
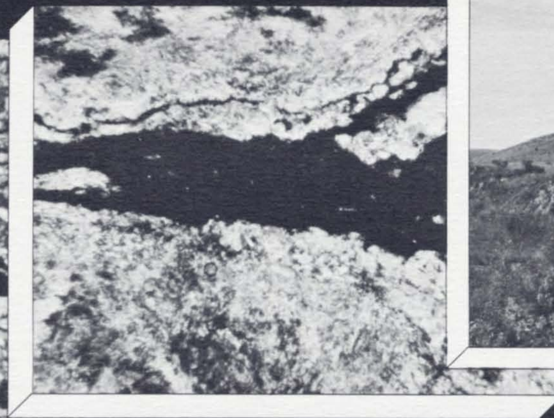
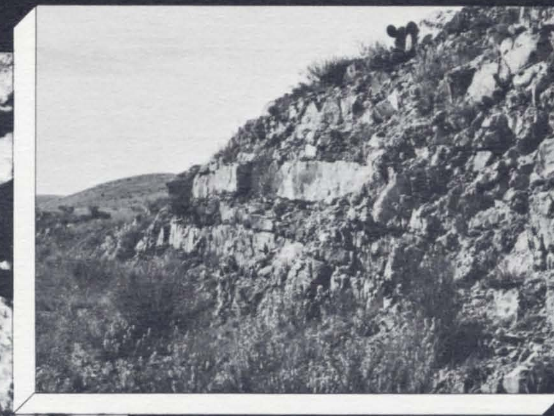
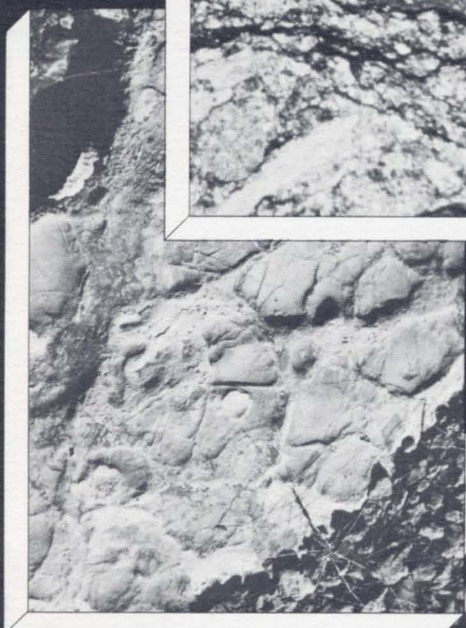

Report of Investigations No. 116

GENESIS AND EMPLACEMENT OF OIL IN THE SAN ANDRES FORMATION,

NORTHERN SHELF OF THE MIDLAND BASIN, TEXAS

Paul J. Ramondetta

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Bureau of Economic Geology
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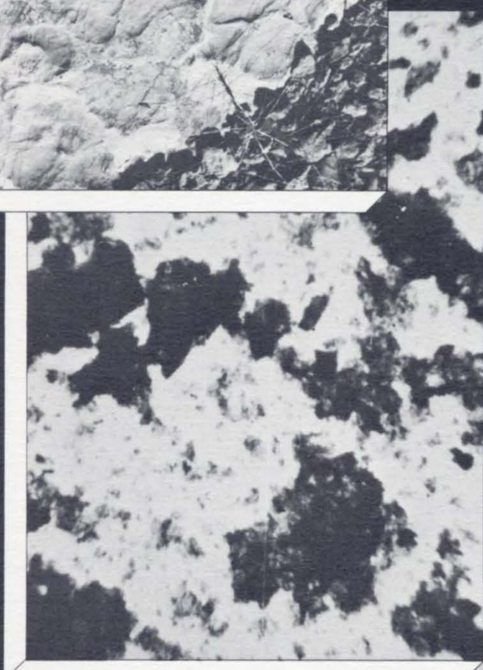

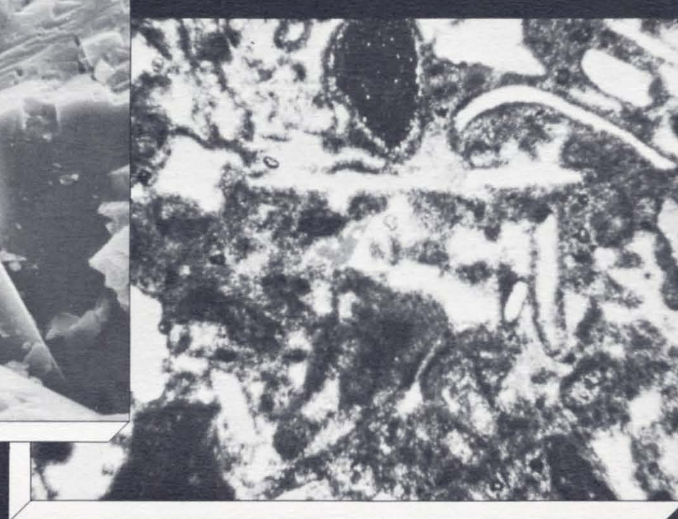

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Research funded by the
U. S. Department of Energy
under Contract Numbers
DE-AC97-79ET44614 and
DE-AC97-80ET46615

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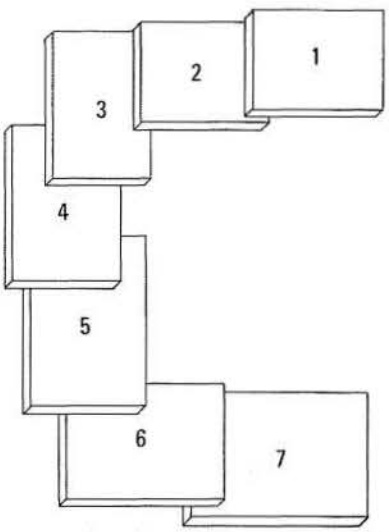

(1) Outcrop of San Andres rocks along the eastern flank of the Sacramento Mountains, New Mexico. (2) and (3) Concentrated organic matter adjacent to displacive nodules of anhydrite. (4) San Andres tidal flat deposit, eastern New Mexico. (5) Membranous plant debris (kerogen) from the Yellowhouse dolomite, southern Palo Duro Basin. (6) Photomicrograph (SEM) of dolomite rhombs from a San Andres pay zone, Cato field, New Mexico. (7) Replacement of skeletal debris and voids by secondary anhydrite.

Photographs 1 through 5 and 7 were taken by Paul J. Ramondetta; photograph 6 was taken by Holly Lanan.

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ABSTRACT

San Andres oil constitutes more than 80 percent of the total production from the Northern Shelf of the Midland Basin, Texas. The San Andres and Clear Fork carbonate rocks of the Northern Shelf contain sufficient amounts of lipid-rich organic material to rank them as potential petroleum source beds. Organic maturation of these rocks, as revealed from vitrinite reflectance and kerogen color, however, is not sufficient to have initiated catagenesis. Therefore, oil within Northern Shelf reservoirs was derived mostly from other sources.

San Andres oils have a common source, as evidenced by their remarkably uniform composition, which is revealed in liquid and gas chromatography, and Bartlesville Energy Technology Center (BETC) distillate analyses. Wolfcampian basinal clastics and dark argillaceous limestones of the northern Midland Basin are the most likely source rocks for this oil. Vertical expulsion of basinal oil through fractures into overlying shelf and shelf-margin carbonates has occurred along the Lower Permian Abo Reef trend. This reef hingeline is a narrow belt of shelf-margin buttresses ranging in age from Strawn to Clear Fork.

The trapping mechanism in the Northern Shelf is a combination of structural and facies control. Good reservoir conditions exist in San Andres strata that are draped and subsequently fractured over the subjacent shelf-margin buttress. Such fracturing should have enhanced conditions for development of secondary porosity during periods of subaerial exposure. Above the Abo Reef trend, a thick porous zone exists in the lower San Andres and upper Clear Fork Formations; shelfward, this porous zone grades into discrete porous layers resulting from cyclic sedimentation in shallow inner-shelf and sabkha environments. These Upper Permian carbonates tend to lose porosity in a northward (updip) direction, where conditions were more evaporitic. This updip change from porous to nonporous facies provides the porosity pinch-out in the vast Levelland - Slaughter - Cato trend of Texas and eastern New Mexico.

Late Cretaceous uplift in New Mexico exposed Permian strata, initiating a west-to-east flow of relatively fresh ground water. Passage of this meteoric water through San Andres and Clear Fork reservoirs caused downdip degradation and flushing of the oil. As a result of this ground-water movement, oil/water contacts tilt downdip 0.3° to 0.5°, and oil production is slightly offset downdip from local structural highs. The San Andres and Clear Fork oil was degraded by anaerobic sulfate-reducing bacteria, which resulted in an enrichment of sulfur and light aromatics and a slight depletion of saturated hydrocarbons. This biodegradation progressively increases updip, as evidenced by higher sulfur contents and lower API gravity.

INTRODUCTION

The purpose of this research was to determine the origin, emplacement, and entrapment of oil produced from the San Andres Formation on the Northern Shelf of the Midland Basin (fig. 1; table 1). The regional study area, shown in figure 1, includes the Northern Shelf, which is separated from the northern Midland Basin by the Abo Reef trend. This reef trend is a long narrow belt of dolomitized reef and carbonate bank deposits of Lower Permian age, stretching from Eddy County, New Mexico, to Hockley County, Texas (Sax and Stenzel, 1968). Shelf-margin deposits ranging in age from Strawn to Clear Fork are found within this belt (fig. 1). The San Andres shelf extends southward onto the Central Basin Platform of Texas, and westward into New Mexico, where it is called the Northwestern Shelf. This broad marine shelf extends northward into the Palo Duro Basin, where it grades into sabkha evaporites and terrigenous continental deposits.

During Late Pennsylvanian and Early Permian (Wolfcampian) time, when basinal subsidence reached a maximum, the Midland Basin was separated from the Palo Duro Basin by the Matador Arch and from the Delaware Basin by the Central Basin Platform; these structural uplifts are shown in figure 1. A smaller basin in northern Lea County, New Mexico, called the Tatum Basin, also existed at that time. By San Andres time, however, carbonate shelf environments had prograded over much of these basinal areas and only the Delaware and southern Midland Basins remained deep.

More than 80 percent of oil production in the Northern Shelf of the Midland Basin is from lower San Andres reservoirs (Texas Railroad Commission, 1979). Understanding the organic geochemistry of

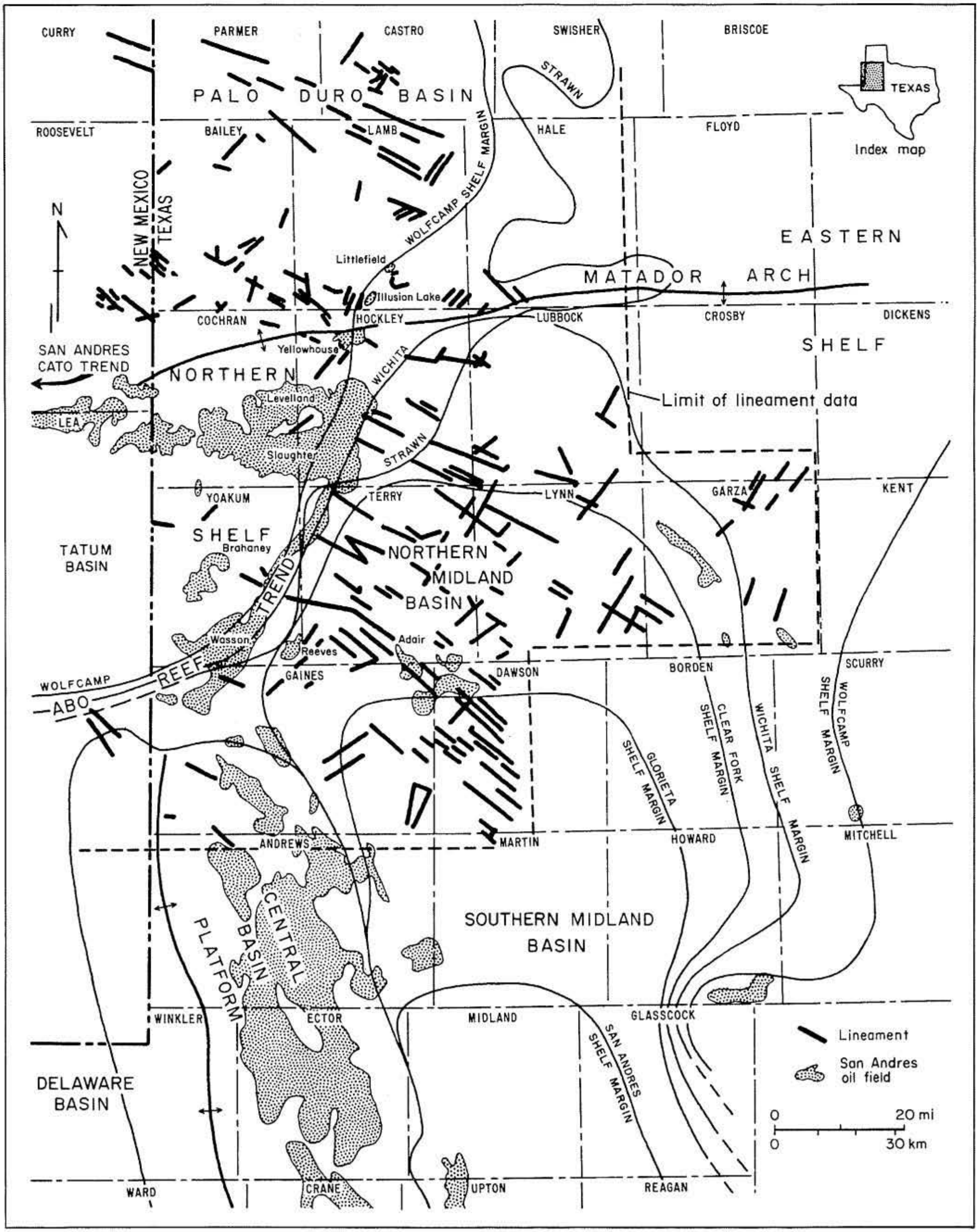


Figure 1. Map of study area showing San Andres oil production, shelf margins, and surface lineaments. Surface lineaments are from Finley and Gustavson (1981), and shelf margin positions are from J. H. Nicholson (personal communication, 1980).

Table 1. Stratigraphic chart, northern Midland Basin.

System	Series or group	Group or formation	
Tertiary		Ogallala	
Cretaceous			
Triassic		Dockum	
		Shelf Facies	*Basinal Facies*
Permian	Ochoa	Dewey Lake	Dewey Lake
		Rustler	Rustler
		Salado	Salado
	Guadalupe	Artesia	Delaware Sand
		Upper San Andres	
		Lower San Andres (Yellowhouse dolomite)	San Andres
	Leonard	Upper Clear Fork-Yeso-Glorieta	Upper Spraberry
		Lower Clear Fork	Lower Spraberry-Dean
		Wichita-Albany-Abo	
	Wolfcamp		
Pennsylvanian	Cisco		
	Canyon		
	Strawn		
	Bend		
Mississippian	Chester		
	Meramec		
	Osage		
	Kinderhook		
Devonian	Woodford		
	Post-Fusselman		
	Pre-Woodford		
Silurian	Fusselman		
Ordovician	Montoya		
	Simpson		
	Ellenburger		
Cambrian	Upper Cambrian		

this reservoir is important to continued exploration for hydrocarbons in the Midland and Palo Duro Basins.

San Andres carbonates, which currently produce hydrocarbons in the southern Palo Duro Basin just north of the Matador Arch, intertongue to the north with relatively massive salt facies (Presley, 1979). Assessing San Andres oil and gas potential is environmentally important in the Palo Duro Basin, where San Andres salt deposits are being evaluated as a possible nuclear waste repository. The presence of hydrocarbons within potential San Andres dolomite reservoirs in the Palo Duro Basin would preclude the use of the intercalated salt as a potential host rock for disposal of nuclear waste.

Three possible origins for San Andres oil on the Northern Shelf are considered herein: (1) in situ generation of hydrocarbons from kerogen in San Andres shelf carbonates, (2) lateral migration from basinal facies to the shelf reservoirs, and (3) vertical migration to shelf reservoirs from deeper and more mature source rocks.

A number of workers have addressed the general geologic development of the Permian Basin: King (1942), Jones (1953), Newell and others (1953), Flawn (1956), Galley (1958), and Hills (1970, 1972). A comprehensive evaluation of petroleum composition in the Permian Basin was made by Jones and Smith (1965).

METHODS

Various organo-geochemical techniques were used to assess source-rock potential for several stratigraphic intervals and to characterize the variety of crude oils in the region. The discussion below summarizes the methods used.

Total Organic Carbon

Total organic carbon (TOC) is essential in assessing source-rock potential because it measures organic richness of rock. Tissot and Welte (1978, p. 431) consider 0.5 percent TOC for clastic rocks and 0.4 percent TOC for carbonate rocks as the minimum values for establishing source-rock potential.

Samples from seven cores of the Yellowhouse dolomite—five from southern Lamb County, one from Swisher County, and one from Randall County, Texas—were analyzed for TOC by a commercial laboratory. The samples were dried,

Table 2. General comparison of various geothermal alteration indices.

Staplin's standard*	Geo-Strat, Inc.* (TAI†)	GeoChem Laboratories*	Vitrinite reflectance (%R_o)
-----	1.00	1	0.23
-----	1.50	1+	0.34
1.0	2.00	1+ to 2−	0.39
1.5	2.50	2−	0.45
2.3	3.00	2− to 2	0.51
-----	3.50	2	0.59
2.6	4.00	2 to 2+	0.72
-----	4.50	2+	0.90
3.0	5.00	2+ to 3−	0.95
3.3	5.50	3−	1.00
3.8	6.00	3− to 3	1.25
-----	6.50	3 to 3+	1.45
3.8-3.9	7.00	3+ to 4	2.25
4.5	7.50	4 to 4+	3.00-4.00
4.8	8.00	4+ to 5	5.00-7.00

*Subjective measurement based on kerogen color. All values approximate.
†Thermal alteration index
Source: Geo-Strat, Inc. (1980)

pulverized, and treated by hot and cold hydrochloric acid to remove carbonate carbon. Total organic carbon was then determined by measuring the evolved CO_2 in an induction furnace and a thermal conductivity cell.

Type of Organic Matter

Organic matter index (OMI) is the next step in assessing source-rock potential because it measures the quality of organic matter in rock. This analysis involves a visual inspection of kerogen, which is an insoluble organic material; it consists of varying amounts of amorphous sapropel, algal debris, spores, pollen, plant cuticle, woody tissue (vitrinite), and inert coaly material (Geo-Strat, Inc., 1980). Amorphous sapropel and algal debris are normally of marine origin (Tissot and Welte, 1978) and constitute prime petroleum source matter because of their richness in lipids. Lipids are hydrogen-rich biogenic materials that are generally insoluble in water but are soluble in fat solvents such as chloroform (Tissot and Welte, 1978, p. 34). Lipids are commonly considered to be a major precursor of petroleum.

Kerogen type was determined for samples from five cores from the Yellowhouse dolomite—four from southern Lamb County and one from Swisher County, Texas. The kerogen was extracted from the rock matrix by hydrochloric and hydrofluoric acids. The organic matter index was determined by assessing the relative abundance of six botanical entities: algae, amorphous debris, spores/pollen, cuticle/membranous debris, vitrinite or woody structured debris, and coaly debris or inert organic material. The OMI value increases from the algal to the coaly end of the spectrum; hence, a low OMI rating indicates more material favorable for petroleum generation than does a high OMI.

Kerogen Color

Kerogen color, which is the basis of the thermal alteration index (TAI), aids assessment of source-rock potential by measuring the degree of geothermal diagenesis of organic matter (Tissot and Welte, 1978, p. 450). Thermal alteration index values are based on kerogen color; for example, a lighter color indicates low values and less maturation (Geo-Strat, Inc., 1980).

The samples that were analyzed for OMI were also tested for TAI by visual inspection of the kerogen.

Vitrinite Reflectance

Vitrinite reflectance (R_o) is another measure of the degree of geothermal diagenesis of organic matter. Vitrinite reflectance equals the percentage of incoming light that is reflected from vitrinite particles (Tissot and Welte, 1978, p. 450). Although different types of organic matter require different temperatures to initiate petroleum generation, 150° F has generally been considered the minimum temperature necessary for oil generation if lipid-rich source material and adequate time are available (Pusey, 1973). This temperature corresponds approximately to an R_o of 0.5 and a TAI of 3.0, or an orange-brown kerogen. Table 2 compares TAI with R_o and other established maturation indices. These values can be integrated with kerogen type (OMI) within organic-rich rocks to determine source-rock potential; figure 2 is a cross plot showing such an integration.

The samples that underwent visual kerogen examination were also analyzed for R_o. Extracted vitrinite particles were air-dried in a vacuum chamber and then embedded in a bioplastic or epoxy plug. A high-resolution oil-immersion microscope calibrated with a known optical standard was used to measure the reflectivity of the vitrinite particles after they were finely polished. These measurements were summarized on individual histograms. An R_o value was interpreted for each sample using the histograms and the TAI data; anomalous values that may have resulted from contamination were excluded.

Composite samples of cuttings and other cores from Dutton (1980b) were analyzed for TOC, OMI, TAI, and R_o in the same way. The results are used in this report.

Analyses of Extracted C_{15+} Organic Matter

Analysis of extracted organic matter (EOM) aids the evaluation of source-rock potential by indicating the degree and type of hydrocarbon generation. The ratio of extracted organic matter to total organic carbon (EOM/TOC) can be used to determine whether the hydrocarbons present are indigenous or have migrated from another source (Baker, 1962). The relative concentrations of saturated hydrocarbons, aromatic hydrocarbons, and asphaltics provide a crude correlation between possible source rock and known petroleum in an area.

Composite samples from seven cores of the Yellowhouse dolomite—five from southern Lamb County and one each from Swisher and Randall Counties—were analyzed by a commercial laboratory. The samples were ground and then extracted using a chloroform solvent. An aliquot of extract was then stabilized by forced evaporation of the solvent at 40° C to determine the amount of extracted C_{15+} organic matter. The extract was passed through a packed methyl silicone column; stabilized extract residues were separated by liquid chromatography into the following fractions: saturated hydrocarbons by n-hexane elution, aromatic hydrocarbons by benzene elution, and asphaltic (nonhydrocarbon) compounds (Core Lab, 1980).

