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Reservoir Characterization of the Smackover Formation in Southwest Alabama

Final Report

By
David C. Kopaska-Merkel
Douglas R. Hall
Steven D. Mann
Berry H. Tew

February 1993

Performed Under Contract No. DE-FG22-89BC14425

Geological Survey of Alabama
Tuscaloosa, Alabama

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

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U.S. Department of Energy
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EXECUTIVE SUMMARY

The Upper Jurassic Smackover Formation is found in an arcuate belt in the subsurface from south Texas to panhandle Florida. The Smackover is the most prolific hydrocarbon-producing formation in Alabama and is an important hydrocarbon reservoir from Florida to Texas.

In this report Smackover hydrocarbon reservoirs in southwest Alabama are described. Also, the nine enhanced- and improved-recovery projects that have been undertaken in the Smackover of Alabama are evaluated. The report concludes with recommendations about potential future enhanced- and improved-recovery projects in Smackover reservoirs in Alabama and an estimate of the potential volume of liquid hydrocarbons recoverable by enhanced- and improved-recovery methods from the Smackover of Alabama.

The Smackover was deposited on a carbonate ramp, similar to that of the present-day Persian Gulf, in much of the Gulf-Coast region. However, in southwest Alabama, Smackover strata were deposited in four interconnected basins: the eastern part of the Mississippi interior salt basin, the Manila embayment (which contains two separate depocenters), the Conecuh embayment, and a basinal area south of the Baldwin high. The distribution of facies was more closely controlled by local paleotopography than by southerly regional dip, as would have been the case in an unmodified ramp setting. High-energy facies were deposited in nearshore areas rimming exposed paleohighs and near the updip limit of Smackover deposition; lower energy strata were deposited in basin centers. Based on ammonites recovered from the lower portion of the unit, the Smackover has been assigned a late Oxfordian age. The Smackover ranges up to more than 550 feet thick in the study area.

Basal Smackover strata in Alabama contain laminar and domal stromatolites; these deposits probably formed in shallow water during the early stages of marine transgression. Middle Smackover strata are dominated by lime mudstone and pelletal or fossiliferous lime wackestone. These strata were deposited at and near the time of maximum transgression, and during and after a period of rapidly increasing water depth. Middle-Smackover lime mudstone is typically laminated and organic rich. Upper Smackover strata were laid down during a relative sea-level stillstand. Progradational strata of the upper Smackover are dominated by ooid grainstone and diverse peritidal carbonates on the flanks of the paleohighs and by pelletal and oncoidal packstone and grainstone in the centers of the depositional basins. The Smackover locally contains substantial amounts of siliciclastic material, particularly near the Conecuh ridge and its associated small paleohighs (e.g., Barnett, North Wallers Creek, Uriah, Vocation, and Burnt Corn Creek fields) and in the Manila embayment. Diagenesis of Smackover reservoirs was dominated by the effects of (1) early cementation, (2) leaching of calcium-carbonate allochems, and (3) dolomitization, both mimetic and nonmimetic. The Smackover Formation is overlain in southwest Alabama by the Buckner Anhydrite Member of the Haynesville Formation, whose basal portion is dominated by subaqueous evaporites in depositional basins, and by peritidal and supratidal evaporitic and siliciclastic strata on the flanks and crests of paleohighs.

As of December 1990, the Smackover had produced oil, condensate and/or natural gas from 73 established fields in Alabama. At that time, cumulative production from Smackover reservoirs in Alabama totaled over 113 million barrels (MMB) of oil (including Norphlet oil production at South Womack Hill field and minor amounts from a few other fields, which are not reported separately), 145 MMB of condensate (including Norphlet condensate production at Hatter's Pond field, which is not reported separately), and 1.12 trillion cubic feet (TCF) of natural gas.

Smackover hydrocarbon traps in southwest Alabama can be characterized as structural or combination structural and stratigraphic traps. Many structural traps result from halokinesis of the Louann Salt, but basement-cored anticlinal traps are locally common. The Buckner Anhydrite Member of the Haynesville Formation commonly forms the seal. Combination traps generally involve porosity or permeability pinch-outs occurring on regional dip, on halokinetically generated anticlines or structural noses, or on basement-related anticlines or faulted anticlines.

Most Smackover reservoirs originated as nearshore-marine carbonate sediments with minor admixtures of noncarbonate material. Some of these reservoirs preserve abundant evidence of their environment of deposition. Others have been highly altered and their origins are unclear. The most common Smackover reservoir rocks are nonskeletal grainstone. Mixed-particle grainstone/packstone is the second most common reservoir type in the Smackover of southwest Alabama. Two other important kinds of reservoir are microbial boundstone and crystalline dolostone. Quartzose sandstone, commonly dolomitic, forms permeable reservoirs locally in southern Monroe County.

In this study, Smackover reservoir rocks are classified using capillary pressure curve shape. CP-curve shape summarizes a wealth of petrophysical information about reservoir rocks, including pore-throat size distribution and estimates of recovery efficiency and permeability. CP-curve class 1 includes samples that have extremely leptokurtic pore-throat size distributions and that exhibit little or no extrusion of mercury during pressure reduction. Samples assigned to CP-curve class 2 differ in exhibiting pore-throat size distributions with minor fine tails. CP-curve class 3 includes samples that exhibit as much as 60 percent mercury extrusion during pressure reduction. CP-curve class 4 includes samples that have mesokurtic pore-throat size distributions (ranging from like those of class 2 to substantially more variable). These samples exhibit a prominent tail of small throats that accounts for as much as 25 percent of the pore volume, or a smooth reduction in volume of pores accessed through smaller and smaller throats over the entire range of pore-throat sizes. Samples assigned to this class extrude up to more than 25 percent of their mercury during pressure reduction. Samples assigned to CP-curve class 5 exhibit platykurtic or polymodal pore-throat size distributions. CP curves assigned to this class are variable, as are porosity values, recovery-efficiency values, and median throat sizes. On average, however, porosity values and throat sizes are smaller than for classes 1 through 4; recovery efficiencies range up to about 40 percent. CP-curve class 6 includes marginal reservoir rocks; porosity values are less than 10 percent and the mean is about 6 percent. These samples have mesokurtic throat size distributions and lack large throats (median throat sizes do not exceed 0.5 m). Recovery efficiencies range between about 30 and 40 percent. CP-curve classes 7 and 8 include nonreservoir rocks exhibiting very small throats.

Three methods of predicting permeability are discussed. The first is based on the relationship between microporosity, as measured from capillary-pressure data and as estimated by calibration of well logs, and permeability. The ultimate goal is to predict permeability values from well logs or from limited amounts of other kinds of data. The second is by measuring median throat size, which is derived from capillary-pressure analysis. Small amounts of microporosity can dramatically depress permeability in the Smackover. It appears that small (centimeter-scale?) areas of small pores and small pore throats act as permeability baffles. The only petrophysical variable investigated that is strongly correlated with permeability is median throat size (MTS). MTS is derived from capillary-pressure analysis, an expensive and time-consuming method which usually requires core samples. However, whereas permeability can be measured only in samples cut from cores, MTS can be calculated from analysis of cuttings. Therefore, permeability can be estimated from noncored intervals. The third method of predicting permeability is from porosity data. The porosity-permeability relationships differ among reservoirs dominated by different kinds of pore systems. Intercrystalline reservoirs exhibit the strongest porosity-permeability relationships, but even for these reservoirs, equations derived from one field will not yield accurate results when applied to another.

Pore systems in reservoir rocks of the Smackover Formation in southwest Alabama are dominated either by moldic plus secondary intraparticle pores or by intercrystalline pores. Intermediate pore systems are less common. Because the Smackover reservoir rocks described here fall naturally into two distinct groups, two pore facies are defined. Pore facies are rock units characterized by certain pore types or combinations of pore types and by certain consequent pore-throat size distributions. Pore facies also possess characteristic fluid-flow properties.

Reservoir rocks assigned to different pore facies are petrophysically, petrographically, and geographically distinct. Those assigned to the moldic pore facies are dominated by moldic plus secondary intraparticle pores. Some samples contain up to about 20 percent interparticle pores. Reservoir rocks assigned to the intercrystalline pore facies are dominated by intercrystalline pores. Moldic pore systems are products of primary sediment fabric, modified by (usually) fabric-selective dolomitization and by dissolution of unstable particles before, during, or after dolomitization. Intercrystalline pore systems are most strongly affected by pervasive fabric-destructive dolomitization, although primary sediment fabric commonly has some effect on the final rock fabric.

This means that geological models of environment of deposition and of diagenetic history are more likely to help interpretation of moldic reservoirs than of intercrystalline reservoirs. Moldic pore systems tend to have higher mean porosity values but lower maximum permeability values than intercrystalline pore systems. Moldic pore systems have more leptokurtic pore-throat size distributions, but are fundamentally heterogeneous at microscopic scales because coarse and fine pores are found together. Intercrystalline pore systems are fundamentally homogeneous at this level, at least in the ideal case. Intercrystalline pore systems are more heterogeneous megascopically (vertically) and therefore have more potential for bypassing of potentially productive intervals. Also, high-permeability thief zones are more abundant in intercrystalline reservoirs. Intermediate samples resemble petrophysically the intercrystalline pore facies, and occupy intermediate regions geographically. Because rocks of the Moldic and Intercrystalline pore facies are readily distinguishable, and exhibit quite different fluid-flow characteristics, the pore-facies classification proposed here may be a useful tool in planning development of Smackover fields in Alabama, and could probably be applied successfully to other porous and permeable carbonate units.

Quantitative (rank) measures of microscopic and megascopic reservoir heterogeneity are used to describe heterogeneity in Smackover hydrocarbon fields in southwest Alabama. Microscopic reservoir heterogeneity (H) is:

$\{[(0.25\sigma\phi) + (\text{mean natural log of K}) + (1.5\sigma \text{ natural log of K})]/3\}.$

Megascopic heterogeneity (MH) is:

$[(\text{\# of reservoir intervals}) + (\text{\# of high-K reservoir intervals}) + (\sigma \text{ of \# of reservoir intervals})]$

where reservoir rock is defined as exhibiting permeability values ≥ 0.1 md and high-K reservoir rock exhibits permeability values ≥ 1.0 md. Both MH and H are determined from core data and are estimates of vertical heterogeneity. The Dykstra-Parsons coefficient (DP) is a measure of microscopic heterogeneity that is partially independent of H ($r^2 = 0.428$).

H and MH are distributed in opposing patterns. H generally decreases from northwest to southeast; MH increases in the same direction. H values are high in the moldic pore facies and low in the intercrystalline pore facies. Reservoirs belonging to the moldic pore facies tend to be homogeneous with respect to MH, whereas reservoirs assigned to the intercrystalline pore facies are characterized by relatively high MH values.

The congruency of patterns of variation of H and MH with pore-system characteristics (controlled by depositional patterns, dissolution, and dolomitization) and regional structural and paleogeographic trends suggests that reservoir heterogeneity characteristics are controlled by structural and paleogeographic setting and by diagenesis. However, because contours of H and MH are approximately normal to structure contours but parallel to Smackover thickness contours (on a regional scale), it appears that depositional setting (or paleogeography) exerted more stringent control on reservoir heterogeneity than did structural evolution. On the scale of a single field, heterogeneity is controlled by depositional and diagenetic patterns.

The distribution of DP values is not related to pore-facies distribution; thus the DP coefficient is less useful for regional heterogeneity studies than is MH or H.

Estimation of H and MH regionally in the Smackover of southwest Alabama will facilitate EOR planning for fields that are still in the early stages of development. Prediction of reservoir heterogeneity characteristics will facilitate advance planning of production strategies and cost/benefit analyses for development of new fields. In addition, it will be possible to identify regions characterized by or containing unusually heterogeneous or unusually homogeneous reservoirs (microscopic, megascopic, or both).

Microscopic lateral heterogeneity (LH) was calculated for 12 of the largest Smackover fields. Relatively sophisticated parameters could not be applied to the Smackover of southwest Alabama because the data are of poor quality. Instead, LH was estimated as a function of the difference between the residual variance about the porosity-permeability trend for single wells and that for entire fields. If a field is perfectly laterally homogeneous, then wells will not differ with respect to their porosity-permeability trends and subtracting the field value from the average of values for single wells yields an LH estimate of zero. Conversely, if a field is highly heterogeneous laterally, then the field value will exhibit a high degree of scatter because wells with very different porosity-permeability relationships will have been lumped together. A high value of LH results. Analysis of the 12 fields for which sufficient data are available indicates that H and LH covary. Also, gas-condensate fields are relatively laterally homogeneous, and oil fields are relatively laterally heterogeneous.

Eleven Smackover fields in Alabama have been unitized through 1990. Three fields were unitized specifically to allow the drilling of a strategically placed well to recover uncontacted oil. Two fields in Alabama are undergoing waterflood projects. Five fields are undergoing gas-injection programs to increase the ultimate recovery of hydrocarbons. In each of the unitized fields where injection or waterflooding has occurred, additional wells have been drilled. These wells have been drilled as either replacement, infill, or strategically located wells, and in each case appear to be an integral part of the enhanced- or improved-recovery project.

Silas and Choctaw Ridge fields were unitized but no enhanced-recovery operations have been initiated. Appleton, Turkey Creek, and Stave Creek fields were unitized for the purpose of strategic well placement. In each case, an additional well was drilled to increase the recovery of hydrocarbons from the field.

Waterflood operations have commenced in Womack Hill field in Choctaw and Clarke Counties, Alabama, and in Jay-Little Escambia Creek (Jay-LEC) fields, located in Escambia County, Alabama, and in Escambia and Santa Rosa Counties, Florida. In the Womack Hill field unit, an additional 13 million barrels have been recovered since unitization. Ultimate recovery from both primary and secondary recovery is predicted to be 17 million barrels of oil. Jay-LEC fields are undergoing infill drilling, waterflood, and gas-injection operations. The waterflood project was begun initially along with an infill-drilling program in areas of low permeability. Prior to completing the waterflood project it was determined that 355 million barrels of oil would remain in the reservoir after waterflooding and therefore, a water-alternating-gas program or "WAG" using methane and later nitrogen was initiated. Jay-LEC fields have produced approximately 399 million barrels of oil, 87 percent of which has been recovered since enhanced-recovery operations were initiated.

Chatom field, in Washington County, is the site of the oldest gas-injection project in Alabama. Primary recovery in the field was estimated to be 6.3 million barrels of condensate. Through 1990, 14.3 million barrels of condensate have been recovered using primary and secondary recovery, an incremental increase of 8 million barrels. Ultimate recovery for Chatom field is projected at 15.8 million barrels. Hatter's Pond field was unitized in 1985 to allow injection of residue gas into the reservoir. A total of 41 million barrels of condensate have been produced from the field, and ultimate recovery under secondary recovery is expected to be 13 million barrels over what would have been produced under primary depletion. Fanny Church field, in Escambia County, was also unitized in 1985. A nitrogen-injection program was commenced in a portion of the field. Primary recovery was estimated to be 3.9 million barrels. However, using nitrogen injection, 7 million barrels could be recovered. Through 1990, 4.3 million barrels of oil have been recovered from the unit. Approximately 9.3 billion cubic feet of gas have been injected into the Smackover reservoir although no injection operations are ongoing.

Unitized fields are found in each of the pore facies defined by Kopaska-Merkel and Mann (1991). Within the moldic pore facies, only strategic well placement has been used. Gas injection and infill drilling are the only enhanced- or improved-recovery techniques used in the intercrystalline pore facies. Enhanced- or improved-recovery methods used in reservoirs with intermediate pore systems include infill drilling, strategic well placement, waterflooding, and gas injection. However, pore-system characteristics should not necessarily restrict the type of enhanced- or improved-recovery methods used. Injection operations should be considered for fields in the moldic pore facies and strategic well placement is a viable option wherever hydrocarbons are updip from existing wells. Also, reservoirs with intercrystalline and moldic pore systems should be evaluated for multiple enhanced- or improved-recovery techniques as have been implemented in Jay-LEC fields.

Unitized fields with intermediate pore systems have produced over 435 million barrels of oil (including the Florida portion of Jay-LEC fields). The intercrystalline pore facies has produced approximately 90 million barrels of liquid hydrocarbons from unitized Smackover fields. Approximately 11 million barrels of hydrocarbon liquids have been produced from unitized reservoirs within the moldic pore facies.

Potential candidates for enhanced or improved recovery are identified based on similarities to fields already unitized. Strategic well placement is the most viable improved-recovery technique for medium to small reservoirs where injection operations are economically prohibitive. By drilling wells at strategic locations portions of the reservoir that would not be drained by existing wells can be penetrated and hydrocarbon recovery increased. Fields that should be considered for strategic well placement include Movico, Blacksher, Barrytown, and North Choctaw Ridge. Candidates for injection include Movico, Big Escambia Creek, and North Choctaw Ridge fields.

The combined estimates, made by operators prior to enhanced- or improved-recovery operations, for secondary production from the nine Alabama Smackover fields currently undergoing such operations, amount to 331.5 million barrels of hydrocarbon liquids. Revision of this estimate based on (1) results of enhanced- and improved-recovery operations through 1990, (2) proposed tertiary recovery from some of these nine fields using reasonable estimates of relevant parameters from this report and from the published literature, and (3) proposed enhanced or improved recovery from potential candidates listed above, yields a new estimate of 468 million barrels of liquid hydrocarbons expected to be produced by enhanced- or improved-recovery methods from the Alabama Smackover. Even this estimate is probably conservative.

ABSTRACT

The Upper Jurassic Smackover Formation is found in an arcuate belt in the subsurface from south Texas to panhandle Florida. The Smackover is the most prolific hydrocarbon-producing formation in Alabama and is an important hydrocarbon reservoir from Florida to Texas. Most Smackover reservoirs originated as nearshore-marine carbonate sediments with minor admixtures of noncarbonate material. Some of these reservoirs preserve abundant evidence of their environment of deposition. Others have been highly altered and their origins are unclear. The most common Smackover reservoir rocks are nonskeletal grainstone, dominated by pellets, ooids, and oncoids, in order of decreasing abundance. Mixed-particle grainstone/packstone is the second most common reservoir type in the Smackover of southwest Alabama. Other important Smackover reservoirs are microbial boundstone and crystalline dolostone. Quartzose sandstone, commonly dolomitic, forms permeable reservoirs with interparticle pore systems locally in southern Monroe County (e.g., North Wallers Creek field). The most common kinds of pores in the Smackover are particle molds, secondary intraparticle (partial moldic) pores, intercrystalline pores, and interparticle pores. The various pore types lend different petrophysical characteristics to pore systems, and combinations of different kinds of pores in varying proportions create further effects.

In this study, Smackover reservoir rocks are classified using capillary-pressure curve shape. CP-curve class 1 includes samples that have extremely leptokurtic pore-throat size distributions and that exhibit little or no extrusion of mercury during pressure reduction. Samples assigned to CP-curve class 2 differ in exhibiting pore-throat size distributions with minor fine tails. CP-curve class 3 includes samples that exhibit as much as 60 percent mercury extrusion during pressure reduction. CP-curve class 4 includes samples that have mesokurtic pore-throat size distributions (ranging from like those of class 2 to substantially more variable). Samples assigned to this class extrude up to 25 percent or more of their mercury during pressure reduction. Samples assigned to CP-curve class 5 exhibit platykurtic or polymodal pore-throat size distributions. CP curves assigned to this class are variable, as are porosity values, recovery efficiency values, and median throat sizes. On average, however, porosity values and throat sizes are smaller than for classes 1 through 4; recovery efficiencies range up to about 40 percent. CP-curve class 6 includes marginal reservoir rocks; porosity values are less than 10 percent and the mean is about 6 percent. These samples have mesokurtic throat-size distributions and lack large throats (median throat sizes do not exceed 0.5 μm). Recovery efficiencies range between about 30 and 40 percent. CP-curve classes 7 and 8 include nonreservoir rocks.

Pore systems in reservoir rocks of the Smackover Formation in southwest Alabama are dominated either by moldic plus secondary intraparticle pores or by intercrystalline pores. Intermediate pore systems are less common. Therefore, two pore facies, rock units characterized by certain pore types or combinations of pore types, and by certain consequent pore-throat-size distributions, are defined. Pore facies also possess characteristic fluid-flow properties. Reservoir rocks assigned to the moldic pore facies are dominated by moldic plus secondary intraparticle pores. Some samples contain up to about 20 percent interparticle pores. Reservoir rocks assigned to the intercrystalline pore facies are dominated by intercrystalline pores. Moldic pore systems are products of primary sediment fabric, modified by (usually) fabric-selective dolomitization and by dissolution of unstable particles before, during, or after dolomitization. Intercrystalline pore systems are most strongly affected by pervasive fabric-destructive dolomitization, although primary sediment fabric commonly has some effect on the final rock fabric. Moldic pore systems tend to have higher mean porosity values but lower maximum permeability values than intercrystalline pore systems. Moldic pore systems have more leptokurtic pore-throat size distributions, but are fundamentally heterogeneous at microscopic levels because coarse and fine pores are mixed together. Intercrystalline pore systems are fundamentally homogeneous microscopically. Intercrystalline pore systems are more heterogeneous megascopically and therefore there is more potential for bypassing of potentially productive reservoir zones. Also, high-permeability thief zones are more likely in intercrystalline reservoirs. Intermediate samples resemble petrophysically the intercrystalline pore facies and occupy intermediate regions geographically.

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INTRODUCTION

This is the final summary report on DOE contract number DE-FG22-89BC14425, entitled "Establishment of an Oil and Gas Database for Increased Recovery and Characterization of Oil and Gas Carbonate Reservoir Heterogeneity." This volume constitutes the final report for the entire project, except for Subtask 1, which was completed with submittal of a computer tape for the TORIS database in December of 1990. For descriptions of methods employed in this project, see Kopaska-Merkel (1991; 1992a). This report is based on reservoir characterizations of all 73 Smackover fields in Alabama (fig. 1, table 1), which were published by Kopaska-Merkel and others (1992).

GEOLOGIC SETTING

A detailed review of the geologic setting of the Smackover in southwest Alabama was presented by Kopaska-Merkel (1992a). That discussion is summarized here.

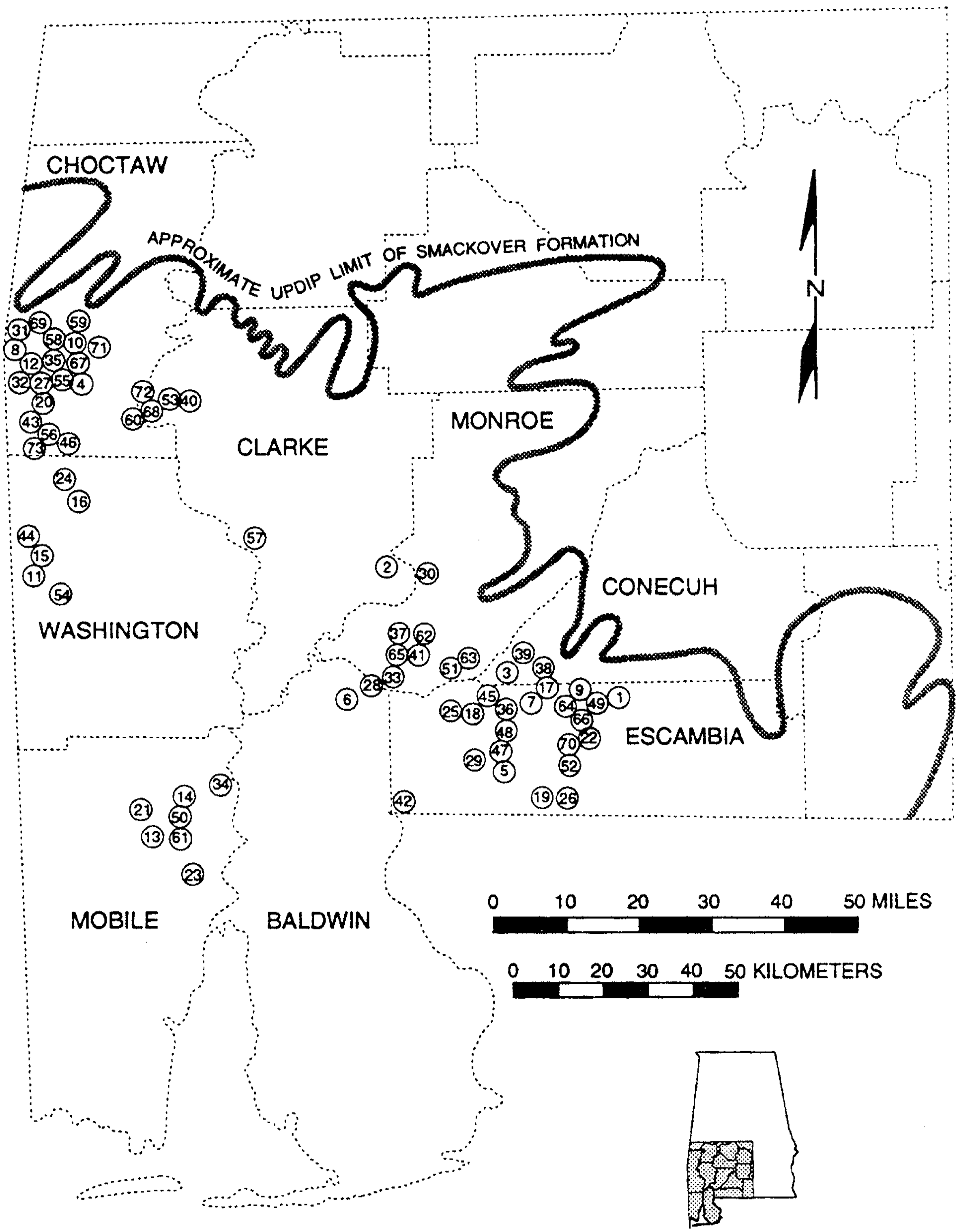


Figure 1.--Location map for all Smackover fields in Alabama as of December 1990.

Table 1.--Smackover fields in Alabama as of December 1990

Field number	Field name	County	Hydrocarbon type
1	Appleton	Escambia	Oil
2	Barlow Bend	Clarke and Monroe	Oil
3	Barnett	Conecuh and Escambia	Oil
4	Barrytown	Choctaw	Oil
5	Big Escambia Creek	Escambia	Condensate
6	Blacksher	Baldwin	Oil
7	Broken Leg Creek	Escambia	Oil
8	Bucatunna Creek	Choctaw	Oil
9	Burnt Corn Creek	Escambia	Oil
10	Chappell Hill	Choctaw	Oil
11	Chatom	Washington	Condensate
12	Choctaw Ridge	Choctaw	Oil
13	Chunchula	Mobile	Oil/Condensate
14	Cold Creek	Mobile	Oil
15	Copeland Gas	Washington	Condensate
16	Crosbys Creek	Washington	Condensate
17	East Barnett	Conecuh and Escambia	Oil
18	East Huxford	Escambia	Oil
19	Fanny Church	Escambia	Oil
20	Gin Creek	Choctaw	Oil
21	Gulf Crest	Mobile	Oil
22	Hanberry Church	Escambia	Oil
23	Hatter's Pond	Mobile	Condensate
24	Healing Springs	Washington	Condensate
25	Huxford	Escambia	Oil
26	Jay-Little Escambia Creek	Escambia	Oil
27	Little Mill Creek	Choctaw	Oil
28	Little River	Baldwin and Monroe	Oil
29	Little Rock	Escambia	Condensate
30	Lovetts Creek	Monroe	Oil
31	Melvin	Choctaw	Oil
32	Mill Creek	Choctaw	Oil
33	Mineola	Monroe	Oil
34	Movico	Baldwin and Monroe	Oil
35	North Choctaw Ridge	Choctaw	Oil
36	North Smiths Church	Escambia	Oil
37	North Wallers Creek	Monroe	Oil
38	Northeast Barnett	Conecuh	Oil
39	Northwest Range	Conecuh	Oil
40	Pace Creek	Clarke	Oil
41	Palmers Crossroads	Monroe	Oil
42	Perdido	Baldwin and Escambia	Oil
43	Puss Cuss Creek	Choctaw	Oil
44	Red Creek	Washington	Condensate
45	Robinson Creek	Escambia	Oil

Table 1.--Smackover fields in Alabama as of December 1990—Continued

Field number	Field name	County	Hydrocarbon type
46	Silas	Choctaw	Oil
47	Sizemore Creek Gas	Escambia	Condensate
48	Smiths Church	Escambia	Condensate
49	South Burnt Corn Creek	Escambia	Oil
50	South Cold Creek	Mobile	Oil
51	South Vocation	Monroe	Oil
52	South Wild Fork Creek	Escambia	Condensate
53	South Womack Hill	Choctaw and Clarke	Oil
54	Southeast Chatom	Washington	Condensate
55	Southwest Barrytown	Choctaw	Oil
56	Souwilpa Creek	Choctaw	Condensate
57	Stave Creek	Clarke	Oil
58	Sugar Ridge	Choctaw	Oil
59	Toxey	Choctaw	Oil
60	Turkey Creek	Choctaw and Clarke	Oil
61	Turnerville	Mobile	Oil
62	Uriah	Monroe	Oil
63	Vocation	Monroe	Oil
64	Wallace	Escambia	Oil
65	Wallers Creek	Monroe	Oil
66	West Appleton	Escambia	Oil
67	West Barrytown	Choctaw	Oil
68	West Bend	Choctaw and Clarke	Oil
69	West Okatuppa Creek	Choctaw	Oil
70	Wild Fork Creek	Escambia	Oil
71	Wimberly	Choctaw	Oil
72	Womack Hill	Choctaw and Clarke	Oil
73	Zion Chapel	Choctaw	Oil

REGIONAL FRAMEWORK

Southwest Alabama is part of the eastern Gulf Coastal Province of North America. This province includes that part of the Gulf Coastal Plain situated east of the Mississippi River and west of the Atlantic Coastal Plain, whose southwestern boundary is the northwest-southeast trending Ocala (or Peninsular) arch in Georgia and Florida. The northernmost extent of outcropping Upper Cretaceous or younger strata is the northern limit of the Coastal Plain, where coastal plain strata unconformably overlie Paleozoic sedimentary and Precambrian and Paleozoic metamorphic and igneous rocks, most of which have been deformed. The southern limit of the Gulf Coastal Plain is the southernmost extent of the continental rise of the Gulf of Mexico (Murray and others, 1985).

The Gulf of Mexico basin did not exist during the Late Paleozoic and early Mesozoic; no Upper Permian to Upper Triassic marine sediments have been found in the circum-Gulf region (Pindell, 1985). Separation of the North American plate from the Afro-South American plate and the opening of the Gulf basin began with continental rifting in the Early Triassic (Wood and Walper, 1974; Murray and others, 1985; Wilson and Tew, 1985). Extensional faulting along the rifted margin of the basin generated a system of grabens and half grabens (Rainwater, 1967; Walper and Rowett, 1972; Beall, 1973; Smith and others, 1981; Mink and others, 1990). These newly formed basins became the loci of deposition of the basal Mesozoic strata: Triassic to Early Jurassic continental siliciclastic red beds and igneous intrusives of the Eagle Mills Formation (e.g., Todd and Mitchum, 1977). During the early stages of basin formation, the Gulf was intermittently invaded by marine waters. Restriction combined with an arid climate caused intense evaporation, and thick successions of evaporites were deposited during the early and middle Jurassic. The Gulf basin was essentially open by the middle Jurassic (Buffler and Sawyer, 1985), and the area was dominated by normal marine and marginal marine conditions from the late Jurassic onward (Murray, 1961).

Mesozoic and Cenozoic strata of the eastern Gulf Coastal Plain comprise a seaward-dipping and thickening wedge of sediment that blanketed the passive southern margin of North America. The following major kinds of structural elements, either alone or combined, have affected eastern Gulf Coastal Plain strata: (1) positive and negative basement features generated during continental collision and suturing or continental rifting; (2) features related to the movement of Jurassic salt; and (3) features associated with igneous activity (fig. 2).

The major positive basement elements that affected Mesozoic sedimentation in the eastern Gulf are the Wiggins arch, the Baldwin high, the Choctaw ridge complex, and the Conecuh ridge complex in southeast Mississippi and southwest Alabama and the Pensacola-Decatur ridge complex in southwest Georgia and northwest Florida. At least some of these features are related to the Appalachian fold and thrust belt that was generated in the Late Paleozoic by the collision of the North American and Afro-South American continental plates. Some of these positive basement elements (e.g., the Wiggins arch) may be isolated horst blocks of continental lithosphere formed during rifting of the Gulf basin (Smith and others, 1981; Miller, 1982).

The Mississippi interior salt basin (MISB) of southern Mississippi and southwest Alabama, which was an actively subsiding depocenter throughout the Mesozoic and into the early Cenozoic, is a broad, prominent depression on the basement surface (Wilson, 1975). The post-Paleozoic succession in the basin is much thicker than in surrounding areas. The MISB overlies an area of attenuated granitic continental crust; crustal thinning resulted from extension of the lithosphere during rifting in the Triassic and Jurassic (Wilson, 1975). Crustal attenuation created a subsiding structural basin cratonward of the rifted and elevated continental margin (Wood and Walper, 1974).

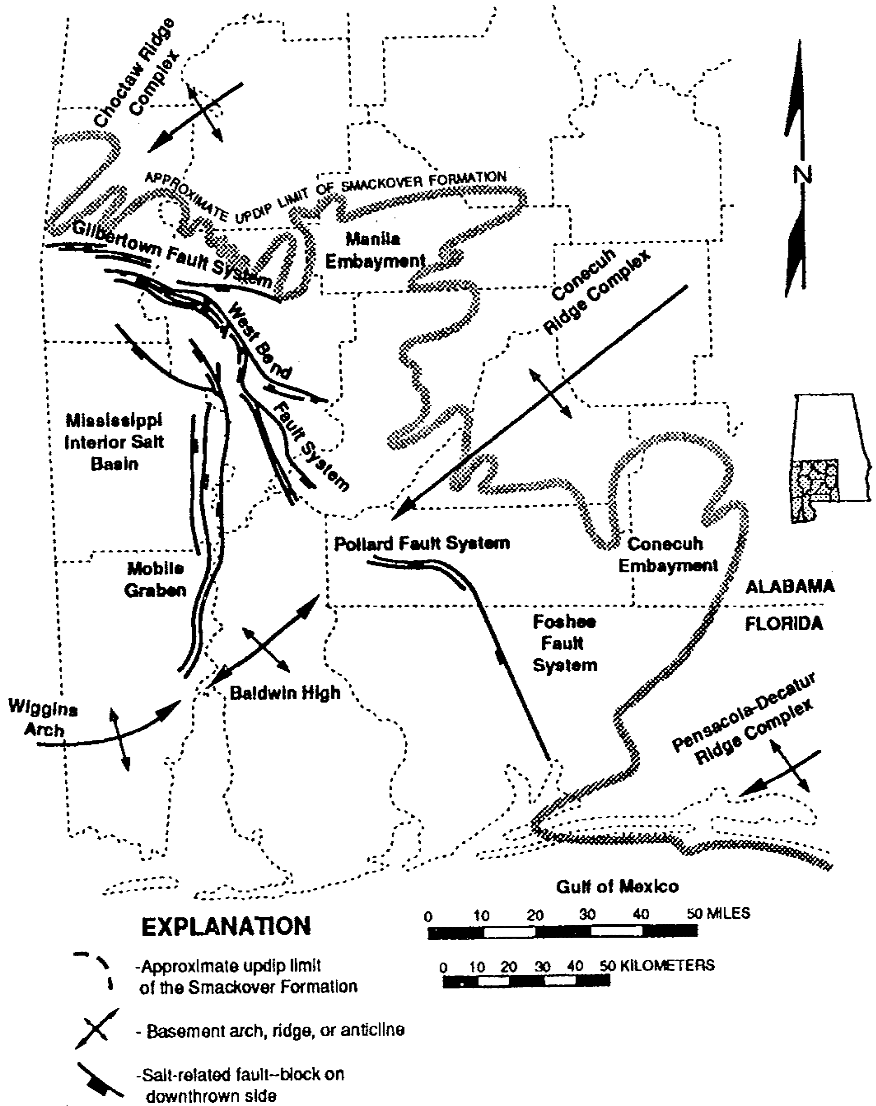
The Conecuh and Manila embayments also were major sites of Mesozoic sedimentation (Mancini and Benson, 1980). The Manila embayment actually contained two separate depocenters during Smackover and Buckner deposition (fig. 3). These negative structural features may have originated as rift grabens during the breakup of Pangea (Miller, 1982).

Movement of the Jurassic Louann Salt has resulted in a complex network of salt-related structural elements in southwest Alabama. Martin (1978) attributed the structural fabric of most of the northern Gulf margin to salt movement. Structural elements in the study area resulting from salt movement include the regional peripheral fault trend, the Mobile graben, and numerous smaller features. Salt movement began in some areas as early as late Smackover time.

STRATIGRAPHY

Pre-Jurassic and Jurassic geologic units found in the subsurface in the study area include pre-Mesozoic "basement" rocks; the Triassic-Lower Jurassic Eagle Mills Formation; the Jurassic Werner Formation, Louann Salt (including Pine Hill Anhydrite Member), Norphlet Formation (including Denkman Sandstone Member), Smackover Formation, and Haynesville Formation (including basal Buckner Anhydrite Member); and the Jurassic-Cretaceous Cotton Valley Group (fig. 2). None of these strata are exposed at the surface in the study area.

Jurassic strata underlying the U.S. Gulf coast contain huge volumes of evaporites: thick halite rock in the Louann and Haynesville, and anhydrite rock in the Werner, Pine Hill, and Haynesville. In addition, eolian strata dominate the Norphlet Formation in the eastern Gulf. Sabkhas and salinas are common in the upper Smackover (e.g., Barnett, Barrytown, Blacksher, Burnt Corn Creek, Chatom, and Zion Chapel fields; Kopaska-Merkel and others, 1992). Early diagenetic fabrics of carbonates of the Smackover and Haynesville formations suggest that meteoric diagenesis was limited. By contrast, indicators of arid-zone diagenesis, such as intrasedimentary penecontemporaneous discoidal gypsum



SERIES	STAGE	ROCK UNIT
Lower Cretaceous	Berriasian	Cotton Valley Group
----- ? -----	---- ? ----	
Upper Jurassic	Tithonian	
	Kimmeridgian	Haynesville Formation
		Buckner Anhydrite Member
	Oxfordian	Smackover Formation
		Norphlet Formation
		Pine Hill Anhydrite Member
----- ? -----	---- ? ----	
Middle Jurassic	Callovian	Louann Salt
		Werner Formation
Lower Jurassic/ Upper Triassic		Eagle Mills Formation
		Undifferentiated Paleozoic and Proterozoic "basement" rocks

Figure 2.--Stratigraphic column in the eastern Gulf and major structural features of southwest Alabama (modified from Mancini and others, fig. 1, 1991).

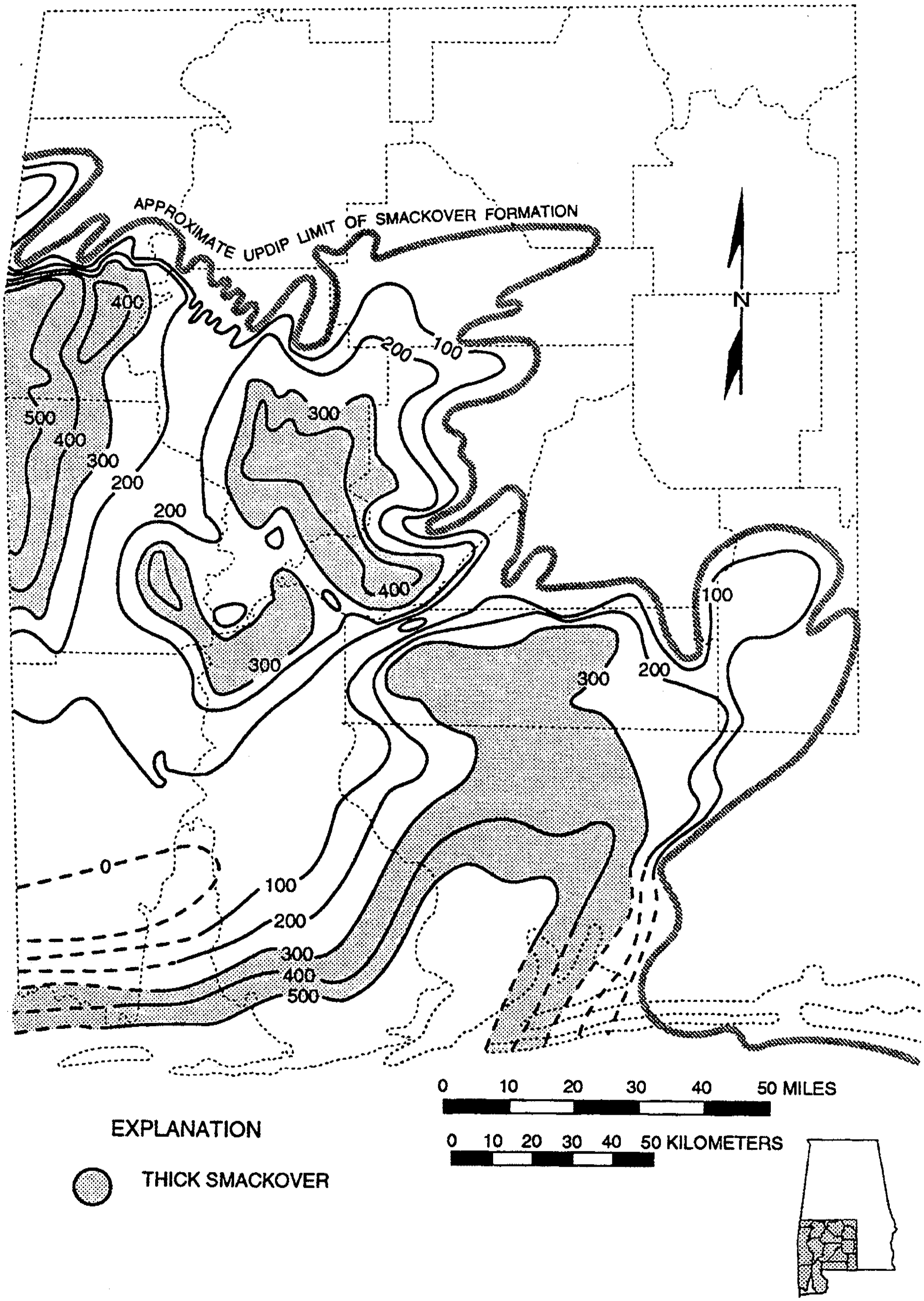


Figure 3.--Isopach map of Smackover Formation, southwest Alabama, showing major depocenters (modified from Wilson, fig. 6, 1975, Mancini and Benson, fig. 3, 1980, and Geological Survey of Alabama, 1985b).

crystals, tepee structures, and calcareous crusts (caliche) are widespread (e.g., Appleton, Barrytown, and Chappell Hill fields; Kopaska-Merkel and others, 1992). Jurassic sediments in the study area were deposited in an arid setting.

NORPHLET FORMATION

The Norphlet Formation (Oxfordian) is a regionally extensive, predominantly continental siliciclastic deposit that is found in the subsurface throughout most of the study area. The Norphlet is dominated by alluvial-fan, wadi, playa, and eolian deposits. Sandstone reworked by marine processes makes up the uppermost part of the unit (Wilkerson, 1981; Mancini and others, 1984, 1985). In southwest Alabama, the Norphlet Formation ranges up to 800 feet in thickness.

During deposition of the Norphlet Formation the study area was dominated by a broad desert plain bordered on the north and east by highlands underlain by Proterozoic and Paleozoic rocks and on the south by the developing Gulf of Mexico basin. Major positive basement features such as the Wiggins arch were partially exposed at this time (Mancini and others, 1985).

The Norphlet is conformably overlain by the Smackover Formation. The contact is commonly abrupt, but is gradational over an interval of a few feet or less in parts of Mobile County (Tolson and others, 1983), including Chunchula field, in Jay field, Escambia and Santa Rosa Counties, Florida (Bliefnick and Mariotti, 1988), and in Barnett field on the Conecuh ridge (Kopaska-Merkel and others, 1992).

SMACKOVER FORMATION

PALEOGEOGRAPHIC SETTING

The Smackover was deposited on a carbonate ramp, like that of the present-day Persian Gulf, in much of the Gulf-Coast region (Ahr, 1973; Mancini and Benson, 1980, 1981; Budd and Loucks, 1981; Moore, 1984). However, in southwest Alabama, deposition of Smackover strata was strongly affected by a system of preexisting ridges and basins (fig. 2). Smackover strata in southwest Alabama were deposited in four interconnected basins: the eastern part of the MISB, the Manila embayment (which contained two separate depocenters during Smackover deposition), the Conecuh embayment (Mancini and Benson, 1980, figs. 2 and 3), and a basinal area south of the Baldwin high. The distribution of facies was more closely controlled by local paleotopography (fig. 3) than by southerly regional dip (fig. 4), as would have been the case in an unmodified ramp setting. High-energy facies were deposited in nearshore areas rimming exposed paleohighs and near the updip limit of Smackover deposition; lower energy strata were deposited in basin centers. Some positive areas, such as the Wiggins arch, were partially exposed throughout Smackover time.

STRATIGRAPHY

The Smackover Formation conformably overlies the uppermost (marine) part of the Norphlet Formation. The Smackover is a platform carbonate that (together with the uppermost Norphlet) comprises the marine (lower) portion of a transgressive-regressive sequence. Based on ammonites recovered from the lower portion of the unit, the Smackover has been assigned a late Oxfordian age (Imlay, 1945). The Smackover ranges up to more than 550 feet thick in the study area (fig. 3).

Basal Smackover strata in Alabama contain laminar and domal stromatolites; these deposits probably formed in shallow water during the early stages of a marine transgression. Middle Smackover strata are dominated by lime mudstone and pelletal or fossiliferous lime wackestone, deposited at and near the time of maximum transgression, and during and after a period of rapidly increasing water depth. Middle-Smackover lime mudstone is typically laminated and organic rich. These strata are inferred to be the source rocks from which most of the oil in Jurassic reservoirs in the study area was generated (Erdman and Morris, 1974; Mancini and Benson, 1980, Hughes, 1984, Oehler, 1984; Sassen and others, 1987; Sofer, 1988; Claypool and Mancini, 1989; Sassen, 1989). During middle Smackover time, prolific production of high-energy carbonate sediment on the flanks

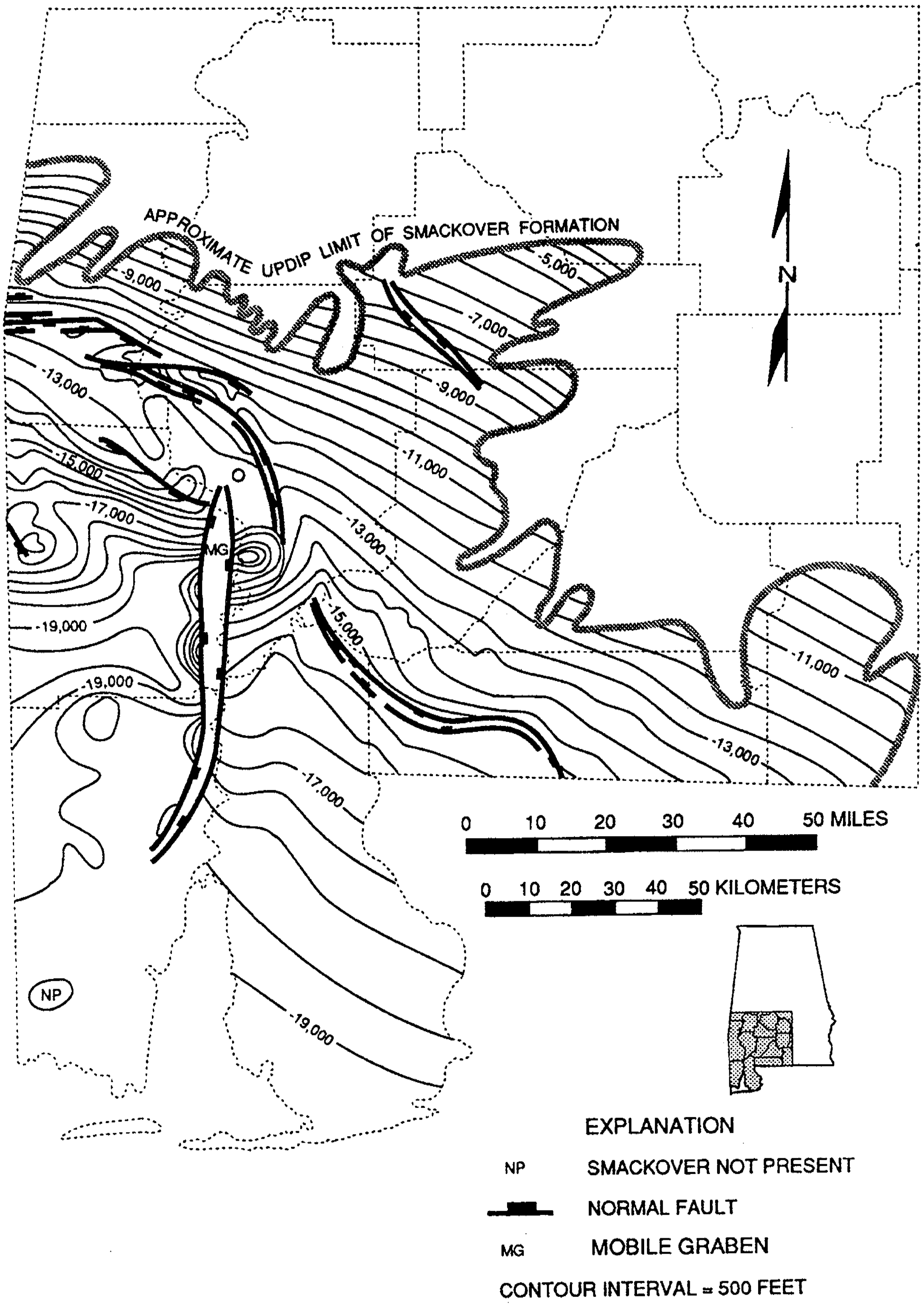


Figure 4.--Regional structure map on top of Smackover Formation for southwest Alabama (modified from Mancini and Benson, fig. 4, 1980, and Geological Survey of Alabama, 1985a).

of the paleohighs initiated a progradational phase of Smackover deposition. Upper Smackover strata were laid down during a relative sea-level stillstand. Progradational strata of the upper Smackover are dominated by ooid grainstone and diverse peritidal carbonates on the flanks of the paleohighs and by pelletal and oncoidal packstone and grainstone in the centers of the depositional basins. Upper Smackover strata are generally arranged in a succession of stacked, upward-shallowing cycles (Mancini and Benson, 1980; Benson, 1984) that grade from subtidal strata at their bases to shallower subtidal to supratidal strata at their tops (Moss, 1987; Benson, 1988; Mancini and others, 1990; Kopaska-Merkel and others, 1992). Cycles capped by supratidal strata are found on paleohighs and near the updip limit of the Smackover (Moss, 1987). Exposure features, including hardened crusts, mudcracks, fenestral fabric, dissolution fabrics, vadose pisoids, and pendant cement, are found at the tops of many cycles (e.g., Barrett, 1987; Benson, 1988; Mancini and others, 1990; Kopaska-Merkel and others, 1992).

The Smackover locally contains substantial amounts of siliciclastic material, particularly near the Conecuh ridge and its associated small paleohighs (e.g., Barnett, North Wallers Creek, Uriah, Vocation, and Burnt Corn Creek fields). Also, terrigenous siliciclastic material is significant in the upper Smackover in parts of the Manila embayment (Wade and others, 1987). The upper Smackover is very argillaceous in the northern part of the embayment; in the southeastern part, several intervals of calcareous sandstone are interbedded with peloidal and oolitic packstone and grainstone (Wade and others, 1987).

Microbial boundstone is a significant component of upper Smackover strata on the north side of the Wiggins arch in Mobile County, Alabama, and on the Conecuh ridge complex in Baldwin County, Alabama (Baria and others, 1982; Benson, 1988). These strata are primarily composed of laminar, digitate, or domal stromatolitic cyanobacteria, along with foraminifers, sponges, and calcareous worm tubes (Benson, 1984; Moss, 1987; Benson, 1988).

DIAGENESIS

Smackover diagenesis in southwest Alabama was dominated by the effects of (1) early cementation, (2) leaching of calcium-carbonate allochems, and (3) dolomitization. Other diagenetic processes that significantly affected Smackover reservoir characteristics include pressure solution, dissolution of calcium-carbonate cement, late (post-dolomitization) calcite and anhydrite cementation, and fracturing, both tectonic and caused by collapse of partially dissolved rock frameworks. Despite gross similarities of diagenesis of the Smackover throughout the Gulf, the diagenetic history and resultant reservoir characteristics of the Smackover of southwest Alabama differ substantially in detail from conditions in the central and western Gulf Coast (Mississippi to south Texas) (e.g., Moore, 1984).

Early marine-phreatic cementation in interparticle pore spaces in particle-supported Smackover carbonates was nearly ubiquitous. Marine-phreatic cement in the Alabama Smackover is fibrous pore-lining calcium carbonate that destroyed interparticle pore throats and in many cases filled primary interparticle pores, forming polygonal boundaries between opposing cement rims. At least some early marine-phreatic pore-lining cement in the Alabama Smackover was aragonitic, as indicated by square crystal terminations still preserved in partially filled primary interparticle pores. Marine-phreatic cementation was suppressed, and primary interparticle porosity preserved, in areas where meteoric waters are most likely to have reached upper Smackover strata. Early freshwater-phreatic (Benson, 1984; Moss, 1987) and vadose (see fig. 19; Kopaska-Merkel, 1992a, Kopaska-Merkel and others, 1992, p. 90) cements were precipitated shortly before (Kopaska-Merkel, 1992a; Kopaska-Merkel and others, 1992) and shortly after (Benson, 1984; Moss, 1987) formation of early marine-phreatic cement in updip areas. These meteoric cements support the inference that meteoric water was responsible for inhibition of marine cementation in updip areas. Where primary interparticle pore space was destroyed by marine-phreatic cement, an initially highly permeable sediment was converted to a relatively impermeable (and nonporous) rock. Meteoric water also influenced early Smackover diagenesis on paleohighs not near the updip limit of the formation (e.g., Bliefnick and Mariotti, 1988; precipitation of freshwater-phreatic cement in Jay field).

In many areas, early marine cementation was followed by leaching of ooids (Smackover ooids in Alabama were aragonitic) and other mineralogically unstable particles. Oncoids tended to be partially dissolved by the formation of small vugs within them; pellets and mollusks were commonly entirely dissolved. This widespread particle dissolution vastly increased porosity values (to 40 percent or more) but had little direct effect on permeability. This early dissolution of mineralogically unstable particles may have been caused by the same meteoric fluids that inhibited marine cementation and precipitated meteoric cements in updip areas. Reservoirs that have been cemented and leached, but not extensively dolomitized, are uncommon and occur mainly in southern Choctaw County and northwestern Clarke County (e.g., some strata in Bucatunna Creek and Womack Hill fields; Kopaska-Merkel and others, 1992.)

During deposition of upper Smackover strata in the eastern part of the MISB a minor relative sea-level drop initiated sabkha development on the crests of many topographic highs (e.g., Chatom and Zion Chapel fields; Kopaska-Merkel and others, 1992; Mann and Kopaska-Merkel, 1992; see also Moss, 1987). These sabkha deposits (and associated salina deposits) contain significant amounts of anhydrite and range up to a few tens of feet in thickness. They are commonly overlain by comparable or greater thicknesses of peritidal carbonates, including reservoir rock, laid down during and after a subsequent minor relative sea-level rise. These in turn are overlain by massive anhydrite of the basal Buckner Anhydrite Member of the Haynesville Formation. The basal massive anhydrite was deposited subaqueously as a result of evaporative concentration of MISB waters (Mann, 1990; Mann and Kopaska-Merkel, 1992).

Early dolomitization of uppermost Smackover strata by reflux of hypersaline brines was widespread, but of minor importance for reservoir evolution. Widespread formation of isotopically light (oxygen isotopes) dolomite in permeable Smackover strata caused extensive post-depositional alteration of Smackover strata (e.g., Benson and Mancini, 1984; Vinet, 1984; Barrett, 1987). This widespread Smackover dolomite, which is responsible for formation and/or preservation of many permeable Smackover pore systems, has been interpreted as mixed-water in origin (e.g., Vinet, 1984; Worrall, 1988; Prather, 1992) or to have formed as a result of lateral migration of formation waters with focusing of flow over paleohighs (Barrett, 1987). Two different forms of isotopically light dolomite are common and likely represent the products of two different episodes of dolomitization. Some isotopically light Smackover dolostone is mimetic; it preserves clear evidence of primary sediment fabrics in the form of (1) inclusions within dolomite crystals, (2) dolomite crystal boundaries that mimic particle boundaries, (3) nondolomitized patches controlled by particle boundaries, and (4) relatively unaltered pores.

