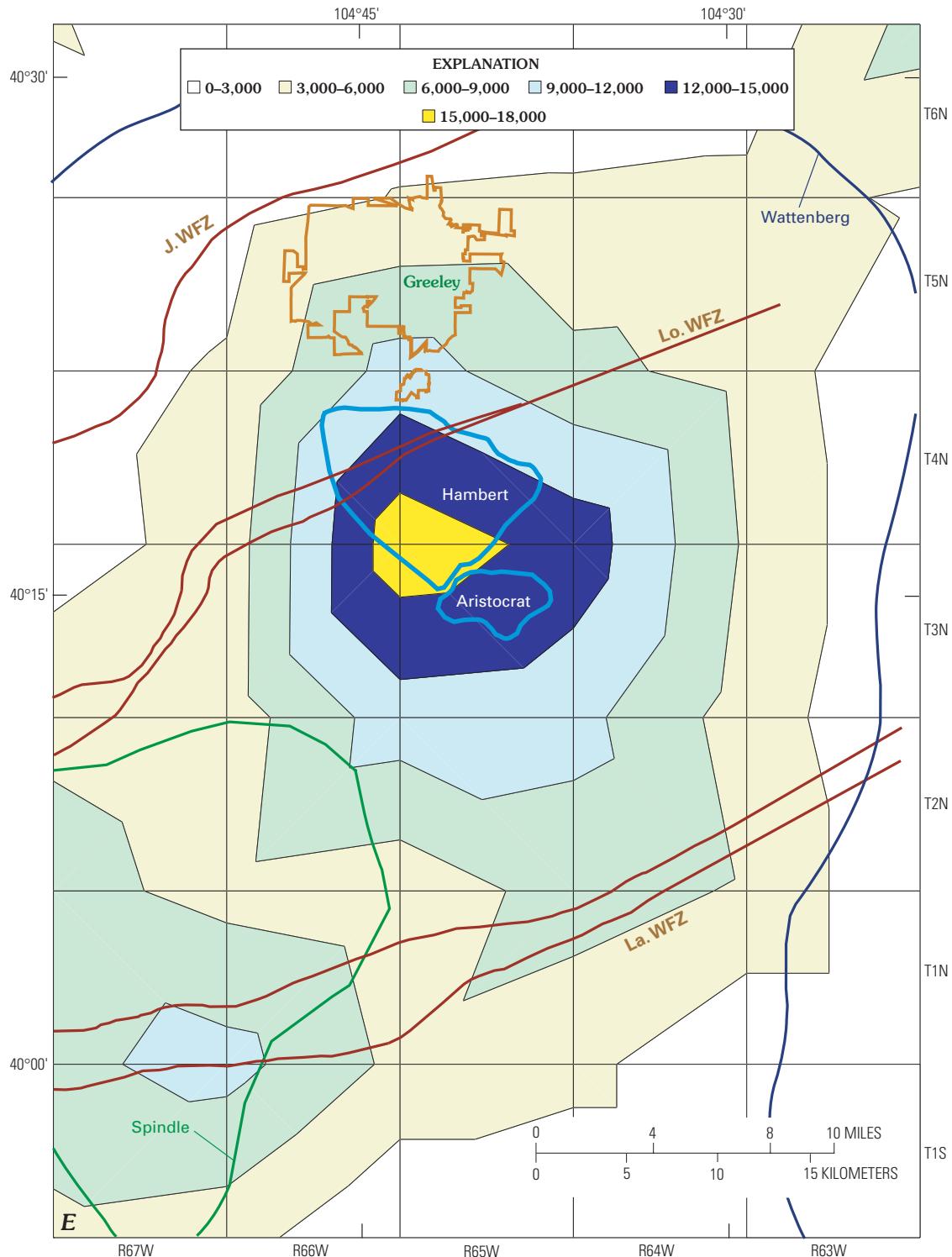
Thickness of Pierre Shale reservoir sandstones in seven fields within the Front Range Urban Corridor ranges from 4 to 48 ft (1 to 15 m); average thickness is 20 ft (6 m), average porosity is 14 percent, and average permeability for two of the



fields is 0.1 mD and 8 mD (Higley and others, 1996). Gross thickness of the Terry ("Sussex") is approximately 150 ft (46 m) in the area of Hambert field; production is from fractures in a low-permeability zone that is approximately 60 ft (18 m) thick near the base of the Terry ("Sussex") (Benson and Davis, 1997). Diagenetic changes in Terry ("Sussex") and Hygiene ("Shannon") sandstones include early precipitation of chlorite, subsequent quartz and calcite cementation, and dissolution

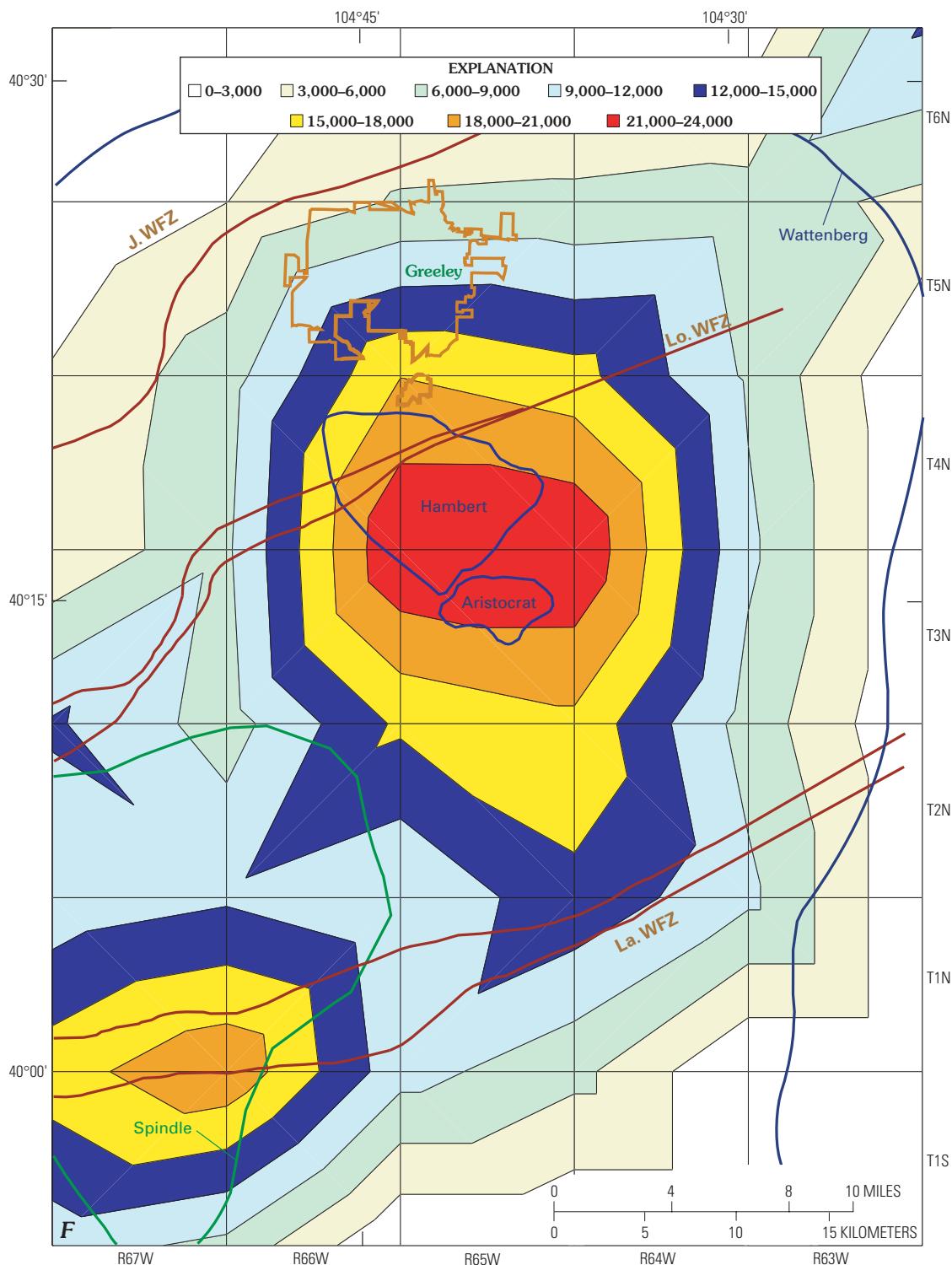
of lithic fragments, calcite, and also feldspars with associated precipitation of kaolinite in pore spaces; pore spaces are largely primary intergranular, secondary intergranular and intragranular, and microporosity in kaolinite (Treckman, 1960; Moredock and Williams, 1976; Porter and Weimer, 1982; Pittman, 1989; and Porter, 1989).

Faults compartmentalize the Terry ("Sussex") Sandstone Member into a number of fault blocks of variable size in the



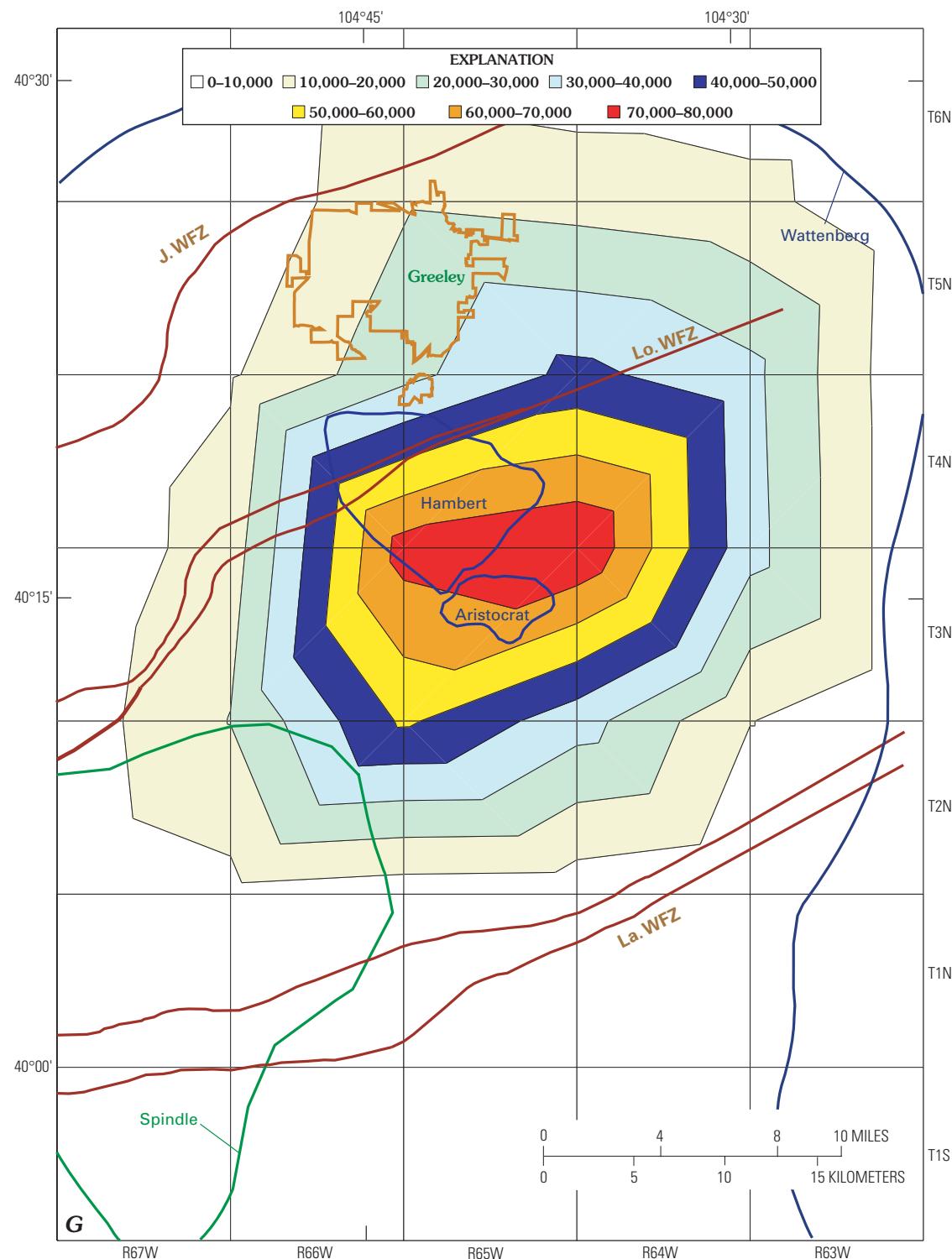
Hambert and Aristocrat fields; vertical offset is on the order of tens of feet (Slatt and Weimer, 1997). Production in the southeastern portion of Hambert field is predominantly oil and in the northwestern part it is primarily gas, with the approximate dividing line being the Longmont WFZ (fig. 8). Evidence that faults may form seals includes (a) higher gas-oil ratios (GORs) for structurally higher wells within small, single fault blocks and (or) for wells in upthrown blocks than for wells in

downdropped blocks; (b) gas-oil contacts at different elevations across blocks; (c) well-log bulk densities that are higher in wells that are cut by faults (suggesting a relatively high-density cement fill); and (d) core of one well that exhibits calcite-filled fractures/faults (Slatt and Weimer, 1997). Stratigraphic reservoir seals are overlying and interbedded marine shales. Oil and condensate gravity ranges from 40° to 65° API (Higley and others, 1996).



The gas-oil ratio (GOR) for Terry ("Sussex") and Hygiene ("Shannon") production at Spindle field averages slightly more than 4,000 scf/bbl, whereas the GORs for these formations in the Hambert and Aristocrat fields range from 20,000 to 40,000 scf/bbl (McKinney, 1993). The difference in GORs in the Spindle field is probably due to greater dilution of gas by oils derived from the underlying Niobrara

and Carlile Formations, and increased migration of gas along the Longmont WFZ into the Hambert and Aristocrat fields (fig. 15). Terry ("Sussex") and Hygiene ("Shannon") gas in these three fields has a specific gravity of 0.7, and oils range in gravity from 40° to 60° API; heating value of the gas is approximately 1,200 BTU per 1,000 scf, and the gas is typically composed of 82.5 percent methane, 8.5

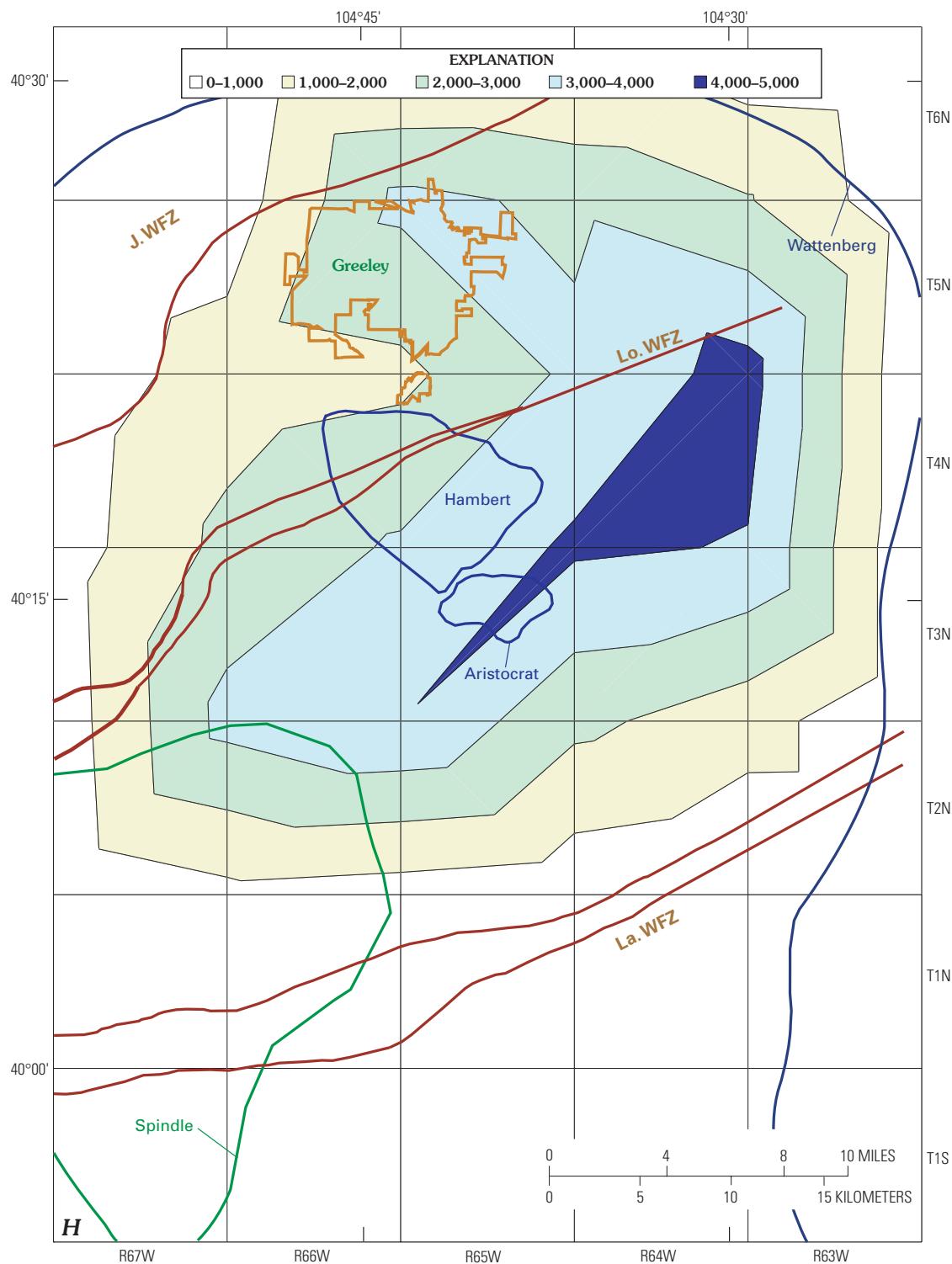


percent ethane, 4.5 percent propane, and 3.5 percent butane (McKinney, 1993).

The Pierre Shale is about 7,000 to 8,000 ft (2,100 to 2,400 m) thick in the area of the Aristocrat, Hambert, and Spindle fields and was deposited offshore in the Cretaceous epicontinental seaway*. The following statistics on Spindle

field formation depths and elevations are derived from the Petroleum Information WHCS database through 1999:

- (1) Depths to the top of the Terry ("Sussex") range from about 4,400 to 5,200 ft (1,300 to 1,600 m), with an average depth of about 4,700 ft (1,400 m) and average elevation of 300 ft (100 m).



(2) Depths to the top of the Hygiene ("Shannon") range from about 4,600 to 5,300 ft (1,400 to 1,600 m), with an average depth of about 5,000 ft (1,500 m) and an average elevation of about sea level.

Terry ("Sussex") and Hygiene ("Shannon") reservoir sandstones are mainly offshore marine linear sandbars that

are enclosed in shales and fine-grained sandstones of the Pierre Shale; they were deposited in response to fluctuations in sea level that influenced depositional energy and patterns of sediment distribution (Porter and Weimer, 1982). They accumulated as north-south-trending marine bar complexes in a shallow shelf environment. The approximately 400-ft-

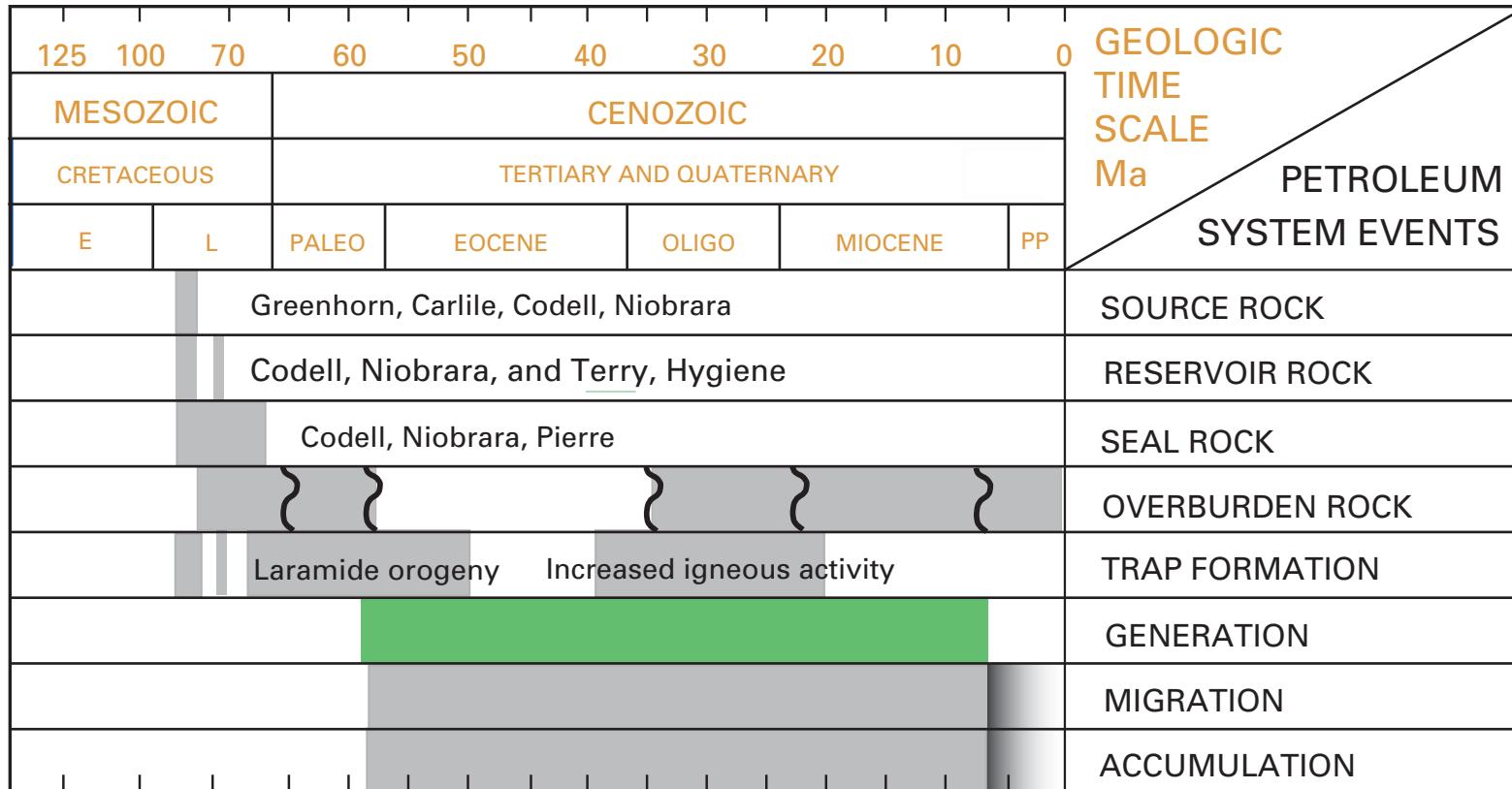


Figure 14. Geologic events chart for Upper Cretaceous formations in the western Denver Basin. Gray intervals mark times of primary events; gradients show possible times of events. Green interval marks time of generation of oil from the Niobrara, Codell, Carlile, and Greenhorn Formations. Wavy black lines indicate ages of probable unconformities. The Paleocene onset of oil generation from the underlying Niobrara Formation and Carlile Shale is associated with the Laramide orogeny; increased thickness of sedimentary strata occurred during and preceding this 67 Ma event. This stratum is largely the Pierre Shale. Generation of oil is due primarily to the greater depth of burial and associated temperature and pressure. Increased thickness of sedimentary strata before the onset of the orogeny indicates that uplift of the Front Range and associated subsidence of the Denver Basin may have been initiated prior to the major phases of mountain building. Abbreviations: E, Early; L, Late; Paleo, Paleocene; Oligo, Oligocene; PP, Pliocene and Pleistocene. Sources of information are Obradovich and Cobban (1975), Tweto (1975, 1980), Irwin (1976), Kauffman (1977), MacMillan (1980), Trimble (1980), Zoback and Zoback (1980), Tainter (1984), Weimer (1984, 1996), Higley and Gautier (1988), Crysdale and Barker (1990), and Higley and others (1992).

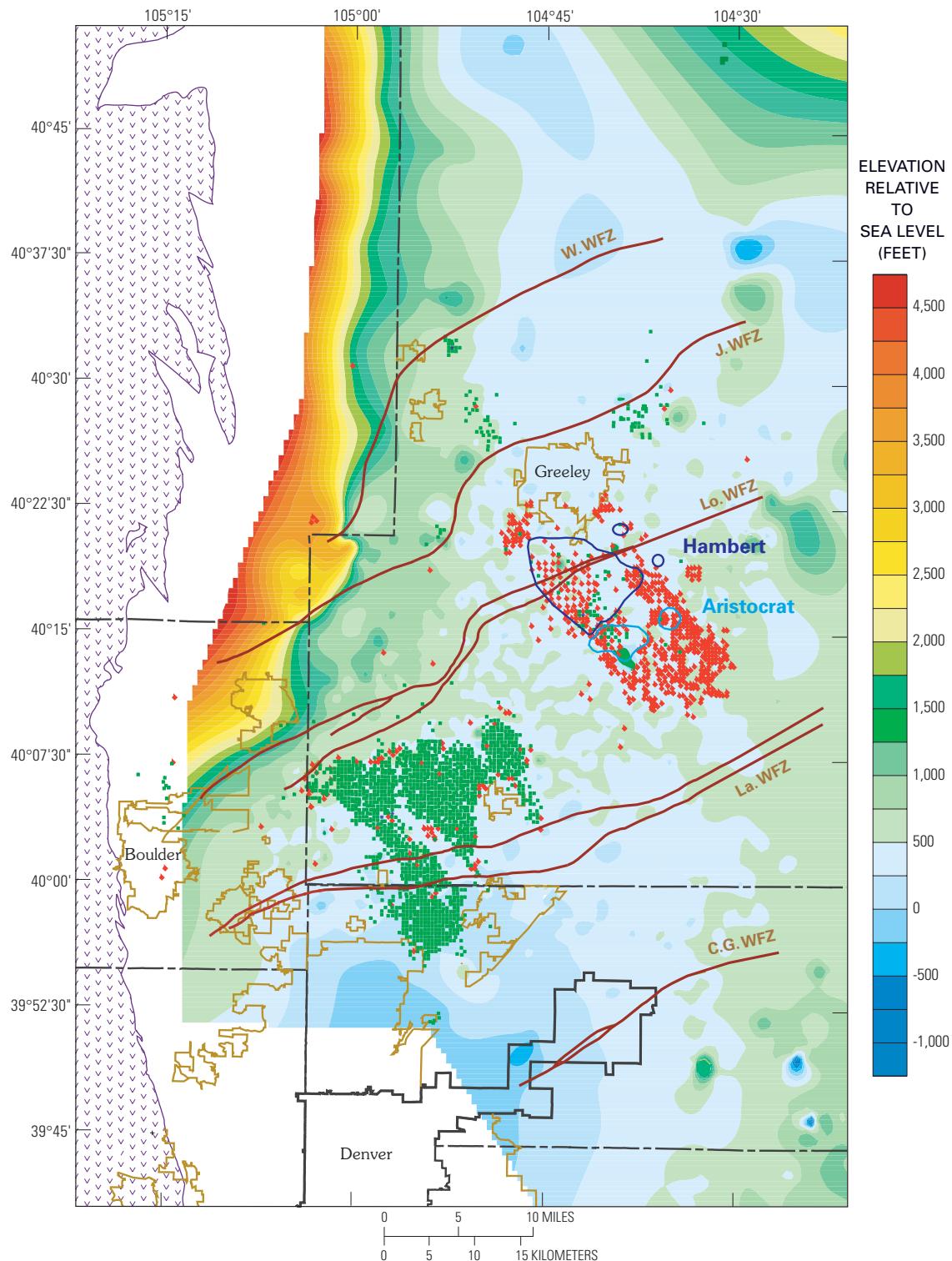


Figure 15. Producing wells from Pierre Shale in a portion of the Front Range Urban Corridor. Oil wells are green, gas wells are red, and oil and gas wells are blue. Color-filled contours are elevations relative to sea level on the top of the Upper Cretaceous Terry ("Sussex") Sandstone Member of the Pierre Shale. Contour interval is 250 feet. Shown are locations of the Windsor (W. WFZ), Johnstown (J. WFZ), Longmont (Lo. WFZ), Lafayette (La. WFZ), and Cherry Gulch (C.G. WFZ) wrench faults. Contour spacing and elevations show a steeply dipping western flank and gently dipping eastern flank of the basin. Small "bulls eyes" are generally single wells with anomalously recorded elevations or formation tops. Spindle field is the green "triangular" located east of Boulder. The scattered gas production south of Greeley includes the Aristocrat, Hambert, and Wattenberg fields. The oil and gas wells within and north of Boulder are from numerous fields.

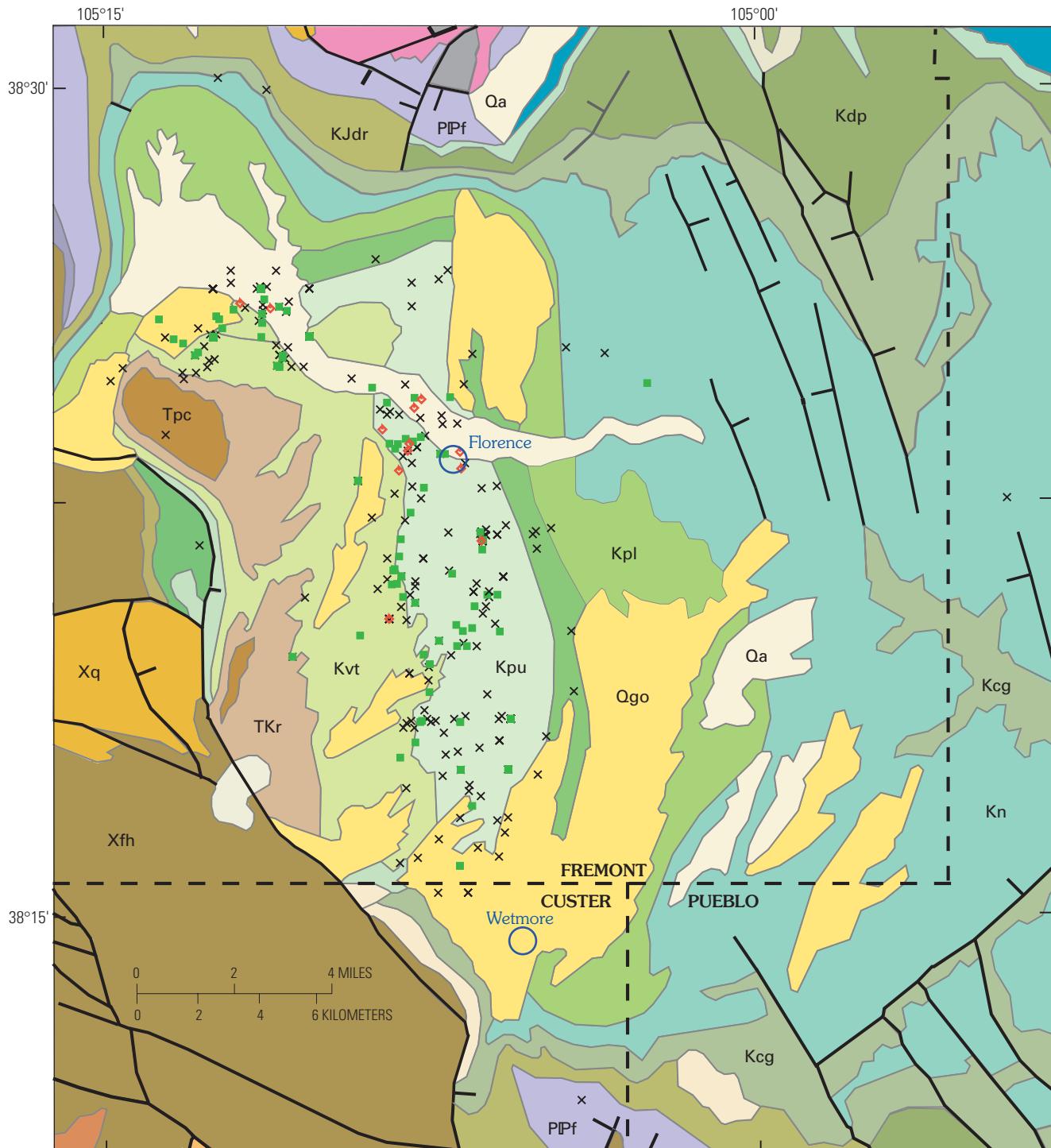


Figure 16. Symbols for oil (green square), gas (red diamond), and dry hole (black x) wells located within the Florence field. Dashed black lines are county boundaries. Solid black lines are faults, and gray lines delineate geologic formations. Formation symbols: Qa, Qgo, Quaternary alluviums and gravels; Tpc and TKr, Tertiary-age Poison Canyon Formation and Tertiary-Cretaceous undifferentiated arkoses; Kpu, Cretaceous upper Pierre Shale; Kpl, lower Pierre Shale (Sharon Springs Member); Kn, Niobrara Formation; Kcg, Carlile Shale, Greenhorn Limestone, and Graneros Shale; Kdp, Dakota (Muddy) Sandstone; KJdr, undivided Cretaceous rocks and Jurassic Morrison Formation; PIPf, Permian and Pennsylvanian Fountain Formation; Xq and Xfh, Precambrian (1.7 to 1.8 billion years old) metamorphic rocks in the mountains west of the field. Geologic base scale is 1:500,000, and nomenclature is from Tweto (1979).

(120-m-) thick Terry and 600-ft-(180-m-) thick Hygiene Members are composed of upward-coarsening sequences of interbedded sandstones, siltstones, and shales. Terry (“Sussex”) strata within the Spindle field consist of a series of stacked shoreface parasequences* that are separated by laterally continuous transgressive marine shales (Slatt and others, 1997). The best reservoirs are crossbedded, fine- to medium-grained sandstones that were deposited in the high-energy crests of marine bars; three separate sandstone bodies in the Terry (“Sussex”) are productive in the Spindle field (McKinney, 1993). The lowermost sandstones, which are the cleanest and thickest, are limited to the northeastern part of the field, whereas the other two productive zones are present over most of the field and exhibit a prominent northwest-southeast orientation: the latter two zones thin to the east and merge in the west and northwest (Pittman, 1989). The uppermost sandstones in the Hygiene (“Shannon”) also produce oil and gas in the northwestern part of the Spindle field (Pittman, 1988).

Trap types in Richard, Terry (“Sussex”), and Hygiene (“Shannon”) reservoirs combine diagenetic-stratigraphic mechanisms with solution gas and water drives (McKinney, 1993). Primary stratigraphic controls are lateral pinch-outs of the reservoir sandstones, due to erosion or nondeposition, and concentration of the most porous and permeable intervals near the seaward edge of individual marine bar sandstones. These are shown on the events chart (fig. 14) as being contemporaneous with deposition of the reservoir facies. Early sediment compaction combined with formation of silica overgrowths, chlorite rims, and calcite cement within the sandstones destroyed the primary porosity in the well-sorted sandstones; secondary porosity that formed as a result of later calcite dissolution was probably associated with fluid migrations along fractures and wrench faults associated with the underlying Wattenberg paleostructure (Porter and Weimer, 1982). Precipitation of early-diagenetic chlorite and ferroan chlorite can also preserve porosity in these marine strata by decreasing secondary cementation by quartz (Higley and others, 1997). Calcite dissolution may have been tied to changes in pore-fluid chemistry that occur with generation and migration of hydrocarbons.

Pierre Shale marine shales across the Denver Basin are thermally immature for generation of hydrocarbons, with the possible exception of the Pierre Shale near the Florence oil field (fig. 16). Primary source rocks for petroleum in the Spindle field area are probably the underlying Niobrara Formation and Carlile Shale (fig. 14). Pittman (1989) indicated that oil probably migrated upward about 2,200 ft (670 m) from the top of the Niobrara to the Terry (“Sussex”) and Hygiene (“Shannon”) oil and gas reservoirs. The probable source of Spindle field gas is migration up fault and fracture systems from the underlying Cretaceous Mowry and Graneros Shales (fig. 2). These shales are thermally mature for gas generation in the Wattenberg field area (Higley and others, 1992).

Fractured Cretaceous Pierre Shale (Florence Field)

The year 1862 marked the birth of oil discoveries in the Denver Basin, when oil was found in a water well that was drilled near the town of Wetmore in south-central Fremont County, south of the present-day Florence field (fig. 16) (Carpenter, 1961). The Oil Spring discovery well encountered oil at a reported depth that ranged from 1,160 to 1,448 ft (354 to 441 m); the purpose was to find water for coal-mine holdings in the area, but what resulted was “a good show of oil” (Kupfer, 1999a). However, only a few barrels of oil were produced from the well. Efforts were made to deepen the well, but the 1881 shut-in date was due to broken machinery, a lost tool, and litigation (Kupfer, 1999a). Alexander M. Cassiday, the “Father” of the Colorado petroleum industry, and his partners promoted this “Oil Spring” and sold it to three men from Boston in 1865 (Kupfer, 1999b).

In 1881, the same Alexander Cassiday with Isaac Canfield discovered the Florence field (Kupfer, 1999b), which is located in a subbasin within the Denver Basin that is about 30 mi (100 km) west of Pueblo, Colo. The Florence field is the oldest continuously working field in the United States (Carpenter, 1961; Kupfer, 1999b). Figure 16 shows locations of wells in and surrounding the Florence field that are oil or gas productive, or dry and abandoned.

Some newspaper and historical reports on Alexander Cassiday indicate that he was working on the “Colonel” Drake discovery well when he read about the Oil Spring oil seep in Zebulon Pike’s report of his western explorations in 1806–1807 (Kupfer, 1999b). However, there is no mention of such a spring in Pike’s journals, nor any record of Cassiday working on the Drake discovery (Kupfer, 1999b), which was drilled in 1859 near Titusville, Pa., and was the first oil well completed in the United States. Before this time, drilling was mostly shallow and for water, and what little oil that was produced was from seeps and pools. Oil for lamps and for lubrication of machinery was expensive in those days. During the 1864 Indian uprising in the West, oil sold for up to \$5 a gallon (Fritz, 1990). Cassiday, his son Des Moines, and his partner B.S. Sherwood spent years promoting and developing the Florence field and mining interests (Kupfer, 1999a). Alexander Cassiday died in a Denver hotel room on November 13, 1887, and is interred in an unmarked grave in Riverside Cemetery in Denver (Kupfer, 1999a).

The area of possible production from fractured Pierre shales is bracketed on the north, west, and southwest by mostly Precambrian-age igneous and metamorphic rocks. The eastern extent is about 2 mi east of the area shown in figure 16 and is the limit of possible oil and (or) gas occurrences. Oil from the Florence field is produced from low-permeability fractured marine shales of the Upper Cretaceous Pierre Shale that are situated in a syncline, or basin-low position, within the Canon City depression (Kupfer, 1999a). This has the appearance of a geologic “cul-de-sac” in which Pennsylvanian through Quaternary sedimentary rocks are surrounded on the

north, west, and southwest by Precambrian metamorphic rocks (fig. 16).

Reservoir rocks in the Florence field are gray to black, organic-rich (high-organic-carbon content) shales and thin, sandy shales of the Sharon Springs Member of the Pierre Shale (fig. 2), which are about 100 ft (30 m) thick (Higley and others, 1996). Depths of production range from about 900 to 3,200 ft (270 to 970 m) (Fritz, 1990; Higley and others, 1996). These shallow depths are critical to continuing production because fracture networks that are open are necessary for oil emplacement and recovery from these low-permeability shales. Orientations of fracture patterns can be either northwest to southeast or northeast to southwest, forming a cross (Fritz, 1990). Primary traps are bounding impervious Pierre shales and lateral pinch-out of open fracture systems.

Well production rates are typically 5 to 100 BO per day (Fritz, 1990). Drive mechanism is an underpressured gravity drainage of oil with minor solution gas drive (Carpenter, 1961; Fritz, 1990). Respective API gravity and sulfur content of oil are about 31° and 0.34 percent (Carpenter, 1961). Maximum field size is about 22,000 acres (Higley and others, 1996).

More than 15.2 MMBO and 19.9 MMCFG have been produced from the Florence field (Lawson and Hemborg, 1999; Petroleum Information/Dwights, 1999b). Estimated ultimate recovery (EUR) of 15.5 MMBO (Higley and others, 1996) could be increased through the use of horizontal drilling in these fractured shale reservoirs. Because drilling and production began at the Florence field before companies were legally required to file well location and production information with the State, field data are unreliable and highly underreported. For example, 1910 is the date of the earliest well listed within the Petroleum Information/Dwights (1999a) Well History Control System database. Wells initially were located in close proximity to existing oil wells, some on closer than 10-acre spacing. The Petroleum Information/Dwights (1999a) database lists 408 wells in the Florence field, of which more than 91 percent reach total depth within the Pierre Shale. About 165 of these wells are reported to produce oil from the Pierre Shale, and two from the Niobrara Formation; the remaining wells either do not have producing formation(s) listed, are shut in, or are nonproductive (dry). Lawson and Hemborg (1999) indicate that the Florence field has only 28 producing wells and 14 that are plugged and abandoned. Because data quality is difficult to document for this field, which was discovered long before companies were required to report well and production information, there is great variation in the estimated number of producing wells and in cumulative production.

Pollastro (1992) indicated that the Niobrara Formation across the Florence field area is thermally mature for oil generation, and may be a source rock based upon the temperature at which the smectite-to-illite transformation occurs. Lillis and others (1998) indicated that the hydrocarbon source rock for Oil Spring samples may be Lower Cretaceous shales, or possibly the Upper Cretaceous Sharon Springs Member of the Pierre Shale; oil samples were from a seep located along

Fourmile Creek, approximately 10 mi (1.6 km) northeast of Canon City and north of the Florence field. Bulk and molecular geochemical analyses of the oil indicate that the probable source rocks for the Oil Spring are the Upper Cretaceous Carlile Shale and Greenhorn Limestone. Fritz (1990) indicated that shales of the Sharon Springs Member of the Pierre Shale are thermally immature to marginally mature in the field area, and the source of the oil may be farther to the west, under the mountains.

Coal-Bed Methane from Denver and (or) Laramie Formations

Coals in the Paleocene and Upper Cretaceous Denver and the Upper Cretaceous Laramie Formations (fig. 2) are potentially productive for coal-bed methane*; but there is no current production, and their potential was not evaluated for this report. Economically recoverable methane from these formations is ranked as hypothetical from continuous-type unconventional reservoirs*. Gas Resource Institute (GRI) (1999) estimated the in-place coal resources for these formations at 51.8 billion short tons of lignite and subbituminous coal, the in-place gas resources at 2 TCF, and the recoverable gas at 0.3 TCF; GRI did not describe the analytical methods used to derive these numbers. Figure 17 shows the areal distribution of coal-bearing rocks of the Laramie Formation in the Colorado portion of the Denver Basin; also illustrated are locations of mines and coal deposits of the Denver Formation in coals that are less than 200 ft (60 m) deep (modified from Landis, 1959; Kirkham and Ladwig, 1979; Kirkham, 1980; and Nichols, 1999). Actual extent of the Denver Formation and associated coals and lignites is greater. The Denver Formation ranges in thickness from 600 to 1,580 ft (180 to 480 m) and is composed mainly of claystone, siltstone, and fine-grained sandstone with minor conglomerate beds and local lava flows (such as the tops of North and South Table Mesas, near Golden, Colo.). The thickness, depths, and eastward dips of the Denver, Arapahoe, and Laramie-Fox Hills Formations are shown in an east-west cross section across the west-central Denver Basin (fig. 18). These formations are aquifers* over most of their extent in the basin. Also shown in figure 18 are nonaquifer, or confining* beds that are located between some of the aquifers (data from Major and others, 1983).

The area around the Wattenberg field has potential biogenic gas reserves from Laramie Formation coals; individual coals range in thickness from 2 to 14 ft (0.6 to 4.3 m), and total coal thickness can exceed 25 ft (7.6 m) (Roberts and Fishman, 2000). The coal lies at depths ranging from less than 200 to more than 1,300 ft (61 to 390 m) (Roberts and Fishman, 2000). The development of coal-bed methane resources in this area may be increased by the current drill spacing of as close as 32 acres, combined with enhanced coal rank that may be associated with a thermal anomaly (Roberts and Fishman, 2000; Higley and others, 1992).

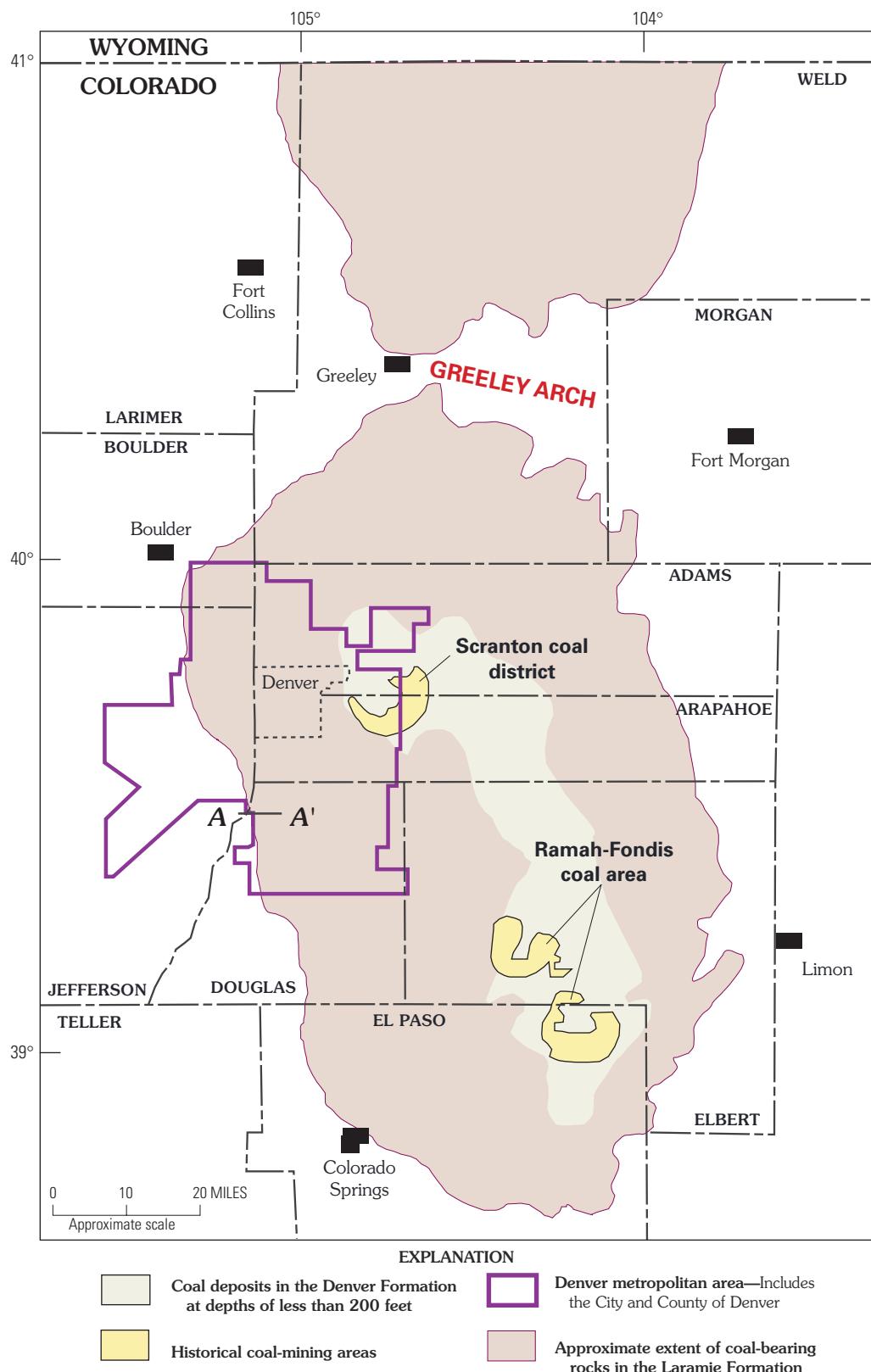


Figure 17. A portion of the Denver Basin showing distribution of coal-bearing strata of the Laramie Formation and extent of coal deposits to 200-foot (60-meter) depth in the Denver Formation. A-A' is the line of cross section shown in figure 18. Modified from Landis (1959), Kirkham and Ladwig (1979), Kirkham (1980), and Nichols (1999).

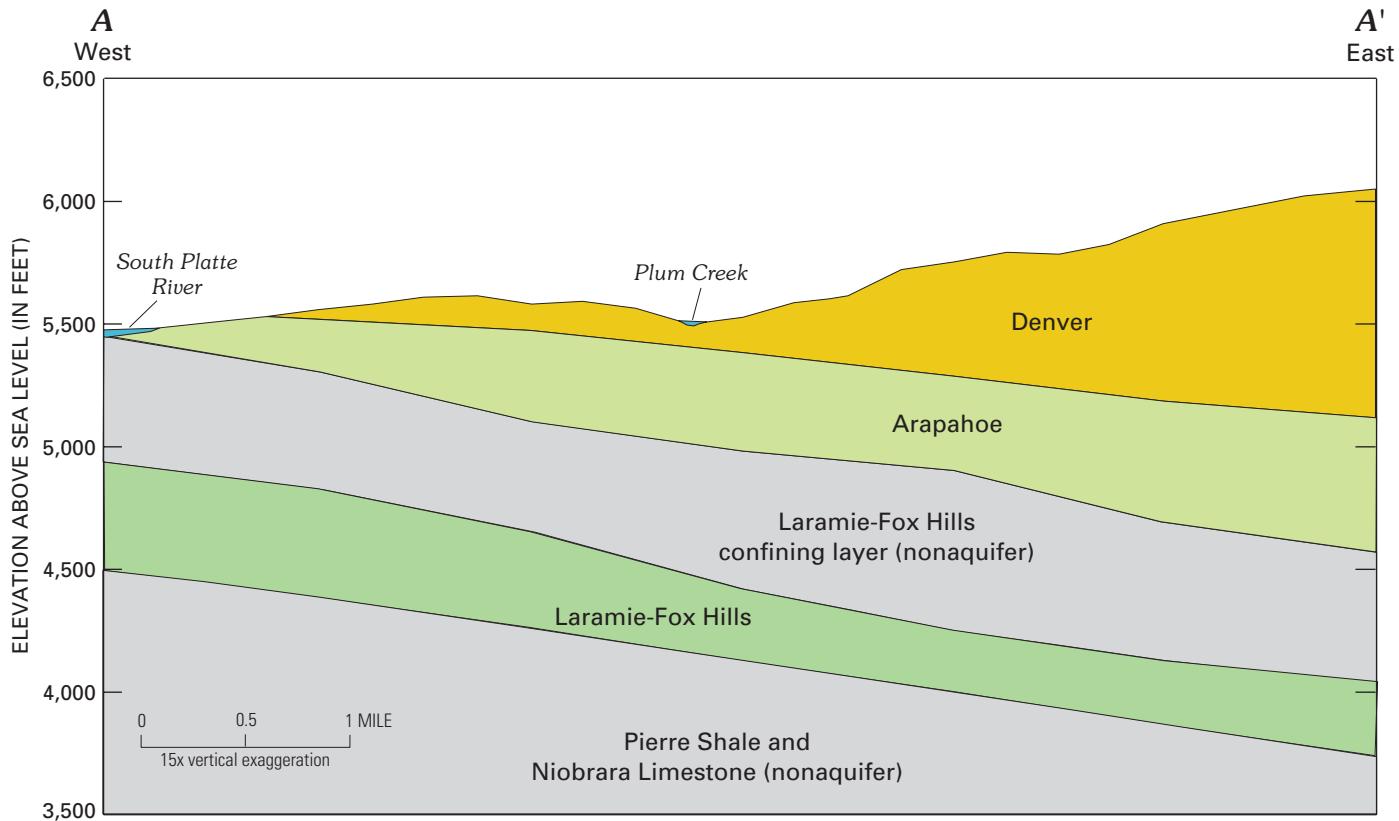


Figure 18. East-West stratigraphic cross section across northwest Douglas County. Shown are the vertical and lateral distribution of Upper Cretaceous and Tertiary Denver, Arapahoe, and Laramie-Fox Hills aquifers within a portion of the Front Range. Line of cross section is shown in figure 17. Data are from Major and others (1983), Robson and others (1998), and U.S. Geological Survey (1990) 1:24,000-scale quadrangle map.

Conclusions

The Denver Basin is an asymmetrical Laramide-age structural basin that contains about 1,500 oil and (or) gas fields that are concentrated along a northeast-trending band from Denver into the panhandle of western Nebraska. Ninety-six of these fields are located within the boundaries of the Front Range Infrastructure Resources Project. More than 52,000 wells have been drilled, of which 29,000 are within the urban corridor. More than 245 MMBO and 2.15 TCFG have been produced, totaling about 23 percent of the oil and 58 percent of the gas in the basin.

The primary producing formation in the Denver Basin and along the Front Range Urban Corridor is the Lower Cretaceous Muddy ("J") Sandstone. This formation, combined with minor production from the Lower and Upper Cretaceous "D" sandstone includes more than 779 BCFG in the Wattenberg field, with an estimated ultimate recovery of 1.27 TCFG. In addition to the Muddy ("J") Sandstone and the "D" sandstone, the Upper Cretaceous Codell Sandstone Member of the Carlile Shale, Niobrara Formation, and Hygiene ("Shannon") and Terry ("Sussex") Sandstone Members of the Pierre Shale are also productive, contributing to the more than 1.50 TCFG,

64.8 MMBO, and 12.8 MMBW that have been produced in the field. These formations, along with the Upper Cretaceous Sharon Springs Member of the Pierre Shale (Florence field) and the Permian Lyons Sandstone (small structural oil fields near the mountain front), contain all of the oil and gas reservoirs in the urban corridor area.

Spindle field production, from its discovery in 1971 to 1999, was 56.8 MMBO, 279 BCFG, and 10.3 MMBW from more than 1,400 wells. More than 97 percent of the field's total oil production and 95 percent of its total gas production is from the Terry ("Sussex") and Hygiene ("Shannon") Sandstone Members of the Upper Cretaceous Pierre Shale. Oil and gas are also produced from the Upper Cretaceous Codell Sandstone Member of the Carlile Shale and the Niobrara Formation, and several leases list production from the Cretaceous Muddy ("J") Sandstone and "D" sandstone.

The Mowry and Graneros Shales are the major source rocks for oil and gas from conventional and unconventional Lower Cretaceous reservoirs in the Denver Basin. Primary source rocks for oil in Upper Cretaceous fields are the Upper Cretaceous Carlile Shale, Greenhorn Limestone, and Niobrara Formation. The probable source rocks for potential Paleozoic reservoirs in the northern Denver Basin are Paleozoic black shales.

