Ute Mountain Ute Indian Reservation

General Setting

The Ute Mountain Ute Reservation is located in the northeastern portion of New Mexico and the southwestern corner of Colorado (Fig. UM-1). The reservation consists of 553,008 acres in Montezuma and La Plata Counties, Colorado, and San Juan County, New Mexico. All of these lands belong to the tribe but are held in trust by the U.S. Government. Individually owned lands, or allotments, are located at Allen Canyon and White Mesa, San Juan County, Utah, and cover 8,499 acres. Tribal lands held in trust within this area cover 3,597 acres. An additional forty acres are defined as U.S. Government lands in San Juan County, Utah, and are utilized for school purposes.

The Allen Canyon allotments are located twelve miles west of Blanding, Utah, and adjacent to the Manti-La Sal National Forest. The White Mesa allotments are located nine miles south of Blanding, Utah, on Utah Highway 47. These lands belong to known members of the Tribe or their heirs; however, the titles are held in trust for these individuals by the U.S. Government. The Ute Mountain Ute Tribe also holds fee patent title to seven tracts of land located in Utah and Colorado totaling 595,647 acres.

The topography of the reservation varies from approximately 4,600 feet near the Four Corners to approximately 10,000 feet at the peak of the Sleeping Ute Mountain. The eastern half of the reservation is characterized by a high mesa cut by the canyon of the Mancos River and numerous side canyons. The western half of the reservation, with the exception of the Sleeping Ute Mountain, is semi-desert grassland.

The reservation ranges in elevations from about 4,600 feet along the San Juan River near Four Corners (the junction of the States of Arizona, Utah, Colorado, and New Mexico) to 9,977 feet on Ute peak. Most of the western part of the reservation is semi-arid, eroded grasslands with some “bullhead” topography near the Utah border. North of the grasslands is the Sleeping Ute Mountain with a cover of scrub cedar, oak, and juniper. The eastern and southern parts of the reservation consist of the deeply cut canyons and mesas of Mesa Verde and Tanner Mesa, and is covered by scrub cedar and juniper.

The only paved highways in the reservation are U.S. Highways 160 and 666 and State Highways 41 and 789 (Fig. UM-2). Two maintained gravel roads cross the reservation: one follows the Mancos River Canyon to the eastern part of the reservation, then southward toward Farmington and the other goes westward from Towaoc to the Cache oilfield then on to Aneth, Utah. Other roads are generally trails passable only to four-wheel-drive vehicles or pickup trucks.

Towaoc, the only town on the reservation, is the site of the Ute Mountain Indian Agency and the residence of most of the people on the reservation. Cortez, Colorado, 16 miles northeast of Towaoc, serves as the principal market center for the area. South of the reservation in New Mexico are the towns of Shiprock, 30 miles from Towaoc, and Farmington, 29 miles east of Shiprock.
Geology

The Ute Mountain Ute Indian Reservation is on the Four Corners platform of the Colorado Plateau, and most of it is underlain by gently dipping Mesozoic age sedimentary rocks (Fig. UM-3). Most of the rocks exposed on the Reservation are sandstones, shales, and mudstones of Cretaceous age; the oldest sedimentary formation exposed is of Jurassic age and the youngest consolidated rocks are Tertiary. The oldest units crop out along the northern and eastern boundaries of the Reservation, and the exposed sedimentary rocks become progressively younger toward the south and east, reflecting the higher topographic position of the Mesa Verde plateau.

The principal area of non-sedimentary rocks in the Reservation is the Ute Mountains, which are formed of Late Cretaceous or Tertiary igneous rocks.

Older sedimentary formations not exposed on the Reservation but occurring in the subsurface include, in descending order, the Old Red Sandstone, Sandstone (Fig. UM-3). The dips in this area are mostly between 20 and 30 degrees. The change in dip toward the San Juan Basin is relatively abrupt, and only a short distance from the steepest part of the monocline the dips in the basin are only 1 to 2 degrees. On the northwest side of the monocline the beds flatten somewhat more gradually to an essentially horizontal position, except at the Southern Ute and Barker Domes (Fig. UM-3). Between the two areas of nearly horizontal beds, which are only 2 to 4 miles apart, there are several thousand feet of structural relief.

The McElmo Dome is immediately north of the Ute Mountains, and only the southwestern part of it lies within the reservation (Fig. UM-3). Its structure is well exposed in McElmo Canyon, which cuts through its southern flank. The dome is asymmetric, steeper on the south where the maximum dip is about 9 ½ degrees. Except for the south side, the flanks of the dome pass into a series of five anticlines, two of which extend into the reservation. A moderately sharp anticline plunges southeastward from McElmo Dome in the vicinity of Ute Peak. It is asymmetric, with a steeply dipping southwest side. A poorly defined anticline extends southwest from McElmo Dome about 4 miles, almost parallel to a graben that lies to the north. The area affected by McElmo Dome and its satellite anticlines is about 20 miles east to west and 10 miles north to south. Barker Dome and Anticline are on the east flank of the Mesa Verde Basin, at the east side of the reservation. The dome is slightly elongated north and south, and extends northward for several miles as the Barker Anticline. Maximum closure is at least 200 feet. South Ute Dome is a small, nearly round dome about a mile wide, immediately southeast of Barker Dome (Fig. UM-3). Its eastern and southern flanks are formed by a bend in the Hogback Monocline, and its western flank is formed by the eastern limb of a south-easterly plunging syncline that exposes South Ute Dome from Barker Dome.

Steeply dipping normal faults occur in the Ute Mountains area on the south, southwest, and northwest flanks of Ute Dome, and to the southwest flank of McElmo Dome. The greatest concentration of faults is on the northwest flank of Ute Dome. Two sets of faults appear to have formed simultaneously in this vicinity; one set strikes nearly west, the other northeast. The west-striking faults parallel west-trending folds and have displacements that rarely exceed 30 feet. The northeast-striking faults appear to be extensions of a zone of faulting that cuts the southwest flank and the central part of McElmo Dome. This zone curves to the nearly east strike and continues toward Cortez, Colorado. The faults along this zone form a graben on the southwestern flank of McElmo Dome and have displacements as much as 180 feet, the greatest known in the Ute Mountain area.

Most of the faults in this area are concentrated on a bend in the Hogback Monocline south of Southern Ute Dome. The strikes of those faults range from N 70 W to N 90 W. Some faults are downthrown to the north, while others are downthrown to the south. Apparently the majority are high-angle normal faults. The two longest faults southeast of Southern Ute Dome have curved traces owing to actual curves in the fault planes rather than to the effect of topography on dipping fault planes. Two miles southwest of Southern Ute Dome, two strike faults die out as small monocline flexures.

Figure UM-3. Tectonic map of the Ute Mountain Ute Indian Reservation. Structure contour lines are drawn on the basis of the Dakota Sandstone (modified after Anderson, 1959).
Paradox Basin Province

The Paradox Basin Province is in southeastern and south-central Utah and southwestern Colorado and encompasses much of the area from latitude 37° to 40° north and from longitude 108° to 114° west (Fig. UM-5). It includes almost all of the Paradox Basin, the Uncompahgre and San Juan uplifts, the San Rafael, Circle Cliffs, and Monument uplifts, the Kaiparowits and Henry Mountains basins, and the Wasatch and Parkinson plateaus (Fig. UM-6). Maximum dimensions of the province area are approximately 280 miles long and 200 miles wide. It covers an area of about 33,000 square miles. The maximum thickness of Phanerozoic sedimentary rocks ranges from 5,000 to 8,000 feet in the central part of the province to more than 15,000 feet in the Paradox Basin, Kaiparowits Basin, and Wasatch Plateau. Rocks in the Paradox Basin range in age from Precambrian through Tertiary (Fig. UM-6).

