PRELIMINARY REPORT: PETROLEUM GEOCHEMISTRY OF THE DENVER BASIN

by

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ABSTRACT

Crude oil and shale samples from the Denver basin of Colorado, Wyoming, and Nebraska were analyzed using organic geochemical techniques to determine oil-source bed relationships.

In general, oils in Cretaceous reservoirs are compositionally similar throughout the basin and are geochemically dissimilar to the oil produced from Permian Lyons Sandstone. The Cretaceous oils are compared with hydrocarbon extracts from Cretaceous shales to determine the stratigraphic occurrence and regional distribution of petroleum source beds. The results show that oils produced from the Cretaceous Terry and Hygiene Sandstone Members of the Pierre Shale, "D", and "J" sandstone reservoirs have probably been derived from the Carlile, Greenhorn, Graneros, and Mowry Formations. The source bed for oil from the Lyons has not yet been identified.

Samples of the Carlile-Greenhorn-Graneros-Mowry interval have been analyzed throughout the basin. Only samples from the basin-axis area contained hydrocarbon distributions similar to those Cretaceous oils. The occurrence of petroleum on the east flank of the basin, in light of the limited geographic distribution of effective source beds, indicates that extensive (as much as about 150 km) lateral migration has occurred. This suggests that an understanding of lateral migration pathways is important for petroleum exploration in the Denver basin.

ACKNOWLEDGEMENTS

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INTRODUCTION

To meet the increasing demand for petroleum and petroleum products amid rapidly declining reserves and increasing production costs, the explorationist must employ all available exploration techniques in order to achieve the highest success ratio possible. Recent publications (Nixon, 1973, Williams, 1974; Dow, 1974) have emphasized the utility of petroleum geochemistry to petroleum exploration. Such studies provide data needed for immediate exploration decisions, and also contribute to our overall understanding of the complicated process of petroleum generation, migration, and accumulation. The general principles of petroleum formation and accumulation, thus revealed, can be applied not only to the particular basin being studied but more generally to petroleum exploration both in frontier areas and in highly developed areas as well.

The purpose of this study is to apply the most recent organic geochemical techniques to the characterization of crude oils in the Denver basin and to correlate these groups, or "families," of oils with their source beds. The crude oil-source rock correlations are developed within both the stratigraphic and geographic geologic framework. The Denver basin was chosen for study for three reasons: (1) there are no published data on the organic geochemistry of the Denver basin of which the authors are aware, (2) it is structurally a relatively uncomplicated basin, and (3) exploratory drilling in the basin has increased markedly in recent years. In 1975, exploratory drilling in the Denver basin was up 31 percent over 1974 (Hinaman and Hudson, 1976), which is well above the nationwide increase for the same year of 6.9 percent (Johnston, 1976).

GEOLOGIC SETTING

The Denver basin, one of the largest basins in the Rocky Mountain area, is an asymmetric basin with its axis located parallel and adjacent to the Front Range of Colorado and the Laramie Range of Wyoming (Fig. 1). The deepest part of the

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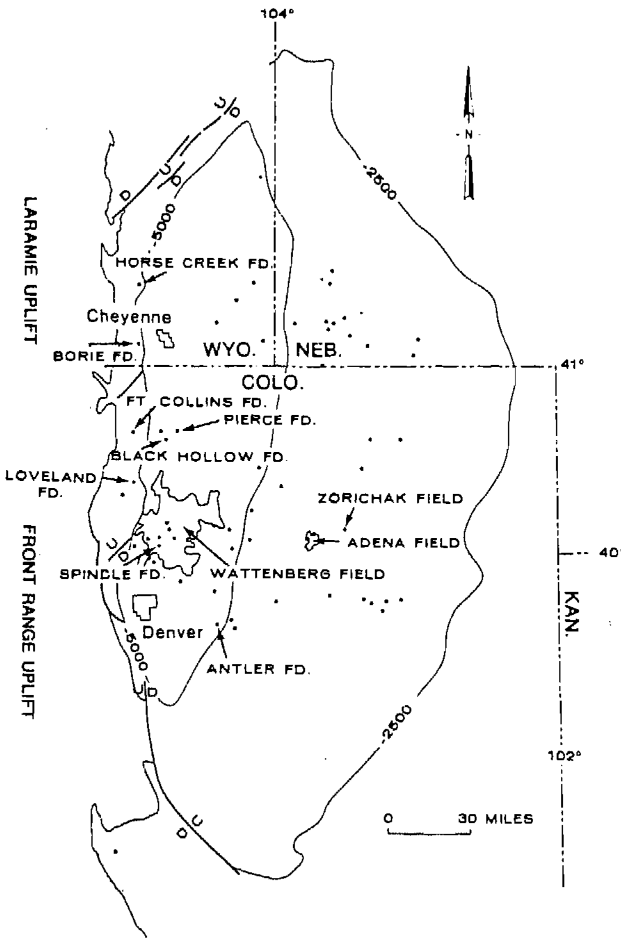

Fig. 1 — Precambrian basement structure contour map of the Denver basin showing oil sample localities (contours are feet below sea level).

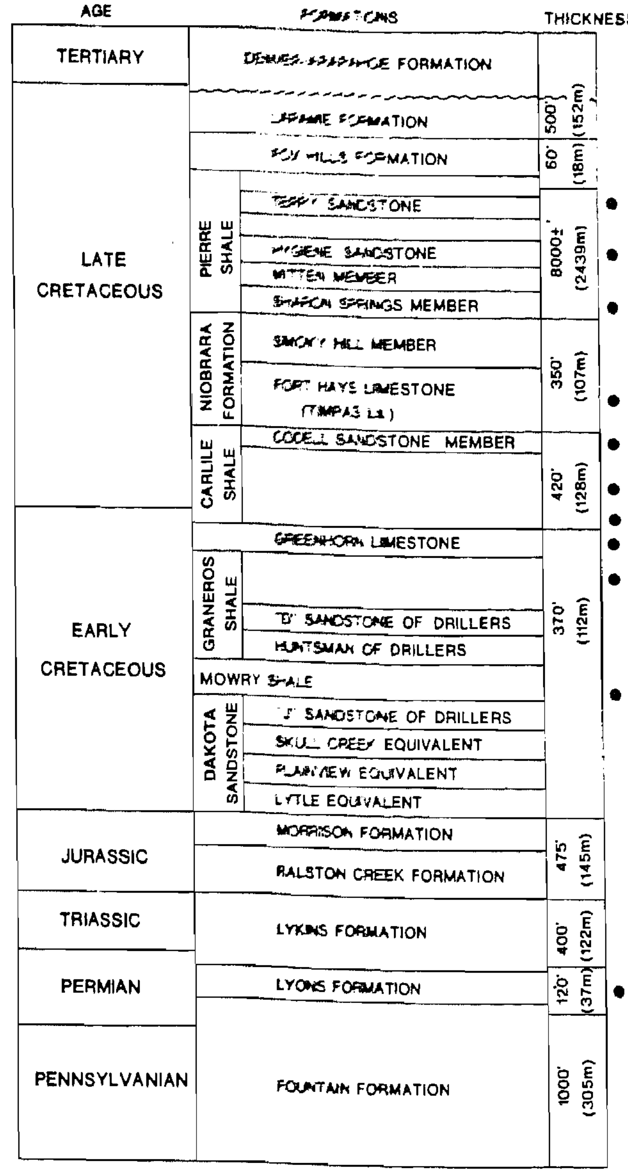

Fig. 2 — Generalized stratigraphic column, Front Range area. Dots indicate units which have oil production. (Modified from Weimer, 1973)

basin is located between Denver and Cheyenne, where the Precambrian basement reaches a maximum depth below sea level of about 7,000 feet (2,134 m). The Precambrian is overlain in this area by a 13,000-foot (3,962 m) -thick sedimentary sequence (Fig. 2).

