

← Contents

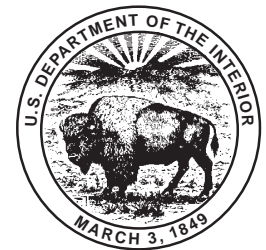
← Previous Section

Deep Natural Gas Resources in the Eastern Gulf of Mexico

By Dudley D. Rice, Christopher J. Schenk, James W. Schmoker, James E. Fox, Jerry L. Clayton, Thaddeus S. Dyman, Debra K. Higley, C. William Keighin, Ben E. Law, *and* Richard M. Pollastro

GEOLOGIC CONTROLS OF DEEP NATURAL GAS RESOURCES IN THE UNITED STATES

U.S. GEOLOGICAL SURVEY BULLETIN 2146-N



UNITED STATES GOVERNMENT PRINTING OFFICE, WASHINGTON : 1997

CONTENTS

Abstract	219
Introduction	219
Geologic Framework.....	220
Thermal Maturity	221
Reservoir Characterization.....	223
Source Rocks.....	225
Natural Gases	226
Liquid Hydrocarbons	226
Summary	227
References Cited	228

FIGURES

1. Map of the study area in the eastern Gulf of Mexico showing major structural features, facies of Norphlet Formation, and location of Norphlet fields	220
2. Generalized north-south cross section of pre-Selma Group Jurassic and Cretaceous strata, southwestern Alabama	221
3, 4. Plots of:	
3. Equivalent vitrinite reflectance versus depth for five locations in the study area	222
4. Vitrinite reflectance versus depth, Exxon State Lease 624 No. 1 well, Mobile Bay.....	222
5. Diagram showing preliminary burial and thermal history reconstruction, Exxon State Lease 624 No. 1 well, Mobile Bay	223
6. Plot of weight percent of clay minerals in bulk rock versus relative weight percent of illite in sandstones of the Norphlet Formation	224
7. Diagram showing preliminary interpretation of thermal maturity versus Norphlet Formation porosity for the study area.....	224
8, 9. Plots of:	
8. Methane $\delta^{13}\text{C}$ versus C_2+ for gas samples from the study area.....	226
9. Toluene to heptane ratios versus heptane to methylcyclohexane ratios for oils and condensates of southwestern Alabama.....	227

Deep Natural Gas Resources in the Eastern Gulf of Mexico¹

By Dudley D. Rice, Christopher J. Schenk, James W. Schmoker, James E. Fox, Jerry L. Clayton, Thaddeus S. Dyman, Debra K. Higley, C. William Keighin, Ben E. Law, *and* Richard M. Pollastro

ABSTRACT

The deep reservoirs of the Upper Jurassic Norphlet Formation in the Gulf of Mexico contain large resources of gas in eolian sandstone reservoirs. Thermal maturity is a major control of these deep accumulations. Thermal gradients vary throughout the study area but are highest south of the Wiggins arch where the potential for deep gas is highest. Thermal modeling indicates that paleotemperatures were higher than present-day temperatures. At a given level of thermal maturity, porosity values for the Norphlet are significantly higher than those of most sandstones worldwide. These high values may be related to (1) early cementation and subsequent dissolution of evaporitic cements (carbonates, anhydrite, and halite), (2) inhibition of quartz diagenesis by chlorite clay cement, which is prevalent in offshore Mobile Bay, (3) overpressuring, (4) inhibition of diagenesis by the presence of hydrocarbons, and (5) the lack of pore fluid volume required to cement the sandstones.

The source for onshore Jurassic hydrocarbons is probably algal carbonate mudstone in the lower part of the Smackover Formation. These carbonate source rocks, however, are probably inadequate to charge the major accumulations of deep, dry gas in the Norphlet in the Mobile Bay area of offshore Alabama and Mississippi. Downdip, more distal, marine, type II kerogen-bearing facies of the undifferentiated Norphlet and Smackover interval are postulated to be the source for these offshore accumulations.

Gases in deep reservoirs of the Norphlet are distinguished by their dryness and by their enrichment in ¹³C, both of which indicate generation at high levels of thermal maturity (metagenesis). Gases in Jurassic reservoirs of the study area contain varying amounts of CO₂ and H₂S that

have an inorganic origin and present problems in drilling, production, and marketing. Geochemical data indicate that liquids in deep Jurassic and Cretaceous reservoirs may have at least two sources. In addition, the condensates may have resulted from either (1) high-temperature cracking of heavier hydrocarbons or (2) evaporative fractionation.

INTRODUCTION

The United States depends on oil and gas as its major sources of energy; however, fewer wells are being drilled today in the United States, the discovery rate of new oil and gas accumulations is declining, and oil production is decreasing. Future supplies of domestic oil and gas will result from improved recovery of discovered hydrocarbons and the development of unconventional resources. One important and essentially undeveloped source of gas is from deep sedimentary basins.

The Gulf of Mexico is one of the Nation's most important provinces for discovered and undiscovered hydrocarbons. In addition, it has an enormous volume of sedimentary rocks deeper than 15,000 ft (4,572 m) and the best potential for deep gas resources. Interesting statistics from the NRG Associates Significant Fields File (greater than 1 million barrels of oil equivalent [BOE]) are summarized for the deep (>14,000 ft, >4,267 m) Gulf Coast Mesozoic producing region (NRG Associates, 1988). The Mesozoic producing region is important for deep gas and includes the East Texas, North Louisiana, and Mississippi salt basins, extending into southwest Alabama and the panhandle of Florida. One hundred and nine deep reservoirs in 97 fields are present in the Gulf Coast Mesozoic producing region, and the first discovery was in 1944. Although a tremendous volume of sedimentary rocks deeper than 15,000 ft is present, the number of significant deep reservoirs decreases with increasing depth. Fifty-eight percent of the significant deep reservoirs are classified as gas producing, and more deep oil reservoirs

¹This paper was originally published, in slightly different form, in "Proceedings of the natural gas research and development contractors review meeting," edited by Rodney D. Malone, Harold Shoemaker, and Charles W. Byer, 1992, U.S. Department of Energy DOE/METC 92/6125, p. 151-166.

are present in the eastern part of the trend where the geothermal gradient is lower. For all depths, 64 percent of the deep reservoirs are clastic, whereas only 36 percent are carbonate. Most of the hydrocarbons in deep reservoirs are structurally trapped resulting from salt diapirism and syndepositional growth faulting.

In this paper we present a progress report on our deep gas studies in the eastern Gulf of Mexico (onshore and offshore Mississippi, Alabama, and Florida) in a study area that includes the Mississippi salt basin (fig. 1). In the study area, numerous deep wells have been drilled, commercial deep hydrocarbon production has been established, and sufficient samples and data are available at intermediate and greater depths with which to conduct studies. The main points of focus in our studies are (1) geologic framework, (2) thermal maturity, (3) reservoir characterization, and (4) hydrocarbon generation and migration. This integrated approach is an attempt to determine the controls, distribution, resource potential, and exploitation and recovery of deep gas.

The research was funded in part by the U.S. Department of Energy under contract DE-A121-83MC0422-5 MOD A044.

