Chapter 2

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

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Chapter 2 of

Petroleum Systems and Assessment of Undiscovered Oil and Gas in the Denver Basin Province, Colorado, Kansas, Nebraska, South Dakota, and Wyoming—USGS Province 39

Compiled by Debra K. Higley

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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

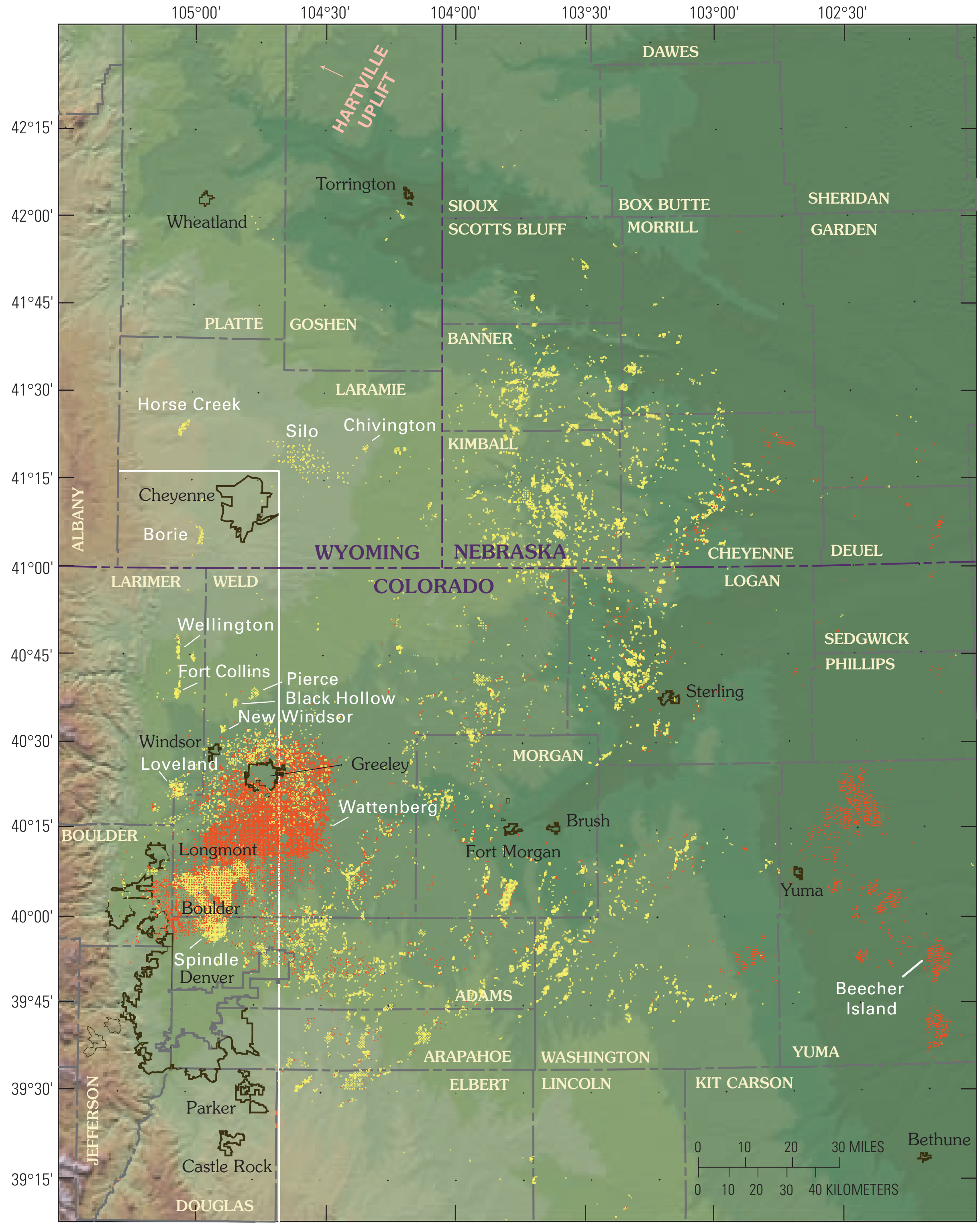


Figure 1. The northern two-thirds of the Denver Basin of Colorado, Nebraska, and Wyoming. Shown are oil (yellow-green), oil and gas (blue), and gas (red) wells across the basin. Major fields within the Front Range area are labeled (white text). The white line shows the northern and eastern boundaries 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.

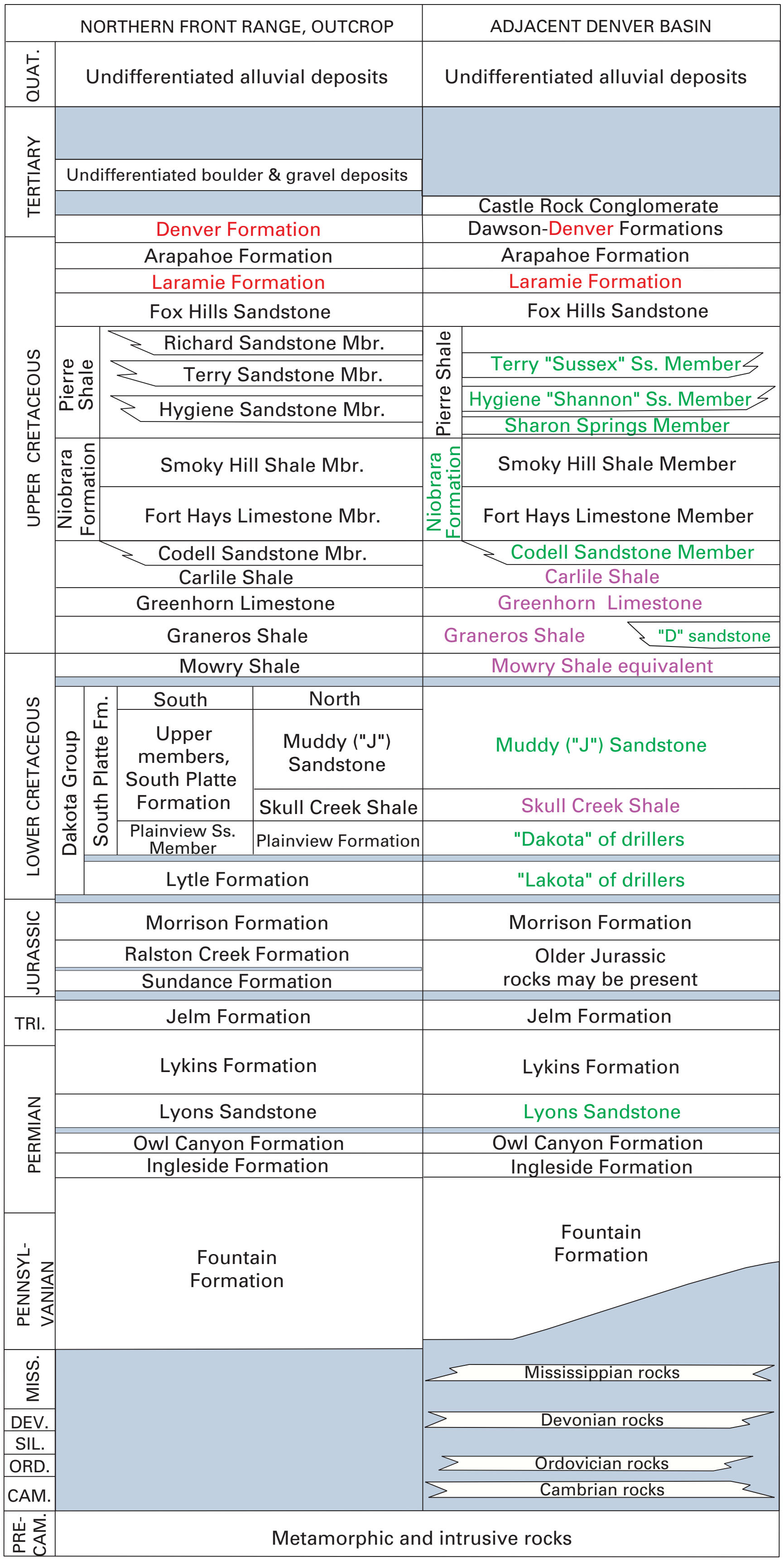


Figure 2. Stratigraphic section of rock units in outcrop and the adjacent Denver Basin. Light blue zones are periods of erosion or nondeposition. Green text marks formations that produce oil and (or) gas. Red text marks formations that have the potential to produce coal-bed methane. Hydrocarbon source rocks are marked with purple text. 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 Hambert 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

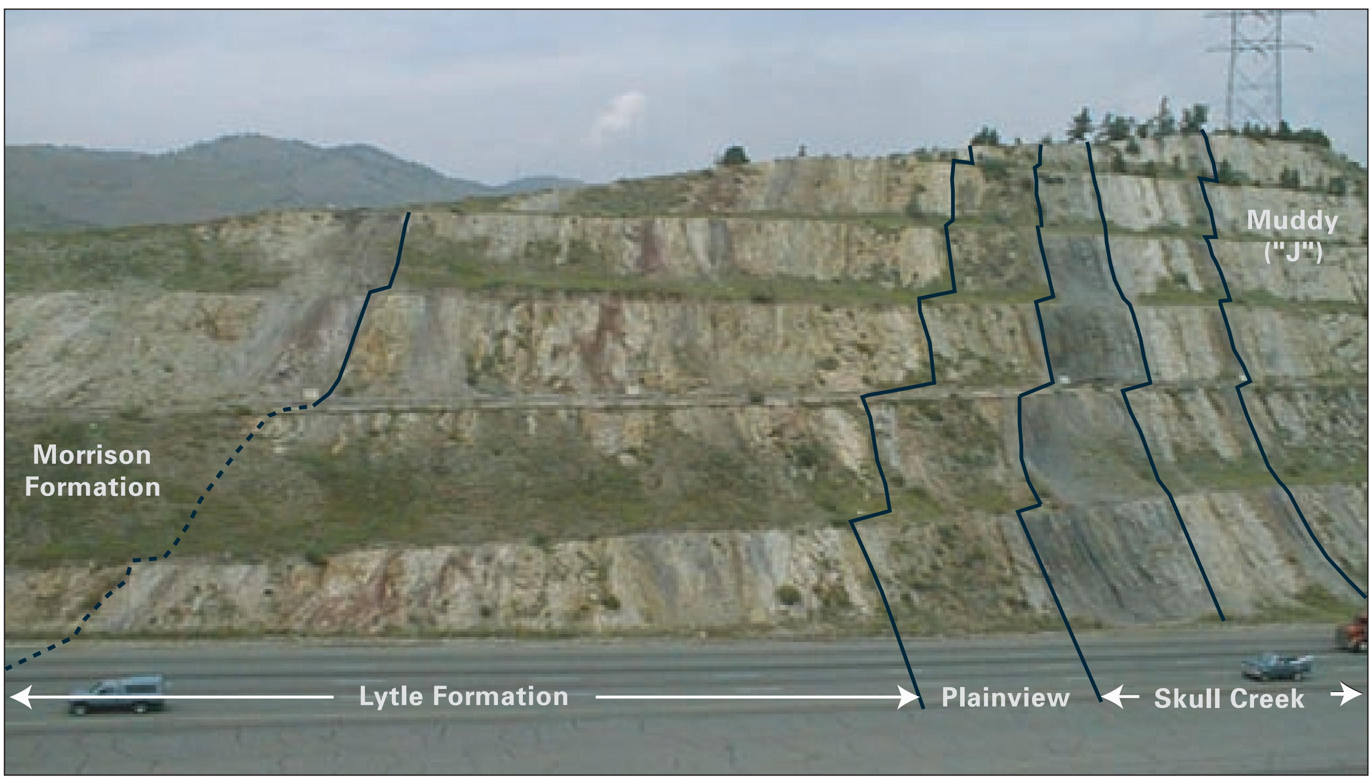


Figure 3. View looking north at an outcrop of Cretaceous (Lytle, Plainview, Skull Creek, Muddy ("J")) and Jurassic (Morrison) Formations. Location is a road cut along Interstate 70, west of Denver, approximately 10 miles (16 kilometers) east of the Rocky Mountains, the foothills of which are shown on 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

