DENVER BASIN PROVINCE (039)

by Debra K. Higley, Richard M. Pollastro, and Jerry L. Clayton

INTRODUCTION

The Denver Basin Province is an asymmetrical Laramide-age structural basin located in eastern Colorado, southeastern Wyoming, the southwestern corner of South Dakota, and the Nebraska Panhandle. Two basin deeps located along the axis of the basin, close to the Front Range, separate the steeply dipping western flank and gently dipping eastern flank. The basin 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, and on the southwest and southeast by the Apishapa Uplift and Las Animas Arch, respectively.

The primary producing plays in this province are the Dakota Group (Combined D and J Sandstones) Play (3905), and the J Sandstone Deep Gas (Wattenberg) Play (3906). Approximately 90 percent of the 800 MMBO and 1.2 TCFG produced from the basin has been from the J sandstone (Land and Weimer, 1978, Tainter, 1984). These two plays include 180 oil accumulations containing 1 or more MMBO. Eighteen fields have produced 6 BCFG or more (Hemborg, 1993d). Half of the province's 1.2 TCFG has been produced from the Wattenberg field; this field was discovered in 1970 and has produced about 0.63 TCFG and 2.2 MMBO from the J sandstone, Codell Sandstone, and Sussex (Terry) Sandstone. The largest oil field in the Denver Basin is Adena with more than 62 MMBO produced from the J and D sandstones and estimated ultimate recoverable of 62.5 MMBO.

Primary trapping mechanisms in most Denver Basin plays are stratigraphic and, secondarily, a combination of stratigraphy and minor structures. Stratigraphic traps are mainly facies change and updip pinch-out of reservoir intervals. Play assignments were determined based on producing age and formations, trapping mechanisms, and petroleum production characteristics.

Six conventional and five unconventional plays were considered and are described in the following order:

CONVENTIONAL PLAYS

3901 Pierre Shale Sandstones Play

3903 Niobrara Chalk–Shallow Biogenic Gas Play

3905 Dakota Group (Combined J and D Sandstones) Play

3907 Basin-Margin Structural Play

3908 Permian-Pennsylvanian Plan

3910 Subthrust Structural Play

UNCONVENTIONAL CONTINUOUS-TYPE PLAYS

3904 Greater Wattenberg Codell/Niobrara Oil and Gas Play

3906 J Sandstone Deep Gas (Wattenberg) Play

3911 Fractured Shale-Pierre Play
Described by Debra K. Higley and Donald L. Gautier

3920 Fractured Niobrara-Greater Silo/Dale Salt-Edge Oil Play
Described by Richard M. Pollastro

3921 Fractured Niobrara-Greater Northern Denver Basin Oil
Described by Richard M. Pollastro

ACKNOWLEDGMENTS

Scientists affiliated with the American Association of Petroleum Geologists and from various State geological surveys contributed significantly to play concepts and definitions. Their contributions are gratefully acknowledged.

CONVENTIONAL PLAYS

3901. PIERRE SHALE SANDSTONES PLAY

Oil and gas in marine-ridge sandstones of the Upper Cretaceous Pierre Shale are primarily stratigraphically trapped. Seals are overlying and updip marine shales. Production from this play is along the western flank of the Denver Basin, at depths of about 4,000–5,500 ft.

Reservoirs: Oil and associated gas are produced from elongate fine-grained sandstones of the Richards Sandstone and Terry and Hygiene Members (informally called the Sussex and Shannon Sandstones). Thickness of reservoir sandstones ranges from 4 to 48 ft; average thickness is 20 ft. This play includes seven accumulations; five of these are listed as stratigraphic traps and 1 is a combination trap. Average porosity is 14 percent; average permeability for two fields is 0.1 mD and 8 mD. Oil gravity ranges from 40^{o} to 65^{o} API.

Structural and diagenetic trapping mechanisms affect petroleum occurrence and recovery. The primary reservoir facies are trough-crossbedded fine- to medium-grained glauconitic sandstones that represent the highest depositional energy. These sandstones are located along the seaward margins and crests of individual sand ridges that characterize the sand bodies (McKinnie, 1993, Pittman, 1988). Reservoir heterogeneity results from (1) numerous permeability boundaries between the thin-bedded reservoir sandstones, (2) interbedding of high- and low-depositional energy sandstone and mudstone, (3) highly variable distribution of porosity and permeability resulting from cementation by calcite and quartz, and (4) pore filling clays and glauconite.

Source rocks and timing: Hydrocarbon source rocks are bounding Pierre shales, and underlying shales of the Niobrara, Graneros, and Mowry. Thermal maturity of samples ranges from about 0.4 percent to more than 1.14 percent mean random vitrinite reflectance (R_m) in the play area (Higley and Schmoker, 1989; Higley and others, 1992; Pollastro, 1992; Tainter, 1984). Timing of oil generation and migration is Late Cretaceous to early Tertiary time; gas generative maturity in the deepest part of the Denver Basin was reached during middle to late Tertiary time (Higley and Gautier, 1988). These estimates are based on the thermal and burial histories of Cretaceous source rocks within the play area (Higley and Schmoker, 1989).

Exploration status: The Wattenberg and Spindle fields were discovered in 1970 and 1972, respectively, and are approximately located within the 0.9 percent R_m contour. The Spindle oil field is the largest producer from this play. Spindle has estimated ultimate recoverable of 60.25 MMBO from Sussex and Shannon sandstones, and depth of production ranges from 4,700 to 5,100 ft. Aristocrat, Hambert, and Wattenberg gas fields are estimated to be 19.5, 45.3, and 7.8 BCFG, respectively.

Resource potential: Potential for significant new discoveries is lowered by reservoir heterogeneity and the fairly extensive exploration in the most favorable exploration targets in the basin. Additional fields may be discovered as offshoots of deep-basin gas exploration and from field growth of Wattenberg.

