Petroleum Geology and Hydrocarbon Plays of the San Juan Basin Petroleum Province

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INTRODUCTION

Location, Size, and Type

The San Juan Basin petroleum province incorporates much of the area from 35° to 38° north latitude and from 106° to 109° west longitude and comprises all or parts of San Juan, McKinley, Rio Arriba, and Sandoval Counties in northwest New Mexico and Montezuma, La Plata, Archuleta, San Juan, Mineral, and Hinsdale Counties in southwestern Colorado (fig. 1). As defined for this study, it includes areas that lie outside the structural or topographic San Juan Basin (figs. 2 and 3). The southern part of the area lies in the Colorado Plateau physiographic province while much of the northern part is within the southern Rocky Mountain province. Nearly all hydrocarbon production and subsurface data are restricted to the topographic San Juan Basin but there is increasing interest in the area surrounding and underlying the San Juan volcanic field. Little information is as yet available in this frontier area and it will not be included in any of the plays discussed in this report.

The San Juan Basin petroleum province covers an area of about 23,700 mi^2 (61,400 km^2). Of this total about 9,900 mi^2 (25,600 km^2) or 42 percent, is administered by the U.S. Government; about 9,500 mi^2 (24,600 km^2) or 40 percent is Indian land; about 3,700 mi^2 (9,600 km^2) or 16 percent is privately held; and about 600 mi^2 (1,600 km^2) or 2 percent is state land.

The San Juan Basin itself has been classified as a craton-accreted margin (complex) basin (type IIB) by Klemme (1986) and as a foredeep basin (type B2) by Bally (1975). A characteristic of these types of basins is that they commonly are filled by sequences comprising two or more cycles of deposition--a first cycle of carbonate shelf or platform sediments and a second cycle of orogenic clastics. The San Juan Basin contains two such sequences or megacycles: (1) Paleozoic and, (2) Upper Cretaceous to Oligocene.

Structural Setting

The San Juan Basin petroleum province contains all or parts of a number of tectonic elements (fig. 2). In their present form most of these are Laramide features but much of the tectonic framework was inherited from older structures. The pre-Laramide structures influenced depositional patterns throughout much of the stratigraphic section thereby affecting reservoir quality and, to some extent, source rock distribution. Laramide tectonic and thermal patterns determined the maturation and migration history within the basin.

The structural San Juan Basin is rimmed on the east, west, and north by uplifts or monoclinal structures with structural relief of as much as 15,000 ft (4570 m). The southern boundary is somewhat nebulously defined as the northern limit of the Chaco slope, a homocline dipping north from the Zuni uplift (fig. 3). The interior of the basin is characterized by gently dipping to flat lying sedimentary rocks and a few widely scattered low-relief domal or anticlinal structures. Very few faults have been mapped at the surface.

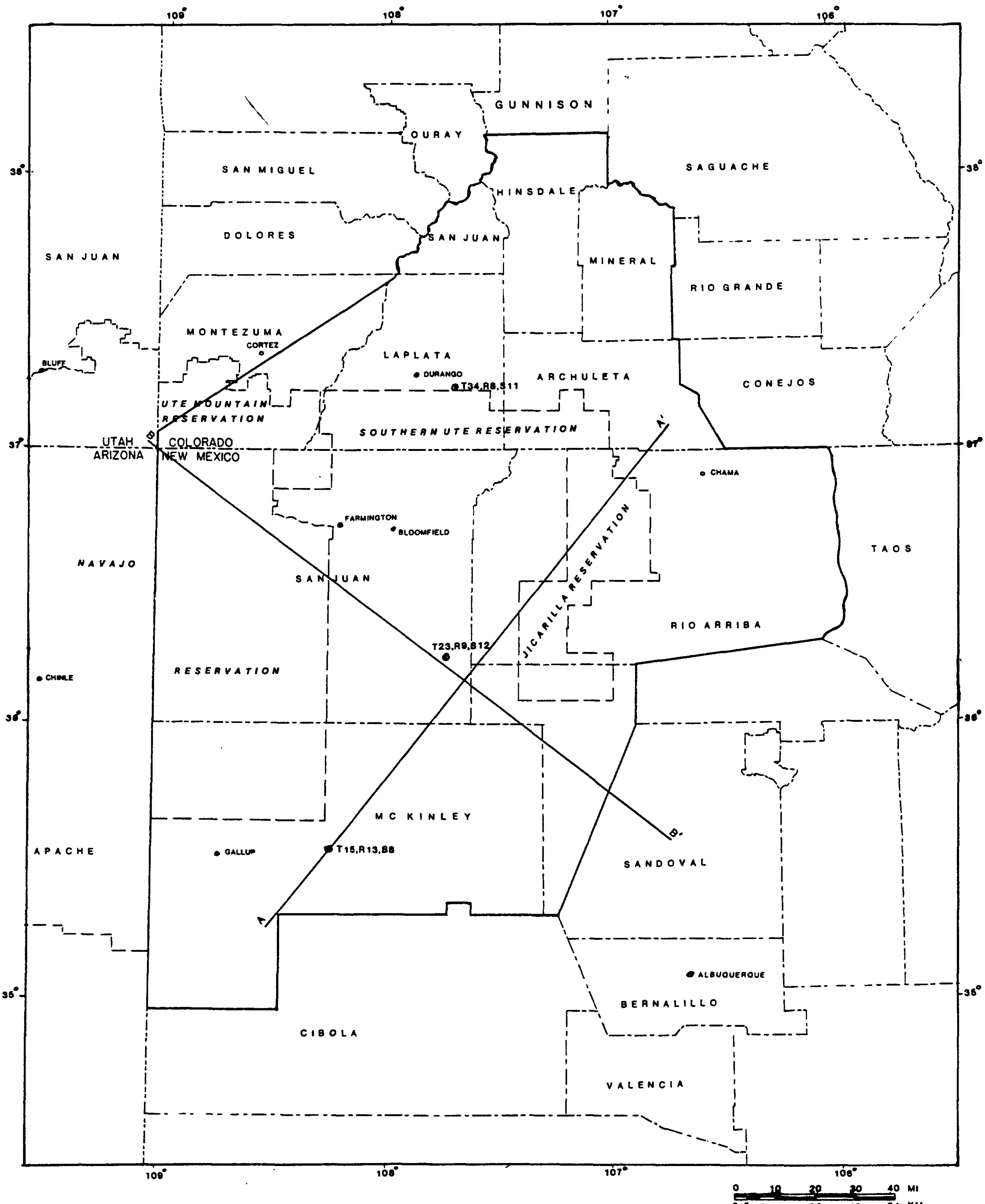

Figure 1.--Location of the San Juan Basin petroleum province in relation to states, counties, and Indian reservations of the Four Corner area. Also shown are the locations of cross sections of figure 4 and wells used for Lopatin diagrams of figure 6.

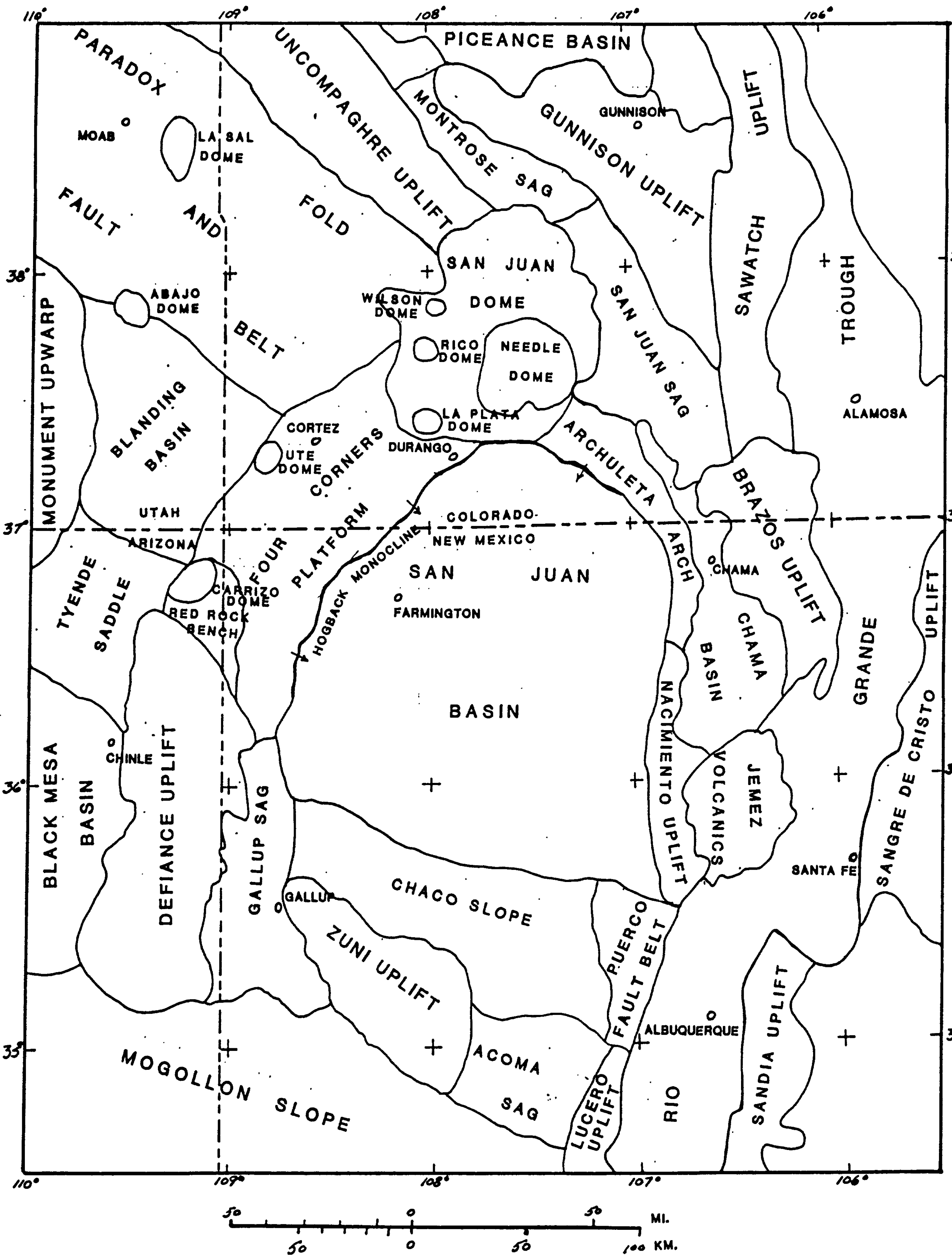

Figure 2.--Structural elements in the vicinity of the San Juan Basin petroleum province (modified after Kelley and Clinton, 1960; Grose, 1972; and Woodward, 1974).

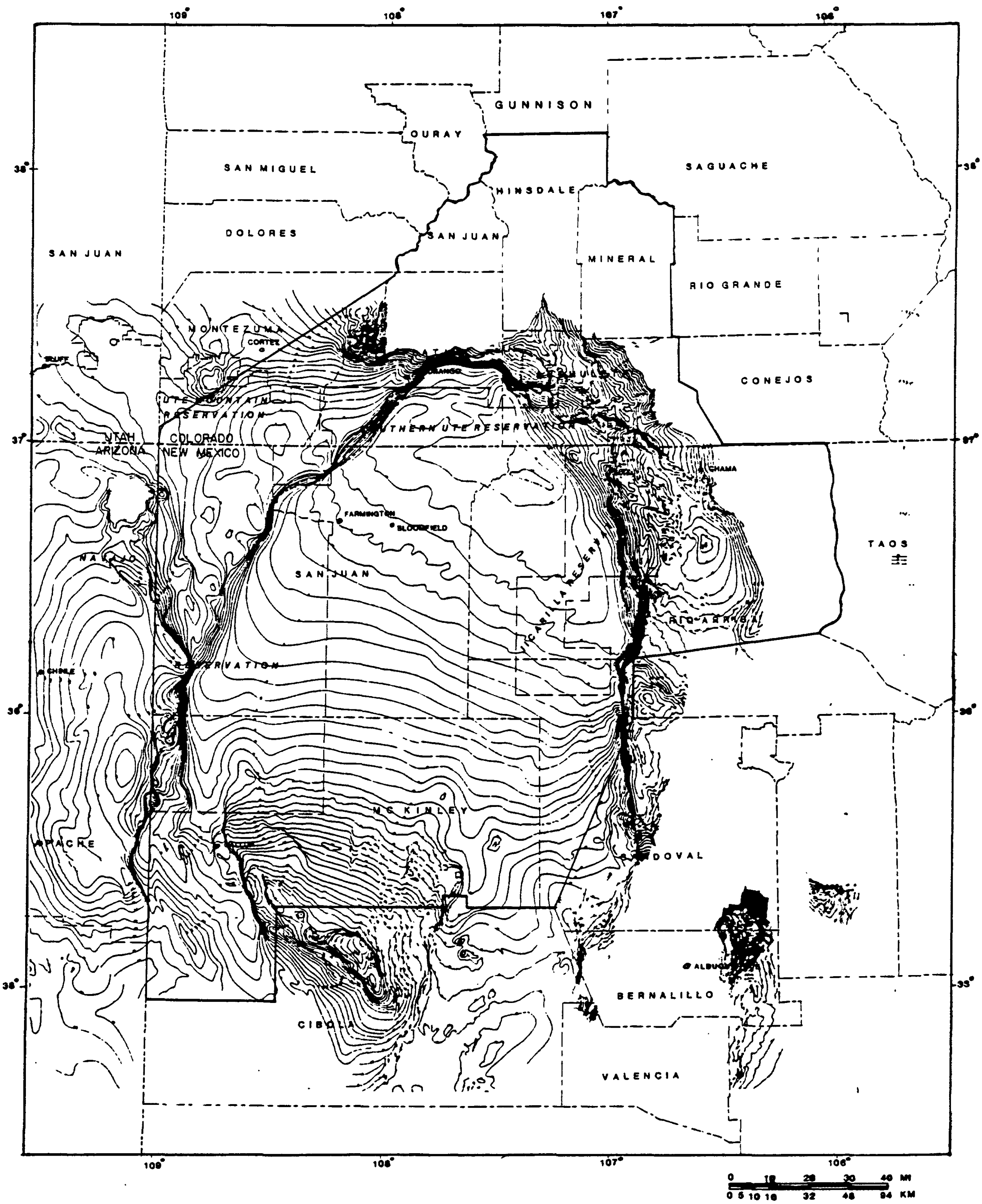

Figure 3.--Generalized structure of the San Juan Basin and vicinity on the base of the Dakota Sandstone (Thaden and Zech, 1984).

Immediately adjacent to the structural basin on the south and west, the Chaco slope and part of the Four Corners platform also lie within the topographic basin. In these areas the sedimentary rocks are gently dipping, but domal and anticlinal structures are more pronounced and more common as are surface faults (fig. 3). Deep-seated structures with little or no surface expression are also more common.

Included in the San Juan Basin petroleum province but separated from the structural and topographic basin by the Hogback monocline and Archuleta arch respectively, the San Juan dome and Chama basin contain sedimentary sequences that are similar to those of the San Juan Basin. Within much of the San Juan dome the sedimentary section is covered by variable thicknesses of volcanic rocks surrounding numerous caldera structures.

Stratigraphy

The stratigraphic section in the San Juan Basin attains a maximum thickness of approximately 15,000 ft (4570 m) in the northeast part of the structural basin (fig. 4) where the Upper Devonian Elbert Formation lies on Precambrian basement. Elsewhere in the province Cambrian, Mississippian, Pennsylvanian or Permian rocks may overlie the Precambrian (fig. 5).

Cambrian

Cambrian rocks are present only in the northern part of the province where there is as much as 150 ft (46 m) of Upper Cambrian quartzite, quartzose sandstone, and local shale lenses of the Ignacio Quartzite. The Ignacio is thought to have been deposited by an eastward-transgressing sea and only preserved in relatively small, isolated down-thrown fault blocks (Stevenson and Baars, 1977).

Devonian

The Devonian of the petroleum province, comprising the Aneth, Elbert, and part(?) of the Ouray Formations, may reach thicknesses of 500 ft (150 m) in the Four Corners area but is absent in the southern San Juan Basin (Stevenson and Baars, 1977). The Upper Devonian Aneth and lower part of the Ouray Formations are primarily limestone and dolomite, whereas, the lower part of the Elbert Formation contains fine- to medium-grained glauconitic sandstones of the McCraken Sandstone Member. The upper member of the Elbert consists of waxy shale, thin-bedded limestone and dolomite, and glauconitic sandstone. Baars (1966) suggested a tidal-flat environment of deposition for the upper member of the Elbert.

Mississippian

Within the San Juan Basin petroleum province, the Mississippian System is composed of limestone and fine-grained dolomite of the Leadville and upper part of the Ouray Limestones. Total thickness is commonly between 150 and 300 ft (50-100 m). Armstrong and Mamet (1977) suggest a subtidal-intertidal depositional environment for the upper part of the Ouray and lower part of the Leadville and sedimentation on a shallow shelf with localized areas of lime mud accumulation or ooid sands developed in shoaling waters for much of the upper part of the Leadville.

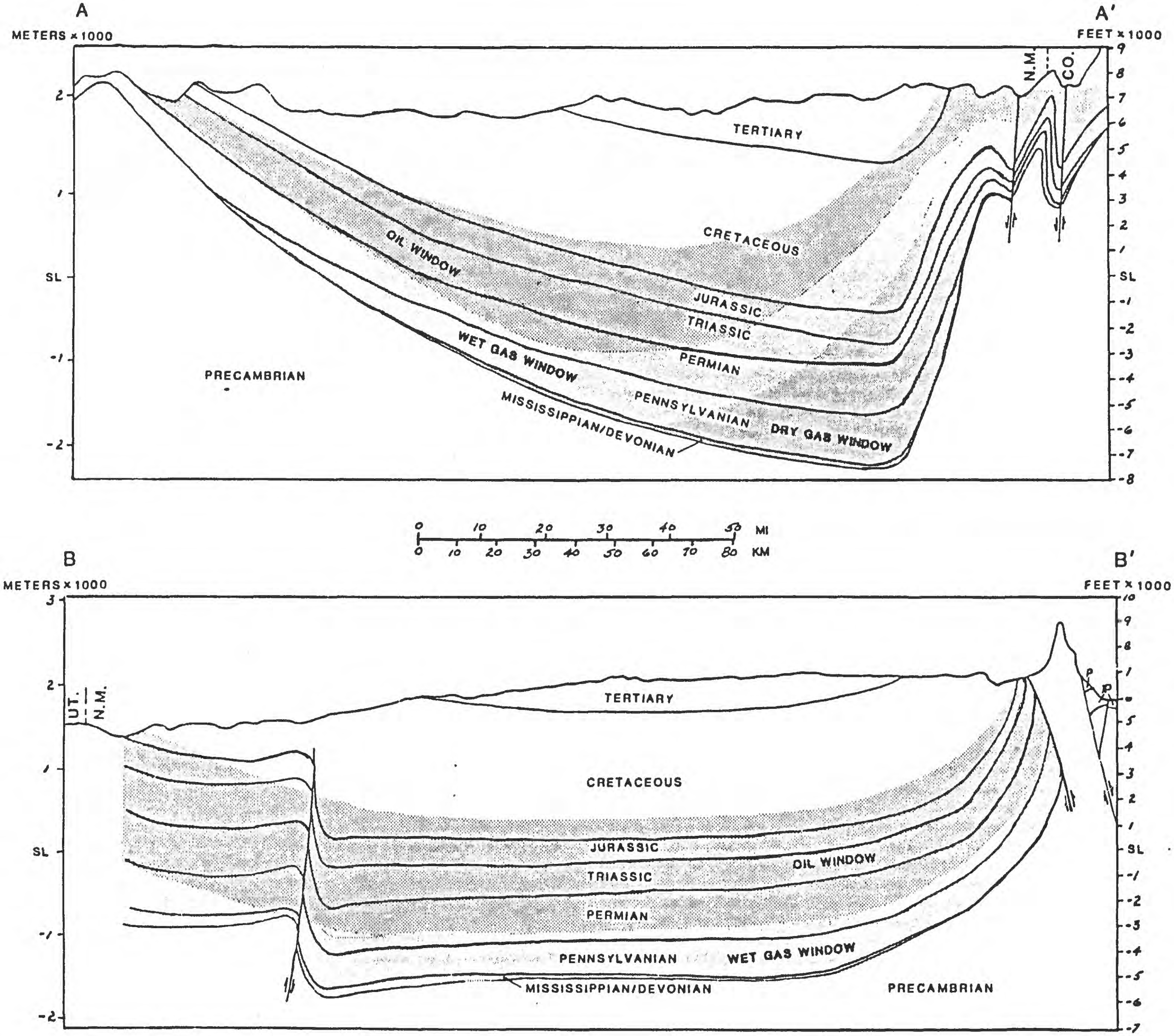

Figure 4.--Generalized cross sections through the San Juan Basin (A-A', southwest to northeast; B-B; northwest to southeast) with approximate maturity levels indicated by shading. Lines of section shown in figure 1.

SAN JUAN BASIN TIME-STRATIGRAPHIC NOMENCLATURE CHART

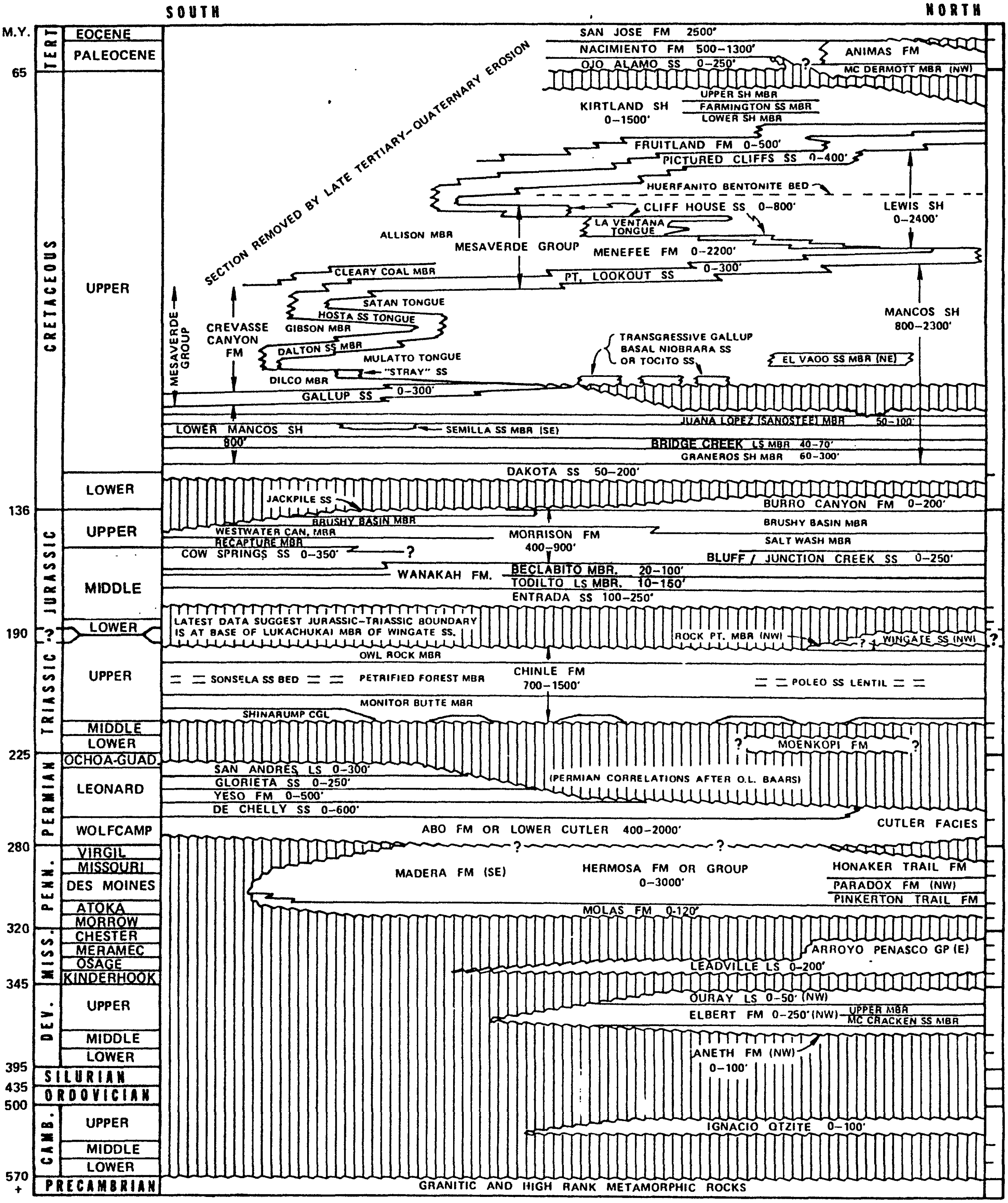

Figure 5.--San Juan Basin time-stratigraphic nomenclature chart (modified after Molenaar, 1977b).

