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POTENTIAL FOR PETROLEUM RESOURCES IN THE PALO DURO BASIN AREA, TEXAS PANHANDLE

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CAUTION

This report describes research carried out by staff members of the Bureau of Economic Geology that addresses the feasibility of the Palo Duro Basin for isolation of high-level nuclear wastes. The report describes the progress and current status of research and tentative conclusions reached. Interpretations and conclusions are based on available data and state-of-the-art concepts, and hence, may be modified by more information and further application of the involved sciences.

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POTENTIAL FOR PETROLEUM RESOURCES IN THE PALO DURO BASIN AREA

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INTRODUCTION

Investigations of the petroleum potential of the Palo Duro Basin have been underway since 1978. This report contains the results of, as yet, unpublished studies carried out during the 1983-84 fiscal year.

The section of this report dealing with pre-Pennsylvanian units in the basin represents the final results of work done on these rocks. Work is continuing on Pennsylvanian and younger strata as further data become available. The second part of this report presents additional data recently gathered on these units.

PRE-PENNSYLVANIAN
(Ruppel)

Introduction

From the standpoint of oil and gas exploration, the Palo Duro Basin is an enigma. Despite the drilling of about 1,000 exploration tests, there is currently no commercial production from the basin. This is surprising in light of the abundant production established in surrounding basins such as the Anadarko, Midland, and Hardeman (fig. 1).

In spite of the lack of exploration success in the basin, optimism has generally remained high. Many previous workers (Totten, 1956; Best, 1963; Soderstrom, 1968) have ascribed this lack of success to the relative sparsity of wells drilled in the area (approximately 7 wells per 100 square miles;

3 wells per 100 square kilometers). Dutton (1980a, 1980b; Dutton and others, 1982), for example, recently concluded that the Palo Duro contains all the prerequisites for oil generation and production: source rocks, sufficient thermal maturity, reservoir rocks, and traps (see, however, Birsa (1977) for an alternative view). The recent discovery, though short-lived, of oil in the Pennsylvanian of Briscoe County in the center of the basin seems to support her analysis.

Although Dutton (1980 a & b) has adequately characterized Pennsylvanian and younger units in the Palo Duro Basin, the potential of the pre-Pennsylvanian rocks in the area is less well known. Dutton's work on thermal maturity (Dutton, 1980b) indicates that Pennsylvanian deposits have reached the oil window. This implies that Mississippian and older rocks should be well within the zone of optimum petroleum-producing conditions. In a preliminary report, Ruppel (in Dutton and others, 1982) indicated that sufficient porosity exists throughout the pre-Pennsylvanian sequence. However, to date, no really comprehensive study of these rocks has been published. This report documents the source rock potential, thermal maturity, and porosity and permeability of these pre-Pennsylvanian rocks.

Methods

Geochemical (total organic carbon, kerogen, and vitrinite reflectance) studies were carried out on samples from 58 wells (figs. 2 and 3). In most cases, geochemical analyses were performed by Geo-Strat, Incorporated, Houston, Texas. A few samples were sent to a second lab for comparative purposes.

All wells used in this study have been assigned unique county/number designations for easy reference (for example, Childress 10). A complete list of all wells referred to in the text is given in Appendix A.

Source Rock Potential

The source rock quality of any rock (that is, a rock's potential for producing hydrocarbons) is dependent on (1) the organic matter content, (2) the type of organic matter, and (3) the thermal maturity of the organic matter. Because shales commonly contain significant amounts of organic matter, they are generally considered to have the greatest source-rock potential. Carbonate rocks, however, also have the potential for producing hydrocarbons. In fact, because these rocks generally contain organic matter that is more oil-prone than that found in shales, carbonates have the potential of being more effective as source rocks than are shales. It is generally accepted that shales must contain a minimum of 0.5% total organic carbon (TOC) to produce commercial quantities of hydrocarbons (Tissot and Welte, 1978). Carbonates, on the other hand, may generate hydrocarbons with as little as 0.12% TOC (Geochem Laboratories, 1980). Hydrocarbon shows have been reported from both Ordovician (fig. 4) and Mississippian (fig. 5) rocks in the Palo Duro Basin indicating that oil has been generated. The source of this oil is unknown. Therefore, it is important to consider the source rock potential of the pre-Pennsylvanian sequence in the Palo Duro in spite of the fact that it contains almost no shale.

Organic Matter Content

Analyses for total organic carbon (TOC) were performed for 51 wells in the Palo Duro and Dalhart Basins. Samples from seven additional wells in the Hardeman Basin were analyzed for comparative purposes. In all, a total of 113 samples were analyzed (Table 1), 72 from cuttings, 41 from core. To avoid possible contamination from Pennsylvanian shale cavings, all cuttings were picked to remove most of the shale fragments. Complete TOC data are presented in Appendix B.

In general, the TOC content of the pre-Pennsylvanian carbonates of the Palo Duro Basin is low. The average value is 0.107 percent (Table 1). This is lower than average values reported for carbonate rocks elsewhere (0.20% TOC; see Tissot and Welte, 1978; Hunt, 1979) and is also below the minimum usually required for carbonate source rocks (0.12-0.30% TOC). There is, however, a great deal of heterogeneity among the pre-Pennsylvanian units (Table 1).

Ellenburger carbonates generally contain little TOC (average 0.09%). These values agree with those obtained from the largely equivalent Arbuckle Group in southern Oklahoma by Cardwell (1977). Cardwell concluded that the Arbuckle and the Ellenburger have little potential to generate hydrocarbons because of low organic matter content. Limestones of the Meramec Group in the Palo Duro and Dalhart Basins also contain little TOC and are thus unlikely source rocks. Values obtained from Chester rocks are higher; however, this may be due to the difficulty of obtaining clean carbonate samples from this commonly shaly interval. The difficulty in separating cavings from overlying Pennsylvanian shales precluded TOC analysis of Chester shales. Total organic carbon in the Osage Group, although variable, is generally higher than in other pre-Pennsylvanian carbonates. The average value recorded for the Osage (0.12% TOC) is marginally above the minimum value required for carbonate source rocks (GeoChem Laboratories, 1980). However, 41 percent of the Osage samples contained more than 0.16% TOC and 16 percent contained more than 0.20% TOC. Highest TOC values in the Osage are found in the northeastern and eastern edges of the Palo Duro Basin (fig. 6). These areas generally coincide with those areas thought to represent deeper, more open-marine conditions. Organic matter content in these areas is everywhere above 0.10% TOC and in some cases above 0.25% TOC. Therefore, although TOC values are generally low in the pre-Pennsylvanian, local areas with at least minimal amounts of organic matter do exist.

Carbonates in the hydrocarbon-producing Hardeman Basin have TOC contents generally similar to those observed in the Palo Duro and Dalhart Basins, although one sample produced a high value of 0.668% TOC. Two samples from shales of the Barnett Formation show that this unit is a much more likely source rock (Table 1).

Organic Matter Type

Only that fraction of organic matter contained in sedimentary rocks that is insoluble in organic solvents (kerogen) has the potential for producing hydrocarbons. Kerogen is composed of both sapropelic and humic materials. Sapropel consists of plant material (algal and amorphous debris) primarily of aquatic origin (Hunt, 1979). Because this material is rich in lipids, it is the most likely source of liquid hydrocarbons. Humus, on the other hand, is kerogen derived primarily from terrestrial plants. Woody humic material (vitrinite) has little potential for oil generation, but is capable of producing gas, usually at somewhat higher temperatures. Inertinite, humic kerogen that consists of carbonized and decomposed plant materials has no potential for hydrocarbon generation.

Kerogen contained in the pre-Pennsylvanian carbonates of the Palo Duro and Dalhart Basins is predominantly sapropelic (average 70%; Table 2). On the average, amorphous kerogen (presumably sapropel) and exinite (herbaceous sapropel that has a somewhat lower oil-generating potential) are subequal. Osage rocks contain a somewhat high amount of amorphous sapropel. Vitrinite is relatively uniform (average 16%) throughout. Identifiable algal material is very rare. Organic matter indices (OMI, see Appendix C) also indicate that the best organic matter assemblages occur in the Osage. A geographic plot of these values reveals a relationship between the interpreted depositional setting of the Osage Group and the distribution of organic matter (fig. 7). The highest percentages of sapropelic kerogen (lowest OMI values) are found in the eastern part of the Palo Duro Basin where apparently deeper water depositional conditions prevailed. A similar relationship between water depth and kerogen type was observed by Dutton (1980b) in Pennsylvanian rocks. Although the Osage Group contains the most oil-prone organic matter among pre-Pennsylvanian carbonates, it should be pointed out that values obtained for younger (Pennsylvanian and Permian) shales are generally better (that is, have a lower OMI).

Results of kerogen analysis of samples from the Hardeman Basin are similar to those described above. The percent of sapropelic kerogen is similar; purer carbonates tend to have slightly higher values than do shales or mixed lithologies (Table 3).

Thermal Maturity

According to Hunt (1979), the thermal history of a source rock is the most important factor in hydrocarbon generation. Hydrocarbons will not be produced no matter how much organic matter is present if a certain level of thermal maturity has not been reached. There is some disagreement about the amount of heating required to generate hydrocarbons. Most studies, however, indicate that while minor amounts of hydrocarbons may be generated during diagenesis of sediments, most oil production occurs during catagenesis (122°F to 300°F; 50°C to 150°C). Intense oil generation generally occurs between 150°F (65°C) and 300°F (150°C)--the oil window (Pusey, 1973). Time of heating, however, is also an important factor (Connan, 1974). Thus, it is the thermal history that determines the maturity of organic matter present.

The present degree of heating in the Palo Duro Basin area can be approximated by calculations of geothermal gradient. Figure 8 is a map of geothermal gradients derived from subsurface borehole log data in the area. Where possible, only temperatures recorded in carbonate (Mississippian or Ordovician) or basement rocks were utilized (this was true for most of the basinal areas). This procedure was followed to reduce local perturbations in gradient common in more heterogeneous lithologies due to differences in thermal conductivity. Analysis of these data reveals no systematic variations among data points. Because measured bottomhole temperatures generally underestimate true conditions (Tissot and Welte, 1978; Connan, 1974), log temperatures were corrected using an empirical curve developed for the Anadarko Basin by Cheung (1975). The resulting map (fig. 8) is similar to most determinations of geothermal gradients in the area (AAPG and USGS, 1976; Woodruff, unpublished map). It should be noted that this map does differ significantly from that published by Dutton (1980a). Her map shows generally lower gradients probably because she used a mean surface temperature of 75^{o}F (24^{o}C) for the area. Climatic data for the region indicate mean surface temperatures of 55^{o}F (13^{o}C) to 62^{o}F (17^{o}C) for the area. Birsa (1977) also derived lower gradients for the area. His data, however, were not corrected to account for nonequilibration.

The data presented in figure 8 illustrate a general west to east increase in geothermal gradient across the Texas Panhandle. Lowest gradients are found in Deaf Smith and Castro Counties. The average gradient for the Palo Duro Basin, however, is about 1.3^{o}F/100 ft (23.7^{o}C/km). Such a gradient implies that sufficient heating to produce catagenesis and the beginning of oil generation (122^{o}F; 50^{o}C) would occur at a depth of about 4,800 ft. The zone of maximum oil generation (the oil window) would be encountered at about 7,000 ft. Essentially all Mississippian and Ordovician rocks in the Texas Panhandle lie below 4,800 ft (1,460 m); most pre-Pennsylvanian rocks in Palo Duro and Hardeman Basins lie well below 7,000 ft (2,135 m). Therefore, unless the geochemical gradient was lower in the past, nearly all pre-Pennsylvanian deposits in the area have reached at least the minimum temperatures necessary to generate hydrocarbons; most deposits should have reached considerably higher temperatures.