GEOLOGIC FRAMEWORK

The northern Gulf of Mexico Basin developed as a post-Paleozoic passive margin on the Ouachita fold belt that has been affected by extensional and gravitational faulting since Triassic time. The petroleum geology of the basin is summarized by Curtis (1991). Unlike other basins developed on passive continental margins, the Gulf Basin is characterized by flowage of Jurassic salt that has resulted in abundant structural traps. Facies patterns and thickness variations reflect a depositional setting of rifted grabens, large-scale basin subsidence, and paleohighs (fig. 1). Triassic and Jurassic strata are evaporitic, eolian, and fluvial-alluvial clastic rocks and shallow-marine and peritidal carbonate rocks. Lower Cretaceous strata are primarily fluvial-deltaic deposits, and Upper Cretaceous strata are deltaic and marine-shelf deposits. Marine transgression continued until Paleocene time, at which time a deltaic system prograded into the area from the northwest.

The stratigraphic framework of the study area is illustrated in a regional north-south cross section that extends from the northern edge of the Gulf Coast Basin to State waters of Mobile Bay on the south (fig. 2). The northern

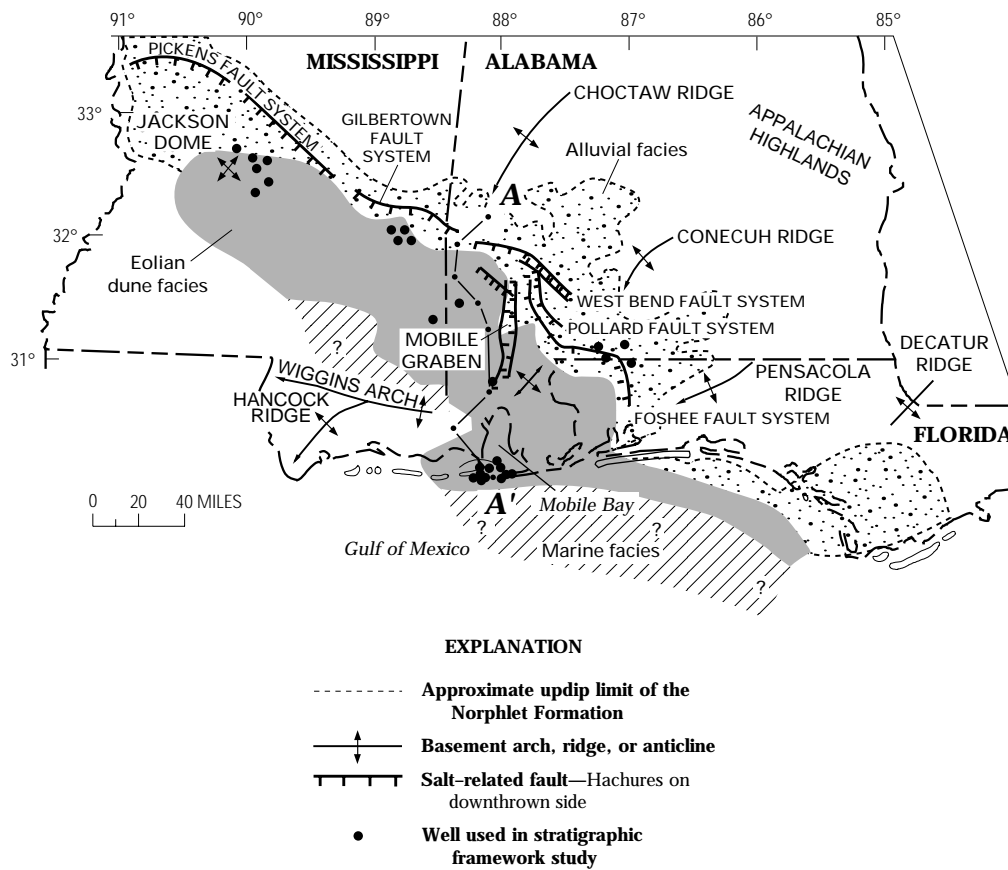


Figure 1. Map of the study area in the eastern Gulf of Mexico showing major structural features, facies of Norphlet Formation, and location of Norphlet fields (circles). Line of section A-A' (fig. 2) is also shown. All of the fault zones make up the regional peripheral fault zone. Modified from Schenk (1990).

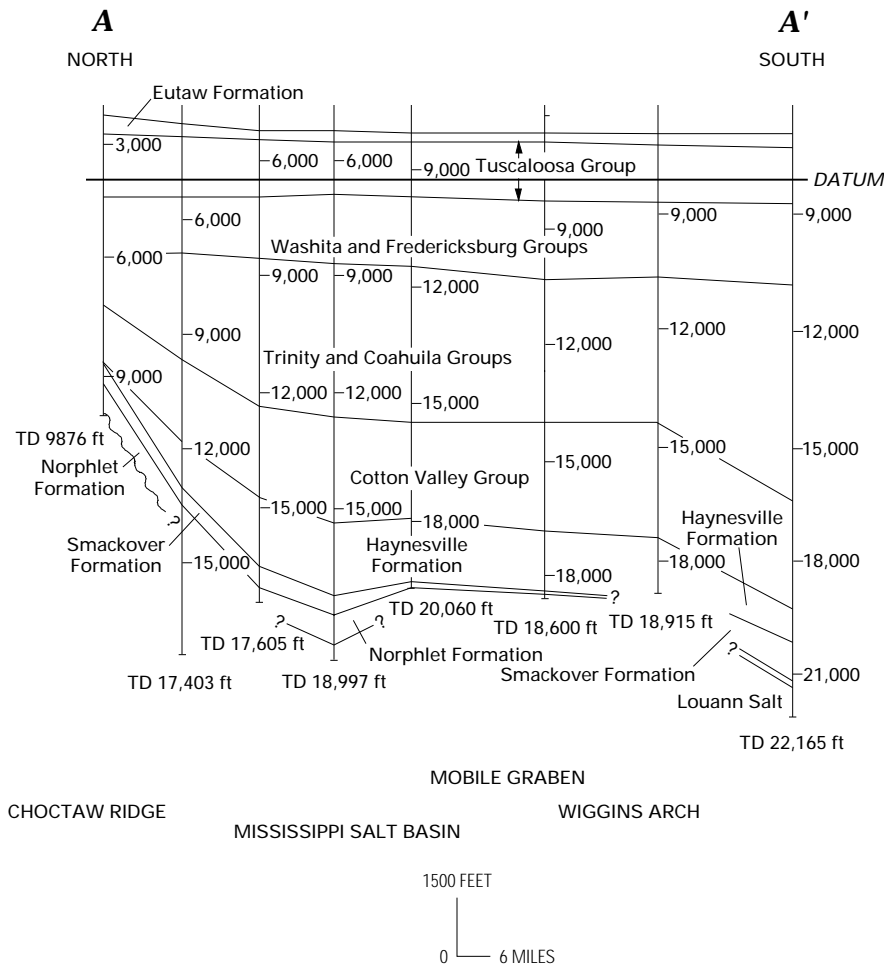


Figure 2. Generalized north-south cross section of pre-Selma Group Jurassic and Cretaceous strata, southwestern Alabama. The Jurassic-Cretaceous boundary is near the top of the Cotton Valley Group. Line of section is shown in figure 1. Modified from Keighin and Schenk (1992).

edge of the basin coincides with the regional peripheral fault zone, the northern limit of Triassic normal-fault rifting, and the northern limit of the Middle and Upper Jurassic Louann Salt. In a southerly direction, the section including the Upper Jurassic Norphlet Formation through Lower Cretaceous Trinity and Coahuila Groups thickens, whereas the remainder of the Cretaceous strata shows no major thickness trends. In addition, the Jurassic and Cretaceous section is more deeply buried to the south because of the prograding Tertiary deltaic section. An unpublished section parallel with the basin margin in Alabama illustrates thickness variations attributed to basement highs.