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Glossary of Terms

Ancestral Rocky Mountains The precursor to the present-day Rocky Mountains. These were present in Paleozoic time and gradually eroded to ground level near the end of Paleozoic time.

API A standard that is adopted by the American Petroleum Institute for categorizing the specific weight (viscosity) of oil.

Aquifer A bed of rock that is sufficiently permeable, or transmits fluids, enough to yield economically significant volumes of water to springs and to wells.

Barrel A standard barrel contains 42 gallons of oil. The oil is composed of liquid hydrocarbons that are used to make things such as engine oil, gasoline, plastics, some medicines, and clothes.

Biogenic gas Gas composed of mostly methane that is produced from bacteria within the rocks. The bacteria eat organic matter and other nutrients within the organic-rich rock or coal and included water.

British Thermal Units (BTU) A measure of the heating ability of a substance, such as coal or oil. It is the unit of heat required to raise the temperature of one pound of water from 63°F to 64°F at sea level.

Coccolith Various microscopic calcareous structures that average about 3 microns in diameter, have many different shapes, and were derived from mostly marine planktonic microorganisms. Coccoliths are found mostly in chalk and sediments of deep-sea depositional environments.

Confining bed A layer of rock that has low permeability (does not transmit fluids) and is stratigraphically adjacent to one or more aquifers.

Conventional oil and gas reservoirs These are most of the oil and gas fields in the United States. They commonly have downdip water contacts and exclude reservoirs that exhibit unusually low pressure, permeability, and unconventional trapping mechanisms.

Diagenesis All the changes undergone by sediment after its initial deposition, excluding surface weathering and metamorphism. It includes processes such as compaction and

various geochemical changes (cementation, dissolution, replacement, for example).

Eolian Deposited by wind currents, such as sand dunes.

Geothermal gradient The rate of increase of temperature in the earth with depth. This value varies with heat flow in the region and thermal conductivity of the rocks, but averages approximately 25°C/km of depth.

Hydraulic fracturing A method fracturing rock in an oil and (or) gas reservoir that involves pumping in water (or other fluids) and sand (or other granular material) under high pressure. The purpose is to create or open fractures in the reservoir in order to increase permeability and flow of oil and (or) gas to the well bore. The sand serves to keep the fractures open.

Illite/smectite geothermometry A method used to determine the degree of thermal maturation for hydrocarbon source rocks. The crystal structure of smectite becomes ordered to illite at temperatures of 100°C or greater. Illite is a general name for a group of three-layer, micalike clay minerals. Smectite is a group of expanding three-layer clay minerals, an example of which is bentonite.

Maceral An organic particle that is part of the coal mass. All petrologic particles that are seen in polished or thin sections of coal.

Methane A colorless, odorless inflammable gas that is composed of one carbon and four hydrogen molecules (CH_4). It is the simplest constituent of natural gas and is found associated with crude oil and is produced from natural sources, such as certain bacteria in marshes and in coal beds.

Millidarcies A unit of measure equal to 1,000th of a Darcy. A Darcy is a standard unit of permeability that is equal to the passage of one cubic centimeter of fluid of one centipoise viscosity that flows in one second under a pressure differential of one atmosphere through a porous medium that has a cross-section area and length of one cubic centimeter.

Parasequence A sequence of geologic events, processes, or strata that are arranged in chronological order. These are relatively

conformable (exhibiting no unconformities [periods of erosion]) genetically related successions of beds or bedsets that are bounded by marine-flooding surfaces or their correlative surfaces. Parasequences are typically shallowing-upward cycles.

Precambrian rocks More than 544 million years old (<http://geology.er.usgs.gov/paleo/geotime.shtml>) (accessed 10/01/04). Rocks that are typical of Rocky Mountain “basement” rocks are the igneous and metamorphic rocks (granite, gneiss, and schist) that are visible while driving through the Rocky Mountains, which are dated at about 1 to 1.8 billion years (Tweto, 1975, 1979). The pink bands that cut across some of the Precambrian rock outcrops are younger intrusions (injections) of magma (molten rock) that were injected into fractures and other zones of weakness in the parent rock and subsequently cooled.

R., Range A unit of survey of the U.S. Public Land Survey. Any series of contiguous townships of the U.S. Public Land Survey, aligned north and south and numbered consecutively east and west from a principal meridian, to which it is parallel.

Retrograde condensate Condensates are liquid hydrocarbons that are primarily gas and light oils (C⁴ to C¹⁰ carbon range).

Seaway Reference here is to the Cretaceous epicontinent seaway, which existed during the Cretaceous Period and joined the Gulf of Mexico and the Arctic Ocean.

Sec., Section (1) One of the 36 units that subdivides a township. It is a piece of land that is generally one mile square. (2) An exposed vertical or inclined surface, such as a cliff or quarry face. (3) Geologic term used for a columnar section, type section, or thin section of rock.

Source rocks Oil and gas are formed mainly from formations that are rich in organic matter that was derived from breakdown of mostly algae and (or) terrestrial plants. These are commonly dark gray marine shales. As these rocks are buried deeper and deeper, the temperature and pressure generally increase to the point at which hydrocarbons are “cooked” out of the shales and (or) organic-rich limestones. These hydrocarbons then migrate through other formations and along fault and fracture systems to be concentrated in the reservoir rocks, where they are trapped. While rocks such as sandstone are solid, they commonly have a network of connected pores that allow fluids and gases to flow into and through them. The volume

of pore space (porosity) and the connections (permeability) can be quantified to estimate how well these fluids flow into and through the rocks. The formations are more like sponges than they appear.

Standard cubic foot A unit of measure equal to one cubic foot. Gas production is commonly reported in thousands of standard cubic feet (MCF).

Stratigraphic traps Oil and (or) gas is trapped primarily by updip or lateral pinch-out of reservoir intervals into relatively impermeable strata, such as shale or cemented formations. Traps commonly form as a result of depositional or diagenetic processes.

Structural traps Oil and (or) gas is trapped by geologic structures such as domes and anticlines, and (or) is a result of faulting or other deformation in which reservoir strata terminate against relatively impermeable strata.

T., Township A unit of survey of the U.S. Public Land Survey. It is an area bounded on the east and west by meridians located about 6 miles apart. A township is normally a square that is subdivided into 36 sections, each of which are approximately 1-mile-square sections. Township, range, and section locations are shown on most topographic maps, for example. The north-south direction is range and the east-west divisions are by township.

Unconventional oil and gas reservoirs A broad class of oil and gas deposits of a type (such as gas in “tight” or low-permeability sandstones and coal-bed methane) that historically has not been produced using traditional development practices. Such accumulations are commonly also called continuous. They are commonly low permeability and do not have downdip water contacts.

Vitrinite reflectance A measure of how macerals (particles) of marine and (or) non-marine organic matter in the shales reflect light waves; as these coal-like macerals are subject to increased pressure and temperature, they reflect more light. How well the macerals reflect the light, how “glossy” they are, is also indicative of how hot the shales were, and from this, whether they were cooked enough to generate oil or gas. Vitrinite reflectance is a measure of the level of thermal stress the rock has been subject to. Abundant terrigenous coaly macerals can decrease the measured onset of gas generation.

Wrench faults These are faults that are mostly vertical and in which the primary ground movement is lateral.



A Model for Determining Potential Areas of Future Oil and Gas Development, Greater Wattenberg Area, Front Range of Colorado

By Troy Cook

Chapter C of
Energy Resource Studies, Northern Front Range, Colorado

Edited by Neil S. Fishman

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A Model for Determining Potential Areas of Future Oil and Gas Development, Greater Wattenberg Area, Front Range of Colorado

By Troy Cook

Abstract

The potential for oil and gas development in the greater Wattenberg area, which lies near the Front Range between Denver and Greeley, Colorado, in the Denver Basin, is moderate to high for oil-and-gas-producing formations of Cretaceous age. The potential for development was determined by modeling existing production of oil and gas from these Cretaceous formations and evaluating where the remaining volume of hydrocarbons exceeds estimates of ultimate recovery from existing wells producing from these units. Although areas of varying potential exist for all producing formations, the likely areas of future oil and gas development would be where the potential exists for recovery of additional hydrocarbons from more than one producing formation. The recompletion of existing wells to tap into other formations for additional oil and gas production is likely where there is high potential for remaining producible hydrocarbons and especially where a significant number of wells exist. The model reveals that the Front Range project area between Denver and Greeley has a high potential for both the drilling of new wells and recompletions of existing wells. Because this is also an area of rapid and continuing urban growth, decisions regarding future land use will be improved with the understanding of where future oil and gas development could be expected in the Front Range of Colorado.

Introduction

The greater Wattenberg area (GWA), named by the Colorado Oil and Gas Conservation Commission for regulatory purposes to define the prolific oil and gas producing region adjacent to the northern Front Range of Colorado (fig. 1), contains thousands of oil and gas wells producing from rocks of Cretaceous age. The western part of the GWA lies within the study area of the Front Range Infrastructure Resources Project (fig. 1) and is just north of Denver, Colo. The most prolific producing formations of Cretaceous age include the Muddy ("J") Sandstone of the Dakota Group, the

"D" Sandstone of the Graneros Shale, the Codell Sandstone Member of the Carlile Shale, the Niobrara Formation, and the Terry and Hygiene Sandstone Members of the Pierre Shale. The Cretaceous-age formations that produce in the GWA fall into both the continuous and conventional (see "Glossary of

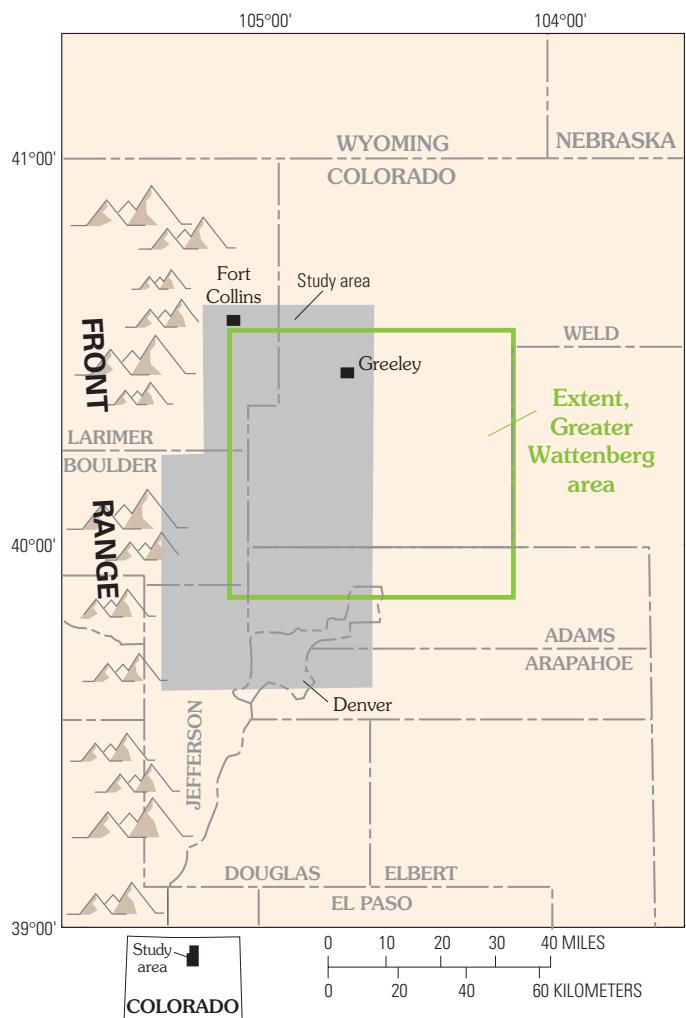


Figure 1. Front Range Infrastructure Resources study area and overlying Wattenberg field and greater Wattenberg area.

Terms" section) accumulation classifications used to assess the volume of undiscovered resources (Higley and Cox, this volume).

Based on an assumption that future oil and gas development will proceed apace of petroleum prices and decreases in regulatory well-spacing requirements, a model for determining remaining areas with potential for exploration and production was developed for the GWA. Land planners and others interested in determining land-use issues will find it important to understand where these potential areas of oil and gas development are located. Because volumetric calculations are applicable regardless of the type of accumulation involved (Craft and Hawkins, 1959), the model is considered applicable to the formations studied.

Sources of Data

All estimated ultimate recoveries for the present study were generated from monthly production volumes contained in the 1999 PI database (PI/Dwights, 1999). These data are stored by lease for large areas of the United States and were the only oil and gas production data used in this study. Because the production database is proprietary, any well locations shown in this chapter for display purposes are from files

that are available to the public (Colorado Oil and Gas Conservation Commission, 2001).

Fundamental Assumptions

The assumptions outlined here were made prior to developing the model that was used to estimate the future petroleum-production potential in the GWA: (1) volumetric calculations could be used to approximate the initial volume of petroleum in any of the reservoirs of interest in the GWA; (2) decline curve analysis could be used to extrapolate well production into the future; (3) sufficient petroleum remains in the various reservoirs to warrant continued exploration for and development of additional resources. The last assumption was made because exploration continues in the GWA, and the rate of drilling new wells or "recompleting" existing wells is one of the highest in Colorado.

Methods of Study

An EUR is generated by examining the historical production of a well as a function of time and quantity of production. Figure 2 shows an example of a semilog plot used to display

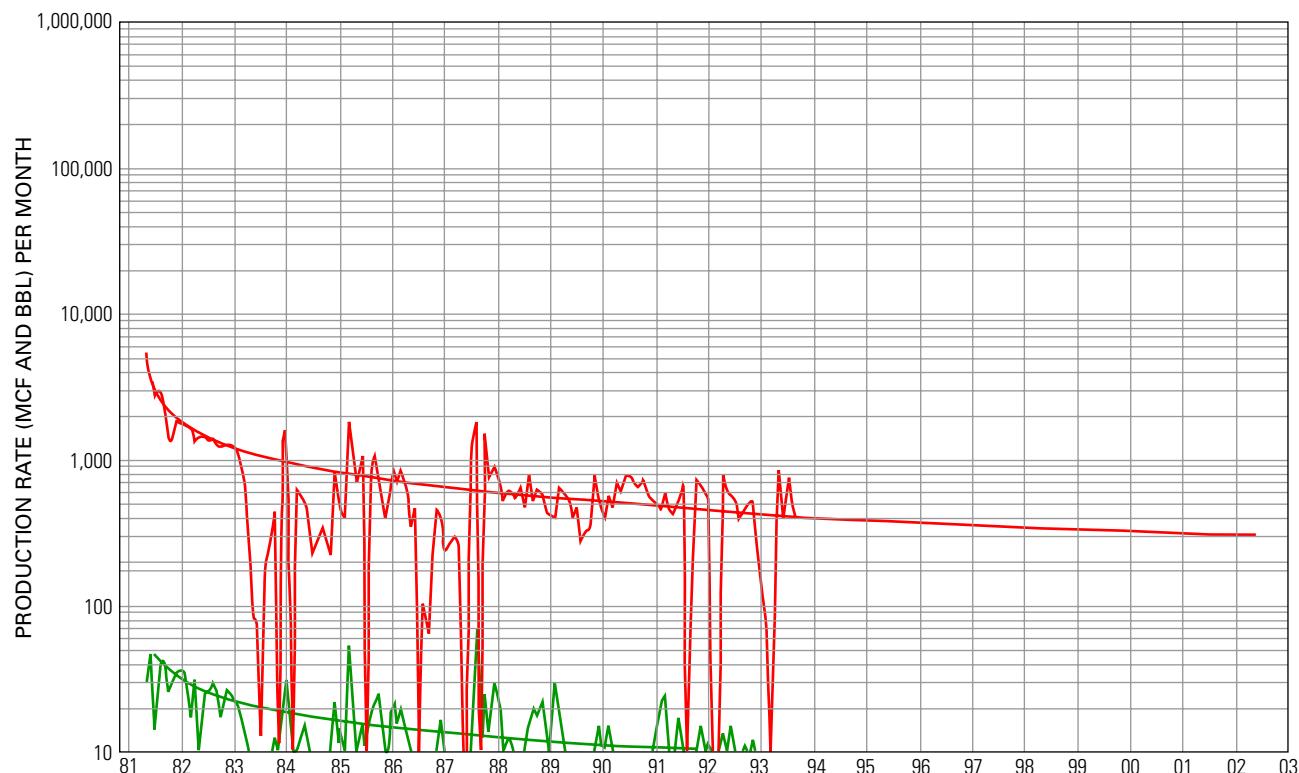


Figure 2. An example of hyperbolic decline and its forecast. The highly variable red line is gas production in thousands of cubic feet per month. The smooth red line is the hyperbolic curve tracking historical production and used to project into the future. The highly variable green line is oil production in barrels per month. The smooth green line is the hyperbolic curve tracking historical production and used to project into the future.

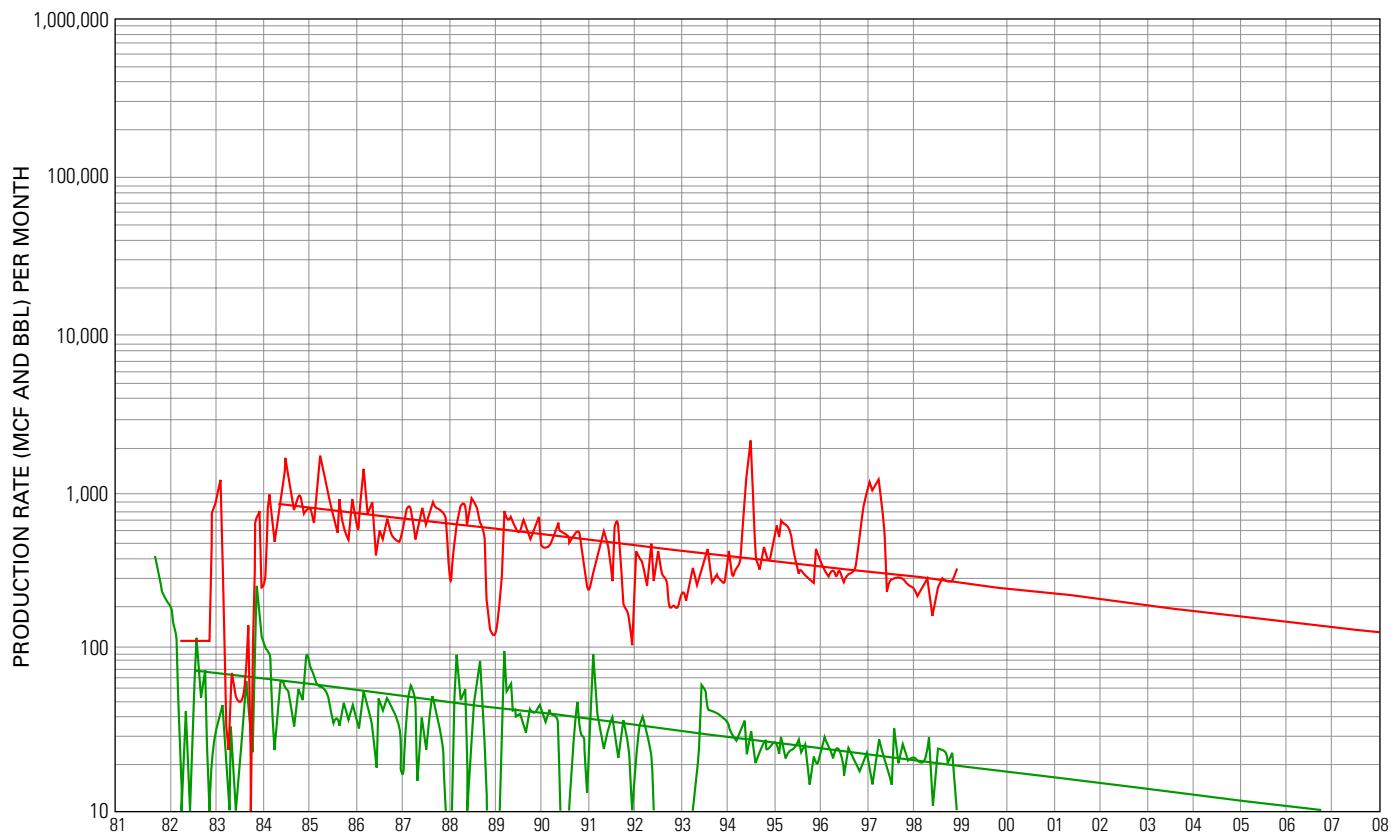


Figure 3. An example of exponential decline and its forecast. The highly variable red line is gas production in thousands of cubic feet per month. The smooth red line is the exponential curve tracking historical gas production and used to project into the future. The highly variable green line is oil production in barrels per month. The smooth green line is the exponential curve tracking historical oil production and used to project into the future.

such data, with time (commonly by either month or year) plotted on the X-axis and production volumes (oil, gas, and water) plotted on the Y-axis. The production history of a well generally follows a pattern of decline, which can be described by a hyperbolic or exponential decline equation; figure 2 is an example of hyperbolic decline and figure 3 is an example of exponential decline. A comparison of these two types of declines can be used to determine which one best represents the production decline of a given well. A decline extrapolated into the future can be terminated after a period of time has elapsed or when the production rate has dropped to a specific level.

In this study the EURs were generated using a 40-year extrapolation of production trends. The primary assumption in this type of forecast is that the well will continue to decline at the same rate as in the past. The cumulative production to date added to the 40-year forecast was used as the basis for generating EURs for all leases in the GWA.

The EURs of individual wells were separated out of multiwell leases by assuming that the first API (American Petroleum Institute, a nationwide unique numbering system for wells) number was the first production profile, the second API number was the second production profile, and so on. If it

was not possible to determine when a well's production stream had come online, the EUR for each well on that lease was calculated by dividing the total lease EUR by the number of wells. The EUR for a lease was determined in the same way an individual well EUR was determined. However, because the production stream of a lease consists of multiple wells with different production declines, a single curve to simulate the decline for the lease may not be totally representative.

To calculate the initial in-place volumes of oil and gas in the GWA, rock and reservoir characteristics such as porosity, pay-zone thickness, and water saturation are needed. For this purpose, the mean porosity for each of the intervals of interest was used and water saturations were assumed to range between 20 percent and 45 percent, depending on the formation in question (see Higley and Cox, this volume). To determine the net pay thickness, all wells within the area of interest that had only a single producing formation listed in the PI/Dwights database were identified. The thickness of the perforated interval for the producing formation of each well was then extracted, and this thickness was contoured using standard geographic information system techniques. The entire GWA was subdivided into a total of 30,900 160-acre units. For the purpose of data contouring, each 160-acre unit was

evaluated for net perforated thickness and then broken into 160 one-acre subunits. The center of each one-acre subunit was assigned a value based on the surrounding contour lines. An average of these one-acre subunits was then used to estimate the net thickness of petroleum-saturated rock for each main 160-acre unit. The perforated thickness data were then used to calculate the initial in-place volumes of oil and gas for each formation. This procedure was performed for each of the producing formations in the GWA.

Description of Model

A computer program was written to produce a model for determining remaining potential areas for future oil and gas development in the GWA. For each of the approximately 31,000 160-acre units in the GWA, an initial pore volume containing oil, gas, and water was calculated for each stratigraphic interval. The EUR volume for any producing interval was then deducted from the initial pore volume for that stratigraphic interval in a particular 160-acre unit. The remaining volume is that which would be possible to drain by potential future wells or recompletions of existing wells. Because the location of a well inside a 160-acre unit is not used for any purpose other than just placing it in the proper 160-acre unit, it is probable that some wells could actually drain oil and gas from adjoining 160-acre units or be drained by a large EUR or close wells in nearby units. To compensate for this, the remaining oil-and-gas-filled pore volume was calculated for each of the eight surrounding 160-acre units. The pore volume of the central 160-acre unit could then drain additional oil and gas volumes from these surrounding units or contribute oil and gas to the surrounding 160-acre units.

Because the final remaining pore volume value for each 160-acre unit is relative only to a specific producing formation, it was necessary to normalize all of the different producing formations so they could be totaled for a combined analysis. This was done by using a weighted average of each 160-acre unit for each of these formations and then expressing a single value for each 160-acre unit as a percentage of potential of all four formations combined. This percentage of pore-volume potential for each 160-acre unit therefore represents a percentage of remaining potential for all four formations rather than a remaining oil and gas volume.

The remaining oil and gas pore volume of a single 160-acre unit was calculated repeatedly, and the model allowed the basic rock properties and water saturations to change with each repetition. The water saturations were varied by 20 percent from the input values, and the contoured stratigraphic thickness was allowed to vary by 10 percent. This was done to account for the fact that no single set of values could accurately represent the rock and water properties in any given 160-acre unit. The final result was the mean of all of the individual model runs. This process was repeated for each 160-acre unit in the GWA.

Before the model was run, all wells within each 160-acre unit were counted for the purpose of categorizing each 160-acre unit with respect to its recompletion and drill-down potential. Any single 160-acre unit with high potential for remaining oil and gas resources and a relatively high number of existing well bores will have a correspondingly high likelihood that some or all of the wells being examined could be used for future production from one or more additional formations.

A summary table was then created for each 160-acre unit that contains (1) the well counts, (2) the remaining oil and gas estimate for each formation in the 160-acre unit, and (3) the weighted total potential value of all four formations. The data were then viewed on a base map of the Front Range Infrastructure Resources Project study area to determine where areas of moderate or high potential for remaining oil and gas exist within the Front Range Infrastructure Resources Project study area and where such areas coincide with urban areas.

Results

The results from each formation were divided into low, high, and moderate groups with respect to oil and gas production potential. The first group is the geographic area of lowest potential for remaining producible oil and gas. This area either has less initial potential or the producible oil and gas will be depleted over the life span of past and current producing wells in the area. The second group has the highest potential for producible oil and gas. In these areas, new wells or the recompletion of existing wells would be necessary to remove the remaining oil and gas. The third group includes areas where further production is likely but the potential is less for substantial future development.

Some examples of these three groups are given in figures 4–10. Figure 4 shows the areas of moderate and high potential for the Muddy (“J”) and “D” sandstones in and around the GWA. Two areas considered to have the highest potential are centered around and slightly to the north of Denver International Airport (DIA) and in a larger tract south of Greeley, Colo. Figure 5 shows that the areas of moderate and high potential for the Niobrara Formation are scattered, with the main body of moderate and high potential not extending as far south as DIA but an area of moderate and high potential existing in the same vicinity as the “J” and “D” sandstones in an area south of Greeley. Figure 6 shows that areas of moderate and high potential in the Terry (“Sussex”) and Hygiene (“Shannon”) Sandstones are small, but they are located where potential also exists for the other three formations of interest. Figure 7 shows that areas of high potential in the Codell Sandstone Member exist primarily along the southern and western sides of the GWA, extending in a more northwesterly direction away from DIA and more toward the areas of highest density of wells drilled to the Terry (“Sussex”) and Hygiene (“Shannon”) Sandstones. Few areas of high potential appear to exist

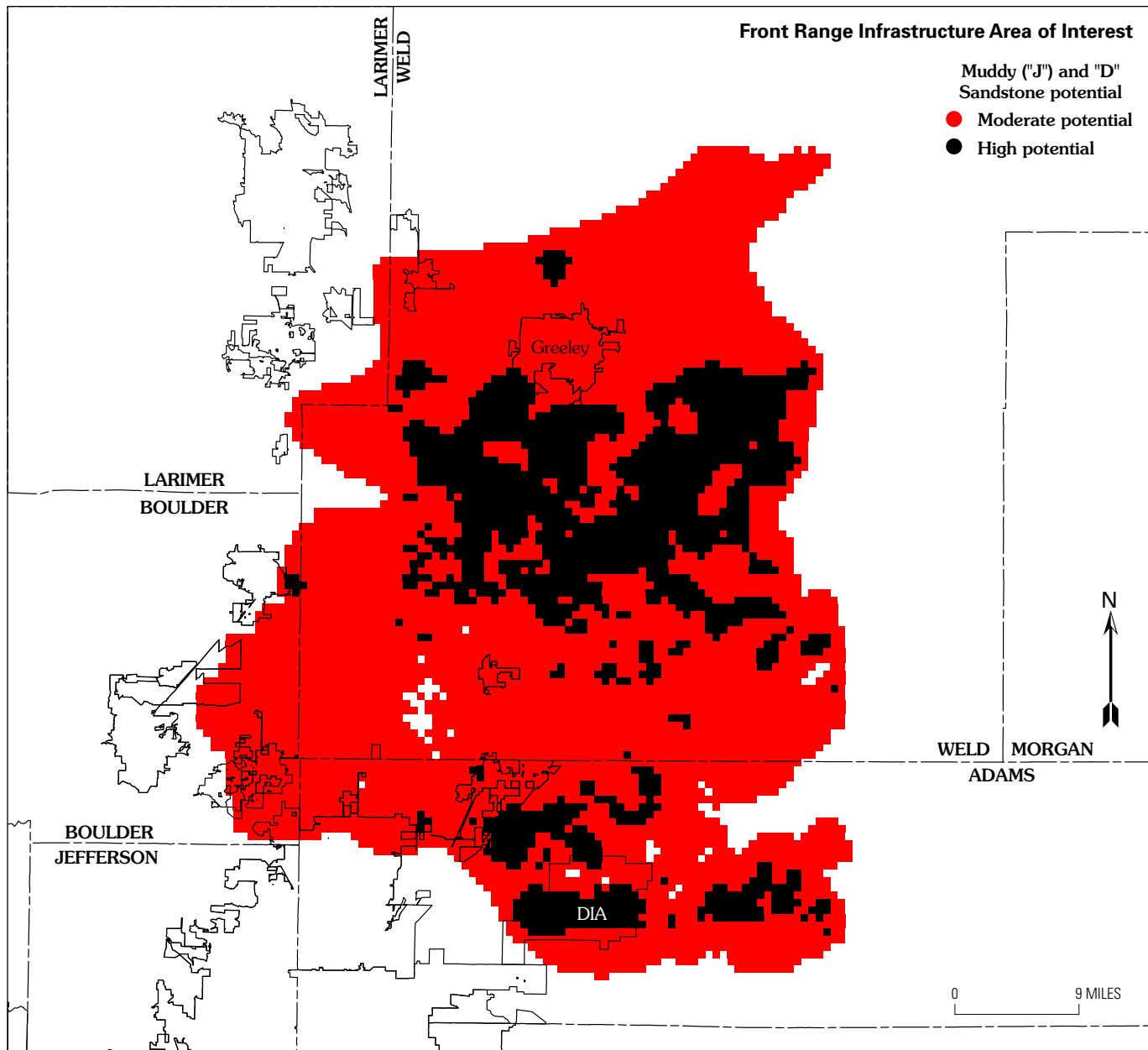


Figure 4. Muddy ("J") and "D" Sandstones areas of development potential.

south of Greeley where there is high potential for "J" and "D" sandstones and the Niobrara Formation.

As mentioned previously, an important economic consideration in the ongoing development of the GWA is the availability of existing wells that were not originally targeted for what would be considered a "secondary" formation. These wells are available in the future for recompletions and drilldowns into formations other than the original producing formation and are usually less expensive to recomplete and drilldown than drilling a new well from the surface. A

well-density map of the area of interest, which shows a count of the number of existing wells in each 160-acre unit, is shown in figure 8. Well density is highest in the main body of the field, concentrated south of Greeley. This area is also where there is high potential for additional producible oil and gas from the Niobrara Formation and the "J" and "D" sandstones. The Codell Sandstone Member in this area has moderate potential as well.

Figure 9 shows areas where all formations, combined, have either moderate or high potential for production of oil

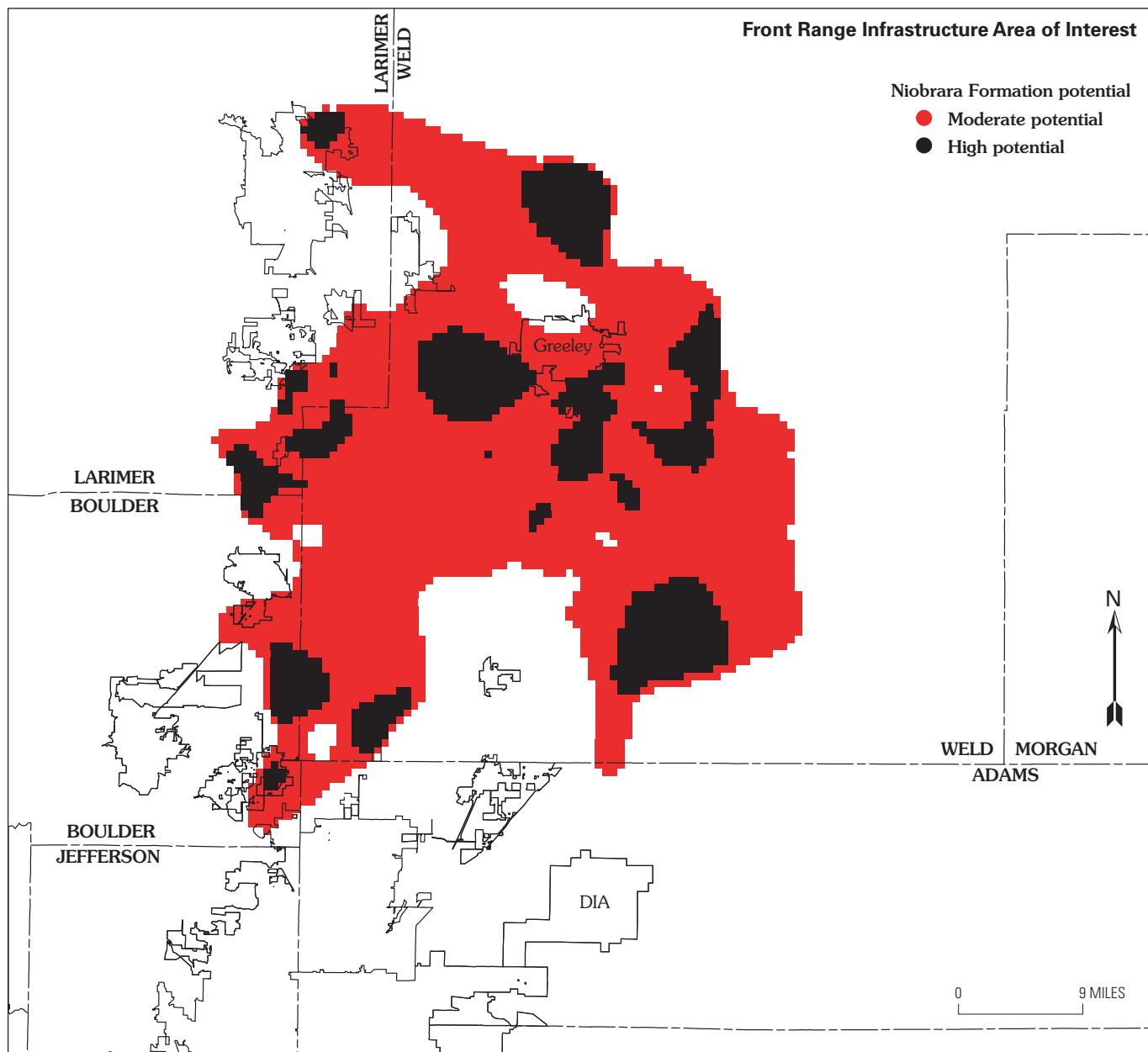


Figure 5. Niobrara Formation areas of development potential.

and gas. The area of highest potential is in the area south of Greeley and extends for quite some distance to the east and west. Another large area of high overall potential is in the vicinity of the main concentration of the Terry and Hygiene wells. Although the Terry and Hygiene Sandstones are not completely underlain by high-potential areas of the other three formations, taken in its entirety the area has the highest potential in the GWA for future development based on the total remaining resources. Figure 9 is the best representation of where future drilling of new wells may take place, based on estimates of the remaining resources.

Figure 10 shows the areas within the GWA with the highest density of wells combined with the areas of moderate and high potential resources for all formations. This area represents the area most likely to be subject to future well recompletions and drilldowns.

Summary

The presence of multiple petroleum-producing formations in the greater Wattenberg area, including a portion of the Front Range Infrastructure Resources Project area,

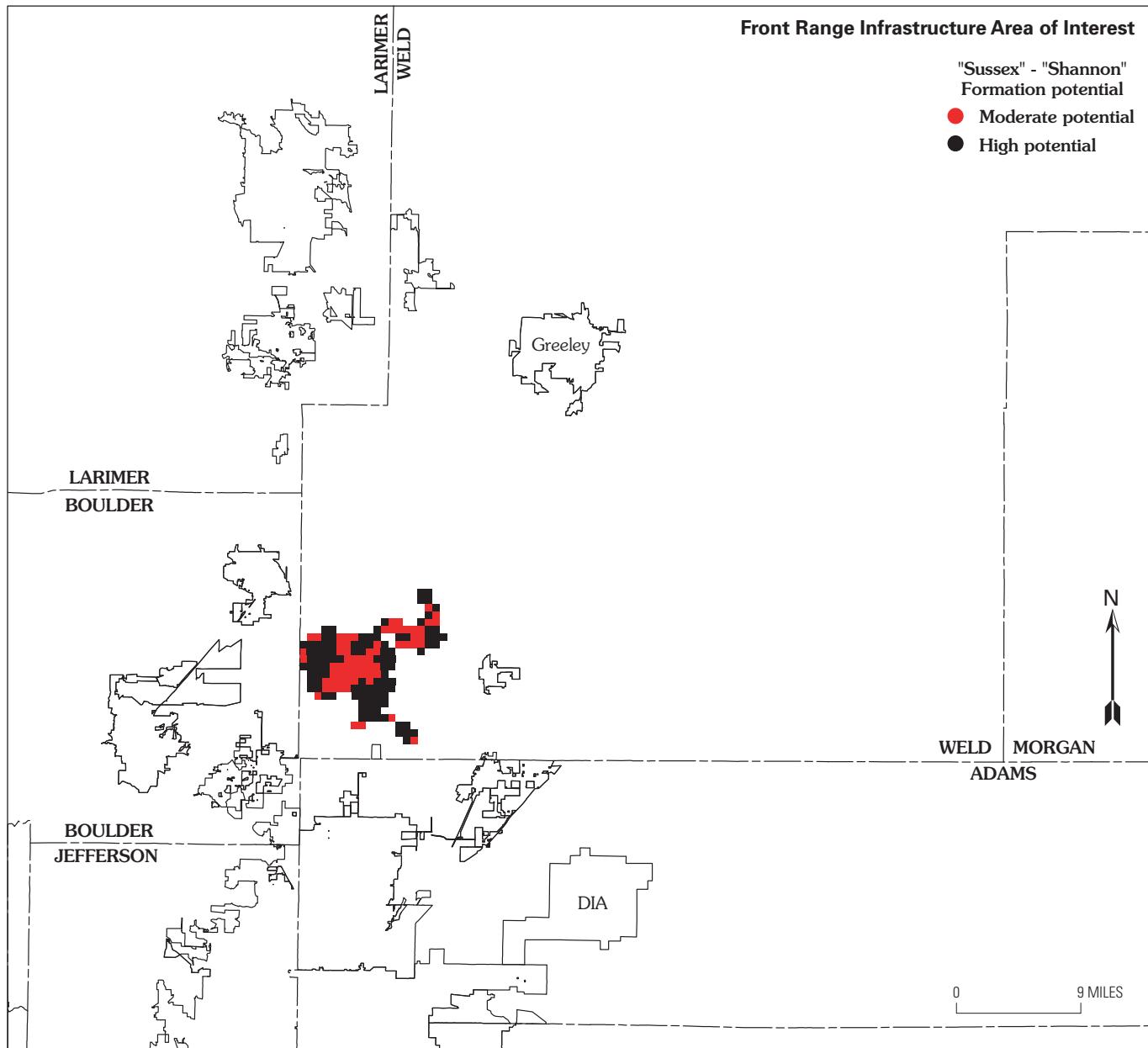


Figure 6. Terry ("Sussex") and Hygiene ("Shannon") Sandstone Members areas of development potential.

and calculations of estimated ultimate recovery of oil and gas indicate potential for the development of additional resources through recompletions and drilldowns, as well as the drilling of new wells in some tracts. Because rapid urban expansion is also occurring within the area designated as the GWA, a broader appreciation for the oil and gas resource potential in this region will contribute to more informed land-use planning efforts and decisionmaking.

Acknowledgments

I would like to thank Mahendra Verma for reviewing the basics of the model and helping me with some of the equations involved and Debra Higley Feldman for sharing her extensive knowledge of the geology of the area with someone who must have tested her patience.

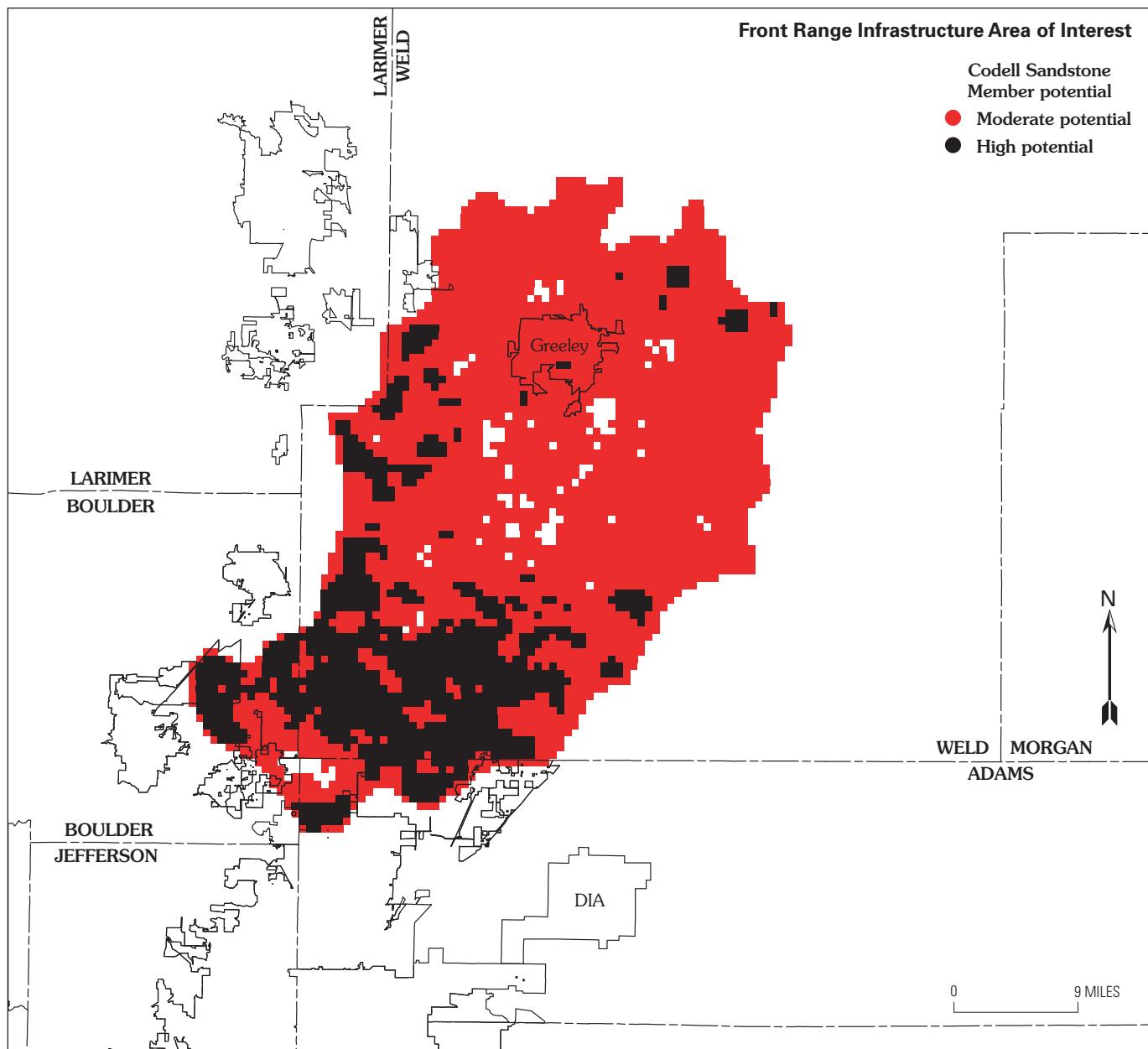


Figure 7. Codell Sandstone Member areas of development potential.

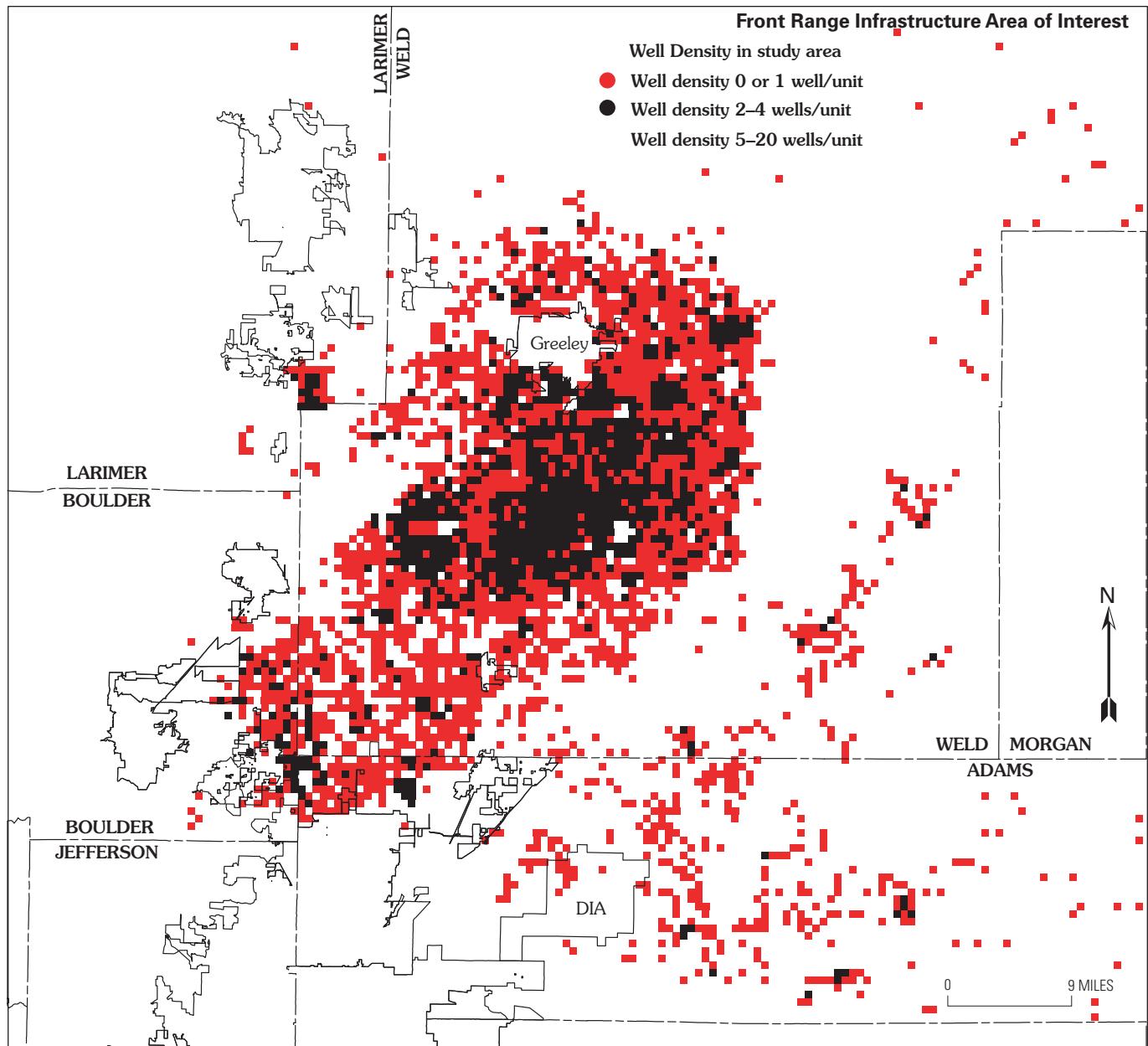


Figure 8. Well density per 160-acre unit, greater Wattenberg area.

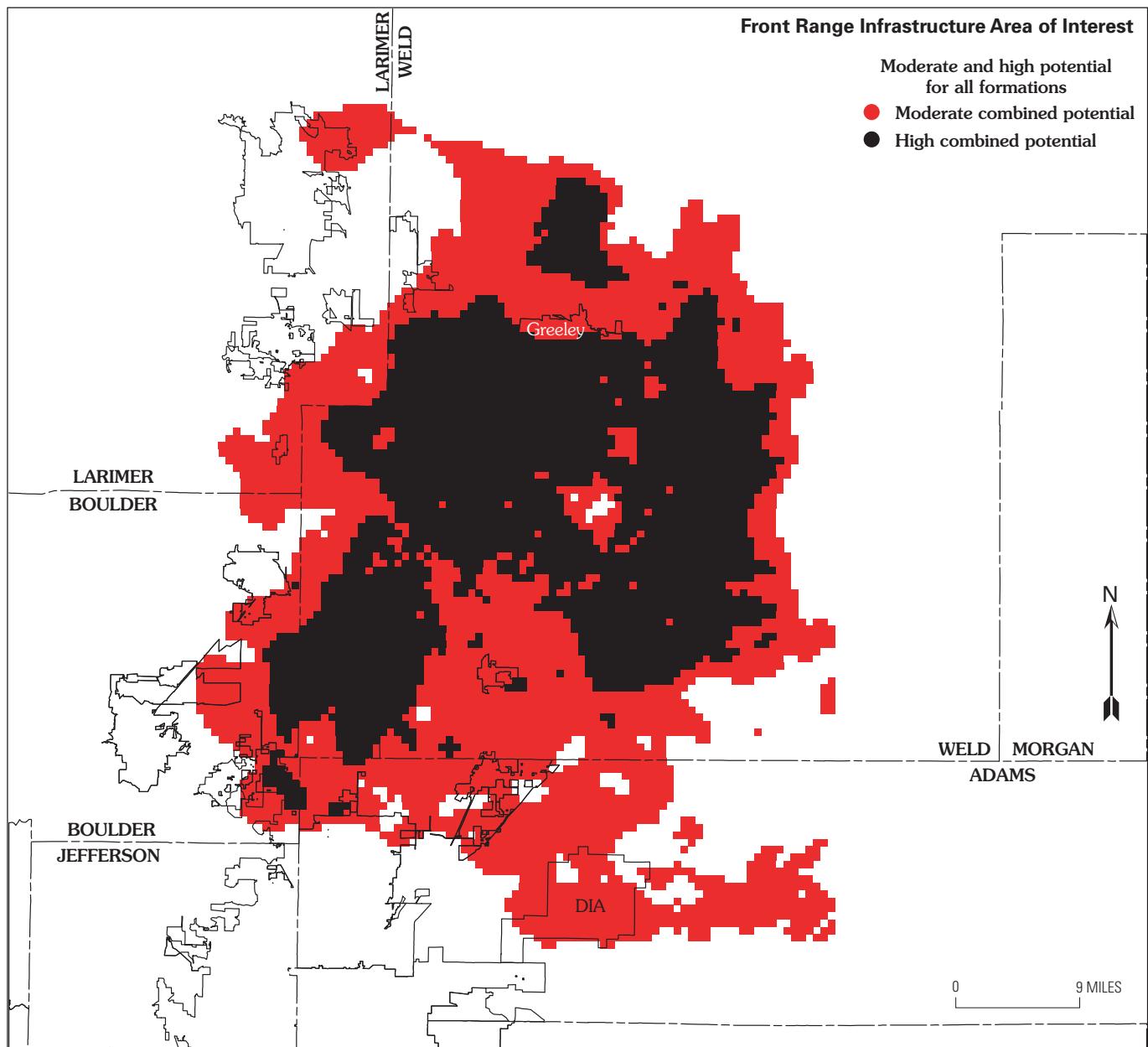


Figure 9. Combined potential development for all formations.

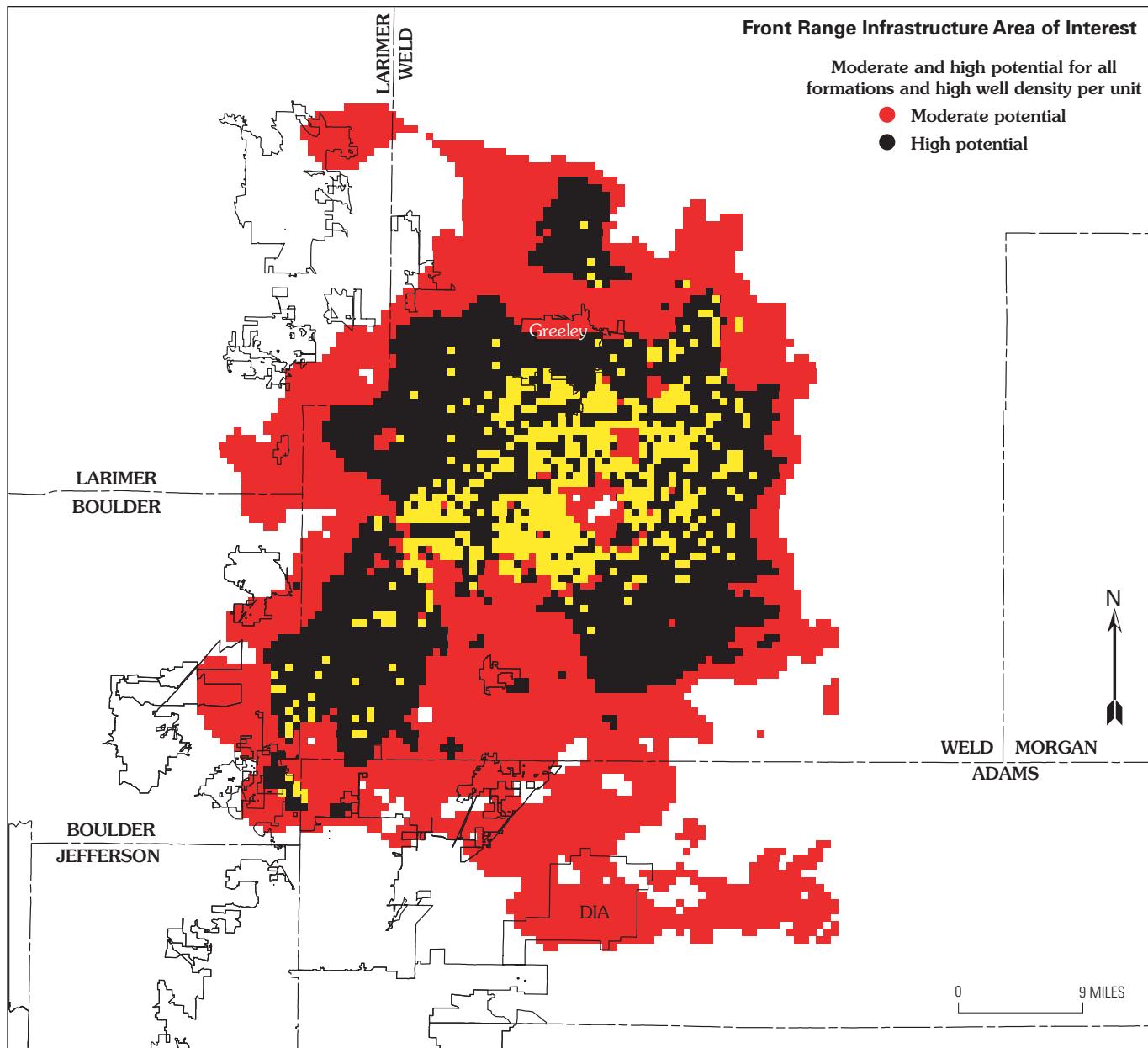


Figure 10. Well density greater than four wells per 160-acre unit and high and moderate development potential. Yellow dots signify areas of both high potential in all formations and well density greater than four wells per 160-acre unit.