In order to estimate thermal maturity, however, it is necessary to know the duration of heating. Since, in most areas of the Palo Duro Basin, the Mississippian is overlain by at least 7,000 ft (2,135 m) of Pennsylvanian and Permian rocks, most pre-Pennsylvanian deposits acquired temperatures sufficient to generate significant quantities of hydrocarbons (150^{o}F; 65^{o}C) at least 230 million years ago (the end of the Permian). Application of these data to any of the methods of estimating thermal maturity (Lopatin, 1971; Posey, 1973; Connan, 1974; Barker, 1979) results in the conclusion that most of these rocks should have entered the maximum zone of oil generation (the oil window).

These conclusions are based on the assumptions that (1) the geothermal gradient was not significantly lower in the past 230 million years from what it is today and (2) that the Palo Duro Basin can be considered a continuously subsiding basin. Although periods of nondeposition and/or erosion occurred in the Mesozoic and early Cenozoic, geologic studies suggest that very little of the sedimentary column has been removed. This implies that depths of burial were never substantially greater than they are now. Therefore, the area can be assumed to have behaved essentially as a continuously subsiding basin throughout most of its history (Mississippian to late Cenozoic). The assumption that heat flow (geothermal gradient) has remained relatively constant is more difficult to confirm.

Changes in geothermal gradient during basin evolution are most commonly interpreted by observation of changes in organic materials. Studies have shown that organic matter alters in a relatively predictable and irreversible fashion due to heating through time. Changes in kerogen color, vitrinite reflectance, and conodont color are some of the more popular methods employed in recent years to determine thermal maturity.

Kerogen color ranges from yellow to black, depending on the degree of heating it has undergone. Staplin (1969) related these color changes to a numerical scale creating a Thermal Alteration Index (TAI). Modifications of this scale have been devised by others (Schwab, 1977; Geochem, 1980). Although based on subjective determinations, TAI is widely used in assessing general thermal maturity. TAI values were obtained for 15 samples (13 wells) in the Palo Duro and Dalhart Basins (Table 2) and nine samples (6 wells) in the Hardeman Basin (Table 3). An average value of 3.08 (scale of Schwab, 1977) for the pre-Pennsylvanian carbonates of the Palo Duro/Dalhart Basins suggests that these rocks are transitional between immature and mature (Schwab, 1977). This TAI value, which is based primarily on Mississippian samples (14 of 15), agrees well with data gathered by Dutton (1980b) for younger rocks: Pennsylvanian, 3.01 TAI; Permian Wolfcamp, 2.95 TAI; Permian Leonard, 2.91 TAI. Although these data reflect a general increase in maturity with geologic age, they also suggest that most of the rocks in the Palo Duro or Dalhart Basins have not matured beyond the transition between immature and mature. TAI values from the Hardeman Basin average 3.73, indicating that the pre-Pennsylvanian there has reached a substantially higher state of maturity. This correlates with the higher geothermal gradient (1.4^{o}F/100 ft) presently observed in that area (fig. 8).

Usable measurements of vitrinite reflectance were obtained from 11 samples in the Palo Duro/Dalhart Basins and six samples in the Hardeman Basin (Tables 2 and 3). The data for the Palo Duro/Dalhart Basins average 0.44% R_o, but are directly proportional to depth (fig. 9). Although vitrinite reflectance data are commonly used to determine thermal history, the interrelationships between reflectance and paleotemperature are not well understood. Dow (1977) believes that although oil formation begins at 0.5% R_o, the peak zone of generation is associated with maturation levels of 0.6% R_o. Others have suggested maturation levels as low as 0.40 or 0.45% R_o. Most, however, associate a reflectance value of 0.5% R_o with the beginning of catagenesis and the onset of peak oil generation (Tissot and Welte, 1978; van Gijzel, 1982), although Tissot (1984) pointed out that this is dependent on the type of organic matter present. A best fit line through the reflectance data gathered for the Palo Duro/Dalhart area (fig. 9) suggests that, on the average, 0.5% R_o is reached at about 7,500 ft (2,285 m). Values of 0.5% R_o or higher occur as high as 6,400 ft (1,950 m), however. Much of this spread in the data can be explained by variations in the geothermal gradient. There is a generally positive relationship between R_o and geothermal gradient in the area. Thus, there is relatively good agreement between (1) the degree of maturation expected, assuming a geothermal gradient of 1.3^{o}F/100 ft) and (2) actual maturation observed based on vitrinite reflectance. The dotted line in figure 9 reflects the expected R_o/depth relationships assuming (1) a gradient of 1.3^{o}F/100 ft (23.7^{o}C/km), (2) 0.5% R_o equals 150^{o}F (65^{o}C), and (3) a reflectance value of 0.2% R_o occurs at the surface (Dow, 1977). The similarity between expected and observed maturation levels in the Palo Duro/Dalhart Basins indicates that (1) geothermal conditions in the past were not substantially different from those today and (2) the area has behaved essentially as a continuously subsiding basin that has not been buried significantly deeper in the past than it is today.

A considerably different situation is indicated for the Hardeman Basin. Vitrinite reflectance values obtained from samples in Hardeman County (Table 3) are much higher (average 0.75% R_o). Although the present geochemical gradient is generally higher in the Hardeman Basin area (average 1.4^{o}F/100 ft; 25.5^{o}C/km), the R_o values are well above those expected for current depths of burial. These values imply a higher geothermal gradient or greater depth of burial in the past. At a constant geothermal gradient (1.4^{o}F/100 ft;

25.5°C/km), an additional 1,100 ft (335 m) would be required to produce the observed thermal maturity in the Hardeman Basin (fig. 10). More data are necessary to fully evaluate this possibility.

Conodont color can also be used as a guide to thermal maturity. Epstein and others (1977) devised a color alteration index (CAI) based on observed color changes in experimentally heated and naturally occurring conodonts. Colors range from pale yellow (CAI = 1) to black (CAI = 5). Conodonts have been recovered from core taken in four wells in the Palo Duro/Hardeman area. Average CAI values increase with depth (fig. 11) as expected. Epstein and others (1977) calibrated conodont CAI with R_o based on relatively few measurements of vitrinite reflectance. The data from the present study indicate that their correlations need to be revised. Comparison of R_o values and CAI in the Palo Duro and Hardeman basin area indicates, for example, that a CAI of 2.0 is equivalent to about 0.5% R_o (fig. 9); Epstein and others (1977) suggest that 2.0 equals at least 0.85% R_o. All data indicate that CAI values represent R_o values lower than those suggested by Epstein and others (1977).

Pre-Pennsylvanian Carbonates as Source Rocks

Studies of vitrinite reflectance indicate that most pre-Pennsylvanian rocks in the Palo Duro and Dalhart Basins should have reached the minimum level of thermal maturity necessary for liquid hydrocarbon generation. Kerogen analyses show that suitable organic matter is present. However, most of these deposits probably contain insufficient TOC to be potential source rocks. The Mississippian Osage Group may be an exception, especially in the northeastern and eastern parts of the Palo Duro Basin where some of these rocks have TOC contents of 0.2% and higher. The potential for pre-Pennsylvanian-sourced hydrocarbons elsewhere in the Palo Duro (or in the Dalhart) Basin is very low.

Source rock potential is much greater in the Hardeman Basin. Thermal maturity is significantly higher and some Mississippian carbonates contain as much as 0.6% TOC. The Barnett Shale, which contains even higher amounts of TOC, is the most important candidate as a source of liquid hydrocarbons in this area.

Other Potential Sources

Dutton (1980a, 1980b; Dutton and others, 1982) has shown that Pennsylvanian and Permian shales in the Palo Duro Basin have source rock potential. These deposits contain up to 1.0% TOC and above. Vitrinite reflectance data (Dutton and others, 1982) indicate that Pennsylvanian rocks are marginally mature (average 0.52% R_0) and Permian rocks marginally immature (average 0.49% R_0). Based on these measurements, Pennsylvanian rocks appear to be slightly more mature than older rocks. This may be related to the observation that threshold temperatures for hydrocarbon generation appear to be lower in carbonates than in shales. Connan (1974) speculated that carbonates contain less clays which may have a catalytic action. Pennsylvanian reflectance data indicate that 6,000 ft (1,830 m) to 7,000 ft (2,135 m) of burial are required to produce sufficient heating (150^{o}F; 65^{o}C) to generate significant quantities of liquid hydrocarbons (0.5% R_0). These calculations are thus in agreement with those performed for pre-Pennsylvanian rocks and support the idea that present geochemical gradients and depths of burial are not greatly changed from those in the past (Dutton, 1983).

Porosity and Permeability

Estimates of Porosity

Porosity values were calculated for pre-Pennsylvanian rocks in 56 wells in the Palo Duro Basin (Table 4) using available geophysical borehole logs. For most of these wells (49) only sonic logs were available; for the rest, bulk density or neutron logs were used to calculate porosity. Average porosity values were determined for ten-foot intervals throughout the pre-Pennsylvanian section; from these, average values were calculated for each lithologic unit in each well. A limestone matrix was assumed throughout the pre-Pennsylvanian section except where sample log data indicated the presence of dolomite. The Ordovician (Ellenburger Group), for example, is essentially all dolomite in the area.

Porosity data on the Chester Group is largely restricted to the eastern part of the Palo Duro Basin (fig. 12). Wells in this area exhibit generally similar average porosity values. The overall average for these rocks is 7.2% (Table 4). However, within the Chester a wide variation in porosity is indicated (0%-33% among ten-foot intervals). Many of the high values observed, however, probably indicate the presence of noncarbonate lithologies. The Chester is known to contain significant quantities of shale and sandstone at various sites throughout the basin. Because a limestone matrix was assumed for the entire unit, these zones appear as anomalously high porosity intervals. Therefore, the overall porosity of the Chester is somewhat less than is indicated.

Meramec Group rocks appear to be the least porous pre-Pennsylvanian deposits in the area (average 4.4%). Because the Meramec is quite homogeneous (little shale or dolomite is present), calculated values are probably more accurate than for other Mississippian units. Although porosities appear, for the most part, to be relatively consistent throughout the lateral and vertical extent of the Meramec (fig. 13), some trends are apparent. With few exceptions, average well porosities of greater than 5% occur only in the northern nd western parts of the basin where overlying Chester rocks have been removed by erosion. In fact, porosity in the Meramec seems to vary directly with distance from the Chester erosional limit (fig. 13). This strongly suggests that Meramec porosity in these areas may have been enhanced by the uplift and partial erosion of the area at the end of the Mississippian. Similar erosion-related porosity is known from the Chester and Meramec in the Anadarko Basin.

In many wells, a slight increase in porosity is noted where the Meramec grades downward into the generally more porous Osage Group. Visible porosity reported on sample logs from wells, in southern Hale County for example, also indicates this trend. Sample logs also record Meramec porosity in other wells for which quantitative data are not available. The Meramec is particularly porous in northwestern Briscoe County; twenty to 100 ft (6 to 30 m) of porous carbonate have been reported for every well in the area.

Although the average porosity calculated for the Osage Group is relatively low (average 6.5%), many wells in the area exhibit significantly higher porosities. Relatively high values (greater than 5%) are observed throughout the central and western parts of the Palo Duro Basin, for example (fig. 14). These are areas that are characterized by high proportions of dolomite. In addition to having higher average porosities, the Osage in these areas contains significant thicknesses of section in which porosities exceed 10 percent (fig. 15). Areas that contain primarily clean limestone, on the other hand, such as the northeastern, eastern, and southern parts of the basin, are characterized by generally low values (fig. 14).

Sample log data generally support porosity trends indicated on borehole logs. Minor increases in apparent porosity observed at the base of the Osage section in some wells in the southern and eastern parts of the basin are caused by the presence of shales and minor sandstones of the so-called Kinderhook Group and are probably not effective. Basal Osage ("Kinderhook") sandstones present in the northern part of the Palo Duro Basin in Donley County are exceptions. In Donley 50, for example, the approximately 50 ft (15.2 m) of sandstone at the base of the Mississippian contain an average porosity of about 23% (maximum of 31%).