A map of the area shown in figure 1 was prepared using the ARC/INFO GIS system (Keighin and Schenk, 1992). At present, the map includes political boundaries and spatial coordinant data, geologic structures such as faults and salt domes, and oil and gas fields. Other features of known latitude and longitude, such as oil and gas wells greater than 10,000 ft, 15,000 ft, and 20,000 ft (3,048, 4,572, 6,096 m), are also included in the GIS file.

Carbonate rocks and sandstone of the Upper Jurassic Smackover and Norphlet Formations, respectively, are major reservoirs for hydrocarbons in the study area. Petroleum geology of the Jurassic section is discussed by Mancini

and Benson (1980), Mancini and others (1985), and Mink and others (1989, 1990). Three hydrocarbon trends that parallel the northern edge of the basin—oil, wet gas and condensate, and dry gas—have been identified. The oil trend is updip of the peripheral fault zone, the dry gas trend is south of the Wiggins arch and partly offshore, and the wet gas and condensate trend is between the oil and dry gas trends (fig. 1). The depth of production in these three trends increases in an offshore direction (fig. 2). The major part of the production in the oil and wet gas and condensate trends is from carbonate reservoirs of the Smackover Formation. Production in the dry gas trend is from eolian sandstones of the Norphlet Formation at depths greater than 20,000 ft (6,096 m), and potential gas resources in the Norphlet are large. Initial production was established in the State and Federal waters of Mobile Bay, offshore Alabama; the most productive wells to date have recently been tested in offshore Mississippi.

THERMAL MATURITY

Thermal maturity influences many processes critical to deep gas accumulation, including generation and migration of hydrocarbons and creation and preservation of reservoir

properties. Figure 3 represents a preliminary attempt to relate thermal maturity, as expressed by equivalent vitrinite reflectance (R_{oeq}) versus depth for five locations in the study area. The plots were derived from published and unpublished data that include vitrinite reflectance, bitumen reflectance, and Rock-Eval maximum-pyrolysis temperature (T_{max}). The equivalent vitrinite reflectance versus depth relations for these five locations are subject to modification as additional data become available.

The equivalent vitrinite reflectance versus depth trends show that thermal maturity increases steadily with depth (fig. 3). Slopes are subparallel, except for curve 4. The steeper slope of curve 4 reflects the influence of the Jackson Dome, a Late Cretaceous subsurface igneous intrusion (fig. 1). At a given depth, equivalent vitrinite reflectance tends to decrease from south to north (curves 2 to 1 and 3 to 5).

Figure 4 is a vitrinite reflectance (R_o) versus depth profile for the Exxon State Lease 624 No. 1 well in State waters of Mobile Bay, Alabama (fig. 1). The well was drilled to a total depth of 22,166 ft (6,756 m) in the Louann Salt and produces dry gas from the Norphlet Formation. The vitrinite reflectance at the surface of about 0.2 percent indicates that the present depth of burial is maximum and that little or no erosion has occurred in this area. The data suggest that two regression lines are possible—a single straight regression line and a two-segment regression line with a bend in the profile at a depth of about 11,000 ft (3,352 m) and a vitrinite reflectance value of 1.2 percent. The maximum vitrinite reflectance at total depth of the well is 2.4 percent, based on a two-segment profile, and 3.7 percent, based on a straight profile.

Examination of other vitrinite reflectance profiles in Mississippi and Alabama indicates that the two-segment profile is probably more representative of the trend. In similar-appearing profiles in the Rocky Mountain region, Law and others (1989) attributed the steeply sloping segment to convective heat-transfer processes related to the presence of abnormally high formation pressures and vertically flowing formation fluids. Other possible explanations include changes in type of organic matter and suppression of thermal maturity due to abnormally high formation pressure. The origin of the two-segment profile in the study area is uncertain and under investigation because thermal maturity is a dominant control of deep gas processes and accumulations.

A preliminary burial and thermal history reconstruction for strata in the Exxon State Lease 624 No. 1 well is shown in figure 5. Based on a present-day thermal gradient of $1.35^\circ\text{F}/100$ ft remaining constant through geologic time, the Louann Salt entered the oil window about 120 m.y. ago during deposition of the Trinity Group. With continued burial, the top of the oil window moved to stratigraphically younger units and is currently in the Cretaceous Fredericksburg and Washita Groups at a depth of about 10,200 ft. Preliminary thermal modeling of this well indicates, however, that the present-day thermal gradient of $1.35^\circ\text{F}/100$ ft or even higher

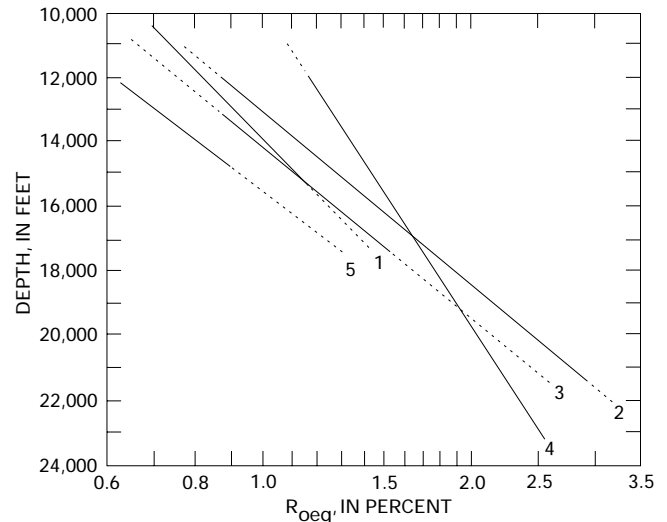


Figure 3. Equivalent vitrinite reflectance (R_{oeq}) versus depth for five locations in the study area. Trends are (1) along border of Alabama and Florida Panhandle; (2) Mississippi and Alabama south of the Wiggins arch; (3) Mississippi salt basin; (4) east flank of Jackson Dome, Mississippi, and (5) Pickens-Gilbertown-Pollard fault zone near Mississippi-Alabama State line.