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Glossary of Terms

Continuous accumulation An oil or gas accumulation that is pervasive throughout a large area, that is not significantly affected by hydrodynamic influences, and for which the chosen methodology for assessment of sizes and number of discrete accumulations is not appropriate (U.S. Geological Survey, 1995). Continuous-type accumulations lack well-defined downdip water contacts. The terms “continuous-type accumulation” and “continuous accumulation” are used interchangeably.

Conventional accumulation A discrete accumulation, commonly bounded by a downdip water contact, which is significantly affected by the buoyancy of petroleum in water (U.S. Geological Survey, 1995). This geologic definition does not involve factors such as water depth, regulatory status, or engineering techniques.

Drainage area A given geographic area, generally measured in acres, from which oil, gas, and water are withdrawn from a well. Drainage area differs from a government-mandated minimum spacing requirement that regulates the density of drilling to minimize the effects on the environment and optimize withdrawal efficiency. The drainage area can be larger or smaller than a regulated spacing requirement.

Estimated ultimate recovery (EUR) EUR is the expected total production of oil and/or gas from a given stratigraphic interval, in a given wellbore, over the life of the well. This estimate incorporates many variables such as the economics of the well, how long the casing can last within the given operating conditions, the length of production stream

forecast that is used, and the historical production-decline history of the well. All of these variables are factored together and a volume is calculated, for both oil and gas, of the EUR of a particular interval in a given well (Seba, 1998).

Lease production A lease is typically a legal document giving an individual or business entity permission to conduct exploration, drilling, and production activities within a specific property. It is possible to have several wells on a given lease, depending on regulatory requirements. The oil and gas production data used for this study were obtained from the Petroleum Information (PI) Production Database (1999), which stores oil and gas production information by lease. Because the PI database stores its production information by lease, it can be difficult to accurately determine the volume of oil and gas produced by a given well. In cases where production volumes could not be apportioned by well, an average was used as the EUR for each well.

Recompletion A recompletion typically involves a change to the producing formation of an existing well. This change can be accomplished by (1) sealing the existing perforations that were used to extract oil and gas from a formation and perforating another interval from which oil or gas can be removed, (2) perforating another formation while continuing to produce from the original one, or (3) drilling the well deeper to another prospective formation. Because they are generally less expensive than the drilling of new wells and hence are more economically viable, recompletions are common in mature petroleum-producing areas such as the GWA.



Origin of Saline Soils in the Front Range Area North of Denver, Colorado

By James K. Otton, Robert A. Zielinski, and Craig A. Johnson

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Abstract

Saline soils along the Front Range north of Denver occur in specific geomorphic and hydrologic settings where ground water enriched in dissolved solids is close to the soil surface for at least part of the year. More than 200 saline soil areas were mapped in a five-quadrangle area extending northward from Northglenn to Johnstown and then westward to Longmont. Saline soils occur on:

1. Upland areas underlain by loess deposits (47 percent of mapped occurrences);
2. Upland areas underlain by residual soils formed on shale (28 percent);
3. Areas along flood plains of minor streams where the upland parts of the drainage basin are dominated by loess deposits (16 percent);
4. Areas of eolian sand immediately adjacent to wetlands or lakes (9 percent).

Saline soils are rare on the flood plains of larger streams that flow eastward across the study area from the mountains to the South Platte River.

Some saline soils occur close to oil production tank batteries, but only two of the tank battery sites examined show clear indications of saltwater leakage from pits or tanks. Soils near these two sites contain chloride-dominant salts in soil leachates, which contrasts with the sulfate-dominated salt assemblages at all other sampled localities.

The mapped saline soils show a preferred geographic distribution, lying primarily in a belt that extends from the city of Loveland southeastward to the northern Denver suburbs. The northern part of this belt is underlain by the Upper Cretaceous Pierre Shale. Numerous depressions have formed on this unit, probably as deflation basins, during the late Pleistocene and early Holocene. Saline soils are rare to absent in areas east of the main area of depressions. These deflation basins appear to be a source for the thick (as much as 2–3 meters) clayey loess that blankets upland areas downwind and may also be a source for windblown salts. This is consistent with a dominantly northwesterly wind direction indicated by linear orientations of dunes and dune axes in the east-central part of the study

area and with prevailing paleowind directions documented in sand-dune areas farther to the east. Sulfur isotopic composition of dissolved sulfate and of sulfate salts in soils in the area of Pierre Shale bedrock is mimicked in saline soils closer to the Denver suburbs despite a transition to other bedrock units. We conclude that the Pierre Shale is a primary source of salts in saline soils of the study area.

Introduction

In many semiarid areas of the Western United States and Canada, farmers and ranchers contend with saline soils that lead to reduced yields on crop and pasture lands (U.S. Department of Agriculture—Natural Resources Conservation Service, 1992). Within the Front Range Infrastructure Resources Project (FRIRP) area (fig. 1), saline soils are common from the northern Denver suburbs north to the latitude of Greeley, an area of about 1,400 km². Surface water and shallow ground water associated with these saline soils and nearby wetlands commonly exceed 5,000 microsiemens per centimeter at 25° Celsius ($\mu\text{S}/\text{cm}$) specific conductance compared to an 838- $\mu\text{S}/\text{cm}$ northern Front Range regional average (Gaggiani and others, 1987) and a range of 100 to 500 $\mu\text{S}/\text{cm}$ for water in irrigation ditches and reservoirs fed directly from streams exiting the mountains (Otton and Zielinski, unpub. data, 2001).

Areas of saline soils are characterized by stunted or missing vegetation, the presence of salt-tolerant plant species, and, commonly, “white alkali” salt crusts. In some places, the salt crusts are sufficiently abundant to form small (a few square meters) to locally large (a few hectares) patches of white soils completely barren of vegetation.

The FRIRP area has many potential sources of soil salinity, including natural salts in bedrock or surficial deposits, fertilizer, oil and gas produced-water spills and leaks, coal-mine waste piles, and runoff from feedlots and roads. Development of saline soils may be enhanced near irrigation ditches and reservoirs where seepage from these features raises the water table and leaches additional salts from the local soils or bedrock.

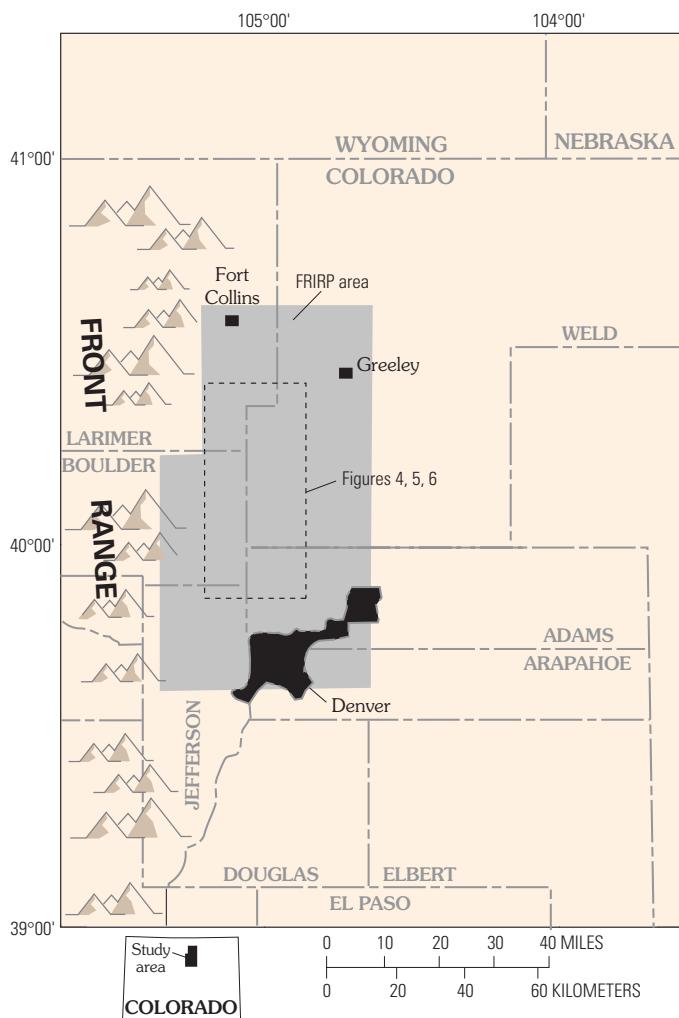


Figure 1. Location of the Front Range Infrastructure Resources Project (FRIRP) area and the study area.

Surface expressions of saline soils can form seasonally in semiarid areas during periods of high ground-water levels that typically occur in the spring after snowmelt, following significant rainstorms, and during seasonal irrigation of fields. Shallow ground water is transported through the capillary fringe toward the surface. The thickness of this capillary fringe is dependent on the texture of the soil. In coarse, permeable, sandy soils the capillary fringe may only be 15 cm thick, whereas in less permeable, silty and clayey soils it may be 1 m or more (Henry and others, 1987). Water within the capillary fringe becomes more saline as it moves toward the surface because part of the water is continuously removed through evapotranspiration and the dissolved solids are concentrated in the remaining water. Where the concentration of dissolved solids exceeds the solubility limits of certain minerals, those minerals precipitate in the soil profile. Salt crusts may form at the soil surface if the water table is high enough to cause the capillary fringe to reach the ground surface.

Unfortunately, high water-table conditions usually occur in the early spring as crops are germinating. If the salinity

exceeds critical levels in the root zone, germination does not occur or seedlings are severely stunted. Later in the growing season, the water table declines in most soils, the surface accumulations of salt are cut off from replenishment, and rainfall flushes salts from the surface or wind blows the salts away. Where the salinity in the root zone decreases to certain tolerance levels, some late-germinating, salt-tolerant forbs may then establish themselves on the saline soil sites.

Saline wetlands have formed in parts of the study area. They occur along stream drainages where saline ground waters are discharged to the surface or where evaporation along the drainage has concentrated salts. Such saline wetlands can be recognized by salt crusts that form on the stems of wetland plants and by the presence of salt-tolerant wetland plant species.

During preliminary springtime field work in the FRIRP study area north of Denver, we noted numerous areas of saline soils, some adjacent to oil and gas production operations (figs. 2A, B, C, D) or coal-mine waste piles. As part of a study of the effects of energy development on the infrastructure of the FRIRP area, one of our goals was to determine whether releases of saline produced water from the oil and gas operations or leaching of salts from coal-mine waste piles was partly responsible for the saline soils. Conversations with some local landowners about saline soils and oil and gas operations on their property indicated that the development of saline soils preceded the oil and gas operations. Moreover, mapping showed that most saline soil areas were not near oil and gas production operations. Aqueous leachates of variably saline soils, including soils near possible produced-water-affected sites, were analyzed for anion compositions. Leachates of natural nonsaline soils were dominated by carbonate and bicarbonate anions; the saline soils were dominated by sulfate; and some soils and waters near oil and gas production pits and tanks were dominated by chloride (Otton and Zielinski, 1999a; and fig. 3, this chapter). Soils affected by chloride-dominated produced-water salts were devoid of vegetation but did not have obvious surface accumulations of white sulfate salts. We conducted a detailed study of one site where both natural salts and produced-water salts leaking from a brine pit were documented (Zielinski and Otton, 2001). A detailed study of a site surrounding a coal-mine waste pile (Zielinski and others, 2001) showed that sulfate and nitrate were leaching from the coal-mine waste into an adjacent wetland, but most salts in the drainage downstream from the wetland were derived from soils underlying adjacent irrigated fields.

The purpose of this report is to document further the geologic origins of sulfate-dominated saline soils of the study area. Data collection included (1) saline soil mapping, sulfur-isotope geochemistry, and mineralogy of saline soils in most of a five-7.5-minute-quadrangle area to establish the location and characteristics of saline soils in the landscape (figs. 4, 5, 6); and (2) compilation of the surficial and bedrock geology in a multiquadrangle area beyond the five-quadrangle saline-soil-mapping area to establish the geologic setting for the saline soils (figs. 5, 6).



Figure 2A. Saline soil area immediately downslope from a tank battery (to the left) along I-25 frontage road north of Denver. Black arrow points to buried produced water tank.



Figure 2B. Saline soils along a drainage (beyond the vehicle, right of the road) and adjacent to a small pond (left of the road) downslope from a tank battery.

Study Methods

Saline soils were mapped by visual observation during road and foot traverses throughout the five-quadrangle study area, primarily in the late winter–early spring when white saline soil crusts show maximum development. The dimensions of the saline soil areas were established by pace and compass surveys or by visual comparison with features of known extent such as houses, roads, topographic features, and fence lines.

The saline soils as mapped represent a minimum for their extent in the study area. Some ranchers have installed drain-tile systems under fields where saline soils occur. We did not attempt to locate such systems or to map them, although we found a few during the course of this study. Many slightly saline soil areas, characterized by subtle variations in plant health or the presence of salt-tolerant species, were not mapped.

The bedrock geology was compiled from maps by Colton (1978), Trimble and Machette (1979), and Scott and Cobban



Figure 2C. Saline soils near a tank battery and irrigation ditch (site A, fig. 6).



Figure 2D. Saline soil area on flood plain of Big Dry Creek abutting berm of storage tank.

(1965) (table 1, fig. 6). The map of loess and eolian sand deposits, residual soils on bedrock, and soils developed on flood plains (fig. 5) was derived from county soil surveys for Adams, Boulder, Larimer, and Weld Counties (Sampson and Baber, 1974; Moreland and Moreland, 1975; Moreland, 1980; Crabb, 1980) by assigning specific soil map units to either a loess or sand geologic map designation following Madole (1995). Other units were assigned to the flood plain or residual soil units based on the soil map unit descriptions. Some soil map units are formed on erosional remnants of Pleistocene

alluvium that occur in upland areas. Because these erosional remnants typically have a thin surface horizon of loess, they were assigned to the loess geologic map unit. Surficial geologic map areas showing hydrologic features and roads were compiled on a digital base map at 1:150,000 scale.

Soil profile samples were collected by augering holes with a 5-cm-diameter soil auger at approximately 15-cm intervals. We also collected a single Pierre Shale sample from the wall of a deep agricultural trench. Water samples were collected in 250-mL bottles prerinse with the sample.

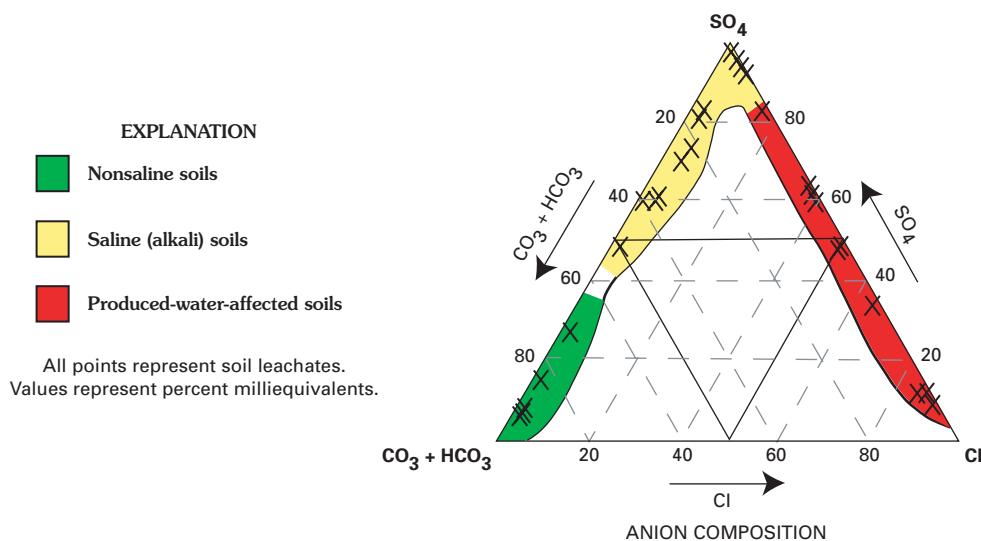


Figure 3. Piper diagram for anions from soil leachates for soils in the study area.

Leachates of the soil and rock samples were prepared by air-drying the sample at 40°C and passing it through a ceramic-plate jaw crusher with a 3-mm opening to disaggregate it. Most of the sample (200 g) was weighed into a plastic beaker and 200 mL of deionized water added. Each 1:1 weight mixture was stirred vigorously, allowed to stand overnight at room temperature, and again stirred vigorously prior to pouring into two 250-mL centrifuge bottles. The slurries were centrifuged at 8,000 rpm for 40 minutes. Clear supernatant was decanted and filtered (0.45 µm). Concentrates of efflorescent salts were collected from the undisturbed surface of saline soil crusts by scraping and lifting with a stainless-steel spatula or knife blade at 23 sites across the study area. Samples were analyzed

within a few days by powder X-ray diffraction (XRD) using CuK α radiation generated at 40 kilovolts and 25 milliamperes. Salt samples also were dissolved in deionized water for sulfur isotope analyses.

Soluble sulfate in surface water, soil leachates, and dissolved efflorescent salt samples was precipitated as barium sulfate by adding barium chloride to filtered sample solutions. Total sulfur in soil samples was extracted from powdered samples by Eschka fusion and recovered as barium sulfate following the procedure of Tuttle and others (1986). The barium sulfates were combusted in an elemental analyzer to form SO₂ gas. The sulfur isotopic composition of the gas was determined using a Micromass mass spectrometer (Micromass

Table 1. Generalized stratigraphy of the study area.

[from Scott and Cobban, 1965; Colton, 1978; and Trimble and Machette, 1979]

Formation	Age	Comments
Alluvium	Pleistocene and Holocene	Occupies modern stream valleys.
Eolian sand and loess	Pleistocene and Holocene	Covers most upland areas and older stream-valley terrace deposits.
Older gravel deposits on uplands	Pleistocene	Occurs irregularly in upland areas.
Denver and Arapahoe Formations	Upper Cretaceous and lower Tertiary	Claystone, siltstone, tuffaceous sandstone and conglomerate. Nonmarine.
Laramie Formation	Upper Cretaceous	Claystone, shale, sandy shale, sandstone, coal near base, lignite near top. Nonmarine.
Fox Hills Sandstone	Upper Cretaceous	Coarsening upward sequence of shale, silty sandstone, and sandstone; local thin coal. Nonmarine.
Pierre Shale—upper transition member	Upper Cretaceous	Sandstone, shaly sandstone, sandy shale. Marine.
Pierre Shale—lower shale and sandstone members	Upper Cretaceous	Silty shale, shale, claystone, sandy siltstone, sandstone. Marine.

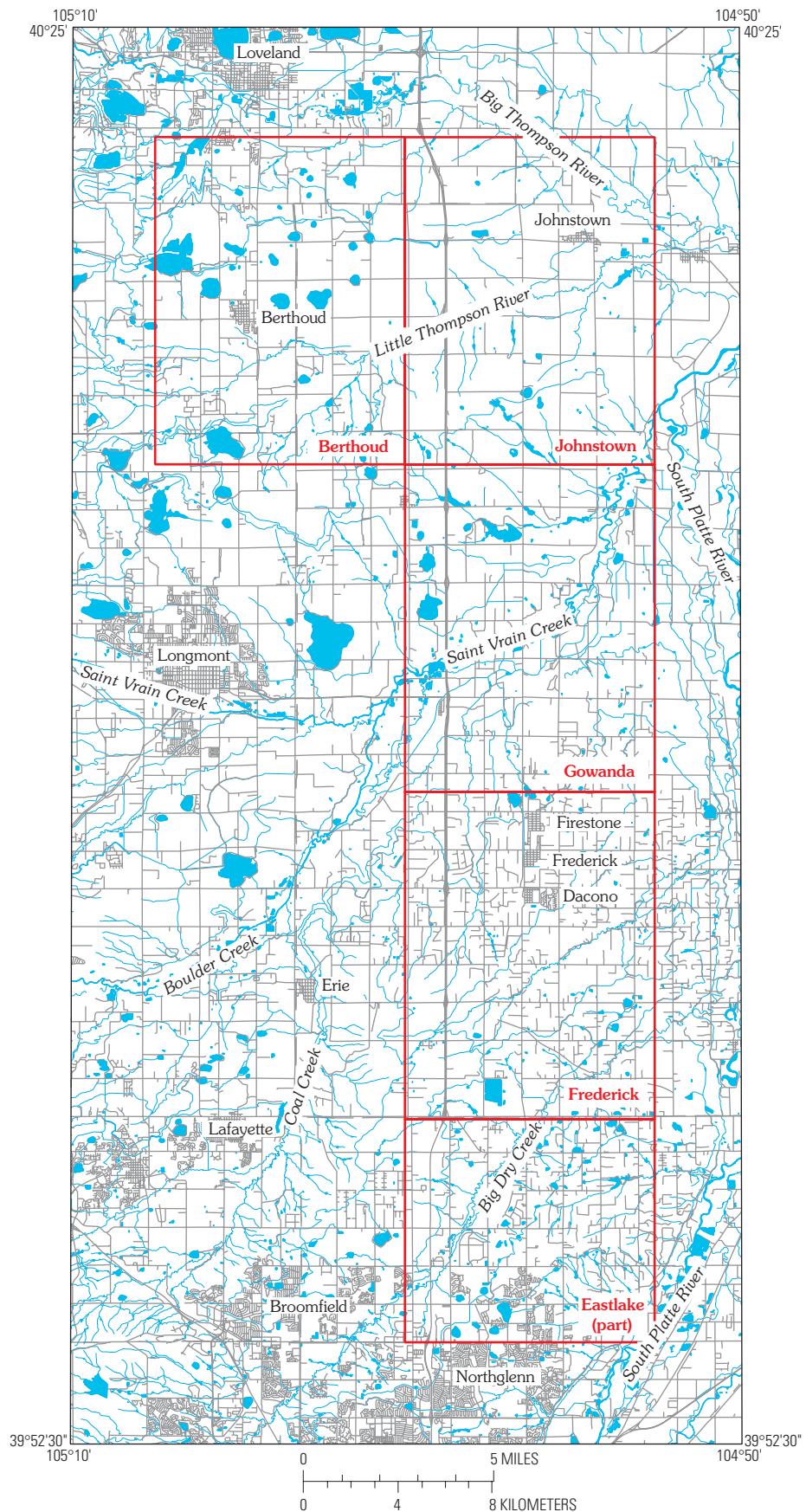


Figure 4. Locations of roads and hydrologic features in the study area. The 7.5-minute quadrangles where saline soils were mapped are outlined and labeled in red.

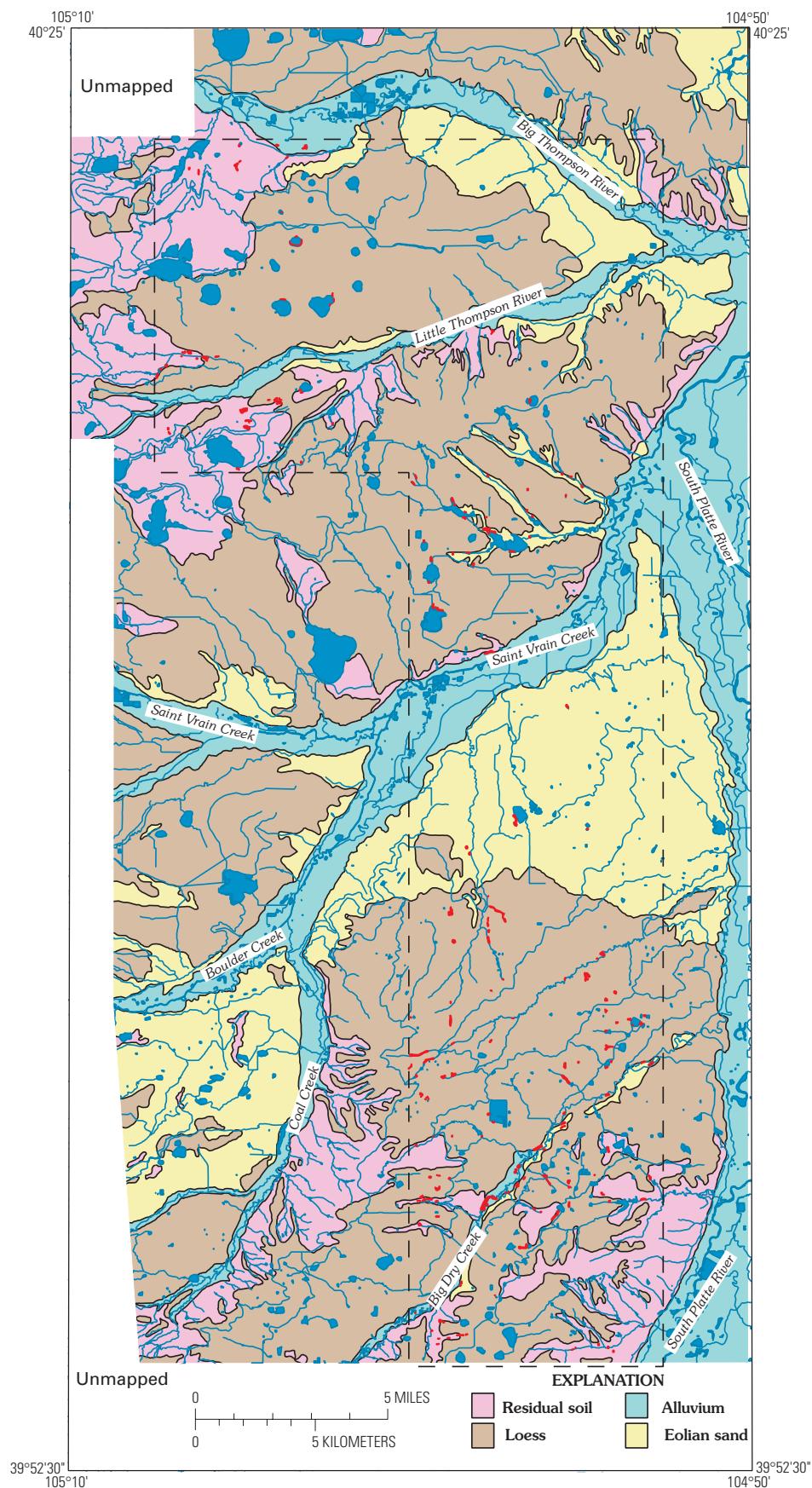


Figure 5. Surficial geologic map of the study area. Dashed line shows area of saline soil mapping. Mapped saline soils are shown in red.

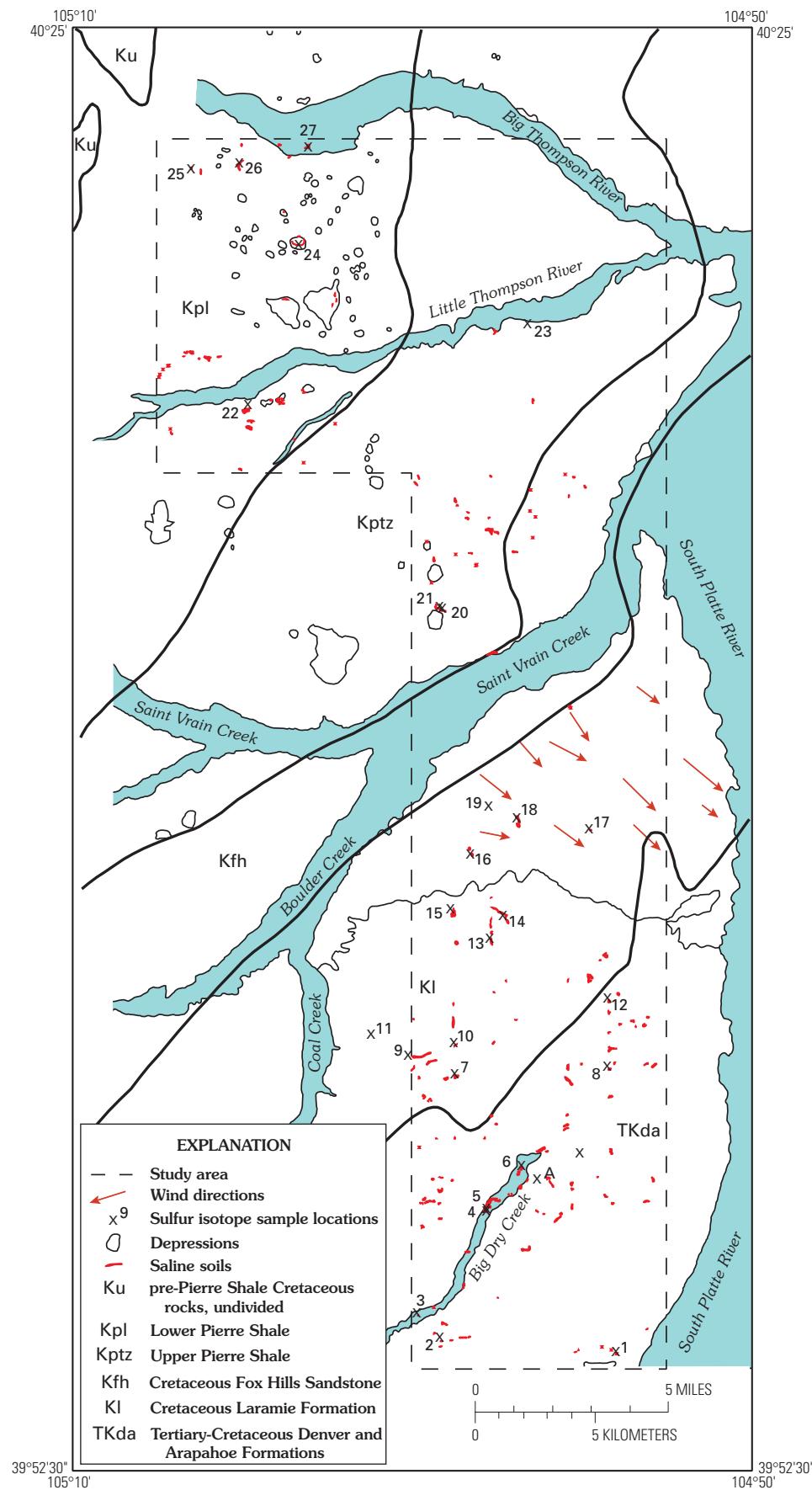


Figure 6. Bedrock geological map of the study area with other features (Colton, 1978; Trimble and Machette, 1979; Scott and Cobban, 1965). Surficial geology linework showing alluvium along streams and the large area of eolian sand is preserved for reference (see fig. 5). Depressions are those mapped by Colton (1978) and this study. Wind directions determined from orientation of linear sand ridges.

UK Limited, Manchester, UK) by a continuous-flow method modified from Giesemann and others (1994). Sulfur isotopic composition is reported in terms of a $\delta^{34}\text{S}$ value:

$$\delta^{34}\text{S} \text{ (per mil, ‰)} = (\text{R}_{\text{sample}}/\text{R}_{\text{standard}} - 1) * 1,000$$

where R is the atomic ^{34}S to ^{32}S ratio and the standard is Cañon Diablo troilite (CDT). Reproducibility was $\pm 0.2\%$ (parts per thousand). Analysis of the National Bureau of Standards NBS 127 seawater standard averaged 21.0% ($n=5$) compared with the value of 20.99% reported by Rees and others (1978) for the modern oceans.

Geologic and Geomorphic Setting

Bedrock Geology

The study area is underlain by middle to Upper Cretaceous and lower Tertiary sedimentary rocks of the northern Denver Basin (Colton, 1978; Trimble and Machette, 1979) (table 1, fig. 6). These beds dip gently southeast across the area toward the center of the basin southeast of Denver. The Upper Cretaceous Pierre Shale underlies the northwest part of the study area including most of the Berthoud and Johnstown 7.5-minute quadrangles and the northwest part of the Gowanda 7.5-minute quadrangle (figs. 4, 6). The Pierre Shale is composed primarily of marine shale, siltstone, sandstone, and minor limestone (Scott and Cobban, 1965). To the southeast, the formation is overlain by nonmarine sedimentary rocks of the Upper Cretaceous Laramie Formation and Fox Hills Sandstone and by the Cretaceous-Tertiary Denver and Arapahoe Formations. These rocks consist variously of shale, siltstone, sandstone, conglomerate, and coal. Coal locally forms substantial seams in the Laramie Formation that have been mined by underground and open-pit methods (Roberts, this volume).

Surficial Geology

Major streams that head in the mountains to the west traverse the study area from west to east, eroding the relatively soft sedimentary bedrock of the area and forming broad valleys along which alluvium of various ages has accumulated (fig. 5). The alluvium is composed primarily of clasts of Precambrian igneous and metamorphic rocks. Smaller streams head within the sedimentary rock terrane of the study area or areas immediately to the west, and their stream valleys are underlain by locally derived alluvium. Of the smaller streams only Big Dry Creek, however, has substantial alluvial deposits (figs. 5, 6). Loess and eolian sand form sheetlike deposits that cover much of the uplands between the stream valleys, although such sand deposits are commonly missing where the topography is steep (fig. 5). The dominant paleowind direction is from the northwest.

Eolian sand deposits are common on the downwind side of the larger stream valleys, indicating that sand may be largely derived from alluvium in those valleys (Reheis, 1980; Muhs and others, 1996). The largest area of eolian sand is southeast of Saint Vrain Creek downstream from its confluence with Boulder Creek (fig. 5). Eolian sand also occurs in smaller accumulations on the downwind side of upland areas and along the Big Dry Creek drainage (fig. 5).

Irregular topographic depressions occur in the northwest part of the study area. Most are underlain by the lower, shale-rich part of the Pierre Shale (fig. 6). The depressions are semicircular and some appear to be overlapping. Larger depressions are used by irrigation companies for water storage. Typically, the companies have enhanced the storage capacity by building dams at low places on the perimeter. These features are believed by Colton (1978) to be deflation basins formed by the wind or perhaps the action of buffalo or cattle. Holliday and others (1996) concluded that depressions occupied by playas in the southern High Plains formed primarily through wind erosion.

Distribution of Saline Soils

In the five quadrangles of the mapped area (figs. 4, 5, 6), saline soils occur most commonly in four geologic settings:

1. Upland areas underlain by loess deposits (47 percent), sited typically in low swales in the landscape, occasionally on hillslopes;
2. Upland areas underlain by residual soils formed on shale (28 percent);
3. Areas along flood plains of minor streams where the upland parts of the drainage basin are dominated by loess deposits (16 percent); and
4. Areas of eolian sand immediately adjacent to wetlands or lakes (9 percent).

Saline soils show a preferred geographic distribution, lying primarily in a belt that extends from the city of Loveland southeastward to the northern Denver suburbs. The northwest part of this belt is underlain by the Pierre Shale, on which the numerous depressions mentioned previously have formed. Saline soils are missing or sparse in the region east of the main area of depressions. This latter area is underlain by upland loess deposits that occupy much of the Johnstown 7.5-minute quadrangle (figs. 4, 5). Saline soils also are rare on the flood plains of the major streams (South Platte River, Saint Vrain Creek, Little Thompson River, Big Thompson River, fig. 5). Only two saline soil areas were mapped—one adjacent to the south margin of the flood plain of Big Thompson River and one west of I-25 near the south edge of the flood plain of Saint Vrain Creek. Saline soils also are rare in the large area of eolian sand southeast of Saint Vrain Creek downstream from its confluence with Boulder Creek (fig. 6).

Wind Direction

The prevailing wind direction during deposition of eolian deposits in northeastern Colorado was evaluated by Madole (1995) and Muhs (1996) from the orientation of linear features in sand-dune areas east of the FRIRP study area. Madole (1995, fig. 10) shows wind directions of about S.40°E. for the area east and northeast of Platteville (just east of the study area). Linear features in dune areas can be observed on the Platteville 7.5-minute quadrangle soil map (Crabb, 1980) for the area immediately east of the north-trending South Platte River. The median value for the orientation of nine well-developed linear features is S.42°E., which is in close agreement with Madole (1995). Within the present study area, dune features also formed in the area of eolian sand in the northern part of the Frederick 7.5-minute quadrangle and the southeastern part of the Gowanda 7.5-minute quadrangle. The orientation of linear features is portrayed in figure 6. The median value for the orientation of the 11 linear features is S.52°E.

Mineralogy of Salt Crusts

Sodium-, magnesium-, and calcium-sulfate minerals, showing varying degrees of hydration, dominate the salt crusts (table 2), in agreement with previous studies of northern Great Plains salts (Keller and others, 1986; Skarie and others, 1987; Mermut and Arshad, 1987; Kohut and Dudas, 1993). The sodium-sulfate salt, thenardite, dominates most assemblages we studied. The relative abundances of the salts varied from location to location even where locations were within a few hundred meters of one another. Variations in the

sulfate-mineral assemblages are probably related to subtle differences in the availability and relative concentration of cations in the soil pore water and changes in temperature and moisture content within the soil profiles. The chloride mineral halite is commonly present in trace amounts, but carbonate minerals are absent.

The sulfate minerals initially form as patches of delicate efflorescent coatings on the soil surface, usually favoring features standing above the surface of the substrate. These coatings eventually coalesce into thicker, more continuous coatings of minerals. The freshly formed crusts are highly susceptible to wind erosion.

Sulfur Isotopes

Sulfur isotopes were measured in salts from surface crusts, surface water, soil leachates, weathered bedrock leachates, and coal-mine spoil at 27 sites across the study area (see figure 6 for numbered locations, table 3 for $\delta^{34}\text{S}$ values, and figure 7 for comparison of values). Values of $\delta^{34}\text{S}$ from salts in surface soils across the entire study area ranged from -16.7 to $+4.3$ with a median value of -4.3 . The only positive value is from salt in disturbed saline soils that lie in depressions associated with coal-mine collapse features (site 16, fig. 6 and table 3). Values of $\delta^{34}\text{S}$ in salts from residual or loessal soils, where the marine Pierre Shale (Kpl and Kptz in fig. 6) is the underlying bedrock (sites 20–22, 24–27, fig. 6), range from -13.6 to -2.3 (median value -8.5 , "C" fig. 7). The median value compares favorably with a $\delta^{34}\text{S}$ value of -7.9 for a weathered Pierre Shale sample taken from a hillslope cut (site 23, fig. 6). Salts from surface soils where nonmarine

Table 2. Evaporite minerals identified by X-ray diffraction.

Mineral	Formula	Comments
Thenardite	Na_2SO_4	Most common saline mineral in the study area, forms as much as 80 percent of some samples.
Mirabilite	$\text{Na}_2\text{SO}_4 \cdot 10\text{H}_2\text{O}$	Hydrated form of thenardite. Found in only one sample carefully kept wet prior to X-ray analysis. May be far more common.
Bloedite	$\text{Na}_2\text{Mg}(\text{SO}_4)_2 \cdot 4\text{H}_2\text{O}$	Common major mineral, commonly present with thenardite.
Konyaite	$\text{Na}_2\text{Mg}(\text{SO}_4)_2 \cdot 5\text{H}_2\text{O}$	More hydrated form of bloedite, generally in the same sample but less abundant.
Pentahydrite	$\text{MgSO}_4 \cdot 5\text{H}_2\text{O}$	Rare.
Hexahydrite	$\text{MgSO}_4 \cdot 6\text{H}_2\text{O}$	Rare.
Epsomite	$\text{MgSO}_4 \cdot 7\text{H}_2\text{O}$	Relatively common, but present only in trace amounts.
Eugsterite	$\text{Na}_4\text{Ca}(\text{SO}_4)_3 \cdot 2\text{H}_2\text{O}$	Relatively common, but present only in trace amounts.
Gypsum	$\text{CaSO}_4 \cdot \text{H}_2\text{O}$	Present in almost all samples in minor to trace amounts.
Halite	NaCl	Common trace to minor mineral, except at a produced-water contaminant site where it is a major component.

sedimentary rocks are the underlying bedrock (1–10, 12–19, fig. 6, table 3) range from -16.7 to -0.4 (excluding the one positive $\delta^{34}\text{S}$ value mentioned above) with a median value of -4.7 (letter D in fig. 7).

Values of $\delta^{34}\text{S}$ in leachates of samples from two coal-mine waste piles were -0.2 and $+6.6$ (sites 11 and 14). At both coal-mine sites, the waste consists mostly of shale and coal derived from the underlying Laramie Formation. Additional sulfur isotope measurements were made on surface soil leachates, seep and surface waters, and coal-mine spoil leachates at an abandoned coal-mine site (Zielinski and others, 2001) at site 14 (fig. 6). $\delta^{34}\text{S}$ of soluble sulfate in 11 samples of the coal-mine spoil and surface water leaching from the coal-mine spoil pile into an adjacent wetland ranges from -2.3 to $+6.9$ with a median value of $+4.2$ (letter A in fig. 7). In contrast, sulfur isotopes derived from the leachates of a nearby thick loess soil profile and a contact seep range from -5.0 to -6.3 (letter B in fig. 7).

In a study of sulfur isotopes in the Pierre Shale and other marine shales of the northern interior of the United States (Colorado, North Dakota, Montana), Gautier (1986) showed wide-ranging but generally negative $\delta^{34}\text{S}$ values ranging from $+16.7\text{\textperthousand}$ to $-34.7\text{\textperthousand}$ CDT (mean $-19.7\text{\textperthousand}$, n=50) with all but three values being negative. The most negative values were found in organic-carbon-rich, laminated shales deposited in

an offshore, anoxic, restricted marine setting ($\delta^{34}\text{S}$ values range from -25 to -36 CDT, mean $-31\text{\textperthousand}$, n=9). The fewest negative values were found in bioturbated silty shales ($\delta^{34}\text{S}$ values range from $+16.7\text{\textperthousand}$ to $-34.58\text{\textperthousand}$ CDT, mean $-12.4\text{\textperthousand}$, n=25). The mean $\delta^{34}\text{S}$ for this study (-5.7) is closest to that of the silty shales of Gautier (1986). Scott and Cobban (1965) suggested that laminated, organic-rich shale is absent in the Pierre Shale northeast of Boulder, where the section is silt- and sand-rich, and thus the range of sulfur-isotope values for salts is expected to be similar to the silty shale subset reported by Gautier.

Discussion

Saline soils are present throughout much of the study area, preferentially in (1) upland areas underlain by loess deposits; (2) upland areas underlain by residual soils formed on shale; and (3) areas along flood plains of minor streams. However, they seem to be concentrated in a belt that extends southeast from the area of depressions on the Pierre Shale south of Loveland to the northern suburbs of Denver. Saline soils are rare on the flood plains of the major streams that originate in the mountains to the west and on the large area of eolian sand south of Saint Vrain Creek. On the flood plains of the major streams, the ground-water chemistry may be much

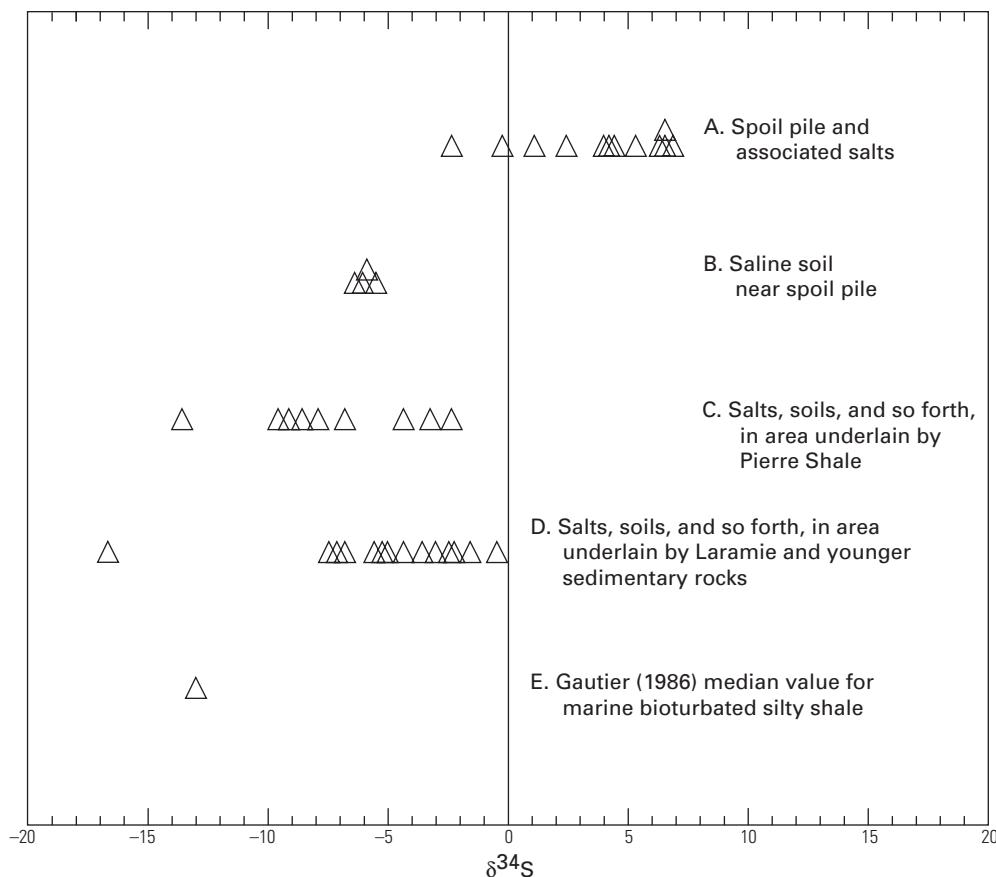


Figure 7. Sulfur isotopic composition of sulfate in salts, soils, coal-mine spoil, rocks, and water in the study area.

Table 3. Sulfur isotope data for salts and other materials in reconnaissance study.
 [See figure 6 for locations of samples]

Map no.	$\delta^{34}\text{S}$	Remarks
1	-7.0 -6.8 -5.7	Soil from tank battery site on ridge crest. Leachate of soil above. Salt at low edge of berm surrounding a brine pit. Thin loess overlying thin residual soil on Denver and Arapahoe Formations bedrock.
2	-16.7	Salt from saline soil on hillslope. Thin loess overlying thin residual soil on Denver and Arapahoe Formations bedrock.
3	-7.0	Salt from saline soil near wetland on flood plain. Thin loess (10 cm) overlying stratified sediment on flood plain.
4	-3.0	Salt from saline soil on flood plain of creek. Thin loess (10 cm) overlying stratified sediment on flood plain.
5	-1.5	Salt from saline soil on flood plain of creek near tank battery. Thin loess (10 cm) overlying stratified sediment on flood plain.
6	-2.2	Salt in saline wheat field on flood plain of creek. Thin loess (10 cm) overlying stratified sediment on flood plain.
7	-4.3	Salt on swale adjacent to small stream, near tank battery. Thick, clayey loess.
8	-4.4	Salt in saline soil near irrigation ditch and small reservoir. Thick, silty loess.
9	-4.3	Salt in swale in field near creek headwaters. Thick, silty loess.
10	-5.5	Salt in soil adjacent to marsh along narrow creek flood plain. Thin clay over stratified sediment on flood plain.
11	-0.2	Salt efflorescence on shaly coal-mine waste.
12	-3.5	Salt from saline soil in upland, downslope from tank battery. Thick, clayey to silty loess.
13	-2.4	Salt in saline soil adjacent to wetland along small stream. Thick, clayey loess.
14	+6.6 -5.0	Salt from shaly coal-mine waste. Salts in low end of saline field. Thick, clayey loess.
15	-5.2	Salt in saline soil along I-25 median. Highly disturbed, but native soil is thick, clayey loess.
16	+4.3	Salt in low depression over coal-mine collapse feature. Disturbed, mapped soil suggests thick, fine eolian sand.
17	-7.4	Salt at margin of highly alkaline pond. Surrounding soils are thick, fine eolian sand.
18	-1.6	Salt at edge of saline marsh west of irrigation lake. Thick, fine eolian sand.
19	-0.4	Salt from saline soil on hillslope below tank battery. Thick, loamy eolian sand.
20	-8.5	Salt in saline marsh at edge of reservoir. Thick, clayey loess.
21	-9.1	Salt in low saline field, north of reservoir. Thick, clayey loess.
22	-2.3 -2.1	Salt in saline wet meadow. Duplicate analysis of above. Thick, wet clay derived from hillslopes underlain by Pierre Shale.
23	-7.9 -6.8	Weathered Pierre Shale in cut. Leachate of weathered Pierre Shale above. Thinly bedded clayey siltstone in hillslope cut used for agricultural storage. No surface soil layer in soil profile.
24	-3.2	Water in highly saline pond. Pond surrounded by thick silt/clay loess overlying Pierre Shale.
25	-13.6	Salt in disturbed soil adjacent to dug pond. Thick, clayey alluvium derived from Pierre Shale.
26	-9.5	Salt from highly saline wet meadow. Clayey alluvium derived from Pierre Shale and clayey loess.
27	-4.3	Salt in field at south edge of broad flood plain of river. Thick, fine silt on flood plain.

less saline because of the influence of low-salinity waters in the streams exiting the mountains. Saline soils may be less likely to form in sandy to gravelly soils because the water table must persist much closer to the land surface (within 15 cm or so) for salts in the capillary fringe to reach the surface.

Saline soils across the study area are dominated by sulfate salts that yield predominantly negative $\delta^{34}\text{S}$ values. The southern part of the study area shows a shift toward less negative values when compared to the northern part of the study area (compare letters C and D values, fig. 7). Nevertheless, in the southern part of the study area, the predominantly negative $\delta^{34}\text{S}$ signature in soils contrasts with the largely positive $\delta^{34}\text{S}$ signature of the underlying nonmarine, locally coal-bearing Laramie Formation bedrock. This contrast and the southerly shift toward less negative values indicates that the overlying loess probably is derived from the local bedrock and outcrop areas of the marine Pierre Shale found to the northwest. This interpretation is consistent with (1) wind directions inferred from the orientation of dunes in the central part of the study area and in areas just to the east (however, it must be noted that the dune features are largely younger than the loess); and (2) the observations of Muhs and others (1999), who noted a westward increase in the clay content of loess in areas east of the FRIRP study area and speculated that the Pierre Shale was the contributor. As suggested by Muhs and others (1999), it seems likely that the Pierre Shale depressions mapped by Colton (1978) are sources for much of the clay fraction of the loess.

Sulfate salts with a negative sulfur isotope signature that occur in soils in the southern part of the study area could be derived from leaching of the clayey loess by infiltrating precipitation. However, salts in the eolian sand area, where clay and silt form only a small fraction of the transported material, also show negative isotopic values. We suggest that, in addition to transport of clay from weathered Pierre Shale, salts were also transported downwind with the fine sediment.

The process of eolian transport of salts can be observed on a large scale for the major playa lake basins of the Southwestern United States, including Owens Lake (Reheis, 1997) and Mono Lake (Mono Lake Committee, 2002). Both lakes have served as major sources of atmospheric dust in the Southwestern United States since water diversion projects lowered the lake levels, exposing mud and salt flats. Reheis (1997) showed that the soluble salt content of Owens Lake-derived dust is as high as 30 percent. At Mono Lake, as of 1989, efflorescent salts covered 65 percent of the exposed lakebed. According to studies at Mono Lake as reported by Mono Lake Committee (2002):

“These efflorescent salt deposits vary—both seasonally and diurnally—in their susceptibility to wind erosion, with wet conditions and warm and dry conditions causing high resistance to wind erosion. Warm and dry conditions favor the formation of a strongly cemented crust, which is prevalent through most of the summer.

“Cool salt deposit temperatures and low surface moisture levels favor the development of powdery noncrystalline salts highly susceptible to wind erosion. Powdery deposits usually form during spring or after fall rains. Daily fluctuations occur, especially in spring and fall, when deposits are wet at night and dry during the day.”

Our observations support the idea that depressions in the Pierre Shale in the northwest part of the study area provided salts and sediment to downwind locations during dry periods in the late Pleistocene. Although most of these depressions are used for irrigation storage and thus water levels are artificially maintained, one is fed only by runoff and ground water (site 24, fig. 6). During 2000, 2001, and early 2002, the size of the lake in this depression has become progressively smaller. In the winter of 2000–2001, the lake was shallow enough that a fishkill occurred. Although we have not observed wind transport of salt and sediment from this depression, salt and mud flats have become progressively more exposed around the shrinking perimeter of the lake. We have also observed the wind picking up salt and sediment from saline fields in the study area and from playa lakes in the Arkansas River Valley in southeastern Colorado.

The paucity of saline soils in the northeastern part of the study area contrasts with their abundance in the southern part of the area, despite the similar extent of mapped loess (Sampson and Baber, 1974; Crabb, 1980). In contrast to the southern part of the study area, however, depressions upwind from the northeast part of the study area are limited in number and size.

Windblown sediment from deflation areas as a source for loess in the saline soils is consistent with work on the origins of loess throughout the rest of northeastern Colorado. Recent investigations of the source materials for loess deposits elsewhere in northeastern Colorado cite alluvial sediment from the major stream valleys (South Platte River, Saint Vrain Creek, and Cache La Poudre River) and bedrock exposures of the White River Group as primary sources based on age, sedimentology, and Pb-Pb ages of mineral grains in these deposits (Muhs and others, 1999; Aleinikoff and others, 1999). In particular, loess may have been derived from the stream alluvium source during those times when glaciers provided large quantities of fine-grained sediment to these valleys. This is consistent with radiocarbon ages of the loess, which overlap the last (Pinedale) glacial period in the Front Range (Muhs and others, 1999). The areas studied by these authors are distant from Pierre Shale outcrops, which are restricted to within a few kilometers of the Front Range. However, Muhs and others (1999) noted that the clay content of loess increases from less than 10 percent at sites near the northeast corner of Colorado to about 30 percent at sites 20 km east of the South Platte River (about 25 km east of the FRIRP study area) and inferred that a clay-rich source of sediment such as the Pierre Shale was necessary. They (Muhs and others, 1999) also noted that Colton (1978) mapped several deflation basins in outcrop areas of the Pierre Shale to the northwest of the loess deposits and inferred that these deflation basins were sources for the clay; the results of our study support these inferences.

Saline soils that occur elsewhere in the semiarid Western United States in areas downwind from outcrops of the Pierre Shale and other marine shales may have some salinity contributed by clay and salt derived from such rocks. In the glaciated terrain of the northern Great Plains, large areas of clayey till derived from marine shale may also be sources of clay and salt in downwind areas of loess deposition. The presence of deflation basins on marine shale outcrops and till areas could be an indicator that downwind saline soils may be present.