The dolomites of the Ellenburger Group exhibit the highest (average 8.8%) and most uniform porosities observed in the pre-Pennsylvanian rocks of the area (Table 4). No general vertical or horizontal porosity trends (fig. 16) are apparent in the Ellenburger in the Palo Duro Basin area, although in some producing areas, increased porosity values have been reported from the top of the unit due to erosion (Bradfield, 1964).

The basal (Cambrian?) sandstones that are present in the eastern parts of the basin also contain local porosity. Although no logs are available to calculate quantitative values, resistivity logs indicate significant porosity in most wells where these sandstones occur.

According to Levorsen (1967), most reservoirs contain porosities of 5 to 30%. This indicates that, with the exception of the Meramec Group, all pre-Pennsylvanian carbonates in the Palo Duro Basin area contain sufficient porosity to act as petroleum reservoirs (the Chester, Osage, and Ellenburger Groups each have average porosities greater than 5%). Actually, because carbonates may contain secondary as well as intergranular porosity, it may be that some of these units (including the Meramec) have higher porosities than have been calculated. This is because sonic logs are incapable of resolving secondary porosity but indicate only intergranular void space. Examination of available core confirms that secondary porosity is present.

Porosity Types

The general scarcity of cores in the Dalhart and Palo Duro Basins makes porosity characterization difficult. Studies of core from producing areas in the Anadarko, Hardeman, and Midland Basins indicate that all types of porosity including intergranular, vugular, and fracture porosity are encountered in the Mississippian and Ordovician (Ellenburger) in these areas. In the productive Mississippian carbonate buildups in the Hardeman Basin, for example, secondary porosity produced by dolomitization is combined with fracture porosity in most areas to produce highly permeable reservoirs (Allison, 1979).

A variety of porosity types are also observed in the Childress 10 well. Minor porosity is ubiquitous in the Meramec grainstones. Most commonly, this porosity takes the form of original void space in bryozoan zooecia. Primary intercrystalline and interparticle porosity is also present. Traces of secondary interparticle and intraparticle porosity and microfracture porosity are less common.

Most of the porosity in the Osage Group is also concentrated in the skeletal sand grainstones (which make up only 17% of the Chappel in the Childress 10 well). Like the Meramec grainstones, most of these deposits contain intraparticle porosity in bryozoan colonies. Secondary porosity, however, accounts for most of the porosity in these rocks. In most cases, this is associated with dolomitization or silicification of the grainstones. Some fracture porosity is also present.

Only Osage Group rocks were cored in the Donley 3 well. These rocks contain no primary porosity, but because of extensive dolomitization, both interparticle and intraparticle porosity is common. Highest porosities are usually observed in the partially dolomitized grainstones. Minor moldic porosity is present in some of the dolosiltstones, however. Some porosity development is also associated with stylolites.

Although no Ellenburger core is available for study in the Palo Duro or Dalhart Basins, core has been examined from wells in the Hardeman Basin. In these cores, the Ellenburger contains primarily intercrystalline and fracture porosity. Small vugs are observed in some zones. Sample logs in the Palo Duro Basin record vuggy and cavernous porosity in most areas.

Permeability

Good quality, quantitative pressure data are available for only a few wells in the area. A direct relationship between calculated porosity and permeability is generally observed, as expected (Table 5). Highest permeabilities are encountered in the Ellenburger (Table 5). Fair (Levorsen, 1967) permeabilities have been recorded for the Chester and Osage. These data tend to indicate that permeabilities in the pre-Pennsylvanian carbonates are somewhat higher than would be expected considering their porosities (Levorsen, 1967). In general, permeabilities of pre-Pennsylvanian rocks in the Palo Duro Basin are comparable with those observed in producing horizons in the Hardeman Basin (Montgomery, 1984).

PENNSYLVANIAN AND LOWER PERMIAN
(Dutton)

Introduction

Earlier studies of Pennsylvanian and Lower Permian source rocks in the Palo Duro Basin (Dutton, 1980; Dutton and others, 1982) have used kerogen color and vitrinite reflectance to measure thermal maturity. During the past year, pyrolysis, a third technique for evaluating maturity of source rocks, has been used. Pyrolysis involves heating a shale sample in the absence of oxygen to break down large hydrocarbon molecules into smaller ones (Milner, 1982). As the temperature is gradually increased, the sample will first give off hydrocarbons (S1) that are already present in the rock either in a free or adsorbed state (Tissot and Welte, 1978). When the temperature is raised further, kerogen in the sample will generate new hydrocarbons (S2), imitating in the laboratory the natural process of hydrocarbon generation. Finally, the CO_2 that is generated during pyrolysis is measured (S3) as an indication of the type of kerogen in the sample, whether it is humic (oxygen-rich) or sapropelic (hydrogen-rich) (Hunt, 1979). Thermal maturity is measured by comparing the temperature of maximum evolution of thermally-cracked hydrocarbons (T-max ^{o}C) versus the proportion of free hydrocarbons (S1) in the sample compared to total hydrocarbons (S1 + S2), that is, T-max ^{o}C versus S1/(S1 + S2) (fig. 1).

Pyrolysis Data

Samples of core and cuttings from the #1 Zeeck, #1 Mansfield, and #1 J. Friemel wells were analyzed by pyrolysis (Table 6). Analysis of four samples from the #1 Zeeck well indicates that the Pennsylvanian shales have reached temperatures sufficient to enter the oil-generation zone, but the Wolfcampian shales have not (fig. 17). However, the Pennsylvanian shales have not matured sufficiently to be able to generate wet gas. Thus, in agreement with the vitrinite reflectance data (Ruppel and Dutton, 1983), pyrolysis indicates that sapropelic source rocks probably are mature, but more humic shales probably are not.

The four samples of cuttings from the #1 Mansfield well comprise both Pennsylvanian and Wolfcampian shales, and all four samples are within the oil-generation zone (fig. 17). These samples are from shallower depths than the two Pennsylvanian shales from the #1 Zeeck well, which may explain why the Mansfield samples apparently are not as mature (fig. 17). Vitrinite reflectance data for the Mansfield shales indicate somewhat lower thermal maturity than is measured by pyrolysis. The vitrinite reflectance data from one geochemistry lab (Lab A) suggest that shales below 6,900 ft (2,100 m) are mature

(R_0 > 0.6 percent). Vitrinite reflectance measured on the same samples by a different lab (Lab 3) indicates a higher maturity, with an R_0 of 0.6 reached at 5,800 ft (1,800 m). Neither set of vitrinite reflectance data suggests that shales as shallow as 5,250 ft (1,600 m) are within the oil-generation window, as is indicated by pyrolysis. However, the maturation information derived from pyrolysis is in reasonably good agreement with the vitrinite reflectance data from Lab B.

Pyrolysis of four samples from the #1 J. Friemel well suggests that these shales have not generated oil. T-max values for three of the shale samples, one Wolfcampian and two Pennsylvanian (Table 6), are sufficiently high to be in the oil-generation zone, but values of S1/(S1 + S2) are quite low (Table 6; fig. 17). The low values of S1 suggest that these shales have not generated oil despite having reached relatively high temperatures. Pyrolysis of a fourth sample from the J. Friemel well, from 7,746.5 ft (2,361.1 m), gave anomalous results. The T-max value is 703°F (373°C), which is considerably lower than all the other Palo Duro samples, even the sample from 1,300 ft (400 m) shallower in the same well (Table 6). The value of S1/(S1 + S2) was anomalously high because of a high S1 peak (Table 6). The reason for these anomalous values is not known.

Vitrinite reflectance data for the J. Friemel samples indicate that shales below about 7,150 ft (2,180 m) have R_0 values greater than 0.6 percent. Therefore, sapropelic (hydrogen-rich) shales should have entered the oil-generation window. Pyrolysis measurements of T-max agree with this interpretation, but the low S1/(S1 + S2) values show that the shales have not generated oil. This suggests that the kerogen is probably dominated by humic organic matter. Microscopic identification of the kerogen in J. Friemel shales confirms that herbaceous organic matter and vitrinite are abundant.

In addition to providing a measure of thermal maturity, pyrolysis also indicates the type of organic matter in the samples. The oxygen content of the kerogen is proportional to the amount of CO_2 that is given off during pyrolysis, and the hydrogen content is proportional to the cracked hydrocarbons (S2) that are liberated (Hunt, 1979). The oxygen index of a sample is defined as milligrams CO_2 (S3) divided by grams of organic carbon; similarly, the hydrogen index is milligrams HC (S2) divided by grams of organic carbon (Table 6). A plot of hydrogen versus oxygen indices can be used to distinguish kerogen types in the same way that plots of atomic ratios of H/C versus O/C are used in van Krevelen diagrams (Tissot and Welte, 1978). Type I, sapropelic kerogen has a high hydrogen index and a low oxygen index (fig. 18). Type III kerogen, which is primarily woody and coaly organic matter, has a low hydrogen index and a high oxygen index. Herbaceous, Type II kerogen has an intermediate hydrogen index (fig. 18). Samples from all three wells fall along the trend of Type III kerogen. The most mature samples are those at the lower left of the hydrogen versus oxygen diagram. The less mature samples are quite close to the theoretical trend line that Type III kerogen should follow as it matures (Hunt, 1979). These results suggest that the shales in all three wells are dominated by Type III kerogen, which yields primarily gas at high temperatures. This conclusion does not agree too well with the microscopic description of the kerogen, which identified abundant herbaceous and amorphous organic matter. Theoretically, these types of kerogen should have higher hydrogen indices and lower oxygen indices than what were observed. The pyrolysis results suggest that much of the amorphous debris is from degraded, herbaceous kerogen and is not derived from algae.

CONCLUSIONS

The pyrolysis data from the Zeeck, Mansfield, and J. Friemel wells suggest that Pennsylvanian and Wolfcampian shales have reached sufficiently high temperatures to generate oil from sapropelic organic matter. However, it appears that much of the kerogen in the Palo Duro Basin is relatively low in hydrogen and rich in oxygen. This type of kerogen will generate gas at high temperatures, but it does not appear that the Palo Duro Basin shales have reached the temperatures necessary to generate gas.

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CAUTION

This report describes research carried out by staff members of the Bureau of Economic Geology that addresses the feasibility of the Palo Duro Basin for isolation of high-level nuclear wastes. The report describes the progress and current status of research and tentative conclusions reached. Interpretations and conclusions are based on available data and state-of-the-art concepts, and hence, may be modified by more information and further application of the involved sciences.