Pennsylvanian

The Pennsylvanian System in the petroleum province is represented by the Molas Formation, which consists of a paleo-sol developed on the underlying Mississippian carbonates and red marine shale, and by the Hermosa Formation of Middle to Late Pennsylvanian age. The Hermosa, which may be as thick as 3,000 ft (914 m), wedges out to the south. Three members of the Hermosa are recognized: the lower member, the Paradox Member, and the upper member (Pinkerton Trail, Paradox, and Honaker Trail Formations of Wengard and Matheny, 1958). The upper and lower members consist primarily of a cyclic sequence of intercalated sandstone and shale beds and thin marine limestone beds of a normal marine environment (Stevenson, 1983). In the Paradox evaporitic basin, the Paradox Member is composed of repetitive cycles of halite, anhydrite, dolomite, and black shale but southeastward into the San Juan Basin it changes facies to restricted marine carbonates and black shale.

Permian

Permian arkosic redbeds overlie the Pennsylvanian marine rocks throughout most of the petroleum province except along the flanks of the basin where the Permian unconformably overlies the Precambrian. In the northern and central part of the San Juan Basin and on the Four Corners platform, the Permian System is composed of the Halgaito, Cedar Mesa, and Organ Rock Formations of the Cutler Group and the overlying eolian DeChelly Sandstone. The source of the reddish-brown arkosic clastics that dominate the 1,000 to 2,500-ft (300-760 m)-thick Cutler Group and equivalent Abo Formation was the Uncompahgre Uplift to the north and northeast (Baars, 1962). In the southern part of the area the Permian System becomes more marine above the Abo Formation where the Yeso Formation, Glorieta Sandstone, and San Andres Limestone are preserved.

Triassic

Within the San Juan Basin petroleum province the Triassic System is represented by continental deposits of the Upper Triassic Chinle Formation in New Mexico and the partly equivalent Dolores Formation in Colorado. Thickness ranges from 0 to 1,600 ft (0-500 m). The overlying eolian Lukachukai Member of the Wingate Sandstone is of questionable age but was assigned to the Early Jurassic by Peterson and others (1977) based on palynomorphs found in the intertonguing Moenave Formation in south-central Utah. The Lukachukai Member is present in the northwestern part of the area only. Elsewhere in the province the Chinle and Dolores are unconformably overlain by the Entrada Sandstone of Middle Jurassic age.

Jurassic

The dominantly continental San Rafael Group and Morrison Formation make up the bulk of the Jurassic System in the petroleum province. The Entrada sandstone is primarily eolian while the Wanakah Formation contains a marine limestone and evaporite member (Todilto Limestone Member in New Mexico, Pony Express Limestone Member in Colorado) at the base overlain by tidal flat and eolian deposits. Along the southwestern margin of the San Juan Basin the eolian Cow Springs Sandstone overlies and intertongues with the Wanakah. Throughout much of the province the Morrison Formation is eolian at the base, fluvial in the middle, and lacustrine at the top. Total thickness of Jurassic rocks in the area ranges from 0 to 1,500 ft (0-450 m).

Cretaceous

Most of the hydrocarbon production in the San Juan Basin petroleum province is from the 6,500-ft (1980 m)-thick Upper Cretaceous section that comprises five major transgressive/regressive cycles. The basal transgression and associated deposits of the Dakota Sandstone advanced from east to west whereas the later transgressions were from the northeast (Molenaar, 1977a). The Dakota Sandstone and coastal barrier sandstone deposits of the Gallup, Point Lookout, Cliff House, and Pictured Cliffs sandstones constitute the principal reservoirs, and black marine shales of the Mancos and Lewis Shales are the primary source rocks of the province. Coal deposits in the Dakota Sandstone, Menefee Formation, and Fruitland Formation not only are a resource in themselves but also are a major source of gas within the central part of the basin.

Tertiary

An unknown thickness of Tertiary continental sediments were deposited and subsequently removed throughout the province. What remains is typically conglomerate, sandstone, arkosic sandstone, and shale of fluvial and lacustrine origin that ranges in thickness from 0 to 4,000 ft (0-1200 m), plus the overlying volcanics in the northern part of the province.

Source Rocks

Principal source rocks in the San Juan Basin petroleum province are marine black shales of the Pennsylvanian Hermosa Formation and Upper Cretaceous Mancos and Lewis Shales; marine limestone of the Pennsylvanian Hermosa and Upper Jurassic Wanakah Formations; and coals of the Upper Cretaceous Dakota Sandstone, Menefee Formation, and Fruitland Formation.

Burial History, Thermal Maturity, Timing of Migration

Prior to Cretaceous time the region of the Colorado Plateau that was to become the San Juan Basin experienced several depositional cycles punctuated by periods of uplift and erosion. At the initiation of Cretaceous marine transgressions there were approximately 6,000 ft (1830 m) of sedimentary rocks overlying the Precambrian basement complex in the northern part of the area and less to the south. During the Late Cretaceous the basin subsided rapidly and received as much as 6,500 ft (1980 m) of marine and continental sediments. In the northern part of the basin, subsidence and marginal uplift continued at a similar or even accelerated rate to the end of the Oligocene resulting in a thick (approximately 7,500 ft; 2280 m) section of continental deposits including volcanic flows and ejecta in the northernmost areas. Uplift and erosion since the close of the Oligocene has left about 15,000 ft (4570 m) of sedimentary fill in the deepest part of the basin.

The thermal history of the basin can be divided into a pre-Tertiary normal basin regime and a Tertiary thermal event. Throughout most of the basin, a thermal gradient of 1.5°F/100 ft (27°C/km) is assumed for the pre-Tertiary (figs. 6.a,b.) except in the southernmost part of the basin where proximity to the intermittently active Zuni uplift and its Precambrian core suggests higher gradients (fig. 6.c). The intrusive and extrusive activity of the San Juan dome beginning in the Paleocene and culminating in a "heat flash" during the Oligocene raised the gradient to approximately 3.1°F/100 ft (55°C/km) according to Bond (1984). In the southern part of the basin, Miocene to Pleistocene volcanism may have raised the gradient to similar values. Data are not available to allow analyses of the gradient in the

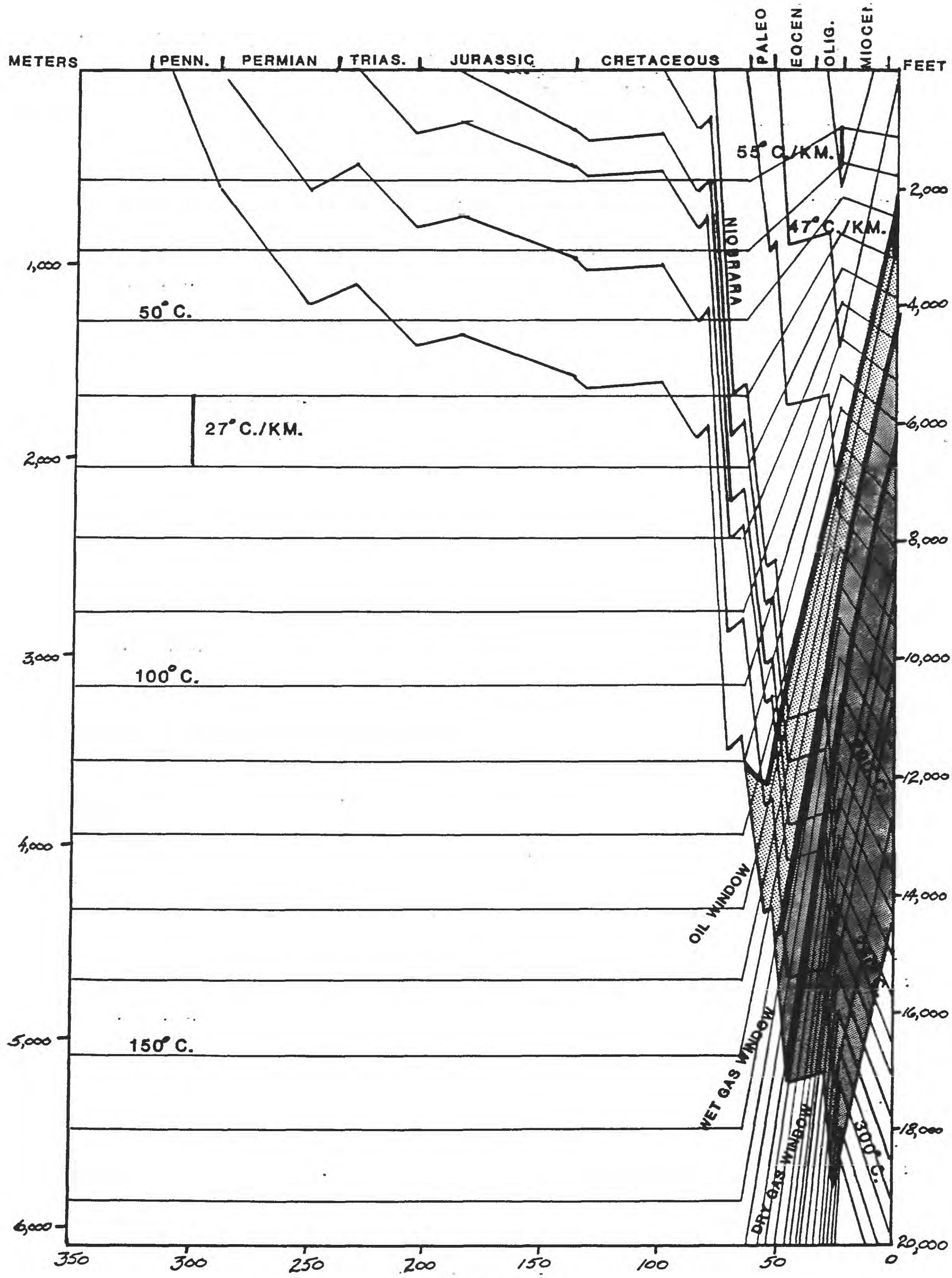

Figure 6a.--Lopatin diagram for north-central San Juan Basin (T. 34 N., R. 8 W., S. 11).

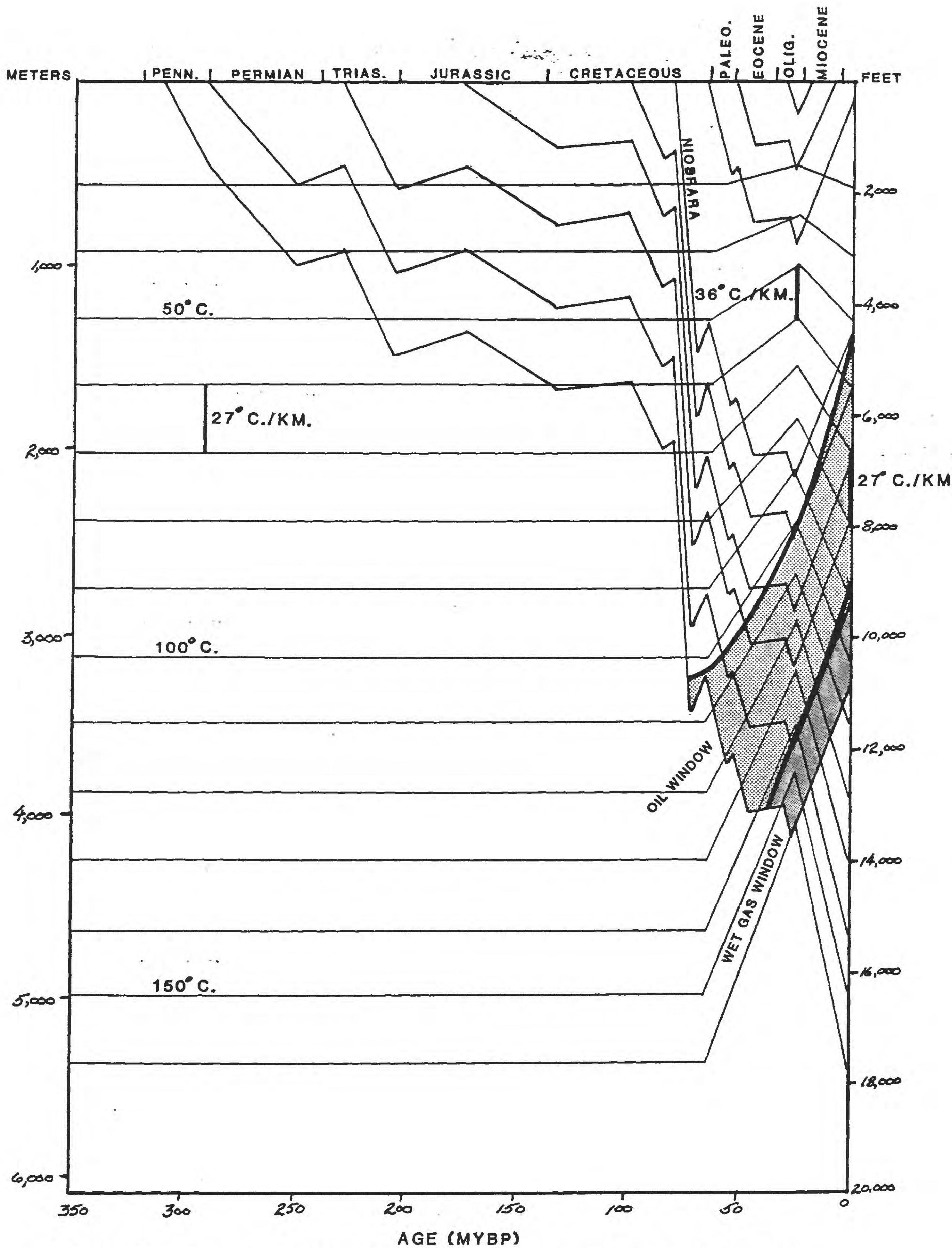

Figure 6b.--Lopatin diagram for south-central San Juan Basin (T. 23N., R. 9W., S. 12).

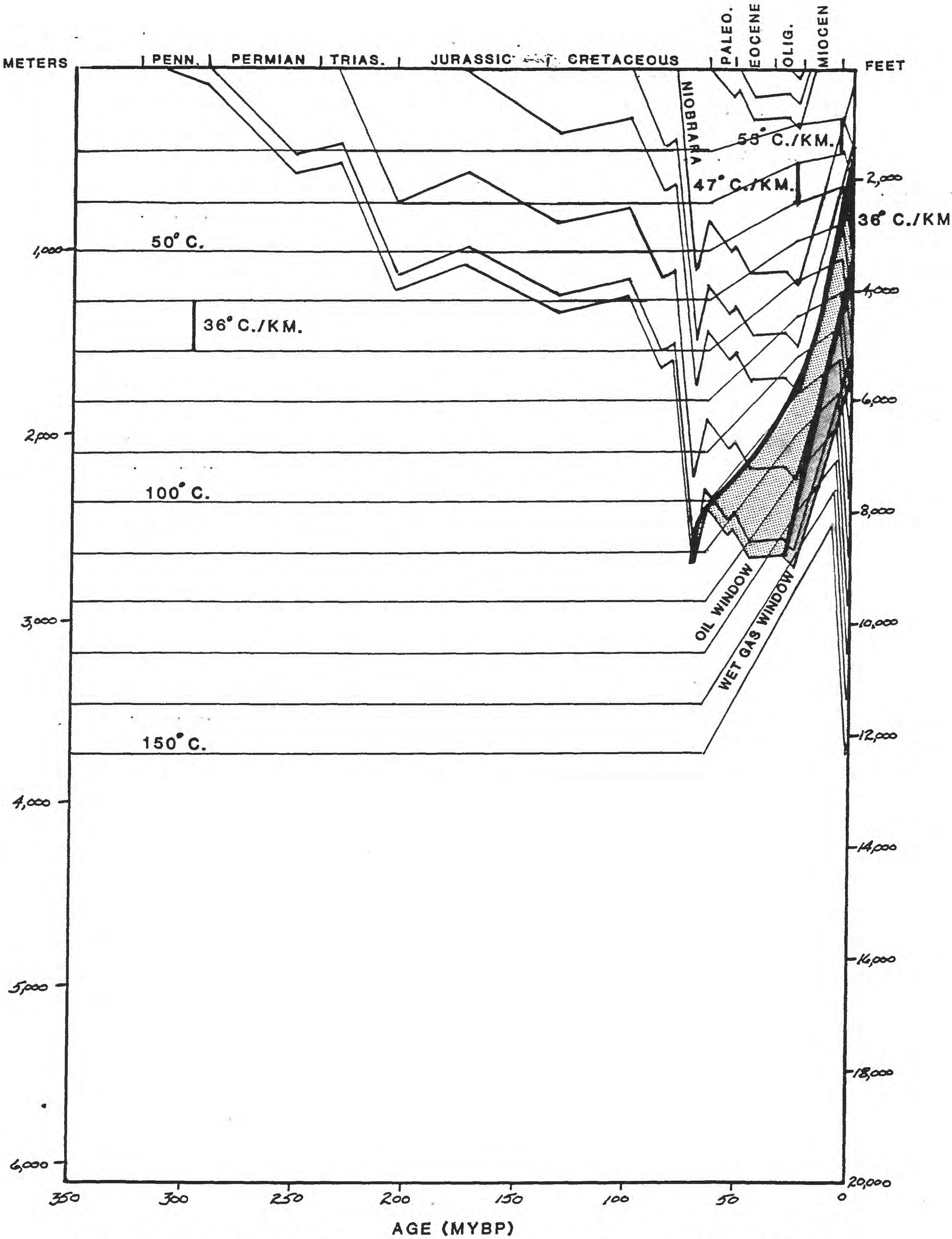

Figure 6c.--Lopatin diagram for southern Chaco slope (T. 15 N., R. 13 W., S. 8).

northernmost part of the petroleum province beneath the volcanics, but it was probably quite high.

Maturity of any particular stratigraphic interval depends both on its burial history and on proximity to one of the major heat sources. Consequently, very few generalizations can be made for the entire basin except that Pennsylvanian strata are at least mature throughout and that the Cretaceous source rocks in the northern part of the basin reached maturity in the Eocene. Bond (1984) credits the Oligocene "heat flash" with eliminating the time consideration from maturation calculations for the Cretaceous section in the northern part of the basin where most of the Cretaceous and older rocks are super mature.

Similar reasoning can be applied to the timing of migration. Nearly all hydrocarbon migration would have taken place since the Late Cretaceous with most having occurred since the Eocene. Basin configuration has remained relatively stable since cessation of Oligocene volcanism.

Hydrocarbon Occurrence

Stratigraphic and Structural Habitat of Petroleum

Most hydrocarbon occurrences in the San Juan Basin petroleum province are at least partially stratigraphically controlled. In the central part of the basin, stratigraphy and hydrodynamic forces control nearly all production while around the margins of the basin, structure and stratigraphy are the primary factors. Although most Pennsylvanian oil and gas is found on structures around the northwestern margin, it commonly accumulates only in the highly porous biothermal limestone buildups. Jurassic oil on the southern margin of the basin is stratigraphically trapped in eolian dunes at the top of the Entrada Sandstone. Nearly all oil and gas in Upper Cretaceous sandstones of the central basin is produced from stratigraphic traps such as reservoir sandstone pinchouts into marine shale or continental shale and coal, or where abnormally thick reservoir sandstone buildups resulted from still stands or tectonic activity during deposition. Around the margins of the basin, the same Cretaceous units produce oil on many of the structures.

Two additional factors affecting the distribution and production of oil and gas from the Upper Cretaceous reservoirs are hydrodynamic forces and differences in permeability. Neither are completely understood but together create a situation where gas in the central basin is structurally lower than oil or water in the same units around the margins. Even though most of the reservoirs of the central basin are saturated with gas, because of their low permeability many will only produce where fractured, either naturally or artificially.

Basis for play definition

In this analysis, plays are defined primarily on the basis of stratigraphy because of the strong stratigraphic controls on the occurrence of hydrocarbons throughout the province. In general, the plays correspond to lithostratigraphic units such as formations or members containing good reservoir rocks and with access to source beds. Several of the plays are further divided into basinal and basin flank components based on both location and dominant trap type.

Criterion for plays selected

The San Juan Basin petroleum province is moderately to well explored in much of the area with a long history of development. The plays selected for discussion in this analysis are the generally recognized producing intervals.

Other prospective areas or intervals

Several prospective exploration targets remain inadequately tested. The entire area surrounding and even underlying some of the volcanics of the San Juan dome has potential for hydrocarbon accumulations especially in the Pennsylvanian and the lower part of the Cretaceous section as do the deeper parts of the section on the Southern Ute and Jicarilla Apache Indian Reservations where very little deep drilling has been attempted. The Mississippian and Pennsylvanian have been inadequately tested throughout most of the area but depth and probable target size east of the Four Corners platform will probably limit activity in the near future. Several large structures in the northern part of the San Juan Basin, such as the Hogback monocline and Archuleta arch (fig. 2) have also been inadequately tested. Recent reprocessing of seismic data along the Hogback monocline suggests easterly directed thrust faulting at depth with as much as 4,000 ft (1220 m) vertical offset and about 3,000 ft (900 m) of overlap along parts of this structure. The southwestern flank of the Archuleta arch has not been explored either by drilling or seismic surveys.

By far the largest undeveloped potential within the petroleum province is coal-bed methane within the Fruitland Formation in the central basin. The few wells producing from this interval show great promise but further development will depend on technological advances in engineering, drilling, and completion techniques.

PRINCIPAL PLAYS

Pennsylvanian

Play description and type

The Pennsylvanian oil and gas play is in mounds of algal (Ivanovia) limestone associated with organic-rich black shale rimming the evaporite sequences of the Paradox Member of the Hermosa Formation. Most of the developed fields within the San Juan Basin petroleum province produce from combination traps on the Four Corners platform at depths ranging from 5,100 to 8,500 ft (1550-2590 m).

Nearly all hydrocarbon production from Pennsylvanian rocks in the vicinity of the San Juan Basin has been from vuggy limestone and dolomite in the Paradox Member of the Hermosa Formation on the Four Corners Platform. Jentgen (1977) described the Paradox Member as containing "complex lateral facies changes, from thick interbedded evaporites and black shale in the northwestern San Juan Basin and the southeasternmost Paradox basin, to thinner conglomeratic and cherty limestone, sandy siltstone, and arkosic rocks in the central San Juan Basin. Evaporites in the Paradox wedge out abruptly in places against carbonate buildups." Hydrocarbon producing zones in the Paradox Member have been given informal names (Malin, 1958) and correlated by Hite (1960) with salt cycles in the Paradox basin. In ascending order, these zones are the Alkali Gulch, Barker Creek, Akah, Desert Creek, and Ismay. The zones gradually become less distinct toward the central part of the San Juan Basin.

Pennsylvanian production on the Four Corners Platform and in the northwestern part of the San Juan Basin is typically both stratigraphically and structurally controlled. Zones of biostromal porosity or "carbonate buildups" located on anticlinal noses or domes and intersected by structure-related fractures are the most common types of traps (Fassett and others, 1978). Carbonate shelf deposits in the San Juan Basin generally rim the Paradox evaporite sequences and may have formed barriers between the central Paradox basin and its inlet to the sea, the Cabezon accessway, in the southeastern part of the San Juan Basin (Wengard and Matheny, 1958). Strong uplift of the Uncompahgre, San Luis, and Penasco highlands resulted in an influx of clastic material and arkose during late Desmoinesian time, initiating the final regression of the Pennsylvanian sea from the area.