Abundant mimetic dolomite in the Smackover of Alabama formed before, during, and after widespread particle dissolution (Kopaska-Merkel and others, 1992). Marine-phreatic calcium-carbonate cement predates dolomitization in most areas; whereas locally primary pore-rimming rhombic dolomite cement appears to have been the earliest cement, or to have precipitated after formation of meniscus cement (see fig. 19 and Kopaska-Merkel, 1992a, fig. 51A). At least some of this mimetic dolomite precipitated before significant compaction. Hence, at least some of the mimetic dolomite, namely that which formed early and in association with widespread particle dissolution, could have formed from mixed waters as hypothesized by Vinet (1984) and by Prather (1992). Post-compaction and post-dissolution mimetic dolomite (e.g., in Gin Creek field, Kopaska-Merkel and others, 1992, p. 222) may have a different origin. However, most porous and permeable mimetic dolostone in the Smackover of Alabama appears to be dominated by pre-compaction dolomite.

Other isotopically light Smackover dolostone is nonmimetic, or fabric destructive. In these rocks, dolomite crystals did not honor particle boundaries, as can be seen clearly in (relatively rare) examples exhibiting faint bands of inclusions that outline particle boundaries and that are transgressed by dolomite crystals. In most Smackover fabric-destructive dolostone, no such bands of inclusions can be seen, and the primary fabric is indeterminable. Nonmimetic Smackover dolostone has been interpreted to have formed from subsurface fluids (e.g., Barrett, 1987; University of Alabama, 1991). Both mimetic and nonmimetic dolostone form excellent reservoirs in the Smackover. Their similarities and differences vis a vis reservoir characteristics and heterogeneity are discussed at length in subsequent sections.

Late baroque (saddle) dolomite is widespread but volumetrically insignificant in the Smackover (e.g., Murray, 1991). Other episodes of dolomitization may have also taken place (e.g., pene-contemporaneous hypersaline dolomitization of lower Smackover strata in the Jay field area of Alabama and Florida; Vinet, 1984).

Late-stage diagenetic processes that were widespread in the Alabama Smackover include stylolitic pressure solution and growth of replacive anhydrite laths. Other late diagenetic processes that were of at least local importance included dissolution of calcium-carbonate cement, dissolution or calcitization of dolomite, calcitization of anhydrite, pressure solution by particle interpenetration, post-dolomitization calcite and anhydrite cementation, and fracturing. Fracturing included both tectonic formation of fracture sets and crushing of dissolution-weakened rock components. These included cement frameworks around particle molds (see fig. 31) and dolomite cement crystals with their cores dissolved. Paragenetic sequences diagramed by Kopaska-Merkel and others (1992) suggest the geographic and temporal distribution of these processes in the Alabama Smackover. Only pressure solution, calcite and anhydrite cementation, and tectonic fracturing exerted more than local effects on porosity and permeability of Smackover reservoirs.

BUCKNER ANHYDRITE

The Smackover Formation is overlain in southwest Alabama by the Buckner Anhydrite Member of the Haynesville Formation, whose basal portion is dominated by subaqueous evaporites (predominantly anhydrite and halite) in depositional basins and by peritidal and supratidal evaporitic and siliciclastic strata on the flanks and crests of paleohighs (Dickinson, 1968; Harris and Dodman, 1982; Moore, 1984; Moore, 1986; Lowenstein, 1987; Mann, 1988, 1990). Deposition of the basal Buckner in the eastern part of the MISB was initiated by partial isolation of the eastern MISB and increase of salinity to the point of gypsum saturation (Mann, 1990; Mann and Kopaska-Merkel, 1992). This chemical event involved a minor relative sea-level fall caused by a net evaporative water loss in the eastern MISB. Thus the massive anhydrite offlaps the underlying peritidal carbonates. Because its origin is a basin-wide (Alabama part of MISB) chemical event, the base of the massive Buckner saltern evaporite is a time plane (see Hardie and others (1978) and Kendall (1988) for discussion of this phenomenon). However, this time horizon may not be identifiable in basin marginal areas, where basal Buckner evaporites were deposited in sabkhas and salinas. On the crests of paleohighs, where uppermost Smackover strata include sabkhas and salinas, the base of the saltern also may be difficult to identify. In addition, halokinesis of the Louann Salt during Buckner time created high-frequency thickness variation in Buckner strata where underlying Smackover strata vary only slightly in thickness.

Analysis of well logs and cores suggests that similar processes operated in the Manila and Conecuh embayments. However, in the Manila embayment, a thin anhydrite interval is overlain by a thick sequence of halite (to the southwest) or sandstone (to the northeast). These two regions were separated during Smackover and Buckner time by a ridge that prevented sand from reaching the southwestern Manila embayment. The Buckner in the Conecuh embayment resembles that in the southwestern Manila embayment; up to about 50 feet of anhydrite is overlain by a thick halite succession. Thick sequences of halite in the Buckner of the Manila and Conecuh embayments suggest that these basins were deep enough to develop permanent haloclines during Buckner time. In the Manila embayment, there appear to be two major areas of Buckner salt, whereas in the Conecuh embayment, salt was deposited primarily in small subbasins.

SMACKOVER PETROLEUM GEOLOGY

Commercial quantities of hydrocarbons were first discovered in the Smackover Formation in Alabama at Toxey field, Choctaw County, in 1967. The Smackover has subsequently proven to be the most prolific hydrocarbon-producing reservoir in southwest Alabama. As of December 1990, the Smackover had produced oil, condensate and/or natural gas from 73 established fields in southwest Alabama. At that time, cumulative production from Smackover reservoirs in Alabama totaled over

113 million barrels (MMB) of oil (including condensate production from Chunchula field and minor Norphlet oil production from several fields), 145 MMB of condensate (including Norphlet condensate production from Hatter's Pond field, which is not reported separately), and 1.12 trillion cubic feet (TCF) of natural gas. Production data were summarized by Hall (1992). Smackover petroleum geology was reviewed by Kopaska-Merkel (1992a), and is briefly summarized here.

Smackover hydrocarbon traps in southwest Alabama are structural or combination structural and stratigraphic traps (Mancini and others, 1990). Many structural traps result from halokinesis of the Louann Salt. The Buckner Anhydrite Member of the Haynesville Formation seals most Smackover traps in Alabama. Basement-related structural traps are common in Monroe, Conecuh, and Escambia Counties. Typically, these traps are anticlines developed over basement paleohighs. The Buckner is the seal for most of these basement-related traps as well.

Combination traps generally involve porosity or permeability pinch-outs on regional dip or on halokinetically generated anticlines or structural noses. Porosity and permeability pinch-outs on basement-related anticlines or faulted anticlines are also recognized in the study area.

Microbially influenced laminated lime mudstone of the lower to middle Smackover Formation is the main source rock for the oil, condensate, and gas in Smackover reservoir rocks (Erdman and Morris, 1974; Mancini and Benson, 1980; Hughes, 1984; Oehler, 1984; Sassen and others, 1987; Sofer, 1988; Claypool and Mancini, 1989; Sassen, 1989). These strata were deposited under low-energy conditions in intertidal to subtidal settings during a marine transgression.

Kerogen in Smackover laminated lime mudstone probably matured to liquid hydrocarbons beginning in the early Cretaceous and continuing into the Tertiary (Mancini and others, 1985; Nunn and Sassen, 1986). Jurassic temperature gradients were about 33°C/km, more than twice the modern gradient (Nunn and Sassen, 1986). Hence, Jurassic strata have probably been close to their current temperatures (90 to 170°C) for the last 100 million years (Nunn, 1984).

Smackover petroleum traps are principally salt-related structural traps. Salt movement was initiated in basinal areas in late Smackover/Haynesville time and continued into the Tertiary in updip areas and along the regional peripheral fault trend (Martin, 1978; Bearden and Mink, 1989). Structural growth coincided with hydrocarbon generation and migration from Smackover source rocks. Emplacement of liquid hydrocarbons in Smackover reservoirs was precisely controlled by relative timing of hydrocarbon generation and migration on the one hand, and trap formation and subsequent structural modification of the reservoir on the other. For example, traps and seals that formed early contain oils near the original composition of Smackover crude oil. Traps that formed later generally contain light oils or condensates. However, maturation and alteration of hydrocarbons in the reservoir can also generate condensates.

Hydrocarbon types, in conjunction with basinal position and relationship to regional structural features, can be used to delineate three Jurassic hydrocarbon trends in Mississippi, Alabama, and Florida (Mink and others, 1985). The three trends are an updip oil trend, an intermediate oil and gas condensate trend, and a downdip gas trend (fig. 5).

The oil trend is north of the regional peripheral fault trend. The principal petroleum traps in this trend include structural (salt related and paleohighs) and combination traps. Haynesville, Smackover and Norphlet fields produce chiefly low to medium gravity oil.

The oil and gas condensate trend lies between the regional peripheral fault trend and the Wiggins arch. The principal petroleum traps are salt-related anticlines and extensional faults and combination traps. Most Jurassic fields in the tri-state area are located in this trend, with fields established in the Cotton Valley, Haynesville, Smackover, and Norphlet. Production from the trend is chiefly medium to high gravity oil, condensate, and gas.

The deep natural gas trend is found south of the Wiggins arch. The principal hydrocarbon traps are salt anticlines. Fields in this trend produce methane gas from the Cotton Valley and Norphlet formations.

A more detailed analysis of the relationship between trap type, basinal position, and hydrocarbon type in the Smackover of Alabama, Mississippi, and the Florida panhandle was published by Mancini and others (1991).

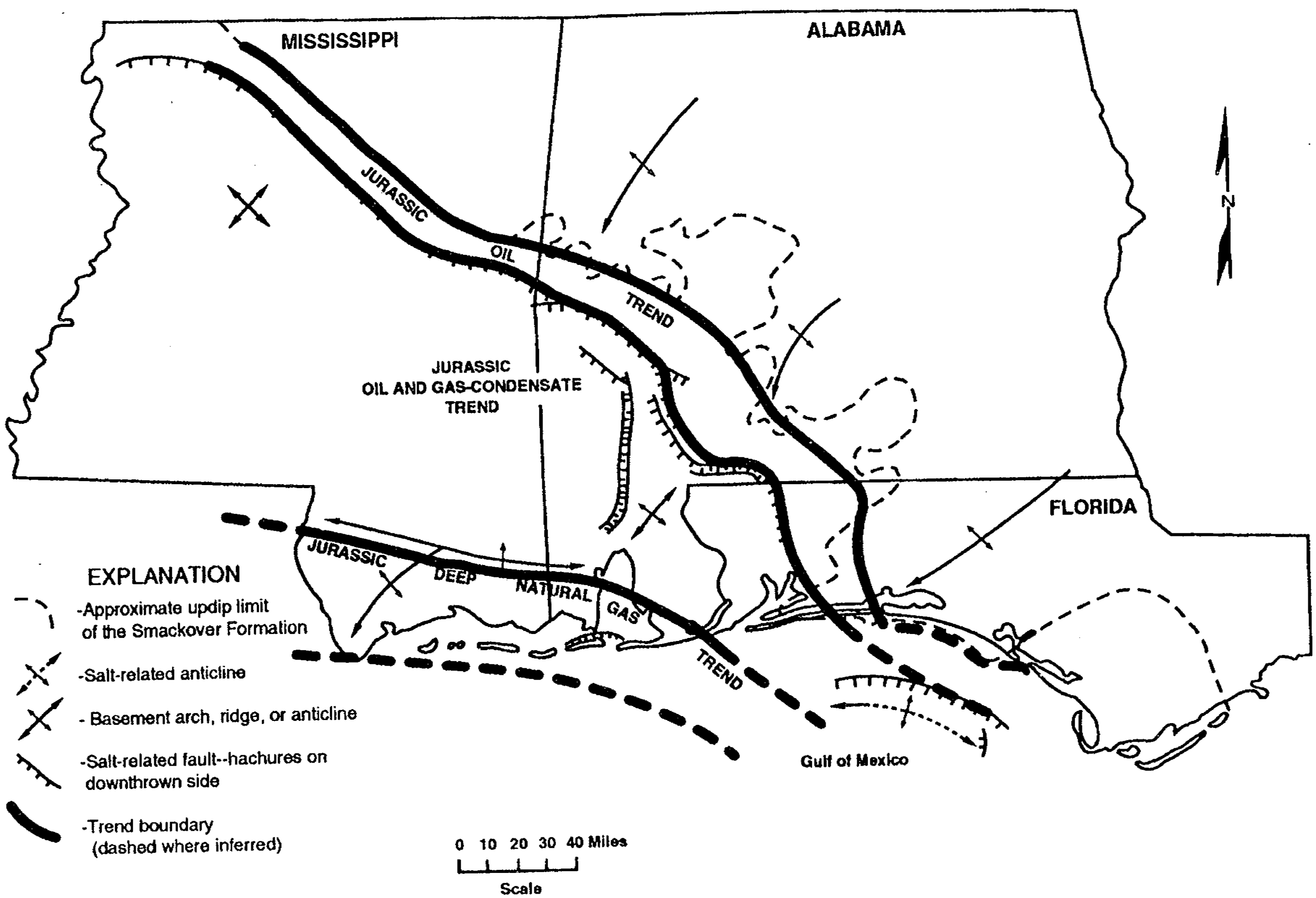


Figure 5.--Hydrocarbon trends, southwest Alabama area.

SMACKOVER RESERVOIR CHARACTERISTICS

GENERAL CHARACTERISTICS OF SMACKOVER RESERVOIRS

In this section, Smackover reservoirs are described in sufficient detail to lay the groundwork for subsequent discussions of petrophysics, petrophysical classification, and heterogeneity classification. First, Smackover carbonate reservoirs are described within the framework of the major structural features that influenced Smackover deposition and diagenesis in southwest Alabama: the adjacent portions of the North American continent, the basins, the paleohighs, and the peripheral fault system. Smackover pore systems are then described in more detail.

CARBONATE ROCK TYPES

Most Smackover reservoirs originated as nearshore-marine carbonate sediments with minor admixtures of noncarbonate material. Some of these reservoirs preserve abundant evidence of their environment of deposition. Others have been highly altered and their origins are unclear. The first group are conveniently classified using the scheme of Dunham (1962), whereas the latter ("crystalline dolostone" to Dunham) can be characterized in more detail following Sibley and Gregg (1987). Smackover reservoirs are classified in this way because the Dunham classification is simple to apply and the categories are directly related to depositional settings. Pore systems are examined more directly in subsequent portions of the report.

The most common Smackover reservoir rocks are nonskeletal grainstone, dominated by pellets, ooids, and oncoids, in order of decreasing abundance. Generally, either ooids or pellets are dominant, though both ooid grainstone and pellet grainstone may be found in a single core (e.g., Silas field, Choctaw County). Oncoids are associated either with ooids or with pellets. The pellets are either small, nondescript ellipsoids of the type commonly ascribed to small gastropods (locally abundant in the Smackover) or polychaetes, or (less commonly) the large, distinctive "Favreina" pellets that are thought to be made by callianassid shrimp. "Favreina" pellets (not technically belonging to genus *Favreina*) are widespread and locally abundant but are much less important to reservoir development than are the small pellets. This is because "Favreina" pellets (1) are less abundant, (2) less commonly form grainstone, and (3) less commonly are dissolved to form molds. Micritic ellipsoids that are all the same size and shape are clearly pellets. Many other micritic ellipsoids are probably pellets, but are called peloids if their origin is in doubt (Friedman and others, 1992). Skeletal particles (the most common are indeterminate mollusk fragments, cerithid gastropods, and echinoderm ossicles), as well as intraclasts and (locally) vadose pisolites, are locally common in the nonskeletal grainstone. High-energy ooid grainstone is most abundant in the upper Smackover on the crests and flanks of paleohighs, and in southern Choctaw County, on the proximal portion of a large Smackover carbonate ramp. Pellet grainstone is most abundant within the basins, especially the MISB (e.g., Chatom field, Washington County).

Mixed-particle grainstone/packstone is another common reservoir type in the Smackover of southwest Alabama. These lower energy strata are compositionally variable and commonly grade upward into grainstone *sensu stricto*. Mixed-particle grainstone/packstone is either dominated by ooids or by pellets, as is the grainstone. Skeletal material is both more abundant and more diverse than in the nonskeletal grainstone. Fossils include mollusks, echinoderm ossicles, encrusting foraminifers, other foraminifers, coral fragments, and sponge fragments.

Microbial boundstone is another important reservoir-rock type. There are at least three common kinds of microbial boundstone in the Smackover of southwest Alabama. These are laminar stromatolites, domal stromatolites, and "microstromatolites." The latter are small (commonly a few cm or less in the longest dimension), lensoid or domal, and are commonly found in groups. They are distinct from the first two kinds of stromatolites, which are wider than cores (2 to 3 inches) and may form bioherms up to several feet thick. Boundstone is commonly associated with pelletal and/or oncoidal packstone and grainstone and with exposure surfaces. Microbial boundstone is most abundant on the southeastern flank of the Manila embayment, where individual microbial reefs exceed 1 meter in thickness (e.g., Lovetts Creek, Vocation, and Little Escambia Creek fields; Kopaska-Merkel and others, 1992).

Crystalline dolostone forms numerous reservoirs in the Smackover of Alabama, especially in Mobile County. Permeable Smackover dolostone in southwest Alabama is commonly either planar-e or planar-s (Sibley and Gregg, 1987). (Planar-e dolomite consists of crystals that exhibit planar boundaries that are crystal faces, whereas crystals in planar-s dolomite exhibit planar boundaries that are not crystal faces.) These rocks are finely crystalline, coarsely crystalline, or exhibit polymodal or platykurtic crystal-size distributions. This has not been investigated quantitatively.

The preceding summary of Smackover reservoir-rock characteristics comes from new observations supplemented by descriptions published by Mancini and Benson (1980, 1981), Benson and Mancini (1982, 1984), and Benson (1985, 1988).

SILICICLASTIC SMACKOVER RESERVOIRS

Quartzose sandstone, commonly dolomitic, with abundant but subordinate feldspar, forms permeable reservoirs locally in southern Monroe County (e.g., North Wallers Creek field; Kopaska-Merkel and others, 1992). Porosity is primarily interparticle. Evidently, the sand was shed in abundance from emergent islands and/or from the nearby North American landmass, overwhelming the autochthonous carbonate sediment sources. Quartzose sandstone has also been found in the upper Smackover of the northern Manila embayment, which contains no Smackover fields. Because this study concerns carbonate reservoirs only, the uncommon siliciclastic reservoirs are not described further.

SMACKOVER PORE SYSTEMS

The occurrence of reservoir-grade rocks (by convention, porosity at least 6 percent and permeability at least 0.1 md) in the Smackover Formation of southwest Alabama is dependent on (1) deposition of porous and permeable sediments in a variety of settings and (2) diagenetic processes which have preserved, enhanced, or created porosity and permeability both in originally permeable strata and in originally impermeable strata.

It is instructive to consider first the kinds of pores (classified using a modified form of the scheme of Choquette and Pray, 1970) that are common in Smackover pore systems, and then to discuss the kinds of porous and permeable pore systems that compose (with their host rocks) Smackover reservoirs. Our modifications to the pore classification of Choquette and Pray (1970) were described by Kopaska-Merkel (1992a).

SMACKOVER PORE TYPES

The most common kinds of pores in the Smackover are particle molds, secondary intraparticle pores, intercrystalline pores, and interparticle pores. Less common, but significant, pore types are fractures, vugs, and cement molds. The various pore types lend different petrophysical characteristics to pore systems, and combinations of different kinds of pores in varying proportions create further effects.

Interparticle pores are permeability enhancers because they tend to form regular networks with abundant connections and because they are connected by large pore throats. The permeability of primary interparticle pore systems is readily destroyed by the precipitation of pore-rimming marine-phreatic cement. Fractures are even more effective permeability enhancers and have fewer opportunities to be cemented because they form later than primary interparticle pores.

Pore systems dominated by molds, vugs, and secondary intraparticle pores are not characterized by high permeability values because these pores tend to be poorly connected and exhibit high aspect (pore-throat size) ratios. The most common kinds of molds are oomolds and pelmolds. Mollusk fragments commonly form molds. Oncoids, echinoderm ossicles, intraclasts, and "Favreina" pellets rarely form molds. Secondary intraparticle pores are most common in ooids and in oncoids, less common in small pellets. "Favreina" also form secondary intraparticle pores, but are less common than the other particle types.

Secondary intraparticle pores resemble molds in being separated from one another by pore systems having different characteristics (the former interparticle spaces). Secondary intraparticle pores are small clusters of small pores, surrounded by pore systems that may be finer or coarser. By contrast, molds are individual large pores surrounded by finer pore systems. There are three kinds of secondary intraparticle pores (Kopaska-Merkel, 1992a). Cement-reduced molds are uncommon but widespread in the Alabama Smackover; microvuggy and intercrystalline secondary intraparticle pores are both abundant and widespread.

Intercrystalline pores typify pore systems whose permeability values depend on crystal size. Intercrystalline pores are commonly well connected by short and homogeneous pore throats, and the pores tend to be all about the same size and shape. Where intercrystalline pores are large, homogeneous, and well connected, permeability values may be extremely high.

Cement molds are not widespread, but locally compose up to 15 percent of pore systems (e.g., fig. 19). However, they have little effect on permeability except where the dissolved cement had occluded primary interparticle pore throats. The most common (or at least most readily identified) kinds of cement molds in the Smackover of Alabama are (1) dissolved meniscus or pore-lining calcium-carbonate cement and (2) molds formed by dissolution of the cores of dolomite cement crystals. This latter process is widespread in the Smackover of Alabama but the crystal molds are commonly filled by late calcite cement (e.g., Appleton field).

Uncommon Smackover pore types include fenestral, fossomoldic, shelter, intershard, and stylolitic pores. These pore types can be significant locally, especially intershard pores (see fig. 31). Intershard pores result from partial crushing of moldic pore systems, and form highly permeable networks.

DIAGENESIS OF SMACKOVER PORE SYSTEMS

Smackover reservoirs can be differentiated on the basis of degree of preservation of depositional fabric (or conversely, the degree of alteration of depositional fabric by diagenesis). The most common mode of fabric destruction in the Smackover is nonfabric-selective dolomitization. The important kinds of Smackover reservoirs are reviewed below, beginning with those least modified by diagenesis and proceeding to those most altered.

The least altered reservoirs are oolitic, oncoidal, and pelletal grainstone, partially or nondolomitized, characterized by complex pore systems with abundant interparticle pores. The other common pore types in these reservoirs are particle moldic, secondary intraparticle, and (locally) cement moldic. These reservoirs have been created by partial occlusion of primary porosity, mainly by marine-phreatic calcium-carbonate cement, followed by extensive dissolutional formation of secondary porosity. These reservoirs exhibit high permeability values because of the abundance of interparticle pores.

Slightly more altered reservoirs are as above, but lack substantial amounts of interparticle porosity. These reservoirs are considered to be more highly altered because the interparticle pores inherited from the precursor sediment have been largely obliterated. These reservoirs are less permeable than those described above.

Reservoirs assigned to the next category are largely or entirely dolomitized. These strata retain clear evidence of depositional fabric, may be characterized by abundant interparticle pores, and contain relatively few intercrystalline pores. Reservoirs with abundant interparticle pores are highly permeable; those with fewer interparticle pores are less so. The process of dolomitization itself has little effect on the porosity and permeability of these reservoirs (Kopaska-Merkel and Mann, 1991b). The pore types and petrophysical characteristics differ only slightly between nondolomitized and dolomitized moldic and secondary intraparticle reservoirs, though dolomitized examples are far more abundant and widespread in the Alabama Smackover. An uncommon but dramatic kind of reservoir in this category is pellet or ooid dolograinstone in which the pellets or ooids are entirely dissolved away and the rock consists of dolomitized interparticle cement. These reservoirs are the products of near-total occlusion of primary porosity, followed by dolomitization and secondary porosity creation by dissolution of unstable particles. The relative timing of the major episodes of dolomitization and dissolution is variable, but dolomitization commonly precedes or is penecontemporaneous with dissolution. These pore systems can exhibit porosity values greater than 40 percent, but permeability values are low. If a pure moldic reservoir is partially crushed, microfractures create intershard porosity and enhance permeability.

More highly altered reservoirs are dolostone, which retains evidence of depositional fabric but contains progressively greater proportions of intercrystalline and unspecified outsize pores and progressively lesser proportions of other pore types. These, and even more highly altered reservoirs described below, are products of nonmimetic dolomitization, which probably took place after mineralogical stabilization and therefore also after secondary porosity formation by dissolution. Permeability values are variable.

Even more highly altered reservoirs retain vestiges of depositional fabric, but an unequivocal assignment using the classification of Dunham (1962) cannot be made. These include completely or largely dolomitized oolitic and pelletal rocks that contain recognizable particles but have been partially converted to homogeneous crystalline dolostone. The pore systems of these rocks are dominated by intercrystalline pores but contain substantial proportions of molds, vugs, and unspecified outsize pores. With greater degree of alteration, the molds and vugs vanish, and the outsize pores are progressively less identifiable as to origin. These reservoirs are characterized by highly variable permeability values, depending primarily on dolomite crystal size and shape, which control the sizes of intercrystalline pore throats.

Another rock type assigned to this alteration category is microbial doloboundstone. These rocks are locally abundant in the lower part of the Smackover and are dominated by intercrystalline and vuggy pores. Shelter porosity may be common, and fracture porosity is widespread. The volume of fracture porosity is small, but fractures have a dramatic effect on permeability values. Thus, reservoirs of this type are among the most permeable in the Smackover.

The most highly altered Smackover reservoirs are devoid of recognizable depositional fabric and contain pore systems dominated by intercrystalline pores. These reservoirs exhibit variable permeability values; highest where the rock fabric is coarse, crystal size is unimodal, and crystals are euhedral.

Smackover pore types and pore systems have now been described in sufficient detail to move on to the topic of reservoir-rock petrophysics. The subject of the relative abundance of pore- and pore-system types is deferred to the section on petrophysical reservoir classification.

PETROPHYSICAL CHARACTERISTICS OF SMACKOVER RESERVOIRS

CAPILLARY-PRESSURE CHARACTERISTICS

Capillary-pressure data were collected on 274 samples taken from 20 cores from 15 Smackover fields (Kopaska-Merkel, 1992a, table 3). Lithologically similar samples yield similar capillary-pressure (CP) curves. Because capillary pressure curve shape is a direct function of the pore-throat size distribution (Kopaska-Merkel, 1991), similarity of CP curves indicates similarity of pore-throat sizes. For example, many samples from moldic reservoirs that retain substantial amounts of primary interparticle porosity tend to exhibit leptokurtic unimodal throat-size distributions. This means that nearly all pores are accessed through large throats of a very restricted size range. These pore throats appear to result from a combination of (1) incomplete cement coatings on the particles (now molds), (2) open primary pores that originally formed a highly permeable network, and (3) interconnection of neighboring particle molds resulting from partial crushing of the rigid cement framework. The effect is to render the small throats between dolomite crystals irrelevant; fluid flow is controlled by the much larger throats between interparticle pores and perhaps by microfractures of about the same width.

Reservoir rocks can be classified on the basis of capillary pressure curve shape, using a descriptive approach applied by Amthor and others (1988) to the Lower Paleozoic Hunton group of the Anadarko basin and to the Ordovician Ellenburger Formation of west Texas. This same approach was used to develop a petrofacies classification of the Hunton Group (Kopaska-Merkel and Friedman, 1989) and one of Mesozoic and Cenozoic strata of the Indian Ocean (Kopaska-Merkel, 1992b).

CP-CURVE CLASSIFICATION

In this section, Smackover reservoir rocks are classified based upon CP-curve shape. CP curves are classified separately to draw attention to the wealth of petrophysical information that CP-curve shape summarizes, including pore-throat size distribution and estimates of recovery efficiency and permeability. New samples for which CP curves have been generated (and this is possible with cuttings if core is not available; Kopaska-Merkel, 1988) can be confidently classified. Class membership is readily determinable from standard CP graphs but carries with it information about petrophysical parameters such as porosity, permeability, and pore-throat size distribution. In a subsequent section, an integrated petrophysical classification of Smackover reservoirs that includes CP-curve shape as well as petrophysical and petrographic parameters is presented.

Smackover CP curves are classified into 8 groups; 5 correspond to reservoir rocks, 1 to borderline reservoir rocks (porosity and permeability values near or below the cutoffs of 6 percent and 0.1 md, respectively), and 2 to nonreservoir rocks (table 2).

Table 2.--Classification of capillary-pressure curves by shape

Class	Throat-size distribution (16th/84th percentile)	Median throat size (μm)	Recovery efficiency (decimal fraction)	Porosity (decimal fraction)	Permeability (md)
1	Leptokurtic (3.15)	Very large (2.70±1.67)	Low (0.02±0.03)	0.20±0.06	36.13±83.43
2	Mesokurtic (6.13)	Large (1.85±1.52)	Low (0.02±0.02)	0.20±0.08	2.24±3.12
3	Leptokurtic (3.01)	Large (2.32±1.48)	High (0.21±0.14)	0.16±0.03	15.38±14.47
4	Mesokurtic (5.69)	Large (1.56±0.89)	Intermediate (0.13± 0.05)	0.13±0.03	8.38±14.29
5	Platykurtic or polymodal (34.26)	Intermediate (1.11±1.14)	Intermediate (0.13±0.11)	0.10±0.08	2.77±4.29
6	Mesokurtic (6.00)	Small (0.22±0.10)	High (0.31±0.06)	0.07±0.02	0.08±0.20
7	Leptokurtic (4.68)	Very small (0.04±0.03)	High (0.31±0.09)	0.02±0.02	0
8	Mesokurtic (5.61)	Very small (0.08±0.10)	Intermediate (0.14±0.06)	0.04±0.03	0.06±0.24

CP-curve class 1 includes samples with leptokurtic (most samples clustered near the mean) pore-throat size distributions that exhibit little or no extrusion of mercury during pressure reduction. Essentially all of the porosity in each of these samples is accessed through throats of a single narrow size range. Samples assigned to this class tend to have large median pore throats and high porosity values; most are ooid dolograinstone or pellet dolograinstone with abundant moldic porosity and many contain substantial amounts of interparticle porosity (fig. 6).

Samples assigned to CP curve class 2 differ from those of class 1 in exhibiting mesokurtic pore-throat size distributions with minor fine tails. Most of the porosity in each of these samples is accessed through throats of a single narrow size range. However, smaller throats are involved in the filling and drainage of roughly 10 to 20 percent of the pore system in these samples. The smaller throats may form a discrete group or may encompass a broad range of sizes (fig. 7). Samples assigned to this class have large pore throats, and porosity values are high. Most samples assigned to this class are pelletal and oolitic dolograinstone, similar to those assigned to class 1; most exhibit either pure moldic pore systems or contain substantial amounts of interparticle porosity. A few contain nearly pure intercrystalline pore systems.

CP-curve class 3 includes samples that have leptokurtic pore-throat size distributions. If a fine tail is present, the volume of pore space associated with each incrementally smaller throat size decreases smoothly, and collectively these smaller throats commonly account for 10 percent or less of the pore system. Most significantly for classification, samples assigned to class 3 commonly exhibit a substantial amount of mercury extrusion during pressure reduction; as much as 60 percent in rare cases (fig. 8). Porosity values are measurably lower than for classes 1 and 2. Whereas the first two CP-curve shape

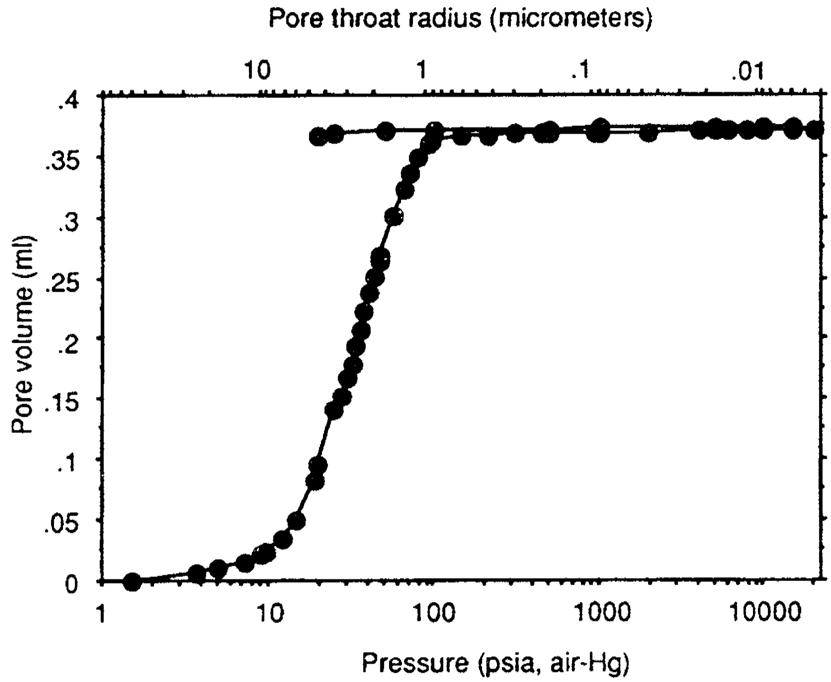


Figure 6.--CP-curve class 1. Example from Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,789 feet. The combination of rapid intrusion (leptokurtic pore-throat size distribution), large pore throats, and negligible extrusion characterize this class. In this and other CP curves, pore-throat radius is calculated from capillary pressure as explained by Kopaska-Merkel (1991) and depth is core depth.

classes are dominated by oolitic and pelletal dolograinstone, samples assigned to this class are more diverse. They include a wide variety of dolograinstone, partially dolomitized grainstone, packstone, and wackestone, crystalline dolostone, and other rock types.

CP-curve class 4 includes samples that have mesokurtic pore-throat size distributions. Many of these samples exhibit a prominent tail of small throats that accounts for as much as 30 percent of the pore volume. Many samples, rather than exhibiting a discrete fine tail, exhibit a smooth reduction in volume of pores accessed through smaller and smaller throats over the entire range of pore-throat sizes. Samples assigned to this class extrude up to 25 percent or more of their mercury during pressure reduction (fig. 9). Median throat sizes and porosity values are lower than in classes 1, 2, and 3. Samples assigned to class 4, like those of class 3, are petrographically diverse. Diverse dolograinstone, partially dolomitized grainstone and packstone, and crystalline dolostone are the most common rock types assigned to class 4. These samples differ from those assigned to class 3 primarily in having a broader range of pore-throat sizes through which substantial volumes of porosity are accessed. The diversity of rock types suggests that there are at least several proximate causes of this broadened pore-throat size range. Many of these samples are dominated by intercrystalline pores, and exhibit platykurtic dolomite-crystal size distributions. Other samples assigned to this class typically contain mixed pore systems in which secondary intraparticle pores and intercrystalline pores are abundant, which probably explains the mesokurtic pore-throat size distributions in these samples.

Samples assigned to CP-curve class 5 exhibit platykurtic or polymodal pore-throat size distributions. CP curves assigned to this class are variable. These samples also have variable porosity values, recovery efficiency values, and median throat sizes. On average, however, porosity values and median throat sizes are smaller than for classes 1 through 4; recovery efficiencies range up to about 40 percent (fig. 10). Samples assigned to class 5 are petrographically diverse; this class specifically differs from classes 1 through 4 in including abundant dolomitized boundstone, in addition to dolograinstone, dolopackstone, and other rock types.

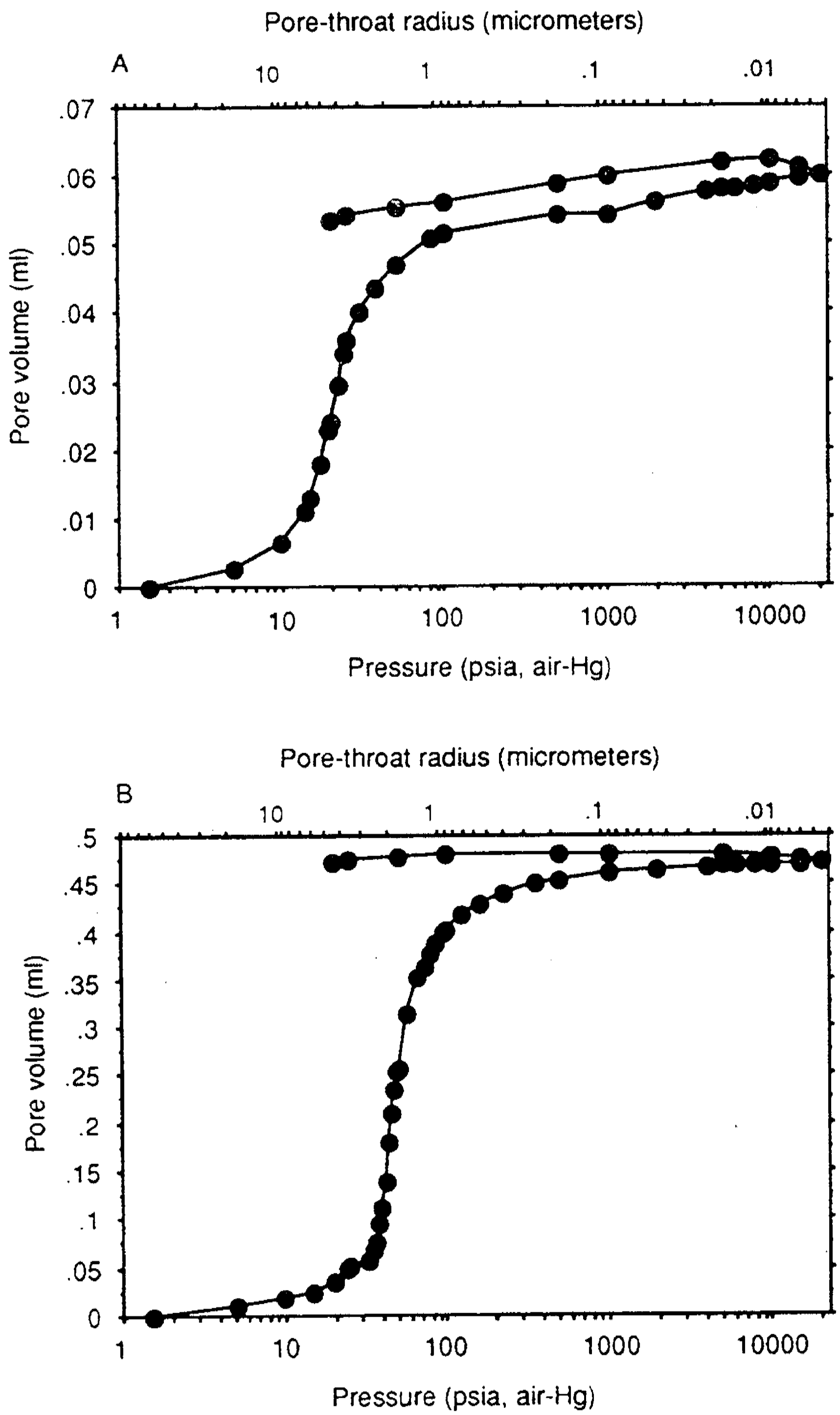


Figure 7.--CP-curve class 2. (A) Example from Permit No. 4577, Huxford field, Escambia County, 14,552.1 feet. Smaller pore throats encompass a discrete size group. (B) Example from Permit No. 2205, Silas field, Choctaw County, 13,613 feet. Smaller pore throats smoothly decrease in abundance with decreasing size. The combination of a leptokurtic to mesokurtic pore-throat size distribution with a fine tail, large pore throats, and negligible extrusion of mercury, characterize this class. See caption to figure 6 for general comments.

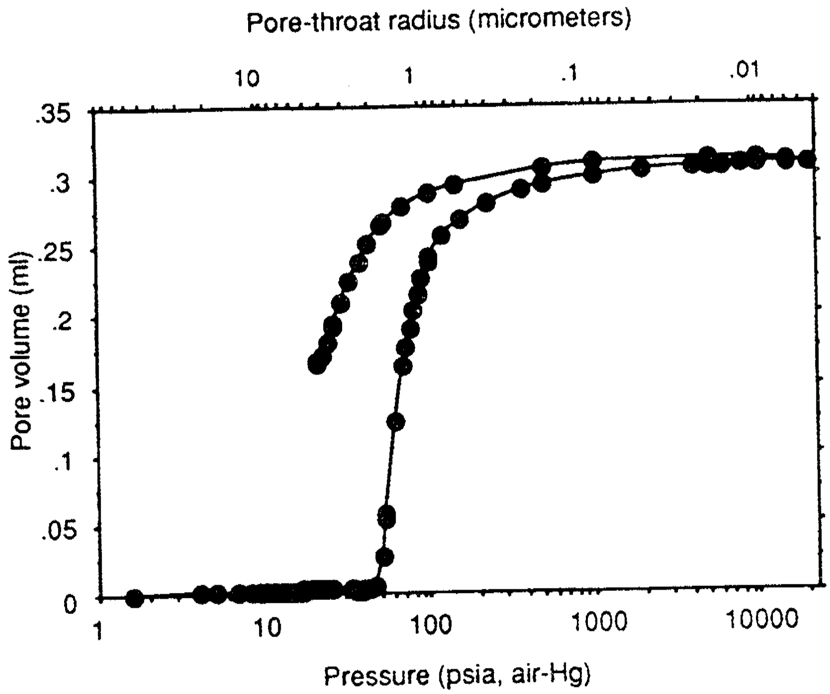


Figure 8.--CP-curve class 3. Example from Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,837.6 feet. The combination of a leptokurtic pore-throat size distribution, large pore throats, and substantial mercury extrusion characterize this class. See caption to figure 6 for general comments.

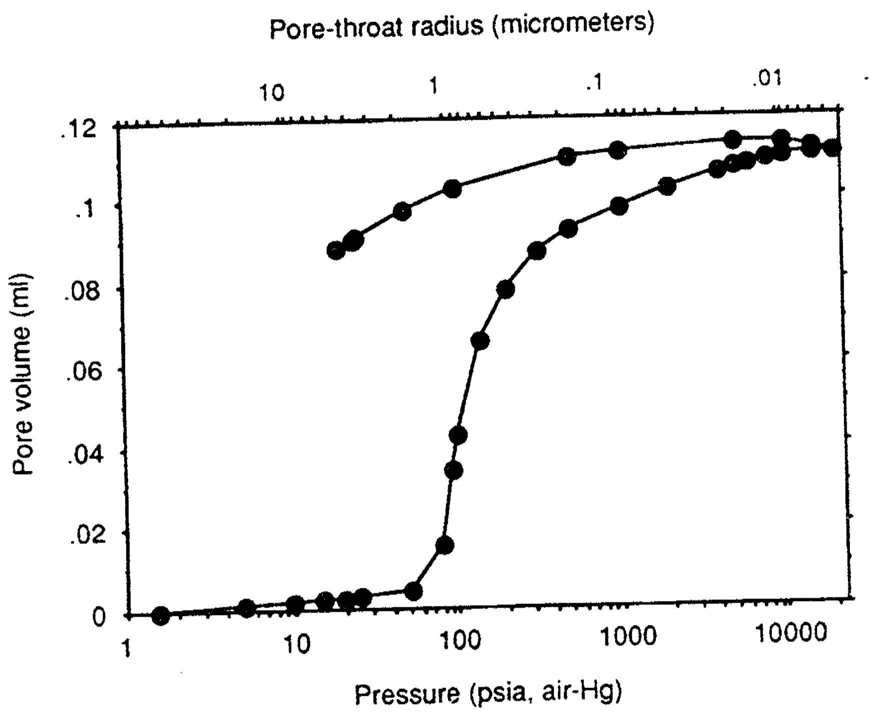
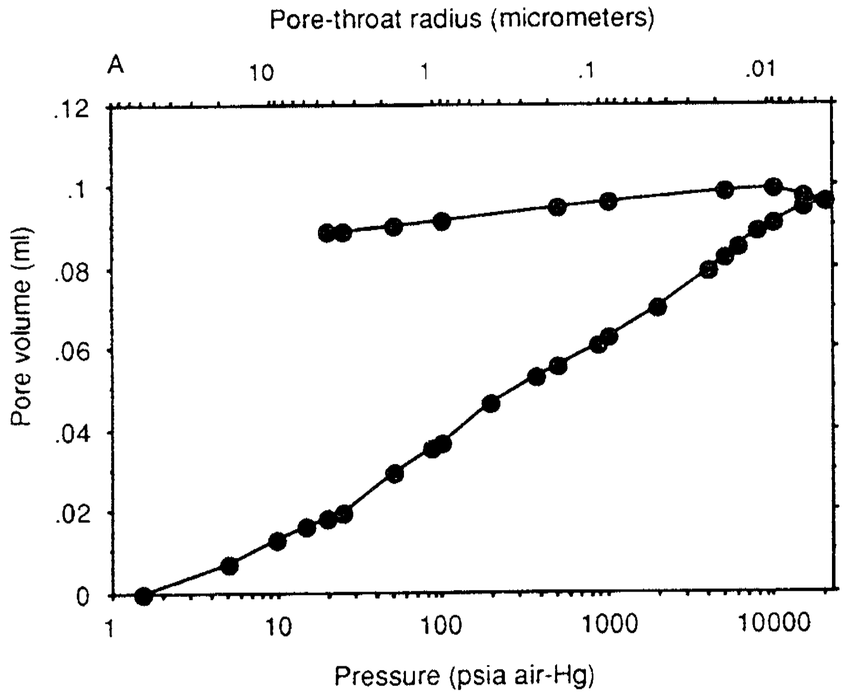


Figure 9.--CP-curve class 4. Example from Permit No. 2327, Womack Hill field, Clarke County, 11,436.1 feet. The combination of a mesokurtic pore-throat size distribution, medium-size throats, and significant extrusion of mercury characterize this class. See caption to figure 6 for general comments.



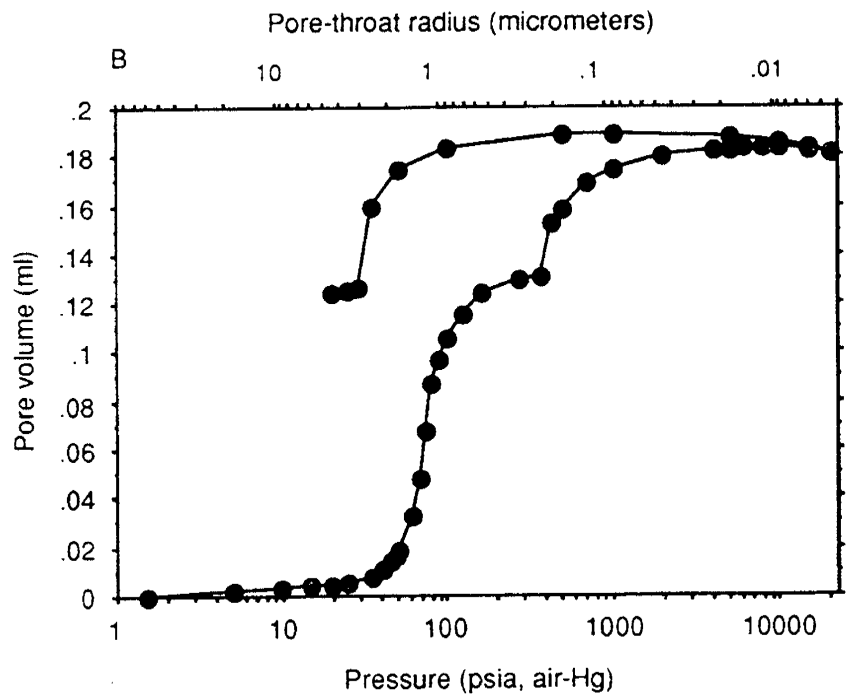


Figure 10.--CP-curve class 5. (A) Platykurtic example from Permit No. 6247, Appleton field, Escambia County, 12,978.8 feet. (B) Polymodal example from Permit No. 2205, Silas field, Choctaw County, 13,601.4 feet. Platykurtic and grossly polymodal curves are diagnostic for this class. See caption to figure 6 for general comments.

CP-curve class 6 includes samples that are marginal reservoir rocks; porosity values are less than 10 percent and the mean porosity value is about 6 percent. These samples have mesokurtic throat-size distributions but lack large throats (MTS does not exceed 0.5 µm). Recovery efficiency ranges between about 30 and 40 percent (fig. 11). These samples include microcrystalline carbonate (e.g., lime mudstone and peloid wackestone), of which some are dolomitized, and crystalline dolostone.

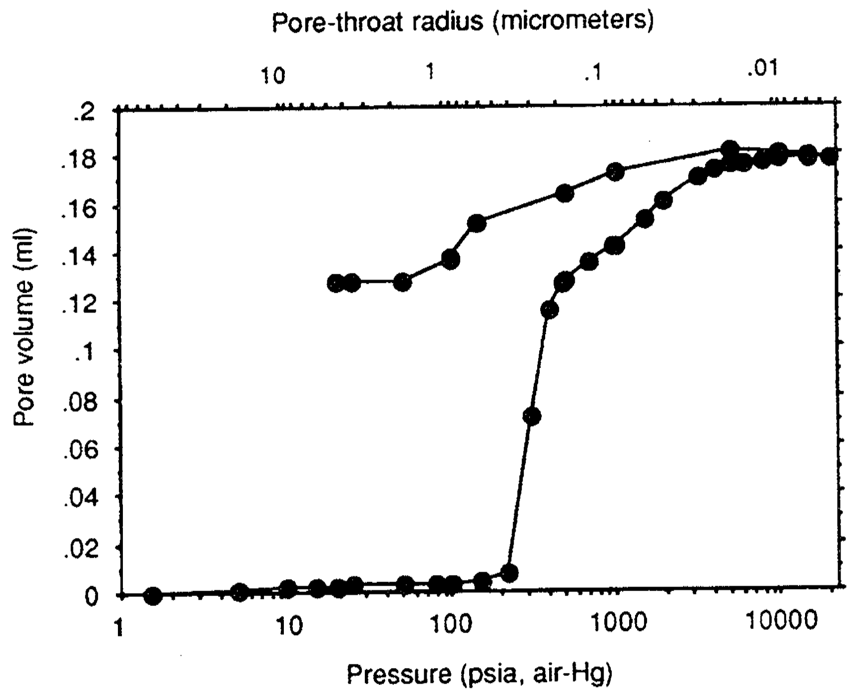


Figure 11.--CP-curve class 6. Example from Permit No. 1654, Little Escambia Creek field, Escambia County, 15,288.5 feet. The combination of small throats, significant mercury extrusion, and a distinct fine tail in the pore-throat size distribution characterize this class. See caption to figure 6 for general comments.

CP-curve classes 7 and 8 include nonreservoir rocks (see table 2).

The CP-curve classification presented here differs from, but is consistent with the design of, those previously devised by Amthor and others (1988), Kopaska-Merkel and Friedman (1989), and Kopaska-Merkel (1992b). The categories used in this report are compared to those used by Kopaska-Merkel and Friedman (1989) in table 3. In essence, two of Kopaska-Merkel and Friedman's categories are subdivided, and samples like those assigned to their category V (which were nonreservoir rocks) have not been observed.

TYPICAL AND ATYPICAL RESERVOIRS

Smackover reservoir rocks can be divided into six groups based on CP-curve shape. However, by looking at CP data another way, one can show that most Smackover reservoir rocks form a group characterized by well-defined trends. Using this approach, the differences between CP-curve shape classes are ignored and overall similarities are considered. This exercise is instructive, because it permits generalizations to be made about petrographic characteristics of the entire "trend." If porosity is compared to MTS (fig. 12), a general trend characterizes most Smackover reservoirs. The greater the porosity, the larger the MTS. For unimodal distributions of roughly similar shape (and

Table 3.--Comparison of capillary-pressure curve classification of this paper with that of Kopaska-Merkel and Friedman, 1989

This paper	Kopaska-Merkel and Friedman
1	IB
2	IB
3	IA
4	IA
5	II
6	III
7	IV
8	IV

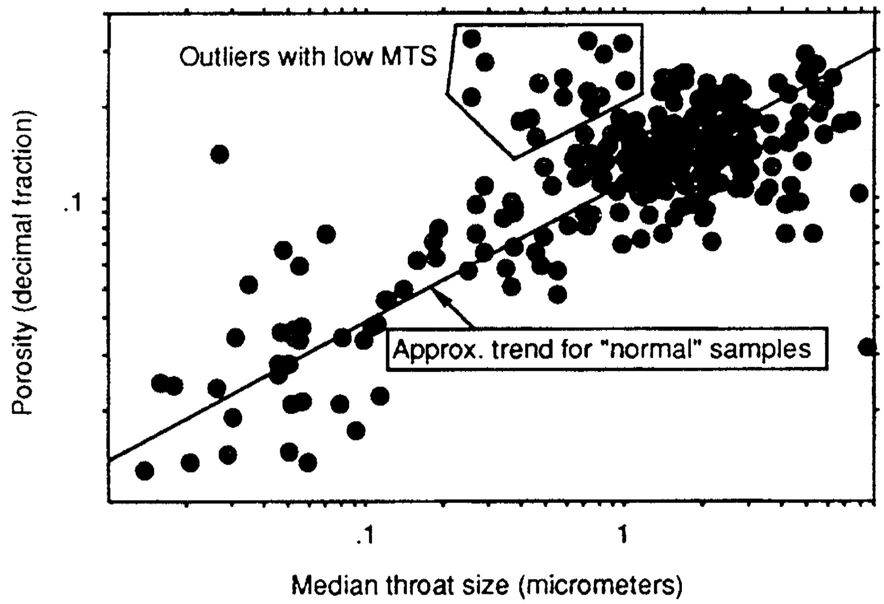


Figure 12.--Porosity vs. median throat size for all Smackover data. Trend fitted by eye.

most Smackover reservoir rocks exhibit CP curves that are of roughly similar shape) median throat size is a fairly unbiased comparative measure of throat size.

Although most Smackover reservoir rocks fit the trend just described, in which MTS and porosity are proportional to one another and positively correlated, there are some exceptions. A group of 15 outliers have unusually low values of MTS (fig. 12). These samples exhibit porosity values of 18 percent or more but MTS values are no greater than 1 micrometer. Eleven of these samples come from reservoirs characterized by nearly pure moldic porosity (with or without interparticle porosity) in which the particle molds are poorly connected. These samples are assigned to CP-curve classes 1 and 2. By contrast with these "perfect" moldic reservoirs, moldic reservoirs that have experienced partial crushing of the rock framework and development of microfractures, which are common in the Smackover of Alabama, fit the general trend illustrated by figure 12 (see fig. 31). The occurrence of noncrushed moldic pore systems within a reservoir interval creates heterogeneity by the development of relatively impermeable high-porosity zones. These zones are commonly no greater than a few centimeters thick, and their lateral extents are probably several meters or less. The effect of this phenomenon on reservoir performance is probably slight, as suggested by two facts. First, megascopic heterogeneity values for mold-dominated reservoirs are low (see section entitled "Megascopic reservoir heterogeneity"). Second, advanced-recovery projects in mold-dominated reservoirs (e.g., Stave Creek field) tend to be highly successful, indicating that reservoirs are not significantly more heterogeneous than modeled. The other four samples with unexpectedly small median throats are assigned to CP-curve class 5. These four samples resemble one another petrographically; they are all ooid dolograinstone or pellet ooid dolograinstone. However, the four CP curves are dissimilar, ranging from gradational to bimodal with a coarse tail to bimodal with a fine tail. It is not clear what factors, if any, tie these four samples to one another or to the other 11 outliers.

POROSITY AND PERMEABILITY DATA

PREDICTING POROSITY

Regionally one can construct a map of average porosity values (one such is presented as figure 37). On a field scale, porosity is best predicted (from core and log data) using a geostatistical technique that preserves as much as possible the variance structure of the data. Hierarchical conditional simulation was applied to porosity data in Chunchula field (University of Alabama, 1991).

PREDICTING PERMEABILITY

Petrophysical data (porosity, permeability, and capillary-pressure analyses) have been analyzed statistically and compared to other kinds of data (e.g., petrographic) in order to predict permeability. The first step was to look for regularities in the petrophysical data. On a regional scale, Smackover reservoir characteristics are remarkably consistent. When a single reservoir is studied (e.g., Silas field in Choctaw County; Kopaska-Merkel and others, 1992) atypical samples are readily distinguished (fig. 13). This graph shows that rock units that were identified as significantly different by visual core description exhibit distinct petrophysical characteristics. This confirms that flow units can be identified by visual core description. As it is necessary to model the 3D distribution of flow units using readily acquired data, the congruence between lithofacies identified in core and petrophysical characteristics is encouraging. Because lithofacies dominated by moldic pores are strongly controlled by depositional fabric, a detailed facies-analytic approach using cores and logs might help refine engineering models of flow-unit distribution by constraining the shapes, sizes, and relative positions of reservoir bodies with moldic pore systems. Such an approach is unlikely to be successful in reservoirs with intercrystalline pore systems because they commonly bear an indeterminable relationship to depositional fabric.

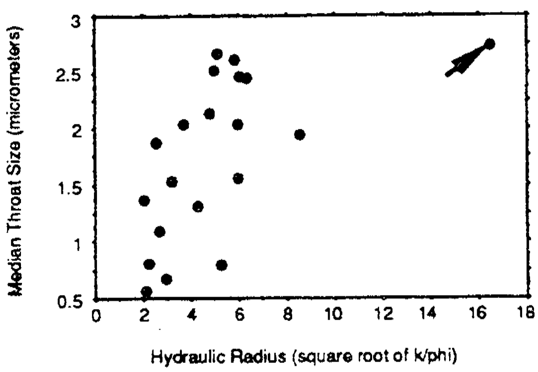


Figure 13.--Median throat size vs. hydraulic radius, Silas field. The sample indicated by the arrow differs petrographically from the other samples and is assigned to a different lithofacies.