During the early Paleozoic the area of the present-day Denver basin was predominantly a marine shelf; it was subsequently uplifted during the mid-Paleozoic exposing the older rocks to erosion. Mississippian and Pennsylvanian sedimentary units deposited on top of this unconformity consist of marine limestones and shales with lesser amounts of detrital alluvial deposits (Martin, 1965). There is no oil or gas production from the Mississippian or Pennsylvanian in the deeper part of the basin, although some oil shows and minor production have occurred in the Pennsylvanian in the southeast part of the basin (Martin, 1965).

The Permian section consists of a variety of detrital, carbonate, and evaporite deposits. The Permian Lyons Sandstone, which is interpreted to be eolian in origin (Walker and Harms, 1972) at the type locality and fluvial farther to the south (Weimer and Land, 1972), produces in the deep part of the basin between Denver and Cheyenne and could be an important target for future exploration.

The Triassic and Jurassic rocks consist of fluvial, orange-red sandstones and red shales with gypsum stringers and marine mudstones, evaporites, and limestones overlain by Upper Jurassic coastal, flood- and alluvial-plain deposits of the Morrison Formation (Martin, 1965). Although there has been at least one minor oil discovery in the Morrison Formation, neither the Triassic nor Jurassic has significant oil or gas production.

Most of the Denver basin oil and gas production occurs in Cretaceous rocks that are approximately 10,000 feet (3049 m) thick in the deep part of the basin near the Central Front Range and consist mostly of deltaic and marine detrital units (Dunn, 1959; Waage, 1959; Martin, 1965; Krutak, 1970; Weimer and Land, 1972; Weimer, 1973). Although oil and gas are produced from a number of Cretaceous reservoirs (Fig. 2), the Lower Cretaceous "D" and "J" sandstones account for more than 90 percent of the total oil and gas production of the basin. The "J" sandstone is generally interpreted as a deltaic sand deposited by a large westerly to northwesterly prograding delta and a smaller northeasterly prograding delta (Fig. 3) which were deposited adjacent to the northwesterly regressing Early Cretaceous western interior seaway (Haun, 1963; Martin, 1965; Weimer, 1970; MacKenzie, 1971; Geyer, 1972; Weimer and Land, 1972; Matuszczak, 1973). As the sea continued to regress, the deltas on either side of the basin may have merged to form a continuous sandstone network (Martin, 1965).

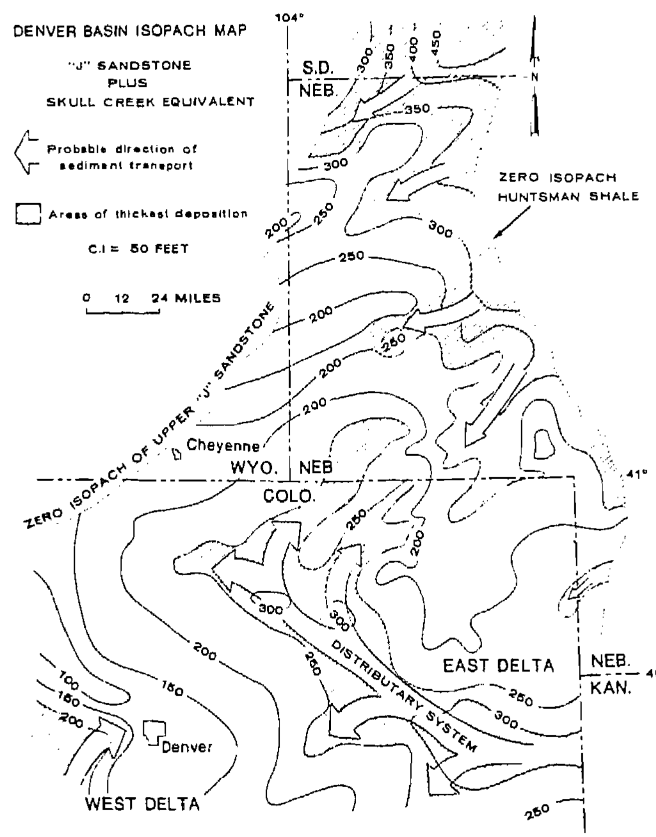

Fig. 3 — Isopach map of "J" Sandstone and Skull Creek equivalent. In addition to the main deltas in Colorado there are several well-defined smaller deltas in Nebraska (modified from Haun, 1963, and Matuszczak, 1973).

The Huntsman Shale was deposited over the "J" sandstone during "an extensive but geologically brief marine incursion" (Geyer, 1972, p. 34). The Mowry Shale was deposited immediately above the "J" sandstone and is overlain by the Huntsman which extends about 75 miles (23 km) south of the zero isopach of the Mowry Shale (Haun, 1963). The overlying "D" sandstone is generally thought to be a fluvial-interfluvial deposit that formed as a coastal plain deposit adjacent to the shoreline (Geyer, 1972; Martin, 1965), although various portions of the "D," similar to the "J," may also be deltaic (Haun, 1963).

Minor oil production occurs in the overlying Graneros Shale, the Greenhorn Limestone, and the Codell Sandstone Member of the Carlile Shale. The overlying Niobrara Formation has oil production in both the Fort Hays Limestone and the Smoky Hill Members. Niobrara oil production is limited to the west flank of the basin.

The Niobrara Formation is overlain by the Pierre Shale which is about 8,000 feet (2439 m) thick along the basin axis. The Pierre consists mostly of marine shale with two important oil and gas-producing sandstones — the Hygiene and Terry Sandstone Members.

CRUDE-OIL CHARACTERIZATION

Seventy-seven oil samples, representing all of the major producing formations in the Denver basin, were collected for geochemical analysis according to the procedure outlined in Figure 4, although not every sample was analyzed by all of the techniques shown. The purpose of these analyses was to determine which oils are genetically related, i.e., which have been derived from a common source rock or source interval. Samples were taken from various fields over the entire basin to provide extensive geographic sample coverage, and in some cases two or more samples were taken from the same field.

Figure 5 shows typical gas chromatograms of the C_{15} + saturated hydrocarbon fractions for the Cretaceous "D," "J," Terry, Fort Hays, and Lytle equivalent oils and the Permian Lyons oil. It is apparent from Figure 5 that the oils produced from the five Cretaceous reservoirs cannot be distinguished by this analysis. The Fort Hays and Lytle equivalent samples were not evaporated during preparation for GC analysis so they contain more of the light hydrocarbons (C_{10}-C_{15}) than the other samples shown in Figure 5. It is important to note the GC analyses of samples collected basinwide show that the Cretaceous oils have similar hydrocarbon distributions throughout the basin.