Most of the production in the province has been from porosity carbonate buildups (mainly algal mounds) around the southwestern shelf margin of the Paradox Basin. The giant Aneth Field, with more than 1 BBOIP ac conta, is as much as two-thirds of the proven resources in the province, and other fields in this primarily stratigraphic play (Porous Carbonate Buildup Play, 2012) as contain much of the rest. Most of the oil or gas plays have a strong structural component, particularly the Banded Fault Blocks, Older Paleozoic (2101), Fractured Interbed Play (2103), and Salt Anticline Flank (2105) plays. The Pennsylvanian-Mississippian Marjor Clastic Play (2006), Permian-Triassic Unconformity Play (2006), and Cretaceous Sandstone Play (2010), as well as the hypothetical Lower Paleozoic/Proterozoic Play (2003) which is described in Northern Arizona Province (024), are combinations of both structure and stratigraphy. The Fractured Interbed Play (2010) is an unconventionally, continuous-type play.
San Juan Basin Province

The San Juan Basin Province incorporates much of the area from latitudes 35° to 38° north and from longitude 106° to 109° west (Fig. UM-5) and consists of all or part of four counties in southwestern New Mexico and six counties in southeastern Colorado. It covers an area of about 22,000 square miles. Almost all hydrocarbon production and available subsurface data are restricted to the San Juan Basin. Also included in the province, but separated from the structural and tectonic San Juan Basin by the Higbuck Mountain and Archuleta Arch, respectively, are the San Juan Dome and Cumbre Basin, which contain sedimentary sequences similar to those of the San Juan Basin (Fig. UM-4). In much of the San Juan Dome area (Fig. UM-5) the sedimentary section is covered by variable thicknesses of volcanic rocks overlying a sequence of unconformities. The stratigraphic section of the San Juan Basin Province (modified after Molenaar, 1996). San Juan Basin - Underpressured Discharge (2252), and San Juan Basin - Underpressured Cretaceous (2253). Schematic north-south cross section of Cretaceous stratigraphy in northeast New Mexico (modified after Molenaar, 1973, 1983 a,b). Eight unconventional plays were assessed: five continuous-type plays and three coal-bed gas plays. Continuous-type plays are Fractured Interbed Play (2201), Dakota Central Basin Gas (2202), Dakota Fractured Shale (2203), Cretaceous Mancos Shale Gas (2204), and Pictured Cliffs Gas (2211) Plays. Also present is the continuous-type Fractured Interbed Play (2214) which is described and assessed in Paradox Basin Province (021). Coal-bed gas plays are San Juan Basin–Overpressured (2250), San Juan Basin–Underpressured Discharge (2252), and San Juan Basin – Underpressured Cretaceous (2253).
Two logs were chosen to represent the stratigraphy of the Ute Mountain Ute Indian Reservation. Cretaceous (upper Dakota-Lewis Shale) is shown in Log 1. The Devonian-Cretaceous (lower Dakota) are shown in Log 2. The locations of these wells are shown in Figure UM-10.

**Well 1:**
Location: Sec 16, T32N, R12W, San Juan County, New Mexico
(from Molenaar and Baird, 1989)

**Well 2:**
Location: Sec 18, T36N, R14W, Montezuma County, New Mexico
(from Molenaar and Baird, 1989)
**Table 1: Play Summary Chart**

The United States Geological Survey identifies several petroleum plays in the San Juan and Paradox Basin Provinces and classifies them as Conventional and Unconventional. The discussions that follow are limited to those with direct significance for future petroleum development in the Ute Mountain Ute Indian Reservation.

### Play Types

**Conventional Plays:** Discrete deposits, usually bounded by a downdip water contact, from which oil, gas or NGL can be extracted using traditional development practices, including production at the surface from a well in a consequence of natural pressure within the subsurface reservoir, artificial lifting of oil from the reservoir to the surface where applicable, and the maintenance of reservoir pressure by means of water or gas injections.

**Unconventional Plays:** A broad class of hydrocarbon deposits of a type (such as gas in “tight” sandstones, gas shales, and coal-bed gas) that historically has not been produced using traditional development practices. Such accumulations include most continuous-type deposits.

<table>
<thead>
<tr>
<th>Play Type</th>
<th>USGS Designation</th>
<th>Description of Play</th>
<th>Oil or Gas</th>
<th>Known Accumulations</th>
<th>Undiscovered Accumulations &gt; 1 MMBOE</th>
<th>Play Probability (chance of success)</th>
<th>Drilling depths (median, mean)</th>
<th>Pay Thickness (median, mean)</th>
<th>Porosity/Permeability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porous Carbonate Buildup Play</td>
<td>2201</td>
<td>Dakota Sandstone (33,000 sq. miles), San Juan Basin (22,000 sq. miles)</td>
<td>Gas</td>
<td>2201 (San Juan)</td>
<td>Gas (5,705 BCFG, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (3000, 6000)</td>
<td>10-90 feet</td>
<td>5-20%/0.25-250mD</td>
</tr>
<tr>
<td></td>
<td>2206</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2206 (San Juan)</td>
<td>Gas (188.85 MMBO, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (1500, 3000)</td>
<td>20-50 feet</td>
<td>10-30%/0.01-50mD</td>
</tr>
<tr>
<td></td>
<td>2208</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2208 (San Juan)</td>
<td>Gas (7.8 BCFG, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (900, 1500)</td>
<td>100-500 feet</td>
<td>N/A</td>
</tr>
<tr>
<td>Vaca - Gallup Sandstone Oil Play</td>
<td>2007</td>
<td>Fractured organic rich marine Mancos Shale, Intertonguing of porous marine sandstone units, primarily within the Coastal marine barrier-bar sandstones in the Upper Cretaceous Tocito and Gallup Lenticular sandstone bodies of the Hermosa Group.</td>
<td>Gas</td>
<td>2007 (San Juan)</td>
<td>Gas (94.42 BCFG, est. mean)</td>
<td>Vaca - Gallup Sandstone Oil Play</td>
<td>1 (1000, 2000)</td>
<td>&lt;50 feet</td>
<td>10-30%/0.01-25mD</td>
</tr>
<tr>
<td></td>
<td>2008</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2008 (San Juan)</td>
<td>Gas (242.32 MMBO, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (7500, 9000)</td>
<td>10-100 feet</td>
<td>10-30%/0.25-250mD</td>
</tr>
<tr>
<td>Mancos Fractured Shale Play</td>
<td>2008</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2008 (San Juan)</td>
<td>Gas (188.85 MMBO, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (900, 1500)</td>
<td>20-50 feet</td>
<td>10% Unlimited</td>
</tr>
<tr>
<td>Central Basin Mesa</td>
<td>2009</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2009 (San Juan)</td>
<td>Gas (10.8 MMBO, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (3000, 6000)</td>
<td>&lt;20 feet</td>
<td>N/A</td>
</tr>
<tr>
<td>Basin Margin Mesa</td>
<td>2010</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2010 (San Juan)</td>
<td>Gas (1, 2, 4, 5, 6, 7, 8)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (3000, 6000)</td>
<td>60-100 feet</td>
<td>5-20%/0.55-100mD</td>
</tr>
<tr>
<td>Dakota Central Basin Gas Play</td>
<td>2006</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2006 (San Juan)</td>
<td>Gas (5.8 MMBO, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (3000, 6000)</td>
<td>&lt;50 feet</td>
<td>N/A</td>
</tr>
<tr>
<td>Buried Fault Blocks Older Paleozoic Play</td>
<td>2011</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2011 (San Juan)</td>
<td>Gas (10.8 MMBO, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (3000, 6000)</td>
<td>&lt;50 feet</td>
<td>N/A</td>
</tr>
<tr>
<td>Fractured Interbed Play (Hypothetical, continuous)</td>
<td>2012</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2012 (San Juan)</td>
<td>Gas (5.8 MMBO, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (3000, 6000)</td>
<td>&lt;50 feet</td>
<td>N/A</td>
</tr>
<tr>
<td>Permian-Pennsylvanian Marginal Clastics Play</td>
<td>2013</td>
<td>Dakota Central Basin Res. Group</td>
<td>Gas</td>
<td>2013 (San Juan)</td>
<td>Gas (5.8 MMBO, est. mean)</td>
<td>Dakota Central Basin Res. Group</td>
<td>1 (3000, 6000)</td>
<td>&lt;50 feet</td>
<td>N/A</td>
</tr>
</tbody>
</table>
### Porous Carbonate Buildup Play (USGS Designation 2102, 2201)

**General Characteristics**

The Porous Carbonate Buildup Play in the Paradox and San Juan Basin Provinces (Fig. UM-11) is primarily a gas play and is characterized by oil and gas accumulations in mounds of algal (Fusulinia) limestone as associated with organic-rich black shalerimming the evaporite sequences of the Paradox Formation of the Hermosa Group (Fig. UM-12). Most developed fields within the play produce from combination traps in the Paradox Basin Province.