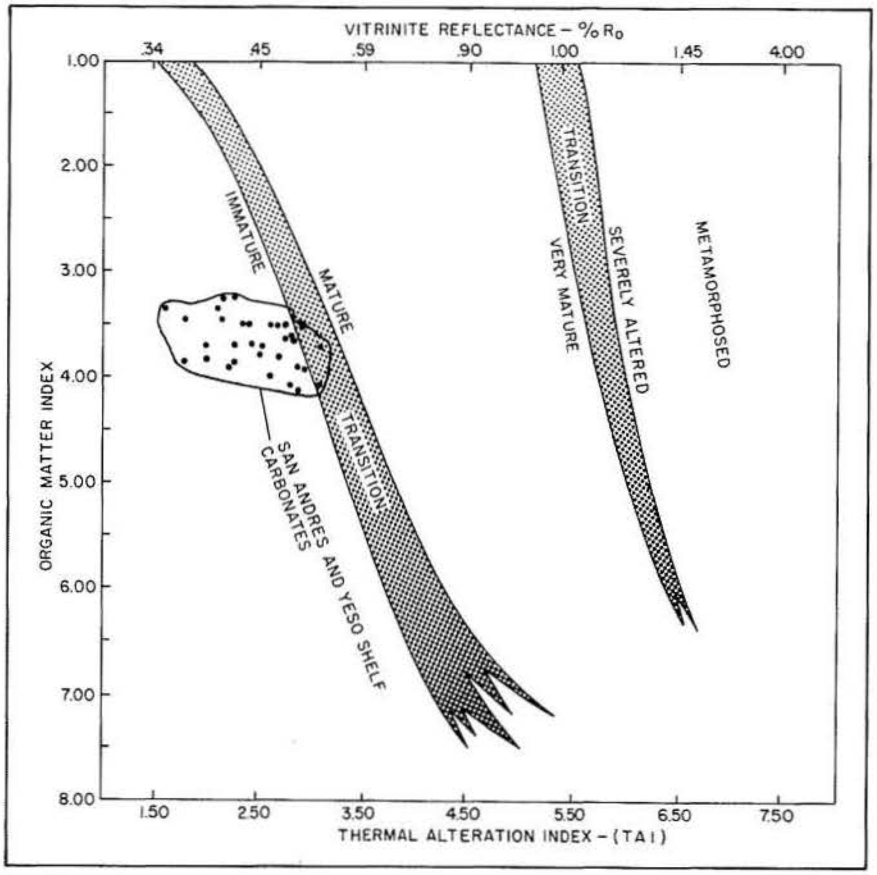


Figure 2. Cross plot comparing geothermal diagenetic criteria (from Geo-Strat, Inc., 1980).

Gas Chromatographic Analysis of Saturated C_{10+} Hydrocarbons

Molecular composition of the saturated C_{10+} hydrocarbons determined by gas chromatography (fig. 3) also aids assessment of source-rock potential. Molecular composition can correlate extracted hydrocarbons to known petroleum in an area by using the gas chromatographs as "fingerprints." Much information can be derived from chromatographs; the following discussion summarizes how this information was used.

(1) The carbon preference index (CPI) measures the dominance of even- or odd-carbon numbers in the C_{24} to C_{34} range (Bray and Evans, 1961). Hydrocarbons within this range are relatively resistant to degradation. The CPI number is determined by using the following equation:

$$\mathrm{CPI} = \frac{1}{2}\left[\frac{\sum_{25}^{33}\text{Odd n-alkanes}}{\sum_{26}^{34}\text{Even n-alkanes}} + \frac{\sum_{25}^{33}\text{Odd n-alkanes}}{\sum_{24}^{32}\text{Even n-alkanes}}\right]$$

Odd-carbon-number preference, or CPI numbers greater than 1.00, indicate thermal immaturity. Even-carbon-number preference, where CPI is less than 1.00, has been associated with immature organic matter originating in carbonate or evaporite rocks or both. Where CPI equals 1.00, the absence of an even or odd preference indicates thermal maturity (Tissot and Welte, 1978, p. 386).

(2) Dominance of light, normal alkane peaks relative to various branched and cyclic paraffins indicates maturity (Bailey and others, 1974; Milner, 1980). Strong background below the baseline of the gas chromatograph (fig. 3) indicates a high naphthene (cyclic paraffin) content. In turn, the high naphthene content implies immaturity, especially when the

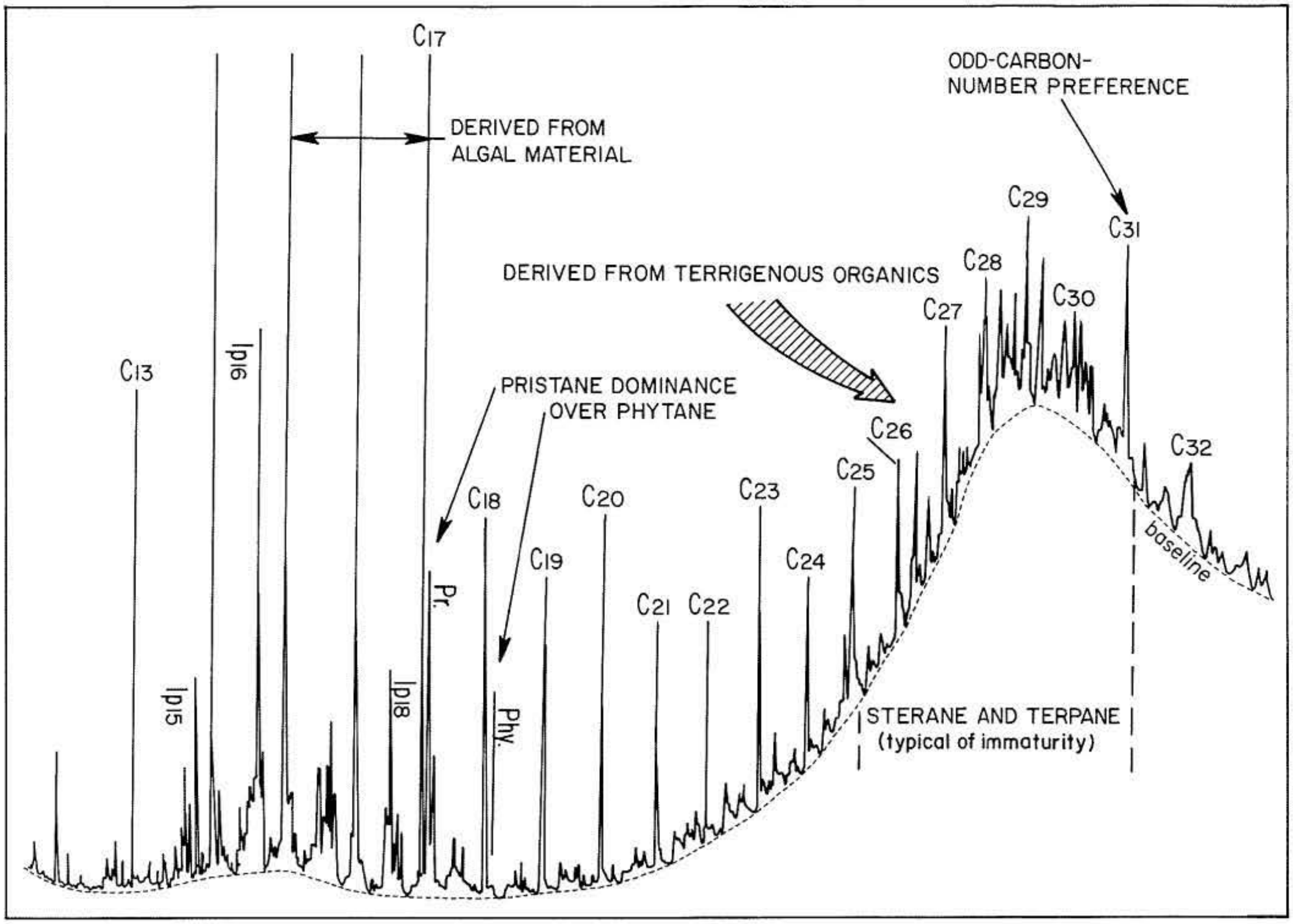


Figure 3. Gas chromatograph of C_{10+} saturated organic extract from Yellowhouse dolomite, DOE-Gruy Grabbe No. 1, Swisher County, Texas.

background is centered between C_{25} and C_{31}, indicating the presence of steranes and terpanes (GeoChem Laboratories, 1980, p. B-21). With increasing maturity, molecules become progressively lighter; this is true for both the normal alkanes and the branched and cyclic paraffins (Bailey and others, 1974; Milner, 1980).

(3) Higher concentrations of ip-C_{16} and ip-C_{18} (isoprenoids) compared with pristane and phytane indicate a possibility of increased thermal cracking, hence, catagenesis (Tissot and Welte, 1978, p. 387).

(4) Normal alkanes ranging from C_{12} to C_{20} are principal biogenic molecules in marine organic matter. They commonly exhibit a predominance of C_{15} and C_{17} n-alkanes, which are probably produced by decarboxylation of C_{16} and C_{18} fatty acids from algae (Tissot and Welte, 1978, p. 380). Terrigenous biogenic molecules include C_{25} to C_{33} n-alkanes with a preference for odd-numbered-carbon chains (Tissot and Welte, 1978, p. 380). It is therefore possible to determine whether the primary source of organic material was marine, terrigenous, or both, by inspecting the distribution of normal alkanes on the gas chromatograph.

(5) Phytane and pristane are two important isoprenoids derived from chlorophyll; they are useful for determining depositional environment and for correlating potential source rocks and oils. Dominance of phytane has been associated with even-carbon-number preference and, therefore, with restrictive carbonate or evaporite environments, or both (Tissot and Welte, 1978, p. 386). Both phytane and pristane are very resistant to biodegradation (Deroo and others, 1977; Barker, 1979, p. 148).

The following technique was used to obtain the gas chromatographs. Aliquots of the extracted organic matter from the seven San Andres samples previously mentioned were processed by replacing the chloroform solvent with an iso-octane solvent without bringing the sample to dryness. This treatment preserves some of the more volatile components. After separation, the saturate fraction is analyzed by gas chromatography and reported as C_{10+} saturates (fig. 3).

Distillate Analyses by Bartlesville Energy Technology Center

Bartlesville Energy Technology Center (BETC) maintains a collection of about 9,000 crude oil analyses (Coleman and others, 1978). The BETC analysis (formerly the U. S. Bureau of Mines' routine analysis of crude oil) includes tests for API gravity, color, viscosity at 100° F, and percent nitrogen and sulfur, as well as the Conradson carbon residue test. Of particular value in characterizing the oil are separate analyses of 15 individual boiling fractions. Each boiling fraction is analyzed for cut temperature, percentage of total oil, specific gravity at 60° F, API gravity at 60° F, correlation index (CI) value, refractive index at 20° C, specific dispersion, viscosity at 100° F, and cloud test.

Correlation index value is particularly important because it has been used for crude oil correlation (Smith, 1940, 1968; Neumann and others, 1941; Radchenko, 1961; Société des Pétroles, 1963; Jones and Smith, 1965; Barbat, 1967; Belt and McGlasson, 1968; Chuber and Rodgers, 1968; Barker, 1979; Hunt, 1979). The correlation index was developed by Smith (1940) and is calculated as follows:

$$CI = 473.7\ G - 456.8 + \frac{48640}{T}$$

where G is the specific gravity of the fraction at 60° F and T is the average boiling point temperature of the fraction in degrees Kelvin.

Pure normal alkanes have a correlation index equaling 0; this index increases with more branched and cyclic molecules. The volume percent of aromatics in fraction n (Vn) can be determined by the following equation:

$$Vn = Cn\ (Dn + .004)\ (Sn - 122.4)$$

where Cn is a constant for fraction n, Dn is the density of fraction n, and Sn is the specific dispersion of fraction n (Coleman and others, 1978).

Correlation indices and aromatic contents are plotted against fraction numbers to yield correlation index profiles and aromatic profiles, respectively (figs. 4 and 5); this allows the comparison and classification of various oils. Fractions 2 to 10, frequently used in this report, reflect the composition of those components whose compounds have boiling points between 167° and 527° F (Coleman and others, 1978).

Gas chromatographic analyses are now considered to provide better correlation than BETC analyses because individual compounds can be compared. The component of the oil that is analyzed by liquid and gas chromatography has a higher boiling point than the component analyzed by the BETC method. Since these molecules have higher boiling points, they are less degradable. A major advantage of BETC analyses, however, is the great number of published analyses, which permit broad regional interpretations of oil characteristics. Gas chromatographic and BETC analyses of four oils from the San Andres provided similar results, supporting the validity of both methods.

THE SAN ANDRES FORMATION—THE MAJOR PETROLEUM RESERVOIR OF THE NORTHERN SHELF

The San Andres Formation consists predominantly of carbonate facies that extend from Central Texas to Arizona and Utah. In the Permian Basin, San Andres carbonates grade northward into anhydrite, salt, and red beds in the northern Texas Panhandle, Oklahoma, and Kansas. The San Andres Formation has been called a progradational unit. The unit grades from deep-water limestones to shallow-water oolite bar deposits, to shallow-shelf or lagoonal carbonates rich in siliciclastics and anhydrite, and finally to sabkha, brine-pan, and mud-flat deposits (Todd, 1976). Progradation of this facies tract proceeded, with interruption, from north to southeast across the Northern Shelf and into the Midland Basin (fig. 6). By the end of San Andres time, open-marine conditions no longer existed on the Northern Shelf, and nearshore sabkha and continental environments predominated.

Evidence for periodic subaerial exposure of the shelf or platform areas during San Andres time has been presented (Hayes, 1959; Chuber and Pusey, 1967; Hills, 1972; Todd, 1976; Ramondetta, in press). Hills (1972) and Todd (1976) postulate large eustatic drops in sea level. They contend that porosity is developed during such times through leaching of unstable carbonates by meteoric waters. Dolomitization, and associated intercrystalline porosity, may also have occurred at this time because of the possible development of a schizohaline environment arising from the influx of

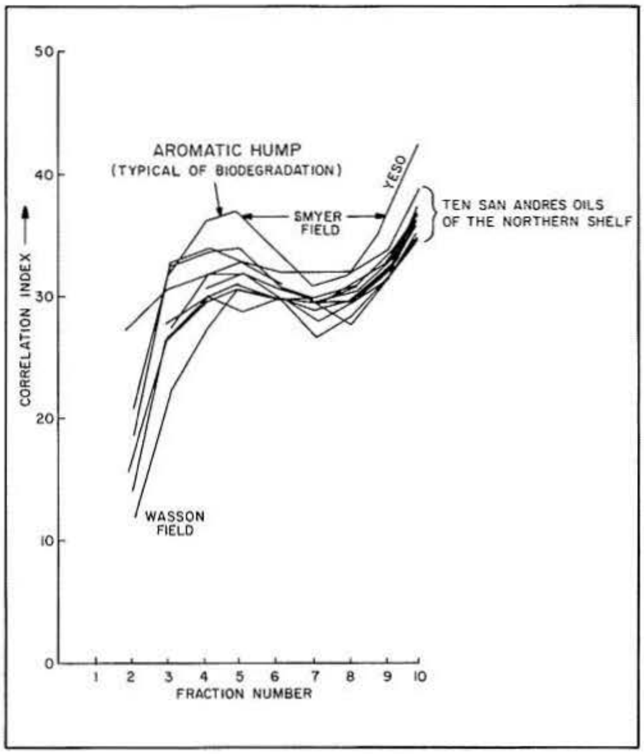


Figure 4. Correlation index profiles of 10 San Andres and 1 Yeso oil, Northern Shelf.

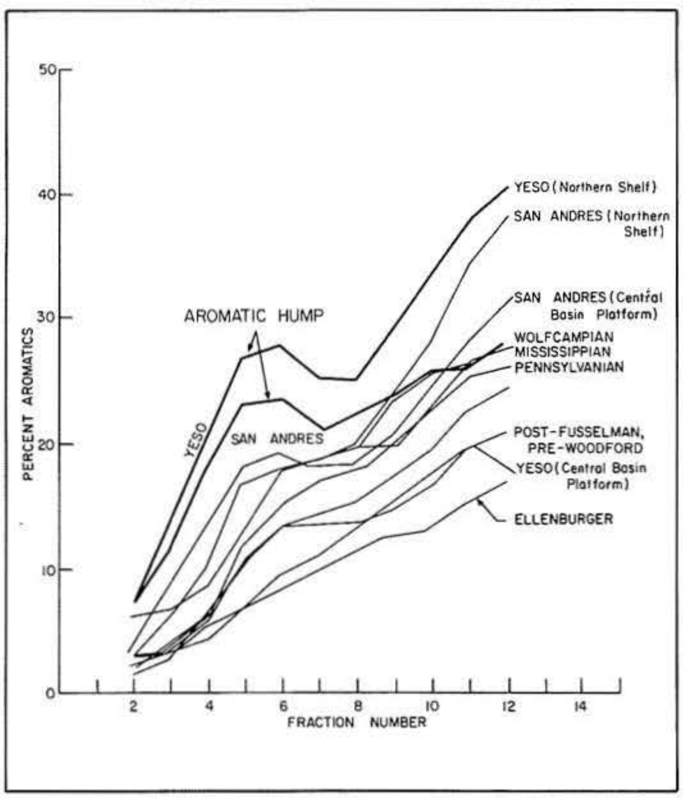


Figure 5. Average aromatic profiles of some principal oils in the Permian Basin.

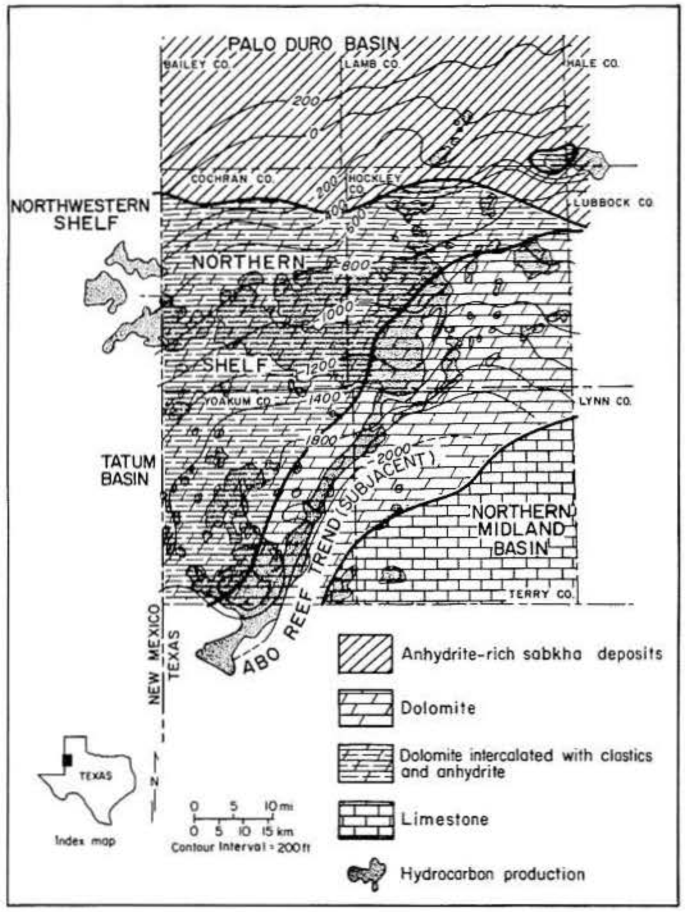


Figure 6. Facies tract, lower San Andres Formation, Northern Shelf. Dominant lithofacies shown either comprise or are stratigraphically equivalent to the major porosity zone (see also fig. 9). Contours represent structure on the π marker.

meteoric water (Folk and Land, 1975). Additional fracture porosity may have been developed after burial.

Visible porosity is normally moldic, resulting from leaching of skeletal debris. Schneider (1943), however, has reported that fine intergranular porosity (between dolomite granules) in the Wasson field is more productive because of its permeability and oil saturation. Origin of intergranular porosity may be linked to the origin of the dolomite. Intercrystalline porosity between dolomite rhombs in producing San Andres strata of the Cato field, New Mexico, is clearly shown in scanning electron microscope (SEM) photomicrographs by Holly Lanan (personal communication, 1981). Coarse moldic pores are less permeable and "commonly fail to show saturation in an otherwise saturated sample" (Schneider, 1943, p. 497). Hence, core descriptions of dolomite that appears nonporous to the unaided eye may often disagree with geophysical well-log data showing gross porosity.

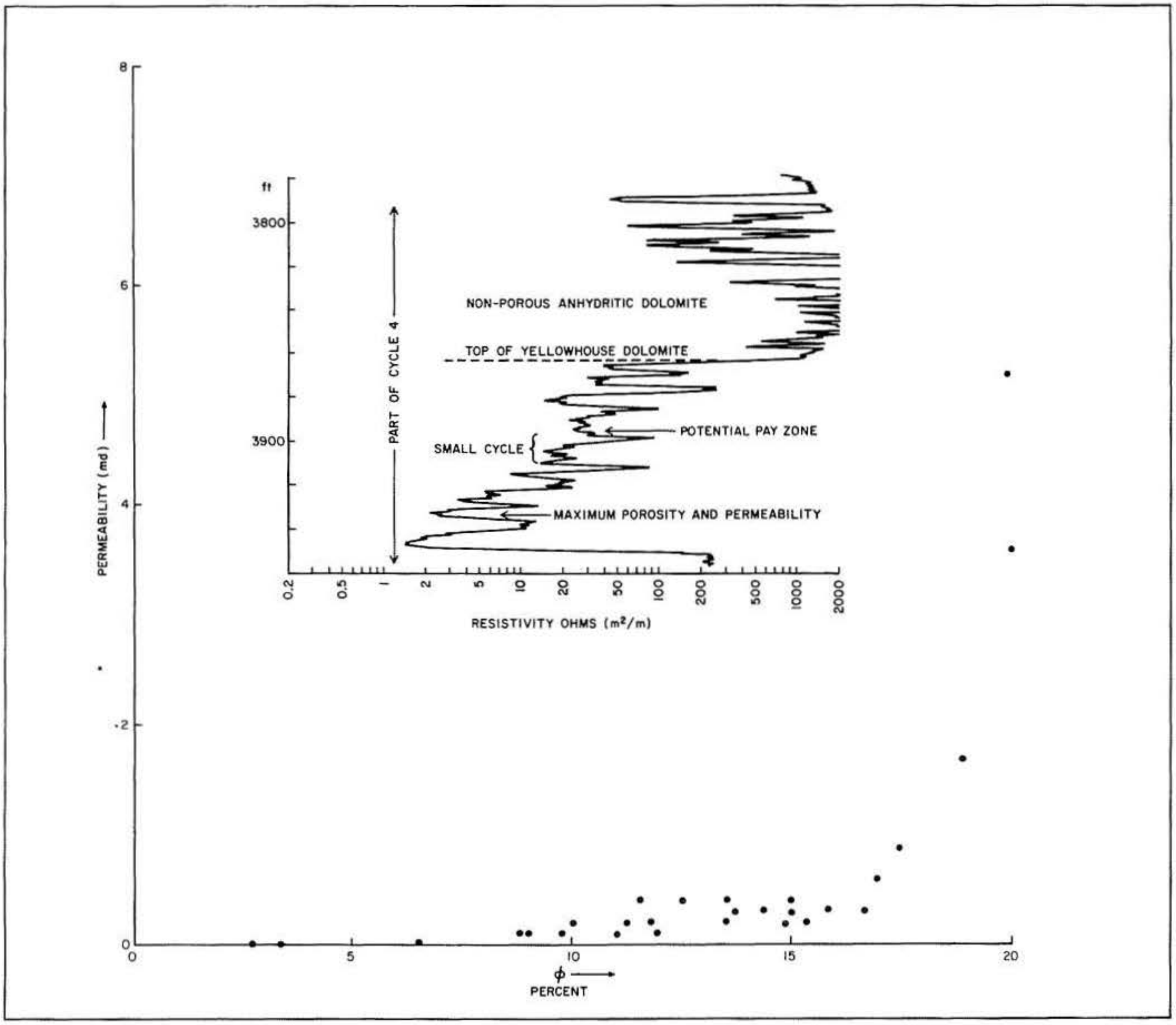


Figure 7. Plot of porosity versus permeability and resistivity log of Yellowhouse dolomite, Littlefield Northeast field, Lamb County, Texas (data courtesy of Argonaut Energy).