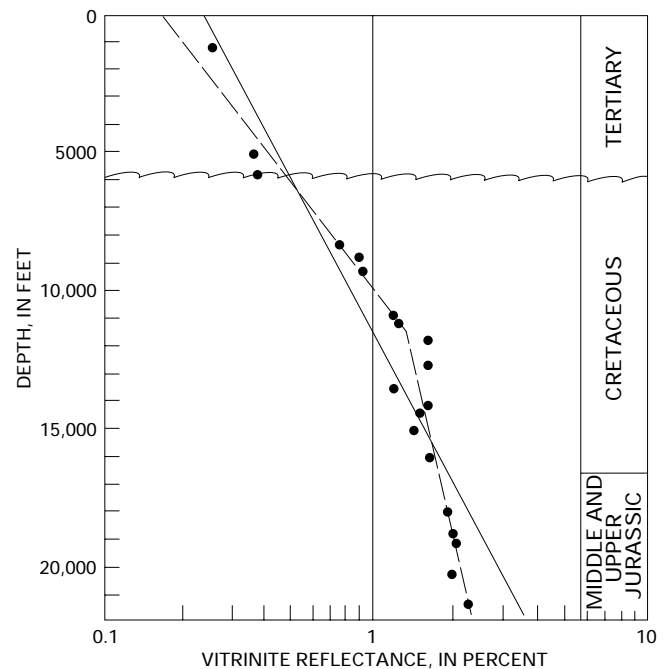


Figure 4. Vitrinite reflectance (R_o) versus depth, Exxon State Lease 624 No. 1 well, Mobile Bay, Alabama. Solid straight line is regression of all vitrinite reflectance data; dashed segmented line is regression of shallow and deep data.

gradients of 1.4°F – $1.5^\circ\text{F}/100$ ft as reported by Wilson and Tew (1985) are insufficient to achieve the measured level of thermal maturity. Therefore, paleotemperatures, at some time, were higher than present-day temperatures.

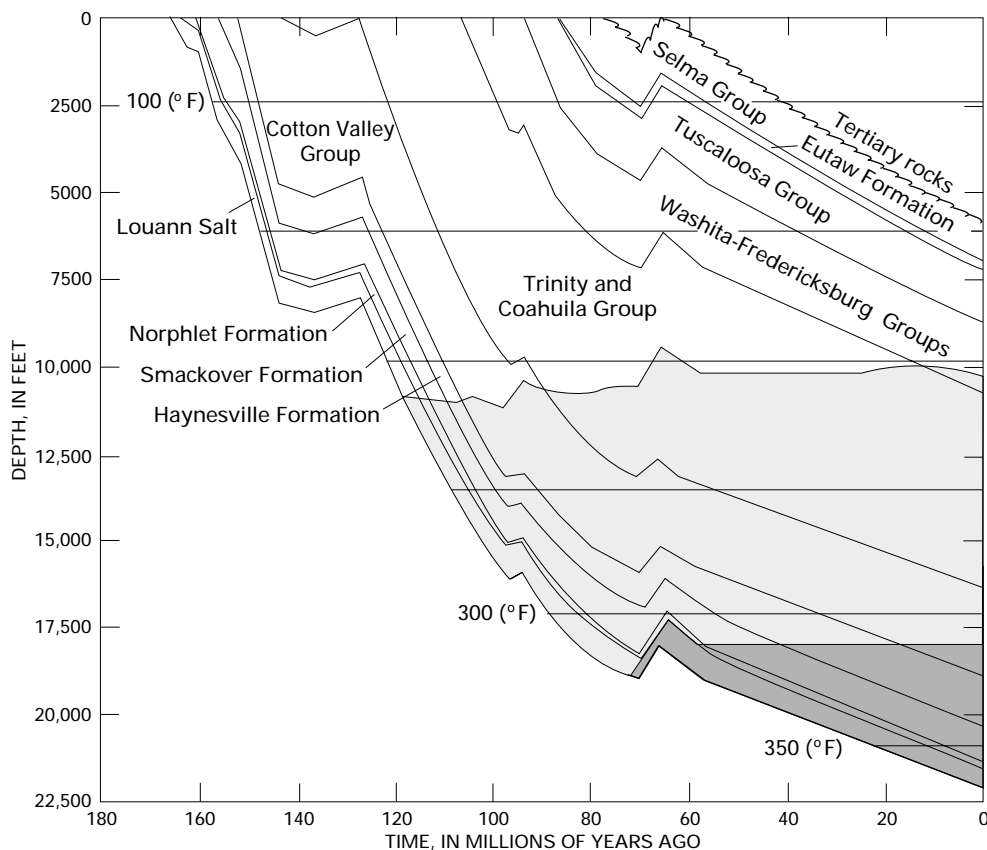


Figure 5. Preliminary burial and thermal history reconstruction, Exxon State Lease 624 No. 1 well, Mobile Bay, Alabama. Light shade represents area within the oil window (catagenesis); medium shade represents area within the gas window (metagenesis).

RESERVOIR CHARACTERIZATION

As stated earlier, sandstones of the Norphlet Formation are major reservoirs for hydrocarbons in the study area and are particularly important for deep dry gas in the Mobile Bay area. Two main facies are commonly recognized in the Norphlet Formation (Schenk, 1990). Conglomerate and red sandstone, siltstone, and shale are updip and along the margins of some of the basement uplifts, and together they are identified as the alluvial facies in figure 1. The conglomerate was deposited in proximal alluvial fan and wadi environments adjacent to basement uplifts and adjacent highlands. The redbed facies are downdip from the conglomerate and are interpreted to be distal alluvial fan and fluvial-wadi sediments.

The major offshore accumulations of deep dry gas are produced from the eolian facies of the Norphlet (fig. 1). The eolian facies is dominated by sandstone that has inversely graded eolian ripple strata and high-angle eolian avalanche strata. This facies also contains interdune, playa, and wadi deposits. The upper part of the Norphlet Formation in the Mobile Bay area is commonly described as massive and is interpreted to represent reworking of the eolian sand by marine waters associated with the Smackover transgression.

The Norphlet sandstones are subarkosic to arkosic in composition. The bulk mineral composition of productive Norphlet sandstones at two areas in Alabama was

determined by X-ray powder diffraction: onshore near the Florida Panhandle at depths of 15,100–15,600 ft (4,754 m) and in State waters of Mobile Bay, Alabama, at depths of 20,100–22,200 ft (6,126–6,766 m). The mean bulk composition, in weight percent, of onshore samples is 58 percent quartz, 26 percent feldspar, 11 percent clay minerals, 4 percent carbonate, and 1 percent pyrite. In contrast, the mean bulk composition of Mobile Bay samples is 65 percent quartz, 28 percent feldspar, 4 percent clay minerals, and less than 1 percent carbonate and pyrite.

The most significant difference in the bulk-mineral composition between the two groups is the amount, as discussed previously, and the type of clays. Clay minerals in the Norphlet sandstones are illite, chlorite, and mixed-layer illite-smectite. The illite-smectite is of the illitic and ordered variety common to deeply buried rocks (Pollastro, 1991). The mean clay-mineral composition of the onshore samples is 90 percent illite, 9 percent illite-smectite, and 1 percent chlorite. In contrast, the samples from Mobile Bay contain mostly chlorite (82 percent) and some illite (15 percent) and illite-smectite (3 percent). The relation between the amount and type of clay minerals is demonstrated in figure 6. The primary differences between the sandstones in these two areas, particularly the clay fraction, suggest that tectonic setting, provenance, and depositional environment were important factors in controlling their composition.