**Reservoirs:** Almost all hydrocarbon production has been from vuggy limestone and dolomite reservoirs in five zones of the Hermosa Group. In ascending order they are the Alkali Gulch, Barker Creek, Akah, Desert Creek, and Ismay Stages (Fig. UM-11). The zones gradually become less distinct toward the central part of the San Juan Basin. Net pay thicknesses generally range from 10 to 50 feet and have porosities of 5-20 percent.

**Source Rocks:** Source beds for Pennsylvanian oil and gas are believed to be organic-rich shales and laterally equivalent carbonate rocks within the Paradox Formation. The presence of hydrogen sulfide (H2S) and appreciable amounts of CO2 at the Barker Creek and Ute Dome fields probably indicates high-temperature decomposition of carbonates (Rice, 1983). Correlation of black dolomitic shale and mudstone units of the Paradox Formation with prodelta facies in clastic cycles present in a proposed fan delta complex on the northeastern edge of the Paradox Evaporite Basin helps to account for the high percentage of kerogen from terrestrial plant material in black shale source rocks.

**Timing and Migration:** In the central part of the San Juan Basin, Pennsylvanian sediments were deposited in the thermal zone of oil generation during the Late Cretaceous to Paleocene, and the dry gas zone during the Eocene to Oligocene. It is also probable that Pennsylvanian source rocks entered the zone of oil generation during the Ololgocean throughout most of the Four Corners Platform. Updp migration and local migration from laterally equivalent carbonates and shale beds in areas of favorable reservoir beds predominate, and reMigration may have occurred in areas of faulting and fracturing.

**Traps:** Combination stratigraphic and structural trapping mechanisms are dominant among Pennsylvanian fields of the San Juan Basin and Four Corners Platform. Most fields are located on structures, although not all of these structures demonstrate closure. The structures themselves may have been a critical factor in the deposition of biocalcitic limestone reservoir rocks. Seals are provided by a variety of mechanisms, including porosity differences in the reservoir rock, overlying evaporites, and interbedded shales. Most production on the Four Corners Platform is from depths of 5,100 to 8,500 feet, but minor production and shows in the central part of the San Juan Basin are from as deep as 11,000 feet.

**Exploration status and resource potential:** Field sizes in the play vary considerably; most oil discoveries are in the 1–10 MMBO size range and include associated gas production. The largest fields, Toctito Dome and Toctito Dome North, have produced a total of about 13 MMBO and 26 BCFG. Eight significant nonassociated and associated gas fields have been developed in the play, the largest of which, Barker Creek, has produced 205 BCFG. The Pennsylvanian is basically a gas play and has a moderate future potential for medium-size fields.

**Characteristics of Play**

In the Ute Mountain Ute Indian Reservation the Paradox Formation is conformably bounded by the Pinkerton Trail Formation at its base and the Homonkey Trail Formation at its top (Fig. UM-14). It ranges from 800 feet thick in the south to 1700 feet thick in the north (Fig. UM-14). The Paradox Formation was deposited during the Desmoinesian age of the Pennsylvanian Period under strong cyclic conditions involving transgressive and regressive movements of the Pennsylvanian sea. The transgressive phase is represented by black or gauge dolomitic muds while the regressive phase is represented by carbonate mounds. Reservoirs within the reservation are bioclastic/biocalcitic carbonate mounds deposited in shallow areas of an evaporite basin. The four main cycles of Desmoinesian deposition are the Barker Creek, Akah, Desert Creek, and Ismay Stages (Fig. UM-13).

The Barker Creek Stage has a gross thickness of 500 feet. It is a fossiliferous, algal, dolomitic limestone with vuggy secondary dolomite. Most reservoir rock is algal, dolomitic limestone with enhanced porosity and permeability due to dolomitization and weathering. The Barker Creek was deposited on paleostuctural features related to the Hogback Lineament.

The Akah Stage is not considered to be an exploration objective within the reservation because salt and anhdydite deposition was dominant during this stage. The Akah Stage represents the maximum extent of evaporite limits.

The Desert Creek Stage carbonates were deposited in a definable arcuate trend around the southeast terminus of the basin. The Desert Creek is bounded by the Chimney Rock and Gothic Shales which represent transgressions (Fig. UM-13). Growth of the Desert Creek carbonate bank occurred during slow subsidence of the Paradox Basin. Source rocks for hydrocarbons are the Chimney Rock and Gothic Shales.

The Ismay Stage is divided into lower and upper units. In the lower unit, bounded by the Gothic and Hovenweep Shales, oil is produced from algal carbonate mound buildups. The upper unit is bounded by the Hovenweep and Boundary Butte Shales. Production there is from algal or fossiliferous detrital bioclastic/biocalcitic reservoirs. The source rocks for the Ismay stage are the Gothic, Hovenweep, and Boundary Butte Shales. During the Ismay Stage the southern part of the basin was slowly subiding.
Analog Fields
Within or Near Reservation
(*) denotes field lies within the reservation boundaries

*Barker Creek Paradox Field* (Fig. UM-15)
Location of discovery well: SE 1/4, SE 1/4, NW 1/4, Sec 21, T32N, R14W, (March, 1945)
Producing formation: Paradox Formation
Number of producing wells: 5 (1977)
Production: 215,279,080 MCFG (1996)
Gas characteristics: BTU 777 (dry basis)
Type of drive: Solution gas, fluid expansion, ineffective bottom water encroachment
Average net pay: 8-100 feet
Porosity: 2-10%
Permeability: extremely variable

Hermon North Field
Location of discovery well: NE 1/4, NW 1/4, sec. 35, T41N, R25W (1991)
Producing formation: Desert Creek Stage, Paradox Formation
Number of producing wells: 1
Production: 0.31 BCFG
Gas characteristics: BTU 914
Type of drive: Gas Expansion
Average net pay: 60 feet
Porosity: 15%
Permeability: 17.7 md

*Wickup Field*
Location of discovery well: SW 1/4, SE 1/4, sec 24, T33N, R14W (March, 1972)
Producing formation: Barrier Creek Stage, Paradox Formation
Number of producing wells: 1 (1983)
Production: 41,372 MCFG (1996)
Gas characteristics: BTU 914
Type of drive: Gas Expansion
Average net pay: 10 feet
Porosity: 8%

**Ute Dome Paradox Field**
Location of discovery well: NE 1/4, NE 1/4, Sec 35, T32N, R14W (September, 1949)
Producing formation: Barrier Creek Stage, Paradox Formation
Number of producing wells: 11 (1977)
Production: 93,586,058 MCFG (1996)
Gas characteristics: BTU 777 (dry basis)
Type of drive: Primary Volumetric with limited water drive in Barrier Creek Zone
Average net pay: 116 feet
Porosity: 3.5%
Permeability: 0.5 md (enhanced by fracturing)

---

**Figure UM-13.** Stratigraphic chart of the Pennsylvanian Hermosa Group illustrating the Paradox facies change across the basin. Each stage is bounded by a time stratigraphic marker bed of sapropelic, dolomitic mud. These markers are continuous and mappable throughout the basin (modified from Harr, 1996).

**Figure UM-14.** Stratigraphic cross section through Ute Mountain Ute Indian Reservation (modified from Huffman and Condon, 1993).

---

**Figure UM-15.** Structure contour map, type log, and cross section of Barker Creek Paradox Field (modified from Matheny, 1978).
Tocito-Gallup Sandstone Oil Play

(Classification: U.S. Geologic Survey designation 2207)

**General Characteristics**

The Tocito-Gallup Sandstone Oil Play is an oil and associated gas play in lenticular sandstone bodies of the Upper Cretaceous Gallup Sandstone and Tocito Sandstone Lentil, associated with Mancos Shale source rocks lying immediately above an unconformity. The play covers almost the entire area of the province (Fig. UM-16). Almost all production has been from the Tocito Sandstone Lentil of the Mancos Shale and the Torrivio Member of the Gallup Sandstone. Locations of oil field discovery wells producing from the Tocito-Gallup Sandstone Oil Play are shown in figure UM-17.

**Reservoirs:** The Tocito Sandstone Lentil of the Mancos Shale is the major oil producing reservoir in the San Juan Basin. The name is applied to a number of lenticular sandstone bodies, commonly less than 30 feet thick, that lie on or just above an unconformity and are of undetermined origin. Reservoir porosities in producing fields range from 4 to 20 percent and average about 15 percent. Permeabilities range from 0.5 to 150 Md and are typically 5 - 100 Md. The only significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above, and in some places scouring into the top of the main marine Gallup Sandstone.