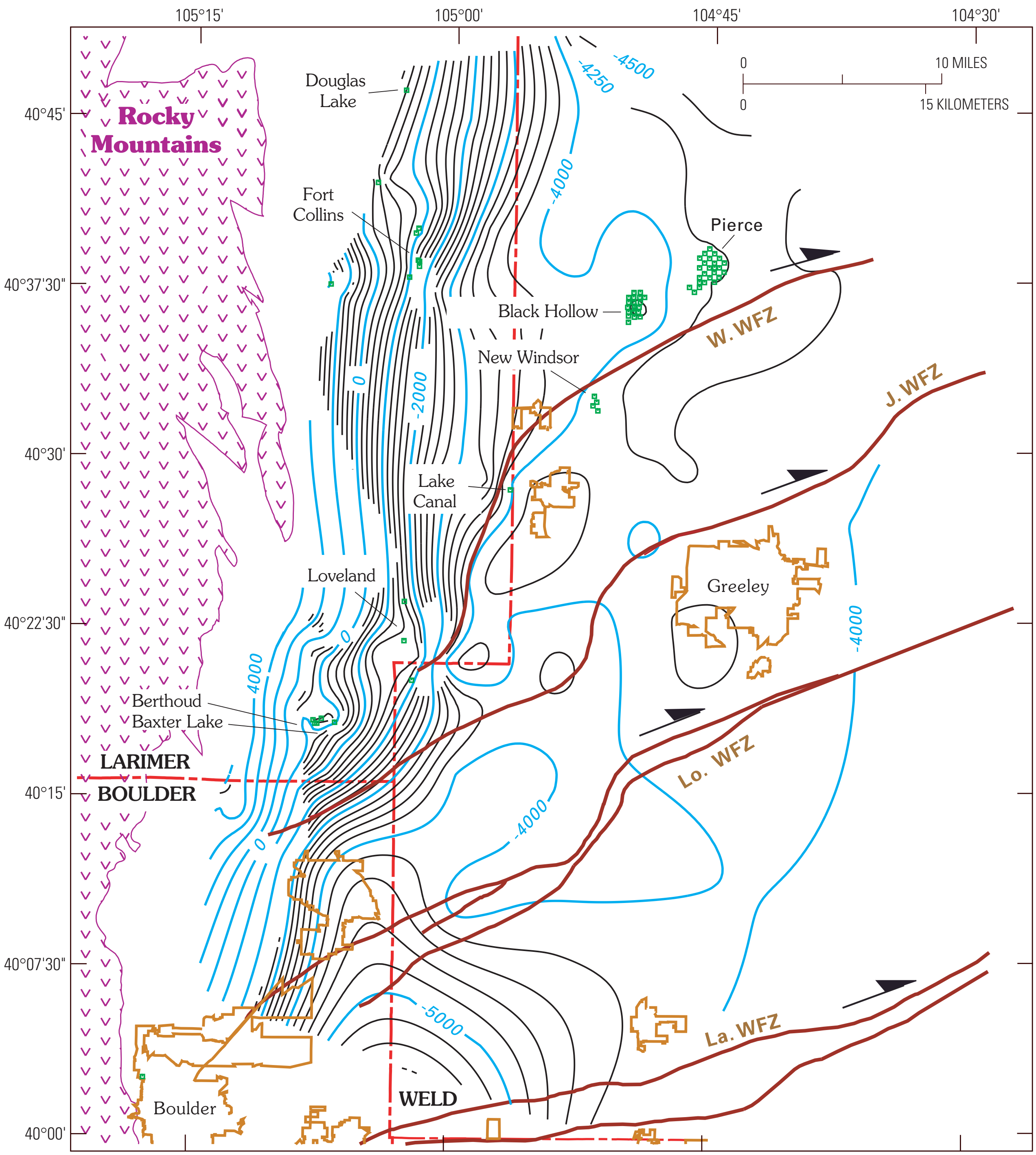


Figure 4. Elevation in feet relative to sea level on the top of the Permian Lyons Sandstone in the Front Range Urban Corridor. Contour interval is 250 feet (76 meters). Producing oil wells (green) are shown for the labeled fields. Labeled wrench faults are Windsor (W. WFZ), Johnstown (J. WFZ), Longmont (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 (1989, 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

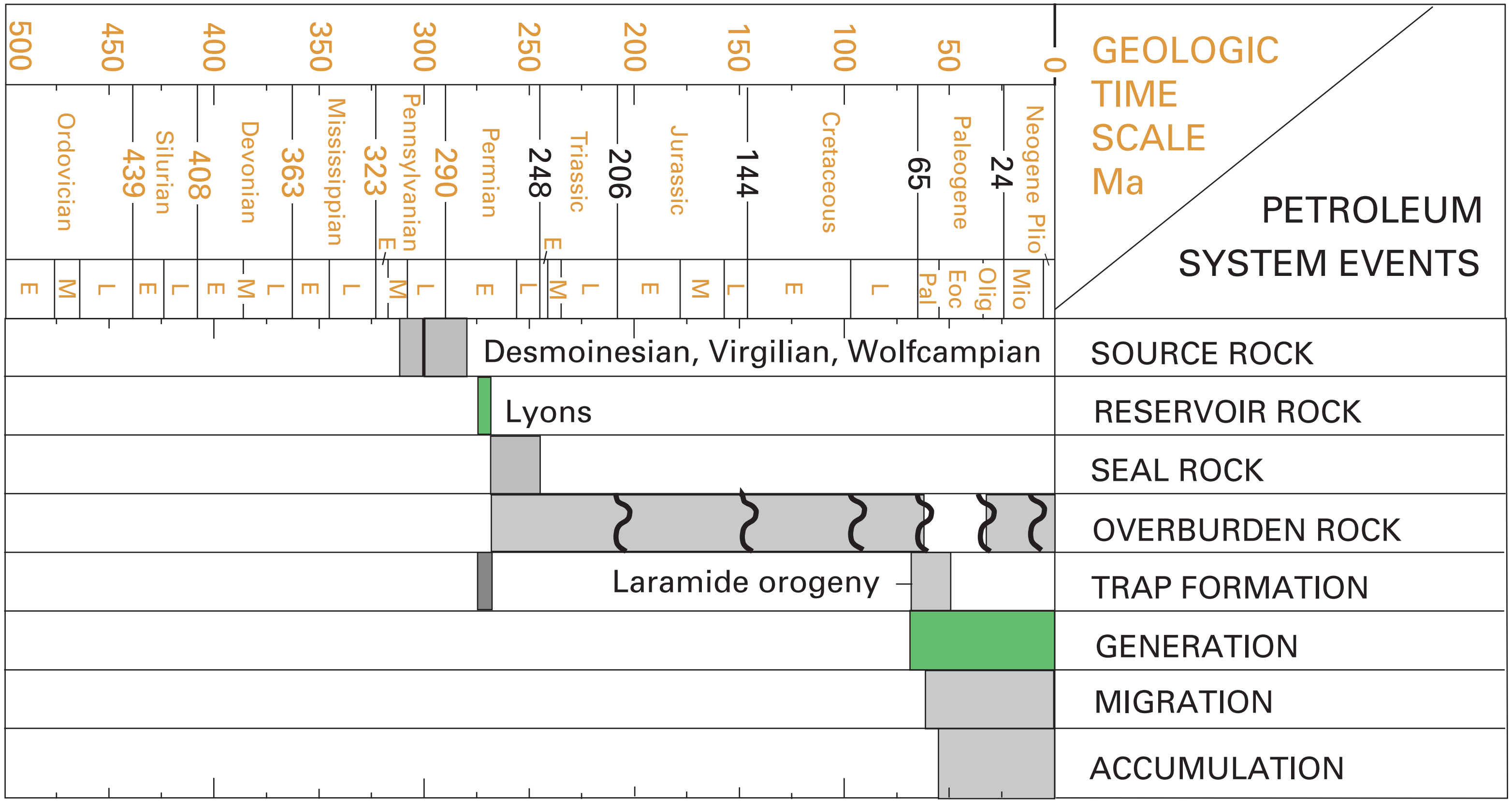


Figure 5. Geologic events chart for the Permian Lyons Sandstone. Gray and green mark times of primary events. Dark gray within the trap formation category indicates the time interval for development of stratigraphic traps. Wavy black lines are times of probable unconformities. Abbreviations for Tertiary 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

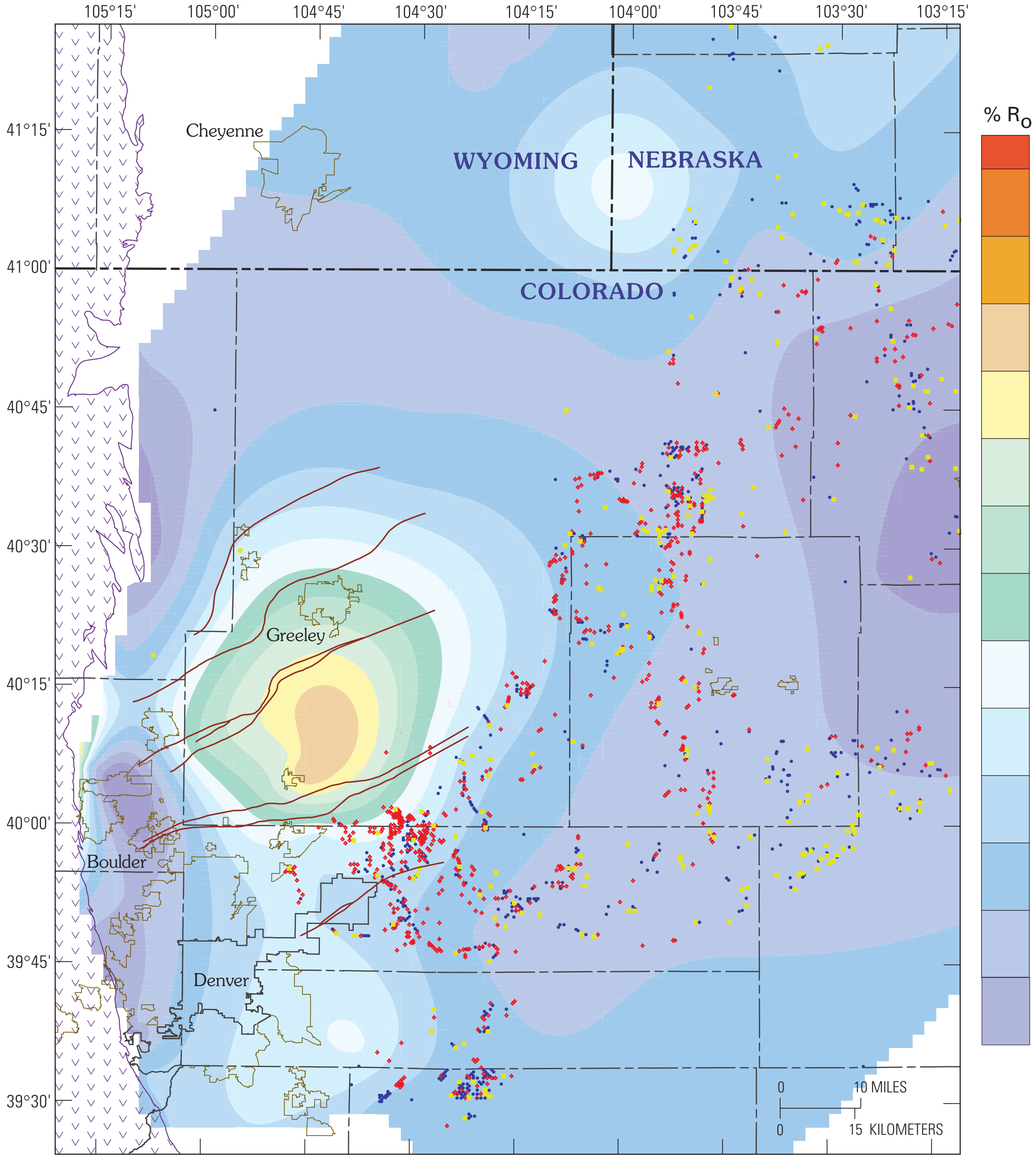


Figure 6. Distribution of oil (yellow), gas (red), and oil and gas (blue) wells that produce from the Lower Cretaceous "D" sandstone across the Denver Basin. Classifications for "D" sandstone wells are based on Petroleum Information/Dwights (1999b) production histories. Color-fill contours are vitrinite 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,