The Lyons oil has a unique C_{15} + hydrocarbon distribution (Fig. 5), which is easily distinguishable from distributions of the Cretaceous oils. The major difference between the Lyons and the Cretaceous oils is the relatively greater abundance of branched compounds compared to the straight-chained isomers in the Lyons. The branched-chain compounds are represented in the chromatograms by peaks which occur adjacent to the normal alkane peaks (compare Fig. 5g and 5h).

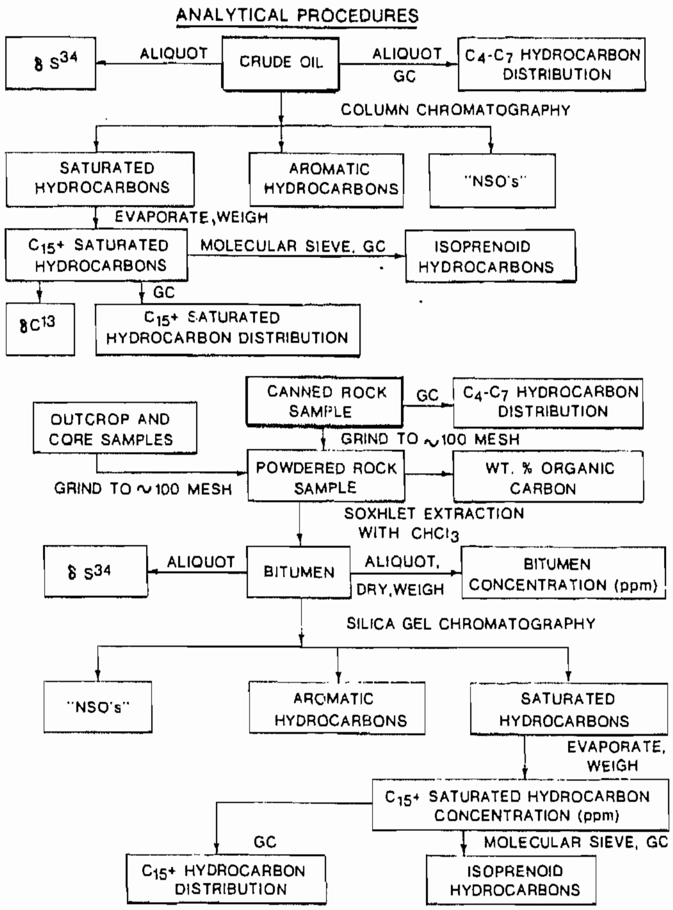

Fig. 4 — General analytical procedures used for analysis of crude oils and rocks. GC (gas chromatography); NSO (nitrogen-sulfur-oxygen-containing compounds); ppm (parts per million).

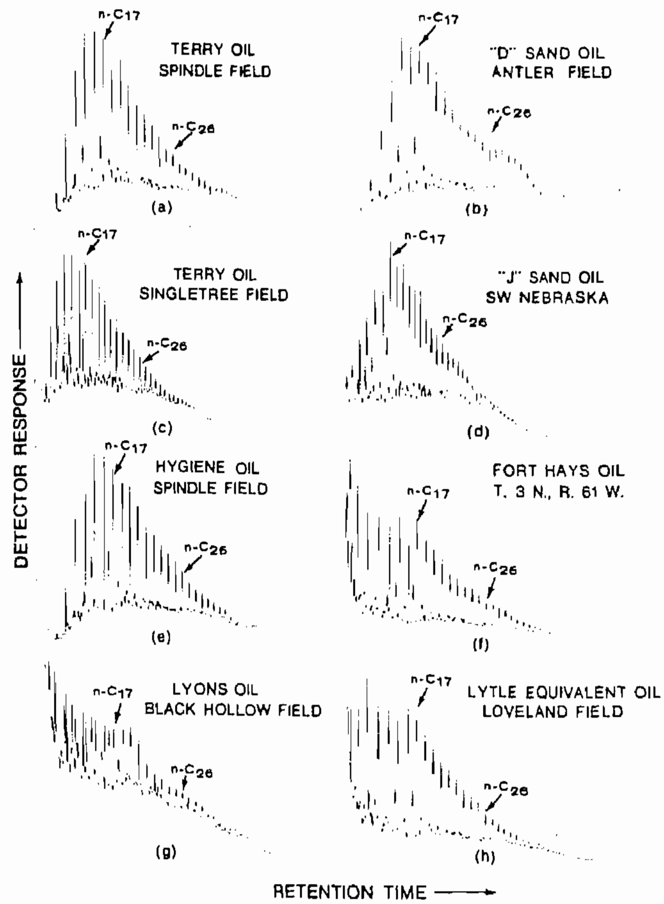

Fig. 5 — Gas chromatograms of Denver basin oils. All samples except the Lytle equivalent (5h), Fort Hays (5f), and Lyons (5g) were evaporated during laboratory preparation for GC resulting in loss of lower carbon number molecules ($<n-C_{15}$). The positions of normal heptadecane ($n-C_{17}$) and normal hexacosane ($n-26$) are indicated on each of the chromatograms. Peak identifications were made by comparing retention times with n-alkane standards.

A more detailed and more diagnostic characterization of oils can be made by comparing their gasoline-range hydrocarbon compositions. Different oil-types — that is, oils derived from different source rocks, and hence different parent organic matter — may contain varying relative amounts of compounds in the C_4-C_7 range because of differences in the chemical composition of the organic matter from which they were derived. Figure 6 shows a three-component plot of normalized percentages of 14 straight-chain, branched, and cyclic C_7 hydrocarbon compounds. This comparison, similar to results of the C_{15+} saturated hydrocarbon gas chromatographic analyses, shows that all of the Cretaceous oils are one oil-type whereas the Permian Lyons oil is a distinctly different oil-type.

A compound-by-compound comparison of the C_4-C_7 components was made using nine gasoline-range hydrocarbon ratios (Table 1). Each ratio compares compounds having similar boiling points so that the physical-chemical effects of secondary processes such as migration and sampling procedure are not confused with primary differences due to the chemical nature of the source material. Figure 7 shows these nine ratios plotted for Terry, Hygiene, "D," "J," and Lyons oils. The Cretaceous Terry, Hygiene, "D," and "J" oils are quite similar. In some cases the variation within one reservoir is as great as between different reservoirs for this analysis. This implies that the Cretaceous oils shown in Figure 7 have been derived from a common source rock; or that different source beds have generated similar oils. In contrast, the Lyons oil appears to be quite different from Cretaceous oils using this comparison.