**Source rocks:** Source beds for Gallup oil are found in the marine Upper Cretaceous Mancos Shale. The Mancos contains 1-3 weight percent organic carbon and produces a sweet, low-sulfur, paraffin-base oil that ranges from 38° to 43° API gravity in the Tocito fields and from 24° to 32° API gravity farther to the south in the Hospah and Hospah South fields.

**Timing and migration:** The Upper Mancos Shale of the central part of the San Juan Basin entered the oil window of zone II in the late Eocene and gas generation in the Oligocene. Migration up dip to reservoirs in the Tocito Sandstone Lentil and regressive Gallup followed pathways similar to those determined by present structure because basin configuration has changed little since that time. Significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above, and in some places scouring into the top of the main marine Gallup Sandstone. South of the zone of sandstone buildups of the Tocito, significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above, and in some places scouring into the top of the main marine Gallup Sandstone.

**Reservoirs:** The Tocito Sandstone Lentil of the Mancos Shale is the major oil producing reservoir in the San Juan Basin. The name is applied to a number of lenticular sandstone bodies, commonly less than 30 feet thick, that lie on or just above an unconformity and are of undetermined origin. Reservoir porosities in producing fields range from 4 to 20 percent and average about 15 percent. Permeabilities range from 0.5 to 150 Md and are typically 5 - 100 Md. The only significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above, and in some places scouring into the top of the main marine Gallup Sandstone.

**Source rocks:** Source beds for Gallup oil are found in the marine Upper Cretaceous Mancos Shale. The Mancos contains 1-3 weight percent organic carbon and produces a sweet, low-sulfur, paraffin-base oil that ranges from 38° to 43° API gravity in the Tocito fields and from 24° to 32° API gravity farther to the south in the Hospah and Hospah South fields.

**Timing and migration:** The Upper Mancos Shale of the central part of the San Juan Basin entered the oil window of zone II in the late Eocene and gas generation in the Oligocene. Migration up dip to reservoirs in the Tocito Sandstone Lentil and regressive Gallup followed pathways similar to those determined by present structure because basin configuration has changed little since that time. Significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above, and in some places scouring into the top of the main marine Gallup Sandstone. South of the zone of sandstone buildups of the Tocito, significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above, and in some places scouring into the top of the main marine Gallup Sandstone.

**Reservoirs:** The Tocito Sandstone Lentil of the Mancos Shale is the major oil producing reservoir in the San Juan Basin. The name is applied to a number of lenticular sandstone bodies, commonly less than 30 feet thick, that lie on or just above an unconformity and are of undetermined origin. Reservoir porosities in producing fields range from 4 to 20 percent and average about 15 percent. Permeabilities range from 0.5 to 150 Md and are typically 5 - 100 Md. The only significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above, and in some places scouring into the top of the main marine Gallup Sandstone.
Characteristics of the Tocito-Gallup Oil Play

In recent years a sequence stratigraphic framework has been applied to the Tocito and Gallup Sandstones near the Ute Mountain Ute Indian Reservation (Jennett and Jones, 1995). This framework explains hydrocarbon occurrence and the stratigraphic traps associated with these units. The northern extent of the Gallup Sandstone production is several miles south of the Indian reservation where it is truncated by the Tocito Sandstone (Fig. UM-18). For this reason the Gallup Sandstone will not be included in the following description. Since the late 1950’s, 130 MMBOE have been produced from the Tocito. The Tocito Sandstone marks a significant change from shoreface/coastal plain depositional systems which prevailed throughout Gallup deposition. The Tocito Sandstone is a transgressive sequence set internally composed of four high-frequency sequences in ascending order they are Tocito-1, Tocito-2, Tocito-3 and Tocito-4 (Fig. UM-19). In the subsurface, the Tocito is distributed into narrow and elongate bodies which trend northwest-southeast (Figs. UM-20 to UM-23).

The high-frequency sequences of the Tocito Sandstone contain the lowstand, transgressive, and usually highstand systems tracts. There are sequence boundaries at the base of each high-frequency sequence represented by irregular erosional surfaces that truncate into the underlying units. Above the erosional surfaces are incised valley fill deposits representing the lowstand systems tracts. The tops of the valley fills represent transgressive flooding surfaces, the passage from valley-filling sedimentation to open-marine/shelfal sedimentation, and the onset to the transgressive systems tracts. The transgressive systems tracts are overlain by distal marine shales of the highstand systems tracts (Tocito-1 and Tocito-2 only). Due to their close vertical juxtaposition, the four Tocito sequences are collectively interpreted as components of a sequence set. The four sequences are thought to reflect higher-order cycles in relative sea level which were superimposed on a longer term cycle.

Hydrocarbon trapping is the result of stratigraphic relationships. Structural dip is uniformly toward the northeast and consequently provides only minor influence on the pooling of hydrocarbons. The four main trapping elements are truncation by younger sequence boundaries, arcuate bends in valleys, updip valley termination, and structural closure (Fig. UM-24).

Figure UM-20. Incised valley fill isopach map of the Tocito-1 incised valley system. Two parallel valleys, the Horseshoe and Many Rocks valleys, are separated by a well-defined interfluve. Note the position and paleocurrent patterns of the Mounds outcrop locality. Reservoir quality sandstone appears to be present farther down the Horseshoe valley (modified after Jennette and Jones, 1995).
The Waterflow Valley contains the thickest interval of sandstone. Note the overall distribution of the lowstand systems tract is more widespread than the Tocito-1 sequence. The Tocito-3 sequence along the southern margin of the Waterflow Valley and the northern margin of the Bisti Valley. Note the areas thinned by truncation by the overlying Tocito-4 sequence boundary, particularly along the southern margin of the Waterflow Valley and toward the outcrop area (modified after Jennette and Jones, 1995).

The isopach patterns mapped in the subsurface continue to respond remarkably well with measured thicknesses of the Tocito at the outcrop (C.V. Campbell, unpublished Exxon Production Research data). Most of the Tocito in outcrop along Rock Ridge and Beautiful Mountain belongs to the Tocito-4 sequence (modified after Jennette and Jones, 1995).
**Analog Fields Near the Reservation**

**Many Rocks Gallup**  
Location of discovery well: SE 1/4, SW 1/4, sec 27, T32N, R17W (1962)  
Producing formation: Cretaceous Gallup Sandstone  
Number of producing wells: 62 (1977)  
Production: 9 MOEB (1995)  
1,047,270 MCFG (1977)  
Gas Characteristics: 1,171 BTU  
Oil Characteristics: 40 ° API gravity  
Type of drive: Solution gas with limited gas expansion  
Average net pay: Upper zone is 5 feet  
Lower zone is 7.5 feet  
Porosity: 15%  
Permeability: 145 mD

**Horseshoe Gallup**  
Location of discovery well: NW 1/4, SW 1/4, sec 8, T32N, R17W (1961)  
Producing formation: Cretaceous Tocito Sandstone  
Number of producing wells: 9 (1983)  
Production: 40 MOEB (1995)  
17,965,301 MCFG (1977)  
Oil characteristics: 35 ° API gravity  
Type of drive: water  
Average net pay: 15 feet  
Porosity: 10-15%  
Permeability: unknown

**Cha Cha Gallup**  
Location of discovery well: NW 1/4, SE 1/4, sec 17, T28N, R13W  
Producing formation: Cretaceous Gallup Sandstone  
Number of producing wells: 42 (1977)  
Production: 14 MOEB (1995)  
17,965,201 MCFG (1977)  
Oil characteristics: 41 ° API gravity  
Type of drive: Solution Gas  
Average net play: Upper zone 10 feet  
Lower zone 10 feet  
Porosity: 13.5%  
Permeability: 57 mD

---

**INCISED VALLEY TRAPPING MECHANISM**

1. **VALLEY CHANGES DIRECTION**

   - Horseshoe Field: 40 MOEB
   - Cha Cha Field: 14 MOEB
   - Many Rocks Field: 9 MOEB
   - Totah Field: 6 MOEB
   - Bisti Field: 54 MOEB
   - Gallagos Field: 10 MOEB

2. **VALLEY TRUNCATED BY YOUNGER SEQUENCE BOUNDARY**

3. **VALLEY TERMINATION**

   - Figure UM-24: Schematic summary of hydrocarbon trapping styles found in the Tocito, stippled patterns indicate the position of oil accumulations (modified after Jennette and Jones, 1995).