Reservoirs

Pennsylvanian reservoirs in the San Juan Basin are developed in the shelf counterparts of the evaporitic sequences of the Paradox Basin. Their depositional history is one of variation in shelf deposition, partial evaporitic cyclic deposition, and changes due to local conditions. A common cycle is a succession of siltstone, black shale, dolomite, argillaceous limestone, bioclastic (algal) limestone, argillaceous limestone, dolomite, and siltstone (Picard and others, 1960). The cyclic character of the basinal evaporitic sequences was first described by Herman and Barkell (1957).

The following brief reservoir descriptions are modified primarily from Picard and others (1960). The Barker Creek zone is the main producer at the Barker Creek field (table 1, fig. 7) where it is predominantly fossiliferous, microcrystalline to large-grained algal limestone with about 20 percent of the interval being calcareous and dolomitic shale. Total thickness is about 230 ft (70 m) with a net pay thickness of about 100 ft (30 m) and a porosity range of 2 to 10 percent. At Tocito dome field (table 1, fig. 7) it is 100 to 120

Table 1.--Pennsylvanian oil and gas fields, San Juan Basin petroleum province (Fassett, 1978, 1983)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
1	Alkali Gulch	T.34 N.,R.12 W.,S.32	1957		30,000,000
2	Barker Creek	T.32 N.,R.14 W.,S.16	1945	200	230,000,000
3	Big Gap	T.27 N.,R.19 W.,S.20	1979	40	50,000
4	Blue Hill	T.32 N.,R.18 W.,S.36	1953		1,300,000
5	Buena Suerte	T.25 N.,R.11 W.,S. 3	1971	10	8,000
6	Cone	T.31 N.,R.18 W.,S.22	1964	16	400,000
7	Four Corners	T.32 N.,R.20 W.,S.29	1956	100	85,000
8	Hogback	T.29 N.,R.16 W.,S.19	1954	450	13,000,000
9	Pajarito	T.29 N.,R.17 W.,S.31	1963	175	150,000
10	Rattlesnake	T.29 N.,R.19 W.,S. 2	1929	950	1,900,000
11	Shiprock N.	T.30 N.,R.18 W.,S.14	1974		70,000
12	Table Mesa	T.27 N.,R.17 W.,S. 3	1961	180	7,500,000
13	Tocito Dome	T.26 N.,R.18 W.,S.17	1963	15,000	30,000,000
14	Tocito Dome N.	T.26 N.,R.18 W.,S. 9	1967	350	700,000
15	Ute Dome	T.32 N.,R.14 W.,S.35	1948	160	85,000,000
16	Wikiup	T.33 N.,R.14 W.,S.24	1972		30,000

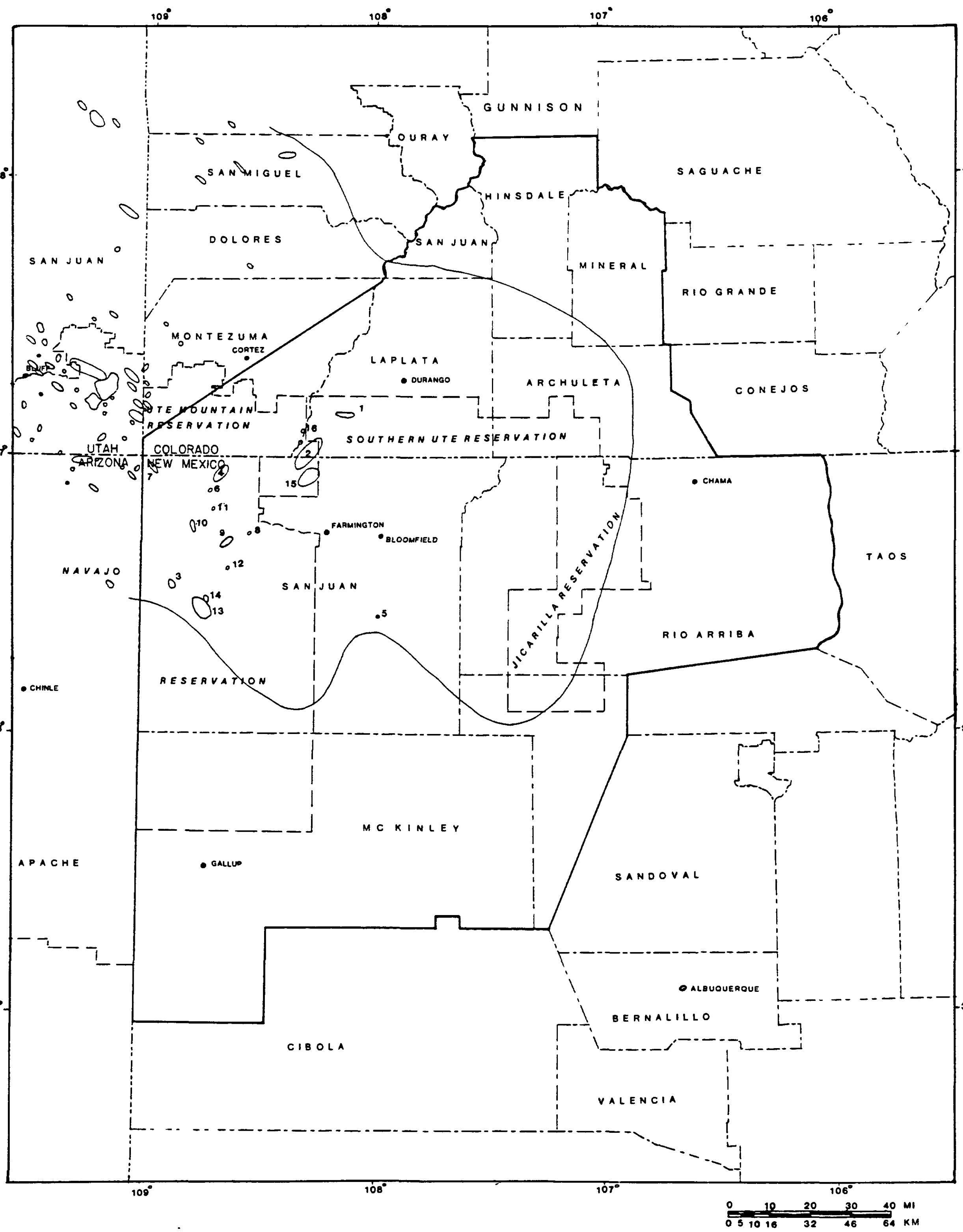

Figure 7.--Pennsylvanian play outline and developed oil and gas fields, San Juan Basin petroleum province. Numbered fields from table 1.

ft (30-36 m) thick with a net pay of about 17 ft (5 m).

The Akah zone at the Hogback field (table 1, fig. 7) contains algal (Ivanovia) limestone, sparsely to moderately fossiliferous limestone, dolomitic limestone, secondary dolomite, and oolitic and pelletoid limestone. Calcarenite, secondary dolomite, and fractured limestone beds are productive where intercrystalline, vuggy, and fracture porosity is found. Total thickness is about 180 ft (55 m) with a net pay of 16 ft (5 m) and a porosity range of 8 to 20 percent.

The Desert Creek zone at the Aneth field (present outside province, but not numbered on fig. 7) is predominantly microcrystalline to large-grained fossiliferous algal limestone with lesser amounts of oolitic limestone and dolomite. The productive intervals at Aneth are calcarenite, calcirudite, secondary dolomite, and oolitic limestone with vuggy intercrystalline, intra-oolitic and inter-oolitic porosity. Total thickness of the zone ranges from 120 to 200 ft (37-61 m) with about 50 ft (15 m) of net pay and 10 percent porosity.

The Ismay zone at the Ismay and Flodine Park fields (present outside province, but not numbered on fig. 7) produces from bioclastic carbonate buildups that occur stacked one above another in three intervals and trend northeast (Mecham, 1978). Porosity and permeability are related to depositional fabric, extent of leaching, and degree of pore filling by calcite and anhydrite. Average porosity is about 11 percent and permeability about 13 millidarcies. Total Ismay thickness is about 200 ft (60 m) with a net pay of 24 to 40 ft (7-12 m).

Traps and seals

Combination stratigraphic and structural trapping mechanisms predominate among Pennsylvanian fields of the San Juan Basin and Four Corners platform. Most are located on structures although not all of these demonstrate closure. The structures themselves may have been a critical factor in the deposition of the bioclastic limestone reservoir rocks (Elias, 1963). A number of the fields are faulted as well, further complicating analyses of the traps. Seals are provided by a variety of mechanisms including porosity differences in the reservoir rock, overlying evaporites, and interbedded shale.

Source rocks and geochemistry

Source beds for Pennsylvanian oil and gas are believed to be organic-rich shales and laterally equivalent carbonates within the Paradox Member (Picard and others, 1960). Rice (1983) concurs and notes that the presence of hydrogen sulfide (H_2S) and appreciable amounts of CO_2 at Barker Creek and Ute dome fields (table 1, fig. 7) indicate high temperature decomposition of carbonates. Ross (1980) was not able to establish a firm correlation between Pennsylvanian oil and bitumen from Pennsylvanian sources in the San Juan Basin but observed similarities of pristane/phytane ratios. Hite and others (1984) correlated the black shale units of the Paradox Member in the Paradox evaporitic basin with prodelta facies in clastic cycles present in the Silverton fan delta complex (Silverton embayment clastic delta of Fetzner, 1960) on the northeastern edge of the basin. This correlation helps explain the high percentage of kerogen from terrestrial plant material in the black shale source rocks.

Pennsylvanian oil in the San Juan Basin ranges from 40° to 55° API gravity and is paraffin based. Rice (1983) states that "the isotopic composition ($\delta^{13}C$ values range from -35.3 to -37.9 permil) and chemical composition (C_1/C_{1-5} values range from 0.98 to 0.95) of natural gases from Barker Creek field suggest they are the product of the post-mature stage."

Timing and migration

In the central part of the San Juan Basin, the Pennsylvanian sediments entered the oil generation window during the Late Cretaceous to Paleocene and the dry gas window during the Eocene to Oligocene (fig. 6a). The burial and thermal histories of the Four Corners platform are not presently available but it seems probable that the Pennsylvanian source rocks would have entered the oil window during the Oligocene over much of the area.

Picard and others (1960) suggested two principal types of hydrocarbon migration in the Pennsylvanian of the Four Corners platform: "(1) An updip migration from the basinward shelf-edge toward the south flank; and (2) local migration in the areas of favorable reservoir beds from laterally equivalent carbonates and their shale laminae and beds." They also thought remigration probable in areas of faulting and fracturing.

Depth of occurrence

Most Pennsylvanian production on the Four Corners platform ranges in depth from 5,100 to 8,500 ft (1550-2590 m). Minor production and shows in the central part of the San Juan Basin occur as deep as 11,000 ft (3350 m).

Exploration status

Table 1 lists all developed fields, active and abandoned, within the province that have produced from the Pennsylvanian as shown on figure 6. The primary source of data for this and similar tables is Fassett (1978, 1983). Figure 8a is the historic finding rate of oil in the Pennsylvanian of the province and 8b is the actual number of oil pools in 500,000 bbl size classes. Figures 9a and 9b are comparable to 8a and 8b for the Pennsylvanian gas fields of the province.

Oil and associated gas, including helium, was first produced from the Pennsylvanian in the San Juan Basin area in 1929 at the Rattlesnake field. Nonassociated gas was first discovered at the Barker Creek field in 1945. The largest Pennsylvanian oil field in the area, Tocito dome, was discovered in 1963 (fig. 8a) after shallow tests produced nothing but water. A well completed in the Mississippian in 1943 produced helium but was abandoned in 1944 because of uncontrollable salt water flow (Spencer, 1978).

Pennsylvanian field sizes vary considerably (table 1). Productive areas range from 40 to 8,000 acres with most production from those larger than 1,000 acres. Most of the oil discoveries are in the 100 to 1,000 MBO (Thousand Barrels Oil) size range with associated gas (fig. 8b). The largest, Tocito dome and Tocito dome north, have produced a total of about 13,000 MBO and 26 BCFG (Billion Cubic Feet Gas). Eight significant nonassociated and associated gas fields have been developed in the area (table 1, fig. 9), the largest of which, Barker Creek, has produced 205 BCFG.

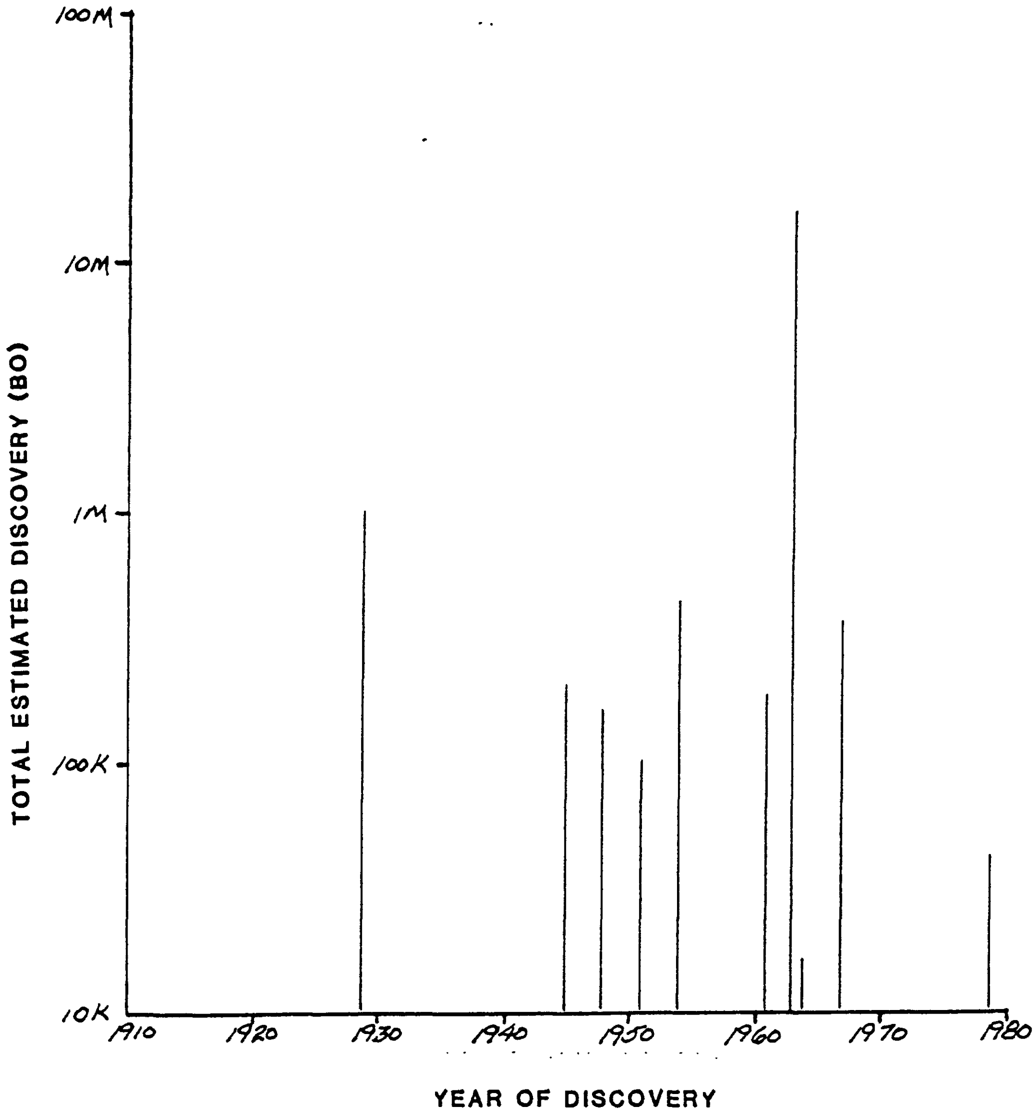

Figure 8a.--History of discovery, Pennsylvanian oil fields, San Juan Basin petroleum province (semi-log plot; K-thousand, M-million).

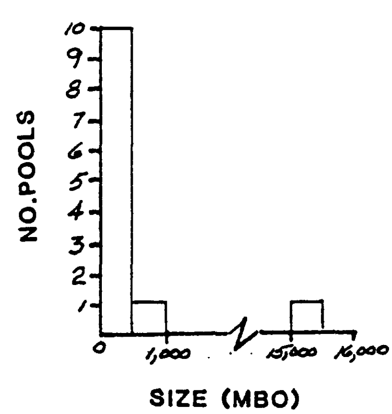

Figure 8b.--Distribution of sizes, Pennsylvanian oil fields, San Juan Basin petroleum province.

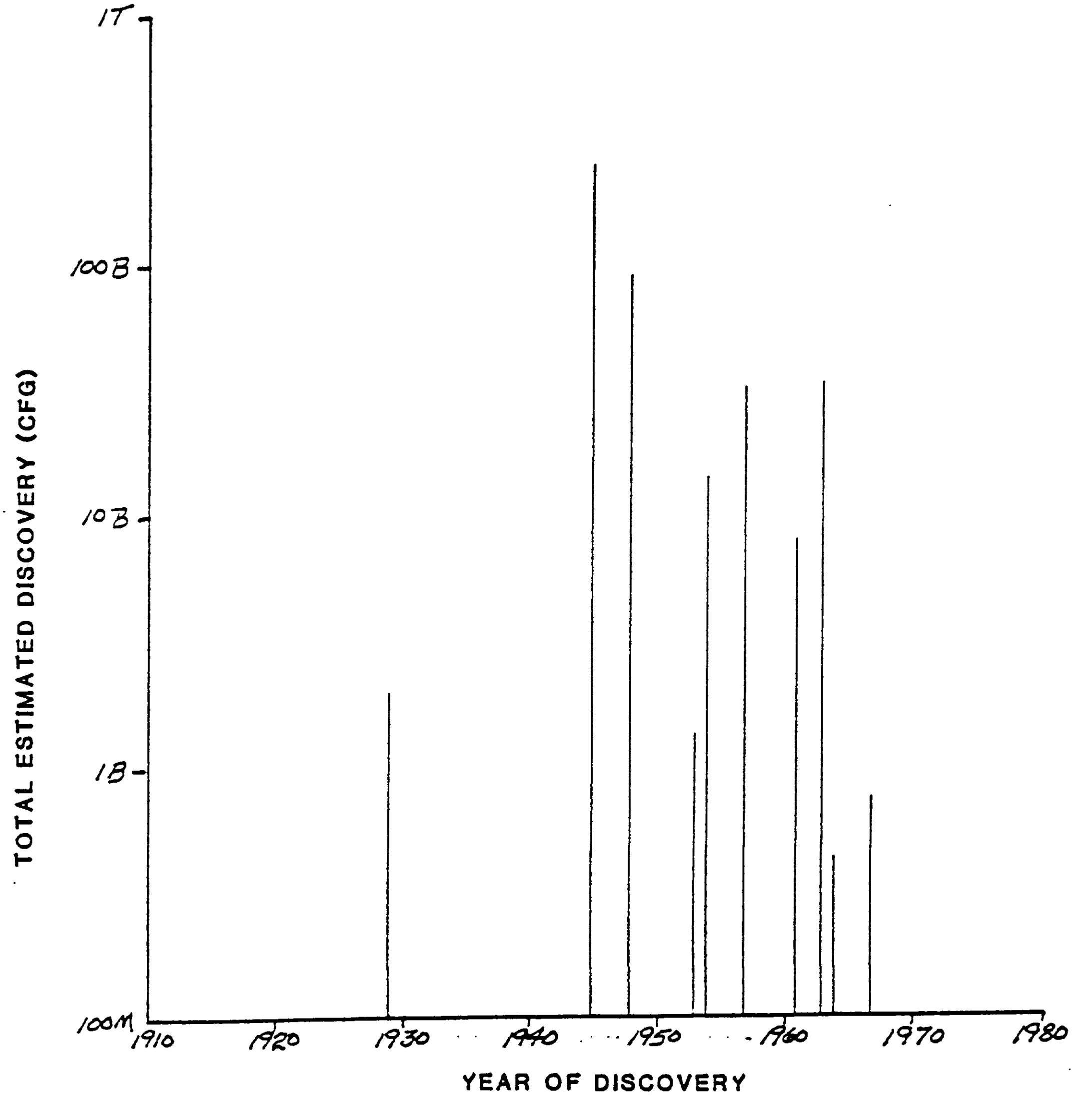

Figure 9a.--History of discovery, Pennsylvanian gas fields, San Juan Basin petroleum province (semi-log plot; M-million, B-billion, T-trillion).

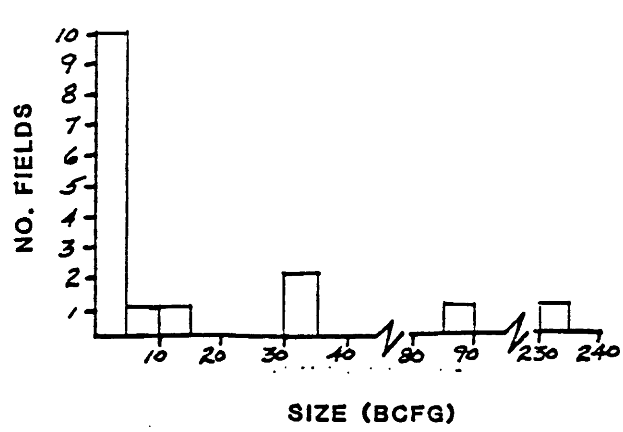

Figure 9b.--Distribution of sizes, Pennsylvanian gas fields, San Juan Basin petroleum province.

The Pennsylvanian interval of the northern part of the San Juan Basin and the Four Corners platform is inadequately explored except in the Four Corners area and is difficult to assess properly because of the paucity of subsurface data. Most structures with surface expression have probably been drilled but there are undoubtedly a number of structures in the subsurface which have not yet been tested. The likelihood that a structure would produce hydrocarbons depends largely on the presence of bioclastic (algal) limestone buildups and a local organic shale deposit. The distribution of these facies on the carbonate shelf marginal to the Paradox evaporitic basin has not been adequately mapped nor has the Silverton fan delta model of Hite and others (1984) been tested.

The probability of finding oil versus gas depends largely on position in the basin. The Pennsylvanian interval falls within the gas generation window throughout the structural San Juan Basin (fig. 4). On the Four Corners platform proximity to the San Juan volcanic centers will determine whether the interval is oil or gas prone, the likelihood of gas increasing northeastward with thermal maturity.

A comparison of figures 8 and 9 suggests that the Pennsylvanian is a reasonably mature gas play but that oil exploration is relatively immature with a good probability of several additional fields in the 1-10 MMBO range in addition to a number of smaller pools. Expected gas field sizes range from 1-10 BCF.

Entrada

Play description and type

The Middle Jurassic Entrada oil play is in relict dune topography on top of the eolian Entrada Sandstone in the southeastern part of the San Juan Basin. It depends on the presence of organic-rich limestone and overlying anhydrite of the Todilto Limestone Member of the Wanakah Formation.

The Entrada Sandstone is an eolian deposit ranging in thickness from about 35 to 300 ft (11-100 m) within the San Juan Basin. Where exposed in outcrops around the perimeter of the basin, the Entrada is dominantly crossbedded dune sandstone with varying amounts of interdune or sabkah deposits. Topographic relief of about 50 ft (15 m) on top of the Entrada along the eastern margin of the basin was interpreted by Tanner (1970) to be preserved eolian dunes. Oil is produced from similar and larger features in the subsurface of the southeastern part of the basin. Core analyses from several of these fields, Ojo Encino (Vincelette and Chittum, 1981) and Media (Reese, 1978), suggests that water reworked the upper part of the Entrada.