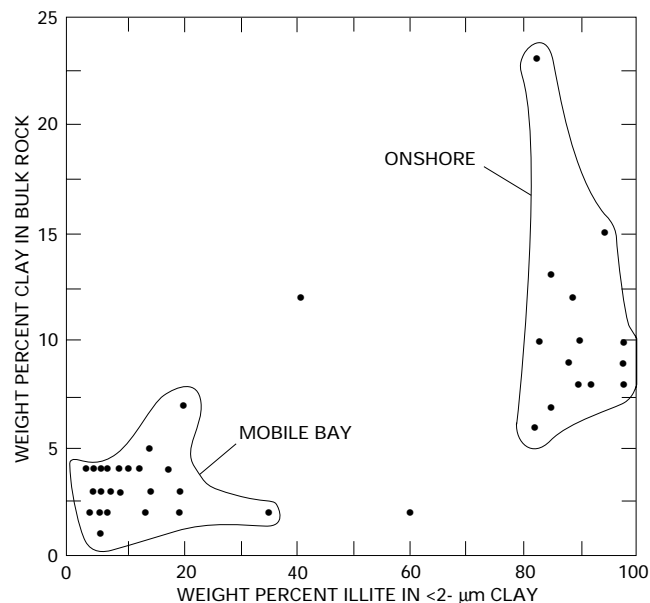


Figure 6. Weight percent of clay minerals in bulk rock versus relative weight percent of illite in sandstones of the Norphlet Formation. Note separation of samples from onshore and Mobile Bay areas.

The porosity of sandstone has been shown to correlate with time-temperature exposure (Schmoker and Gautier, 1988; Schmoker and Higley, 1991). A measure of integrated thermal history, such as vitrinite reflectance, is thus a useful parameter for empirical porosity prediction. Based on figure 3, equivalent vitrinite reflectance (R_{oeq}) of the Norphlet Formation ranges from about 0.65 percent near the Pickens-Gilbertown-Pollard fault zone to 3.0 or higher in Federal waters offshore Alabama. Core-plug porosity data for the Norphlet Formation that span this range have been gathered from a number of locations. Preliminary interpretation suggests that, at a given level of thermal maturity, porosity of the Norphlet Formation is significantly higher than porosity of most other sandstones around the world.

Figure 7 is a sketch illustrating the higher than expected porosity values for the Norphlet. The "type curve" in this figure is a porosity-equivalent vitrinite reflectance curve considered to be representative of sandstones in general (Schmoker and Gautier, 1989). The hachured zone depicts the porosity range of the Norphlet Formation as a function of thermal maturity. The key point is that Norphlet porosities are high, as compared to typical sandstone, not just offshore but throughout the study area.

Preservation of sandstone porosity in Norphlet sandstones has been cited in the literature as a function of (1) overpressuring, (2) inhibition of diagenesis by the presence of hydrocarbons, (3) inhibition of quartz diagenesis by the presence of chlorite clay cement, (4) the general lack of pore fluid volume required to cement the sandstones with quartz following mechanical compaction, and (5) early cementation

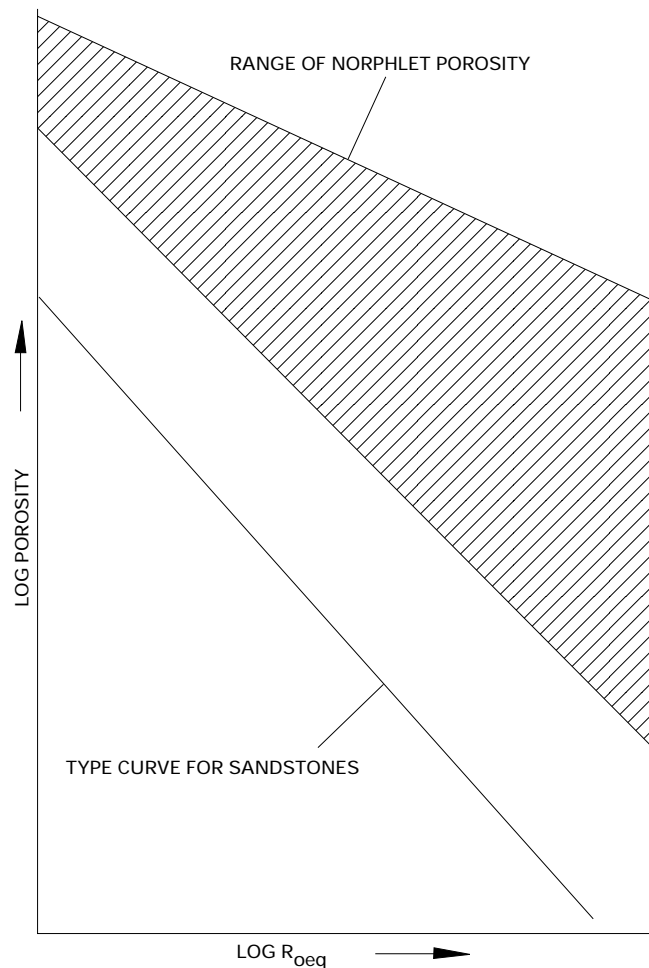


Figure 7. Preliminary interpretation of thermal maturity versus Norphlet Formation porosity for the study area. Porosity of Norphlet Formation is higher than porosities of sandstones in general (type curve from Schmoker and Gautier, 1989) if compared on basis of thermal maturity (equivalent vitrinite reflectance, R_{oeq}) over a wide range of thermal maturity.

and subsequent dissolution of evaporitic cements (carbonates, anhydrite, and halite). Each of these is discussed separately.

Overpressuring was cited by Dixon and others (1989) as acting to forestall compaction and preserve a few percent porosity in Norphlet sandstones. Compilations of pressure data for the present study illustrate that almost all onshore Norphlet fields are only slightly overpressured, the exception being a few fields proximal to the Jackson Dome. Offshore, overpressuring may be more important and may actually preserve a few percent of Norphlet sandstone porosity. The majority of Norphlet porosity onshore, however, is not due to overpressuring.

Dixon and others (1989) also concluded that diagenesis was inhibited by the presence of hydrocarbons in the pore spaces, resulting in porosity preservation. Many wells onshore, however, have encountered Norphlet sandstone

reservoirs that are water wet; little of the porous sandstone had ever contained hydrocarbons, questioning the general application of the role of hydrocarbons in preserving Norphlet porosity.

Chlorite clay has been cited as a cause of porosity preservation generally through the inhibition of quartz cementation, which then leaves pores relatively open (Thompson and Stancliffe, 1990). As discussed previously, chlorite is the dominant clay type in sandstones of the Mobile Bay area, although the total clay content is relatively low as compared to that of onshore sandstones. In this study, many examples of quartz cementation subsequent to chlorite growth have been documented; again, the general application of the role of chlorite in porosity preservation is suspect. Samples from offshore wells that contain abundant chlorite have, in some cases, contained quartz cement (Rice and others, 1992).

Ajdukiewicz and others (1991) concluded that pore fluid migration through Norphlet sandstones was inadequate to cement the sandstones with quartz and that this lack of cementation was the main reason for preservation of deep porosity. This concept deserves more study because Norphlet sandstones may have been somewhat isolated from fluid flow by the underlying Louann Salt. As was discussed for chlorite, however, many samples from both onshore and offshore wells contain quartz cement, indicating that fluids were moving through the Norphlet sandstone. Although the general application of this cause is suspect, the amount of pore fluids moving through the Norphlet may have been less than the amount moving through similar sandstones in other basins. More work, especially diagenetic modeling, is needed to focus on this problem.