3903. NIOBRARA CHALK-SHALLOW BIOGENIC GAS PLAY

Dry, nonassociated gas of probable biogenic origin is produced from shallow chalk and shale reservoirs of the Upper Cretaceous Niobrara Formation. This play is located on the gently dipping eastern flank of the basin; the play is delineated by depth limits of about 800 ft to 4,000 ft.

Reservoirs: Gas is produced from underpressured, stratigraphically trapped gas in fine-grained, low-permeability, high-porosity, organic-rich chalks. Reservoir quality is controlled by burial diagenesis (Scholle, 1977) and influenced by fracturing. Average porosity ranges from 32 to 40 percent for five fields; permeability (excluding fracture permeability) ranges from 0.1 to 16 mD with an average of 1 mD (Hemborg, 1993b).

The Niobrara Formation ranges in thickness up to about 450 ft (Burchett, 1992) in the play area. The principal reservoir for gas is the upper 10–45 ft of the Smoky Hill Member of the Niobrara Formation. Depths of production range from 1,500 ft (Beecher Island field) to more than 2,900 ft (White Eagle field).

Source rocks, timing and migration: Estimated vitrinite reflectance in the play area is about 0.3-0.4 percent R_m (Smagala and others, 1984, Tainter, 1984). Owing to the low permeability of the reservoir rocks, low levels of thermal maturity, and organic carbon contents of chalks and shales that average 3.2 percent (Rice, 1984), the gas is believed to be generated in place from the Niobrara Formation. Gas composition in the Waverly-Eckley fields area is about BTU 1030, specific gravity of 0.60, 89 percent methane, 3 percent ethane, 3 percent propane, and 5 percent nitrogen (Hemborg, 1993b).

Traps: Trapping mechanisms are overlying Pierre Shale and low-relief structural noses.

Exploration status: Eight fields in the eastern Denver Basin have cumulative production greater than 6 BCFG of Niobrara biogenic gas; nine fields contain estimated ultimate recoveries greater than 6 BCFG. The best known field of this play is the Beecher Island field in Yuma County, southeast Denver Basin, Colorado. More than 16.7 BCFG has been produced since the field was discovered in 1919. Estimated ultimate recovery is estimated at 58.5 BCFG.

Resource potential: Low to moderate rates of exploration in the play area, combined with geologic and hydrodynamic information on the basin, indicate high potential for continued field growth and for additional field discoveries containing gas reserves equal to or greater than 6 BCFG.

3905. DAKOTA GROUP (COMBINED J AND D SANDSTONES) PLAY

Included in this play are oil and minor gas from the J sandstone of the Muddy Sandstone of the Dakota Group, and the overlying D sandstone, both Lower Cretaceous units. The production fairway of the play is located in the central and northeastern parts of the basin, covering approximately half the province. Oil and gas traps are stratigraphic and combination; seals are primarily overlying marine mudstones and lateral-and-updip change in facies from porous and permeable sandstone to mudstone and cemented sandstones. Depths of production are from about 3,000 to more than 8,000 ft.

Reservoirs and traps: Primary productive facies are fine- to medium-grained sandstones of distributary channel and delta-front depositional environments. Hydrodynamics and location of distributary channel systems influence hydrocarbon migration and trapping mechanisms. The Dakota Group reaches thicknesses of 540 ft (Higley and Schmoker, 1989; Sonnenberg, 1985). Thickness of producing formations averages about 25 ft. Median core porosity for the J sandstone across the basin ranged from about 24 percent at 4,000 ft depth to 7 to 10 percent at 9,000 ft. Average porosity for J sandstones is about 9.5 percent and ranges up to 28 percent on the eastern flank of the basin (Higley and Schmoker, 1989). Average porosity and permeability for the J sandstone in the Adena field are 19.7 percent and 356 mD. Average porosity and permeability of the D sandstone reservoirs are 15 percent and 187 mD (Hemborg, 1993c). Permeability may reach as much as 2,200 mD and averages less than 500 mD for J and D fields with listed permeability data.

Source rocks, timing and migration: Incised Dakota Group drainage patterns (Weimer and others, 1986) with subsequent deposition of distributary channel sandstones provided both reservoir and migration pathways for oil. Thermal maturity data across the northern two thirds of the basin indicate that values range from about 0.4 to 1.14 percent R_m. Many fields on the eastern flank of the basin are located in areas where source rocks are marginally mature (less than 0.6 percent R_m). Mowry, Graneros, J sandstone, and Skull Creek shale source rocks in one well near the Wattenberg "hot spot" were analyzed by Rock-Eval pyrolysis of TOC; TOC ranged from 2.37 percent to 0.8 percent at depths of 8,282 to 8,353 ft, respectively. Source rock shales were sampled from wells scattered across the Denver Basin. TOC values ranged from 0.24 to 67.7 percent by weight; 2.5 percent by weight is a good approximation of average TOC for Dakota Group source rocks.

Exploration status: More than 90 percent of the more than 800 MMBO and 1.2 TCFG produced from the basin has been from this play (Land and Weimer, 1978, Tainter, 1984). Hemborg (1993c, d) listed cumulative oil production for the J and D sandstones as 298.2 and 168.7 MMBO, respectively. This play contains 196 reservoirs of 1 MMBOE or greater. Trapping mechanisms are stratigraphic (90 reservoirs), structural (18), and combination (133). The Wellington oil field, located proximal to the Front Range Uplift, is the earliest discovery for this play (1923); J sandstone production here is controlled by anticlinal closure (Hemborg, 1993d). The first D sandstone discovery was the 1930 Greasewood field, which had commercial production from two wells (Hemborg, 1993c).

Adena is the largest oil field in the basin with J sandstone production of about 59 MMBO, 4.7 MMBNGL, and 64.4 BCFG; estimated ultimate recoveries are 62.5 MMBO, 4.7 MMBNGL, and 64.4 BCFG. D sandstone estimated ultimate recoveries for this field are 3.5 MMBO, 1.2 MMBNGL, and 16.8 BCFG.