Porosity and permeability vary considerably within oil-bearing strata of the Northern Shelf (Chuber and Pusey, 1967; Zaaza, 1981), even within thin, porous intervals. The results of 29 porosity and permeability measurements of the Yellowhouse dolomite (lower San Andres), Littlefield Northeast field, Lamb County, are shown in figure 7. The depth range of samples is small (3,880 to 3,939 ft), yet porosity varies from 2.7 to 20.7 percent and permeability from less than 0.1 to 8.3 millidarcys (md). The relationship is not linear; permeability increases dramatically in samples containing greater than 17 percent porosity. This variability in seemingly uniform lithology suggests a change in type of porosity above the 17-percent threshold, perhaps from mostly moldic porosity to both moldic and intercrystalline porosity. Such vertical changes in porosity tend to restrain the oil within relatively thin reservoirs, hence preventing vertical migration and aiding in the development of updip, porosity pinch-out traps (fig. 7).

Porosity is better developed in fine-grained rocks; diagenesis has destroyed the initial depositional porosity in the San Andres grainstones, leaving wackestones and stromatolitic mudstones as the principal reservoir beds (Chuber and Pusey, 1967).

Cyclic Sedimentation in the San Andres

San Andres strata exhibit a gradual southerly or basinward shift of facies through time, reflecting

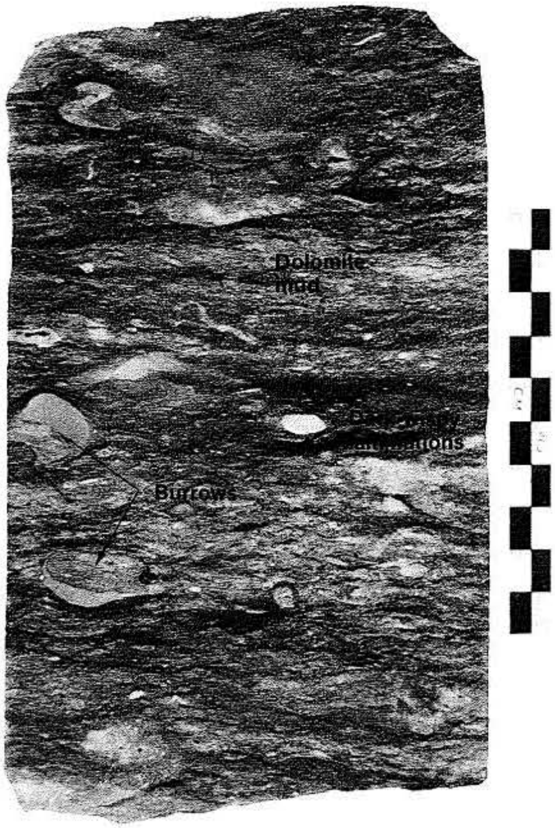


Figure 8. Wispy-laminated, burrowed, porous Yellowhouse dolomite, Atlantic Oil Ryan No. 1, Lamb County, Texas. Photograph by M. W. Presley.

their progradational character (Gustavson and others, 1980). Numerous second- and third-order transgressive-regressive cycles (fig. 7) interrupt this general southerly regression. Periodic transgression is recorded by widespread porous dolomites (fig. 8). The most extensive transgressive dolomite bed is the Yellowhouse dolomite (fig. 9; table 1), which is the reservoir in the Yellowhouse field and other northerly San Andres oil fields. The reservoirs are typically buff- or tan-colored, finely crystalline to finely granular dolomites. To the south (for example, in southern Hockley County), the main oil production is from younger reservoirs, such as the Slaughter zone (fig. 9). These younger porous beds pinch out to the north, before reaching the Matador Arch, whereas the older San Andres reservoirs maintain productive porosity as far north as the southern part of the Palo Duro Basin (fig. 9).

Individual porous dolomite beds merge toward the paleodepositional high of the Abo Reef trend, where they form a thick porous zone (the major porosity zone) in lower San Andres and Clear Fork strata (figs. 6 and 9). This thick porous zone is underlain by either dolomite or limestone of lower porosity.

Porous, cyclic San Andres and Clear Fork dolomites (fig. 8) are overlain by laterally persistent, nonporous dolomite that was deposited in an intertidal to supratidal environment. Anhydrite-rich and containing bedded anhydrite (fig. 10), these nonporous beds form an effective seal for the underlying reservoir, which in turn maintains lateral continuity among the oils of the Northern Shelf. Southward progradation resulting in these seal beds was complete over much of the Northern Shelf by mid-San Andres time.

These nonporous deposits observed in core record prograding sabkha deposition (Presley, 1979). Uppermost facies in depositional cycles consist of anhydrite, salt (fig. 11), or red beds. Each cycle terminates with renewed transgression and carbonate deposition. To the north, porous carbonates thin into evaporites, reducing porosity (for additional information about San Andres cyclicity in areas remote from sabkha facies, see Chuber and Pusey [1967] and Perez de Mejia [1977]).

Relationships Among Structure, Facies, and Porosity

Many researchers agree that the trapping mechanisms for San Andres fields on the Northern Shelf combine structural and facies control (Schneider, 1943; Chuber and Pusey, 1967; Dunlap, 1967; Hills, 1972; Otte, 1974; Ramondetta, in press). Structural closure (fig. 12) in itself is not great enough to account for the thick oil columns observed in the Northern Shelf, as in Wasson and Reeves fields (Chuber and Pusey, 1967). Porosity pinch-outs updip from productive structures account for much of the trapped oil.

The shift of facies to the south, combined with the cyclic sedimentation previously discussed, results in lateral porosity changes. The regional updip-oriented change from porous to nonporous facies in central Hockley and Cochran Counties (figs. 9 and 12) is steplike and has resulted in the vast Levelland - Slaughter trend. Very little, if any, structural control is apparent in most of the Levelland - Slaughter trend (fig. 12). North, or updip of the Levelland field, porosity is largely replaced by secondary anhydrite (fig. 13; Dunlap, 1967). This pore-filling anhydrite probably came from overlying evaporite deposits. This regional facies change continues across the Northwestern Shelf of eastern New Mexico, controlling a belt of San Andres hydrocarbon production that extends as far west as the Pecos River in Chaves County, New Mexico (fig. 14). The northernmost oil production is from the Yellowhouse - Illusion Lake - Littlefield trend.

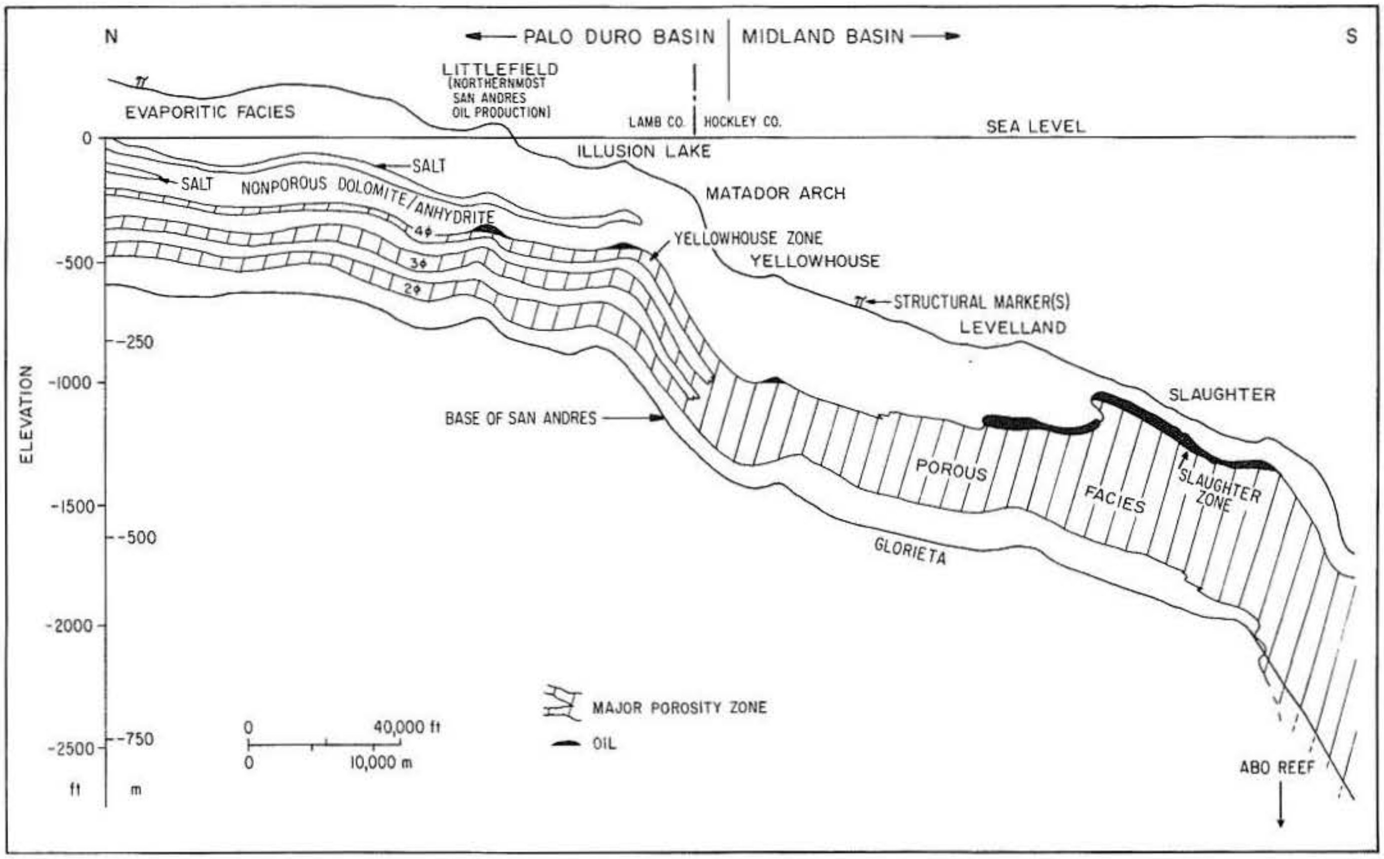


Figure 9. Cross section of lower San Andres Formation, Northern Shelf, showing porosity relationships.

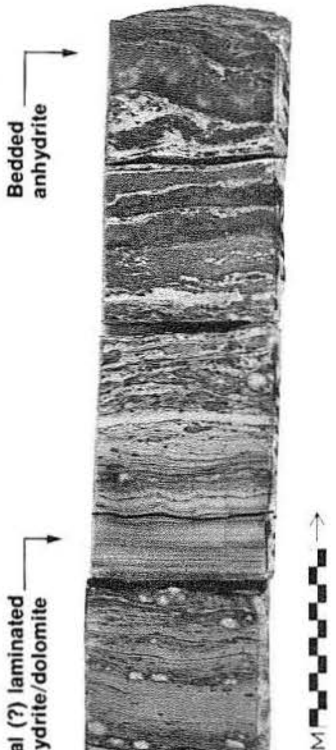


Figure 10. Laminated, nonporous anhydrite/ dolomite, lower San Andres Formation, Atlantic Oil Ryan No. 1, Lamb County, Texas. Photograph by M. W. Presley.

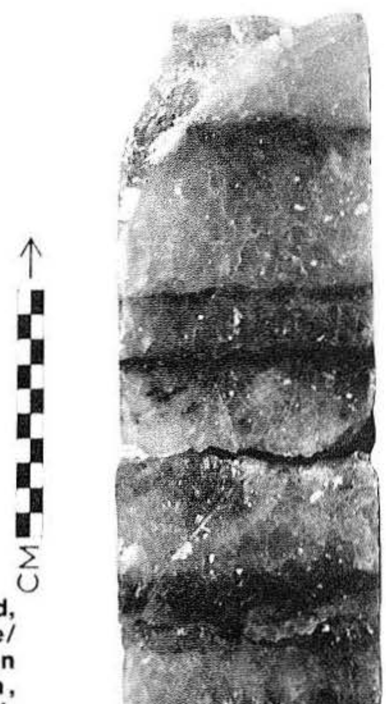


Figure 11. Banded salt, lower San Andres Formation, DOE-Gruy Grabbe No. 1, Swisher County, Texas. Photograph by M. W. Presley.

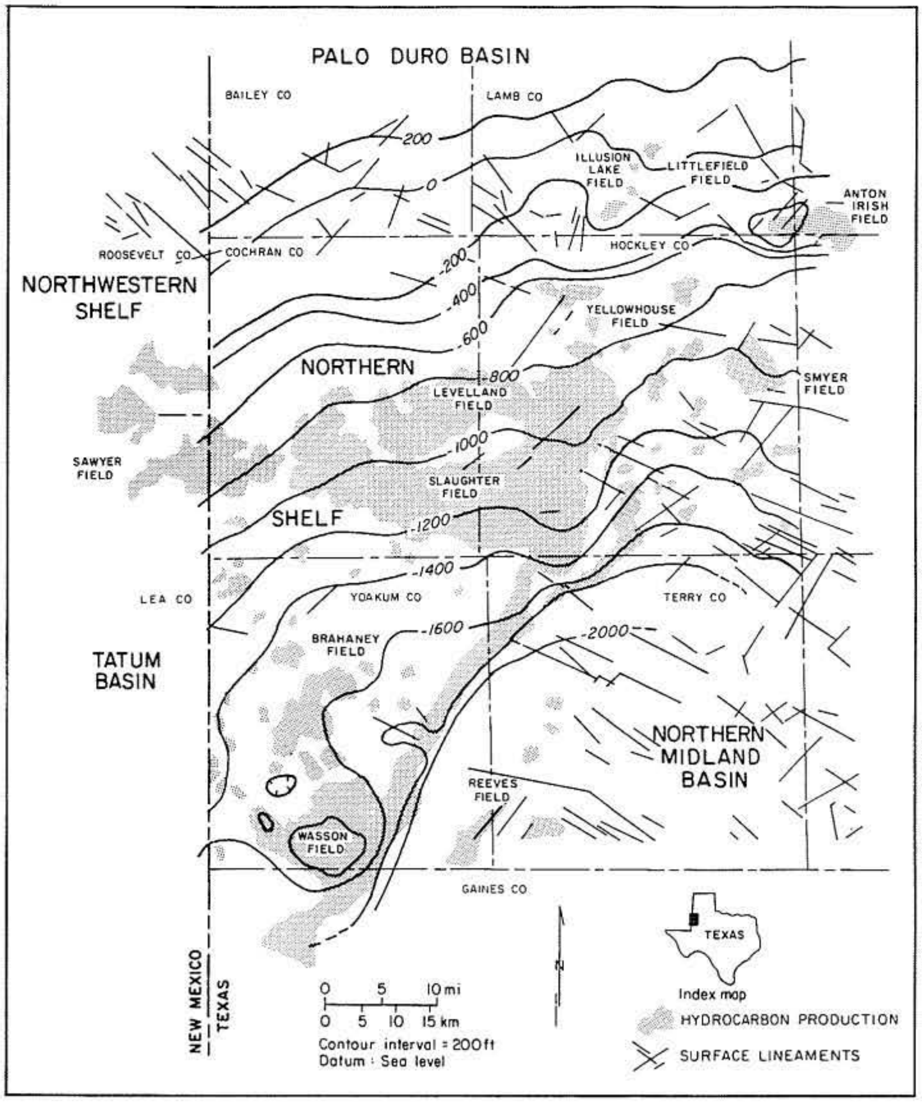


Figure 12. Structure map of the π marker, Northern Shelf, showing surface lineaments (Finley and Gustavson, 1981) and oil production.

Attempts to extend the trend farther north have been unsuccessful (fig. 15).

Farther north in the Palo Duro Basin, thick salt units directly overlie the transgressive dolomites; porosity in the dolomites has been largely filled by salt (Handford and others, in preparation). This infilling further reduces the probability of long-range lateral migration of San Andres oil beyond the southern fringe of the Palo Duro Basin.

Because much of the San Andres porosity was probably developed during subaerial exposure, surface topography must have exerted considerable control. Deeper water shelf carbonates were less likely to develop adequate porosity because exposure of these strata to such diagenesis was less likely. These deeper water carbonate muds escaped dolomitization in many cases, and are now limestones of relatively low porosity. Nonporous limestones constitute much of the lower San Andres and Clear Fork strata of the deeper outer shelf to the east and southeast of the Abo Reef trend (fig. 6).

It follows that conditions favoring porosity occurred in structurally high areas that were also depositional highs. Stratigraphic thinning of the San Andres occurs over many of the structural highs, indicating that present structures were also positive during deposition (Ramondetta, in press). Stratigraphic thinning usually coincides with oil occurrence, even in pre-San Andres oil fields. Thinning is accompanied by an improved and thickened porous zone, as evidenced from various porosity logs (Ramondetta, in press). Schneider (1943) further verified that the most prolific oil-producing strata in the Wasson field are massive reeflike, porous carbonates on structural and paleodepositional highs along the eastern margin of the field (fig. 6). Structurally lower areas that flank the Wasson high

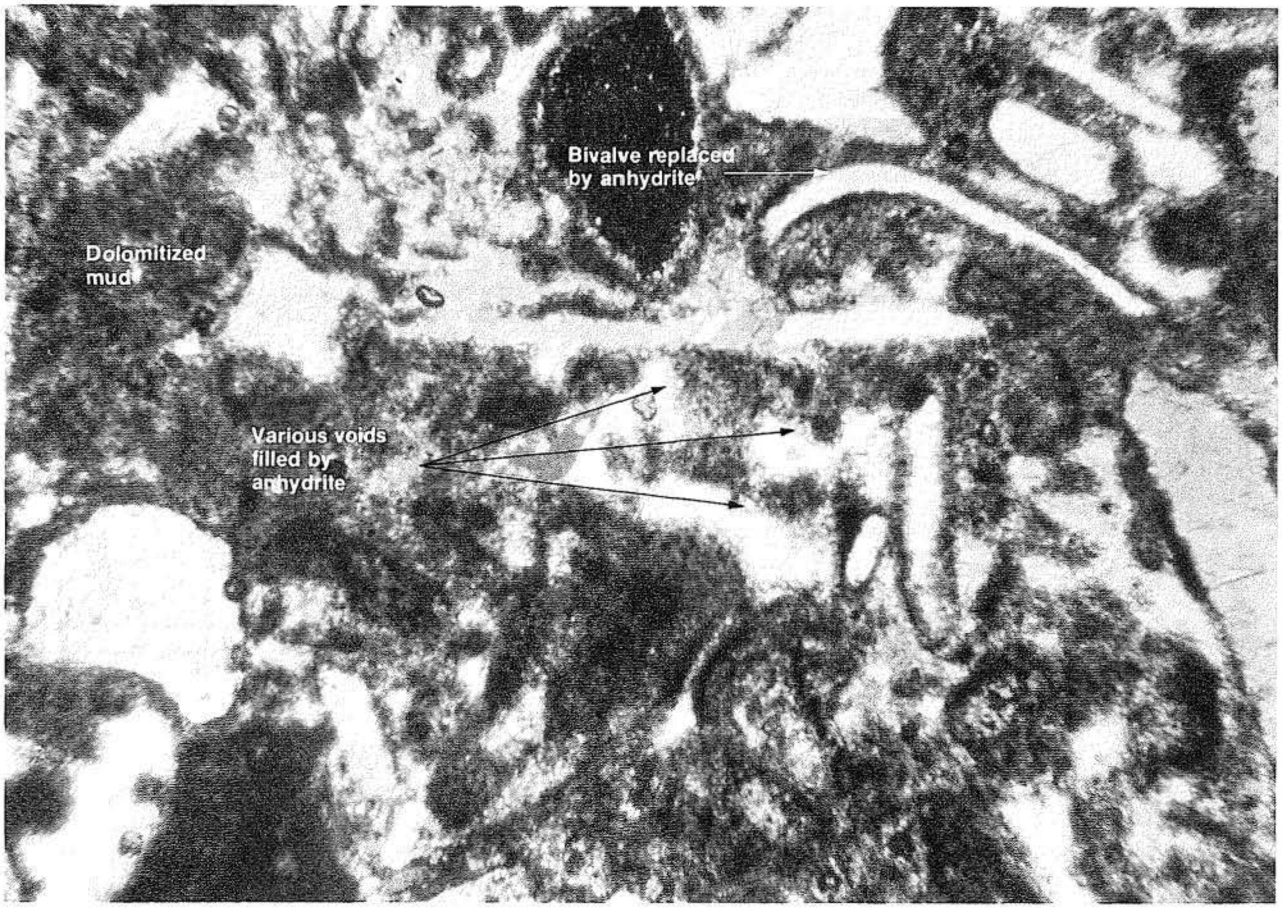


Figure 13. Replacement of skeletal debris and voids by secondary anhydrite, Yellowhouse dolomite, Argonaut Energy (Crown Petroleum) Baumgart No. 1, Lamb County, Texas. Width of photograph equivalent to 2.66 mm of thin section.

on the north and west contain carbonates intercalated with more bedded siliciclastic and anhydrite strata; hence, the structural flanks are less porous and productive. During times of moderately low sea-level conditions, porosity could have been leached over the exposed Wasson structure while anhydrite and siliciclastic deposition in shallow lagoons along the flanks lowered porosity. Hence, oil entrapment is affected by both structure and an updip porosity pinch-out. The Wasson paleohigh may have been caused by the buttressing effect of the underlying Abo Reef trend. Another example of improved porosity over a structural high is the Anton Irish structure along the Matador Arch (fig. 12). Prograding sabkha deposits surrounded but failed to cover the Anton Irish structure during much of lower San Andres deposition, resulting in a relatively uninterrupted porous section over the structure compared with the surrounding area (fig. 6).