APPENDIX A

WELLS REFERENCED IN THIS REPORT

BEG Designation	Operator	Well
Armstrong 16	Hassie Hunt Trust Estate	J. A. Cattle Company #1
Armstrong 21	H. L. Hunt	Ritchie #4
Bailey 7	El Paso Natural Gas Co.	West Texas Mortgage and Loan #1
Bailey 17	Phillips Petroleum Co.	Stephens A#1
Bailey 20	Shell Oil Co.	Nichols #1
Briscoe 3	Hassie Hunt Trust Estate	Owens #1
Briscoe 5	H. L. Hunt	Ritchie #9
Briscoe 6	H. L. Hunt	Ritchie #2
Briscoe 13	W. J. Weaver	Adair #1
Briscoe 21	Cockrell Corp.	C. O. Allard #1
Briscoe 23	Amerada Petroleum Corp.	J. C. Hamilton #1
Castro 11	Sun Oil Co.	Herring #1
Castro 14	Sun Oil Co.	A. L. Haberer #1
Castro 16	Ashmun and Hilliard	John L. Meritt #1
Castro 18	Anderson-Prichard Oil	Fowler-McDaniel #1
Childress 3	The Texas Co.	P. B. Smith #1
Childress 10	Wes-Tex and Coastal State Gas Producing Co.	Steve Owens #A-1
Childress 15	Skiles Oil Corp.	Cliff Campbell #1
Childress 23	The Texas Co.	F & M Trust Co. #1
Childress 48	U. H. Griggs	Smith #1
Childress 49	Sinclair Oil & Gas Co.	Willard Mullins #1
Childress 59	The Texas Co.	Hughes #1
Childress 74	British-American Oil Prod. Co.	E. V. Perkins Co. #1
Collingsworth 19	Superior Oil Co.	M. F. Brown #85-75

BEG Designation	Operator	Well
Cottle 6	Falcon Seaboard Drilling Co.	Yarborough #1
Cottle 17	Great Western Drilling Co.	Portwood #1
Cottle 20	Meeker and Gupton	Carroll #1
Cottle 37	Humble Oil and Refining Co.	Matador L&C Co. #J-1
Cottle 41	Baria and Werner Et Al.	Lloyd Mayes #1
Cottle 49	Stanolind Oil and Gas Co.	T. J. Richards #1
Cottle 83	Robinson Bros. Drilling Co.	Harrison #1
Cottle 121	Signal Oil & Gas Co.	Swenson #1
Dallam 7	Humble Oil and Refining Co.	Sheldon #1
Dallam 29	Humble Oil and Refining Co.	Belo #1
Donley 3	Service Drilling Co.	Kathleen C. Griffen #1
Donley 23	Humble Oil and Refining Co.	T. L. Roach #1
Donley 25	Placid Oil Co.	W. R. Kelly #1
Donley 26	Rip Underwood and Corsica Oil Co.	V. W. Carpenter #1
Donley 30	Stanolind Oil and Gas Co.	Troy Broome #1
Donley 31	Shell Oil Co.	Finch #1
Donley 34	E. B. Clark and General Crude Oil Co.	P. B. Gentry #1
Donley 41	H. L. Hunt	Ritchie #5
Donley 45	Lazy R. G. Ranch Co.	Welch #1
Donley 50	Stone and Webster Engineering Corp.	Sawyer #1
Floyd 2	E. B. Clark Drilling Co.	Hall #1
Floyd 3	Ralph J. Abbey et al.	Howard #1
Floyd 5	Cockrell Corp.	Wells #1
Floyd 10	Sinclair Oil and Gas Co.	Massie #1
Floyd 13	Cockrell Corp.	Karstetter #1
Floyd 14	Cockrell Corp.	Thomas #1
Floyd 21	Poff-Brinsmere	Krause #1
Floyd 39	Harken Oil and Gas Inc.	Pigg #1
Hale 9	Honolulu Oil Corp.	Clements #1

BEG Designation	Operator	Well
Hall 1	Amarillo Oil Co.	Grace Cochran #1
Hall 4	Humble Oil and Refining Co.	Moss #1
Hall 18	Amerada Petroleum Corp.	Hughes #1
Hall 28	Phillips Petroleum Co.	Hughes #1
Hardeman 10	Magnolia Petroleum Co.	S. E. Malone #1
Hardeman 27	Wayne Moore	Swindell #1
Hardeman 33	Sun Oil Co.	Eugene B. Smith #1
Hardeman 42	Sun Oil Co.	Quanah Townsite Unit #1
Hardeman 44	Standard Oil Company of Texas	R. H. Coffee #1
Hardeman 46	Humble Oil and Refining Co.	Kent McSpadden #1
Hardeman 47	Sun Oil Co.	J. A. Thompson #1
Hardeman 105	Shell Oil Company	Schur #2
Hardeman 108	J. K. Wadley and K. E. Jennings	Bell & Michael #1
Hartley 13	Standard Oil Co. of Texas	Jessie Herring Johnson Et Al #1
Hartley 22	Standard Oil Co. of Texas	Alice Walker 1-26-1
Hartley 27	Pure Oil Co.	Lankford #1
Moore 30	Shamrock	Taylor #2
Motley 18	Humble Oil and Refining Co.	Matador L&C #2-H
Motley 38	Humble Oil and Refining Co.	Matador #4-B
Motley 50	Skelly Oil Co.	Tom Windham #1
Parmer 10	Sunray Oil Corp.	Kimbrough #1
Parmer 12	Convest Energy Corp.	O. L. Jarman #1
Swisher 6	Standard Oil Co. of Texas	Johnson #1
Swisher 9	Humble Oil & Refining Co.	Nanny #1
Swisher 12	Frankfort Oil Co.	Sweatt #1
Swisher 13	Sinclair Oil & Gas Co.	Savage #1

APPENDIX B

TOTAL ORGANIC CARBON (TOC) DATA FROM THE TEXAS PANHANDLE

Well	Depth (ft)	Unit	Type of Sample	TOC (%)	Dominant Lithology
Armstrong 16	6840-6910	Osage	cuttings	0.140	cherty limestone
Armstrong 21	6580-6600	Meramec	cuttings	0.092	cherty limestone
Bailey 7	8700-8750	Ellenburger	cuttings	0.030	dolomite
Bailey 17	7890-8000	Osage	cuttings	0.014	cherty limestone
Bailey 17	8050-8130	Ellenburger	cuttings	0.012	dolomite
Bailey 20	8580-8700	Meramec	cuttings	0.074	cherty limestone
Bailey 20	8750-8850	Osage	cuttings	0.036	cherty dolomite
Briscoe 3	8280-8300	Osage	cuttings	0.246	cherty dolomite
Briscoe 3	8040-8060	Meramec	cuttings	0.076	limestone/dolomite
Briscoe 3	7800-7820	Meramec	cuttings	0.112	cherty limestone
Briscoe 5	7240-7400	Meramec	cuttings	0.208	cherty limestone
Briscoe 6	6850-6880	Osage	cuttings	0.062	cherty dolomite
Briscoe 13	8500-8650	Meramec	cuttings	0.148	limestone
Castro 14	8680-8750	Osage	cuttings	0.018	cherty limestone
Castro 18	9260-9290	Meramec	cuttings	0.066	cherty limestone
Childress 3	5400-5430	Ellenburger	cuttings	0.132	cherty dolomite
Childress 3	5240-5270	Osage	cuttings	0.188	cherty limestone
Childress 10	5847	Meramec	core	0.032	limestone
Childress 10	5860	Meramec	core	0.052	limestone
Childress 10	5878	Meramec	core	0.024	limestone
Childress 10	5915	Meramec	core	0.026	limestone
Childress 10	6055	Osage	core	0.094	limestone
Childress 10	6069	Osage	core	0.460	limestone, clay, chert
Childress 10	6114.5	Osage	core	0.244	limestone
Childress 10	6160	Osage	core	0.142	limestone
Childress 10	6204.5	Osage	core	0.034	limestone
Childress 10	6228	Osage	core	0.078	limestone
Childress 15	4640-4660	Osage	cuttings	0.114	cherty limestone
Childress 15	4810-4830	Ellenburger	cuttings	0.074	cherty dolomite

Childress 23	7430-7580	Osage	cuttings	0.086	shaly, cherty, limestone/dolomite
Childress 48	7250-7350	Chester	cuttings	0.322	shaly limestone
Childress 59	8170-8180	Osage	cuttings	0.042	cherty limestone
Childress 59	8000-8020	Osage	cuttings	0.086	cherty limestone
Collingsworth 19	4529-4619	Osage	cuttings	0.024	cherty limestone
Collingsworth 19	4790-4850	Ellenburger	cuttings	0.010	cherty dolomite
Collingsworth 19	5415-5495	Ellenburger	cuttings	0.024	dolomite
Collingsworth 19	5640-5680	Cambrian	cuttings	0.026	sandstone
Cottle 6	7650-7700	Osage	cuttings	0.104	cherty limestone
Cottle 6	7790-7880	Osage	cuttings	0.328	cherty, shaly limestone
Cottle 6	7940-8000	Ellenburger	cuttings	0.142	cherty dolomite
Cottle 17	7980-8010	Ellenburger	cuttings	0.102	cherty dolomite
Cottle 17	7830-7860	Osage	cuttings	0.112	cherty limestone
Cottle 20	7680-7710	Osage	cuttings	0.270	cherty limestone
Cottle 37	7630-7660	Osage	cuttings	0.078	cherty limestone
Cottle 49	7820-7860	Ellenburger	cuttings	0.010	dolomite
Cottle 83	6420-6450	Osage	cuttings	0.090	shaly, cherty, limestone
Cottle 121	5400-5430	Osage	cuttings	0.148	chert
Dallam 7	5230-5260	Osage	cuttings	0.104	dolomite, cherty, limestone
Dallam 7	5760-5780	Ellenburger	cuttings	0.034	cherty dolomite
Dallam 29	5860-5880	Meramec	cuttings	0.036	shaly limestone
Dallam 29	6050-6090	Osage	cuttings	0.138	shaly, cherty, dolomite
Donley 3	4228.3	Meramec	core	0.034	limestone
Donley 3	4242.3	Meramec	core	0.102	limestone, claystone
Donley 3	4247	Meramec	core	0.100	siltstone
Donley 3	4250	Meramec	core	0.128	siltstone/claystone
Donley 3	4253.5	Meramec	core	0.112	silty limestone
Donley 3	4259	Meramec	core	0.228	silty claystone
Donley 3	4260	Meramec	core	0.264	calcareous sandstone
Donley 23	5050-5200	Ellenburger	cuttings	0.156	dolomite
Donley 25	6850-6950	Osage	cuttings	0.156	shaly, cherty, limestone
Donley 26	5630-5690	Osage	cuttings	0.148	cherty dolomite
Donley 30	6390-6465	Ellenburger	cuttings	0.166	dolomite
Donley 34	6710-6750	Ellenburger	cuttings	0.180	dolomite
Donley 41	6390-6420	Osage	cuttings	0.204	limestone
Donley 45	5140-5160	Ellenburger	cuttings	0.184	dolomite
Donley 50	4520-4530	Osage	cuttings	0.116	limestone
Donley 50	4650-4660	Ellenburger	cuttings	0.080	dolomite

Floyd 2	9400-9468	Meramec	cuttings	0.030	limestone
Floyd 21	7700-7750	Meramec	cuttings	0.070	cherty limestone
Hale 9	9710-9770	Meramec	cuttings	0.018	cherty limestone
Hall 1	6150-6330	Osage	cuttings	0.054	cherty limestone
Hall 1	6480-6600	Ellenburger	cuttings	0.070	dolomite
Hall 4	4700-4750	Ellenburger	cuttings	0.002	cherty dolomite
Hall 28	7760-7820	Osage	cuttings	0.022	cherty limestone/dolomite
Hall 28	7960-8000	Ellenburger	cuttings	0.010	dolomite
Hardeman 10	8558-8560	Chappel (base)	cuttings	0.020	limestone
Hardeman 33	8390-8400	Barnett	cuttings	0.934	shale
Hardeman 42	8702	St. Louis	core	0.060	limestone
Hardeman 42	8720	St. Louis	core	0.062	limestone
Hardeman 42	8752	Chappel	core	0.002	limestone
Hardeman 42	8790	Chappel	core	0.016	limestone
Hardeman 42	8810	Chappel	core	0.002	limestone
Hardeman 42	8830	Chappel	core	0.016	limestone
Hardeman 42	8850	Chappel	core	0.016	limestone
Hardeman 42	8874	Chappel	core	0.140	dolomite
Hardeman 42	8907	Chappel	core	0.010	dolomite
Hardeman 44	8130	St. Louis	core	0.076	calcareous shale
Hardeman 44	8138	St. Louis	core	0.032	calcareous shale
Hardeman 44	8143	Top Chappel	core	0.668	limestone
Hardeman 44	8306	Chappel	core	0.124	limestone
Hardeman 44*	8306	Chappel	core	0.120	limestone
Hardeman 46	8185	Chappel	core	0.240	limestone
Hardeman 47	8110-8120	Barnett	cuttings	0.726	calcareous shale, shaly limestone
Hardeman 105	7967	Chappel	core	0.058	dolomite
Hardeman 105*	7967	Chappel	core	0.225	dolomite
Hardeman 105	8018	Chappel	core	0.184	dolomite
Hardeman 105*	8018	Chappel	core	0.240	dolomite
Hardeman 105	8085	Chappel	core	0.236	dolomite
Hardeman 105*	8085	Chappel	core	0.290	dolomite
Hardeman 105	8113	Ellenburger	core	0.288	dolomite
Hardeman 105	8164	Ellenburger	core	0.180	dolomite
Hardeman 105	8231	Ellenburger	core	0.120	dolomite
Hartley 22	8410-8470	Osage	cuttings	0.044	limestone
Hartley 27	7585-7590	Ellenburger	cuttings	0.030	cherty dolomite

Moore 30	5542-5546	Meramec	cuttings	0.000	cherty limestone
Moore 30	5850-5870	Osage	cuttings	0.148	shaly, cherty limestone
Motley 18	7700-7770	Osage	cuttings	0.126	shaly, cherty limestone
Motley 18	7780-7820	Ellenburger	cuttings	0.136	cherty dolomite
Motley 38	9270-9340	Meramec	cuttings	0.040	cherty limestone
Motley 50	6750-6810	Chester	cuttings	0.100	shaly, sandy limestone and shale and sandstone
Motley 50	6850-7000	Meramec	cuttings	0.096	cherty limestone
Motley 50	7190-7240	Osage	cuttings	0.166	cherty limestone
Parmer 10	8840-8870	Ellenburger	cuttings	0.306	shaly, sandy, cherty dolomite
Swisher 6	8820-8870	Meramec	cuttings	0.054	shaly, cherty limestone
Swisher 13	9310-9340	Meramec	cuttings	0.170	sandy limestone

*Duplicate analysis by second laboratory.