Resource potential: Although this play has been maturely explored, good potential remains for additional ^{3}1 MMBOE field discoveries within and bordering the fairway, which is located in northeastern Colorado, the Nebraska Panhandle, and southeastern Wyoming. Additional discoveries in this play are associated with locations of distributary channel systems, areas of generation and migration of hydrocarbons, and structural elements associated with the northeastern extension of the Colorado Mineral Belt into the Nebraska Panhandle.

3907. BASIN-MARGIN STRUCTURAL PLAY

This play borders the western and northwestern margin of the Denver Basin. Production began early in the history of exploration in the basin. Oil and minor gas were produced from the Permian Lyons Formation, from small anticlines proximal to the western margin. Traps are structural and combination structure and stratigraphic.

Reservoirs: Potential reservoir rocks in the play are eolian, fluvial, and marine sandstones of the Lyons Formation. Current depths of production are about 3,000–10,000 ft for the basin-margin anticlines.

Source rocks, **timing and migration:** Paleozoic black shales in the northern and northeastern Denver Basin have high potential as source rocks (Clayton, 1992; Clayton and others, 1992) and should be within the thermal zone of oil generation at the approximate 7,000–13,000 ft depths of possible undiscovered fields. Clayton found that black shales of the Desmoinesian section in the northern and northeastern Denver Basin generated and possibly expelled oil at low levels of thermal maturity (0.4-0.6 percent R_m equivalent).

Traps: Structural traps were formed during the Laramide orogeny starting about 65 Ma; migration of oil into the reservoirs postdates this time. Structural traps proximal to the Hartville uplift are largely Paleozoic in age, based on westward thinning of strata and unconformable contacts with the overlying Triassic Chugwater Formation (Sonnenberg, 1985). Laramide reactivation of the Hartville Uplift and the Rocky Mountains resulted in erosion of Paleozoic strata and in creation of structural traps along the Front Range and southeast of the uplift.

Exploration status: Oil was discovered in the Lyons Sandstone in 1953 at the Keaton field. The largest fields are Black Hollow and Pierce, in Weld County, Colorado, which have each produced more than 10 MMBO with ultimate recoverable resources of about 17.5 and 19.5 MMBO, respectively. Four fields are located in this play. These are Berthoud, Black Hollow, New Windsor, and Pierce. Average porosity and permeability for three fields are about 9 to 12 percent and 21 to 88 mD.

Resource potential: The Paleozoic section bordering the Hartville Uplift contains potential for further oil and gas production. Pennsylvanian and Permian carbonates in the Hartville Uplift area contain reservoir-grade porosity and permeability (Sonnenberg, 1985). Oil shows, but no producing wells, are present in Pennsylvanian carbonates and sandstones southeast of the uplift. Permian age (Wolfcamp) strata in the northwest Denver Basin ranges in thickness from 300 to 500 ft. Underlying Pennsylvanian-age strata are 600 to more than 800 ft thick. The thinly bedded sandstone and carbonate units wedge-out towards the Hartville Uplift (Sonnenberg, 1985).

Extensive exploration combined with detailed geologic studies along the Front Range indicates little potential for additional field discoveries here. Some potential exists for discovery of Paleozoic reservoirs in the Hartville Uplift area, although exploration and seismic data are limited and uncertainty in assessment is large.

3908. PERMIAN-PENNSYLVANIAN PLAY

This play covers most of the Denver Basin, excluding areas west of the Basin-Margin Structural play (3907) boundary. Production is located in northeastern Colorado and the Nebraska Panhandle.

Reservoirs: Oil is primarily produced from cyclical carbonates of the Admire Group of the Permian Wolfcamp; some oil is also produced from the Wykert sandstone interval of the Council Grove Group. Minor amounts of oil are also produced from Pennsylvanian age sandstone, limestone, and dolomite in the Nebraska Panhandle and far eastern flank of the basin. Prospective depths of production are about 4,000–10,000 ft from cyclical sandstone-limestone-dolomite sequences of the Desmoines, Missouri, and Virgil. The Morrow Sandstone produces mainly oil in the southeastern Denver Basin; this is assessed in the Las Animas Arch Province (044) as the Lower Pennsylvanian (Bend) Sandstone Play (4404) .

Traps: Trapping mechanisms for Wolfcamp reservoirs in the Nebraska Panhandle, Golden, Colo. area are updip and overlying low porosity and permeability evaporites (F.F. Meissner, Colorado School of Mines, 1993 oral comm.), facies change, and low-relief structural noses. Reservoir seals are overlying evaporites and mudstones. Primary trapping mechanisms for Pennsylvanian plays in the adjacent Midcontinent region consist of low relief structural noses and combinations of structure and updip porosity and permeability pinch-outs; stratigraphic trapping in bars and channel sandstones and against unconformably overlying low-permeability formations may also occur. Porosity and permeability development of Pennsylvanian and Permian strata in the Central Kansas Uplift Province is associated with uplift and erosion; production is concentrated in the more porous strata proximal to the basin axis.

Source rocks, timing and migration: Thermal maturity of overlying Lower Cretaceous shales ranges from about 0.4 to 0.9 within the play area. Black shales of the Desmoinesian section in the northern and northeastern Denver Basin have high potential as source rocks (Clayton, 1992; Clayton and others, 1992). Clayton found that the shales generated and possibly expelled oil at low levels of thermal maturity (0.4-0.6 percent R_m equivalent). Some Virgil and Wolfcamp rocks also have high organic carbon contents (up to about 4 percent) and are potential source rocks for these oils (Sulistyo, 1994). The probable time of oil generation and migration is Late Cretaceous through much of Tertiary, based on burial history reconstruction of overlying Cretaceous and Tertiary strata.