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Effects of the Oil, Natural Gas, and Coal Production Infrastructure on the Availability of Aggregate Resources and Other Land Uses, Northern Front Range of Colorado

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Chapter E of
Energy Resource Studies, Northern Front Range, Colorado

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Abstract

Oil, natural gas, and coal have been produced across much of the area underlying the plains immediately adjacent to the northern part of the Front Range of Colorado. More than 7,000 oil and (or) natural gas wells and some 130 abandoned coal mines are in the study area, which includes parts of Adams, Boulder, Denver, Larimer, and Weld Counties in eastern Colorado. Extraction of these energy resources requires a production infrastructure that remains in place throughout production; some of the infrastructure remains in place long after production ceases. Thus, production of energy resources can limit use of the land for other purposes including production of aggregate resources, development of urban and commercial buildings, and farming.

The petroleum-production infrastructure, exclusive of setbacks and easements, occupies as much as 1,300 acres of the land surface in the study area, much of which is devoted to access roads. Although most of this land area currently is classified as planted or cultivated, petroleum is also produced at many places on land classified as urban or commercial. Extensive urban/commercial development in northwestern Adams, southwestern Weld, and northeastern Boulder Counties is underway where (1) many petroleum wells already exist, (2) future exploration of petroleum is considered likely, and (3) continued urban growth is anticipated. With regard to effects on aggregate production, it can be demonstrated that at two separate sites approximately 123,000 tons and 358,000 tons of aggregate, respectively, will not be mined due to petroleum production.

Past coal mining has left behind an extensive network of coal-mine workings, some of which present hazards to uses of the overlying land surface. Subsidence of the land surface, due to the collapse of abandoned underground mine workings, presents challenges for most uses of the land. However, subsidence is most likely to affect the land surface where the mine workings are relatively shallow. Of the total land area in the Boulder-Weld coal field that overlies abandoned mine

workings, only about 28 percent overlies relatively shallow abandoned workings and most of this land is classified as planted/cultivated. The potential effects of subsidence on urban development, although not large, remain a hazard, in part due to coal-mine fires that lead to collapse of abandoned mine workings long after mining ends and become an important factor in long-term land-use planning.

Significant attempts have been made to mitigate conflicts among those competing for use of the land. Petroleum producers are increasing efforts to work closely with governmental planners, aggregate production companies, developers, and farmers to minimize conflicts and promote good relations. Continued efforts toward mitigation of potential issues will promote better decisionmaking for future uses of the land.

Introduction

Extraction of energy resources (oil, natural gas, and coal) requires construction of a production infrastructure (for example, extraction equipment, storage facilities, roads, and rail lines) that remains in place throughout resource production and, in some cases, long after extraction ceases. In general, the presence of the energy-production infrastructure restricts use of the underlying and adjacent land for other purposes. These restrictions are rooted in an energy-production company's ownership or lease of the mineral estate, which includes all or part of the valuable substances, such as oil, natural gas, metals, and gemstones, found in the subsurface in addition to an implied easement to use as much of the surface estate as is reasonably necessary to obtain the energy resources under the property. As such, energy-production companies are legally entitled to gain access to those surface areas reasonably necessary to explore for and produce the underlying resources, whether or not they own the surface estate. Nevertheless, mitigation of the disturbed land and (or) reasonable compensation is afforded the owner of the surface estate following exploration and (or) production.

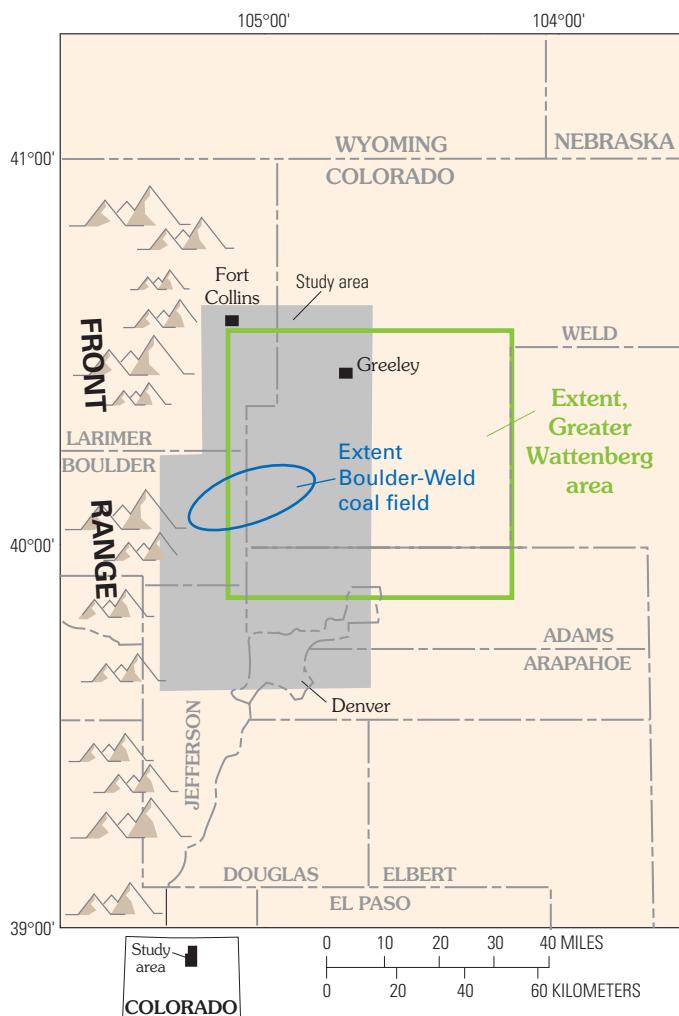


Figure 1. Location of the study area (gray) in the urban corridor adjacent to the northern part of the Front Range of Colorado. Also shown is the extent of the greater Wattenberg area and the Boulder-Weld coal field.

In the northern part of the Front Range of Colorado and the land area immediately to the east (fig. 1), herein referred to as the northern Front Range Urban Corridor, thousands of active petroleum (oil and (or) natural gas) wells and some 130 abandoned coal mines are located in an area that has also experienced extensive population growth over the last 30 years. Furthermore, in this same geographic area, population growth rates are expected to exceed those predicted for the remainder of the United States for perhaps the next 20 years or more (Denver Regional Council of Governments, 2003; Colorado Department of Local Affairs, 2003). The area of continued population growth in the northern Front Range Urban Corridor is also favorable for continued exploration and development of additional petroleum resources (Cook, this volume; Higley and Cox, this volume). Although coal mining in the area has ceased, coal remaining in the ground may contain significant quantities of potentially recoverable natural gas (Roberts and Fishman, 2001; Wray and Koenig, 2001).

The northern Front Range Urban Corridor also overlies important quantities of aggregate resources, including sand, gravel, and crushed stone (Knepper and others, 2001), all of which are used in large volumes in the construction and maintenance of urban and commercial structures. Aggregate is used in the construction of roads, sidewalks, building foundations, airports, and other facilities necessary for the sustainability, vitality, and growth of any populated area, and it also is used as a raw material in building products such as concrete, asphalt, shingles, and brick. Nevertheless, the availability of aggregate resources in the northern Front Range Urban Corridor can be limited through land-use regulations. Furthermore, development of other natural resources, including petroleum, can also limit the volume of aggregate available for use (Fishman and others, 1999). Thus, there is growing concern as to how land is used by groups with, at times, competing interests.

The results of a study to better understand the effects of energy resource production on land use are presented in this paper. The geographic extent of our study was confined to approximately 2,200 mi² in the northern Front Range Urban Corridor in an area that also includes the rapidly urbanizing parts of Adams, Boulder, Denver, Larimer, and Weld Counties (fig. 1). Of particular interest is the manner by which the infrastructure required for the production of energy resources affects availability of aggregate resources (gravel and sand) in addition to other uses of the land surface. We also present examples of how companies, working cooperatively and constructively with others, have found ways to mitigate conflicts that arose from competing interests in use of the land in this region.

Energy and Aggregate Production and Evolving Land Use

To more fully understand how production of petroleum and coal resources may affect other land uses, we provide a brief overview of these resources as well as an overview of aggregate resources in the region. Also included is a discussion of the nature of urban growth in recent years, particularly as it bears on conflicts with development of energy resources.

Petroleum Resources

Although petroleum was first produced along the Front Range over 130 years ago (Higley and Cox, this volume), only in the past 30 years have large volumes of petroleum been discovered and produced. Much of the more recent exploration and production has been focused in the greater Wattenberg area (GWA), the geographic extent of which (fig. 1) was defined for regulatory purposes by the Colorado Oil and Gas Conservation Commission (an agency of the State of Colorado) to ensure the responsible development of petroleum resources. The study area for this project encompasses the western part of the GWA (fig. 1). Currently there are more than 7,000 wells that produce oil, gas, or both in

the study area, and permitting continues for drilling of new wells. Production through 2000 from the entire GWA, which includes numerous individual oil and natural gas fields within and outside of the study area, has exceeded 2 trillion cubic feet of gas and more than 245 million barrels of oil (Higley and Cox, this volume). Accessibility to local markets in the Front Range has made the GWA an important energy-producing province in Colorado.

Rocks of Cretaceous age serve as both reservoir and source rocks for the petroleum produced in the study area, although some production also occurs from rocks of Permian age (fig. 2). The dominant Cretaceous producing formations include the (1) Muddy ("J") Sandstone of the Dakota Group; (2) other sandstones in the Dakota Group including the Plainview ("Dakota" of drillers) and Lytle Formations ("Lakota" of drillers); (3) "D" sandstone of the Graneros Shale; (4) Codell Sandstone Member of the Carlile Shale; (5) Niobrara Formation; and (6) Terry "Sussex" Sandstone, Hygiene "Shannon" Sandstone, and Sharon Springs Members of the Pierre Shale (fig. 2). Oil is the principal resource produced from sandstones in the Pierre Shale, whereas oil or natural gas or both may be produced from the other formations of Cretaceous age (Higley and Cox, this volume). Oil is also produced from wells drilled into the Permian Lyons Sandstone (fig. 2). Source rocks for most of the petroleum produced in the GWA include the Cretaceous Mowry, Graneros, and Carlile Shales and the Greenhorn Limestone (fig. 2) (Weimer, 1996; Higley and Cox, this volume). The Skull Creek Shale may have also served as a source rock, although to a lesser degree than the others (Higley and Cox, this volume).

Because current estimates are that petroleum production in the GWA will continue for at least another 30 years (Higley and Cox, this volume), the production infrastructure will remain throughout this period of time. The nature of the production infrastructure required for any given petroleum well, and hence the land-surface area devoted to it, varies across the study area. A pump jack (fig. 3A) is used where significant pumping capacity is needed to bring petroleum and associated waters to the surface, as is the case for most wells that produce from the sandstones in the Pierre Shale and the Lyons Sandstone. Once at the surface, the produced fluids (petroleum and possibly water) undergo preliminary processing onsite, which typically requires a water/oil/gas separator (fig. 3B) and tanks to store oil and associated produced water (fig. 3C), although several wells that individually produce low volumes of oil and water may share a single separator and storage tank. Field observations reveal that in places, only one battery of tanks and associated separation equipment may be necessary for as many as five oil wells. In contrast, a well that produces natural gas and little or no other fluid (oil or water) generally requires a smaller site for the wellhead (fig. 3D) than that used for a pump jack because no pumping equipment is needed. Pipelines are required between wells and production facilities (oil tank, water pit, and separator) as well as to transport natural gas from the lease. Though buried, pipelines usually require some access for maintenance and repair,

which is why an easement is present around them. A road is required to all producing wells (fig. 3E) and to appropriate pumping and storage equipment so operators may have ready access to wells and associated equipment for monitoring and maintenance. Commonly, flow lines that direct petroleum and produced water from a well to storage or transfer equipment are placed under access roads to minimize surface disruption of the production equipment.

Coal Resources

Coal was first produced along the Front Range in the early 1860s in the southwestern part of the currently defined Boulder-Weld coal field (BWCF) in Boulder and Weld Counties (fig. 1). Coal from the BWCF was mined continuously until the last mine was closed in 1979 (Kirkham and Ladwig, 1980). In addition to the BWCF, coal was produced in other Front Range counties (Kirkham and Ladwig, 1980; Roberts, this volume). Focus in this report, however, will be on the coal mines in the BWCF because of the wealth of data that are available for the more than 130 mines in the coal field. Coal produced from the BWCF totaled approximately 107 million short tons, which represents more than 82 percent of all the coal mined throughout the northern Front Range (Kirkham and Ladwig, 1980; Tremain and others, 1996).

The Cretaceous Laramie Formation (fig. 2) is the dominant coal-producing interval in the region (Kirkham and Ladwig, 1979; Roberts and Kirschbaum, 1995; Weimer, 1996). The overlying Tertiary Denver Formation (fig. 2) has produced a minor amount of lignite. Laramie Formation coal has a rank ranging from subbituminous B to subbituminous C, with a sulfur content of generally less than 1 percent (Kirkham and Ladwig, 1979) and a heating value as much as 9,000 BTU (Roberts, this volume). Coal from the Laramie Formation was used locally, as well as in the numerous mining towns and camps in the nearby mountains (Tremain and others, 1996), for both domestic and industrial purposes.

The production infrastructure needed to mine coal can be extensive and includes the mine workings (fig. 4A) and associated buildings, rail lines, and coal preparation/loadout facilities (fig. 4B). Within the study area, most of the mining-related infrastructure has been removed and much of the affected land surface reclaimed for post-mining urban or commercial development (Roberts, this volume). Virtually all coal from the BWCF was mined underground, generally at depths ranging from less than 50 ft to approximately 500 ft (Myers and others, 1975; Roberts and others, 2001). Extraction of coal from mines in the BWCF was accomplished using "room-and-pillar" mining methods (Myers and others, 1975; Roberts and others, 2001), whereby coal is mined from "rooms" whereas "pillars" are left between mined-out rooms to support the mine roof (fig. 5).

The method of coal mining in the BWCF and depth to coal are of importance because both influence the stability of the land surface overlying the mines. Locally, rooms in some of the abandoned mine workings have collapsed (Myers and

NORTHERN FRONT RANGE, OUTCROP			ADJACENT DENVER BASIN
QUAT.	Undifferentiated alluvial deposits	Undifferentiated alluvial deposits	
TERTIARY	Undifferentiated boulder & gravel deposits		
	Denver Formation	Castle Rock Conglomerate	
	Arapahoe Formation	Arapahoe Formation	
	Laramie Formation	Laramie Formation	
	Fox Hills Sandstone	Fox Hills Sandstone	
	Richard Sandstone Mbr.	Pierre Shale	
	Terry Sandstone Mbr.	Terry "Sussex" Ss. Member	
	Hygiene Sandstone Mbr.	Hygiene "Shannon" Ss. Member	
		Sharon Springs Member	
	Smoky Hill Shale Mbr.	Smoky Hill Shale Member	
	Niobrara Formation		
	Fort Hays Limestone Mbr.	Fort Hays Limestone Member	
	Codell Sandstone Mbr.	Codell Sandstone Member	
	Carlile Shale	Carlile Shale	
	Greenhorn Limestone	Greenhorn Limestone	
	Graneros Shale	Graneros Shale	"D" sandstone
	Mowry Shale	Mowry Shale equivalent	
LOWER CRETACEOUS	Dakota Group		
	South	North	
	Upper members, South Platte Formation	Muddy ("J") Sandstone	Muddy ("J") Sandstone
	South Platte Fm.	Skull Creek Shale	Skull Creek Shale
	Plainview Ss. Member	Plainview Formation	"Dakota" of drillers
		Lytle Formation	"Lakota" of drillers
JURASSIC			
	Morrison Formation	Morrison Formation	
	Ralston Creek Formation	Older Jurassic rocks may be present	
	Sundance Formation		
TRI.			
	Jelm Formation	Jelm Formation	
	Lykins Formation	Lykins Formation	
PERMIAN			
	Lyons Sandstone	Lyons Sandstone	
	Owl Canyon Formation	Owl Canyon Formation	
	Ingleside Formation	Ingleside Formation	
PENNSYL-VANIAN			
	Fountain Formation	Fountain Formation	
MISS.			
		Mississippian rocks	
DEV.			
SIL.		Devonian rocks	
ORD.			
CAM.		Ordovician rocks	
PRE-CAM.		Cambrian rocks	
		Metamorphic and intrusive rocks	

Figure 2. Generalized stratigraphic columns showing units exposed in outcrops along the northern part of the Front Range of Colorado and units in the subsurface in the Denver Basin, immediately to the east in the project study area. Shaded intervals represent periods of erosion or nondeposition. Formations labeled in green are the most important petroleum reservoir rocks, those labeled in purple are source rocks for the petroleum, and those labeled in red have produced coal or lignite. Ss., sandstone; Fm., formation; Mbr., member; PRECAM., Precambrian; CAM., Cambrian; ORD., Ordovician; SIL., Silurian; DEV., Devonian; MISS., Mississippian; TRI., Triassic; QUAT., Quaternary. Sources of stratigraphic nomenclature include MacKenzie, 1971; Pipiringos and O'Sullivan, 1976; Irwin, 1977; Colton, 1978; Kirkham and Ladwig, 1979; Tweto, 1979; Trimble and Machette, 1979; Bryant and others, 1981; Hansen and Crosby, 1982; Bradock, and others, 1988; Braddock and others, 1989; and Madole and others, 1998.

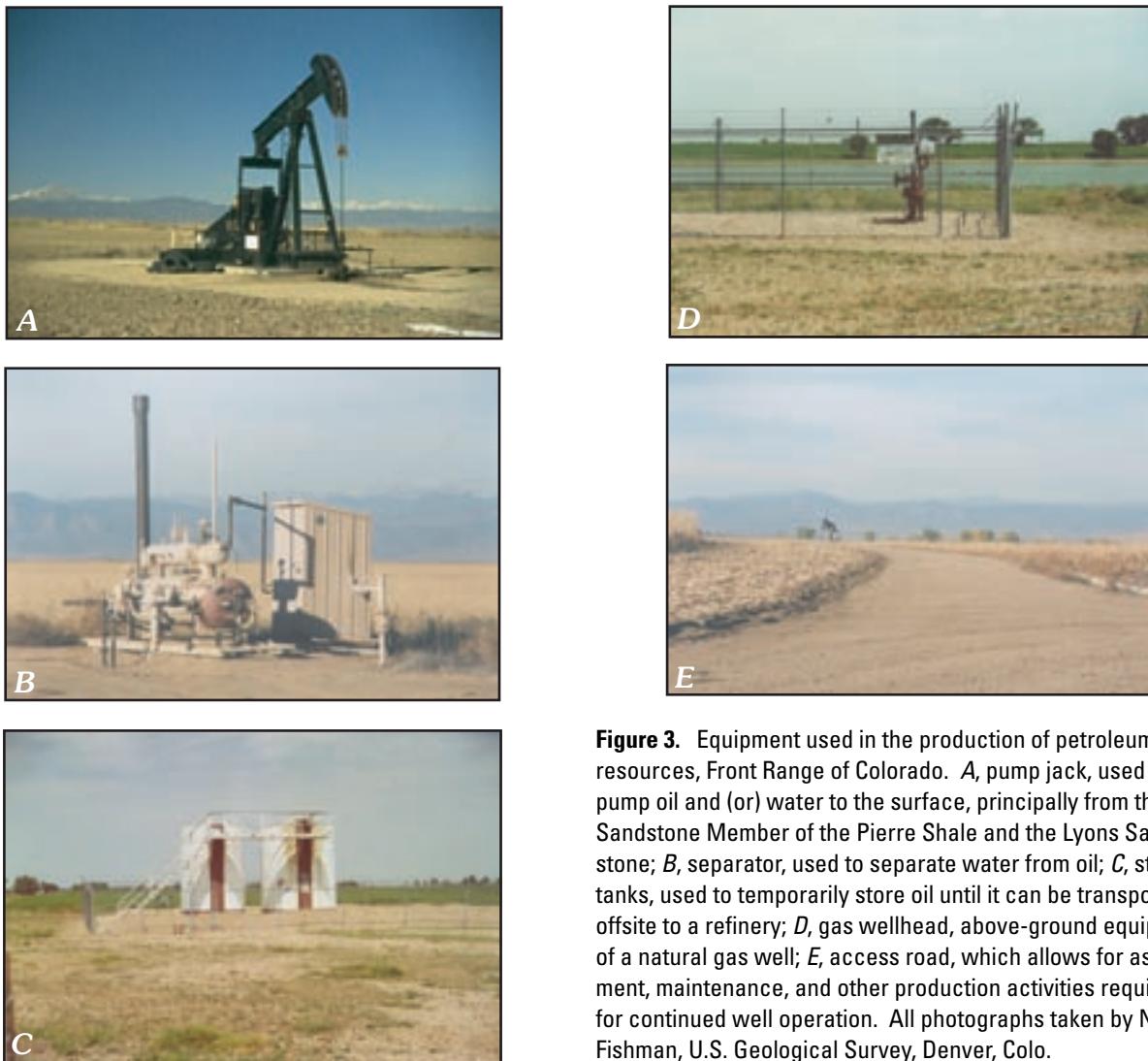


Figure 3. Equipment used in the production of petroleum resources, Front Range of Colorado. *A*, pump jack, used to pump oil and (or) water to the surface, principally from the Terry Sandstone Member of the Pierre Shale and the Lyons Sandstone; *B*, separator, used to separate water from oil; *C*, storage tanks, used to temporarily store oil until it can be transported offsite to a refinery; *D*, gas wellhead, above-ground equipment of a natural gas well; *E*, access road, which allows for assessment, maintenance, and other production activities required for continued well operation. All photographs taken by N.S. Fishman, U.S. Geological Survey, Denver, Colo.

others, 1975; Hynes, 1987; Herring and others, 1986; Roberts, this volume), and progressive upward caving of the overlying rock and soil has resulted. Locally, this caving has caused physical disruption, or subsidence, of the land surface (fig. 6).

The degree to which the land surface over abandoned coal mines in the BWCF has subsided varies, ranging from well-developed collapse pits to no obvious surface expression of subsidence (Myers and others, 1975; Hynes, 1987; Turney, 1985; Herring and others, 1986; Roberts, this volume). Although it is exceedingly difficult to accurately identify the subsidence potential in the BWCF, investigations have documented strongly developed subsidence features overlying some shallow (less than 100 ft deep) mines, whereas well-defined subsidence features are difficult to identify where undermining was deeper (more than 200 ft) (Myers and others, 1975).

Coal-mine fires in the BWCF remain a concern; fires have been documented in the coal field as recently as 1988 (Rushworth and others, 1989). In addition to the threat of a fire as it bears on public safety, coal-mine fires can actually

promote subsidence as pillars and other supporting features in the abandoned mines burn, which thereby compromises remaining support in the abandoned mine. The long-term effects of underground coal mines on land use are largely a function of the subsidence potential of mined-out areas.

Aggregate Resources

Urban and commercial growth in the Front Range Urban Corridor has increased the demand for aggregate resources (Wilburn and Langer, 2000). For economic reasons, most aggregate used in the region has come from sources within approximately 40 miles of the market area (Socolow, 1995). Most historical sand and gravel mining within the study area took place in the valleys of major drainages including the Big Thompson River, Boulder Creek, Cache La Poudre River, Clear Creek, Saint Vrain Creek, and South Platte River (fig. 7). Depletion of some of these local sources of sand and gravel, as well as zoning restrictions, land-use conflicts, urban development, and environmental concerns, has resulted in a



Figure 4. Production infrastructure associated with underground coal mines, Front Range of Colorado. *A*, Photograph showing underground workings in the Eagle Mine, a formerly active mine in the Boulder-Weld coal field. See Roberts and others (2001) for mine location. Photograph courtesy of Lafayette Miners Museum, Lafayette, Colo. *B*, Photograph showing rail lines, mine buildings, and other surface infrastructure associated with the Simpson Mine, a formerly active mine in the Boulder-Weld coal field. See Roberts and others (2001) for mine location. Photograph courtesy of Lafayette, Colorado, Public Library.

progressive downstream migration of sand and gravel extraction operations, particularly along the South Platte River (Arbogast and others, 2002; Lindsey and others, 1998).

Approximately 80 percent of the aggregate used in the Front Range is extracted from accumulations of surficial (Quaternary) deposits of sand and gravel (fig. 2; Knepper and others, 2001). In the Front Range, sand and gravel was deposited by streams in flood-plain and alluvial-fan depositional settings (Lindsey and Langer, 1999). Principal sources of high-quality aggregate are found in the Piney Creek, Broadway, and Louviers Alluvium, which are outwash units of Quaternary age in the study area.

Generally, for deposits along the Front Range, a large volume of coarse gravel rather than silt and (or) clay provides a good measure of the economic value of the deposit. A greater volume of coarse particles is desired because much of this coarser material is eventually used in concrete, asphalt, or road base or for other construction applications (Knepper and others, 2001). A persistent decrease in the coarseness and, therefore, the amount of valuable gravel compared to less valuable sand in aggregate deposits away (downstream)

from the mountain front (Langer and Lindsey, 1999) results from the downstream decrease in carrying capacity of streams and rivers (Wilburn and Langer, 2000). The gravel content of the South Platte River locally increases where tributaries issuing from the nearby mountain front provide an influx of coarse aggregate (Wilburn and Langer, 2000). Even though aggregate deposits farther from the mountain front contain fewer coarse (more than 0.25 inch in diameter) particles, fine (less than 0.25 inch in diameter) particles from those deposits may be mined and combined either with coarse aggregate from elsewhere or crushed stone from local Front Range rock quarries to make a marketable product. Because these deposits contain less gravel than those closer to the mountains, more aggregate must be removed to meet the growing needs of consumers (Langer and Lindsey, 1999; Knepper and others, 2001).

Highest quality aggregate deposits, those that contain an abundance of competent, coarse particles, typically are in flood-plain and low terraces associated with major streams or rivers in the area, whereas aggregate deposits underlying intermediate terraces are commonly of medium quality

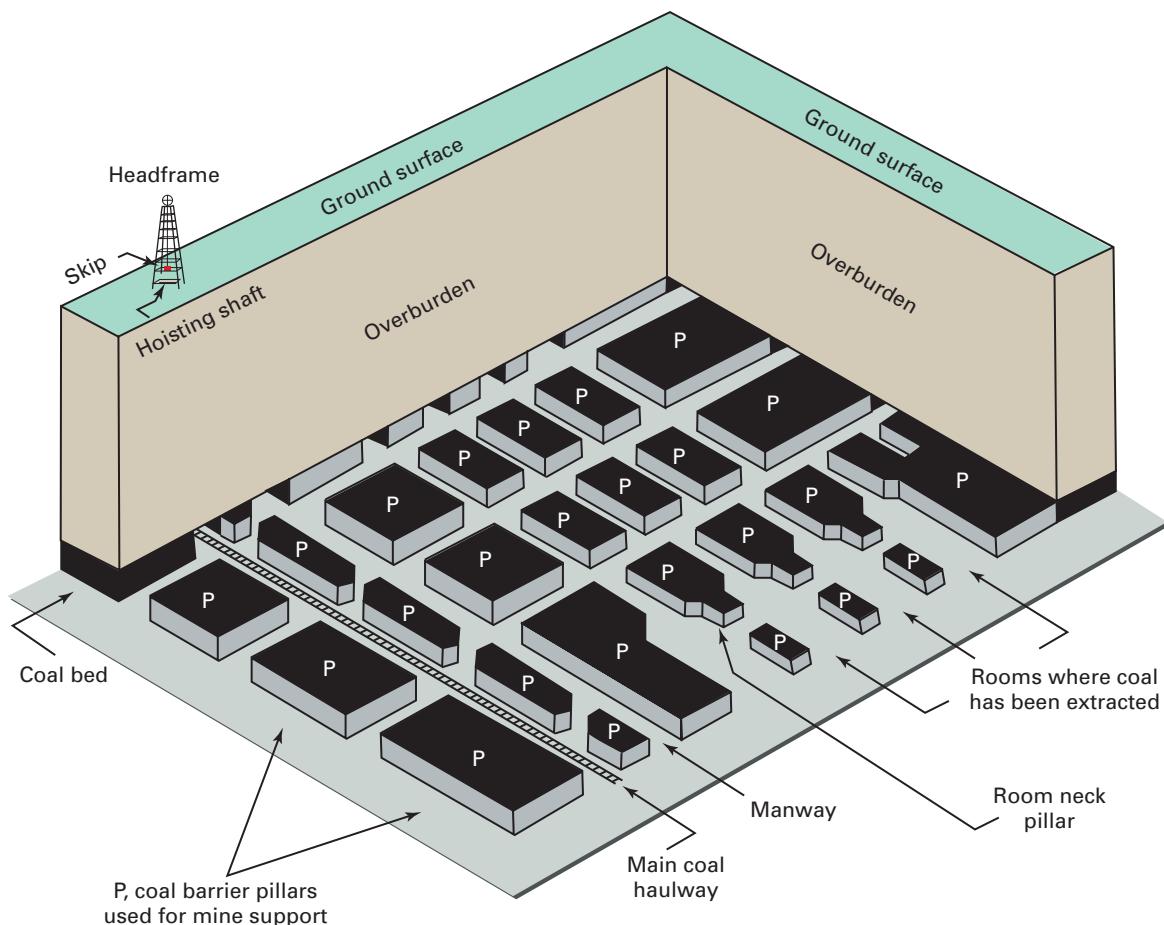


Figure 5. Generalized diagram showing rooms and pillars in a conventional underground coal mine. Modified from Dames and Moore (1985).



Figure 6. Photograph showing surface subsidence features (black arrow) caused by the collapse of underground coal-mine workings of the Lewis Mine, Boulder-Weld coal field. See Roberts and others (2001) for mine location. Photograph courtesy of R.B. Colton (U.S. Geological Survey Scientist Emeritus), U.S. Geological Survey, Denver, Colo.

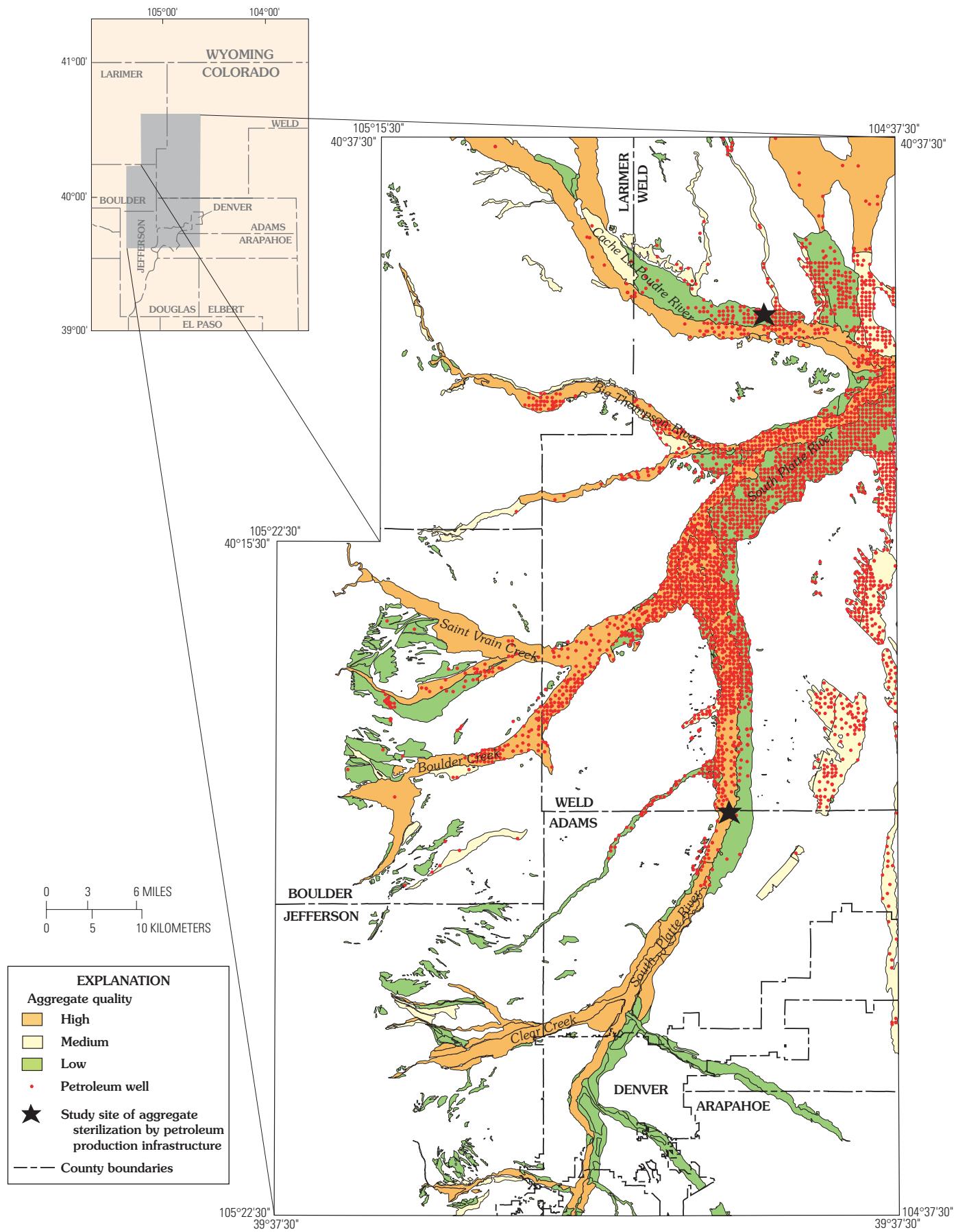


Figure 7. Distribution of high, medium, and low quality aggregate (from Schwochow and others, 1974) and study sites (black stars) where aggregate has been sterilized by the petroleum production infrastructure, Front Range of Colorado.

because they contain more-weathered (degraded) coarse particles and more silt and clay than high-quality aggregate (Langer and Lindsey, 1999). Lowest quality aggregate deposits lie beneath alluvial fans, high-dissected terraces, and in paleovalley fills; except where composed of hard quartzite, this aggregate is not commonly of commercial value (Langer and Lindsey, 1999; Knepper and others, 2001).

Evolving Land Use

Until the mid-1970s, petroleum production in the Front Range Urban Corridor was a fraction of present levels, being principally in rural areas largely removed from urban centers (Fishman and Roberts, 2001) and away from areas of significant production of aggregate resources. Although the land surface devoted to the production of petroleum at that time did not significantly interfere with aggregate production or with urban and commercial land uses, it did affect, at least locally, farming and grazing. Since the mid-1970s, however, increased exploration and production of petroleum resources has taken place largely within Adams, Boulder, and Weld Counties (fig. 1). Aggregate mining and urban expansion have also taken place in much of this same area (Arbogast and others, 2002). In some areas aggregate operations, urban development, and petroleum production have overlapped (Fishman and Roberts, 2001). Prediction of the degree to which overlap of competing land uses continues will be determined, in part, by the accuracy in projections of population growth, areas slated for urban expansion, and areas likely to see natural resource (oil, gas, and aggregate) development.

Effects of the Energy-Production Infrastructure

There are many facets to a more complete understanding of how petroleum and coal production has affected aggregate production and affected other land uses. In turn, petroleum

production may be affected by aggregate mining or urban/commercial development. We have attempted to explore some of these facets in this paper. A summary of this work is presented herein, and details regarding the different data sets used in our analyses and also the methods used to quantify the effects of petroleum production are in the Appendix.

Effects of Petroleum Production on Aggregate Resources

With thousands of producing petroleum wells in the GWA, it is not surprising to find many locations where wells drilled to petroleum reservoir rocks at depths of many thousands of feet also penetrate deposits of aggregate near the surface. Maps that were plotted after combining well location and aggregate deposit data (fig. 7) reveal that in the study area alone, 1,466 wells currently producing petroleum have penetrated aggregate deposits of various quality (table 1). Most wells that intersect aggregate deposits are in areas containing flood-plain or terrace deposits located along drainages including the Big Thompson River, Boulder Creek, Cache La Poudre River, Saint Vrain Creek, and South Platte River (fig. 7). Although these rivers and creeks flow through several counties, most of the wells that have been identified to intersect aggregate deposits do so in Weld County, with fewer wells penetrating aggregate deposits in northern Adams, eastern Boulder, and southeastern Larimer Counties (fig. 7).

Locations where petroleum wells were drilled through high- and medium-quality aggregate are of interest because these are the sites where aggregate mining is either currently underway or where, for economic reasons, aggregate is most likely to be mined in the future. A total of 675 wells, or 46 percent of the 1,466 petroleum wells that penetrated aggregate deposits, contacted aggregate of medium or high quality (table 1). Of those 675 wells, 516 (76 percent) penetrate high-quality aggregate deposits and 159 (24 percent) were drilled through medium-quality aggregate deposits (table 1). For the 516 wells drilled through high-quality aggregate deposits, 385

Table 1. Number of petroleum wells in relation to aggregate quality and landform unit classification within the study area. See Appendix for information concerning sources of data used in this table.

Aggregate quality	Landform unit and resource classification	Number of petroleum wells	Number of wells per aggregate quality
High-quality aggregate	Flood-plain gravel	385	
	Terrace gravel	118	
	Upland gravel	1	
	Valley-fill gravel	12	516
Medium-quality aggregate	Flood-plain gravel and sand	1	
	Terrace gravel and sand	117	
	Upland gravel and sand	41	159
Low-quality aggregate	Terrace sand	749	
	Paleovalley-fill sand	42	
Total		1,466	1,466

(about 75 percent) were drilled through flood-plain gravels, whereas 118 (about 23 percent) were drilled through terrace gravels (table 1); the remaining 13 wells (less than 3 percent) were drilled largely through other gravels. For those wells drilled through medium-quality aggregate deposits, 117 (about 74 percent) were drilled through terrace gravel and sand; the remaining 42 wells (26 percent) were drilled through either upland gravel and sand or flood-plain gravel and sand deposits (table 1).

Although this study focused on those locations where petroleum wells were drilled through medium- or high-quality aggregate deposits, a brief discussion of the wells drilled through low-quality aggregate deposits is included for completeness and also because we recognize that the value of an aggregate deposit can change as a result of changing economic conditions or increased market demand. Of the 1,466 petroleum wells drilled through aggregate deposits, 791 penetrated low-quality aggregate deposits composed of terrace sands (95 percent of the deposits) and valley-fill sand deposits (5 percent) (table 1).

The presence of petroleum-production infrastructure can affect the availability of aggregate resources where the two resources coexist, but the proportion of aggregate that is precluded from extraction (herein termed "sterilized") as a result of petroleum production varies from site to site. Factors that ultimately determine the total area of land set aside for petroleum production include (1) the nature of the petroleum well (oil relative to gas) and whether a pump jack, which occupies more surface area than a gas wellhead, is necessary; (2) the presence and nature of additional production equipment onsite (for example, tank battery, separator, flow lines); (3) the length of the access road leading to the site; (4) the location of the access road; (5) setback requirements, outlined in local and State regulations to ensure safety, particularly along roadways and easements, and to promote and maintain stability of manmade structures; and (6) the location of pipelines and flowlines that carry petroleum and other produced fluids away from the well. If the thickness of an aggregate deposit is known, the volume of sterilized aggregate can be calculated for a given site.

A mined-out aggregate site on the Cache La Poudre River (fig. 7) is used to illustrate where the petroleum-production infrastructure has had a relatively minimal effect on the availability of aggregate resources. This site was chosen on the basis of field observations and information obtained from documents, mine plans, and mine/reclamation-plan permits filed with the Division of Minerals and Geology, State of Colorado. Some of the more significant reasons for choosing this site are the following: (1) the mine plan indicates that the gas well-head is to be set back only 50 ft from the edge of the aggregate mine workings at the bottom of the pit; (2) the mine plan also indicates that the access road leading to the well head is 625 ft long and 100 ft across; (3) no additional production equipment is present on the land surface; and (4) the aggregate deposit underlying the site is relatively thin (about 20 ft). Calculations reveal that approximately 81,900 yd^3 of aggregate has been

sterilized at this site as a result of the petroleum-production infrastructure (see Appendix). Assuming that the aggregate weighs about 1.5 tons/ yd^3 , then approximately 123,000 tons of aggregate was left in place to allow for production of natural gas. Based on the information available from the Division of Minerals and Geology, this volume of aggregate is approximately 5 percent of the total volume of aggregate present within the area permitted for mining at this site.

An active aggregate mine site on the South Platte River (fig. 7) is used to illustrate where the petroleum-production infrastructure has had an important effect on the availability of aggregate resources in an active mining operation. A review of documents and mine-plan information filed with the State of Colorado for this mine revealed that a much larger area of land has been committed for petroleum production equipment and facilities than at the site on the Cache La Poudre River. The South Platte River site (1) contains a variety of production equipment (tank battery and separator) as indicated from field observations, (2) includes a road designed to access the entire pad, and (3) is underlain by sand and gravel deposits ranging from 25 to 50 ft thick with an average thickness of about 35 ft. Calculations reveal that approximately 238,770 yd^3 of aggregate will be sterilized by the petroleum-production infrastructure at this site (Appendix). Again assuming that the aggregate weighs about 1.5 tons/ yd^3 , then about 358,000 tons of aggregate will be left in place as a result of petroleum production at this site. Based on the information available from the Division of Minerals and Geology, this volume of "lost" aggregate is approximately 4.35 percent of the total volume present within the area permitted for mining at this site.

Effects of Petroleum Production on Land Use

The thousands of producing petroleum wells in the GWA along with the associated production infrastructure also limit use of the land directly underneath and also adjacent to the production infrastructure for additional purposes beyond the mining of aggregate. Utilizing geographic information system (GIS) technologies, the area of land used for petroleum production in relation to recognized land-use classification in the study area (see Appendix) was estimated. Minimum and maximum areas of land devoted to production equipment (pump jacks, wellheads, tank batteries) were calculated because of the large variability in total square footage devoted to the equipment that was noticed during field observations and measurements. In contrast, field observations revealed little variability in the width of access roads (about 10 ft), and because the total length of access roads was estimated by GIS techniques (see Appendix), it was possible to calculate the approximate total land area devoted to access roads. Thus, a single value is used herein for land area devoted to access roads rather than a minimum and maximum. Although setbacks and (or) easements exist around all well sites (in part to ensure ready access for well maintenance and repair), periodic use of the land within a given setback for purposes other than petroleum

production is possible, as indicated from field observations and conversations with surface owners. Furthermore, although there are regulations defining the dimensions of a setback, negotiations between petroleum producers and surface owners can result in a decrease in these dimensions, so it is not possible to designate a uniform area to a setback around a well, and we did not do so in our calculations. Nevertheless, land within the setbacks may directly influence future aggregate or urban/commercial development.

A total of 7,035 actively producing petroleum wells exist within the study area that pump from one or more of the various producing formations. This number is large due to the relatively high density of wells within the GWA. A minimum of approximately 1,123 acres and a maximum of approximately 1,338 acres are devoted to the production infrastructure in the study area (table 2), most of which is devoted to access roads (table 2).

Approximately 69 percent of the surface area used for petroleum production in the study area is on land characterized

as planted/cultivated, based on land-use land-classification maps (table 3); most of the remaining acreage is on land classified as natural herbaceous. Interestingly, energy-production equipment does indeed occupy a small area of land used for either urban or commercial purposes (table 3); however, rapid urban development and the drilling of many new wells in the past few years (subsequent to collection of the land-use data) in areas north of Denver have resulted in numerous examples of new urban development in close proximity to or surrounding production equipment (fig. 8).

Although emphasis in this study was placed on evaluating the effects of petroleum production on other land uses, petroleum production has, in turn, been affected by such land uses as aggregate production, urban development, and past coal mining. The presence of an aggregate mine, or a site that is now a lake or pond due to flooding of a former mine site, has necessitated moving several known petroleum well sites. Directional drilling (drilling at an angle rather than vertically) was required in order to access the available petroleum from

Table 2. Range of acreage devoted to the energy production infrastructure in the study area. See Appendix for details regarding calculation of minimum and maximum acreage.

Production infrastructure characteristic	Minimum acreage	Percentage of minimum acreage	Maximum acreage	Percentage of maximum acreage
Access road	1,070	95	1,070	80
Pump jack	25	2	111	8
Wellhead (gas and gas+oil)	17	2	133	10
Tank batteries	11	1	24	2
Total	1,123	100	1,338	100

Table 3. Total number of acres devoted to the petroleum production infrastructure in the study area as a function of land-use classification. See Appendix for information concerning source of data used in this table.

Land-use classification	Minimum acreage	Maximum acreage
Agricultural business	9	11
Canal/Ditch	2	3
Commercial/Light industry	3	5
Communications and utilities	3	3
Emergent wetlands	10	12
Entertainment/Recreation	2	3
Forested	25	27
Heavy industry	0	0
Institutional	0	0
Lake/Pond	0	0
Natural herbaceous	254	292
Orchards/Vineyards/Groves	1	1
Other	11	13
Planted/Cultivated	777	932
Reservoir	9	10
Shrubland	2	2
Single-family residential	10	17
Stream/River	4	4
Transportation	2	4



Figure 8. Photograph showing the juxtaposition of a pump jack and recently completed homes in the greater Wattenberg area, Front Range of Colorado. Note the wooden fence constructed around the production equipment. Photograph taken by N.S. Fishman, U.S. Geological Survey, Denver, Colo.

the revised well location. Although the petroleum resources may still be acquired through directional drilling, the cost to drill and maintain a directional well is greater than a vertical well.

State of Colorado regulations for drilling in areas containing urban development have resulted in restrictions, at least locally, on petroleum exploration and development. In areas where there is high-density urban development, drilling for petroleum must be set back at least 350 ft from existing buildings or platted building sites (Colorado Oil and Gas Conservation Commission, 2003). Drilling setbacks from existing structures have been established largely for safety purposes, to protect people and property, and to protect the well-site infrastructure. Thus, even though petroleum producers might own or lease the mineral rights underlying an urban setting, setbacks prevent drilling at some locations. These setbacks may have a net effect of sterilizing some portion of the petroleum resources in the Front Range Urban Corridor.

Given the number of abandoned mines and the number of petroleum wells in the study area, it is not surprising to find places where wells were drilled through abandoned mine workings. A plot of well locations along with the extent of mine workings in the BWCF reveals that 231 wells have been drilled through abandoned workings. Most such wells are in Weld County, where there is a greater density of wells and numerous large abandoned mines. The degree to which past coal mining has affected petroleum production in ways other than the technological and safety challenges presented to petroleum companies when drilling through the voids of the abandoned workings was not determined.

Effects of Coal Production on Aggregate Resources

More than 130 abandoned mines remain as evidence of the once bustling mining industry of the BWCF, a northeasterly trending group of mines that extend from southeastern Boulder County into Weld County (fig. 1). Although the areal extent of the workings of some of these mines is small (a few acres projected on the land surface), elsewhere, the areal extent of individual or multiple adjacent mines is quite large (hundreds of acres projected on the land surface). Any possible effects of past mining on aggregate availability or other land use would be largely confined to just those areas that are undermined or immediately adjacent to mined areas. Furthermore, there is likely to be a greater potential for an abandoned mine in the BWCF to affect the land surface where the workings are at shallow depths (less than 200 ft) (Myers and others, 1975; Roberts, this volume).

Few abandoned coal mines in the BWCF underlie aggregate deposits, regardless of aggregate quality (fig. 9). Thus, past coal mining will have little effect on potential extraction of aggregate within the undermined areas of the BWCF. In fact, only about 75 acres of land containing aggregate deposits of all qualities overlie abandoned coal mines (table 4), of which 51 acres (68 percent) contain aggregate deposits of medium or high quality. Of those 75 acres, about 36 acres (48 percent) containing aggregate deposits overlie abandoned mines that are less than 200 ft deep, whereas only about 3 acres (about 4 percent) containing aggregate deposits overlie mines that are less than 100 ft deep.

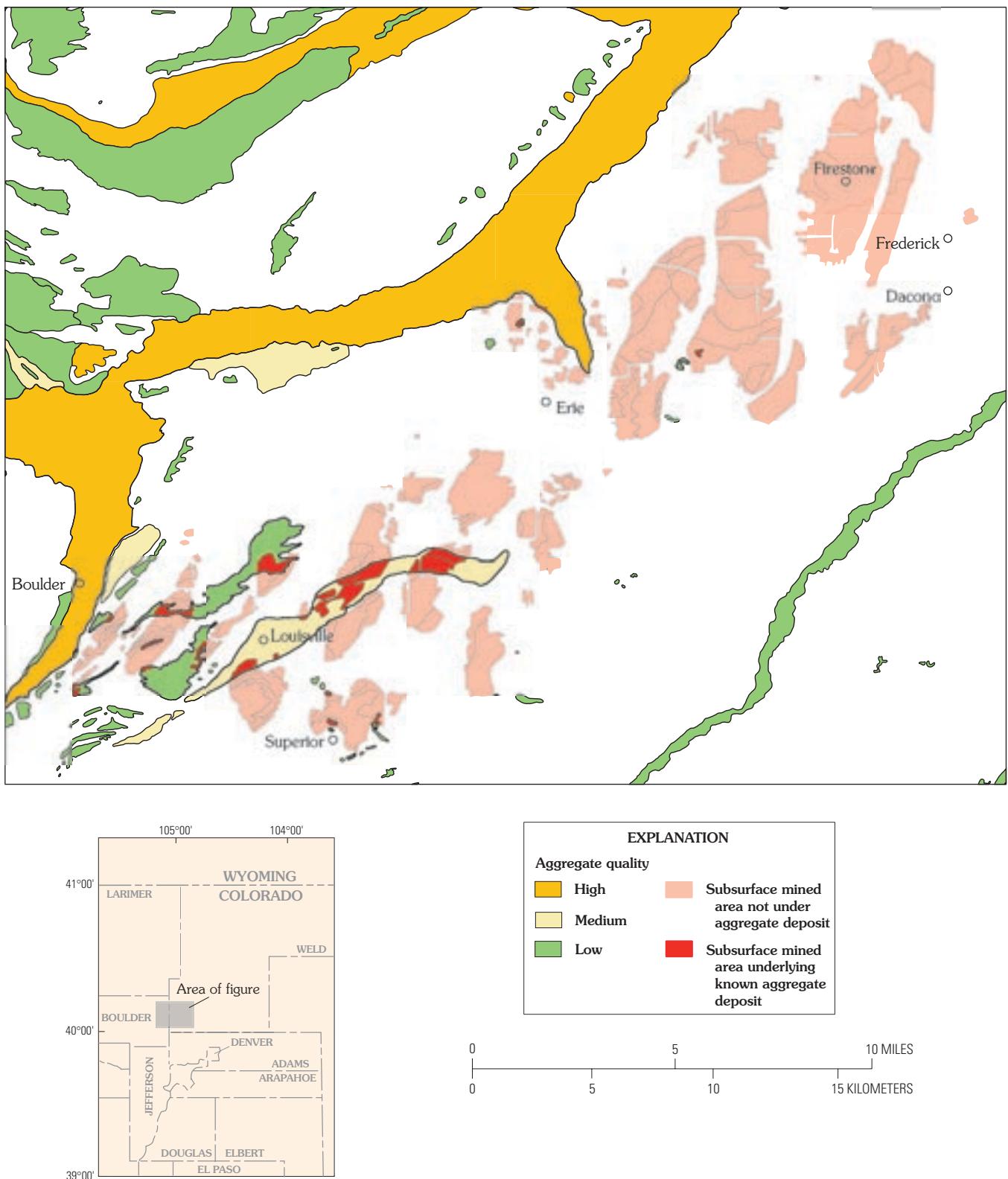


Figure 9. Extent of abandoned coal mines in the Boulder-Weld coal field (pink areas) on which is superimposed the distribution of deposits containing aggregate of various quality. Areas shown in red are where an aggregate deposit overlies an abandoned mine. Lines within abandoned mines denote limit of individual mine workings. Coal-mine data from Roberts and others (2001), and aggregate data from Schwochow and others (1974).

Effects of Coal Production on Land Use

Approximately 1,730 acres of land throughout the BWCF is undermined by abandoned mines (table 5). Of the affected land, almost 62 percent (1,069.9 acres) is classified as planted/cultivated, about 20 percent (354.7 acres) is classified as natural herbaceous (table 5), and approximately 14 percent (246.1 acres) is classified as urban, commercial, or transportation (table 5).

Of the 1,730 acres of land overlying abandoned mines, 512.1 acres (about 30 percent) is undermined by shallow (less than 200 ft deep) mine workings; this includes 300.8 acres (59 percent) classified as planted/cultivated and 105.3 acres (about 21 percent) classified as natural herbaceous (table 5). Importantly, of the 512 acres undermined by shallow abandoned coal mines, a combined total of 90.9 acres (about 18 percent) is classified as either urban, commercial, or transportation (table 5).

Discussion

Exploration and development of energy resources has led to aggregate sterilization, modification of land-use plans, and other consequences. On the other hand, production of both energy and aggregate resources also has had positive effects on the northern Front Range region. Because most of the extracted energy and aggregate resources are used locally, residents of the Front Range have benefited from the integration of these resources into local markets. In addition, the exploration and production industries have been a source of employment for many people in the region. Production of these resources has generated severance tax revenue, some of which has been returned for use by State and local governments.

Numerous factors may ultimately influence the degree to which production of energy resources affects availability of aggregate resources, development, or other land uses. Factors

related to energy production that may have significant effects on land use include the following: (1) producing wells in areas of current aggregate mining or areas containing economic deposits of aggregate; (2) producing wells in areas of current urban/commercial development or areas planned for development; (3) areas of potential future petroleum production; (4) the successful application of advanced petroleum recovery technology, which can extend the production life of wells; and (5) the amount of surface disruption due to subsidence that has occurred above abandoned coal mines. In contrast, factors related to energy production that exert minimal effects on land use, particularly in the future, include (1) plugging and abandoning existing wells prior to aggregate mining, (2) plugging and abandoning existing wells prior to urban/commercial development, and (3) mining coal at levels that were sufficiently deep to minimize the threat of associated subsidence.

Some of these listed factors are economically controlled, which indicates that a change in economic conditions can potentially affect the significance of one or more factors. For example, a rise in oil or gas prices may encourage continued petroleum production from an otherwise subeconomic well or perhaps the drilling of a new well, whereas a drop in prices might force abandonment of a well earlier than expected. The effects of coal production on land use is substantially reduced or may be removed entirely once production ceases, with the possible exception of subsided ground above shallow or otherwise unstable mined-out areas.

Quantifying the long-term effects of energy production on land use across the study area is difficult because changing economic conditions, technology, demand, and public opinion can all individually or collectively affect future decisionmaking. Nevertheless, it is possible to place some of the effects of petroleum production on other land uses into a context to illustrate local effects. As an example, we compared the volume of aggregate sterilized by petroleum production in the two examples given earlier in this chapter to the total volume

Table 4. Acreage of land containing aggregate deposits of various quality undermined by abandoned coal mines, Boulder-Weld coal field. See Appendix for information concerning the source of data used in this table.