Finally, several studies have focused on the dynamics of early evaporitic cements as a prime cause of excellent Norphlet porosity. The interpretation of the importance of early cements has polarized; Dixon and others (1989) concluded that early cements were of minor importance to deep porosity preservation, whereas Lock and Broussard (1989) believed that early cements were critical to porosity preservation. Our studies, as well as others, show that dolomite, calcite, anhydrite, and halite were early cements (Marzano and others, 1988) and that halite in particular is considered to be more significant in porosity preservation than has been generally realized (Hartman, 1968). Halite was observed in samples from several wells in the area extending from the Jackson Dome to southwestern Alabama. Halite is easily removed from core samples during normal preparation processes; in samples prepared with oil rather than water, more halite was observed (Rice and others, 1992). Thus, the amount of halite reported in core samples may be artificially low due to sample preservation. Halite probably formed before chlorite and before significant quartz cementation. It does not grow pseudomorphically within a pore system—that is, it does not peripherally replace framework minerals—so its removal leaves no trace of its former

presence, unlike carbonates or anhydrite. Studies continue on the significance of halite in porosity preservation.

To sum up, each of these five factors may be important locally, but focus is being placed on the regional aspects and the importance of the dynamics of early cementation and late dissolution as the main causes of porosity preservation in the Norphlet Formation.

SOURCE ROCKS

The productive area of the Norphlet Formation in the study area is characterized by oxidizing eolian and alluvial environments and transgressive marine depositional environments. Adequate hydrocarbon source rocks have not been identified in the Norphlet in its main productive area, south of the Wiggins arch.

The underlying Middle and Upper Jurassic Louann Salt forms a permeability barrier that seemingly rules out hydrocarbon migration into the Norphlet from older formations. The Norphlet is overlain by the Smackover Formation, which in turn is overlain by the Haynesville Formation. Evaporites in the lower part of the Haynesville Formation form an upper seal that appears to prevent hydrocarbon migration into the Norphlet-Smackover system from younger formations.

Perhaps because of a lack of other candidates, algal carbonate mudstones of the Smackover are commonly assumed to be the source rocks for hydrocarbons in Norphlet reservoirs (Sassen and others, 1987; Claypool and Mancini, 1989). This assumption is qualitative, however, and is not documented by mass-balance calculations. Measured total organic carbon values of selected Smackover samples from wells in Alabama rarely exceed 1.0 percent and more typically are 0.2–0.3 percent (Claypool and Mancini, 1989). The volume represented by these nonrandom samples is unknown but possibly is quite small.

Drilling results indicate that onshore Norphlet hydrocarbon potential is limited by adequate onshore source rocks. Many salt-related structures that have large closure are wet, and others have only a thin hydrocarbon column in the Norphlet (Bolin and others, 1989). Smackover production demonstrates that migrating oil and gas could reach these structures and that they are sealed. These circumstances suggest that the supply of hydrocarbons in onshore areas is generally insufficient to charge Norphlet traps.

In sharp contrast, offshore salt-related structures in the Norphlet contain very large volumes of hydrocarbons. Mancini and others (1987) estimated that the total reserves in State waters of Alabama range from 4.3 to 7.1 TCFG. T.J. Woods (Gas Research Institute, personal commun., 1992) estimated, on the basis of recent discoveries, that the gas resources of the Norphlet in the study area are tens of trillion cubic feet. The generalization can thus be made that the

hydrocarbon potential of the Norphlet in offshore areas is not limited by source rocks.

A hypothesis that explains the difference between onshore and offshore hydrocarbon abundance in the Norphlet is that the principal source rocks for the major offshore Norphlet gas accumulations are not algal carbonate mudstones of the Smackover but rather are downdip, more distal, undifferentiated Norphlet-Smackover equivalent marine facies as suggested in figure 1. Such facies, having a thickness of 1,100 ft (335 m) or more, were encountered in a well approximately 20 mi offshore, south of the Alabama-Florida State line (Mink and others, 1990).

According to this hypothesis, the large offshore Norphlet fields are charged by hydrocarbons generated and expelled from roughly age equivalent, downdip marine facies. The Wiggins arch-Conecuh ridge system (fig. 1), over which the Norphlet thins or pinches out, tends to block the updip migration of these hydrocarbons into onshore areas. The availability of hydrocarbons in onshore areas is thus severely restricted as compared to that in offshore areas and may depend on the source-rock potential of the Smackover, which probably is quite limited overall.

This hypothesis explains the regional hydrocarbon distribution in the Norphlet Formation of the study area and could be incorporated into exploration, development, and resource assessment strategies. Quantitative geochemical investigations of source-rock potential, source rock volume, and petroleum types are needed to support or discredit this hypothesis, as well as to better understand generally the Norphlet-Smackover system of the study area.

NATURAL GASES

Thirty gas samples from the study area were analyzed for molecular and isotopic composition. The samples are from Norphlet and Smackover reservoirs in the oil, wet gas and condensate, and dry gas trends.

The gas samples become chemically drier (C_2 , 49–0 percent) and isotopically heavier (methane $\delta^{13}C$, -55 to -21) with increasing depth of burial (11,400–23,600 ft; 3,474–7,193 m) and increasing level of thermal maturity. Two groups of gases can be distinguished on the basis of composition; one group comprises samples from the oil and wet gas and condensate trends, and the other comprises samples from the dry gas trend (fig. 8). The gases from the oil and wet gas and condensate trends are chemically wet (C_{2+} >15 percent) and isotopically light (methane $\delta^{13}C$ values <-41); this composition indicates that they were generated during catagenesis. In contrast, the gases from the dry gas trend are dry (C_{2+} <1 percent) and enriched in heavy ^{13}C in the methane component (methane $\delta^{13}C$ values >-38). These dry gases were generated at high levels of thermal maturity (metagenesis) and resulted mainly from thermal cracking of

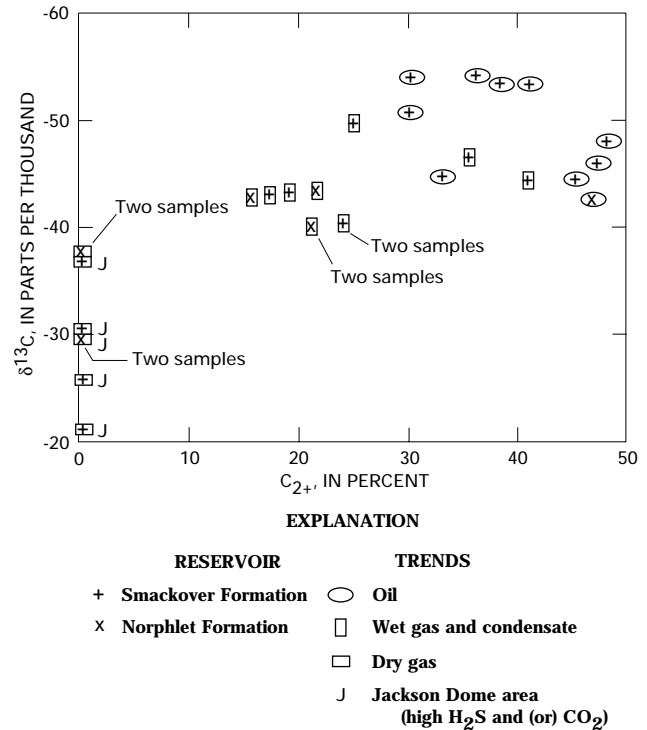


Figure 8. Methane $\delta^{13}C$ versus C_{2+} for gas samples from the study area.

oils and heavier hydrocarbons generated from marine source rocks.