Overlying the Entrada throughout the San Juan Basin, the Todilto Limestone Member of the Wanakah Formation consists of a lower, 3-to 10-ft (1-3 m)-thick limestone, and in the eastern part of the basin, an upper 0-125-ft (0-38 m)-thick anhydrite/gypsum unit. In the deeper parts of the depositional basin, where the anhydrite is present, the limestone is organic rich, whereas beyond the limits of the anhydrite the limestone was deposited in oxygenated water and therefore, has a much lower organic-carbon content.

Reservoirs

Some of the relict dunes are as thick as 100 ft (30 m) but have flanks that dip at only 2 degrees (Vincelette and Chittum, 1981). They are composed of fine-grained, subrounded, well-sorted sandstone which is massive or horizontally bedded in the water reworked zone and thinly laminated, steeply dipping crossbedded in the lower part. Porosity (average 23 percent), and permeability (average 370 md) are very good throughout. Average net pay in the developed fields (table 2, fig. 10) is 23 ft (7 m).

North of the producing area, in the deeper, northeastern part of the San Juan Basin, the porosity in the Entrada diminishes rapidly (Vincelette and Chittum, 1981). Compaction and silica cement make the Entrada very tight below a depth of 9,000 ft (2,700 m). South and west of the producing area, no sandstone buildups have been found, although in a recent seismic study in the Crownpoint, New Mexico area several structures similar to those illustrated by Vincelette and Chittum (1981) were found in the Entrada (Zech and others, 1985). None of these have been drilled, however, so their origin is still unknown.

Traps and seals

All traps so far discovered in the Entrada are stratigraphic and are sealed by the Todilto limestone and anhydrite. Local faulting and drape over deep-seated faults has enhanced, modified, or destroyed the potential closures of the Entrada sand ridges, so must be taken into consideration. Hydrodynamic tilting of oil/water contacts and/or "base of movable oil" interfaces has had a destructive influence on the oil accumulations in that the direction of tilt typically has an updip component. Rates of calculated hydrodynamic tilt for the various fields range from 60 to 80 ft/mi (11-15 m/km) and may be in nearly any direction except north (Vincelette and Chittum, 1981).

Table 2.--Entrada oil fields, San Juan Basin petroleum province (Fassett, 1978, 1983)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
1	Eagle Mesa	T.19 N.,R. 4 W.,S.12	1975	1,615	
2	Leggs	T.21 N.,R.10 W.,S.11	1977	275	
3	Media	T.19 N.,R. 3 W.,S.14	1953	2,198	
4	Media SW	T.19 N.,R. 3 W.,S.22	1972	1,800	
5	Ojo Encino	T.20 N.,R. 5 W.,S.21	1976	150	
6	Papers Wash	T.19 N.,R. 5 W.,S.15	1977	2,000	
7	Snake Eyes	T.21 N.,R. 8 W.,S.20	1977	500	

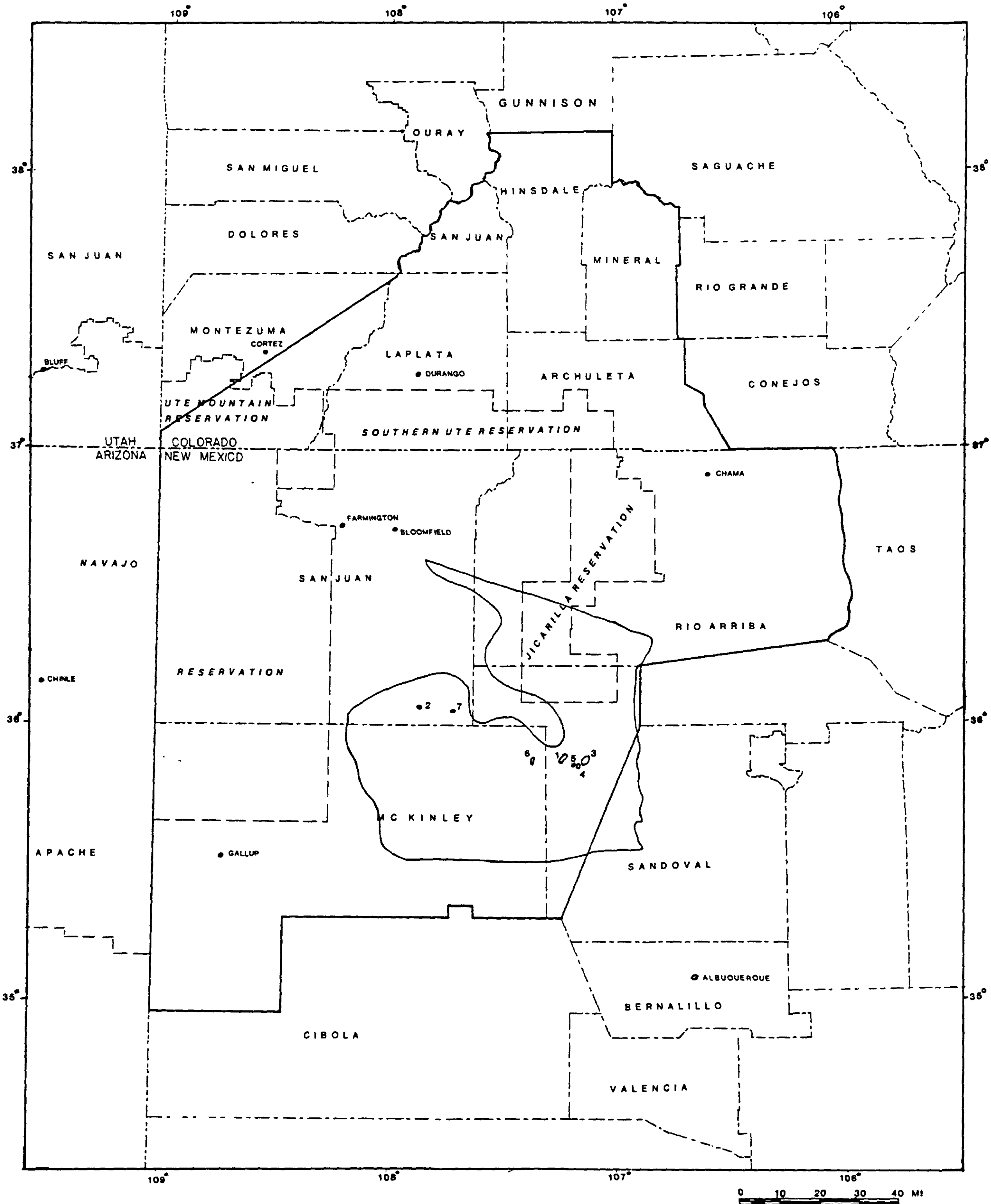

Figure 10.--Entrada play outline and developed oil fields, San Juan Basin petroleum province. Numbered fields from table 2.

Source rocks and geochemistry

Limestone in the Todilto Limestone Member of the Wanakah Formation has been identified as the source of Entrada oil by Ross (1980) and Vincelette and Chittum (1981). Ross (1980) states: "This oil is clearly unique as demonstrated by the high pour point (90°F), low pristane/phytane ratio (0.86), and even-carbon predominance (0.91 CPI), suggestive of genesis from a carbonate source sequence." Entrada oil has an average API gravity of 33°, an initial boiling point of 205°F (96°C), and a paraffin base with the possible exception of the Media field which Reese (1978) characterized as asphaltic based.

Vincelette and Chittum (1981) note the "correlation between the presence of organic material in the Todilto Limestone and the presence of the overlying Todilto anhydrite". This association limits the source rock potential of the Todilto to the deeper parts of the depositional basin in the eastern San Juan Basin. Elsewhere, the limestone was oxygenated during deposition and much of the organic material destroyed.

Timing and migration

Maximum depth of burial throughout most of the San Juan Basin occurred during the Oligocene. In the eastern part of the basin the Todilto entered the oil generation window during the Oligocene (fig. 6b). Migration into the Entrada reservoirs either locally or updip to the south probably occurred almost immediately. However, as Vincelette and Chittum (1981) point out, "in some Entrada oil fields, remigration of the original accumulations has occurred subsequent to original emplacement. Whether such remigration is due to a change in the hydrodynamic gradient, post-accumulation structural movement, leakage out of the reservoir, or a combination of these factors has not been determined. . ."

Depth of occurrence

All fields developed to date have been at depths of 5,000 to 6,000 ft (1525-1825 m). A maximum depth of 9,000 ft (2,740 m) was placed on suitable reservoir conditions due to increasing cementation (Vincelette and Chittum, 1981).

Exploration status

The initial Entrada discovery, Media, was made in 1953 (table 2, fig. 11), but only produced 14,196 bbl of oil before being abandoned because of increasing water production. The field was reopened in 1969 when an offset to the discovery well was completed at 500 bbl of oil and 1,500 bbl of water per day. Development was inhibited by problems of high water cut and high pour point, problems common to all subsequent Entrada development. Between 1972 and 1977, seven Entrada fields similar to Media were discovered, primarily though seismic techniques. Sizes range from 100 to 400 acres with total estimated production varying between 150 and 2,000 MBO each.

A number of areas of anomalously thick Entrada in the southeastern part of the San Juan Basin have yet to be tested. There is a high probability that at least some of these areas of thick Entrada would have closures containing oil in economic quantities but also with the same development problems as the developed fields. Limiting factors include presence of sufficient topographic relief on top of the Entrada, local structural conditions, hydrodynamics, source-rock and oil migration history, and local porosity/permeability variations in the Entrada (Vincelette and Chittum, 1981).

Figure 11 suggests an immaturely explored play and much of the area is sparsely drilled. Most of the finds to date have been on the basis of seismic data and additional coverage will probably result in new prospects.

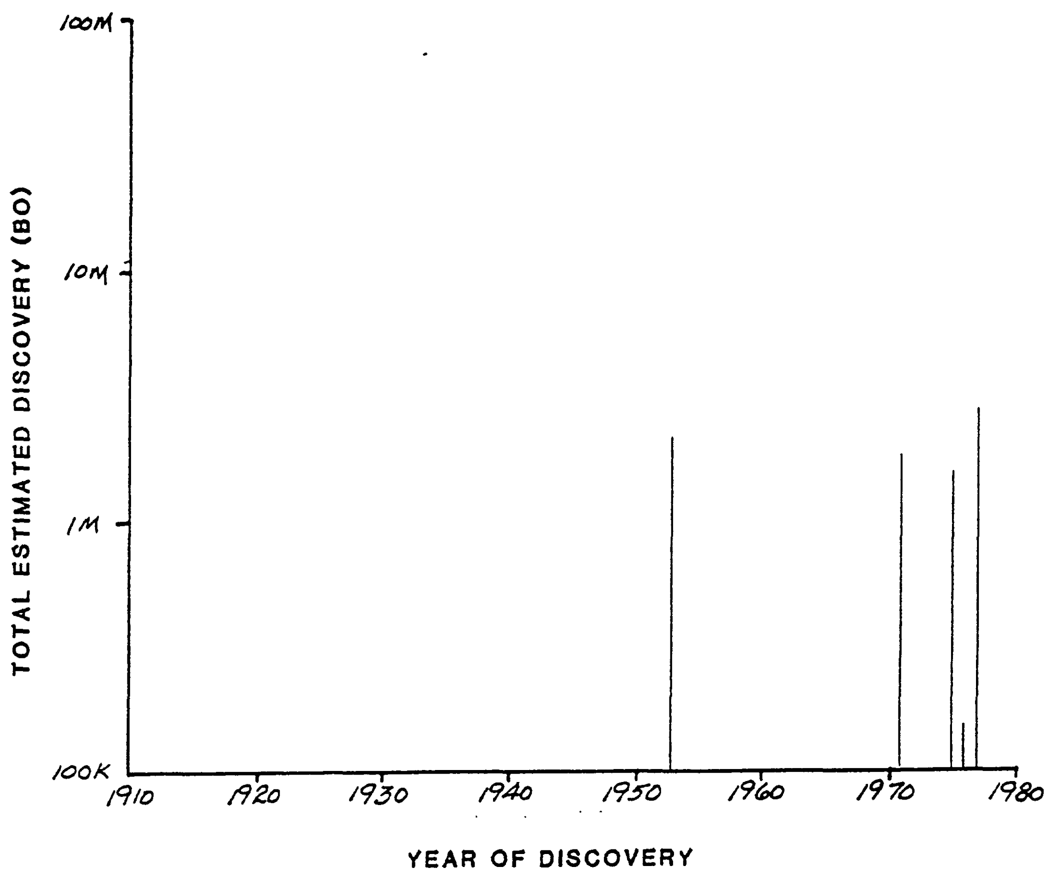

Figure 11a.--History of discovery, Entrada oil fields, San Juan Basin petroleum province (semi-log plot; K-thousand, M-million).

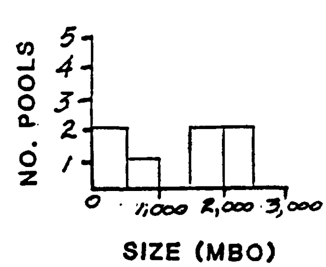

Figure 11b.--Distribution of sizes, Entrada oil fields, San Juan Basin petroleum province.

Dakota

Play description and type

The Upper Cretaceous Dakota oil and gas play is in coastal barrier marine sandstone and continental fluvial sandstone units primarily within the transgressive Dakota Sandstone. It is divided into a basinal gas play that is dominantly stratigraphic and a basin flank oil and gas play that is typically both stratigraphic and structural.

The Dakota producing interval is defined by the New Mexico Oil Conservation Commission as extending 400 ft (122 m) below the Greenhorn Limestone (Bridge Creek Limestone) Member of the Upper Cretaceous Mancos Shale. This definition includes the Graneros Shale Member of the Mancos and in many places upper sandstones and shales of the underlying Lower Cretaceous Burro Canyon Formation or Upper Jurassic Morrison Formation. The Dakota Sandstone of the San Juan Basin is a transgressive deposit resting on an erosional unconformity, but as Fassett and others (1978) point out, it is not a "typical" littoral marine transgressive unit. In the northwestern part of the basin the Dakota is largely composed of fluvial sandstones, coal, and carbonaceous shale with some marine sandstone at the top, whereas, in the southeastern part it is nearly all marine sandstone and shale. In the central part of the basin the Dakota is generally nonmarine at the base and becomes increasingly marine upward.

Owen (1973) described five major depositional units in the Dakota of the San Juan Basin: (1) braided-stream sandstone (present primarily in the Chama basin and northeastern part of the San Juan Basin); (2) meandering-stream complex; (3) coastal shale; (4) coastal sandstone; (5) offshore shale. All five are rarely present at any particular locality and one or more may dominate in various parts of the basin. Because of the wide variety of depositional environments, lithologies vary considerably as do reservoir quality and trapping mechanisms.

Most gas produced from the Dakota is from the giant Basin Dakota field in the central part of the basin where the trapping mechanism is hydrodynamic and stratigraphic. Away from the central basin, oil and gas are produced from both stratigraphic and structural or combination traps. Production is greatest from the upper marine part of the interval but significant amounts of both oil and gas have been produced from the nonmarine section as well.

Reservoirs

Owen (1973) describes the channel sandstone of the meandering-stream complex as ". . .mostly quartz and chert-rich arenites with local pebbly beds and thin conglomerates near the base. . ." and notes that "most of the channel sandstones are fine-grained, with some medium-grained strata in the fairly abrupt transition between the pebbly beds and the fine beds." Most of the channel sandstones are composed of fining upward, crossbedded trough sequences. The coastal sandstone unit is a coarsening upward, fine- to very fine grained, well sorted, quartz-rich sandstone that is commonly burrowed and horizontally bedded or crossbedded. Net pay thicknesses range from 10 to 100 ft (3-30 m).

Reservoir quality within the Dakota producing interval is highly variable. Most of the sandstone within the Basin Dakota field of the central basin is considered "tight" with porosities ranging from 5 to 15 percent and permeabilities from 0.1 to 0.25 millidarcies (Hoppe, 1978). Fracturing, both natural and induced, is essential for effective development (Deischl, 1973). In contrast, the Lone Pine field (table 3, fig. 12) in the southern part of the San Juan Basin has an average porosity of 20 percent and permeability range of about 80 to 150 millidarices (Storhaug, 1978). Permeabilities elsewhere may be as high as 400 millidarcies.

Traps and seals

Dakota production is from a variety of traps throughout the San Juan Basin. Most is to some extent stratigraphically controlled although this is rarely the primary mechanism. Production in the Basin Dakota field in the central basin is determined partially by the distribution of marine sandstone buildups, but many of these sandstone are continuous to the outcrop with no known seal between. Dieschl (1973) suggested "decreased permeability and strong hydrodynamic pressure" as the trapping mechanism. He further states: "it is apparent that the Basin Dakota gas accumulation is a rather unique situation in that the gas is present on the flanks and bottom of a large depression and is not localized by structural configurations. The transmissibility of the Dakota sandstones is generally consistent from the central basin to the outcrop and, therefore, hydrodynamic forces, acting in a basinward direction, are essential to prevent the gas from escaping." Fassett and others (1978) note that there are problems with this explanation and that the mechanism is still poorly understood.

Most oil production from the Dakota is from structural or combination traps away from the central basin. The Price Gramps, Table Mesa, Hogback, and Lone Pine fields (table 3, fig. 12), four of the largest Dakota oil fields, are located on faulted anticlinal structures. The seal in most Dakota fields is provided by either marine shale or paludal carbonaceous shale and coal.

Source rocks and geochemistry

Source beds for Dakota oil and gas are highly variable. Nonassociated gas from the Basin Dakota field was interpreted by Rice (1983) as having been generated during late mature and post-mature stages and probably had a Mancos Shale source. The chemical composition (C_1/C_{1-5}) ranges from 0.99 to 0.86 and the isotopic composition ($\delta^{13}C$) from -31.4 to -41.9 per mil (Rice, 1983). Condensate production within the New Mexico portion of the basin averages 0.4 gal/mcf (0.05 dm^3/m^3) of nonassociated gas (Fassett and others, 1978).

Nonassociated gas produced from the Dakota at Barker Creek field has almost identical chemical and isotopic composition as gas from underlying Pennsylvanian reservoirs (Rice, 1983). Based on this and several other lines of evidence, Rice (1983) concluded that it had migrated from the deeper (6,000 ft, 1.8 km) more mature Pennsylvanian strata. Because of the difference in depth and the presence of a number of intervening potential reservoirs, it seems likely that faulting provided the conduit along which the gas migrated.

Table 3.--Dakota oil and gas fields, San Juan Basin petroleum province (Fassett, 1978, 1983)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
1	Barker Creek	T.32 N.,R.14 W.,S.16	1925		150,000,000
*2	Basin	T.27 N.,R.10 W.,S. 4	1947		5,000,000,000
3	Blackeye	T.20 N.,R. 9 W.,S.29	1972	5	
4	Chacon	T.23 N.,R. 3 W.,S.23	1974	3,000	83,000,000
5	Cinder Buttes	T.32 N.,R.12 W.,S.13	1966		250,000
6	Dufer's Point	T.25 N.,R. 8 W.,S.17	1959	600	5,000,000
7	Five Lakes	T.22 N.,R. 3 W.,S.25	1970	50	
8	Hogback	T.29 N.,R.16 W.,S.19	1922	6,000	
9	Hospah	T.17 N.,R. 9 W.,S.12	1967	230	1,500,000
10	Lindrith	T.24 N.,R. 2 W.,S.20	1949	35	
11	Lindrith S.	T.23 N.,R. 4 W.,S. 5	1958	NA	NA
12	Lindrith W.	T.24 N.,R. 4 W.,S. 1	1959	NA	NA
13	Lone Pine	T.17 N.,R. 9 W.,S.13	1970	5,000	8,000,000
14	Marcelina	T.16 N.,R. 9 W.,S.18	1975	650	300,000
15	Menefee Mtn.	T.35 N.,R.13 W.,S.16	1978	NA	NA
16	Middle Canyon	T.32 N.,R.15 W.,S.14	1969	5	
17	Ojito	T.25 N.,R. 3 W.,S.18	1958	203	312,000
18	Point Lookout	T.36 N.,R.14 W.,S.29	1930		50,000
19	Price Gramps	T.33 N.,R. 2 E.,S.24	1935	7,200	75,000
20	Rattlesnake	T.29 N.,R.19 W.,S. 1	1924	5,000	250,000
21	Red Mesa	T.33 N.,R.12 W.,S.23	1924	500	550,000
22	Salt Creek	T.30 N.,R.17 W.,S. 4	1958	170	
23	Shiprock N.	T.30 N.,R.18 W.,S.14	1966	1	
24	Sierra	T.35 N.,R.13 W.,S. 5	1957	170	35,000
25	Slick Rock	T.30 N.,R.17 W.,S.36	1966	850	
26	Snake Eyes	T.21 N.,R. 8 W.,S.20	1971	30	1,000,000
27	Stoney Butte	T.21 N.,R.14 W.,S. 1	1950	8	
28	Straight Canyon	T.31 N.,R.16 W.,S.14	1975		250,000
29	Table Mesa	T.27 N.,R.17 W.,S. 3	1925	1,400	150,000

Table 3.--Dakota (Continued)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
30	Ute Dome	T.32 N.,R.14 W.,S.36	1921	160	20,000,000
31	Wildhorse	T.26 N.,R. 4 W.,S.27	1960	97	1,500,000

*Present Basin Dakota field formed by combining following fields in 1961

Angels Peak	T.27 N.,R.10 W.,S. 4	1947
Ignacio	T.33 N.,R. 7 W.,S.18	1950
Kutz W.	T.28 N.,R.12 W.,S.22	1951
Huerfanito	T.26 N.,R. 9 W.,S. 3	1951
Huerfano	T.26 N.,R.10 W.,S.24	1951
Campanero	T.27 N.,R. 5 W.,S. 4	1952
Blanco	T.31 N.,R.10 W.,S.27	1952
Largo	T.27 N.,R. 9 W.,S. 3	1955
Otero	T.25 N.,R. 5 W.,S.22	1955
Campanero E.	T.27 N.,R. 4 W.,S. 7	1955

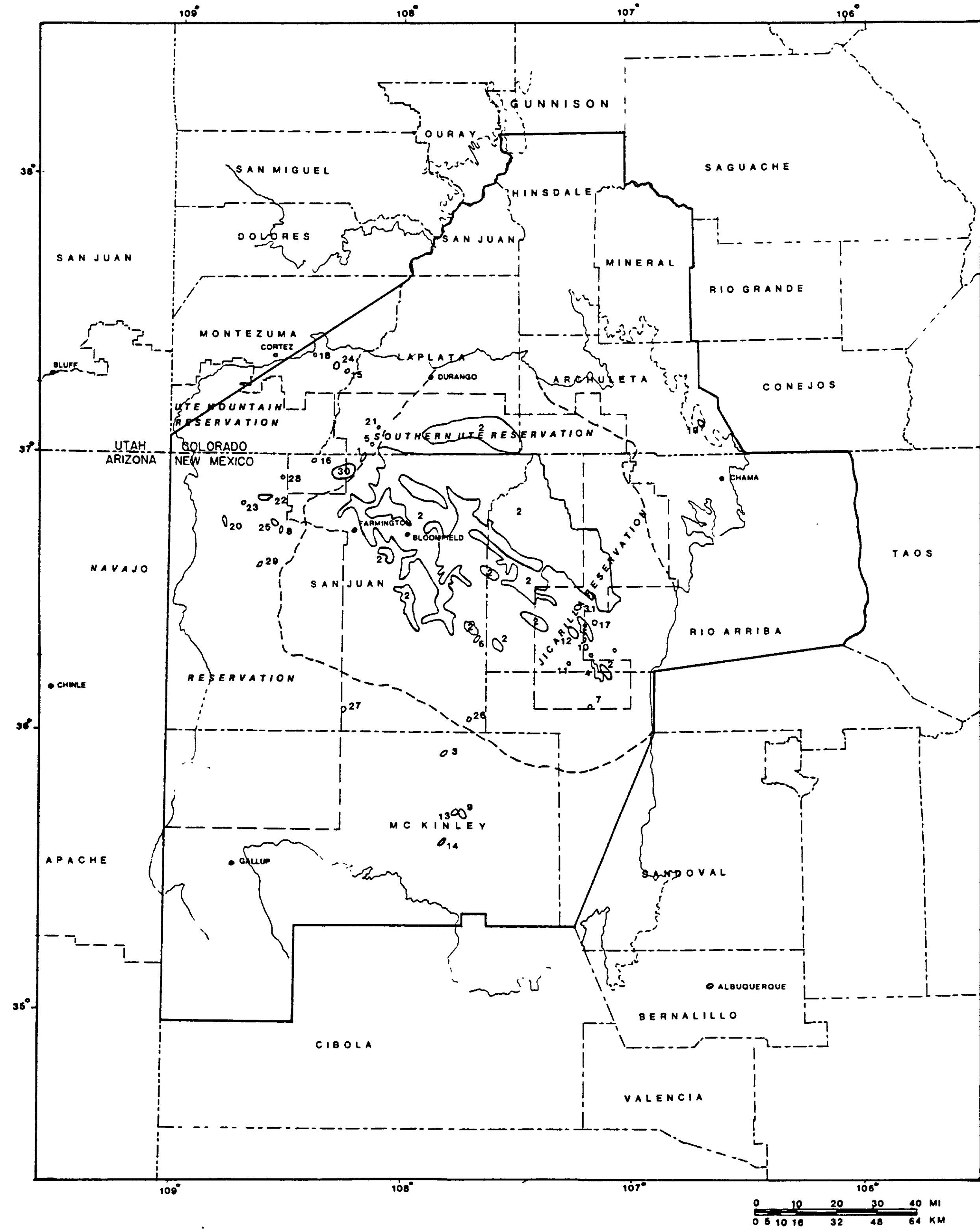

Figure 12.--Dakota play outline and developed oil and gas fields, San Juan Basin petroleum province. Broken line separates basinal and basin flank parts of play. Numbered fields from table 3.