Three possible methods of predicting permeability present themselves. The first is based on the relationship between microporosity, as measured from capillary-pressure data and as estimated by calibration of well logs, and permeability. The ultimate goal is to predict permeability values from well logs or from limited amounts of other kinds of data. The second way to predict permeability is by measuring MTS, which is derived from capillary-pressure analysis. The third method of permeability prediction is to predict permeability from porosity.

INFLUENCE OF MICROPOROSITY

Small amounts of microporosity can dramatically depress permeability in Smackover reservoir rocks (fig. 14). It appears that small (centimeter-scale?) areas of small pores and small pore throats act as permeability baffles. Thus, by understanding the distribution of microporosity one might be able to predict permeability variation.

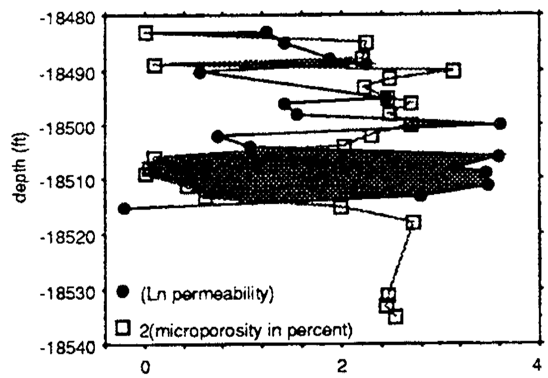


Figure 14.--Example of inverse relationship between permeability and microporosity, Chunchula field. Porosity values are doubled so that the two curves can be plotted on a common scale. Shaded areas indicate crossover of curves.

At least in some cores, the proportion of "microporosity" (defined as pores intruded at pressures greater than 1,000 psia) is roughly inversely proportional to permeability (see fig. 14). However, in other cores, this is not true, and there is no overall relationship for all samples between these two variables. Evidently, some kinds of microporosity influence permeability and others do not. Sw values can be measured and related to pore-throat size distributions to study the pore-throat size that would separate "true" micropores, those that will not contain movable hydrocarbons from those slightly larger pores that are small, but that may contain movable hydrocarbons. These problems have not yet been evaluated for the Alabama Smackover.

PREDICTION FROM MEDIAN THROAT SIZE

One approach to predicting porosity and permeability, stochastic modeling, has been applied to Chunchula field, Mobile County (University of Alabama, 1991). Another approach is to predict permeability deterministically, using geological or engineering data. Of all of the variables investigated, only MTS is strongly correlated with permeability (fig. 15). MTS is derived from capillary-pressure analysis. This method requires expensive and time-consuming studies of rock samples, commonly from cores. However, whereas permeability can only be measured in samples cut from cores, MTS can be calculated from capillary-pressure analysis of cuttings (Purcell, 1949; Kopaska-Merkel, 1988). Therefore, permeability can be estimated from noncored intervals using this method. As explained in the methods section, this approach does not work if the pore throats are too large.

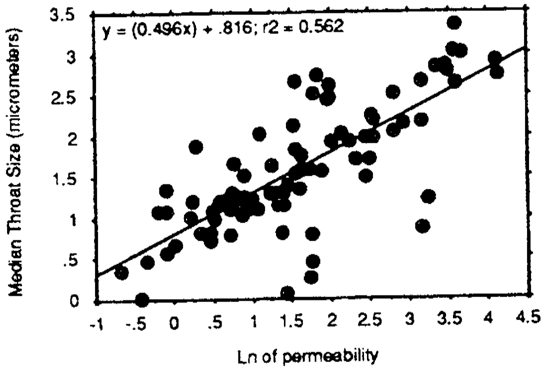


Figure 15.--Median throat size vs. natural log of permeability, all data.

If a reservoir simulation is planned in a field for which only some wells have been cored, MTS values from capillary-pressure analysis of cuttings can be used to derive permeability values for noncored wells. This increases the size and accuracy of the dataset for geostatistical models that will provide the grid-block numbers for the simulation. Permeability also can be estimated in noncored wells if permeability can be calibrated to well logs. Even if well logs are successfully calibrated to permeability, the MTS method provides an independent estimate; the two estimates can be used to check each other.

Permeability also can be calculated from capillary-pressure data in other ways (e.g., Jennings, 1987; Ma and others, 1991) but these are not appropriate for a regional study like this one.

PREDICTION FROM POROSITY

The prediction of permeability from porosity is a well-known technique that begins with the relationship between core porosity and core permeability, which is then generalized by calibration of well logs so that permeability can be predicted from log porosity throughout the reservoir. This is normally followed by some kind of geostatistical analysis so that interwell permeability values can be predicted. This technique has been most successful in sandstone reservoirs (Weber and van Geuns, 1990, reviewed some approaches and problems of permeability estimation), but has also been successfully applied to carbonate reservoirs (e.g., Lucia and Fogg, 1990, and references therein). Lucia (1983) suggested that porosity and permeability are strongly correlated in carbonates dominated by intercrystalline or interparticle porosity, provided that crystal size and particle size are used to divide the reservoir into what Lucia (1983) called particle-size groups. These groups have different porosity-permeability relationships expressed as power-law equations. Lucia (1983) stated that what he called "vuggy porosity" in carbonate reservoirs (which included moldic pores and probably some partial molds) did not yield simple, widely applicable equations relating porosity to permeability. Lucia's "particle-size" control on the slope of the porosity-permeability relationship (Lucia, 1983) cannot be tested using data from the Alabama Smackover, because only a few reservoirs meet the requisite conditions and these all have dolomite crystals of about the same size.

Smackover fields dominated by intercrystalline porosity do not follow a single porosity-permeability trend, nor do they all exhibit strong correlation between porosity and permeability (fig. 16; Kopaska-Merkel and others, 1992). Also, some but not all Smackover fields containing substantial amounts of moldic and secondary intraparticle porosity exhibit strong correlation between porosity and permeability (fig. 16; Kopaska-Merkel and others, 1992). It would not be possible to predict permeability with acceptable accuracy by using in one field a porosity-permeability equation derived from one or more other fields, at least for the Smackover of Alabama. However, moldic reservoirs exhibit the lowest r^2 values for the relationship between porosity and permeability, and intercrystalline reservoirs exhibit the highest values, which is consistent with the relationships found by Lucia (1983) and Lucia and Fogg (1990). Further, as r^2 values increase from moldic to intermediate

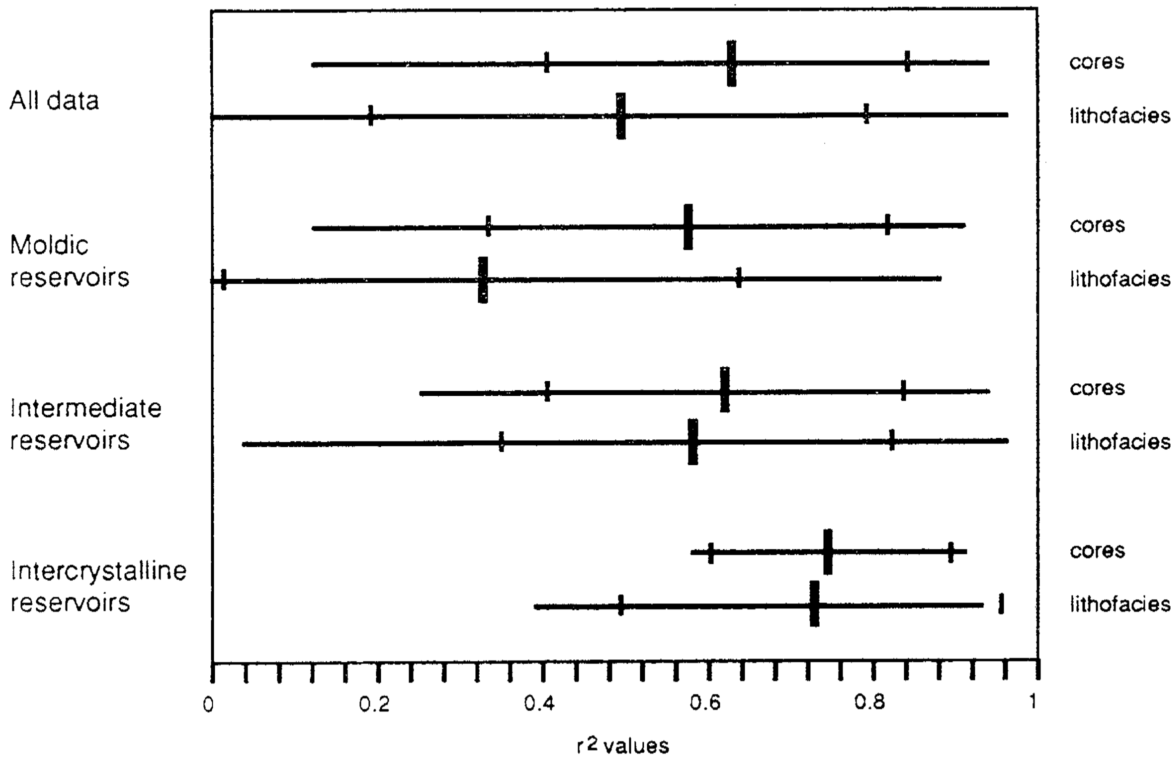


Figure 16.--r^2 values for porosity and permeability, Smackover cores and reservoir lithofacies by pore facies. Vertical bars indicate mean values and $\pm$ one standard deviation. Horizontal bars indicate range of r^2 values. Data for 27 fields including 45 lithofacies.

to intercrystalline reservoirs, the standard deviations of r^2 values decrease, which also supports Lucia's (1983) contention that intercrystalline reservoirs are characterized by more direct relationships between porosity and permeability. This trend is fully consistent with the trends in microscopic heterogeneity described in a later section of this report. In conclusion, permeability will likely be predictable with greater accuracy and precision in intercrystalline than in moldic reservoirs, but the particular relationship should be determined from data from the field in question, and even some nearly pure moldic reservoirs exhibit sufficiently robust porosity-permeability trends for the approach to be successful.

The same trends in r^2 values and in standard deviation of r^2 values that are seen with whole-core data are observable using data for individual lithofacies (fig. 16). However, r^2 values are lower, and standard deviation of r^2 values are higher for individual lithofacies than for whole cores, at least in the Smackover of Alabama. This is not necessarily true of siliciclastic reservoirs (see discussion by Weber and van Geuns, 1990). This is because a single lithofacies tends to exhibit reduced variation in porosity and in permeability. Any trend is less apparent because the "noise" of permeability variation that is not related to porosity is evidently of comparable magnitude within lithofacies and within cores, even where lithofacies exhibit distinct differences in range and central tendency of porosity and permeability. Also, part of the porosity-permeability trend seen in whole-core data is between lithofacies variation, a result of lumping of low-porosity low-permeability lithofacies with high-porosity high-permeability lithofacies.

PETROPHYSICAL RESERVOIR CLASSIFICATION

STATEMENT OF PURPOSE

Smackover reservoir rocks are classified petrophysically in order to identify groups of reservoirs that are expected to respond similarly to attempts to produce reservoir fluids. In doing so, attention must be directed to pore systems, the networks of holes in the rock. In other words, it is much more useful to look at what is not there than at what is there. The shapes, sizes, distribution, surface textures, and connectivity of pores (as well as temperature, pressure, and fluid characteristics) control fluid behavior in reservoirs.

The pore systems of reservoir rocks are the end products of a long and complicated series of processes beginning with sediment deposition and continuing through burial diagenesis (fig. 17). Pore-system geometry and topology exert greater control on the hydrocarbon-production potential of reservoir rocks (especially permeability and nonwetting-fluid trapping) than any features of the rock matrix.

CLASSIFICATION OF PORES

DOMINANT PORE TYPES IN THE SMACKOVER OF SOUTHWEST ALABAMA

The three most common kinds of pores in the Smackover in Alabama are (1) moldic plus secondary intraparticle pores, (2) interparticle pores, and (3) intercrystalline pores (Kopaska-Merkel, 1990). Together, these three pore types account for more than 95 percent of total porosity in the thin sections studied (Kopaska-Merkel and Mann, 1991a; Kopaska-Merkel, 1992a, table 6). Pore types and their relative proportions in reservoir rocks were determined by point counting petrographic thin sections.

The lumping of all particle molds together in one group, regardless of the nature of the particles from which the molds were derived, honors petrophysical similarities and differences among reservoir-rock samples. Samples from different reservoirs that have similar pore types have similar fluid-flow characteristics. Least-squares regression lines of porosity on natural log of permeability from two cores from different fields, both characterized by moldic pore systems, are nearly identical in slope and intercept (fig. 18A and B). By contrast, sets of samples characterized by different pore types exhibit differing slopes and/or intercepts on porosity-permeability plots (fig. 18C). The similarities between figures 18A and 18B are all the more remarkable because the core in B is dominated by pellet dolograinstone and the core in A contains abundant ooids. Ooids differ mineralogically from pellets (aragonite vs. calcite in the Smackover of Alabama) and are substantially larger (ooid diameters are 600 to >1,000 mm; 5 to 10 times pellet diameters). Thus, both susceptibility to dissolution and initial permeability values are dramatically different for ooid grainstone and pellet grainstone. Reservoir rocks that are generally classified in different "trends" because they differ in depositional fabric and original mineralogy (e.g., aragonitic ooids vs. calcitic pellets) and come from different paleogeographic settings (e.g., Chatom and Gin Creek fields, Washington and Choctaw Counties, respectively; Mancini and Benson, 1980) may nevertheless exhibit pore systems that are lumped together. This is justified because the petrophysical similarity between samples that is congruent with the pore-type classification is more significant to fluid-flow characteristics than are depositional differences.

Just as particle type may not strongly influence reservoir characteristics, the process of dolomitization *per se* does not necessarily cause a change in pore types. Dolostone and limestone both exhibit moldic pore systems. More importantly, petrophysical characteristics such as permeability and porosity also may be conserved through dolomitization. An oomoldic dolograinstone is petrophysically very similar to an oomoldic lime grainstone, though dolograinstone is commonly slightly more permeable. See, for example, Kopaska-Merkel and others (1992) and compare Chappell Hill field lithofacies 1 and 2 and Bucatunna Creek field lithofacies 1, 2, and 3. Naturally, dolomitization of an impermeable lime mudstone has more potential for permeability

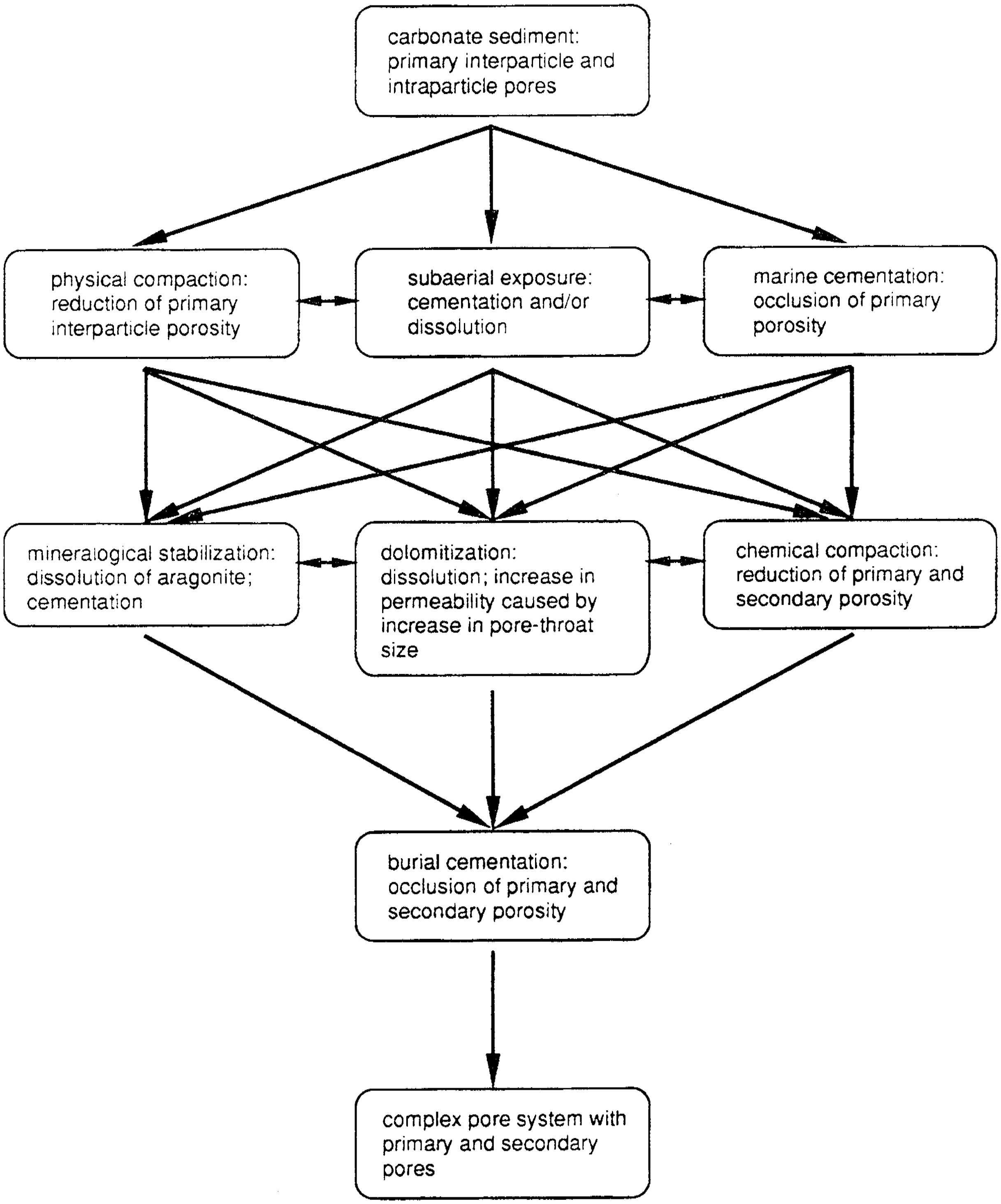


Figure 17.--Flow chart of important diagenetic processes that affected Smackover pore systems after sediment deposition.

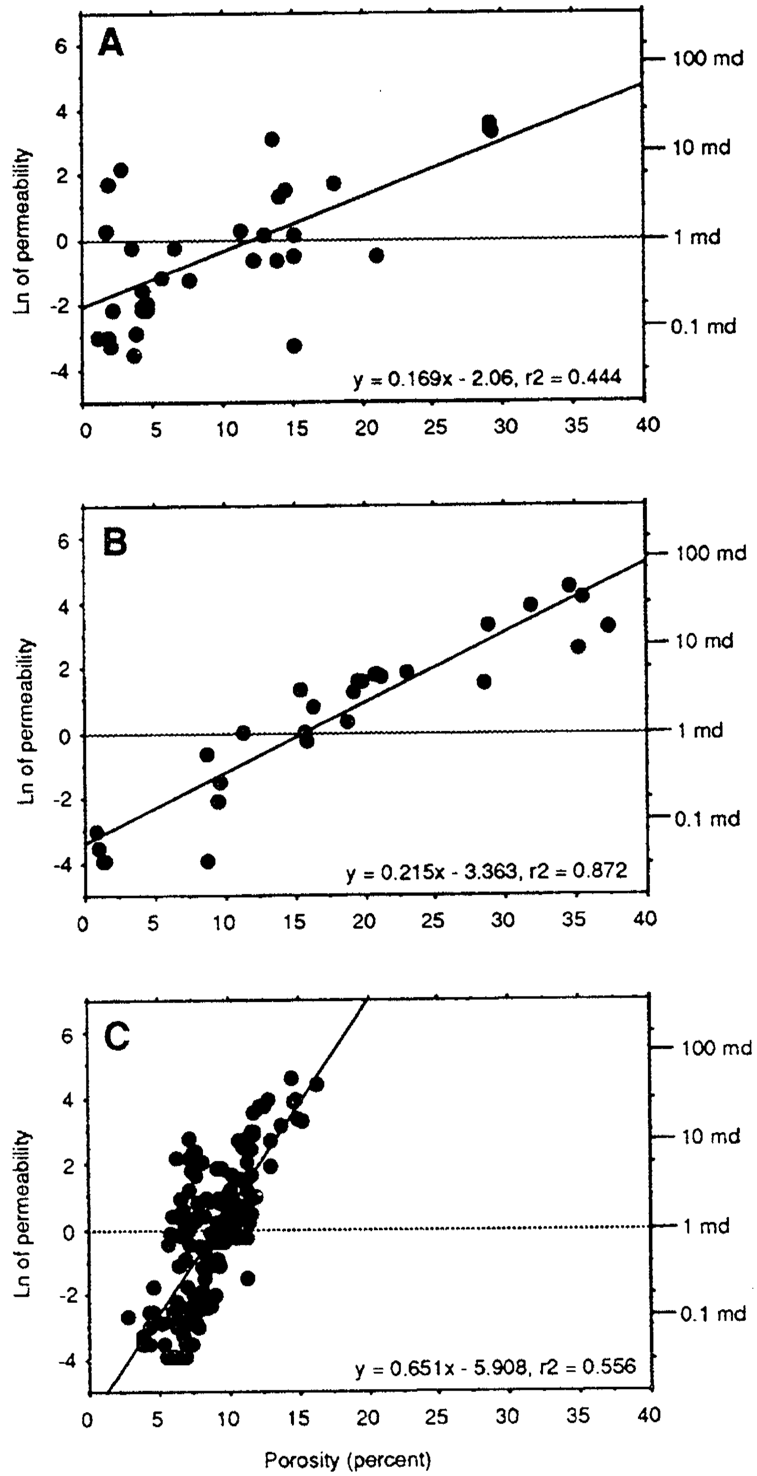


Figure 18.--Porosity vs. natural log of permeability, bivariate plots with least-squares regression lines and equations. Plots are based on commercial porosity and permeability data collected at 1-foot intervals. (A) Permit No. 3312, Gin Creek field, Choctaw County; (B) Permit No. 7044, Chatom field, Washington County. The regression lines are virtually coincident. (C) Permit No. 3535, Lovetts Creek field, Monroe County. The intercrystalline-dominated pore system in this core is very different from the moldic pore systems of the first two cores. The slope and intercept of the regression line for this data set are quite different from those in A and B.

enhancement (e.g., Bliefnick and Mariotti, 1988, their figures 23 and 24). The inclusion of secondary intraparticle pores with moldic pores requires some explanation. Secondary intraparticle pores in the Smackover consist mainly of three kinds: (1) small vugs that lie entirely within partially dissolved particles (fig. 19) or partial molds that conform to the internal fabrics of original particles (fig. 20); (2) polygonal pores between dolomite crystals within particles that were partially replaced by planar-e unimodal dolomite (Sibley and Gregg, 1987) before dissolution of remnant calcium carbonate (fig. 21); and (3) reduced molds that have been nearly occluded by late cementation (these are uncommon in the Alabama Smackover). Secondary intraparticle pores are classified with molds because, like molds, they do not form a continuous network. Secondary intraparticle pores, like molds, are found within former particles and are separated from one another by whatever occupies the spaces between the former particles. In the Smackover, this intervening material is commonly marine-phreatic calcium-carbonate cement (fig. 22), microspar (fig. 23), dolomite, or anhydrite cement.

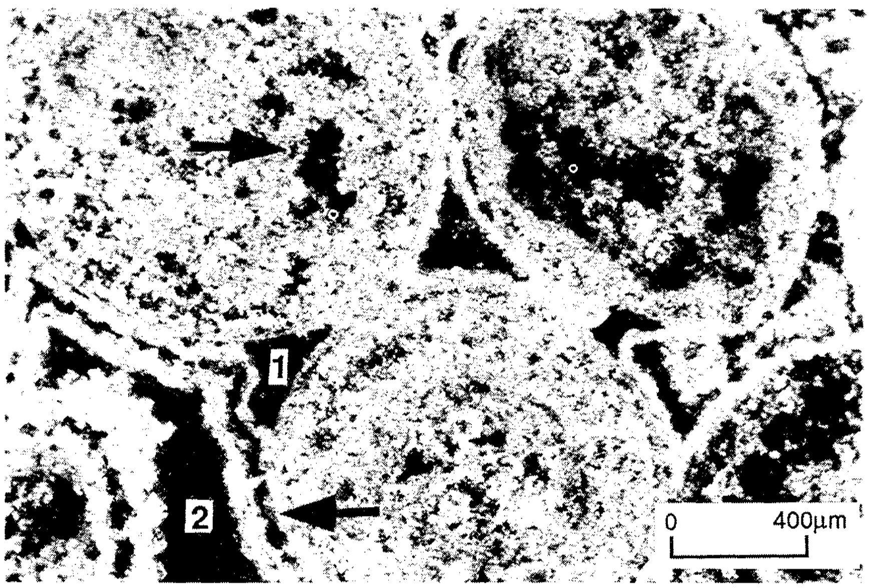


Figure 19.--Secondary intraparticle pores (upper arrow) that are small vugs lying entirely within partially dissolved particles. This view also includes meniscus cement moldic porosity (1), pore rimming cement moldic porosity (lower arrow), and interparticle porosity (2). Thin-section photomicrograph, Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,755.5 feet.

By contrast with secondary intraparticle pores and molds, interparticle pores are large and form well-connected networks. Because interparticle pores, where they occur, tend to be found with moldic and/or secondary intraparticle pores, they add a high-permeability pore-system element to the essentially low-permeability moldic or secondary intraparticle pore system (fig. 24). Thus, even the addition of 5 to 10 percent interparticle pores can dramatically increase the permeability of a moldic (or secondary intraparticle) pore system. However, the situation just described only obtains if the primary interparticle pores have not been significantly affected by the formation of pore-rimming cement. In tropical shallow-marine settings, high-permeability carbonate sands tend to be quickly cemented by marine-phreatic cements (e.g., Friedman and others, 1992). These cements typically consist of blades or fibers of aragonite or of high-magnesian calcite that radiate outward from and completely coat all exposed particle surfaces (e.g., Longman, 1980). A relatively modest amount of pore-rimming marine-phreatic cement will block pore throats quite effectively (fig. 22). If, however, marine sediments come under the influence of meteoric waters before cementation in the marine environment, then meteoric-phreatic cement may form, and it is far less effective at blocking pore

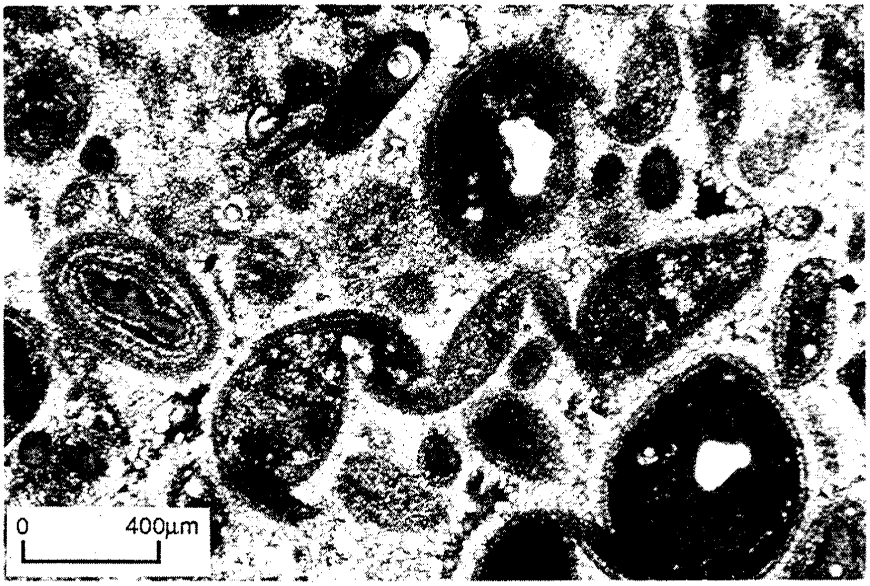


Figure 20.--Secondary intraparticle pores that are partial molds conforming to the internal fabric of the original particle. Note ooid on left side of photomicrograph in which certain concentric laminae have been selectively dissolved. Also note partially collapsed fabric in center of photomicrograph. Black areas are pores. Thin-section photomicrograph, Permit No. 2753, Bucatunna Creek field, Choctaw County, 12,272 feet.

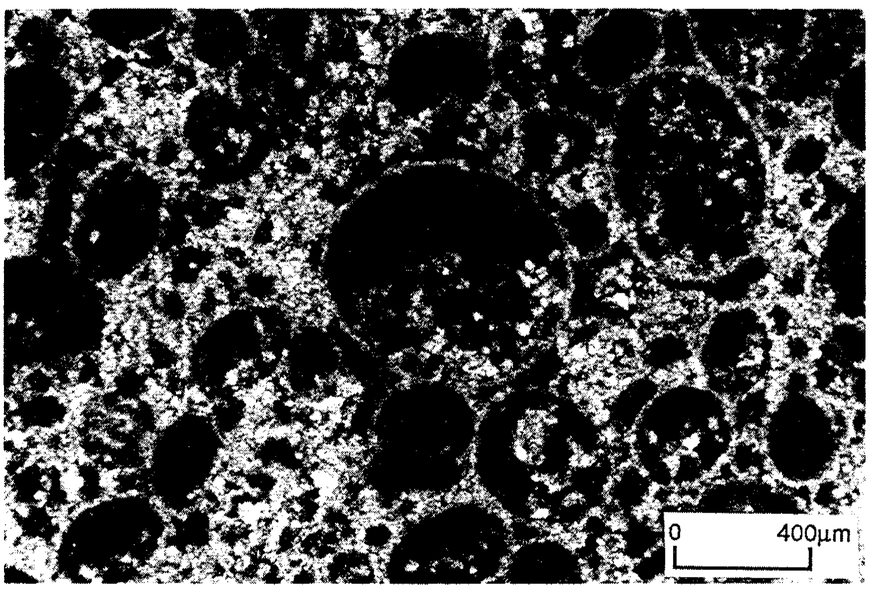


Figure 21.--Secondary intraparticle pores that are polygonal intercrystalline pores between dolomite crystals (e.g., within ooid in center of photomicrograph). The ooid was partially replaced by planar-e dolomite before dissolution of remnant calcium carbonate caused collapse of the dolomite crystals into the bottom of the mold and formation of a geopetal fabric. Dark areas are pores. Thin-section photomicrograph of ooid dolograinstone, Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,782.9 feet.

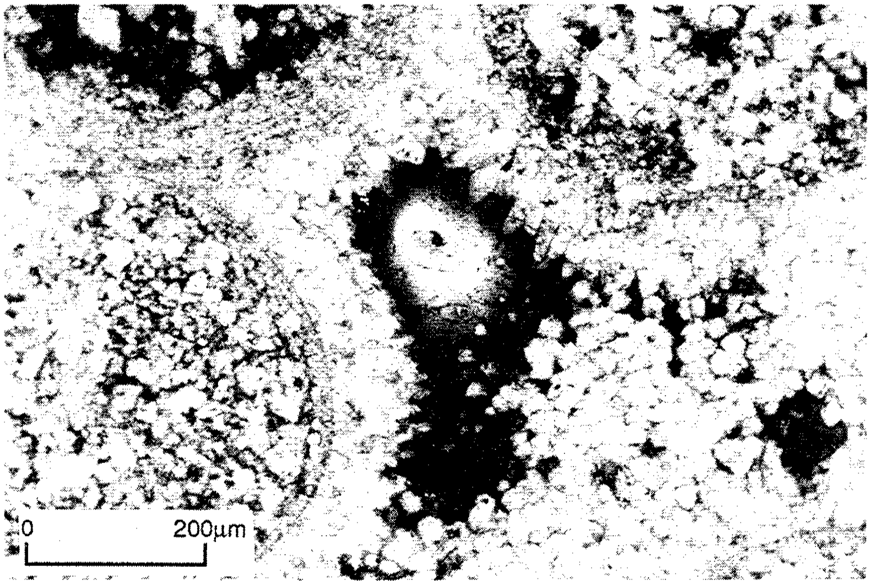


Figure 22.--Marine-phreatic pore-rimming cement blocking primary interparticle pore throats and separating ooids with secondary intraparticle porosity. Dark areas are pores; white blotch in center is incompletely stained epoxy in large interparticle pore. Thin-section photomicrograph, Permit No. 2753, Bucatunna Creek field, Choctaw County, 12,261 feet.

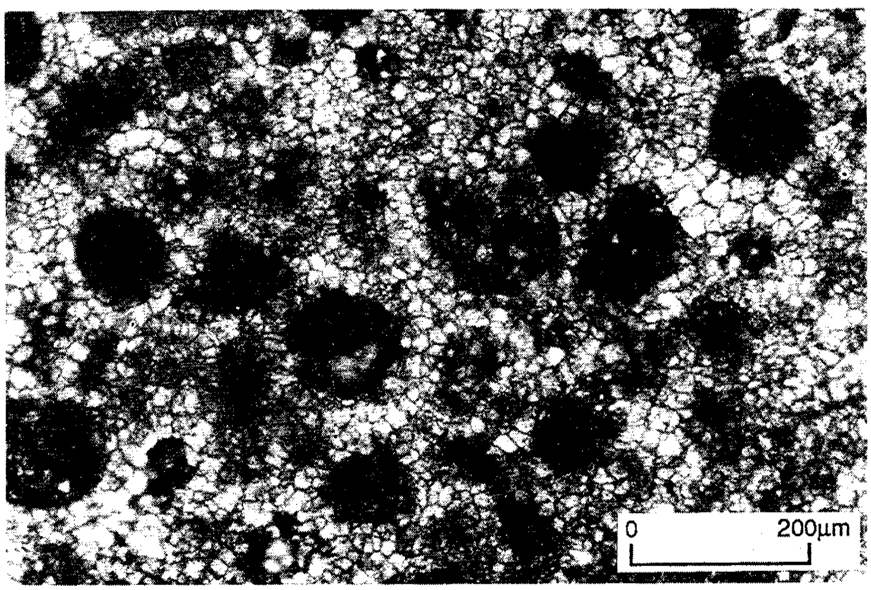


Figure 23.--Microspar between particle molds in pellet grainstone. This is an inverted fabric, in which former particles have become secondary porosity and former primary interparticle pores now are filled with calcium carbonate. Thin-section photomicrograph, Permit No. 3312, Gin Creek field, Choctaw County, 13,462.1 feet. Dark areas are porosity, mostly pelmoldic.

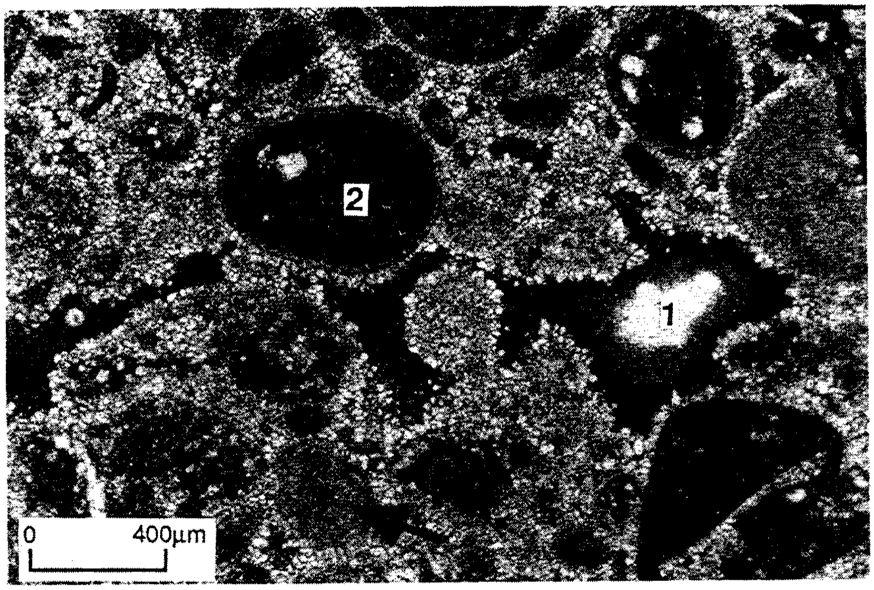


Figure 24.--Well-connected interparticle porosity (1) associated with moldic (2) and secondary intraparticle (arrow) porosity in pellet ooid grainstone. Interparticle pores add a high-permeability element to a fundamentally low-permeability secondary pore system. Thin-section photomicrograph, Permit No. 2753, Bucatunna Creek field, Choctaw County, 12,272 feet. Dark areas are pores; white blotch on right is incompletely stained epoxy in pore.

throats (Longman, 1980; Halley and Harris, 1979, their fig. 7). (One reason for this is that the low concentration of calcium and bicarbonate in meteoric water does not permit rapid precipitation of calcium carbonate.) Well-preserved interparticle porosity that has not been severely affected by early cementation is restricted to regions close to sources of meteoric water: the updip areas and the tops of some paleohighs (Moss, 1987; Kopaska-Merkel, 1992a).

Intercrystalline pores, though commonly smaller than interparticle pores, also form well-connected networks. In the ideal case, dolomite crystals are all about the same size and shape and therefore the pores among them are as well (fig. 25). In reality, there are commonly patches of coarser or finer dolomite crystals, crystals of different modal sizes may be commingled, or the crystals may vary continuously in size and/or shape.

TERNARY PORE PLOTS

Ternary diagrams whose apices are pore types (ternary pore plots; Kopaska-Merkel and Mann, 1990, 1991a, b) are constructed such that the three apices together account for most of the pores observed in a carbonate rock unit. This approach simplifies the interpretation of pore systems by focusing on only three major components and by displaying these data on a simple graphic plot that makes trends and clustering of samples obvious. Ternary pore plots provide information on the shapes and origins of pore-system elements.

For this study the three apices of ternary pore plots were chosen as follows: (1) moldic plus secondary intraparticle, (2) interparticle, and (3) intercrystalline. Most Smackover reservoir rocks fall close to either the moldic apex or the intercrystalline apex of ternary pore plots, with most of the remaining pore systems falling between these two extremes (fig. 26). The spectrum of Smackover pore systems is not a continuum, but represents partial mixing of two distinct end members. This suggests that Smackover pore systems can be usefully classified according to their positions in moldic-intercrystalline porosity space. Smackover reservoir rocks are classified into moldic and intercrystalline pore facies based on associations of pore types that are genetically related and petrophysically similar.

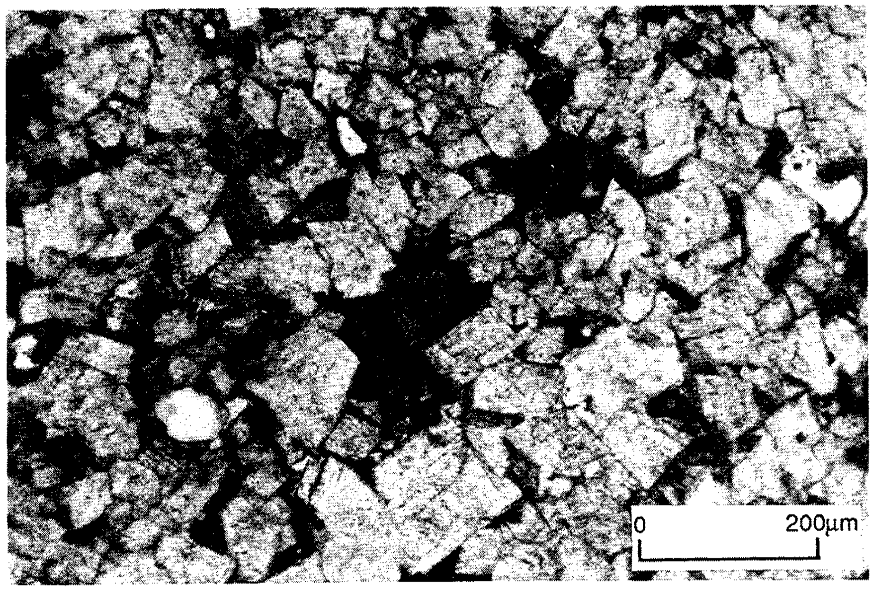


Figure 25.--Example of intercrystalline pore facies. Planar-e dolostone. Dark areas are pores. Permit No. 6846, Hatter's Pond field, Mobile County, 18,152.9 feet.

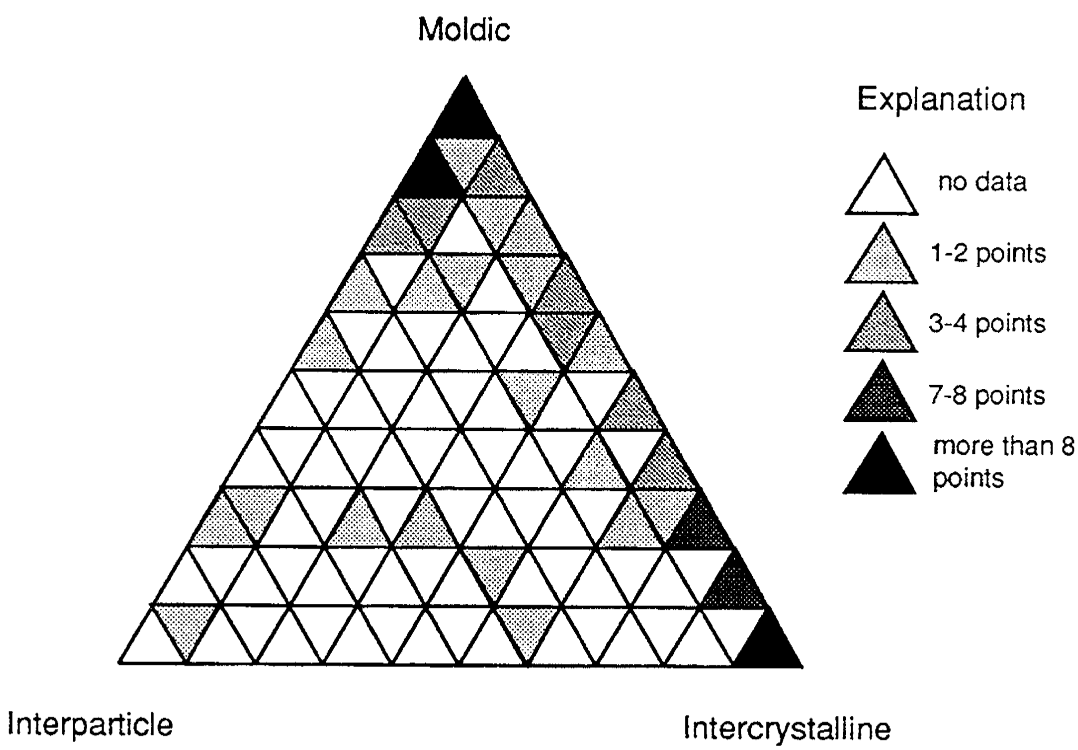


Figure 26.--Ternary pore plot that illustrates preponderance of end-member samples. No cells contain 5 or 6 data points.

PORE FACIES

Two distinct but partially intergrading pore facies are recognized in the Smackover of southwestern Alabama: the moldic pore facies and the intercrystalline pore facies (fig. 27; Kopaska-Merkel and Mann, 1991b). These pore facies are defined on the basis of the relative proportions of particle molds (assumed to include secondary intraparticle pores unless stated otherwise) and intercrystalline pores, which together account for greater than 85 percent of the total porosity in the Smackover of southwest Alabama (Kopaska-Merkel and Mann, 1991b). An arbitrary percentage of 60 percent of the dominant pore type has been selected as the boundary for pore facies. Most samples studied plot close to either the moldic or the intercrystalline apex of a ternary pore plot (fig. 26). Thus, the two pore facies are not end-members on a continuum, but are distinct entities. Pore systems that are intermediate in pore-type composition, and hence cannot be assigned to either pore facies, are discussed in a later section.

MOLDIC PORE FACIES

The moldic pore facies is volumetrically dominated by particle molds (fig. 28) and plots near the particle-moldic apex on a ternary pore plot (fig. 29). This pore facies characterizes particle-supported carbonate rocks that have been partially to wholly cemented in the shallow marine phreatic diagenetic environment (summarized by Longman, 1980) and whose particles have undergone partial to complete dissolution. Peloidal and oolitic grainstone are the most common particle-supported rocks in the Smackover. Most reservoirs assigned to the moldic pore facies have been partially to entirely fabric-selectively (mimetically) dolomitized. Dolomitization of calcium-carbonate cement before dissolution of unstable particles was common in the moldic pore facies. (Particle molds in the moldic pore facies do not contain centripetal dolomite cement fabrics, but do commonly contain geopetal dolomite silt or porous frameworks of dolomite crystals that do not exhibit cement-like fabrics; see fig. 21.) However, dolomitization *per se* had little effect on pore-system characteristics. This decoupling of fabric-selective dolomitization from pore-system modification is typical of the moldic pore facies.

Petrophysically the moldic pore facies is characterized by large pores, determined by former particle sizes (fig. 28), and relatively high pore/throat size (aspect) ratios. Pore size and shape are determined by the former particle boundaries; pores are commonly spherical to elliptical and several hundred micrometers across because the most common particles were peloids and ooids. Throat size and shape, by contrast, are determined by the characteristics of the rock framework. Chief among these factors is dolomite crystal size. Relatively large pores commonly translate into relatively large pore volumes for reservoirs dominated by moldic porosity. However, high aspect ratios, and the decoupling of porosity and throat size, mean that permeability values increase only slightly with increasing porosity values. This is illustrated by a porosity-permeability plot in which the slope of the least-squares regression line is low (fig. 30). Pore-throat shapes are variable, but sheetlike throats are most common.

Samples of reservoir strata assigned to the moldic pore facies tend to yield CP curves of classes 1 and 3. These CP-curve classes are characterized by leptokurtic throat-size distributions, by very large median throats, and by variable recovery efficiencies. Particle-moldic pore systems, consisting of delicate cement frameworks, are highly susceptible to collapse (possibly under the influence of tectonic stresses) and concomitant formation of collapsed-moldic fabrics (figs. 20 and 31). In extreme cases, cement-shard diagenetic grainstone may form, in which the rock consists primarily of fragments, or shards, of cement. Such rocks may be exceedingly permeable, because the intershard porosity can develop highly interconnected pore systems, which characteristically have large pore throats.

INTERCRYSTALLINE PORE FACIES

The intercrystalline pore facies is volumetrically dominated by intercrystalline pores (fig. 25), plots near the intercrystalline apex of a ternary pore plot (fig. 32), and characterizes strata that have been

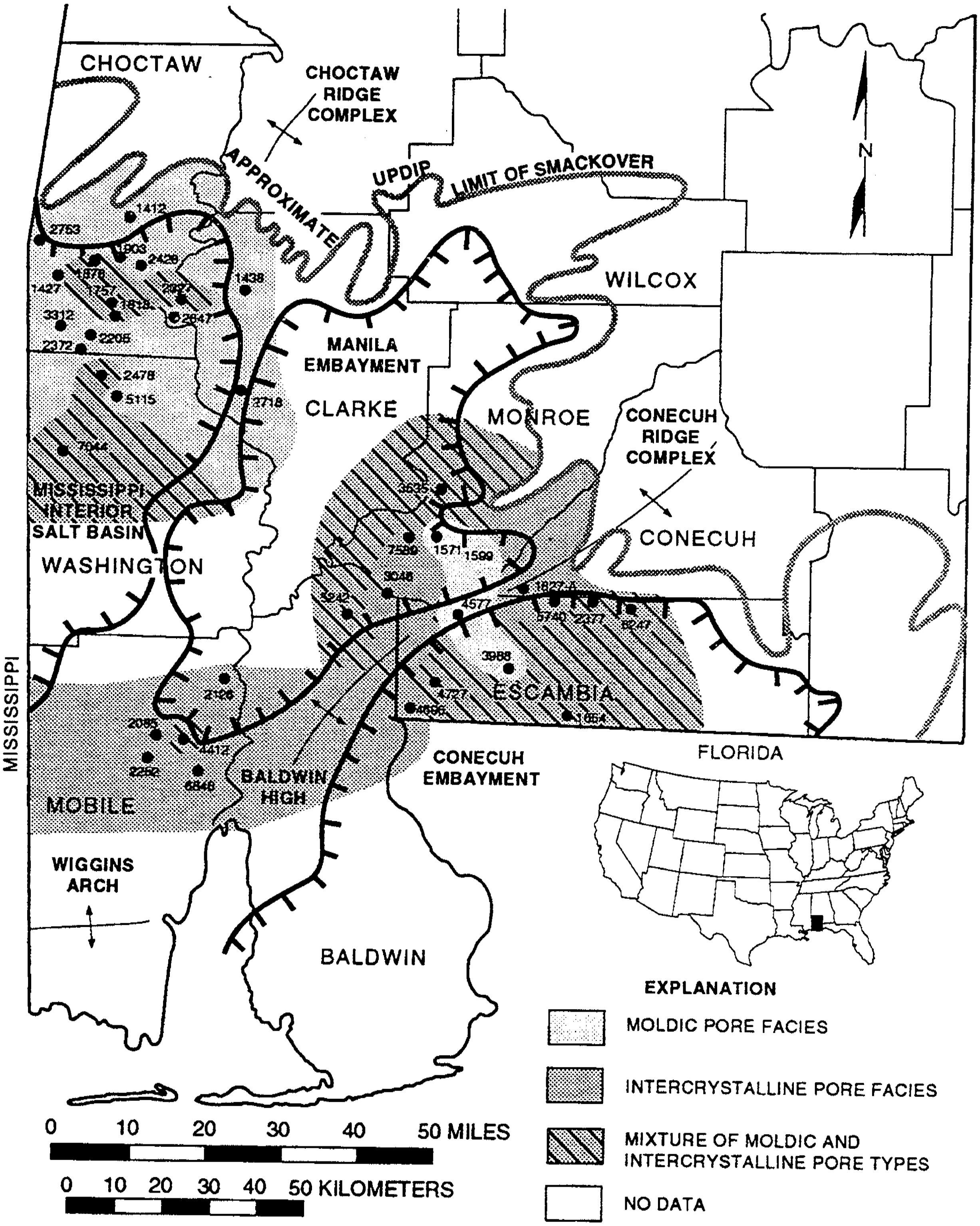


Figure 27.--Map of southwest Alabama showing the distribution of the moldic and intercrystalline pore facies, as well as regions characterized either by mixed pore systems, or by the co-occurrence of the two pore facies. The areas of no data contain few Smackover penetrations. Wells 1571 (Uriah field, Monroe County) and 7589 (North Wallers Creek field, Monroe County) contain quartzose sandstone reservoirs. (Modified from Kopaska-Merkel and Mann, 1991b.)

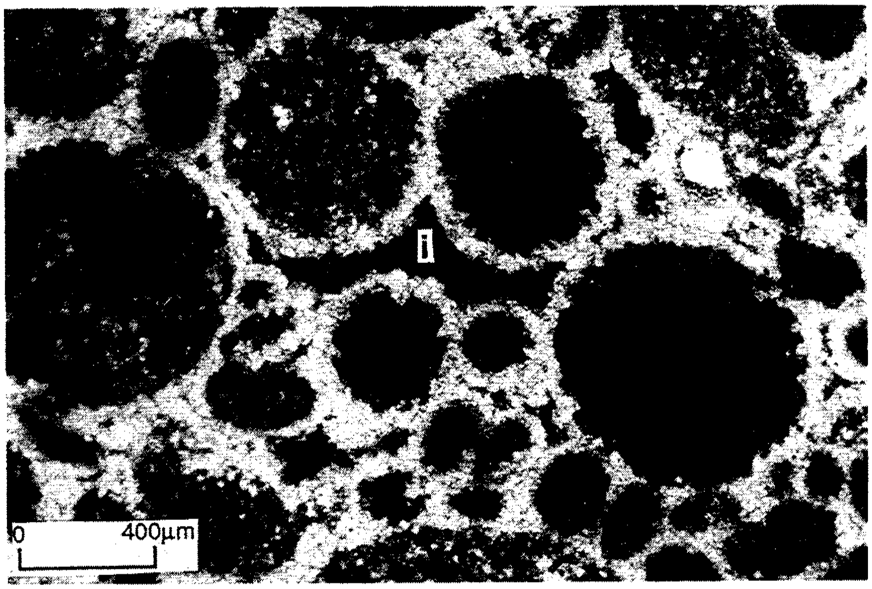


Figure 28.--Example of pore system dominated by moldic and interparticle pores. This rock consists primarily of dolomitized pore-rimming cement that forms a "dolomite-sponge" fabric. Partially dolomitized ooids and peloids now consist of porous dolomite-crystal frameworks enclosing secondary-intraparticle pores. Small interparticle pores were entirely filled with cement, whereas large interparticle pores were only rimmed with cement, and considerable interparticle porosity remains (e.g., letter "i" on figure). Dark areas are pores. Thin-section photomicrograph of peloid ooid dolograinstone from lithofacies 1 in Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,766 feet.

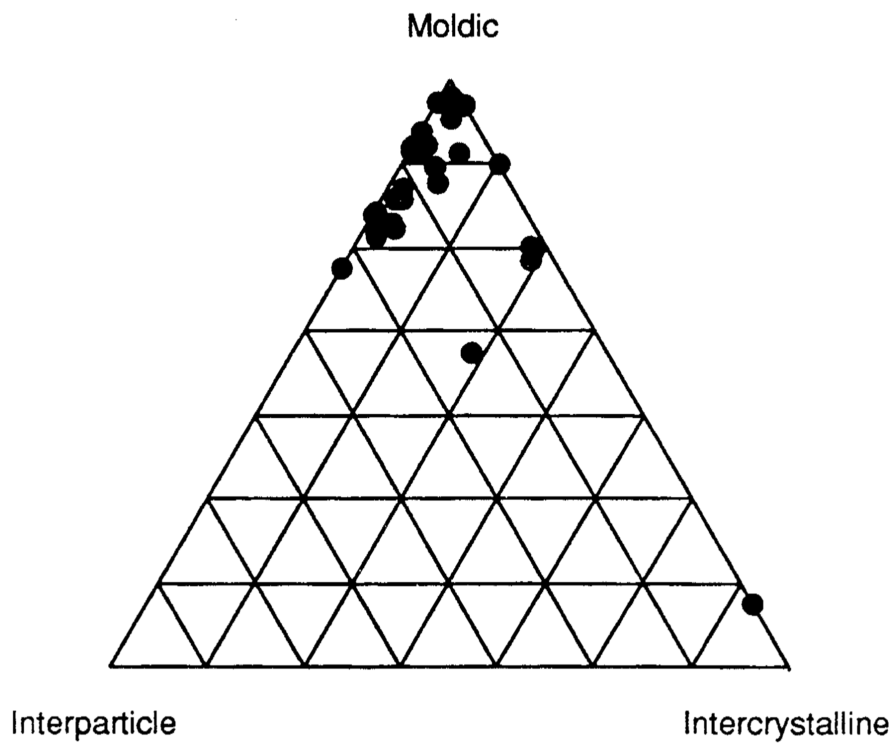


Figure 29.--Ternary pore plot of example of moldic pore facies. Permit No. 2205, Silas field, Choctaw County. One sample from the base of the permeable interval is dominated by intercrystalline pores (see also fig. 13).

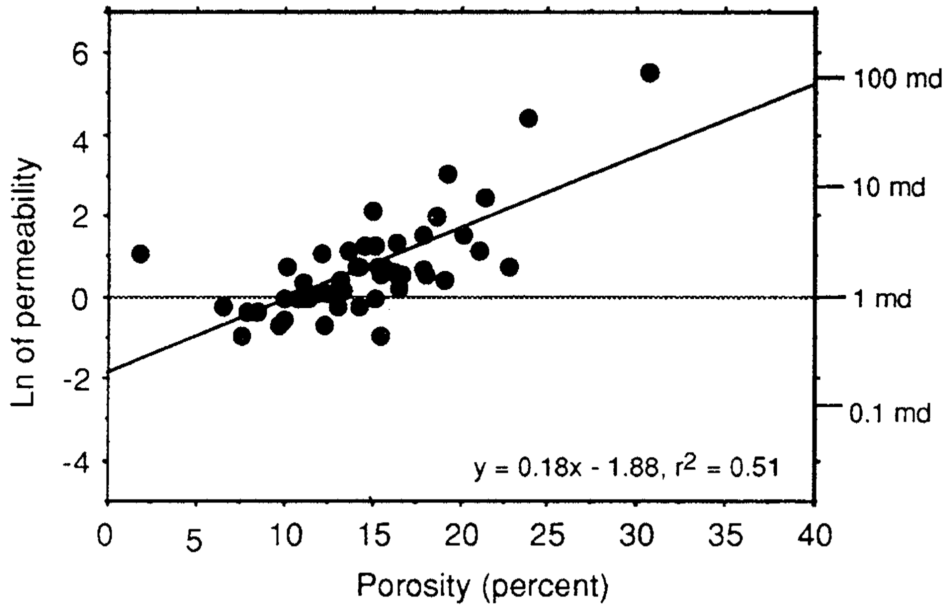


Figure 30.--Moldic pore facies, plot of porosity vs. natural log of permeability. Slope of regression line is less than for the intercrystalline pore facies. Permit No. 2426, Chappell Hill field, Choctaw County.