Exploration status: Producing Permian fields in the Denver Basin Province include Kleinholz and Anna in Nebraska and Marks Butte and Marks Butte North in Wyoming; also, some shows of oil have been noted in Laramie County, Wyoming. Oil is trapped in the Kleinholz field by facies change and a structural nose; more than 0.5 MMBO has been produced from Permian Wolfcamp dolomites and the Wykert sandstone since 1986. Ultimate recovery is 2.8 MMBO and depth of production is about 8,100 ft. The Swearingen field of the Denver Basin in Nebraska produces oil and gas from a depth of 8,190 ft in the Pennsylvanian Missouri and 7,900 ft (2,400 m) in the Permian Admire. The Bird field, also in the northeast Denver Basin, produces oil from the J and D sandstones and Permian Wolfcamp, Virgil, and Missouri sandstones. Depth of production is about 6,800 ft.

Resource potential: Subsurface mapping, core, and thermal maturity studies indicate potential for significant discoveries. The northeastern Denver Basin will probably have additional ^{3}1 MMBO discoveries. Raul and Loeffler (1994) have indicated areas of porous, potentially productive Wolfcamp dolomites bordering the southeastern flank of the basin and bordering Fountain Formation arkoses along the western boundary.

3910. SUBTHRUST STRUCTURAL PLAY (HYPOTHETICAL)

This hypothetical conventional play includes possible production of oil and gas from Mesozoic and (or) Paleozoic sediments buried under thrust-faulted Precambrian rocks bordering the western margin of the Denver Basin. Current exploration information is confined to seismic data with minor hydrocarbon shows in outcrops and in several wells. Outcrop locations are Turkey Creek, southwest of Denver, and Four Mile Canyon, north of the Canon City embayment.

Reservoirs: Proposed reservoir units include the Lower Cretaceous J sandstone of the Dakota Group, and, to a lesser extent, the Pennsylvanian Fountain Formation, and the Permian Lyons Sandstone. Reservoirs may be associated with fractures.

Source rocks, timing and migration: Because of insulating effects of overlying Precambrian rocks, influence of high-heat flow associated with the Colorado Mineral Belt and other tectonic features, and the depths of occurrence (6,000 to more than 14,000 ft), potential source rocks would be mature to overmature. Some production could be shallower, as depth is based partly on thickness of overlying Precambrian strata. Probable source rocks are the Lower Cretaceous Mowry, Graneros, and Skull Creek Shales. Source rock richness would range from 0.24 to 67 percent TOC, averaging probably 2.5-5 percent, based on published and unpublished thermal maturity data (Higley and Gautier, 1988; Higley and others, 1992; Tainter, 1984). Permian and Pennsylvanian age black shales may also have generated hydrocarbons and would be the source of oil and gas for possible Paleozoic fields. TOC of these samples ranges from about 1 to 42 percent in the northern Denver Basin (Clayton, 1992; Clayton and others, 1992; J.L. Clayton, unpub. data, 1994). Times of oil generation and migration would probably correspond to those of other areas in the basin; oil generation would have begun following the Laramide orogeny (about 68 Ma) and may be continuing now.

Traps: Potential trapping mechanisms are structural and stratigraphic. Hydrocarbons could be trapped under the thrust sheet of Precambrian rocks and may occur in stratigraphically trapped reservoirs. Primary time of formation of structural traps is Cretaceous to possibly Eocene time; formation is associated with the Laramide orogeny and uplift of the Rocky Mountains. Potential hydrocarbon traps of Paleozoic strata may also be associated with ancestral uplift of the Rocky Mountains.

Resource potential: This play was not quantitatively assessed. The potential exists for economic accumulations based on the presence of oil seeps east of the Front Range Uplift, and of porous and permeable J sandstone distributary channel systems bordering the Front Range. However, lack of information on potential traps, seals, and reservoir favorability precluded resource estimation.

UNCONVENTIONAL PLAYS

Continuous-Type Plays

3904. GREATER WATTENBERG CODELL/NIOBRARA OIL AND GAS

In this unconventional continuous-type play, oil and gas are stratigraphically trapped in marine sandstones of the Cretaceous Codell Sandstone (Wall Creek/Turner equivalents) and cyclical-bedded chalk, marl, and shale of the Niobrara Formation. The Codell and Niobrara are evaluated together because as much as half of the wells per field report commingled production (1993 Colorado Oil and Gas Comm). Reservoir sandstones exhibit low porosity and permeability and are classified as tight gas sands. This play is located in the deeper part of the basin north of Denver. Most production is in the areas of the Wattenberg and Spindle fields. Productive depths are about 3,000–8,000 ft. Average depth is 6,800 ft.

Reservoirs: Niobrara Formation thickness ranges from 240 to 330 ft; four 20-30 ft thick chalk zones in the unit are productive (Hemborg, 1993a). Thickness of reservoir sandstones ranges from 22 to 35 ft for five fields (Weimer and Sonnenberg, 1983). Core examination indicates Niobrara and Codell porosity are commonly 10 percent or less, primarily due to abundant pore-filling clay, calcite cements, and iron oxide (Hemborg, 1993a). Porosity in the Codell Sandstone ranges from about 10 to 22 percent at Hambert field, southeast of Greeley, Colo. Codell Sandstone at Wattenberg field (discovered 1970) has an average porosity and permeability of 14 percent and 0.1 mD.

Source rocks, timing and migration: Source rocks are probably the organic-rich Mowry, Graneros, and Niobrara Formations. Thermal maturity data from underlying Mowry and Graneros Shales suggest thermal maturity levels of 0.8 percent R_m and greater in the play area.

Exploration status: Basin center Codell/Niobrara fields with ultimate recoveries greater than 6 BCFG include Bracewell, Eaton, Greeley, Kersey, and Wattenberg. The Hambert and Loveland fields have smaller Codell/Niobrara reserves. The earliest production from this play was from shallow fractured sandstones of the Boulder field (discovered 1901); about 800,000 BO and 52,000 CFG have been produced from the Niobrara and Codell. Codell sandstone production through 1990 for the Wattenberg field is 15 MMBO, 10 MMBNGL, and 0.135 TCFG with ultimate recoveries of 27 MMBO, 26 MMBNGL, and 0.318 TCFG.