Oil produced from the Dakota on the Chaco slope has a marine Cretaceous source identified as the Mancos Shale by Ross (1980). API gravities range from 44° to 59° with green to brown colors (Fassett and others, 1978). Oil produced from the Dakota on the Four Corners Platform (fig. 2) have similar API gravities but on the basis of chemical and isotopic compositions were classified by Ross (1980) as originating from nonmarine Cretaceous source rocks of the Lewis-Mesaverde interval. Although these source beds are nearly 4,000 ft (1220 m) above the Dakota, stratigraphically, they are brought into nearly the same structural position across the Hogback monocline (fig. 3) (Thaden and Zech, 1984).

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 (fig. 6a). Along the southern margin of the central basin the Dakota and lower Mancos entered the oil generation window during the Late Miocene (fig. 6b). It is not known at what point the hydrodynamic forces reached sufficient strength to establish a trapping mechanism but Early Miocene would seem a reasonable estimate for the establishment of the present-day uplift and erosion pattern throughout most of the basin. Migration of oil in the Dakota was still taking place in the Late Miocene or even more recently in the southern part of the San Juan Basin.

Depth of occurrence

Oil and gas are produced from the Dakota interval at depths ranging from about 1,000 to 8,000 ft (300-2440 m). Gas production in the central part of the basin is typically at depths of 6,500 to 7,500 ft (1980-2280 m). Oil production around the margin of the basin ranges in depth from 1,000 to 3,000 ft (300-900 m).

Exploration status

The first Dakota discoveries were made in the early 1920's (table 3, fig. 13a) on small anticlinal structures on the Four Corners Platform (fig. 2). The central basin Dakota discovery well was drilled in 1947 (fig. 14a) in the Angel Peak area south of Bloomfield, New Mexico (fig. 12). Although a number of discoveries were made within the central part of the basin during the early and mid 1950's (table 3), by the end of 1958 there were only 46 producing Dakota wells within the central basin (Deischl, 1973). The Basin Dakota field was formed February 1, 1961 by combining several existing fields (table 3) and by the end of 1976 it contained 2,400 producing wells that had produced over 2.7 trillion cubic feet with an estimated total production exceeding 5 trillion cubic feet (Hoppe, 1978).

Dakota oil fields range in size from 40 to 10,000 acres with most production from fields of 100 to 2,000 acres. Approximately 30 percent of the oil fields have an estimated total production exceeding 1,000 MBO (fig. 13b) with the largest (Price Gramps) estimated at just over 7,000 MBO (table 3). About 13 billion cubic feet of associated gas has been produced through 1985.

Future gas production from the Dakota interval will depend largely on the development of tight gas sand production technology. The limits of production from the Basin Dakota field have not yet been defined and new discoveries are still being made. Although of lesser importance, Dakota oil production is more dependent on better understood mechanisms and future discoveries seem likely, as basin structure and Dakota depositional patterns are more fully understood.

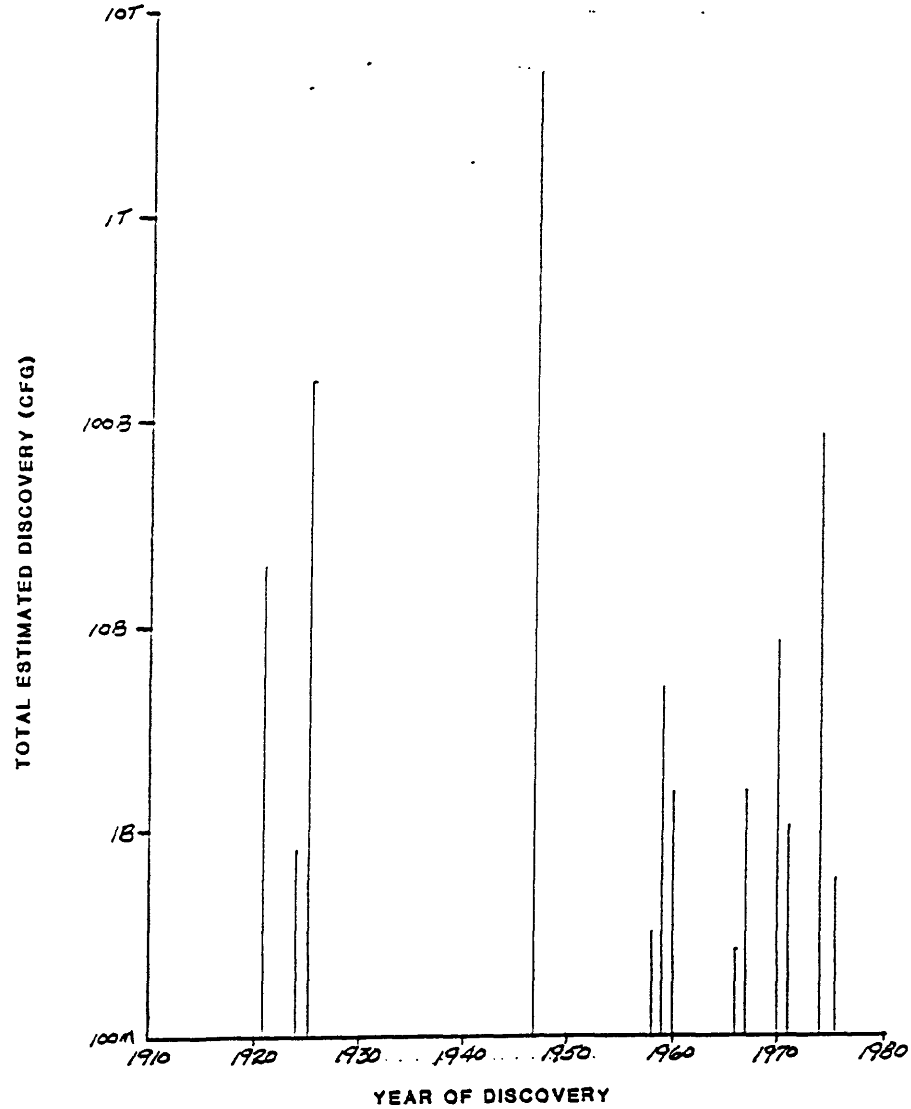

Figure 13a.--History of discovery, Dakota oil fields, San Juan Basin petroleum province (semi-log plot; K-thousand, M-million).

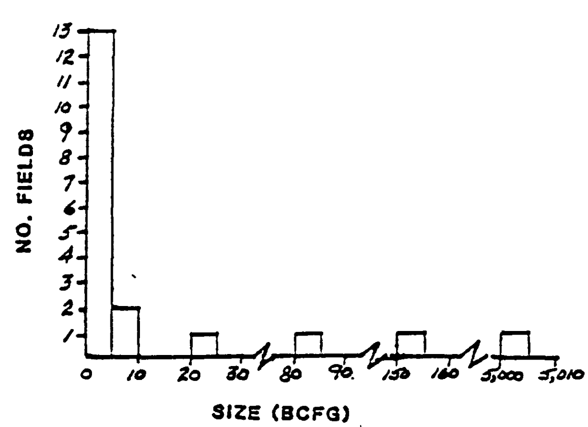

Figure 13b.--Distribution of sizes, Dakota oil fields, San Juan Basin petroleum province.

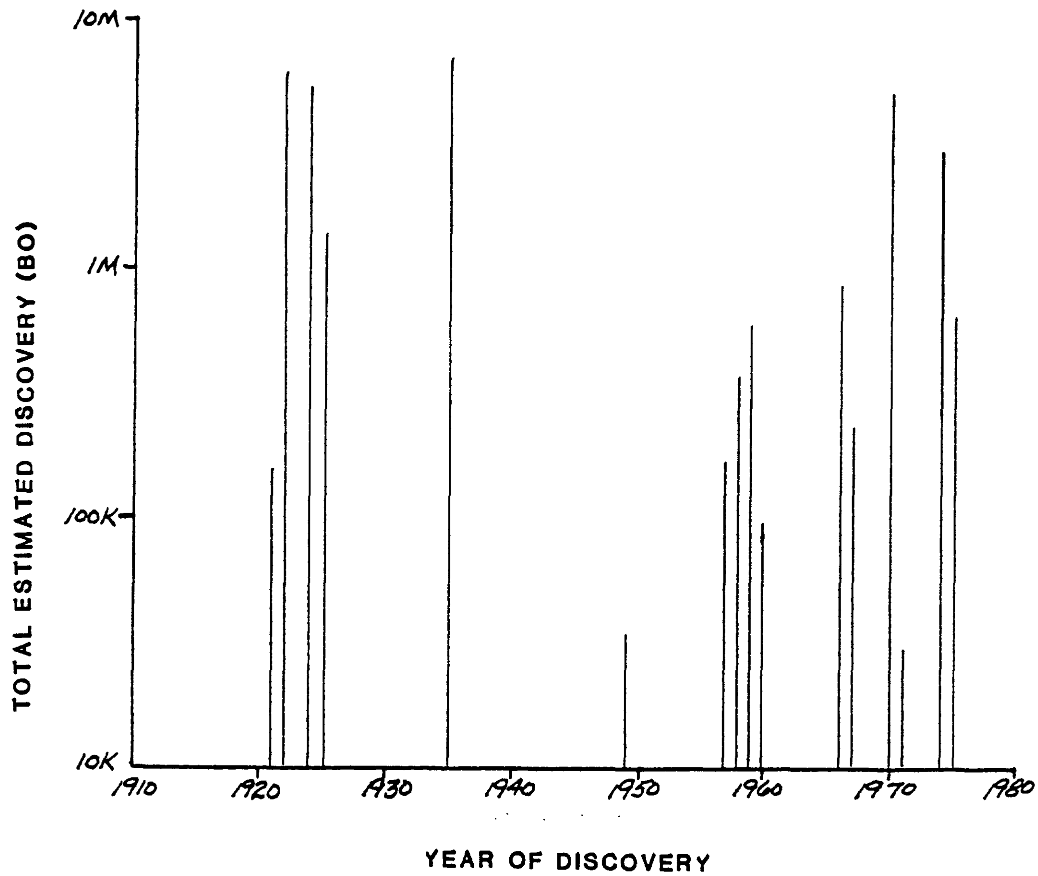

Figure 14a.--History of discovery, Dakota gas fields, San Juan Basin petroleum province (semi-log plot; M-million; B-billion, T-trillion).

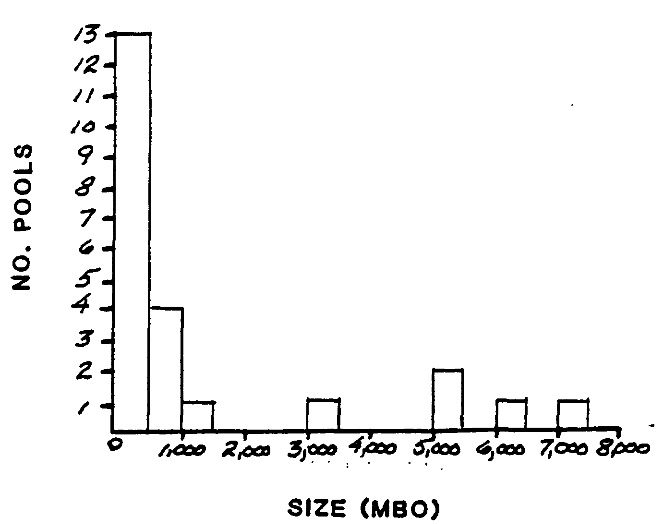

Figure 14b.--Distribution of sizes, Dakota gas fields, San Juan Basin petroleum province.

Figure 13 illustrates the relative immaturity of Dakota oil exploration. This play is primarily in combination traps around the margins of the central part of the San Juan Basin. Drilling density is sparse in much of the area and additional discoveries in the 1-10 MMBO size range seem likely. Figure 14 may be somewhat misleading as the 5TCF Basin Dakota field is shown as a single discovery in 1947 whereas in reality it is a combination of discoveries made between 1947 and 1961. This is not quite as bad as it may first appear, however, since nearly all of the Dakota in the central part of the basin is saturated with gas. Additional gas discoveries in the Basin Dakota field and around its margins appear probable.

Gallup

Play description and type

The Gallup is primarily an oil and associated gas play in bar-like sandstone bodies of the Upper Cretaceous Tocito sandstones lying immediately above an unconformity. Most production is from stratigraphic traps along a NW-SE trending belt adjacent to the southern margin of the central San Juan Basin.

As used here and by the New Mexico Oil and Gas Conservation Commission, the Gallup interval comprises the marine lower Mancos Shale above the Bridge Creek Limestone Member (formerly Greenhorn Limestone Member), the regressive marine lower Gallup Sandstone, the fluvial Torrivio Member of the Gallup Sandstone, the nonmarine coal bearing Dilco Coal Member of the Crevasse Canyon Formation, the transgressive marine Tocito Sandstone Lentil of the Mancos Shale, and the marine upper part of the Mancos Shale. Overall thickness of this interval is about 1,500 to 2,000 ft (450-600 m) and the lithology is dominantly dark gray marine shale. With the exception of a small amount of oil from several fields in fractured Mancos Shale, nearly all production from this thick and rather nebulous interval has been from the Tocito Sandstone Lentil of the Mancos Shale and the Torrivio Member of the Gallup Sandstone. Nomenclatural problems within this interval have caused some confusion and were discussed at some length by Fassett and others (1978), Fassett and Jentgen (1978), and Molenaar (1973).

The Tocito Sandstone Lentil of the Mancos Shale is the major oil producer in the San Juan Basin. The name is applied to a number of lenticular sandstone bodies commonly less than 50 ft (15 m) thick that lie on or just above the Niobrara unconformity and are of undetermined origin. Most of the sandstone buildups are encased in and intertongue with Mancos Shale forming stratigraphic traps along a northwest-southeast trending zone through the central part of the San Juan Basin and continuing onto the Four Corners Platform to the northwest. 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 regressive marine Gallup Sandstone. The Torrivio is typically encased in finer-grained sediments of the Dilco Coal Member below and the Mancos Shale above. Hospah and Hospah South, the largest fields developed in the regressive Gallup (table 4, fig. 15), are combination stratigraphic and structural traps.

Reservoirs

Maximum sandstone development in the Tocito Sandstone Lentil occurs within a northwest-trending belt beyond the northeastern limit of the regressive Gallup Sandstone. The origin of the long, narrow sandstone bodies paralleling the paleoshoreline is still poorly understood but many of the bar-like bodies are associated with topography on the underlying Niobrara unconformity (Lamb, 1968; McCubbin, 1969). Sabins (1963) did not recognize the unconformity. Where the Tocito crops out along the northwest side of the San Juan Basin it is typically two ledges of thin bedded, bioturbated, medium- to coarse-grained calcareous sandstone containing scattered quartz granules and pebbles and thin beds of quartz granule conglomerate and shell hash containing shark teeth (Huffman, 1976, 1979). The ledges are 3-6 ft (1-2 m) thick and appear to have a sheet geometry although exposures are too limited to determine their continuity over long distances. Porosities in the producing fields range from 4 to 20 percent and average about 15 percent. Permeabilities range from 0.5 to 150 millidarcies with 50 to 100 millidarcies being most typical.

The main producing interval at the Hospah fields on the Chaco Slope (fig. 15) has been called the Hospah Sandstone but was correlated to the Torrivio Member of the regressive Gallup by Molenaar (1973). The Torrivio is a high-energy fluvial channel deposit that genetically belongs with the nonmarine Dilco Coal Member of the Crevasse Canyon Formation (Molenaar, 1973; Kirk and others, 1978). Along the outcrops in the southern part of the San Juan Basin the Torrivio is an angular to subangular, very poorly to moderately well sorted, very coarse to fine-grained feldspathic sandstone containing medium- to very large scale trough crossbeds. It commonly is composed of 25 percent granule-size quartzose grains, sparse chert and quartzite pebbles, and significant amounts of interstitial clay. Plant debris and carbonaceous material occur on bedding planes and in lenses of conglomerate composed of granules, pebbles, and clay clasts at the base of troughs. The geometry is a series of troughs, each as much as 16 ft (5 m) thick, that coalesce into lenticular bodies of sandstone, which in turn combine with similar sandstone bodies or intertongue laterally and vertically with carbonaceous mudstone. Porosity of the Torrivio at Hospah field is 24 to 30 percent and permeability ranges from 200 to 500 millidarcies.

Traps and seals

Nearly all Gallup production is from stratigraphic traps. The Tocito bar-like sandstone bodies are encased in and intertongue with the marine Mancos Shale, likewise, the fluvial channel Torrivio Member is encased in and intertongues with finer grained sediment of the Dilco Coal Member. The most notable exception to this generality is the Hospah field where faulting is combined with the stratigraphic controls to form the trapping mechanism. Some additional production also comes from fractured Mancos Shale on or above structures.

Source rocks and geochemistry

Source beds for Gallup oil have been identified as the marine Upper Cretaceous Mancos Shale (Ross, 1980). Rice (1983) also cited the Mancos as the source of both associated and nonassociated gas produced from the Gallup interval. The Mancos contains 1-3 weight percent organic carbon (Ross, 1980) 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 south in the Hospah fields. Associated gas from the Tocito has a chemical composition (C_1/C_{1-5}) of 0.77 and an isotopic ($\delta^{13}C_1$) range of -48.4 to -48.7 per mil. Nonassociated gas compositions are 0.83 and -45.7 per mil, respectively (Rice, 1983).

Timing and migration

The upper Mancos Shale of the central part of the San Juan Basin entered the oil generation window in the late Eocene and the gas window in the Oligocene (fig. 6a). Migration updip to reservoirs in the Tocito Sandstone Lentil and regressive Gallup followed pathways similar to those determined by present structure since basin configuration has changed little. Migration was facilitated by the presence of sheet sandstone and siltstone bodies in the Tocito interval above the Niobrara unconformity.

Table 4.--Gallup oil and gas fields, San Juan Basin petroleum province (Fassett, 1978, 1983)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
1	Alamito	T.23 N.,R. 7 W.,S.31	1971	175	900,000
2	Albino	T.32 N.,R. 8 W.,S.26	1973	200	
3	Amarillo	T.28 N.,R.13 W.,S.33	1958	55	
4	Angel's Peak	T.27 N.,R.10 W.,S.34	1958	854	66,000,000
5	Armenta	T.29 N.,R.10 W.,S.28	1980	NA	NA
6	Aztec Wash	T.32 N.,R.17 W.,S. 8	1961	50	4,000
7	B S Mesa	T.26 N.,R. 4 W.,S. 5	1964	110	12,000,000
8	Bisti	T.25 N.,R.12 W.,S.16	1955	51,000	
9	Blanco Tocito S	T.26 N.,R. 6 W.,S. 9	1951	5,600	12,000,000
10	Boulder	T.28 N.,R. 1 W.,S.15	1961	2,000	1,700,000
11	Campo	T.29 N.,R. 4 W.,S.11	1973	120	
12	Cha Cha	T.28 N.,R.13 W.,S.17	1959	9,000	18,000,000
13	Chipeta	T.33 N.,R.18 W.,S.35	1974	400	
14	Choza Mesa	T.28 N.,R. 3 W.,S. 6	1975		44,000
15	Chromo	T.32 N.,R. 1 E.,S. 4	1929	200	
16	Cinder Buttes	T.32 N.,R.12 W.,S.13	1966		50,000
17	Counselors	T.23 N.,R. 6 W.,S. 3	1981	575	251,000
18	Cuervo	T.24 N.,R. 8 W.,S.27	1981	50	75,000
19	Devil's Fork	T.24 N.,R. 7 W.,S.24	1958	2,170	36,000,000
20	Dufer's Point	T.25 N.,R. 8 W.,S.17	1959	200	20,000
21	Escrito	T.24 N.,R. 7 W.,S.27	1957	3,500	19,000,000
22	Flora Vista	T.30 N.,R.12 W.,S. 2	1961	100	8,700,000
23	Gallegos	T.26 N.,R.12 W.,S.14	1954	2,256	39,000,000
24	Gavilan	T.25 N.,R. 2 W.,S.26	1982	7,500	37,500,000
25	Horseshoe	T.30 N.,R.16 W.,S. 4	1956	40,000	7,900,000
26	Hospah	T.17 N.,R. 9 W.,S. 1	1927	9,200	
27	Hospah S.	T.17 N.,R. 9 W.,S.12	1965	9,000	6,000,000
28	Jewett Valley	T.29 N.,R.16 W.,S. 3	1961	22	
29	Knickerbocker Butte	T.30 N.,R.10 W.,S.17	1975	250	1,500,000
30	Kutz	T.27 N.,R.11 W.,S. 9	1958	542	2,300,000

Table 4.--Gallup (Continued)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
31	La Plata	T.31 N.,R.13 W.,S. 5	1959	650	
32	Largo	T.26 N.,R. 7 W.,S. 3	1961	105	13,600,000
33	Lindrith	T.24 N.,R. 4 W.,S. 1	1959	75	750,000
34	Lindrith S.	T.23 N.,R. 4 W.,S. 5	1958	3,200	
35	Lindrith W.	T.24 N.,R. 4 W.,S.24	1978	100	130,000
36	Long Hollow	T.34 N.,R.11 W.,S.21	1981	NA	NA
37	Lybrook	T.23 N.,R. 7 W.,S. 9	1957	700	5,141,000
38	Mancos River	T.32 N.,R.18 W.,S.15	1927	25	
39	Many Rocks	T.32 N.,R.17 W.,S.27	1962	3,100	
40	Many Rocks N.	T.32 N.,R.17 W.,S.18	1963	560	76,000
41	Marcelina	T.16 N.,R. 9 W.,S.18	1977	NA	NA
42	Meadows	T.30 N.,R.15 W.,S.33	1961	105	400,000
43	Media	T.19 N.,R. 3 W.,S.22	1969	20	
44	Mesa	T.32 N.,R.18 W.,S.24	1961	600	60,000
45	Miguel Creek	T.16 N.,R. 6 W.,S.29	1973	55	
46	Nageezi	T.23 N.,R. 9 W.,S. 1	1971	75	
47	Ojito	T.25 N.,R. 3 W.,S.17	1974	500	2,000,000
48	Ojo	T.18 N.,R.15 W.,S.26	1961	10	900,000
49	Otero	T.22 N.,R. 5 W.,S. 1	1955	2,500	13,500,000
50	Pinon	T.28 N.,R.12 W.,S.14	1966	360	950,000
51	Puerto Chiquito E.&W.	T.26 N.,R. 1 W.,S. 5	1960	14,500	15,000,000
52	Ramona	T.33 N.,R.18 W.,S.15	1965	2	
53	Rattlesnake	T.29 N.,R.19 W.,S. 2	1968	6	
54	Red Mesa	T.33 N.,R.12 W.,S.23	1924	1,000	1,000,000
55	Regina	T.24 N.,R. 1 W.,S.36	1979	12	73,000
56	Rosa	T.32 N.,R. 5 W.,S.20	1971	120	
57	Rusty	T.22 N.,R. 7 W.,S.16	1975	50	300,000
58	San Ysidro	T.21 N.,R. 3 W.,S.29	1981	670	700,000
59	Shiprock	T.29 N.,R.18 W.,S.17	1959	300	
60	Shiprock N.	T.30 N.,R.18 W.,S.14	1967		82,000
61	Simpson	T.28 N.,R.12 W.,S.26	1959	900	3,300,000