APPENDIX C

Calculation of Organic Matter Index (OMI)

Organic Matter Index is a technique devised by Geo-Strat, Inc. of Houston, Texas for characterizing the mixture of kerogen types present in a given sample. The OMI index is determined by assigning numbers to each kerogen type (see below), then calculating the average value based on the percentage of each type present. Since the lowest numbers are assigned to liptinic kerogens, the lower the OMI, the more oil prone the kerogen in the sample.

KEROGEN TYPE	OMI NUMBER	
Algae	1	Liptinite
Amorphous	2	
Spores, Pollen	3	
Culticle, Membranous Debris	4	
Woody Structured Debris	5	Vitrinite
Coaly Debris	6	Inertinite

TABLE 1

SUMMARY OF
TOTAL ORGANIC CARBON
DATA

UNIT	NUMBER OF ANALYSES	% TOTAL ORGANIC CARBON HIGH	LOW	MEAN	STD.DEV.	(T.O.C.) MEDIAN
		PALO DURO & DALHART BASINS				
MISSISSIPPIAN	66	0.460	0.000	0.111	0.088	0.096
CHESTER	2	0.322	0.100	0.211	0.157	-----
MERAMEC	27	0.264	0.000	0.089	0.067	0.076
OSAGE	37	0.460	0.014	0.123	0.094	0.104
LOWER ORDOVICIAN						
ELLENBURGER	21	0.306	0.002	0.090	0.080	0.080
CAMBRIAN?	1	0.026	0.026	0.026	-----	-----
TOTALS	88	0.460	0.000	0.107	0.086	0.094
		HARDEMAN BASIN				
MISSISSIPPIAN	20	0.934	0.002	0.183	0.253	0.058
CARBONATE	18	0.668	0.002	0.109	0.160	0.062
BARNETT SHALE	2	0.934	0.726	0.830	0.147	-----
ORDOVICIAN						
(ELLENBURGER)	3	0.120	0.288	0.196	0.085	0.180

Table 2. Kerogen Data, Palo Duro and Dalhart Basins

WELL NAME	DEPTH (FT)	UNIT	LITHOLOGY	R_o (%)	TAI (Geostrat Inc.)	OMI (Geostrat Inc.)	KEROGEN TYPES (%) SAPROPEL LIPTINITE	HUMUS VITRINITE	INERTINITE
BRISCOE 3	8280-8300	OSAGE	DOLOMITE	0.52	3.00	4.47	71	18	11
BRISCOE 13*	8310-8390	CHESTER	LIMESTONE	0.55	3.00	5.30	50	30	20
BRISCOE 13*	8810-8890	OSAGE	LIMESTONE	0.52	3.00	4.95	63	16	21
CHILDRESS 10	6069	OSAGE	LIMESTONE	0.41	2.85	3.63	81	6	13
CHILDRESS 10	6228	OSAGE	LIMESTONE	0.45	3.00	3.65	82	6	12
COTTLE 20	7680-7710	OSAGE	LIMESTONE	0.50	3.00	3.65	76	18	6
COTTLE 41*	7060-7140	CHESTER	LIMESTONE	0.54	3.00	4.50	84	8	8
DALLAM 7	5230-5260	OSAGE	LIMESTONE	--	3.00	4.30	65	15	20
DALLAM 29	6050-6090	OSAGE	SHALY DOLOMITE	0.44	3.00	4.40	65	10	25
DONLEY 3	4260	MERAMEC	SANDY LIMESTONE	0.37	2.85	4.78	61	28	11
DONLEY 41	6390-6420	OSAGE	LIMESTONE	0.53	3.43	3.95	72	14	4
MOORE 30	5850-5870	OSAGE	SHALY LIMESTONE	--	3.00	3.23	84	8	8
MOTLEY 18	7700-7770	OSAGE	SHALY LIMESTONE	--	3.43	3.67	78	11	11
PARMER 10	8840-8870	ELLENBURGER	SHALY LIMESTONE	0.52	3.14	4.89	61	22	17
SWISHER 13	9310-9340	MERAMEC	LIMESTONE	--	3.50	5.20	50	35	15
*From Dutton (1980B)			AVERAGE	0.44	3.08	4.34	70	16	14
			STANDARD DEVIATION	0.07	0.21	0.21	11	9	4

Table 3. Kerogen Data, Hardeman Basin

WELL NAME	DEPTH (FT)	UNIT	LITHOLOGY	R_o (%)	TAI (Geostrat Inc.)	OMI (Geostrat Inc.)	KEROGEN TYPES (%) SAPROPEL	HUMUS	
							LIPTINITE	VITRINITE	INERTINIT
HARDEMAN 33	8390-8400	BARNETT	SHALE + LIMESTONE	0.86	3.33	4.33	61	17	22
HARDEMAN 42	8874	CHAPPEL	DOLOMITE	--	5.00	3.37	79	16	5
HARDEMAN 44	8143	CHAPPEL	LIMESTONE	0.85	3.33	4.21	70	10	20
HARDEMAN 44	8306	CHAPPEL	LIMESTONE	0.76	3.33	4.33	84	8	8
HARDEMAN 44*	8306	CHAPPEL	LIMESTONE	--	--	--	86	14	0
HARDEMAN 46	8185	CHAPPEL	LIMESTONE	0.60	3.33	3.33	84	7	7
HARDEMAN 47	8110-8120	BARNETT	SHALE/ LIMESTONE	--	3.33	4.33	61	17	22
HARDEMAN 105	7967	CHAPPEL	DOLOMITE/ LIMESTONE	--	--	--	84	16	0
HARDEMAN 105	8018	CHAPPEL	DOLOMITE/ LIMESTONE	0.64	3.43	3.63	75	19	6
HARDEMAN 105*	8018	CHAPPEL	DOLOMITE/ LIMESTONE	--	--	--	100	0	0
HARDEMAN 105	8085	CHAPPEL	DOLOMITE/ LIMESTONE	0.77	--	--	100	0	0
HARDEMAN 105	8113	ELLENBURGER	DOLOMITE	--	4.20	3.90	80	5	15
HARDEMAN 105	8164	ELLENBURGER	DOLOMITE	--	4.33	5.17	45	22	33
			AVERAGE	0.75	3.73	4.06	78	12	11
			STANDARD DEVIATION	0.11	0.62	0.58	16	7	11

*Duplicate analysis performed by a second laboratory.

TABLE 4

AVERAGE OF WELL POROSITIES IN THE PRE-PENNSYLVANIAN SEQUENCE, PALO DURO BASIN

	MEAN (%)	RANGE (%)	STANDARD DEVIATION (%)	NUMBER OF WELLS
MISSISSIPPIAN				
CHESTER	7.2	3.2-19.0	3.2	36
MERAMEC	4.4	1.6-10.9	1.9	45
OSAGE	6.5	2.1-13.2	3.1	47
ORDOVICIAN				
ELLENBURGER	8.8	5.1-17.9	3.1	18

TABLE 5

PERMEABILITY DATA

MISSISSIPPIAN	n	ave(md)	std.dev.(md)	range(md)
CHESTER	3	3.7	4.1	0.2 - 8.3
MERAMEC	1	0.7	---	---
OSAGE	3*	7.1	5.8	1.3 -12.9
TOTAL	7	4.7	4.8	0.2 -12.9
ORDOVICIAN				
ELLENBURGER	4	38.6	60.1	.001-127.0

PERMEABILITY/POROSITY INTERRELATIONSHIPS

MISSISSIPPIAN	K(md)	ϕ (%)
DONLEY 31	0.7	3.2
DONLEY 50*	12.9	19.3
ORDOVICIAN		
COTTLE 17	1.6	5.6
DONLEY 31	127.0	10.7

* all values calculated from DST data except for Donley 50 (OSAGE) for which pump test data was used.

TABLE 6. Results of Organic Carbon Analysis and Rock-Eval Pyrolysis

Depth (ft)	T.O.C. (% Wt)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	T-max (^oC)	Production Index S1/(S1+S2)	$\frac{S2}{S3}$	Hydrogen Index	Oxygen Index	Genetic Potential
#1 Mansfield										
5250-5260	0.74	0.14	0.60	1.20	439	0.19	0.50	81	162	0.74
6340-6350	2.23	0.38	3.20	0.94	444	0.11	3.40	143	42	3.58
6940-6960	1.86	0.35	2.33	1.26	443	0.13	1.84	125	67	2.68
7060-7100	1.25	0.26	1.24	1.28	442	0.17	0.96	99	102	1.50
#1 J. Friemel										
6444.5	1.21	0.19	2.87	0.78	439	0.06	3.67	237	64	3.06
7746.5	0.25	1.20	0.23	0.44	373	0.85	0.52	92	176	1.43
8108.9	1.42	0.14	1.77	0.72	441	0.07	2.45	124	50	1.91
8232.9	1.50	< 0.10	1.76	0.70	444	---	2.51	117	46	< 1.86
#1 Zeeck										
5454.9	0.43	0.05	0.26	0.26	428	0.16	1.00	60	60	0.31
6001.0	0.45	0.05	0.25	1.08	426	0.17	0.23	55	240	0.30
7306.6	0.71	0.10	0.29	1.65	450	0.26	0.18	40	232	0.39
7381.8	0.62	0.05	0.22	1.01	455	0.19	0.22	35	162	0.27

T.O.C. = Total organic carbon, wt. %
S1 = Free hydrocarbons, mg HC/g of rock
S2 = Residual hydrocarbon potential (mg HC/g of rock)
S3 = CO_2 produced from kerogen pyrolysis (mg CO_2/g of rock)
PC* = 0.083 (S1 + S2)

Hydrogen Index = mg HC/g organic carbon
Oxygen Index = mg CO_2/g organic carbon
PI = S1/(S1 + S2)
T-max = Temperature Index, degrees C
Genetic Potential = S1 + S2 (kg/ton of rock)