The iso/cyclic saturated hydrocarbon fractions of 46 Denver basin oils were analyzed to determine their relative concen-

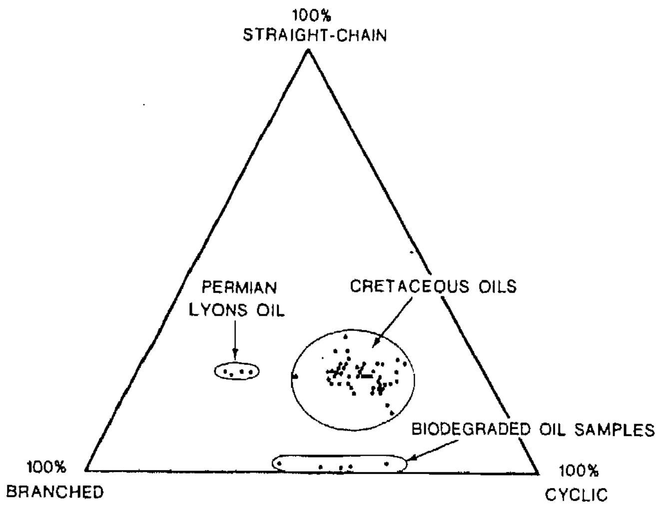

Fig. 6 — C_7 hydrocarbon distribution for Denver basin oils. The samples which plot at the bottom of the ternary diagram (i.e., low normals) are low API-gravity oils (20°-25°) from shallow reservoirs on the east flank of the basin. These oils have probably been biodegraded.

Table 1. — C_4-C_7 Hydrocarbon Component-Pairs Compared for Correlation of Oil Types (modified from Erdman and Morris, 1974).

Component-Pairs	Boiling Points °C
1. iso-butane/n-butane	-11.7/ -0.5
2. iso-pentane/n-pentane	27.9/ 36.1
3. cyclopentane/2,3-dimethylbutane	49.3/ 58.0
4. 2-methylpentane/3-methylpentane	60.3/ 63.3
5. n-hexane/methylcyclopentane	68.7/ 71.8
6. 2-methylhexane/2,3-dimethylpentane	90.1/ 89.8
7. 3-methylhexane/1,1-dimethylcyclopentane	91.9/ 87.9
8. 1-trans-3-dimethylcyclopentane/1-trans-2-dimethylcyclopentane	91.7/ 91.8
9. n-heptane/methylcyclohexane	98.4/100.9

trations of C_{15}-C_{20} isoprenoids. Figure 8 compares the average relative amounts of the C_{15}-C_{20} isoprenoids for Cretaceous oils and Permian Lyons oil. The Lyons oil is unusual in that it has a much lower relative concentration of pristane (iC_{19}) than do the Cretaceous oils. Without exception, in all Cretaceous oils analyzed pristane is more abundant than either iC_{18} or phytane (iC_{20}). For 30 samples of Cretaceous oils collected from throughout the basin, pristane represents an average of 31.13 ($\sigma = 1.90$) percent of the C_{15}-C_{20} isoprenoid fraction and phytane constitutes an average of 16.26 ($\sigma = 1.85$) percent of this fraction. The average pristane-to-phytane ratio is 1.91 for Cretaceous oils and 0.83 for the four samples of Lyons oil

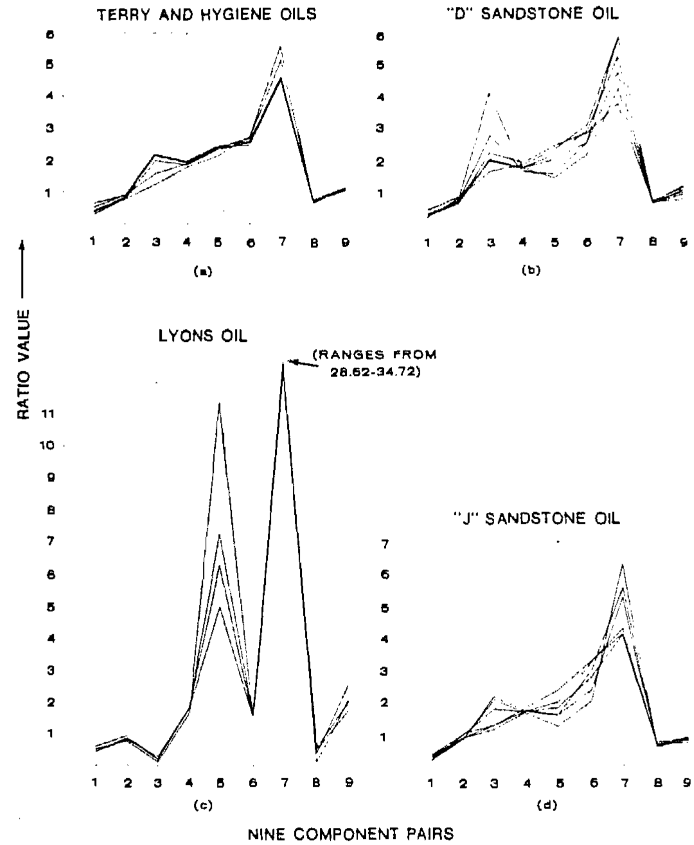

Fig. 7 — Gasoline-range (C_4-C_7) hydrocarbon-composition ratios for Denver basin oils. In addition to the high values for ratios of component-pairs 5 and 7 for the Lyons oil, note the very low component pair ratio of 3, which is indicative of the high amount of branched compounds relative to cyclics for the Lyons oil.

analyzed. Also, the Lyons oil has a greater relative concentration of iC_{15} than do the Cretaceous oils (Fig. 8).

Two samples of oil from the Fort Hays Limestone Member of the Niobrara Formation (Fig. 2) were analyzed for C_{15}-C_{20} isoprenoid distribution and are compositionally similar to the other Cretaceous oils (Fig. 8).

These comparisons again support the hypothesis that the Cretaceous oils have all been derived from the same source rock or source interval and the Lyons oil is genetically unrelated to the Cretaceous oils. Two noteworthy exceptions to this pattern are the "J" oils from the Borie and Horse Creek fields of southeast Wyoming (Fig. 1). Both of these oils have higher pristane/phytane ratios than the other Cretaceous oils examined, and they are the only two oils examined which have iC_{18}/phytane ratios less than one (Fig. 8).

Carbon isotope ratios have been used in other basins to dif-

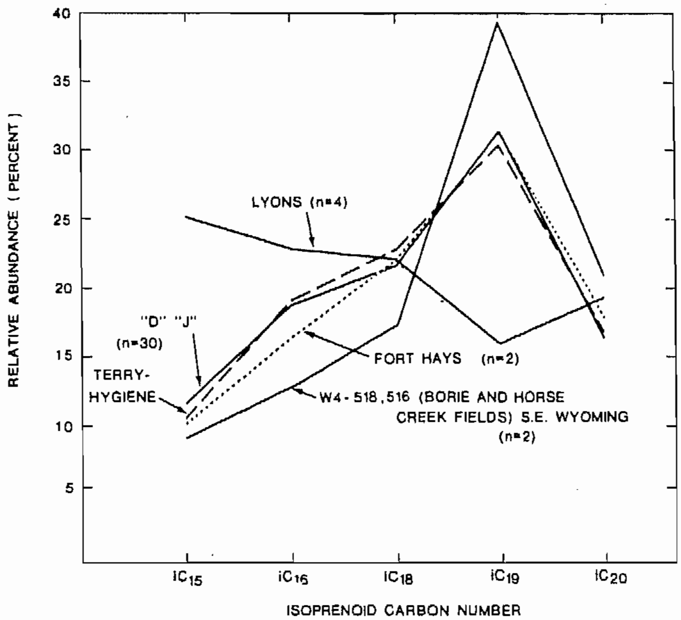

Fig. 8 — C_{15}-C_{20} isoprenoid distribution for Denver basin oils; n, number of samples.