Resource potential: Probability of discovery of additional 6 BCFG equivalent fields is decreased by the low permeability and high rates of exploration in the most favorable areas of the play (overlying the Wattenberg field). Additional fields may be discovered through northward extension of deep basin gas exploration.

3906. J SANDSTONE DEEP GAS (WATTENBERG) PLAY

Gas and NGL produced from this unconventional continuous-type play are from combination stratigraphic/structural/ diagenetically trapped reservoirs of the Lower Cretaceous Muddy (J) sandstone. This play is located along the basin axis in the deepest areas of the basin in Colorado and Wyoming. Production from this play corresponds to the FERC tight gas category.

Reservoirs and traps: Gas is produced from mainly fine-grained quartz arenites of nearshore marine sandstones of the Fort Collins Member of the Muddy (J) Sandstone and, to a lesser extent, distributary channel sandstones of the Horsetooth Member. Porosity and permeability range from 8 to 12 percent and 0.01 to 5 mD; they average 9.5 percent and 0.05 mD (Hemborg, 1993d, Higley and Schmoker, 1989). Low porosity and permeability are related to burial depth and diagenesis, and to depositional environment. Thickness of reservoir intervals averages 20 ft. Reservoirs are underpressured and produce from depths of about 7,200–8,500 ft. Production of gas is decreased by low porosity and permeability, interbedding of thin reservoir sandstones with burrowed mudstone/sandstones and cemented sandstones, and pore-filling kaolinite and minor illite-smectite. Production is enhanced by moderate to extensive fracturing, and by late-diagenetic porosity enhancement through dissolution of calcite cements (Higley and Schmoker, 1989).

Source rocks, timing and migration: The presence of elevated mean random vitrinite reflectance values from 1.1 to 1.75 percent R_m in the area of the Wattenberg field, combined with carbon stable isotope composition of the gas, suggests gas has a thermogenic origin, with contribution from Type III organic matter (Higley and Schmoker, 1989, Higley and others, 1992, Tainter, 1984). Gas generative maturity in the play area was reached during middle to late Tertiary time (Higley and Gautier, 1988). TOC values average about 2.5 percent by weight for the Graneros, Mowry, and Skull Creek Shales hydrocarbon source rocks.

Exploration status: Two fields located within the play, Wattenberg and Bear Gulch, contain estimated ultimate reserves of 6 BCFG or greater. Wattenberg field, in Weld

County, Colorado, is the largest field with more than 487 BCFG produced, proved reserves of 1.3 TCFG and ultimate recoverable estimated some sources as much as 2.6 TCFG. The Wattenberg field was discovered in 1970. Average reservoir depth is 7,350 ft. Bear Gulch field (1973) has produced 2.668 BCFG and about 240,000 barrels each of NGL and oil from the J sandstone; D sandstone production is .624 BCFG, 56,000 barrels of NGL, and 100,000 BO. Estimated ultimate recoveries for Bear Gulch field are about 3.4 BCFG and 7.4 BCFG from the J and D sandstones, respectively. Average depth of Bear Gulch production is 8,000 ft.

Resource potential: Additional discoveries will result primarily from growth and extension of the Wattenberg field discovery. The basin deep of Wyoming does not have deep gas production; however exploration has been very limited, and some potential for deep gas exists here. Lower levels of thermal maturity of J sandstone source rocks in the Wyoming portion of the play suggests only limited potential for gas.

3911. FRACTURED SHALE-PIERRE PLAY

By Debra K. Higley and Donald L. Gautier

Oil is produced from underpressured, relatively impermeable shales of the Upper Cretaceous Pierre Shale Play (3911). This is an unconventional play largely because of low permeability (primarily fracture permeability) and the association of regional tectonics and faulting with distribution of fields and recovery of oil. The Florence oil field of the Canon City embayment is the oldest continuously producing field in the world; the Pierre shale is the only reservoir in this play.

Reservoir rocks: Reservoir facies are gray to black organic-rich shales, and thin sandy shales. The Pierre Shale in the field is about 100 ft thick. Because open fracture networks are critical to oil emplacement and production, fractured-shale reservoirs are primarily shallow. Depths of production range from about 900 to 2,600 ft. Maximum field size is 22,000 acres.

Traps: Most of the tectonic and sedimentologic factors important in forming Niobrara fractured reservoirs (see unconventional Fractured-Niobrara Plays 3920 and 3921) are also present within the Pierre shales--that is, presence of open fractures, organic-rich shales as an in-place source of oil, and brittle reservoir rocks with bounding seals. Traps are bounding shales and lateral loss of fracture systems. Underlying shales limit influx of water into the reservoir. Drive mechanism is gravity drainage with minor solution gas drive; initial field pressure was 5-10 psi (Carpenter, 1961).

Exploration status: The Florence field was discovered in 1862 with discovery of oil in a water well drilled near the town of Wetmore, Colorado (Carpenter, 1961). More than 15.1 MMBO and .012 BCFG were produced through 1990 from fractured Pierre shales. Ultimate recoveries are estimated at 15.5 MMBO and .018 BCFG. API gravity of oil is about 31°; sulfur content is about 0.34 percent.

Resource potential: Potential is very low for additional ^{3}1 MMBO fractured Pierre Shale discoveries, although there may be additional small field discoveries in other areas of the province. The primary factor limiting new discoveries is the presence of open fracture networks in thermally mature brittle shales.