[<, less than]

Depth to mine workings (feet)	Aggregate quality (acres)			Total acres
	High	Medium	Low	
0–50	0	0	1	1
50–100	<1	1	1	2
100–150	<1	5	<1	5
150–200	0	28	<1	28
200–250	0	16	2	18
250–300	0	1	16	17
300–350	0	<1	3	3
350–400	0	0	1	1
400–450	0	0	<1	0
Total acres	<1	51+	24+	75

Table 5. Total acres of land (rounded to one decimal place) overlying abandoned coal-mine workings, at various depths, in relation to land-use classification. See Appendix for information concerning the source of information used in this table.

Land-use classification	Depth (feet)								Total acres	
	0–50	50–100	100–150	150–200	200–250	250–300	300–350	350–400		
Agricultural business	0.0	0.1	0.3	1.4	0.9	1.6	0.0	0.4	1.1	5.8
Commercial/Light industry	0.0	3.4	3.5	9.9	8.0	10.8	1.8	4.6	2.3	44.2
Communications and utilities	0.0	0.0	0.0	0.3	0.0	1.3	0.0	0.0	0.8	2.4
Emergent wetlands	0.0	0.2	0.0	0.0	0.0	0.5	1.0	0.2	0.0	1.8
Entertainment/Recreation	0.0	0.9	0.2	4.6	3.5	4.5	3.8	3.7	3.0	24.0
Forested	1.2	0.6	0.2	2.5	4.5	0.2	0.0	0.6	0.0	9.8
Institutional	0.0	0.0	0.1	0.7	2.6	0.0	0.0	0.0	0.0	3.4
Multifamily residential	0.0	0.0	0.0	0.4	0.2	0.0	0.3	0.0	0.2	1.1
Natural herbaceous	8.9	24.8	33.7	37.9	71.8	97.6	33.7	13.1	33.3	354.7
Planted/Cultivated	1.5	88.7	70.1	140.5	217.4	193.3	114.4	82.0	161.9	1,069.9
Reservoir	0.0	0.1	0.0	0.9	0.8	8.1	0.1	0.4	1.6	12.0
Shrubland	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Single-family residential	0.7	17.6	20.3	26.3	41.5	20.7	21.7	7.5	3.4	159.6
Transportation	0.0	3.0	3.3	3.2	8.4	8.2	4.8	5.7	4.5	41.2
Total acres	12.4	139.5	131.6	228.6	359.6	346.7	181.6	118.2	212.0	1,730.2

of aggregate produced in the State of Colorado for 1999, the last year for which such data are available. For the site along the Cache La Poudre River, the approximately 123,000 tons of aggregate sterilized by the petroleum production infrastructure represents only a small fraction of the more than 45,200,000 tons of aggregate produced in Colorado in 1999 (annual production data from Bohlen, 1999). For the site along the South Platte River, the approximately 358,000 tons of aggregate sterilized by the petroleum production infrastructure represents less than 1 percent of the aggregate produced in Colorado in 1999. It is likely, however, that the aggregate sterilized by petroleum production will be permanently removed from the resource base of aggregate because it would be very expensive, at a later date, to mine the aggregate left behind.

The volume of aggregate sterilized at a given site by petroleum production may, however, represent a large portion of the total volume of aggregate available for mining at that location. At the Cache La Poudre site, the approximately 123,000 tons of aggregate sterilized by the petroleum production infrastructure represents about 5 percent of the aggregate that could have been mined at that site. At \$8.15 and \$4.86 per metric ton, the average prices for graded coarse and fine aggregate produced in Colorado in 2000 (U.S. Geological Survey, 2000), respectively, the aggregate sterilized at the Cache La Poudre site would have a gross value of approximately \$672,000 (Appendix), if sold in that year. At the South Platte River site, the approximately 358,000 tons of aggregate sterilized by the petroleum-production infrastructure represents about 4.35 percent of the aggregate resource at that site. Again, using the average prices for graded aggregate produced in Colorado in 2000 (U.S. Geological Survey, 2000), the aggregate sterilized at the South Platte River site would have a gross value of approximately \$1,959,000, again assuming all would have been sold during 2000. The effects of petroleum production on aggregate availability may increase if aggregate producers continue to move downstream, particularly along the South Platte River, into areas containing not only unmined aggregate resources but also a greater density of existing petroleum wells. This downstream area along the South Platte River also has a relatively high potential for additional exploration for petroleum (Cook, this volume), which may increase the potential for future sterilization of aggregate resources by petroleum production unless the production had already ended.

The effects of coal mining in the BWCF are largely a function of the hazards associated with the abandoned mines. Although much of the surface evidence of coal mining, such as mine buildings, rail lines, and tipple and loadout sites, has been removed, hazards related to subsidence and mine fires remain. Open underground rooms in mine workings are still present, leaving the possibility of additional collapse and subsidence. How much of the additional land surface may be affected by future coal-mine-related subsidence cannot be determined, but it is unlikely such subsidence would significantly affect aggregate production in the northern Front Range inasmuch as abandoned coal mines underlie few areas containing aggregate deposits (see fig. 9).

Fires have occurred in mines throughout much of the mining history of the BWCF (Roberts and others, 2001) and have been documented as recently as 1988 in some abandoned mines (Rushworth and others, 1989). The fires started either spontaneously or were ignited by human activity (Myers and others, 1975; Herring and others, 1986). Because these fires burn whatever coal remains in the mines, including that in supporting pillars, they can lead to collapse and surface subsidence long after mine abandonment (Myers and others, 1975; Herring and others, 1986). Airborne magnetic surveys are useful in detecting highly magnetic rocks that form as a result of fires in abandoned coal mines (Rodriguez, 1983), so areas susceptible to fire-related subsidence in the BWCF may be identified by geophysical methods. A recent magnetic survey of limited areal extent not only detected highly magnetized rock associated with a known mine fire, but identified similarly magnetized rock in areas where mine fires were not known to have existed, at least while the mine was in operation (Fishman and others, 2001). Thus, fire-related subsidence may continue to be of concern in some areas of the BWCF into the foreseeable future.

Mitigating Conflict

Conflicts arising from resource development in the northern Front Range of Colorado can be intense and complex in nature. Examples were presented in foregoing sections to illustrate cases where development of energy resources has sterilized aggregate resources and, conversely, where petroleum production is affected by alternate land uses. Although concerted efforts have been made in recent years to mitigate conflicts between various parties, much more planning on a regional scale could be done to further minimize conflicts well into the future.

Land-use conflicts between energy and aggregate producers are not new, but novel approaches to potential resolutions have been implemented to the benefit of both industries, ultimately benefiting the consumer as well. Some relatively straightforward solutions have included moving components of the petroleum-production infrastructure such as pipelines, flow lines, access roads, and tank batteries to minimize aggregate sterilization without compromising petroleum production. Although setting aside a site to house production equipment for multiple petroleum wells may indeed sterilize a significant volume of aggregate under that site, several smaller, individual well sites that would be necessary instead of a large multiwell site may serve to sterilize an even greater volume of aggregate. Overall, the loss in total aggregate production due to petroleum production would be less with a single, larger well site.

Significant quantities of petroleum remain in the ground for exploitation in the northern Front Range Urban Corridor (Higley and Cox, this volume; Cook, this volume) even though urban expansion is placing petroleum production in direct land-use competition. Although petroleum producers,

as owners or lessees of the mineral estate, have legal access to the land surface to pursue exploitation of petroleum resources, existing regulations prevent or limit exploration and production activity where urban/commercial development has already occurred. Furthermore, some wells in developed areas are being abandoned for various economic or political reasons. Thus, urban development has led to sterilization of some portion, albeit possibly small, of the petroleum resource base.

In an attempt to minimize litigation, energy-production companies are working more closely with developers to reduce the number and severity of surface-use conflicts between petroleum production and urban growth. One solution is to allow petroleum producers to site and drill wells prior to the start of urban development. Another solution is to set aside a location from which multiple wells, drilled vertically or directionally, can be placed to minimize the number of drill sites in or near urban development. An additional solution is to relocate pipelines, access roads, and production facilities to sites where the effects on surface development are minimized. All of these solutions involve consideration from a developer in return for the energy-producing company's relinquishment of the right to access specific areas.

Because much of the land surface in the study area is planted/cultivated, conflicts between petroleum producers and farmers are inevitable. Some have been mitigated effectively, however, through constructive communication between producers and farmers. The intentional positioning of well sites outside the perimeter of a center-pivot irrigation system provides a good example of how effective communication allowed a petroleum producer to gain access to the land surface for exploration and production of oil without interfering with the irrigation system. Active communication also has resulted in construction of low-profile production facilities specifically designed to allow for irrigation equipment to pass over the top of the petroleum-production infrastructure. Another tool used to minimize conflict is to schedule well drilling and maintenance so as not to coincide with planting, irrigating, and harvesting activities, which minimizes losses to the farmer without serious consequences to the petroleum producer.

Past efforts to mitigate conflicts may not always work in the future. Nevertheless, petroleum-production companies are finding it beneficial to work more closely with governmental planners, aggregate-production companies, developers, and farmers to minimize conflict and promote good relations. As urban expansion continues in the northern Front Range of Colorado, the availability of resources needed to build and sustain urban areas will be further challenged. Thus, the quality of life for residents of the Front Range depends on balancing competing interests through wise decisionmaking.

Conclusions

Oil, natural gas, and coal have been produced for more than 100 years from subsurface deposits across much of

the area underlying the plains immediately adjacent to the northern Front Range of Colorado. More than 7,000 petroleum wells and some 130 abandoned coal mines are in the area of this study, which includes parts of Adams, Boulder, Denver, Larimer, and Weld Counties in eastern Colorado. Because energy producers are legally afforded access to the land surface to search for and produce resources, regardless of who owns the land surface, production of energy resources can limit use of the land for other purposes including production of aggregate resources, development of urban and commercial buildings, and farming.

Energy production has had a direct effect on the production of aggregate resources in the region. At one study site, approximately 123,000 tons of aggregate was precluded from production as a result of the production of energy resources, whereas at a second site approximately 358,000 tons of aggregate will remain unmined due to energy production. These amounts are individually less than 1 percent of the total output of aggregate from Colorado in 1999. Nevertheless, the approximately 123,000 tons of sterilized aggregate at the one site is about 5 percent of the total volume of aggregate present in that mine area and would have a gross value, at average prices for the year 2000, of about \$672,000. The approximately 358,000 tons of aggregate sterilized at a second site represents about 4.35 percent of the total volume of aggregate present there and would be worth, at average prices for the year 2000, about \$1,959,000. Thus, at both sites, the petroleum-production infrastructure sterilizes an appreciable amount of aggregate.

Energy production also has affected use of the land surface throughout the study area. The energy-production infrastructure, exclusive of setbacks, potentially may consume as much as 1,300 acres of land surface across the region, much of which is devoted to access roads leading to well sites. Although most of this land area is classified as planted/cultivated, an increasing amount of energy is being produced on land that is classified as urban or commercial.

Past coal mining has left behind an abundance of coal-mine workings, some of which present hazards to uses of the overlying land surface. Subsidence of the land surface, caused by the collapse of abandoned underground mines, precludes most options for land use because of the unstable nature of the subsided ground. Subsidence is most likely to affect land use where the mine workings are at relatively shallow depths; only about 28 percent of the land surface over all the mine workings in the BWCF overlies these relatively shallow mines, and most of that land is classified as planted/cultivated. Although the potential effects of subsidence on urban development are not large, this risk should not be overlooked. Coal-mine fires, some of which have been burning in recent years, are troublesome because they may burn the coal in pillars left behind, causing the workings to collapse. Such surface subsidence from coal-mine collapse presents challenges when planning for future land use.

Perhaps most important are the efforts being made to mitigate conflict between those competing for use of the land.

Petroleum-production companies are finding it increasingly beneficial to work closely with governmental planners, aggregate-production companies, developers, and farmers to minimize problems and promote good relations. Expanded efforts toward mutually acceptable solutions will go far in promoting wise, well-reasoned decisions for future uses of the land.

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Appendix

Base cartographic data used in this study were from digital files obtained from colleagues at the U.S. Geological Survey; the data are available as downloadable files from <http://rockyweb.cr.usgs.gov/frontrange/datasets.htm>. These files include political boundaries, hydrography, public land survey system, roads, and miscellaneous transportation. Each of the data sets were projected with the following parameters: Projection, Universal Transverse Mercator (UTM); Zone, 13; Units, meters; Datum, NAD 83; and Spheroid, GRS 1980. Detailed metadata are found at the Web site.

Well locations were obtained from digital files available from the Colorado Oil and Gas Conservation Commission (Colorado Oil and Gas Conservation Commission, 2001). Well locations were determined digitally by using an automated program that converts locations from the Commission's analogue database to UTM Zone 13 (NAD 27) coordinate values. If precise locations were uncertain, then the well coordinates were calculated to be at the center of a quarter-quarter section. The well location file was created at a scale of 1:24,000 (Colorado Oil and Gas Conservation Commission, 2001). Although detailed information concerning the type of petroleum produced from individual wells (oil or gas, and so forth) and producing formation was obtained from proprietary files (IHS Corporation, 2001), these data were used only for informational and analytical purposes and not for displaying well locations.

Field observations and geographic information system (GIS) investigations were used to identify sites where aggregate operations occur along with petroleum production. Visiting 13 sites allowed for selection of two that seemed to represent end members in terms of the volume of aggregate that might be sterilized by petroleum production. The locations of the two sites were identified from topographic maps, which then allowed for determination of the mine

names and locator information in files at the Division of Minerals and Geology, State of Colorado. The files, which are of public record, were used to identify the shape and dimensions of the areas set aside for petroleum production in both mines. Other information obtained from these files included the total area expected to be mined, the thickness of the aggregate deposits at both mine sites, and the nature of the mining operations, which in turn served to constrain our calculations of aggregate resources sterilized by petroleum production.

For the aggregate operation on the Cache La Poudre River (see text fig. 7), the mine-plan files reveal that the land overlying the aggregate deposit that was set aside for petroleum production is elongate in shape, with the pad around the gas well at one end. The plans filed with the Division of Minerals and Geology reveal that the access road, under which is the gas pipeline leading from the well, is 100 ft wide. A slope with a ratio of 3:1 (three horizontal feet for one vertical foot) was used to determine the shape and dimension of the apron along each side of the access road and around the well pad, based on documents filed with the Division of Minerals and Geology. Information regarding the thickness of the aggregate deposit, also in files at the Division of Minerals and Geology, allowed us to calculate the volume of aggregate sterilized by the production infrastructure at this site (fig. A1). Conversion of volumetric calculations from cubic yards to tons was desired because most reports of aggregate production are presented in terms of tons. The gross value of aggregate sterilized by the petroleum production infrastructure was calculated assuming that 35 percent of the volume of the aggregate at the site was coarse aggregate with a value of \$8.15/metric ton, and the remaining 65 percent of the aggregate was assumed to be fine sand with a value of \$4.86/metric ton.

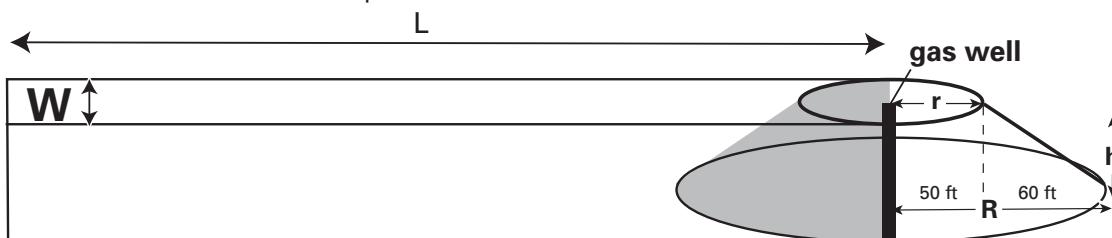
For the aggregate operation on the South Platte River (text fig. 7), the area of land overlying the aggregate deposit that was set aside for petroleum production is irregular in shape (fig. A2), as indicated in drawings included in the files at the Division of Minerals and Geology, State of Colorado. Due to the irregular shape of the site, calculations of the volume of aggregate under the petroleum-production infrastructure required multiple steps. For convenience, this petroleum-production infrastructure site was broken into numerous triangular or rectangular segments to allow for calculation of the volume of aggregate sterilized. Although this method introduced error into the calculations, the magnitude of the error is considered minimal because subdividing the area this way closely approximated the entire site. Information regarding the thickness of the mined deposit, also found in the files from the Division of Minerals and Geology, allowed us to calculate the volume of aggregate sterilized by the production infrastructure at this site. An excavation slope with a ratio of 0.5:1 (one-half foot horizontal for one vertical foot) was used to determine the shape and dimension of the apron along the perimeter of part of the site (fig. A2), whereas a slope with a ratio of 3:1 (three horizontal feet for 1 vertical foot) was used to determine the shape and dimension of the remaining apron

Calculation of aggregate sterilized by gas well pad, Cache La Poudre site

- A. To calculate volume of aggregate beneath 1/2 of the setback to the gas wellhead (remaining part of the setback incorporated into the calculations for aggregate beneath road)

AI.

For $h = 20'$ = thickness of sand and gravel deposit
 $r = 50'$ = anticipated distance of gas well from edge of mining
 $R = 110' = r + \text{distance from horizontal using a } 3:1 \text{ slope}$
 $L = 625' = \text{from maps filed with State of Colorado}$
 $W = 100' = \text{from maps filed with State of Colorado}$



For 1/2 of the pad around gas well (unshaded area) using formula to calculate volume of frustum of right circular cone

$$V_{\text{tot}} = \frac{\pi}{3} (R^2 + rR + r^2)h$$

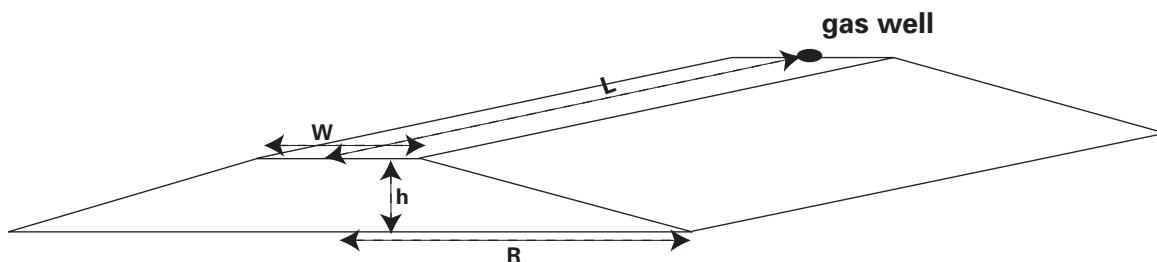
$$V_{\text{tot}} = \frac{\pi}{3} (110^2 + (50*110) + 50^2)20/3$$

$$V_{\text{tot}} = 420,973 \text{ ft}^3$$

$$V_{1/2\text{tot}} = 420,973 \text{ ft}^3/2$$

$$V_{1/2\text{tot}} = 210,487 \text{ ft}^3$$

- B. To calculate volume of aggregate beneath road, including 1/2 of setback to gas wellhead



For $L = 625'$ = from maps filed with State of Colorado
 $W = 100'$ = from maps filed with State of Colorado
 $h = 20'$ = thickness of sand and gravel deposit
 $R = 110'$ = distance from center of road to lower edge of mined area, assuming a $3:1$ slope
Calculated as if a rectangular box 160' wide, 20' high, and 625' long

$$V_{\text{tot}} = \text{width} \times \text{height} \times \text{length}$$

$$V_{\text{tot}} = 160' \times 20' \times 625'$$

$$V_{\text{tot}} = 2,000,000 \text{ ft}^3$$

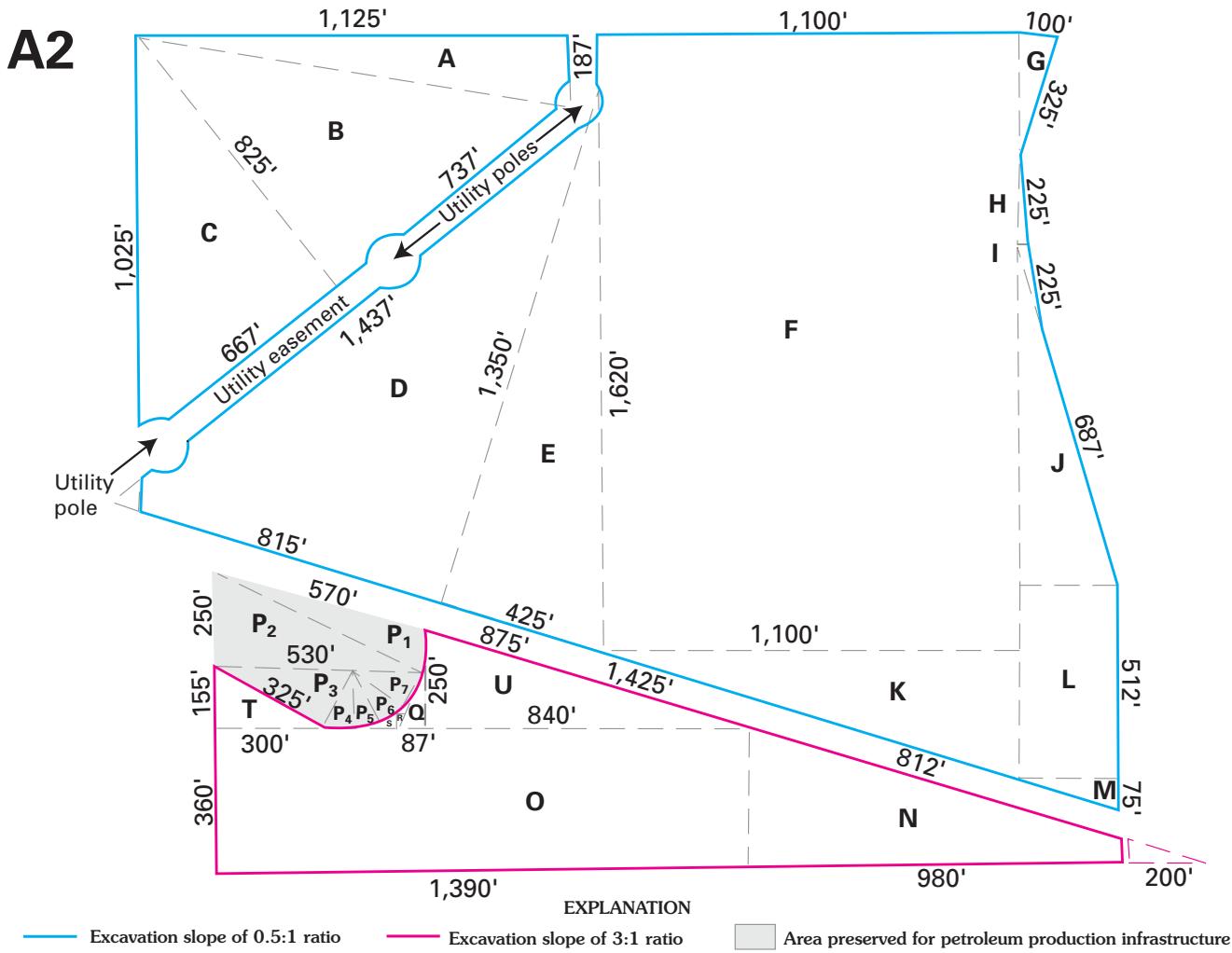
$$\begin{aligned} \text{Total volume} &= \text{volume of access road} + \text{volume of 1/2 of frustum of right circular cone} \\ &= 2,000,000 \text{ ft}^3 + 210,487 \text{ ft}^3 \\ &= 2,210,487 \text{ ft}^3 \end{aligned}$$

Conversion of V to yd^3

$$2,210,487 \text{ ft}^3 \times \text{yd}^3/27 \text{ ft}^3 = 81,870 \text{ yd}^3$$

Conversion of yd^3 to tons

$$81,870 \text{ yd}^3 \times 1.5 \text{ tons/yd}^3 = 122,805 \text{ tons of sand and gravel}$$



Assuming an average thickness of aggregate under the entire area of 35'

Volume of aggregate under any triangular shaped area = $1/2 \times (\text{base}) \times (\text{height}) \times 35'$ (e.g. V_B)

Volume of aggregate under any rectangular shaped area = $(\text{length}) \times (\text{width}) \times 35'$ (e.g. V_F)

$$V_{P_{\text{tot}}} = V_{P_1} + V_{P_2} + \dots + V_{P_7} = 6,446,825 \text{ ft}^3$$

$$\text{Volume of aggregate at site} = V_{\text{tot}} = V_A + V_B + V_C + \dots + V_U + V_{P_{\text{tot}}} = 163,521,960 \text{ ft}^3$$

$$V_{\text{frustrum}} = \pi (R^2 + rR + r^2)h/3, \text{ where } R = 173.5', r = 68.5', \text{ and } h = 35' = 1,710,884 \text{ ft}^3$$

$$V_{\text{apron}_1} = \text{Aggregate in apron of 0.5:1 excavation slope} = 1/2 \times (\text{base}) \times (\text{height}) \times \text{length}_{\text{tot}} = 3,370,028 \text{ ft}^3$$

$$V_{\text{apron}_2} = \text{Aggregate in apron of 3:1 excavation slope} = 1/2 \times (\text{base}) \times (\text{height}) \times \text{length}_{\text{tot}} = 10,407,600 \text{ ft}^3$$

$$V_{\text{available}} = V_{\text{tot}} - (V_{\text{apron}_1} + V_{\text{apron}_2} + V_{\text{frustrum}}) = 148,033,448 \text{ ft}^3$$

$$V_{P_{\text{tot}}}/V_{\text{available}} \times 100 = \% \text{ of aggregate sterilized by petroleum production infrastructure} = 4.35\%$$

$$\text{Conversions: } V_{P_{\text{tot}}} = 6,446,825 \text{ ft}^3 \times \text{yd}^3/27\text{ft}^3 \times 1.5 \text{ tons/yd}^3 = 358,157 \text{ tons}$$

$$V_{P_{\text{tot}}} = 358,157 \text{ tons aggregate} \times 0.91 \text{ Metric tons/ton} = 325,923 \text{ Metric ton}$$

Gross value of aggregate under petroleum production infrastructure

$$\text{Gross value of coarse aggregate} = 325,923 \text{ Metric tons} \times 0.35 \times \$8.15/\text{Metric ton} = \$ 929,695$$

$$\text{Gross value of fine aggregate} = 325,923 \text{ Metric tons} \times 0.65 \times \$4.86/\text{Metric ton} = \$1,029,591$$

TOTAL GROSS VALUE OF ALL STERILIZED AGGREGATE = \$1,959,286

at the site (fig. A2). The slope ratios were determined from documents filed with the Division of Minerals and Geology.

For the utility easement through the aggregate operation on the South Platte River (fig. A2), the easement devoted to each of the parts of the three utility poles that extend beyond the utility access road was estimated to be equivalent to a single, circular cone. Thus, the volume of aggregate sterilized by the utility poles that extended beyond the access road was calculated using the frustum for right circular cone formula.

For all calculations, a conversion factor of 1.5 tons per cubic yard was used to determine the total tonnage of aggregate sterilized at the site along the South Platte River. The gross value of aggregate sterilized by the petroleum-production infrastructure was calculated assuming that 35 percent of the aggregate at the site was coarse aggregate, with a value of \$8.15/metric ton, and the remaining 65 percent of the aggregate was assumed to be fine sand with a value of \$4.86/metric ton.

Field observations and measurements, as well as GIS investigations, were useful in estimating the land area that is devoted to petroleum production. It is important to note that, for this study, the land area devoted specifically to the production infrastructure was estimated and did not include setbacks or easements. Setbacks and easements were not included because some of the land with an easement, particularly in agricultural areas, can continue to be used for purposes other than petroleum production. Only during times of well maintenance is land within setbacks used by the producer. Field observations and measurements were used to determine a range in total area of land that may be devoted to production equipment, including pump jacks, wellheads, tank batteries, and access roads (see text fig. 3). The field measurements were then used to calculate the variations in land area that production equipment may occupy at individual sites throughout the study area. It was then possible to calculate minimum and maximum areas devoted to the production equipment. In general, a pump jack is needed to produce oil and associated water from the Terry Sandstone Member of the Pierre Shale and the Lyons Sandstone. Field measurements revealed a minimum area ($1,000 \text{ ft}^2$) and maximum area ($4,500 \text{ ft}^2$) devoted to such pump jacks. Of the well sites visited ($n=21$), about one-half occupied a large (maximum) area of land, whereas the remainder occupied a small (minimum) area of land. Because there are more than 1,100 wells that produce from these formations, it was impractical to visit all wells to evaluate the actual area occupied at each. Thus, we arbitrarily assigned one-half of them a maximum land area and the remainder a minimum land area for the purposes of calculating total land area devoted to production from these wells. As such, errors were introduced into the calculations of the land area devoted to this production equipment, so the figures presented herein should be viewed only as an approximation of the land area devoted to petroleum production.

Calculations performed to determine the area of land devoted to oil, oil and gas, or gas wells requiring production

equipment other than a pump jack required some assumptions as well. Wells that do not require a pump jack occupy less area than wells that do require a pump jack. Again, field observations and measurements were used to establish the range in areas occupied by this equipment. Field measurements ($n=16$) revealed a minimum (110 ft^2) and maximum ($1,000 \text{ ft}^2$) area devoted to such wellheads and that about one-half the well sites occupied a large (maximum) area of land whereas the remainder occupied a small (minimum) area of land. In the absence of any observable systematic distribution in the area of land devoted to smaller pumping equipment, we arbitrarily assigned one-half of these wells a maximum value of land area and the remaining wells a minimum value of land area occupied by this production equipment. Errors introduced into the calculations of the land area devoted to this production equipment are likely, so the results should be viewed as only an approximation.

Access roads were measured onsite ($n=10$) to determine their width and length. Although the length of these roads was highly variable, their width was more consistent, based on our observations and measurements. We used a 10-ft width for all access roads when calculating the total land area devoted to these features. The length of roads was measured or estimated from digital base cartographic data, depending on the availability of data. Where well sites were known but no access road was observed in the digital files, we estimated the length of the road by plotting a straight line from the well to the closest known road. Although this may have introduced errors into our calculations, it is likely that most access roads are designed to traverse the shortest route from an established county or municipal road to reduce construction costs. Thus, we feel that our estimations are not seriously in error.

Once the dimensions of the production infrastructure were established and assigned to all wells in the study area, it was possible not only to calculate the land area occupied by the infrastructure but also to assign total area of land occupied as a function of land-use land-cover (LULC) (see text table 3). The LULC data, which are now publicly available as digital layers through the USGS Web site (<http://rockyweb.cr.usgs.gov/frontrange/datasets.htm>), were provided by USGS staff studying these features in the Front Range. The LULC data have been projected with the following parameters: Projection, Universal Transverse Mercator (UTM); Zone, 13; Units, meters; Datum, NAD 83; and Spheroid, GRS 1980. The LULC data were produced from high-resolution imagery acquired in 1997. Although the land-classification scheme used was based on that published by Anderson and others (1976), the scheme represents a modification of their work (Carol Mladinich, U.S. Geological Survey, oral commun., 2002) because land classifications were broken into greater detail than was originally done by Anderson and others (1976). Detailed explanation of the LULC scheme used for our study can be found at this Web site.

Glossary of Terms

Boulder-Weld Coal Field (BWCF) The geographic area in which coal was produced in Boulder and Weld Counties from the Laramie Formation from the late 1850's through the 1970's.

Frustum A portion of a cone that is formed by cutting off the top by a plane parallel to the base.

Greater Wattenberg area (GWA) A geographic area defined by the Colorado Oil and Gas Conservation Commission for oil and gas regulatory purposes, especially as it pertains to oil and gas production from formations of Cretaceous age. The south and north boundaries are Townships 2 South and 7 North, respectively, and the east and west boundaries are Ranges 61 West and 69 West, respectively. All are relative to the Sixth Prime Meridian.

High density (pertaining to oil and gas setback requirements) An area, determined when an oil or gas well is permitted, where thirty-six (36) or more actual or platted building units are within 1,000-foot radius or 18 or more building units are within any semicircle of the 1,000-foot radius from the wellhead or production facility.

Land use land cover (LULC) Categorization of land features at a minimum area of 2.5 acres from remotely sensed data. Categories were initially defined by Anderson and others (1976) and have since been modified to include more category levels including urban parks, natural grasslands, major retail, light industry, and row crops.

Mineral estate Refers to an interest in real property, as shown by real estate records, that is not owned as the full fee title to the real property. The owner or lessee of the mineral estate has rights to the valuable subsurface substances. The rights afforded the owner or lessee of the mineral estate are commonly referred to as mineral rights.

Set-back requirements from manmade structures As per Colorado law, at the time of drilling a petroleum well, the wellhead must be 150 feet away from any manmade structure, or 350 feet in an area of high density (see above definition for high density).

Surface estate Refers to an interest in real property that is less than full fee title and does not include the mineral estate as shown by real estate records. The rights afforded the owner or lessee of the surface estate are commonly referred to as surface rights.



Coal in the Front Range Urban Corridor—An Overview of Coal Geology, Coal Production, and Coal-Bed Methane Potential in Selected Areas of the Denver Basin, Colorado, and the Potential Effects of Historical Coal Mining on Development and Land-Use Planning

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Chapter F of
Energy Resource Studies, Northern Front Range, Colorado

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Coal in the Front Range Urban Corridor—An Overview of Coal Geology, Coal Production, and Coal-Bed Methane Potential in Selected Areas of the Denver Basin, Colorado, and the Potential Effects of Historical Coal Mining on Development and Land-Use Planning

By Stephen B. Roberts

Abstract

The Denver Basin contains an estimated 30–40 billion short tons of coal in Upper Cretaceous and Tertiary strata at depths of less than 3,000 feet, and from the late 1850s through the 1970s coal mining was an integral part of many communities in the Front Range Urban Corridor. There has been no commercial coal mining in the Denver Basin for more than 20 years, however, and the likelihood of any significant revival of coal mining seems remote at this time (2004). This is due, in part, to the increased competition for land arising from population growth and the consideration that rapid expansion of urban, commercial, and residential development would probably inhibit coal-mining ventures in many areas along the Front Range. However, even though renewed coal mining will not likely compete with other land-use interests in the foreseeable future, other coal-related issues, such as the potential for development of coal-bed gas (methane) resources and continued effects stemming from historical underground coal mining, might be factors to consider in future land-use plans for certain areas.

Coal deposits within the Laramie Formation (Upper Cretaceous: Maastrichtian) and the Denver Formation (lower Tertiary: Paleocene) are distributed throughout much of the Denver Basin. More than one-third of the total land area in Colorado underlain by coal-bearing rocks at depths of less than 3,000 feet lies within the Denver Basin. During 120 years of coal mining activity, more than 130 million tons of coal was produced. Of this total, more than 99 percent came from the Laramie Formation. The formation ranges from about 350 to 1,800 feet in thickness, and coal of subbituminous rank is concentrated in the lower 300 feet. Laramie coal beds range from less than 1 foot thick to more than 20 feet thick locally. Estimates of the remaining (unmined) coal in beds greater than 2.5 feet thick and at depths of less than 3,000 feet are about 20–25 billion tons. The Denver Formation ranges in thickness from 600 to 1,580 feet, and beds of lignitic coal are concentrated in the upper 500 feet

of the formation. Lignite beds are as thick as 55 feet in some areas of the Denver Basin, and estimates of the remaining (unmined) coal resources in coal beds greater than 4 feet thick and at depths of less than 1,000 feet are on the order of 10–15 billion tons.

To date, there has been no coal-bed methane production in the Denver Basin. However, the successful production of coal-bed methane in other basins, particularly in the Powder River Basin (Wyoming and Montana), has helped to stimulate interest in studying the potential for coal-bed methane development in the Denver Basin. This interest might be based largely on the success of coal-bed methane development from subbituminous coal beds that are comparable in rank to coal in the Laramie Formation and on estimates indicating that there could be as much as 2 trillion cubic feet of coal-bed methane (in place) within the combined Laramie and Denver Formations. The Laramie Formation might be more prospective for coal-bed gas than the Denver Formation, given the slightly higher apparent rank of the Laramie coal beds, the widespread distribution of the formation throughout the Denver Basin, and limited desorption data that indicate total coal gas contents of about 24 cubic feet per ton in some Laramie coal beds. In addition, the potential for recovery of “behind-pipe” coal-bed methane resources in existing gas wells penetrating the Laramie Formation might be facilitated in areas such as the Wattenberg gas field, where a gas recovery and transport infrastructure is already established.

Effects from historical underground coal mining operations continue to exist in certain areas of the basin. Even though much of the surface expression of mine development has been removed or masked by increasing urban and residential development, subsurface features of underground mining, such as shafts and open mine rooms, are still present. Because of this, the potential remains for underground fires and for coal-mine subsidence in abandoned mine areas. Coal-mine subsidence is a dynamic process that can occur many years after a mine has been abandoned. Progressive upward collapse of roof rock and overburden above an abandoned mine can cause the development of subsidence features at the

ground surface, thereby creating a potential for damage to new or existing structures (roads, houses, businesses, and so forth) in susceptible areas. Although numerous investigations of coal-mine subsidence in the Denver Basin have identified subsidence-prone areas and have established some criteria for land-use planning above abandoned mines, subsidence prediction is commonly hampered by the availability and quality of historical mine maps and records, limitations in the applicability of established predictive models, and the variability in subsurface mine conditions. Available data can be supplemented by drilling programs, which can improve upon existing mine data and greatly enhance an understanding of present-day mine conditions in specific sites. All of these data are critical for ensuring safe development in undermined areas.

Introduction

The Denver Basin, as defined by Matusczak (1973), occupies an area of about 70,000 mi² in eastern Colorado, western Nebraska, and southern Wyoming (fig. 1). Because the Front Range Infrastructure Resources Project (FRIRP) of the U.S. Geological Survey (USGS) was designed to address issues related to energy, land, water, aggregate, and biological resources in the Front Range Urban Corridor in and near the Denver metropolitan area (for example, see Fishman, this volume), only areas within the Colorado part of the Denver Basin were studied. Therefore, it should be noted that any reference to the Denver Basin in this chapter refers only to the Colorado part of the basin as designated by Matusczak (1973).

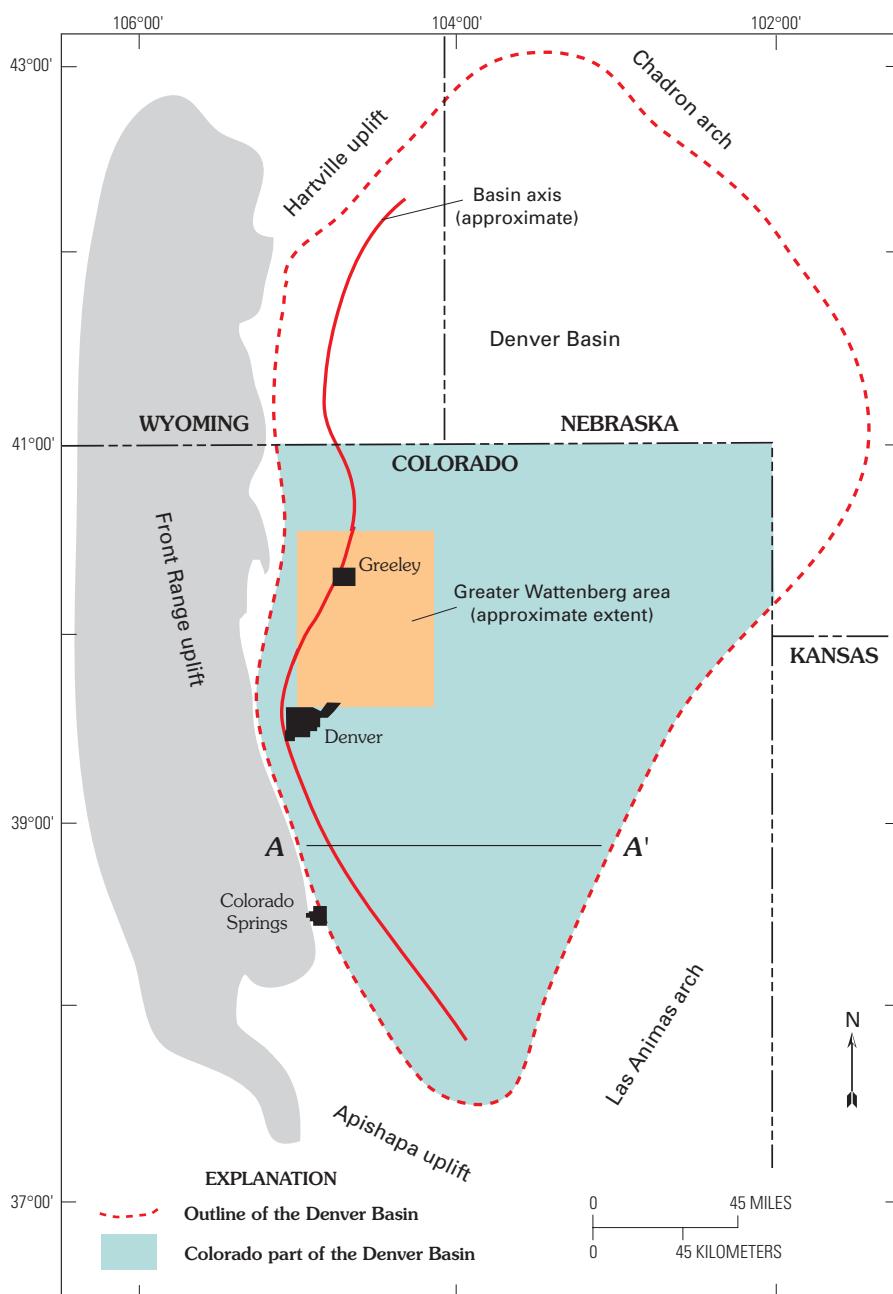


Figure 1. Approximate extent of the Denver Basin and bounding structural features, and the location and extent of the greater Wattenberg area (GWA), Colorado. The GWA is an area in which a coal-bed methane pilot study was conducted as part of the Front Range Infrastructure Resources Project. Cross section A–A' is shown in figure 11. Denver Basin extent modified from Matusczak (1973).

The Denver Basin contains an estimated 30–40 billion tons of coal in Upper Cretaceous and Tertiary strata at depths of less than 3,000 ft (for example, see Kirkham and Ladwig, 1979), and from the late 1850s through the 1970s, underground coal mining was an integral part of many communities in the Front Range Urban Corridor. There has been no commercial coal mining in the Denver Basin for more than 20 years, however, and the likelihood of any significant revival of coal mining in the basin seems remote at this time. This is primarily because the coal-production infrastructure has already been dismantled and removed, and the reestablishment of a competitive coal industry in the Denver Basin might be difficult given the established commercial coal production in other Colorado coal fields and in adjacent States such as Utah and Wyoming. Additionally, the competition for land arising from population growth and the associated expansion of urban, commercial, and residential developments would probably inhibit coal-mining ventures in many areas along the Front Range. However, even though coal mining will likely not be renewed in the foreseeable future, other coal-related issues, such as the potential for development of coal-bed gas (methane) resources and continued effects stemming from historical underground coal mining, might be a factor in land-use planning in certain areas of the Denver Basin. Studies of the coal-bed methane potential are still in a relatively fledgling state, and there is currently no production of this resource in the basin. Successful coal-bed methane production in other Colorado basins, and in Wyoming and New Mexico, has helped to spark an interest in the Denver Basin methane potential. If this resource eventually proves to be economic, companies interested in developing coal-bed methane might also enter the competitive quest for land within the basin.

Perhaps the current, most important “coal-related” issues in the Denver Basin stem from historical coal mining. Effects from historical coal mining can range from visible remnants of coal production (for example, railroad beds, abandoned buildings, mine dumps, and so forth) to potentially more serious problems, such as coal-mine fires and coal-mine subsidence resulting from the collapse of open shafts, rooms, and entryways in abandoned underground coal mines. Coal-mine subsidence is a particularly important consideration, as this process can induce sinking or collapse of the ground surface above an abandoned mine, which, in turn, can cause serious structural damage to buildings and infrastructure (for example, roads, gas lines, and so forth) that might exist on or in the subsiding ground. As communities continue to expand into undermined areas where a potential for coal-mine subsidence still exists, careful planning is needed to help ensure that the type of development (for example, residential or commercial) and corresponding construction design are appropriate for these areas. Because this issue has been of considerable interest and concern for some time, numerous studies pertaining to the coal-mine subsidence potential in certain Front Range areas were conducted during the 1970s and 1980s (for example, see Mernitz, 1971; Myers and others, 1975; Hynes, 1987; Dames and Moore, 1985; Turney, 1985, 1986; Matheson and

Bliss, 1986; Herring and others, 1986). Some of these studies were initiated because of land-use statutes (laws) enacted by the Colorado Legislature during the 1970s. Provisions within these statutes define natural or manmade subsidence (for example, coal-mine subsidence) as a geologic hazard and stipulate that geologic reports be completed for specific categories of subdivision in unincorporated areas (for example, see Turney, 1986). Because of the continued potential for coal-mine subsidence, land developers might be required to provide relevant geologic and coal-mine subsidence information to city and county planners during the platting process, should the area slated for development overlie abandoned coal mines. In addition, although many land-use decisions ultimately reside with city and county governments, provisions in the State legislation also stipulate that the Colorado Geological Survey (CGS) should serve in an advisory capacity by reviewing geologic and subsidence reports prior to development. Based on these reviews, the CGS can then provide recommendations on the suitability of the proposed development to city and county planners (Turney, 1986). Thus, by recognizing that potential coal-mine subsidence hazards exist in certain areas of the Front Range Urban Corridor, a legislated process has been put in place whereby the CGS, local governments, and developers can work in tandem to determine the most suitable land use or development scheme in undermined areas.

This report summarizes the coal geology and coal-mining history in the Denver Basin, addresses some elements of the coal-bed methane potential based on data in and near the greater Wattenberg area (fig. 1), and provides a broad overview of the basic concepts and potential effects related to coal-mine fires and coal-mine subsidence in abandoned coal-field areas. In regard to coal-mine subsidence, the primary intent of this report is to provide (1) basic information regarding potential issues that might arise from existing or planned residential and urban development in undermined areas, and (2) general descriptions of some of the theories and methodologies (models) applied in past analyses of subsidence potential in the Front Range Urban Corridor. It is hoped that this summary information, as well as the published references listed throughout the text, will help guide the reader to additional and more detailed information regarding the potential effects of historical coal mining. It should also be noted that an extensive repository of detailed information pertaining to abandoned coal mines in the Denver Basin and other Colorado coal areas is housed in the office of the Colorado Geological Survey in Denver, Colorado, and interested readers should consult with the CGS on general matters related to coal-mining effects, as well as for site-specific concerns.

Denver Basin Coal Geology

Environments conducive for the development of coal were present in the Denver Basin during deposition of the Laramie Formation in the Late Cretaceous and again during

deposition of the Denver Formation in the early Tertiary (fig. 2). As a result, coal deposits within these two formations are distributed throughout much of the basin; in fact, more than one-third of the total land area in Colorado that is underlain by coal-bearing rocks at depths of less than 3,000 ft lies within the Denver Basin (Kirkham and Ladwig, 1979). During 120 years of coal-mining activity, more than 130 million tons of coal was produced from nine areas in the basin. Of this total, more than 99 percent came from the Laramie Formation.

Laramie Formation

The Laramie Formation is Late Cretaceous (Maastrichtian) in age and was deposited about 70 million years ago (Ma) in an alluvial plain/coastal plain setting along the western margin of the Western Interior seaway (fig. 3) (Roberts and

Kirschbaum, 1995). Coal beds within the formation developed from peat accumulation in coastal plain mires, inland from shoreline (beach) and nearshore/offshore environments represented by the partly equivalent and underlying Fox Hills Sandstone and Pierre Shale, respectively (fig. 2). Retreat of the Cretaceous seaway during the Maastrichtian resulted in the eastward progradation of marine, shoreface, and coastal plain/mire environments (fig. 3) and the corresponding deposition of Laramie coal across the extent of the present-day Denver Basin in Colorado. Subsequent erosion of Upper Cretaceous rocks along the Greeley arch segmented coal-bearing strata in the Laramie Formation into two distinct areas north and south of the arch (fig. 4) (for example, see Kirkham and Ladwig, 1979; Curtis, 1988). Kirkham and Ladwig (1979) designated the area north of the arch as the Cheyenne Basin and the area south of the arch as the Denver Basin, and they reported that

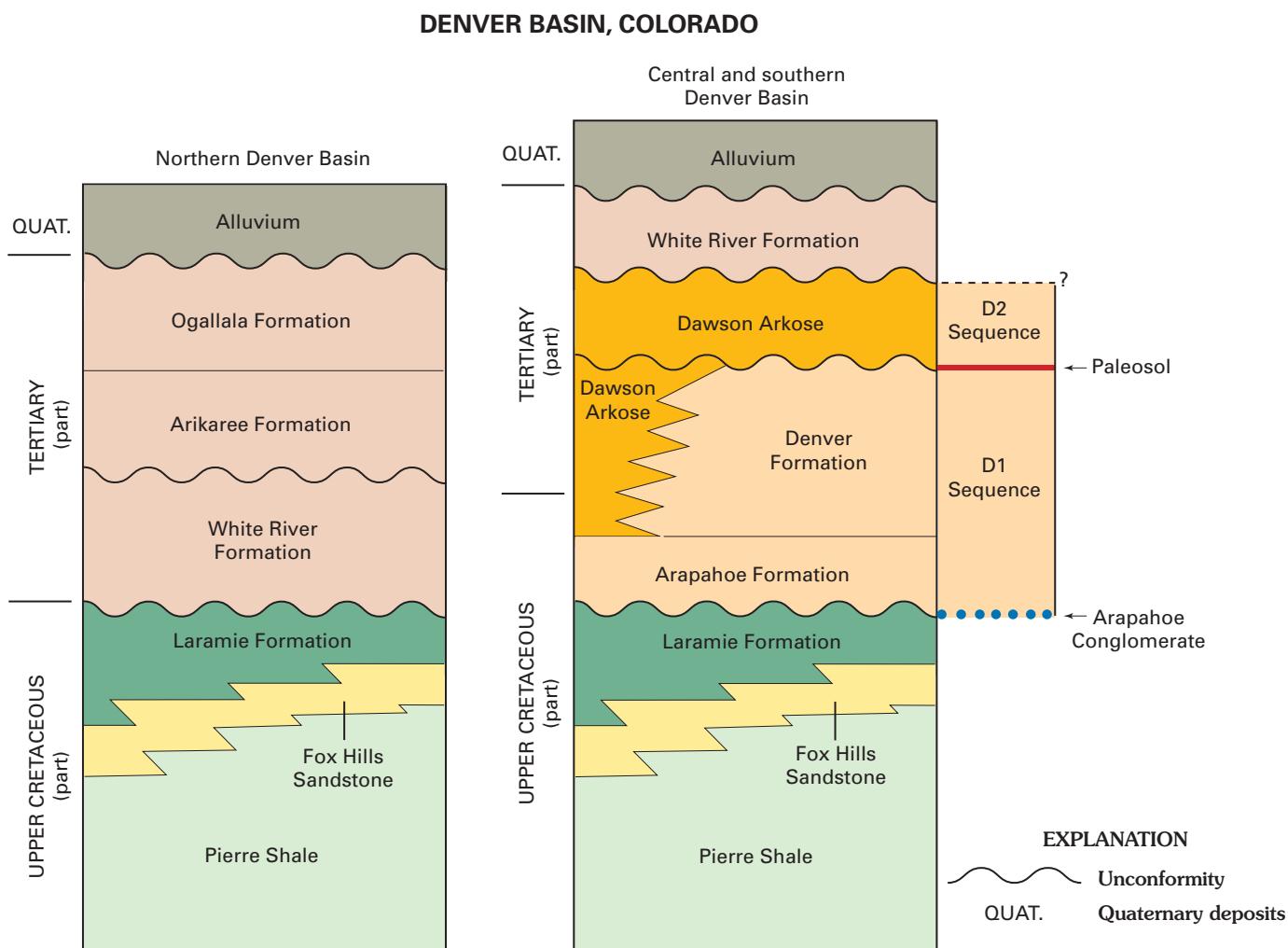


Figure 2. Generalized Upper Cretaceous and Tertiary stratigraphy for different areas in the Denver Basin, Colorado. Modified from Kirkham and Ladwig (1979, 1980) and Nichols (1999). D1 and D2 sequences represent Laramide synorogenic deposits as defined by Reynolds (1997). Diagram not to scale.

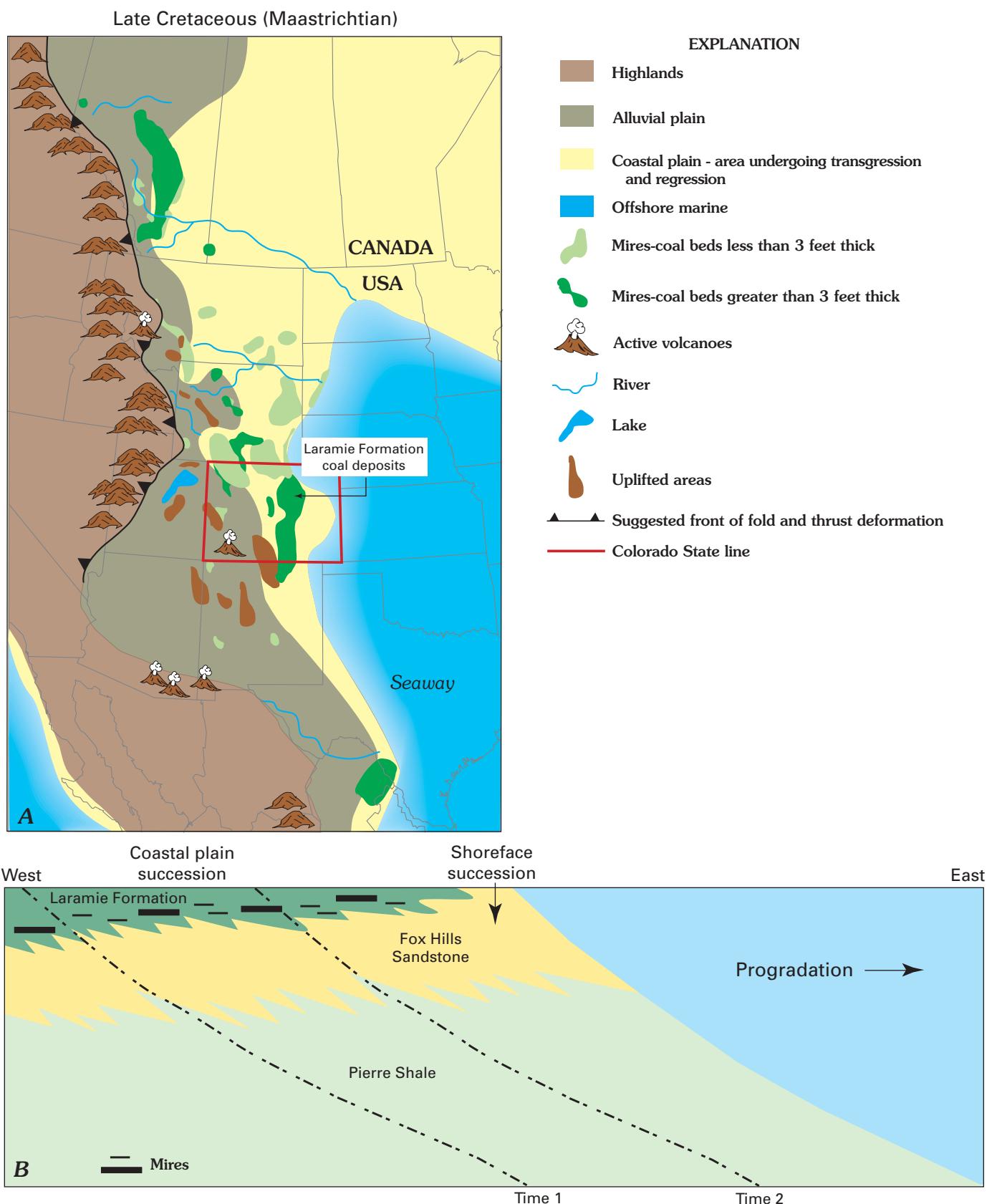


Figure 3. Maps and diagrams showing (A) paleogeography during Late Cretaceous (Maastrichtian) time, and (B) progradational setting of Upper Cretaceous rocks in the Pierre Shale, Fox Hills Sandstone, and Laramie Formation in the Denver Basin, Colorado. Diagram (A) modified from Roberts and Kirschbaum (1995); diagram (B) modified from Weimer (1977).