   - Figure UM-25: Isopach map of the “upper sand pay zone” for the Many Rocks Field (modified after Matheny and Little, 1978).

   - Figure UM-26: Isopach map of the “lower sand pay zone” for the Many Rocks Field (modified after Matheny and Little, 1978).

   - Figure UM-27: Stratigraphic cross section of the “lower sand pay zone” for the Many Rocks Field. Hydrocarbons are trapped in the Tocito-1 lowstand systems tract (Fig. UM-19) along updip bends in the valley (modified after Jennette and Jones, 1995; Matheny and Little, 1978).
MANCOS FRACTURED SHALE PLAY

General Characteristics
The Mancos Fractured Shale Play is a confirmed, unconventional, continuous-type play. It is dependent on extensive fracturing in the organ-rich marine Mancos Shale. Most developed fields in the play are associated with anticlinal and monocline structures around the eastern, northern, and western margins of the San Juan Basin (Figs. UM-28 and UM-29).

Reservoirs: Reservoirs are comprised of fractured shale and interbedded coarser clastic intervals at approximately the Tocito Bentonite stratigraphic level.
Source rocks: The Mancos Shale contains 1-3 weight percent organic carbon and produces a sweet, low-sulfur, paraffin-base oil that ranges from 33° to 43° API gravity.
Timing: The Upper Mancos Shale of the central part of the San Juan Basin entered the thermal zone of oil generation in the late Eocene and of gas generation in the Oligocene.
Traps: Combination traps predominate. Traps are formed by fractures in shale and by interbedded clastics on structures.

Characteristics of Mancos Fractured Shale Play in the Ute Mountain Ute Indian Reservation

The Mancos Fractured Shale Play produces oil from fractures in the Nebraskan-Carlieage clastic sediments (Fig. UM-30) which represent the first regressive wedge in the San Juan Basin. These sediments have little or no effective porosity and permeability except that associated with fractures. The units of interest to oil exploration are the basal Dakota Sandstone, Nebraskan-Carlie unconformity (Upper Mancos Shale-Tocito Sandstone contact), and Carlie Shale/Dakota Sandstone contact interval above the Juana Lopez. The Nebraskan-Carlie stage is laterally consistent with respect to siltstone content, cement content, and other observable stratigraphic phenomena.

The Hogback Monocline and Mancos Creek Monocline (Fig. UM-29) are the structural features associated with fractures in the Mancos Shale. The Hogback Monocline is located in the northwest flank of the San Juan Basin in the southeast section of the Ute Mountain Ute Indian Reservation. It has a dip as great as 60° and has up to 8000 feet of structural relief. The Mancos Creek Monocline is located south of the reservation and extends only a few miles. Fractures are mostly associated with areas of maximum flexure and where anticlines and synclines intersect the monoclines (Figs. UM-31 and 32). The fractures are best developed parallel to the trend of the fold. They range in size from hairline cracks to 1 ¾ inches wide.

Oil reservoirs associated with the Mancos Fractured Shale Play depend on porosity and permeability provided by the fractures. The reservoirs are lithologically controlled only to the extent that brittle competent intertapes capable of fracturing are present. The fractures have greater lateral than vertical continuity. The basic tools used in exploration for fracture permeability are structure contour maps and isopachs maps showing brittle intertapes in dominantly shale sequences. Trap types are structural-stratigraphic-fracture traps. The reservoirs are primarily driven by gravity drainage.
Figure UM-31. Generalized structure contour map of Verde field. Structure contours are on top of the Point Lookout Sandstone Member of the Mesaverde Group (modified from Hayes and Zapp, 1955).

Verde Oil Field
- Location of discovery well: se ¼, sec 14, T31 N, R15W, NMPM (September 1955)
- Producing formation: Fractured interval in Niobrara age Mancos Shale
- Number of producing wells: 27 (1978)
- Production: 7,789,304 bbl. (1977)
- Oil characteristics: 38° - 42° API Gravity
- Type of drive: Gravity drainage in entire field as a "unit"

La Plata Gallup Field
- Location of discovery well: se ¼, sw ¼, sec 5, T31 N, R13W, NMPM (April 1959)
- Producing formation: Fractured Mancos Shale
- Number of producing wells: 4 (1978)
- Production: 527,862 bbl. (1977)
- Oil characteristics: Sweet yellow-green, 30° API Gravity
- Type of drive: Combination gravity and solution gas

Gamma Ray - Induction
- Elev - R.K. B. 6075
- La Plata Mancos No. P-31

Figure UM-32. Structure contour map and type log of the La Plata Gallup field. Structure contour lines are on the "E" marker within the Mancos Shale (top of the Niobrara Stage) which generally produces the highest electrical log resistivities in the Mancos Shale (modified after Greer, 1978).
Central Basin Mesaverde Gas Play (USGS Designation 2209)

General Characteristics
The unconventional continuous-type Central Basin Mesaverde Gas Play is in sandstone buildups associated with stratigraphic traps in the Upper Cretaceous Point Lookout and Cliff House Sandstones as the central San Juan Basin (Fig. UM-35). The major gas-producing interval in the San Juan Basin, the Upper Cretaaceous Mesaverde Group, is composed of the regressive marine Point Lookout Sandstone, the transgressive marine Cliff House Sandstone, and the uppermost marine Cliff House Sandstone. Total thickness of the interval ranges from about 500 to 2,500 feet, of which 20-30 percent is sandstone. The Mesaverde interval is enclosed by marine shale: the Mancos Shale is beneath the interval and the Lewis Shale above (Fig. UM-34).

Reservoirs: Principal gas-reservoir productive in the Mesaverde interval are the Point Lookout and Cliff House marine sandstones. Smaller amounts of dry, nonassociated gas are produced from thin, kilometric channel sandstone reservoirs and thin coal beds of the Menefee. Much of this play is designated as tight, and reservoir quality depends mostly on the degree of fracturing. Together, the Blanco Mesaverde and Ignacio Blanco fields account for about 10 percent and permeability less than 2 mD; total pay thickness is 20-200 feet. Smaller Mesaverde fields have porosities ranging from 14 to 28 percent and permeabilities from 2 to 400 mD, with 6-25 feet of pay thickness.

Source Rocks: The carbon composition \( C_1 / C_2 \) of 0.99-0.79 and isotopic carbon \( d_{13} \) range of -33.4 to -46.7 per mil of the nonassociated gas suggests a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation (Ross, 1980). API gravity of Mesaverde oil ranges from 37° to 50°. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into fluvial deposits may also play a role. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into thin, lenticular channel sandstone reservoirs and thin coal beds of the Menefee. Much of this play is designated as tight, and reservoir quality depends mostly on the degree of fracturing. Together, the Blanco Mesaverde and Ignacio Blanco fields account for about 10 percent and permeability less than 2 mD; total pay thickness is 20-200 feet. Smaller Mesaverde fields have porosities ranging from 14 to 28 percent and permeabilities from 2 to 400 mD, with 6-25 feet of pay thickness.

Source Rocks: The carbon composition \( C_1 / C_2 \) of 0.99-0.79 and isotopic carbon \( d_{13} \) range of -33.4 to -46.7 per mil of the nonassociated gas suggests a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation (Ross, 1980). API gravity of Mesaverde oil ranges from 37° to 50°. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into fluvial deposits may also play a role. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into thin, lenticular channel sandstone reservoirs and thin coal beds of the Menefee. Much of this play is designated as tight, and reservoir quality depends mostly on the degree of fracturing. Together, the Blanco Mesaverde and Ignacio Blanco fields account for about 10 percent and permeability less than 2 mD; total pay thickness is 20-200 feet. Smaller Mesaverde fields have porosities ranging from 14 to 28 percent and permeabilities from 2 to 400 mD, with 6-25 feet of pay thickness.