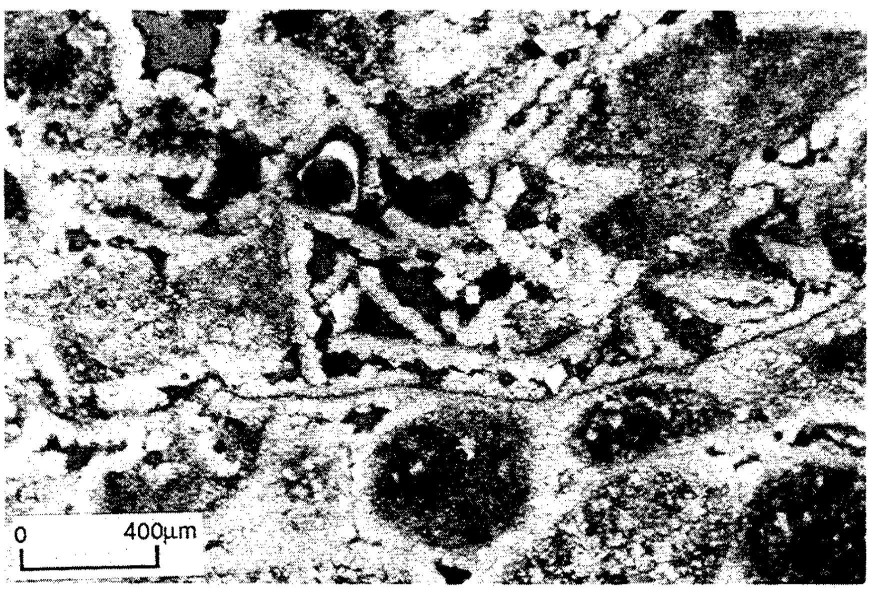


Figure 31.--Collapsed moldic fabric (center of photomicrograph) in ooid dolograinstone. Ooids, some with secondary intraparticle porosity, are separated by pore-rimming cement and relict interparticle porosity, most clearly seen on lower part of photomicrograph. Dark areas are pores. Thin-section photomicrograph, Permit No. 3312, Gin Creek field, Choctaw County, 13,454.5 feet.

pervasively nonfabric-selectively dolomitized. Primary rock fabric has less influence on the distribution of intercrystalline porosity than on other kinds of pores. (Subtle variation in dolomite-crystal size is commonly observed and may result from effects of primary rock fabric.) Dolomite in the intercrystalline pore facies is predominantly planar-e or planar-s, so pores are commonly polygonal and pore throats sheetlike.

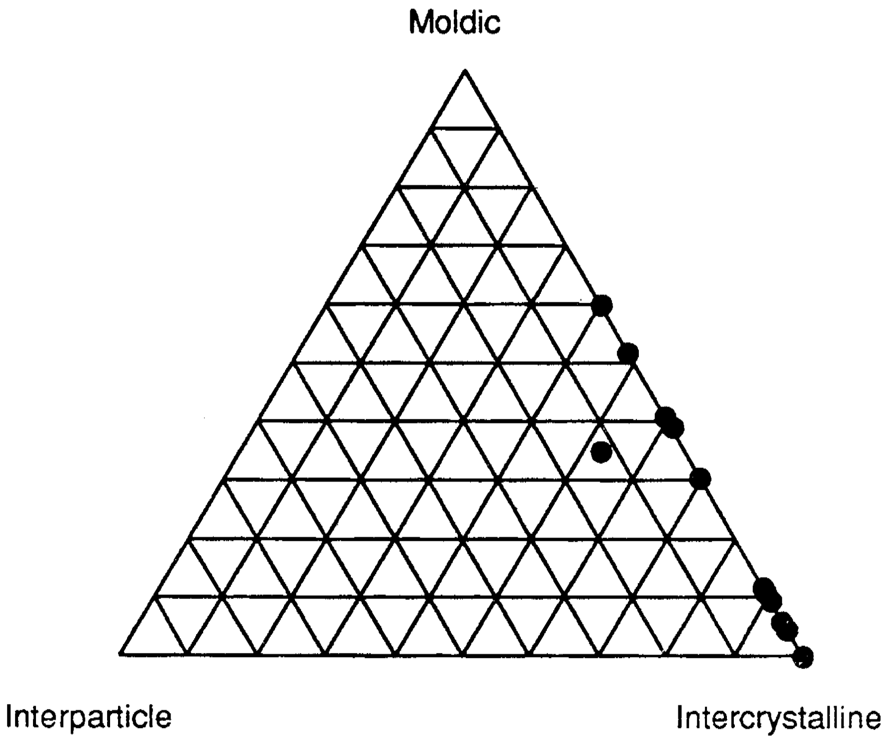


Figure 32.--Ternary pore plot of example of Intercrystalline Pore Facies. Permit No. 6846, Hatter's Pond field, Mobile County.

Pore volume in the intercrystalline pore facies is typically less than in the moldic pore facies. However the aspect ratio is also smaller, and a certain porosity value in the intercrystalline pore facies typically corresponds to a higher permeability than in the moldic pore facies. (Wardlaw and Cassan [1979] showed that a large aspect ratio strongly and adversely affects flow of nonwetting fluids.) Although the range of porosity and mean porosity of the intercrystalline pore facies is less than that of the moldic pore facies, the mean maximum permeability and maximum permeability range is higher in the intercrystalline pore facies (fig. 33). The slopes of least-squares regression lines of porosity on natural log of permeability are high (fig. 34) for the intercrystalline pore facies.

Samples from reservoirs assigned to the intercrystalline pore facies typically yield CP curves in class 4, which is characterized by mesokurtic throat-size distributions, large median throats, and intermediate recovery efficiencies. The differences between the two facies are much greater if samples with significant interparticle porosity are excluded from the moldic pore facies (fig. 33). (This point is discussed further in the section on heterogeneity within the moldic pore facies.)

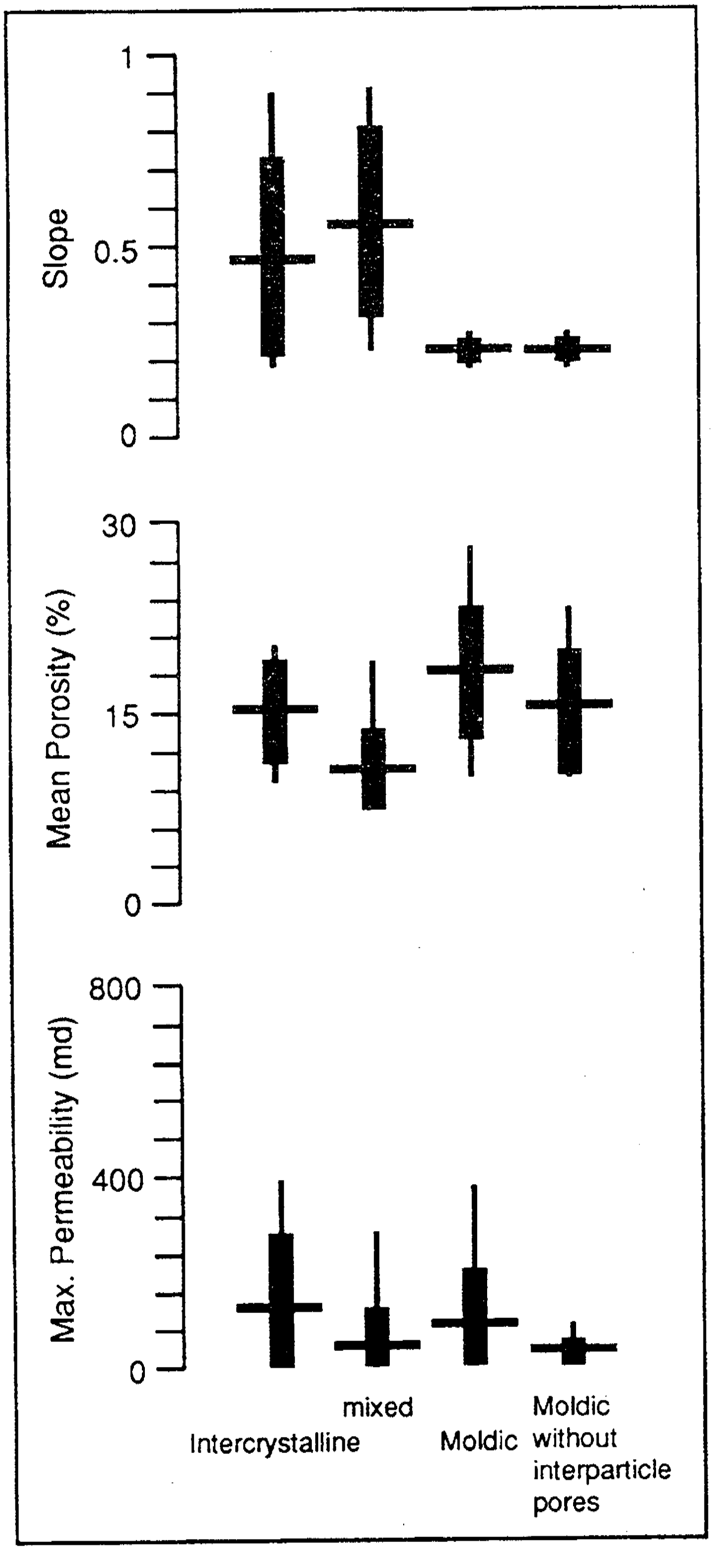


Figure 33.--Summary of some statistical parameters for Moldic and Intercrystalline pore facies mixed or intermediate samples, and for samples of the Moldic Pore Facies without interparticle pores. Horizontal bars are means, wide vertical bars are one standard deviation, and narrow vertical bars are ranges. Further discussion in text.

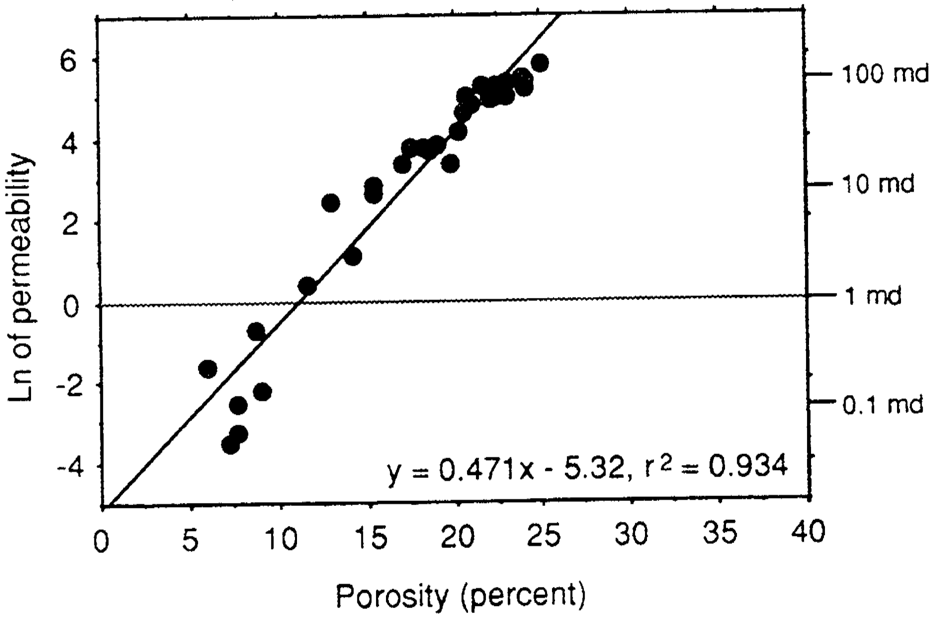


Figure 34.--Intercrystalline pore facies, plot of porosity vs. natural log of permeability. Slope of regression line is higher than for the moldic pore facies. Permit No. 4727, Big Escambia Creek field, Escambia County, lithofacies 1.

DISCUSSION OF PORE FACIES

COMPARISON OF PORE-FACIES CHARACTERISTICS

The two pore facies exhibit substantially different petrophysical characteristics (fig. 33). The mean slope of regression lines of porosity on natural log of permeability for the intercrystalline pore facies is 0.47, with a range of 0.19 to 0.90 (fig. 34). The mean slope for the moldic pore facies is 0.22 with a range of 0.18 to 0.27 (fig. 30). The higher slopes for the intercrystalline pore facies mean that in this pore facies permeability values may be more readily predicted from porosity data. Also, as mentioned in a previous section of this report, correlation coefficients for porosity vs. permeability are substantially higher in the intercrystalline pore facies, which contributes to improved accuracy and precision of prediction of permeability from porosity in the intercrystalline pore facies. Porosity values are commonly higher in the moldic pore facies, which has a range of mean porosity of 10.2 to 28.0 percent compared to 9.6 to 20.5 percent for the intercrystalline pore facies. Greater hydrocarbon volumes can be stored in reservoirs dominated by the moldic pore facies, but connectivity is better in the intercrystalline pore facies. The mean maximum permeability for the intercrystalline pore facies is 130 md; the corresponding value is 91 md for the moldic pore facies. High-permeability fluid conduits are more common in the intercrystalline pore facies than in the moldic pore facies.

In addition to the differences just mentioned, the moldic and intercrystalline pore facies exhibit distinctly different CP curves. Moldic pore facies CP curves (classes 1 and 3) are characterized by leptokurtic throat-size distributions, very large median throats, and variable recovery efficiencies, whereas intercrystalline pore facies curves (class 4) commonly exhibit mesokurtic throat-size distributions, large median throats, and intermediate recovery efficiencies. Thus, the most obvious difference is in the kurtosis of the throat-size distribution, but porosity values differ as well.

This analysis is supported by data reported by Melas and Friedman (1992) from Jay-Little Escambia Creek (LEC) field, Escambia County, Florida. (Jay-LEC is a single reservoir, but Melas and Friedman studied only the Florida portion, which is named Jay field.) Most of the Smackover reservoir in Jay-LEC field is dominated by intercrystalline pores and probably would be assigned to the intercrystalline pore facies. Moldic pores are common in a restricted interval in at least one well (Melas and Friedman, 1992). Capillary-pressure curves of class 4 appear to characterize the volumetrically dominant intercrystalline portion of the Jay-LEC field reservoir (e.g., Melas and Friedman, 1992, fig. 12). A CP curve of class 2, which is similar to class 4, was also observed by Melas and Friedman (1992, fig. 16, B). The minor moldic reservoir facies in Jay-LEC field is characterized by CP curves of class 3 (Melas and Friedman, 1992, fig. 17B). The relationship between CP-curve shape and pore facies in Jay-LEC field appears to be completely consistent with that observed for Smackover reservoirs in Alabama.

The pore facies also differ in the relationship between thermal maturity (R_o) and porosity. Porosity and R_o show a significant inverse correlation in the moldic pore facies:

$$\text{10th percentile } \phi = -14.013(R_o) + 14.785 \quad (r^2 = 0.437).$$

By contrast, the relationship between porosity and R_o in the intercrystalline pore facies is essentially nonexistent:

$$\text{10th percentile } \phi = 2.382(R_o) + 0.475 \quad (r^2 = 0.045).$$

The different relationships between R_o and porosity in the two pore facies are a function of the different diagenetic pathways that created the two kinds of reservoirs. Evidently, the nonmimetic dolomitization process that created intercrystalline reservoirs in the Alabama Smackover was not controlled by burial depth. This is not to say that dolomitization occurred syndepositionally at the surface. Rather, a single burial-dolomitization event seems to have affected most of the Smackover reservoirs in the southern part of the study area. The relatively slight differences in depth (or in thermal maturity) among these reservoirs had no effect on the extent of nonmimetic dolomitization.

A practical consequence of these relationships is that porosity values could be crudely predicted from R_o values in the moldic pore facies, but not in the intercrystalline pore facies.

Moldic and secondary intraparticle pores differ fundamentally from intercrystalline pores. This difference has a major effect on fluid-flow properties of pore systems dominated by one or the other of these two kinds of pores. Moldic (and secondary intraparticle) pore systems are heterogeneous on a microscopic scale because they consist of large pores (or clusters of relatively large pores) that are connected to one another by distinctly different (commonly finer) pore systems. The large pores are the particle molds, and the fine pores are found in the material that has filled the original interparticle primary porosity. In the Smackover, this material is commonly either dolomitized carbonate cement (by far the most common), dolomitized lime mud, or calcium carbonate cement (fig. 23). Note that pore sizes, but not necessarily pore-throat sizes, are inherently heterogeneous in the moldic pore facies. By contrast, intercrystalline pore systems are essentially homogeneous, because they are developed in rock fabrics that tend to consist of unimodal leptokurtic distributions of dolomite crystals that are all about the same shape (fig. 25). Moldic pore systems have a significant potential for trapping hydrocarbons within the large molds, because the high aspect ratio (pore/throat size ratio) at the interface between the molds and the surrounding much smaller intercrystalline pores puts stress on the continuous nonwetting phase (oil, in water-wet reservoirs) (Yu and Wardlaw, 1986a). This facilitates rupture of the continuous nonwetting phase, and isolated oil globules left behind in particle molds are permanently trapped. By contrast, in intercrystalline pore systems, aspect ratios are relatively low and uniform, and the potential for trapping is thereby diminished. However, under conditions of intermediate wettability, which may be fairly common in carbonate oil reservoirs, snap-off of nonwetting phase in high-aspect-ratio pore systems is inhibited (Morrow, 1990). This may be one of the reasons that Smackover advanced-recovery projects in moldic reservoirs commonly produce more oil than was expected (Hall, 1992).

The range of slopes of regression lines of porosity on natural log of permeability for the intercrystalline pore facies is much greater than for the moldic pore facies. The relationship between permeability and porosity is less variable in the moldic pore facies because fewer processes (i.e., cementation and dissolution) operate to produce the moldic pore facies, whereas a third process, nonfabric-selective dolomitization, is also important in the evolution of Interparticle Pore Facies. Dolomitization, as mentioned earlier, has had little effect on pore-system characteristics of the moldic pore facies. Furthermore, depositional lithofacies may be less variable in the moldic pore facies. The moldic pore facies is dominated by oolitic and peloidal grainstone, so the aspect ratio in this pore facies is relatively invariant. In the intercrystalline pore facies, however, all primary rock fabrics from mud-supported to particle-supported may be nonfabric-selectively dolomitized, producing a wide range in dolomite-crystal size. Crystal-size variation produces wide variation in pore sizes and probably in aspect ratios in the Interparticle Pore Facies. Nevertheless, porous and permeable strata assigned to the intercrystalline pore facies tend to be former grainstones and packstones (e.g., Bliefnick and Mariotti, 1988; Kopaska-Merkel and others, 1992, pages 280-290) rather than mud-supported rocks.

HETEROGENEITY WITHIN THE MOLDIC PORE FACIES

All high-permeability examples of the moldic pore facies contain substantial amounts of interparticle porosity. Interparticle pores are remnants of the primary rock-pore system that is commonly destroyed by marine-phreatic rim cementation in the Smackover of Alabama. As rim cement increases in thickness pore throats are closed off and permeability is rapidly reduced. However, if marine-phreatic cementation is prevented, or is interrupted at an early stage, commonly by exposure of the rocks to meteoric water, the coating of rim cement is thin and permeability values remain high. The results of the preservation of primary interparticle pore throats are dramatically shown in figure 33. The entire moldic pore facies has a mean porosity of approximately 18 percent. Excluding samples containing significant interparticle porosity, the mean porosity is only about 16 percent. However, mean maximum permeability is reduced by a factor of 3 and maximum permeability is reduced by a factor of 4 if samples having significant interparticle porosity are excluded. Clearly, high permeability values in the moldic pore facies are a function of the preservation of interparticle porosity. Most samples containing significant interparticle porosity are found near the Smackover subcrop or on paleohighs where meteoric water was available to shut off marine cementation. The part of the moldic pore facies lacking interparticle porosity is characterized by permeability values substantially less than those of the intercrystalline pore facies (fig. 33).

INTERMEDIATE PORE SYSTEMS

The two pore facies commonly intergrade to form mixtures, in which no pore type composes more than 60 percent of the total porosity. These mixtures are of two kinds. One kind of intermediate pore system consists of thin (millimeter to meter) layers characterized by either moldic or intercrystalline pores, intercalated with layers dominated by the other major pore type. These "intermediate" pore systems are heterogeneous on a macroscopic scale (levels 3 or 4; fig. 35 in this report), but on a microscopic scale they can be assigned to one pore facies or the other. The second kind of intermediate pore system is macroscopically homogeneous, but is heterogeneous at level 5, consisting of intimately commingled moldic, secondary intraparticle, and intercrystalline pores. These rocks are referred to as having mixed pore systems. For mapping purposes in the Smackover in southwest Alabama the two kinds of intermediate pore systems can be lumped together in an informal "intermediate pore facies," though to some extent this must obscure petrophysical differences between the two kinds of intermediate pore systems. In strata having mixed pore systems, "isolated" particle molds are commonly connected by networks of intercrystalline pores which control fluid-flow over macroscopic distances. Intermediate pore systems must experience a similar effect on a larger spatial scale.

Intermediate pore systems petrophysically resemble the intercrystalline pore facies in many ways. The slopes of regression lines of porosity on natural log of permeability for intermediate pore systems are similar to those for the intercrystalline pore facies (fig. 33). Maximum permeability values for intermediate pore systems are depressed, perhaps because the co-occurrence of pores and throats of varying sizes and shapes interferes with efficient drainage of fluids. Mean porosity values are lower in intermediate pore systems for reasons yet unknown.

CP curves derived from samples exhibiting intermediate pore systems span a range of shapes that encompass those of both moldic and intercrystalline pore facies (classes 3 and 4 are both common). Whereas in many respects intermediate pore systems resemble the pore systems of reservoirs assigned to the intercrystalline pore facies, in CP-curve shape they resemble both end-members. In addition, representatives of CP-curve class 5 are fairly common in samples with intermediate pore systems.

These curves are platykurtic or polymodal, with intermediate throat sizes and recovery efficiencies. These curves evidently result from mixtures at core-plug scales of two or more kinds of pore system.

Intermediate pore systems exhibit an R_o- ϕ relationship like that of moldic pore systems:

$$\text{10th percentile } \phi = -8.111 (R_o) + 13.324 \quad (r^2 = 0.548)$$

GEOGRAPHIC DISTRIBUTION OF PORE FACIES

Because pore types are determined by original depositional patterns (modified by diagenesis), rocks classified by dominant pore types are spatially segregated; this was demonstrated for the Smackover of Alabama by Benson (1985) and is confirmed by our work reported here and in Kopaska-Merkel and Mann (1991b). The spatial segregation of pore types permits mapping of pore facies. The moldic pore facies dominates to the northwest (Choctaw, western Clarke, and Washington Counties) and the intercrystalline pore facies to the south and east (Mobile, Monroe, Baldwin, Escambia, and Conecuh Counties) (fig. 27). Pore-facies distributions overlap in some areas (e.g., western Monroe County) and multiple pore facies occur in many Smackover fields (table 4). Areas characterized by the co-occurrence of the two pore facies are assigned to the informal "intermediate pore facies." Also assigned to this informal "pore facies" are reservoir rocks characterized by mixed pore systems.

The distribution of pore facies in the Smackover of southwest Alabama is congruent with variation in petrophysical parameters (e.g., average porosity, maximum permeability, pore-throat size distribution [CP-curve shape]) as is implied by the petrophysical differences between the pore facies. Pore-facies distribution is also congruent with variation in heterogeneity values (discussed in a following section) and with the distribution of large-scale paleogeographic features (see fig. 2).

RESERVOIR HETEROGENEITY

The ultimate volume of hydrocarbons recovered from a reservoir is strongly affected by the 3D shape (at all scales larger than the size of a small pore throat, about 0.01 µm) of the hydrocarbon-bearing pore system in that reservoir. Spatial variability within the pore system (reservoir heterogeneity) can have a significant effect on the ultimate volume of hydrocarbons recovered. Reservoirs that have little internal variability may produce up to 80 percent of the original oil in place (OOIP); more heterogeneous reservoirs tend to produce less (Geological Survey of Alabama, 1990). During primary recovery, extremely heterogeneous reservoirs may produce as little as 10 percent of the OOIP.

Geologic heterogeneity that controls the distribution and migration of oil within a reservoir is created by the same processes that molded the reservoir itself. Reservoir heterogeneity may be depositional, diagenetic, or structural and may occur on a variety of scales ranging from that of individual pores to fieldwide. Five levels of heterogeneity are based on the areal extent of units considered to be internally homogeneous (fig. 35) (Moore and Kugler, 1990, fig. 2, p. 3). At the largest scale, level 1, a reservoir is surrounded by nonreservoir rock. Features that affect fluid flow over distances greater than the average well spacing within a single reservoir are the homogeneous units of level 2 heterogeneity. Level 3 heterogeneity consists of differences between features that have areal extents less than the average well spacing in the region under consideration but considerably greater than the diameter of a well bore. Level 4 heterogeneity is concerned with features at the scale of a well bore or core. Level 5 heterogeneity occurs at scales of hundreds of pores and pore throats down to that of a single pore. When quantifying reservoir heterogeneity, one must account for heterogeneity at both large and small scales, because the two are not necessarily covariant.

Because pore-system topology, the proximate control of reservoir heterogeneity, is a product of the depositional, diagenetic, and structural history of a given reservoir, reservoirs with similar histories may have similar amounts and kinds of heterogeneity. Classification of reservoirs into trends on the basis of similarities in depositional, diagenetic, and structural histories may be useful in predicting reservoir heterogeneity.

Table 4.--Estimated percentages of pore types and pore facies, Smackover fields in southwest Alabama

Field	Percent moldic[1]	Percent interparticle	Percent intercrystalline	Percent other	Pore facies
Appleton	37	0	46	17	intermediate
*Barnett	41	0	56	3	intercrystalline
Barrytown	47	0	25	28	intermediate
Big Escambia Creek	30	0	52	18	intermediate
Blacksher	56	8	29	7	intermediate
Bucatunna Creek	88	10	0	2	moldic
Burnt Corn Creek	0	0	55	45	intermediate
Chappell Hill[2]	60	8	25	7	moldic
Chatom	58	0	42	0	intermediate
Choctaw Ridge	97	3	0	0	moldic
Chunchula[3]	1	0	99	0	intercrystalline
Crosbys Creek	93	7	0	0	moldic
East Barnett	16	0	83	1	intercrystalline
Gin Creek	90	10	0	0	moldic
Hatter's Pond[2]	33	0	62	5	intercrystalline
Healing Springs[2]	42	0	42	16	intermediate
Huxford	61	7	20	12	moldic
*Little Escambia Creek	84	1	14	1	intermediate
Little River	31	1	60	8	intercrystalline
Lovetts Creek	52	1	36	11	intermediate
Movico	35	0	65	0	intercrystalline
North Choctaw Ridge	42	7	37	14	intermediate
North Wallers Creek[4]	0	33	67	0	intercrystalline
Perdido	28	0	69	3	intercrystalline
Silas[5]	86	8	5	1	moldic
Sizemore Creek	78	0	0	21	moldic
Stave Creek	47	34	18	1	moldic[6]
Sugar Ridge	76	3	21	0	moldic
Toxey	84	1	7	8	moldic
Turnerville	54	0	46	0	intermediate
Uriah[4]	63	7	29	1	moldic
Vocation	69	4	25	2	moldic
West Barrytown	31	2	54	13	intermediate
West Bend	86	6	8	0	moldic
*Womack Hill	27	2	41	0	intermediate
Zion Chapel	67	10	21	2	moldic

*Note: 60 percent cutoffs were used to define pore facies for all but three fields. Except where noted, the estimated percentages are derived from core description. Barnett field appeared to be characterized by an intermediate pore system based on core examination, but thin sections revealed that most pores are intercrystalline. The core described from Little Escambia Creek field was dominated by molds, but published descriptions of this field indicate that the pore system is more typically intermediate. The core described from Womack Hill field was short and dominated by intercrystalline pores, but examination of numerous thin sections from this and other cores in the field suggests that the reservoir is intermediate.

[1]Including secondary intraparticle porosity.
[2]Percentages are rough estimates.
[3]From core of Permit No. 2218 only (the actual percentage of moldic pores is at least 10).
[4]Carbonate rock only.
[5]From thin-section examination.
[6]Interparticle porosity is counted with moldic porosity in this case.

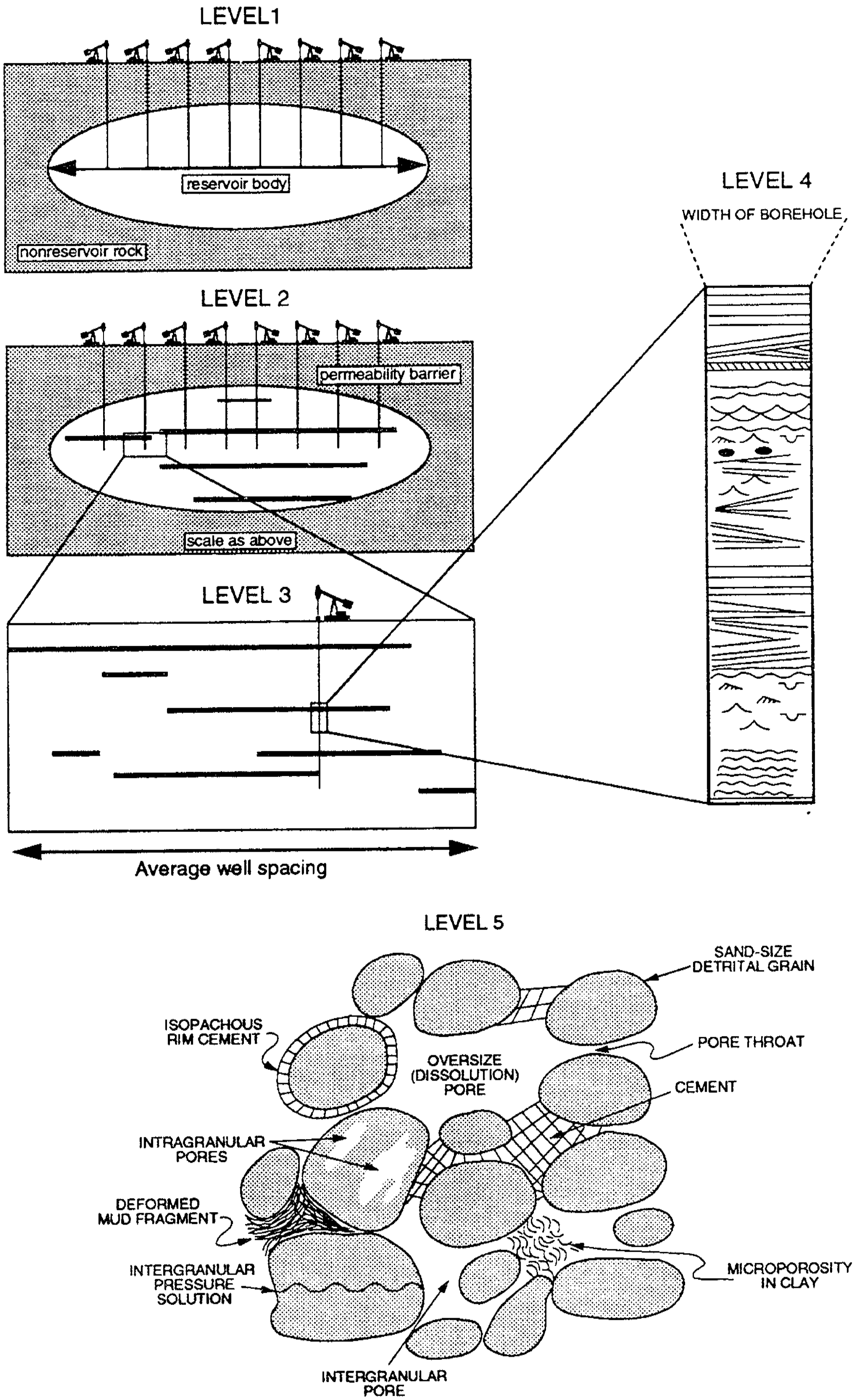


Figure 35. Levels of heterogeneity (Moore and Kugler, 1990, fig. 2, p. 3).

Reservoirs formed in different geologic settings exhibit different rock fabrics, and therefore, different hydrocarbon-recovery factors. Carbonate rock units tend to be less efficient hydrocarbon producers than siliciclastic rock units. This is because carbonate reservoirs tend to be more complex. Among carbonate reservoirs, the products of some depositional and diagenetic settings are more homogeneous (and produce a higher percentage of their contained hydrocarbons) than others. In other words, carbonate rock bodies differ systematically in the presence, abundance, and distribution of features that affect fluid flow. Finley and others (1988) ranked carbonate reservoirs formed in depositional settings ranging from supratidal flats to deep ocean basins on a scale of reservoir complexity from 1 to 10. Twelve categories were defined primarily on the basis of depositional setting. Diagenesis was considered as a factor affecting heterogeneity in three categories. The classification was based upon interpretations of rock characteristics. Smackover reservoirs in southwest Alabama can be assigned to at least four categories: evaporitic flats, dolomitized restricted platforms, open shelves, and oolitic bars and barriers.

One of the attractions of a depositional-setting based reservoir heterogeneity classification is the common perception that environment of deposition is easier to predict than what might be termed "diagenetic facies." In a general sense this is true, but strata deposited under similar conditions can and do develop extremely different pore systems. This is one of the limitations of a reservoir heterogeneity classification based on depositional setting. Reservoir heterogeneity is more accurately described by a classification based directly on the physical characteristics of the reservoir. This is the approach taken in the pore-facies classification presented in an earlier section of this report.

The classification of Finley and others (1988) consists of a fixed number of discrete categories. These categories were chosen by examination of a training set, a set of reservoirs that were deposited in a variety of depositional settings. The categories of which the classification is composed were named on the basis of what was found in the training set (450 oil reservoirs from Texas). When such a classification is applied to a new data set it may need to be modified to accommodate characteristics of the new data that were not found in the training set.

The classification of Finley and others (1988) was subsequently modified, and data from New Mexico and Oklahoma were added to the training set (ICF, 1989; DOE, 1990). The classification was further modified for the TORIS database by the Reservoir Classification Task Force (1990; fig. 36). Smackover reservoirs in Alabama fall into the restricted shelf category in the revised classification (they were assigned to four different categories in the original classification of Finley and others, 1988). This twice-revised classification is currently undergoing review by the DOE and by others, and additional revisions may be made (DOE, 1990). The instability of the classification, in which a given reservoir may change its pigeonhole each time the classification is revised, provides opportunities for error. Further, whenever a revision is implemented, terminology in the existing literature becomes obsolete.

The pore-facies classification described in this report was developed, like that of Finley and others (1988), using a training set. Both classifications consist of a fixed number of discrete categories. However, the pore-facies classification is based upon well-defined published criteria (pore types; Kopaska-Merkel and Mann, 1991b). Although the pore-facies classification would be of limited value in classifying reservoirs that are not dominated by moldic and/or intercrystalline pores, such reservoirs are uncommon, and the pore-facies classification may be generally applicable.

In this section, two semi-independent vertical heterogeneity parameters are defined, megascopic heterogeneity and microscopic heterogeneity, and are used to describe the distribution of vertical reservoir heterogeneity in Smackover hydrocarbon fields in southwest Alabama. The distribution of the Dykstra-Parsons coefficient, which is a measure of microscopic heterogeneity, is also described, and the results are compared to those of the other two measures. All three heterogeneity measures measure different aspects of reservoir heterogeneity (see figs. 38, 39, and 42); hence, all three may be of value in evaluating reservoir heterogeneity. These heterogeneity estimates, in combination with the pore-facies classification, provide simple estimates of the kinds and amounts of heterogeneity in Smackover reservoirs. Because all three components of heterogeneity (μH, MH, and DP coefficient) are distributed nonrandomly, the heterogeneity characteristics of a potential Smackover reservoir can be predicted in advance of the drill. A measure of lateral heterogeneity is also defined and related to variation in vertical heterogeneity, hydrocarbon type, and well spacing. These heterogeneity

I. Depositional Systems
- Lacustrine
- Peritidal
  - Supratidal
  - Intertidal
  - Subtidal
- Shallow Shelf
  - Open Shelf
  - Restricted Shelf
- Shelf Margin
  - Rimmed Shelf
  - Ramp
- Reefs
  - Pinnacle Reefs
  - Bioherms
  - Atolls
- Slope/Basin
  - Debris Fans
  - Turbidite Fans
  - Mounds
- Basin
  - Drowned Shelf
  - Deep Basin

II. Diagenetic Overprint
- Compaction/Cementation
- Grain Enhancement
- Dolomitization
- Dolomitization (Evaporite)
- Massive Dissolution
- Silicification

III. Structural Compartmentalization
- Natural Fracture Porosity
- Unstructured
- Faulted (normal, reverse, or strike-slip)
- Fault/Fold (normal, reverse, or strike-slip)
- Folded

Figure 36.--Classification of carbonate reservoir heterogeneity used in TORIS database.

measures may be applicable to Smackover reservoirs outside Alabama, and to other carbonate reservoirs as well.

Once the heterogeneity characteristics of a reservoir have been estimated, more detailed studies are required to identify the specific features that cause heterogeneity and to map their distribution in three dimensions. This was the subject of a study of Chunchula field (University of Alabama, 1991). In that study, poor reservoir performance under gas injection was attributed to the existence of uncontacted reservoir compartments. When heterogeneity is mapped in detail, it becomes possible to locate uncontacted reservoir, to target infill wells, to better identify the limits of the reservoir and locate step-out wells, and to define flow paths that will benefit enhanced- or improved-recovery programs. A better understanding of the factors controlling the distribution and movement of hydrocarbons in Smackover reservoirs will also help in identifying the most profitable development strategies.

VERTICAL RESERVOIR HETEROGENEITY

INTRODUCTION AND DISCUSSION OF PARAMETERS

Vertical heterogeneity in a carbonate reservoir is determined by the number and distribution of features occurring on a wide variety of scales. A ranking scheme for reservoir heterogeneity should ideally consider all possible features. From a practical standpoint, the scheme should use data that are readily available. Toward this end, the ranking scheme proposed here relies heavily on data obtainable from porosity logs and core analysis. Because permeability distribution is critical to reservoir performance, permeability data are used to estimate reservoir heterogeneity. If porosity logs have been calibrated to permeability using core data, then porosity logs as well as core data can be used to estimate heterogeneity. Another method is to estimate permeability from MTS using CP analyses of cuttings.

Because the distribution of reservoir heterogeneity is nonrandom, heterogeneity values in regions for which permeability data are not available can be predicted from reservoir-heterogeneity maps using geostatistics. (An example of this approach was described by the University of Alabama, 1991.)

For the purpose of this study, reservoir rocks were defined to include all strata having porosity values ≥ 6 percent and permeability values ≥ 0.1 md. Six parameters that appear to have the greatest influence on reservoir heterogeneity were measured or calculated for all fields for which the necessary data were available. (Additional parameters were also calculated but yielded no additional information.) These six parameters are:

1. Average Number of Reservoir Intervals (by well)
2. Average Number of High-Permeability Reservoir Intervals (by well)
3. Standard Deviation of Number of Reservoir Intervals (by well)
4. Standard Deviation of Porosity
5. Mean Permeability
6. Standard Deviation of the Natural Log of Permeability

The first three parameters were used to calculate megascopic reservoir heterogeneity (MH); the last three were used for microscopic reservoir heterogeneity (µH). All six parameters could be calculated for 31 fields; parameters 4 through 6 could be calculated for an additional 22 fields, making a total of 53 fields for which µH could be calculated (table 5). (Fewer fields provided MH values because at least two wells are needed to calculate parameter 3.) Microscopic and megascopic reservoir heterogeneity are separated because, as will be seen below, their spatial distributions are almost diametrically opposed. If the two scales of heterogeneity were measured by a single equation, then their opposite distributions would be obscured.

Before the results of the heterogeneity calculations are described, the reasons for choosing the parameters used in the equations are given, beginning with MH.

The equation for megascopic reservoir heterogeneity (MH) employs the first three parameters listed above:

$$[(\#\text{ of reservoir intervals}) + (\#\text{ of high-K reservoir intervals}) + (\sigma \text{ of } \#\text{ of reservoir intervals})].$$

Many other parameters could be employed to calculate MH, such as average reservoir-interval thickness, average thickness of high-permeability reservoir intervals, standard deviation of the number of high-permeability reservoir intervals, standard deviation of reservoir-interval thickness, or

Table 5.--Parameters used to calculate reservoir heterogeneity and three reservoir-heterogeneity factors

Field	mean phi	sd phi	mean ln k	sd ln k	µH	MH	#res. int.	#high k res.	stdev # res.	DP coeff.
Appleton	10.6	3.1	1.25	1.39	1.37					0.96
Barlow Bend	12.6	5.6	0	2.99	2.30					0.95
Barnett	9.7	2.5	0.22	2.16	1.36	8.34	3.67	2.33	2.34	0.88
Barrytown	18.9	4.2	2.02	0.97	1.51	3.25	1.5	0.75	1	0.63
Big Escambia Creek	14.1	4.5	0.64	2.03	1.60	10.1	4.7	2.63	2.71	0.92
Blacksher	11.6	4.27	1.19	2.41	1.96	13.5	5.29	3.71	4.46	0.95
Broken Leg Creek	11.7	3.2	1.5	2.12	1.83					0.94
Bucatunna Creek	18	5.6	0.46	1.2	1.22	6.62	1.5	3	2.12	0.76
Chappell Hill	16.2	4.9	1.29	1.65	1.66	4.91	2.67	1.67	0.58	
Chatom	20.7	6.24	1.62	0.54	1.83	9.54	4.5	3.75	1.29	0.93
Choctaw Ridge	19.4	5	3.06	1.62	2.25	3.16	1.4	0.8	0.96	0.80
Chunchula	12.9	3.6	0.44	1.69	1.29	5.66	2.75	1.64	1.27	0.87
Cold Creek	9.9	3.7	0.01	1.85	1.24	9.65	4	3	2.65	0.86
Copeland	15.6	5.8	0.69	1.6	1.51					0.82
Crosbys Creek	21.4	9.2	-0.52	1.33	1.26	5.73	2	2	1.73	0.79
Fanny Church	12.7	3.7	0.18	1.96	1.35	10.2	4.88	1.53	3.82	0.85
Hatter's Pond	13.4	4	0.99	1.75	1.54	7.17	2.68	2.32	2.17	0.90
Huxford	9.8	2.5	2.04	2.36	2.07	10.5	4.75	2.75	2.99	0.91
Little Escambia Creek	12.7	3.9	0.07	1.95	1.32	9.54	4	1.8	3.74	0.90
Little Mill Creek	24.1	5.8	4.6	2.41	3.22		1	0		0.92
Little River	11.8	4.3	1.68	2.61	2.22					0.96
Lovetts Creek	9.5	2.4	0.81	1.66	1.30	12	4.4	3.6	3.97	0.91
Melvin	20.3	3.4	3.32	1.47	2.13					0.83
Mill Creek	20.6	5.8	2.82	2.15	2.50	2.11	1	0.4	0.71	0.89
Mineola	14.6	3.4	3.01	1.52	2.05					
Movico	17.2	4.8	2.81	1.46	2.07	2.21	1.5	0		0.91
North Choctaw Ridge	20.3	5.6	2.68	1.43	2.08	3.89	1.89	1.22	0.78	0.95
North Wallers Creek	12.9	2.8	2.12	1.62	1.75					0.954
Northwest Range	9.2	2.0	0.56	1.77	1.24					
Pace Creek	17.3	7.18	2.56	2.66	2.78					
Palmers Crossroads	16.3	5.3	2.29	2.20	2.31					0.955
Perdido	10	1.6	0.2	1.34	0.87	3.91	1.33	2	0.58	0.84
Puss Cuss	21.3	7.4	1.79	1.49	1.96					0.78
Red Creek	19.6	7.8	1.28	1.95	2.05		1	1		0.93
Robinson Creek	10.4	4.3	0.3	2.01	1.46					
Southeast Chatom	22.4	6.7	0.76	1.66	1.64	6.5	3	3.5	0	0.87

Table 5.--Parameters used to calculate reservoir heterogeneity and three reservoir-heterogeneity factors—Continued

Field	mean phi	sd phi	mean ln k	sd ln k	µH	MH	#res. int.	#high k res.	stdev # res.	DP coeff.
Silas	15.9	6.7	0.44	1.99	1.70	7.8	3	1.33	3.46	0.87
Sizemore Creek	13.5	4.4	0.19	2.2	1.53					0.87
Stave Creek	15.9	4.4	2.1	1.94	2.04	6.98	2.33	2.33	2.31	0.92
Sugar Ridge	19.5	7.1	2.22	1.69	2.18	6.13	3	1.5	1.63	0.96
Southwest Barrytown	17	6.1	2.05	2.5	2.44					0.74
Turkey Creek	20.6	4.4	3.85	1.12	2.21					0.69
Uriah	10.8	2.9	2.83	2.09	2.23					0.78
Vocation	12.4	3.9	2.52	2.11	2.22	9.61	3.92	3.08	2.61	0.97
Wallace	9.5	2.51	-0.3	1.71	0.96					
Wallers Creek	12.7	3.8	1.16	1.98	1.69	4.49	1.67	1.67	1.15	0.92
West Appleton	13.3	4.6	3.02	1.86	2.32					
West Barrytown	18.9	3.6	2.72	1.32	1.87	5.39	2.25	1.25	1.89	0.74
West Bend	14.8	3.7	1.32	1.94	1.72	5.96	2.25	2	1.71	0.95
Wild Fork Creek	11.2	2.5	0.9	1.25	1.13					0.77
Wimberly	19.8	6.6	2.11	1.59	2.05	4.53	2.33	0.67	1.53	0.80
Womack Hill	18.5	4.4	2.28	1.48	1.87	6.14	2.58	1.79	1.77	0.96
Zion Chapel	19.5	7.4	1.98	1.64	2.10	4.53	2.33	0.67	1.53	0.82

numbers or thicknesses of very high permeability reservoir intervals (e.g., greater than 10 md permeability, greater than 100 md permeability, etc.). None of these parameters were used to calculate MH for two reasons. First, all the parameters listed, as well as innumerable others like them, are closely correlated with parameters 1, 2, and 3. Thus, adding them to the equation for MH would scarcely reduce the unexplained variance in MH. The effort of collecting the additional data would yield little return. Second, the three parameters chosen were those for which the largest number of fields possessed the requisite data for the calculation of MH. Addition or substitution of any of the alternative parameters listed above would have greatly reduced the number of fields for which MH could be calculated.

The equation for microscopic reservoir heterogeneity employs the last three of the six parameters listed above:

$$(\mu H) = \{[(0.25\sigma\phi) + (\text{mean of natural log of K}) + (1.5\sigma \text{ of natural log of K})]/3\}.$$

As with MH, other parameters could have been used, such as maximum porosity, maximum permeability, and mean porosity. However, in the calculation of µH it is important to include only appropriate parameters. For example, mean porosity has been used by others to calculate reservoir heterogeneity. But mean porosity is not directly related to the ability of the formation to produce hydrocarbons efficiently. It is not how much of a rock is empty space that determines how easy it is to remove the contained fluids, but rather how variable and how coarse the pore system is. Some of the most variable pore systems on a microscopic level (level 5) are moldic pore systems, because of their inherent bimodality and high aspect ratios (discussed in previous sections). Moldic reservoirs are also the most porous (fig. 37). However, some relatively low-porosity pore systems are also quite variable, because of high-amplitude variations in both porosity and permeability. Yet another problem with using mean porosity is that, despite the differences between high-porosity pore systems and highly variable pore systems, mean porosity is strongly correlated with standard deviation of porosity (r^2 = 0.64). Therefore, only one of these two parameters should be used to avoid unintentional weighting of the result. It is more appropriate to use the standard deviation of porosity, which is directly related

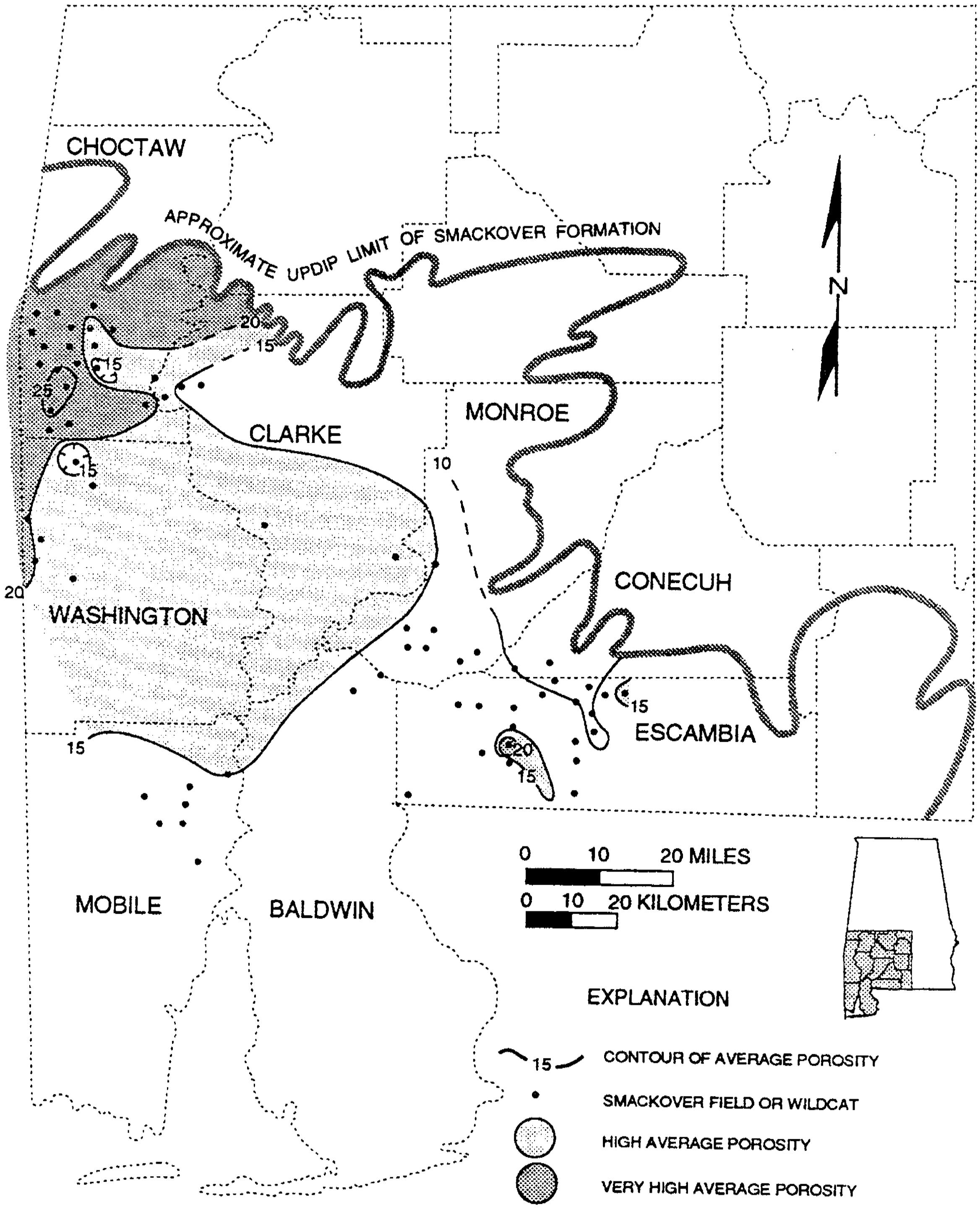


Figure 37.--Map of average porosity of Smackover fields, southwest Alabama. Average porosity values are highest in southern Choctaw County and substantially lower to the south and east on the north flank of the Wiggins arch and the Conecuh ridge complex, and in the Conecuh embayment. The distribution of average porosity values closely parallels the distribution of reservoir types in the Smackover (compare fig. 27, which shows the distribution of pore facies in Smackover reservoirs). Moldic reservoirs, which are less severely altered than intercrystalline reservoirs, are, on the average, more porous. Diagenetic control of porosity development is suggested by the lack of correspondence of variation in average porosity values to paleogeography, structural boundaries, or to depositional setting. Porosity in percent; contour interval=5 percent. Dots are Smackover fields (see fig. 35). Data taken from Bolin and others, 1989.

to variation in pore-system characteristics. Maximum porosity and maximum permeability are highly unstable measurements, because they are strongly affected by single outlying data points; for this reason, these two parameters were rejected.

μH is not, strictly speaking, a measure of vertical heterogeneity, because data from all wells within a field are lumped together to generate this parameter. However, because wells are thousands of feet apart whereas samples from a single core are 1 foot apart, μH is more strongly affected by vertical heterogeneity than by lateral heterogeneity. μH is primarily a measure of one aspect of vertical heterogeneity.

Another kind of parameter might be used to estimate microscopic heterogeneity. This class of parameters includes median pore-throat size and other measures of pore-throat size distribution that are derived from capillary-pressure measurements. However, these data are expensive to collect and are generally available only from a few wells. For this reason, they are not used to estimate heterogeneity. If large amounts of capillary-pressure data are available, then some measures of the dispersion of pore-throat sizes could be useful in estimating microscopic heterogeneity, for they are directly related to the efficiency of production of nonwetting fluids.

MEGASCOPIC RESERVOIR HETEROGENEITY

The numbers of reservoir intervals, numbers of high-permeability reservoir intervals, and the standard deviation of the numbers of reservoir intervals measure large-scale (levels 3 and 4; see fig. 35) heterogeneity defined by depositional, diagenetic, and structural setting. These three parameters are summed in the calculation of megascopic reservoir heterogeneity (MH): [(# of reservoir intervals) + (# of high-K reservoir intervals) + (σ of # of reservoir intervals)].

Reservoirs belonging to the moldic pore facies tend to be vertically homogeneous at large scales (low values of MH), whereas reservoirs assigned to the intercrystalline pore facies are characterized by relatively high values of MH. Intercrystalline reservoirs may be heterogeneous at large scales because the process of nonfabric-selective dolomitization was patchy on a vertical scale of meters to tens of meters. This process was also patchy horizontally as indicated by lateral variation in petrographic parameters within Chunchula field, Mobile County (University of Alabama, 1991). By contrast, moldic reservoirs are relatively homogeneous vertically at meter to decameter scales, indicating that sedimentary features such as dunes, bars, beach foreshores, spits, and channels (at least some of which have been recognized in cores of moldic reservoirs; Kopaska-Merkel and others, 1992) may have exerted relatively little influence on reservoir heterogeneity. Hence, carbonate depositional microfacies patterns may be crude predictors of reservoir distribution.

The distribution of MH values is shown by figure 38. MH values are high on the north flank of the Wiggins arch, on the Conecuh ridge complex and in the Conecuh embayment. MH values are low near the Choctaw ridge complex. The Conecuh ridge complex is characterized by high values of both microscopic and megascopic heterogeneity; it is the only major structural feature in southwest Alabama for which this is true. The boundaries of regions of low or high MH values do not correspond to the boundaries of major structural features.

A low-relief paleogeographic high, a salt-cored anticline that extends southward from the vicinity of Silas field in southern Choctaw County to Chatom field in west-central Washington County (see fig. 1), is characterized by relatively high values of MH. This anticline did not exist during most of Smackover time, for it is superimposed on a thick westward-thickening wedge of Smackover strata (see fig. 3), which do not thin on the crest of the salt-cored anticline. However, the anticline's crest is marked by the development of uppermost Smackover sabkhas on local highs. Typically, 10 feet or less of sabkha deposits are overlain by 20 to 40 feet of peritidal carbonates, including reservoir rock, which in turn are overlain by basal Buckner saltern deposits. These relationships indicate that the salt-cored anticline began to form in latest Smackover time (Mann and Kopaska-Merkel, 1992). Diagenesis seems to have strongly affected MH, as indicated by the geographic correspondence between pore facies and MH values (see fig. 27).