ferentiate oil families (Williams, 1974; Koons, et al, 1974). The carbon isotopic composition of the C_{15+} saturated hydrocarbon fractions of Denver basin oils are given in Table 2. The values are reported as per mil deviations relative to the Chicago PDB standard. The δC^{13} values of Terry-Hygiene oils range from −27.8°/oo to −28.3°/oo with an average value of −28.1°/oo, compared to a range from −28.0°/oo to −29.0°/oo and an average of −28.6°/oo for "D" - "J" reservoirs. The Lyons oil has an average δC^{13} of −28.3°/oo. Since the variation within oils from a particular reservoir is as great as the variation between reservoirs, carbon isotopes cannot be used to distinguish oil-types in the Denver basin. This emphasizes the importance of a multi-parameter approach in oil family studies.

Table 2. — Stable Carbon Isotope Composition of Saturated Hydrocarbon Fractions of Oils.

Reservoir	Avg. δC^{13} PDB	Range of Values
Terry and Hygiene	−28.1°/oo	−27.8°/oo to −28.3°/oo
"D" and "J"	−28.6°/oo	−28.0°/oo to −29.0°/oo
Lyons	−28.3°/oo	−28.1°/oo to −28.8°/oo

IDENTIFICATION OF SOURCE BEDS

The crude-oil characterization showed two major oil-types in the Denver basin — the Permian Lyons oil and the Cretaceous oils from the "J," "D," Hygiene, and Terry reservoirs. On the basis of similar hydrocarbon composition alone, the oil produced from the Fort Hays Limestone Member of the Niobrara Formation could be considered the same oil-type as that produced from the other Cretaceous reservoirs. Less important producing intervals, such as the Pierre Shale and Niobrara fractured reservoirs, the Greenhorn Limestone, and the Graneros Shale, are not included in the present study. Even though the Lyons Sandstone and the Lower Cretaceous reservoirs are separated vertically by as little as about 900 feet (274 m) in the central Front Range area (Weimer, 1973), no evidence was found for mixing of the two oil-types.

The same techniques (Fig. 4) used to identify oil families were applied to the identification of source beds. The source-rock evaluation was carried out within both a stratigraphic and a geographic framework. Cretaceous shale samples were obtained from outcrops, canned cuttings, and cores to provide good stratigraphic and geographic sample coverage (Fig. 9). To determine which units are potential source rocks, the entire Cretaceous section was sampled from the shale above the Terry Sandstone Member down to the Skull Creek equivalent, although not at each sample locality. In order to be considered a probable source rock, two requirements must be fulfilled. First, a rock must have sufficient overall organic richness[1] to have expelled an economically significant accumulation of petroleum, and second, the molecular distribution of hydrocarbons must be similar to that of the crude oils examined. In general, this means that the compositional differences between a potential source rock and the associated oils must be no greater than the range of variation observed for the oils themselves.

Samples of Cretaceous shales were analyzed for organic carbon and extracted with chloroform to determine their overall organic richness. The results of these analyses are given in Table 3. Each of the stratigraphic units that was sampled contained at least some samples which are rich enough to be considered favorable potential source rocks of petroleum. The Skull Creek equivalent contains the leanest samples overall of any of the formations studied (average hydrocarbon concentration = 203 ppm). With the exception of two samples — PS-29 and Pull-6 — the Pierre Shale is not exceptionally organic-rich. However, both the Skull Creek equivalent and the Pierre Shale contain sufficient quantities of hydrocarbons to be considered as potential petroleum source rocks, and neither can be eliminated on the basis of insufficient organic richness. By comparison, other Cretaceous units have much more favorable source potential. The Huntsman (of drillers), Mowry, Greenhorn, Graneros, Carlile, and Niobrara all contain above-average amounts of hydrocarbons and have excellent petroleum source potential using that measurement.

[1] There is no general agreement among geochemists as to exactly what the minimum amount of organic matter required for an effective source rock is, because the mechanism and efficiency of primary migration are not understood. The criterion used in this paper is that a source rock must have above-average amounts of organic matter according to Hunt (1961).

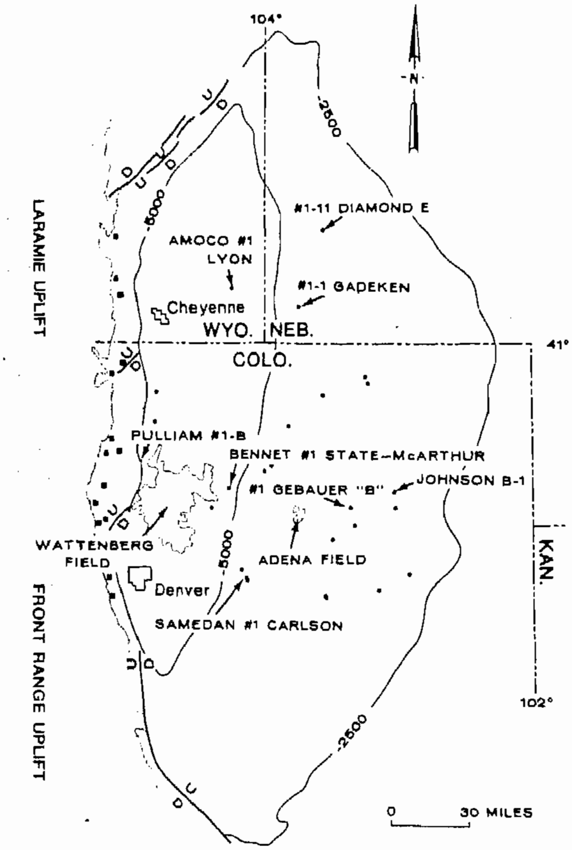

Fig. 9 — Map showing rock-sample localities. Dots indicate well samples (cores or cuttings); squares indicate outcrop samples.

In general, the samples collected from outcrops contain lower amounts of organic matter than do equivalent subsurface samples (Table 3). The organic matter in the outcrop samples has probably been depleted by surface weathering (Clayton and Swetland, 1976).

It is important to note that these organic-rich intervals are not restricted to the basin axis. The equivalent stratigraphic units on the east flank of the basin are similarly organic-rich. For example, samples GEB-1B, BA-6819, and SK (Table 3), taken from the Plains #1 Gebauer "B," Bennett #1 State - McArthur, and Samedan #1 Carlson wells respectively (Fig. 9), all have above-average organic richness (Hunt, 1961), similar to their basinward stratigraphic equivalents.

Tissot and others (1974) showed that petroleum-generation is influenced not only by the diagenetic history of a potential source-rock but also by the type of organic matter contained in the rock. Organic matter which is hydrogen-deficient may generate gas, but is unlikely to generate significant quantities of hydrocarbons even under optimum thermal conditions. Therefore, organic richness measurements alone cannot be used to estimate the petroleum-generating capacity of a potential source rock unless the type of organic matter is known. The above average amounts of solvent-extractable hydrocarbons contained in many of the Denver basin samples (Table 3) indicate that oil-prone organic matter is present and that significant hydrocarbon-generation has occurred.