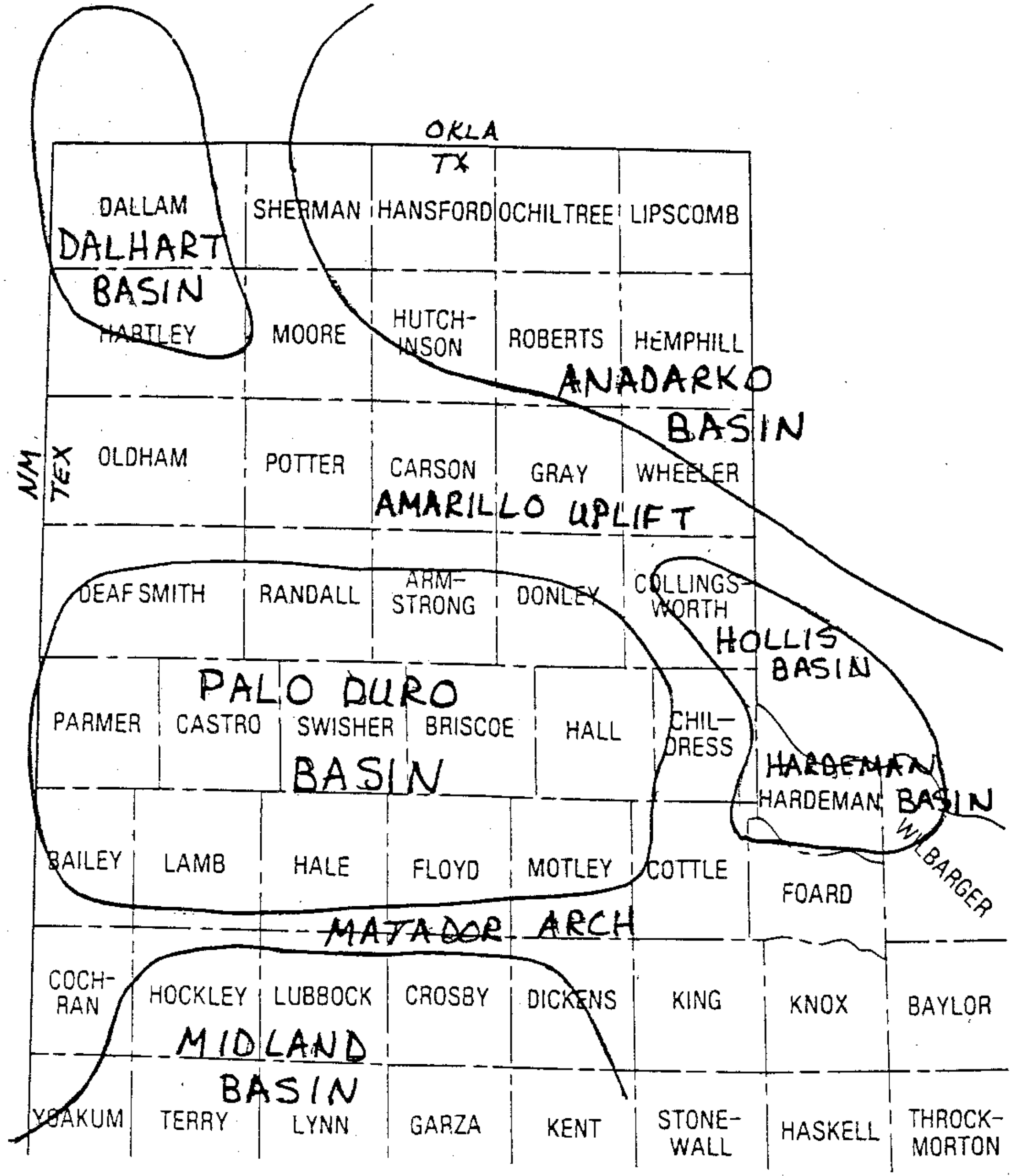


Figure 1. Locality map showing Palo Duro Basin and other geologic features in the Texas Panhandle area.

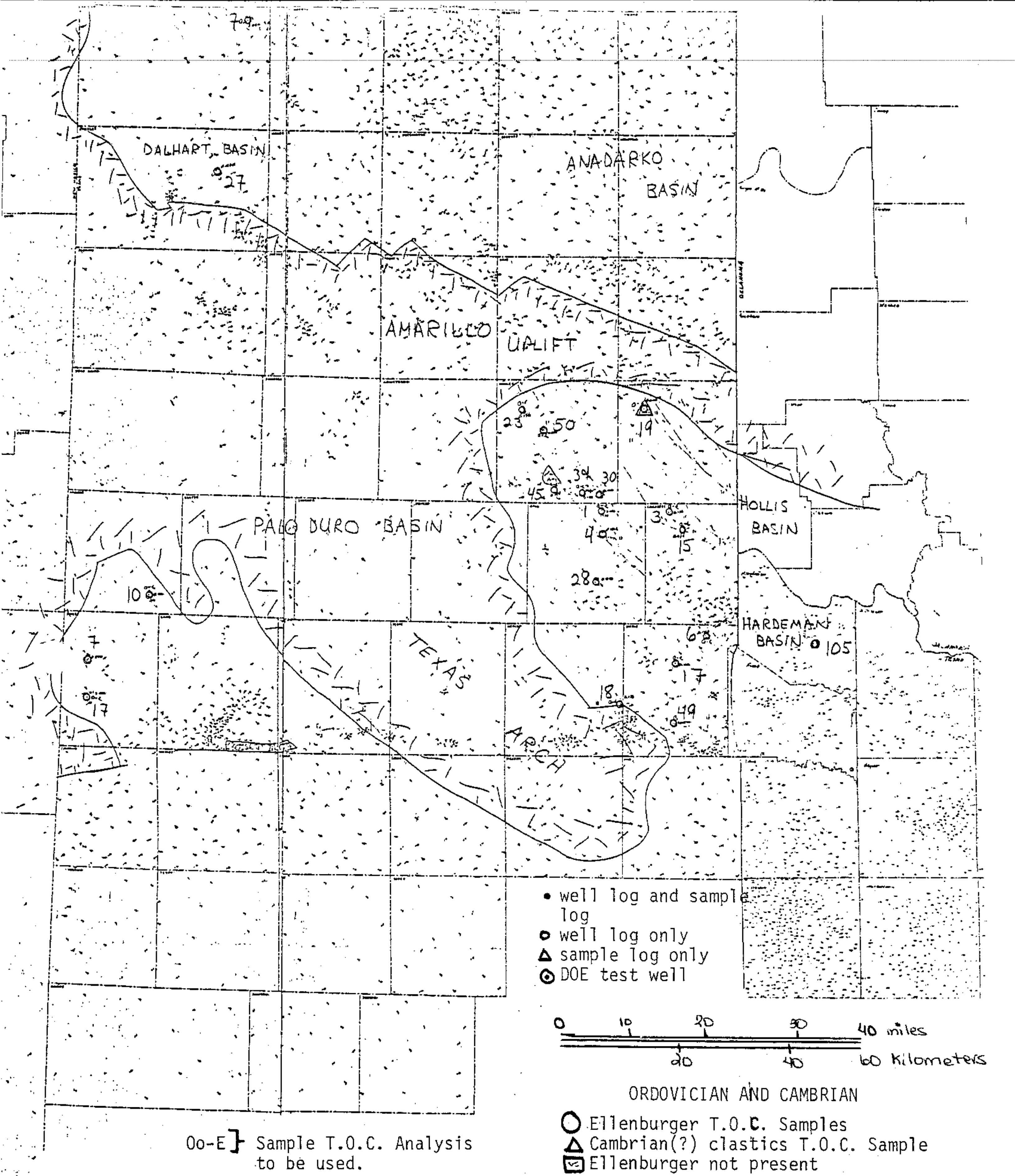


Figure 2. Map of Texas Panhandle showing wells in which Ordovician (Ellenburger Group) and Cambrian (?) rocks were sampled for geochemical analysis. Well names are given in Appendix A.

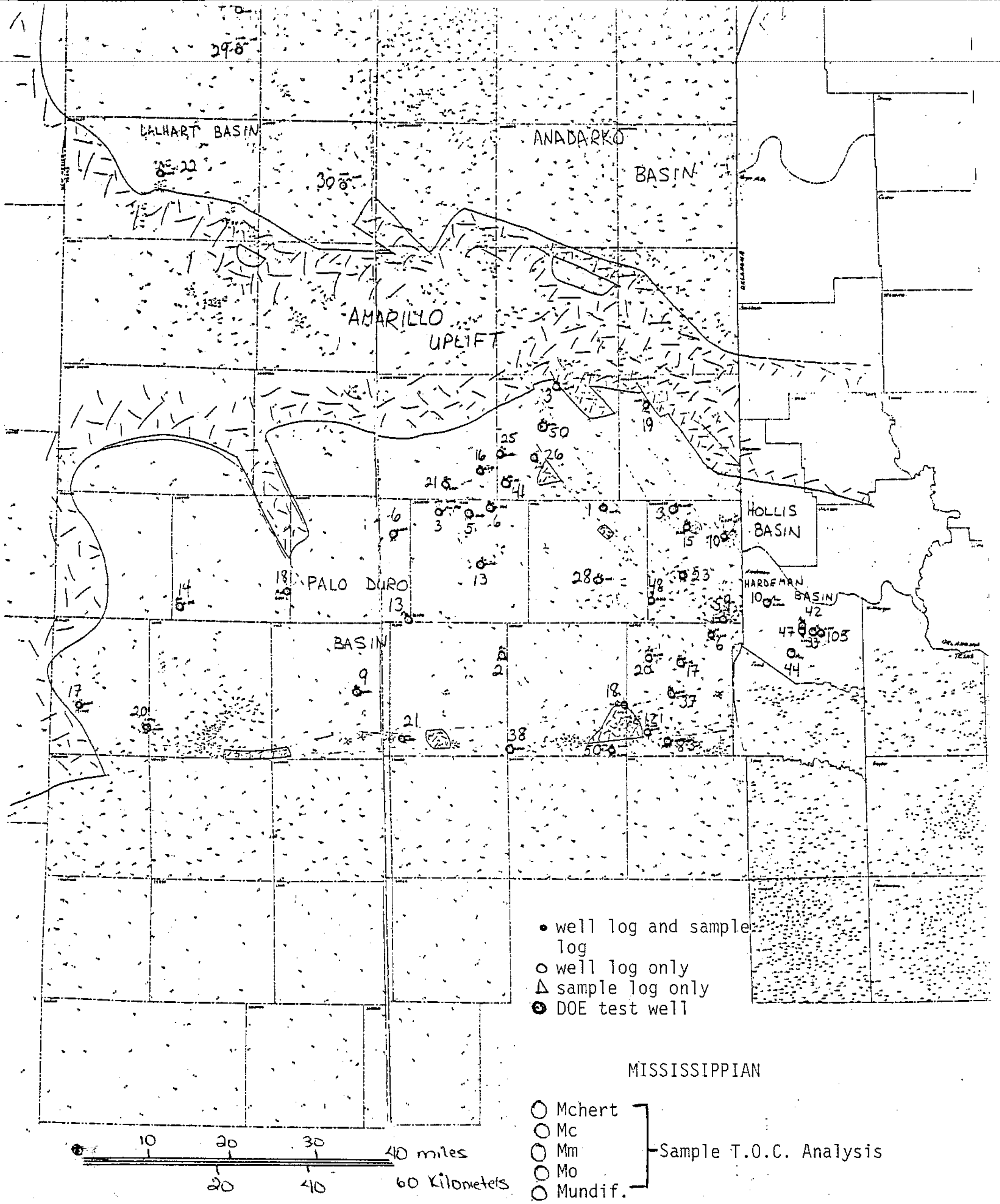


Figure 3. Map of Texas Panhandle showing wells in which Mississippian rocks were sampled for geochemical analysis. Well names are given in Appendix A.