Niobrara Fractured Limestone Oil Plays

3920. FRACTURED NIOBRARA-GREATER SILO-DALE SALT EDGE OIL PLAY

Oil is produced from organic-rich, underpressured and fractured, cyclic-bedded chalk, marl, and calcareous shale of the Upper Cretaceous Niobrara Formation in the northeastern portion of the Denver basin. These micritic limestones have low (<0.01 mD) matrix permeability and low (<10 percent, and typically 6-8 percent) matrix porosity and are considered as an unconventional resource. Thus, although the matrix of target units in the Niobrara is oil saturated, macro- and microsize natural fractures are required to transmit fluid to the well bore. The Fractured Niobrara Greater Silo-Dale Salt Edge oil play lies exclusively in Laramie County, Wyoming and comprises two fields; one field, Silo field, is of minimum size. Silo field, located in the deeper part of the northern Denver basin, lies along the western edge of the northwest-trending Morgan County low where stuctural and lithologic factors imply a fault controlled basement trough; Dale field directly to the east has essentially merged with Silo and is referred to here as the greater Silo-Dale play. Silo represents a "sweet spot" for fracture production. Silo field, discovered in 1981, is located at the intersection of two major structural trends and in an area of homoclinal dip. It is suggested that thinning of the of Niobrara units and increase in regional dip indicate a draping over an irregular salt solution edge in Lower Permian rocks (Weimer, 1984; Montgomery, 1991; Sonnenberg and Wiemer, 1993). Open vertical or near-vertical fractures (with coexisting vertical stylolites) form the reservoir at Silo. These fractures are interpreted to be extentional and formed under compression by wrench faulting (Sonnenberg and Wiemer, 1993). Fracture enhancement may be associated with the salt edge (Montgomery, 1991a, b). Horizontal drilling at Silo field began in 1990 and cumulative oil production for all wells through July, 1993 was 3.14 MMBO; cumulative gas production was 1.69 BCFG. Cumulative oil production from 49 vertical wells since 1983 was 1.4 MMBO compared to 1.7 MMBO for 32 horizontal wells since 1990. Stell and Brown (1992) have estimated that cumulative oil production from average horizontal wells at Silo is about two and a half times that for average vertical wells. They report that average vertical EUR is about 34 MBO and the horizontal EUR is 88 MBO. Ultimate Niobrara recoveries for Silo field are estimated at 4.9 MMBO and 3.4 BCFG, and are probably low considering the recent production statistics resulting from horizontal wells.

Generally, five chalk and four calcareous shale units that are cyclic in nature comprise the Niobrara in this part of the Denver Basin. Oils are sourced from organic-rich (up to about 6 weight percent total organic carbon) beds having high acid-insoluble contents in the upper Smoky Hill Member. Kerogens are primarily oil-prone algal Type II. Niobrara source beds probably reached thermal maturity beginning in the Late Cretaceous (Clayton and Swetland, 1980; MacMillan, 1980; Tainter, 1982). Production in the Silo-Dale area is entirely from the Niobrara with most from the middle chalk unit or chalk "bench", informally designated as the "B bench". Although the B bench is the principal target interval, some vertical production has also come from the lowest chalk unit in the Smoky Hill Member, the "C bench". Pay thickness in the "B bench" ranges from about 25 to 35 ft. This principal target zone is commonly traced as a continuous unit in geophysical logs and corresponds to maximum resistivity and mimimum gamma ray measurements (Smagala et al., 1984; Johnson and Bartche, 1991a,b; Pollastro, 1992). Oils produced from the Niobrara have API gravities of about 35 to 38¡ and, on average, GOR's from 500 to 1000; completion GOR of these oils tend to rise after high initial flow rates. Production is lower in wells that do not lie directly on the salt edge trend and consequently GOR's are higher (Stell and Brown, 1992). Spacing for Niobrara wells has been at 40 acres; however, there is substantial evidence of interference between the two best vertical wells along the trend (Montgomery, 1991) suggesting that larger spacing is necessary. On its own motions, the Wyoming Oil and Gas Commission is currently reviewing orders for 640-acre Niobrara spacing units in Silo field (Petroleum Information, Rocky Mountain Region Report, Section 1, March 1, 1994).

The play boundary for potential Niobrara fractured limestone oil production is determined mainly by two factors: 1. the degree of thermal maturity (burial history), and 2. the type and degree of fracturing, which varies regionally. In the Silo-Dale Salt Edge play, the boundary lies within an area of thermal hydrocarbon generation estimated from thermal maturity indicators and along a fracture trend that approximates the Permian salt edge. The thermal maturity of the Niobrara is defined on the basis of vitrinite reflectance (Ro) measurements (Tainter, 1982; Rice, 1984; Higley and Gautier, 1988) and clay-mineral geothermometry using mixed-layer illite/smectite in Niobrara bentonite beds (Pollastro, 1992; 1993). Fracture patterns and intensities have been mapped and defined by Merin and Moore (1986) and Sonnenberg and Weimer (1993), among others.

3921. FRACTURED NIOBRARA-GREATER NORTHERN DENVER BASIN OIL PLAY (CONFIRMED)

Oil is produced from fractured Niobrara and commonly comingled with the immediate underlying fractured Codell Sandstone in the greater Denver Basin. This play is considered having moderate to low potential throughout the basin. The play area excludes the area outlined by the Silo-Dale Salt-Edge Oil Play (3920), southeastern Wyoming, and lies north of the Greater Wattenberg Codell/Niobrara Oil and Gas Play (3904). The east and west boundaries of the play are defined by a combination of thermal maturity indicators (R_o~7.0), structure, and production history.