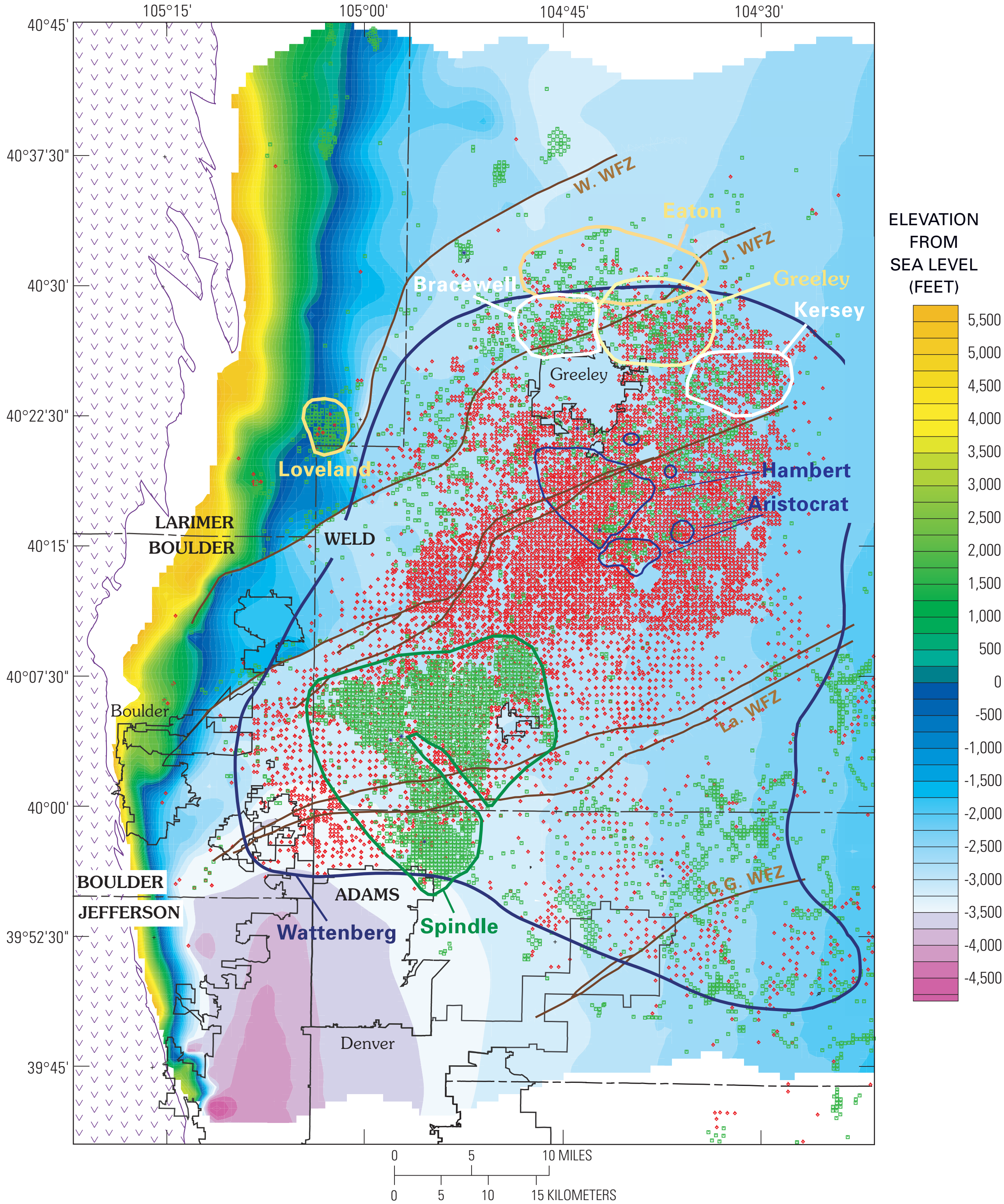


Figure 8. Locations of oil and (or) gas wells within a portion of the Front Range Urban Corridor. Oil wells are green, gas wells are red dots, and oil and gas wells have blue symbols. Color-filled contours are elevation relative to sea level on the top of the Lower Cretaceous Muddy ("J") Sandstone. Contour 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.

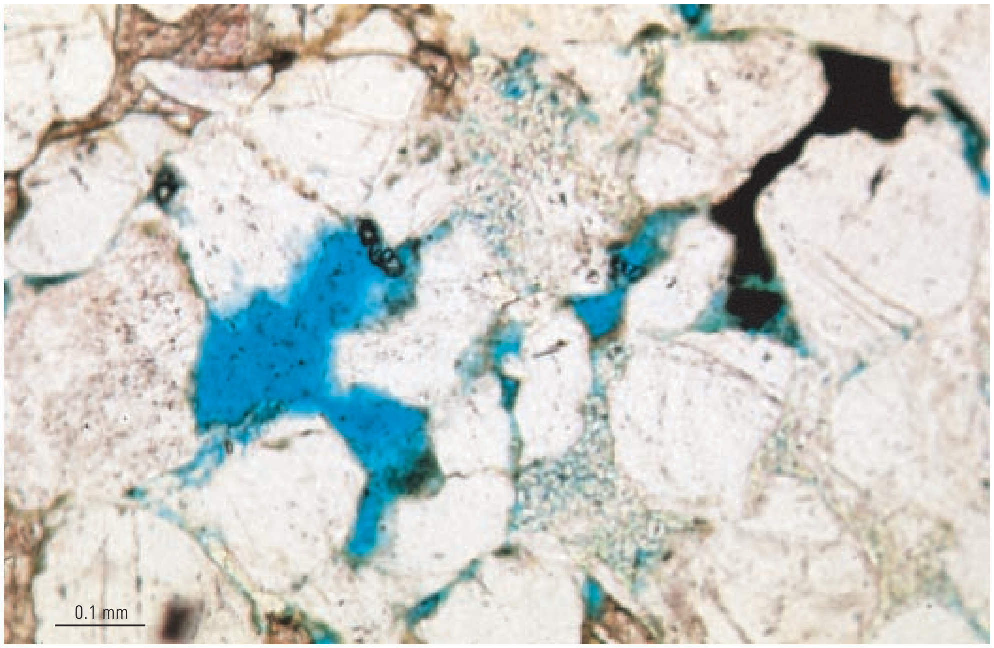


Figure 9. Thin section photomicrograph of a fine- to medium-grained sandstone in the Horsetooth Member of the Muddy ("J") Sandstone, Kachina field, Washington County. Image is transmitted light. Black pore-filling is oil, blue pore-filling is epoxy. Quartz (white) grains have quartz overgrowths. Kaolinite (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,

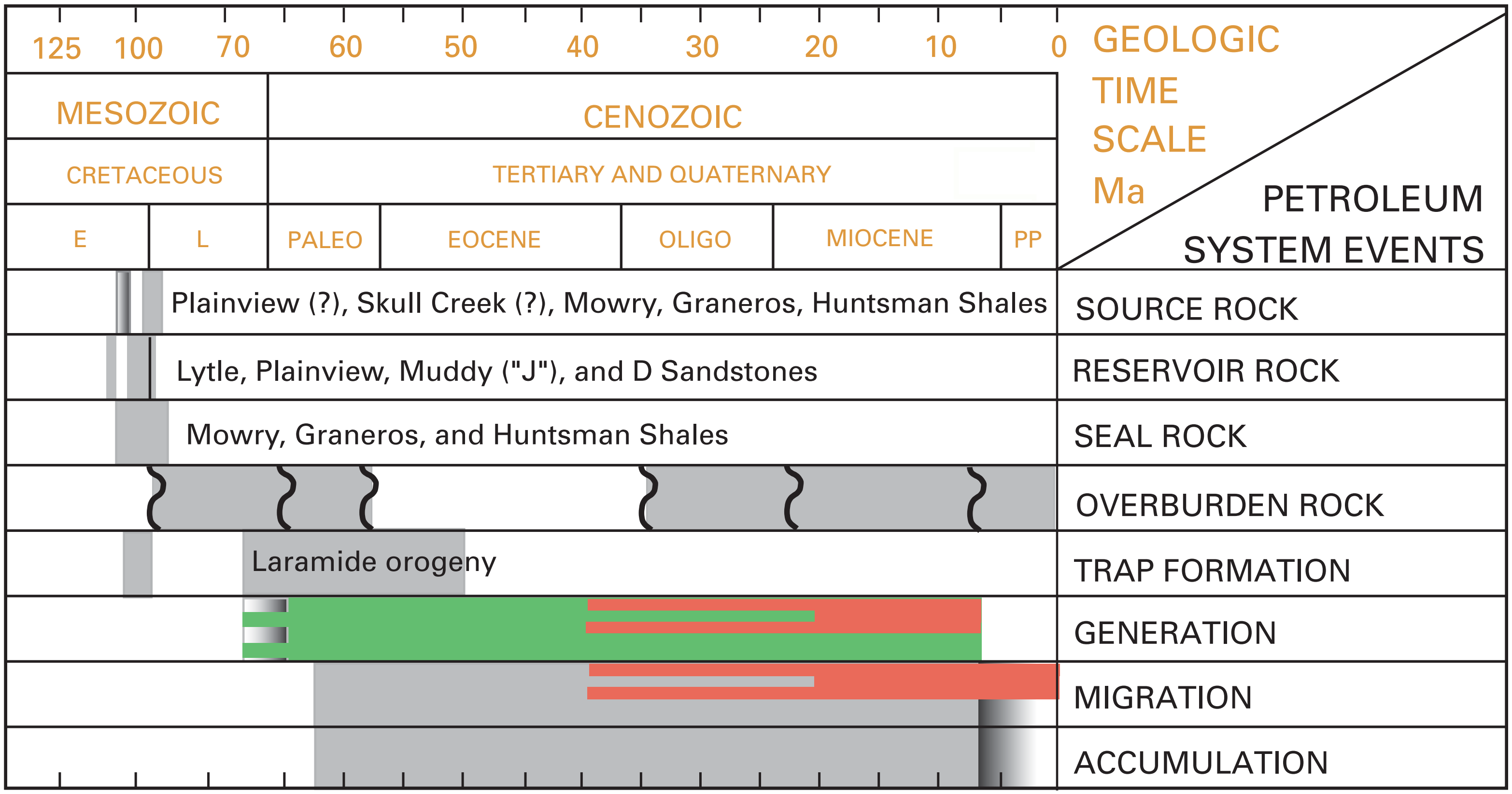


Figure 10. Geologic events chart for the Cretaceous “D” and Muddy (“J”) Sandstones in the Front Range Urban Corridor, Denver Basin. Gray intervals mark times of primary events; gradients show possible times of events. Green and red are respective times of generation of oil and gas from the Mowry and 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).