Table 4.--Gallup (Continued)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
62	Tapacito	T.26 N.,R. 5 W.,S.18	1965	560	25,000,000
63	Totah	T.29 N.,R.13 W.,S.27	1959	3,400	6,750,000
64	Verde	T.31 N.,R.15 W.,S.14	1955	7,950	3,240,000
65	Walker Dome	T.15 N.,R.10 W.,S.13	1956	NA	NA
66	Waterflow S.	T.29 N.,R.15 W.,S.19	1963	224	250,000
67	White Wash	T.24 N.,R. 9 W.,S. 2	1977	120	
68	Wildhorse	T.26 N.,R. 4 W.,S.21	1957	190	37,000,000

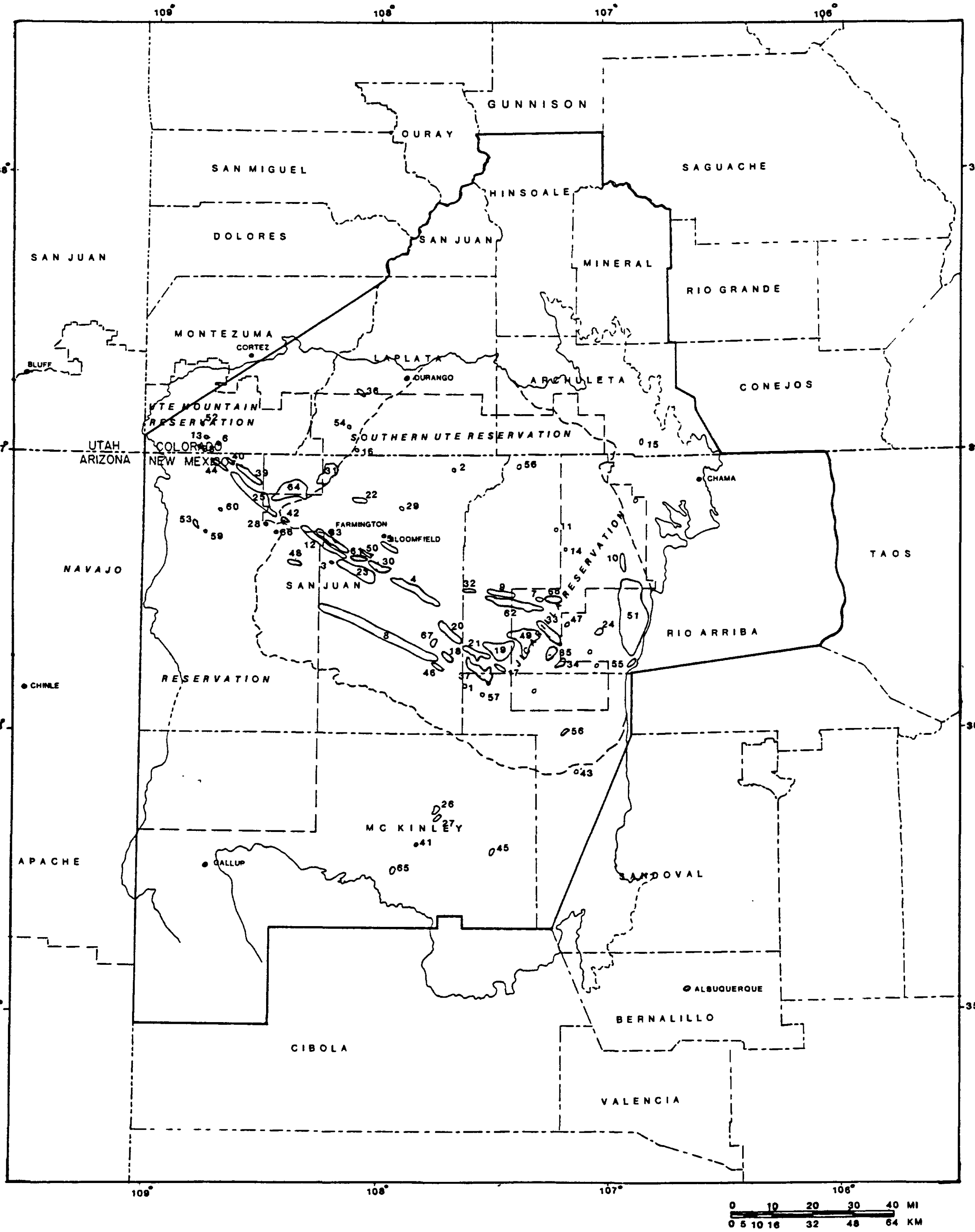

Figure 15.--Gallup play outline and developed oil and gas fields, San Juan Basin petroleum province. Broken line separates basinal and basin flank parts of play. Numbered fields from table 4.

Depth of occurrence

Oil has been produced from the Gallup interval at depths ranging from about 400 to 7,700 ft (120-2350 m). The belt of Tocito sandstone buildups produces from about 1,500 ft (450 m) on the Four Corners Platform as in the northwest part of the Horseshoe field (fig. 15), and from about 4,500 to 5,500 ft (1370-1675 m) farther to the southeast in the central part of the basin. The regressive Gallup in the southern part of the San Juan Basin produces from about 1,500 ft (450 m) at the Hospah fields. Oil seeps and oil-stained sandstone occur at several locations along the outcrops in the southern and western parts of the basin (Molenaar, 1973).

Exploration status

Initial Gallup discoveries were made in the mid 1920's at Red Mesa in Colorado and Hospah in New Mexico (table 4, fig. 16a). The major discoveries, however, were not made until the late 1950's and early 1960's (table 4, figs. 16a, 17a) in the deeper Tocito fields, the largest of which, Bisti, encompasses 37,500 acres with an estimated total recovery of 51,000 MBO (table 4). Most Gallup fields are classified as oil fields with associated gas, although several produce nonassociated gas. Total production through 1985 was approximately 165,000 MBO, 490 MBNGL (Thousand Barrels Natural Gas Liquids) 350 BCF associated gas, and 71 BCF nonassociated gas.

Gallup fields are typically 1,000 to 10,000 acres in area with 15 to 30 ft (5-10 m) of pay. About one third have an estimated total production exceeding one million barrels of oil and one billion cubic feet of associated gas (table 4, figs. 16b, 17b). All of the larger fields produce from the Tocito Sandstone Lentil of the Mancos Shale and are stratigraphically controlled.

South of the zone of bar-like sandstone buildups of the Tocito, the regressive Gallup produces primarily from the fluvial channel sandstone of the Torrivio Member. The only large field producing from the Torrivio is Hospah field, which is primarily a structural trap. Other such traps probably exist in the southern half of the basin and are likely to have been charged during the Oligocene. Evidence of oil migration can be found in several locations along the outcrops in both the southern and western parts of the basin.

The possible relationship of deep-seated basement structures to Gallup deposition and younger structures has yet to be determined. The aerial distribution of Tocito sandstone buildups is very similar to those in the overlying Mesaverde (fig. 18) and Pictured Cliffs (fig. 21) suggesting a common control. If such a control exists, the implications for future exploration could be significant.

Figure 16 reflects a mature cycle of exploration and suggests the possibility of a second cycle. Drilling density is very high along the known trend of Tocito sandstone bodies and much lower to the south. Hospah type accumulations are possible nearly anywhere on the Chaco slope.

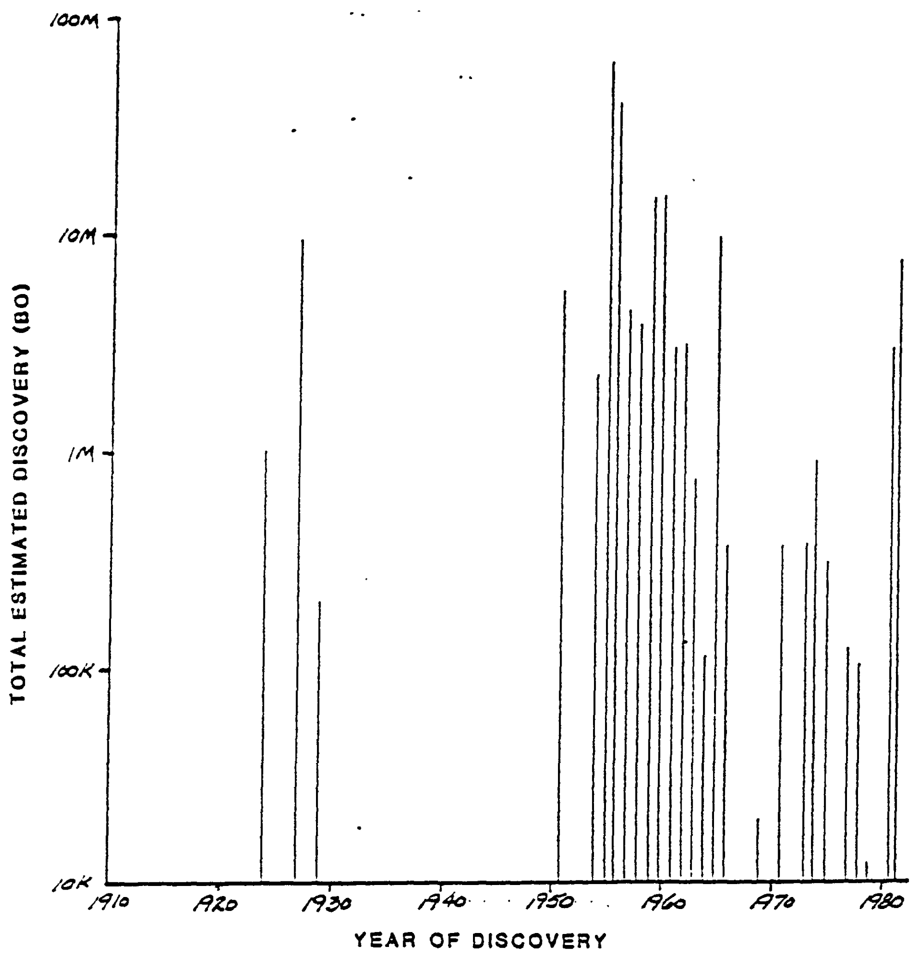

Figure 16a.--History of discovery, Gallup oil fields, San Juan Basin petroleum province (semi-log plot; K-thousand; M-million).

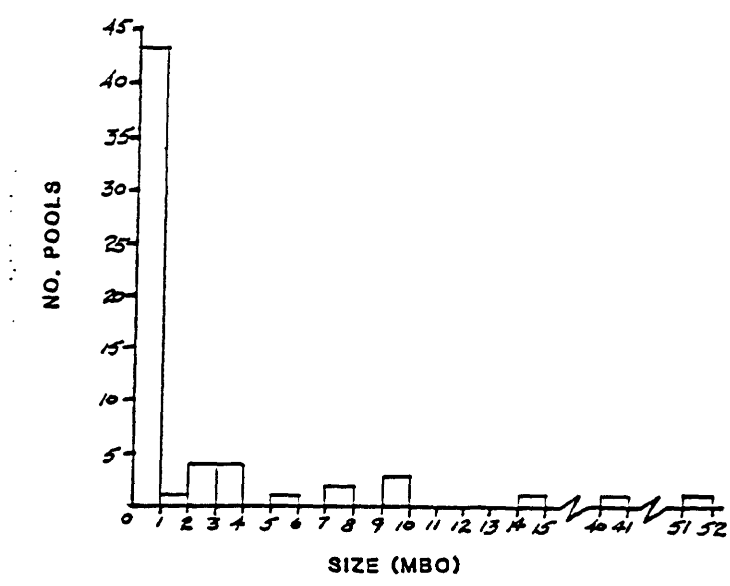

Figure 16b.--Distribution of sizes, Gallup oil fields, San Juan Basin petroleum province.

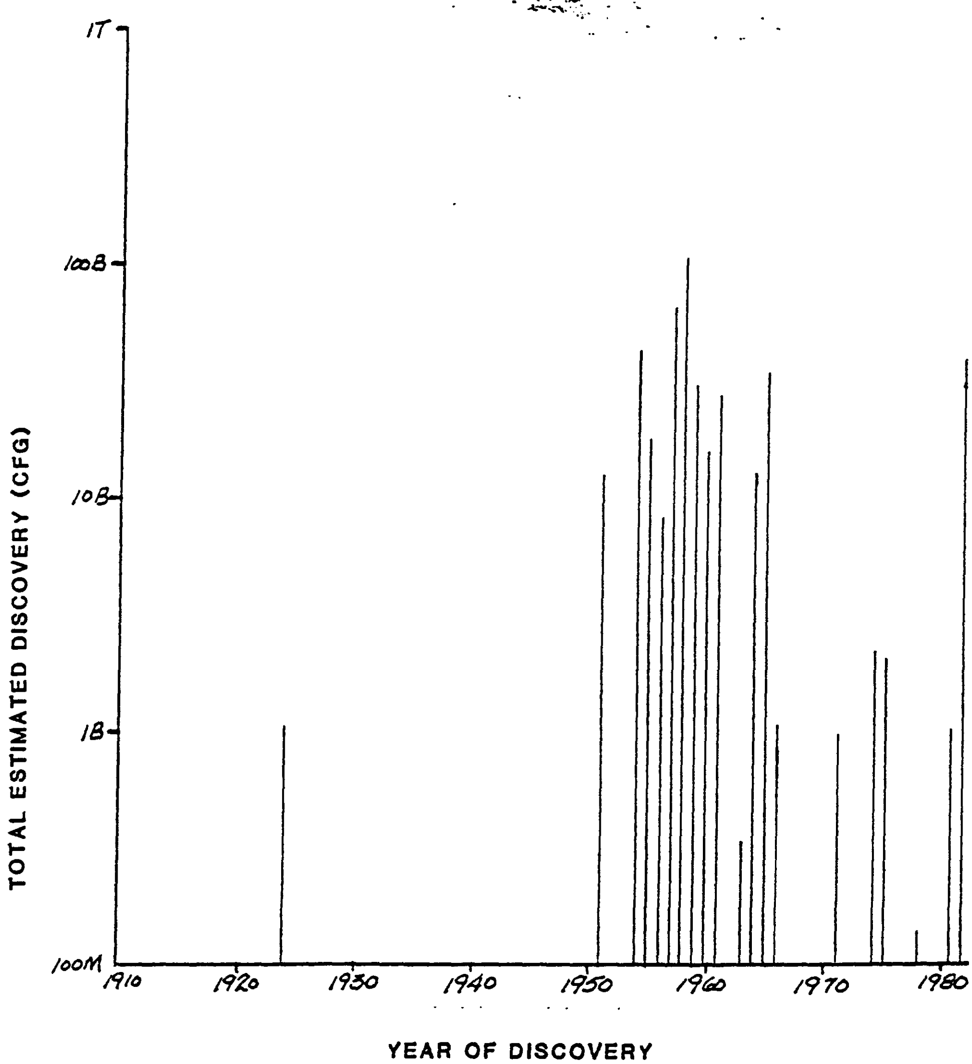

Figure 17a.--History of discovery, Gallup gas fields, San Juan Basin petroleum province (semi-log plot; M-million, B-billion, T-trillion).

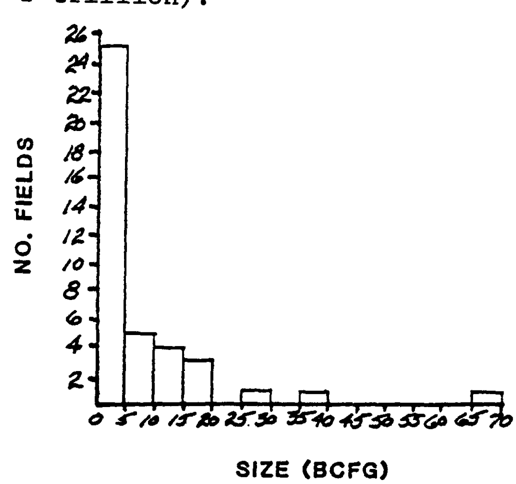

Figure 17b.--Distribution of sizes, Gallup gas fields, San Juan Basin petroleum province.

Mesaverde

Play description and type

The Mesaverde is primarily a gas play in sandstone buildups associated with stratigraphic rises in the Upper Cretaceous Point Lookout and Cliff House Sandstones. It is divided into a basinal gas play that is dominantly stratigraphic and a basin flank oil and gas play that is typically both stratigraphic and structural.

The major gas producing interval in the San Juan Basin, the Upper Cretaceous Mesaverde Group, comprises the regressive marine Point Lookout Sandstone, the nonmarine Menefee Formation, and the transgressive marine Cliff House Sandstone (fig. 5). Total thickness of the interval ranges from about 500 to 2,500 ft (150-750 m), of which 20 to 50 percent is sandstone. The Mesaverde interval is enclosed by marine shale with the Mancos Shale beneath and the Lewis Shale above.

Most wells are completed through the entire interval so it is difficult to assign definite volumes of production to specific units but the Point Lookout is thought to be the major producer primarily because it is thicker and has greater continuity than the Cliff House (Fassett and others, 1978; Rice, 1983). Both the Point Lookout and Cliff House Sandstones intertongue with the intervening nonmarine Menefee Formation that is composed of carbonaceous shale, siltstone, fluvial channel sandstone, and coal. The basal Point Lookout Sandstone is transitional and intertonguing with the underlying Mancos Shale. Stratigraphic rises in the Point Lookout resulting from stillstands or brief reversals in the general regression produce sandstone bodies as thick as 300 ft (90 m) intertongued with finer-grained nonmarine deposits of the Menefee on the updip side.

Similar mechanisms produced intertonguing of the Cliff House Sandstone and the overlying Lewis Shale. A combination of several of these tongues is locally known as the "Chacra producing interval" (Fassett and others, 1978) which is included here in the Mesaverde interval.

Reservoirs

The principal gas reservoirs in the Mesaverde interval are the Point Lookout and Cliff House marine sandstones with a small amount of dry nonassociated gas produced from thin lenticular channel sandstone bodies and thin coal beds of the Menefee. Reservoir quality in the Mesaverde depends largely on the degree of fracturing.

Hollenshead and Pritchard (1961) describe the Point Lookout as a fine to very fine grained, well cemented, angular to subangular sandstone composed of 55 percent quartz, trace chert, 15 percent feldspar, 5 percent rock fragments, 15 percent argillaceous cement, and 10 percent silica cement. The same authors describe the Cliff House as very fine grained, well cemented, angular to subangular sandstone composed of 60 percent quartz, 10 percent feldspar, 5 percent rock fragments, 10 percent argillaceous cement, and 15 percent silica cement.

Together the Blanco Mesaverde and Ignacio Blanco fields (table 5, fig. 18) account for nearly half of the total nonassociated gas and condensate production from the San Juan Basin. Within these two fields, porosity averages about 10 percent and permeability about 2 millidarices with a total pay thickness range of 20 to 200 ft (6-60 m). Smaller Mesaverde fields have porosities from 14 to 28 percent and permeabilities from 2 to 400 millidarcies with 6 to 25 ft (2-8 m) of pay thickness. The Chacra interval averages about 10 percent porosity and 0.3 millidarcies permeability with 8 to 40 ft (2.5-12 m) of pay thickness.

Traps and seals

Gas accumulation and production from the Mesaverde interval is controlled by the pattern of sandstone distribution, lithologic characteristics of the sandstone, degree of fracturing, and hydrodynamic factors (Hollenshead and Pritchard, 1961). Thick sandstone buildups associated with stratigraphic rises in the Point Lookout and Cliff House Sandstones are the major producers and have been mapped across the San Juan Basin from northwest to southeast. Stratigraphic traps along these rises are produced by intertonguing of the marine sandstone reservoir rocks with finer grained continental and marine sediments. These rises parallel and overlie similar trends in both younger and older Cretaceous marine sandstones suggesting deep-seated structural control. Fracturing of the reservoir rocks along these trends could also have resulted from movement on underlying structures but this is highly speculative.

The trapping mechanisms for the largest fields in the central part of the San Juan Basin are not well understood. Both the Blanco Mesaverde and Ignacio Blanco fields are thought to employ hydrodynamic forces to contain the gas in structurally lower parts of the basin (Hill and others, 1961; Fassett and others, 1978) but other factors such as cementation and swelling clays may also play a role. Most of the smaller fields are either stratigraphic traps or a combination of stratigraphic and structural. Chacra fields are nearly all stratigraphic.

Updip pinchouts of marine sandstone into finer grained paludal or marine sediments account for nearly all of the stratigraphic traps with a shale or coal seal. Structural or combination structural/stratigraphic traps with similar seals have accounted for most of the small amount of oil production from the Mesaverde.

Source rocks and geochemistry

Analyses of Mesaverde hydrocarbons indicate different sources for the nonassociated gas and the oil. Rice (1983) reports a ratio of liquids to gas production of 0.17 gal/mcf (0.02 dm^3/m^3) and states that "most of the liquids produced within the central basin qualify as condensates, that is, they are hydrocarbon mixtures that are gaseous in the ground, condense into fluid when produced, and have an API gravity greater than 60°." The chemical composition (C_1/C_{1-5}) of 0.99-0.79 and isotopic ($\delta^{13}C_1$) range of -33.4 to -46.7 per mil of the nonassociated gas together with several other criteria suggest to Rice (1983) a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation.