Draping and subsequent fracturing of San Andres strata over structural or shelf-margin buttresses may also have controlled some entrapment. Resulting fractures could have furnished porosity, as well as promoted conditions for further development of porosity, by allowing circulation of fluids. Such conditions have been reported for the underlying Abo Reef carbonates (Wright, 1962).

The Yellowhouse - Illusion Lake - Littlefield reservoir trend (fig. 15) is an example of San Andres strata draped over the subjacent Wolfcampian shelf margin (fig. 1). Figure 15 illustrates the steeper basinward, or southeastern, flank of this anticline and the mild structural closure along the crest where entrapment occurs. Slight stratigraphic thinning indicates that the crest was topographically higher during deposition. Similar structural and stratigraphic patterns occur throughout the Northern and Northwestern Shelves wherever San Andres producing trends exist. Such producing trends commonly coincide with underlying shelf-margin trends, such as the Abo Reef trend.

The San Andres shelf margins prograded far to the south over basinal deposits, thus diminishing the deep-basin area (fig. 1). Euxinic black mud, fine sand,

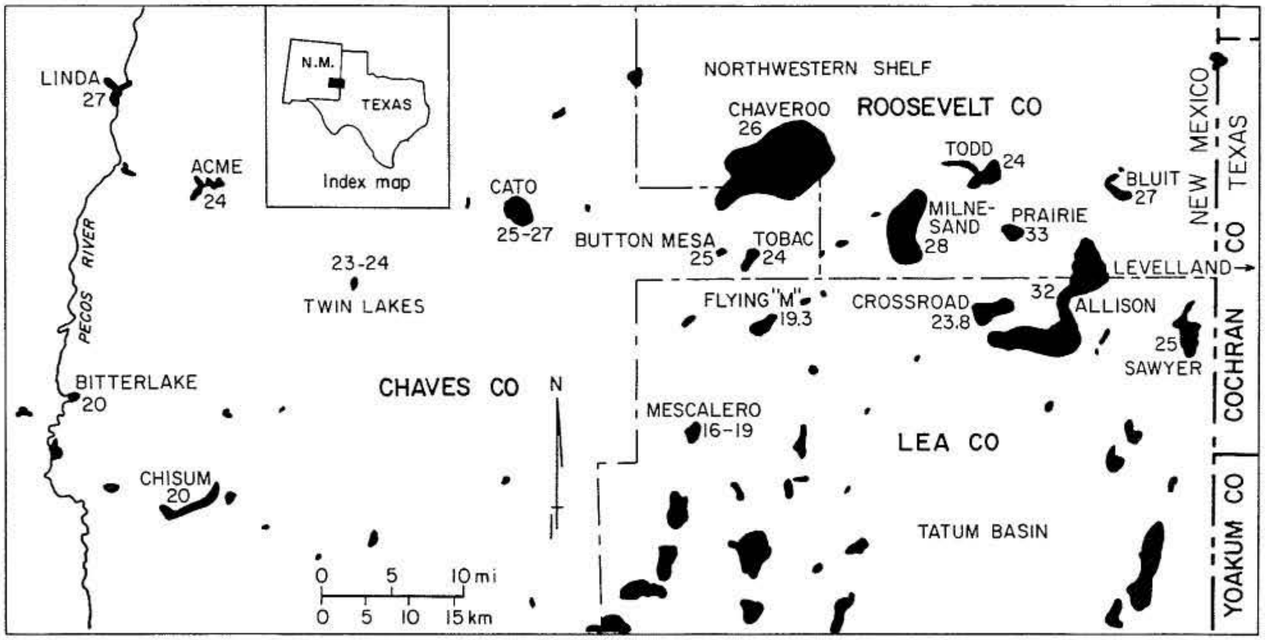


Figure 14. Map of San Andres oil fields showing numerical API gravities for Northwestern Shelf, New Mexico. API gravities from Roswell Geological Society (1956, 1960, 1967).

silt, and argillaceous limestones were deposited in the basin in front of the prograding shelf edge (Hills, 1972, p. 2313). Very little porosity and, hence, little oil has been found in these basinal facies.

Facies relationships are more abrupt in underlying Wolfcampian and Leonardian rocks. Porous carbonate buttresses form narrow, linear trends along the shelf margin, rapidly grading shelfward into nonporous facies (Jones and Smith, 1965). Therefore, these older reservoirs are less widespread than the San Andres shelf units; Galley (1958) concludes that this may explain the smaller and fewer Wolfcampian and Leonardian oil fields compared with those producing from lower Guadalupian reservoirs.

SOURCE-ROCK POTENTIAL OF SAN ANDRES AND CLEAR FORK CARBONATES

Total Organic Carbon

Average TOC values for San Andres and Clear Fork shelf carbonates were determined from 18 wells in the study area (fig. 16; table 3). Values for the shelf carbonates commonly exceed the 0.4-percent criterion for carbonate rocks to be considered as potential source beds. Total organic carbon values, however, are facies dependent and are, hence, variable even within short distances. Dark, argillaceous facies can be up to 10 times richer in TOC than adjacent buff-colored dolomite.

Average TOC in San Andres and Clear Fork strata generally increases to the south and east, reaching a maximum of 3.1 percent on the Eastern Shelf. Total organic carbon values in the study area are relatively high compared with rocks in other carbonate-evaporite basins. For example, within the South Florida Basin, Florida, TOC values are generally below 0.3 percent for Cretaceous and Tertiary limestones (Palacas, 1978, p. 11).

Type of Kerogen

Average OMI values for San Andres and Clear Fork shelf carbonates were determined from 17 wells in the study area (fig. 16; table 3). Samples from all but three southern wells in the study area contain more membranous plant debris than amorphous sapropel and algal debris (fig. 17; table 3). In addition, smaller amounts of woody and coaly debris are present. Foraminiferal linings, algal cysts,

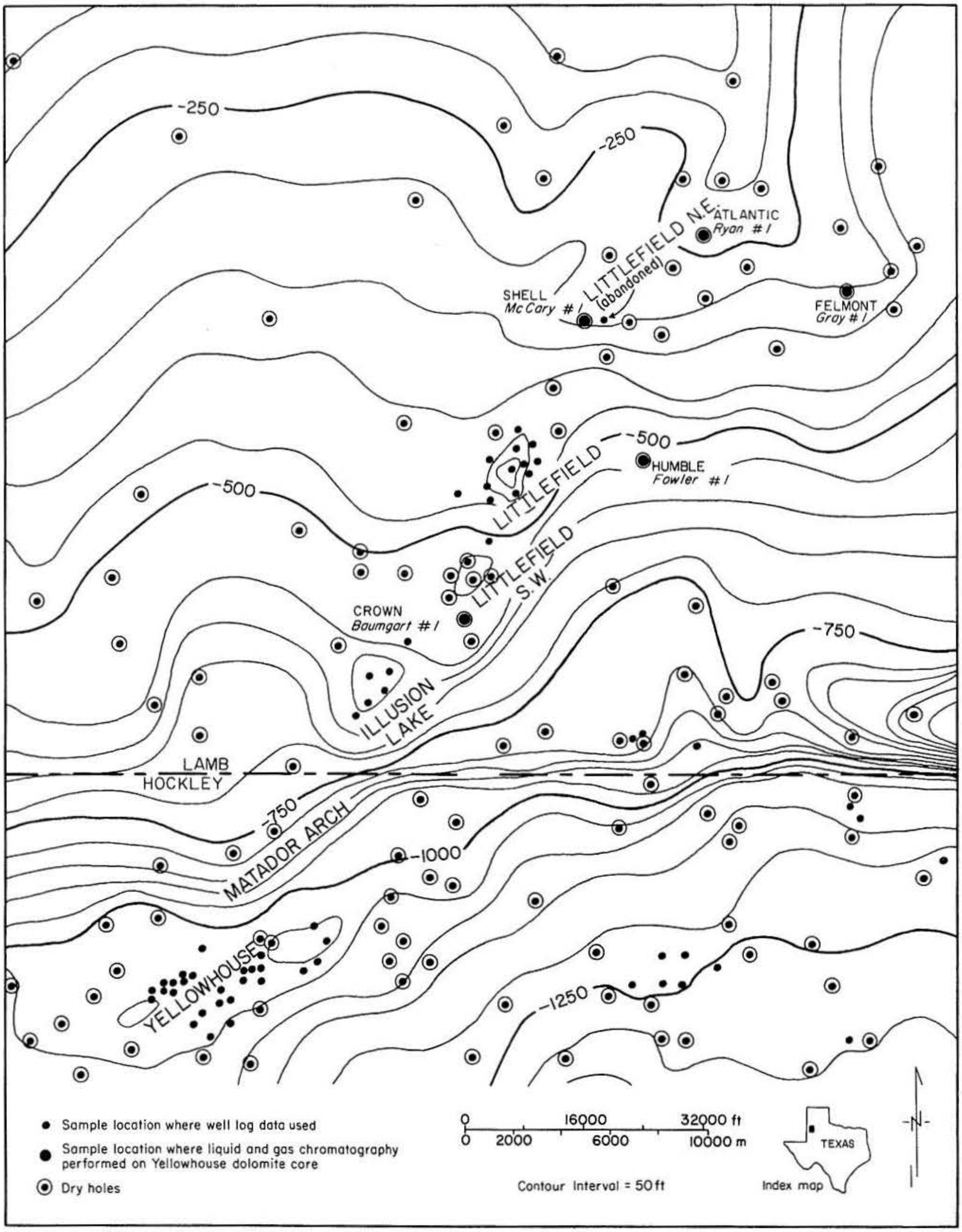


Figure 15. Structure map on the top of Yellowhouse dolomite, northern Hockley and southern Lamb Counties, Texas, indicating core sites.

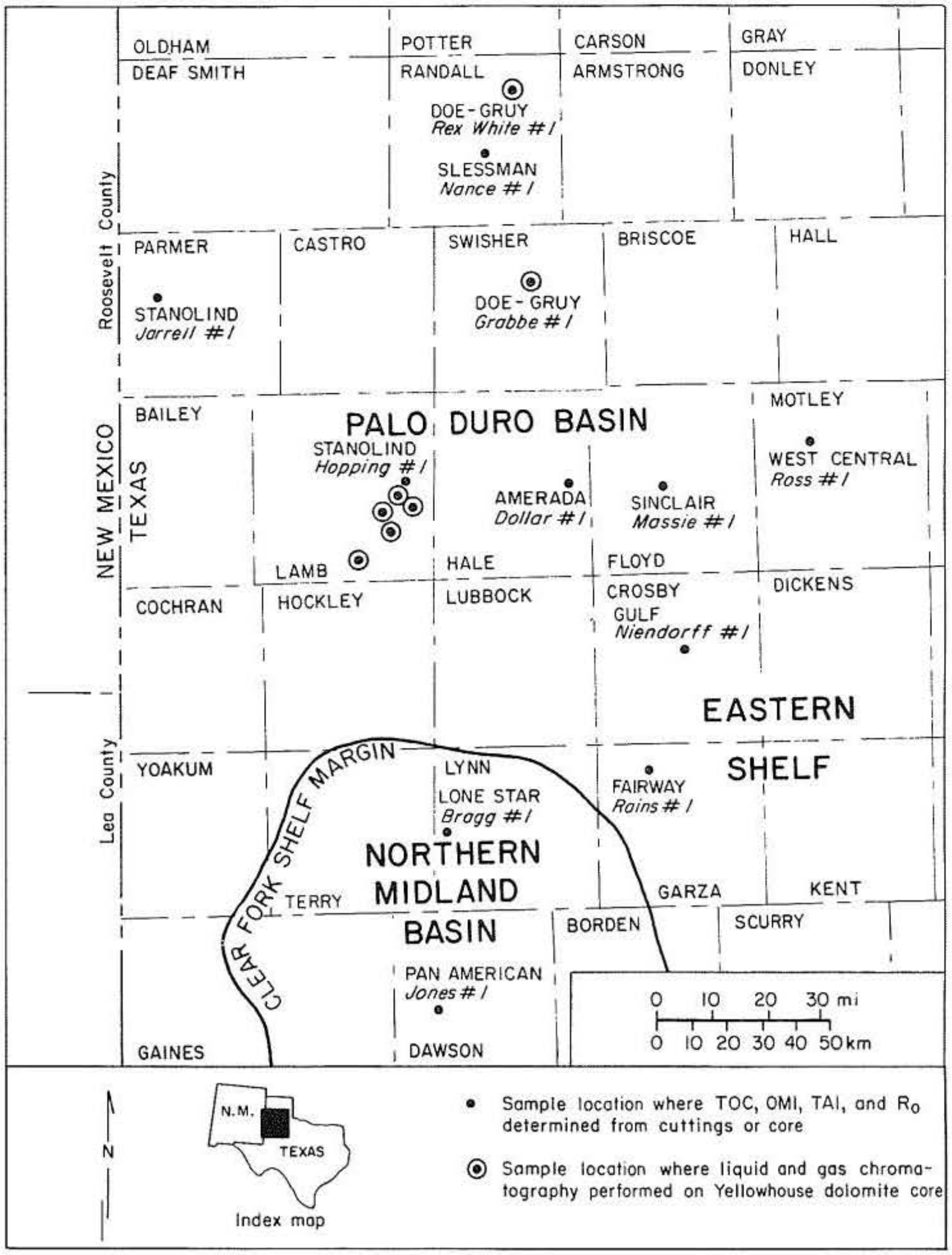


Figure 16. Map of the study area showing sample locations for organo-geochemical analyses.

and scolecodonts (fossil worm jaws) have also been recognized. A rare and interesting occurrence of lithified cytoplasmic material within spore walls was also identified; these features are unique to evaporitic environments (K. W. Schwab, personal communication, 1979). Algal debris in these rocks is rich in lipids, as evidenced by ultraviolet fluorescence (K. W. Schwab, personal communication, 1979). Samples from the three southern wells in Dawson, Lynn, and Garza Counties, Texas, conversely exhibit a strong dominance of amorphous sapropel and algal debris (fig. 18), reflecting deeper water conditions. Hence, kerogen quality is better to the south.

Organic matter occurs predominantly in carbonate muds, in both burrowed (subtidal) and unburrowed (supratidal) laminated facies in the San Andres. Organic matter is commonly concentrated near anhydrite nodules and appears to have been squeezed and contorted by secondary growth of the anhydrite (see figs. 19 to 21). The anhydrite nodules are commonly rimmed with both organic material and pyrite. Organic matter also concentrates along stylolites and fractures.

Thin laminae and lentils of dark-gray to black asphaltic shales are intercalated with shelf carbonate beds. Total organic carbon values in these lentils and laminae may be as high as 4 percent; they may be rich in both amorphous debris and membranous plant debris. Chuber and Pusey (1967, p. 141) described these zones as consisting mostly of "carbonaceous plant material."

Table 3. Organo-geochemical analyses of San Andres and Clear Fork shelf carbonates.

County, state	Operator	Well	Depth (ft)	TOC (%)	OMI	TAI	R_o (%)	EOM (ppm)	HC (ppm)	HC/ EOM (%)	EOM/ TOC (%)	HC/ TOC (%)
Data from Ramondetta, this report												
Randall, TX	DOE-Gruy	Rex White No. 1	1,960-2,030	0.28	3.70	2.54	0.39	494	191	39	18	6.8
Swisher, TX	DOE-Gruy	Grabbe No. 1	2,693-2,796	0.26	3.78	2.43	0.42	262	81	31	10	3.1
Lamb, TX	Shell	McCary No. 1	3,892-3,926	0.33	3.79	2.70	0.45	435	181	42	13	5.4
Lamb, TX	Atlantic Oil	Ryan No. 1	3,824-3,872	0.57	3.49	2.74	0.45	726	134	18	13	2.3
Lamb, TX	Felmont	Gray No. 1	3,865-3,894	0.43	3.61	2.72	0.47	443	72	16	10	1.6
Lamb, TX	Humble	Fowler No. 1	4,075-4,096	0.63	-----	-----	-----	836	272	33	13	4.3
Lamb, TX	Argonaut Energy (Crown)	Baumgart No. 1	4,071-4,094	0.87	3.50	2.67	0.44	1,410	370	26	16	4.2
Data modified from Dutton (personal communication, 1980)												
Lamb, TX	Stanolind	Hopping No. 1	3,840-3,920	0.5	4.08	2.80	-----	-----	-----	-----	-----	-----
Hale, TX	Amerada	Dollar et al.	2,600-5,480	1.7	3.52	2.89	0.43	-----	-----	-----	-----	-----
Randall, TX	Slessman et al.	Nance No. 1	3,620-4,570	1.4	4.12	2.87	-----	-----	-----	-----	-----	-----
Motley, TX	West Central Drilling	Ross No. 1	1,380-5,680	3.1	3.91	2.93	0.41	-----	-----	-----	-----	-----
Parmer, TX	Stanolind	Jarrell No. 1	3,300-5,240	1.3	4.08	3.04	-----	-----	-----	-----	-----	-----
Floyd, TX	Sinclair	Massie No. 1	2,210-5,990	3.1	3.96	2.98	0.46	-----	-----	-----	-----	-----
Roosevelt, NM	Stevens Oil	O'Brien No. 1	2,650-2,835	2.0	3.65	3.14	-----	-----	-----	-----	-----	-----
Crosby, TX	Gulf	Niendorff No. 1	3,010-6,690	2.0	3.85	2.25	0.37	-----	-----	-----	-----	-----
Lynn, TX	Lone Star	Bragg No. 1	4,710-6,810	1.5	3.46	2.12	0.37	-----	-----	-----	-----	-----
Dawson, TX	Pan American	Jones No. 1	4,710-6,790	1.2	3.24	2.12	0.42	-----	-----	-----	-----	-----
Garza, TX	Fairway Oil and Gas	Rains No. 1	2,510-5,990	2.0	3.36	2.10	0.35	-----	-----	-----	-----	-----

TOC = total organic carbon
OMI = organic matter index
TAI = thermal alteration index
R_o = vitrinite reflectance
EOM = extracted C_{15+} organic matter
HC = C_{15+} hydrocarbons

The presence of anhydrite in San Andres strata on the Northern Shelf indicates high salinities that must have existed in more restrictive environments. Chuber and Pusey (1967, p. 141) noted that fusulinids and corals are absent and that nonskeletal grains such as pellets, ooliths, lumps, and intraclasts are far more common than skeletal grains. Although the quantity and diversity of life must have been periodically destroyed on this saline shelf, presence of amorphous algal debris indicates that algal mats, at least, were able to survive the salinities (Todd, 1976), as they do today along sabkhas of the Trucial Coast of the Persian Gulf (Kinsman, 1966; Butler, 1969).

Thus, the source of organic material is twofold, originating from both indigenous algal debris and terrigenous plant material that washed onto the shelf during storms and periods of subaerial exposure. Consequently, terrigenous organic material should be less common in a seaward direction; this is confirmed by the low OMI values in the three southern locations that were sampled. Because of the abundance of membranous plant debris in all samples, except those from Dawson, Lynn, and Garza Counties, Texas, the kerogen is generally considered to be of intermediate quality for oil generation potential.

Maximum Burial Temperature

Average TAI and R_o values for San Andres and Clear Fork shelf carbonates were calculated from the same 17 wells in the study area previously analyzed for TOC and OMI (fig. 16; table 3). Kerogen color ranges from pale yellow to yellow orange at four wells in the southern part of the Northern Shelf of Texas (Crosby, Lynn, Garza, and Dawson Counties); R_o values for those four wells average 0.38. North or updip from those four locations the kerogen color ranges from pale yellow to orange, and R_o values average 0.44. Although kerogen quality is lower, organic diagenesis is more advanced, but not sufficiently advanced to have generated significant amounts of hydrocarbons (catagenesis).