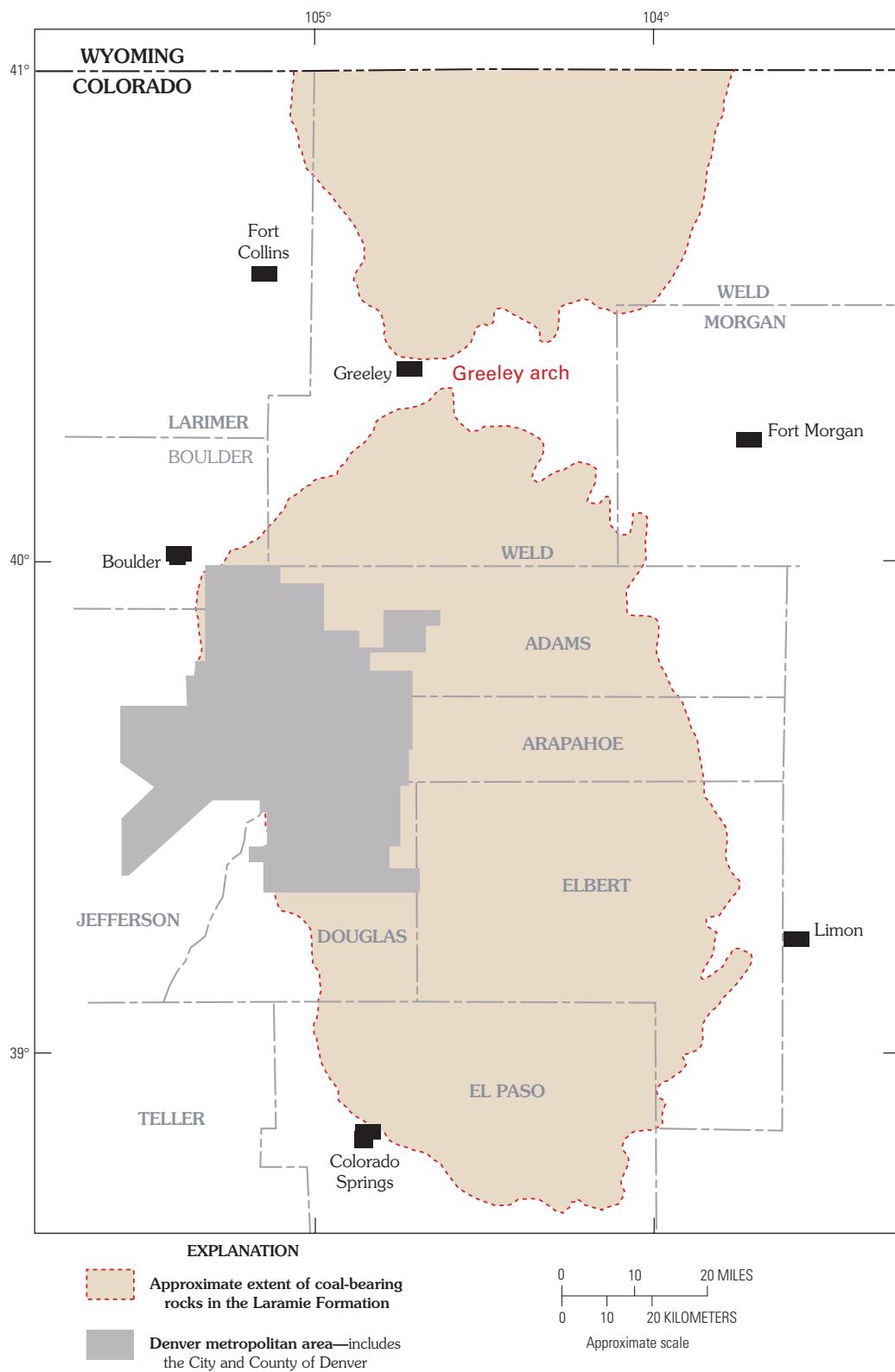


Figure 4. Approximate extent of coal-bearing rocks in the Laramie Formation in areas north and south of the Greeley arch, Denver Basin, Colorado. Kirkham and Ladwig (1979, 1980) designated the area north of the arch as the Cheyenne Basin and the area south of the arch as the Denver Basin. In this study, "Cheyenne Basin" terminology is not applied, and both areas are included in the Denver Basin.

there was about 1,000 ft of structural relief on the arch relative to the adjacent basins. In addition, these authors observed that north of the arch, an 1,800- to 4,700-ft-thick interval of uppermost Cretaceous through Eocene (?) strata, including (but not limited to) all or parts of the Arapahoe and Denver Formations and the Dawson Arkose, is absent. As a result, the Laramie Formation to the north of the arch is unconformably overlain by Oligocene deposits of the White River Formation, whereas south of the arch, the formation is unconformably overlain by Upper Cretaceous rocks in the Arapahoe Formation (Kirkham and Ladwig, 1979) or by equivalent strata (in part) included in the D1 synorogenic sequence of Raynolds (1997) (fig. 2). Although these data, as well as additional data in Kirkham and Ladwig (1979) and Curtis (1988), provide support for differing depositional histories north and south of the Greeley arch, the term “Cheyenne Basin” is not applied in subsequent discussions in this report in order to maintain consistency with terminology used in other FRIRP studies (for example, see Fishman, this volume; Higley and Cox, this volume). However, differences in Laramie Formation stratigraphy and coal geology will be addressed specifically for areas north and south of the arch.

In general, the Laramie Formation consists primarily of sandstone, siltstone, claystone, shale, carbonaceous shale, and coal. North of the Greeley arch, the total preserved thickness ranges from about 1,600 to 1,800 ft; south of the arch, the thickness ranges from about 350 to more than 1,000 ft (Weimer, 1977; Kirkham and Ladwig, 1980). The formation is generally divided into lower and upper parts, based primarily on lithologic differences and, to some degree, on the stratigraphic distribution of coal beds. Kirkham and Ladwig (1979) define the top of the lower part of the Laramie as the top of the uppermost coal bed that is present within the lower 300 ft of the formation, and this definition is generally adhered to in this report. The overall lithologic composition of the Laramie is fairly consistent throughout the Denver Basin, although the relative abundance, thickness, and stratigraphic distribution of different lithologies can vary markedly from place to place. For example, in areas north of the Greeley arch, the upper part of the formation includes abundant sandstone beds that range from 10 to 125 ft thick, whereas south of the arch, the upper part of the formation is composed primarily of claystone, shale, and only thin interbeds of sandstone (for example, see Kirkham and Ladwig, 1979, 1980; Dames and Moore, 1985). In addition, the quantity and thickness of coal beds is variable, and, although primary coal deposits are generally concentrated in an interval within 300 ft of the base of the formation, some areas may contain as many as 16 coal beds whereas other areas contain only 2 to 3 beds or are devoid of coal. Individual coal-bed thickness can range from less than 1 ft to more than 20 ft in isolated areas. Kirkham and Ladwig (1980) estimate that approximately one-third of the area south of the Greeley arch and about one-sixth of the area north of the arch are underlain by Laramie coal beds greater than 5 ft thick. Estimates of the remaining (unmined) coal in beds thicker than 2.5 ft and at depths less than 3,000 ft are about 20–25 billion tons (Kirkham and Ladwig, 1979).

Laramie Formation Coal Geology—North of the Greeley Arch

Coal deposits in the Laramie Formation north of the Greeley arch are relatively thin and discontinuous, and these factors probably account for the limited coal exploration and production relative to other areas of the Denver Basin (for example, see Kirkham and Ladwig, 1980). Because of limited exploration, the distribution of coal and associated lithologies in the Laramie north of the arch is less well known than areas to the south. It has been documented, however, that in addition to the main coal zone in the lower 200–300 ft of the formation, another coal zone is present about 300–500 ft above the lower coal zone in some areas. This upper coal zone includes as many as six beds that are generally 1.5 ft thick or less, although it is unknown as to whether some or all of these beds thicken in adjacent areas (Kirkham and Ladwig, 1979). The limited mining activity (figs. 5 and 6) that did take place north of the Greeley arch, however, only targeted beds in the lower coal zone. Mined coal-bed thickness ranged from about 3.5 to 7.0 ft, and average as-received heat-of-combustion values in the mining areas ranged from 7,200 to 8,000 BTU/lb (fig. 5) (Kirkham and Ladwig, 1979; Kirkham, 1978a).

Laramie Formation Coal Geology—South of the Greeley Arch

Because of the extensive coal exploration and production in areas south of the Greeley arch, more data are available pertaining to the stratigraphy and coal geology of the Laramie Formation in this area of the Denver Basin. The lower part of the formation ranges from about 100 to 300 ft thick (Kirkham and Ladwig, 1979) and consists of alternating beds of sandstone, siltstone, claystone, carbonaceous shale, and coal. The upper part, which ranges from 200 to more than 1,000 ft thick, is composed predominantly of claystone with only minor sandstone, siltstone, and sporadic, thin coal beds (for example, see Weimer, 1977). Historically, coal was mined primarily from beds in the lower part of the Laramie.

In the Boulder-Weld coal field, as many as 16 coal beds are present locally (Kirkham and Ladwig, 1980). As-received heat-of-combustion values ranged from 8,200 to more than 9,900 BTU/lb, and the apparent rank of the coal ranged from subbituminous C to subbituminous B (Kirkham, 1978a; Kirkham and Ladwig, 1980). Seven potentially minable coal beds in the lower part of the Laramie Formation were identified by Lowrie (1966) and were designated as coal beds No. 1 through No. 7 in ascending order (fig. 7). The following summary descriptions of these coal beds are modified from Myers and others (1975), Kirkham and Ladwig (1980), and Spencer (1986).

Coal beds Nos. 3–6 were the primary targets for past coal production, as coal beds No. 1, No. 2, and No. 7 are generally too thin and lenticular for economic extraction. Coal bed No. 1 ranges from 1 to 3 ft thick and generally lies directly on or

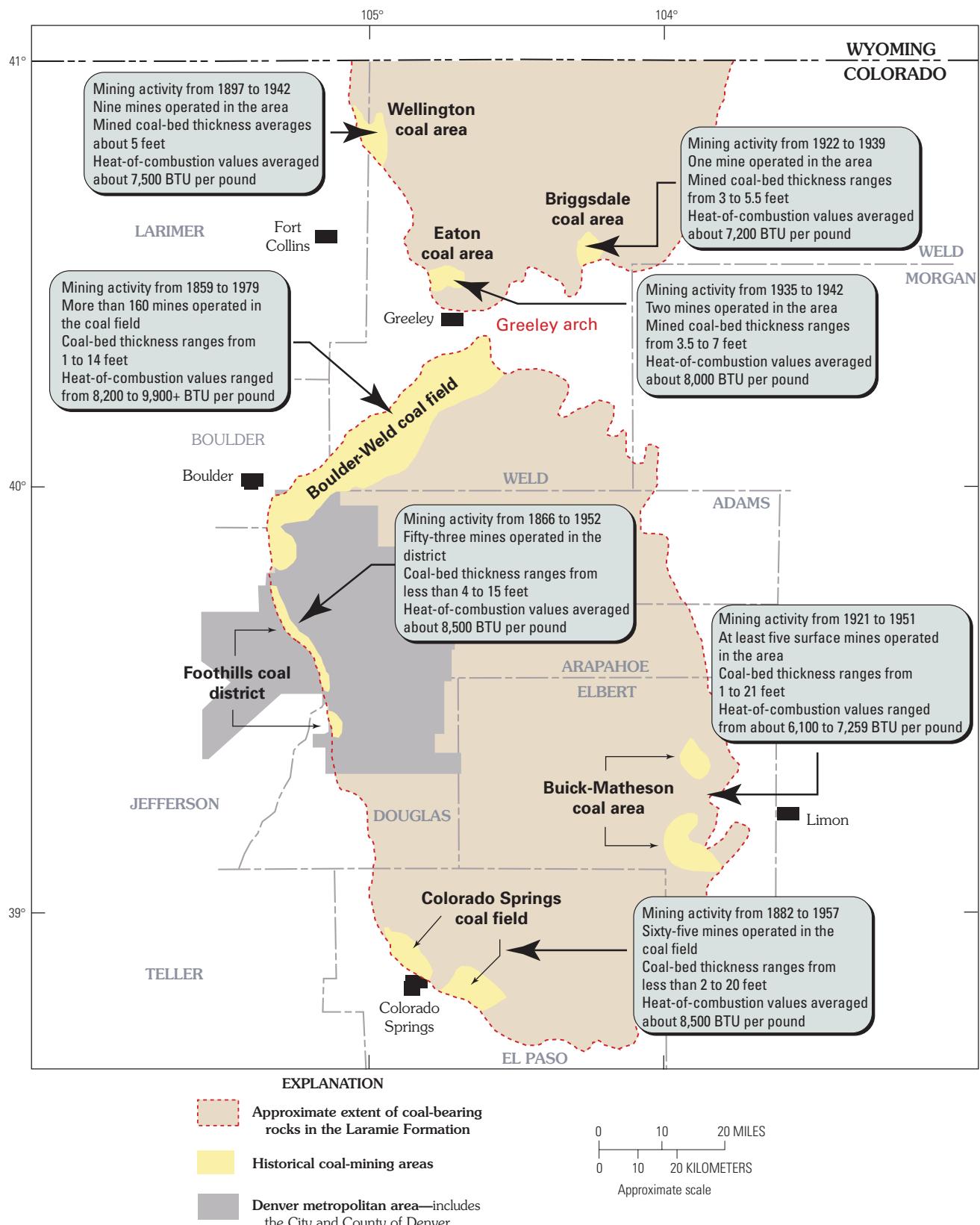


Figure 5. Areas of historical coal production from the Laramie Formation and the dates of mining activity, number of coal mines, coal-bed thickness ranges, and heat-of-combustion values in each mining area, Denver Basin, Colorado. Map and coal data from Kirkham and Ladwig (1979, 1980).

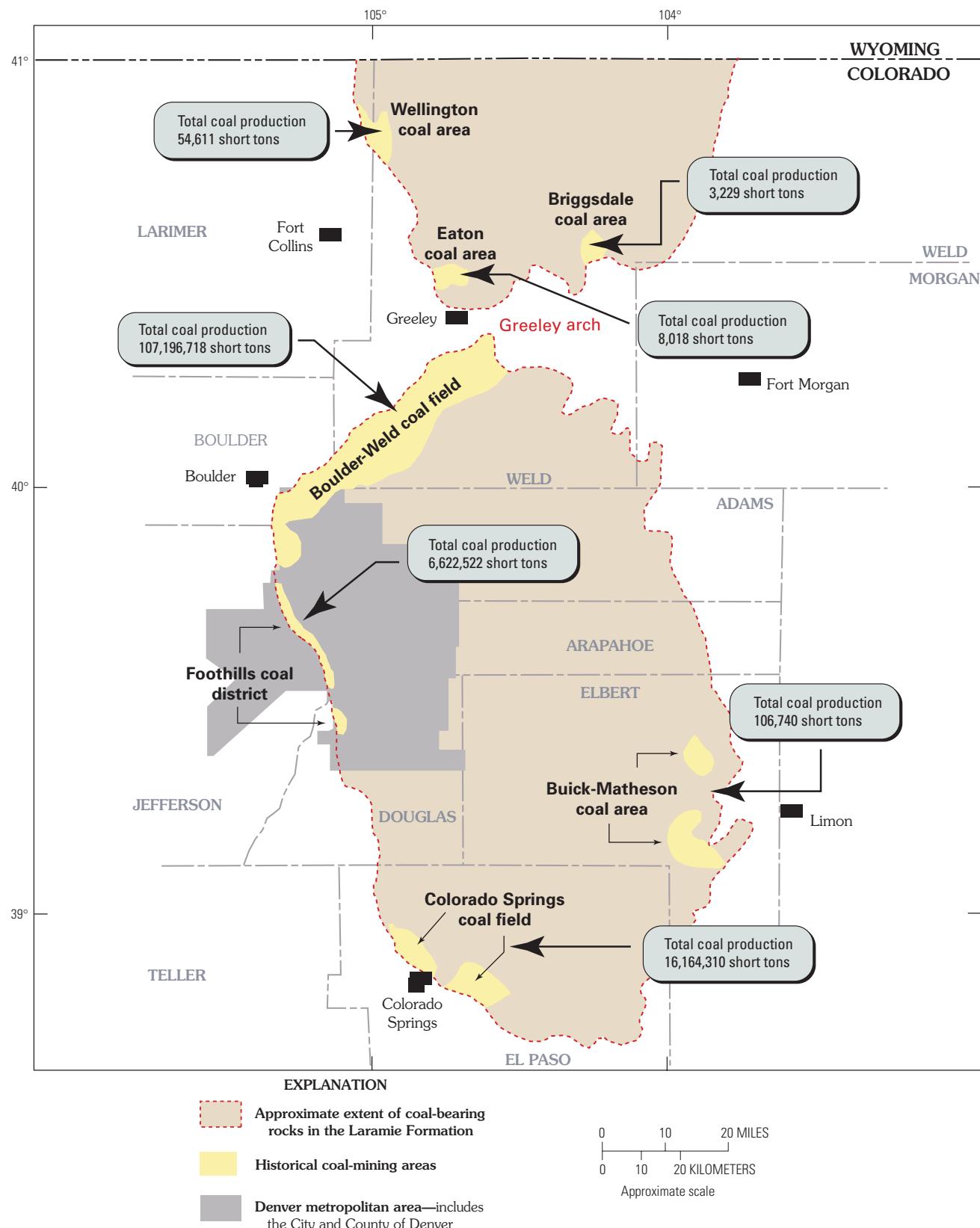


Figure 6. Total coal production from the Laramie Formation in areas of historical coal mining, Denver Basin, Colorado. Map and coal production data from Kirkham and Ladwig (1979, 1980).

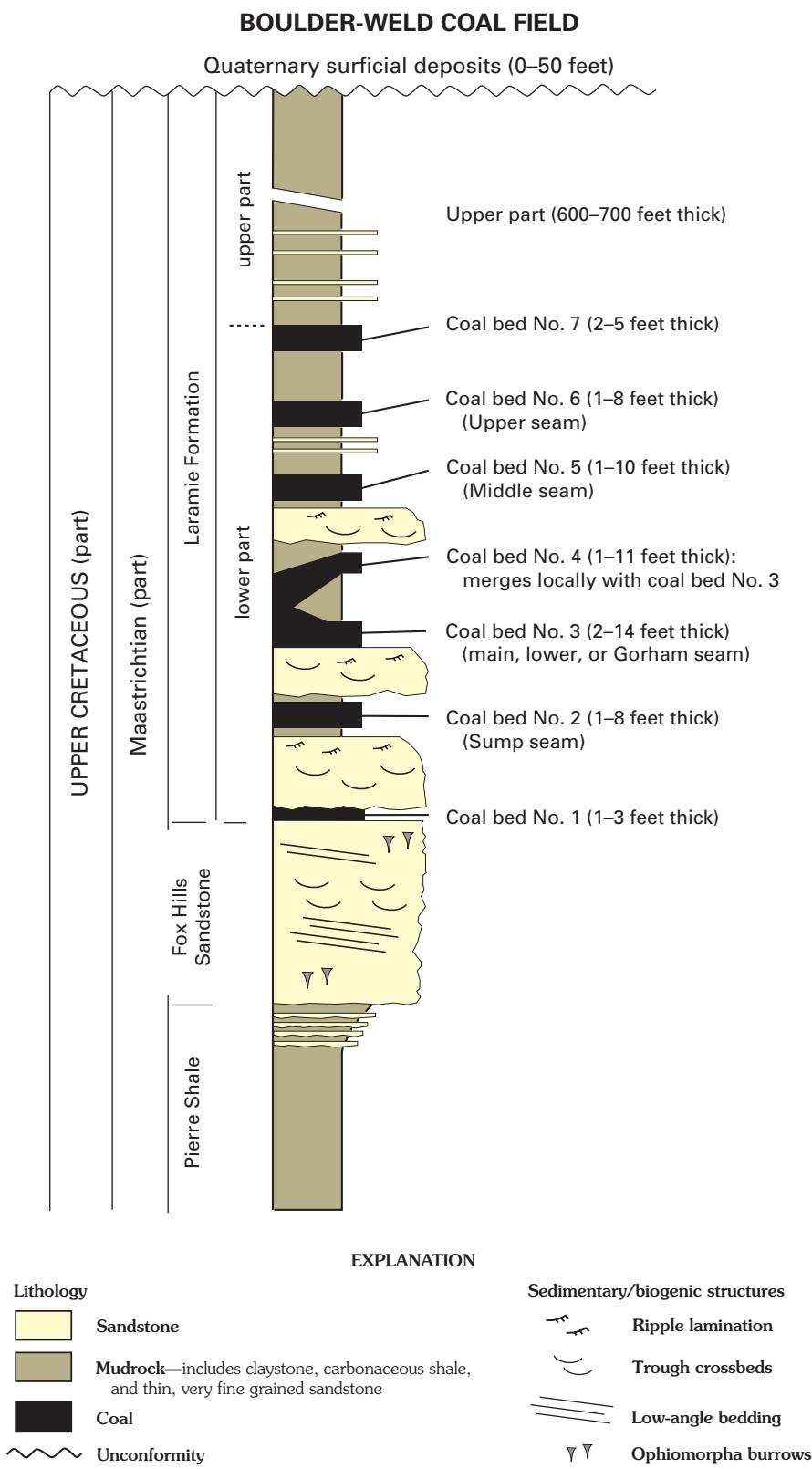


Figure 7. Generalized stratigraphic column showing lithology, inferred sedimentary structures, and coal-bed distribution and nomenclature in the Laramie Formation (Upper Cretaceous), Boulder-Weld coal field, Denver Basin, Colorado. Coal-bed nomenclature is based on Lowrie (1966). Column modified from Myers and others (1975) and Kirkham and Ladwig (1979). Column not to scale.

within a few feet above the top of the Fox Hills Sandstone; the base of the coal bed marks the base of the Laramie Formation in the coal field. Overlying coal bed No. 2 ranges from 1 to 8 ft thick and is present some 11–65 ft stratigraphically above the No. 1 bed. Locally, coal bed No. 2 was also designated as the “Sump seam” based on its close stratigraphic proximity to the overlying No. 3 coal bed. Coal bed No. 3, also known as the “main seam,” the “lower seam,” or the “Gorham seam,” is the bed that was mined most extensively in the Boulder-Weld coal field, primarily because of its lateral continuity and thickness, which ranges from 2 to 14 ft. It lies from 10 to 45 ft above the No. 2 bed and locally coalesces with the overlying No. 4 coal bed (fig. 7). Where they are not merged with one another, as much as 30–35 ft of rock may separate the No. 3 and No. 4 coal beds. Coal bed No. 4 ranges in thickness from 1 to 11 ft and is typically from 10 to 50 ft stratigraphically below the overlying bed. The No. 5 coal bed, also known as the “Middle seam,” ranges in thickness from 1 to 10 ft and lies some 20–75 ft below the No. 6 coal bed. The No. 6 coal bed, also designated as the “Upper seam,” ranges from 1 to 8 ft thick; although this coal bed is laterally continuous over a fairly large area of the coal field, its variable thickness limited production in many areas. The No. 6 coal bed lies from 30 to 100 ft stratigraphically below the overlying No. 7 coal bed, which ranges from 2 to 5 ft thick.

In the Foothills District, south of the Boulder-Weld coal field (fig. 5), one to six coal beds are present in the lower part of the Laramie Formation, and coal-bed thickness ranges from about 4 ft to as much as 15 ft (for example, see Kirkham and Ladwig, 1979). As-received heat-of-combustion values averaged about 8,500 BTU/lb. In the northernmost part of the Foothills District, two coal beds designated as coal bed A (upper) and coal bed B (lower) were mined at depths ranging from 800 to 1,000 ft. The B coal bed lies about 100–150 ft above the base of the Laramie and ranges from about 6 to 11 ft thick. The overlying A coal bed ranges from about 4 to 8 ft thick (Weimer, 1977), and the two coal beds are separated by an interval of claystone and siltstone that varies in thickness from 20 to 80 ft (Camacho, 1969).

In the southwestern part of the Denver Basin, in and near the Colorado Springs coal field (fig. 5), the lower part of the Laramie Formation ranges from 150 to 200 ft thick, and the upper part ranges from 100 to 150 ft thick (fig. 8). Heat-of-combustion values for coal beds in the lower part of the formation averaged about 8,500 BTU/lb (Kirkham, 1978a). The following summary of stratigraphy and coal geology is based primarily on Goldman (1910), Kirkham and Ladwig (1979), and Dames and Moore (1985), and the reader should consult those reports for more detailed information on the Laramie Formation in this area.

The lower part of the Laramie in the Colorado Springs coal field includes alternating beds of very fine to fine-grained sandstone, claystone, and coal, whereas the upper part is composed primarily of claystone with thin interbeds of fine-grained sandstone. Goldman (1910) designated three coal beds in the lower part of the formation as coal beds A–C in

ascending order; other unnamed thin and lenticular coal beds are also present in the area (fig. 8). Most of the mines in the Colorado Springs coal field produced coal from the A and B coal beds. Coal bed A is present from 30 to 65 ft above the base of the formation, and as a single bed, is as thick as 20 ft locally. Elsewhere in the coal field, coal bed A splits into two coal beds separated by about 8 ft of rock; in more extreme cases, the bed splits into a series of four to five thin coal beds separated by rock partings. Coal bed B is present from 25 to 50 ft above coal bed A, with massive sandstone typically separating the two coal beds. Coal bed B is as much as 13 ft thick locally, although the bed is more typically 5 ft thick or less throughout much of the Colorado Springs coal field. Coal bed C is lenticular and in places is absent. Where coal bed C is present, it lies from 20 to 50 ft stratigraphically above coal bed B and generally is less than 2 ft thick.

In south-central and southeastern parts of the Denver Basin, in and adjacent to the Buick-Matheson coal area (fig. 5), two primary coal beds, designated coal beds A and B in ascending order, are present in the lower part of the Laramie Formation. Although this terminology is similar to terminology described herein for the Colorado Springs coal field, the stratigraphic relation between identically named coal beds in the two areas is not known. In the Buick-Matheson area, the A coal bed, which splits into upper and lower beds in some areas, is present within 0–15 ft of the base of the Laramie. The B coal bed is 15–50 ft stratigraphically above the A coal bed, or above the upper A coal bed where the A bed is split (Eakins and Ellis, 1987). Thin, sporadic coal beds are locally present above the B coal bed. Where the A coal bed forms a single bed, its thickness ranges from less than 2 ft to as much as 15 ft. Where split, the upper A bed is 1 to 21 ft and the lower A bed is 1 to 10 ft thick. The B coal bed ranges in thickness from 1 to 5 ft (Eakins and Ellis, 1987). As-received, heat-of-combustion values for these coal beds range from 6,100 to 7,259 BTU/lb (Kirkham and Ladwig, 1979; Eakins and Ellis, 1987).

Laramie Formation Coal Production

Past coal production from the Laramie Formation took place in seven areas of the Denver Basin. Coal mining operations began in the late 1850s and continued until 1979 (fig. 5). Kirkham and Ladwig (1979; 1980) report that a total of 130,156,148 short tons of Laramie coal was produced between 1884 and 1979. Of this total, about 107 million tons was mined from the Boulder-Weld coal field, more than 16 million tons was mined from the Colorado Springs coal field, and about 6.6 million tons was mined from the Foothills coal district (fig. 6). These three areas accounted for more than 99 percent of all the coal mined in the Laramie Formation. Throughout the coal-mining history of the Denver Basin, more than 295 mines were opened. Nearly all of these mines were underground operations, but there were at least seven surface (strip) mines that produced a total of about 254,000 short tons.

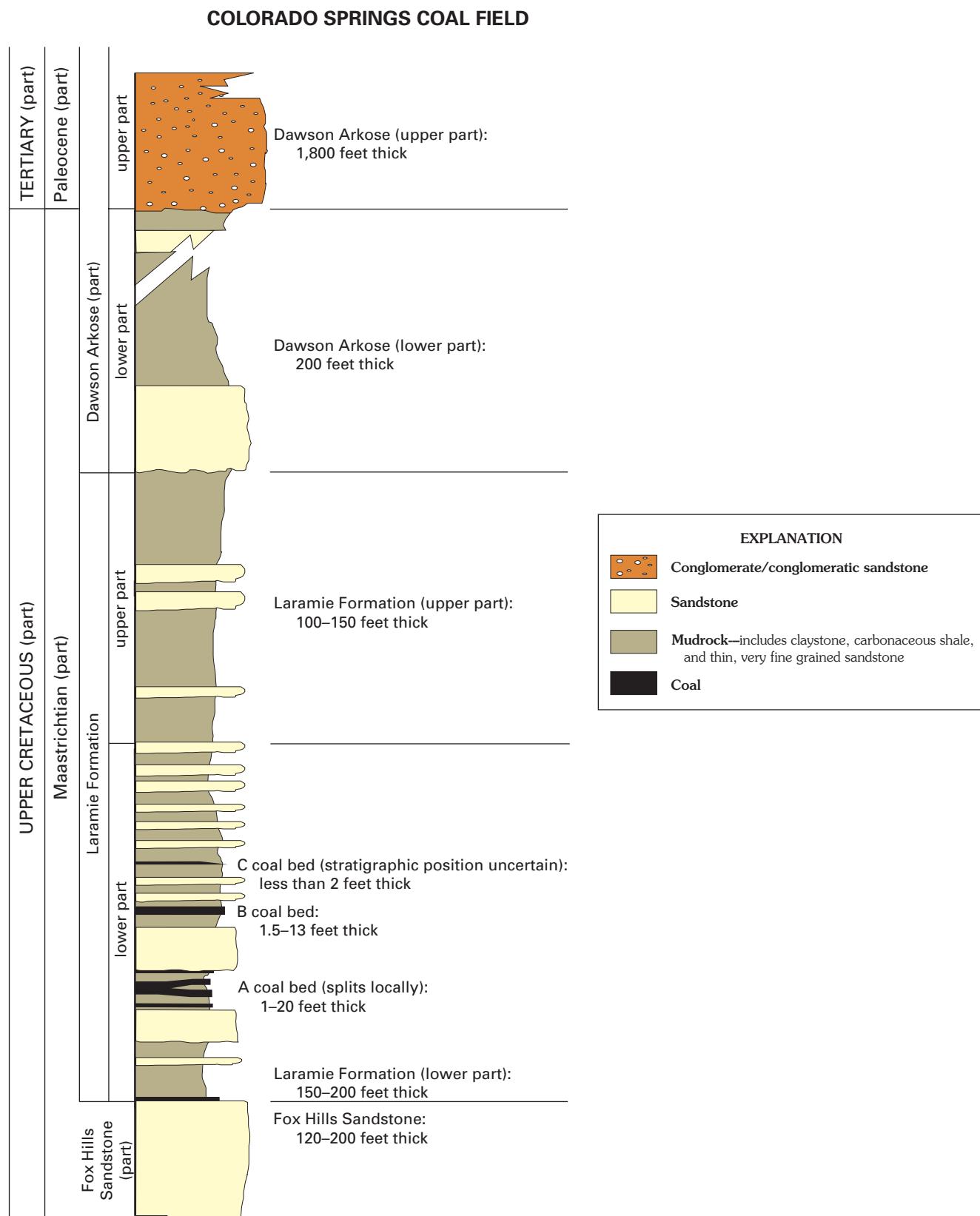


Figure 8. Generalized stratigraphic column showing lithology, and coal-bed distribution and nomenclature in the Laramie Formation (Upper Cretaceous), Colorado Springs coal field, Denver Basin, Colorado. Coal-bed nomenclature is based on Goldman (1910). Column modified from Dames and Moore (1985). Column not to scale.

Coal production north of the Greeley arch, in the Briggsdale, Eaton, and Wellington coal areas (fig. 6), totaled only about 67,000 short tons.

Where Laramie coal beds are relatively flat lying or gently dipping, most of the underground mines used room-and-pillar mining methods, with some amount of retreat mining (pillar pulling) upon completion of coal extraction. Coal-extraction percentages in room-and-pillar mines varied from 25 to 75 percent and averaged about 50–60 percent; where retreat mining techniques were used, extraction percentages increased to 70–95 percent and averaged 80–85 percent (Matheson and Bliss, 1986). A schematic diagram depicting the general layout of a typical room-and-pillar mine is shown in figure 9, although it should be noted that many older mines in the Denver Basin did not always adhere to such an orderly scheme of development. Access to the underground coal mines was primarily achieved through vertical shafts or sloped entryways. Vertical shaft dimensions were commonly 6 ft by 6 ft (single compartment), although shafts that were 6 ft by 12 ft (double compartment) were also used to facilitate the raising and lowering of two mine cars simultaneously (Dames and Moore, 1985). The grade of the sloped entryways was

typically on the order of 12 percent, although entry grades as steep as 20 percent were used in some mines in the Colorado Springs coal field (Dames and Moore, 1985). Wooden timbers supported both vertical shafts and slope entries. At the level where the vertical or sloped entry intersected the coal bed, the main entry or haulageway was constructed, either perpendicular to or approximately parallel to the strike of the coal bed (fig. 9). The main haulageway generally consisted of two parallel tunnels oriented in such a way that fresh air could be blown in one tunnel, circulated through the mine, and exhausted out of the other tunnel (Hart, 1986). Vertical airshafts, dug from the ground surface to the mine level, provided additional ventilation where needed. Cross entries (fig. 9), cut at right angles to the main haulageway, were used to access mine rooms where coal extraction took place. Mine rooms were generally on the order of 18–20 ft wide and could be as much as 100–300 ft long, although the length of the room was variable, depending on its location in the mine and the historical period during which the mining took place (Dames and Moore, 1985; Hart, 1986). Mined coal was hauled from the rooms to the base of the slope entry or shaft in mine cars, which could hold as much as 2,500 to 3,000 pounds

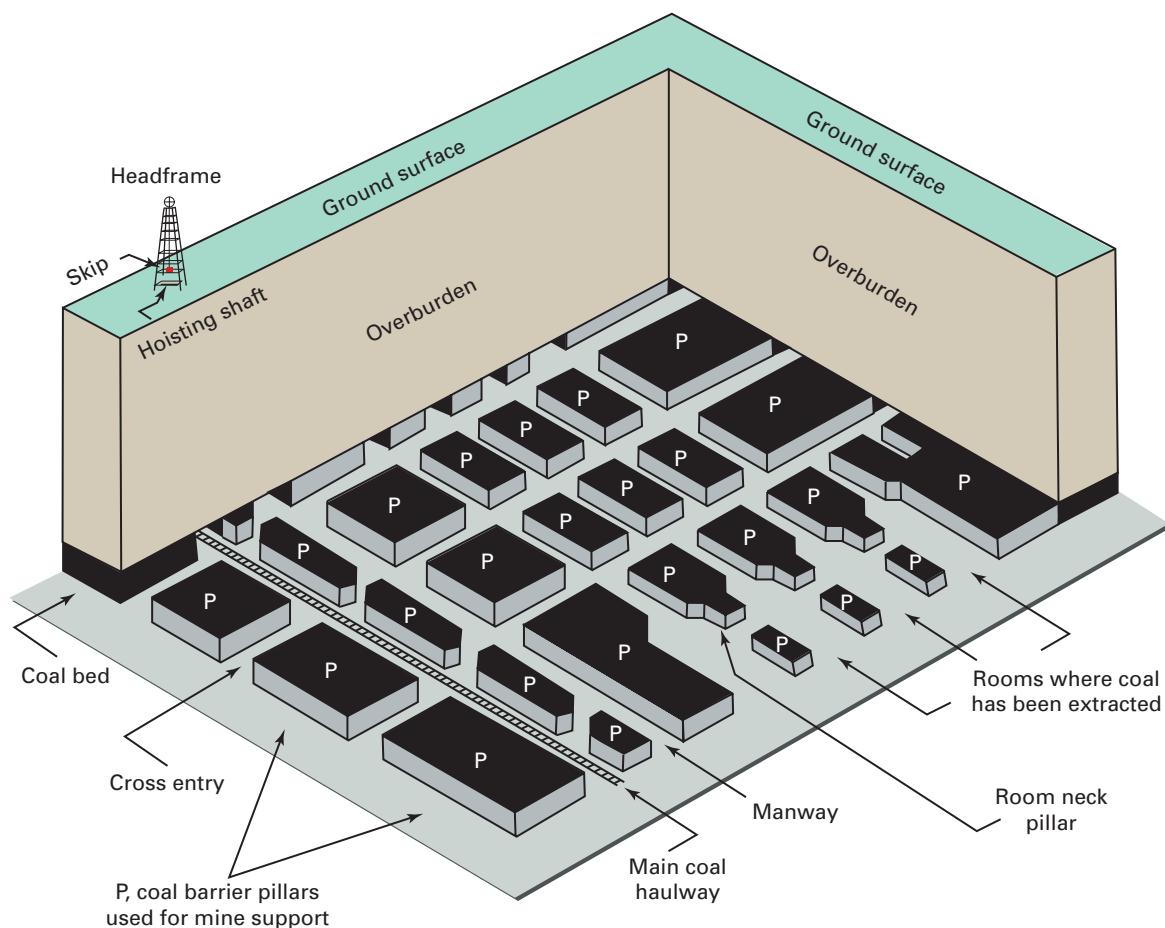


Figure 9. Basic components and configuration of a room-and-pillar coal mine. Diagram modified from Dames and Moore (1985).

of coal (Hart, 1986). Mules pulled mine cars until as recently as the 1940s, but through time, electric motors and continuous mining machines with conveyor systems replaced mulepower as the hauling mechanism of choice. During mining, pillars of coal, usually 20–30 ft wide, separated individual mine rooms. When adjacent rooms were mined to their complete length, many of these coal pillars were pulled (mined) as mining retreated from that area (Hart, 1986).

Where coal beds in the Laramie Formation are steeply dipping, such as in the Foothills coal district (fig. 5), a process termed “stope mining” was used. By this method, haulageways were constructed parallel to the strike of the coal bed, and stopes on the order of 30–100 ft high and 50–100 ft wide were driven upward to mine coal above the haulageways (Matheson and Bliss, 1986). Multiple stope levels commonly were developed in these mines, and the vertical dimension between stope levels was on the order of 75–150 ft. For more details on this mining technique, the reader is referred to descriptions by Hart (1986).

Denver Formation

The Denver Formation ranges in age from Late Cretaceous (Maastrichtian) to early Tertiary (Paleocene) (for example, see Nichols, 1999). Strata within the formation accumulated in a realm of high accommodation (high subsidence) associated with thrust uplift of the Front Range and corresponding subsidence of the Denver Basin (for comparison, see Raynolds, 1997). Coal in the Denver Formation resulted from peat accumulation in mires that developed within interfluvial areas east of the Front Range highlands during the Paleocene (fig. 10). The formation overlies the Arapahoe Formation of Late Cretaceous age and is laterally equivalent to (in part) and overlain by the Dawson Arkose (fig. 2), a unit that ranges in age from Late Cretaceous (Maastrichtian) to Tertiary (Eocene) (for example, see Nichols, 1999). Strata within the Dawson Arkose (part) and Denver Formation are included in the unconformity-bounded D1 sequence of Raynolds (1997) (fig. 11) and are considered to represent a west-east continuum of synorogenic deposits consisting of a coarse-grained, proximal facies (Dawson Arkose) along the western margin of the Denver Basin and a dominantly fine-grained distal facies (Denver Formation) near the basin center and on the east basin margin.

The Denver Formation ranges in thickness from 600 to 1,580 ft and consists mainly of claystone and siltstone, with interbeds of very fine to fine-grained sandstone and, more rarely, conglomerate; lava flows are present locally within the formation (for example, see Kirkham and Ladwig, 1979). Coal and associated carbonaceous shale beds are concentrated in the upper 500 ft of the formation, and coal beds are distributed over an area of about 1,700 mi². As discussed in a previous section, the Denver Formation is not present north of the Greeley arch; thus coal within the formation is present only in areas south of the arch. Estimates of the remaining (unmined) coal resources in the Denver Formation in coal beds thicker

than 4 ft and at depths less than 1,000 ft are on the order of 10–15 billion tons (Kirkham and Ladwig, 1979).

Denver Formation Coal Geology

Thicker accumulations of coal in the Denver Formation are concentrated in and near the Scranton and Ramah-Fondis mining districts (figs. 12 and 13), where historical mining took place from the late 1800s to 1940. The apparent rank of the coal is primarily lignite A, although thin intervals of coal have been analyzed as subbituminous C in apparent rank (Kirkham and Ladwig, 1979). Because of the lignitic nature of the coal, the term “lignite” may be used interchangeably with the term “coal” in subsequent descriptions in order to maintain consistency with terminology applied previously in studies of coal in the Denver Formation (for example, see Soister, 1972; Kirkham and Ladwig, 1979, 1980; Nichols, 1999).

Most all of the lignite beds include numerous non-coal partings that range in thickness from about 0.1 inch to more than 2 ft. Kirkham and Ladwig (1979) estimated that the net lignite bed thickness (excluding partings) is generally 70–90 percent of the gross lignite bed thickness (including partings). In addition, because of observed differences in coal stratigraphy and abundance, the coal-bearing interval has been subdivided geographically into northern and southern lignite areas. Within this framework, the Scranton mining district lies within the northern lignite area and the Ramah-Fondis mining district lies within the southern lignite area (fig. 12). In between the northern and southern lignite areas, coal in the formation is far less abundant and in some cases is absent (for example, see Kirkham and Ladwig, 1979). West of the northern and southern lignite areas, in the deeper subsurface of the Denver Basin, coal is present, but the distribution, thickness, and extent of the coal are less well understood because of limited drill-hole information. In addition, coal beds in the formation tend to thicken and thin abruptly, and although the maximum reported coal thickness for individual beds might be relatively high, the areal extent of thick coal accumulations is generally limited. The following summary focuses on coal data from the northern and southern lignite areas and is based primarily on information in Kirkham and Ladwig (1979, 1980), Brand and Eakins (1980), and Eakins and Ellis (1987); additional references are cited where applicable.

In the northern lignite area, Soister (1972) designated five coal beds as the A–E lignite beds, in descending order (fig. 14). The B and C lignite beds have also been informally referred to as the Lowry and Bennett lignite beds, respectively; the E lignite bed is also known as the Watkins bed. The uppermost A lignite bed occurs at the top of the Denver Formation, just below thick, arkose-rich sandstones in the Dawson Arkose. An additional interval containing numerous unnamed lignite beds is also present below the E lignite bed near the base of the lignite zone. The gross thickness (including partings) of the E lignite bed averages 20–30 ft, and the maximum gross thickness is as much as 55 ft locally. The E lignite bed splits in some areas, and the gross thickness of the upper split

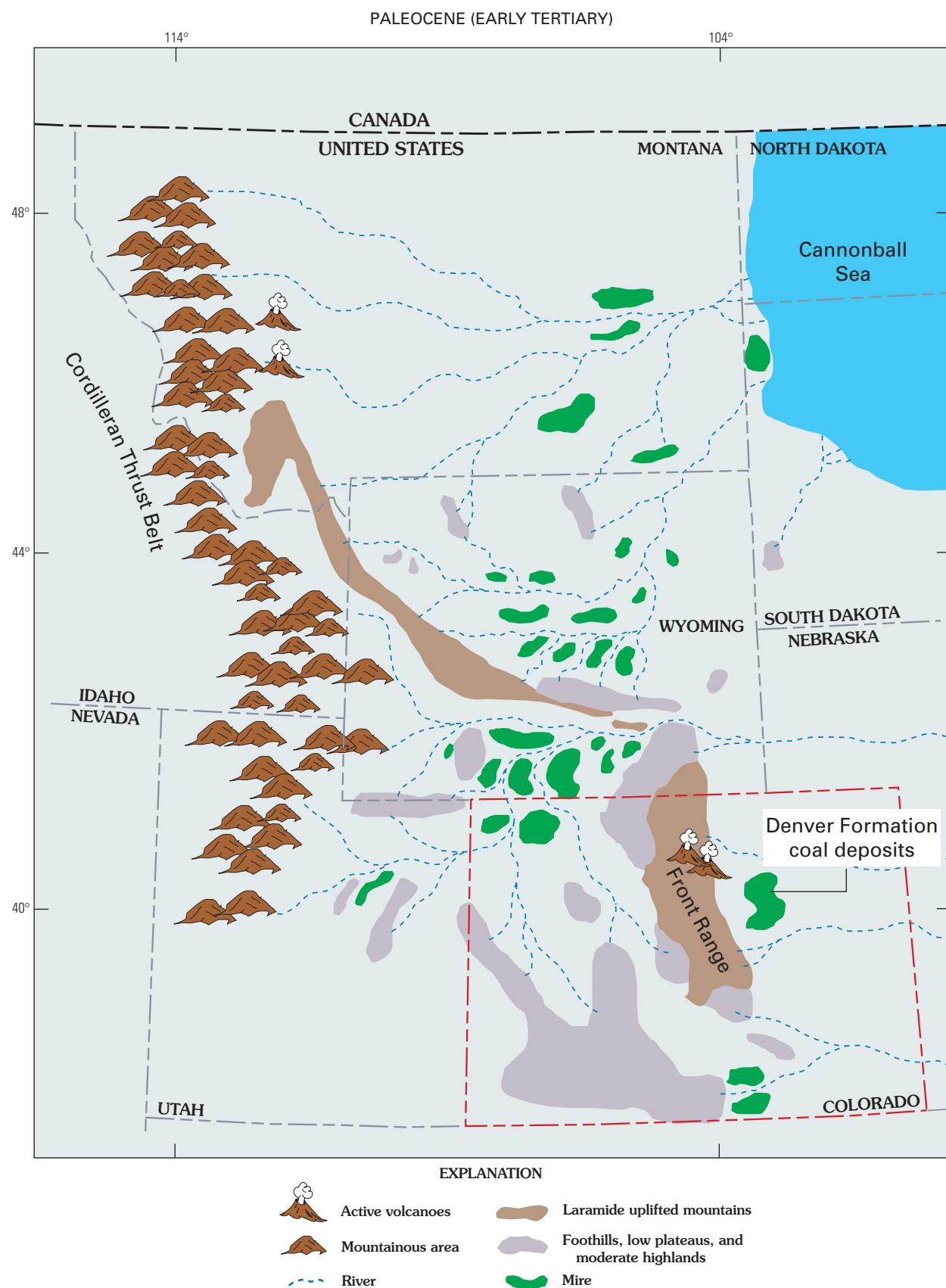


Figure 10. Interpreted paleogeography during the early Tertiary (Paleocene) in the Rocky Mountain region. Modified from Flores and others (1997).

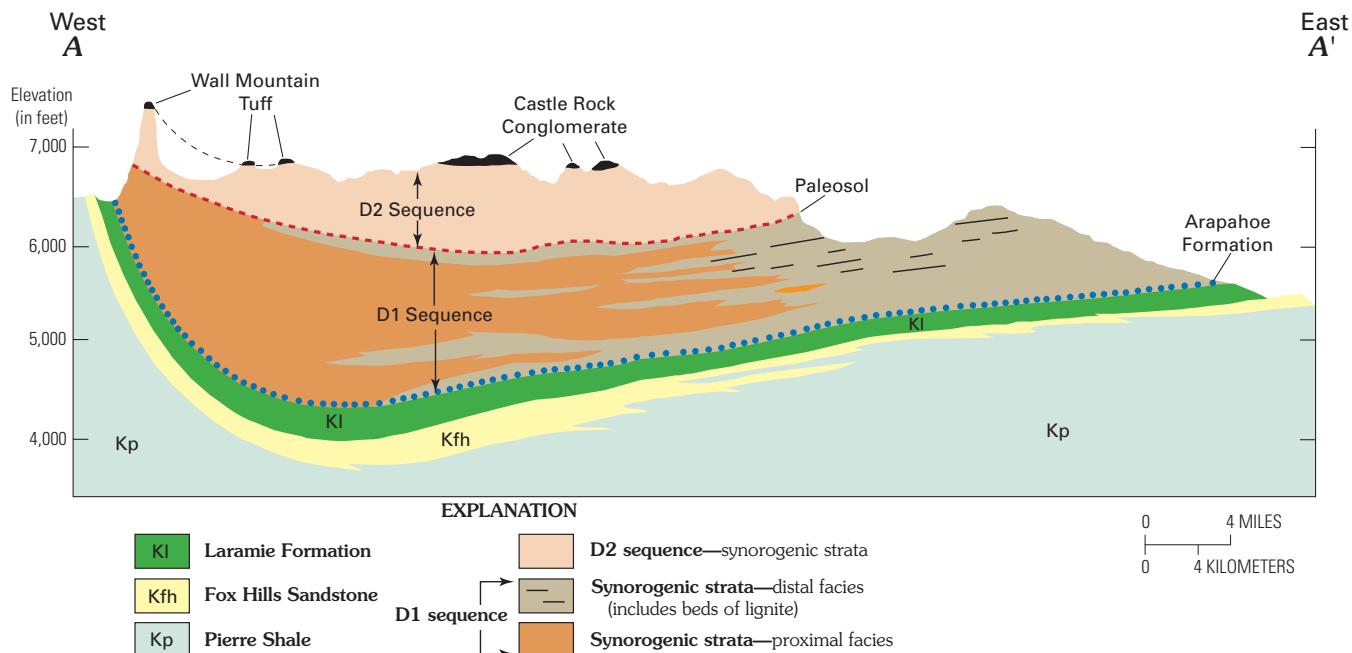


Figure 11. West-east cross section A–A' showing the distribution of synorogenic deposits in the unconformity-bounded D1 and D2 sequences, Denver Basin, Colorado. Location of cross section is shown in figure 1. Modified from Reynolds (1997).

ranges from less than 5 ft to about 55 ft, whereas the lower split varies from less than 5 ft to 25 ft in thickness. The E lignite bed is the most continuous of the coal beds and has been traced over a distance of about 24 miles. The C lignite bed (Bennett bed) ranges in gross thickness from less than 5 ft to more than 30 ft, and the B lignite bed (Lowry bed) ranges in thickness from less than 5 ft to 30 ft (fig. 14) (for comparison, see Brand and Eakins, 1980). The A and D lignite beds are typically 10–15 ft thick.

In the southern lignite area (fig. 12), informally named lignite beds (descending order) include the Wolf bed, the Comanche bed, the upper, middle, and lower Kiowa beds, and the Bijou bed; additional unnamed lignite beds are also present in the area (fig. 14). The Wolf bed lies about 25–75 ft below the base of the Dawson Arkose, and it is the thickest individual coal bed in the southern lignite area, ranging from 18 to 29 ft in gross thickness. However, as much as 20–40 percent of the gross thickness of the Wolf bed may be attributable to non-coal partings. The Comanche bed lies 15–100 ft stratigraphically below the Wolf bed and is as thick as 26 ft in limited areas near the Ramah-Fondis mining district. The upper, middle, and lower Kiowa beds compose a zone of coal that ranges from 15 to 80 ft thick. The top of the Kiowa coal zone (top of the upper Kiowa bed) is generally within 22–110 ft below the base of the Comanche bed. Total cumulative coal thickness for beds in the zone is as much as 30 ft, although the individual thickness for the upper, middle, and lower Kiowa beds generally ranges from 5 to 10 ft, including partings. Locally the three individual beds coalesce to form one coal bed known as the Kiowa bed. The Bijou bed lies from 60 to 80 ft below the base of the Kiowa coal zone and attains a maximum thickness of 19 ft.

Denver Formation Coal Production

Production of coal from the Denver Formation amounted to less than 1 percent of the total production in the Denver Basin and was minimal relative to coal production from the Laramie Formation. Most of the production took place in the Scranton mining district, where a recorded 35,789 short tons of coal was produced from one mine from the late 1800s (1886?) until 1900 (figs. 12 and 13) (Kirkham and Ladwig, 1979). In the Ramah-Fondis mining district, just over 3,000 short tons of coal was mined during the period from 1909 to 1940. Few details are available regarding which coal beds were mined and the type of mining method that was used. Because of the limited tonnage of coal produced in these two areas, it is assumed that most of the mines were small surface-mining operations.

Coal-Bed Methane Potential

The presence of natural gas in coal beds has long been recognized. Historically, gas generated from coal beds was a hazard to the coal-mining industry because of its propensity for ignition and explosion in underground mines. Although coal-bed gas continues to be a potential hazard to the coal-mining industry, this abundant resource has also proven to be a valuable part of the Nation's natural gas endowment. The mean estimate of technically recoverable gas resources from coal beds in the conterminous United States is nearly 50 trillion cubic feet (Tcf) (U.S. Geological Survey National Oil and Gas Assessment Team, 1996).