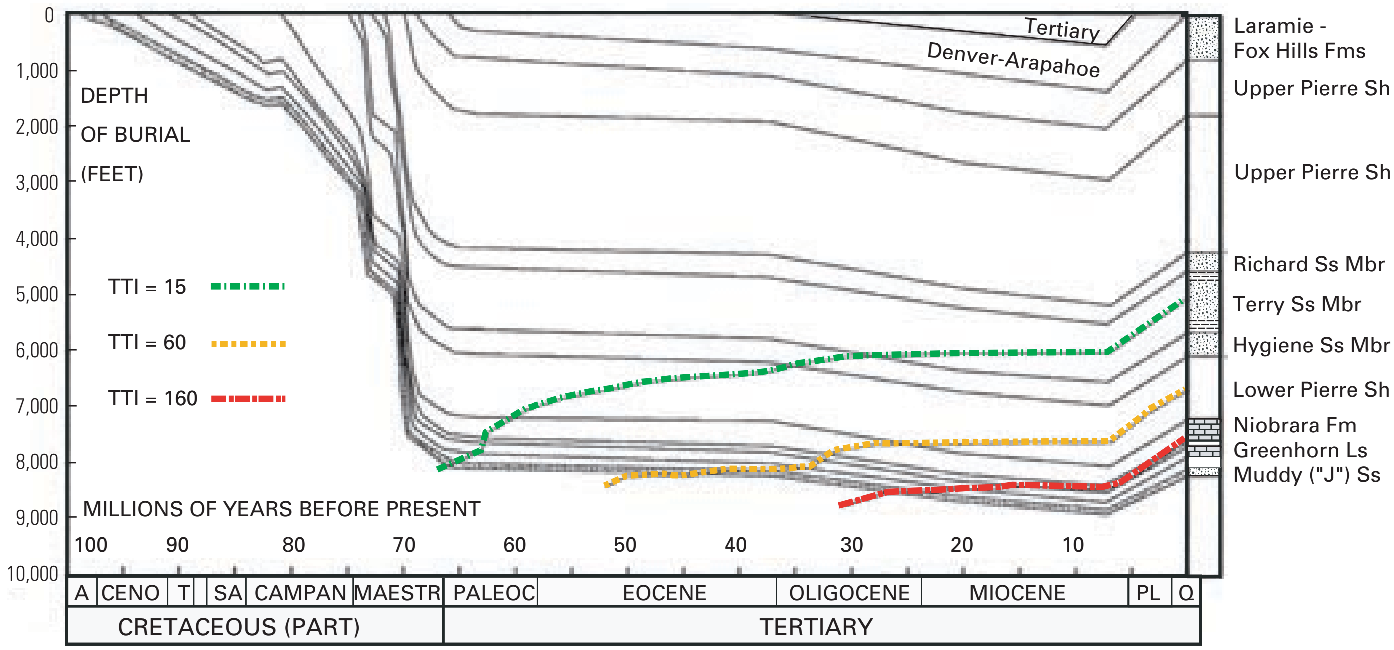


Figure 11. Burial history reconstruction of the Lower Cretaceous Muddy ("J") Sandstone in the No. 1 G.W. Steiber Unit gas well, Wattenberg field. Time-temperature indices (TTI) were determined using a constant geothermal gradient of 2.55 F°/100-foot burial depth. The model includes a conservative estimate 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 Hambert 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, 1983); 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 13*A–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 13*A–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 MCFG and 26 BO per day; these rates decrease through time such that the daily well production after 1 year is 43 MCFG 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. 13*A*, *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. 13*E*, *F*). The high oil-producing area (fig. 13*C*, *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

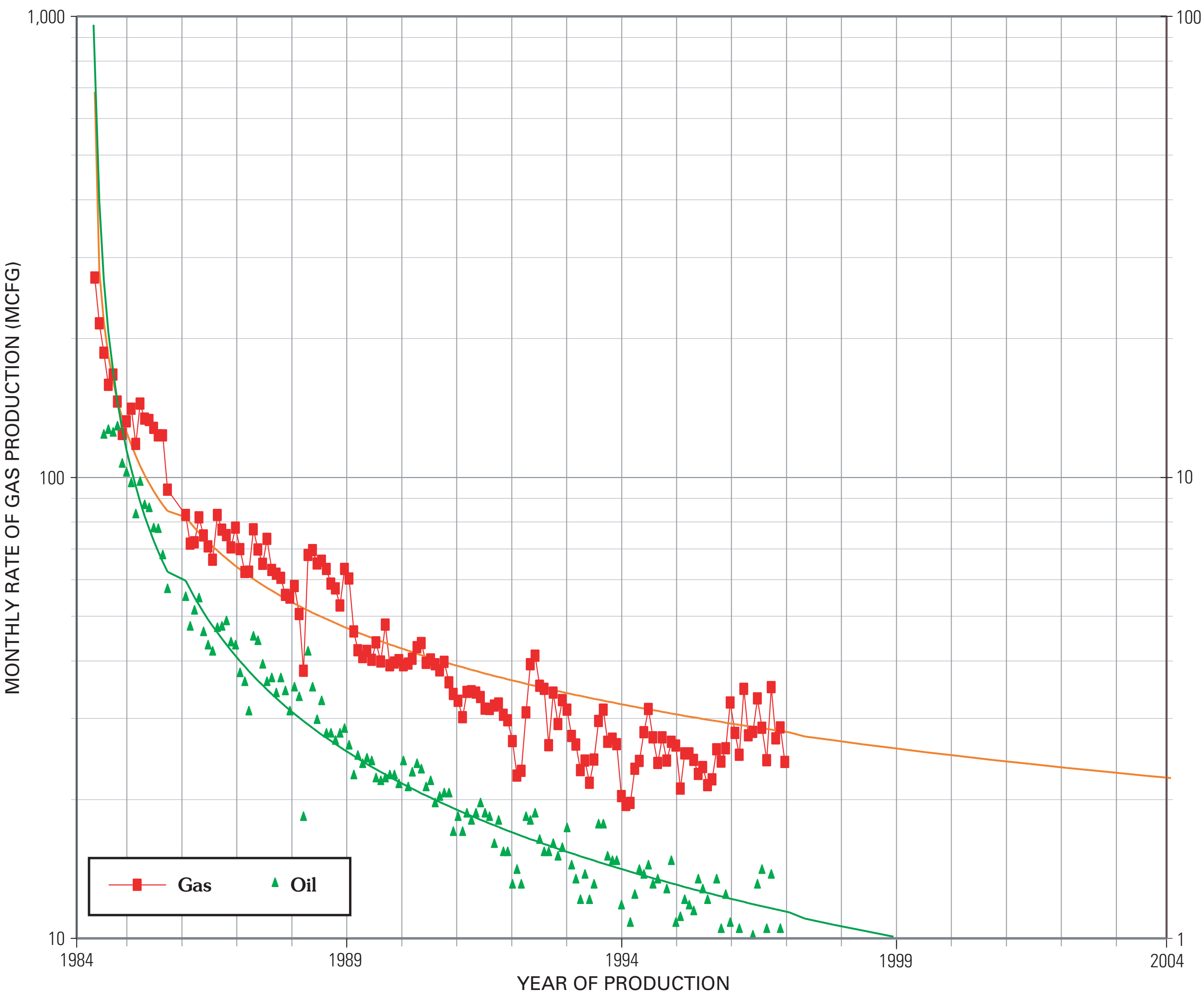


Figure 12. Decline curve of monthly oil and gas production for a typical Niobrara/Codell well in the Wattenberg gas field (Cox, 1998). Vertical scale is thousand cubic feet of gas (MCFG) and barrels of oil (BO).

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
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
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
Averages	---	155	26	5,949	128	11	11,576	195	---	---
TOTALS	4,796	---	---	---	---	---	---	---	529,303	48,775