The modern geothermal gradient on the Northern Shelf is approximately 1.1° F/100 ft (Dutton, 1980a), as determined by bottom-hole temperature values from well logs. With such a geothermal gradient, a depth of at least 7,700 ft (assuming a surface temperature of 65° F) is necessary for catagenesis. Even the underlying Clear Fork shelf carbonates are mostly above this depth. Therefore, on the basis of the present depth range and geothermal gradient, San Andres and Clear Fork shelf carbonates are

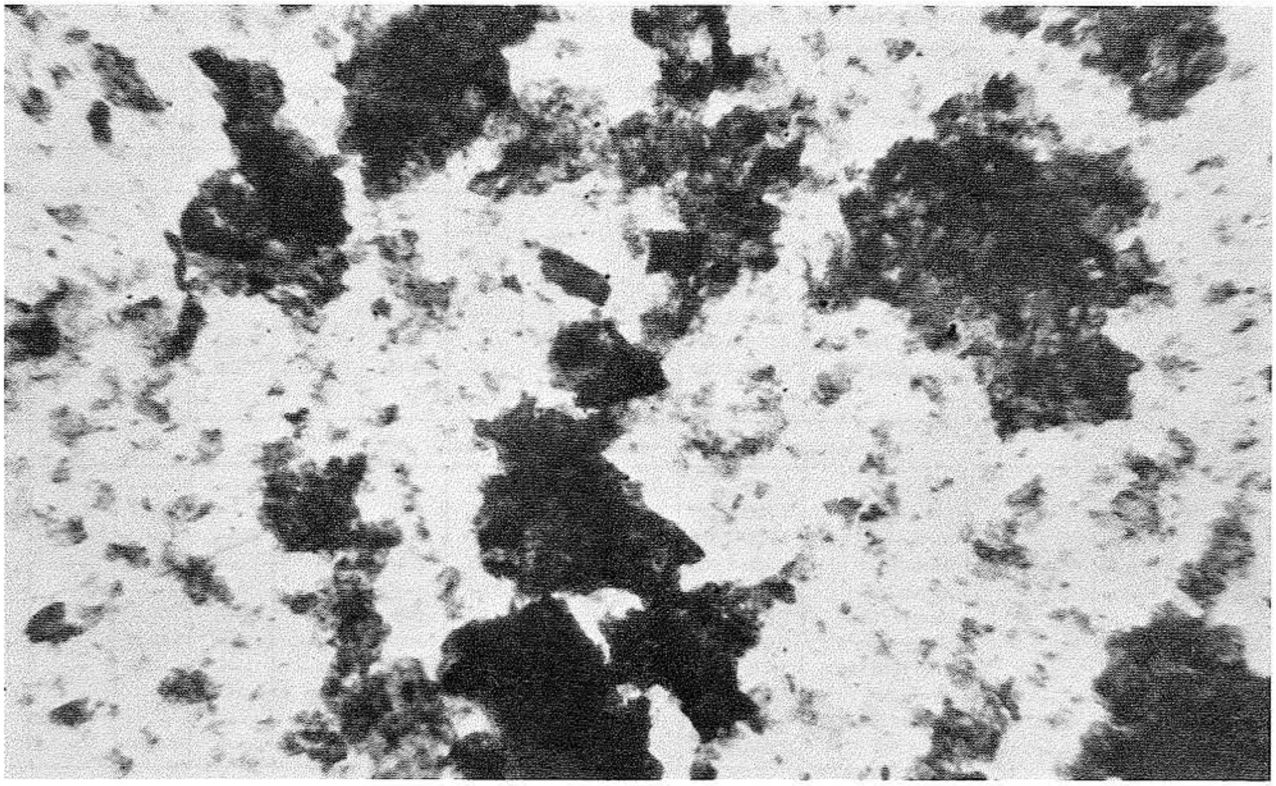


Figure 17. Membranous plant debris (kerogen), Yellowhouse dolomite, Shell McCary No. 1, Lamb County, Texas. Width of photograph equivalent to 0.65 mm of thin section.

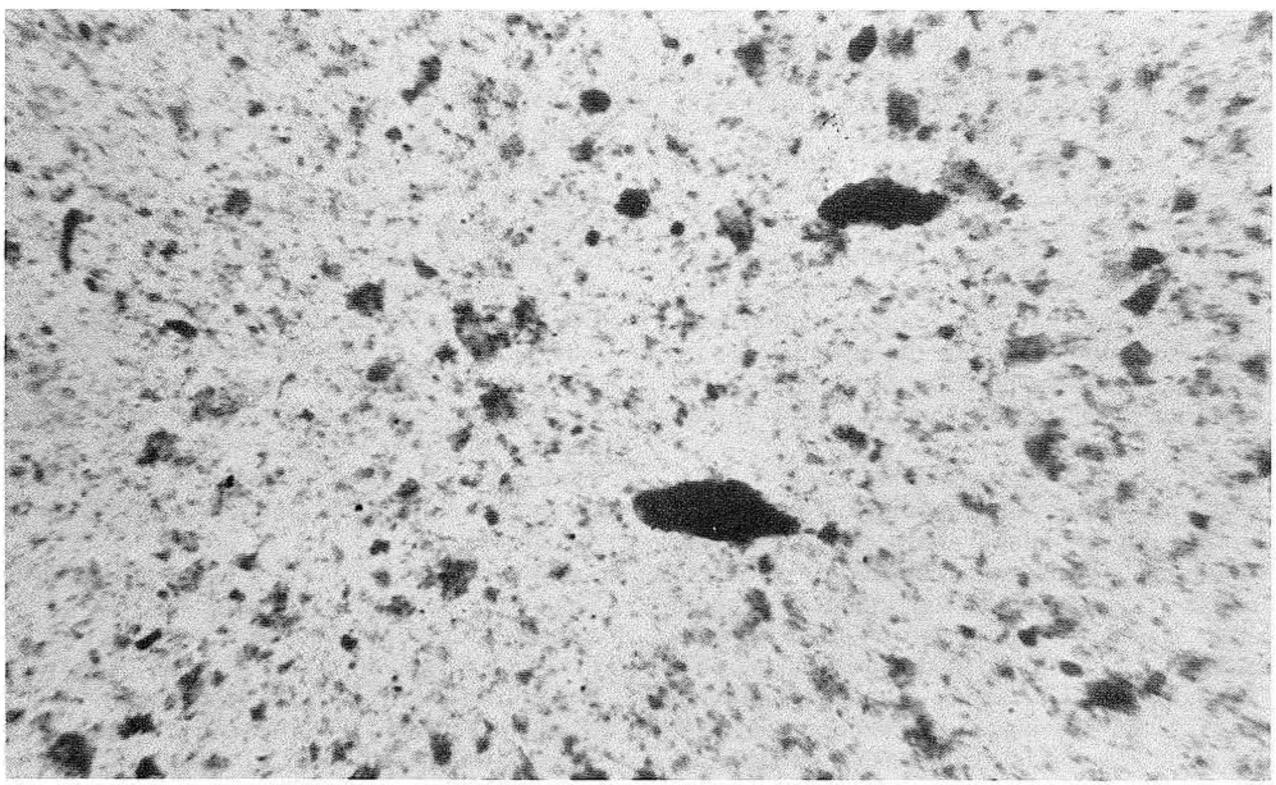


Figure 18. Amorphous sapropel (kerogen), Wolfcampian basinal deposits, Lone Star Bragg No. 1, Lynn County, Texas. Width of photograph equivalent to 0.65 mm of thin section.

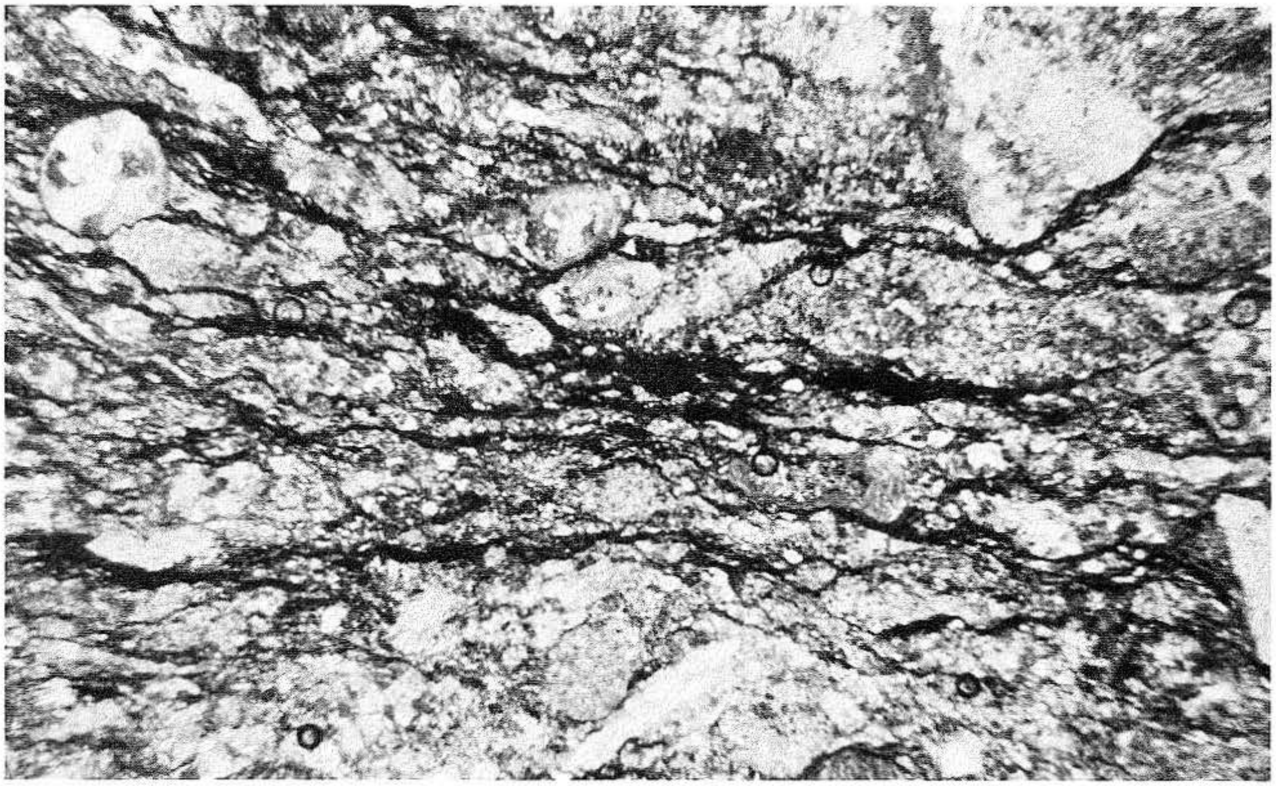


Figure 19. Concentrated organic matter adjacent to displacive nodules of anhydrite, Yellowhouse dolomite. Sample from Felmont Gray No. 1 well, southern Lamb County, Texas, from depth of 3,880 ft. Width of photograph equivalent to 2.66 mm of thin section.

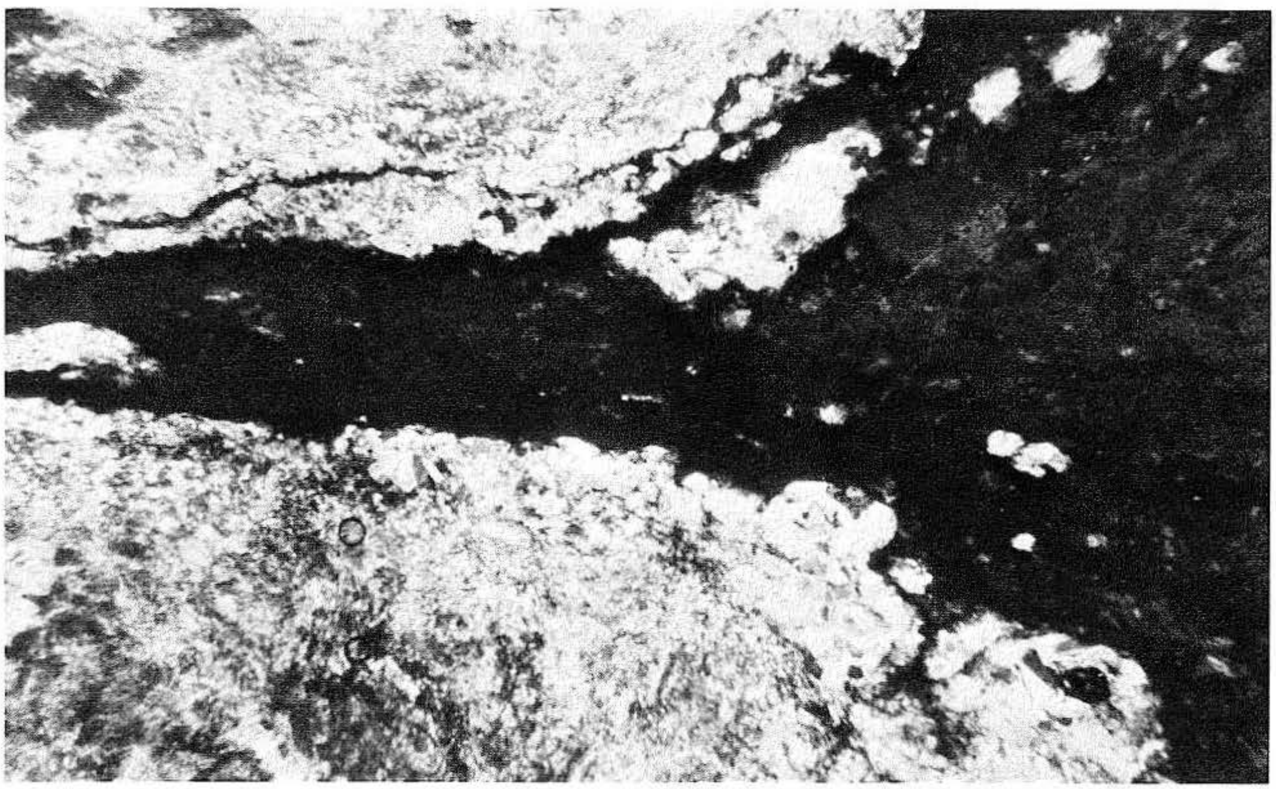


Figure 20. Concentrated organic matter adjacent to displacive nodules of anhydrite, Yellowhouse dolomite. Sample from Atlantic Oil Ryan No. 1 well, southern Lamb County, Texas, from depth of 3,819 ft. Width of photograph equivalent to 2.66 mm of thin section.

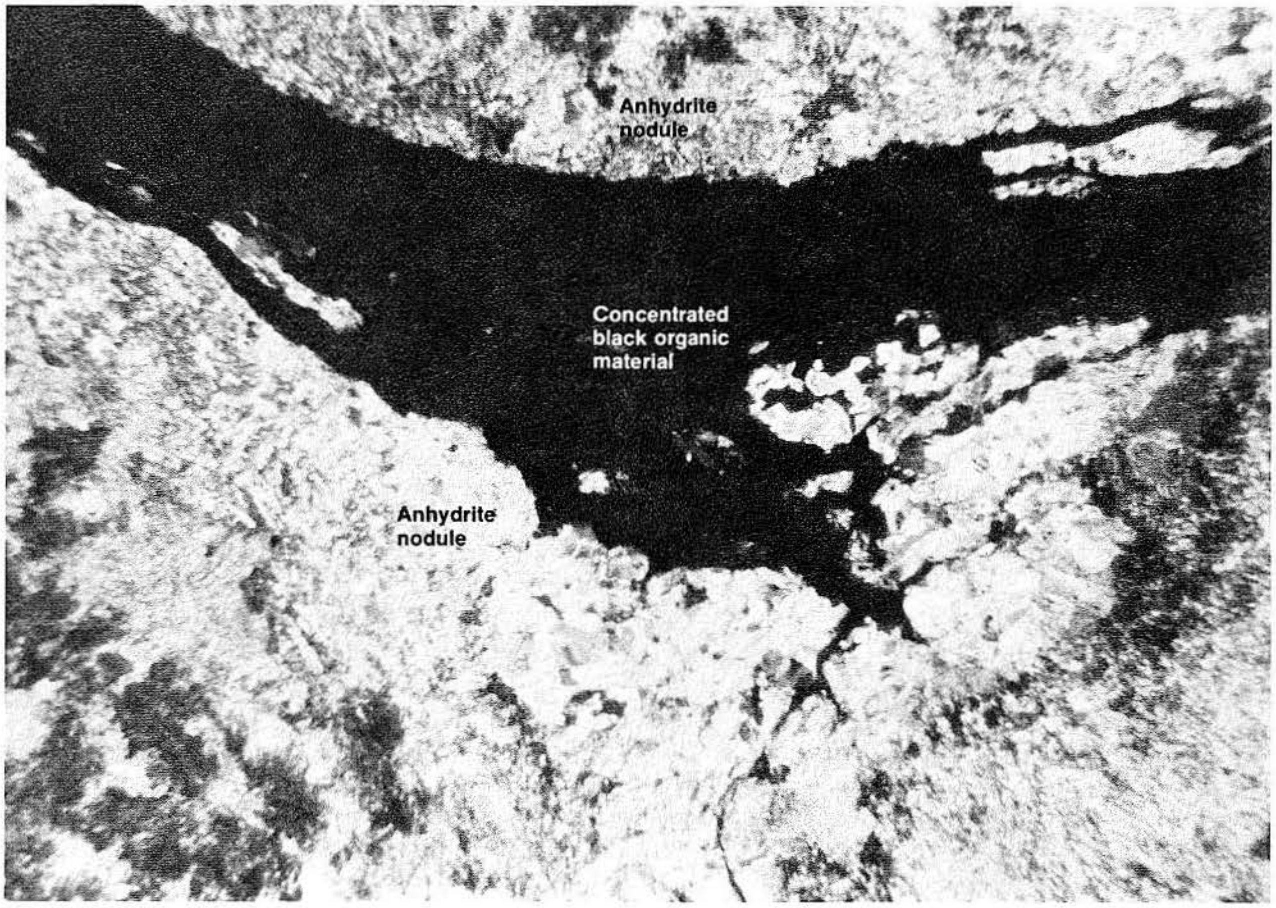


Figure 21. Concentrated organic matter adjacent to displacive nodules of anhydrite, Yellowhouse dolomite. Sample from Atlantic Oil Ryan No. 1 well, southern Lamb County, Texas, from depth 3,818 ft. Width of photograph equivalent to 2.66 mm of thin section.

considered to be thermally immature for hydrocarbon generation.

Integration of Kerogen Data

Average values of OMI, TAI, and R_o have been plotted in figure 2 to compare these parameters with hydrocarbon source potential. According to this cross plot, San Andres and Clear Fork shelf carbonates lie in the immature zone. It must, therefore, be concluded that source potential for these carbonates is quite poor and that the large reserves in San Andres and Clear Fork oil fields did not form in situ. Dutton (1980b) reached the same conclusion concerning the source potential of these carbonates in the Palo Duro Basin.

Gas Chromatographic Analyses of the Saturated C_{10+} Organic Extract

Values determined by analysis of the organic extracts (fig. 3; tables 3 through 5) confirm that the indigenous hydrocarbons in San Andres shelf carbonates are not mature. The ratio of extracted organic matter to total organic carbon (EOM/TOC) ranges from 10 to 18 percent (table 3), suggesting that the extractable organic material formed from in-place kerogen (indigenous) rather than being a migrated petroleum (from another source).

San Andres shelf carbonates are considered immature for the following reasons:

(1) The C_{15+} organic extract is highly asphaltic and naphthenic (table 4). Although saturates constitute up to 35 percent of the extract from a few samples, it is a highly naphthenic fraction, as evidenced by the large naphthene envelope, or background (the area below the baseline, fig. 3). The proportion of naphthenes to the total saturate fraction ranges from 75 to 85 percent for the seven samples (table 4).

(2) The C_{15+} organic extract is rich in steranes and terpanes, as evidenced by the strong background between nC_{25} and nC_{31} (fig. 3).

(3) There is a general lack of a light-end bias on the gas chromatograph (fig. 3). Figure 3 shows a

Table 4. Organo-geochemical analyses of the Yellowhouse dolomite, Palo Duro Basin.

				Gross composition of EOM			Data on the saturate fraction				
County, state	Operator	Well	Depth (ft)	SAT (%)	AROM (%)	ASPH (%)	Paraffin (%)	Isoprenoid (%)	Naphthene (%)	CPI no.	PH/PR
Randall, TX	DOE-Gruy	Rex White No. 1	1,960-2,030	26.9	11.8	61.3	13.7	0.9	85.4	1.10	0.86
Lamb, TX	Argonaut Energy (Crown)	Baumgart No. 1	4,071-4,094	2.7	23.4	73.9	19.5	6.0	74.5	-----	1.06
Lamb, TX	Shell	McCary No. 1	3,892-3,926	35.4	6.2	58.4	16.0	1.5	82.5	1.08	0.83
Lamb, TX	Humble	Fowler No. 1	4,075-4,096	14.3	18.3	67.4	14.7	2.2	83.1	1.07	1.00
Swisher, TX	DOE-Gruy	Grabbe No. 1	2,693-2,796	20.6	10.3	69.1	15.1	1.8	83.1	1.58	0.64
Lamb, TX	Atlantic Oil	Ryan No. 1	3,824-3,872	8.4	10.0	81.6	22.9	1.7	75.4	1.08	1.09
Lamb, TX	Felmont	Gray No. 1	3,865-3,894	4.5	11.9	83.6	20.1	1.5	78.4	1.10	1.06

SAT = C_{15+} saturated hydrocarbons
AROM = C_{15+} aromatic hydrocarbons
ASPH = C_{15+} asphaltic organic materials
CPI = carbon preference index (C_{24} - C_{34})
PH = phytane
PR = pristane

bimodal distribution of normal alkanes and a skewness toward the heavy end for cyclic paraffins. See table 5 for a complete tabulation of normal alkane distribution.

(4) A lack of dominance and uniformity exists among the light normal alkanes; numerous high-amplitude peaks between the main n-alkane peaks indicate significant amounts of branched paraffins such as the isoprenoids (ip) (tables 4 and 5).

(5) Low ratios of extracted organic matter to total organic carbon (EOM/TOC) (table 3) characterize in-place and immature organic material.

(6) Compositional mismatch is noted between the rock extract and crude oil produced from the same stratigraphic unit (Yellowhouse dolomite) in southern Lamb County (fig. 9). This mismatch is most evident at the heavy end of the gas chromatograph.

(7) The ratio of ip_{18} and ip_{16} to pristane and phytane is approximately half that of the San Andres oils. This suggests less thermal cracking in the extract.

(8) There is a slight to strong preference for odd-carbon-number molecules on the basis of CPI numbers (fig. 3; table 4). In most cases the degree of odd-carbon-number preference should reflect the degree of immaturity, but analysis of organic content in the Northern Shelf is further complicated because the area was a carbonate/evaporite environment; such environments are normally associated with even-carbon-number preference. Hence, indigenous organic matter in the evaporite environment exhibits even-carbon-number preference, and allochthonous terrigenous organic matter that was washed in during storms and periods of subaerial exposure exhibits strong odd-carbon-number preference. The result is an average CPI number of 1.09 obtained through mixing. (This average excludes the anomalously high CPI value of 1.58 obtained from a Swisher County sample.) This slight preference for odd-carbon numbers contrasts with a CPI of 0.96 for four San Andres oils of the Northern Shelf. This carbon number relationship is one of the criteria for the compositional mismatch between oil and rock extract.

In addition to assessing immaturity, the gas chromatographic spectrum also displays information on the source of organics and on the environment of deposition. The bimodal distribution of normal alkanes for San Andres samples (fig. 3; table 5), previously discussed as an indicator of immaturity, shows one mode located near nC_{17} and another near nC_{23} (table 5). This bimodal distribution reconfirms a hypothesis of dual sources of organic material. The nC_{15} and nC_{17} molecules are typically derived from algal material and the heavier alkanes from terrigenous organics. This variability in source is also reflected by other geochemical parameters, such as the phytane/pristane ratio. Considerable variation exists between the various gas chromatographs (table 5). This variability contrasts with the San Andres oils of the Northern Shelf, which exhibit considerable uniformity.