Figure 10 shows a comparison of the gasoline-range (C_4-C_7) hydrocarbon composition of well cuttings from the Pulliam #1-B well (location shown in Fig. 9) compared with the average value for the Cretaceous oils. The closest match between the average oil values and the rock cuttings occurs in the interval containing the Greenhorn, Graneros, upper part of the Carlile, and Huntsman units which suggests that the Cretaceous oils studied have been derived from this 500 to 600 foot (152- to 183-m) thick organic-rich interval.

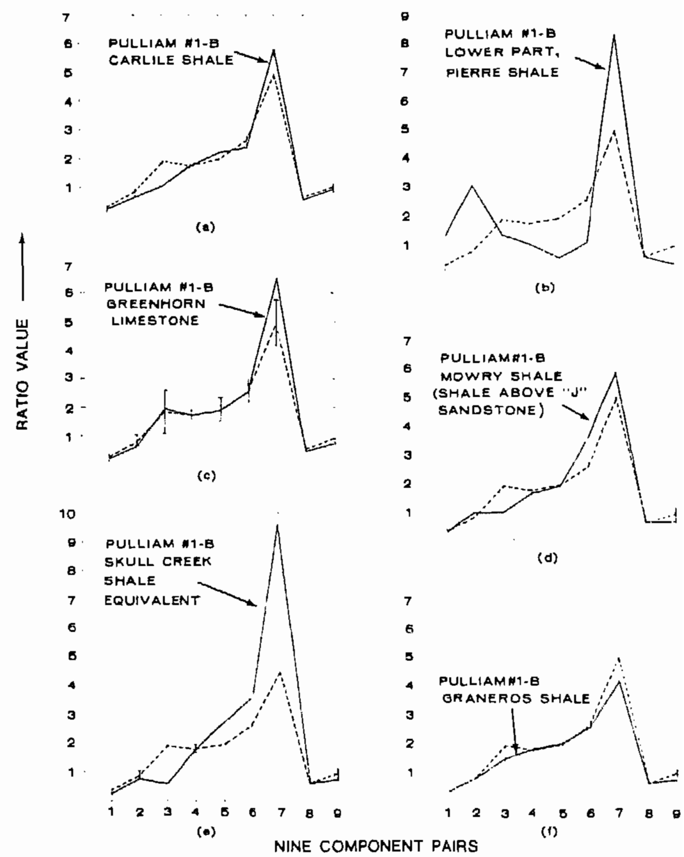

Fig. 10 — Comparison of gasoline-range (C_4-C_7) hydrocarbon composition for Cretaceous rocks from the Pulliam #1-B well (T.5N., R. 68W.) and Cretaceous oils. Bars are one standard deviation. Dashed line represents average values for all Cretaceous oils from "J," "D," Terry, and Hygiene reservoirs.

From a geological standpoint the lower part of the Pierre and Skull Creek equivalent could also be considered possible source rocks since they are immediately overlain by the oil-producing

Table 3. Geochemical Data for Rocks

Sample Number	Stratigraphic Unit	Type of Sample	Bitumen (ppm)	Organic Carbon (wt. %)	Total C_{15}+ Hydrc. (ppm)	$\frac{HC}{Org. C} \times 100$
LK-26	upper Pierre Sh.	outcrop	157	0.7	55	0.8
PS-29	lower Pierre Sh.	outcrop	2404	3.1	2000	6.5
PS-33	lower Pierre Sh.	outcrop	524	2.9	162	0.6
PS-39	lower Pierre Sh.	outcrop	603	3.6	124	0.3
PS-28	lower Pierre Sh.	outcrop	441	1.0	302	3.0
PS-50	upper Pierre Sh.	outcrop	88	0.5	25	0.5
Pull-6	lower Pierre Sh.	cuttings	1067	1.5	857	5.7
Pull-7	lower Pierre Sh.	cuttings	197	1.1	147	1.3
Pull-8	lower Pierre Sh.	cuttings	—	0.6	—	—
JC-6	Niobrara Fm.	outcrop	2922	3.4	1206	3.0
PS-30	Niobrara Fm.	outcrop	1675	2.1	1562	7.4
L-7115	Niobrara Fm.	cuttings	1381	1.8	751	4.2
PS-32	Carlile Sh.	outcrop	670	0.9	487	5.4
L-7305	Carlile Sh.	cuttings	1783	2.8	981	3.5
Pull-5	Carlile Sh.	cuttings	1444	1.2	1043	8.7
Pull-4	Greenhorn Ls.	cuttings	754	1.5	582	1.3
PS-31	Graneros Sh.	outcrop	2357	3.5	2056	5.9
PS-34	Graneros Sh.	outcrop	1829	3.5	1146	3.3
PS-41	Graneros Sh.	outcrop	214	1.8	24	0.1
PS-42	Graneros Sh.	outcrop	236	1.1	20	0.2
Pull-3	Graneros Sh.	cuttings	2047	2.5	1635	6.5
L-7828	Graneros Sh.	core	1334	2.3	832	3.6
GEB-1B	Graneros Sh.	core	1230	3.6	776	2.2
SK	Huntsman (of drillers)	core	1618	2.6	1164	4.5
N1	Huntsman (of drillers)	core	240	1.0	143	1.4
C1	Huntsman (of drillers)	core	—	1.8	—	—
PS-44	Mowry Sh.	outcrop	509	2.3	146	0.6
PS-48	Mowry Sh.	outcrop	3813	2.8	2377	8.5
JC-9	Mowry Sh.	outcrop	543	1.8	328	1.8
L-7900	Mowry Sh.	core	2081	3.6	1627	4.5
PS-49	Skull Creek	outcrop	142	1.5	49	0.3
PS-37	Skull Creek	outcrop	441	1.2	53	0.4
PS-46	Skull Creek	outcrop	240	1.0	—	—
Pull-1	Skull Creek	cuttings	316	1.0	212	2.1
CH-7048	Skull Creek	core	512	2.2	294	1.3
CH-7029	Skull Creek	core	232	0.8	163	2.0
BA-6819	Skull Creek	core	321	2.5	446	1.8

Hygiene and "J" sandstone, respectively. However, both of these shales contain gasoline-range hydrocarbon distributions which are quite different from those of the Cretaceous oils and, therefore, are not likely source rocks (Fig. 10). It should be noted that the Pierre Shale samples analyzed were not collected from precisely the same area where Terry and Hygiene production occurs (Fig. 9). It is conceivable that the Pierre Shale in the producing area is geochemically different from either the Pulliam #1-B samples or the outcrop samples analyzed.

No sample of the Niobrara Formation was available from the Pulliam #1-B well for gasoline-range hydrocarbon analysis. However, analysis of the Niobrara from the Amoco #1 Lyon well located in southeast Wyoming (Fig. 9) revealed that it contains a gasoline-range hydrocarbon distribution which differs from the average value for the oils in much the same way that the value of the lower part of the Pierre Shale does (high values for ratio numbers 2, 3, and 7, low value for 5).