Fractures in the Niobrara appear to be present throughout the northern Denver Basin and are suggested by lineaments mapped by Landsat Imagery (Merin and Moore, 1986) and by seismic data (Davis, 1985; Sonnenberg and Weimer, 1993). Oil production in the play area is demonstrated mostly from small isolated fields or wells, commonly with only a few hundred to a few thousand barrels. However, a few wells having cumulative production of about 30,000 BO in Weld County, Colorado, best describe the general nature of the play. Enhanced fracturing in the areas of these fields may be due to draping over local facies, such as channels, of J Sandstone. This is suggested from the distribution of J Sandstone production and by regional isopachs shown by Weimer and others, 1986. The play area and its potential is generally defined from Chug Springs field, Platte County, Wyoming, to the north, through Laramie County, Wyoming, to the northeast corner of Larimer County and north-northeastern portions of Weld County, Colorado, where Hereford and Tornado Butte fields are located. The southernmost portion of the play extends a south-southeast finger just into the northwest corner of Morgan County, Colorado.

This play is probably best represented by the low to moderate production in wells throughout the area with cumulative production ranging from a few thousand to 30,000 BO. Those wells off the main fairway in the Silo area of Play 3920 probably also represent typical wells for Play 3921, with cumulative median EUR of about 10-12,000 BO.

REFERENCES

Burchett, R.R., 1992, Niobrara gas indications cover wide area of western Nebraska: Oil and Gas Journal, p. 60-63.

Carpenter, L.C., 1961, Florence-Canyon City field, Parker, J. M., Colorado-Nebraska oil and gas field volume: Rocky Mountain Association of Geologists, p. 130-131.

Clayton, J.L., 1992, Geochemical evidence for Paleozoic oil in the Lower Cretaceous O Sandstone, Northern Denver Basin: American Association of Petroleum Geologists Bulletin, v. 73, p. 977-988.

Clayton, J.L., and Swetland, P.J., 1980, Petroleum generation and migration in Denver basin: American Association of Petroleum Geologists Bulletin, v. 64, p. 1613-1633.

Clayton, J.L., Warden, A., Daws, T.A., Lillis, P.G., Michael, G.E., and Dawson, M., 1992, Organic geochemistry of black shales, marlstones, and oils of Middle Pennsylvanian rocks from the Northern Denver and Southeastern Powder River Basins, Wyoming, Nebraska, and Colorado: U.S. Geological Survey Bulletin 1917-K, p. 1-44.

Curtis, B.F., 1988, Sedimentary rocks of the Denver Basin, *in* Sloss, L.L., ed., Sedimentary cover-North American craton; Geology of North America, volume D-2: Geological Society of America, p. 182-196.

Davis, T.L., 1985, Seismic evidence of tectonic influence on development of Cretaceous listric normal faults--Boulder-Wattenberg-Greeley area, Denver Basin, Colorado: The Mountain Geologist, v. 22, p. 47-54.

Hemborg, T., 1993a, Codell Sandstone and Niobrara Formation (Wattenberg area), *in* Atlas of major Rocky Mountain gas reservoirs: New Mexico Bureau of Mines and Mineral Resources, p. 107-108.

Hemborg, T., 1993b, Niobrara chalk biogenic gas, *in* Atlas of major Rocky Mountain gas reservoirs: New Mexico Bureau of Mines and Mineral Resources, p. 109-111.

Hemborg, T., 1993c, D Sand, *in* Atlas of major Rocky Mountain gas reservoirs: New Mexico Bureau of Mines and Mineral Resources, p. 112-113.

Hemborg, T., 1993d, Muddy (J) Sandstone, *in* Atlas of major Rocky Mountain gas reservoirs: New Mexico Bureau of Mines and Mineral Resources, p. 113-114.

Higley, D.K., and Gautier, D.L., 1988, Burial history reconstruction of the Lower Cretaceous J sandstone in the Wattenberg Field, Colorado, "hot spot", *in* Carter, L.M.H., ed., U.S. Geological Survey Research on Energy Resources; V.E. McKelvey

Forum on Mineral and Energy Resources: U.S.Geological Survey Circular 1025, p. 20.

Higley, D.K., Gautier, D.L., and Pawlewicz, M.J., 1992, Influence of regional heat flow variation on thermal maturity of the Lower Cretaceous Muddy ("J") sandstone, Denver Basin, Colorado, *in* Magoon, L. B., ed., The petroleum system--Status of research and methods, 1992: U.S. Geological Survey Bulletin 2007, p. 66-69.

Higley, D.K., and Schmoker, J.W., 1989, Influence of depositional environment and diagenesis on regional porosity trends in the Lower Cretaceous "J" sandstone, Denver Basin, Colorado, *in* Coalson, E. B., ed., Petrogenesis and petrophysics of selected sandstone reservoirs in the Rocky Mountain region: Rocky Mountain Association of Geologists, p. 183-196.

Irwin, D., ed., 1972, Subsurface cross sections of Colorado: Rocky Mountain Association of Geologists Special Publication 2, 39 p., 24 plates.

Johnson, R.A., and Bartsch, R.T. 1991a, Using resistivity to assess Niobrara fracture patterns for horizontal wells: Oil and Gas Journal, v. 89, p. 99-103.

Johnson, R.A., and R.T. Bartsch, 1991b, Analyzing resistivity, oil production of Niobrara in Wyoming's Silo Field: Oil and Gas Journal, v. 89, p. 68-71.

Land, C.B., and Weimer, R.J., 1978, Peoria Field, Denver Basin, Colorado-J sandstone distributary channel reservoir, *in* Pruit, J.D., and Coffin, P.E., eds., Energy resources of the Denver Basin: Rocky Mountain Association of Geologists, p. 81-104.

MacMillan, L.T., 1980, Oil and gas in Colorado--A conceptual view, *in* Kent, H.C., and Porter, K.W., eds., Colorado Geology: Rocky Mountain Association of Geologists Guidebook, p. 191-197.

McKinnie, N., 1993, Sussex (Terry) and Shannon (Hygiene) Sandstones, *in* Atlas of major Rocky Mountain gas reservoirs: New Mexico Bureau of Mines and Mineral Resources, p. 106.

Merin, I.S., and Moore, W.R., 1986, Application of Landsat imagery to oil exploration in Niobrara Formation, Denver basin, Wyoming: American Association of Petroleum Geologists Bulletin, v. 70, p. 351-359.