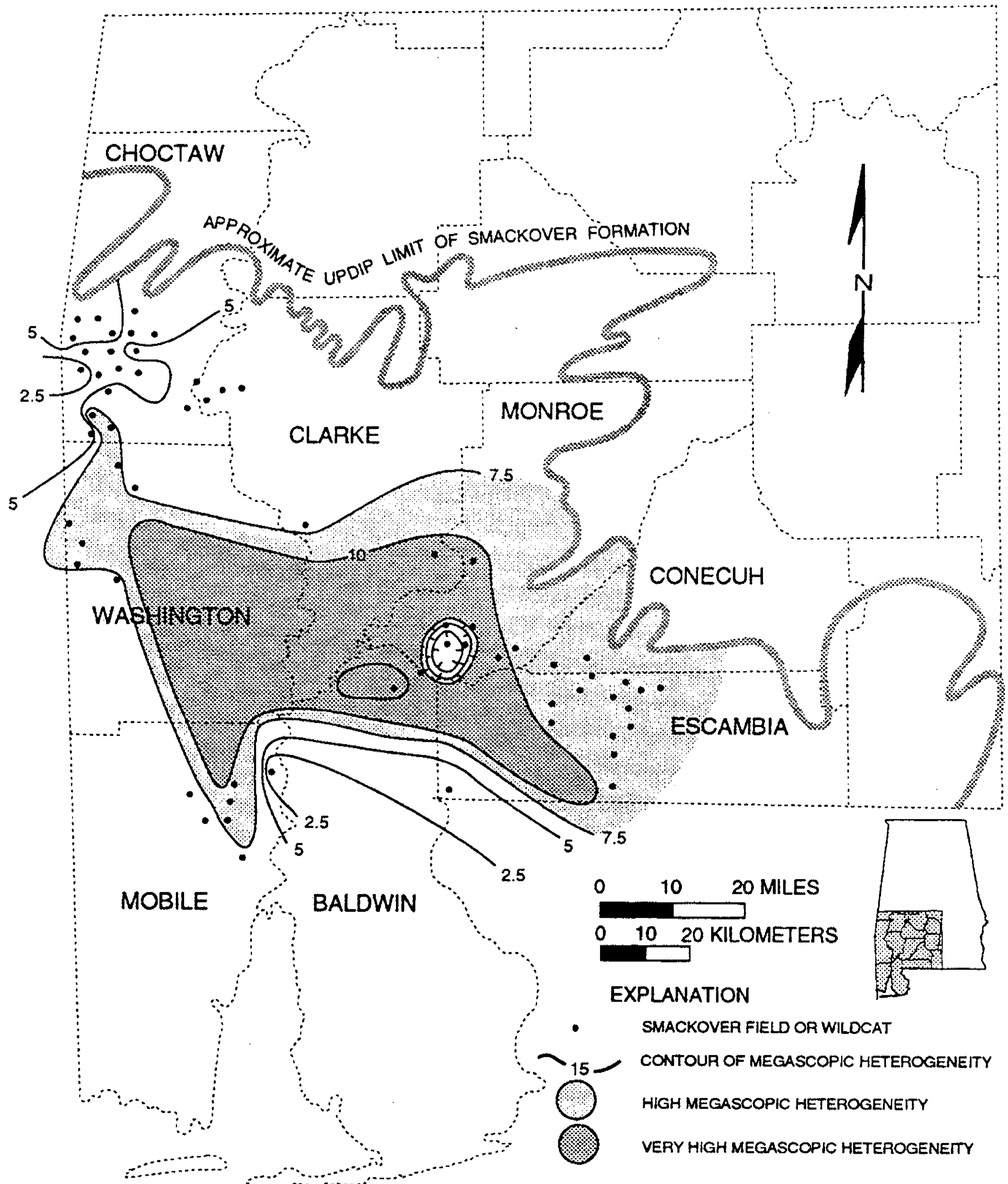


Figure 38.--Map of megascopic reservoir heterogeneity (MH) of Smackover fields, southwest Alabama. The geographic pattern of MH variation is roughly opposite to that of microscopic reservoir heterogeneity. High values characterize the entire southern part of the study area except just south of the Baldwin high. A slender promontory of heterogeneous reservoirs projects northward from the central part of the Mississippi interior salt basin towards the Choctaw ridge complex. This area is the site of a linear salt ridge that already possessed significant relief during late Smackover time (Mann and Kopaska-Merkel, 1992). Dimensionless; contour interval = 2.5. MH is calculated from commercial permeability data.

MICROSCOPIC RESERVOIR HETEROGENEITY

Microscopic reservoir heterogeneity (μH) is based upon the standard deviation of porosity, the mean of natural log of permeability, and the standard deviation of natural log of permeability: $\{[(0.25\sigma\phi)+(\text{mean of natural log of K})+(1.5\sigma \text{ of natural log of K})]/3\}$. These parameters all measure variation in pore system characteristics at small scales (level 5 heterogeneity; see fig. 35). In the equation for μH, the standard deviation of porosity is multiplied by 0.25. This fractional weighting is performed because (1) porosity values cover a wider range than do values of the natural log of permeability (table 5), and (2) porosity variation is less critical to reservoir heterogeneity (has a lesser effect on producibility of hydrocarbons) than the permeability value. Hydrocarbon production efficiency is more sensitive to variation in permeability than to variation in porosity. Similarly, the standard deviation of natural log of permeability is multiplied by 1.5, which increases its contribution to μH. This is because changes in the amount of variation in permeability have a greater effect on hydrocarbon production, through mechanisms such as bypassing of oil in regions of lower permeability, than does a simple shift in permeability distribution. The particular weights chosen are, of necessity, somewhat arbitrary.

The distribution of μH values in the Smackover of southwest Alabama is shown by figure 39. In the following paragraphs, the pattern of H variation is discussed in more detail.

μH values are high in moldic reservoirs and low in intercrystalline reservoirs. This may result from the fundamentally heterogeneous nature of moldic pore systems (in which large pores are juxtaposed with small throats) compared to intercrystalline pore systems. However, the definition of μH contains no reference to pore type. μH is simply a function of porosity and permeability variation. Perusal of figures 37, 40, and 41 reveals that high values of porosity and permeability, but not of the standard deviation of permeability, are responsible for the high values of μH in the northwestern part of the study area.

Movico and Hatter's Pond fields (Baldwin and Mobile Counties, and Mobile County, respectively; see fig. 1) have substantially higher values of μH than do nearby fields. Movico reservoir differs from its neighbors in other ways as well: MH (fig. 39), thickness of the Smackover (fig. 3), average porosity (fig. 37), mean K (fig. 40), and σ of K (fig. 41). Both Movico and Hatter's Pond fields differ from their neighbors in their values of the Dykstra-Parsons coefficient (fig. 42) and of the standard deviation of porosity (fig. 43). These two fields are structurally different from their neighbors (their traps are genetically related to the Mobile graben). They are also the most easterly of the fields on the north flank of the Wiggins arch, which may be significant if regional paleogeography had a noticeable effect on pore-system development. Whatever the cause(s), fields associated with the southern part of the Mobile graben, especially Movico field, exhibit dramatically different reservoir characteristics from nearby fields on the north-facing distally-steepened ramp that forms the north flank of the Wiggins arch. Specifically, the ramp fields are less porous and less permeable, but also less heterogeneous (microscopically), than the Mobile graben fields.

Smackover reservoirs in southern Choctaw County display regional patterns of μH that seem to be controlled by paleogeographic setting. Two north-south regions of high and low μH cut across the peripheral fault trend (fig. 39), but are subparallel to the buried Choctaw ridge complex immediately to the north (Wilson and others, 1980). The region characterized by higher values of μH overlies a basement ridge, and the region characterized by lower values of μH overlies a trough on the basement surface (fig. 39; Wilson and others, 1980).

μH, like MH, exhibits high values on the crest of the early formed salt-cored anticline in western Washington County. This is because the reservoirs there are moldic (and are microscopically heterogeneous) and the early salt movement and sabkha formation in the upper Smackover helped create compartmentalized reservoirs.

Uriah and Palmers Crossroads fields are neighbors characterized by high values of μH. Another field in this area, North Wallers Creek field, has a moderately high value of μH. The reservoir at Uriah field consists of intercalated sandstone and dolostone, that at Palmers Crossroads field contains both carbonate and siliciclastic components (based on interpretation of geophysical logs), and that at North Wallers Creek field is dolomitic sandstone. A nearby field, Barnett, contains intercalated dolomitic sandstone and dolostone, but the reservoir consists entirely of dolostone. It seems that a

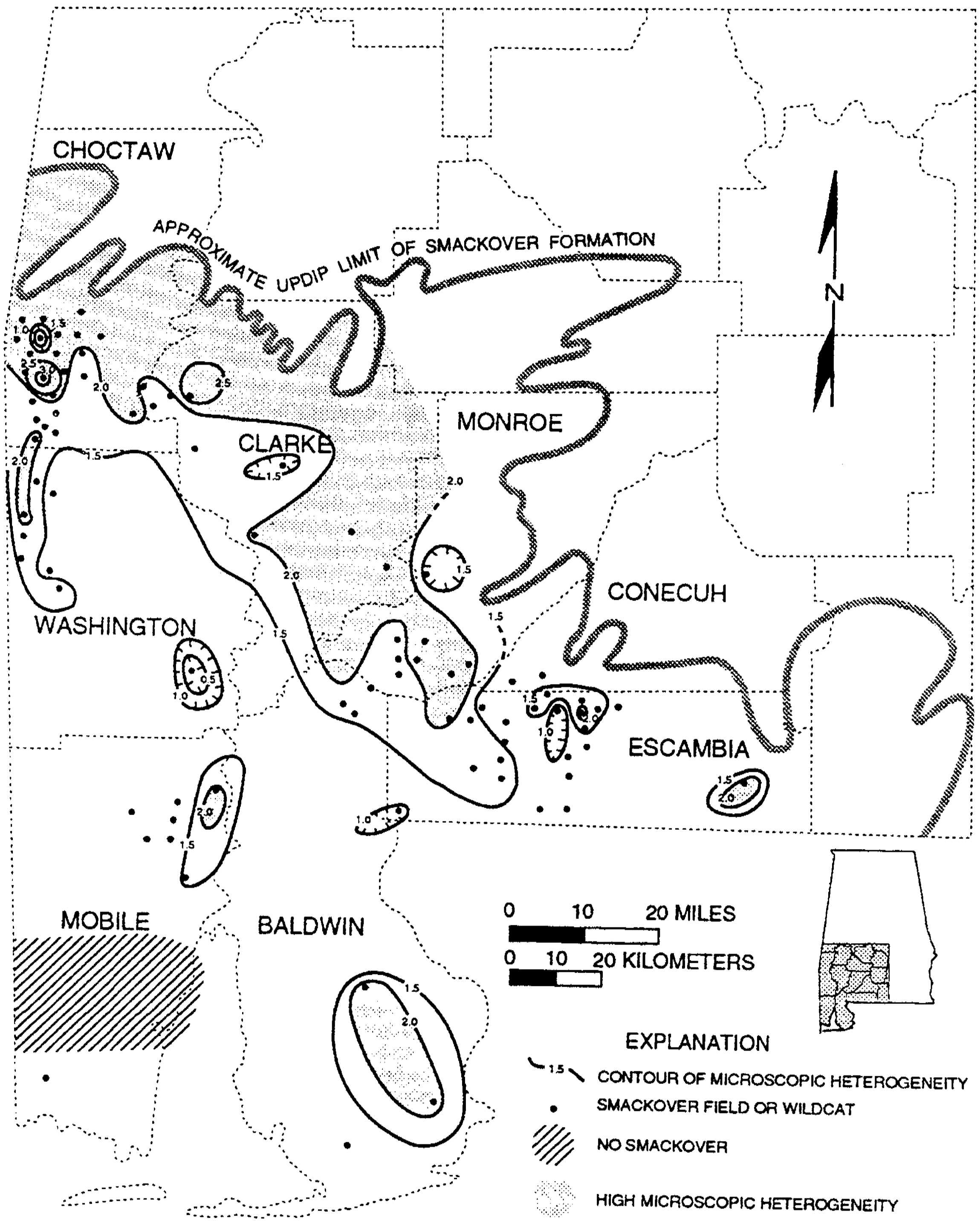


Figure 39.--Map of microscopic reservoir heterogeneity (μH) of Smackover fields, southwest Alabama. μH is highest in southern Choctaw County and diminishes smoothly to the south and east. Uniformly low values typify the north flank of the Wiggins arch and the Conecuh embayment. High-frequency variation in H in southern Choctaw County may be related to the effects of paleotopography (the Choctaw ridge complex) on petrophysical characteristics of Smackover reservoirs. High μH in the upper Manila embayment probably results from the mixing of siliciclastic and carbonate sediment in the Smackover there and concomitant increase in reservoir complexity. Dimensionless; contour interval=0.5. μH is calculated from commercial porosity and permeability analyses of core plugs.

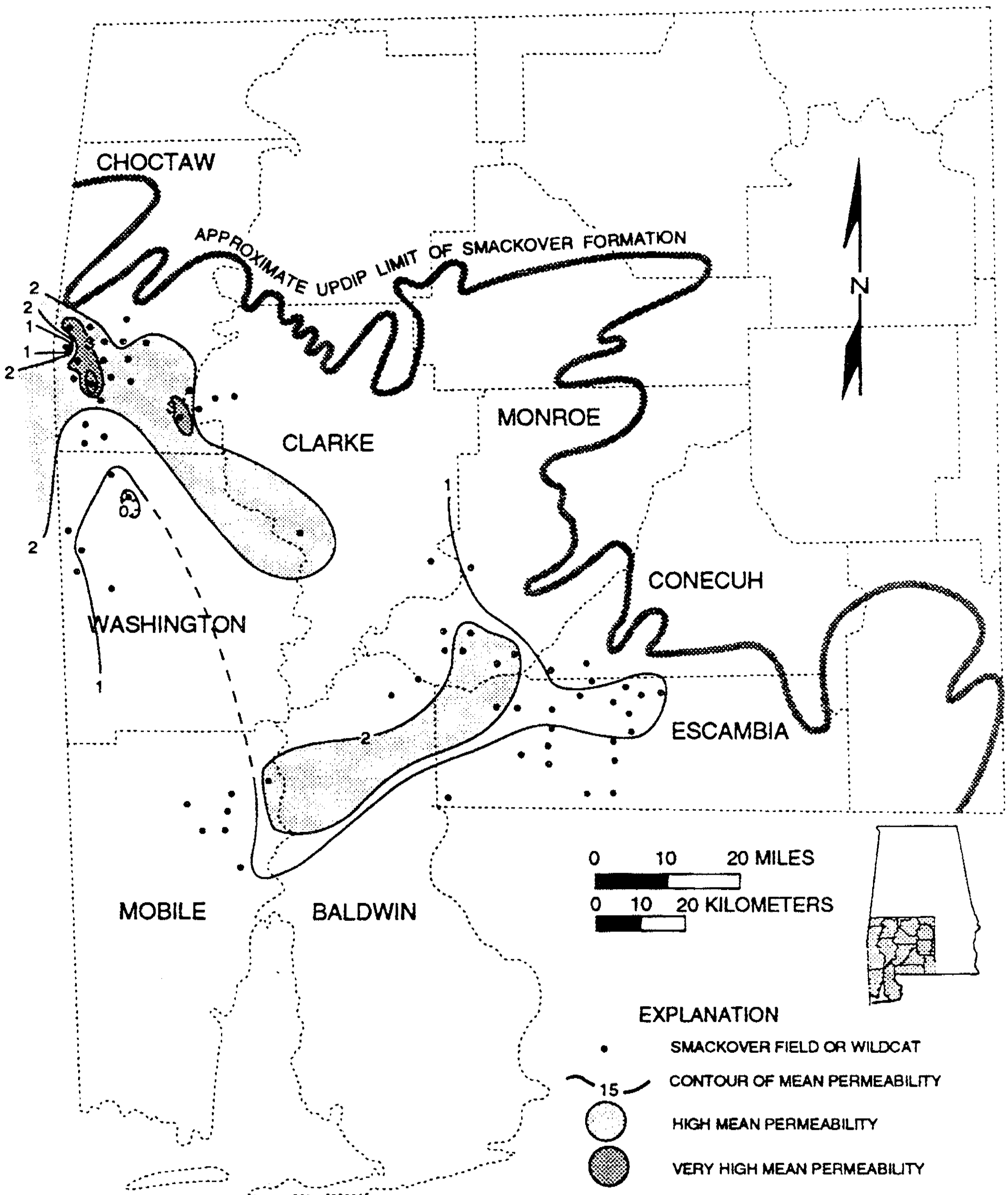


Figure 40.--Map of mean permeability of Smackover fields, southwest Alabama. The distribution of mean permeability is similar to that of average porosity (fig. 37). The most obvious difference is the presence of a low-amplitude permeability high along the Baldwin high and the Conecuh ridge complex. Natural log of permeability (in md); contour interval = 1.0. Data taken from commercial permeability analyses of core plugs.

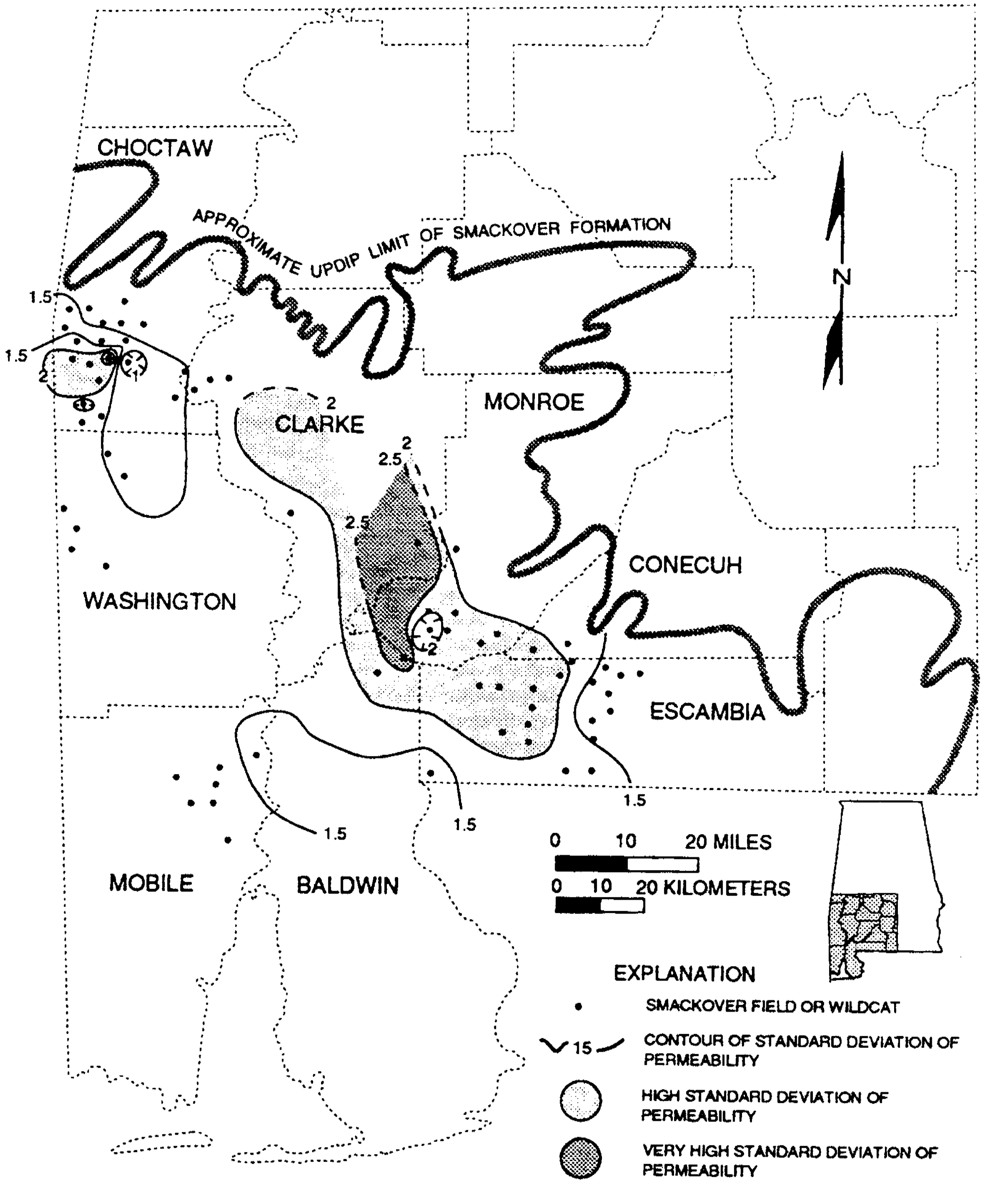


Figure 41.--Map of standard deviation of permeability of Smackover fields, southwest Alabama. Interestingly, this map does not show the same pattern as do the maps of mean permeability and maximum permeability. On the contrary, a large area of highly variable permeability values occupies at least part of the Manila embayment, the Conecuh ridge, and the northern part of the Conecuh embayment. A small region of moderately high values is found in southwestern Choctaw County, but for the most part this region is characterized by low values of permeability standard deviation. The Mississippi interior salt basin and the north flank of the Wiggins arch are characterized by uniformly low values of permeability standard deviation. Natural log permeability (in md); contour interval=0.5). Data taken from commercial permeability analyses of core plugs.

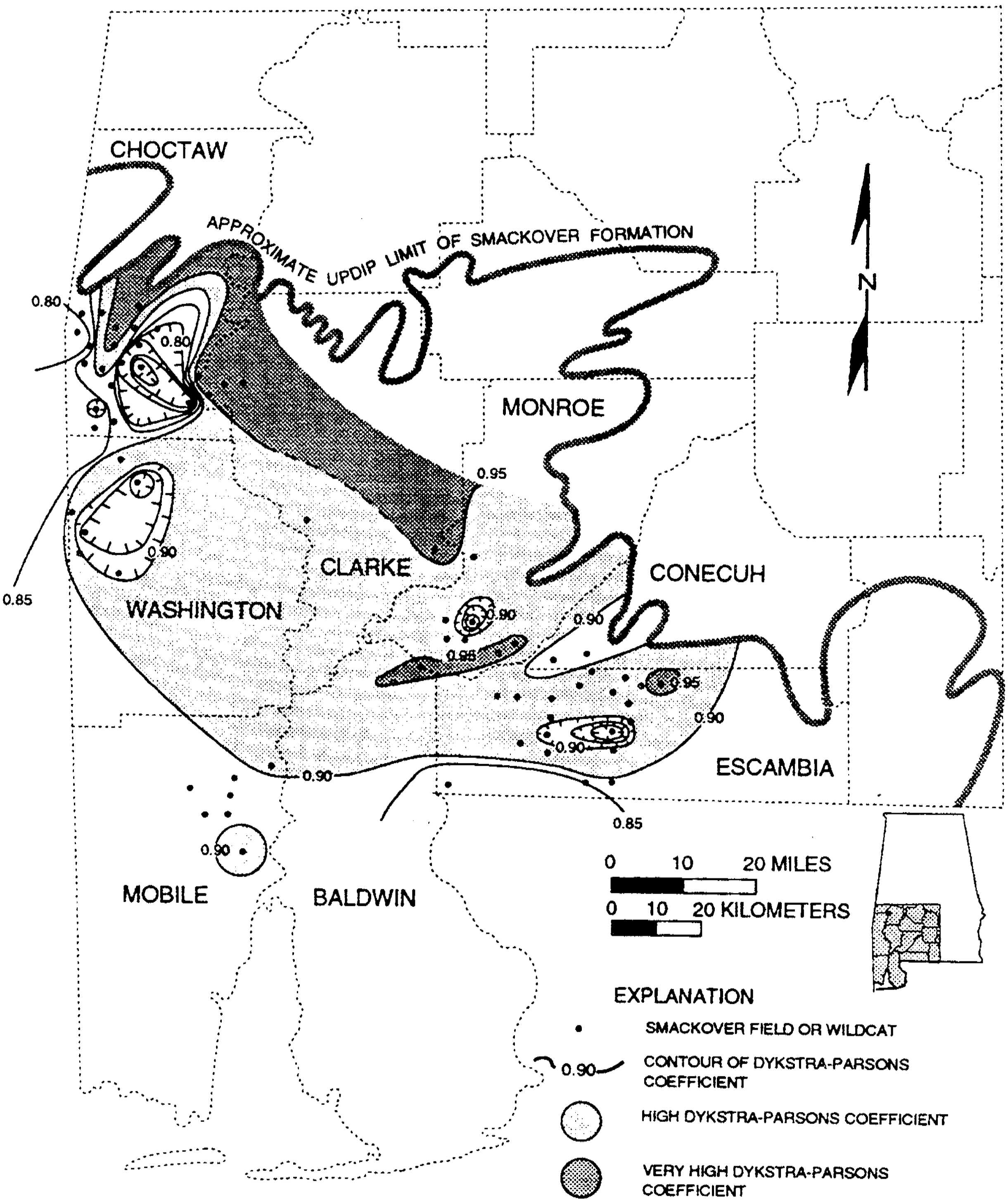


Figure 42.--Map of Dykstra-Parsons coefficient for Smackover fields, southwest Alabama. The DP coefficient appears to be strongly affected by paleotopographic patterns; note especially the high values concentrated along the Conecuh ridge and the southwesterly trends in southern Choctaw County, which parallel underlying basement topography. Variation in the DP coefficient does not correspond to pore-facies patterns. Dimensionless; contour interval=0.05. The DP coefficient is calculated from commercial permeability analyses of core plugs.

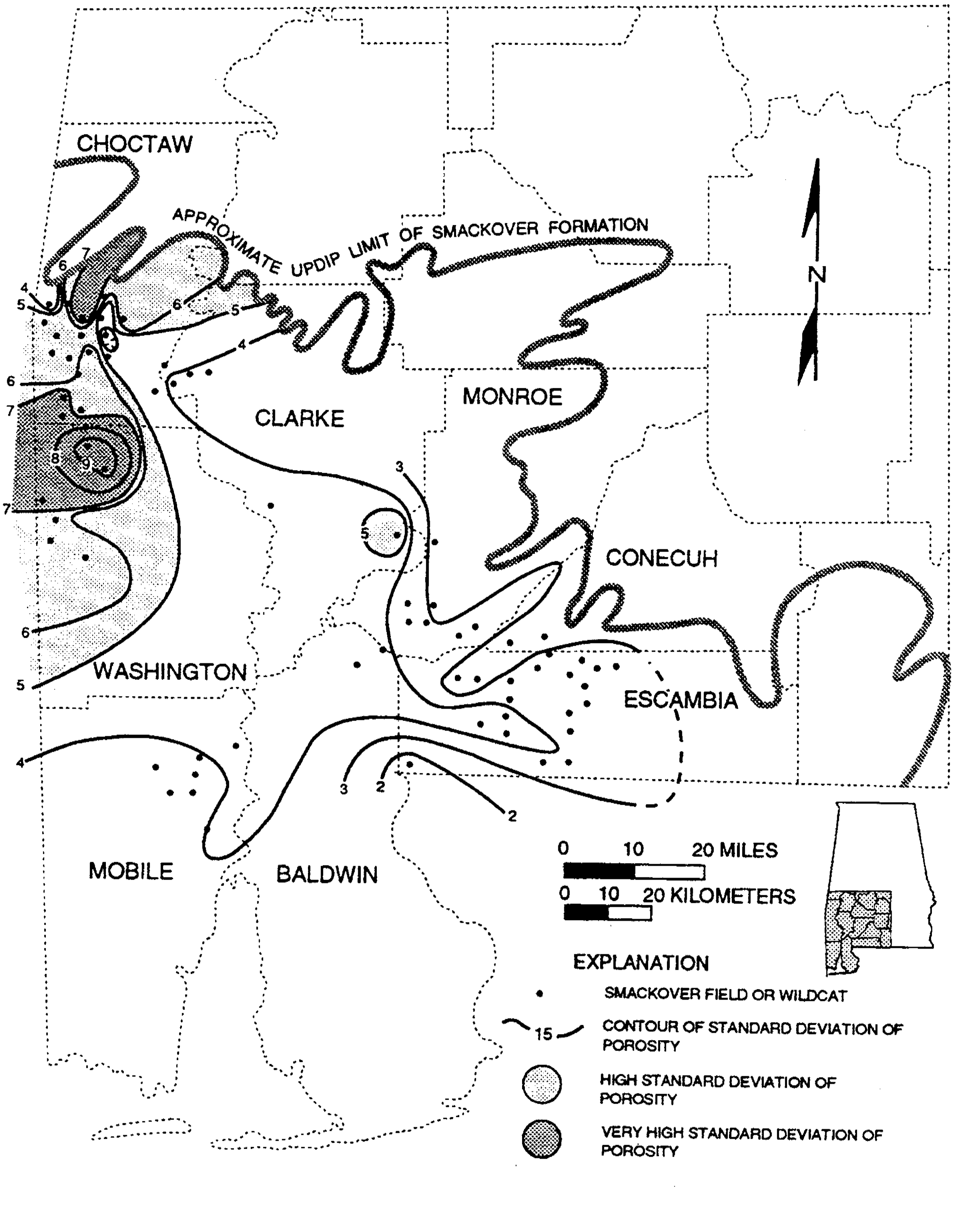


Figure 43.--Map of standard deviation of porosity of Smackover fields, southwest Alabama. Standard deviation of porosity is strongly affected by paleotopography, but generally decreases from northwest to southeast. This is similar to the pattern exhibited by average porosity. Porosity in percent; contour interval = 1.0. Standard deviation of porosity is calculated from commercial porosity analyses of core plugs.

local source of quartzose sand in this area created several heterogeneous reservoirs consisting of mixed siliciclastic and carbonate strata. The updip parts of the Manila embayment contain substantial admixtures of quartzose sand. Where sand and carbonate are commingled, µH values are likely to be high. If there are areas within the updip part of the Manila embayment where quartzose sandstone dominates the reservoir, then µH values may be low in these areas.

Various petrographic parameters show different relationships to paleotopography, present structure, and to each other. For example, average porosity (fig. 37) and standard deviation of porosity (fig. 43) display similar patterns that are unlike those of the other parameters. Local variation in porosity values (fig. 43) shows strong control by paleotopography whereas average porosity (fig. 37) does not. The distribution of maximum permeability (fig. 44) is also sensitive to paleotopographic control. Inspection of the maps presented in this section shows that each aspect of the pore system has responded to the various controlling factors in subtly different ways. Thus, heterogeneity measures that encompass multiple parameters may better represent overall heterogeneity than any one of the individual parameters.

RELATIONSHIP BETWEEN MH AND µH

The pattern of variation in µH is roughly opposite to that of MH. µH values generally decrease from northwest to southeast. The Conecuh ridge complex is roughly the southeastern limit of high values of µH. This inverse relationship between MH and µH is not surprising if one recalls that moldic reservoirs are inherently heterogeneous on a microscopic scale, but are characterized by relatively few and homogeneous flow units. By contrast, intercrystalline reservoirs are inherently homogeneous microscopically, but are relatively heterogeneous megascopically (Kopaska-Merkel and Mann, 1991b). This relationship between µH and MH has implications for reservoir development. One should not expect to find reservoirs that are homogeneous at all scales in the Smackover of southwest Alabama. Instead, the reservoir modeler should expect to face significant variation in reservoir heterogeneity on at least two scales, but the magnitude of the problem at one scale may be inversely proportional to that at the other scale. Because the most common advanced-recovery methods that are used in the Alabama Smackover are waterflooding and various types of gas injection (Masingill, 1990), MH may be more important in the short term than µH. This is because injection-type advanced-recovery processes are adversely affected by large-scale permeability heterogeneity (e.g., Major and Holtz, 1990; Thomas and Bibby, 1991).

The congruency of the patterns of variation of µH and MH with pore-system characteristics (controlled by depositional patterns and modulated by dissolution and dolomitization) and with regional structural and paleogeographic trends suggests that reservoir heterogeneity characteristics are controlled by structural and paleogeographic setting and by diagenesis. However, because contours of µH and MH are approximately normal to structure contours but subparallel to Smackover thickness contours, it appears that depositional setting (or paleogeography) exerted more stringent control on reservoir heterogeneity than did structural evolution. The detailed patterns of µH variation in southern Choctaw County suggest control by NE-SW trending paleotopography, whereas the pattern of MH variation in the same area suggest control by the E-W trending peripheral fault trend. The Mobile graben appears unrelated to µH variation, probably because its major growth occurred after Smackover deposition.

DYKSTRA-PARSONS COEFFICIENT

The Dykstra-Parsons coefficient, like µH, is not, strictly speaking, a measure of vertical heterogeneity, for it is commonly applied to an entire field. The DP coefficient measures overall heterogeneity, both vertical and lateral together. However, because wells are far apart and permeability samples within a core are spaced 1 foot apart, the DP coefficient, like µH, is primarily a measure of vertical heterogeneity. The DP coefficient was devised to evaluate the probability of success of waterflooding (Dykstra and Parsons, 1950). The DP coefficient is [(log mean K)-(log K @ -1 σ)]/log mean K. (Other formulations yield essentially the same result.) Thus, if there is no variation of

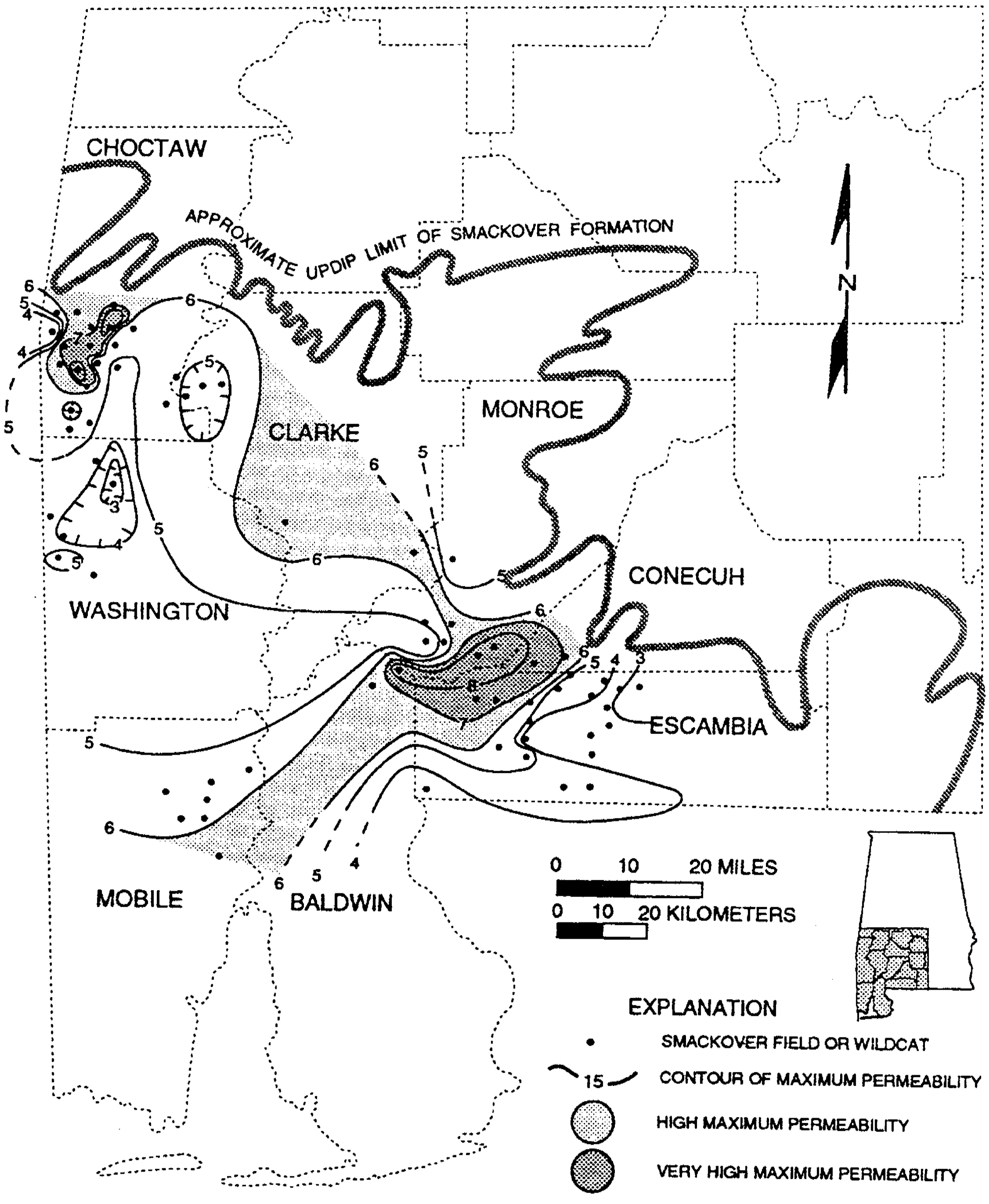


Figure 44.--Map of maximum permeability of Smackover fields, southwest Alabama. This map shows two areas characterized by high values of maximum permeability: one in southern Choctaw County overlying the southerly extension of the Choctaw ridge complex, and one overlying the western end of the Conecuh ridge complex. The high-permeability intervals in southern Choctaw County are characterized by reservoirs consisting of ooid dolograinstone and lesser peloidal and oncoidal grainstone and dolograinstone. These strata are cross laminated or (less commonly) laminated, and exhibit pore systems dominated by moldic pores but containing 10 percent or more interparticle porosity. By contrast, the high-permeability reservoirs found overlying the western part of the Conecuh ridge complex are highly altered planar-e and planar-s dolostones. The pore systems are almost pure intercrystalline. Natural log of permeability (in md); contour interval 1.0. Data taken from commercial permeability analyses of core plugs.

permeability, the standard deviation of K is zero, and the DP coefficient is also zero. The maximum value of the DP coefficient, 1.0, corresponds to the condition of maximum heterogeneity (Craig, 1971). The DP coefficient is a measure of microscopic heterogeneity, as is μH, but the two have contrasting distributions (fig. 42). The DP coefficient is partially correlated with μH ($r^2=0.428$). The distribution of DP coefficient values is also dramatically different from the distribution of σ natural log of K values (fig. 41), though the former is essentially a normalized version of the latter. The distribution of the DP coefficient, unlike those of MH and μH, bears no obvious relationship to pore-facies distribution. Also, the pattern of DP coefficient variation is more complex. Hence, it is more difficult to predict the DP coefficient value in advance of the drill. It is recommended, therefore, that μH, rather than the DP coefficient, be used to represent microscopic heterogeneity if only one microheterogeneity parameter is to be used.

LATERAL RESERVOIR HETEROGENEITY

Accurate evaluation of lateral heterogeneity is difficult. Data for a single field typically consist of a small number of wells distributed over an area of several square miles. For Smackover fields in Alabama, typical well spacing is 160 acres. By contrast, many reservoir heterogeneity studies have dealt with fields characterized by spacings of 40 acres, 20 acres, or even less (e.g., Honarpour and others, 1991). Virtually no data are available for well separation distances of less than about 1,500 feet. Spatial correlation over distances on the order of 2,000 to 10,000 is amenable to study for most fields.

Because of the sampling constraints outlined above, there have been few published attempts at defining lateral heterogeneity. One simple technique involves calculation of reservoir continuity between well pairs (George and Stiles, 1978). The technique involves determination of reservoir continuity (in percent) between each possible pair of wells within a field area. These data are then plotted against the distance between the wells in each pair. Wells close together are expected to have a high continuity index and the index is expected to decrease as the distance between wells increases. The rate of this decrease is a measure of reservoir continuity which is, in turn, a measure of lateral heterogeneity.

Though the technique is simple, it has important limitations. Accurate correlation of specific reservoir zones is essential. In fields with few or widely spaced wells, this can be a problem. Also, the position of the wells relative to one another within the field is important. Significant differences are expected in the continuity between wells oriented parallel to depositional strike and those oriented perpendicular to strike. Correlation indices are strongly influenced by the shape of the reservoir; irregularly shaped reservoirs have different continuity-distance relationships in different directions. Finally, this method is highly inaccurate if lateral continuity is high (Fogg and Lucia, 1990), but this is probably not the case in most Alabama Smackover fields.

The continuity-index technique was applied to nine Smackover fields in Alabama (Geological Survey of Alabama, 1990). The continuity index was plotted against the distance between wells for all well pairs within each field. These crossplots (included in Geological Survey of Alabama, 1990) appear to show a decrease in continuity index with increasing distance. Some Smackover reservoirs exhibit a pronounced preferred orientation of continuity index, whereas others do not (Geological Survey of Alabama, 1990). Different reservoir intervals within a single field tend to have similar continuity vs. distance relationships but the relationships vary substantially from field to field.

The technique described above, although it is one of the few geologically based techniques available, is ineffective in evaluating the lateral continuity of reservoirs in the Smackover Formation of southwest Alabama. The small number of wells and the large distances between wells in most fields make the reliability of correlations of reservoir intervals between wells questionable and prevent the evaluation of correlations over short distances (generally less than 1,500 feet). For most fields continuity-distance plots show a high degree of scatter, and estimates of the correlation distance are problematic at best. Also, reservoir shape strongly affects continuity data. For these reasons, the lateral continuity ranking provided by the technique is a poor estimate of reservoir continuity (Geological Survey of Alabama, 1990).

Even if the technique were more accurate, it only measures 3D continuity of the reservoir. It cannot account for internal barriers to lateral fluid flow. A reservoir may have excellent overall lateral continuity but contain numerous barriers to lateral fluid flow and thus be laterally heterogeneous. Conversely, another reservoir may have less lateral continuity but lack internal barriers to fluid flow; thus, lateral heterogeneity values are low.

A cruder method of assessing lateral reservoir heterogeneity was also attempted. This is necessary where data are insufficient for more sophisticated techniques such as conditional simulation (e.g., Lucia and Fogg, 1990; University of Alabama, 1991). The method involves comparing porosity-permeability plots for single wells to similar plots from multiple wells from the same field. Thus, this is a way to measure microscopic lateral heterogeneity. If lateral heterogeneity is significant then r^2 will be lower for the multi-well plots. This is because when wells with different porosity-permeability characteristics are lumped together, variance increases and r^2 decreases.

The method was applied as follows. Only wells with at least 30 non-zero permeability analyses were counted, and only fields with at least four wells satisfying the first criterion were included. These restrictions were necessary because small data sets would severely bias results. Short cores have a high probability of yielding biased samples from vertically heterogeneous reservoirs, and if too few cores are included in the multi-well calculations, then even if lateral heterogeneity is significant, it cannot be detected. Twelve fields met these criteria (table 6).

Table 6.--Lateral heterogeneity in 12 Smackover fields

Field	Normalized lateral heterogeneity	H	Acreage	Spacing	Fluid type
Big Escambia Creek	0.1	1.6	15858	640	gas-condensate
Chunchula	0.1	1.29	22113	640	gas-condensate
Hatter's Pond	0.1	1.54	6418	640	gas-condensate
Chatom	0.5	1.83	2080	640	gas-condensate
Womack Hill	0.6	1.87	1719	100	oil
Barnett	0.8	1.36	1237	160	oil
Blacksher	1	1.96	1123	160	oil
Fanny Church	1.3	1.35	653	160	oil
Vocation	1.3	2.22	775	160	oil
North Choctaw Ridge	1.4	2.08	779	80	oil
Sugar Ridge	4.3	2.18	249	140	oil
Lovetts Creek	4.9	1.3	202	160	oil

Only the larger Smackover fields met the necessary criteria, but these are the very fields for which lateral heterogeneity (LH) is of interest, because EOR projects are not economically feasible for small fields. Table 6 includes all parameters studied that exhibit any relationship to LH. LH = [((average r^2 for single wells in field - fieldwide r^2) + 1)/field acreage] * 1,000. LH is normalized by division by the field area (in acres); the result is multiplied by 1,000 simply for convenience. LH is a rank parameter; the numbers have only qualitative significance. LH is most strongly related to µH: the average value of µH for the six fields with the highest values of LH is 1.85, vs. 1.58 for the six fields with the lowest values of LH. LH is also correlated with both hydrocarbon type (oil vs. gas-condensate) and (inversely) with spacing. Spacing and hydrocarbon type are obviously related to one another; with the exception of Movico Field, which is a special case, only gas-condensate fields are drilled on 640-acre spacing versus 80 to 160 acres for most oil fields. Therefore the relationship between LH and spacing is probably a function of that between LH and hydrocarbon type. There is no evidence that LH is related to pore facies. The important results of this analysis are three.

First, LH and µH are positively correlated, which means that, at least for the Smackover in Alabama, vertical and lateral microscopic heterogeneity are correlated with one another. Vertical heterogeneity is easier to estimate and therefore lateral heterogeneity can be predicted from it on a regional scale. Second, large gas-condensate fields are less laterally heterogeneous whereas (relatively) large oil fields are more laterally heterogeneous. This suggests that for the oil fields, bypassing of mobile oil is a real possibility. Third, LH, a new, simple measure of microscopic lateral heterogeneity, may be a valuable tool for characterization of reservoir heterogeneity where more sophisticated methods cannot be applied because of insufficient data. LH can be used as a modifying factor for economic analyses of EOR feasibility.

Lateral heterogeneity may be better assessed by direct measurement of well to well fluid flow (e.g., tracer studies or pulse testing). Unfortunately, these kinds of data are generally not available for the Smackover in southwest Alabama. One approach that is applicable to the Smackover of southwest Alabama is the calculation of drainage areas for individual wells based on pressure and/or production data. This technique was used to define lateral heterogeneity in Chunchula field, Mobile County (University of Alabama, 1991). Lateral heterogeneity can also be investigated using conditional simulation, but for this technique the dearth of data for short distances is a severe problem. Using these techniques, the University of Alabama (1991) concluded that Chunchula field is laterally heterogeneous.

PREDICTION OF RESERVOIR HETEROGENEITY

It is desirable to estimate reservoir heterogeneity early in the field-development process. The goal is to use the estimate of the amount and kind of heterogeneity in preparing the field-development plan from as early a stage as possible. Ideally, then, the heterogeneity characteristics of the reservoir would be known with some accuracy in advance of the drill. One would also like to be able to refine this estimate substantially after drilling only one or a few wells.

Using the heterogeneity parameters presented here the nature and degree of heterogeneity can be predicted by reference to the reservoir-heterogeneity maps (figs. 38, 39, and 42) or to the pore-facies map (fig. 27) (which may contain information where the heterogeneity maps contain none). Alternatively, the pore facies in the target area may be calculated and the heterogeneity values predicted from the known relationships between pore facies and heterogeneity. The mean values of µH and MH for the moldic pore facies are 1.96 and 5.48, whereas the same values for the intercrystalline pore facies are 1.62 and 8.26 (table 7). Values of µH and MH for intermediate pore systems are nearly identical to those for the intercrystalline pore facies. If a well is drilled and no core is cut, then the pore-system characteristics can be determined from cuttings (including capillary-pressure data; Kopaska-Merkel, 1988). In this way, pore facies can be used to predict heterogeneity where no measurement of permeability is possible and hence MH and µH cannot be calculated.

Table 7.--Heterogeneity characteristics of Smackover pore facies

Pore facies	µH				MH			
	Range	Mean	Standard deviation	N	Range	Mean	Standard deviation	N
Moldic	1.22-3.22	1.96	0.42	24	2.11-9.54	5.48	1.63	17
Intermediate	0.87-2.30	1.65	0.45	15	2.21-13.46	8.39	3.89	9
Intercrystalline	1.24-2.22	1.62	0.42	6	5.66-10.49	8.26	1.93	5

HETEROGENEITY AND PRIMARY RECOVERY

All four heterogeneity measures are essentially uncorrelated with primary recovery factor (PRF) (fig. 45). Possible reasons for this are discussed in a later section of this report. The only parameter measured that shows a significant relationship to PRF is MTS (fig. 46). If the indicated positive

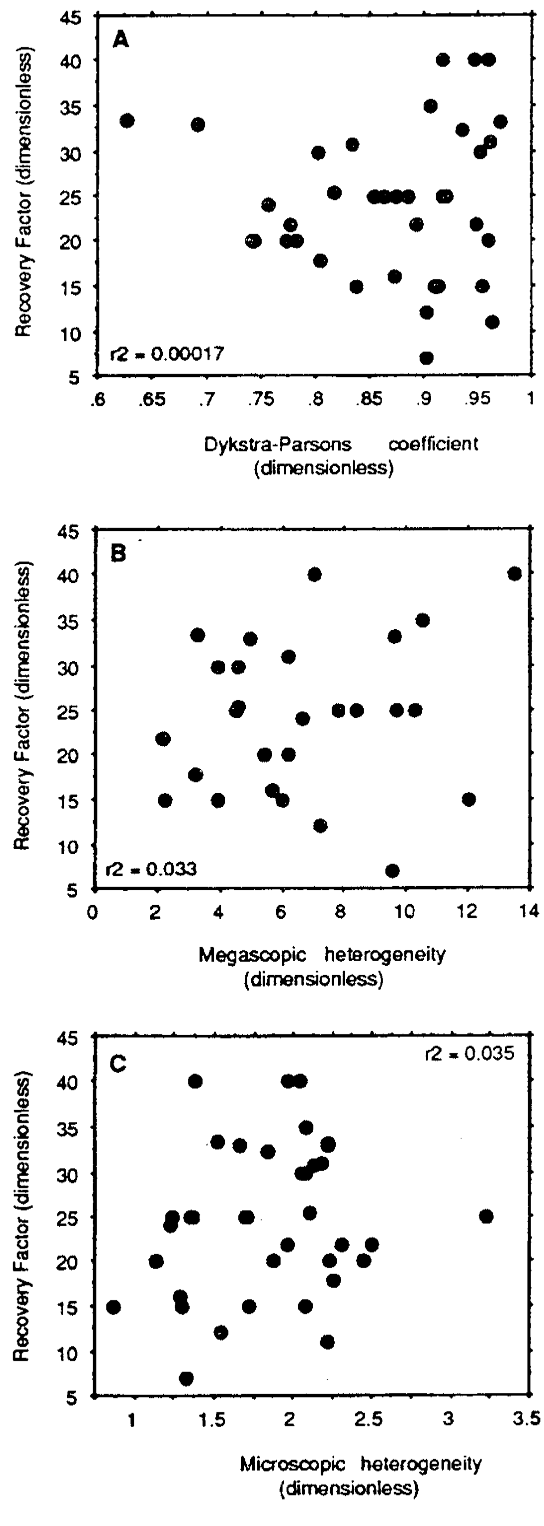


Figure 45.--Bivariate plots of three measures of reservoir heterogeneity vs. primary recovery factor. (A) DP coefficient, (B) MH, and (C) μH. None of the three heterogeneity factors exhibit a significant correlation with primary recovery factor.

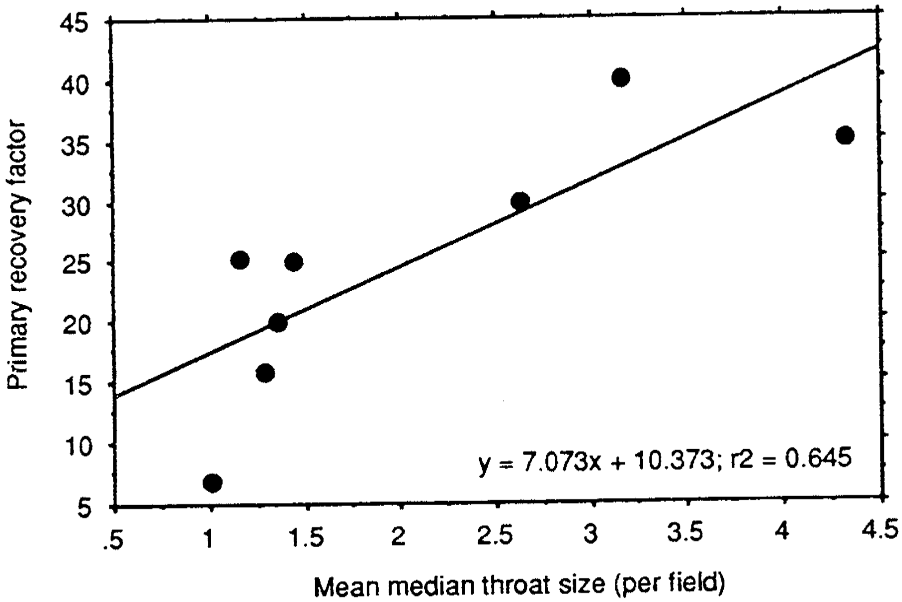


Figure 46.--Bivariate plot of MTS and PRF. Only eight fields have both adequate CP data (≥8 samples) to calculate mean MTS and a reliable PRF. $r^2=0.645$, which is probably significant even given the small sample size. See text for further discussion.

relationship between MTS and PRF can be relied upon (bearing in mind the small sample size) then the implications are profound. No other petrophysical parameter, even with many more samples (e.g., permeability) shows a significant relationship to PRF (fig. 45). It appears that the single most important factor controlling PRF is the size distribution of pore throats through which the oil must flow. PRF prediction can best be made from capillary-pressure data. However, because this inference is supported by scanty data, skepticism is required. Further research, specifically collection of additional CP data, is planned. The results will show whether the relationship between MTS and PRF is robust.

ENHANCED- OR IMPROVED-RECOVERY PROJECTS IN THE SMACKOVER OF ALABAMA

In the remainder of this report the effectiveness of enhanced- and improved-recovery operations in Smackover reservoirs of Alabama is evaluated. Eleven Smackover fields in Alabama have been unitized through 1990 (table 8); nine of these have undergone or are undergoing some kind of enhanced- or improved-recovery project. (See Hall, 1992, for a description of unitization procedures in Alabama.) Enhanced- or improved-recovery techniques that have been used in Alabama include infill drilling and strategic well placement (improved-recovery methods) and waterflood and gas injection (enhanced- or improved-recovery methods). The general characteristics of these fields were described by Kopaska-Merkel and others (1992) and by Hall (1992). The results of the unitization projects are described and evaluated in this report. Projected and actual incremental hydrocarbon recoveries are compared for mature enhanced- and improved-recovery projects. The goals are (1) to determine which methods have been most effective at increasing Smackover hydrocarbon recovery, (2) to identify possible candidates for enhanced or improved recovery among Alabama Smackover fields, and (3) to make general recommendations regarding potential future enhanced- and improved-recovery projects in the Smackover of Alabama. These results may also be relevant to enhanced or improved recovery from other carbonate reservoirs.

Table 8.--Characteristics of unitized Smackover fields in Alabama

Field	Type Unitization	Effective Date	Fluids Injected	Date of Injection	Production prior to Unitization (BBLS)	Production after Unitization (BBLS)	Total Production (BBLS)
Appleton	Fieldwide	5/1/88	None	NA	937,425	994,987	1,932,412
Chatom	Fieldwide	5/1/76	Residue gas	8/76	2,217,288	12,149,473	14,366,761
Choctaw Ridge	Partial	5/1/74	None	NA	1,952,598	1,670,011	3,622,609
Chunchula	Fieldwide	2/1/81	Residue gas and N_2	4/82 7/84	10,751,233	36,839,254	47,590,487
Fanny Church	Partial	1/1/85	N_2	12/85	2,308,798	1,982,333	4,291,131
Hatter's Pond	Fieldwide	5/1/85	Residue gas	7/85	21,292,820	20,387,249	41,680,069
Little Escambia Creek	Fieldwide	3/1/74	Water Water and CH_4 Water and N_2	3/74 1/81 12/81	3,967,377	26,232,835	30,200,212
Silas	Fieldwide	9/1/76	None	NA	12,875	1,736,800	1,749,675
Stave Creek	Fieldwide	3/15/85	None	NA	1,278,927	1,669,365	2,948,292
Turkey Creek	Partial	1/1/75	None	NA	858,062	1,902,811	2,760,873
Womack Hill	Partial	1/1/75	Water	7/75	2,536,279	13,216,488	15,752,767

OVERVIEW OF SMACKOVER PRODUCTION

Smackover fields in southwest Alabama have produced nearly 260 million barrels of oil and condensate since the discovery in 1967 of oil in the Smackover of Alabama (table 9). Cumulative production from the Smackover is 54 percent of total oil and condensate produced in Alabama. Mobile County accounts for over 35 percent of all liquid hydrocarbons produced from the Smackover (table 9; fig. 47) and has produced more liquid hydrocarbons per pool than any other county in the Smackover trend (figs. 48 and 49). Mobile County averages more than 13 million barrels of liquid hydrocarbons per pool (fig. 49). The largest Smackover discoveries in Alabama were made during the early 1970's: Hatter's Pond, Womack Hill, Big Escambia Creek, Chatom, Chunchula, and Jay-LEC fields. All these major fields are still producing and all but Big Escambia Creek field are undergoing some type of enhanced or improved recovery. Of the 260 million barrels of oil and condensate produced from the Smackover in Alabama, 167 million barrels (64 percent) have been produced from the 11 unitized Smackover fields; 119 million barrels were produced after unitization (fig. 50). For a review of the history of hydrocarbon play development in the Smackover of Alabama, see Hall (1992).

Table 9.--Geographic distribution of Smackover production and pools ranked by cumulative production per pool

County	Cumulative Production (BBLS)	Number of pools[1]	Cumulative Production per pool (BBLS/pool)
Mobile	92,864,648	7	13,266,378
Clarke	22,272,323	6	3,712,054
Escambia	79,877,828	22	3,630,810
Washington	17,002,404	6	2,833,734
Choctaw	41,095,122	22	1,867,960
Baldwin	1,977,280	4	494,320
Monroe	3,783,764	9	420,418
Conecuh	735,677	4	183,919
TOTAL	259,609,046		AVERAGE: 3,508,230

[1]Pools crossing county boundaries are assigned to both counties

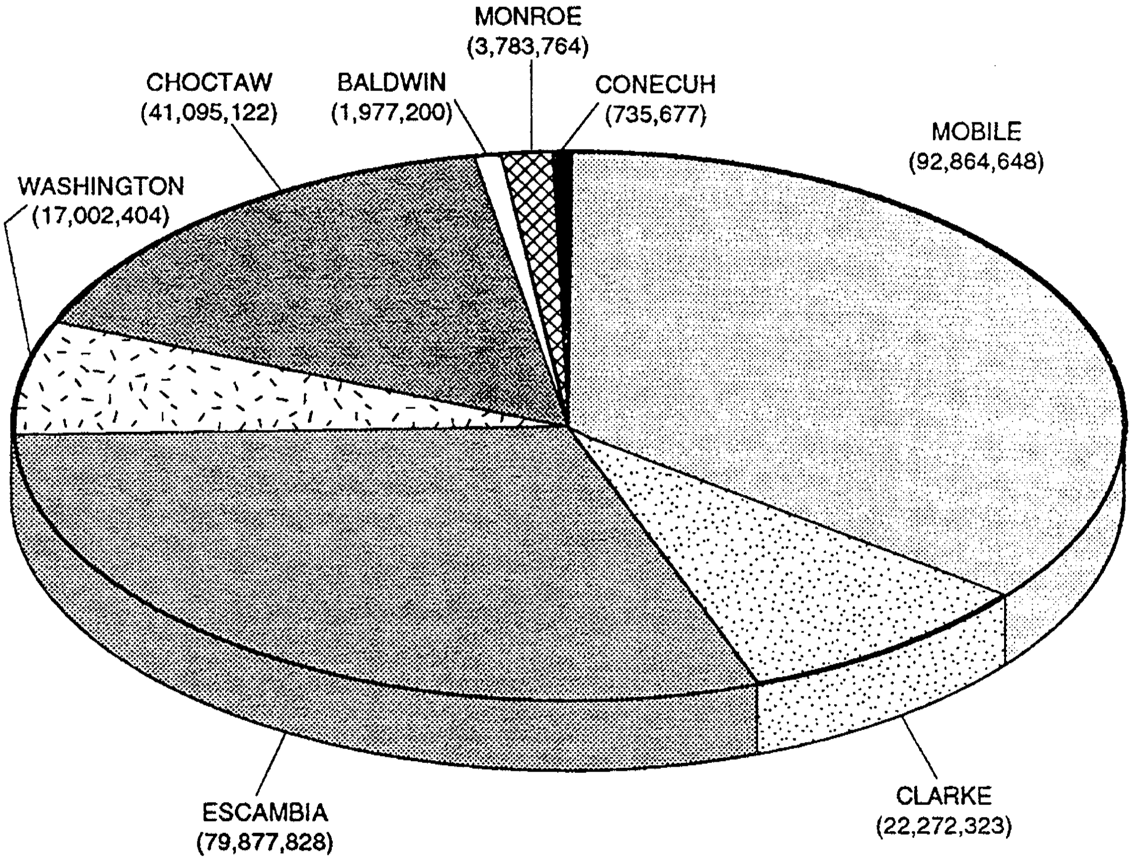


Figure 47.--Pie diagram indicating cumulative Smackover production for each county in southwest Alabama's Smackover trend. (Values in parentheses indicate cumulative liquid production (in barrels) through December 31, 1990.)