Preliminary sulfur isotope data indicate that the Niobrara Formation may be the source of the oil produced from both the Fort Hays Limestone and Smoky Hill Members. Although the Fort Hays and Smoky Hill oils have hydrocarbon compositions similar to those of other Cretaceous oils, they are isotopically lighter ($\delta S^{34} = -15.69$°/oo) than the average value for the other Cretaceous oils ($\delta S^{34} = -10.42$°/oo for 13 samples of "D," "J," Terry, and Hygiene oils) (Table 4). The chloroform extract of one rock sample from the Smoky Hill Member of the Niobrara Formation was analyzed, and it has a sulfur isotopic composition similar to the Niobrara Formation oils (Table 4). Additional samples of the Niobrara have been collected, and further work is in progress to better evaluate its source-rock qualities.

On the basis of overall organic richness and compositional

Table 4. — Sulfur Isotope Data for Oils and Rock Extracts. The data are given as per mil deviations relative to the Canon Diavlo standard.

Sample Identification	Number of Samples	Average $\delta^{34}S$ (Range)
Terry and Hygiene oil	7	−11.50°/oo (−9.72°/oo to −13.01°/oo)
"D" and "J" oil	6	− 9.17°/oo (−9.30°/oo to −10.27°/oo)
Niobrara oil		
Smoky Hill Mbr.	2	−15.69°/oo
Fort Hays Ls.	1	−15.15°/oo
Niobrara Rock Extract		
Smoky Hill Mbr.	1	−15.17°/oo
Lyons oil	1	−2.80°/oo

comparisons, the Carlile (including the Huntsman) -Greenhorn-Graneros-Mowry sequence is the **stratigraphic** interval which is the most likely source for the Cretaceous oils produced from the "J," "D," Terry, and Hygiene reservoirs. In order to determine the **geographic** distribution of source beds, Cretaceous shale samples from this same stratigraphic interval were collected from various parts of the basin. As noted previously, the Cretaceous shales basinwide contain above average amounts of organic carbon and extractable hydrocarbons. Therefore, no oil-source bed relationships in the Denver basin can be developed within a geographic framework on the basis of organic richness measurements alone. Instead, geographic variations in source rock potential are based on observed regional variation in compositional similarities or dissimilarities between Cretaceous shale samples from the Carlile (including the Huntsman)-Greenhorn-Graneros-Mowry interval and Cretaceous oils.

Figure 11a shows a comparison of the gasoline-range hydrocarbon composition of the upper part of the Graneros and the Huntsman shale from a well in southwest Nebraska (#1-1 Gadeken, T.14N., R.58W.) with the average values for 10 crude oils from the same area. The upper part of the Graneros and the Huntsman from this part of the basin have C_4-C_7 hydrocarbon distributions which are strikingly different from those of the oils, suggesting that the oils have migrated into this area from the deeper part of the basin. Also shown in Figure 11 is a comparison of an oil-stained sample from the #1-1 Gadeken well from the "J" sandstone. To check for oil-staining, a few chips of the sample were put into a test-tube with dicholoromethane and placed under ultraviolet light. A strong fluorescence was observed for the "J" sample; whereas, the

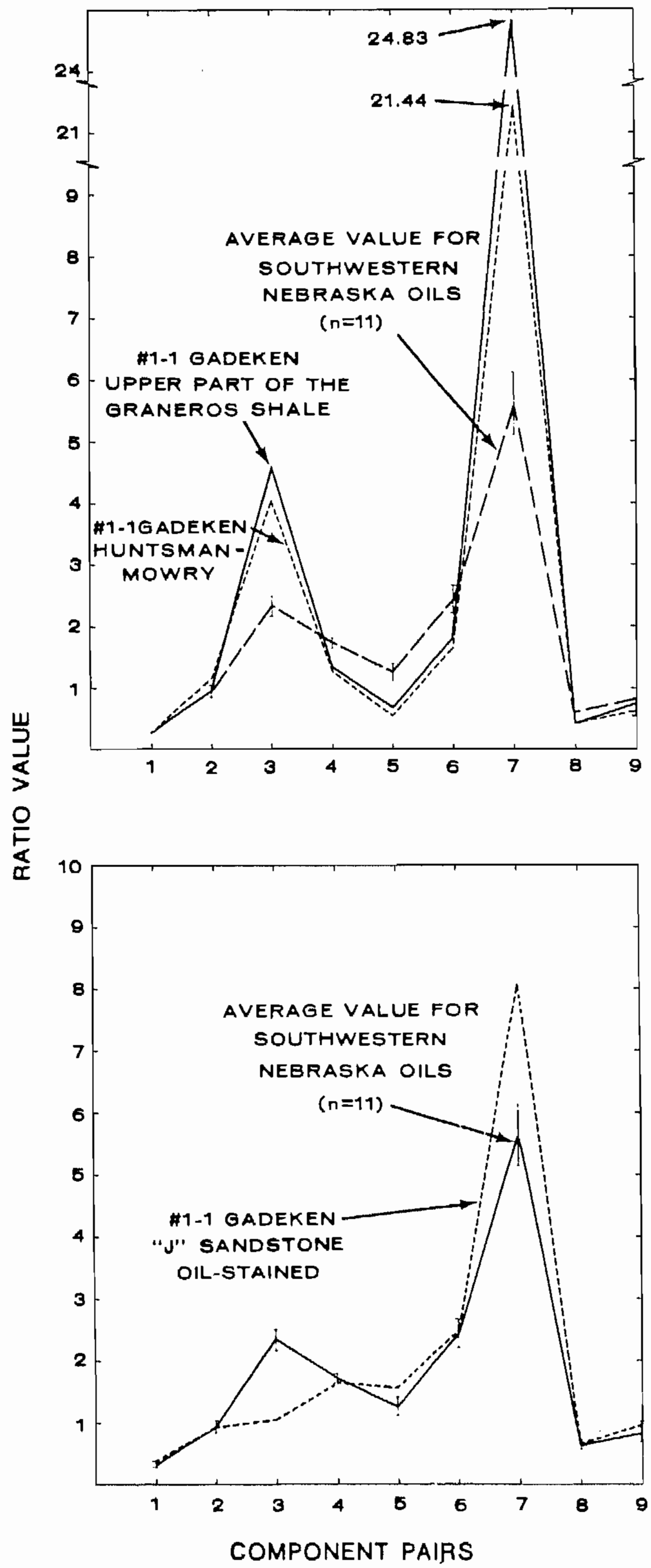

Fig. 11 — Comparison of gasoline-range hydrocarbon composition of well cutting samples from southwest Nebraska and average Nebraska oil composition. Bars are one standard deviation. Oil stained sample from "J" sandstone approximates average oil composition more closely than do adjacent shales.

shales immediately above and below this oil-stained interval did not show oil-staining (fluorescence). These comparisons show that the stained sample approximates the average crude-oil composition more closely than do the adjacent upper part of the Graneros and the Huntsman shale.