Source Rocks: The carbon composition \( C_1 / C_2 \) of 0.99-0.79 and isotopic carbon \( d_{13} \) range of -33.4 to -46.7 per mil of the nonassociated gas suggests a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation (Ross, 1980). API gravity of Mesaverde oil ranges from 37° to 50°. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into fluvial deposits may also play a role. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into thin, lenticular channel sandstone reservoirs and thin coal beds of the Menefee. Much of this play is designated as tight, and reservoir quality depends mostly on the degree of fracturing. Together, the Blanco Mesaverde and Ignacio Blanco fields account for about 10 percent and permeability less than 2 mD; total pay thickness is 20-200 feet. Smaller Mesaverde fields have porosities ranging from 14 to 28 percent and permeabilities from 2 to 400 mD, with 6-25 feet of pay thickness.

Source Rocks: The carbon composition \( C_1 / C_2 \) of 0.99-0.79 and isotopic carbon \( d_{13} \) range of -33.4 to -46.7 per mil of the nonassociated gas suggests a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation (Ross, 1980). API gravity of Mesaverde oil ranges from 37° to 50°. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into fluvial deposits may also play a role. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into thin, lenticular channel sandstone reservoirs and thin coal beds of the Menefee. Much of this play is designated as tight, and reservoir quality depends mostly on the degree of fracturing. Together, the Blanco Mesaverde and Ignacio Blanco fields account for about 10 percent and permeability less than 2 mD; total pay thickness is 20-200 feet. Smaller Mesaverde fields have porosities ranging from 14 to 28 percent and permeabilities from 2 to 400 mD, with 6-25 feet of pay thickness.

Source Rocks: The carbon composition \( C_1 / C_2 \) of 0.99-0.79 and isotopic carbon \( d_{13} \) range of -33.4 to -46.7 per mil of the nonassociated gas suggests a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation (Ross, 1980). API gravity of Mesaverde oil ranges from 37° to 50°. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into fluvial deposits may also play a role. Production depths are most commonly from 4,000 to 5,300 feet. Updip pinchouts of marine sandstone into thin, lenticular channel sandstone reservoirs and thin coal beds of the Menefee. Much of this play is designated as tight, and reservoir quality depends mostly on the degree of fracturing. Together, the Blanco Mesaverde and Ignacio Blanco fields account for about 10 percent and permeability less than 2 mD; total pay thickness is 20-200 feet. Smaller Mesaverde fields have porosities ranging from 14 to 28 percent and permeabilities from 2 to 400 mD, with 6-25 feet of pay thickness.
Basin Margin Mesaverde Oil Play and Central Basin Mesaverde Gas Play

Stratigraphy and Analog Fields
The Cliff House and Point Lookout Sandstones are the producers of the Basin Margin and Central Basin Mesaverde Plays in the Ute Mountain Ute Indian Reservation.

The Point Lookout Sandstone is the most extensive regressive marine Cretaceous sandstone in the San Juan Basin. The unit progrades from south west to northeast in a series of imbricated sandstone units (Fig. UM-36). The depositional environments present in the Cliff House Sandstone are fluviolacustrine, shoreface, and delta front. Reservoir characteristic studies have shown that the upper shoreface and shoreface/delta front have the highest permeabilities at 10-80 mD. Permeabilities between 0.3 and 3 mD are more common to lower shoreface sediments. The highest amounts of carbonate cement are present in the lower to middle shoreface. Varying depositional environments and their changing lithologies create distinctive divisions in the Point Lookout log responses (Figs. UM-37, -38, and -39). These divisions are used by exploration geologists to correlate productive zones.

Further work in the Mesaverde reveals the Point Lookout shoreface prograded in a staircase fashion across the basin, as a series of steps and risers until it reached its seaward depositional limit (Fig. UM-36). At this limit, there is a change in the stacking pattern of genetic sequences from seaward stepping to landward stepping. This marks the beginning of the Cliff House shoreface aggradation. Reservoir-quality sandstones in the two vertically stacked shorefaces at the turnaround position are 70 meters thick.

Figure UM-37. Index map showing location of drill holes 1HCMS and 2HCMS referred to in Figure UM-38 (modified after Keighin, Zech, and Dunbar, 1993).

Figure UM-38. Comparison of depositional facies in the Point Lookout Sandstone, as determined from cores, for core holes 1HCMS and 2HCMS (Fig. UM-37). Numbered arrows indicate locations of thin sections examined. (*) patterns indicate zones of mineralogical similarity within depositional environments, as determined by modal point-count analysis (modified after Keighin, Zech, and Dunbar, 1993).

Figure UM-36. Diagram of the stacking patterns of genetic sequences in the Mesaverde Group, and the temporal reflections among the five formations which compose it (modified after Cross and Lessenger, 1997).
Analog Fields within or near Reservation

(Oil producing fields belong to Basin Margin Mesaverde Oil Play; Gas producing fields belong to Central Basin Mesaverde Gas Play)

**Nenahnezad Mesaverde**
(Fig. UM-40)

- Location of discovery well: nw sw, sec. 10, T29N, R15W (1970)
- Producing formation: Cretaceous, Menefee Formation (lower part)
- Number of producing wells: 0
- Production: 1025 bbl (1983)
- Type of drive: pumped
- Average net pay: 30 feet
- Porosity: 23%

**Twin Mounds Mesaverde**

- Location of discovery well: se sw sec. 4, T29N, R14W (1954)
- Producing formation: Cretaceous Point Lookout Sandstone
- Number of producing wells: 0
- Production: 654,884 MCFG (1983)
- Gas characteristics: Btu 1,153
- Type of drive: Volumetric with possibly partially active water drive
- Average net pay: 10 feet
- Porosity: 25%
- Permeability: 6 mD

---

**Figure UM-39.** Log of the Mesaverde pool stratigraphic units. Well is in the Jerome McHugh Southern Ute NO. 3, NW, NW sec 20, T32N, R9W, La Plata County, CO (modified after Han, 1988, p. 123).

**Figure UM-40.** Structure contour map, isopach map, and type log for the Nenahnezad Mesaverde field (modified after Melbox, 1983).
Basin Margin Dakota Oil Play (1963 Designation 2:206)

General Characteristics
The Basin Margin Dakota Oil Play is both a structural and stratigraphic play on the northern, southern, and western sides of the central San Juan Basin, and the southeastern part of the Ute Mountain Ute Indian Reservation (Figs. UM-41 and UM-42). Because of the variability of depositional environments in the transgressive Dakota Sandstone, it is difficult to characterize a typical reservoir lithology. Most production has been from the upper marine part of the interval but significant amounts of both oil and gas also have been produced from the nonmarine section.

Reservoirs: The Late Cretaceous Dakota Sandstone varies from dominantly nonmarine channel deposits and interbedded coal and conglomerate in the northwest to dominantly shallow marine, commonly burrowed deposits in the southeast. Net pay thicknesses range from 10 to 100 ft; porosities are as high as 20% and permeabilities are as high as 400 mD.

Source rocks: Along the southern margin of the play, the Cretaceous marine Mancos Shale was the source of the Dakota oil. API gravities range from 44° to 59°. On the Four Corners Platform to the west, nonmarine Mancos Shale was the source of the Dakota oil. API gravities are as high as 25°.

Timing and migration: Depending on location, the Dakota Sandstone and Lower Mancos Shale entered the oil window during the Oligocene to Miocene. In the southern part of the area, migration was still taking place in the late Miocene or even more recently.

Traps: Fields range in size from 40 to 10,000 acres and most production is from fields of 100-2,000 acres. Stratigraphic traps are typically formed by updip pinchout of porous sandstone into shale or coal. Structural traps on faulted anticlines sealed by shale form some of the larger fields in the play. Oil production ranges in depth from 1,000 to 3,000 feet.

Exploration status and resource potential: The first discoveries in the Dakota play were made in the early 1920's on small anticlinal structures on the Four Corners Platform. Approximately 90% of the oil fields have an estimated total production exceeding 1 MMBbl, and the largest field (Price Gramps) has production of 7 MMBbl. Future Dakota oil discoveries are likely as basin structure and Dakota depositional patterns are more fully understood.