Meyer, H.J., and McGee, H.W., 1985, Oil and gas fields accompanied by geothermal anomalies in Rocky Mountain region: American Association of Petroleum Geologists Bulletin, v. 69, p. 933-945.

Montgomery, S., 1991a, Horizontal drilling in the Niobrara; Northern D-J Basin, Part 1--Regional geology and drilling history: Petroleum Frontiers, v. 8, no. 1, 65 p.

Montgomery, S., 1991b, Horizontal drilling in the Niobrara; Northern D-J Basin, Part 2--Silo Field: Petroleum Frontiers, v. 8, no. 2, 48 p.

Pittman, E.D., 1988, Diagenesis of Terry Sandstone (Upper Cretaceous), Spindle Field, Colorado: Journal of Sedimentary Petrology, v. 58, p. 785-800.

Pollastro, R.M., 1992, Natural fractures, composition, cyclicity, and diagenesis of the Upper Cretaceous Niobrara Formation, Berthoud field, Colorado, *in* Schmoker, J.W., Coalson, E.B., and Brown, C.A., eds., Geological Studies Relevant to Horizontal Drilling: Examples from Western North America: Rocky Mountain Association of Geologists, p. 243-255.

Pollastro, R.M., 1992, Clay minerals as geothermometers--Indicators of thermal maturity for hydrocarbon exploration, *in* Magoon, L. B., ed., The petroleum system--Status of research and methods, 1992: U.S. Geological Survey Bulletin 2007, p. 61-66.

Pollastro, R. M., 1993, Considerations and applications of the illite/smectite geothermometer in hydrocarbon-bearing rocks of Miocene to Mississippian age: Clays and Clay Minerals, v. 41, p. 119-133.

Raul, E.P., and Loeffler, P.T., 1994, New plays in an old playground--Using sequence stratigraphy: Virgin and Wolfcamp strata, Denver Embayment, Eastern Colorado, *in* Dolson, J.C., Hendcricks, M.L., and Wescott, W.A., eds., Unconformity-related hydrocarbons in sedimentary sequences: Rocky Mountain Association of Geologists, p. 267-278.

Rice, D.D., 1984, Relation of hydrocarbon occurrence to thermal maturity of organic matter in the Upper Cretaceous Niobrara Formation, Eastern Denver Basin--Evidence of biogenic versus thermogenic origin of hydrocarbons, *in* Woodward, J., and others, eds., Hydrocarbon source rocks of the Greater Rocky Mountain area: Rocky Mountain Association of Geologists Guidebook, p. 365-368.

Scholle, P.A., 1977, Chalk diagenesis and its relation to petroleum exploration--Oil from chalks, a modern miracle: American Association of Petroleum Geologists Bulletin, v. 61, p. 982-1009.

Smagala, T.M., Brown, C.A., and Nydegger, G.L., 1984, Log-derived indicator of thermal maturity, Niobrara Formation, Denver Basin, Colorado, Nebraska, Wyoming, *in* Woodward, J., and others, eds., Hydrocarbon source rocks of the Greater Rocky Mountain area: Rocky Mountain Association of Geologists 1984 Guidebook, p. 355-363.

Sonnenberg, S.A., 1985, Northwest Denver Basin/southeast Hartville Uplift, *in* Gries, R.R., and Dyer, R.C., eds., Seismic exploration of the Rocky Mountain Region: Rocky Mountain Association of Geologists, p. 213-217.

Sonnenberg, S.A., and Weimer, R.J., 1993, Oil production from Niobrara Formation, Silo field, Wyoming--Fracturing associated with a possible wrench fault system(?): The Mountain Geologist, v. 30, p. 39-53.

Stell, J.R. and Brown, C.A., 1992, Comparison of production from horizontal and vertical wells in the Austin Chalk, Niobrara, and Bakken plays, *in* Schmoker, J.W., Coalson, E.B., and Brown, C.A., eds., Geological Studies Relevant to Horizontal Drilling: Examples from Western North America: Rocky Mountain Association of Geologists, p. 67-87.

Sulistyo, Gunardi, 1994, Oil-source rock correlation study of the Upper Pennsylvanian Virgil and Lower Permian Wolfcamp in southwestern Nebraska: Golden, Colorado, Colorado School of Mines, M.S. thesis.

Tainter, P.A., 1982, Investigation of stratigraphic and paleostructural controls on hydrocarbon migration and entrapment in Cretaceous D and J sandstone of the Denver basin: Boulder, Colorado, University of Colorado, M.S. thesis, 235 p.

Tainter, P.A., 1984, Stratigraphic and paleostructural controls on hydrocarbon migration in Cretaceous D and J sandstone of the Denver Basin, *in* Woodward, J.F., Meissner, F., and Clayton, J., eds., Hydrocarbon source rocks of the Greater Rocky Mountain Region: Rocky Mountain Association of Geologists, p. 339-354.

Weimer, R.J., 1984, Relation of unconformities, tectonics, and sea-level changes, Cretaceous of western interior, U.S.A., *in* Schlee, J.S., ed., Interregional unconformities and hydrocarbon accumulations: American Association of Petroleum Geologists Memoir 36, p. 7-35.

Weimer, R.J., and Land, C.B., 1978, Field guide to Dakota Group (Cretaceous) stratigraphy Golden-Morrison area, Colorado: The Mountain Geologist, v. 9, p. 241-267.

Weimer, R.J., and Sonnenberg, S.A., 1983, Codell Sandstone, new exploration play: Oil and Gas Journal, v. 81, no. 22, p. 161-177.

Weimer, R.J., Sonnenberg, S.A., and Young, G.B., 1986, Wattenberg Field, Denver Basin, Colorado, *in* Spencer, C.W., and Mast, R.F., eds., Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology 24, p. 143-164.