Nonhydrocarbon gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) make up a significant component of many of the gases produced from Jurassic reservoirs. The highest values of CO_2 (as much as 99 percent) and H_2S (as much as 45 percent) are in the vicinity of the Jackson Dome. Gases having these high CO_2 and H_2S contents are dry and are associated with the isotopically heaviest methane (methane $\delta^{13}C$ >-36.9) (fig. 9). Many of the gases from all three producing trends contain at least some CO_2 and H_2S , which are a concern in the drilling, production, and marketing of the gas. The CO_2 was probably derived from the high-temperature decomposition of carbonate rocks (Hunt, 1979), such as those in the Smackover Formation, and the CO_2 dilutes of the hydrocarbon gases. The H_2S probably resulted from thermochemical sulfate reduction at high temperatures (Orr, 1977), and the source of the sulfate was probably anhydrite in the overlying Haynesville Formation. Unfortunately, methane can be destroyed by reactions with H_2S and sulfur compounds.

LIQUID HYDROCARBONS

Twenty-six liquid samples, including both medium-gravity oils and condensates, from southwestern Alabama were analyzed. The samples are from all major producing

intervals, but most are from Jurassic reservoirs to depths of about 18,000 ft (5,486 m). Stable carbon isotope ratios ($\delta^{13}\text{C}$) of the aromatic and saturated hydrocarbon fractions range from -25.5 to -22.0 , within the range of $\delta^{13}\text{C}$ values reported by Sofer (1984) for oils derived from marine organic matter. Oils and condensates produced from Cretaceous reservoirs are depleted in ^{13}C by about 1.0 relative to Jurassic oils and condensates. The difference in carbon isotope ratios between aromatic and saturated hydrocarbons ($\delta^{13}\text{C}$ aromatic $\delta^{13}\text{C}$ saturated, or Δ , is generally about 1.0 for Jurassic oils (Smackover Formation) and about 0.5 for oils from the Mississippi salt basin. In other words, the aromatic hydrocarbons are isotopically heavier (more ^{13}C enriched) than the saturated hydrocarbons. Δ values for Cretaceous liquids are quite variable and show no systematic trend. The isotope data indicate that at least two types of source rock have generated and expelled the liquids in these Cretaceous and Jurassic reservoirs.

Results of whole-oil gas chromatography show that the relative amount of toluene (normalized to C_7 compounds) generally increases with increasing depth of the producing reservoir to about 13,000 ft (3,962 m). No systematic relation between depth and amount of toluene is evident in samples from reservoirs deeper than 13,000 ft. Heptane values (Thompson, 1987) range from 27 to 48 (fig. 9). According to Thompson's interpretation, oils having heptane values in the range of from 17 to 30 are mature (catagenesis), and values greater than 30 are typical of supermature oils and condensates (metagenesis).

All liquids, except three from the Jurassic, have API gravities greater than 40° , but only five of the Jurassic oils

have heptane values significantly into the supermature range ($\text{API} > 35^\circ$) according to Thompson's criterion. The combination of high API gravity values and relatively low heptane values (mature) could be explained by evaporative fractionation. Evaporative fractionation is a process whereby normal oils yield condensates that are enriched in toluene (Thompson, 1987). The high toluene to heptane ratios of some of the Jurassic oils and condensates that have heptane values of less than about 30 would be consistent with Thompson's hypothesis (fig. 9). Condensates are usually attributed to generation by thermal cracking of preexisting oil at elevated temperatures, whereas evaporative fractionation does not require high-temperature cracking to generate condensates. In the present study, a combination of thermal cracking and evaporative fractionation is suggested because high heptane values and the distribution of alkanes, not shown here, suggest that at least some condensates are very mature.

SUMMARY

Natural gas from deep (>15,000 ft, 4,572 m) sedimentary basins in the United States is an important source of hydrocarbons. The Gulf of Mexico is one of the Nation's most important provinces for discovered and undiscovered hydrocarbons, including deep gas. Major resources of deep gas are present in eolian sandstone reservoirs of the Upper Jurassic Norphlet Formation in the study area and are being studied for this project.

Thermal maturity is a major control of deep gas processes and accumulations. Thermal gradients vary throughout the study area but are highest south of the Wiggins arch where the potential for deep gas is highest. Thermal modeling indicates that paleotemperatures were higher than present-day temperatures.

At a given level of thermal maturity, porosity values for the Norphlet are significantly higher than those of most sandstones worldwide. These high values may be related to (1) early cementation and subsequent dissolution of evaporitic cements (carbonates, anhydrite, and halite), (2) inhibition of quartz diagenesis by the presence of chlorite clay cement, which is prevalent in offshore Mobile Bay, (3) overpressuring, (4) inhibition of diagenesis by the presence of hydrocarbons, and (5) the general lack of pore fluid volume required to cement the sandstones.

The source for onshore Jurassic hydrocarbons, which are mostly in carbonate reservoirs in the upper part of the Smackover Formation, is probably algal carbonate mudstones in the lower part of the Smackover; however, these carbonate source rocks are probably inadequate to charge the major accumulations of deep, dry gas in the Norphlet in the Mobile Bay area of offshore Alabama and Mississippi. Downdip, more distal, marine, type II kerogen-bearing facies of the undifferentiated Norphlet and Smackover

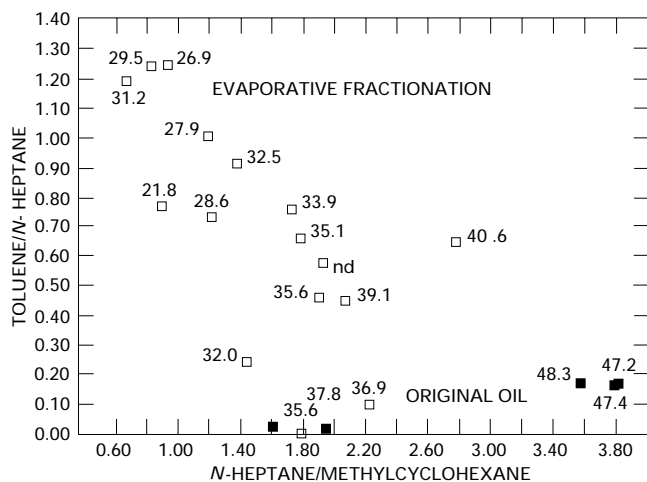


Figure 9. Toluene to heptane ratios versus heptane to methylcyclohexane ratios for oils and condensates of southwestern Alabama. Jurassic liquids are plotted as open squares, Cretaceous samples as solid squares. Numbers refer to heptane values ($100 \times$ heptane (Σ cyclohexane through methylcyclohexane). Modified from Thompson (1987).

interval are postulated to be the source for these offshore accumulations.

Gases in deep reservoirs of the Norphlet are distinguished by their dryness and by their enrichment in ^{13}C , both of which indicate generation at high levels of thermal maturity (metagenesis). Gases in Jurassic reservoirs of the study area contain varying amounts of CO_2 and H_2S , which have an inorganic origin and present problems in drilling, production, and marketing. Geochemical data indicate that liquids in deep Jurassic and Cretaceous reservoirs may have at least two sources. In addition, the condensates may have resulted from either (1) high-temperature cracking of heavier hydrocarbons or (2) evaporative fractionation.