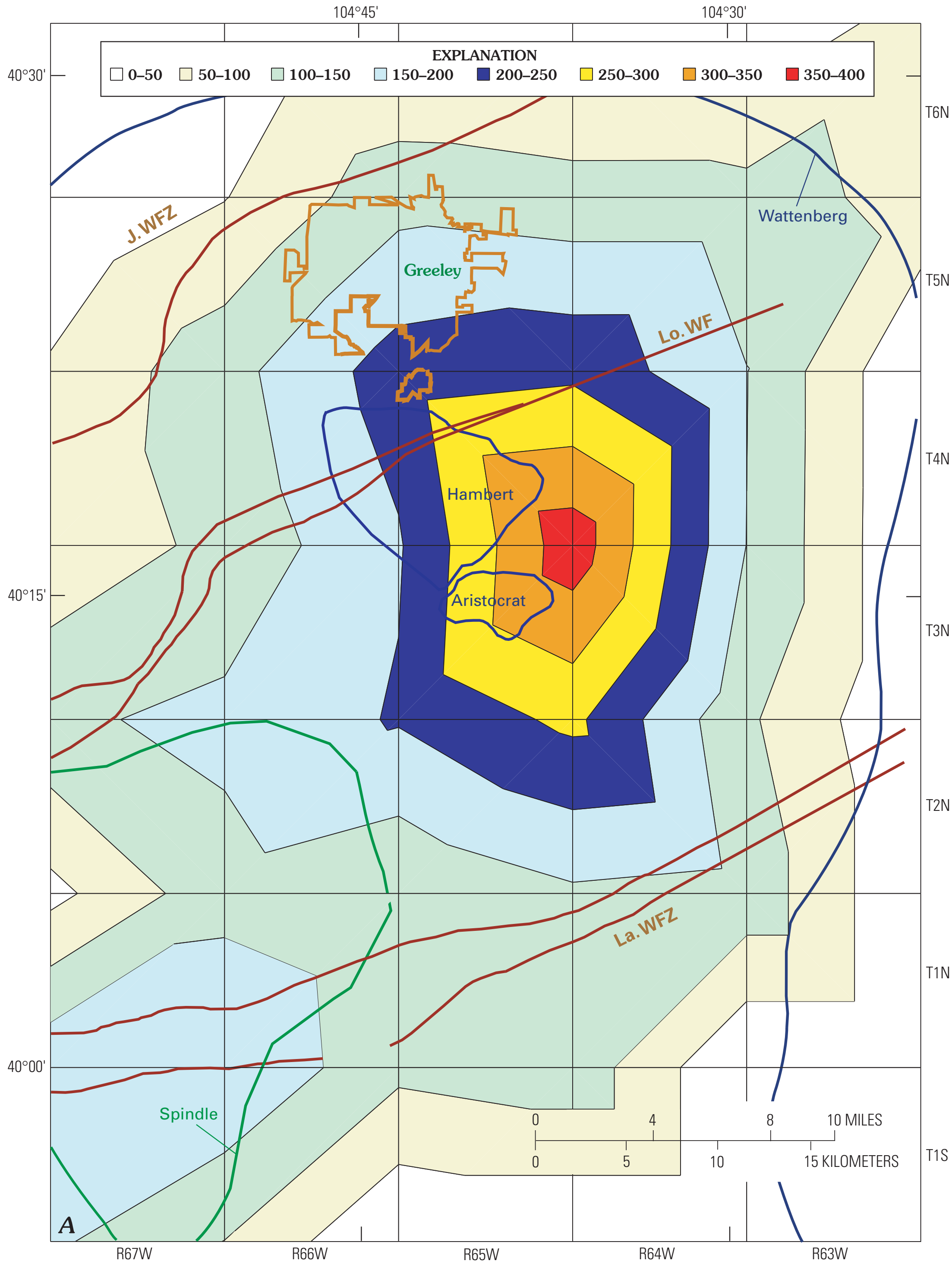
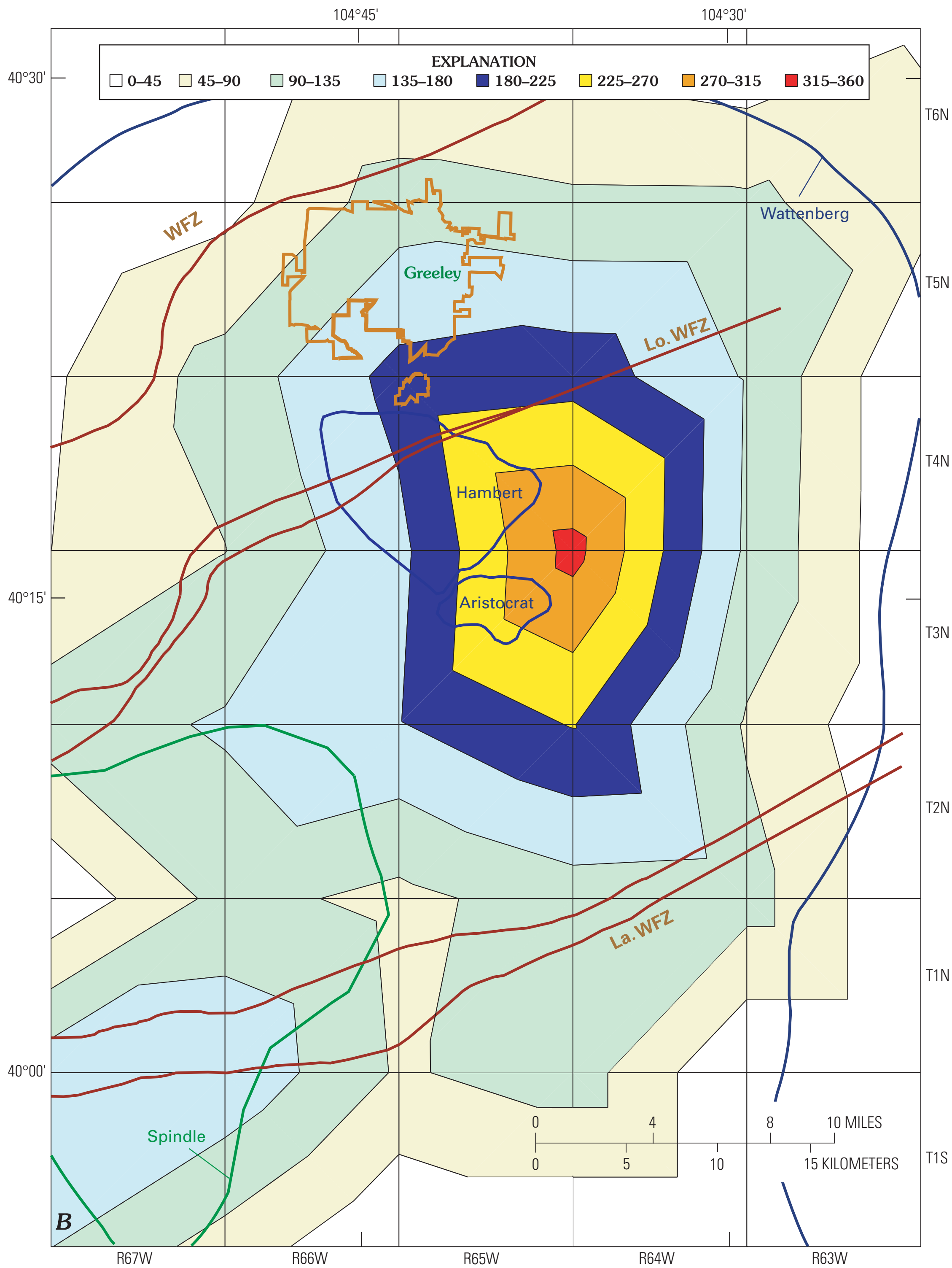
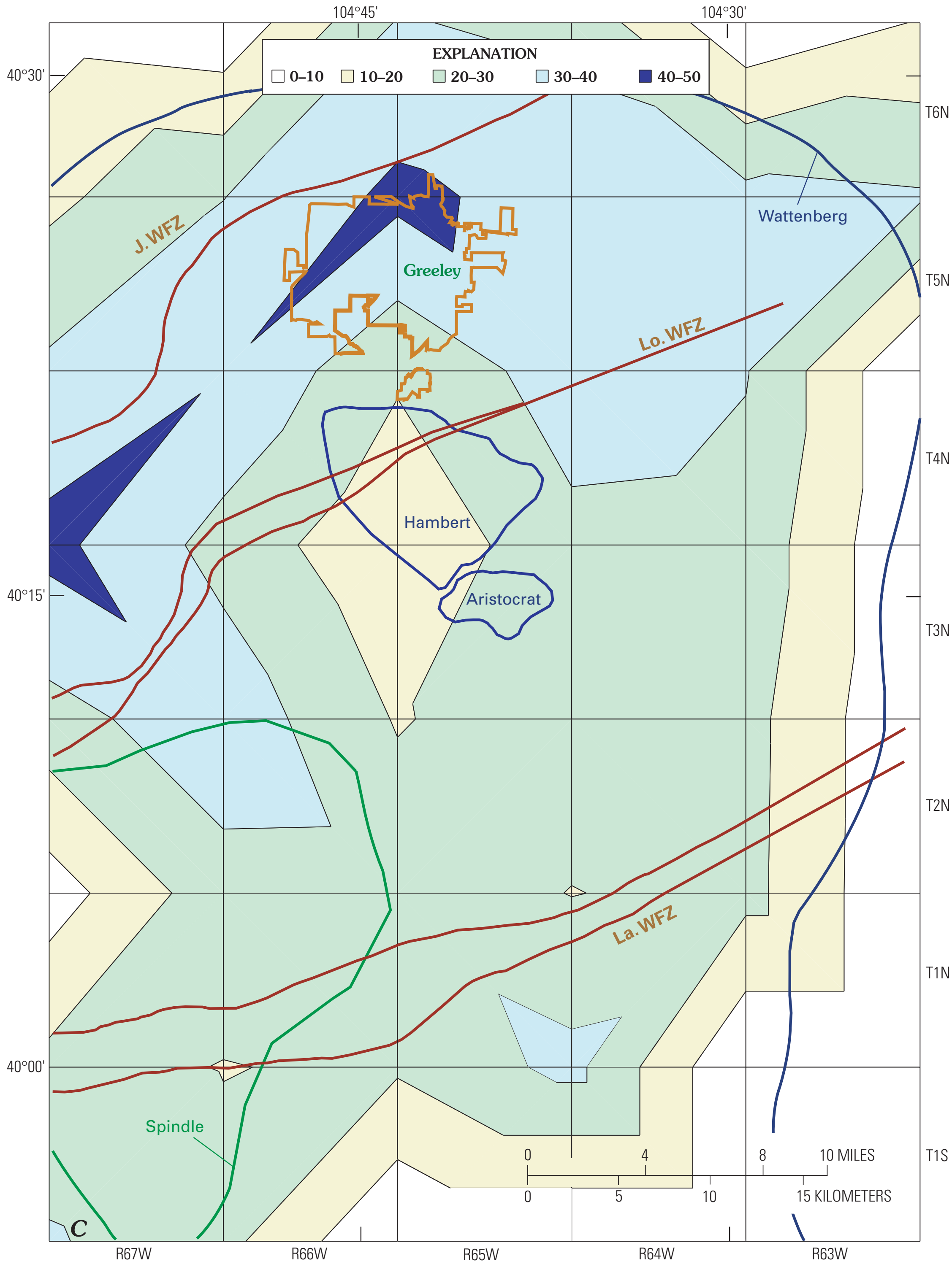


Figure 13*A*–*H* (above and following pages). Plots show oil and gas production characteristics of Niobrara/Codell production from the Wattenberg field (Petroleum Information production data through 1997, modified from Cox, 1998). Production values were determined from wells that were aggregated by township 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.

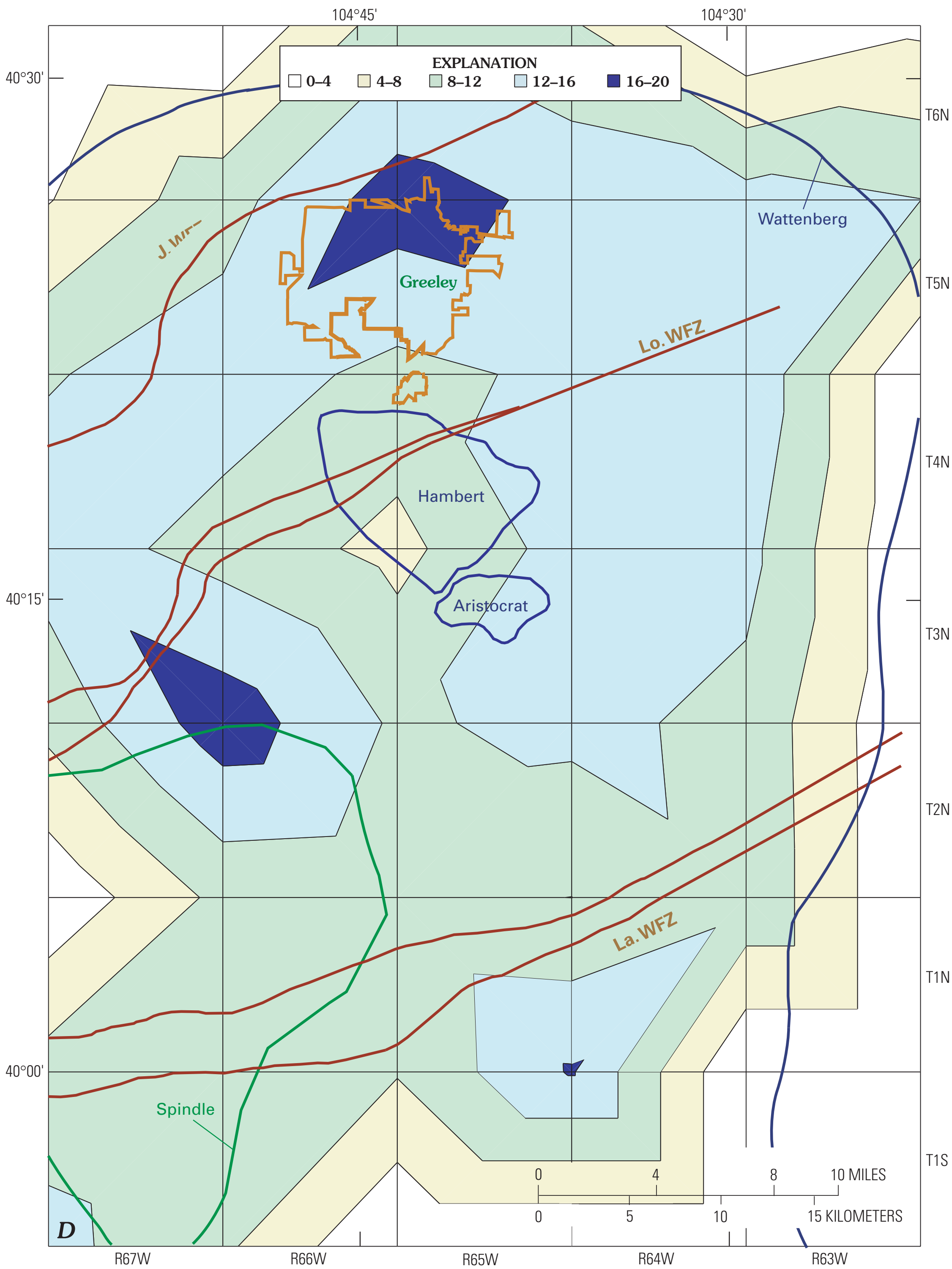
Cumulative production from the more than 1,400 wells in the Spindle field is more than 56.8 MMBO and 278 BCFG (Colorado Oil and Gas Commission, 1998). More than 97 percent of the field's total oil production and 95 percent of the total gas production is from Terry ("Sussex") and Hygiene ("Shannon") Sandstones (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.