Interestingly, the sample with the greatest odd-carbon-number preference (Swisher County, Texas) also displays the strongest pristane dominance and a relatively high organic matter index (tables 3 and 4). This relationship might indicate a stronger influx of terrigenous organic material at this location than at other sample wells throughout the Northern Shelf.

Table 5. Normalized paraffin distribution, Yellowhouse dolomite,

County, state	Operator	Well	Depth (ft)	nC_{15}	nC_{16}	nC_{17}	ip_{19}	nC_{18}	ip_{20}	nC_{19}
Randall, TX	DOE-Gruy	Rex White No. 1	1,960-2,030	4.2	4.0	5.9	3.1	6.6	3.2	9.8
Lamb, TX	Argonaut Energy (Crown)	Baumgart No. 1	4,071-4,094	6.0	6.8	7.1	11.7	6.6	11.8	5.3
Lamb, TX	Shell	McCary No. 1	3,892-3,926	3.3	4.1	5.2	4.5	4.9	4.0	4.9
Lamb, TX	Humble	Fowler No. 1	4,075-4,096	4.9	6.4	8.6	6.3	10.0	6.7	8.5
Swisher, TX	DOE-Gruy	Grabbe No. 1	2,693-2,796	10.6	10.9	12.1	6.1	6.8	4.3	5.7
Lamb, TX	Atlantic Oil	Ryan No. 1	3,824-3,872	2.2	2.9	4.1	3.3	4.3	3.8	3.8
Lamb, TX	Felmont	Gray No. 1	3,865-3,894	2.6	3.4	5.3	3.3	6.1	3.8	4.7

*All distribution values reported as percentages.

Conclusions Concerning In Situ Generation of Oil on the Northern Shelf

Although the necessary ingredients for oil generation are present in the San Andres and Clear Fork carbonates of the Northern Shelf, the thermal environment was insufficient to initiate catagenesis. Organic liquids formed by the diagenesis that did occur do not rank as commercial oil deposits, although they could be responsible for minor oil shows, stains, odors, and the asphaltic appearance of some black laminae reported throughout the Northern Shelf. Similar oil shows have also been reported in other immature carbonate sections, such as the South Florida Basin, Florida (Palacas, 1978).

Even if a case could be made for marginal source potential, in situ generation cannot explain the vast oil reserves in the San Andres Formation of the Northern Shelf. To account for these oils, good source rocks must be identified, and migration routes postulated.

MIGRATION OF OIL FROM BASIN TO SHELF

The general concept of oil originating in deep, subsiding basins and being expelled into surrounding shelf-margin facies is widely accepted and has been postulated by researchers for many years (for example, Weeks [1952], Galley [1958], and Jones and Smith [1965], among others). This interpretation is especially significant in the Permian Basin, where many major oil reservoirs rim the deep basins; the relationship between shelf-margin positions and San Andres oil production is illustrated in figure 1. San Andres basinal deposits, however, are too distant (fig. 1) and too cool (as inferred from Dutton's [1980b] data) to be considered adequate source rocks for San Andres oil on the Northern Shelf.

Oil production from Guadalupian (San Andres) rocks is far greater than production from any other stratigraphic unit in the Permian Basin. On the Northern Shelf alone, oil from San Andres shelf facies accounted for more than 80 percent of the cumulative production through 1978 (Texas Railroad Commission, 1979). The overwhelming dominance of San Andres (Guadalupian) oil over Leonardian and Wolfcampian oil exists despite a combined rock volume of Leonardian and Wolfcampian strata approximately twice that of Guadalupian strata. As will be discussed later, these older units also have a much greater source potential than do the younger and shallower Guadalupian rocks, which are mostly shelf carbonates. The following discussion will demonstrate that Wolfcampian basinal deposits of the northern Midland Basin (fig. 22) are the most likely source rocks for the oil within San Andres reservoir rocks.

Source-Rock Potential of Wolfcampian and Leonardian Basinal Deposits of the Midland Basin

Houde (1979) demonstrated adequate source-rock potential in dark-colored argillaceous carbonates and calcareous shales of Spraberry age in the southern Midland Basin. He concluded that oil formed in situ from organic-rich Spraberry basinal rocks.

It follows that if those Leonardian-age (Spraberry) rocks are adequate source beds, then

Palo Duro Basin.*

nC_{20}	nC_{21}	nC_{22}	nC_{23}	nC_{24}	nC_{25}	nC_{26}	nC_{27}	nC_{28}	nC_{29}	nC_{30}	nC_{31}	nC_{32}	nC_{33}	nC_{34}	nC_{35}
11.1	9.0	6.6	5.4	3.3	3.7	3.3	3.4	3.4	3.6	3.1	2.7	1.6	1.4	1.0	0.6
4.5	4.1	4.7	4.9	5.0	3.9	3.6	3.1	3.0	2.5	2.0	1.4	0.7	0.8	0.3	0.2
4.2	4.2	4.8	4.6	4.7	4.7	5.0	5.5	5.4	6.3	6.2	4.7	3.6	2.8	1.6	0.8
5.3	4.3	5.1	4.7	4.6	3.8	3.5	3.3	3.2	3.2	2.8	1.9	1.3	1.1	0.2	0.1
4.0	3.9	3.7	4.9	3.5	4.0	3.1	3.7	3.2	3.3	2.3	1.8	0.7	0.9	0.3	0.3
3.5	4.0	5.5	6.0	5.8	5.8	5.6	5.5	5.7	6.6	6.5	5.5	4.0	3.0	1.7	1.0
3.8	4.4	6.1	6.4	5.6	5.5	5.4	5.9	5.7	6.1	5.1	4.1	2.6	2.2	1.2	0.7

the underlying Wolfcampian basinal facies must have even better source-rock potential, assuming that adequate amounts of suitable organic material are present. Geochemical data (Dutton, 1980b) obtained from cuttings of the Lone Star Bragg No. 1 well, Lynn County, Texas (fig. 22), indicate the approximately 1,000 ft of gray calcareous Wolfcampian shales to be much richer than the overlying Spraberry and underlying Pennsylvanian deposits. Total organic carbon averages 2.8 percent in Wolfcampian strata, reaching a maximum of 4.4 percent, whereas the section of overlying Spraberry and Dean strata averages only 1.2 percent TOC and the underlying Pennsylvanian carbonates average only 0.8 percent TOC. With OMI values averaging less than 3.4, R_o values measuring above 0.6, and modern temperatures ranging from 160° to over 180° F (as determined from bottom-hole temperatures obtained from well logs in the area), the Wolfcampian section undoubtedly possesses good source-rock potential.

The northern Midland Basin during Wolfcampian time was a rather small area between the Horseshoe Atoll to the east and the Abo Reef trend to the west (fig. 22). This rather small, restricted basin was largely surrounded by carbonate terrane; hence, the basinal deposits average 50 to 75 percent carbonate. The clastics, however, average 75 to 100 percent shale, the rest being siltstone and sandstone (Galley, 1958). Mesohaline conditions probably prevailed, and contributed to the deposition of dark basinal limestones. Such limestones are usually rich in organic material and are generally considered good potential source rocks (Kirkland and Evans, 1981).

Distribution of Source-Rock Facies

Wolfcampian basinal shales are relatively thin (1,000 ft) at the Bragg well owing to the underlying Horseshoe Atoll. The shales thicken away from the atoll, especially to the south where they actually have produced oil in a few short-lived fields in Upton County, Texas (Jones and Smith, 1965). West of the atoll, the basinal shale section can be traced (by using well log measurements) to southeastern Yoakum County, Texas, where shales pinch out abruptly against the Abo Reef trend. Maximum thickness of the basinal shales is nearly 2,000 ft (fig. 22). To the northeast in the Palo Duro Basin, the basinal shale section thins and becomes more calcareous (Handford, 1980). Northward into the Palo Duro Basin, TOC values decrease and OMI values increase (Dutton, 1980b). Hence, source-rock potential of Wolfcampian shales decreases to the north, coincident with decreased oil production from the Wolfcampian shelf-margin trend (Texas Railroad Commission, 1979).

Pennsylvanian shales in the southern part of Palo Duro Basin, however, are probable source rocks for the oil recently discovered in Briscoe County; the reservoir rocks are Pennsylvanian (Strawn) shelf-margin carbonates. This is the first oil discovery in the Palo Duro Basin except along its borders; it ought to stimulate much drilling activity along the shelf margins.

Anomalously high fluid pressures and temperatures exist in the Wolfcampian basinal deposits. Temperatures (as determined from bottom-hole readings obtained from well logs) are abruptly higher in basinal deposits than in overlying shelf carbonates in Terry and Yoakum Counties. A potentiometric map of the fluid surface in Wolfcampian deposits in that area (McNeal, 1965, p. 314) shows an anomalous northwesterly dip across the northern Midland Basin, which contrasts with the general easterly dip of the potentiometric surface found elsewhere in the region. This demonstrates present fluid flow from the northern Midland Basin into the Abo Reef trend and the Northern Shelf, even though there is a regional easterly flow in surrounding areas.

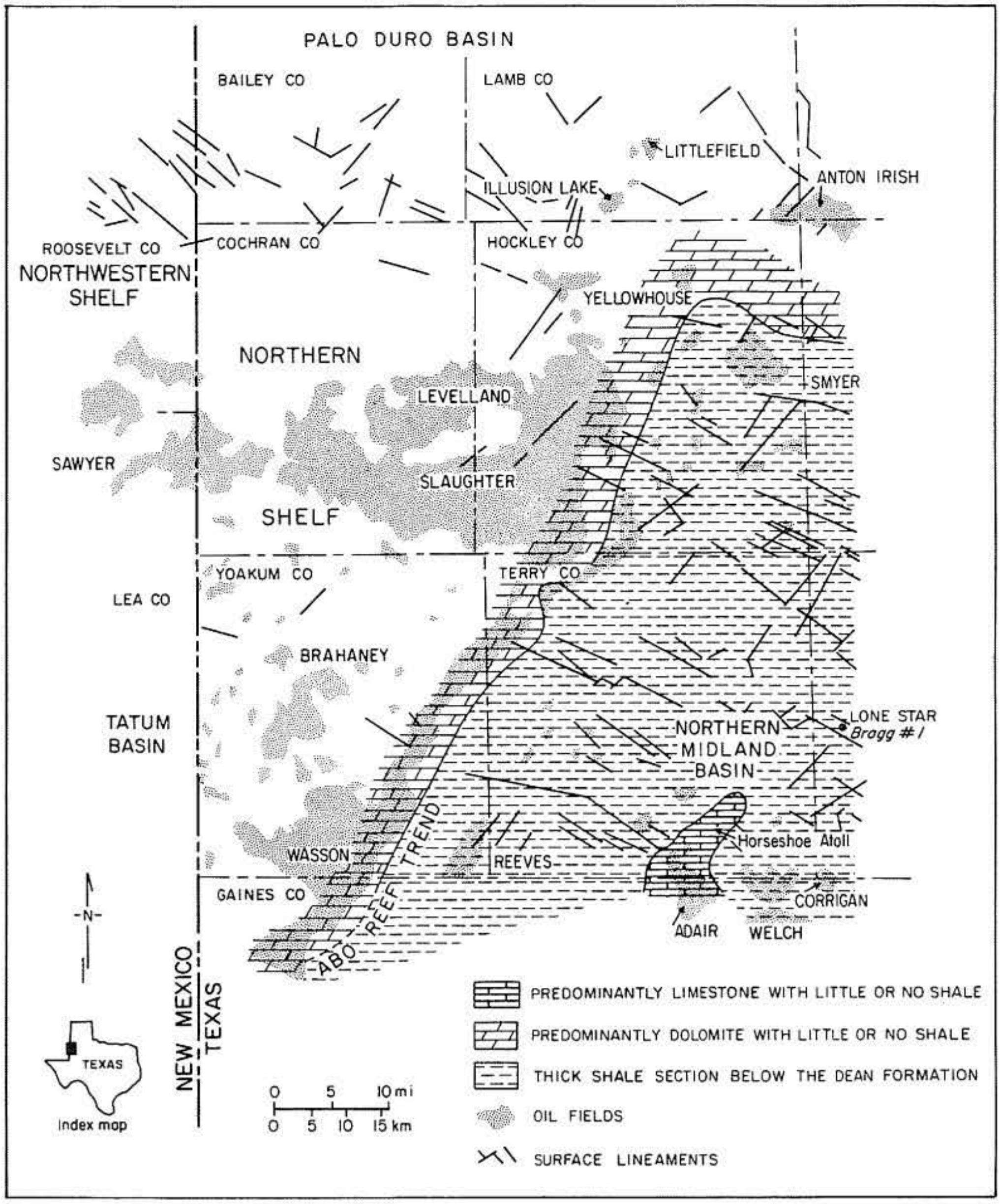


Figure 22. Distribution of source-rock facies.

Significance of the Abo Reef Trend

The Abo Reef trend defines the southeast border of the Northern Shelf and the northwestern margin of the Midland Basin in Gaines, Yoakum, northwest Terry, and Hockley Counties, Texas (fig. 1; Sax and Stenzel, 1968). Infill of the Midland Basin consists of dark shale, silt, fine sand, and argillaceous limestone. These fine-grained basinal clastics can be compacted up to 65 percent when buried under 100 ft of sediment (Weller, 1959, p. 289), whereas shelf and shelf-margin carbonates exhibit considerably less compaction. Differential shale/carbonate compaction can lead to flexure, fracturing, and development of a hingeline just basinward of the shelf-margin buttress. Wright (1962) reported fractures throughout the Abo Reef carbonates. As much as 2,200 ft of abrupt structural relief exists in Leonardian strata across the Abo Reef trend; some of this relief, however, is due to depositional topography (Jeary, 1978).

The abrupt dip along the Abo Reef trend disappears to the northeast, where the Abo shelf edge bifurcates (fig. 1), and the shelf-to-basin transition is poorly defined and ramplike rather than clifflike. Hence, the hingeline effect diminishes northward into the Palo Duro Basin.

The overlying San Andres carbonates drape the irregularly compacted strata, leading to fractures and to oil entrapment where dip is greatest. Similar draping over a Devonian reef buttress in Norman Wells field, Canada, has led to extension joints in overlying strata and vertical transmission of oil from the petroliferous reef via the fractures to the surface (Link, 1952, p. 1508).

The compactible nature of basinal Wolfcampian and Leonardian clastic facies has led to extensive fracturing, as demonstrated by distribution of surface lineaments (fig. 22). Study of figures 12 and 22 shows that the Northern Shelf (away from structural trends such as the Matador Arch) is relatively free of well-defined lineaments; this reflects the lower compactibility of shelf and shelf-margin carbonates as opposed to basinal areas. Lineaments exhibit two dominant trends in the northern Midland Basin—one N. 30° E. to N. 40° E., generally parallel to the shelf-margin hingeline, the other orthogonal. Lineaments near Reeves field exhibit a similar orientation to a fracture system described by Chuber and Pusey (1967; fig. 12). A northeast-southwest fracture system was reported in the Reeves field in southeastern Yoakum County by Chuber and Pusey (1967, p. 139, 150), who state:

> The fractures resulted from overburden compaction forces which appear to have concentrated San Andres breakage along an underlying carbonate shelf edge trend.... After lithification, the weight of the overburden produced a fracture system, which may have provided access routes for oil migration.

Wilkinson (1953) recognized a major N. 25° E. fracture trend and a poorly developed orthogonal set in Spraberry basinal deposits in Midland, Glasscock, Upton, and Reagan Counties, Texas. He attributed the fractures, in part, to gentle subsidence of compacting Spraberry shales; this subsidence "would stretch the pre-existent mass of rocks from the buttressing positive element of the Eastern Platform" (Wilkinson, 1953, p. 263). Such stretching should cause the greatest amount of rupture adjacent to areas of maximum subsidence. Wilkinson also notes that producing Spraberry trends are parallel to the northeast-southwest-trending fractures. Fractures have been reported to be associated with other similar hingeline oil fields, such as Chapman Deep along the northern hinge of the Delaware Basin, Reeves County, Texas (Mazzullo, 1981).

The shelf-margin flexure (drape) in San Andres strata (fig. 12) is a northeast-trending monoclinal fold whose axial plane dips shelfward (to the northwest). Using this structural model, one would expect extension joints in overlying strata. Joints should parallel the shelf-margin buttress, as do the reported fractures and some of the lineaments near the hingeline (fig. 12). Hobbs and others (1976, p. 294) state that joints perpendicular to a fold hinge may also develop; such joints might be responsible for northwest-southeast-trending lineaments near the shelf-margin hingeline (fig. 12).

Compression of the deeper source-rock strata in the inner arc of such a monocline could result in higher fluid pressures and eventual expulsion of those fluids. Such fluid flow from basin to shelf could cause hydrofracturing, further increasing the mobility of the oil.

Strata as young as Dockum (Late Triassic) exhibit up to 250 ft of structural relief over the Abo Reef trend (McGowen and others, 1979), indicating that subsurface compaction and subsidence continued at least after Triassic time.

Expulsion of oil from deep basin to shelf margin was less prolific in the Palo Duro Basin. In addition to the lower source-rock potential of the thinner Palo Duro basinal shales, less relief occurs on the hingeline between basin and shelf. Also, potential San Andres shelf reservoirs are less likely to be porous owing to the abundance of evaporite cement. Superposition of shelf margins along the Abo Reef trend (fig. 1) favors accumulation of large amounts of oil; such superposition does not occur in the Palo Duro Basin.

Compositional Relationships Among Oils of the Abo Reef Trend

In order to test a model of vertical hydrocarbon migration along the Abo Reef trend, compositions of the various oils were studied. If indeed these oils originated from the same basinal (Wolfcampian) source rocks, their compositions should be similar, except for changes related to their respective reservoir environments.

Much of the Northern Shelf oil probably entered the shelf sequence near the giant Wasson field, where structural relief is greatest. The first reservoir encountered by any upward-moving basinal oil would be in the Wichita-Albany Group. Hence, the composition of the oil found within this stratigraphic unit should represent the least-altered basinal Wolfcampian oil.

Within multipay fields along the Abo Reef trend, San Andres and Wichita-Albany oils are compositionally similar, as revealed by correlation index profiles, aromatic profiles (figs. 23 to 25), liquid and gas chromatographic analyses (figs. 26 and 27; table 6), and the hydrogen/carbon ratio of the asphaltic component (table 6). The major difference between San Andres and Wichita-Albany correlation index profiles is the presence of an aromatic hump exhibited by the San Andres oil (figs. 23 to 25). This difference, however, can be explained through biodegradation of the San Andres oil

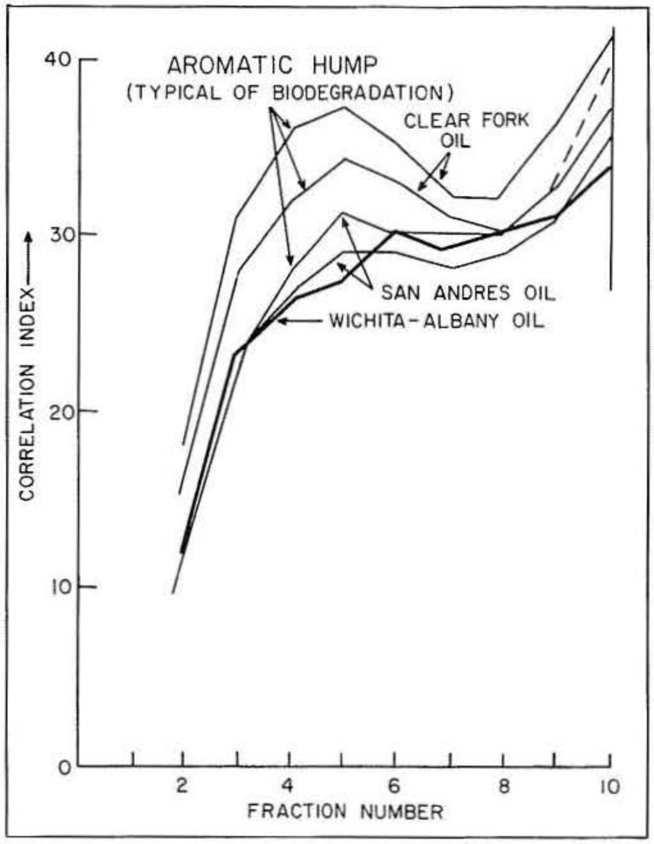


Figure 23. Correlation index profiles for five oils, Abo Reef trend, eastern Wasson field, Gaines and Yoakum Counties, Texas.

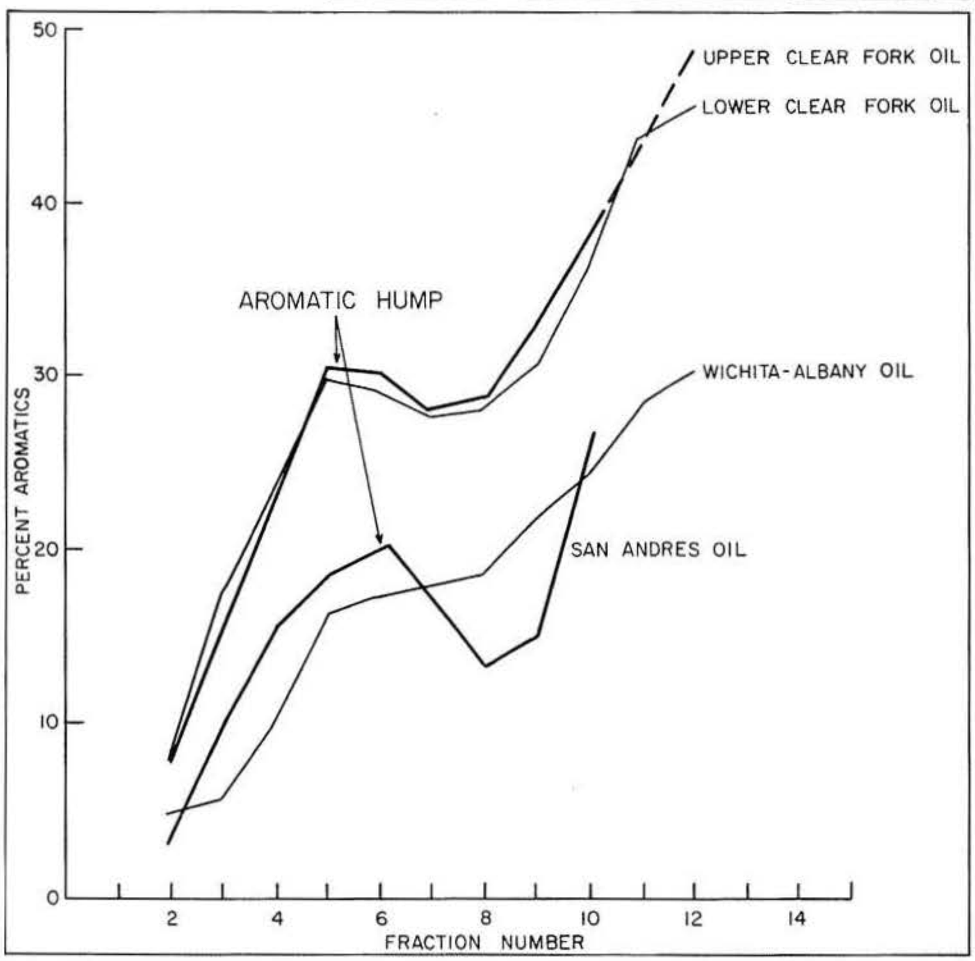


Figure 24. Aromatic profiles for four oils, Abo Reef trend, eastern Wasson field, Gaines and Yoakum Counties, Texas.