Table 5.--Mesaverde oil and gas fields, San Juan Basin petroleum province (Fassett, 1978, 1983)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
1	Adobe	T.24 N.,R. 4 W.,S.13	1981	NA	NA
2	Animas	T.31 N.,R. 4 W.,S. 6	1975		3,400,000
3	Blackeye	T.20 N.,R. 9 W.,S.32	1972	40	
4	Blanco	T.30 N.,R. 9 W.,S.29	1927		12,000,000,000
5	Bloomfield	T.29 N.,R.10 W.,S.18	1972		11,000,000
6	Chaco Wash	T.20 N.,R. 9 W.,S.21	1961	100	
7	Crouch Mesa	T.29 N.,R.11 W.,S. 6	1961		7,000,000
8	Cuervo	T.27 N.,R. 8 W.,S.28	1958	60	
9	Devil's Fork	T.24 N.,R. 6 W.,S.16	1969	100	300,000
10	Flora Vista	T.30 N.,R.12 W.,S.22	1961	97	25,000,000
11	Franciscan Lake	T.20 N.,R. 5 W.,S. 7	1975	400	
12	Gobernador	T.20 N.,R. 9 W.,S.32	1972	200	
13	Gonzales	T.25 N.,R. 5 W.,S. 6	1971		50,000,000
14	Harris Mesa	T.28 N.,R. 9 W.,S.29	1956		21,000,000
15	Ignacio Blanco	T.32 N.,R.11 W.,S.15	1952		550,000,000
16	Largo	T.27 N.,R. 8 W.,S.23	1972		33,000,000
17	Navajo City	T.30 N.,R. 8 W.,S.35	1974		11,600,000
18	Nenahnezad	T.29 N.,R.15 W.,S.10	1970	1	
19	Otero	T.25 N.,R. 5 W.,S.23	1956		172,000,000
20	Parlay	T.22 N.,R. 3 W.,S.29	1971	121	
21	Red Mesa	T.33 N.,R.12 W.,S.23	1924	1,000	1,000,000
22	Red Mountain	T.20 N.,R. 9 W.,S.29	1934	300	
23	Rusty	T.22 N.,R. 7 W.,S.14	1975		6,000,000
24	San Luis	T.18 N.,R. 3 W.,S.21	1950	70	
25	San Luis S.	T.18 N.,R. 3 W.,S.33	1959	NA	NA
26	Seven Lakes	T.18 N.,R.11 W.,S.18	1911	4	
27	Star	T.19 N.,R. 6 W.,S.16	1974	NA	NA
28	Stoney Butte	T.22 N.,R.14 W.,S.36	1928	NA	NA
29	Torreon	T.18 N.,R. 4 W.,S.22	1953	.3	
30	Twin Mounds	T.29 N.,R.14 W.,S. 4	1954		650,000
31	Venado	T.22 N.,R. 5 W.,S. 8	1971	45	

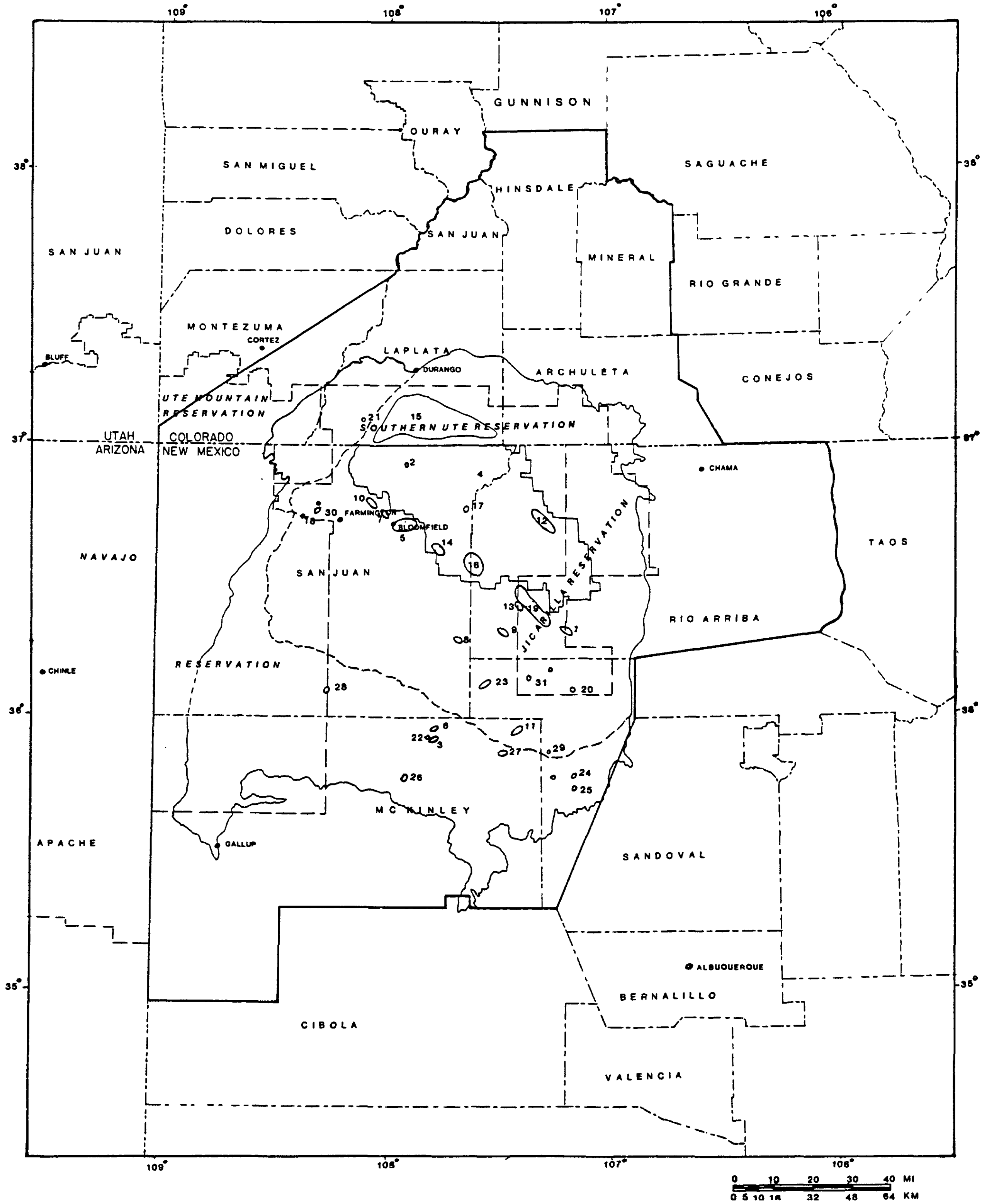

Figure 18.--Mesaverde play outline and developed oil and gas fields San Juan Basin petroleum province. Broken line separates basinal and basin flank parts of play. Numbered fields from table 5.

Oil is produced primarily from the transitional interval between the Mancos Shale and the Point Lookout Sandstone. Ross (1980) positively correlated the composition of Mesaverde oil with bitumen from the marine Mancos Shale. API gravity of Mesaverde oil ranges from 37° to 50°.

Timing and migration

In the central part of the San Juan Basin the Mancos Shale entered the oil generation window in the Eocene and the gas window in the Oligocene (fig. 6a). The Menefee Formation also entered the gas generation window in the Oligocene (fig. 6a). Because the basin configuration was similar to that of today, updip migration would have been toward the south. Migration was impeded by hydrodynamic pressures directed toward the central basin as well as by the deposition of authigenic swelling clays due to dewatering of Menefee coals.

Depth of occurrence

The Mesaverde interval crops out around the perimeter of the central part of the San Juan Basin and reaches depths of approximately 7,000 ft (2,130 m) in the basin. Production depths range from 300 to 5,300 ft (90-1600 m) but most has been from 4,100 to 5,300 ft (1250-1600 m). Production from the Chacra interval is in the 1,900 to 3,800 ft (580-1150 m) range.

Exploratory status

The first oil producing area in the state of New Mexico, the Seven Lakes field, was discovered by accident in 1911 when a well being drilled for water produced oil from the Menefee Formation at a depth of approximately 350 ft (106 m). The only significant Mesaverde oil field, Red Mesa (table 5) was discovered in 1924 (fig 19). The Blanco Mesaverde discovery well was completed in 1927 and the Ignacio Blanco Mesaverde discovery well in 1952 (table 5, fig. 20a). Together these two adjacent fields encompass much of the central part of the San Juan Basin, more than 1,000,000 acres, and have produced about 7,000 BCF of gas and more than 19,000 MBO of condensate which is approximately half of their estimated total recovery.

Most recent discoveries have been in the Chacra interval. Sizes range from 2,000 to 10,000 acres and estimated total recovery from 10 to 35 BCF (table 5, fig. 20). Mesaverde oil fields are generally small, less than 1,000 acres, and range in estimated total recovery from 300 to 400,000 Bbl of oil. (table 5, fig. 19b)

The occurrence of gas in the lower parts of the basin has been generally ascribed to the action of hydrodynamic forces but this trapping mechanism is incompletely understood in the San Juan Basin. The probability of large gas production outside of the central part of the basin must be considered low until this factor is better understood and until tight gas sand production technology improves.

Figure 19 suggests immature oil discovery in the Mesaverde but the field sizes are small and drilling density is moderate to heavy throughout the area so future discoveries are likely to be small also. Figure 20 indicates mature gas exploration so future discoveries will probably be in the 1-10 BCFG range.

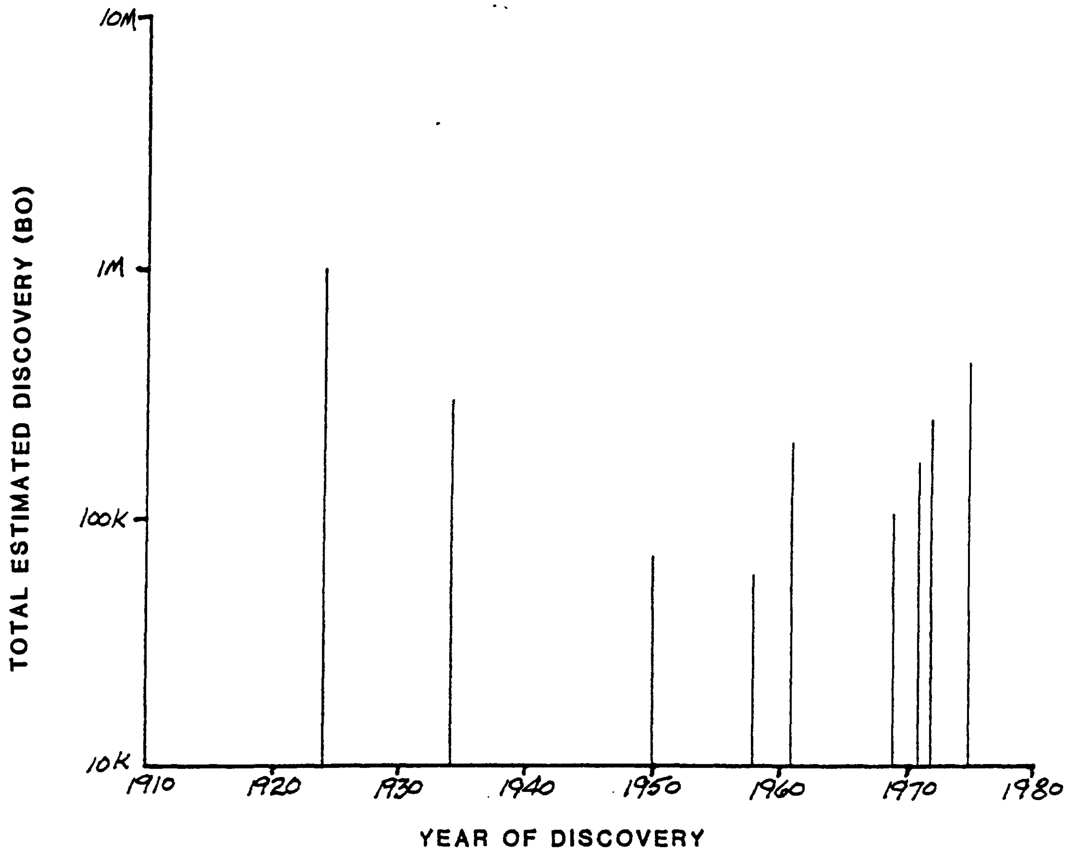

Figure 19a.--History of discovery, Mesaverde oil fields, San Juan Basin petroleum province (semi-log plot; K-thousand, M-million).

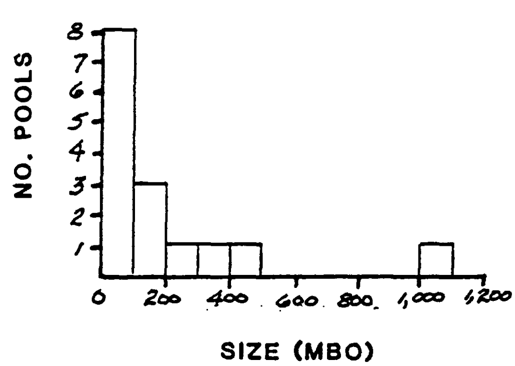

Figure 19b.--Distribution of sizes Mesaverde oil fields, San Juan Basin petroleum province.

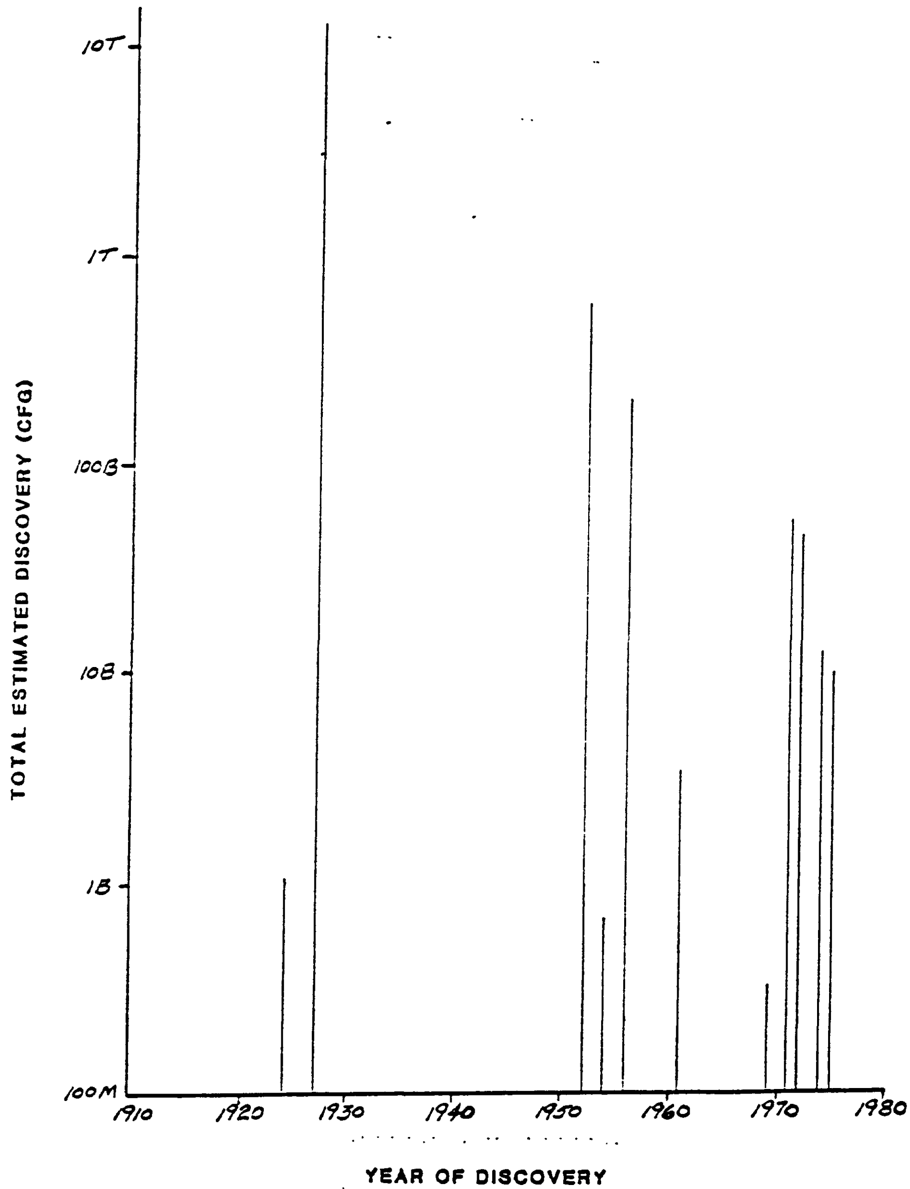

Figure 20a.--History of discovery, Mesaverde gas fields, San Juan Basin petroleum province (semi-log plot, M-million, B-billion, T-trillion).

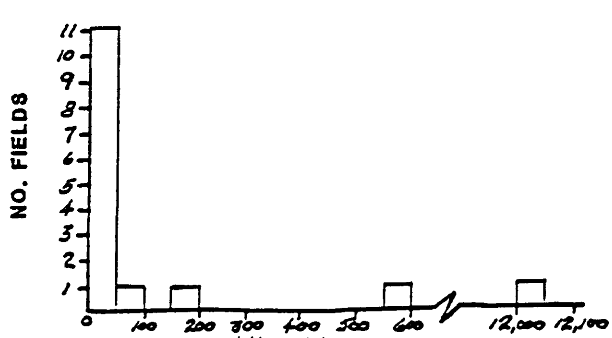

Figure 20b.--Distribution of sizes, Mesaverde gas fields, San Juan Basin petroleum province.

Pictured Cliffs

Play description and type

Hydrocarbon production from the Upper Cretaceous Pictured Cliffs sandstone has been primarily gas from stratigraphic traps in sandstone beds enclosed in shale or coal at the top of the unit. Still stands or brief reversals in the regression of the Cretaceous sea to the northeast produced thicker shoreline sandstones which have been the most productive.

The Pictured Cliffs Sandstone is the uppermost regressive marine sandstone in the San Juan Basin. It ranges in thickness from 0-400 ft (0-122 m) and is conformable with both the marine Lewis Shale beneath and the overlying nonmarine Fruitland Formation. The lower part is a transitional zone with interbedded sandstone and marine shale. The upper part is massive fine-grained marine sandstone which is interbedded with coal and fluvial units of the Fruitland.

Reservoirs

Reservoir quality within the Pictured Cliffs is determined to a large extent by the abundance of authigenic clay (Cumella, 1981). Burgener (1953) described a typical sandstone as being composed of 86 percent quartz, 7 percent potassium feldspar, 6 percent plagioclase feldspar, and 4 percent coal fragments. Cementing material averages 60 percent calcite, 30 percent clay, and 10 percent silica. Average porosity is about 15 percent and permeability averages 5.5 millidarcies although many fields are less than 1 millidarcy. Pay thicknesses range from 5-150 ft (1.6-45 m) but are typically less than 40 ft (12 m).

Reservoir quality improves southward from the deepest parts of the basin due to secondary diagenetic effects (Cumella, 1981). Low permeabilities in the northernmost part of the basin are caused primarily by the precipitation of authigenic illite-smectite clay that Meissner (1984) attributes to the "expulsion of highly reactive waters produced by coal maturation (Law and others, 1983) in the overlying Fruitland Formation."

Traps and seals

Stratigraphic traps resulting from landward pinchout of nearshore and foreshore marine sandstone bodies into finer grained silty, shaly, and coaly facies of the Fruitland Formation (especially in the areas of stratigraphic rises) produce most of the hydrocarbons. These rises are concentrated along a northwest-southeast-trending "fairway" in the central part of the basin generally overlying similar trends in the Gallup and Mesaverde intervals. Seals are formed by the finer grained back-beach and paludal sediments into which the marine sandstone intertongues throughout most of the central part of the basin. The Pictured Cliffs is sealed off from any connection with other underlying Upper Cretaceous reservoirs by the Lewis Shale.

Source rocks and geochemistry

The source of the Pictured Cliffs gas was probably the overlying and interbedded Fruitland coal (Rice, 1983). The gas is nonassociated with very little condensate (0.006 gal/mcf, 0.0008 dm^3/m^3), as are the Fruitland/Kirtland gases, with a chemical composition (C_1/C_{1-5}) of 0.98-0.70 and an isotopic ($\delta^{13}C_1$) range of -40.7 to -45.8 per mil (Rice, 1983), also very similar to the Fruitland/Kirtland gases. The volume of coal at a rank of high volatile A bituminous to medium volatile bituminous in the Fruitland Formation lying in deeper parts of the basin is more than sufficient to account for the volume of gas in both the Pictured Cliffs and Fruitland/Kirtland reservoirs (Meissner, 1984).

Timing and migration

Gas generation from the Fruitland coals was probably at a maximum during the late Oligocene and the Miocene (fig. 6a). Updip gas migration would have been predominantly toward the southwest because the basin configuration was similar to that of today. Most of the traps formed by landward pinchout of sandstone tongues into the continental deposits and by stratigraphic rises parallel to the paleoshoreline were ideally situated to be charged during the migration (Meissner, 1984). Rice (1983) questions the updip migration mechanism because of low permeabilities and discontinuity of the upper Pictured Cliffs Sandstones but Meissner (1984) notes that the low-permeability rocks are all gas-saturated and that the stratigraphic discontinuities probably have limited seal capacities.

Depth of occurrence

The Pictured Cliffs Sandstone crops out around the perimeter of the central part of the San Juan Basin and reaches depths of about 4,300 ft (1310 m). Most production has been from depths of 1,000 to 3,000 ft (305-915 m). Depths along the "fairway" range from 1,500 to 3,500 ft (450-1060 m).

Exploratory status

Gas was discovered in the Pictured Cliffs in 1927 at the Blanco and Fulcher Kutz fields of northwest New Mexico (table 6, fig. 21). Most of the Pictured Cliffs fields were discovered before 1954 with only 9 relatively small fields coming into production since then (table 6, fig. 22). Of the 25 fields having significant production from the Pictured Cliffs, 7 are thought to exceed 100 BCF total production and 1, South Blanco, to exceed 1,000 BCF (Fassett, 1978). Cumulative production through 1985 amounted to about 90 MBO, 3,000 BCF gas, and 370 MBbls condensate. Field sizes range from 1,000 to 236,000 acres with most falling in the 10,000 to 90,000 acre range. Discoveries since 1954 have been smaller, averaging 3,000 acres and 11 BCF estimated ultimate recovery.

Much of the resource potential of the Pictured Cliffs depends on future recovery technology. A large quantity of gas is held in tight sandstone reservoirs north of the currently producing areas. Stratigraphic traps and excellent source rocks exist in the deeper parts of the basin but low permeabilities due to authigenic illite-smectite clay have so far limited production.

Figure 22 indicates mature exploration in the Pictured Cliffs with probable future discoveries in the 1-10 BCF range with the possibility of one or more in the 10-100 BCF range. The high density of drilling within the play area supports such a conclusion.

Table 6.--Pictured Cliffs gas fields, San Juan Basin petroleum province (Fassett, 1978, 1983)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
1	Albino	T.32 N.,R. 8 W.,S.26	1973		4,520,000
2	Aztec	T.30 N.,R.11 W.,S.10	1941		433,000,000
3	Ballard	T.25 N.,R. 7 W.,S. 4	1953		480,000,000
4	Blanco	T.30 N.,R. 9 W.,S.29	1927		800,000,000
5	Blanco E.	T.30 N.,R. 4 W.,S.18	1952		32,500,000
6	Blanco S.	T.26 N.,R. 6 W.,S.15	1951		1,400,000,000
7	Choza Mesa	T.29 N.,R. 4 W.,S.35	1953		6,000,000
8	Fulcher Kutz	T.29 N.,R.11 W.,S.34	1927		326,000,000
9	Gavilan	T.25 N.,R. 2 W.,S.14	1949		97,000,000
10	Harper Hill	T.29 N.,R.14 W.,S. 1	1969		3,900,000
11	Huerfano	T.26 N.,R.10 W.,S.25	1950		1,600,000
12	Ignacio-Blanco	T.33 N.,R. 7 W.,S. 7	1951		10,000,000
13	Kutz W.	T.27 N.,R.12 W.,S.12	1950		212,000,000
14	Nipp	T.26 N.,R.12 W.,S.17	1975		7,500,000
15	Ojo	T.28 N.,R.15 W.,S.36	1972		2,000,000
16	Potwin	T.24 N.,R. 8 W.,S.15	1976		100,000
17	Tapacito	T.26 N.,R. 4 W.,S.14	1954		392,000,000
18	Twin Mounds	T.30 N.,R.14 W.,S.33	1954		1,600,000
19	Waw	T.27 N.,R.13 W.,S.32	1970		4,000,000

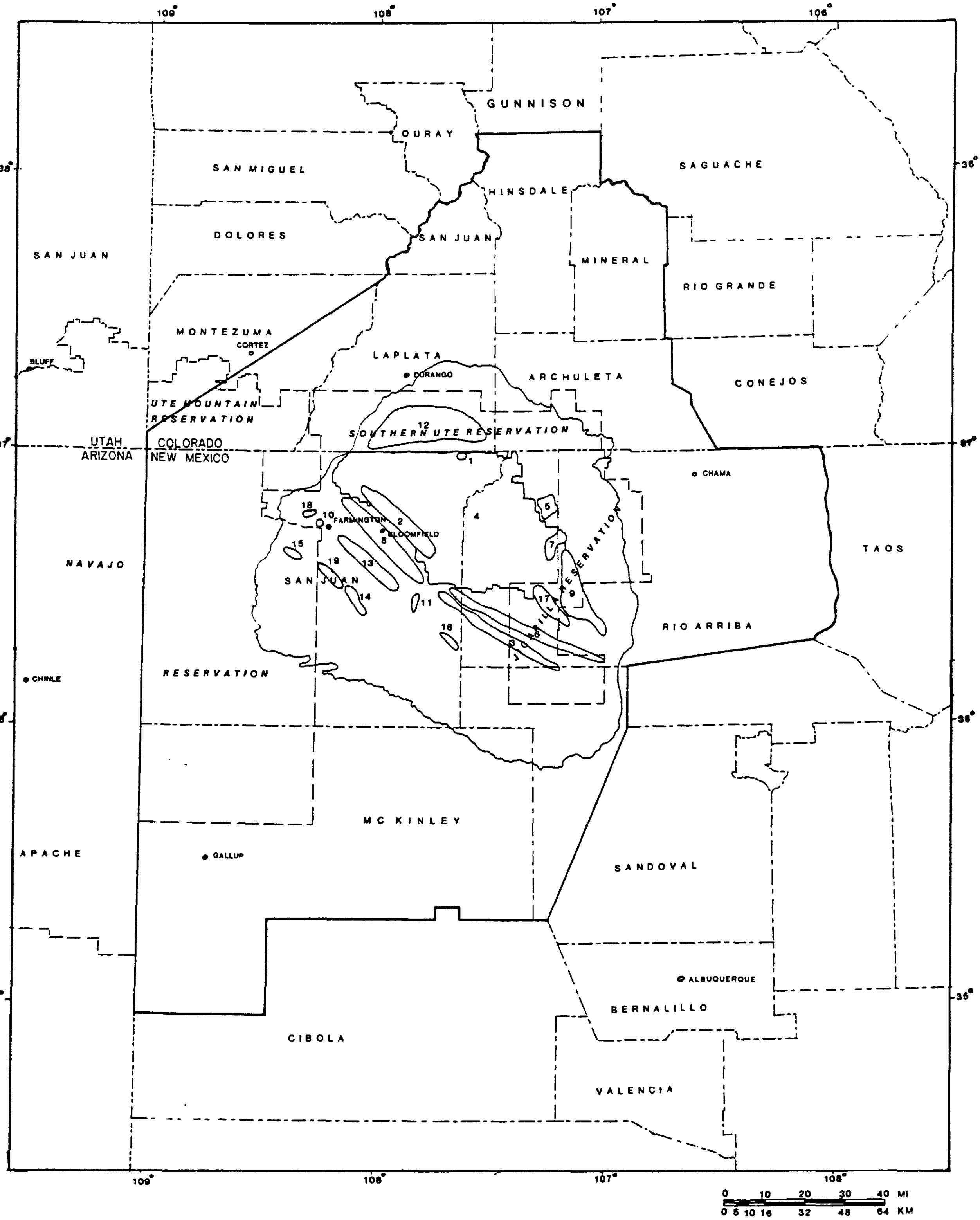

Figure 21.--Pictured Cliffs play outline and developed gas fields, San Juan Basin petroleum province. Numbered fields from table 6.