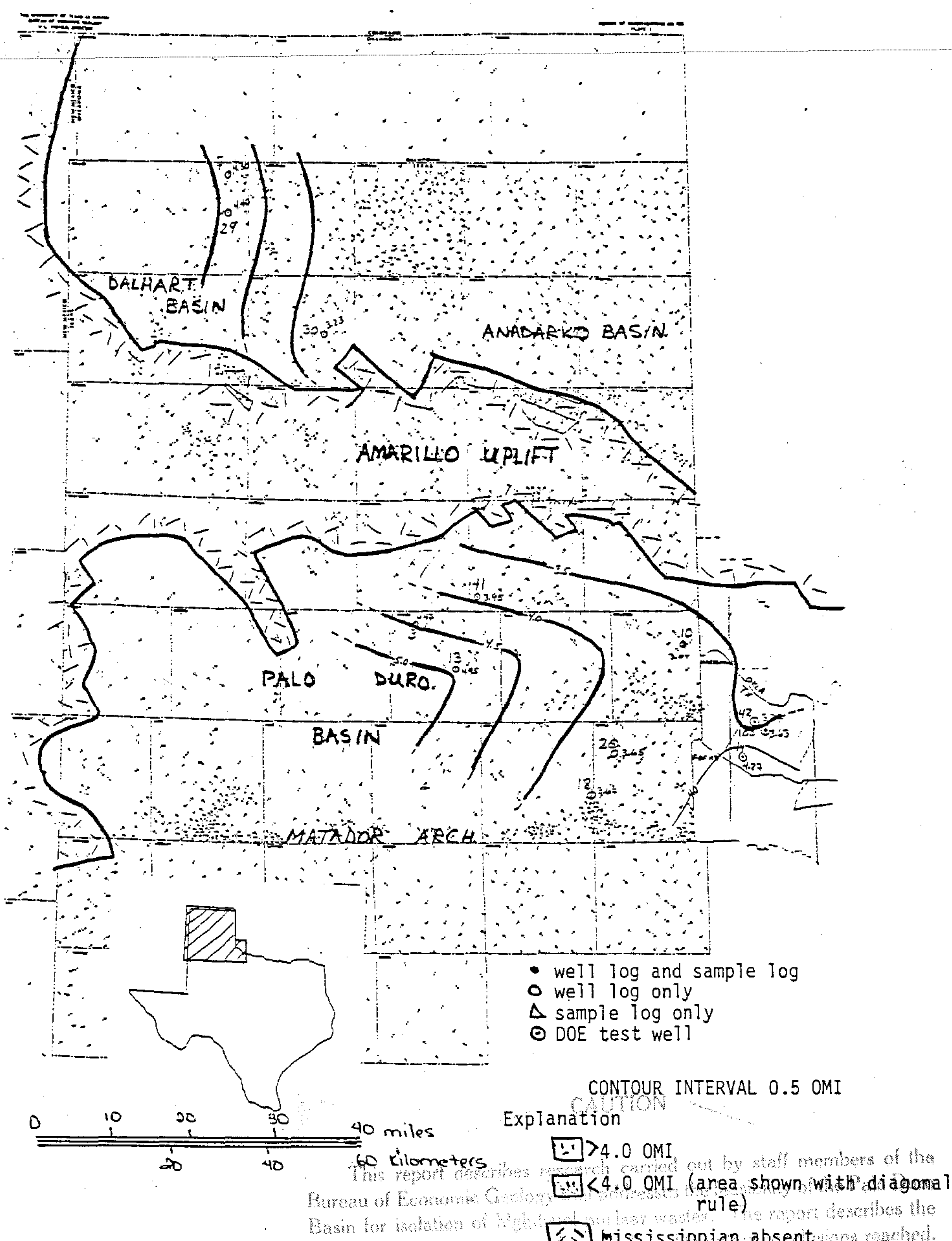


Figure 7. Distribution of Organic Matter Index (OMI) values in the Osage Group. OMI was designed by Geo-Strat, Inc. Lower values reflect increasingly higher quality organic matter. See Appendix for explanation.

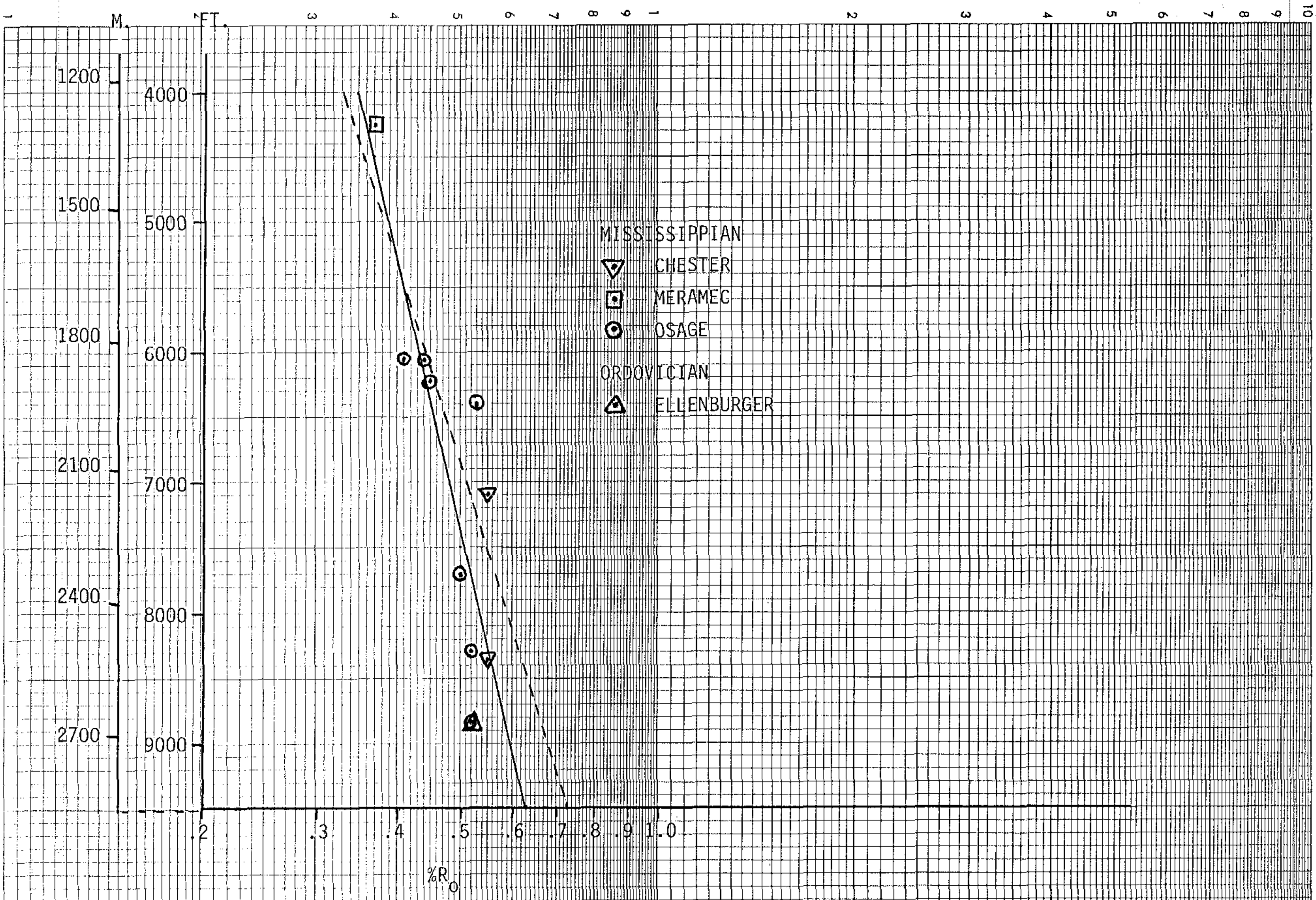


Figure 9. Plot of vitrinite reflectance (R_o) data versus depth, Palo Duro Basin.

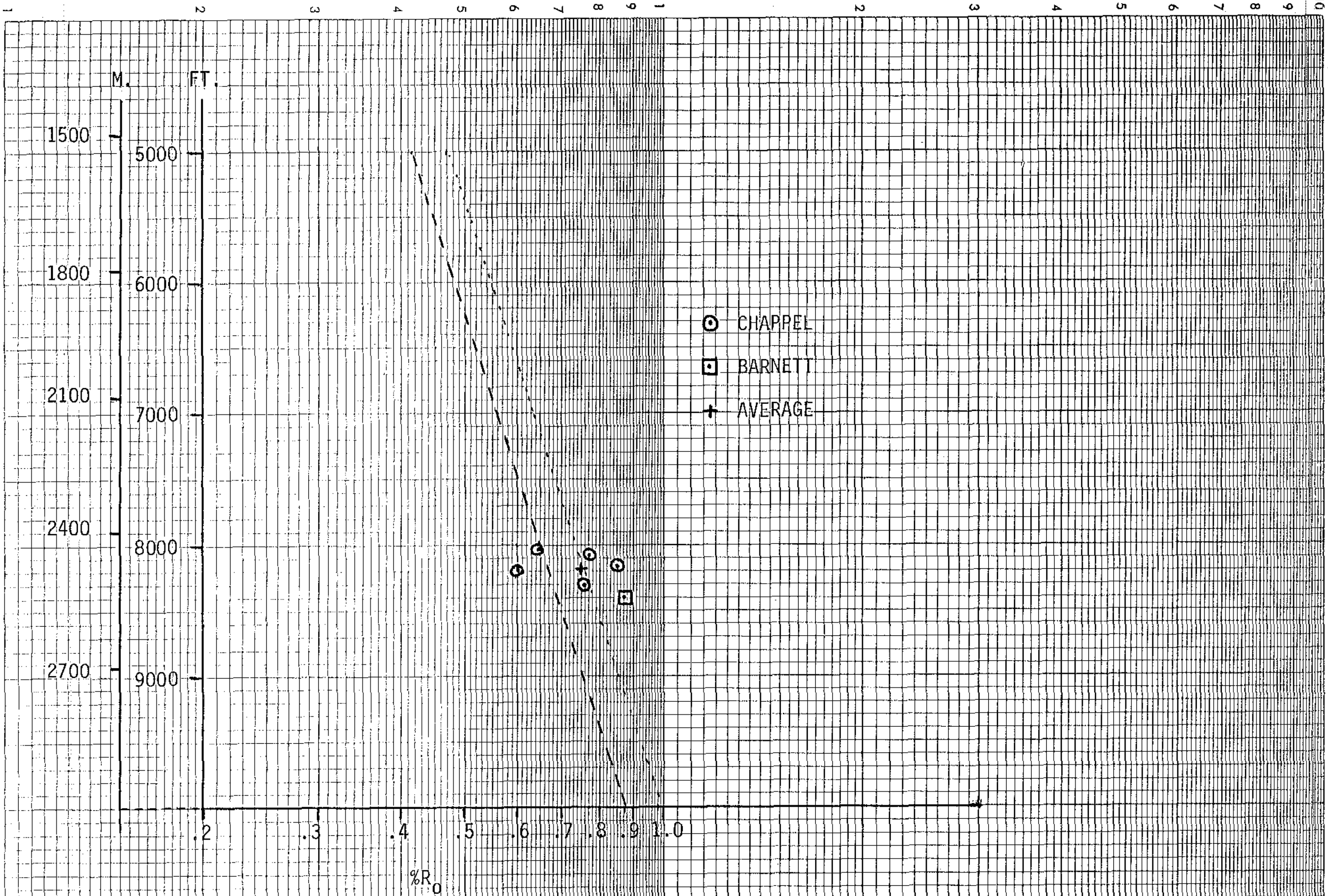


Figure 10. Plot of vitrinite reflectance (R_o) data versus depth, Hardeman Basin.