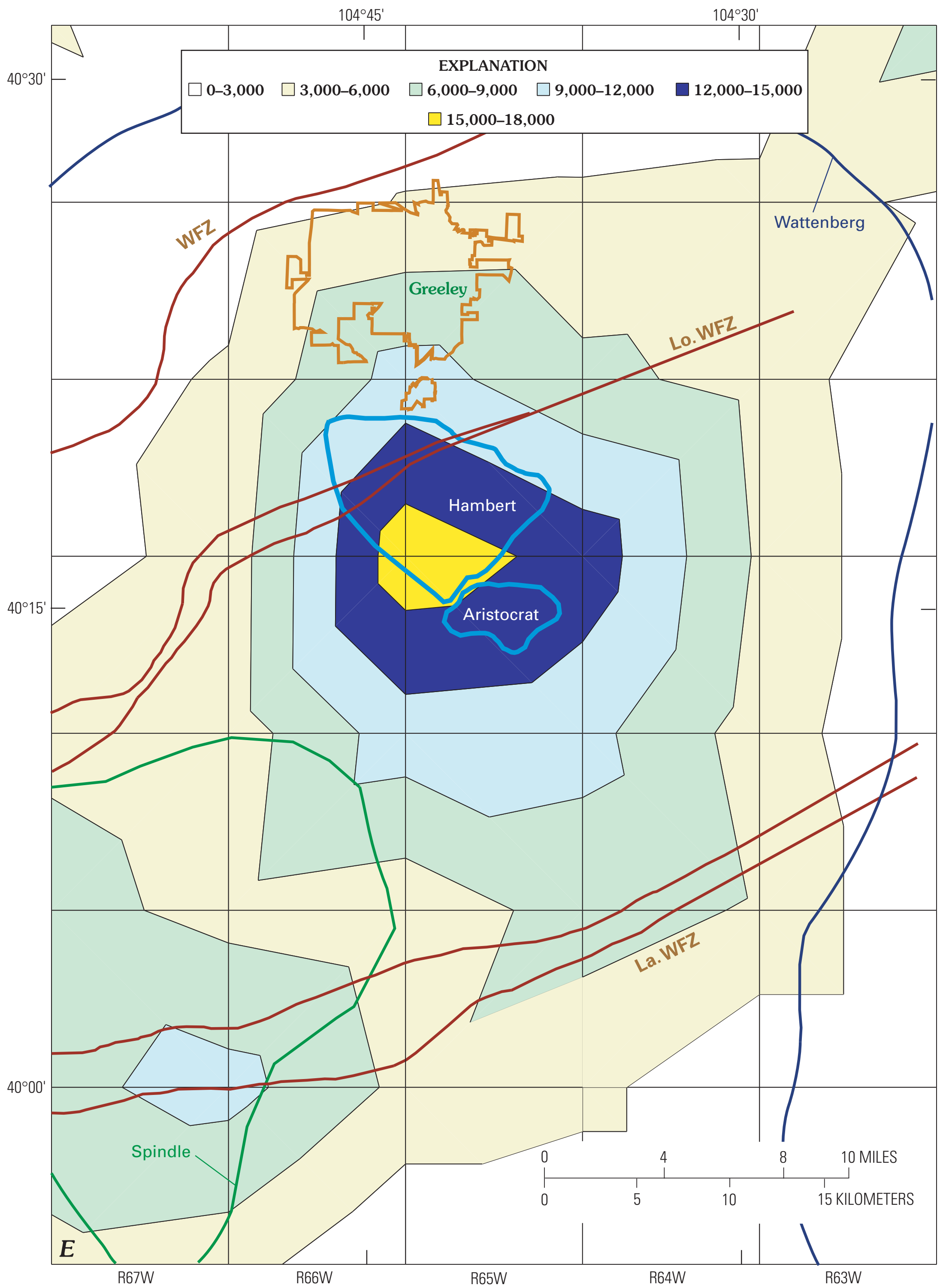
Oil and gas from the Spindle, Hambert, and Aristocrat fields are mostly from the Terry (“Sussex”) Sandstone Member; monthly gas production from these fields has declined from a peak of more than 1.4 BCF in the late 1970s to 509 MMCF by the end of 1990 (McKinney, 1993). Eighteen other fields in the Denver 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

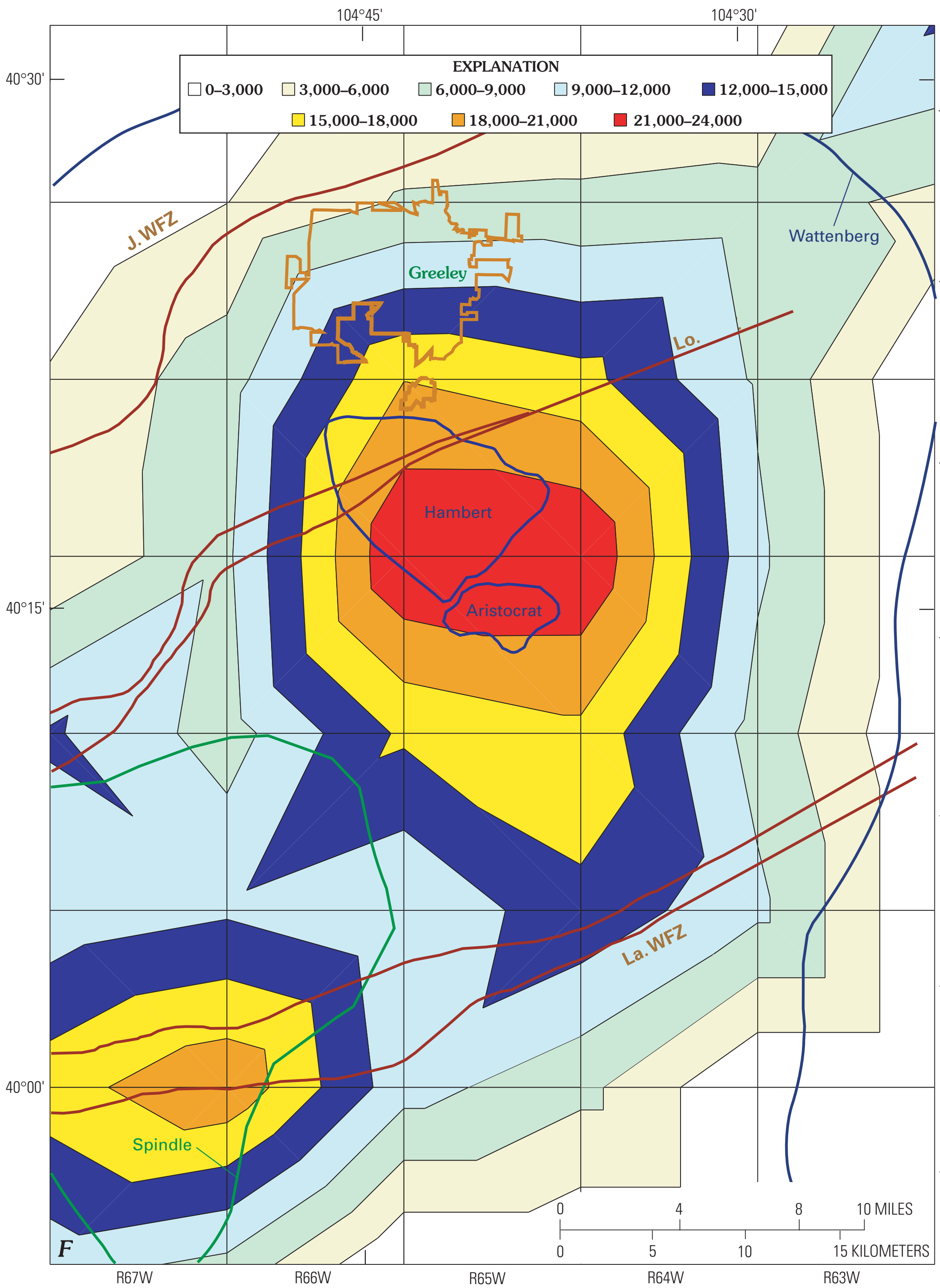


fields is 0.1 mD and 8 mD (Higley and others, 1996). Gross thickness of the Terry ("Sussex") is approximately 150 ft (46 m) in the area of Hambert field; production is from fractures in a low-permeability zone that is approximately 60 ft (18 m) thick near the base of the Terry ("Sussex") (Benson and 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).

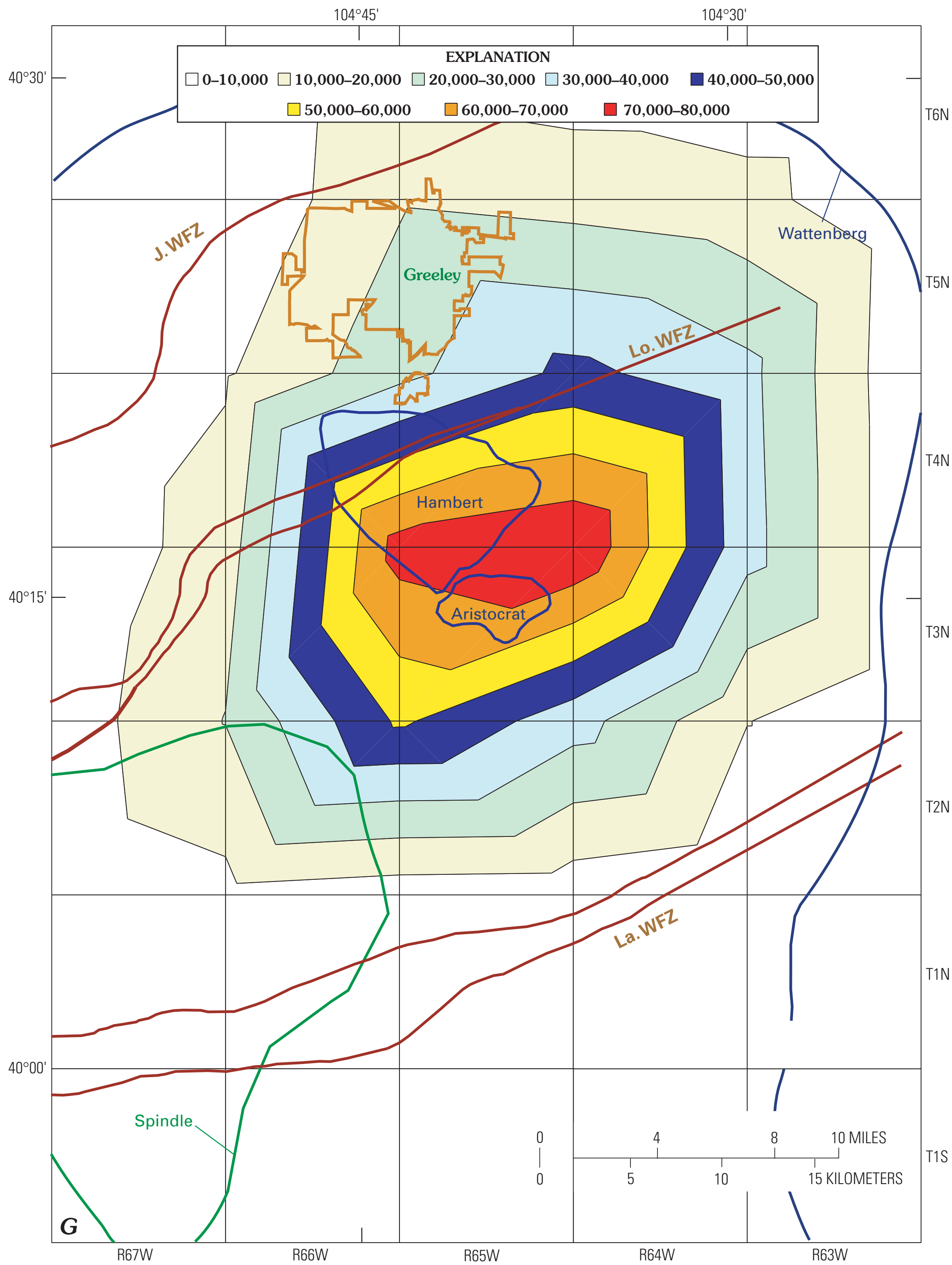
Faults compartmentalize the Terry ("Sussex") Sandstone Member into a number of fault blocks of variable size in the



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 downthrown 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).