A comparison of the C_7 hydrocarbon composition of cuttings from two southwestern Nebraska wells (#1-1 Gadeken and #1-11 Diamond E, Fig. 9) and several Nebraska crude oils is illustrated in Figure 12. As shown in Figure 12, the oil-stained "J" sample from the Gadeken well has a C_7 hydrocarbon distribution similar to that of the crude oils. The other samples from the #1-1 Gadeken well (including the shales above and below the stained interval) and the #1-11 Diamond E well have C_7 distributions unlike those of the oils (Fig. 12). This provides further evidence that the hydrocarbons detected in the "J" interval of the Gadeken well were not derived from the adjacent shales but instead must have migrated laterally into this area from elsewhere in the basin.

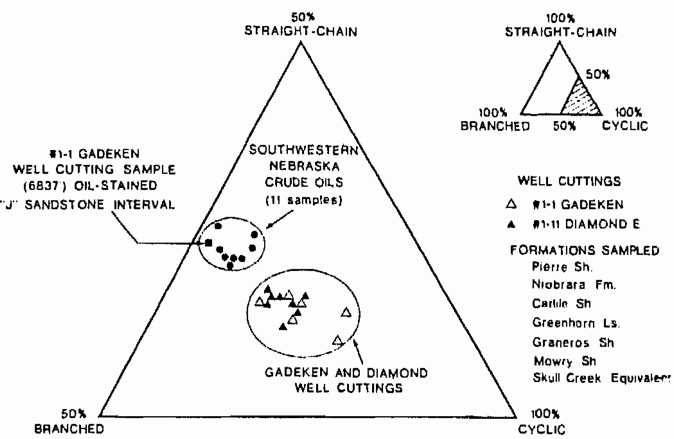

Fig. 12 — Comparison of C_7 hydrocarbon distributions — southwest Nebraska well cutting samples and nearby oils. Oil-stained rock sample from #1-1 Gadeken well has same composition as oils and different composition from shales above and below it from same well.

A comparison of the C_{18}-C_{20} isoprenoid composition of Cretaceous oils and selected rock extracts is shown in Figure 13. The C_{15} and C_{16} isoprenoids are preferentially lost during sample preparation of rock extracts and cannot be used in the comparison. The upper part of the Carlile, Greenhorn, and Huntsman samples from the Pulliam #1-B well plot in the same area as the 38 Cretaceous oil samples shown, while the upper part of the Graneros and the Huntsman from the #1-1 Diamond E well of southwest Nebraska fall outside the area of the oils. Also the lower part of the Pierre Shale from the Pulliam #1-B well differs markedly from the oils in that it has a much higher ratio of iC_{19} to iC_{18} and iC_{20} than do the oils (Fig. 13). A sample of the Huntsman shale from a core on the east flank of the basin (Johnson B-1, T.3N., R.51W.) plots outside the area of the ternary diagram shown in the enlargement in Figure 13. The upper part of the Graneros from a core on the east flank of the basin also plots outside the area of the oils (Fig. 13). Thus, only those samples from the basin axis area (Pulliam #1-B) have compositions similar to those of the oils.

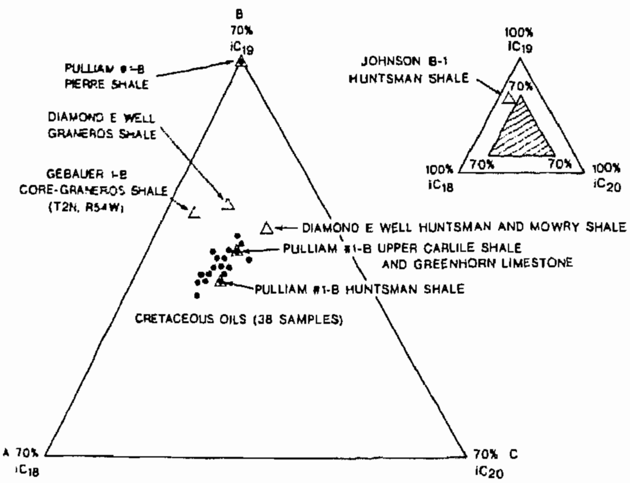

Fig. 13 — C_{18}-C_{20} isoprenoid composition of Cretaceous oils and rock extracts.

SUMMARY AND CONCLUSIONS

Geochemical analyses of possible source beds for the Cretaceous oil-type produced from the "J," "D," Terry, and Hygiene reservoirs has shown that the Carlile-Greenhorn-Graneros-Mowry interval is the most probable source. Regional source rock-crude oil correlations indicate that the Cretaceous shales on the east flank of the basin are geochemically dissimilar to Cretaceous crude oils from nearby fields indicating that the oils are not derived from local sources but migrated laterally into the area. The geochemically most favorable source beds are located along or near the basin axis north of Denver probably extending at least as far north as the Wyoming border. Additional data are needed to evaluate the source-rock potential of Cretaceous shales in southeastern Wyoming. As shown in Figure 1, several crude oil samples were collected from Wyoming and, in general, these oils are geochemically similar to other Cretaceous oils. However, as mentioned previously, the "J" sandstone oils from the Borie and Horse Creek fields are compositionally different from other Cretaceous oils, including those from other reservoirs in Wyoming.

For the easternmost oil occurrences to have been derived from this source area along the basin axis, extensive updip lateral migration on the order of 150 km is required. Similar migration distances have been suggested for Paleozoic oils in the Williston basin (Dow, 1974) and for oils presumably derived from black shale members of the Permian Phosphoria Formation of Wyoming, Idaho, and Utah (Claypool, et al, 1977). The Lower Cretaceous "J" sandstone is a possible lateral-migration pathway for Denver basin oils. This sandstone may form a continuous sandstone network connecting the reservoirs on the east flank with the source rocks located near the basin axis. Although the hydrodynamic gradient of the "J" is variable and the local direction of slope is dependent upon changes in thickness and permeability of the sandstone, the net movement in the basin is northeast (Haun, written comm., 1977). If a similar hydrodynamic condition existed at the time when primary migration occurred, it could have provided the driving force for long-distance secondary migration.

Detailed understanding of the three-dimensional geometry and regional distribution of sandstone bodies in the Denver basin can provide a better understanding of lateral-migration pathways. Because of the localized nature of effective source beds in the Denver basin and the evidence of extensive lateral migration, such an understanding of avenues of migration has more important application in exploration than do source-rock-evaluation studies. Relatively underdeveloped areas located between the source-bed area and the areas of present-day production are possible future areas for further Cretaceous oil discoveries. Matuszczak (1973) has suggested that a gas area, similar to Wattenberg, may exist in northernmost Colorado and southeastern Wyoming.

For the Terry and Hygiene oils produced along the basin axis to have been derived from the Carlile-Greenhorn-Graneros-Mowry interval more than 2,500 feet (914 m) of vertical migration is required. Faults common along the west flank of the basin may be possible migration pathways.

Characterization of the Lyons oil shows that it is different from Cretaceous oils and was probably derived from a different source bed. Its source bed has not yet been identified, but Permian carbonate units are possible sources. Further work is in progress to identify the source rock for the Lyons oil and to determine its regional extent and possible significance for future Permian exploration.

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