REFERENCES CITED

- Ajdkiewicz, J.M., Paxton, S.T., and Szabo, J.O., 1991, Deep porosity preservation in the Norphlet Formation, Mobile Bay, Alabama [abs.]: American Association of Petroleum Geologists Bulletin, v. 75, p. 533.
- Bolin, D.E., Mann, S.D., Burroughs, D., Moore, H.E., Jr., and Powers, T.J., 1989, Petroleum atlas of southwestern Alabama: Geological Survey of Alabama Atlas 23, 218 p.
- Claypool, G.E., and Mancini, E.A., 1989, Geochemical relationships of petroleum in Mesozoic reservoirs to carbonate source rocks of Jurassic Smackover Formation, southwest Alabama: American Association of Petroleum Geologists Bulletin, v. 73, p. 904–924.
- Curtis, D.M., 1991, The northern Gulf of Mexico Basin, *in* Gluskoter, H.J., Rice, D.D., and Taylor, R.B., eds., Economic geology, U.S.: Geological Society of America, Boulder, Colorado, The Geology of North America, v. P-2A, p. 301–324.
- Dixon, S.A., Summers, D.M., and Surdam, R.C., 1989, Diagenesis and preservation of porosity in the Norphlet Formation (Upper Jurassic), southern Alabama: American Association of Petroleum Geologists Bulletin, v. 73, p. 707–728.
- Hartman, J.A., 1968, The Norphlet Formation, Pelahatchie field, Rankin County, Mississippi: Gulf Coast Association of Geological Societies Transactions, v. 18, p. 2–11.
- Hunt, J.M., 1979, Petroleum geochemistry and geology: San Francisco, W.H. Freeman, 617 p.
- Keighin, C.W., and Schenk, C.J., 1992, The ARC/INFO Geographic Information System applied to geologic investigations of the Norphlet Formation, Alabama and Mississippi [abs.]: U.S. Geological Survey Circular 1074, p. 41.
- Law, B.E., Nuccio, V.F., and Barker, C.E., 1989, Kinky vitrinite reflectance well profiles—Evidence of paleopore pressure in low-permeability gas-bearing sequences in Rocky Mountain foreland basins: American Association of Petroleum Geologists Bulletin, v. 73, p. 999–1010.
- Lock, B.E., and Broussard, S.W., 1989, The Norphlet reservoir in Mobile Bay; origins of deep porosity: Gulf Coast Association of Geological Societies Transactions, v. 39, p. 187–194.
- Mancini, E.A., and Benson, D.J., 1980, Regional stratigraphy of Upper Jurassic Smackover carbonates of southwest Alabama: Gulf Coast Association of Geological Societies Transactions, v. 30, p. 151–165.
- Mancini, E.A., Mink, R.M., Bearden, B.L., and Hamilton, R.P., 1987, Recoverable natural gas reserves for the Jurassic Norphlet Formation, Alabama coastal area: Gulf Coast Association of Geological Societies Transactions, v. 37, p. 153–160.
- Mancini, E.A., Mink, R.M., Bearden, B.L., and Wilkerson, R.P., 1985, Norphlet Formation (Upper Jurassic) of southwestern and offshore Alabama: American Association of Petroleum Geologists Bulletin, v. 69, p. 881–898.
- Marzano, M.S., Pense, G.M., and Andronaco, P., 1988, A comparison of the Jurassic Norphlet Formation in Mary Ann field, Mobile Bay, Alabama, to onshore regional Norphlet trends: Gulf Coast Association of Geological Societies Transactions, v. 38, p. 85–100.
- Mink, R.M., Bearden, B.L., and Mancini, E.A., 1989, Regional Jurassic geologic framework of Alabama coastal waters area and adjacent Federal waters area: Marine Geology, v. 90, p. 39–50.
- Mink, R.M., Tew, B.H., Mann, S.D., Bearden, B.L., and Mancini, E.A., 1990, Norphlet and pre-Norphlet geologic framework of Alabama and panhandle Florida coastal waters area and adjacent Federal waters area: Geological Survey of Alabama Bulletin 140, 58 p.
- NRG Associates Inc., 1988, The significant oil and gas fields of the United States (through June 30, 1988): Available from Nehring Associates, Inc., P.O. Box 1655, Colorado Springs, Colorado 80901.
- Orr, W.L., 1977, Geologic and geochemical controls on the distribution of hydrogen sulfide in natural gas, *in* Campos, R., and Goni, J., eds., Advances in organic geochemistry 1977: Madrid, Empresa Nacional Adaro de Investigaciones Mineras, v. 7, p. 571–597.
- Pollastro, R.M., 1991, Composition, clay mineralogy, and diagenesis of the Simpson Group (Middle Ordovician), Grady County, Oklahoma: U.S. Geological Survey Bulletin 1866-H, 19 p.
- Rice, D.D., Schenk, C.J., Schmoker, J.W., Fox, J.E., Clayton, J.L., Dyman, T.S., Higley, D.K., Keighin, C.W., Law, B.E., and Pollastro, R.M., 1992, *in* Malone, R.D., Shoemaker, Harold, and Byer, C.W., eds., Proceedings of the natural gas research and development contractors review meeting: U.S. Department of Energy DOE/METC 92/6125, p. 151–166.
- Sassen, R., Moore, C.H., and Meendsen, F.C., 1987, Distribution of hydrocarbon source potential in the Jurassic Smackover Formation: Organic Geochemistry, v. 11, p. 379–383.
- Schenk, C.J., 1990, Overview of eolian sandstone diagenesis, Upper Jurassic Denkman Sandstone Member of the Norphlet Formation, Mississippi and Alabama, *in* Fryberger, S.G., Krystinik, L.F., and Schenk, C.J., eds., Modern and ancient eolian deposits—Petroleum exploration and production: Denver, Rocky Mountain Section, SEPM, v. 20, 12 p.
- Schmoker, J.W., and Gautier, D.L., 1988, Sandstone porosity as a function of thermal maturity: Geology, v. 16, p. 1007–1010.
- 1989, Compaction of basin sediments: modeling based on time-temperature history: Journal of Geophysical Research, v. 94, p. 7379–7386.

- Schmoker, J.W., and Higley, D.K., 1991, Porosity trends of the Lower Cretaceous J sandstone, Denver Basin, Colorado: *Journal of Sedimentary Petrology*, v. 61, p. 909–920.
- Sofer, Z., 1984, Stable carbon isotope compositions of crude oils: *American Association of Petroleum Geologists Bulletin*, v. 68, p. 31–49.
- Thompson, A., and Stancliffe, R.J., 1990, Diagenetic controls on reservoir quality, eolian Norphlet Formation, South State Line field, Mississippi, *in* Barwis, J.H., McPherson, J.G., and Studlick, J.R.L., eds., *Sandstone petroleum reservoirs*: New York, Springer-Verlag, p. 205–224.
- Thompson, K.F.M., 1987, Fractionated aromatic petroleums and the generation of gas-condensates: *Organic Geochemistry*, v. 11, p. 573–590.
- Wilson, G.V., and Tew, B.H., 1985, Geothermal data for southwest Alabama: State Oil and Gas Board of Alabama Oil and Gas Report 10, 125 p.