FLUID COMPOSITION

Determination of reservoir-fluid chemical and physical properties is important in evaluating enhanced- or improved-recovery candidates and techniques to be used. Some enhanced-recovery techniques are more applicable to heavy oils whereas others are effective with lighter hydrocarbons (van Poollen and Associates, Inc., 1980) like those commonly found in the Smackover of Alabama. Characteristics of the reservoir fluid also affect the amount of oil that can be produced by both primary and secondary recovery (National Petroleum Council, 1976). Smackover fields undergoing enhanced or improved recovery include both light-oil and gas-condensate reservoirs.

The Jurassic of the eastern Gulf Coast region has been divided into three producing trends based on type of hydrocarbon produced (fig. 5) (Mink and others, 1985; Mancini and others, 1986). The oil trend lies updip from the regional peripheral fault system in Alabama; produced hydrocarbons are predominantly oil. The oil and gas-condensate trend lies between the oil and deep natural gas trends; fields within this trend produce oil, gas-condensate, and gas. Downdip of the Wiggins arch is the deep natural gas trend which extends into the offshore areas of the Gulf of Mexico (Mink and others, 1985; Mancini and others, 1986). No Smackover fields have been established within the deep

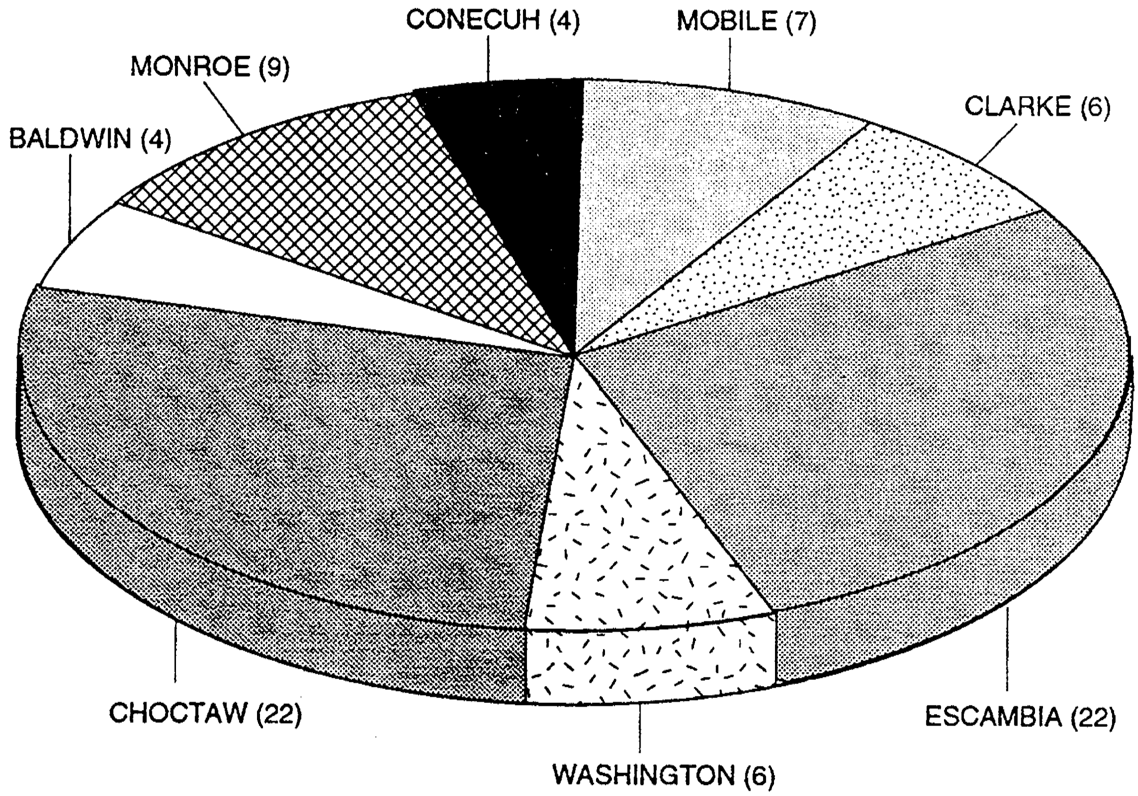


Figure 48.--Pie diagram indicating distribution of Smackover reservoirs in southwest Alabama. (Values in parentheses indicate the number of pools within each county as of December 31, 1990.)

natural gas trend in Alabama; production is confined to the Cotton Valley Group and Norphlet Formation.

Hydrocarbon liquids produced from the Smackover Formation of southwest Alabama range from 18° gravity oil to 64° gravity condensate (table 10). Wellstreams from Jurassic fields commonly contain nonhydrocarbon gases (e.g., hydrogen sulfide, nitrogen, and carbon dioxide). In some fields, these components are volumetrically important (table 10). In Big Escambia Creek field, more than 53 mole percent of the wellstream is nonhydrocarbon components.

WELL SPACING

In Smackover reservoirs of southwest Alabama, competitive unit sizes range from 40 to 640 acres. Unit shape varies from square to elongate rectangular; some units have been configured to take into consideration the overall development scheme of the reservoir.

Choctaw and Clarke counties exhibit the widest variability in unit spacing of Smackover oil reservoirs (40 to 160 acres). Unit configuration ranges from square to elongate rectangular to variously polygonal. Oil was discovered early in the Smackover in Choctaw and Clarke Counties, and most fields were established prior to 1980, before statewide consistency in spacing requirements was implemented (table 11).

The largest units for a Smackover oil reservoir are in Movico field, which contains irregular 640-acre units. Movico field is located in the Mobile River Delta of Mobile and Baldwin Counties in an ecologically sensitive area. The large size of these development units was the result of environmental

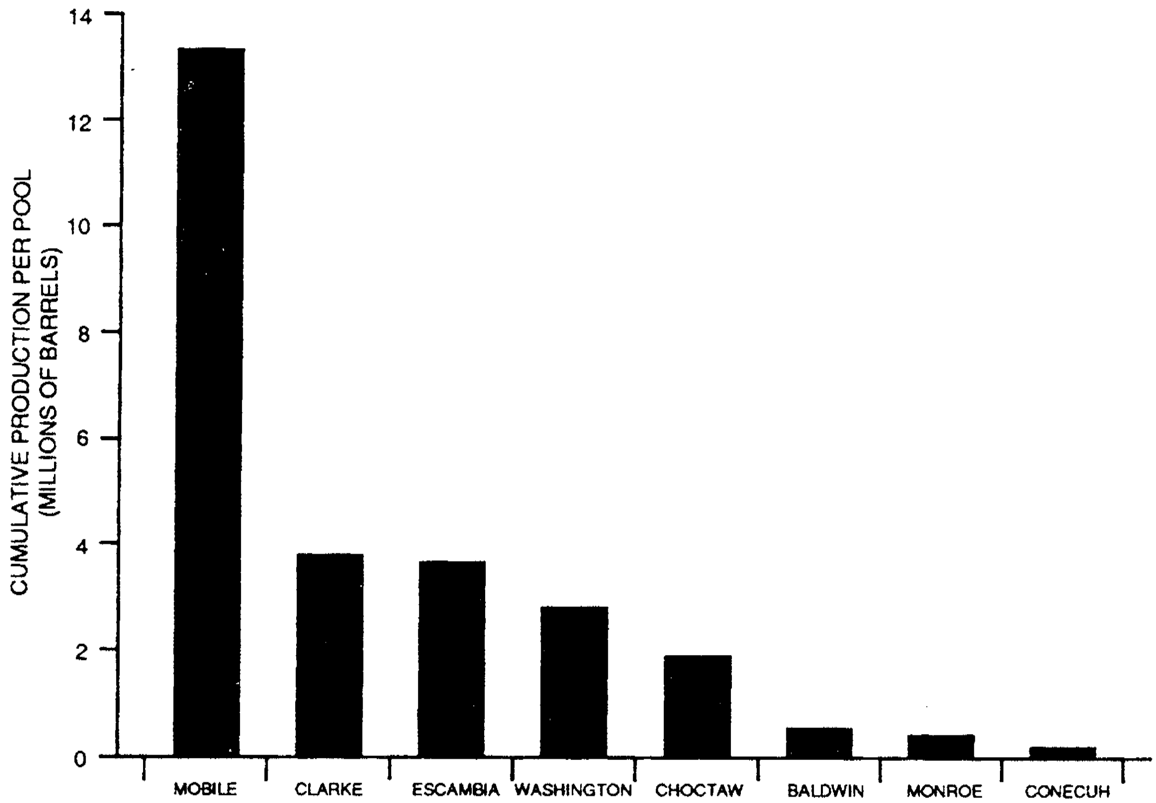


Figure 49.--Average cumulative Smackover production per pool for counties in southwest Alabama.

concerns over the fate of wetland habitat and the apparent ability of the discovery well to adequately drain the unit.

The most common spacing of Smackover oil pools in Alabama is 160 acres, the maximum allowed by Alabama's spacing statute (table 11). Nearly 70 percent of Smackover oil reservoirs in Alabama are developed on 160-acre spacing and the majority of these units are square. Only three oil fields established since 1980, South Womack Hill, West Okatuppa Creek, and Movico, have been spaced on units other than 160 acres. Alabama's regulatory authority, the State Oil and Gas Board of Alabama, prefers that these 160-acre units be governmental quarter sections unless special permission is obtained from the Board (Rogers and Mancini, 1991). This policy was adopted to reduce the risk of island acreage within developing fields. Island acreage is land between producing units that is both undrained and too small to be developed as units within the field. The 160-acre limit for oil units results from the widely held belief that most Smackover oil wells in Alabama can effectively drain 160 acres. The poor correlation between spacing and primary recovery factor (Kopaska-Merkel, 1992a) is consistent with this hypothesis.

Spacing regulations provide for an offset, or minimum, distance a well can be located from the closest development-unit boundary. In 160-acre units the offset distance is commonly 660 feet. These offset distances were established in order to reduce drainage of hydrocarbons from outside the production units, to provide some assurance of efficient recovery of hydrocarbons in the field, and to prevent drilling of unnecessary wells. Wells may be located closer to the boundary in special instances where reducing the offset distance is required to prevent waste while protecting the rights of the mineral owners.

Most Smackover gas-condensate reservoirs in Alabama have been competitively spaced on 640 acres. This is due to the more effective drainage of gas-condensate reservoirs as opposed to oil

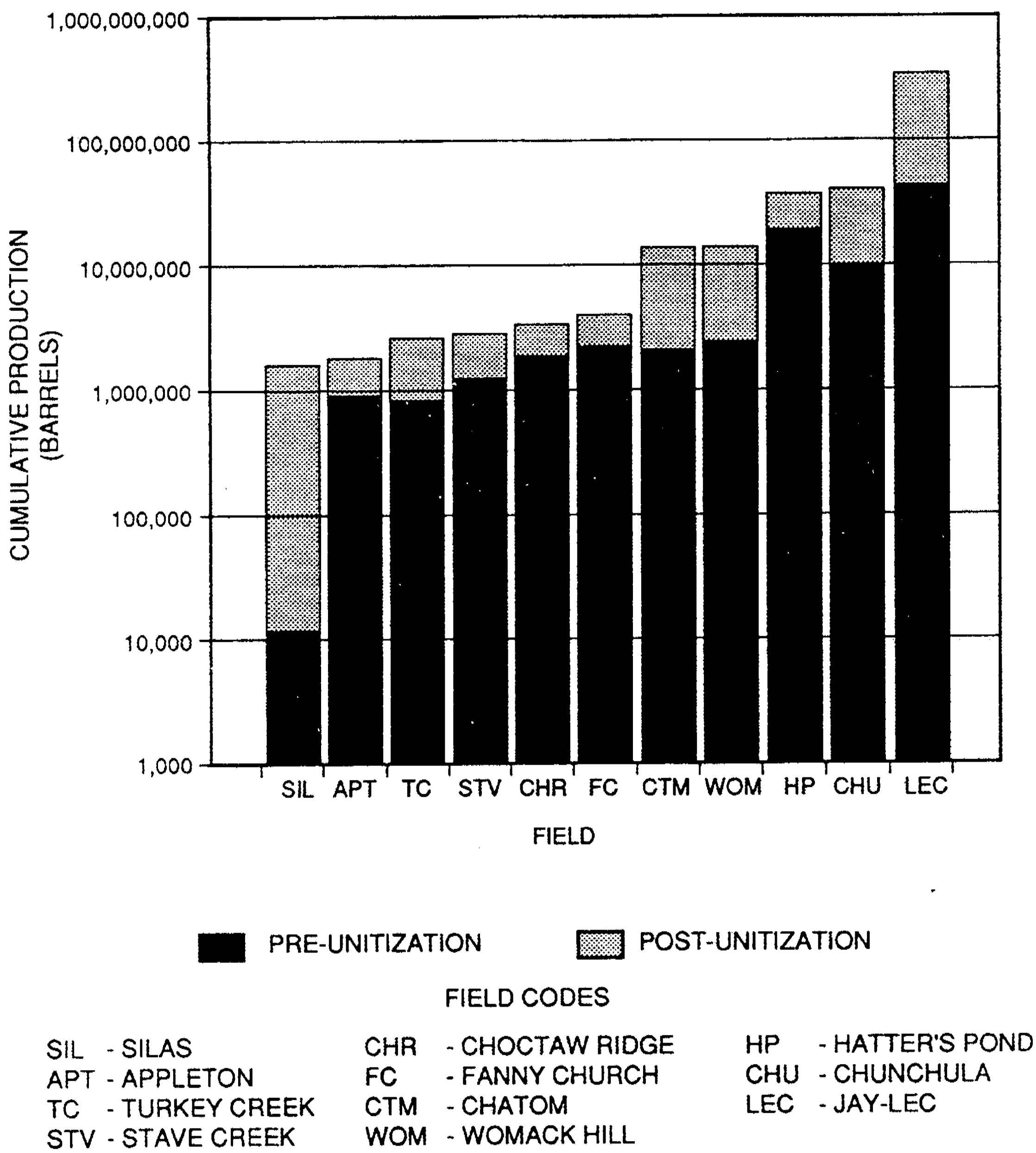


Figure 50.--Pre-unitization versus post-unitization production for unitized Smackover fields in southwest Alabama. (Jay-LEC fields contain production information from both Alabama and Florida portions of the fields.) Vertical scale is logarithmic.

reservoirs. Major gas-condensate fields in Alabama such as Big Escambia Creek, Hatter's Pond, Chunchula, and Chatom fields are all spaced on 640 acres. Sizemore Creek and Little Rock fields are spaced on 320-acre units because the reservoirs in these fields are smaller than 640 acres. Souwilpa Creek field was originally defined as an oil field, but was later redesignated a gas-condensate reservoir and the existing 160 units were retained.

Table 10.--Variation in wellstreams of Smackover fields in southwest Alabama

Field	Hydrocarbon Type	API gravity (degrees)	H_2S (Mole percent)	CO_2 (Mole percent)	N_2 (Mole percent)	Total Non-HC's (Mole percent)
Appleton	oil	52	1.75	1.38	5.7	8.83
Barlow Bend	oil	35	nil[1]	0.19	7.74	7.93
Barnett	oil	49	NA	1.85	8.86	10.71
Barrytown	oil	45	0.45	0.92	9.74	11.11
Big Escambia Creek	condensate	46	25.69	24.88	2.54	53.11
Blacksher	oil	43	0.77	0.35	3.71	4.83
Broken Leg Creek	oil	41	nil[1]	0.71	4.27	4.98
Bucatunna Creek	oil	37	0.84	0.81	5.74	7.39
Burnt Corn Creek	oil	49	3.45	0.39	3.51	7.35
Chappell Hill	oil	38	0.52	1.02	5.05	6.59
Chatom	condensate	55	16.7	2.92	1.3	20.92
Choctaw Ridge	oil	41	2.1	0.63	8.85	11.58
Chunchula	oil/condensate	60	0.01	2.26	5.67	7.94
Cold Creek	oil	59	0	1.56	4.16	5.72
Copeland	condensate	41	22.94	5.52	0.02	28.48
Crosbys Creek	condensate	NA	16.4	1.7	1.62	19.72
East Barnett	oil	45	NA	0.92	8.9	9.82
East Huxford	oil	39.5	0	0.57	2.54	3.11
Fanny Church	oil	51	4.7	1.53	0.87	7.1
Gin Creek	oil	48	17.43	5.47	1.76	24.66
Gulf Crest	oil	55.3	NA	1.05	NA	1.05
Hanberry Church	oil	46	2.1	4.06	10.91	17.07
Hatter's Pond	condensate	61	0.62	4.97	6.28	11.87
Healing Springs	condensate	54	37.55	4.11	0.84	42.5
Huxford	oil	51	0.07	3.31	11.78	15.16
Little Escambia Creek	oil	51	8.78	2.24	1.28	12.3
Little Mill Creek	oil	40	*	0.37	9.64	10.01
Little River	oil	40	*	0.46	3.22	3.68
Little Rock	condensate	54	15.91	2	NA	17.91
Lovetts Creek	oil	32	*	0.3	10.37	10.67
Melvin	oil	18	NA	NA	NA	NA
Mill Creek	oil	42	1.6	0.38	0.8	2.78
Mineola	oil	39.3	0	0.46	5.82	6.28
Movico	oil	44	0	0.99	5.7	6.69
North Choctaw Ridge	oil	39	2.1	0.68	5.39	8.17
North Smiths Church	oil	44.7	*	1.06	6.3	7.36
North Wallers Creek	oil	36.9	nil[1]	0	3.73	3.73
Northeast Barnett	oil	45.2	NA	NA	NA	NA

NA=Not available.
* = Less than 0.001.
[1]As reported by operator.

Table 10.--Variation in wellstreams of Smackover fields in southwest Alabama—Continued

Field	Hydrocarbon Type	API gravity (degrees)	H_2S (Mole percent)	CO_2 (Mole percent)	N_2 (Mole percent)	Total Non-HC's (Mole percent)
Northwest Range	oil	NA	NA	NA	NA	NA
Pace Creek	oil	38	0	0.52	23.69	24.21
Palmers Crossroads	oil	39.2	NA	NA	NA	NA
Perdido	oil	60	nil[1]	1.04	7.87	8.91
Puss Cuss Creek	oil	42	19.65	2.38	1.05	23.08
Red Creek	condensate	48	37.39	9.94	0.54	47.87
Robinson Creek	oil	52.4	0	0.85	5.31	6.16
South Burnt Corn Creek	oil	49	0.68	3.29	5.68	9.65
South Cold Creek	oil	44	NA	2.26	1.89	4.15
South Wild Fork Creek	condensate	45.8	3.75	1.36	2.3	7.41
South Womack Hill	oil	39.2	NA	NA	NA	NA
Silas	oil	42	11.78	1.88	0.72	14.38
Sizemore Creek	condensate	NA	6.07	30.37	3.27	39.71
Smiths Church	condensate	57.6	8.83	16.5	0.5	25.83
South Vocation	oil	57	NA	NA	NA	NA
Southeast Chatom	condensate	63.7	17.29	6.26	2.04	25.59
Souwilpa Creek	condensate	49	25.16	4.33	0.91	30.4
Stave Creek	oil	41	*	2.42	28.81	31.23
Sugar Ridge	oil	38	1.98	1.14	5.23	8.35
Southwest Barrytown	oil	45.1	NA	NA	NA	NA
Toxey	oil	20	NA	NA	NA	NA
Turkey Creek	oil	43	*	0.24	29.73	29.97
Turnerville	oil	55	NA	1.76	2.91	4.67
Uriah	oil	39	0	0.6	1.31	1.91
Vocation	oil	54	0	0.63	7.11	7.74
Wallace	oil	44	nil[1]	1.04	3.61	4.65
Wallers Creek	oil	37	0	NA	NA	0
West Appleton	oil	46.4	0.69	1.63	3.59	5.91
West Barrytown	oil	46	NA	NA	NA	NA
West Bend	oil	42	*	0.64	10.12	10.76
West Okatuppa Creek	oil	26	0	0.05	0.45	0.5
Wild Fork Creek	oil	43.1	6.36	4.8	8.63	19.79
Wimberly	oil	37	0.01	0.08	4.12	4.21
Womack Hill	oil	37	nil[1]	NA	NA	0
Zion Chapel	oil	42	22.87	1.68	3.45	28

NA = Not available
* = Less than 0.001
[1]As reported by operator.

Table 11.--Spacing requirements of Smackover fields in southwest Alabama

Field	Type reservoir	Date field established	Required spacing (acres)	Unit shape	Distance from unit lines (in ft)	Distance between wells (in ft)
Appleton	oil	6/26/85	160	contiguous acreage	660	1,320
Barlow Bend	oil	9/12/86	160	governmental 1/4	660	1,320
Barnett	oil	6/20/75	160	contiguous acreage	660	1,320
Barrytown	oil	4/19/72	120-160	contiguous acreage	500	1,000
Big Escambia Creek	condensate	2/23/72	640	contiguous acreage	1,320	no requirement
Blacksher	oil	5/1/81	160	governmental 1/4	660	1,320
Broken Leg Creek	oil	12/16/88	160	contiguous acreage	660	no requirement
Bucatunna Creek	oil	7/7/78	80	contiguous acreage	330	660
Burnt Corn Creek	oil	3/7/86	160	contiguous acreage	660	1,320
Chappell Hill	oil	5/2/78	120	contiguous acreage	330	660
Chatom	condensate	11/20/70	640	governmental section	1,320	no requirement
Choctaw Ridge	oil	10/20/67	80	two contiguous 40's	510	1,020
Chunchula	oil/condensate	11/26/74	640	contiguous acreage	1,320	no requirement
Cold Creek	oil	3/7/80	160	governmental 1/4	660	no requirement
Copeland	condensate	7/17/75	640	contiguous acreage	1,320	no requirement
Crosbys Creek	condensate	1/29/88	640	governmental section	1,320	no requirement
East Barnett	oil	6/24/88	160	contiguous acreage	660	no requirement
East Huxford	oil	2/16/90	160	governmental 1/4	660	no requirement
Fanny Church	oil	9/28/73	160	governmental 1/4	660	no requirement
Gin Creek	oil	3/25/86	160	governmental 1/4	660	1,320
Gulf Crest	oil	3/11/88	160	contiguous acreage	660	no requirement
Hanberry Church	oil	9/11/87	160	governmental 1/4	660	1,320
Hatter's Pond	condensate	12/16/75	640	governmental or contiguous	1,320	no requirement
Healing Springs	condensate	11/1/84	640	governmental	1,320	2,640
Huxford	oil	2/23/84	160	contiguous acreage	660	1,320
Little Escambia Creek	oil	9/25/70	160	governmental 1/4	660	no requirement
Little Mill Creek	oil	9/29/78	160	contiguous acreage	500	1,000
Little River	oil	11/25/81	160	governmental 1/4	660	1,320
Little Rock	condensate	5/23/86	320	governmental 1/2 section	660	no requirement
Lovetts Creek	oil	5/14/82	160	governmental 1/4	660	1,320
Melvin	oil	6/28/77	80-120	contiguous acreage	330	1,000
Mill Creek	oil	10/30/75	120	rectangular	500	1,000
Mineola	oil	11/1/90	160	governmental 1/4	660	no requirement
Movico	oil	10/26/82	640	contiguous acreage	1,320	2,640
North Barnett	oil	5/30/91	160	contiguous acreage	500	1,000
North Choctaw Ridge	oil	4/19/72	80	contiguous 1/4 1/4's	500	1,000
North Choctaw Ridge (revised)	oil	1/26/73	120	contiguous acreage	500	1,000
North Choctaw Ridge (revised)	oil	9/14/73	120-160	contiguous acreage	500	1,000

[1]Changed from oil to gas pool
[2]120 acres with 30 percent tolerance
[3]Unit no longer than 3 times its width
[4]Field discovered earlier. Field rules established by Board Motion

Table 11.--Spacing requirements of Smackover fields in southwest Alabama—Continued

Field	Type reservoir	Date field established	Required spacing (acres)	Unit shape	Distance from unit lines (in ft)	Distance between wells (in ft)
North Smiths Church	oil	3/2/90	160	contiguous acreage	660	no requirement
North Wallers Creek	oil	7/27/90	160	governmental 1/4	660	no requirement
Northeast Barnett	oil	3/2/90	160	contiguous acreage	660	1,320
Northwest Range	oil	12/14/90	160	contiguous acreage	660	no requirement
Pace Creek	oil	2/28/87	160	governmental 1/4	660	1,320
Palmers Crossroads	oil	11/14/88	160	governmental 1/4	660	no requirement
Perdido	oil	8/30/84	160	contiguous acreage	660	1,320
Puss Cuss Creek	oil	8/3/79	160	contiguous acreage	660	1,500
Red Creek	condensate	6/28/84	640	contiguous acreage	1,320	no requirement
Robinson Creek	oil	10/17/90	160	governmental 1/4	660	no requirement
Silas	oil	12/17/75	160	contiguous 80's	600	1,500
Sizemore Creek	condensate	7/21/86	320	contiguous acreage	660	no requirement
Smiths Church	condensate	8/5/88	640	governmental section	1,320	no requirement
South Burnt Corn Creek	oil	12/18/87	160	governmental 1/4	660	1,320
South Cold Creek	oil	3/7/80	160	governmental 1/4	660	no requirement
South Vocation	oil	6/27/86	160	governmental 1/4	660	no requirement
South Wild Fork Creek	condensate	1/20/89	640	governmental 1/4	1,320	no requirement
South Womack Hill	oil	11/1/85	40	contiguous acreage	330	no requirement
Southeast Chatom	condensate	6/24/88	640	contiguous acreage	1,320	no requirement
Southwest Barrytown	oil	5/23/86	160	governmental 1/4	660	1,320
Souwilpa Creek[1]	oil	8/3/79	160	two 80 acre tracts	600	1,500
Souwilpa Creek (revised)	condensate	12/21/79	160	governmental 1/4	600	1,500
Stave Creek	oil	11/2/79	120[2]	contiguous acreage	500	1,500
Sugar Ridge	oil	1/15/74	120-160[3]	rectangular	500	1,500
Toxey	oil	1/19/68	40	governmental 1/4 1/4	150 of center	660
Turkey Creek	oil	12/19/69	160	four 40's	510	1,020
Turnerville	oil	3/7/86	160	governmental 1/4	660	1,320
Uriah	oil	1/29/71	160	governmental 1/4 or contiguous	660	1,320
Vocation	oil	11/17/72	160	contiguous acreage	660	1,320
Wallace	oil	12/18/87	temp. 160	four contiguous 40's	660	1,320
Wallers Creek	oil	10/10/85	160	contiguous acreage	660	1,320
West Appleton	oil	2/16/90	160	governmental 1/4	660	1,320
West Barrytown	oil	9/22/76[4]	130	contiguous acreage	330	1,200
West Bend	oil	12/21/79	160	contiguous acreage	660	1,500
West Okatuppa Creek	oil	12/16/88	80	two 40 acre tracts	330	no requirement
Wild Fork Creek	oil	4/15/88	160	contiguous acreage	660	no requirement
Wimberly	oil	12/16/76	55-135	contiguous acreage	330	1,320
Womack Hill	oil	4/30/71	80-120	contiguous acreage	510	1,020
Zion Chapel	oil	3/4/77	160	two 80 acre tracts	660	1,500

ENHANCED- OR IMPROVED-RECOVERY TECHNIQUES

Eleven fields (or portions thereof) have been unitized for the purpose of increasing the ultimate recovery of hydrocarbons (table 8). Six of these fields were unitized for the purpose of introducing external energy sources, which involves the injection of gas or water. The other five fields were unitized without any specific timetable for fluid injection but instead for the purpose of strategic/infill drilling or regulation of production rates. Two Smackover fields in Alabama, Silas and Choctaw Ridge fields, were unitized without plans for enhanced or improved recovery, but for the purpose of regulating production rates and reducing operating costs. (See Hall, 1992, for further discussion.) Strategic well placement involves the drilling of additional well(s) at specific locations to increase hydrocarbon recovery.

In some instances, wells are strategically located to encounter hydrocarbons updip of existing wells. In other instances, wells may be located in areas where porosity or permeability values are lower than in the surrounding areas, inhibiting effective recovery of hydrocarbons. Recovery from such areas will be most cost effective with smaller well spacing. Three Smackover fields in Alabama have been unitized to allow drilling of additional well(s) at strategic locations (table 8). In each case, this was the only enhanced- or improved-recovery mechanism employed. Additional wells drilled in these fields were located so that hydrocarbons could be efficiently recovered. Waterflooding is an enhanced-recovery technique that involves the injection of water into a reservoir to force crude oil toward producing wells (Schumacker, 1978). This technique provides for increased sweeping of hydrocarbons and increases recovery. Womack Hill and Jay-LEC fields are undergoing enhanced-recovery projects in which waterflooding is an integral part. Injection of gas is the most common enhanced-recovery method used in Smackover reservoirs of southwest Alabama. Gas injection is being used in five fields in Alabama (table 8), two oil fields and three gas-condensate fields. Gases injected include residual methane and nitrogen. Multiple enhanced- or improved-recovery techniques are being implemented in Jay-LEC fields (which compose a single pool). Infill drilling, waterflood, and gas injection have all been implemented successfully.

UNITIZED FIELD CHARACTERIZATIONS AND ENHANCED- OR IMPROVED-RECOVERY PROJECTS

Eleven Smackover fields have been unitized in southwest Alabama through 1990 (fig. 11, table 8). In this section, these fields are described and the enhanced- and improved-recovery projects evaluated. More detailed field descriptions were presented by Hall (1992) and additional data were provided by Kopaska-Merkel and others (1992). The fields are grouped by pore facies (Kopaska-Merkel and Mann, 1991b) because pore-system characteristics have profound effects on fluid flow properties of hydrocarbon reservoirs (e.g., Wardlaw and Taylor 1976; Wardlaw and McKellar, 1981) and strongly influence hydrocarbon production potential of reservoirs (Kopaska-Merkel and Mann, 1991b). In the Smackover of Alabama, reservoirs with different pore systems have been developed using different enhanced- and improved-recovery techniques (table 12). The relationship between pore facies and secondary hydrocarbon recovery is discussed further in a later section.

FIELDS IN THE MOLDIC PORE FACIES

Four unitized fields in Alabama are assigned to the moldic pore facies of Kopaska-Merkel and Mann (1991b) (table 12). They are oil fields that have combination drives and proven productive areas of less than 1,000 acres each and cumulative production per field less than 4 million barrels of oil.

CHOCTAW RIDGE FIELD

Choctaw Ridge field was discovered in 1967 by Pruet and Hughes Company with the drilling of the Trice No. 1 well (Permit No. 1413) in Choctaw County, Alabama. The discovery well was perforated in the Smackover Formation from 11,940 to 11,952 feet and 11,963 to 11,964 feet. The trap is

Table 12.--Distribution of unitized fields relative to pore facies

Pore facies	Field	EOR method	Cumulative production (BBLS)
Moldic	Choctaw Ridge	none	3,622,609
	Silas	none	1,749,675
	Stave Creek	strategic well	2,948,292
	Turkey Creek	strategic well	2,760,873
TOTAL			**11,081,449**
Intercrystalline	Chunchula	gas injection	47,590,487
	Hatter's Pond	gas injection	41,680,069
TOTAL			**89,270,556**
Intermediate	Appleton	strategic well	1,932,412
	Chatom	gas injection	14,366,761
	Fanny Church	gas injection	[1] 4,291,131
	Jay-LEC	infill drilling waterflood gas injection	[2] 399,324,471
	Womack Hill	waterflood	[3] 15,752,867
TOTAL			**435,667,642**

[1]Production from Steely pod only
[2]Includes Alabama and Florida portions of field
[3]Production from Womack Hill field unit only

structural; the field is located on a faulted salt-cored anticline with over 150 feet of structural closure (fig. 51). The most porous portion of the reservoir is in the uppermost Smackover. Porosity ranges from 7.5 to 31.1 percent and averages 19.39 percent with a standard deviation of 4.95 percent. Permeability for the Smackover reservoir ranges from 1.9 to 1,410 md with a geometric mean of 21.44 md (Kopaska-Merkel and others, 1992). The Smackover reservoir consists of oolitic and pelletal dolomitic grainstone and dolograinstone that was deposited on a high-energy subtidal shoal. Moldic pores predominate (61 percent of the pores identified). Secondary intraparticle pores (36 percent) and interparticle pores (3 percent) account for the rest of the reservoir (Kopaska-Merkel and others, 1992). A total of 7 wells were completed as producers in the field, 6 of which were still producing at the time of unitization. Prior to unitization in 1974, 1.9 million barrels of oil and 1.2 billion cubic feet of gas had been produced. Cumulative production from the field is 3.6 million barrels of oil and 1.85 billion cubic feet of gas.

SILAS FIELD

Silas field was discovered in Choctaw County, Alabama, with the drilling of the Chesnut Unit 4-15 No. 1 well (Permit No. 2084) in 1975. The well was completed in the Smackover Formation in the interval from 13,564 to 13,578 feet. Silas field is located on a faulted salt-cored anticline (fig. 52). Average pay thickness is 16 feet. Field limits encompass 1,280 acres (Kopaska-Merkel and others, 1992). The main porous and permeable reservoir interval is located in the upper Smackover. Porosity ranges from 4.9 to 29.80 percent with an average of 15.08 percent and a standard deviation of 6.95 percent. Permeability ranges from 0.05 to 216 md with a geometric mean of 1.17 md (Kopaska-Merkel and others, 1992). The reservoir is dominated by peloidal ooid dolograinstone interpreted to have been deposited in a beach-barrier complex. Moldic and secondary intraparticle pores dominate. Six wells are located within the field limits; two are productive. Total reservoir volume of Silas field is approximately 5,335 acre feet (Pruet and Hughes Co., Exhibit 8, Docket No. 8-13-763, State Oil and Gas Board of Alabama). The field is interpreted to produce by a combination drive consisting of

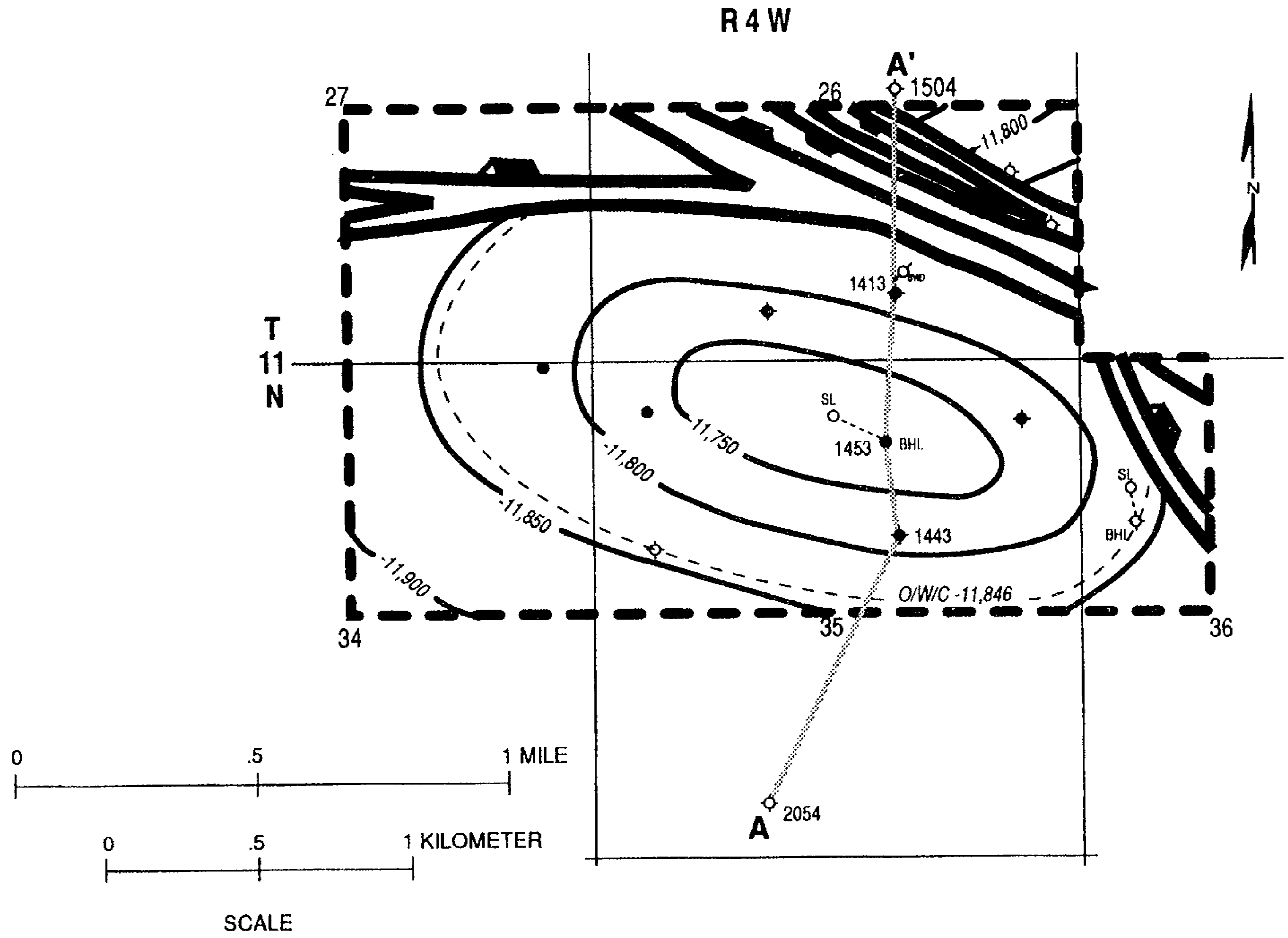


Figure 51.--Structure contour map on top of Smackover Formation in Choctaw Ridge field, Alabama (modified from Pruet and Hughes Company, Exhibit 2, April 30, 1974, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

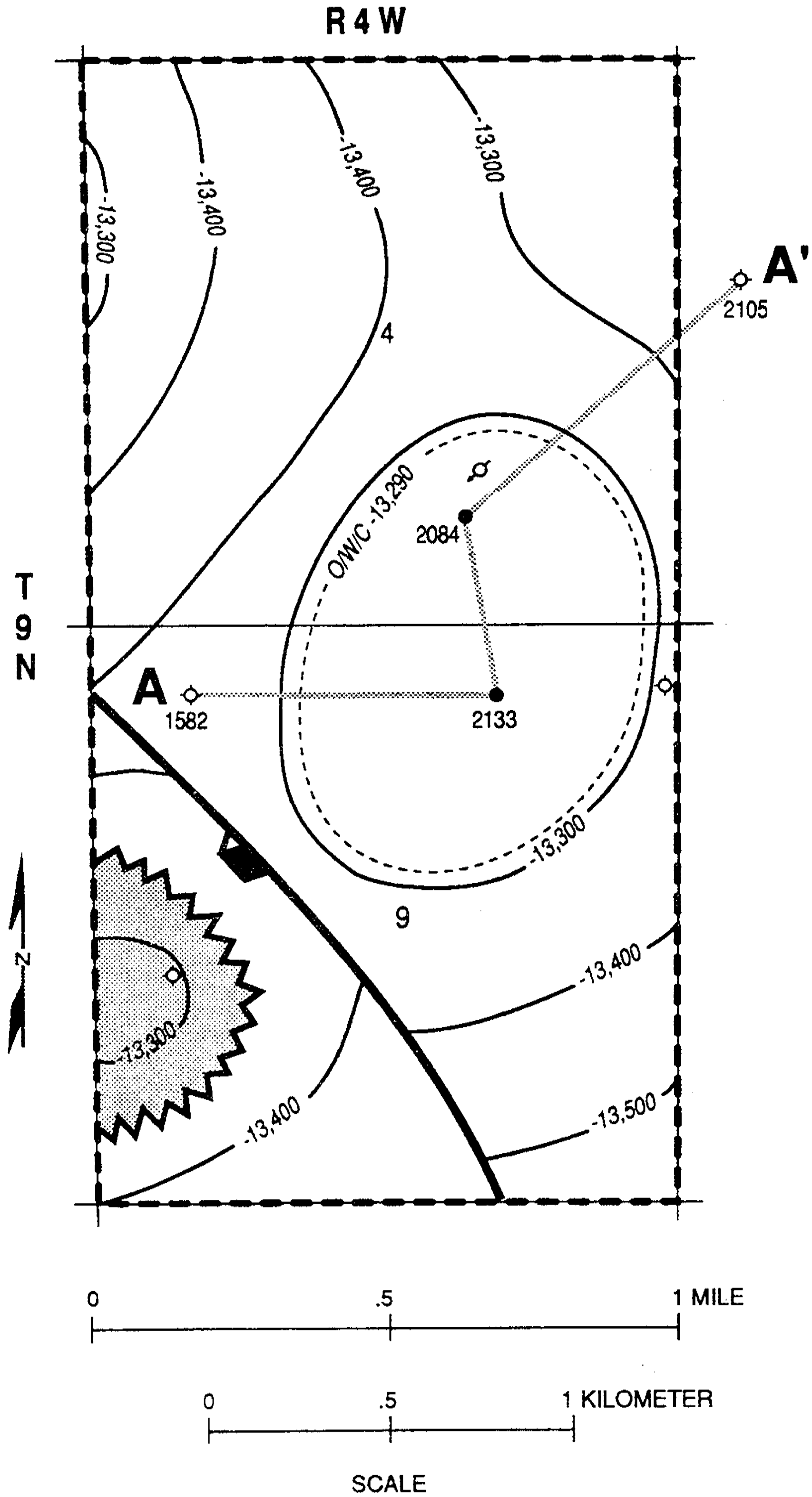


Figure 52.--Structure contour map on top of Smackover Formation in Silas field, Alabama (modified from Pruet and Hughes Company, Exhibit 3, Docket No. 8-13-763, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992)).

solution-gas expansion and water influx. The original bottomhole pressure of the field was 6,429 psia and has since dropped to 3,448 psia (Kopaska-Merkel and others, 1992). Cumulative production from the field is 1.7 million barrels of oil and 1.8 billion cubic feet of gas.

STAVE CREEK FIELD

Stave Creek field was discovered in 1979 with the drilling of the McCorquodale 25-1 No. 1 well. The Smackover was perforated between 12,454 and 12,473 feet. The Stave Creek structure proved to be difficult to predict and of 12 wells drilled in the field, 8 were dry holes. The field limits encompass 1,400 acres of which 193 are interpreted to be productive (Kopaska-Merkel and others, 1992). The Stave Creek structure is a salt-cored anticline (fig. 53) ; relief of the structure is greater than 350 feet. Average pay thickness in the field is 65 feet, and an oil-water contact is at a subsea depth of 12,400 feet. The initial reservoir pressure was 6,046 psia and the drive mechanism is interpreted to be primarily water with a solution-gas component (Kopaska-Merkel and others, 1992). The Buckner Anhydrite seals the Smackover reservoir, which is extremely porous at the top of the interval. Porosity in the Smackover ranges from 4.9 to 26.7 percent and averages 15.3 percent with a standard deviation of 4.8 percent. Permeability ranges from 0.02 to 733 md with a geometric mean of 5.67 md (Kopaska-Merkel and others, 1992). The reservoir in the McCorquodale 25-1 well in Stave Creek field is an ooid dolograinstone, which is believed to have been deposited in a high-energy shoal environment. Interparticle, secondary intraparticle, and moldic pores are the most common pore types and account for 34, 26, and 21 percent, respectively, of the pores identified. Three wells had been completed as producers prior to the unitization hearings which were held in February 1985.

The operator proposed that drilling a well on the crest of the structure would allow for the recovery of oil located above the highest perforations in the field (Pruet Oil Co., Exhibit 2, Docket No. 1-23-8528, State Oil and Gas Board of Alabama). Total reserves within the field were calculated to be over 6 million barrels of oil, of which approximately 3 million barrels were interpreted to be recoverable. The operator concluded that there were approximately 26 crestal acres of Smackover reservoir not drained by existing wells. This area was interpreted to contain 371,900 stock-tank barrels of oil, of which over 188,000 barrels could be recovered. Including this "attic oil," there would be 1.9 million barrels of remaining recoverable oil (Pruet Oil Co., Exhibits 5 & A-10, Docket No. 1-23-8528, State Oil and Gas Board of Alabama). The field was unitized in 1985 with an effective date of March 15. The Stave Creek Field Unit No. 1 (Permit No. 4681) was drilled into the apex of the Stave Creek reservoir and tested at a rate of 535 barrels of oil per day on a 14/64-inch choke in October 1985. This well has cumulatively produced approximately 760,000 barrels of oil, which is 26 percent of the field's total production and approximately 45 percent of the field's production since unitization.

Prior to unitization, Stave Creek field had produced 1,278,927 barrels of oil and 336,790 MCF of gas (Masingill, 1990). Since unitization, Stave Creek field has produced 1,669,365 barrels of oil through December 1990. Cumulative production for the field through December 1990 is 2,948,292 barrels. Oil and gas production in the field are decreasing while water production is on the increase (fig. 54).

TURKEY CREEK FIELD

Turkey Creek field, Choctaw and Clarke Counties, Alabama, was discovered by Chesley Pruet in 1969 with the drilling of the Alco Land and Timber Company, Inc.-Power Unit 28-5 No. 1 well (Permit No. 1509). The discovery well was perforated in the Smackover Formation from 12,378 to 12,930 feet. The field is located on a salt-cored anticline that is cut by a down-to-the-north normal fault with over 100 feet of displacement at the Smackover horizon (fig. 55). The trap is a combination trap. Average net pay thickness is 18 feet. The field limits encompass 1,920 acres, of which 995 are interpreted to be oil productive (Kopaska-Merkel and others, 1992). Porosity values are highest in the upper Smackover, and range from 12.4 to 33.7 percent with an average of 20.6 percent and a standard deviation of 4.4 percent. Permeability ranges from 1.4 to 385 md with a geometric mean of 47.02 md (Kopaska-Merkel and others, 1992). The field was initially characterized by low gas/oil ratios and low pressures. Between the years of 1969 and 1975, the water level in the field rose 11 feet from its

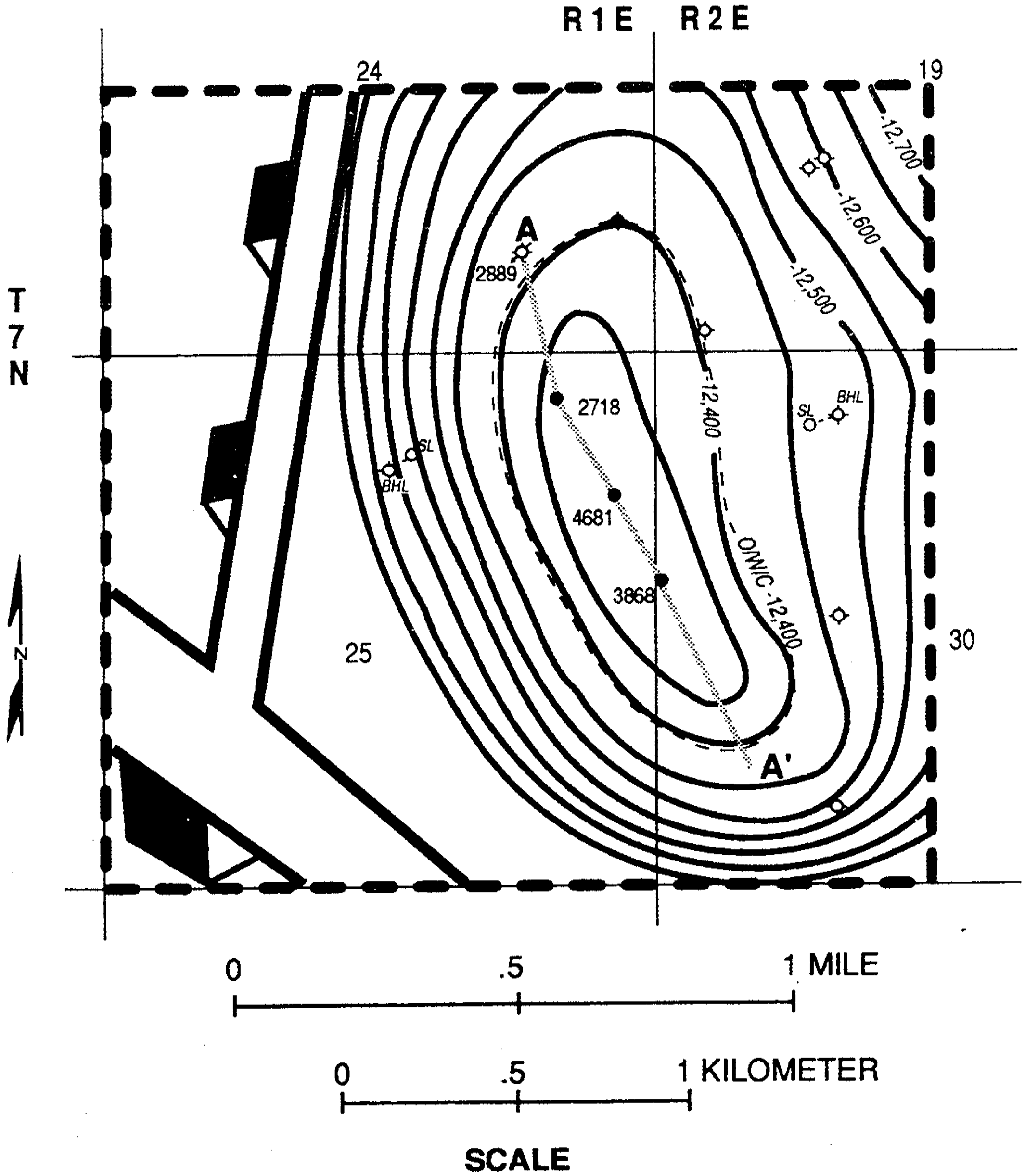


Figure 53.--Structure contour map on top of Smackover Formation in Stave Creek field, Alabama (modified from Pruet Oil Company, Exhibit 2, Docket No. 1-23-8528, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

original subsea depth of 12,378 to a subsea depth of 12,367 feet (Pruet and Hughes Co., Exhibit 3, Docket No. 10-22-747, State Oil and Gas Board of Alabama). The drive mechanism is believed to be solution-gas expansion and water influx (Kopaska-Merkel and others, 1992).

Turkey Creek field was unitized in 1975. At the time of unitization, the field contained three producing wells, which had cumulatively produced over 858,062 barrels of oil and 42,903 MCF of gas (Masingill, 1990). Original oil-in-place for Turkey Creek field is estimated to be approximately 12.2 million barrels of stock-tank oil (Pruet and Hughes Co., Exhibit 4, Docket No. 10-22-747, State Oil and Gas Board of Alabama). The field was unitized by Pruet and Hughes Company to allow the drilling of an additional well within the field. The additional well was warranted because it was estimated that

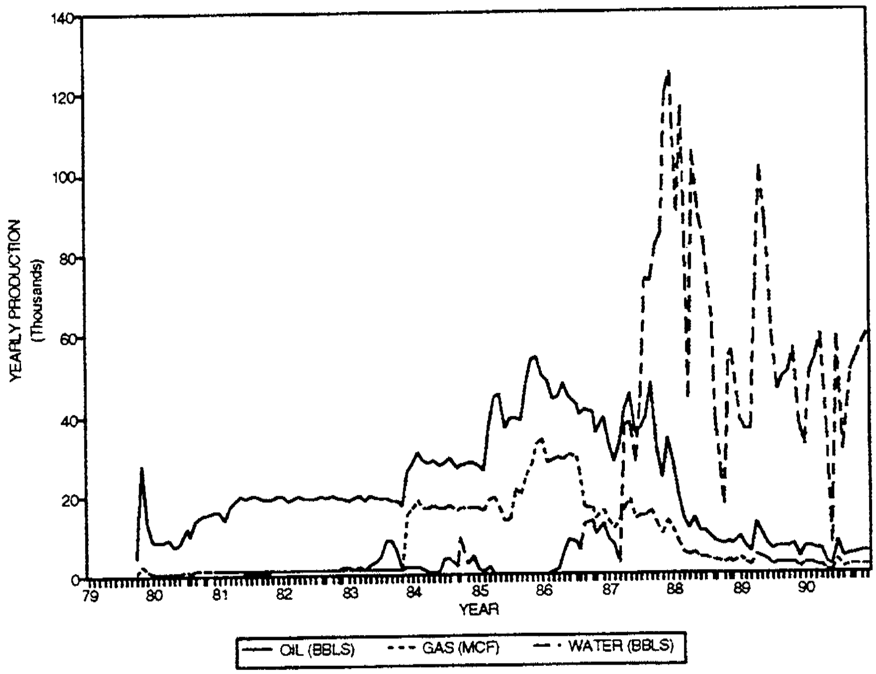


Figure 54.--Graph of production history of Stave Creek field, Alabama.

there was updip of existing wells approximately 820 acre-feet of reservoir which contained an additional 309,000 stock-tank barrels of recoverable oil (Pruet and Hughes Co., Exhibit 4, Docket No. 10-22-747, State Oil and Gas Board of Alabama). The entire unitized area encompassed 480 acres.

At the time of unitization, the operator estimated that only 6.8 percent of the original oil-in-place had been recovered, and by unitizing the field and allowing for an additional well, 4.2 million barrels of oil could ultimately be recovered from the reservoir. The additional updip well being proposed by Pruet and Hughes would contribute 309,000 stock tank barrels of this oil (Pruet and Hughes Co., Exhibit 4, Docket No. 10-22-747, State Oil and Gas Board of Alabama). The Alco Land and Timber Co., Inc.-Power Unit 28-3 No. 1 well (Permit No. 2030) was completed in the Smackover Formation in 1975 and tested at a rate of 308 barrels of oil and 27 MCF of gas per day on pump. The well has produced 608,306 barrels of oil.

Since Turkey Creek field was discovered, it has produced approximately 2.7 million barrels of oil and 137 million cubic feet of gas through December 31, 1990. Approximately 68 percent of the oil produced was recovered after unitization. The field is currently producing 102 barrels per day. Production from the field in 1990 was 37,457 barrels of oil and 1,871 MCF of gas. In Turkey Creek field oil production is declining while water production is on the increase (fig. 56).

FIELDS IN THE INTERCRYSTALLINE PORE FACIES

Two unitized fields in southwest Alabama are assigned to the intercrystalline pore facies (table 12). Both are gas-condensate fields, and traps are structural or combination types. Total production from Chunchula and Hatter's Pond fields is over 89 million barrels of condensate.