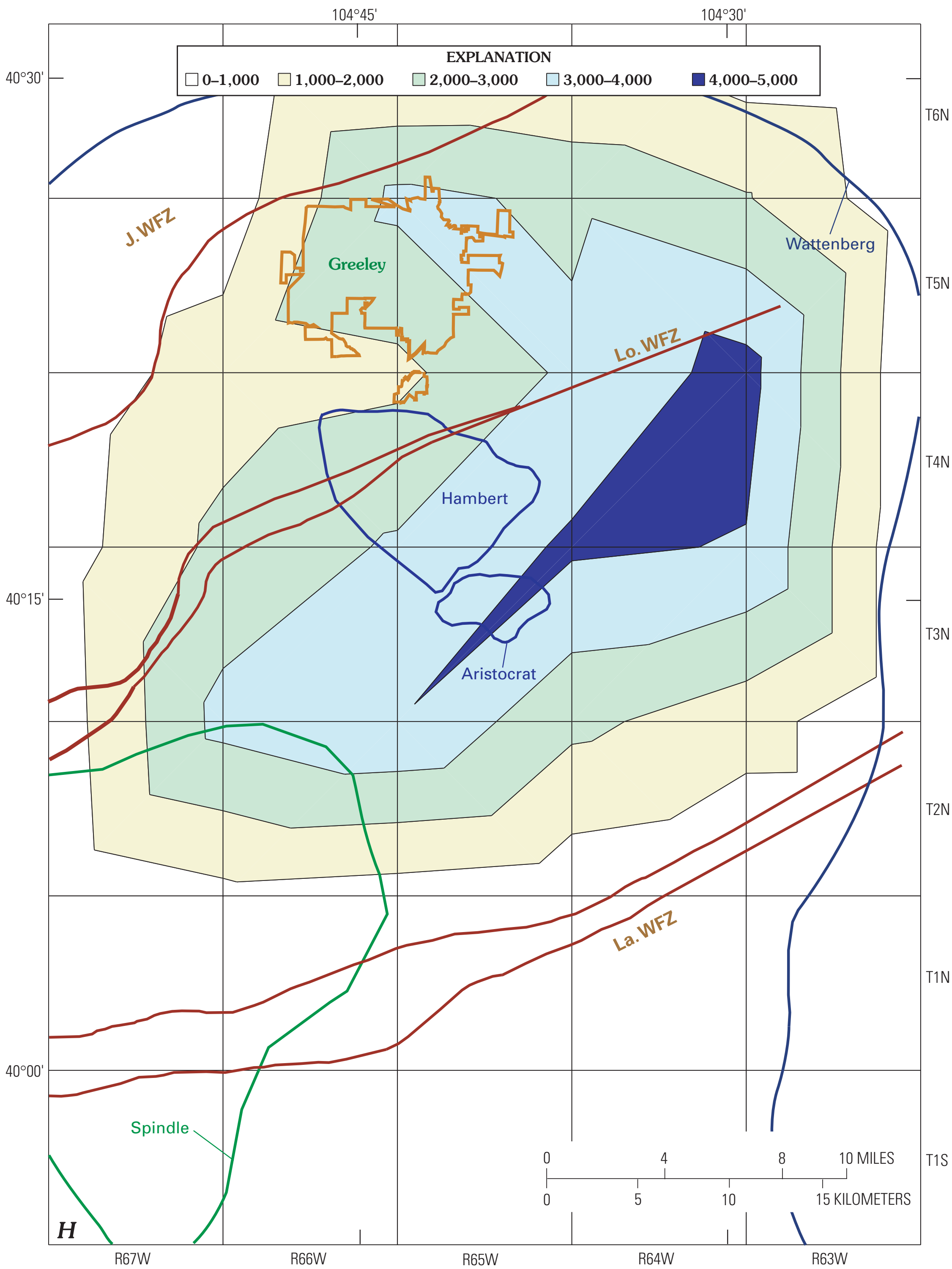
The gas-oil ratio (GOR) for Terry ("Sussex") and Hygiene ("Shannon") production at Spindle field averages slightly more than 4,000 scf/bbl, whereas the GORs for these formations in the Hambert and Aristocrat fields range from 20,000 to 40,000 scf/bbl (McKinney, 1993). The difference in GORs in the Spindle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

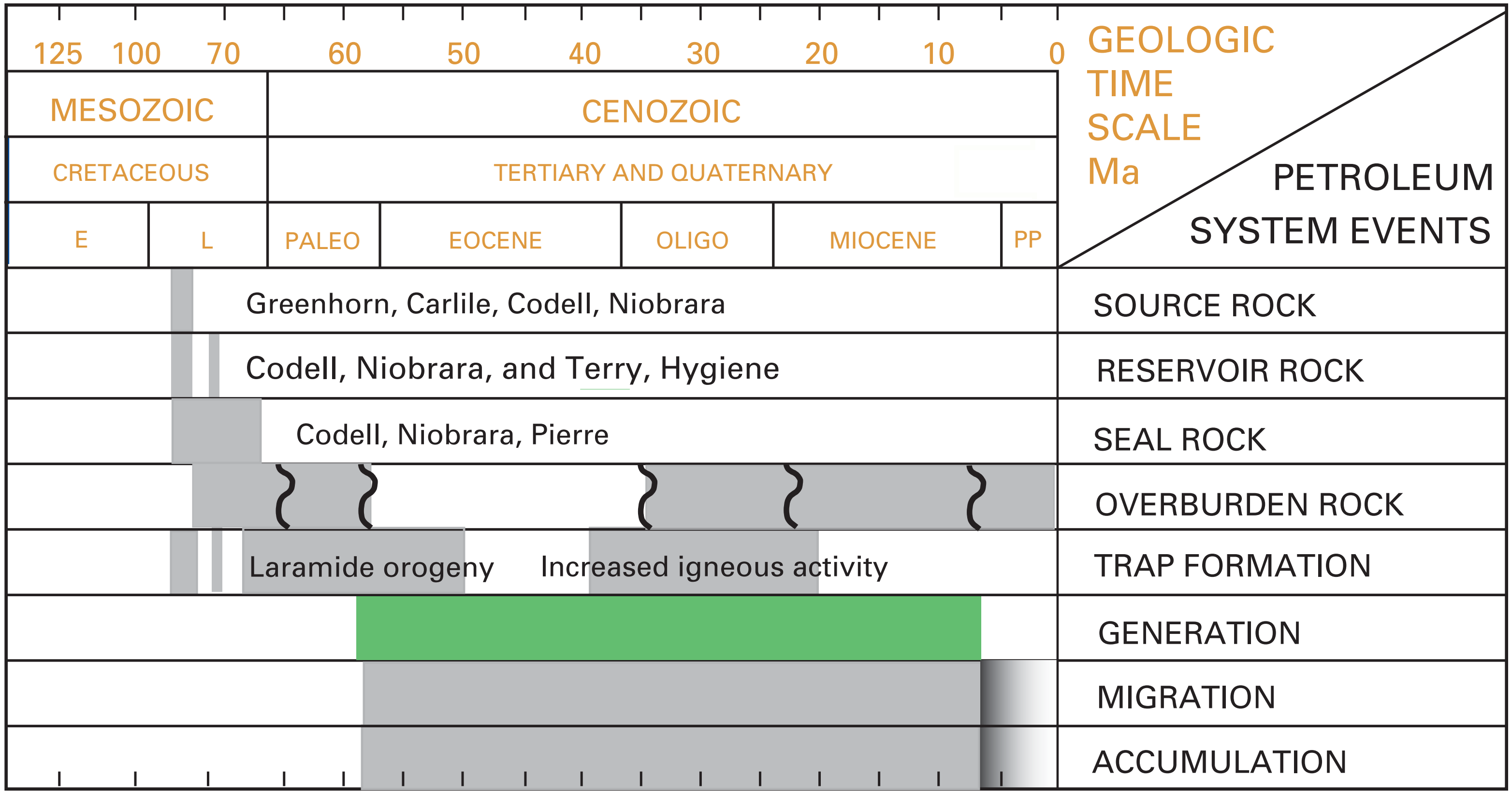


Figure 14. Geologic events chart for Upper Cretaceous formations in the western Denver Basin. Gray intervals mark times of primary events; gradients show possible times of events. Green interval marks time of generation of oil from the Niobrara, Codell, Carlile, and Greenhorn Formations. Wavy black lines 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).

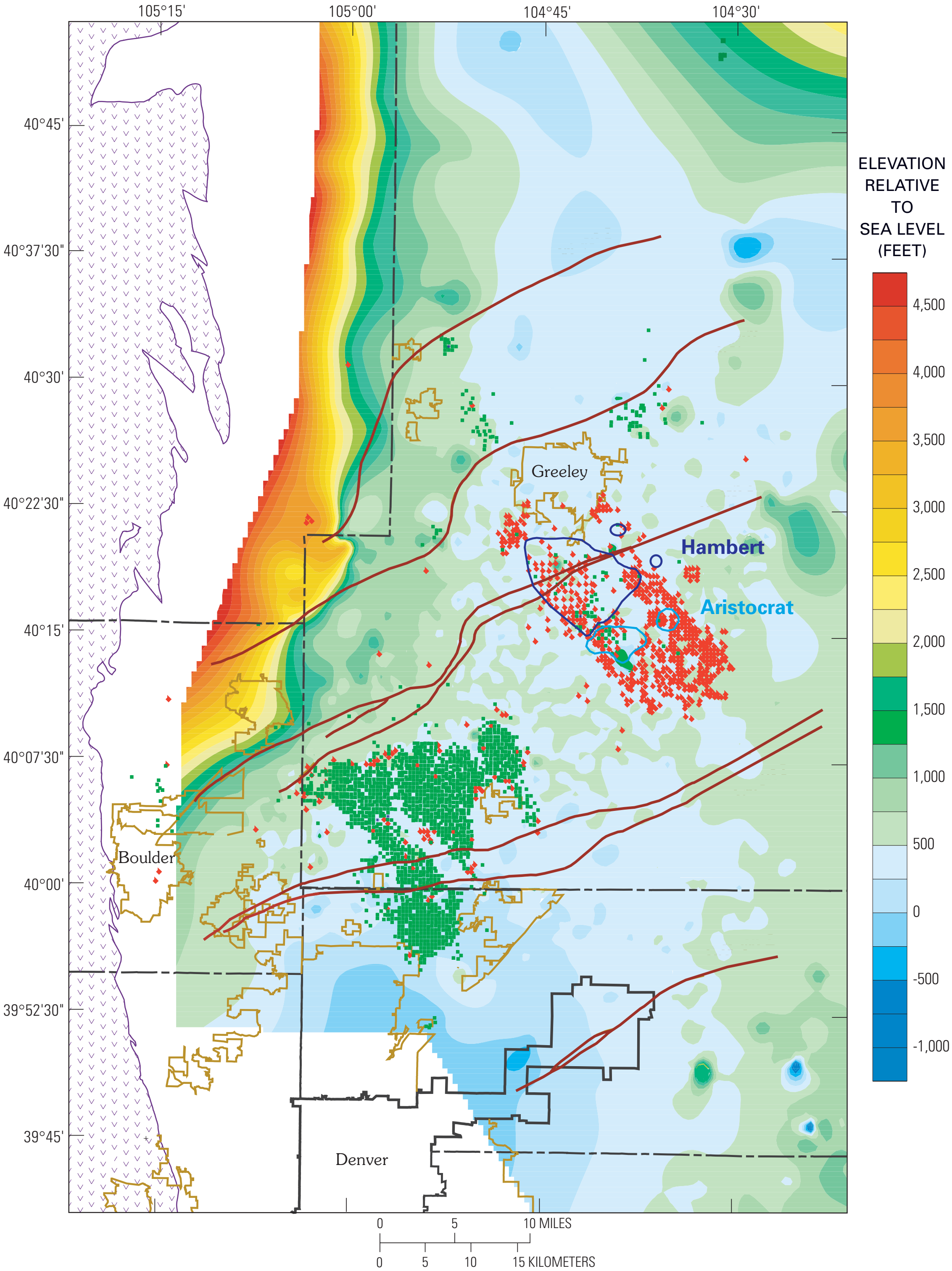


Figure 15. Producing wells from Pierre Shale in a portion of the Front Range Urban Corridor. Oil wells are green, gas wells are red, and oil and gas wells are blue. Color-filled contours are elevations relative to sea level on the top of the Upper Cretaceous Terry ("Sussex") Sandstone Member of the Pierre 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.