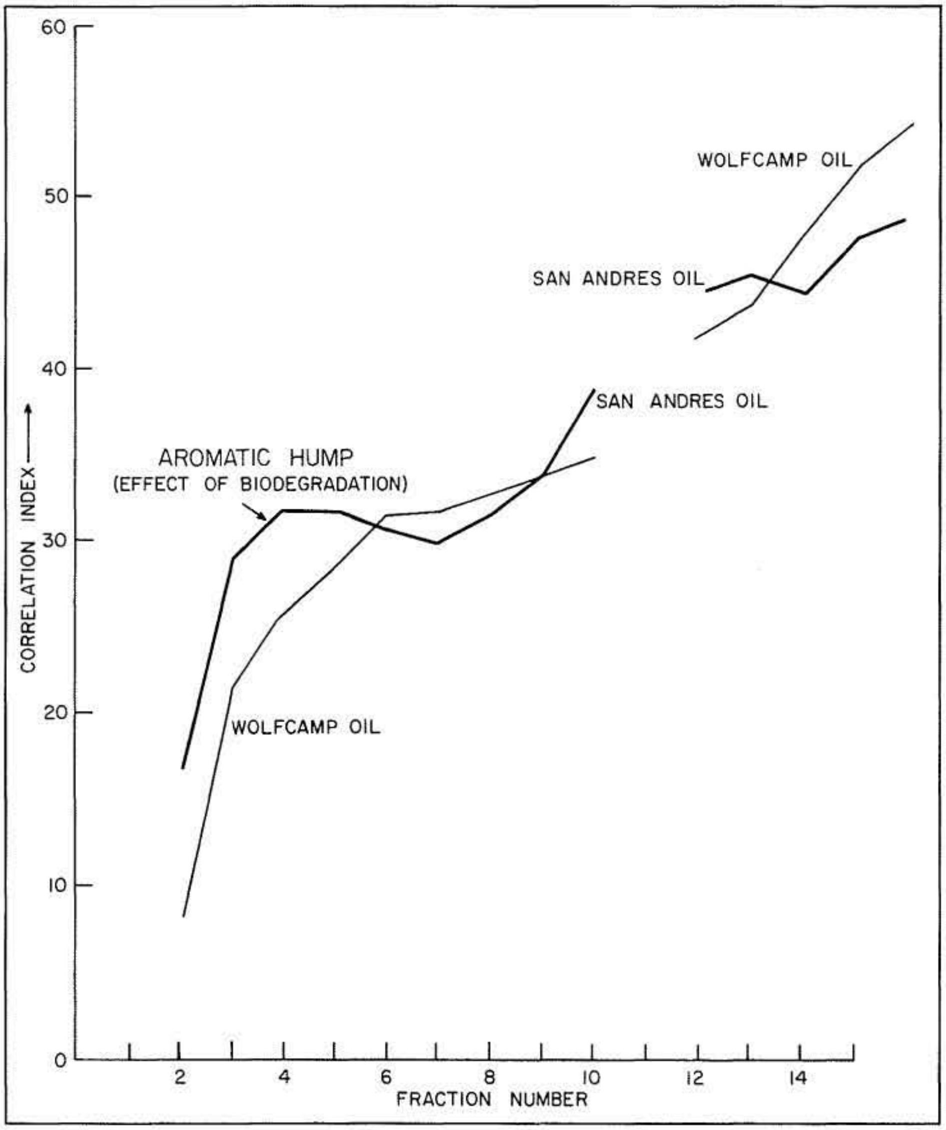


Figure 25. Correlation index profiles for Wolfcamp and San Andres oil from multipay Adair field, Terry County, Texas. Gap in profile indicates change in laboratory testing procedures.

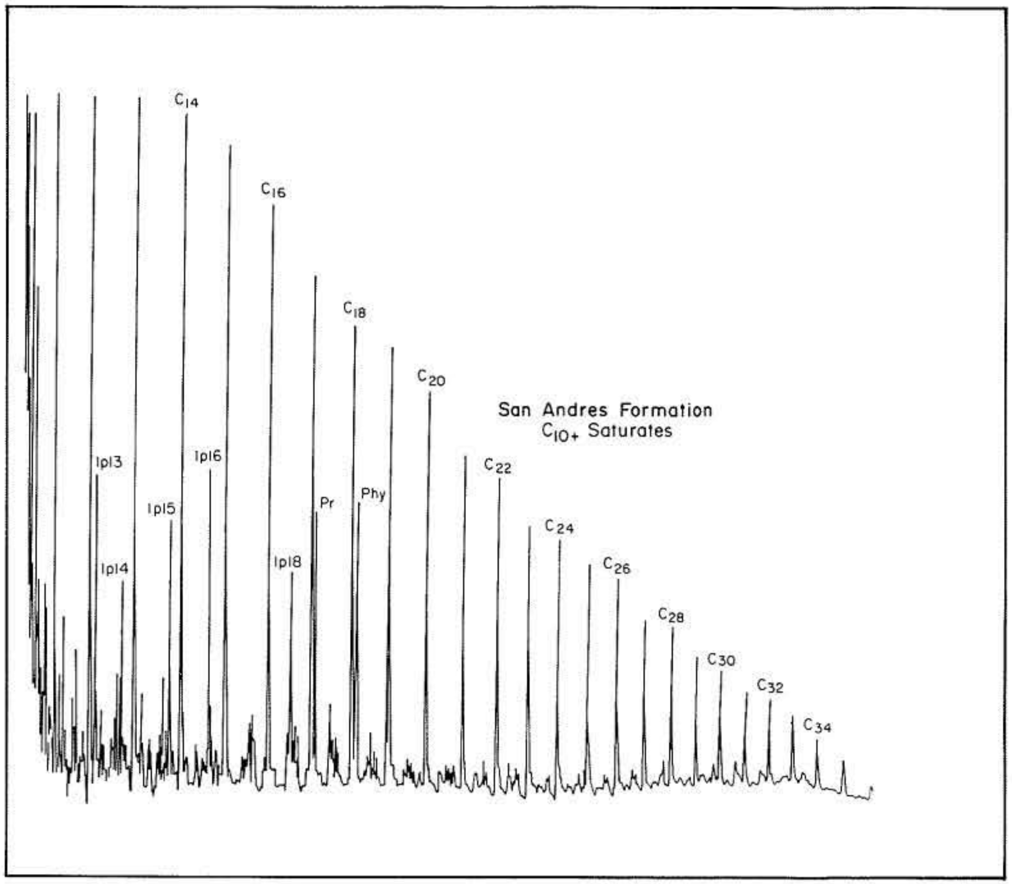
(Jones and Smith, 1965), a topic that will be discussed below.

Correlation index profiles indicate that Clear Fork oils (fig. 23) differ from San Andres and Wichita-Albany oils. This difference may be related to somewhat different source rocks (basinal Leonardian instead of basinal Wolfcampian beds) that have different levels of thermal maturity. The strong aromatic hump displayed by these oils probably indicates greater biodegradation.

Gas chromatographs of Wichita-Albany oil and San Andres oil from the eastern Wasson field (fig. 26) indicate similar distributions of n-alkanes and isoprenoids. The San Andres oil, however, is slightly enriched in isoprenoids compared with n-alkanes, which may indicate a slight degradation of the oil. Nevertheless, the gas chromatography spectra suggest that the two oils are genetically related.

Sequence of Oil Migration from the Northern Midland Basin

Compositional relationships among the oils of the Abo Reef trend may best be explained by the timing of oil expulsion from the basin. Expulsion of oil can occur only after temperature sufficient for maturation is reached during burial. Continued burial will then aid expulsion. Wolfcampian shales in the northern Midland Basin reached this stage before overlying Leonardian source beds did; hence emplacement of Wolfcampian oils in equivalent Wolfcamp or Wichita-Albany shelf-margin reservoirs occurred first. Oil migration up vertical fractures along the shelf-margin hingeline into the younger Clear Fork and San Andres reservoirs also occurred at this time. Excellent reservoir conditions throughout the San Andres shelf favored



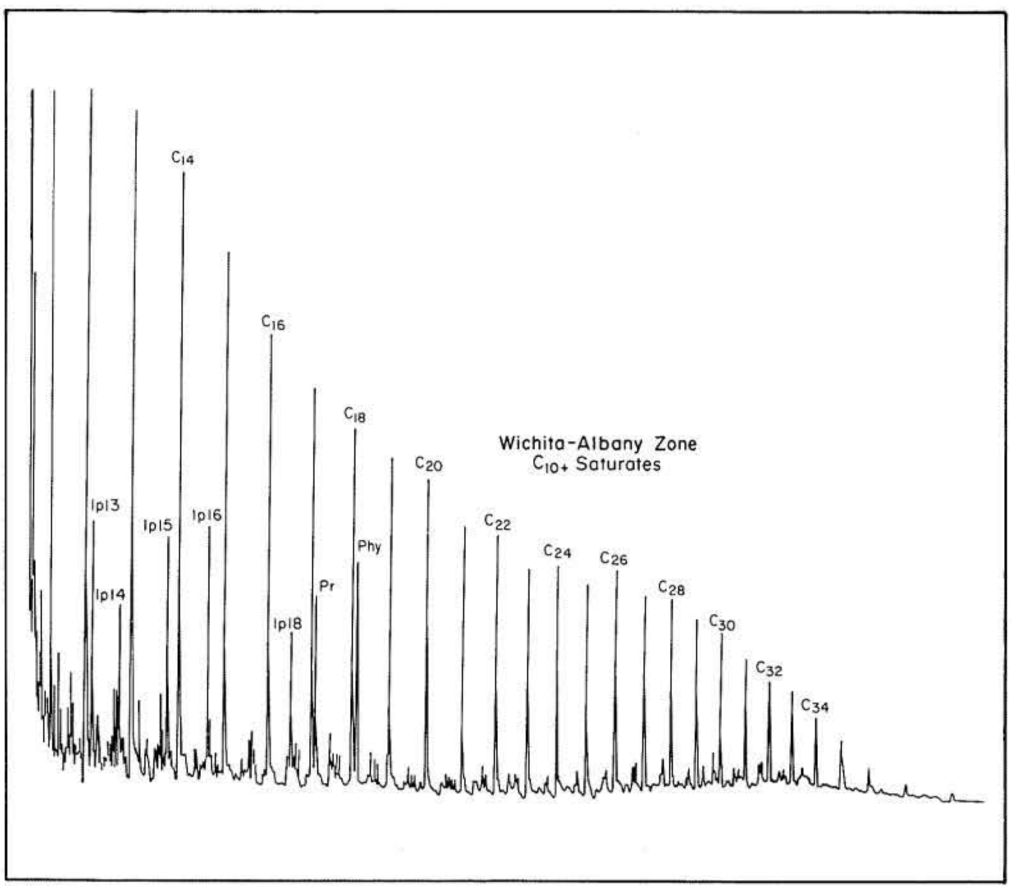


Figure 26. Gas chromatographs of San Andres (top) and Wichita-Albany (bottom) oil, Abo Reef trend, eastern Wasson field, Gaines County, Texas.

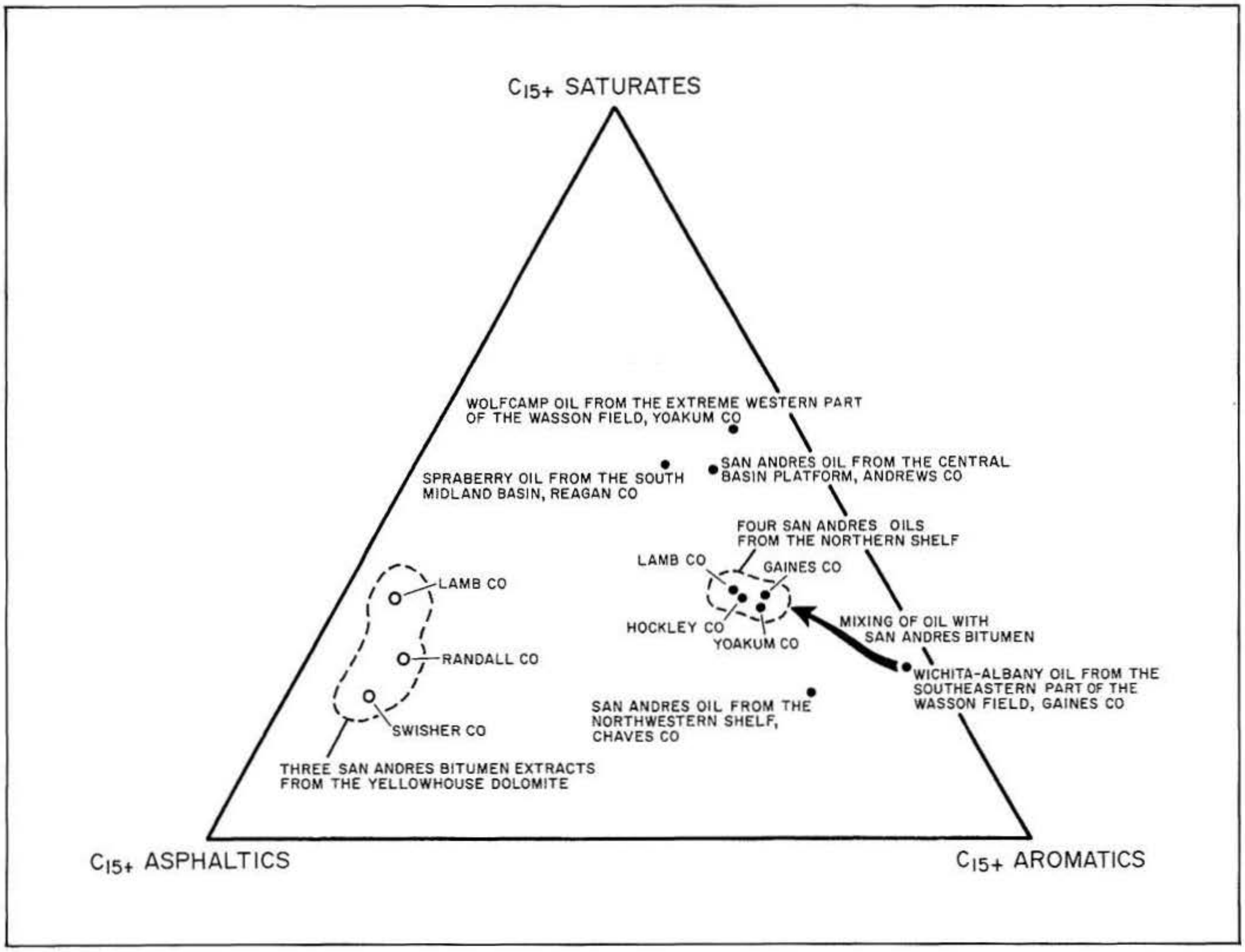


Figure 27. Ternary diagram of oils and extracts of the study area.

widespread accumulation. Structural closure of the largest accumulation (Wasson field) was well developed by the end of the Permian (Schneider, 1943, p. 507). Sometime thereafter, burial became sufficiently deep for the expulsion of Leonardian oils and subsequent emplacement in laterally equivalent Clear Fork reservoirs; this Leonardian oil, however, was probably less prolific than the oil that was previously expelled from Wolfcampian strata. After emplacement of Wolfcampian and Leonardian basinal oil into San Andres and Clear Fork reservoirs, biodegradation altered the composition of the oil, a topic that will be discussed below.

Oil Migration South and West of the Northern Midland Basin

Migration apparently occurred also between source beds in the southern Midland Basin and reservoirs of the Central Basin Platform. However, differences in the basinal source rocks and varying amounts of biodegradation that occurred on the Central Basin Platform complicate comparisons. Additionally, the complex structural relationships on the Central Basin Platform caused a mixing of the oils, some of which are as old as Ellenburger (Stenzel, 1965, p. 247; Williams, 1965). For the above reasons, developing a complete source model for Central Basin Platform oils would be far more difficult than that for the Northern Shelf oils.

The composition of oils in San Andres reservoirs in eastern New Mexico and westernmost Texas may have been modified by additional oil expelled from the Tatum Basin in northeastern Lea County, New Mexico. Prolific production rims the Tatum Basin (fig. 14). Composition of Wolfcampian oil from the westernmost part of Wasson field (table 6) contrasts with the other Northern Shelf oils, reflecting this inferred difference in source.

Table 6. Liquid and gas chromatographic analyses of various oils in the study area.

Field, county, state	Depth (ft)	Saturates* (%)	Aromatics* (%)	Asphaltics* (%)	H/C in the asphaltics	PH/PR	CPI no.	$\frac{ip_{16} + ip_{18}}{PR + PH}$	Province	Reservoir age
VARIOUS UNRELATED OILS IN THE REGION										
Twin Lakes, Chaves, NM	2,530-2,630	19.8	63.4	16.8	-----	1.47	0.96	1.07	Northwestern Shelf	San Andres
Crossroad, Roosevelt, NM	-----	-----	-----	-----	-----	-----	0.94†	-----	Northwestern Shelf	San Andres
Martin, Andrews, TX	4,300	51.4	36.1	12.5	-----	0.84	1.00	1.13	Central Basin Platform	San Andres
Spraberry, Reagan, TX	6,400-7,100	52.0	29.9	18.1	-----	0.78	1.11	0.82	Southern Midland Basin	Spraberry
Western Wasson, Yoakum, TX	8,421-8,584	56.7	36.4	6.9	1.14	0.76	1.04	1.02	Western part of Northern Shelf	Wolfcampian
GENETICALLY RELATED NORTHERN SHELF OILS										
Illusion Lake, Lamb, TX	4,070-4,140	34.0	47.2	18.8	1.36	1.08	0.96	0.87	Northern Shelf	San Andres
Levelland, Hockley, TX	4,707-4,818	33.2	48.2	18.6	1.36	1.07	0.96	0.85	Northern Shelf	San Andres
Ownby West, Yoakum, TX	5,254-5,360	31.9	51.4	16.7	1.39	1.07	0.97	0.85	Northern Shelf	San Andres
Wasson, Gaines, TX	4,904-5,031	34.1	50.7	15.2	1.37	1.04	0.96	0.95	Northern Shelf	San Andres
Wasson, Gaines, TX	7,753-7,849	23.4	73.5	3.1	1.26	1.15	0.98	0.98	Northern Shelf	Wichita-Albany

†From Bray and Evans (1961)
*Of the C_{15+} fraction

Table 7. General characteristics of principal oils in the Midland Basin.