CHUNCHULA FIELD

Chunchula field, in Mobile County, was discovered by Union Oil Company of California in 1974. The discovery well, the International Paper Company 22-13 No. 1 well (Permit No. 1886), was

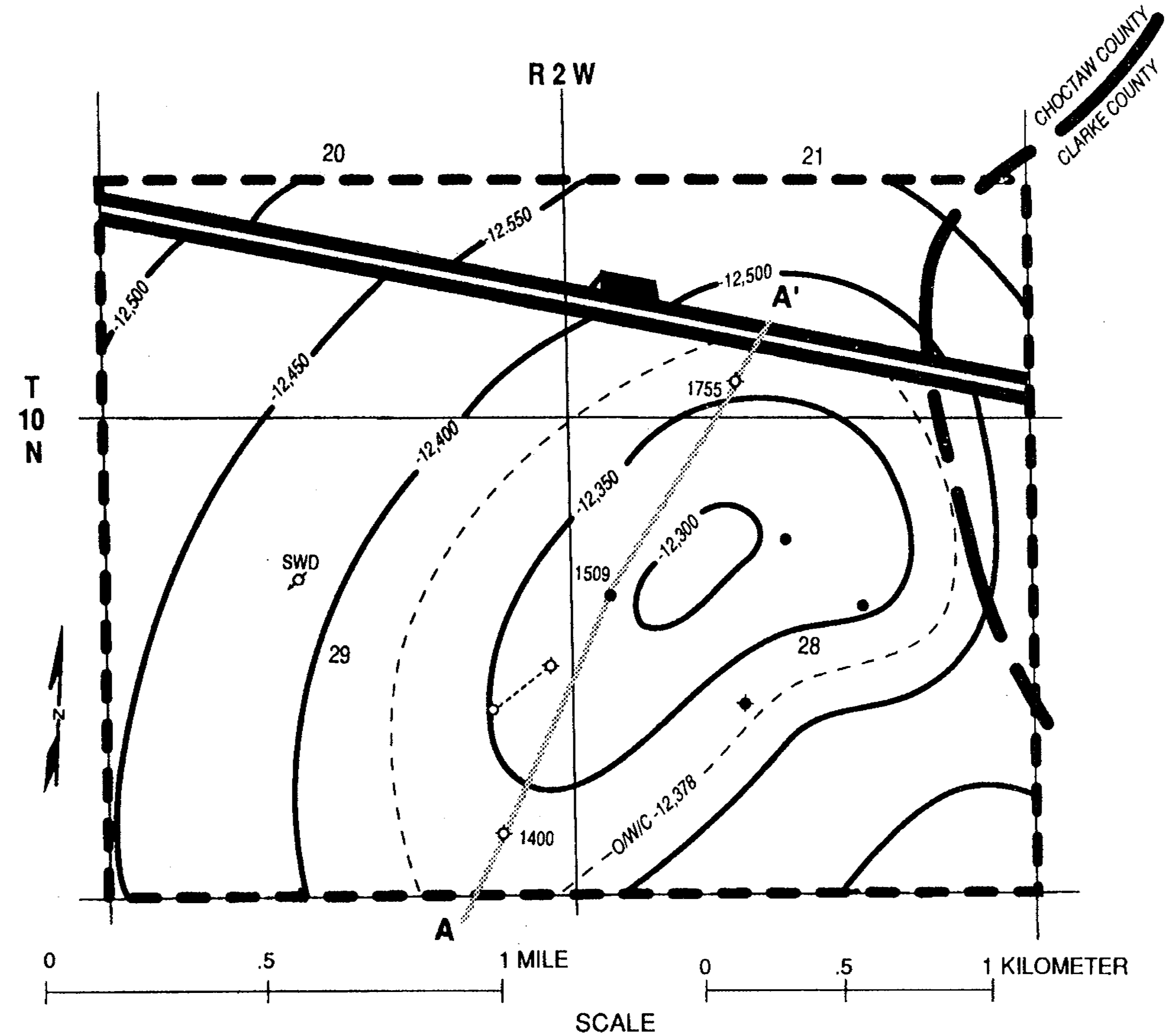


Figure 55.--Structure contour map on top of Smackover Formation in Turkey Creek field, Alabama (modified from Fina Oil and Chemical Company, Exhibit 3, Docket No. 6-23-8823, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

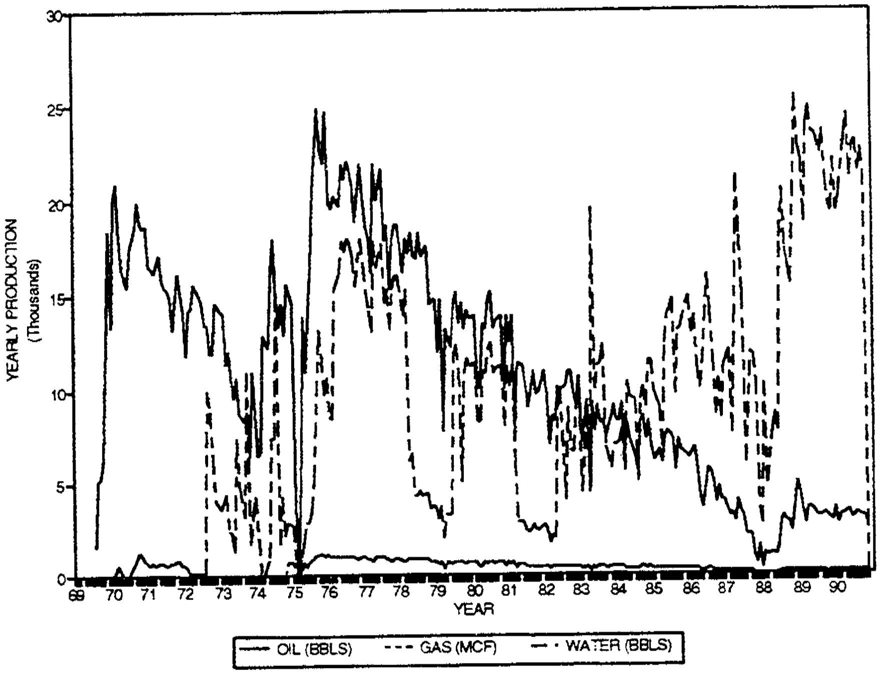


Figure 56.--Graph of production history of Turkey Creek field, Alabama.

completed in the Smackover Formation and perforated in the interval between 18,421 to 18,438 feet. Chunchula field is a major hydrocarbon accumulation with field limits encompassing more than 25,000 acres (Kopaska-Merkel and others, 1992). Chunchula field has a combination trap. The field is located on a broad salt-cored anticline which has minimal structural relief (fig. 57). The gas-water contact in the field varies considerably. Average net pay thickness is 34 feet (Kopaska-Merkel and others, 1992). The Smackover reservoir in Chunchula field was described in detail by the University of Alabama (1991). Porosity averages 12.9 percent and permeability averages 6.2 md. The reservoir is dominated by intercrystalline pores, but interparticle, moldic, secondary intraparticle, and vuggy pores are all important. The original bottomhole pressure in Chunchula field was 9,255 psia and had declined to 4,317 psia by December 1990 (Kopaska-Merkel and others, 1992).

A reservoir-fluid study of the International Paper Company 22-13 well (Permit No. 1886B) suggested that the fluid in the Chunchula reservoir exists in an undersaturated gas phase. Additional reservoir-fluid data presented to the State Oil and Gas Board of Alabama in 1983 indicated that Chunchula field hydrocarbons existed as both a dense wet gas and a highly volatile oil. Both the wet gas phase and the volatile oil phase have essentially the same chemical composition and differ only in phase present. Very slight changes in chemical composition, pressure, or temperature will cause the reservoir fluids to exhibit a dew point (gas phase), in some instances, or a bubble point (oil phase) in others. The factor controlling which phase is present appears to be structural position in the reservoir (Testimony of R. B. Bellamy, December 21, 1983, State Oil and Gas Board of Alabama). Oil is present around the flanks of the reservoir and gas is dominant on the crest. A transition zone with both oil and gas lies between the two. Thirty-four producing units were established at the time of unitization in 1981.

As a part of this project (Subtask 4), researchers at the University of Alabama performed a detailed geological, engineering, and statistical study of the Chunchula reservoir and of the effectiveness of the enhanced-recovery program. These data were used to develop a model of Chunchula field, and reservoir simulations were performed using MASTER, a reservoir-simulation program developed by the U.S. Department of Energy. For a discussion of the results of the University's research and their recommendations, please refer to University of Alabama (1991).

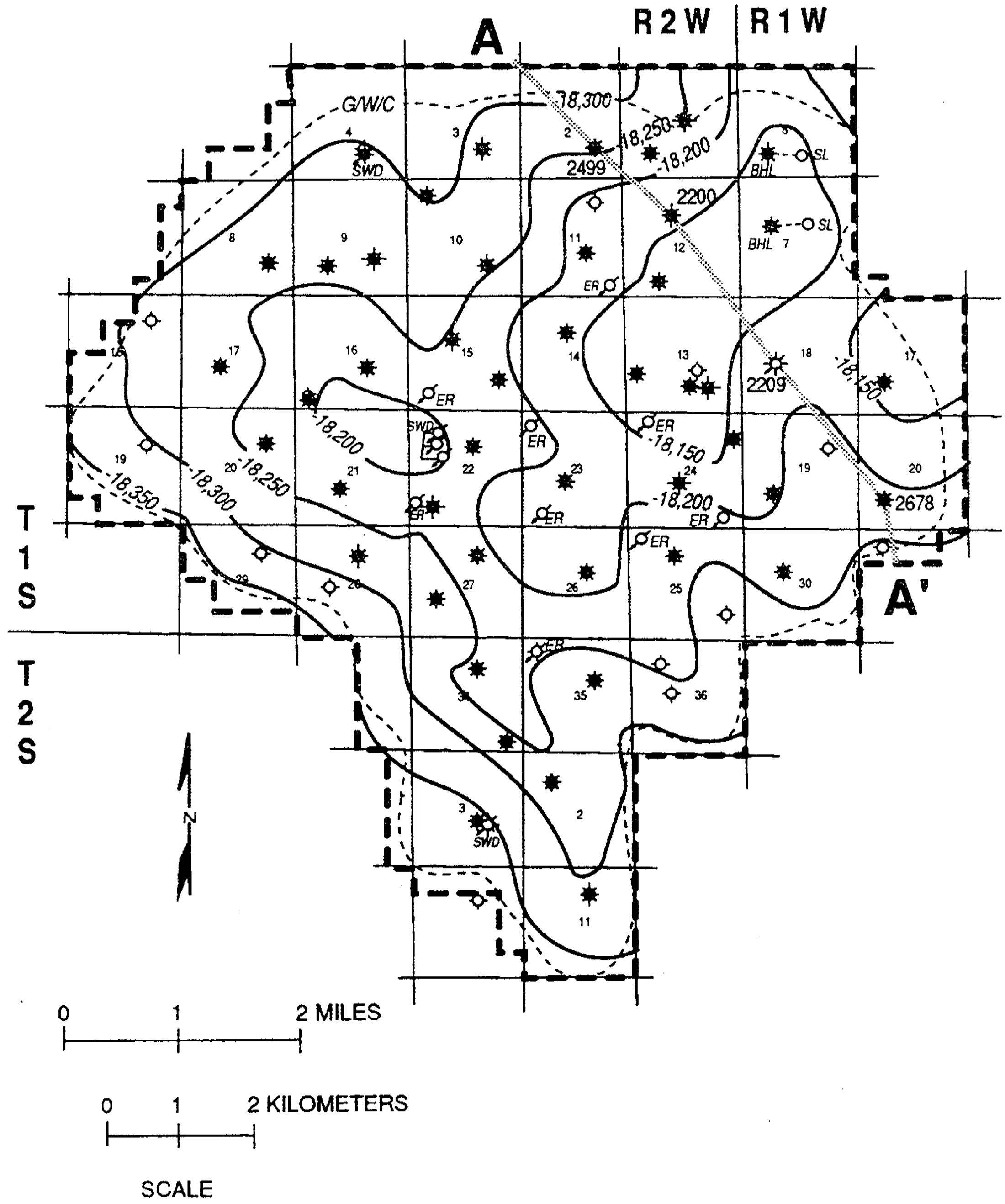


Figure 57.--Structure contour map on top of Smackover Formation in Chunchula field, Alabama (modified from Union Oil Company of California, Exhibit 5, Docket No. 11-7-8021, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

HATTER'S POND FIELD

Hatter's Pond field was discovered in 1974 by Getty Oil Company with the drilling of the Peter Klein 3-14 No. 1 well (Permit No. 1978) in Mobile County, Alabama. The well was drilled to a total depth of 18,358 feet and completed in the Smackover through a perforated interval of 18,042 to

18,062 feet (Masingill, 1990). The reservoir is classified as a gas-condensate reservoir. The underlying Norphlet Formation also produces hydrocarbons (Benson and Mancini, 1982). Hatter's Pond field is located on a faulted salt-cored anticline (fig. 58). The structure trends northeast-southwest adjacent to the Mobile graben and has more than 700 feet of structural relief. Salt piercement occurs on the eastern side of the fault adjacent to the major down-to-the-east normal fault. The field limits encompass more than 9,000 acres of which 6,418 are interpreted to be underlain by hydrocarbons. The average net pay thickness is 59 feet (Kopaska-Merkel and others, 1992). Porosity ranges from 1.2 to 24.4 percent and averages 9.4 percent with a standard deviation of 6.0 percent. Permeability ranges from 0.01 md to 177 md and has a geometric mean of 1.44 md (Kopaska-Merkel and others, 1992). Average porosity and permeability (for reservoir rock only) are 13.5 percent and 10.6 md, respectively (Murray, 1991). Reservoir rock in Hatter's Pond field is dominated by particle-supported dolostone with intercrystalline and (less abundant) interparticle and moldic pores. The original reservoir pressure of Hatter's Pond field was 9,150 psi. Thirteen units were developed during competitive operations. Prior to unitization the field produced 21 million barrels of condensate and 82.7 billion cubic feet of gas (Masingill, 1990).

Hatter's Pond field was unitized with an effective date of May 1, 1985. The proposed unit, which contained approximately 9,100 acres, consisted of all previous production units as well as acreage outside those units that was interpreted to be underlain by the Smackover-Norphlet gas pool. The Hatter's Pond Unit contained 96,622.8 porosity acre-feet of productive pore volume (Getty Oil Co., Exhibit 16, Docket No. 4-11-841, State Oil and Gas Board of Alabama). A porosity cutoff of 6 percent and permeability cutoff of 0.1 millidarcy were used in determining net pay which was then used to determine pore volume (Getty Oil Co., Exhibit 2, Docket No. 4-11-841, State Oil and Gas Board of Alabama).

Engineering studies performed by the operator indicated that the additional recoverable reserves under primary production would be 130 billion cubic feet of full wellstream gas which would contain 69.9 billion cubic feet of sales gas, 33.1 million barrels of condensate, and 6 million barrels of natural gas liquids (Getty Oil Co., Exhibit 21, Docket No. 4-11-841, State Oil and Gas Board of Alabama). However, it was projected that with gas injection, 251 billion cubic feet of full wellstream gas would be recovered which would include 182 billion cubic feet of reservoir gas, 46.5 million barrels of condensate, and 8.7 million barrels of natural gas liquids (Getty Oil Co., Exhibit 22, Docket No. 4-11-841, State Oil and Gas Board of Alabama). Condensate recovery would be increased by 40 percent and recovery of natural gas liquids would be increased by 45 percent. Therefore, the projected benefit of initiating gas injection would be approximately 13.4 million barrels of condensate, 2.5 million barrels of natural gas liquids, and more than 9 billion cubic feet of sales gas.

Since unitization in 1985, two wells have been converted from producers to injection wells. Both wells are located at median elevation in the reservoir. Four producing wells have also been drilled within the field. Since the field was unitized, 20.4 million barrels of condensate and 88.6 billion cubic feet of gas have been produced, through December 1990. Production since the field was established is 41.6 million barrels of condensate (fig. 59) and 171.3 billion cubic feet of gas.

FIELDS IN THE INTERMEDIATE PORE "FACIES"

Five unitized Smackover fields are located within the intermediate pore "facies" (table 12). Hydrocarbon phases include oil and gas-condensate. Reservoirs range in size from less than 400 acres to over 14,000 acres. Traps include structural and combination traps. Production from unitized fields in the intermediate pore "facies" is more than 435 million barrels of oil and condensate, including the Florida portion of Jay-LEC fields.

APPLETON FIELD

Appleton field was discovered by Texaco, Inc., in 1983, but was not formally established as a field until 1985 (Sexton, 1987). The field is located in north-central Escambia County, Alabama and produces from the Smackover Formation at a depth of approximately 12,900 feet. The structure in Appleton field is anticlinal with distinct structural lobes (fig. 60). Two lobes have separate water levels

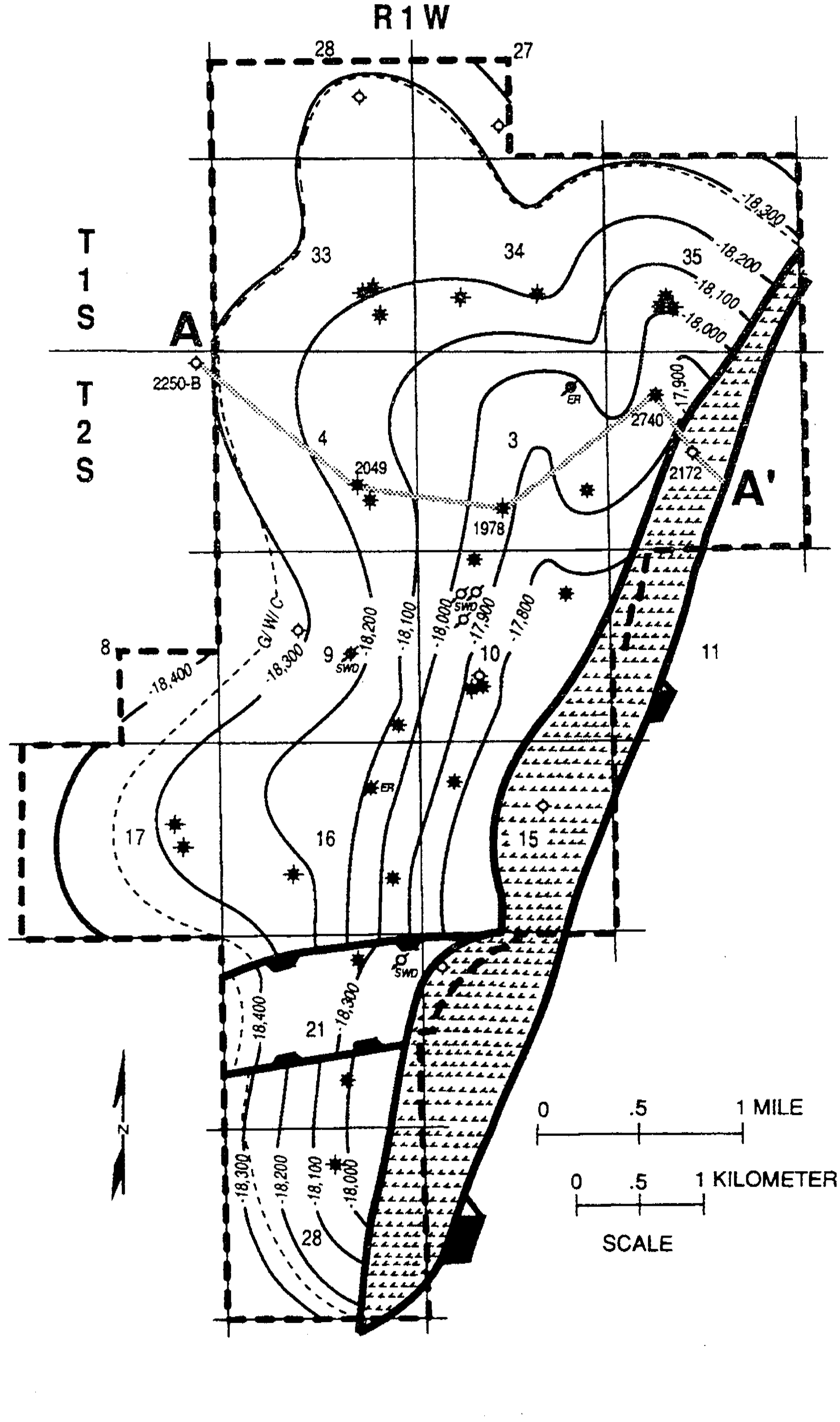


Figure 58.--Structure contour map on top of Smackover Formation in Hatter's Pond field, Alabama (modified from Getty Oil Company, Exhibit 11, Docket No. 4-11-841, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

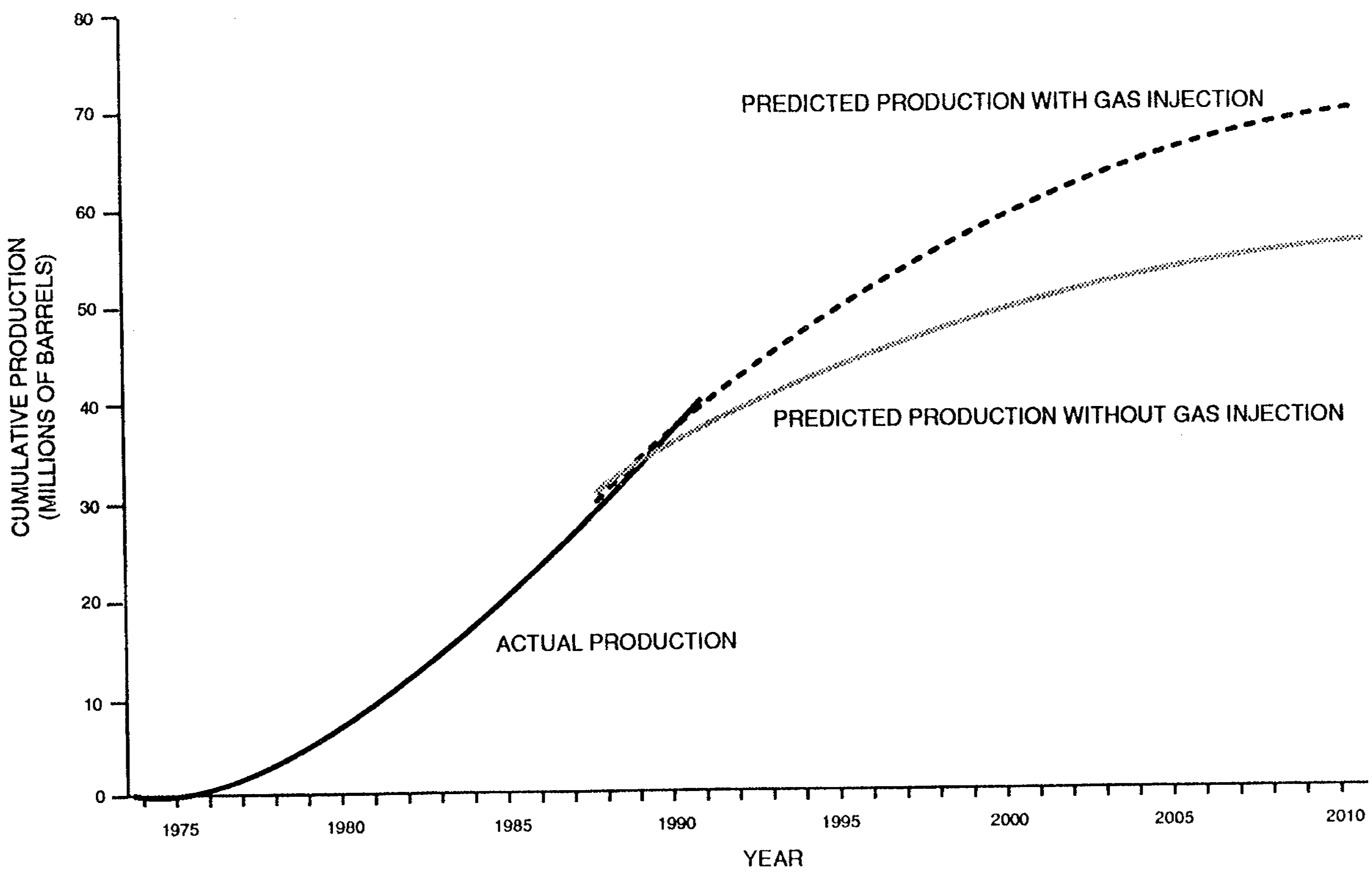


Figure 59.--Predicted versus actual cumulative production in Hatter's Pond field, Alabama (modified from Getty Oil Company, Exhibit 11, Docket No. 4-11-841, State Oil and Gas Board of Alabama).

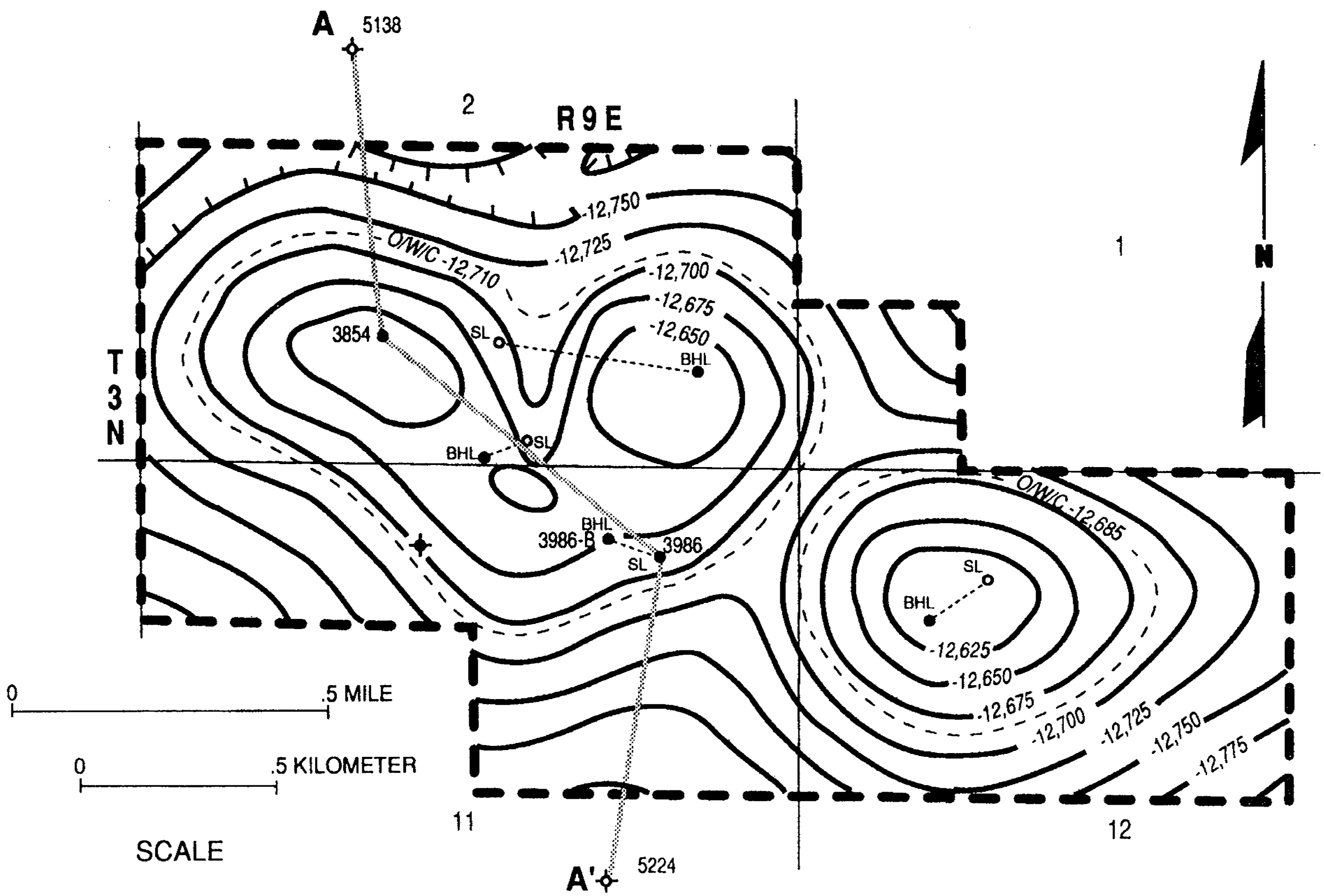


Figure 60.--Structure contour map on top of Smackover Formation in Appleton field, Alabama (modified from Texaco, Inc., Exhibit 6, Docket No. 8-9-891, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

indicating two distinct pools within the field. Water levels within the field range from 12,685 to 12,710 feet subsea and define the two reservoirs. The Appleton anticline is a basement-cored paleotopographic high. The Smackover reservoir in Appleton field includes a variety of particle-supported and microbially bound lithotypes deposited in a shoal complex that developed on and around the paleohigh. Kopaska-Merkel and Mann (1991b) placed the Smackover reservoir of Appleton field in the intermediate pore "facies." Pore types in Appleton field include intercrystalline, moldic, and vuggy pores. Average pay thickness in the field is 39 feet (Kopaska-Merkel and others, 1992). Porosity is present throughout the Smackover in the McMillan 2-14 No. 1 well (Permit No. 3854). The reservoir fluids in Appleton field exist as a undersaturated oil reservoir with a bubble-point pressure of 3,416 psia. The original bottomhole pressure was 6,264 psia. The interpreted drive mechanism for the field is a combination of solution-gas expansion and water influx. As originally established, Appleton field contained 960 acres. Prior to unitization Appleton field contained four producing wells and produced 937,425 barrels of oil and 1.7 billion cubic feet of gas.

Texaco, Inc., requested that the field be unitized to allow drilling of an additional well within the field limits. Units for existing wells surrounded an advantageous location that could be drilled only if the field was unitized. Exhibits indicated that an additional 220,000 barrels of oil and 402 million cubic feet of gas could be recovered from the field. Original oil-in-place in Appleton field was estimated to be 5.3 million stock-tank barrels (Texaco, Inc., Exhibit 10-A, Docket No. 3-10-8814, State Oil and Gas Board of Alabama).

The field was unitized in 1988 with an effective date of May 1, 1988. In March of 1989, the D.W. McMillan Trust 2-15 No. 5 was drilled as an infill well in an attempt to improve recovery. The well was located in the southern part of Section 2 and was expected to encounter the reservoir on the crest of the structure. Based on exhibits presented by Texaco, the D.W. McMillan Trust 2-15 No. 5 well should have encountered the Smackover reservoir at a subsea depth above 12,650 feet and penetrated over 60 feet of reservoir quality rock (Texaco, Inc., Exhibit 3, Docket No. 3-10-8814, State Oil and Gas Board of Alabama). However, the well penetrated the Smackover reservoir significantly lower than had been expected. The Smackover reservoir in the well was encountered at a subsea depth of 12,693 feet and the well penetrated approximately 8 feet of reservoir-quality rock (Texaco, Inc., Exhibits 17 and 20, Docket No. 8-9-891, State Oil and Gas Board of Alabama). In January of 1991, the well was sidetracked approximately 700 feet to the southwest where the well encountered permeable and porous Smackover at a subsea depth of 12,663 feet and penetrated 35 feet of Smackover pay.

A graph of field production excluding the D.W. McMillan Trust 2-15 No. 5 well versus production from all wells shows production in the field as a result of the D.W. McMillan 2-15 No. 5 well (fig. 61). The graph indicates that the D.W. McMillan Trust 2-15 No. 5 well produced at a much higher flow rate than the average of the other wells in the field. Note that although production for both the D.W. McMillan Trust 2-15 No. 5 well and the average of the initial field wells is in a state of decline, the D.W. McMillan Trust 2-15 No. 5 well produces at a significantly higher rate than the average of the other wells in the field and increases the monthly per-well production rates.

Production from Appleton field is declining (fig. 62). Prior to unitization, Appleton field had produced approximately 937,000 barrels of oil and 1.7 billion cubic feet of gas (Masingill, 1990). Production after unitization has accounted for 995,000 barrels of oil through December 1990. Cumulative production for the field through December 1990 is 1.9 million barrels of oil and 3.5 billion cubic feet of gas.

CHATOM FIELD

Chatom field was discovered by Phillips Petroleum Company in 1970 with the drilling of the Williams "AA" No. 1 well in Washington County. The well was perforated between 15,999 and 16,114 feet in the Smackover Formation. Chatom field is situated on a salt-cored anticline which has in excess of 800 feet of closure (fig. 63). The trap is interpreted to be structural. The lowest known gas is interpreted to be at a subsea depth of 16,004 feet and the highest known water is interpreted to be at a subsea depth of 16,141 feet (Phillips Petroleum Co., Exhibit 1A, Docket Nos., 5-17-881 through 5-17-883, State Oil and Gas Board of Alabama). Porosity within the Smackover ranges from 0.13 to 37.2 percent and averages 14.7 percent with a standard deviation of 10.2 percent. Permeability ranges

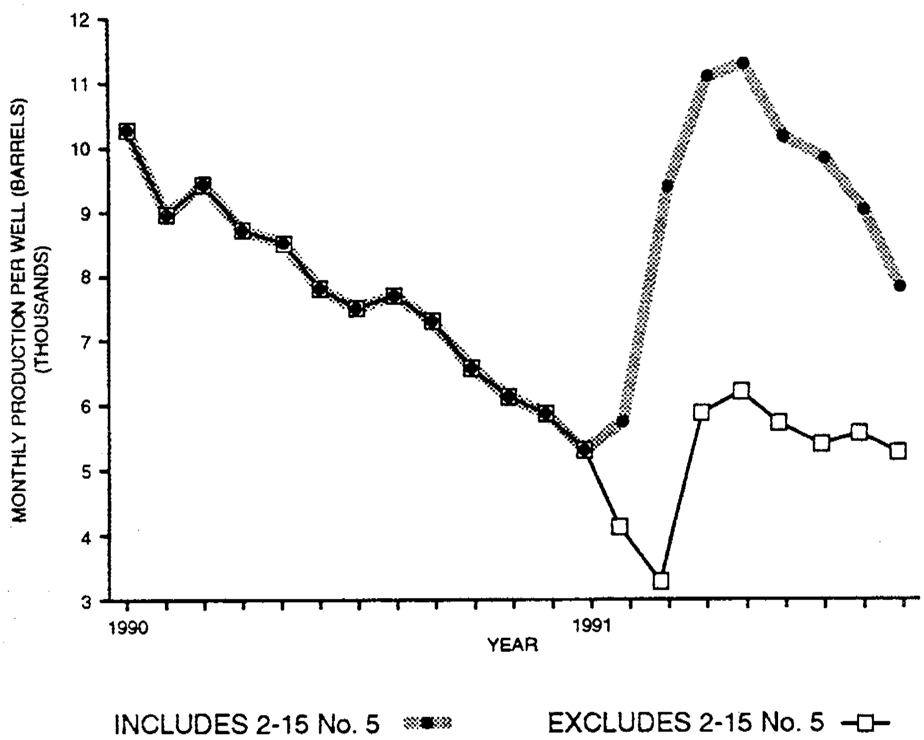


Figure 61.--Graph of production history of Appleton field including the D. W. McMillan 2-15 No. 5 well versus field production excluding the D. W. McMillan 2-15 No. 5 well on a per well basis.

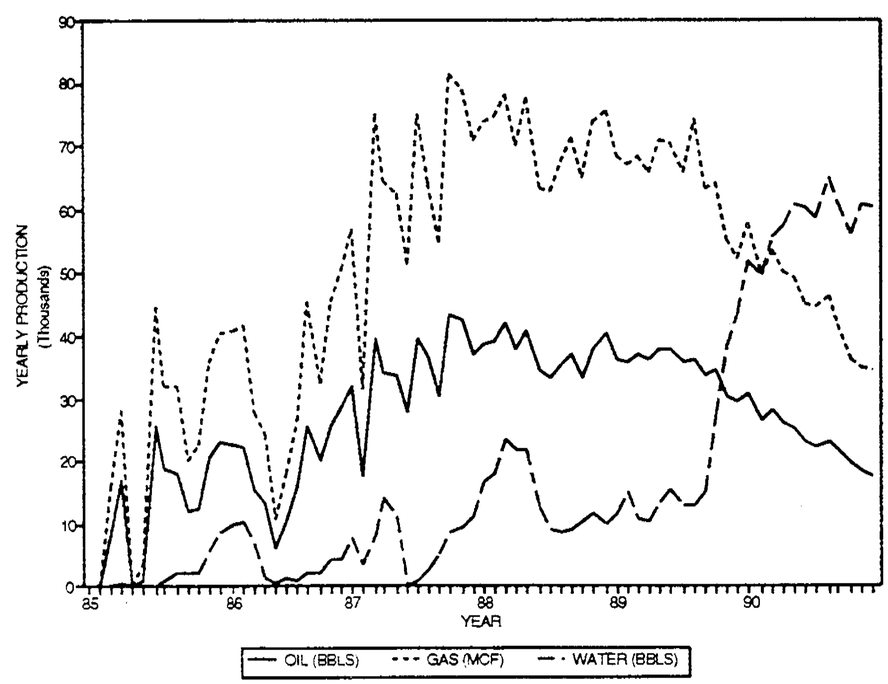


Figure 62.--Graph of production history of Appleton field, Alabama.

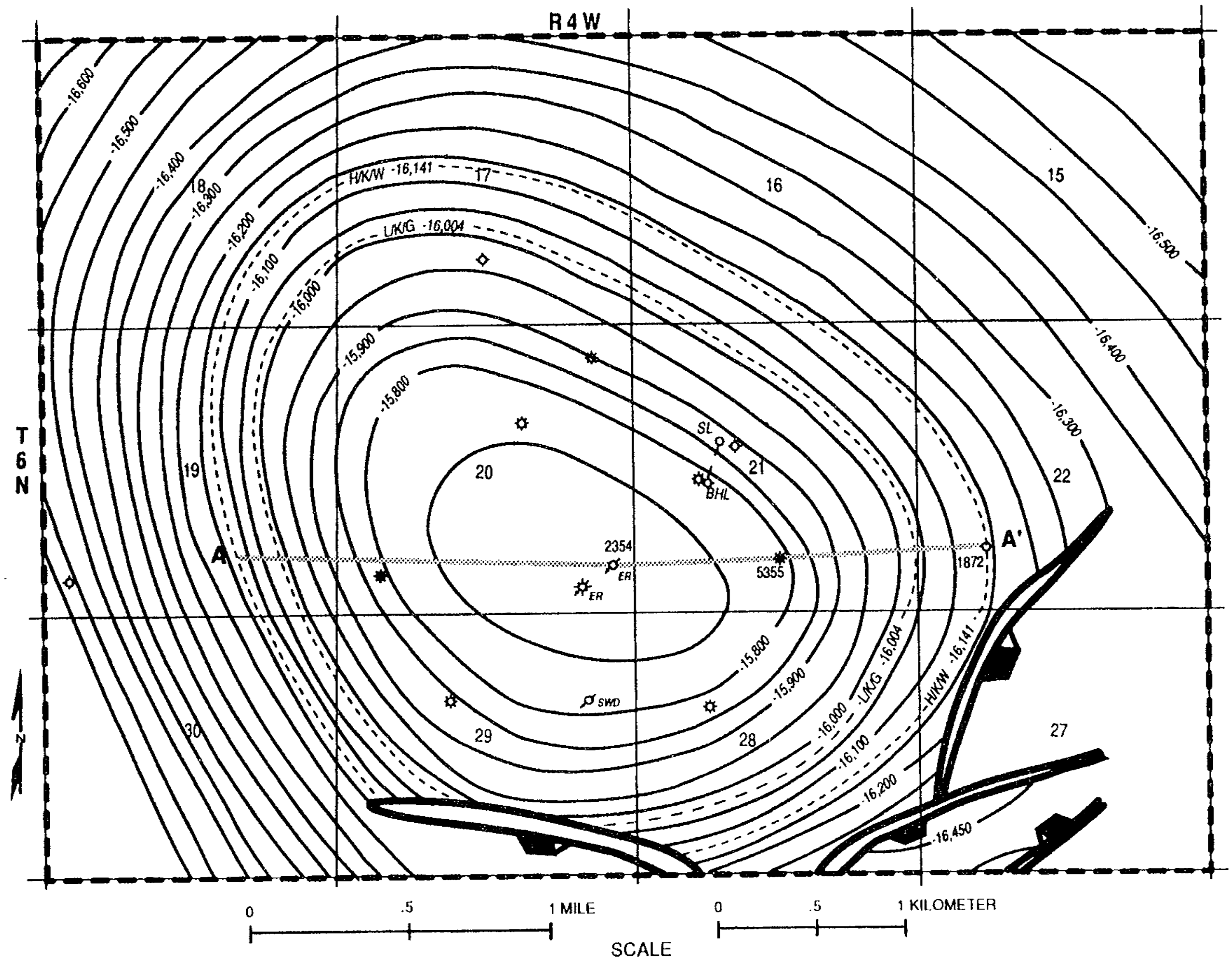


Figure 63.--Structure contour map on top of Smackover Formation in Chatom field, Alabama (modified from Phillips Petroleum Company, Exhibit 1A, Docket Nos. 5-17-881 through 5-17-883, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

from 0.02 to 196 md with a geometric mean of 1.21 md. The Smackover reservoir in Chatom field includes highly altered dolostone with abundant intercrystalline pores and pellet dolograinstone dominated by moldic porosity. Four productive wells were drilled during competitive operations and cumulative production prior to unitization accounted for 2.2 million barrels of condensate and 9.7 billion cubic feet of gas (Masingill, 1990).

The oldest gas-injection program in Alabama is at Chatom field. Chatom field was unitized in 1976 with the purpose of recycling residue gas to increase ultimate recovery (Masingill, 1991). The field area unitized for secondary-recovery operations consisted of 3,300 acres, and the original reservoir volume was determined to be 82,104.7 acre-feet using a 9 percent porosity cutoff (Phillips Petroleum Co., Exhibit 5, Docket No. 4-22-762, State Oil and Gas Board of Alabama). Exhibits presented at the hearing indicated recycling of residue gas would result in 9 million additional barrels of condensate and 5.5 million additional barrels of natural gas liquid. Also, with gas recycling, sulfur recovery would be increased from 196,030 long tons to 530,860 long tons (Phillips Petroleum Co., Exhibit 6, Docket No. 4-22-762, State Oil and Gas Board of Alabama). An injection well was drilled at the apex of the Chatom field anticline to inject gas into the Chatom reservoir and a producing well was converted to a gas injection well. Injection began in 1976 and over 67 billion cubic feet of gas has been injected through 1990 (Masingill, 1991). Since the field was unitized, five production wells have been drilled into the field. Producing wells were situated on the flanks of the structure to recover the hydrocarbons.

After unitization, the yearly production rate increased for Chatom field (fig. 64). The field has produced over 14 million barrels of condensate through 1990. This includes approximately 8 million barrels of condensate that would not have been produced by primary recovery. Chatom field is still producing, and in 1990 produced 690,000 barrels of condensate.

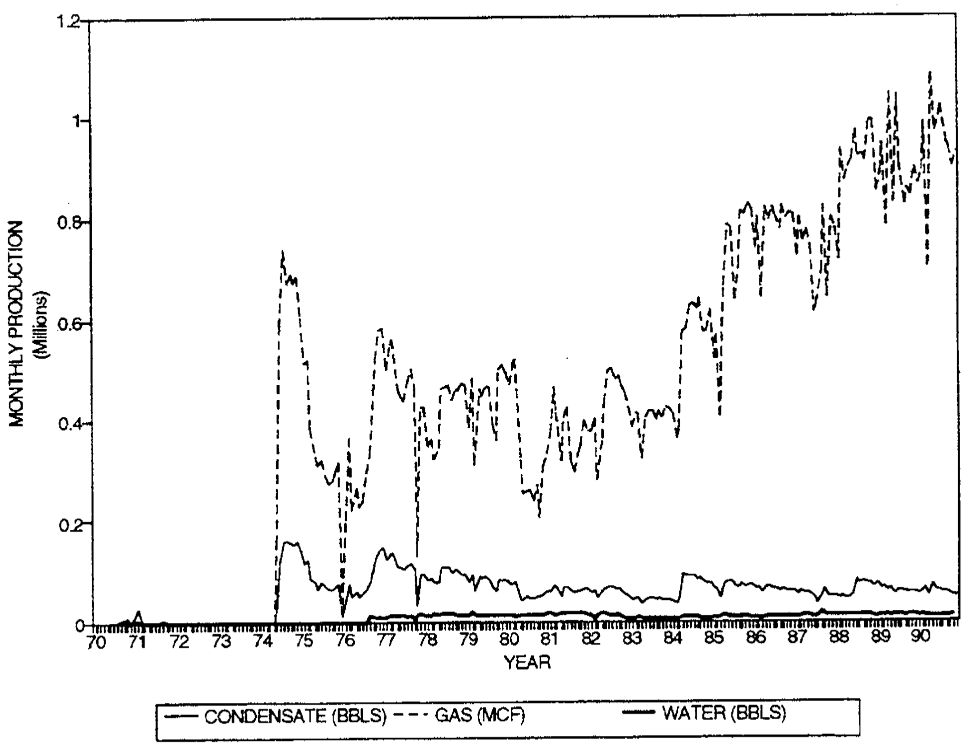


Figure 64.--Graph of production history of Chatom field, Alabama.

FANNY CHURCH FIELD

Fanny Church field was discovered in 1973 with the drilling of the Jimmy L. Bush, et ux. No. 25-3 well (Permit No. 1833) by Exxon Corporation in Escambia County, Alabama. The well was perforated in the Smackover Formation in the interval of 15,377 to 15,457 feet. Fanny Church field is located on a northwest-southeast trending monocline which dips gently to the southwest (fig. 65). The hydrocarbon trap at Fanny Church field is a combination trap where both structural dip and facies variations provide the trapping mechanism. Porous and permeable reservoir rocks in the Fanny Church field are located in pods that may be laterally extensive and are not believed to be in pressure communication with one another (Exxon Corporation, Exhibit No. E-1, Docket No. 12-13-842, State Oil and Gas Board of Alabama). Porous zones occur throughout much of the Smackover in Fanny Church field. Porosity in the Smackover reservoir ranges from 1 to 23.2 percent with an average of 10.7 percent; the standard deviation is 4.4 percent. Permeability ranges from 0.02 to 120 md; the geometric mean is 0.37 md (Kopaska-Merkel and others, 1992). Fanny Church field encompasses 3,960 acres. The field has a total of seven wells that were completed as producers, five of which were still producing as of January 1, 1985. Prior to unitization in 1985, Fanny Church field had produced approximately 2.3 million barrels of oil and 3 billion cubic feet of gas (Masingill, 1990). Geologic and engineering data suggest that in Fanny Church field there are approximately four separate lenses of reservoir quality rock. Three of these lenses are interpreted to be small, but the fourth encompasses more than 700 acres and contains three productive wells. This lens of productive Smackover reservoir is called the Steely pod and encompasses the Dora J. Steely 36-2 well (Permit No. 1869), the Zelma Pugh 26-15 well (Permit No. 3307B), and the St. Regis Paper Co. 35-1 well (Permit No. 3154) (Exxon Corp., Exhibit G-5, Docket No. 12-13-842, State Oil and Gas Board of Alabama).

Fanny Church field was unitized in 1985. The unit operator, Exxon Corporation, intended to institute a miscible-gas injection program in the Steely pod using nitrogen as injection gas, increasing the ultimate recovery of oil in the Steely pod from 30 percent to approximately 54 percent (Exxon Corp., Exhibit E-7, Docket No. 12-13-842, State Oil and Gas Board of Alabama). Exxon estimated that recovery from the Steely pod would only be 3.9 million stock tank barrels of oil under primary recovery, but with miscible-gas injection, the recoverable reserves would be approximately 7 million barrels of oil (an increase of 3.1 million barrels). Implementation of gas injection would also extend the life of the field 4.5 years (Exxon Corp., Exhibits E-8 and E-11, Docket No. 12-13-842, State Oil and Gas Board of Alabama).

Two wells were drilled after approval of unitization. The Dora J. Steely 36-6 No. 1 well (Permit No. 4531) was drilled and then plugged. The A.G. Brantley et al. 36-5 No. 1 well (Permit No. 4922) was drilled and completed as a commercial well. The well had an initial flow rate of 672 barrels of oil and 798 MCF of gas per day. Both wells were located in the central portion of the Steely pod in the northwest quarter of Section 36. Two wells within the Steely pod (the Zelma Pugh 26-15 No. 1 and the Dora J. Steely 36-2) were converted to injection wells to be used in the enhanced-recovery project. Injection operations began in 1985 and a total of 9.3 billion cubic feet of gas were injected into the reservoir before these two wells were reconverted to producing wells. At the present time, no wells within the unit are being used for injection.

Production from the Fanny Church field has been declining in recent years (fig. 66). Through 1990, Fanny Church field has produced 5.69 million barrels of oil. The Steely pod has produced nearly 4.3 million barrels of oil or 75 percent of the total production from the field. Approximately 46 percent of this total or 1.9 million barrels have been produced since the Steely pod was unitized. Since its establishment, the unit has produced 1.9 million barrels of oil and 3.5 billion cubic feet of gas through 1990. Total production from the unit area is 4.29 million barrels of oil and 6.6 billion cubic feet of gas. In 1990, the Upper Smackover Reservoir unit produced at a rate of 521 barrels of oil per day (fig. 67).

JAY-LITTLE ESCAMBIA CREEK FIELDS

Little Escambia Creek field was discovered in 1970 by Humble Oil and Refining Company with the drilling of the T.R. Miller Mill Co. Unit 32-2 No. 2 (Permit No. 1562) in Escambia County, Alabama. The well was perforated in the Smackover Formation between 15,380 and 15,470 feet. Little Escambia

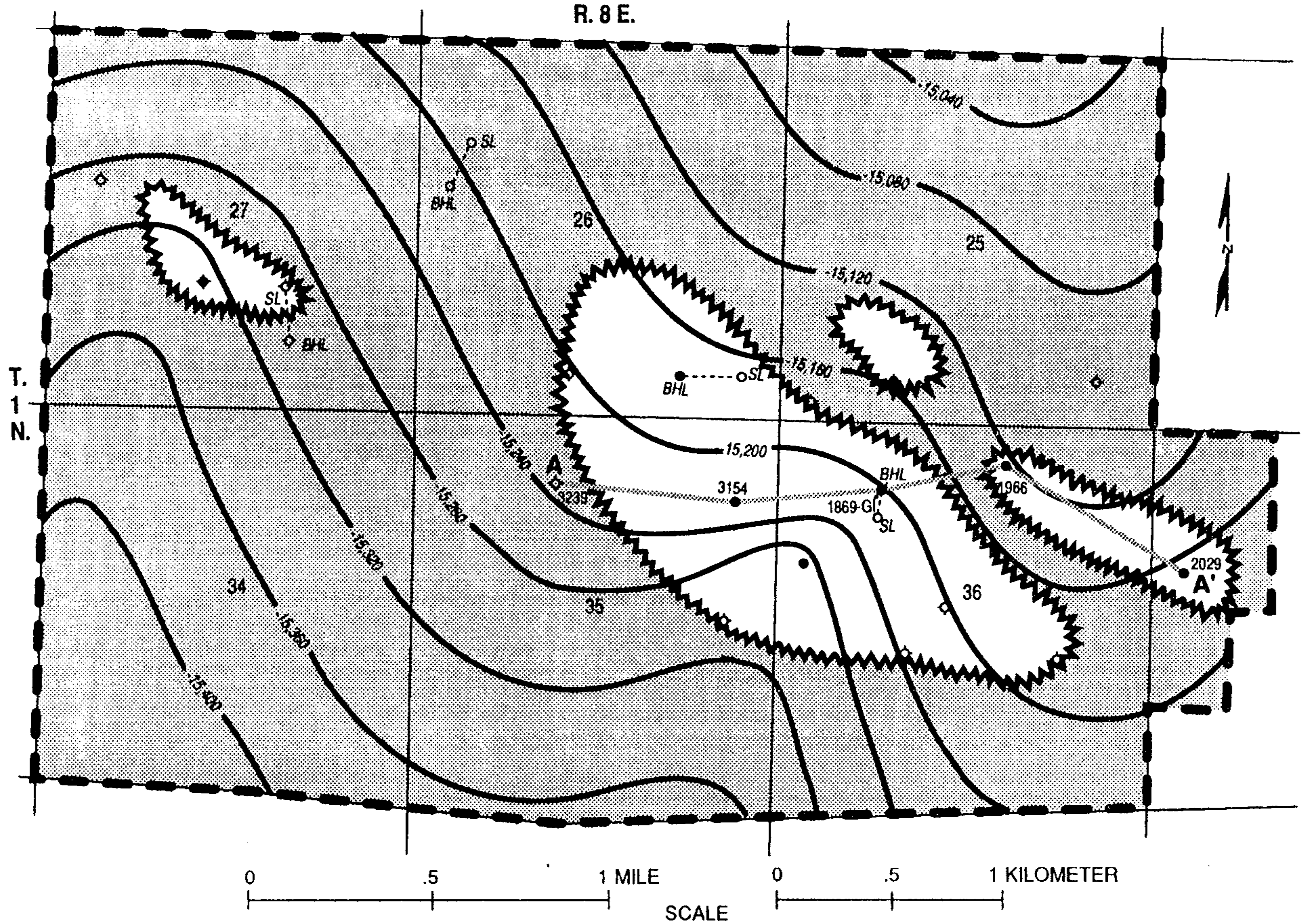


Figure 65.--Structure contour map on top of Smackover Formation in Fanny Church field, Alabama (modified from Exxon Corporation, Exhibit G-3 through G-5, Docket No. 12-13-842, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

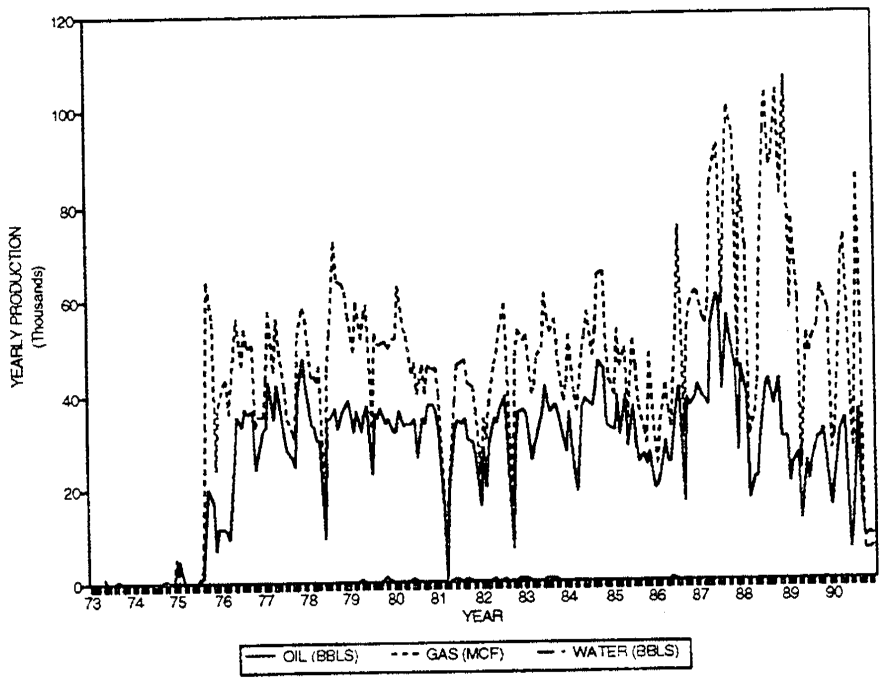


Figure 66.--Graph of production history of Fanny Church field, Alabama.

Creek field is part of a large hydrocarbon accumulation that extends into Escambia and Santa Rosa Counties, Florida, where it is designated Jay field (fig. 68). Jay-LEC fields encompass 14,400 productive acres (Shirer and others, 1978). Most of the field is located in Florida. Within the Alabama portion of the field, Little Escambia Creek field limits encompass 3,840 acres, of which 1,304 are proven to be productive (Kopaska-Merkel and others, 1992). The Jay-LEC reservoir (which includes both Smackover and Norphlet strata) is located on a large salt-cored anticline that trends northwest-southeast just west of the southern extension of the Foshee-Pollard fault system (Ottmann and others, 1973; Sigsby, 1976). The hydrocarbon trap in Little Escambia Creek field is a combination trap. Little Escambia Creek field is located on the north-plunging anticlinal nose of the structure. Also, a facies change to the north provides an impermeable barrier to updip migration of hydrocarbons. Average pay thickness in the Alabama portion of Jay-LEC fields is 82 feet. Porosity in the field ranges from 2.10 to 23.8 percent and averages 11 percent with a standard deviation of 4.3 percent. Permeability in the field ranges from 0.02 to 91 md with a geometric mean of 0.38 md. Porous and permeable zones exhibiting a wide variety of pore systems (most of which are dominated by either intercrystalline pores, secondary intraparticle pores, or multiple pore types) are interbedded with nonporous intervals. Hydrocarbons in Jay-LEC fields are in an undersaturated oil phase. Original bottomhole pressure was 7,850 psia and the bubble point of the hydrocarbons was 2,830 psia. Prior to unitization in 1974, Jay-LEC fields had approximately 85 productive wells within the field limits. Six of these wells were located in Alabama. Cumulative production prior to unitization in the Alabama portion of the field was 3.9 million barrels of oil and 5.4 billion cubic feet of gas (Masingill, 1990). Jay-LEC fields contain 14,415 productive acres. Average net pay thickness of the Smackover-Norphlet oil pool was determined to be 95 feet. The original oil-in-place was calculated to be 728 million stock tank barrels (Langston and Shirer, 1985). The drive mechanism for Jay-LEC fields is solution gas expansion coupled with water influx (Applegate and Lloyd, 1985; Lloyd and others, 1986).