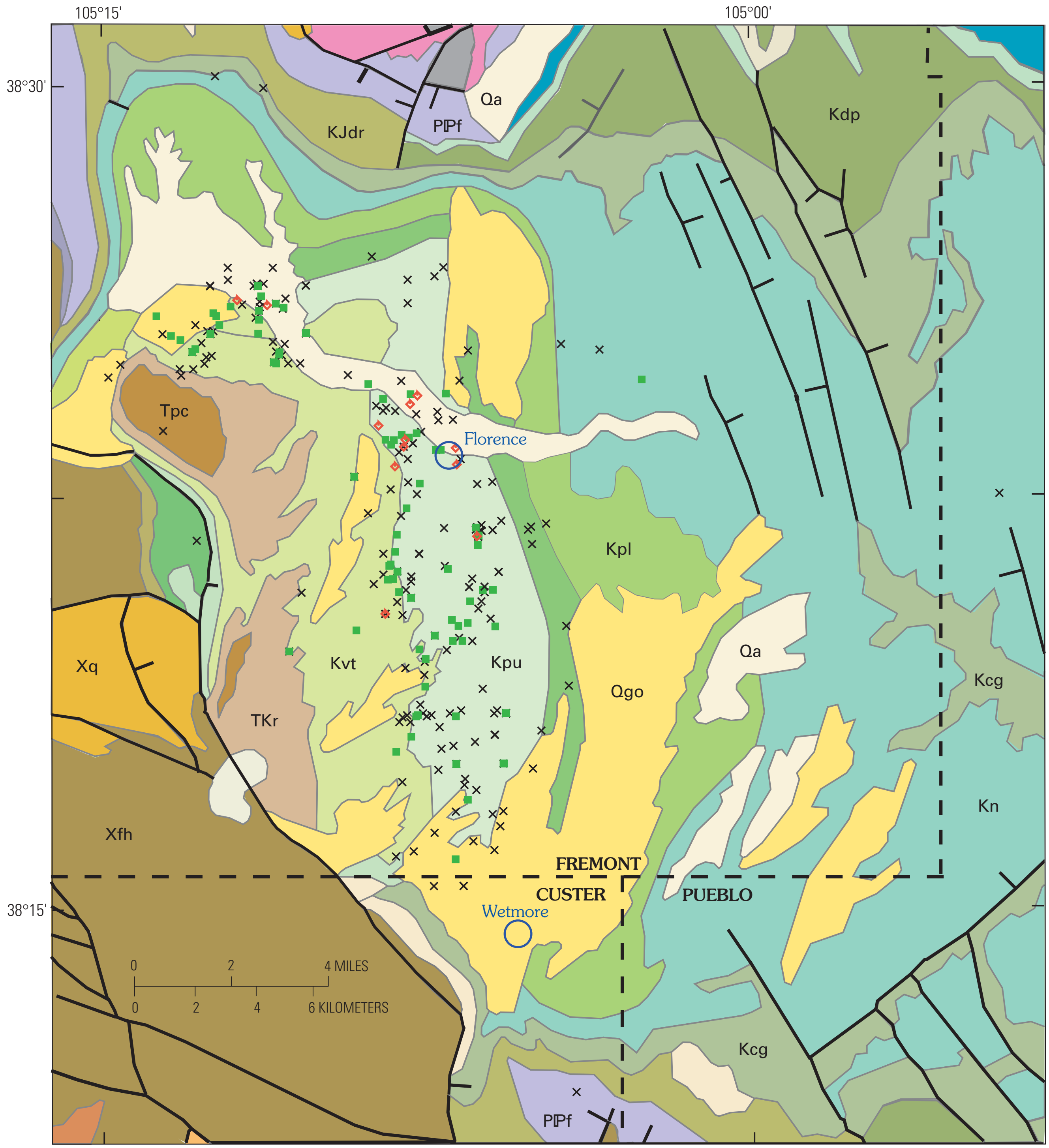


Figure 16. Symbols for oil (green square), gas (red diamond), and dry hole (black x) wells located within the Florence field. Dashed black lines are county boundaries. Solid black lines are faults, and gray lines delineate geologic formations. Formation symbols: Qa, Qgo, Quaternary alluviums and gravels; 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).

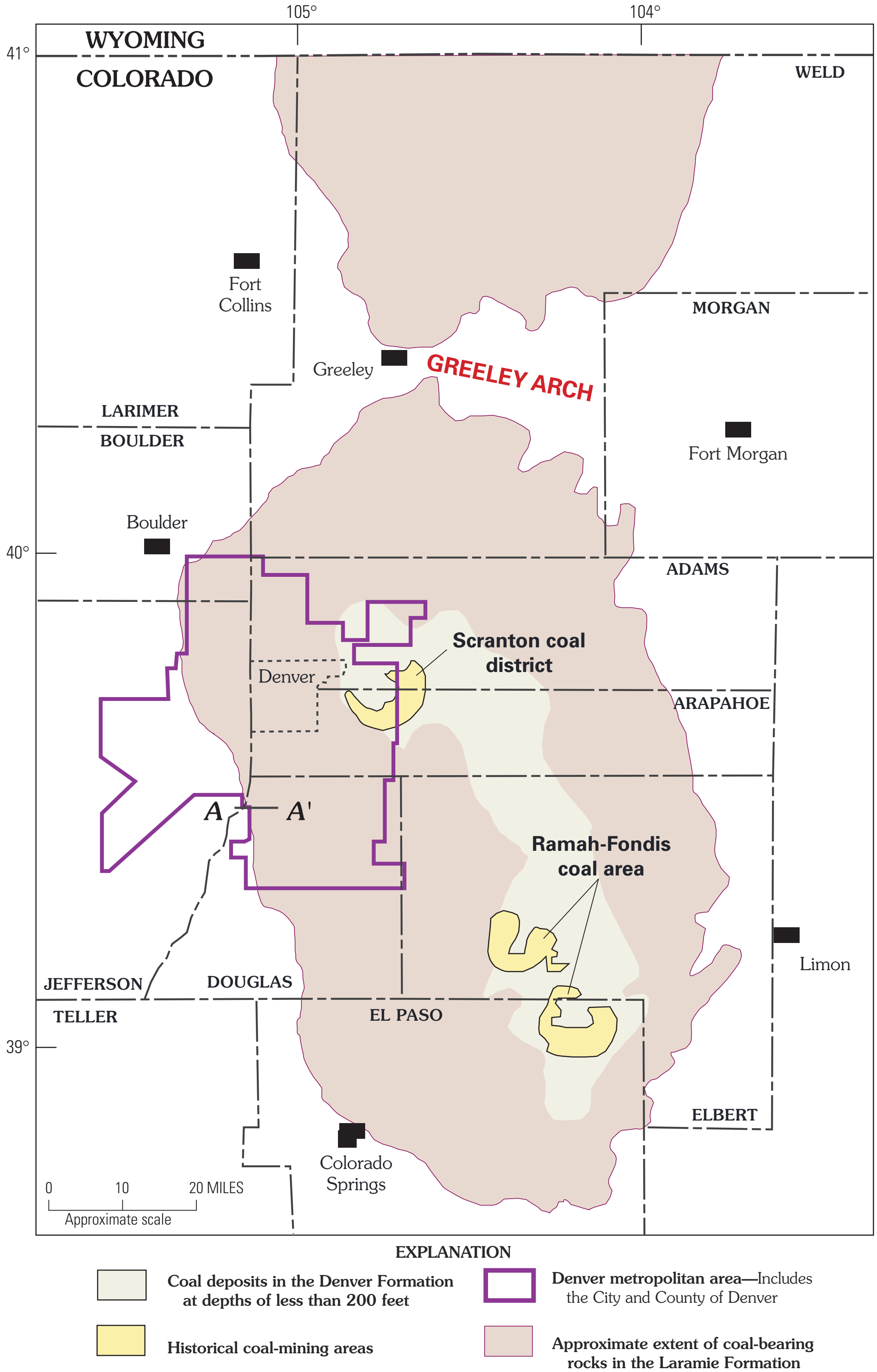


Figure 17. A portion of the Denver Basin showing distribution of coal-bearing strata of the Laramie Formation and extent of coal deposits to 200-foot (60-meter) depth in the Denver Formation. *A–A′* is the line of cross section shown in figure 18. Modified from Landis (1959), Kirkham and Ladwig (1979),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

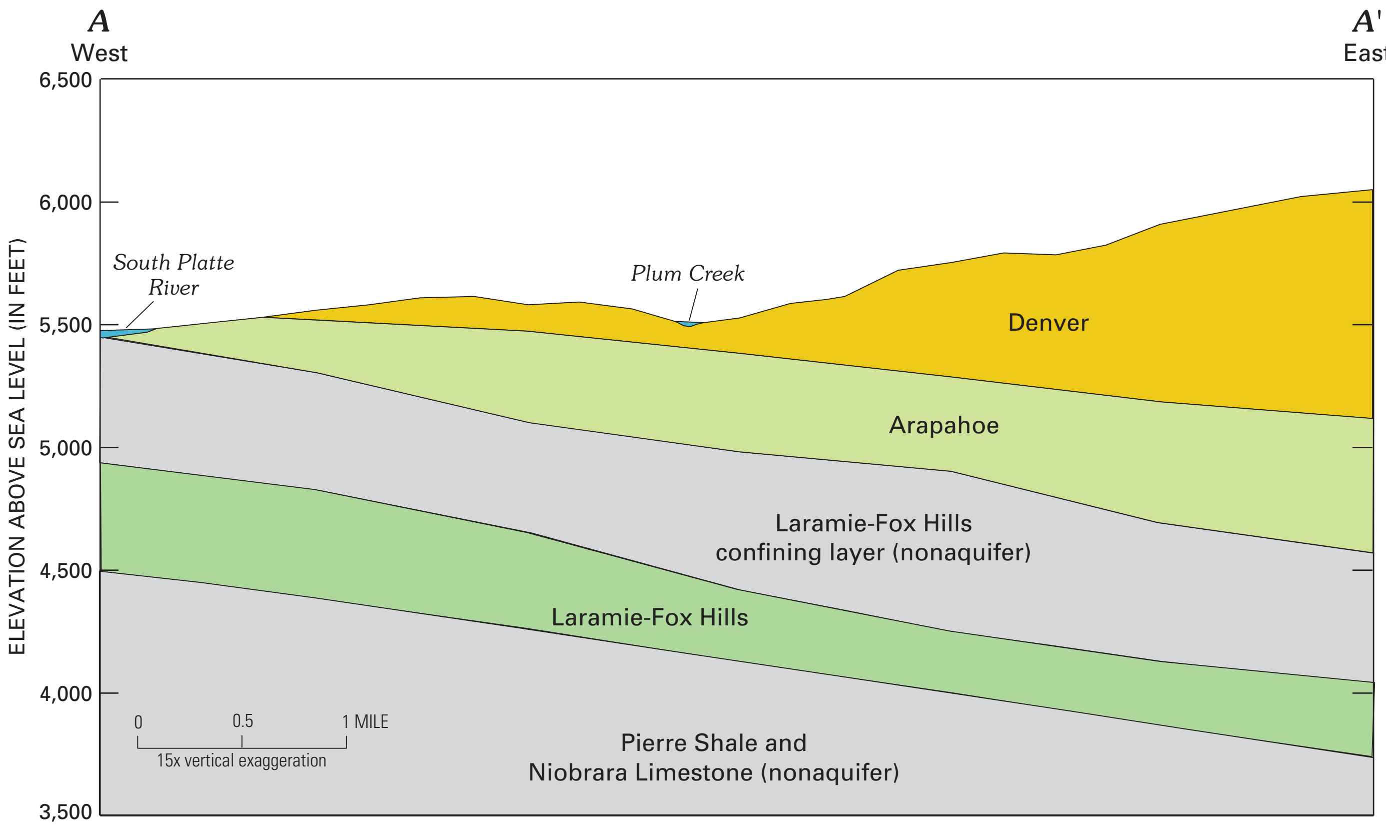


Figure 18. East-West stratigraphic cross section across northwest Douglas County. Shown are the vertical and lateral distribution of Upper Cretaceous and Tertiary Denver, Arapahoe, and Laramie-Fox Hills aquifers within a portion of the Front Range. Line of cross section is shown in figure 17. Data are 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.

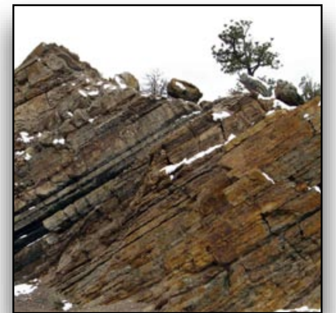
Illite/smectite geothermometry A method used to determine the degree of thermal maturation for hydrocarbon source rocks. The crystal structure of smectite becomes ordered to illite at temperatures of 100°C or greater. Illite is a general name for a group of three-layer, micalike clay minerals. Smectite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



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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 (C^4 to C^{10} carbon range).

Seaway Reference here is to the Cretaceous epicontinental 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) nonmarine 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.