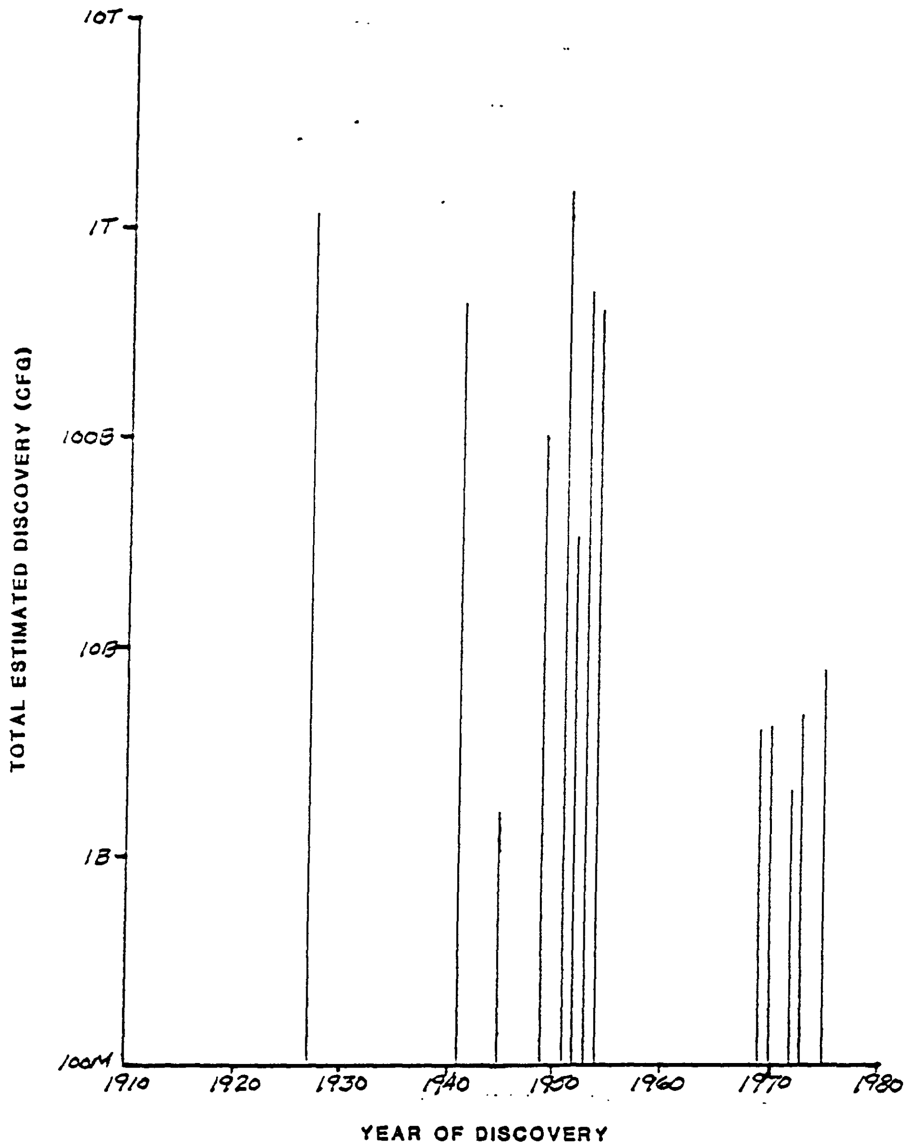

Figure 22a.--History of discovery, Pictured Cliffs gas fields, San Juan Basin petroleum province (semi-log plot; M-million, B-billion, T-trillion).

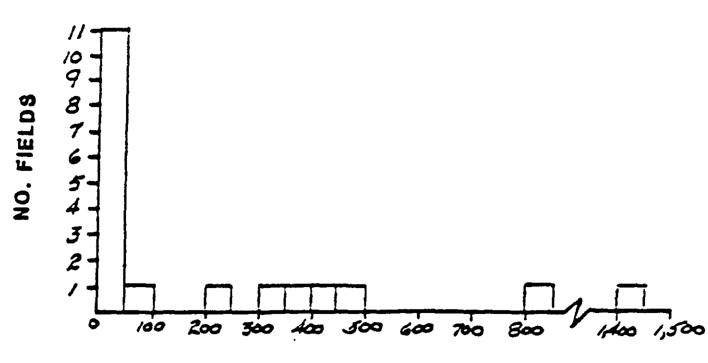

Figure 22b.--Distribution of sizes, Pictured Cliffs gas fields, San Juan Basin petroleum province.

Fruitland/Kirtland

Play description and type

Hydrocarbon production from the Upper Cretaceous Fruitland/Kirtland interval has been primarily gas from stratigraphic traps in lenticular fluvial sandstone bodies enclosed in shale and/or coal. Limited production of coalbed methane from the lower part of the Fruitland has been recorded since the 1950's.

The Fruitland and Kirtland Formations are continental deposits with a maximum combined thickness of more than 2,000 ft (610 m). The Fruitland is composed of interbedded sandstone, siltstone, shale, carbonaceous shale, and coal. Fassett and Hinds (1971) estimated approximately 200 billion tons of coal in beds 2 ft (60 cm) or more thick, predominantly in the lower third of the Fruitland. Sandstone occurs primarily in northerly trending channel deposits in the lower part. The upper part of the formation is dominantly siltstone and shale. The lower part of the overlying Kirtland Shale is dominantly siltstone and shale, differing from the upper Fruitland mainly in the absence of carbonaceous shale and coal. The upper two-thirds or more of the formation, known as the Farmington Sandstone Member, is composed of interbedded sandstone lenses and shale.

Reservoirs

Reservoirs within the Fruitland/Kirtland are predominantly lenticular fluvial channel sandstone bodies and most are considered tight gas sands. Average composition of Fruitland sandstones in the northern part of the San Juan Basin is 85 percent quartz, 6.5 percent orthoclase feldspar, 5.5 percent plagioclase feldspar, and 2.7 percent coal (Burgener, 1953). It is commonly calcite cemented with average porosity of 10-18 percent and low permeability (0.1 to 1.0 millidarcy). Pay thicknesses range from 15 to 50 ft (5-15 m).

The Farmington Sandstone Member of the Kirtland Shale is typically fine grained with an average composition of 21 percent quartz, a trace to 5 percent chert, 12 percent potash feldspar, 33 percent plagioclase feldspar, 9 percent biotite, and 20 percent clay cement (Dilworth, 1960). Porosity ranges from 3 to 20 percent and permeability from 0.6 to 9 millidarcies. Pay thicknesses are generally in the 10 to 20 ft (3-6 m) range.

Traps and seals

The discontinuous lenticular channel sandstone bodies that form the reservoirs in both the Fruitland and Kirtland Formations intertongue with overbank mudstone and shale deposits and with paludal coals and carbonaceous shale in the lower part of the Fruitland. Although some of the fields are located on structures, the traps themselves are predominantly stratigraphic at updip pinchouts of sandstone into the fine-grained sediments forming the seal.

Source rocks and geochemistry

The Fruitland/Kirtland interval produces nonassociated gas with very little condensate which Rice (1983) correlated with nonmarine (coaly) source rocks. Chemical composition (C_1/C_{1-5}) of Fruitland gases ranges from 0.99 to 0.87 and isotopic ($\delta^{13}C_1$) compositions range from -41.8 to -44.2 per mil (Rice, 1983). Although an abundance of coal exists in close proximity to the gas-productive area, Rice (1983) points out that it is not thought to be of sufficient rank to produce significant amounts of gas. In the northern part of the basin, however, Fruitland coals have vitrinite reflectance values ranging from 0.75 to 1.5, indicating a high volatile A-bituminous to medium volatile rank, high enough to produce large quantities of hydrocarbons.

Timing and Migration

Deepest burial throughout the San Juan Basin probably occurred during the Oligocene (fig. 6a), which also coincided with the thermal pulse related to volcanic and intrusive activity in the San Juan uplift along the northern edge. In the northern part of the basin the Fruitland/Kirtland interval entered the oil window during the latest Eocene and the wet gas window probably during the Oligocene (fig. 6a). It is doubtful that the Fruitland coal beds ever reached the dry gas generation window since the well for which the Lopatin diagram (fig. 6a) was prepared is very close the deepest part of the basin (fig. 3). Migration of hydrocarbons updip through fluvial channel sandstone is suggested by the occurrence of gas production from immature reservoirs and by the aerial distribution of production from the Fruitland (fig. 23). Basin configuration has changed little since the Oligocene so that migration paths would be updip to the south since formation of the hydrocarbons (Meissner, 1984).

Depth of occurrence

The outcrop belt of the Fruitland/Kirtland interval defines the central part of the San Juan Basin. Sandstones and coals in the lower part of the Fruitland reach maximum depths of about 4,000 ft (1220 m). Most production has been from depths of 1,500 to 2,700 ft (457-823 m). Production from the Farmington Sandstone Member of the Kirtland Shale has been from 1,100 to 2,300 ft (335-700 m).

Exploratory status

The first commercially produced gas in the state of New Mexico was discovered in 1921 in the Farmington Member at a depth of 900 ft (275 m) in what later became part of the Aztec field. An unknown quantity of gas was produced during the 1920's before the field was abandoned. Gas was first discovered in the Fruitland in 1952 at the Gallegos Aztec fields (table 7, fig. 24a). Three oil fields and 22 gas fields in the Fruitland/Kirtland have produced 70 MBO oil, 39 BCF gas, and 21 MBbls condensate. Distribution of estimated ultimate recovery by field is plotted in figure 24b. Field sizes range from 160 acres to 32,000 acres with nearly 50 percent in the 1,000 to 3,000 acres size. It is difficult to get accurate size and production values because many fields produce from the underlying and interbedded Pictured Cliffs Sandstone as well.

The near linear northeasterly alignment of fields along the western side of the basin (fig. 23) suggests a fluvial channel system of northeasterly flowing streams. Similar channel systems are probable in other parts of the basin (Fassett and Hinds, 1971) and are likely to contain similar amounts of hydrocarbons. Undiscovered pools will probably be in the 1,000 to 3,000 acre size range at depths between 1,000 and 3,000 ft (300-900 m). Because most large structures have probably been tested, future discoveries will undoubtedly be in updip stratigraphic pinchouts of channel sandstone into coal or shale. A large undeveloped potential exists in the coals themselves and coalbed methane remains an unknown. Recent estimates of this potential resource in the San Juan Basin range from about 25 TCF (Bryer and others, 1984; Meissner, 1984) to 31 TCF (Choate and Rightmire, 1982).

Figure 24 suggests a maturely explored play as does the high density of drilling in much of the play area, however, because many of the Fruitland/Kirtland fields are small, relative to the underlying Mesaverde and Dakota fields, they have often been ignored. This may well change as more activity focuses on the Fruitland coals.

Table 7.-Fruitland/Kirtland oil and gas fields, San Juan Basin petroleum province (Fassett, 1978, 1983)

No.	Field	Location discovery well	Date of discovery	Estimated ultimate recovery Oil (MBO)	Gas (MCFG)
1	Alamo	T.30 N.,R. 9 W.,S. 4	1967	NA	NA
2	Aztec	T.30 N.,R.11 W.,S.16	1952		33,600,000
3	Aztec N.	T.30 N.,R.10 W.,S.20	1954		1,700,000
4	Bisti	T.26 N.,R.12 W.,S.31	1979		250,000
5	Blanco	T.30 N.,R. 8 W.,S.29	1968		11,400,000
6	Conner	T.30 N.,R.14 W.,S. 1	1976		200,000
7	Cottonwood	T.32 N.,R. 5 W.,S.35	1953	NA	NA
8	Crouch Mesa	T.29 N.,R.12 W.,S. 4	1959		124,000
9	Farmer	T.30 N.,R.11 W.,S. 4	1979	NA	NA
10	Flora Vista	T.30 N.,R.12 W.,S.10	1956		1,700,000
11	Gallegos	T.27 N.,R.11 W.,S.27	1952		1,300
12	Gallegos S.	T.26 N.,R.12 W.,S.12	1968		10,000,000
13	Glades	T.32 N.,R.12 W.,S.36	1978		1,710,000
14	Harper Hill	T.29 N.,R.14 W.,S. 1	1969		3,900,000
15	Ignacio-Blanco	T.34 N.,R. 8 W.,S.18	1951		50,000,000
16	Jasis Canyon	T.29 N.,R. 8 W.,S.36	1976		400,000
17	Kutz	T.28 N.,R.11 W.,S.28	1956		16,000,000
18	Kutz W.	T.29 N.,R.13 W.,S.23	1952		1,370,000
19	La Jara	T.30 N.,R. 6 W.,S.13	1955	NA	NA
20	Los Pinos N.	T.32 N.,R. 7 W.,S.18	1953		929,000
21	Los Pinos S.	T.31 N.,R. 7 W.,S.17	1953		2,500,000
22	Mt. Nebo	T.28 N.,R.10 W.,S.28	1972		1,600,000
23	Nipp	T.26 N.,R.12 W.,S.17	1975	NA	NA
24	Oswell	T.30 N.,R.11 W.,S.34	1932	70	
25	Pinon	T.28 N.,R.12 W.,S.13	1966		5,406,000
26	Pinon N.	T.29 N.,R.12 W.,S.28	1966		180,000
27	Pump Mesa	T.32 N.,R. 8 W.,S.32	1969		425,000
28	Sedro Canyon	T.31 N.,R. 9 W.,S.23	1973		1,000,000
29	Wyper	T.30 N.,R.12 W.,S.19	1946	7	

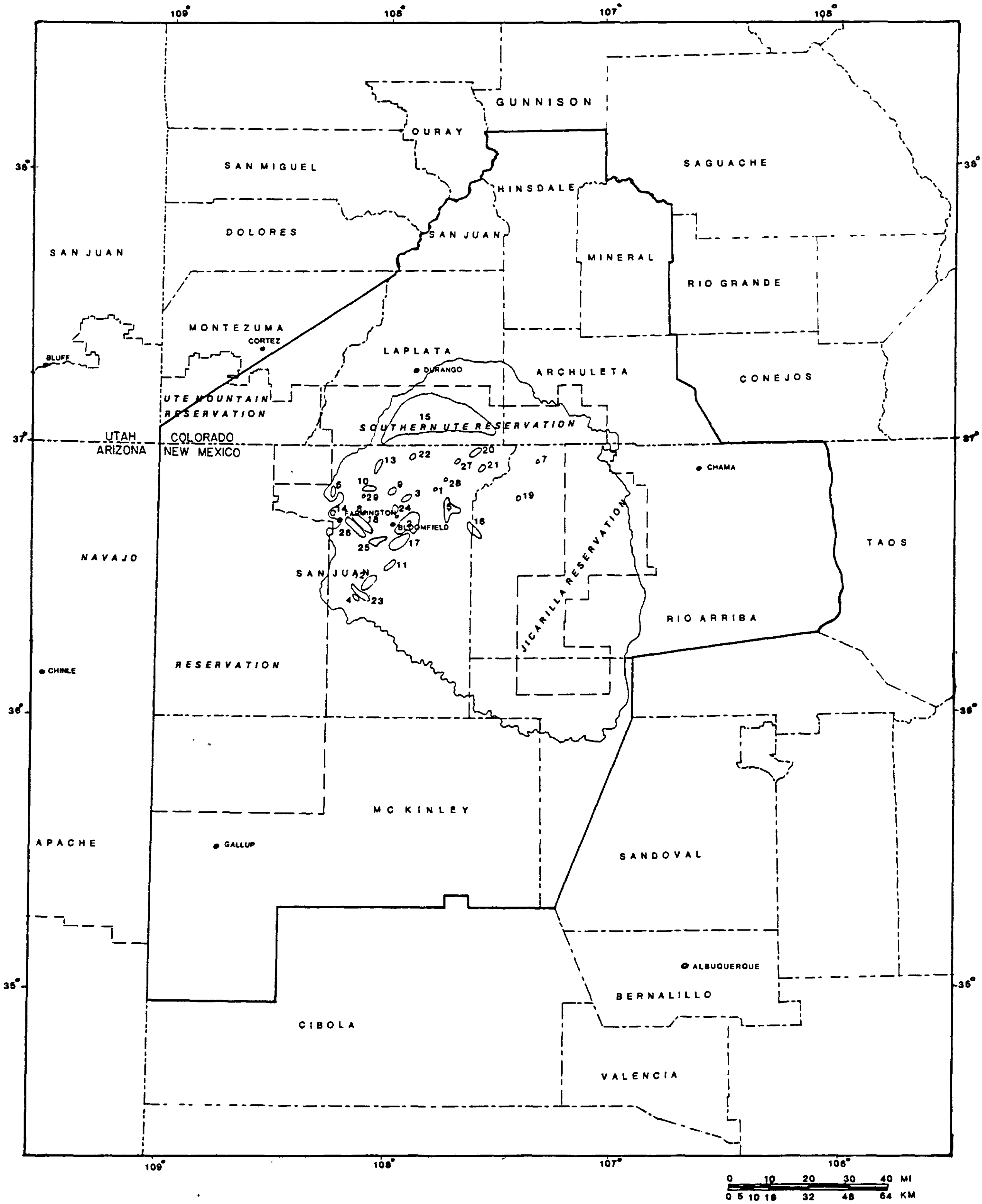

Figure 23.--Fruitland/Kirtland play outline and developed gas fields, San Juan Basin petroleum province. Numbered fields from table 7.

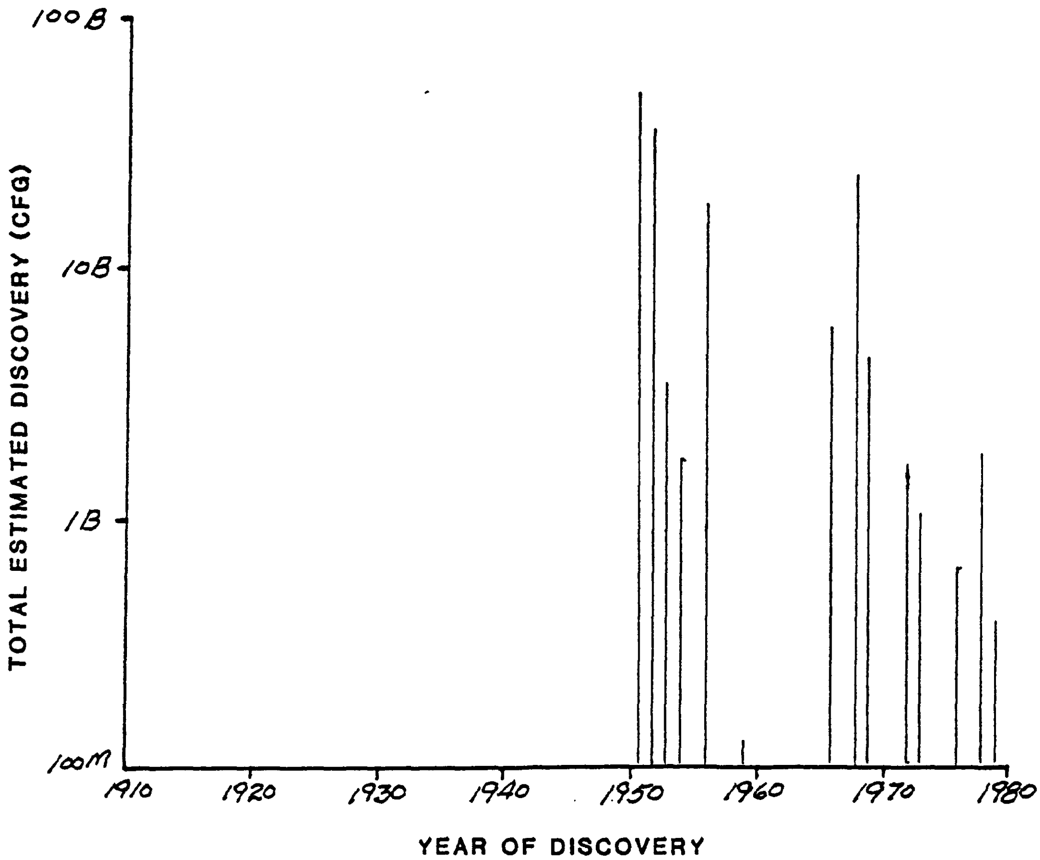

Figure 24a.--History of discovery, Fruitland/Kirtland gas fields, San Juan Basin petroleum province (semi-log plot; M-million, B-billion).

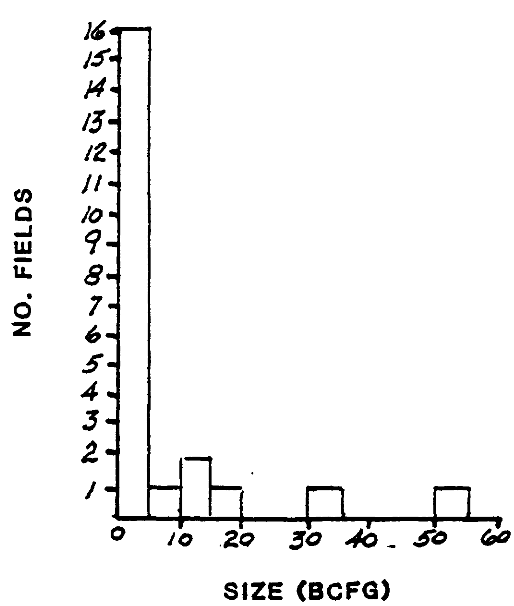

Figure 24b.--Distribution of sizes, Fruitland/Kirtland gas fields, San Juan Basin petroleum province.

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