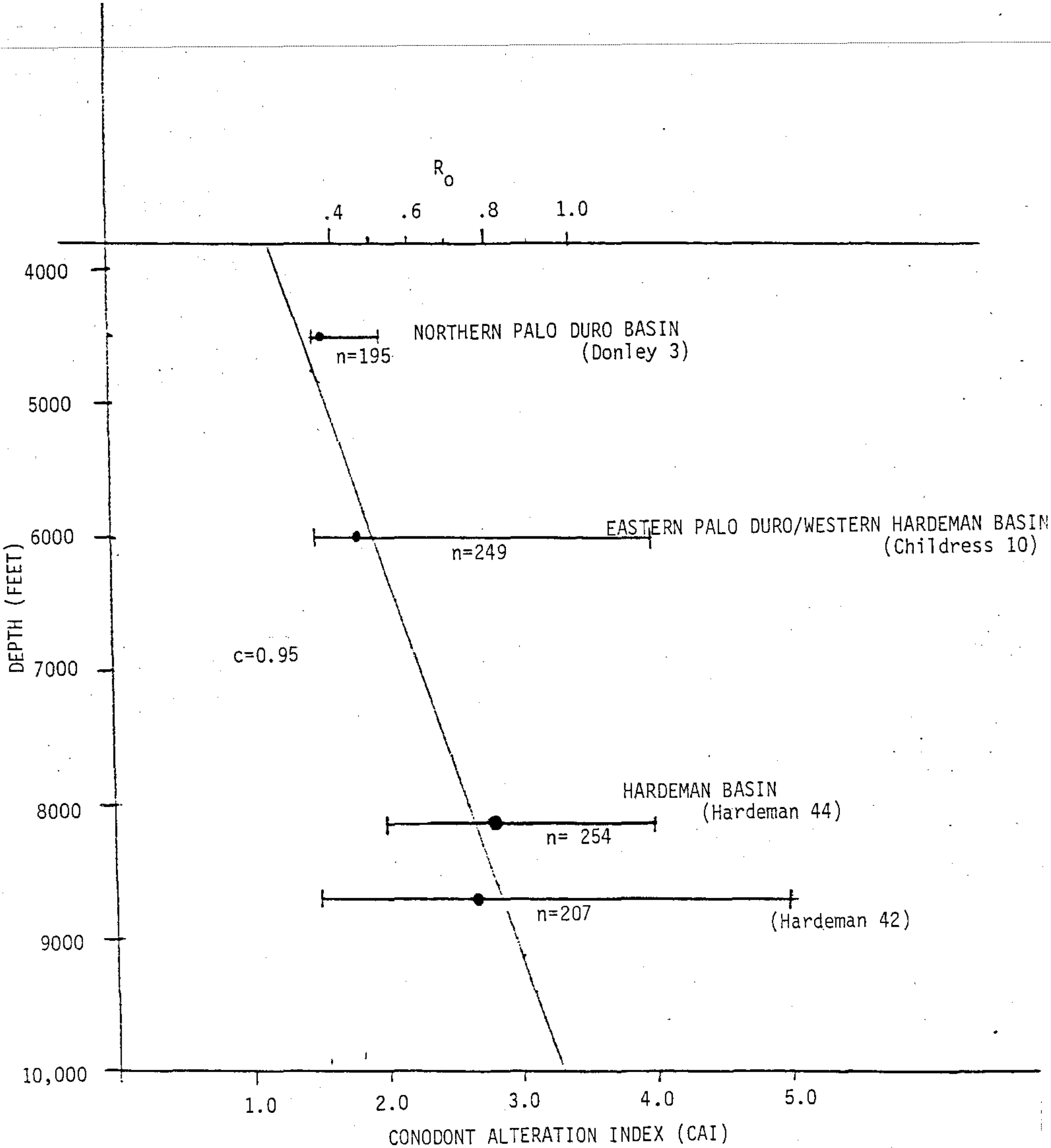
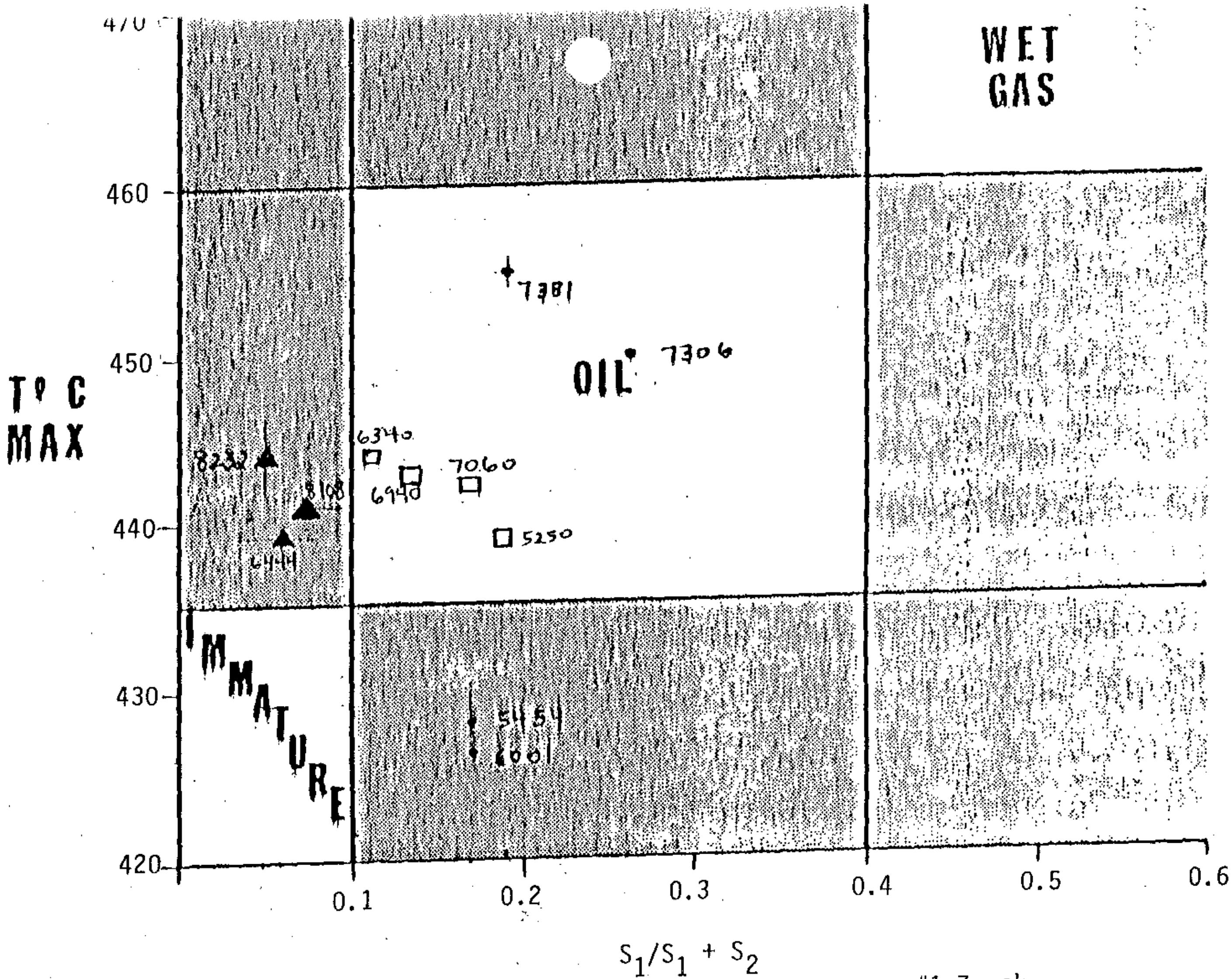


Figure 11. Plot of Conodont Alteration Index (CAI) with depth.



S1 = Volatile (free) hydrocarbons

S2 = Thermally generated hydrocarbons formed during pyrolysis

T°C max = Temperature of maximum evolution of 52 hydrocarbons

#1 Zeeck

#1 Mansfield

#1 J. Friemel

core = solid

cuttings = open

Figure 17. A plot of pyrolysis T-max °C against the ratio S1/(S1 + S2) defines the oil-generation zone (GeoChem Laboratories, 1980). Pennsylvanian and Wolfcampian shales from the #1 Mansfield well and Pennsylvanian shales from the #1 Zeeck well plot in the oil zones. All samples from #1 J. Friemel well and Wolfcampian shales from #1 Zeeck well plot outside the oil-generation zone and are probably immature.

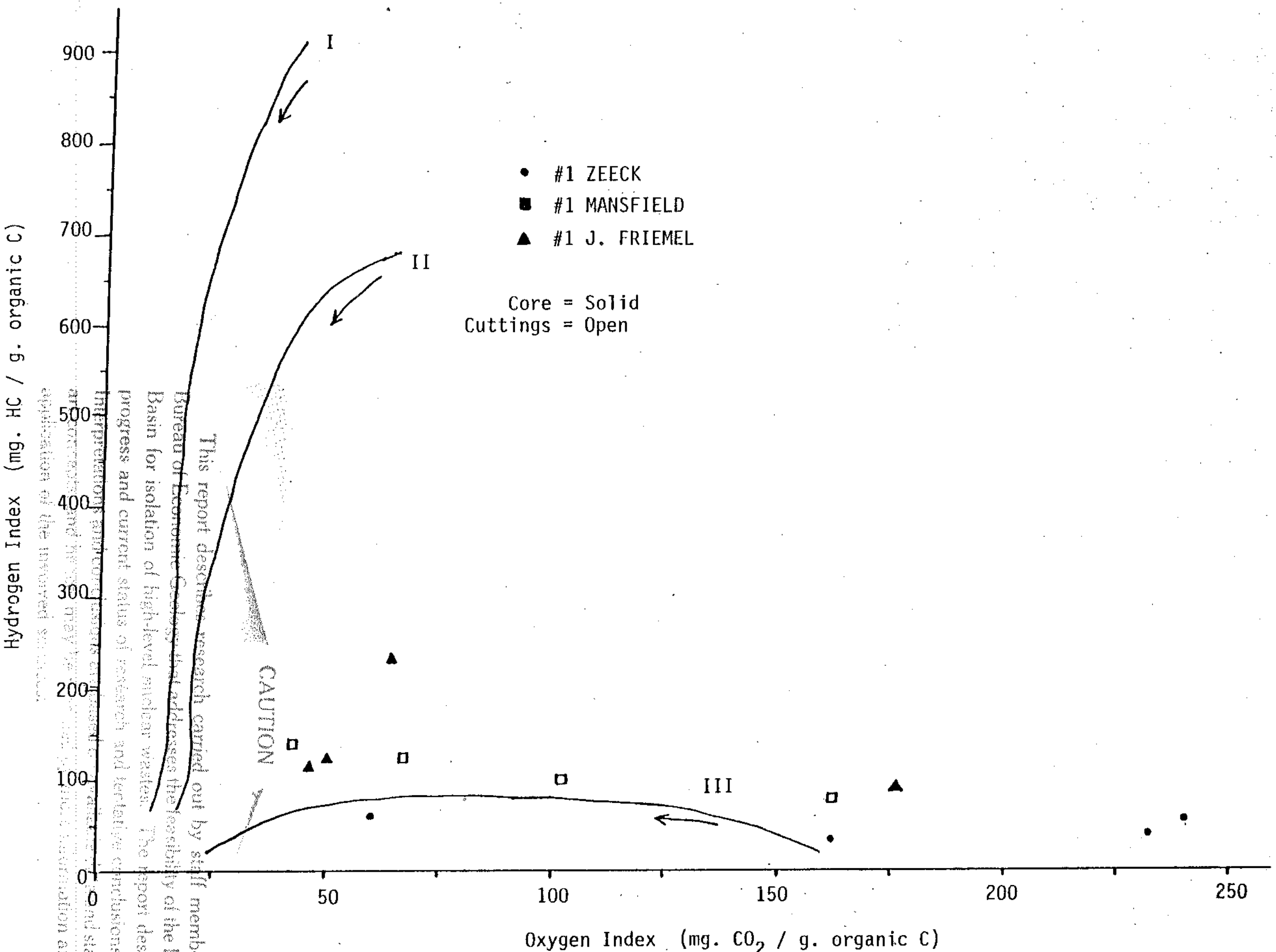


Figure 18. Source rock types classified by hydrogen and oxygen indices (from Tissot and Welte, 1978). Palo Duro Basin samples plot along the trend of Type III, or humic, kerogen.