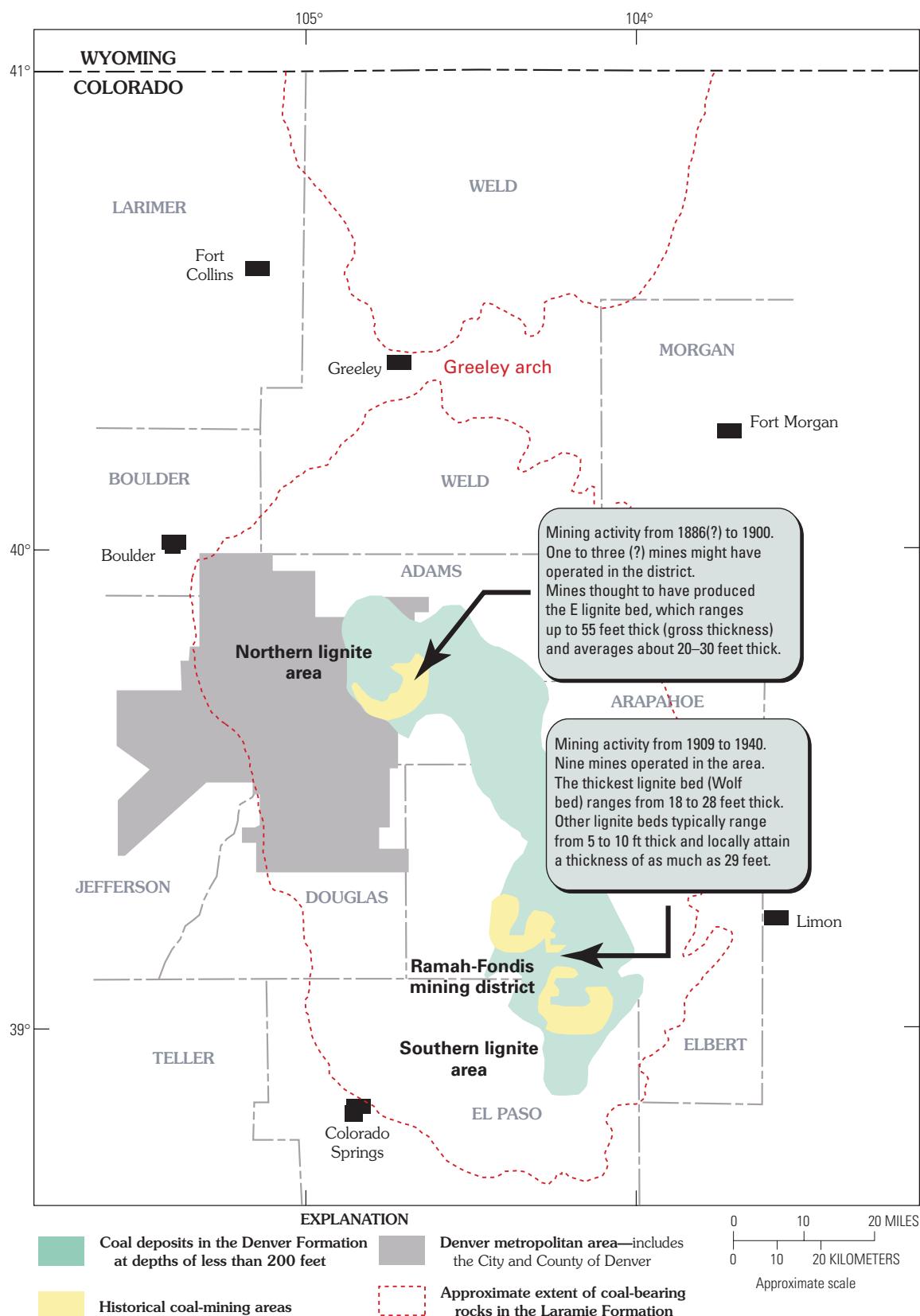


Figure 12. Areas of historical coal production from the Denver Formation and the dates of mining activity, number of coal mines, coal-bed thickness ranges, and heat-of-combustion values in each mining area, Denver Basin, Colorado. Map and coal data from Kirkham and Ladwig (1979, 1980).

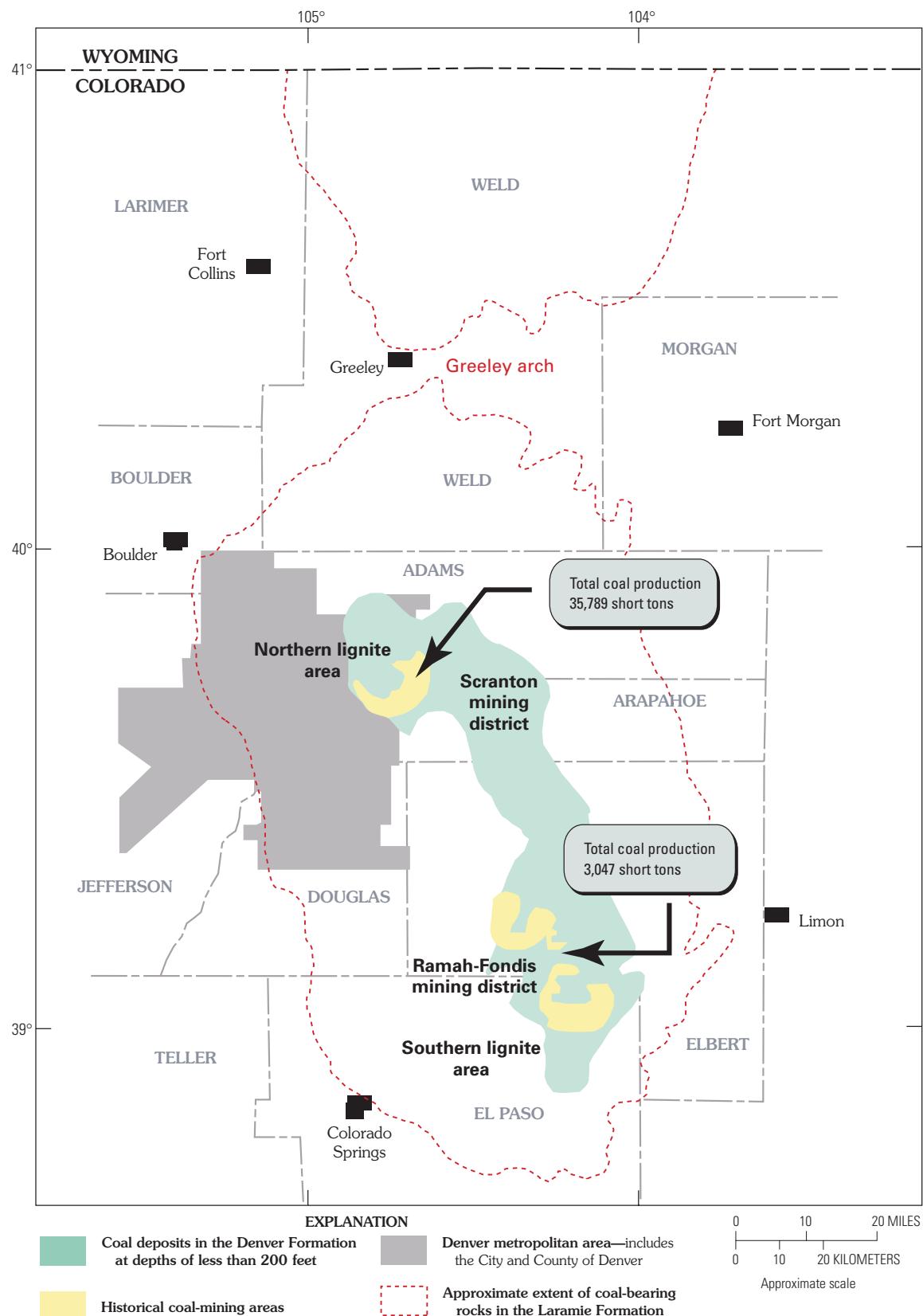


Figure 13. Total coal production from the Denver Formation in areas of historical coal mining, Denver Basin, Colorado. Map and coal production data from Kirkham and Ladwig (1979, 1980).

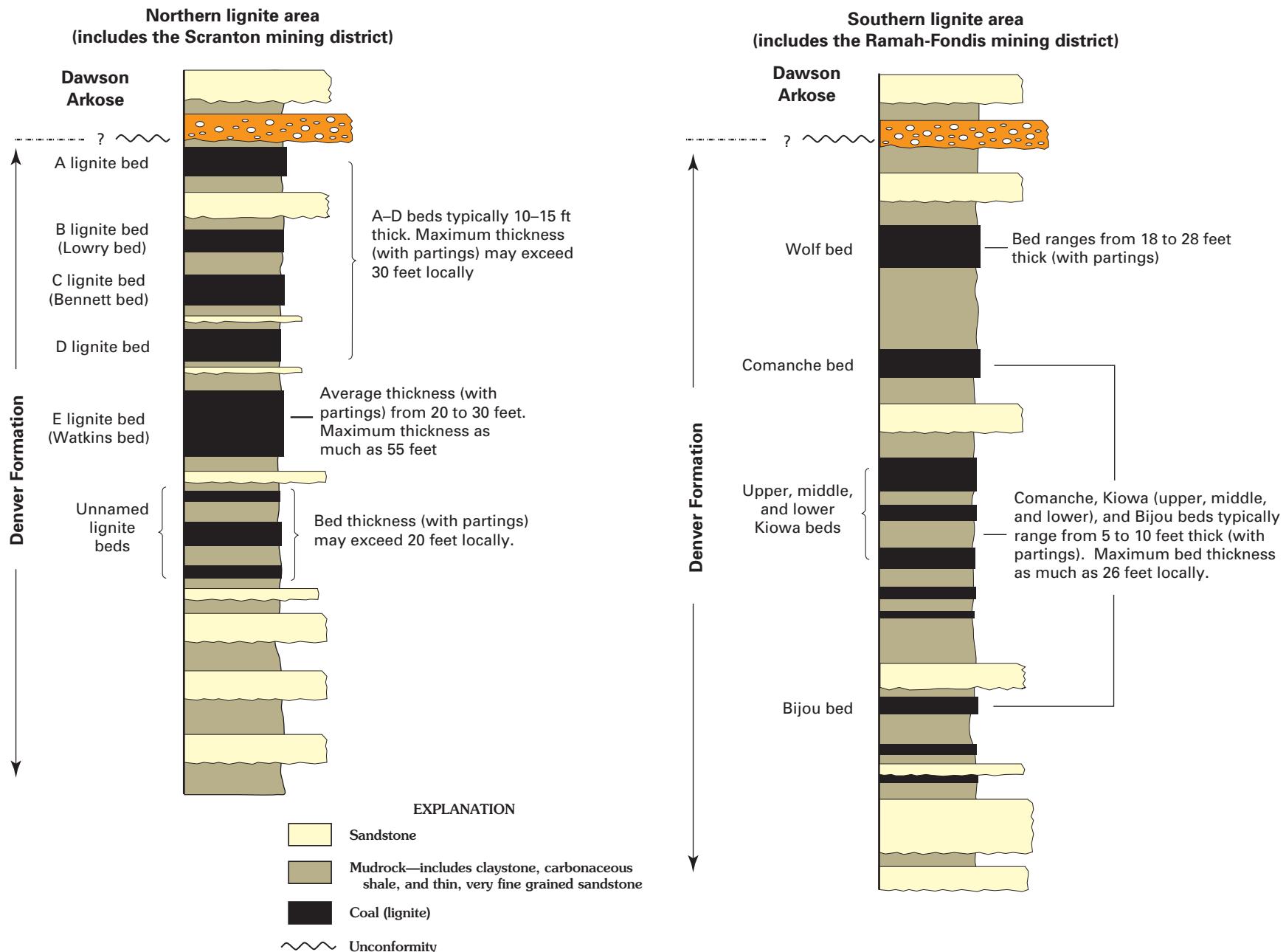


Figure 14. Generalized stratigraphic columns showing coal (lignite) beds and associated lithologies in the Denver Formation in the northern and southern lignite areas, Denver Basin, Colorado. Modified from Kirkham and Ladwig (1979). Columns not to scale.

Methane is typically the dominant component of the natural gases within coal beds, although other hydrocarbon gases (for example, ethane and propane) as well as varying amounts of nitrogen and carbon dioxide can also be present (for example, see Rice and others, 1993; Johnson and Flores, 1998). The generation of gas, both biogenic and thermogenic, takes place during coalification, the process by which accumulated plant material (peat) is transformed to coal (for example, see Rice and others, 1993). In general, biogenic gas forms during the early stages of coalification in low-rank coal (such as lignite and subbituminous coal beds) from the decomposition of organic matter by microorganisms. Thermogenic gas is generated during the latter stages of coalification, as increased heat and pressure cause the release of gases rich in methane and carbon dioxide. Initial onset of thermogenic gas (methane) generation generally corresponds to a coal rank of high-volatile bituminous (Rice and others, 1993). A late stage of biogenic gas can also be generated in coal of any rank in areas where ground-water flow again creates an environment favorable for microbial decomposition of organic matter in the coal (for example, see Rice and others, 1993; Johnson and Flores, 1998). Additional information on the generation, characteristics, and resource assessment of coal-bed gas is given by Rightmire (1984), Rice and others (1993), and Mavor and Nelson (1997).

In the United States, the recovery of gas from coal dates back to the 1900s (Rightmire, 1984), when methane recovered from a water well that penetrated coal beds in the Powder River Basin (Wyoming) was used as a source of heating fuel (for example, see Mavor and Nelson, 1997). By the late 1970s, some production of coal-bed methane was established in the Warrior Basin (Alabama and Mississippi) and the San Juan Basin (Colorado and New Mexico). An increase in exploration and production of this resource took place in the 1980s, in large part because of a Federal tax credit given to producers of coal-bed methane (for example, see Rice and others, 1993). Today, continued interest in the development of methane from coal beds has sparked exploration and development projects in many areas of the United States and throughout the world.

Currently, there is no coal-bed methane production in the Denver Basin. However, the successful production of coal-bed methane from areas such as the Warrior and San Juan Basins, coupled with the great increase in coal-bed methane production in the Powder River Basin (Wyoming and Montana), has helped to stimulate interest in the potential for coal-bed methane development in the Denver Basin. Such interest is greatly enhanced by the small, relatively inexpensive drilling rigs and minimal wellhead equipment required for the successful completion of coal-bed gas wells (fig. 15), as well as the fact that in the Powder River Basin production is primarily from subbituminous coal beds that are comparable in rank and depth to coal beds in the Laramie Formation in the Denver Basin.

The Gas Research Institute (GRI) (1999) estimated that there might be as much as 2 Tcf of coal-bed methane (in place)

within the Laramie and Denver Formations in the Denver Basin. Of this total, GRI (1999) suggests that some 0.3 Tcf of coal-bed methane could be a recoverable resource. The main difficulty in assessing the coal-bed methane potential for the Laramie and Denver Formations is the limited published data related to the gas composition and gas content of the coal beds. Because the rank of these coal beds is low (lignite–subbituminous), and without thermal maturity and gas composition data to indicate otherwise, it is assumed that coal-bed gas in these formations is primarily biogenic and consists mainly of methane (for example, see Rice and others, 1993).

Tremain and Toomey (1983) compiled desorption data for selected coal regions in Colorado, including total coal-bed gas estimates for coal core samples recovered in five drill holes in the Denver Basin. In two of the drill holes (Biosphere #1 and CGS-10C; fig. 16), coal beds within the Denver Formation were analyzed, and in three drill holes (Marshall #2, CGS-4C, and CGS-5C; fig. 16), coal beds in the Laramie Formation were analyzed. The total gas contents (cubic feet of gas per ton of coal [ft^3/ton]) were determined using the U.S. Bureau of Mines direct method, which is described in detail by Diamond and Levine (1981). By this method, the total gas content for each coal sample represents the cumulative (summed) total of lost gas, desorbed gas, and residual gas. Lost gas is that gas lost during the time required to drill, retrieve, and seal the coal sample in an airtight canister. Desorbed gas is that gas emitted by the coal sample while it is sealed in the airtight canister, and residual gas is measurable gas that remains in the coal matrix after all other gas is emitted from the sample in the canister.

A summary of total gas content analyses for coal beds in the Denver and Laramie Formations in the Denver Basin, as reported in Tremain and Toomey (1983), is as follows:

Drill hole: Biosphere #1 (Sec. 4, T. 4 S., R. 64 W.)

Formation tested: Denver Formation

One coal bed analyzed: E bed (Watkins bed); core sample

Coal-bed thickness: 29 ft

Desorbed coal sample numbers: 121 and 122

Sample 121: Sample depth from 127 to 135 ft

Apparent rank: subbituminous C

Total gas content: 4 ft^3/ton

Sample 122: Sample depth from 140.2 to 144.6 ft

Apparent rank: lignite A

Total gas content: 11 ft^3/ton

Drill hole: CGS-10C (Sec. 8, T. 5 S., R. 65 W.)

Formation tested: Denver Formation

One coal bed analyzed: Unnamed; core sample

Coal-bed thickness: 19.4 ft

Desorbed coal sample numbers: 164 and 165

Sample 164: Sample depth from 434.3 to 434.9 ft

Apparent rank: subbituminous C

Total gas content: 0 ft^3/ton

Sample 165: Sample depth from 435 to 445 ft

Apparent rank: subbituminous C

Total gas content: 0 ft^3/ton



Figure 15. Photographs showing (A) truck-mounted drilling rig exploring for coal-bed methane, and (B) a completed coal-bed methane wellhead in the Powder River Basin, Wyoming. Photographs provided courtesy of M.S. Ellis, U.S. Geological Survey, Denver, Colorado.

Drill hole: CGS-4C (Sec. 34, T. 2 S., R. 60 W.)

Formation tested: Laramie Formation

One coal bed analyzed: Unnamed; core sample

Coal-bed thickness: 5 ft

Desorbed coal sample number: 161

Sample 161: Sample depth from 109 to 114 ft

Apparent rank: subbituminous C

Total gas content: 4 ft³/ton**Drill hole: CGS-5C (Sec. 4, T. 3 S., R. 61 W.)**

Formation tested: Laramie Formation

Two coal beds analyzed: Unnamed; core samples

Coal-bed thickness: 6.7 ft (bed 1) and 8 ft (bed 2)

Desorbed coal sample numbers: 162 (bed 1) and 163 (bed 2)

Sample 162: Sample depth from 306.3 to 308 ft

Apparent rank: subbituminous B

Total gas content: 24 ft³/ton

Sample 163: Sample depth from 362.5 to 371 ft

Apparent rank: subbituminous C

Total gas content: 0 ft³/ton**Drill hole: Marshall #2 (Sec. 21, T. 1 S., R. 70 W.)**

Formation tested: Laramie Formation

Two coal beds analyzed: One unnamed bed and the Gorham (No. 3) bed; core samples

Coal-bed thickness: 2.5 ft (unnamed bed) and 9.75 ft (Gorham bed)

Desorbed coal sample numbers: 196 (unnamed bed) and 197–198 (Gorham bed)

Sample 196: Sample depth from 37.5 to 40 ft

Apparent rank: not determined

Total gas content: 0 ft³/ton

Sample 197: Sample depth from 81.4 to 84.4 ft

Apparent rank: not determined

Total gas content: 1 ft³/ton

Sample 198: Sample depth from 88 to 91 ft

Apparent rank: not determined

Total gas content: 1 ft³/ton

Because the gas-content data listed above were derived from the desorption of coal samples at ambient temperature and pressure conditions in the Denver Basin, Tremain and Toomey (1983) suggested that these total gas values might be on the order of 20 percent higher than values at standard conditions (that is, 68°F and 14.7 psia (1 atmosphere)). In addition, the direct method might have a 25–30 percent uncertainty, based in large part on unknown factors related to lost gas determinations (as reported in Rightmire, 1984, after Kim, 1977). Results of desorption analyses listed above appear to indicate that gas contents of Laramie and Denver Formation coal beds are somewhat low, especially when compared to gas contents of coal beds in the Warrior and San Juan Basins, which can exceed 500 ft³/ton (for example, see Hewitt, 1984; Choate and others, 1984). However, reported gas contents for subbituminous coal in the Powder River Basin (Fort Union Formation), which can vary from 6 to more than

74 scf/ton, are commonly in the range of 20–40 scf/ton (for example, see Stricker and others, 2000; Boreck and Weaver, 1984). Meaningful comparison between Denver Basin and Powder River Basin coal-bed methane potential cannot be made without additional gas-content data from coal beds in the Denver Basin. The fact that all the sampled coal beds listed above were at shallow depths (88–445 ft) may have affected the analytical results. Previous studies indicate that coal beds at shallow depths (less than 500 ft) could have a significantly diminished potential for coal-bed methane retention (for example, see Rightmire, 1984). However, depth alone does not appear to exert a consistent control on coal-bed methane content, given that significant methane production at depths of 500 ft or less is ongoing in the Powder River Basin (Stricker and others, 2000; Johnson and Flores, 1998). An additional factor resulting in low coal-bed gas contents in one case might relate to the presence of abandoned underground coal mines. The Marshall #2 drill hole (fig. 16), in which gas contents in Laramie Formation coal beds were essentially nil, is located in a heavily undermined area near the Lewis No. 2 and associated underground mines in the southwestern part of the Boulder-Weld coal field. Because of the shallow depth at which these coal beds were sampled (less than 100 ft) and the proximity to shallow, mined-out areas within 100 ft of the surface (for example, see Myers and others, 1975; Roberts and others, 2001), it seems highly probable that any gas generated within the sampled coal beds in this drill hole could have easily leaked (migrated) into surrounding voids or mine cavities. Low gas contents reported for Denver Formation coal samples (drill holes Biosphere #1 and CGS-10C; fig. 16) might be a result of the slightly lower rank of the coal samples (subbituminous C-lignite A), the shallow depth of the samples, or a combination of these factors.

Greater Wattenberg Area: Coal-Bed Methane Pilot Study

As part of the FRIRP, a small-scale pilot study was undertaken in the greater Wattenberg area (GWA) (fig. 17) to gain some perspective on the coal-bed methane potential in the Laramie Formation in the northern part of the Denver Basin (Roberts and Fishman, 2000). The GWA incorporates about 2,900 mi² in parts of Jefferson, Denver, Boulder, Weld, Adams, Larimer, and Morgan Counties and extends from T. 2 S. to T. 7 N., and from R. 61 W. to R. 69 W. The area includes most of the Boulder-Weld coal field and additional areas (Eaton and Briggsdale coal areas, fig. 5) where Laramie Formation coal was mined in the past. Significant volumes of natural gas have been produced in this area, primarily from the Wattenberg gas field. In the GWA, commingled gas production from all Cretaceous units is allowed, and recently relaxed drill-spacing requirements (spacing less than 40 acres) might encourage recompletion efforts in existing wells to tap into additional pay zones. Potential coal-bed methane resources in the Laramie Formation overlie targets of current gas

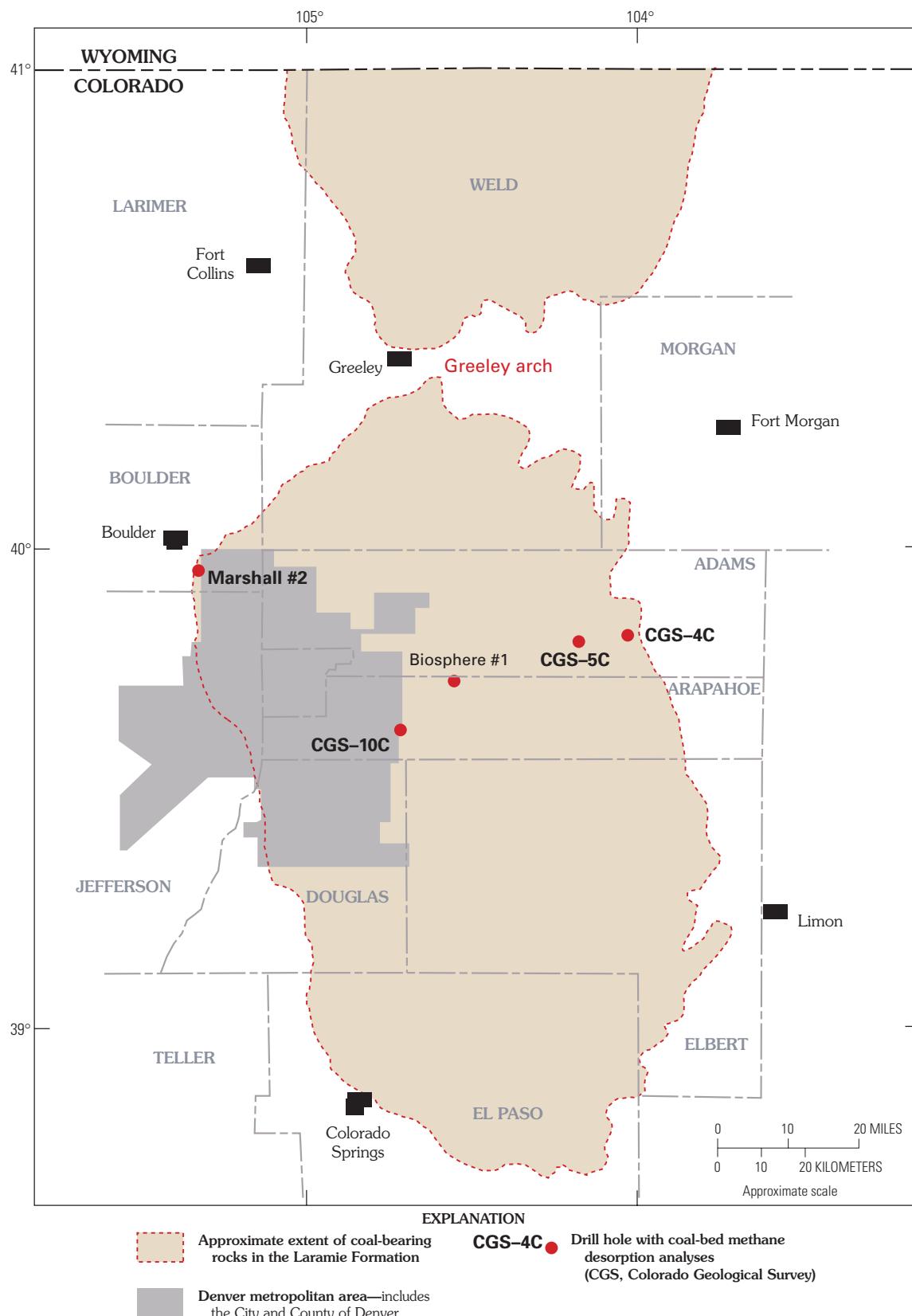


Figure 16. Drill holes in which coal beds were sampled and desorbed for coal-bed methane content in the Denver Basin, Colorado. Drill-hole locations based on Tremain and Toomey (1983). Extent of coal-bearing rocks in the Laramie Formation from Kirkham and Ladwig (1979).

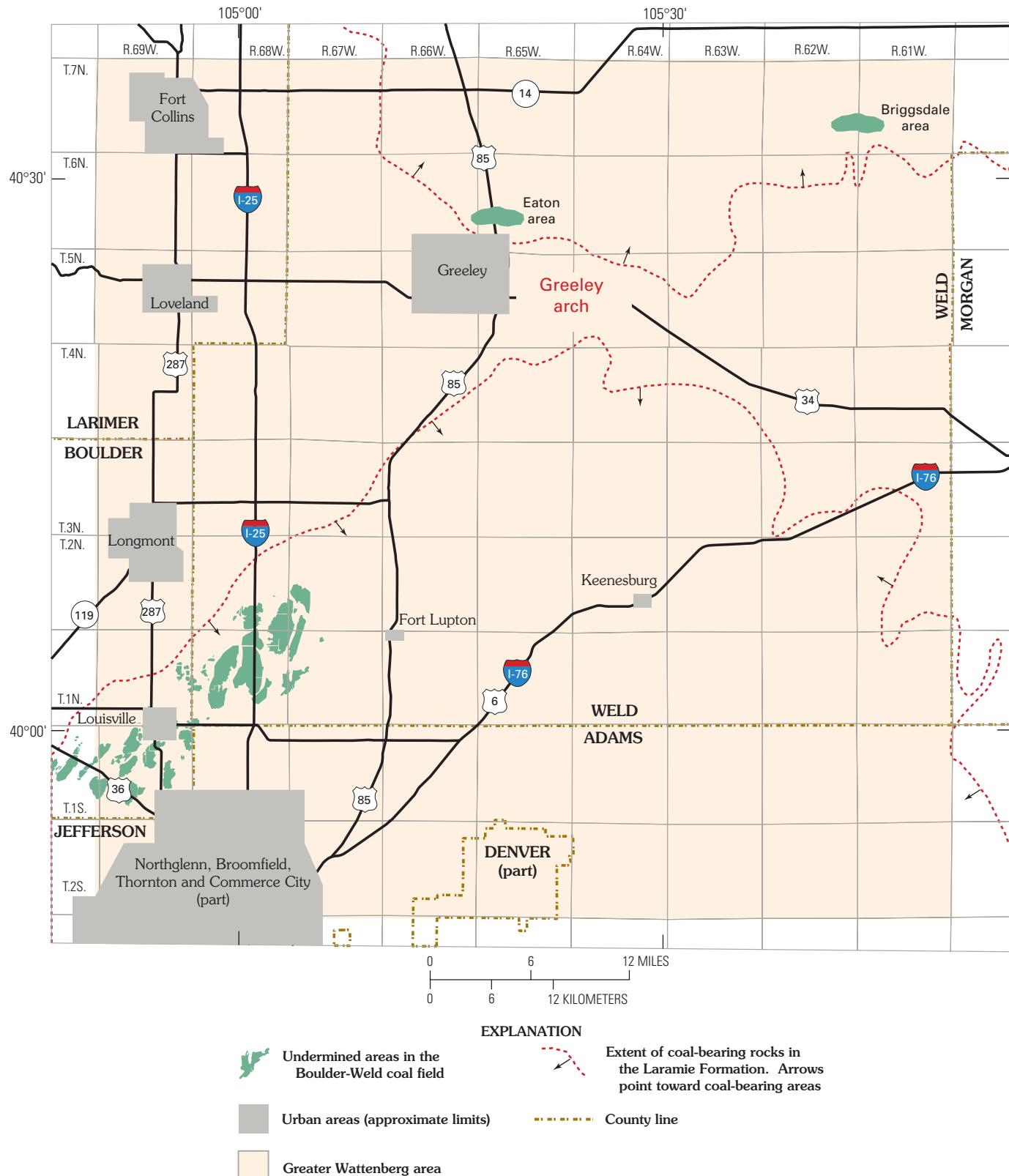


Figure 17. Extent of the greater Wattenberg area, Denver Basin, Colorado.

production in deeper, older Cretaceous strata and could be considered as a shallow, “behind-pipe” resource in existing gas wells. For this reason, and because a well-developed infrastructure (for example, roads, pipelines, and so forth) for gas production is already in place, the GWA was chosen for the pilot study.

Evidence for the presence of methane in Laramie Formation coal in the GWA includes (1) coal-bed methane desorption analyses from drill holes CGS-4C, CGS-5C, and Marshall #2 (Tremain and Toomey, 1983) described in the previous section, and (2) reports of mine fires, gas explosions, and gassy mines in the Boulder-Weld coal field (fig. 18) (Fender and Murray, 1978). At least eight mines in the coal field experienced mine fires or explosions during their history, and an additional eight coal mines reported the presence of gas. Perhaps some of the more compelling evidence for the gassy nature of Laramie Formation coal was recorded in the Eagle mine in the northeastern part of the Boulder-Weld coal field (fig. 18), where more than 7,000 ft³ of gas per day (28 ft³ of gas per ton of mined coal) was emitted during the first quarter of 1976 (Fender and Murray, 1978). It is interesting to note that this volume of gas emitted from the Eagle mine is comparable to the desorbed coal-bed methane content (24 ft³/ton) reported for the upper coal bed in CGS-5C (Tremain and Toomey, 1983). However, whether or not these values are indicative of the overall methane content one may anticipate for Laramie Formation coal in the basin is unknown, particularly given the absence of significant gas noted in other desorbed coal samples.

Another key factor for determining the coal-bed methane potential in the Laramie Formation relates to coal thickness and distribution. In the central and southern parts of the GWA, subsurface data from 74 coal exploratory drill holes (Kirkham, 1978b) and interpretations of geophysical logs in 16 oil and gas test wells indicate that the total coal thickness within the lower part of the Laramie ranges from a few feet or less (traces of coal) to as much as 35 ft in T. 1 S., R. 69 W. (fig. 19). In, general, thicker total coal accumulations are present in the western part of the GWA, in and near the Boulder-Weld coal field. Individual coal-bed thickness can vary from less than 1 ft to as much as 9 ft locally, and the number of coal beds varies from 2 to 12.

Plate 1 shows the thickness and distribution of Laramie coal beds within the GWA in east-west ($A-A'$), and north-south ($B-B'$) cross sections. Partial geophysical log records (natural-gamma and resistivity traces) within the coal-bearing part of the Laramie Formation and closely associated strata are shown for each well. The datum in both cross sections is the top of the Fox Hills Sandstone, which is in sharp contact with overlying, coal-bearing strata of the Laramie Formation. In many areas, a thin (less than 2-ft-thick) coal bed overlies the Fox Hills Sandstone. The contact separating the Fox Hills Sandstone and the underlying Pierre Shale is gradational and generally represents the transition from marine shale to marginal marine and shoreface sandstone, siltstone, and sandy shale. On plate 1, the base of the Fox Hills Sandstone, as

interpreted from geophysical logs, is placed at the base of the lowest sandstone unit overlying a thick shale succession in the upper part of the Pierre Shale. In drill holes 1–16, interpretations of coal-bed presence and thickness are based primarily on natural-gamma (gamma ray), bulk density, and (or) resistivity logs from oil and gas test wells. Coal-bed interpretations in drill hole CGS-5C are from Brand (1980), and corresponding coal-bed gas content data are from Tremain and Toomey (1983). The primary coal-bearing interval in the Laramie Formation is designated as the lower Laramie coal zone. The upper limit of this coal zone generally corresponds to the top of the uppermost coal bed identified in the Laramie Formation, and the lower limit is the top of the Fox Hills Sandstone. However, in drill holes 5, 6, and 8, queried coal beds that are present stratigraphically above the lower Laramie coal zone were not included as part of the zone because of less definitive geophysical log data and the apparent disparity in coal-zone thickness in these drill holes compared to adjacent drill holes. The maximum thickness of the coal zone in these cross sections is about 290 ft (drill hole 1, $A-A'$; pl. 1); the minimum thickness is about 80 ft in drill hole CGS-5C, near the eastern limit of Laramie Formation coal-bearing rocks. Maximum depth to the top of the coal zone exceeds 1,300 ft near the south-central boundary of the GWA. However, throughout most of the study area, the depth to the top of the coal zone is less than 1,000 ft. Thicker coal accumulations in and near the Boulder-Weld coal field (fig. 19) are at depths of less than 500 ft. Correspondingly, the lower Laramie coal zone is thickest in the coal field area. Individual coal-bed thickness along these lines of cross section ranges from 2 to 8 ft.

In addition to the variability in total coal thickness observed in the GWA, there is also a marked variation in heat-of-combustion (BTU/lb) values for Laramie coal. Average (arithmetic mean), as-received heat-of-combustion (BTU/lb) values for Laramie coal beds, based on analyses of coal-mine samples (for example, see Kirkham, 1978b) and coal core samples (Brand, 1980) range from 7,200 to more than 9,900 BTU/lb (fig. 20). Average, as-received heat-of-combustion values reported for coal beds in the Boulder-Weld coal field are commonly 1,000 BTU/lb, or more, higher than values reported in most other areas of the Denver Basin (for comparison, see Kirkham and Ladwig, 1979, 1980). The Boulder-Weld coal field, in part, overlies a thermal anomaly that has been identified in the Wattenberg gas field (for example, see Myer and McGee, 1985; Higley and Gautier, 1988), just northeast of the coal field. The anomaly is recognized by an unusually high temperature gradient and high vitrinite reflectance (R_o) values (fig. 20) determined for the Lower Cretaceous “J” Sandstone and associated hydrocarbon source rocks including the Graneros, Mowry, and Skull Creek Shale units. The apparently anomalous heat flow in this area has been attributed to igneous intrusions emplaced along projected fault trends of the Colorado mineral belt in basement rocks in the northern Denver Basin (for example, see Weimer, 1996; Myer and McGee, 1985). Wrench faults and subsidiary faults at depth might have provided conduits for heat flow into

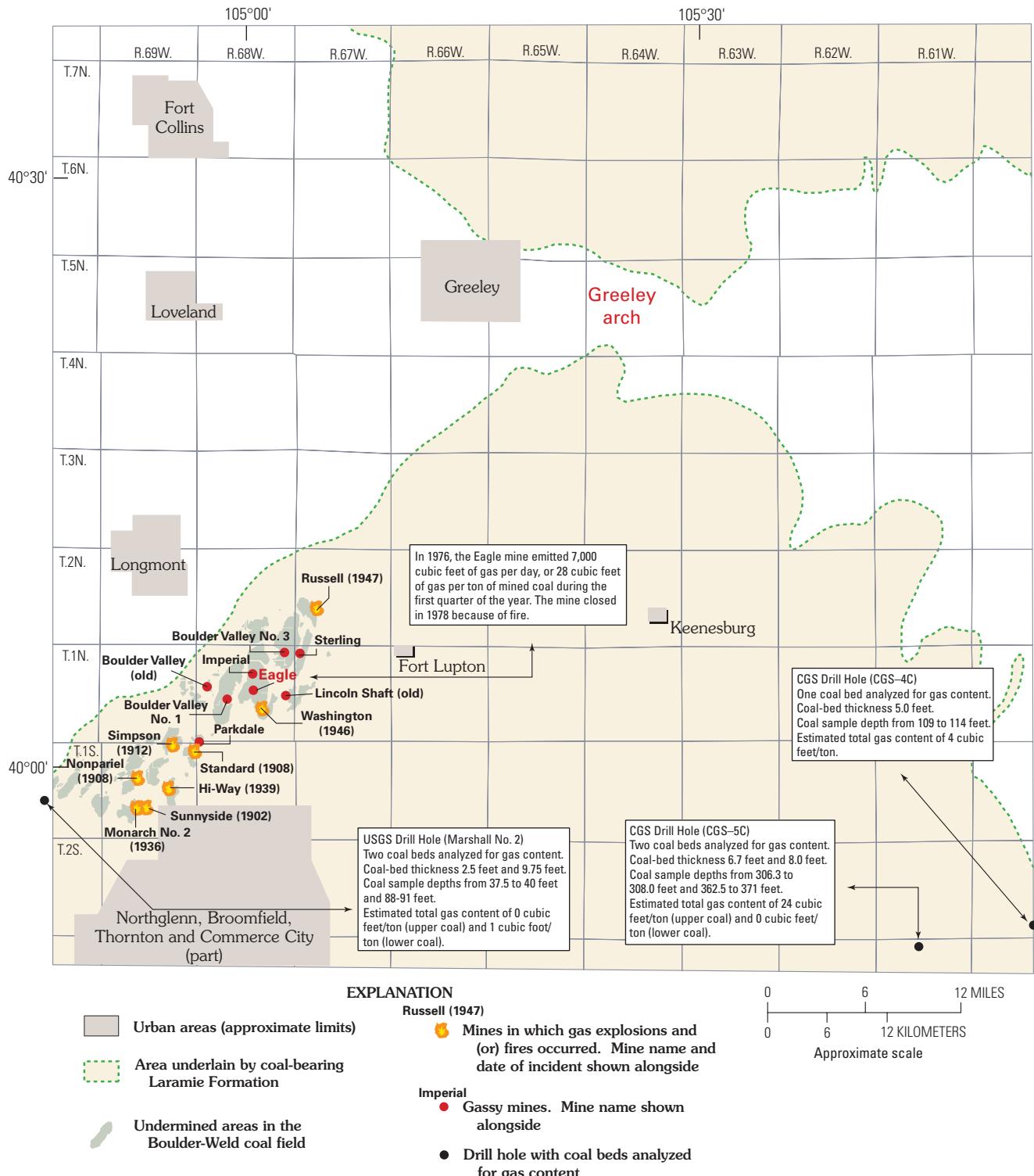


Figure 18. Locations of gassy coal mines, or coal mines that experienced fires or gas explosions, and the locations of drill holes in which Laramie Formation coal beds were analyzed for total gas content in the northern part of the Denver Basin, Colorado. Mine data from Fender and Murray (1978). Data on coal-bed gas content from Tremain and Toomey (1983).

overlying sedimentary units. Higher heat-of-combustion (BTU/lb) values in coal-beds in the Boulder-Weld coal field might also relate to heat flow from intrusions at depth, although this concept is speculative. Regardless of the causal

mechanism, higher heat-of-combustion values in the Boulder-Weld coal field likely relate to higher coal ranks (albeit slight) and possibly a corresponding higher potential for coal-bed gas generation relative to the rest of the GWA.

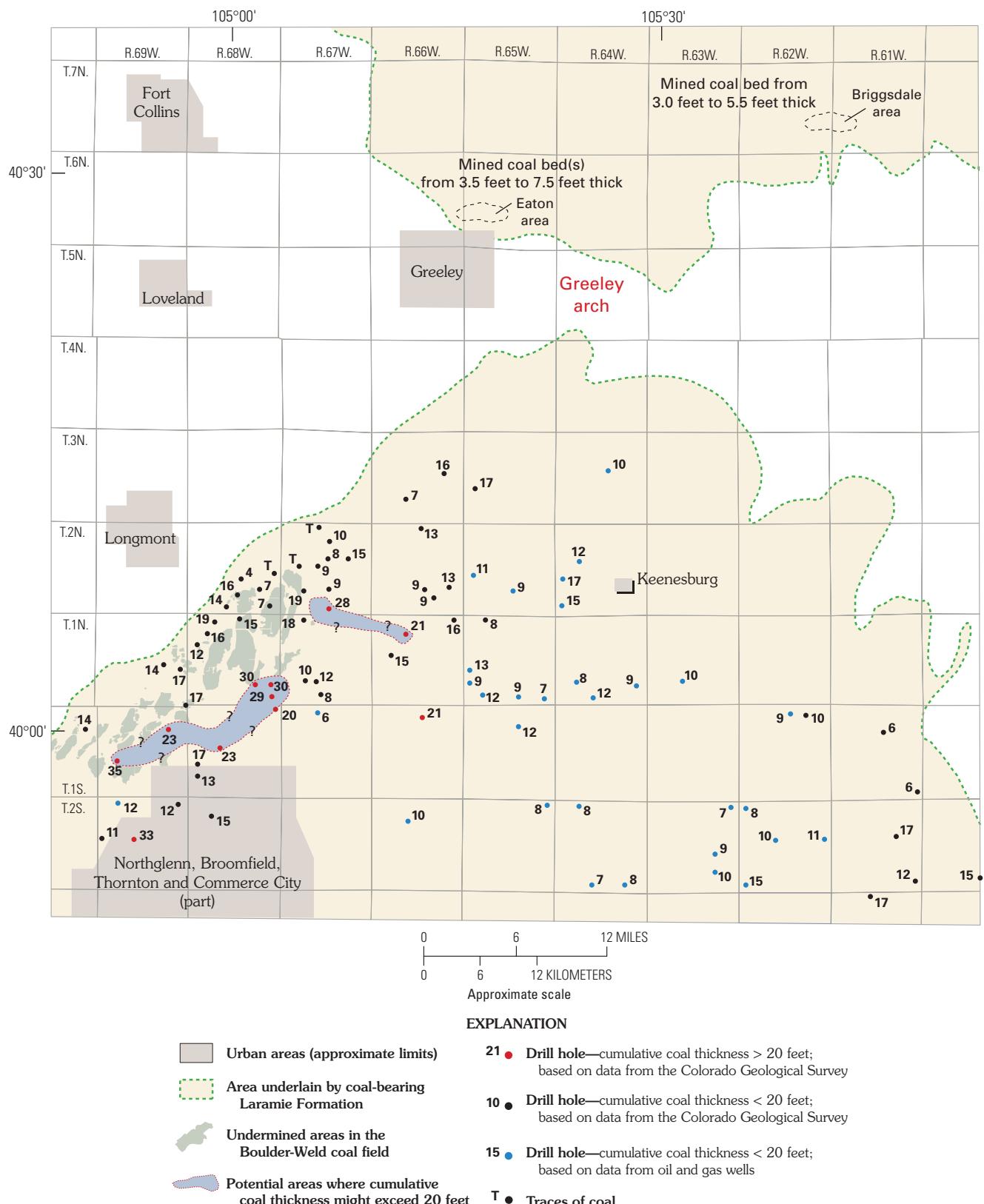


Figure 19. Total coal thickness in drill holes penetrating the lower part of the Laramie Formation in the northern part of the Denver Basin, Colorado. Total coal thickness data based on interpretations of geophysical logs from oil and gas test wells and from drill-hole data reported by Kirkham (1978b), Brand (1980), and Brand and Caine (1980).

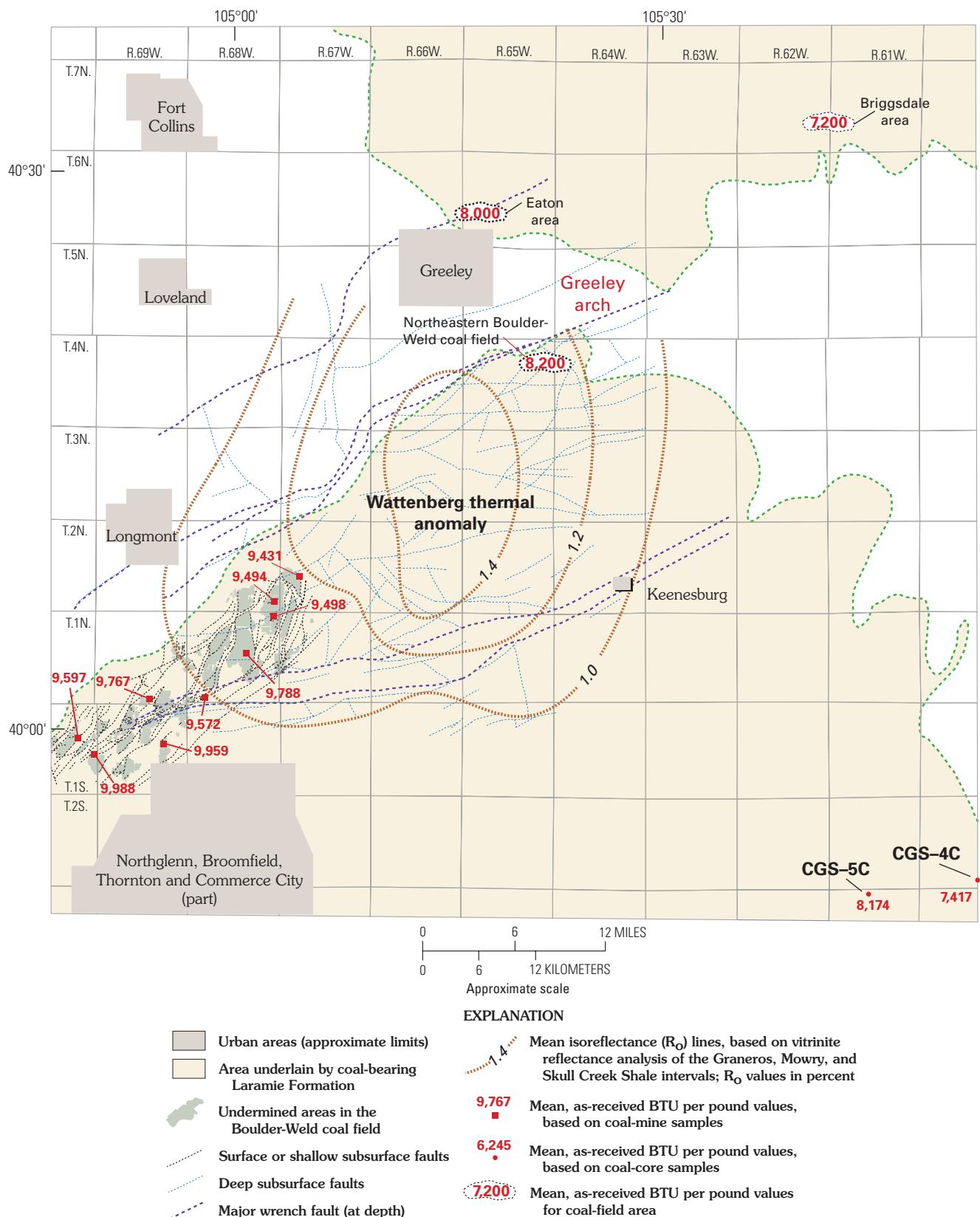


Figure 20. Heat-of-combustion values for coal beds in the lower part of the Laramie Formation in the northern part of the Denver Basin, Colorado. The position of the Wattenberg thermal anomaly is based on vitrinite reflectance data from the Graneros Shale, Mowry Shale, and the Skull Creek Shale intervals. Heat-of-combustion values are from Kirkham (1978a) and Tremain and Toomey (1983). Vitrinite reflectance data (isoreflectance lines) are from Higley and Gautier (1988) and Higley and others (1992).

Although the data listed herein are inconclusive with regard to the coal-bed methane potential for the Laramie Formation in the GWA, positive indicators for a potential coal-bed methane resource include (1) the presence of coal-bed gas, as evidenced by historical records of gassy mines and gas explosions (or fires) in coal mines in the Boulder-Weld coal field, (2) estimated total gas contents of as much as 24 ft³/ton at some locations, (3) a relatively continuous distribution of coal beds in the Laramie Formation throughout the area, and (4) cumulative (total) coal-bed thickness exceeding 30 ft and individual coal-bed thickness of as much as 12 ft locally. Conversely, certain geologic factors characteristic of the GWA could limit the developmental potential of this resource. For example, in places where total coal accumulations exceed 20 ft and where individual coal beds can be 8 ft thick or more, the lower Laramie coal zone is generally shallow (depth of less than 500 ft) and coal beds are in close proximity to faulted and undermined areas in the Boulder-Weld coal field. The shallow depth and proximity to faults and abandoned underground mines could limit coal-bed gas retention because of leakage through mined-out cavities (voids) or faults, or the up-dip migration of gas to nearby outcrops. In addition, in the south-central part of the GWA where greater coal depths (more than 500 ft) might enhance coal-bed methane retention, reported total coal accumulations are typically less than 20 ft and commonly less than 10 ft. The limited volume of coal in these areas could also reduce the coal-bed methane resource potential.

Coal-Bed Methane Summary

Conceptually, the mere presence of coal in the Denver Basin signals a potential for coal-bed methane resources. However, certain factors could limit or possibly negate successful coal-bed methane development. Comparison to the successful development of shallow, coal-bed methane resources from low-rank coal in the Powder River Basin indicates that similar production in the Denver Basin might be feasible. It is important to consider, however, the extreme differences in coal thickness and coal resource volumes between these two basins. In the Powder River Basin, individual coal-bed thickness can exceed 200 ft (for example, see Mapel, 1959; Roberts, 1986), and current coal-bed methane production commonly targets coal beds as thick as 100 ft or greater (for example, see Stricker and others, 2000). Most of that production is from coal beds in the Wyodak-Anderson coal zone, which is as much as 550 ft thick and can include as many as 11 coal beds that average as much as 25 ft in thickness (Stricker and others, 2000; Flores and Bader, 1999). Total coal resource estimates in the Wyodak-Anderson coal zone in the Wyoming part of the Powder River Basin are about 510 billion short tons (Ellis and others, 1999).

Individual coal beds in the Laramie can be as thick as 20 ft; however, they are more commonly less than 10 ft thick

throughout most of the Denver Basin. Coal resource estimates for coal beds greater than 2.5 ft thick and at depths less than 3,000 ft are about 20–25 billion short tons (Kirkham and Ladwig, 1979). Denver Formation lignite beds are as much as 55 ft thick locally but usually contain non-coal partings that range in thickness from several inches to more than several feet. Estimated lignite resources, in beds at least 4 ft thick and at depths of less than 1,000 ft, are about 10–15 billion short tons; resources at depths of more than 1,000 ft are probably less than 1 billion short tons. It is apparent that coal volumes in the Wyodak-Anderson coal zone in the Powder River Basin are more than an order of magnitude greater than coal volumes in the Laramie and Denver Formations combined. The great volume of coal associated with thick coal beds in the Powder River Basin, even though the coal beds are of low rank, has undoubtedly enhanced coal-bed methane production (in part) because of the potential for large volumes of coal-bed gas per unit area of land (for example, see Choate and others, 1984). Thus, even if gas contents of coal in the Denver Basin prove to be comparable to gas contents in coal beds the Powder River Basin, the much smaller volume of coal resources could limit the overall coal-bed methane potential in this area.

Another factor that should be considered is the close association of coal beds in the Laramie Formation with the Laramie-Fox Hills aquifer, which is pervasive throughout the Denver Basin and is one of the primary sources of freshwater for residential, agricultural, and commercial use. The aquifer is present in basal sandstone units of the Laramie Formation, sandstone and siltstone units in the Fox Hills Sandstone, and more rarely, siltstone and sandstone units in the uppermost part of the Pierre Shale (Robson and others, 1981). Thin coal beds in the lower part of the Laramie are commonly interbedded with the aquifer in much of the Denver Basin; in areas such as the Boulder-Weld and Colorado Springs coal fields and the Foothills coal district (fig. 5), the aquifer includes thicker coal beds historically targeted for mining (for example, see Kirkham and Ladwig, 1979). To successfully develop a coal-bed methane resource, a process of dewatering might be required in order to remove in-situ water from the coal bed(s) and allow for the release of methane from the coal matrix (desorption) to a well bore for recovery (for example, see Rice and others, 1993). Water yields related to coal-bed methane production are variable; for example, water production associated with coal-bed methane development in the Powder River Basin has ranged historically from 0 to as much as 1,000 barrels of water per day in some wells (Tyler and others, 1995). Production of substantial quantities of water can result in drawdown of existing subsurface water tables with time and can require special constraints with regard to disposal of the produced waters. Given that coal beds with potential methane resources in the lower part of the Laramie Formation are within or immediately overlying the Laramie-Fox Hills aquifer throughout the Denver Basin, careful consideration to development of any coal-bed methane resource is necessary to ensure that associated water production would not impinge on the quality of the aquifer.

Additional studies detailing the subsurface thickness and distribution of coal beds, combined with more definitive analyses of coal-bed gas content and composition, are needed in order to better understand the coal-bed methane potential in the Laramie and Denver Formations. Although the Denver contains the thickest coal beds in the Denver Basin, the relatively low rank and abundance of non-coal partings, coupled with relatively low gas contents (0–11 ft³/ton) recorded to date (Tremain and Toomey, 1983), might reduce the potential for significant coal-bed methane resources within this formation. Coal beds in the Laramie Formation might be more prospective for coal-bed gas, to some degree, based on their higher rank, relatively higher gas contents, and widespread distribution throughout the Denver Basin. Although individual coal beds in the Laramie Formation are generally thin (less than 15 ft thick), total (cumulative) coal accumulations in the lower 200–250 ft of the formation exceed 20–30 ft in a number of areas throughout the basin (for example, see Brand and Eakins, 1980; Eakins, 1986; Eakins and Ellis, 1987). In areas where these thicker accumulations are present, coal-bed methane recovery from multiple coal beds within a relatively narrow stratigraphic interval could enhance the potential for development, should coal-bed gas contents be of sufficient volume. Higher heat-of-combustion values measured in coal beds in the Boulder-Weld coal field could reflect a slightly elevated rank and a corresponding increase in the potential for coal-bed methane resources in that area. In addition, recovery of “behind-pipe” coal-bed methane in existing gas wells penetrating the Laramie Formation might be considered in areas such as the Wattenberg gas field in the northern part of the Denver Basin. Recompletion in these existing wells, if feasible within economic and engineering constraints, might decrease the need for new drilling. Additional gas production would be facilitated by the gas recovery and transport infrastructure that is already established in these areas.