Field, county, state	S (%)	N (%)	API°	N/S	Residuum (%)	Depth (ft)	Viscosity (sec/100° F)	Cumulative production (10^6 bbl) as of Jan. 1, 1979 (Texas Railroad Commission, 1979)
DEGRADED SHELF DAUGHTER OIL								
SAN ANDRES, NORTHWESTERN SHELF								
*Twin Lakes, Chaves, NM	3.04	0.091	24.5	0.030	30.7	2,530-2,630	48	-----
Crossroad, Roosevelt, NM	-----	-----	23.8	-----	-----	-----	-----	-----
SAN ANDRES, NORTHERN SHELF								
*Illusion Lake, Lamb, TX	2.18	0.110	28.6	0.050	29.3	4,070-4,100	54	1.9
Yellowhouse, Hockley, TX	2.15	0.11	30.0	0.051	28.5	4,500-4,600	54	8.7
*Levelland, Hockley, TX	2.12	0.136	31.1	0.064	28.3	4,707-4,818	48	293.5
Slaughter, Hockley, TX	1.90	0.089	32.3	0.047	26.7	5,000-5,250	45	763.0
Buckshot, Cochran, TX	2.79	0.10	25.0	0.036	34.6	4,950	86	9.2
Landon, Cochran, TX	2.11	-----	31.5	-----	27.7	4,900-5,030	48	5.4
Brahaney, Yoakum, TX	2.45	0.122	28.4	0.050	32.9	5,301	59	29.4
*Ownby West, Yoakum, TX	2.38	0.107	28.4	0.045	31.9	5,254-5,360	51	0.8
Ownby, Yoakum, TX	2.28	0.101	29.7	0.044	30.8	-----	56	8.0
Reeves, Yoakum, TX	1.77	0.092	33.8	0.052	26.5	4,968-4,998	42	19.5
*Wasson, Yoakum, TX	1.90	0.081	32.8	0.043	27.8	4,900-5,150	43	1,118.9
Cedar Lake, Gaines, TX	2.04	0.092	33.0	0.045	27.1	4,600	46	61.3
Adair, Terry, TX	2.04	-----	33.0	-----	26.4	4,866-4,927	44	40.3
Welch, Dawson, TX	2.13	0.092	32.8	0.043	27.2	4,901-4,967	47	105.6
Seminole, Gaines, TX	1.86	0.104	33.6	0.056	20.6	5,240-5,270	43	274.0
Seminole West, Gaines, TX	2.11	0.108	31.9	0.051	25.4	5,009	48	26.5
GMK, Gaines, TX	1.98	0.095	30.8	0.048	27.9	5,648-5,662	48	9.0
	2.13†	0.103†	31.0†	0.048†	28.2†	-----	51†	2,775.0‡
RELATIVELY UNALTERED PARENT BASINAL OIL								
SPRABERRY, BASINAL								
Spraberry Deep, Dawson, TX	0.17	-----	37.2	-----	25.5	6,770-6,811	41	8.8
	0.30	-----	37.6	-----	-----	6,400-6,675	-----	
Spraberry Deep W., Dawson, TX	0.16	0.14	35.8	0.88	-----	7,018	-----	5.1
	0.22	0.21	36.4	0.95	-----	6,420	-----	5.0
Jo Mill, Borden, TX	0.11	0.118	37.4	1.07	-----	7,300	-----	48.6
Arthur, Borden, TX	0.14	0.127	36.2	0.91	-----	7,565	-----	10.0
Breedlove, Martin, TX	0.16	0.130	40.9	0.81	-----	7,937	-----	0.9
Spraberry Trend, Midland, TX	0.11	0.120	39.2	1.09	24.9	8,000	40	204.6
Benedum, Upton, TX	0.07	0.105	38.2	1.50	-----	7,423-7,642	-----	21.2
	0.14	-----	40.2	-----	-----	7,560-7,615	-----	
*Spraberry, Reagan, TX	0.09	0.099	38.4	1.10	26.4	6,400-7,100	45	8.6
	0.15†	0.131†	38.0†	1.04†	25.6†	-----	42†	312.8‡

(continued)

Table 7 (continued)

Field, county, state	S (%)	N (%)	API°	N/S	Residuum (%)	Depth (ft)	Viscosity (sec/100° F)	Cumulative production (10^6 bbl) as of Jan. 1, 1979 (Texas Railroad Commission, 1979)
WOLFCAMPIAN, NORTHERN SHELF								
*Wasson, Yoakum, TX (Wichita-Albany)	0.31	0.047	41.3	0.15	17.2	8,204-8,404	37	23.5
Brahaney, Yoakum, TX	0.19	0.069	41.1	0.36	-----	9,028	-----	0.3
Adair, Terry, TX	0.38	0.089	40.4	0.23	15.0	8,434-8,540	37	44.5
	0.29†	0.068†	40.9†	0.25†	16.1†	-----	37†	68.3‡
CLEAR FORK, NORTHERN SHELF								
Anton Irish, Lubbock, TX	2.54	0.167	28.9	0.066	25.1	6,003-6,132	49	1.9
Anton Irish, Hale, TX	2.14	-----	31.0	-----	-----	5,498-5,888	-----	113.3
Smyer, Hockley, TX	3.04	0.111	24.9	0.037	34.1	5,850-5,875	55	24.8
Wasson, Yoakum, TX	1.10	0.06	33.2	0.055	21.7	7,006-7,340	42	
	1.60	0.087	31.0	0.054	23.1	6,402-6,804	43	82.3
	1.40	0.07	31.9	0.050	-----	6,338-6,686	-----	
Prentice, Terry, TX	2.08	0.086	28.7	0.041	29.6	6,580-6,730	47	
	2.66	0.096	29.1	0.036	27.1	5,966-5,984	44	111.9
Prentice, Yoakum, TX	2.60	0.109	25.9	0.042	-----	6,460-6,760	-----	
Russell, Gaines, TX	1.23	0.081	34.6	0.066	21.7	7,350-7,700	39	48.0
	2.04†	0.96†	29.9†	0.050†	26.1†	-----	46†	382.2‡

*Samples analyzed by gas chromatography †Average values of fields sampled ‡Total production from fields reported

Source: Texas Railroad Commission (1979). Compositions are from Coleman and others (1978), and open files of BETC.

SAN ANDRES OIL OF THE NORTHERN SHELF

Composition

Sulfur content of San Andres oil is normally slightly more than 2 percent (for BETC analyses, see Coleman and others [1978]; table 7), making this oil a sour crude with resulting strong odors. API gravity determinations range from 25° to 33°; most values are above 28° (Coleman and others, 1978; table 7). On the average, San Andres oils of the Northern Shelf are the most aromatic oils of the Permian Basin, except for upper Clear Fork oils of the Northern Shelf (fig. 5). Other BETC analyses also indicate a similar composition for San Andres oils throughout the Northern Shelf (table 7).

In all, the 18 San Andres oils from the Northern Shelf that were analyzed exhibit good to excellent correlation, meaning that they constitute a distinctive group (for correlation index profiles for 10 of these oils, see fig. 4). As illustrated in figure 5, a wide variety of aromatic profiles is possible among oils of different stratigraphic units; correlation index profiles of unrelated oils from the Permian Basin also show great variability.

This distinctive group of San Andres oils encompasses southern Lamb, Hockley, Cochran, Yoakum, Terry, northern Gaines, and northwestern Dawson Counties, Texas. Western limits are not defined owing to a lack of BETC analyses for San Andres oils in Roosevelt and northern Lea Counties, New Mexico.

Liquid and gas chromatographic analyses of the C_{10+} saturate fraction further document the compositional similarity of four San Andres oils of the Northern Shelf (to emphasize this genetic similarity, five unrelated oils are included for comparison in table 6) (fig. 27). The four San Andres

Northern Shelf oils are from wells in Illusion Lake in Lamb County, Levelland in Hockley County, Ownby West in Yoakum County, and Wasson in Gaines County, Texas. These widely spaced but uniform oils are highly aromatic. The C_{15+} component contains 47 to 51 percent aromatics, 32 to 34 percent saturates, and 15 to 19 percent asphaltics (fig. 27; table 6). San Andres oils exhibit a slight preference for even-carbon-number chains as well as a slight preference for phytane over pristane. These characteristics, along with the high aromatic content, have been associated with oils originating in restricted carbonate or evaporite environments, or both (Tissot and Welte, 1978, p. 386). Such environments existed in the northern Midland Basin during Wolfcampian time, as previously mentioned.* In general, Wolfcampian oils are more aromatic than older Permian Basin crudes (fig. 5) whose source rocks were probably deposited under less restrictive conditions.

San Andres oils are richer in C_{15+} saturates and asphaltics (table 6) than is the Wichita-Albany oil (which is closer to the source). This difference may be caused by contributions from immature in situ organic material (bitumen) within the San Andres carbonates. Bitumen from the San Andres Formation is highly asphaltic and naphthenic in the C_{15+} fraction (fig. 27; table 4), and thus would dilute the aromatic content and enrich the saturate and asphaltic fractions. Other slight compositional differences between San Andres and Wichita-Albany oils, such as phytane/pristane and hydrogen/carbon ratios of the asphaltic component (table 6), can also be explained on the basis of mixing. Higher temperature of the Wichita-Albany reservoir may have also contributed to slight compositional variations between San Andres and Wichita-Albany oils, especially affecting the hydrogen/carbon ratio.

Production Data

The greatest volume of oil was trapped in the southeastern part of the Northern Shelf, either on or near the underlying Abo Reef trend. Wasson, Reeves, Cedar Lake, Adair, Welch, Seminole, Seminole West, and GMK oil fields account for nearly 70 percent of the cumulative San Andres production on the Northern Shelf through 1978 (all production data from Texas Railroad Commission [1979]). Most of that production was from the Wasson field, mainly from the eastern section (Schneider, 1943, p. 509); basinal source rocks are subjacent to this area of high oil production.

The Levelland and Slaughter trend in the updip (northern) part of the Northern Shelf accounts for another 38 percent of San Andres production on the Northern Shelf; remaining fields produce only 2 percent of the total. Three Northern Shelf oil fields, Wasson, Levelland, and Slaughter, account for about 78 percent of the total San Andres production.

DEGRADATION AND FLUSHING OF EMPLACED SAN ANDRES AND CLEAR FORK OILS

On the basis of evidence presented, it can be concluded that the San Andres oils on the Northern Shelf of the Midland Basin are genetically related and are not indigenous to the shelf carbonates in the reservoir section. Source for this oil is mostly Wolfcampian basinal calcareous shales of the northern Midland Basin. The oil migrated shelfward toward the Abo Reef trend where it was expelled upward through vertical fractures into porous San Andres carbonates. The next concern is what happened after emplacement.

Biodegradation

Late Cretaceous uplift in New Mexico exposed Permian strata, initiating a west-to-east flow of moderately fresh ground water. This is confirmed by McNeal's (1965) potentiometric surface map of San Andres fluids. Passage of this water, most likely contaminated with bacteria, through anhydrite-rich San Andres and Clear Fork reservoirs has caused degradation and flushing of the oil in a downdip direction.

The composition of any particular oil depends not only on its source but also on its reservoir. Much work has focused on the bacterial degradation of oil in reservoirs, particularly that of western Canada (Evans and others, 1971; Bailey and others, 1973a; Deroo and others, 1977). Researchers all concluded that normal alkanes and light naphthenes are preferentially oxidized to CO_2, resulting in an enrichment of sulfur-rich asphaltenes.

Neglia (1979) differentiates the effects of aerobic and anaerobic attack. Aerobic bacteria require

*In this case the restricted carbonate or evaporitic environment is mesohaline and should not be confused with the highly evaporitic environment associated with San Andres strata.

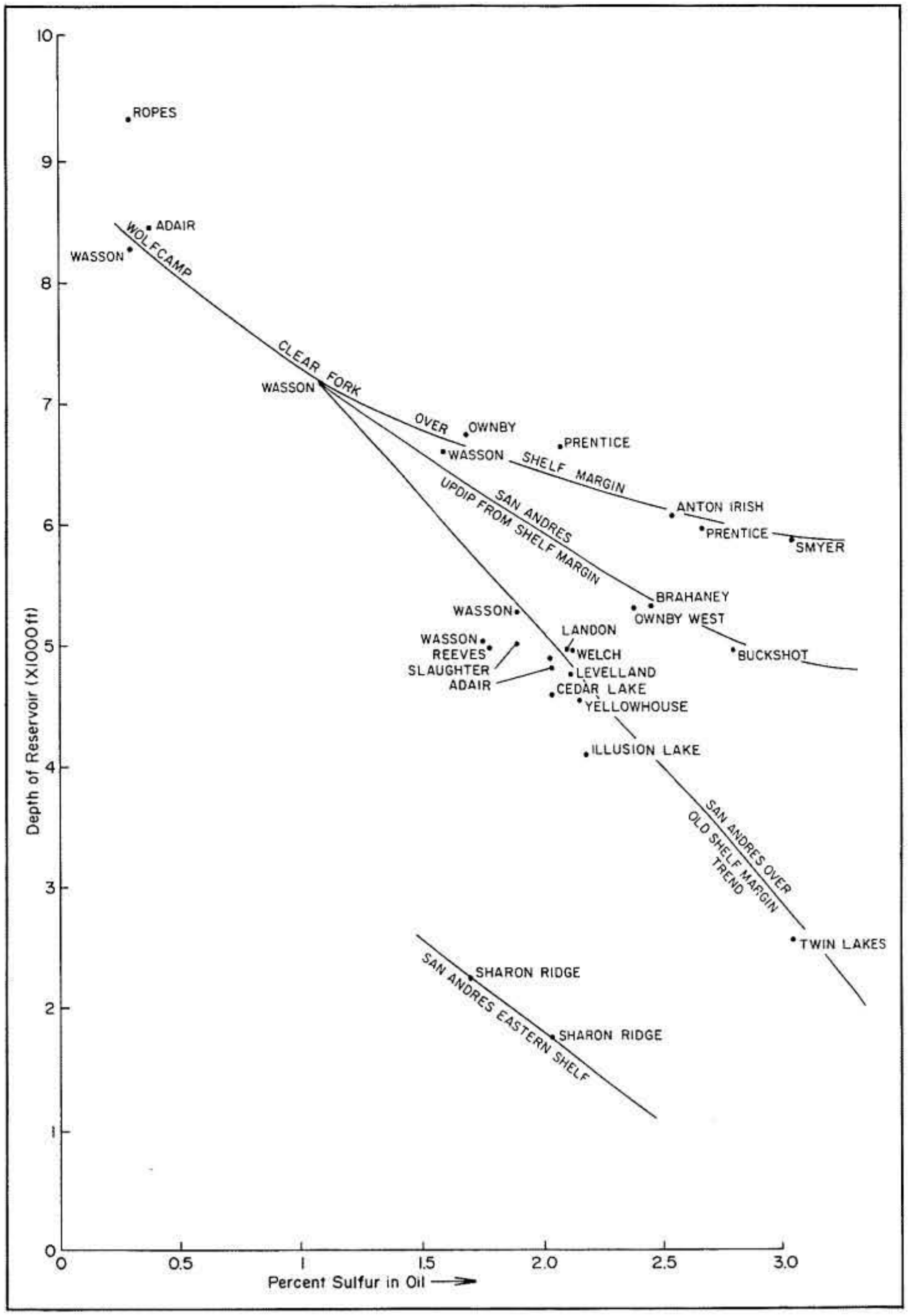


Figure 28. Percent sulfur versus depth of reservoir for various oils in study area.

dissolved oxygen to survive; anaerobic bacteria, however, can flourish in sulfate-rich reservoirs by reducing sulfate to sulfur, thus producing their oxygen supply. As a result, there is an actual addition of sulfur to the oil (Bailey and others, 1973b, p. 1288). The sulfur may then "dehydrogenate" naphthenes, producing aromatics and H_2S. These bacterial reactions favor low temperatures (20° to 50° C) and are strongly reduced above 65° C.

Biodegradation of San Andres and Clear Fork oils by anaerobic sulfate-reducing bacteria is a hypothesis used by Jones and Smith (1965, p. 162) to explain the association of highly sulfurous and aromatic oil in the anhydrite-rich reservoirs of the Northern Shelf. This association between sulfur, aromatics, and sulfate is documented and mapped by Belt and McGlasson (1968) for Yeso oils; they also find that these oils are isotopically heavier with respect to carbon.

Jones and Smith (1965, p. 126, 190) demonstrate that biodegraded oils have an anomalously high aromatic content in certain low boiling fractions. The correlation index and aromatic profiles (figs. 4, 5, and 23 to 25) illustrate this aromatic anomaly with a maxima or aromatic hump at fractions 4, 5, and 6. They demonstrate that these boiling fractions are rich in toluene and xylenes. In fact, Wasson and Slaughter oils contain more than 1.5 percent toluene, whereas "most crude oils do not exceed 0.80 percent toluene" (Smith, 1968, p. 75). This finding is consistent with a chemical property of toluene; that is, it is very resistant to biodegradation (Bailey and others, 1973b, p. 1287). Hence, the aromatic hump represents a residual enrichment of certain light aromatics in relation to other light hydrocarbons that have been preferentially depleted. Because aromatics have higher correlation index values than other hydrocarbons with similar boiling points, correlation index values increase for those boiling fractions, causing the aromatic hump. The relationship between the aromatic hump and biodegradation was restated by Barker (1979) and Hunt (1979, p. 387-388). Wolfcampian and Wichita-Albany oils, however, exhibit the normal gradual increase in correlation index values with boiling fraction (figs. 23 and 25) because there is no preferential enrichment of light aromatics.

Isoprenoids are more resistant to biodegradation than n-alkanes; hence, upon degradation the proportion of isoprenoids to n-alkanes should increase. The C_{10+} gas chromatographs (fig. 26), however, indicate that San Andres oil is only slightly more depleted in n-alkanes relative to isoprenoids than is Wichita-Albany oil. However, diagnostic changes on the correlation index profile appear in lower boiling-point fractions and, hence, would not be reflected in gas chromatographic values of the C_{10+} saturates (higher boiling points). For the same reason, the C_{15+} aromatic content does not reflect the preferential enrichment of toluene (C_7H_8) and other light aromatics that occurs during biodegradation. Apparently biodegradation was not strong enough to greatly affect the higher boiling-point fractions.

Parent, unaltered basinal oils such as Spraberry in the southern Midland Basin (fig. 1) are sweet crudes, rich in naphthenes (Jones and Smith, 1965) and low in sulfur (table 7). Spraberry is particularly rich in nitrogen and naphthenes (Jones and Smith, 1965). In contrast, the daughter San Andres and Clear Fork oils of the Northern Shelf are sour crudes, highly aromatic and sulfurous (table 7). In addition, these altered oils have lower API gravities and are generally more viscous (table 7).

Figure 28 indicates the relation between depth of reservoir and sulfur content. Shallow reservoirs are subject to greater amounts of biodegradation and are therefore richer in sulfur. Three separate gradients are generated: Clear Fork oils, San Andres oils over a shelf margin, and San Andres oils landward of a shelf margin. For San Andres oils, the landward gradient defines higher sulfur contents than the gradient generated from fields along older shelf-margin trends. Landward areas received more anhydrite deposition and, hence, sulfurization is more pronounced. Likewise, the same process causes Clear Fork oils to be more sulfurous; Schneider (1943) found that Clear Fork strata in the Wasson field are more anhydritic than overlying San Andres strata.

Biodegradation reaches a maximum on the Northwestern Shelf because of the very shallow, anhydrite-rich reservoirs and their proximity to ground-water recharge areas to the west. All of the diagnostic qualities of degraded oil, such as low API gravity (fig. 14), high sulfur and aromatic content, aromatic hump on correlation index and aromatic profiles, and high viscosity, are quite pronounced for oils on the Northwestern Shelf. Some oil stains and seeps reported in outcrop may, in fact, be mature San Andres oil that was heavily degraded as it migrated updip to the surface.

Downdip Flushing of San Andres Oils

McNeal's (1965, p. 315) potentiometric surface map of San Andres fluids indicates a general west-to-east flow of ground water. Structural trends, like those near the Yellowhouse - Illusion Lake - Littlefield trend (fig. 15), cause local variations from the mostly west-to-east flow direction (flow is mostly north to south along this trend).

Ground-water movement has caused oil/water contacts to tilt in the direction of flow (Otte, 1974). True dip of these contacts can be determined directly from elevation data on top of reservoirs and the lateral limits of oil production. This dip ranges from 0.3° to 0.5° downdip (the direction of flow). This conforms to the theoretical dip of roughly 0.5°, on the basis of Hubbert's (1953) equation:

$$\tan \theta = \frac{\rho w}{\rho w - \rho oil} \frac{\Delta h}{\Delta x}$$

where θ is the dip of the oil/water contact,

ρw is the density of the underlying water ($\approx$1.2),

ρoil is the density of the oil ($\approx$0.88), and

$\frac{\Delta h}{\Delta x}$ is the lateral pressure gradient from the potentiometric surface map ($\approx$10 ft/mi or 0.0019).

Oil production is slightly offset from the structural crests in the direction of flow as predicted by Hubbert (1953, p. 2000-2005).

CONCLUSIONS

San Andres oils on the Northern Shelf were derived mostly from Wolfcampian basinal deposits in the northern Midland Basin. Primary migration of fluids occurred from the basin toward the Abo Reef trend. Vertical fractures caused by hingeline compactional effects at the shelf margin facilitated vertical migration into the stratigraphically higher San Andres and Clear Fork shelf and shelf-margin carbonate reservoirs. Draping and subsequent fracturing of San Andres and Clear Fork strata over the irregularly compacted substratum along the Abo shelf-margin buttresses improved conditions for development of porosity by meteoric waters during periods of subaerial exposure. Such draping also produced trap closures.

Extensive porous dolomites in the lower San Andres Formation are widespread petroleum reservoirs on the Northern Shelf. Lateral updip migration of oil to the north and west has occurred in these discrete porous and permeable stratigraphic units. Updip to the north, replacement of pore space by secondary anhydrite defines a northern limit for oil migration. The vast Levelland - Slaughter - Cato trend of Texas and eastern New Mexico results from this regional porosity pinch-out. Farther north, thick salt beds directly overlie the potential San Andres dolomite reservoir beds. Salt-filled pore voids exist throughout most of the Palo Duro Basin. Long-range updip migration of San Andres oil beyond the southern fringe of the Palo Duro Basin is, therefore, highly unlikely.

Although adequate source-rock potential does exist in underlying Pennsylvanian and Wolfcampian shales of the Palo Duro Basin, the same mechanism that moved oil up along the Abo Reef trend was probably inoperative in the Palo Duro Basin. Here, migration was blocked, because of the thick impervious evaporite and red-bed section above and below potential San Andres carbonate reservoirs. Also the sharp shelf-to-basin break present along the Abo Reef trend is missing in the Palo Duro Basin. Some of the reported oil shows and oil stains in the Palo Duro Basin may, however, be due to small amounts of such oil.

In situ source-rock potential in San Andres and Clear Fork carbonates is inadequate. However, a small amount of organic diagenesis did occur and may be responsible for some reported oil shows and stains. Evidence indicates mixing of limited indigenous organic material with oil that migrated from Wolfcampian basinal source rocks.

Very limited source-rock potential exists within the San Andres Formation. Blockage of migration routes precluded migration of oil into these units within most of the Palo Duro Basin. Consequently, the petroleum resource potential for the San Andres in the Palo Duro Basin is bleak.

Late Cretaceous tilting exposed Permian strata in New Mexico. As a result, Permian reservoirs east of the new recharge zone were invaded by relatively fresh ground water. As this water passed through the anhydrite-rich aquifers, sulfate-reducing anaerobic bacteria attacked saturated hydrocarbons, causing an enrichment in light aromatics and sulfurous compounds. All San Andres oil on the Northern Shelf has been affected in a similar manner, resulting in a uniform composition for these oils. This biodegradation had a greater effect on shallow reservoirs. Degradation of oil reaches a maximum in shallow reservoirs near the Pecos River, New Mexico. Here, some oil stains and seeps reported in outcrop may be mature San Andres oil that has been heavily degraded during updip migration to the surface.

ACKNOWLEDGMENTS

Ella Mae Shelton and Joe L. Lacina kindly helped acquire data at the Bartlesville Energy Technology Center. Perry Ganus of Shell, Richard Houde of Conoco, Carl Bizzell of Depco, Larry Wooten of Argonaut Energy, Neil Petersen of Superior Oil, and Roy Bauer of Amoco provided data and samples. Assistance also came from two coworkers, formerly with the Bureau of Economic Geology: Kinji Magara (now a private geological consultant) provided guidance and shared ideas about fluid expulsion; Mark Presley (now with Delta Drilling) provided guidance and encouragement throughout the project. Research was funded by the U.S. Department of Energy under contract numbers DE-AC97-79ET44614 and DE-AC97-80ET46615.

The manuscript was critically reviewed by L. F. Brown, Jr., Kinji Magara, William Galloway, Amos Bein, D. R. Baker, and Shirley Dutton.

Fannie M. Sellingsloh, under the direction of Lucille C. Harrell, Bureau of Economic Geology, typeset the manuscript. Rebecca P. Lasley edited the report. John T. Ames, Mark T. Bentley, Micheline R. Davis, Margaret R. Day, Jeffrey Horowitz, and Jamie McClelland, under the direction of J. W. Macon, Chief Cartographer, drafted the figures. Judy P. Culwell conceived the cover design and Jamie S. Haynes completed it. The layout was designed by Jamie S. Haynes.

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