Enhanced- or improved-recovery operations in Jay-LEC fields involve waterflooding, gas-injection, and infill drilling. Jay-LEC fields were unitized in 1974 for the purpose of implementing water injection. Through 1978, injection rates averaged 200,000 barrels of water per day, which

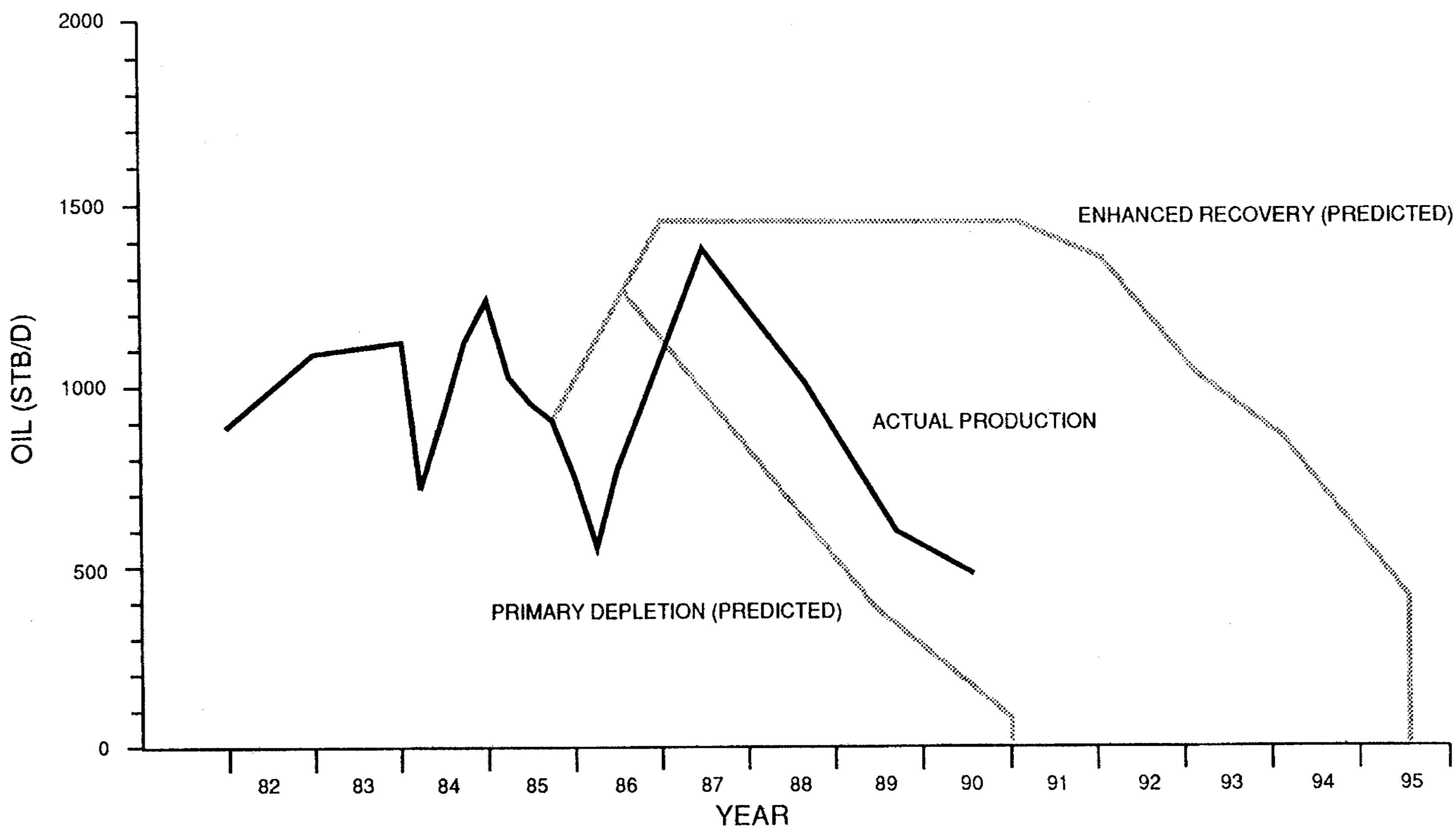


Figure 67.--Predicted versus actual daily production in Fanny Church field unit.

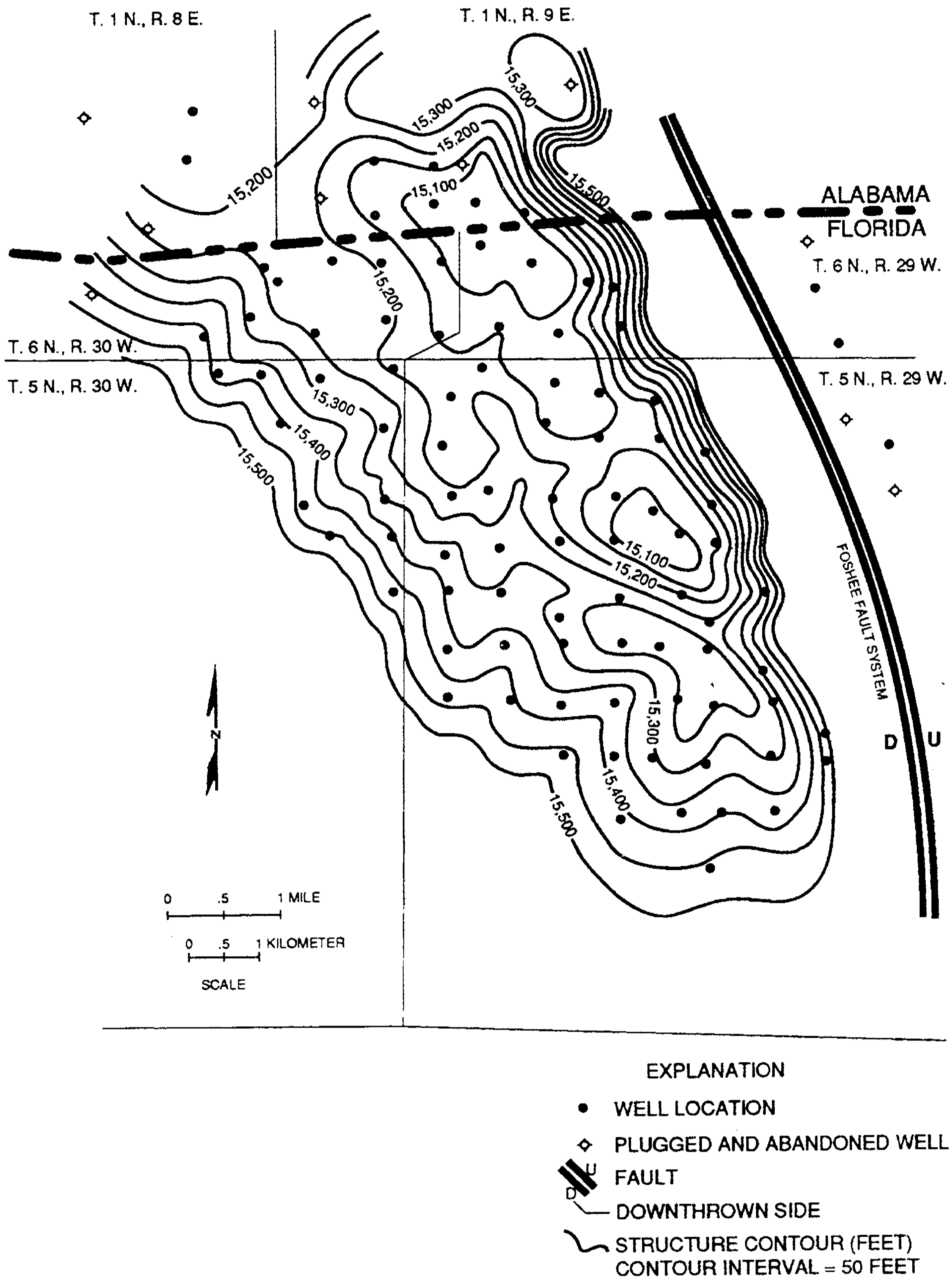


Figure 68.--Structure contour map on top of Smackover Formation in Jay-Little Escambia Creek fields, Santa Rosa and Escambia Counties, Florida, and Escambia County, Alabama (modified from Davis and Lambert, 1963).

resulted in an average of 105,000 stock-tank barrels of oil per day being produced from the Jay-LEC unit (Shirer and others, 1978).

Jay-LEC fields in Escambia County, Alabama, and Escambia and Santa Rosa Counties, Florida, provide an excellent example of how effective reservoir management can significantly increase recovery. Rapid pressure decline observed in the reservoir necessitated implementation of a waterflood project. Reservoir pressure had declined more than 1,500 psig in one year and, based on engineering estimates, only 17 percent of the oil (120.7 million barrels) would be recovered under primary recovery (Exxon Corp., Exhibit E-7, Docket No. 12-7-73, State Oil and Gas Board of Alabama). A water-injection program was implemented in the field using 25 injection wells situated in a staggered 3:1 line drive pattern (Langston and others, 1981). Waterflood operations began in 1974, and injection volumes averaged 200,000 barrels of water per day by 1978 (Shirer and others, 1978). By implementing a waterflood project, it was estimated that an additional 216 million barrels of oil could be recovered from Jay-LEC fields. By 1978, recovery from the field had totaled approximately 204 million stock tank barrels of oil, which was 84 million barrels more than could have been recovered under primary recovery alone (Shirer and others, 1978). In addition to the waterflood, infill drilling and gas injection have been implemented in Jay-LEC fields.

A gas-injection program was commenced in Jay-LEC fields in 1981. Estimations of remaining oil after waterflood were 355 million barrels of oil and 13 percent of this oil (47 million barrels) could be recovered by implementing the water-alternating-gas (WAG) program (Langston and Shirer, 1985). WAG operations began in 1981 and methane gas was used initially. A total of 2 billion cubic feet of methane gas was injected into the reservoir until a nitrogen source was developed. Water was injected into the reservoir along with the methane and nitrogen (Langston and Shirer, 1985).

Infill drilling in Jay-LEC fields was an important part of the waterflooding project (Langston and Shirer, 1985). Modeling studies indicated that the 160-acre spacing was inadequate to effectively sweep low-permeability areas. A total of 37 infill wells were drilled by 1984 in lower permeability areas of the field. Spacing in the affected area was reduced from 160 acres to 112 acres per well. As of 1985, infill wells had produced more than 76 million barrels of oil (Langston and Shirer, 1985) which indicates that the infill-drilling program was successful. Total production from Jay-LEC fields through 1990 is 399 million barrels of oil. An additional 93 million barrels of oil is expected to be recovered from the fields (Tootle, 1991).

WOMACK HILL FIELD

Womack Hill field was discovered by Pruet and Hughes Company and Pelto Oil Company in 1970 with the drilling of the Carlisle Unit 16-4 No. 1 well (Permit No. 1573). The Carlisle Unit was completed in the Smackover Formation and was perforated between 11,432 and 11,442 feet. Since its discovery, Womack Hill field has produced over 25 million barrels of oil, making it the third largest oil field in Alabama. (Citronelle field, which produces from Cretaceous strata, and Little Escambia Creek field are larger.) Field limits encompass 3,485 acres of which 1,637 are interpreted to be productive (fig. 69) (Kopaska-Merkel and others, 1992). Total reservoir net pore volume for Womack Hill field is approximately 20,578 acre-feet with a productive area encompassing approximately 1,770 acres (based on an 11 percent porosity cutoff). Original oil-in-place in Womack Hill field was estimated to be over 87 million barrels of stock-tank oil (Pruet and Hughes Co., Exhibit 8, Docket No. 11-26-746, State Oil and Gas Board of Alabama). Womack Hill field is located on a faulted salt-cored anticline which abuts the peripheral fault system that transects much of southwest Alabama. The structure is elongate, being over 4 miles long and less than 1 mile wide (fig. 69). Structural closure on the Womack Hill anticline is over 300 feet. The trap in Womack Hill field is interpreted to be structural but a major permeability barrier transects the field perpendicular to the axis of the structure. This permeability barrier is narrow, vertical, and completely separates the two parts of the field. The water level which defines the western end of the field is 214 feet lower than the water level to the east. Reservoir-grade porosity is present throughout much of the Smackover reservoir, which is overlain by thick Buckner anhydrite. Porosity in the field ranges from 2.2 to over 33.9 percent and averages 17.6 percent. Standard deviation of porosity values is 5.3 percent. Permeability in the field ranges from 0.02 to over 386 md and has a geometric mean of 6.66 md. Average net pay thickness in the field is 56

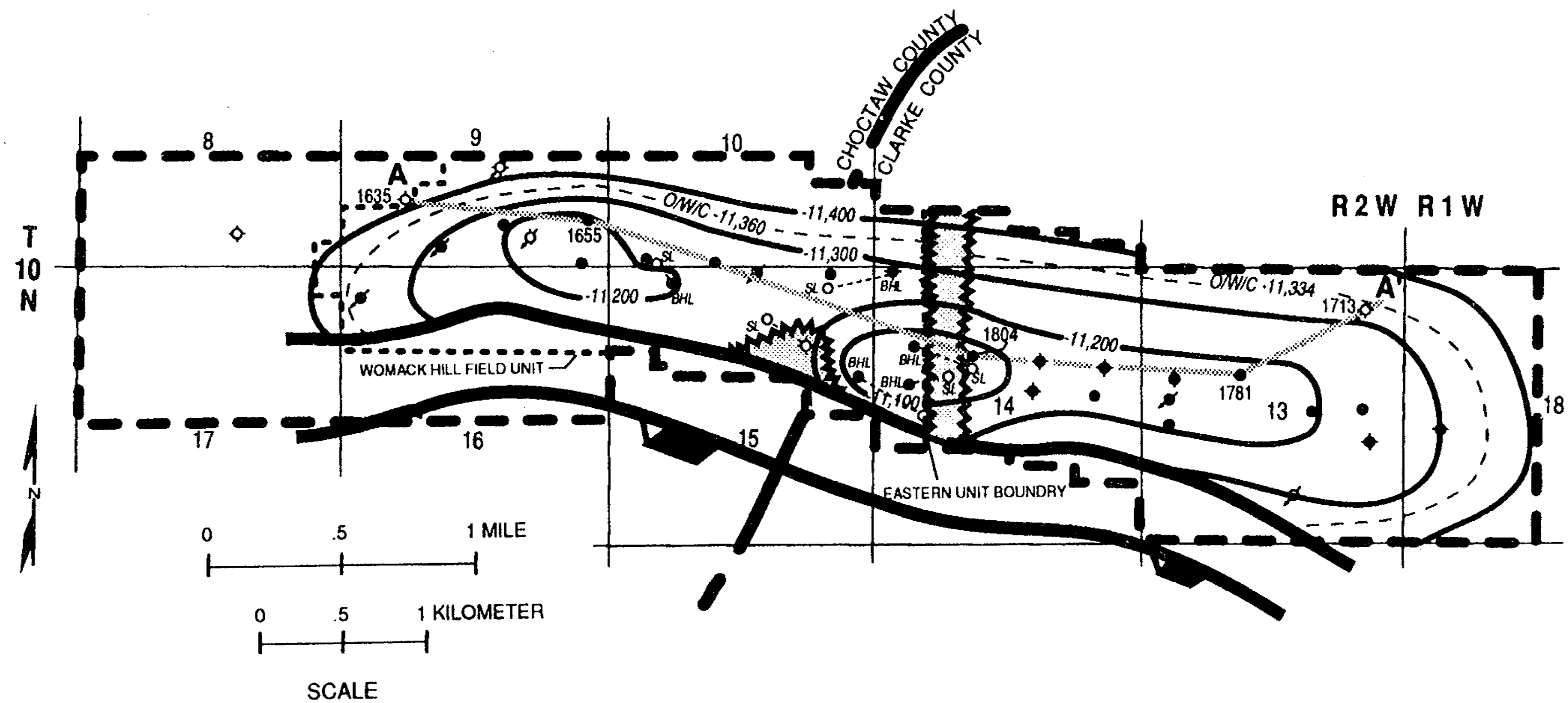


Figure 69.--Structure contour map on top of Smackover Formation in Womack Hill field, Alabama (modified from Pruet and Hughes Company, Exhibit 4, Docket No. 11-26-746, State Oil and Gas Board of Alabama; from Kopaska-Merkel and others, 1992).

feet (Kopaska-Merkel and others, 1992). The Smackover reservoir of Womack Hill field includes abundant moldic, secondary intraparticle, interparticle, and intercrystalline pores. As of March 1974, 17 wells had been completed in Womack Hill field (Pruet and Hughes Co., Exhibit 8, Docket No. 11-26-746, State Oil and Gas Board of Alabama). The field was developed on units elongate perpendicular to the axis of the anticline, and unit size varies between 80 to 120 acres. Most of these units are the approximate width of 40-acre tracts.

In November of 1974, Pruet and Hughes Company petitioned the State Oil and Gas Board of Alabama requesting that the western portion of Womack Hill field be unitized. During development of the field, it was determined that the Womack Hill reservoir contains an area of reduced permeability near the eastern boundary of the 14-4 unit. Further, it was determined that the eastern portion of the field had a strong water-drive mechanism which maintained reservoir pressure, whereas the western end of the field was experiencing a rapid pressure decline. Original reservoir pressure in Womack Hill field was 5,418 psi. By April 1, 1974, reservoir pressure in the eastern portion of the field was determined to be approximately 5,250 psig with a recovery of 4,763 stock-tank barrels of oil per psi drop in reservoir pressure; pressure in the western end of the field had declined to approximately 4,050 psig with an oil recovery of 1,311 stock-tank barrels per psi of reservoir pressure drop (Pruet and Hughes Co., Exhibit 8, Docket No. 11-26-746, State Oil and Gas Board of Alabama). In other words, recovery in the eastern portion of the field was approximately 3.5 times better than that experienced on the western end.

Based on reservoir modeling (Pruet and Hughes Co., Exhibit 8, Docket No. 11-26-746, State Oil and Gas Board of Alabama), it was determined that primary recovery from the entire field should be approximately 25.5 million barrels, or 29.2 percent of the oil-in-place. The model did confirm that a barrier to fluid flow exists within the field. Because of the high recovery of oil being observed in the eastern end of the field it was determined that only the western part of the field should be unitized (Pruet and Hughes Co., Exhibit 8, Docket No. 11-26-746, State Oil and Gas Board of Alabama).

The productive area of the western end of the field contains 796 acres and 10,514 acre-feet of reservoir pore volume. Original oil-in-place in the western end of the field was in excess of 46 million stock tank barrels of oil. As of March 1974, the western end of the field had produced approximately 1.8 million barrels of oil and ultimate primary recovery was estimated to be approximately 13 million stock tank barrels of oil with an abandonment pressure of 1,500 psig (Pruet and Hughes Co., Exhibit 8, Docket No. 11-26-746, State Oil and Gas Board of Alabama).

The western end of Womack Hill field was unitized in November 1974, with an effective date of January 1, 1975. A waterflood project, including drilling of both injector and producer wells, was proposed. Projected ultimate recovery of oil from the western end of Womack Hill field as a result of the waterflood was approximately 17 million barrels of oil, a 30 percent increase over expected primary recovery (Pruet and Hughes Co., Exhibit 8, Docket No. 11-26-746, State Oil and Gas Board of Alabama).

Once the field was unitized, four injector wells were located along the flanks of the reservoir. Along the crest of the structure, six production wells were drilled. One of these wells (Permit No. 2737-B) was plugged and abandoned as noncommercial.

In 1990, Womack Hill field produced 794,599 barrels of oil and has produced 25 million barrels of oil since its discovery in 1970 (fig. 70). Production from the Womack Hill field unit since unitization totals over 13 million barrels. Total water injected into the unit exceeds 20 million barrels. In 1990, the field unit produced 568,650 barrels of oil. The Womack Hill Field Unit 14-5 No. 2 well (Permit No. 4575-B), which was drilled on the eastern end of the unit and was completed in 1985, has produced nearly 780,000 barrels of oil through 1990.

Production from the Womack Hill field unit (WHFU) under waterflood tracked predictions of production under primary recovery until 1985, when a significant increase in hydrocarbon recovery began to be realized (fig. 71). In 1990, actual cumulative production exceeded for the first time estimated production using enhanced or improved recovery. The behavior of the WHFU under waterflood operations resulted from several factors. One of these was the drilling in 1985, 10 years after unitization, of a strategically placed well that appears to have drained previously uncontacted attic oil (Permit No. 4575-B; Kopaska-Merkel and others, 1992). This well accounts for part, but not all, of the dramatic increase in incremental production from the WHFU during 1985-87. Since 1987,

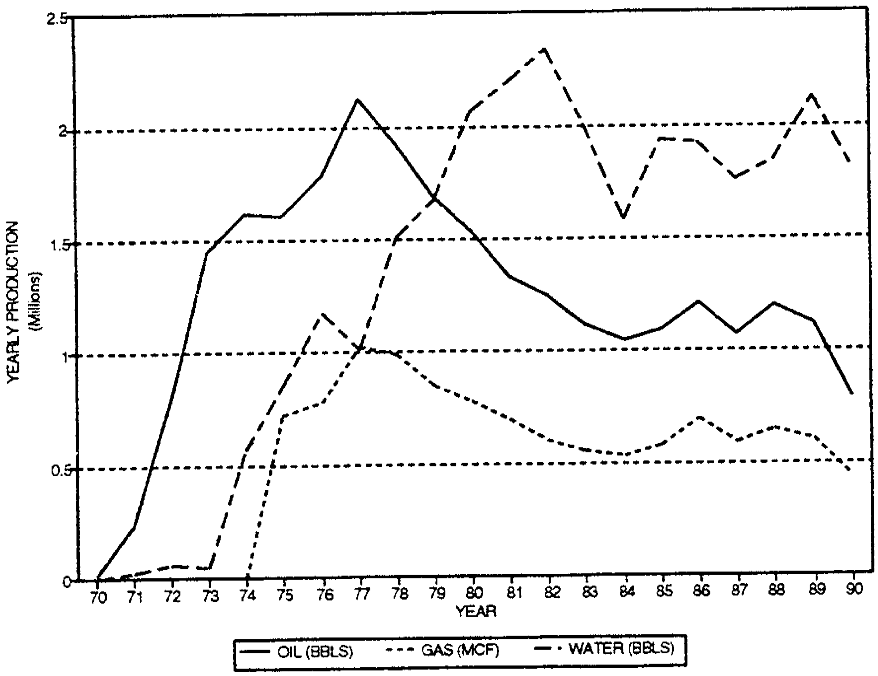


Figure 70.--Graph of production history of Womack Hill field, Alabama.

continued high production rates from the unit cannot be attributed to production from the new well (Permit No. 4575-B) because the increased production from the WHFU during this period was much greater than production from Permit No. 4575-B (fig. 72). At this point it is not clear what the ultimate recovery from the WHFU will be. However, based on the generally good performance so far of the infill wells drilled in association with unitization, the outlook is good. Similar carbonate reservoirs in west Texas have performed well under waterflood with infill wells (Wu and others, 1989).

DISCUSSION OF RESULTS

PORE-SYSTEM CHARACTERISTICS AND ENHANCED OR IMPROVED RECOVERY

Kopaska-Merkel and Mann (1991b) recognized two pore facies in the Smackover of southwest Alabama based on pore types and pore-throat-size distributions (fig. 27): the moldic pore facies and the intercrystalline pore facies. Reservoirs with mixtures of pore types were also identified. The moldic pore facies contains 26 fields; the intercrystalline pore facies contains 18; and 29 fields have a mixture of pore types. Fifty-one percent of hydrocarbon liquids are produced from intermediate pore systems, making this "facies" the most productive in Alabama (table 13). Major fields which produce from the intermediate pore "facies" include Big Escambia Creek, Chatom, Little Escambia Creek, Womack Hill, Fanny Church, and Appleton. The Florida portion of Jay-LEC fields is excluded from this analysis, but if it was included the amount of oil produced from the intermediate pore "facies" would be an additional 369 million barrels. Large fields completed within the moldic pore facies include Choctaw Ridge, Stave Creek, and Turkey Creek fields. Hatter's Pond and Chunchula fields are the two major producers of liquid hydrocarbons from the intercrystalline pore facies.

Within the moldic pore facies only strategic well placement has been implemented. The dearth of injection operations in moldic reservoirs must be, at least in part, a function of the relatively small size

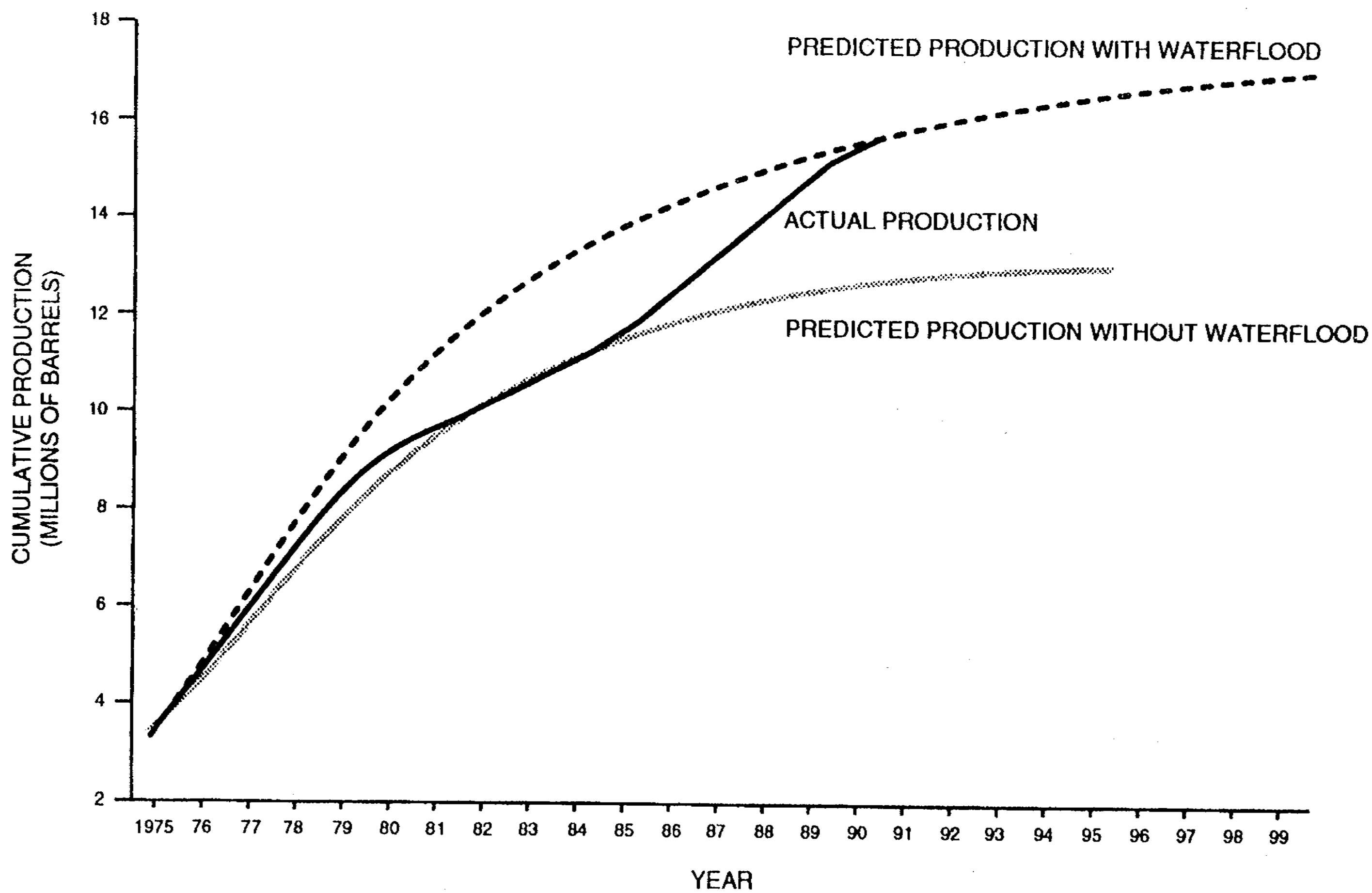


Figure 71.--Predicted versus actual cumulative production in Womack Hill field unit.

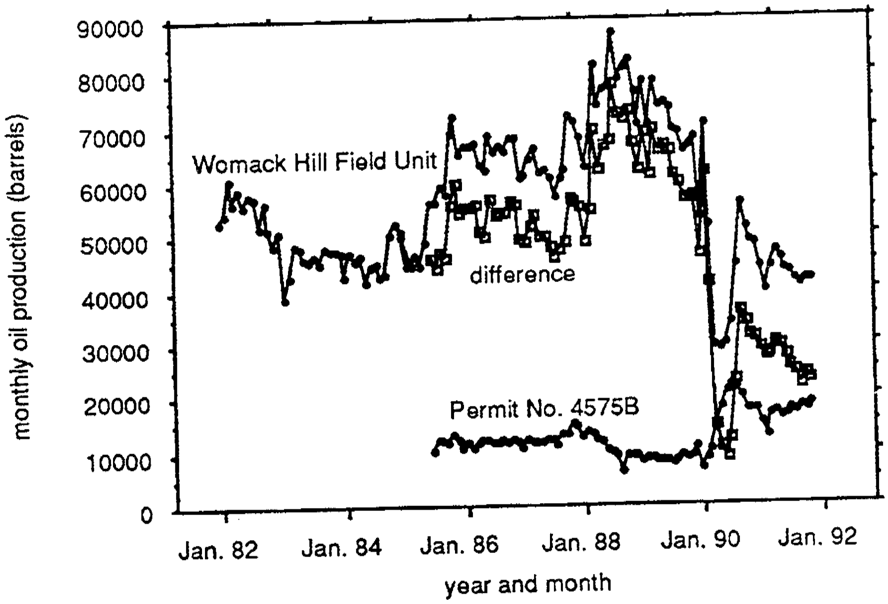


Figure 72.--Monthly oil production from Womack Hill field unit and from Permit No. 4575-B (which began producing in August of 1985), and the difference between the two.

Table 13.--Pore facies relative to distribution of (a) Smackover production, and (b) number and types of fields in each facies

	Moldic Pore Facies	Intermediate pore "facies"	Intercrystalline Pore Facies
(a)			
Oil (bbls)	29,284,751 (97%)[1]	79,232,016 (59%)[1]	5,429,494 (6%)[1]
Condensate (bbls)	1,041,867 (3%)[1]	54,942,709 (41%)[1]	89,686,244 (94%)[1]
Total liquids (bbls)	**30,326,618 (12%)[2]**	**134,174,725 (51%)[2, 3]**	**95,115,738 (37%)[2]**
(b)			
Oil fields	22	21	16
Condensate fields	4	8	2
Total fields	**26**	**29**	**18**
CUMULATIVE PRODUCTION PER FIELD (BBLS)	1,166,408	**4,626,715**	**5,284,208**

[1]Percentage of facies total production
[2]Percentage of Smackover total production
[3]Includes only Alabama portion of Jay-LEC fields

of moldic reservoirs in the Smackover of Alabama (table 12). However, there appears to be no compelling reason why waterflooding could not be applied successfully to moldic reservoirs. Several lines of evidence support this inference. First, although very strongly water wet moldic reservoirs are vulnerable to poor oil recovery resulting from snap off (Yu and Wardlaw, 1986a, b), many (perhaps most) carbonate oil reservoirs are of intermediate wettability, which should vastly improve recovery compared to the water-wet case (Morrow, 1990). Second, the Womack Hill field unit, which has an important moldic component (Kopaska-Merkel and others, 1992), has undergone waterflooding with satisfactory results for more than 15 years. Third, 24 carbonate reservoirs in west Texas have all responded well to waterflooding (Wu and others, 1989). Moldic Smackover reservoirs in Alabama may behave similarly, even though west Texas carbonate reservoirs tend to be dominated by interparticle and intercrystalline porosity. A final favorable indication is that moldic reservoirs in the Smackover of Alabama have performed better than expected under unitization. This may be a result of favorable wetting characteristics. Another possibility has to do with the bimodal pore systems in the moldic pore facies. Moldic reservoir zones interpreted to have high water saturations may produce water-free oil because the water is held within microporosity (e.g., the Rodessa Limestone in Running Duke field, East Texas basin; Keith and Pittman,1983). Finally, megascopic heterogeneity tends to be low in reservoirs completed in the moldic pore facies implying less oil will be bypassed during production. More than 11 million barrels of oil and condensate have been produced from unitized fields in the moldic pore facies.

Unitized fields assigned to the intercrystalline pore facies are Hatter's Pond and Chunchula fields. Gas injection and infill drilling are the only enhanced- or improved-recovery techniques presently employed within this facies. Total production from these two fields is nearly 90 million barrels of condensate. Intercrystalline reservoirs tend to be relatively megascopically heterogeneous and compartmentalization of reservoirs is likely, as has been inferred for Chunchula field by the University of Alabama (1991). Similar reservoirs in west Texas appear to contain substantial volumes of uncontacted mobile oil because of megascopic reservoir heterogeneity (e.g., Fogg and Lucia, 1990; Major and others, 1990; Major and Holtz, 1990).

The intermediate pore "facies" contains the largest variation in enhanced- or improved-recovery techniques used. Strategic well placement, infill drilling, waterflood, and gas injection are being implemented in fields assigned to this pore facies. Strategic well placement was used in Appleton field; waterflood operations have been implemented in Jay-LEC and Womack Hill fields; gas injection and infill drilling have been implemented in Chatom, Fanny Church, and Jay-LEC fields. Production from unitized fields within the intermediate pore "facies" is more than 435 million barrels of oil (including the Florida portion of Jay-LEC).

Intercrystalline and intermediate reservoirs that have been unitized are undergoing injection programs and have performed about as well as, or less well than, expected. The reasons for this are not entirely clear, but these reservoirs are obviously candidates for additional reservoir characterization, and possible tertiary oil recovery projects, because they may not be achieving their potential. In support of this observation, Jay-LEC field is currently undergoing a successful tertiary oil-recovery project that was implemented after detailed reservoir characterization showed that secondary recovery from waterflood alone was not draining the reservoir efficiently. Also, well-studied reservoirs in west Texas (i.e., the Grayburg in Dune field and the San Andres in East Pennwell field) that have similar pore systems to intercrystalline and intermediate Smackover reservoirs in Alabama have been shown to contain substantial amounts of unrecovered but recoverable mobile oil under mature waterflood operations (Fogg and Lucia, 1990; Major and others, 1990).

CANDIDATES FOR ENHANCED OR IMPROVED RECOVERY IN ALABAMA

Size is an important factor in determining if a reservoir is suitable for enhanced- or improved-recovery operations and what type of techniques should be implemented (fig. 73). In the smallest fields, enhanced or improved recovery are not generally viable because these fields (those with less than a million barrels of production) do not have the reserves or areal extent to justify drilling of additional wells, and the cost of implementing an injection program would be prohibitive. Fields which have cumulative production in excess of 1 million barrels but less than 5 million barrels should be evaluated in terms of strategic well placement. Many fields in Alabama have limited areal extent, and spacing requirements (usually one well per 160 acres for oil and 640 acres for gas) may prohibit efficient well placement unless the fields are unitized. Even certain small fields spaced on 160-acre units may benefit from an additional well. Unitization would permit strategic well placement to recover reserves that would otherwise not be produced.

Strategic well placement is most viable in small- to medium-size reservoirs where initial development made prohibitive the drilling of additional wells without unitization. Also, reservoirs having a drive mechanism with a water-influx component seem most likely to benefit from strategic well placement. Potential candidates for strategic well placement include Blacksher, Barrytown, and North Choctaw Ridge fields. Each field has reserves-in-place similar to those fields in which strategic

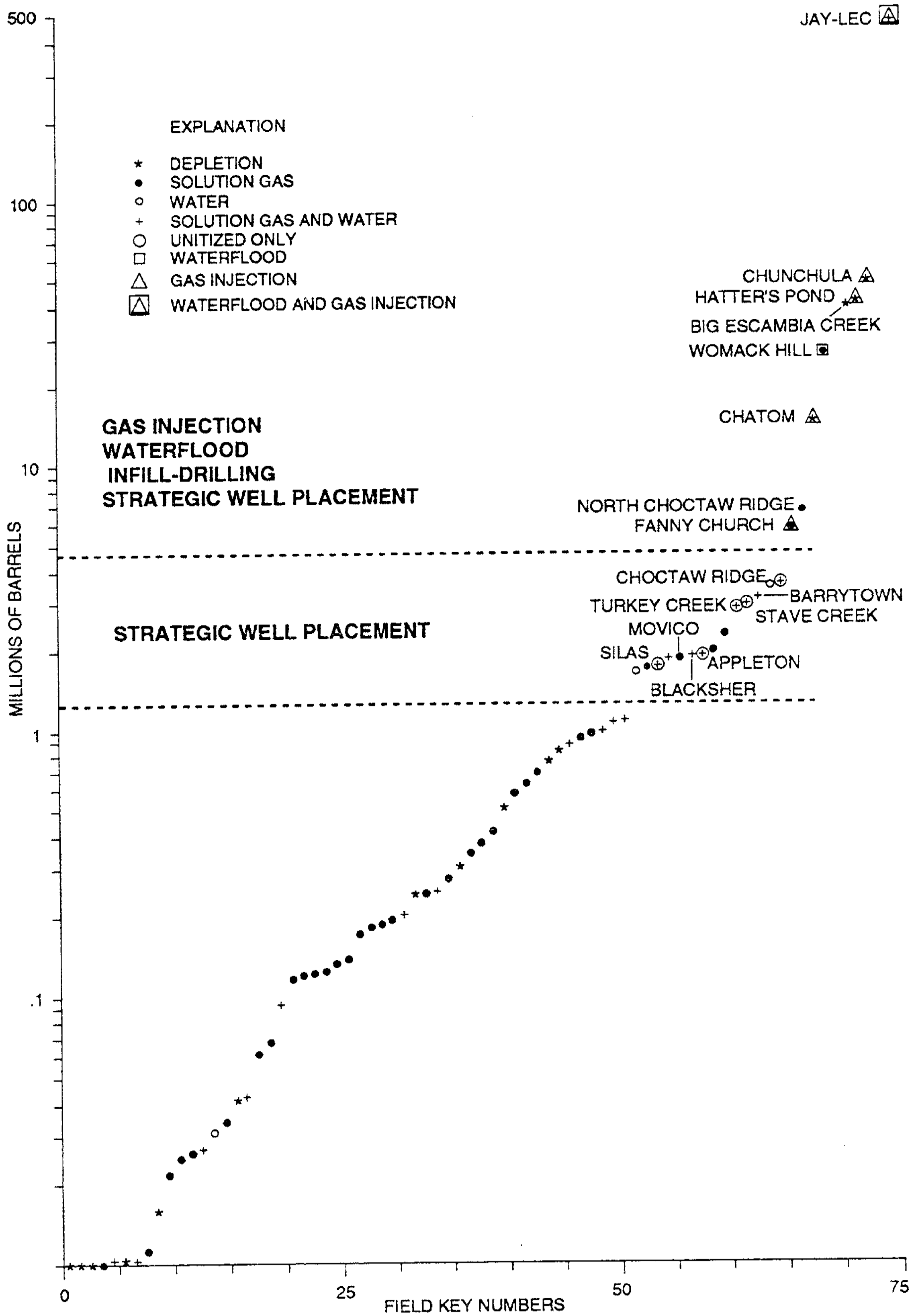


Figure 73.--Graph of cumulative hydrocarbon production of Smackover fields in southwest Alabama (Field ranking by cumulative production; data from Hall, 1992, table 2.)

well placement has been implemented. Each field is classified as oil with API gravities for Blacksher, Barrytown, and North Choctaw Ridge being 43°, 45°, and 39°, respectively, which are comparable to fluid characteristics of the fields in which strategic well placement has been used. Barrytown and North Choctaw Ridge fields have similar trap types to fields in which strategic well placement has been used (Hall, 1992; Kopaska-Merkel, 1992a; Kopaska-Merkel and others, 1992). Barrytown and North Choctaw Ridge fields resemble existing fields in which strategic well placement has been employed because they have moldic reservoirs (Kopaska-Merkel, 1992a; Kopaska-Merkel and others, 1992). Although Blacksher field is in the intermediate pore facies, it has a water-influx component to its drive mechanism and part of the reservoir is moldic (Kopaska-Merkel, 1992a); hence, Blacksher field should also be considered for possible strategic well placement. If these fields contain attic oil, then strategically placed wells should increase ultimate recovery.

Movico field should be considered as a potential candidate for strategic well placement and possibly for injection. Movico field is assigned to the intercrystalline pore facies and, although strategic well placement has not been used in this pore facies, structure maps provided by Kopaska-Merkel and others (1992) indicate uncontacted reservoir updip. However, Movico is interpreted as having a solution-gas-expansion drive mechanism (Kopaska-Merkel and others, 1992) which may not provide for effective recovery during primary operations. Therefore, a program to maintain reservoir pressure or increase sweep efficiency may be necessary. Gas injection programs are presently being implemented in nearby Chunchula and Hatter's Pond fields in the intercrystalline pore facies.

Injection programs have been implemented in large fields such as Chunchula, Chatom, Hatter's Pond, Womack Hill and Jay-LEC. These fields contain the reserves necessary to economically justify the fiscal outlays necessary to implement injection programs. Projects that involve injection of fluids into a reservoir to improve recovery of hydrocarbons seem to be most applicable to fields with considerable reserves and natural drive mechanisms that are ineffective in moving hydrocarbons to the producing wells. Other large fields should also be evaluated for potential injection programs.

Big Escambia Creek field, in Escambia County, is the largest Smackover field in Alabama that has not undergone some type of injection program. It is dominated by intermediate pore systems, as are Jay-LEC and Fanny Church fields, which are currently undergoing injection programs. However, Jay-LEC and Fanny Church fields are oil fields whereas Big Escambia Creek produces 46° gravity gas condensate. Also, Big Escambia Creek's wellstream is dominated by nonhydrocarbon components (approximately 53 mole percent). Hydrogen sulfide is the largest single component, contributing more than 25 mole percent of the wellstream. Detailed reservoir studies should be performed on the Smackover reservoir of Big Escambia Creek to determine if enhanced- or improved-recovery operations should be implemented in the field.

North Choctaw Ridge field is large, but it is assigned to the moldic pore facies, and no injection programs have been implemented in this pore facies in Alabama. Also, North Choctaw Ridge's drive mechanism is the result of gas expansion. Nevertheless, the effectiveness of the drive in the field is uncertain, so North Choctaw Ridge seems to be a potential candidate for increased recovery by injection operations.

Infill drilling appears most applicable in larger fields that are undergoing some type of injection program. Infill drilling has been implemented in fields undergoing waterflood and gas injection and has improved recovery in those fields. Therefore, any field in which injection operations are considered should also be evaluated for infill drilling.

EXPECTED VOLUME OF LIQUID HYDROCARBONS RECOVERABLE BY ENHANCED OR IMPROVED RECOVERY FROM SMACKOVER FIELDS IN ALABAMA

Some general conclusions can be drawn from the results of existing enhanced- or improved-recovery projects in Smackover fields in Alabama and from the preceding section. The total volume of secondary liquid-hydrocarbon production from the nine Alabama Smackover fields currently undergoing enhanced or improved recovery was expected to be 331.5 MMB (projections of operators before initiating enhanced- or improved-recovery operations). If one assumes that moldic reservoirs currently undergoing only strategic well placement are waterflooded, with an incremental recovery equal to the average of 24 west Texas carbonate reservoirs (Wu and others, 1989) and that currently waterflooded reservoirs undergo infill drilling with results like those found by Wu and others (1989), then the prediction increases to 446.4 MMB. Finally, if the four oil fields discussed in the previous section undergo recommended enhanced- and improved-recovery operations with average results (compared to Alabama Smackover enhanced- and improved-recovery projects and to the results reported by Wu and others, 1989), then the predicted secondary liquid-hydrocarbon volume becomes 464.5 MMB. This is 133 MMB more than the original projection for the nine fields now undergoing enhanced- or improved-recovery operations. This is a fairly conservative number, because large fields now undergoing gas injection (Fanny Church, Chatom, and Hatter's Pond) have not been evaluated as candidates for multiple enhanced-recovery methods. Conservatively, if tertiary recovery accounts for 5 percent of the OOIP from these fields, then the ultimate enhanced- or improved-recovery prediction becomes at least 468 MMB, about 137 MMB more than original predictions for the nine fields undergoing enhanced or improved recovery. Nearly all of this comes from intermediate reservoirs because of the large contribution of Jay-LEC fields, and moldic reservoirs account for less than 1 percent of the total. Intercrystalline reservoirs contribute about 11 percent of the total.

SUMMARY AND CONCLUSIONS

Most Smackover reservoirs originated as nearshore-marine carbonate sediments with minor admixtures of noncarbonate material. Some of these reservoirs preserve abundant evidence of their environment of deposition. Others have been highly altered and their origins are unclear. The most common Smackover reservoir rocks are nonskeletal grainstone. Mixed-particle grainstone/packstone is the second most common reservoir type in the Smackover of southwest Alabama. A third important kind of reservoir is microbial boundstone. A fourth reservoir type is crystalline dolostone. Quartzose sandstone, commonly dolomitic, forms permeable reservoirs locally in southern Monroe County.

The most common kinds of pores in the Smackover are particle molds, secondary intraparticle (partial moldic) pores, intercrystalline pores, and interparticle pores. Less common, but significant, pore types are fractures and vugs. The various pore types lend different petrophysical characteristics to pore systems, and combinations of different kinds of pores in varying proportions create further effects. Interparticle pores are permeability enhancers because they tend to form regular networks with abundant connections and because they are interconnected by large pore throats. Fractures are even more effective permeability enhancers. Pore systems dominated by molds, vugs, and secondary intraparticle pores are not characterized by high permeability values because these pores tend to be poorly connected, and exhibit high aspect (pore-throat size) ratios. The most common kinds of molds are oomolds and pelmolds. Secondary intraparticle pores differ from molds in being substantially smaller. Intercrystalline pores form pore systems with variable permeability values, depending on crystal size. Intercrystalline pores are commonly well connected by short and homogeneous pore throats, and the pores tend to be all about the same size and shape. Where intercrystalline pores are large, homogeneous, and well connected, permeability values may be extremely high.

In this study, Smackover reservoir rocks are classified using capillary-pressure-curve shape. CP-curve shape summarizes a wealth of petrophysical information about reservoir rocks, including pore-throat size distribution and estimates of recovery efficiency and permeability. CP-curve class 1 includes samples that have extremely leptokurtic pore-throat size distributions and that exhibit little or no extrusion of mercury during pressure reduction. Samples assigned to CP-curve class 2 differ in exhibiting pore-throat size distributions with minor fine tails. CP-curve class 3 includes samples that exhibit as much as 60 percent mercury extrusion during pressure reduction. CP-curve class 4 includes samples that have mesokurtic pore-throat size distributions exhibiting a prominent tail of small throats that accounts for as much as 25 percent of the pore volume, or a smooth reduction in volume of pores accessed through smaller and smaller throats over the entire range of pore-throat sizes. Samples assigned to this class extrude up to more than 25 percent of their mercury during pressure reduction. Samples assigned to CP-curve class 5 exhibit platykurtic or polymodal pore-throat size distributions. CP curves assigned to this class are variable, as are porosity values, recovery efficiency values, and median throat sizes. On average, however, porosity values and throat sizes are smaller than for classes 1 through 4; recovery efficiencies range up to about 40 percent. CP-curve class 6 includes marginal reservoir rocks; porosity values are less than 10 percent and the mean is about 6 percent. These samples have mesokurtic throat size distributions and entirely lack large throats (median throat sizes do not exceed 0.5 μm). Recovery efficiencies range between about 30 and 40 percent. CP-curve classes 7 and 8 include nonreservoir rocks and have very small throats.

Three methods of predicting permeability are discussed. The first is based on the relationship between microporosity, as measured from capillary-pressure data and as estimated by calibration of well logs, and permeability. The ultimate goal is to predict permeability values from well logs, or from limited amounts of other kinds of data. The second is by measuring MTS, which is derived from capillary-pressure analysis. Small amounts of microporosity can dramatically depress permeability in the Smackover. It appears that small (centimeter-scale?) areas of small pores and small pore throats act as permeability baffles. The only petrophysical variable investigated that is strongly correlated with permeability is MTS. MTS is derived from capillary-pressure analysis, an expensive and time-consuming method which usually requires core samples. However, whereas permeability can only be measured in samples cut from cores, MTS can be calculated from analysis of cuttings. Therefore, permeability can be estimated from noncored intervals. The third method of predicting permeability is from porosity data. The porosity-permeability relationships differ among reservoirs dominated by different kinds of pore systems. Intercrystalline reservoirs exhibit the strongest porosity-permeability relationships, but even for these reservoirs, equations derived from one field will not yield accurate results when applied to another.

Pore systems in reservoir rocks of the Smackover Formation in southwest Alabama are dominated either by moldic plus secondary intraparticle pores or by intercrystalline pores. Intermediate pore systems are less common. Because the Smackover reservoir rocks studied fall naturally into two distinct groups, two pore facies, which are rock units characterized by certain pore types or combinations of pore types, and by certain consequent pore-throat size distributions are defined. Pore facies also possess characteristic fluid-flow properties.

Reservoir rocks assigned to different pore facies are petrophysically, petrographically, and geographically distinct. Those assigned to the moldic pore facies are dominated by moldic plus secondary intraparticle pores. Some samples contain up to about 20 percent interparticle pores. Reservoir rocks assigned to the intercrystalline pore facies are dominated by intercrystalline pores. Moldic pore systems are products of primary sediment fabric, modified by (usually) fabric-selective dolomitization and by dissolution of unstable particles either during or after dolomitization. Intercrystalline pore systems are most strongly affected by pervasive fabric-destructive dolomitization, although primary sediment fabric commonly has some effect on the final rock fabric. This means that geological models of environment of deposition and of diagenetic history are more likely to help interpretation of moldic reservoirs than of intercrystalline reservoirs. Moldic pore systems tend to have higher mean porosity values but lower maximum permeability values than intercrystalline pore systems. Moldic pore systems have more leptokurtic pore-throat size distributions, but are fundamentally heterogeneous at microscopic scales because coarse and fine pores are found together. Intercrystalline pore systems are fundamentally homogeneous at this level, at least in the ideal case. Intercrystalline pore systems are more heterogeneous megascopically (vertically) and therefore have more potential for bypassing of potentially productive intervals. Also, high-permeability thief zones are more abundant in intercrystalline reservoirs. Intermediate samples resemble petrophysically the intercrystalline pore facies and occupy intermediate regions geographically. Because rocks of the moldic and intercrystalline pore facies are readily distinguishable and exhibit quite different fluid-flow characteristics, the pore-facies classification proposed here may be a useful tool in planning development of Smackover fields in Alabama and probably could be applied successfully to other porous and permeable carbonate units.

Quantitative (rank) measures of microscopic and megascopic reservoir heterogeneity are used to describe heterogeneity in Smackover hydrocarbon fields in southwest Alabama. Microscopic reservoir heterogeneity (μH) is $\{[(0.25\sigma\phi)+(\text{mean natural log of K})+(1.5\sigma \text{ natural log of K})]/3\}$. Megascopic heterogeneity (MH) is $[(\#\text{ of reservoir intervals})+(\#\text{ of high-K reservoir intervals})+(\sigma \text{ of } \#\text{ of reservoir intervals})]$ where reservoir rock is defined as exhibiting permeability values $\geq$ 0.1 md and high-K reservoir rock exhibits permeability values $\geq$1.0 md. Both MH and μH are determined from core data and are estimates of vertical heterogeneity. The Dykstra-Parsons coefficient is a measure of microscopic heterogeneity that is partially independent of μH ($r^2 = 0.428$).

μH and MH are distributed in opposing patterns. μH generally decreases from northwest to southeast whereas MH values increase along the same trend. μH values are high in the moldic pore facies and low in the intercrystalline pore facies. The congruency of patterns of variation of μH and MH with pore-system characteristics (controlled by depositional patterns, dissolution, and dolomitization) and regional structural and paleogeographic trends suggests that reservoir heterogeneity characteristics are controlled by structural and paleogeographic setting, and by diagenesis. However, because contours of μH and MH are approximately normal to structure contours but parallel to Smackover thickness contours, it appears that depositional setting (or paleogeography) exerted more stringent control on reservoir heterogeneity than did structural evolution. The distribution of DP coefficient values is not related to pore-facies distribution; thus the DP coefficient is less useful for regional heterogeneity studies than is MH or μH.

Microscopic lateral heterogeneity (LH), a relative, or rank, parameter, was calculated for 12 of the largest Smackover fields. Relatively sophisticated parameters could not be applied to the Smackover of southwest Alabama because the data are of poor quality. Instead, LH was estimated as a function of the difference between the residual variance about the porosity-permeability trend for single wells and that for entire fields. If a field is perfectly laterally homogeneous, then wells will not differ with respect to their porosity-permeability trends, and subtracting the field value from the average of values for single wells yields an LH estimate of zero. Conversely, if a field is highly heterogeneous laterally, then the field value will exhibit a high degree of scatter because wells with very different porosity-permeability relationships will have been lumped together. A high value of LH results. Analysis of the 12 fields for which sufficient data are available indicates that μH and LH covary. Also, gas-condensate fields are relatively laterally homogeneous, and oil fields are relatively laterally heterogeneous.

Estimation of μH and MH regionally in the Smackover of southwest Alabama will facilitate planning for fields that are still in the early stages of development. Prediction of reservoir heterogeneity characteristics will facilitate advance planning of production strategies and cost/benefit analyses for development of new fields. In addition, it will be possible to identify regions characterized by or containing unusually heterogeneous or unusually homogeneous reservoirs (microscopic, megascopic, or both) and to flag areas likely to present minor or severe development problems. These regional relationships can be used as a guide when making geologic models of individual reservoirs. The relationship between pore facies, μH, and MH will permit prediction of 3D continuity and porosity and permeability characteristics of reservoirs using an integrated geological/engineering approach. For fields assigned to the moldic pore facies, a more detailed geological analysis of the depositional environments and diagenetic history of reservoir strata can be achieved. This may permit a more detailed assessment of the shapes and distributions of flow units and of the distribution of permeability baffles and barriers. For intercrystalline reservoirs, a stochastic approach to modeling reservoir porosity and permeability characteristics is preferable.

Well spacing in Alabama is variable among fields and may hinder effective hydrocarbon recovery. Unitization has provided the mechanism for increasing the recovery of hydrocarbons from many Smackover fields in southwest Alabama. Nine of the 11 unitized fields in the Smackover of Alabama have undergone some type of enhanced- or improved-recovery technique. Enhanced- or improved-recovery procedures used in the Smackover Formation of Alabama include infill drilling, strategic well placement, water injection, residue gas injection, nitrogen injection, and combinations of two or more of these approaches.

The pore-facies classification of Kopaska-Merkel and Mann (1991b) provide a means to classify unitized reservoirs within Alabama based on pore types and pore-throat size distributions. Reservoirs with intermediate pore systems are the most productive in Alabama. Twenty-nine fields with intermediate pore systems account for approximately 51 percent of the hydrocarbons produced from the Smackover Formation of Alabama. There are 24 fields in the moldic pore facies and 18 fields in the intercrystalline pore facies and they account for 12 and 37 percent, respectively, of the hydrocarbon liquids produced. Fields undergoing enhanced or improved recovery are found in each pore facies. Within the moldic pore facies are Choctaw Ridge, Silas, Stave Creek, and Turkey Creek fields. Hatter's

Pond and Chunchula fields are assigned to the intercrystalline pore facies. Appleton, Jay-LEC, Fanny Church, Womack Hill, and Chatom fields have reservoirs with intermediate pore systems.

Strategic well placement is the only improved-recovery technique that has been implemented within the moldic pore facies. Waterflood operations have only been implemented in reservoirs with intermediate pore systems. A portion of Womack Hill field is successfully undergoing waterflood. Gas-injection programs have been implemented in Chunchula and Hatter's Pond fields in the intercrystalline pore facies; and in Fanny Church and Chatom fields in the intermediate pore "facies." Additional wells have been drilled in each of the fields undergoing injection operations. These wells have been drilled as either replacement, infill, or strategically placed wells and facilitate the recovery of hydrocarbons in the injection programs. Jay-LEC fields provide an excellent example of how multiple enhanced- or improved-recovery methods can significantly improve ultimate recovery of oil from the Smackover Formation. Approximately 87 percent of the oil produced from Jay-LEC was under enhanced or improved recovery. The implementation of waterflood, infill drilling, and gas injection vastly improved recovery. Even if enhanced- or improved-recovery operations are not applicable to a specific field, unitization can provide the economic stimulus for increased recovery of hydrocarbons and equitable distribution of revenues.

Field size affects the viability of enhanced- or improved-recovery operations because of economic factors and can be used in conjunction with reservoir characteristics and drive mechanism to evaluate candidates for enhanced- or improved-recovery operations. Blacksher, Barrytown, Movico and North Choctaw Ridge fields should be considered for strategic well placement. Potential candidates for injection operations include Big Escambia Creek, Movico, and Choctaw Ridge field. Infill drilling should be considered for Chunchula field because of the compartmentalization of the reservoir.

The combined estimates, prior to enhanced- or improved-recovery operations, for secondary production from the nine Alabama Smackover fields currently undergoing such operations, amount to 331.5 million barrels of hydrocarbon liquids. Revision of this estimate based on (1) results of enhanced- or improved-recovery operations through 1990, (2) proposed tertiary recovery from some of these nine fields using reasonable estimated of relevant parameters from this report and from the published literature, and (3) proposed enhanced or improved recovery from potential candidates listed above, yields a new estimate of 468 million barrels of liquid hydrocarbons expected to be produced by enhanced- or improved-recovery methods from the Alabama Smackover. Even this estimate may be conservative.

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GLOSSARY

ENHANCED RECOVERY – Involves injection of fluids or other techniques other than drilling of additional wells.

IMPROVED RECOVERY – The drilling of additional wells in a field (strategic or not).

LEPTOKURTIC – Exhibiting a frequency distribution in which most values are clustered about the mean.

MESOKURTIC – Exhibiting a frequency distribution in which values are moderately dispersed about the mean.

PLATYKURTIC – Exhibiting a frequency distribution in which values are greatly spread out from the mean.

PORE THROATS – The narrow openings that connect the larger openings in a pore system.

SECONDARY INTRAPARTICLE – Pertaining to pores, formed after deposition, that exist only within sedimentary particles.

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