Effects from Historical Coal Mining

Although there has been no active coal mining in the Denver Basin for more than 20 years, potential effects from previous mining still exist in certain areas of the basin. Because historical production of coal in the Denver Formation was essentially limited to shallow operations in fairly small areas, little or no detrimental effect to date has resulted from these mining operations. However, underground coal mining in the Laramie Formation was quite extensive, and potential effects related to these abandoned underground mines still linger in fields where Laramie coal was produced. Most of the major surface remnants of these underground mines, such as mine dumps, surface excavations, hoisting frames (head-frames), and the buildings necessary for mining operations, have been removed, often to accommodate or facilitate urban growth. Removal of such structures and the subsequent development or expansion of residential and urban facilities

into coal-field areas have significantly masked the imprint of previous mining activities. However, even though much of the surface expression of mine development has been mitigated, subsurface features of underground mining, such as shafts, slope entries, and open mine rooms are still present. Because of this, potential effects such as fires in the abandoned mines and ground-surface collapse (subsidence) over undermined areas still exist in heavily mined areas along the Front Range corridor.

Coal-Mine Fires

Coal-mine fires can occur during the active process of mining and well after mining activity has ceased. These fires can result from the accidental or intentional ignition by man and by the process of spontaneous combustion (for example, see Dunrud and Osterwald, 1980; Herring and others, 1986; Rushworth and others, 1989) that results from rapid, highly exothermic chemical reactions that can raise the temperature of the coal to the point of ignition (Rushworth and others, 1989). In coal mines that have been abandoned for a significant period of time, spontaneous combustion can be a more likely cause of fires. Factors that control spontaneous combustion in coal include the rate of airflow, moisture content of the coal, and coal rank (Kim, 1977). Coal of subbituminous rank, such as coal beds in the Laramie Formation, is prone to self-ignition in abandoned underground mines where air and moisture entering the mine workings can induce these exothermic reactions, causing unmined coal to ignite spontaneously. The resulting coal mine fire then propagates through the unmined coal toward a source of oxygen, such as an open mine room or entry. Fire propagation can also be facilitated by the development of fire-induced fractures or fissures that form in the overburden (roof rock) as the fire burns. These features provide additional conduits for oxygen flow, which continues to fuel the fire (Rushworth and others, 1989). Coal fires in abandoned mines can be quite striking and at times are visible at the ground surface (fig. 21). Fires in shallow mines emit noxious fumes, steam, and heat to the ground surface through active vents, which typically form just in front of the advancing fire (J.L. Herring, U.S. Geological Survey, oral commun., 1984, as reported in Rushworth and others, 1989). Additionally, coal fires can generate sufficient heat to bake and fuse overlying and adjacent rocks, resulting in the formation of clinker deposits within the abandoned mines and on the ground surface.

In the Denver Basin, fires in abandoned coal mines near the town of Marshall (fig. 22) in the Boulder-Weld coal field were documented as recently as 1988 (Rushworth and others, 1989). Such fires have been observed since the early 1900s, and local residents have reported anomalously high ground-surface temperatures and the occurrence of methane explosions with fire plumes soaring high into the air (Herring and others, 1986). Historical coal-mine fires in the area are also evidenced by deposits of clinker, which are present within

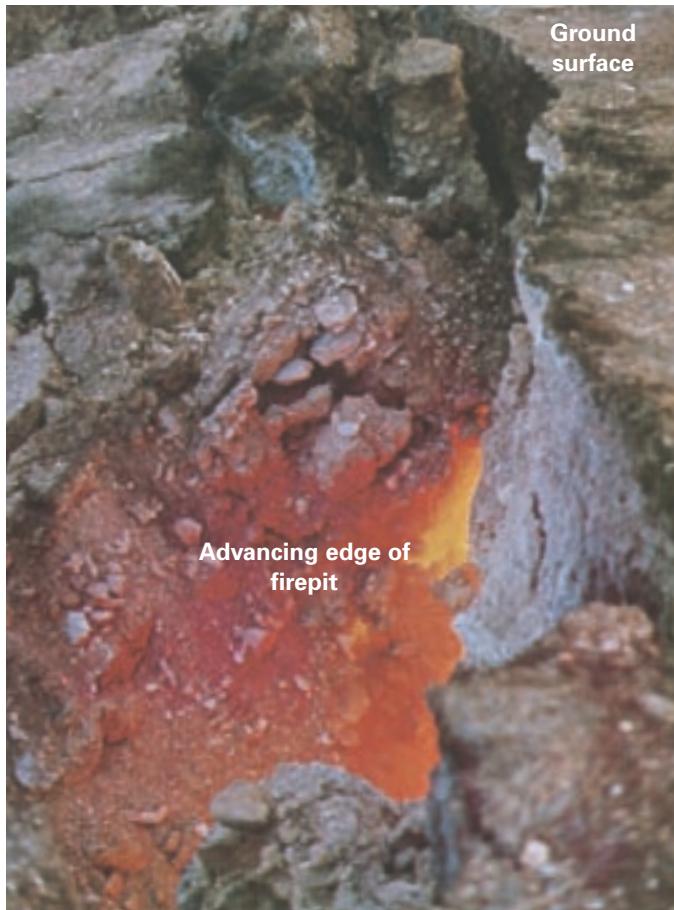


Figure 21. Photograph of an active fire in an abandoned underground coal mine near Sheridan, Wyoming. Photograph from Dunrud and Osterwald (1980).

the Marshall Nos. 1 and 3 and the Lewis Nos. 1 and 2 mines (Herring and others, 1986). Underground mines near Marshall are commonly at depths of less than 100 ft (for example, see Myers and others, 1975; Roberts and others, 2001), and the shallow depth to old workings might have, in part, facilitated ignition of the fires. In the early 1980s, steam plumes generated from an underground fire associated with the abandoned Marshall No. 3 coal mine (fig. 22, site A) were clearly visible during winter months along the east side of Highway 93. In 1982, the USGS and the Office of Surface Mining (OSM) undertook a shallow drilling project to better define the limits of the active fire in a small study area surrounding the fire site (S.B. Roberts, USGS, unpub. data, 1982). During the course of this study, anomalously high temperatures (that is, higher than ambient temperatures of 50° to 60°F) were recorded in shallow drill holes (less than 100 ft) near the site, indicating a possible underground, extraneous heat source such as burning coal in the abandoned mine. Qualitative assessment of subsurface temperatures within the study area indicated that the active burn was restricted to a small area along the western edge of the Marshall No. 3 mine (fig. 22). The fire was subsequently smothered by the addition of a 2-ft-thick cover of fill

dirt on the ground surface above the mine (Herring and others, 1986). In 1988, the Colorado Geological Survey (CGS) reported that there was an active fire in the abandoned Lewis No. 1 and No. 2 coal mines, also near Marshall (fig. 22, site B) (Rushworth and others, 1989). A fire at this location had been previously reported by Myers and others (1975) and was also observed by personnel of the CGS and the Colorado Inactive Mine Reclamation Program (CIMRP) in 1984. A return visit to the site by CGS workers in 1988 revealed little change from 1984, although vents emitting heat and smoke on the hillside overlying part of the mine were still evident. Minor damage resulted from the fire, and some 800 ft of an irrigation ditch breached by the fire had to be rebuilt and reinforced during a reclamation project in 1986 (Rushworth and others, 1989).

Coal-Mine Subsidence

An additional and perhaps more widespread effect of historical coal mining in the Denver Basin relates to ground surface subsidence above abandoned underground coal mines. Coal-mine subsidence is well documented along the Front Range, particularly in the Colorado Springs and Boulder-Weld coal fields (for example, see Myers and others, 1975; Dames and Moore, 1985; Herring and others, 1986; Matheson and Bliss, 1986). Aerial photographs of the Marshall area (figs. 23 and 24) in the southwestern part of the Boulder-Weld coal field attest to the visible scarring that can result from ground surface subsidence in undermined areas. Coal-mine subsidence is a dynamic process that can take place concurrently with mining or can occur many years after a mine has been abandoned. Once a volume of coal (or rock) is extracted within an underground mine, the void (cavity) that remains after extraction can serve as a focal point for collapse of the mine roof and subsequent sagging or collapse of the overburden above the mined-out cavity. Progressive upward collapse/sagging of the overburden with time can cause subsidence features (depressions) to develop on the ground surface. Because of the rapid expansion of urban and residential development over undermined areas in the Denver Basin, an obvious ramification of the subsidence process is the potential for damage to new or existing structures (roads, houses, businesses, and so forth).

Terms such as depressions, local depressions, sags, troughs, localized troughs, holes, sinkholes, potholes, and subsidence pits have been used by previous authors to describe the various ground-surface features resulting from subsidence over abandoned coal mines (for example, see Myers and others, 1975; Dunrud and Osterwald, 1980; Turney, 1985; Dames and Moore, 1985; Matheson and Bliss, 1986). Additional surface features include tension cracks that can form at the margins of subsidence depressions and compression bulges that form within the depressions themselves (Dunrud and Osterwald, 1980). In general, there is a dimensional hierarchy of surface collapse features, ranging from small subsidence pits and sinkholes to substantially larger troughs and depressions.

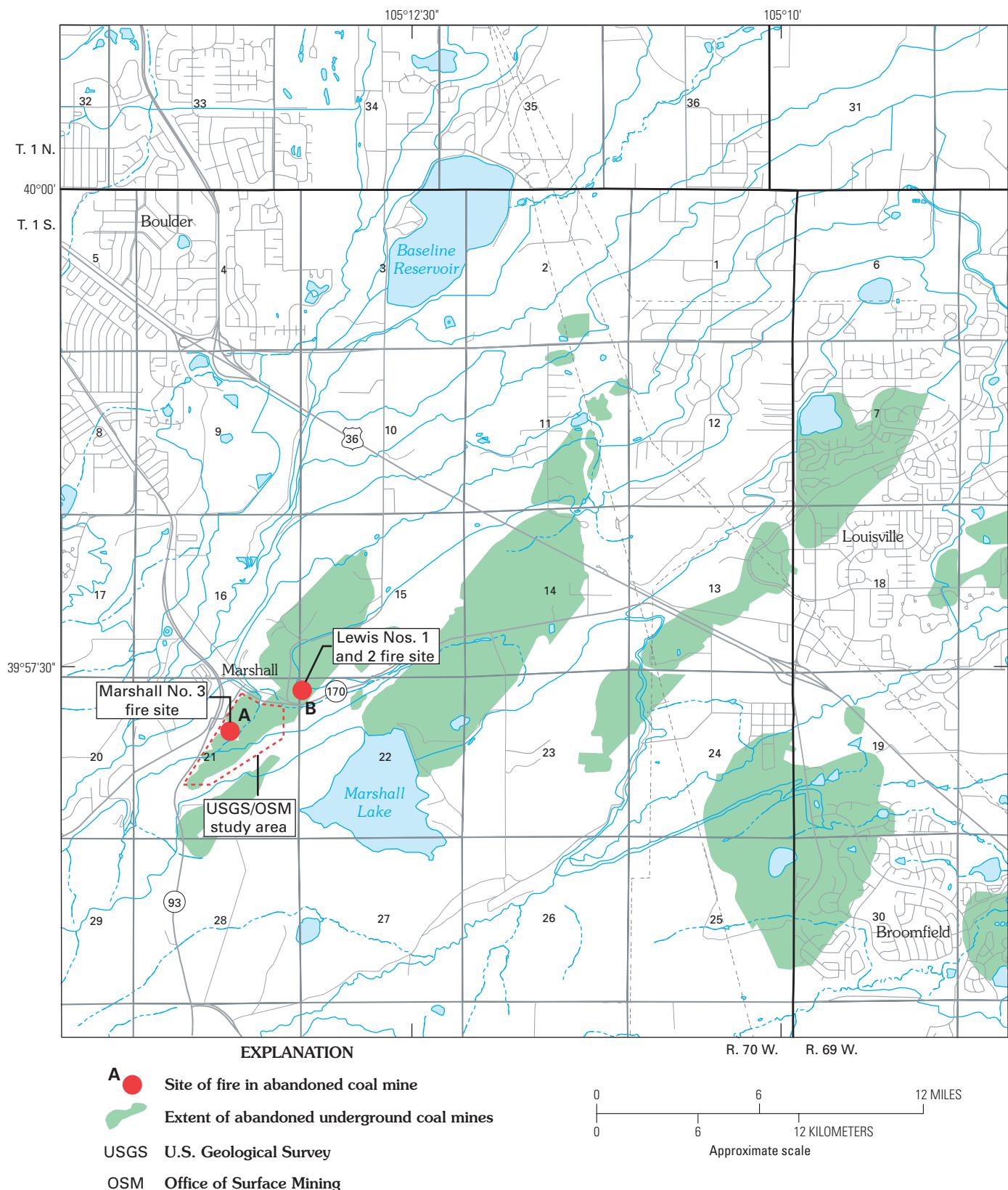


Figure 22. Extent of abandoned underground coal mines, the location of a 1982–83 cooperative U.S. Geological Survey (USGS) and Office of Surface Mining (OSM) coal-mine fire study site, and the location of historical underground coal-mine fires near the town of Marshall, Colorado. Location of the Lewis Nos. 1 and 2 fire site from Rushworth and others (1989). Extent of abandoned mines based on Myers and others (1975) and Roberts and others (2001).



Figure 23. Oblique aerial photograph (looking northwest) showing surface subsidence features caused by the collapse of underground coal mines near the town of Marshall, Colorado, in 1973. Photograph courtesy of R.B. Colton (scientist emeritus), U.S. Geological Survey, Denver, Colorado.

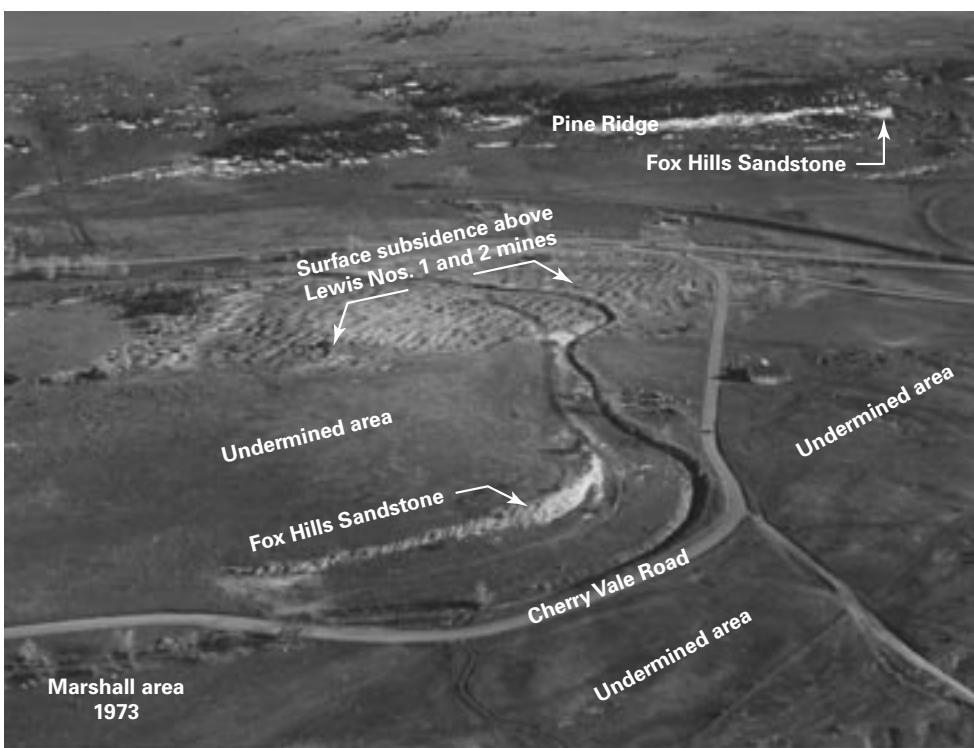


Figure 24. Oblique aerial photograph (looking south) showing surface subsidence features caused by the collapse of underground coal mines along the Cherry Vale Road, near the town of Marshall, Colorado, in 1973. Photograph courtesy of R.B. Colton (scientist emeritus), U.S. Geological Survey, Denver, Colorado.

For this report, the term subsidence pit is used in reference to the smaller features (for example, sinkholes and potholes), and the term trough is used to describe larger collapse features. It is important to bear in mind, however, that the basic “cause and effect” processes that form subsidence pits and troughs are similar in many respects, and the differences relate more to the variations in their surface expression, size, and effect.

Subsidence pits can be as much as several tens of feet in breadth, generally have circular to elliptical shapes, and can

exceed 10 ft in depth in certain areas of the Denver Basin (for example, see Myers and others, 1975; Matheson and Bliss, 1986). These pits can develop rapidly, usually within a period of hours to a few days (Turney, 1985). Where mined coal beds are essentially flat lying, subsidence pits form in response to a process termed “chimney subsidence” (Matheson and Bliss, 1986). Chimney subsidence results from the collapse of roof rock and overlying overburden into an underground void, such as an abandoned room in a coal mine. Through time,

continued collapse (caving) of the overburden into the void results in the migration of the void upward, toward the ground surface (fig. 25). In steeply dipping coal beds, a process termed “stoping” results in a similar, upward void migration in an updip direction, along the coal bed toward the ground surface (Turney, 1985). Subsidence pits develop as intervening strata between the mine cavity and the ground surface collapse into or sag downward toward the void (fig. 26). In general, the breadth of a subsidence pit is more or less coincident with the breadth of the underlying mine cavity (fig. 27). The depth of a subsidence pit, however, can be influenced by several factors, including (but not limited to) the thickness of the mined coal, the nature of the ground-surface material above the mine, and the bulking characteristics of the overburden between the mined horizon and the ground surface (Dames and Moore, 1985; Turney, 1985). Logically, the height of an underground void generally corresponds to the thickness of the mined coal bed; theoretically, the maximum depth of a subsidence pit should correspond closely to this mined-coal thickness. However, in cases where the ground surface consists of loosely consolidated sediment or soil, the pit depth can exceed the mined-coal thickness because loose surface material can be washed into the underlying mine and subsequently be dispersed by ground-water movement through the abandoned mine (fig. 27) (Turney, 1985).

The bulking characteristics of the mine roof and overburden also serve to control the depth of a subsidence pit above a collapsed room. In general, the term “bulking” relates to the volume and density of the loosely packed rubble column that accumulates in a mine void as a result of roof/overburden failure. When consolidated roof/overburden rock collapses and accumulates as rubble in the underlying mine void, the volume of space occupied by the collapsed rubble is always greater than the volume occupied by that same rock prior to collapse (for example, see Herring and others, 1986). During chimney subsidence, multiple phases of upward void migration and caving result in a series of vertically stacked “bulking zones” of rubble, which form as the collapse of roof/overburden rock propagates upward and caved material drops into the remaining void space (for comparison, see Dames and Moore, 1985). In this process, the first (lowest) phase of collapse has the greatest magnitude of vertical movement because caved materials have the full thickness and extent of the mined horizon in which to fall. This magnitude of vertical movement allows for the collapsed material to “bulk” fully within the original mined horizon, potentially filling a significant volume of the void space. Correspondingly, this first bulking zone also achieves a minimum density relative to the density of the consolidated material prior to collapse (Dames and Moore, 1985). Through time, as the void continues to migrate upward because of caving, successive bulking zones should exhibit decreased bulking and density changes as the magnitude of vertical displacement in the void decreases. Ultimately, this process can terminate when the accumulated (bulked) rubble column has essentially filled the void and has the strength to support the overlying rock (for example, see Dames and

Moore, 1985). If an underground void has migrated to a level conducive to ground-surface sagging or collapse, the magnitude of the surface subsidence should correspond closely to the height (thickness) of the remaining void. If most of the void has been filled by rubble, the depth of the resulting surface subsidence feature might be significantly less than the thickness of the original, mined-coal horizon. In deep mines, it is feasible that a cycle of chimney subsidence, from the initial roof collapse to the point of stability, could take place with no surface subsidence effects at all (for comparison, see Hynes, 1987). However, although depth to the abandoned mine is certainly a factor influencing the magnitude of surface subsidence, and the majority of subsidence pits related to chimney subsidence are over mines within 100 ft of the ground surface, some pits have formed above underground mines as deep as 350 ft (Turney, 1985).

In contrast to subsidence pits, subsidence troughs are broad, “dish-shaped” areas of lowered (subsided) ground surface that form in response to the process of trough subsidence (for example, see Turney, 1985; Matheson and Bliss, 1986). Troughs are larger in areal dimension than subsidence pits and can be hundreds to thousands of feet in breadth (Matheson and Bliss, 1986). A single trough might actually include numerous subsidence pits, which can form after the subsidence trough has developed (for example, see Dunrud and Osterwald, 1980). Troughs tend to develop over areas where continuous, high-extraction mining of a coal bed has generated a large, open cavity with little or no roof support. As the mine roof sags or collapses into the unsupported void, the overlying overburden can collapse or sag correspondingly. Ultimately, a trough of depression can form on the ground surface, as the sag is propagated upward (fig. 28) (Myers and others, 1975). The surface disturbance resulting from trough subsidence exceeds the areal dimension (breadth) of the underground void (for example, see Myers and others, 1975). In areas where room-and-pillar methods were used for coal extraction, trough subsidence can occur where multiple coal pillars in an abandoned, underground mine have collapsed simultaneously or in rapid succession, resulting in the development of a large open void encompassing all or parts of multiple mine rooms; this chain reaction of pillar failure can initiate when the weight of the overburden exceeds the strength of the existing coal pillars (Turney, 1985). As one pillar collapses, overburden stress on adjacent pillars increases, potentially causing successive pillar failure over a large area. Coal-mine fires in room-and-pillar mines can also facilitate trough subsidence through the process of burning multiple pillars of coal as the fire propagates through the mine, resulting in collapse of the overburden above the burned pillars. Additionally, subsidence troughs can also form as a result of “pillar punching” when the weight of the overburden essentially pushes intact coal pillars downward, into a softened mine floor, causing sag in the overlying rock (fig. 29) (for example, see Roenfeldt and Holmquist, 1986).

In addition to subsidence features caused by chimney and trough subsidence, there is also the potential for pits and holes

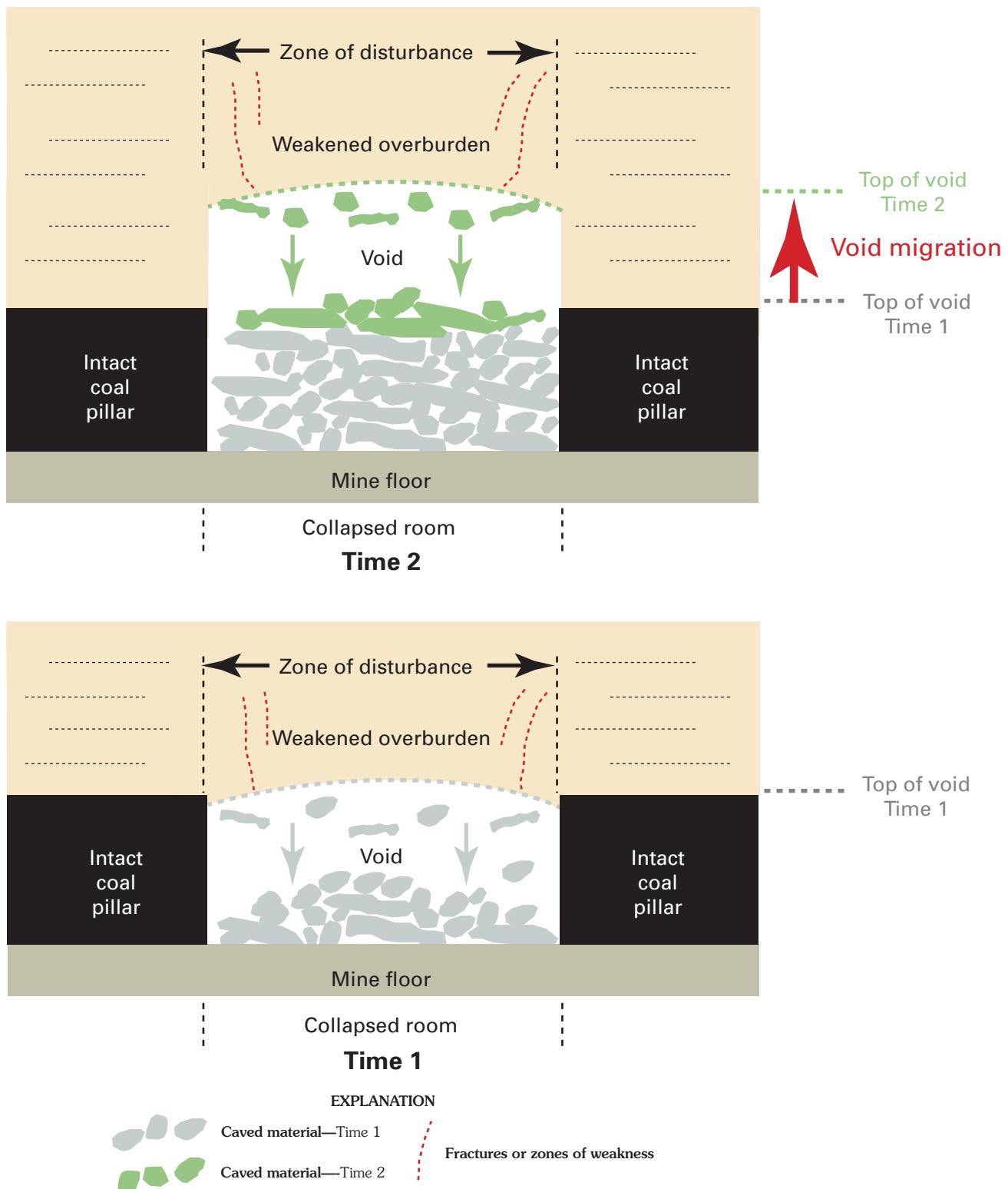


Figure 25. Diagram showing the process and results of roof and overburden collapse (chimney subsidence) into an abandoned room of an underground coal mine. From time 1 to time 2, progressive failure (collapse) of weakened roof rock or overburden above the mine room results in the accumulation of caved material (rubble) in the open cavity and the apparent upward migration of the void. In this process, bedded rock units in the zone of disturbance might be subject to downward sagging or separation as the effects of mine collapse are propagated upward. Diagram not to scale.

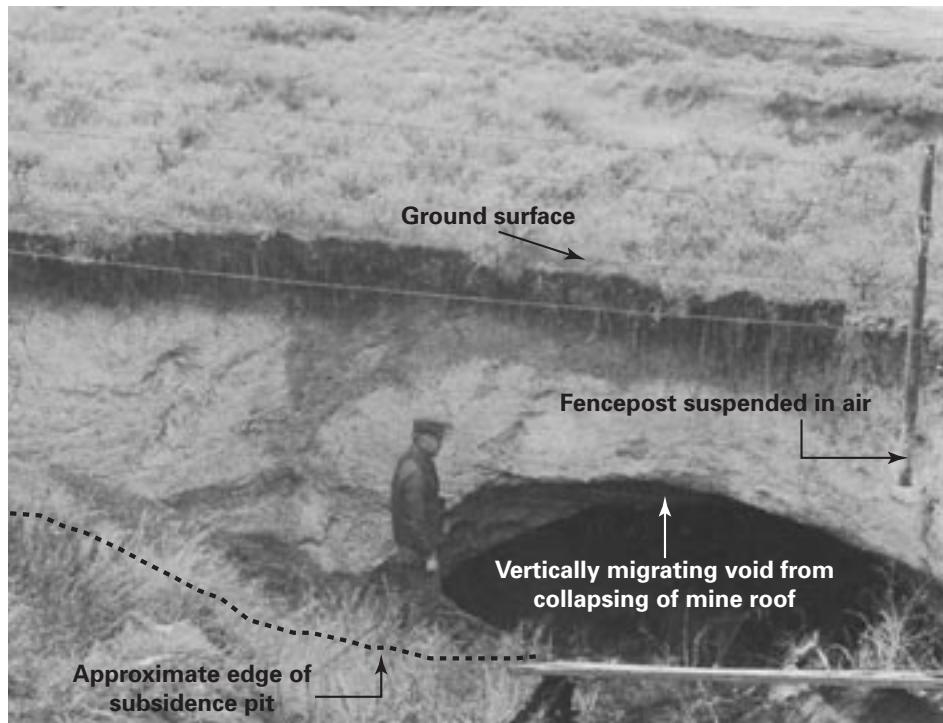


Figure 26. Photograph showing surface subsidence pit and associated void that has migrated upward above an abandoned underground coal mine near Sheridan, Wyoming. Depth to the original mine workings is about 30 ft below ground surface. Photograph from Dunrud and Osterwald (1980).

to form by the sudden and rapid collapse of abandoned mine shafts and steeply sloped entryways. Upon abandonment of the mine, these shafts might have been poorly backfilled with unconsolidated mine material and waste in attempts to seal the entries. Through time, this unconsolidated material can fail downward, allowing for the shaft to reopen suddenly. Additionally, where inclined slope entries (adits) used for mine access were at or close to the ground surface and constructed in poorly consolidated surficial material, there is a potential for the collapse or caving of the ground surface overlying these shallow adits (Turney, 1985).

Subsidence Prediction

Because of the potential damage that can result from coal-mine subsidence, subsidence prediction has become an important tool for land-use considerations in the Denver Basin. However, although the processes of subsidence are reasonably well understood, difficulty arises when trying to accurately predict when and where subsidence will occur. Numerous techniques (models) aimed at determining the subsidence potential in undermined areas have been developed, and reports by Myers and others (1975), Hynes (1987), Dames and Moore (1985), and Matheson and Bliss (1986) contain detailed information on the application of various models in mine-subsidence investigations in Denver Basin coal fields. In addition, Roenfeldt and Holmquist (1986) provide a detailed review of past and present analytical approaches to subsidence prediction related to underground coal mining. The following discussion provides a general overview of some basic concepts and models generally applied to

subsidence prediction, and describes other factors that can influence subsidence potential.

Surface effects of mine subsidence that result in property damage principally arise from vertical subsidence, associated primarily with chimney subsidence processes, and horizontal ground strain, tilt, and curvature of the ground surface resulting primarily from trough-type subsidence (for example, see Hynes, 1987; Turney, 1985). Subsidence, whether vertical or with an oblique component, can cause appreciable damage to structural foundations as well as disruptions of adequate grades necessary for proper drainage in sewer lines, ditches, and streams (Hynes, 1987). Horizontal ground strain, both compressive and tensional, can be imparted on structures affected by the development of a trough of depression (zones of tension and compression, fig. 28). Strain is the measure of the change in length of an object (relative to its original length) when placed under stress; compressive strain results in "shortening" whereas tensional strain results in "lengthening" of the object (for example, see Hynes, 1987). Compressive strain can result, for example, in the buckling of roads and sidewalks, and tensional strain can cause damage to buildings (such as cracks in walls, ceilings, and foundations) by forces literally pulling the structure apart (for example, see Turney, 1985). An additional component termed tilt, which is also commonly associated with trough subsidence, can adversely affect drainage gradients in sewer lines and drainage ditches and can place significant tensional strain on a structure as it tilts into the edge of a trough; taller buildings (more than three stories) and longer structures are more susceptible to damage resulting from surface tilt (Hynes, 1987). Curvature, which is the change in tilt over a given distance, generates tensional and compressive strains and can also induce rotational stresses

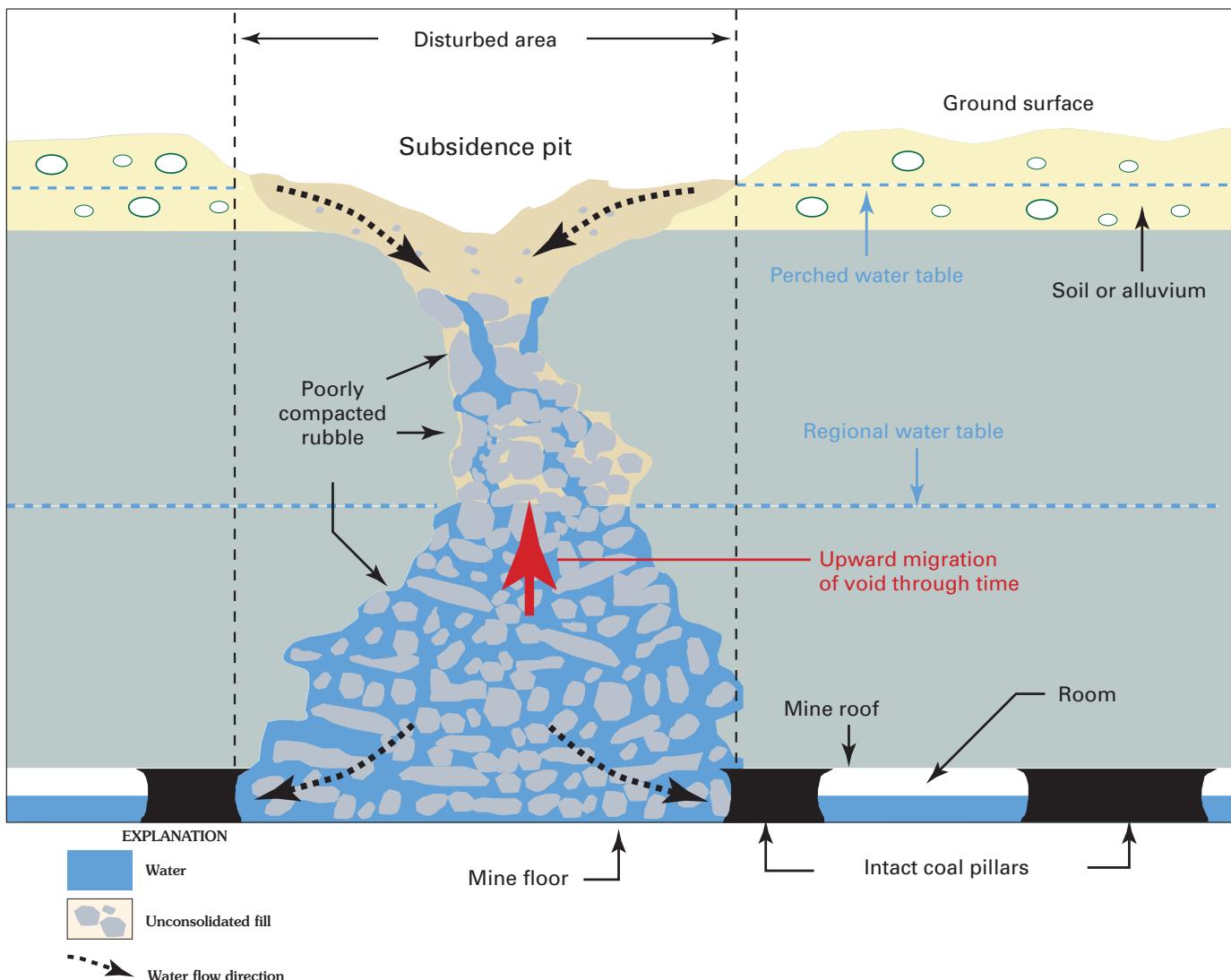


Figure 27. Diagram depicting the chimney subsidence process and its potential effects on the ground surface. Overburden collapse and upward void migration above an abandoned room in an underground coal mine has resulted in the development of a subsidence pit (sinkhole) on the ground surface. In chimney subsidence, the areal dimensions of the subsidence pit correspond closely to the dimensions of the collapsed mine room below ground. In this scenario, the depth of the subsidence pit increases as shallow water washes loose surface material downward through the caved rubble into the collapsed mine room. Diagram not to scale. Modified from Turney (1985).

that can damage rigid underground pipes, gas lines, and conduits (Hynes, 1987).

The processes of chimney and trough subsidence described in previous sections are basic concepts that aid in interpretations of surface subsidence potential above abandoned coal mines. However, application of these theories in subsidence prediction is not always straightforward, as varying conditions related to mining techniques, overburden characteristics, and data availability might necessitate modification to the subsidence concepts on a site-specific basis. In all cases, it is critical to have accurate map data depicting such elements as mine elevation, orientation and extent of mining operations, room-and-pillar locations and size, major and minor

haulageways, entries, and shaft locations. Most, perhaps all, of the underground mines in the Denver Basin are now inaccessible, so improvements of or additions to the existing map information usually are not feasible without extensive and costly drilling programs. Maps for some of the older mines, which might have been abandoned since the late 1800s or early 1900s, are highly variable in terms of accuracy and completeness. Because such maps are key to analyzing the potential for subsidence, attempts at subsidence prediction in some areas can be hampered significantly if the available maps are inadequate. In addition, information on the mined coal-bed thickness, dates of mining, mining sequence, number of beds mined, coal extraction percentages, and retreat mining

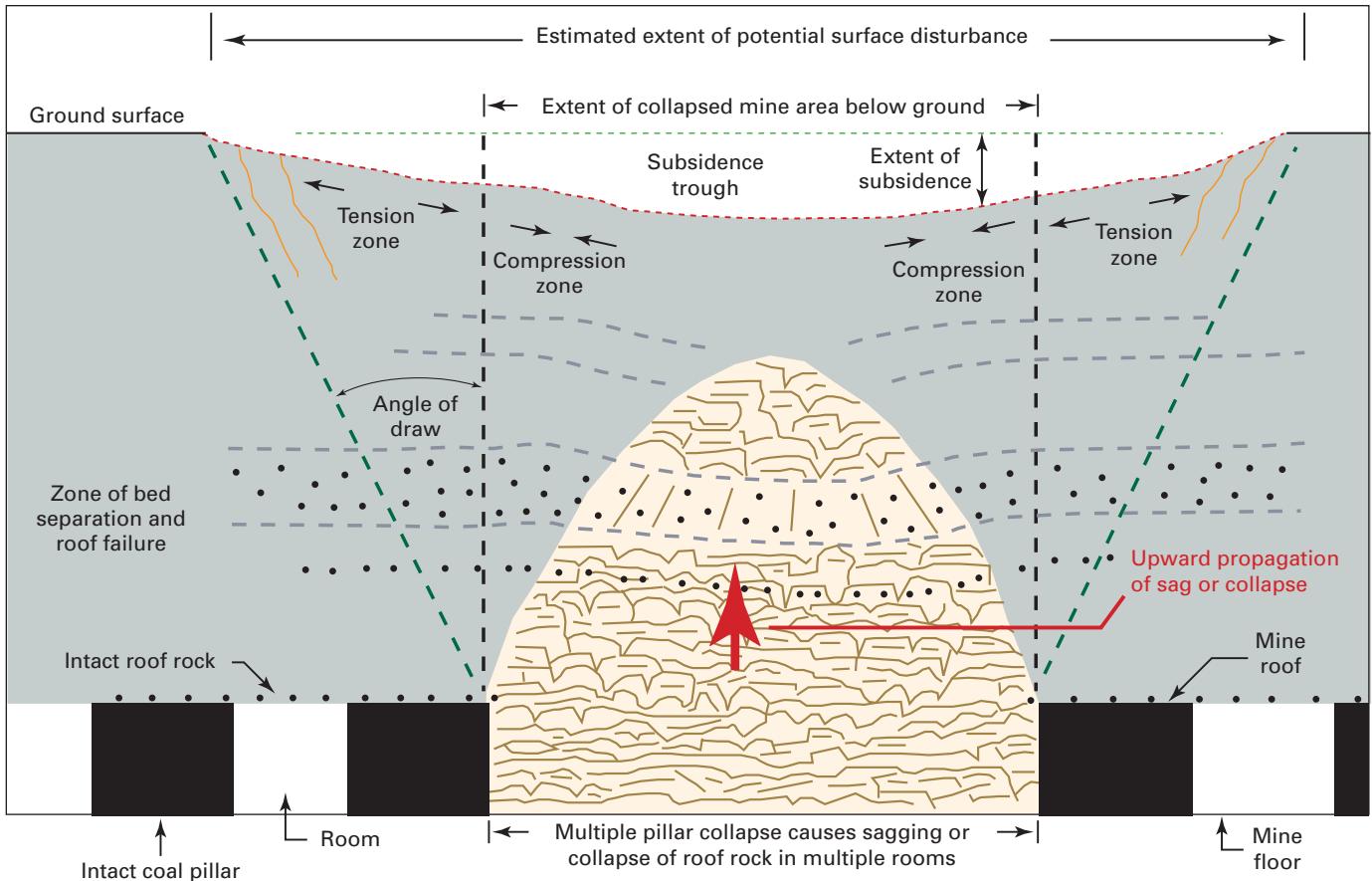


Figure 28. Diagram depicting the process and potential ground-surface effects of trough subsidence. In this scenario, the collapse of multiple coal pillars separating adjacent mine rooms results in the development of a large underground void. Overlying strata are weakened and sag or collapse into the underlying void. As this sagging/collapse propagates upward, a subsidence trough can develop on the ground surface. In trough subsidence, the areal dimensions of the subsidence trough on the ground surface exceed the areal dimensions of the underground cavity. Diagram not to scale. Modified from Turney (1985).

practices (pillar pulling) is also critical for accurate determinations of the subsidence potential in any given area (for comparison, see Roenfeldt and Holmquist, 1986).

In many cases, the prediction of surface effects caused by chimney subsidence is based heavily on an understanding of the bulking characteristics of the roof rock and overburden in the area of concern. If a model for prediction of the potential surface subsidence is constrained within a framework of bulking characteristics alone, the theory of harmless depth can be applied (Hynes, 1987). According to Hynes, the harmless depth theory, which dates back to the 19th century (for example, see Roenfeldt and Holmquist, 1986), relies on the concept that as a caving void migrates upward, the volumetric increase because of bulking will fill the void as long as there is a sufficient thickness of overburden to generate the volume of rock required to fill the original void. Harmless depth, then, is that depth beyond which subsidence (caving) in underground workings will have no effect on the ground surface. Because of the variability and lateral discontinuity of rock types in the Laramie Formation, bulking characteristics of roof rock and

overburden can vary, both vertically and laterally, within a fairly small area. Bulking characteristics for different rock types can be determined through laboratory experiments, resulting in the calculation of a bulking factor (bulking coefficient) that reflects the percentage increase in the volume of rubble generated by the collapse of a specific rock type (for example, see Hynes, 1987; Herring and others, 1986). Hynes (1987) reported bulking factors ranging from 1.25 to 1.30 (25–30 percent volume increase) for sandstone and siltstone, and from 1.1 to 1.2 (10–20 percent volume increase) for shale and claystone in the northeastern part of the Boulder-Weld coal field. Bulking factors such as these can then be used to estimate the thickness of overburden required to fill a void, using the equation:

$$d = t / [(v_f - v_i)/v_i]$$

where d is the thickness of overburden required to fill the void, t is the thickness of the mined interval (void height), and $[(v_f - v_i)/v_i]$ represents the bulking factor (bulking coefficient), based on laboratory estimates of the initial (v_i) and final (v_f)

rock volumes before and after collapse, respectively (for comparison, see Herring and others, 1986). An application of this formula is as follows. If a composite bulking factor of 1.1 (10 percent volume increase) is assumed for the overburden above a mined void thickness of 10 ft, a rock column of 100 ft in thickness would be required to fill the void.

By changing the bulking factor to 1.05 (5 percent volume increase), a rock column of 200 ft would be required to fill the same void (Hynes, 1987). In the first example, if the depth to the void was greater than 100 ft, then theoretically no surface disturbance should result from underground mine collapse.

Thus, 100 ft is considered as the “harmless depth.”

It is important to remember, however, that this calculation relies primarily on bulking characteristics alone and assumes essentially flat-lying coal beds. For this reason, this approach might not be applicable in all areas of the Denver Basin.

An additional model, which incorporates bulking aspects described here combined with a stable arch concept, can also be useful in predicting subsidence over room-and-pillar mines; Hynes (1987) has provided details of this model. Because bulking properties are so critical to interpretations of potential surface subsidence using these concepts, extensive drilling and rock-sample analyses may be required to accurately assess these properties when used for predictive purposes.

Models used to analyze larger scale trough-subsidence potential are commonly based on studies of subsidence above longwall mines. One of the more widely used models was devised through subsidence studies over longwall mines in the United Kingdom, sponsored by the National Coal Board (NCB) of Britain (for example, see Hynes, 1987; Roenfeldt and Holmquist, 1986). In longwall mining, coal is extracted from a large, continuous room (panel), which has no internal roof support except along the coal face that is being actively mined. Coal extraction by this method typically approaches 100-percent recovery in modern longwall panels (Lee Osmanson, U.S. Geological Survey, oral commun., 2001). The NCB model is based on the principle that the continuous and virtually complete extraction of coal, coupled with the corresponding lack of roof support in a longwall panel, causes a predictable fracturing and caving of the immediate mine roof and a corresponding collapse or sagging of the overburden into the void created by mining (for example, see Roenfeldt and Holmquist, 1986). The sag is propagated upward through the overburden and can result in the development of a trough of depression at the ground surface; the maximum depth of the depression will be no more than the thickness of the mined coal bed in this model (Myers and others, 1975). Subsidence over longwall mines is commonly concurrent with the active process of mining. As coal extraction in a longwall panel progresses, shallow troughs of depression can form on the ground surface, with the deepest part of the trough centered over the underground mine opening. Maximum subsidence (maximum depth) of the surface trough is achieved once an underground mine opening has reached a critical width (for example, see Myers and others, 1975), which is constrained (in part) by the thickness and depth of the mined-coal interval, size of the

panel, and the physical characteristics of the overburden. If mining continues beyond the point of critical width, the maximum depth of the subsidence trough will remain constant, but a larger area of the ground surface will be subjected to maximum subsidence. After mining has ceased, subsidence can continue steadily or stop for a period of time until subsequent failure of the overburden results in the resumption of subsidence (Myers and others, 1975). As a tool for the prediction of potential subsidence effects, the NCB model can help determine the vertical and horizontal displacement of the ground surface, horizontal ground strain, and ground-surface tilt and curvature above longwall panels; the magnitude of these ground-surface features is closely tied to the width, depth, and height of the coal extraction zone (Hynes, 1987).

The NCB model has served as a basis for interpretations of trough-type subsidence in studies of Denver Basin coal fields (for example, see Myers and others, 1975; Hynes, 1987; Turney, 1985). However, practical application of the NCB model in the Denver Basin is limited because the vast majority of coal mines along the Front Range used room-and-pillar extraction techniques, which in contrast to longwall mining do not typically result in the development of a large, completely unsupported coal extraction zone in the subsurface. Even where retreat-mining (pillar pulling) practices were invoked, it is unlikely that all coal pillars or manmade supports were removed, either for engineering or safety reasons. Because the remaining coal pillars and supports could continue to provide roof stability for an indeterminant amount of time, the development of subsidence troughs on the ground surface above room-and-pillar mines might not follow as orderly and predictable a pattern as would be expected over longwall mines (Myers and others, 1975). In a study of mine subsidence in the Colorado Springs coal field by Dames and Moore (1985), troughlike subsidence over room-and-pillar mines was observed to be irregular, and the authors of that report interpreted that the interior of any given subsidence trough would likely undergo varying periods of tension and compression, depending on the timing required for failure of existing coal pillars and supports. They also suggested that as overburden above the room-and-pillar mine decreases, trough subsidence would primarily be a series of sinkholes resulting from the collapse of mine rooms with scattered larger depressions (troughs) forming from the general failure of pillars or mine floor over the larger areas. The NCB model, therefore, is less applicable in areas where historical mining conditions do not completely mimic longwall mining conditions (for example, see Hynes, 1987).

Other interrelated factors that can influence subsidence prediction include the amount of time that has elapsed since mining ceased and the particular subsurface conditions in the abandoned mines. In a study of chimney subsidence in the Front Range area, Matheson and Bliss (1986) suggested that the dominant portion of subsidence takes place within 30 to 40 years after mining; after that amount of time, subsidence continues but at a much slower rate. In addition, the surface expression of most of the subsidence pits (sinkholes) studied

in the Denver Basin did not appear until 10 to 20 years after mining ceased. These authors also reported that in the decade between 1976 and 1986, the majority of chimney subsidence features that developed were the result of surface collapse over slope entries and shallow haulageways in abandoned mines rather than subsidence above abandoned mine rooms. Because so much of the underground mining (particularly the shallow mining) in the Denver Basin ceased 40 to 50 years ago (fig. 5) (Kirkham and Ladwig, 1979), it is possible that a significant portion of the potential coal-mine subsidence effects have already manifested themselves in certain areas of the basin (for example, see Myers and others, 1975; Dames and Moore, 1985; Herring and others, 1986; Matheson and Bliss, 1986). However, Dames and Moore (1985) suggested that chimney subsidence associated with room-and-pillar mines might not be completed for hundreds of years after the closure of a mine, depending on the strength characteristics of the mine roof and overburden, ground-water conditions in the mine, and the condition and abundance of manmade mine supports.

Subsurface conditions in abandoned room-and-pillar mines can also impede or hasten subsidence processes in an unpredictable fashion. For example, in mines that are flooded,

softening of the mine floor can induce pillar punching and associated trough subsidence in overlying strata (fig. 29) (for example, see Roenfeldt and Holmquist, 1986). Conversely, water in a completely or partially flooded mine can also inhibit subsidence by providing buoyancy support to the mine roof and overburden above flooded areas and by slowing the weathering degradation of coal pillars, thus preventing or delaying pillar and roof collapse for an unpredictable number of years (Turney, 1985). Through time, regional or local lowering of the water table could subsequently free all or part of the mine from water. The loss of water would decrease support of the mine roof and overburden and allow for the hastened degradation of coal pillars due to slaking and weathering in the air-filled cavities (Turney, 1985).

In summary, subsidence prediction in undermined areas of the Denver Basin is hampered to some degree by (1) availability and quality of historical mine maps and records; (2) limitations in the applicability of established predictive models in some cases; and (3) the variability in subsurface mine conditions resulting from the incomplete removal of pillars and support structures, local mine flooding, and the time elapsed since mine abandonment. Available data can be supplemented

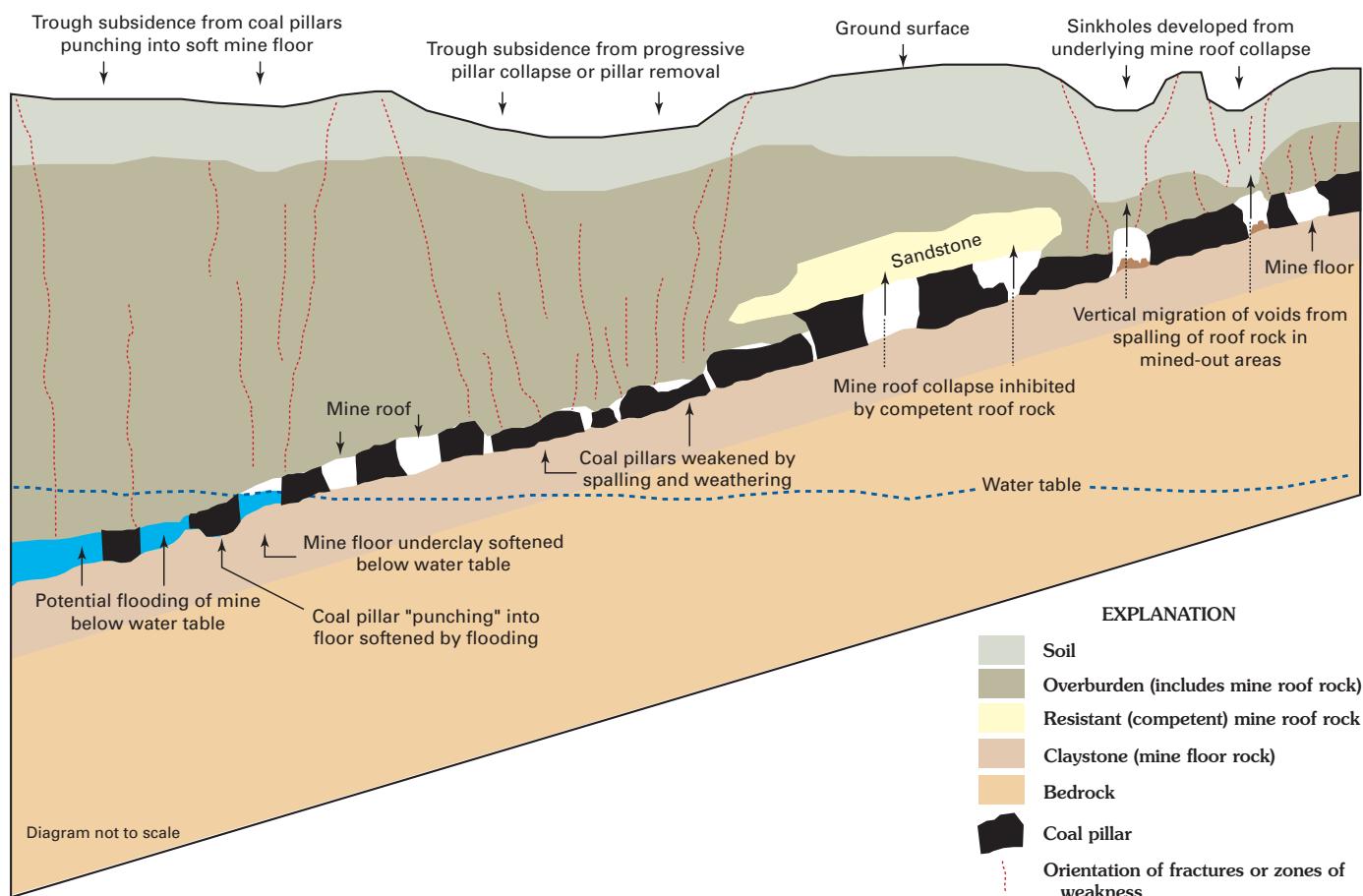


Figure 29. Schematic diagram summarizing ground-surface collapse (subsidence) resulting from mine roof and pillar collapse and from pillar punching in abandoned underground coal mines. Diagram is not to scale and is modified from Roenfeldt and Holmquist (1986).

by additional drilling, borehole logging, and core sample analyses, which can improve upon existing mine data and greatly enhance an understanding of present-day mine conditions in specific sites. Additional drilling data are also invaluable for anticipating engineering and structural requirements necessary for safe development and mitigation of potential subsidence effects. However, drilling programs can be costly and difficult (if not impossible) to undertake in undermined areas that have already been overtaken by urban and residential development. Thus, the greater need for new drilling programs might apply to undermined areas slated for new urban, residential, or commercial development.

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Two miners inside the Black Diamond Mine No. 2, near Lafayette, Colorado. Photograph, taken in 1942, courtesy of Lafayette Public Library.