Stratigraphy
The Dakota Sandstone is a coastal plain deposit laid down in front of the advancing Mancos Sea. In the Ute Mountain Ute Indian Reservation the lower Dakota consists primarily of ribbon-type fluvial sandstone bodies and the upper Dakota consists of carbonaceous paludal shales deposited in coastal plain or deltaic environments. The Dakota unconformably overlies the fluvial deposits of the Burrow Canyon Formation (Fig. UM-43). This unconformity progressively truncates older units from northeast to southwest. The upper boundary is conformable with the Mancos Formation. Reservoirs in the Basin Margin Dakota Oil Play are controlled by stratigraphic and structural trapping (Fig. UM-44). Successful exploration for lower Dakota Sandstone production is accomplished by careful mapping of channel sandstones and close attention to oil and gas shows in the thin porous sandstones that may develop into channels.
Analog Fields Inside or Near Reservation
(*) denotes field lies inside reservation boundaries

Middle Canyon Dakota Field
(Fig. UM-44)
- Location of discovery well: NE ¼, SW ¼, sec. 14, T32N, R1 W (September 1969)
- Producing formation: Cretaceous Dakota Sandstone
- Number of producing wells: 1
- Production: 4,886 BO (1971)
- Type of drive: Water
- Average net pay: 20 feet
- Porosity: 12.1 %
- Permeability: 0.3 mD

Salt Creek Dakota Field
- Location of discovery well: SW ¼, NW ¼, Sec 4, T30N, R17W (July, 1958)
- Producing formation: Cretaceous Dakota Sandstone
- Number of producing wells: 6 (1977)
- Production: 88,604 BO (1977)
- Gas characteristics: 51.8 ° API Gravity
- Type of drive: Water
- Average net pay: 30 - 40 feet
- Porosity: 16 %
- Permeability: 0.8 mD

Menefee Mountain Field
- Location of discovery well: NW ¼, NE ¼, Sec 16, T35N, R13W (July, 1978)
- Producing formation: Cretaceous Dakota Sandstone
- Number of producing wells: 3 (1981)
- Production: 33,956 BO (1981)
- Gas characteristics: 34 ° API Gravity
- Type of drive: Water
- Average net pay: 15 feet
- Porosity: 12 - 14 %
- Permeability: Unknown

Figure UM-44. Cross section showing producing interval of the Dakota Sandstone in the Middle Canyon Field (modified after Stevensen, 1978).
**DAKOTA CENTRAL BASIN GAS PLAY**  
(U.S. Geol. Survey Designation 2205)

**GENERAL CHARACTERISTICS**
This Dakota Central Basin unconventional continuous-type play is contained in coastal marine barrier-bar sandstone and continental fluviodeltaic sandstone units, primarily within the transgressive Dakota Sandstone. It is located in the northeastern part of the San Juan Basin province and the southeastern corner of the Ute Mountain Ute Indian Reservation (Figs. UM-45 to UM-47).

**Reservoirs:** Reservoir quality is highly variable. Most of the marine sandstone reservoirs within the central basin field are considered tight. Source beds for oil and gas are also variable. The Dakota Sandstone was still taking place in the late Miocene, of even older. Non-associated gas in the Dakota pool was generated during the late Miocene (Huff, 1987). It is not known at what point hydrodynamic forces reached sufficient strength to act as a trapping mechanism, but the early Miocene is likely for the establishment of the present-day uplift and basinward direction, have been suggested as a trapping mechanism, but these forces are still poorly understood. The seal is commonly pro vided by either marine shale or paludal carbonates. Production is primarily from depths ranging from 10,000 to 15,000 feet.

**Source Rocks:** Quality of the source beds for oil and gas is also variable. Non-associated gas in the Dakota pool was generated during the late Miocene and postmature stages and probably had a marine Mancos Shale source (Rice, 1983). Timing and Migration: In the northern part of the central San Juan Basin, the Dakota Sandstone and Mancos Shale entered the oil generation window in the Eocene and were elevated to temperatures appropriate for the generation of dry gas by the late Oligocene. Along the southern margin of the central basin, the Dakota and lower Mancos entered the thermal zone of oil generation during the late Miocene (Huff, 1987). It is not known at what point hydrodynamic forces reached sufficient strength to act as a trapping mechanism, but the early Miocene is likely for the establishment of the present-day uplift and erosion pattern throughout most of the basin. Migration of the oil in the Dakota was still taking place in the late Miocene, of even more recently, in the southern part of the San Juan Basin.

**Traps:** The Dakota gas accumulation in the central basin is on the flanks and bottom of a large depression and is not localized by structural trapping (Fig. UM-46). The fluid transmissibility characteristics of Dakota sandstones are generally consistent from the central basin to the outcrop. Hydrodynamic forces, acting in a basinward direction, have been suggested as the trapping mechanism, but these forces are still poorly understood. The seal is commonly provided by either marine shale or paludal carbonates. Production is primarily from depths ranging from 6,500 to 7,500 feet.

**Exploration status and resource potential:** The Dakota discovery well in the central basin was drilled in 1947 southeast of Farmington, New Mexico. The Dakota Basin Field, containing the Dakota gas pool, was formed February 1, 1961, by combining several existing fields. By the end of 1993 it had produced over 4.0 TCFG and 38 MMB condensate. Almost all of the Dakota interval in the central part of the basin is saturated with gas, and additional future gas discoveries within the central basin field and around its margins are possible.

**Source Beds for Oil and Gas:**
The source beds for oil and gas are also variable. Non-associated gas in the Dakota pool was generated during the late Miocene and postmature stages and probably had a marine Mancos Shale source (Rice, 1983).

**Timing and Migration:** In the northern part of the central San Juan Basin, the Dakota Sandstone and Mancos Shale entered the oil generation window in the Eocene and were elevated to temperatures appropriate for the generation of dry gas by the late Oligocene. Along the southern margin of the central basin, the Dakota and lower Mancos entered the thermal zone of oil generation during the late Miocene (Huff, 1987). It is not known at what point hydrodynamic forces reached sufficient strength to act as a trapping mechanism, but the early Miocene is likely for the establishment of the present-day uplift and erosion pattern throughout most of the basin. Migration of the oil in the Dakota was still taking place in the late Miocene, of even more recently, in the southern part of the San Juan Basin.

**Traps:** The Dakota gas accumulation in the central basin is on the flanks and bottom of a large depression and is not localized by structural trapping (Fig. UM-46). The fluid transmissibility characteristics of Dakota sandstones are generally consistent from the central basin to the outcrop. Hydrodynamic forces, acting in a basinward direction, have been suggested as the trapping mechanism, but these forces are still poorly understood. The seal is commonly provided by either marine shale or paludal carbonates. Production is primarily from depths ranging from 6,500 to 7,500 feet.

**Exploration status and resource potential:** The Dakota discovery well in the central basin was drilled in 1947 southeast of Farmington, New Mexico. The Dakota Basin Field, containing the Dakota gas pool, was formed February 1, 1961, by combining several existing fields. By the end of 1993 it had produced over 4.0 TCFG and 38 MMB condensate. Almost all of the Dakota interval in the central part of the basin is saturated with gas, and additional future gas discoveries within the central basin field and around its margins are possible.
Analog Fields in and near Reservation

(*) denotes field lies inside Reservation boundaries

*Barker Creek Dakota
Location of discovery well: se ne 16 - T32N - R14W (1925)
Producing formation: Upper Cretaceous Dakota Sandstone, Paradox Formation
Number of producing wells: 5 (1977)
Production: 215,279,080 MCFG (1996)
Gas characteristics: Sweet gas
Type of drive: Gas expansion
Average net pay: 40 feet
Porosity: 14%
Permeability: 0 - 1500 md, average = 16.5 md

*Ute Dome Dakota
Location of discovery well: se 35 - T32N - R14W (1921)
Producing formation: Cretaceous Dakota Sandstone, Paradox Formation
Number of producing wells: 14 (1977)
Production: 93,589,058 MCFG (1996)
Type of drive: Combination water drive and volumetric
Average net pay: 30 feet
Porosity: 15%
Permeability: 10 md

*Basin Dakota
Location of discovery well: ne nw 4 - T27N - R10W NMPM (April 1947)
Producing formation: Cretaceous Dakota Sandstone
Number of producing wells: 2395
Production: Gas: 2,753,610,459 MCFG
Oil: 27,186,314 BO
Characteristics: Gas: 1100 BTU
Oil: 50 °API Gravity
Type of drive: Gas expansion (upper part), Water drive (lower part)
Average net pay: 50-70 feet
Porosity: 5-15%
Permeability: 0.1 - 0.25 md

Figure UH-48. Structure contour map of the top of the Graneros Shale, cross section, and type log for the Barker Creek Dakota Field (modified after Matheny, 1978)
Buried Fault Blocks, Older Paleozoic Play
(U.S.G.S. Designation 2101)

General Characteristics
The play is based on the occurrence of oil accumulations in fault blocks involving pre-Pennsylvanian rocks, mainly in the salt anticlinal area of the Paradox Basin, and it covers an area of approximately 7,500 square miles (Fig. UM-49). Most of the structures are associated with the salt anticlines themselves and were growing at the same time that the salt was moving.

Reservoirs: Reservoirs are in porous dolomite or dolomitic limestone beds of the Mississippian Leadville Limestone (Figs. UM-50, -52, and -53) and the Upper Devonian McCracken Sandstone Member of the Elbert Formation. The McCracken Sandstone (Figs. UM-51 and -53) is mainly a dolomitic sandstone, sandy dolomite, and dolomitic mudstone. Cyclical fluctuations in relative sea level during McCracken time produced three coarsening-upward intervals (parasequence sets) which correspond to the main reservoir units. Depositional environments range from intertidal-supratidal carbonate flat to siliciclastic prodelta and delta front. Reservoir flow units are strongly dominated by siliciclastic lithofacies, whereas carbonate lithofacies compose major flow barriers and baffles.

Source Rocks: Probable source rocks are the organic-rich black dolomitic shales of the Pennsylvanian Paradox Formation. Migration into Leadville or McCracken reservoirs occurred where fault blocks are in structural and (or) depositional contact with the black shale, which is generally low, but is as much as several hundred mD in places.

Timing and Migration: Hydrocarbon generation began as early as Permian time and has continued to the present in some cases. Migration into pre-salt reservoirs was probably contemporaneous with the growth of salt structures. Migration pathways were enhanced by severe fracturing of interbedded organic-rich shale during salt movement.

Traps: Known traps are on uplifted fault blocks adjacent to salt anti-
clines or swells. Seals are Paradox Formation evaporite beds that overlie, or are in fault contact with, Mississippian or Devonian reservoirs. Drilling depths range from 7,000-8,000 feet at the Lisbon field, and to greater than 10,000 feet in other areas.

Exploration Status and Resource Potential: Six oil and gas accumulations produce from pre-salt structural blocks. The largest of these is the Lisbon field, which is approximately 43 MMBO and 250 BCFG in size. The remainder of the fields are noncommercial or marginally commercial. The play is only moderately explored with respect to smaller structures. Future potential is low to moderate, and based on previous production history, undiscovered fields are estimated to be small to medium in size and have minimal oil columns.

Figure UM-48. Location of Buried Fault Blocks, Older Paleozoic Play and location of oil and gas discovery wells for named fields (modified after Peterson, 1996).

Figure UM-50. Structure Contour Map of the top of the Mississippian Leadville Limestone and location of cross section in figure UM-53 (modified from Condon, 1996).
Figure UM-51. Isopach map of the McCracken Sandstone Member of the Elbert Formation. Contour intervals are 25 ft (modified from Condon, 1995).

Figure UM-52. Isopach map of the Mississippian Leadville Limestone. Contour intervals are 100 ft (modified from Condon, 1995).

Figure UM-53. Stratigraphic section of Pre-Pennsylvanian units in the Ute Mountain Ute Indian Reservation and surrounding area. All logs are gamma ray-neutron, except for log number 6 which consists of a spontaneous-potential and resistivity curves. Horizontal scale is variable (modified from Condon, 1995).
Analog Field Near Reservation

Lisbon Field
(Figs. UM-54 - UM-57)

Location of discovery well: ne ne, sec. 10, T30S, R24E (1959)
Producing formation: McCracken Sandstone Member of the Elbert Formation, Leadville Limestone
Number of producing wells: 11
Production: 1,465 BCFG, <1 MMBO McCracken (1996)
Oil characteristics: 60 MMBO Leadville (1996)
Average net pay: 39.4 Feet
Porosity: 0.3 - 16.9%
Permeability: <0.01 - 272 mD

Figure UM-54. Structure contour map of the top of the F2 flow unit for Lisbon field and location of cross section in Figure UM-55 (modified after Cole and Moore, 1996).

Figure UM-55. Structure cross-section of Lisbon field (after Cole and Moore, 1996).

Figure UM-56. Type log for McCracken unit at Lisbon Field (modified after Cole and Moore, 1996).

Figure UM-57. Type log for Leadville Limestone unit at Lisbon Field (modified after Fouret, 1996)

LISBON FIELD
STRUCTURAL CROSS-SECTION

EST. OIL-WATER CONTACT
(-2340' SUBSEA)
Fractured Interbed Play (USGS Designation 2103)

General Characteristics
This unconventional continuous-type oil and gas play is oil prone throughout most of the Paradox Basin but is more gas prone to the east close to the ancestral Uncompahgre uplift (Fig. UM-58). The reasons for this change in character are increased depth of burial and percentage of terrestrial organics to the east.

Reservoirs: The play depends on extensive fracturing in the organic-rich dolomitic shale and mudstone in the interbeds between evaporites of the Pennsylvanian Paradox Formation and carbonate and clastic rocks of the related cycles on the shelf of the Paradox evaporite basin. These shales and mudstones may be as thick as 130 feet but are more commonly less than 20 feet thick.

Source rocks: These organic-rich black dolomitic shales and mudstones are the source rocks for most, if not all, of the oil and gas in the Paradox Basin. Total organic carbon commonly ranges from 1 to 5% but may be as high as 20%. Oil produced by these source rocks typically has 40°-43° API gravity and low sulfur content.

Timing and migration: The thermal history of these rich source rocks is determined mostly by depth of burial and to a lesser degree by the added effect of the Oligocene volcanic activity. Pennsylvanian, Permian, Late Cretaceous, and early Tertiary sediments thicken significantly to the east so that the Pennsylvanian section entered the thermal zone of oil and gas generation at different times depending on location. Close to the Uncompahgre Uplift, Pennsylvanian rocks may have generated oil as early as the Permian; elsewhere these rocks may have entered the oil generation zone in the Late Cretaceous, and early Tertiary sediments.

Exploration status and resource potential: Until recently, the only significant production from this play was from the Lone Canyon field discovered in 1962. Recently, near Bartlett Flat field has been developed by directional drilling in the Lone Canyon field at a depth of approximately 9,000 feet. The Cane Creek, Chimney Rock, Gothic, and Hovenweep Shales have the most potential due to both organic content and thickness.

Permian-Pennsylvanian Marginal Clastics Gas Play (USGS Designation 2104)

General Characteristics
This hypothetical play, formerly known as the Silverton Delta Play (Peterson, 1989), has been renamed to more accurately reflect the geometry and depositional environment of the reservoir rocks. The Silvertown fan delta is limited to an area near the Colorado-Utah state line, but marginal clastic rocks extend the length of the ancestral Uncompahgre uplift (Fig. UM-59). These clastics were deposited as coalesced outwash fans that intertongue with the cyclic marine deposits of the Pennsylvanian Hermosa Group.

Reservoirs: Gas shows have been encountered in porous and permeable sandstone intervals within the generally arkosic Permian Cutler Formation in the vicinity of the ancestral Uncompahgre Uplift. Such potential reservoir rock is present where feldspar and clay were winnowed out by wave action or fluvial stream flow. For most of the area, the lower part of the Pennsylvanian interval is more likely to contain these beds than the upper part because of the lower original feldspar content of the lower part. In the upper part of the Pennsylvanian interval, the southeastern Paradox Basin province is more likely to contain such beds because of the presence of a large fan delta complex that provided the necessary depositional environments to clean the sandstones.

Source rocks: This play is dependent on the presence of Domomocene, organic-rich, dolomitic shale and mudstone in contact or close proximity to reservoir lithologies. Because this juxtaposition is necessary close to the ancestral Uncompahgre Uplift, the play is gas prone due to the predominance of Type III kerogen from the uplift, as well as the depth of burial in the deep trough along the basin margin.

Traps: Trap types are expected to be dominantly combinations of updip pinchouts of permeable sandstone lenses localized on folded and faulted structures. Seals are provided by shale beds as well as by reduced permeability due to clay.

Exploration status and resource potential: Little exploration has taken place within this play and there is no production to date, but shows have been reported from Permian Cutler sandstone bodies. The presence of excellent source rocks and structures are factors in its favor.

Figure UM-58. Location of Fractured Interbed Play (modified after Gaubert, et al., 1996).

Figure UM-59. Location of Permian-Pennsylvanian Marginal Clastics Gas Play (modified after Gaubert, et al., 1996).