CONSOLIDATION OF GEOLOGIC STUDIES OF GEOPRESSURED-GEOTHERMAL RESOURCES IN TEXAS

1990 Annual Report

J. A. Raney (Project Director), S. J. Seni, J. R. DuBar,
and T. G. Walter

Prepared for the U.S. Department of Energy
Advanced Technologies Division
under Cooperative Agreement No. DE-FC07-85NV10412

Bureau of Economic Geology
W. L. Fisher, Director
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Section I

Colocation of Geothermal and Heavy-Oil Reservoirs: A South Texas Update

Steven J. Seni and Timothy G. Walter

Bureau of Economic Geology

The University of Texas at Austin

ABSTRACT

In a five-county area of South Texas, geopressured-geothermal reservoirs in the upper Wilcox Group are colocated with heavy-oil reservoirs in the overlying Jackson Group. In 1990, research at the Bureau of Economic Geology concentrated on evaluating the potential of using geopressured-geothermal water for hot-water flooding of heavy-oil reservoirs. Favorable geothermal reservoirs are defined by thick deltaic sandstones and growth-fault-bounded compartments. Potential geothermal reservoirs are present at a depth of 11,000 ft (3,350 m) to 15,000 ft (4,570 m) and contain water at temperatures of 350°F (177°C) to 383°F (195°C) in Fandango field, Zapata County. One potential geothermal reservoir sandstone in the upper Wilcox (R sandstone) is composed of a continuous sand body 100 ft (30 m) to greater than 200 ft (>61 m) thick. Fault blocks average 2 to 4 mi^2 (5.2 to 10.4 km^2) in area.

Both heavy-oil (average API=19) and light-oil (average API=26) reservoirs in South Texas are present in sandstones of the Jackson Group Mirando trend. The updip pinch-out of strike-oriented sheet sandstones in the Jackson Group largely controls the distribution of Mirando-trend heavy-oil reservoirs. The lateral continuity of heavy-oil reservoirs minimizes reservoir compartmentalization, which could disrupt injected-fluid flow paths.

Geologic and engineering research that still needs to be conducted includes (1) studies of the chemical compatibility between injected geothermal fluids and clay matrix of heavy-oil reservoirs, (2)

detailed field studies of geometry and size of geothermal reservoirs, (3) detailed field studies of geometry and size of heavy-oil reservoirs, and (4) studies of changes in the temperature and chemistry of geothermal fluids when injected into heavy-oil reservoirs.

INTRODUCTION

The Gulf Coast Geopressured-Geothermal program is part of a long-term cooperative agreement between the U.S. Department of Energy, The University of Texas Center for Petroleum and Geosystems Engineering, and the Bureau of Economic Geology. The ultimate goal of the program is to demonstrate the economic viability of using geopressured-geothermal water as an alternative energy resource. In 1990, research at the Bureau of Economic Geology is concentrating on evaluating the potential of using geopressured-geothermal water for hot-water flooding of heavy-oil reservoirs. This initial evaluation demonstrates colocation of geothermal and heavy-oil resources in South Texas and characterizes the geologic framework that controls the size, location, and distribution of both the geothermal and heavy-oil resources.

In a five-county area of South Texas (Zapata, Webb, Duval, Jim Hogg, and Starr Counties), known geopressured-geothermal fairways in the deep upper Wilcox Group lie below the shallow Mirando heavy-oil trend (fig. 1). The geothermal fairway is associated with an area of active exploration for overpressured gas in the deep upper Wilcox in South Texas. Geothermal waters produced from the Wilcox Group could be injected in shallow heavy-oil reservoirs to supply both the heat energy and fluid for enhanced oil recovery by steam or hot-water flooding. A schematic flowchart illustrates how hot water produced from the hot-water production well would be piped to the surface and injected into a shallow heavy-oil reservoir (fig. 2). The vertical production distances within the hot-water production well would be approximately equivalent to the distances involved with transport along the surface.

This novel type of geothermally enhanced oil recovery (GTEOR) would conserve natural resources and produce additional oil resources by improving recovery efficiency. GTEOR also preserves water resources that otherwise would be used for conventional waterfloods and saves energy that would be consumed through combustion to generate steam or hot water.

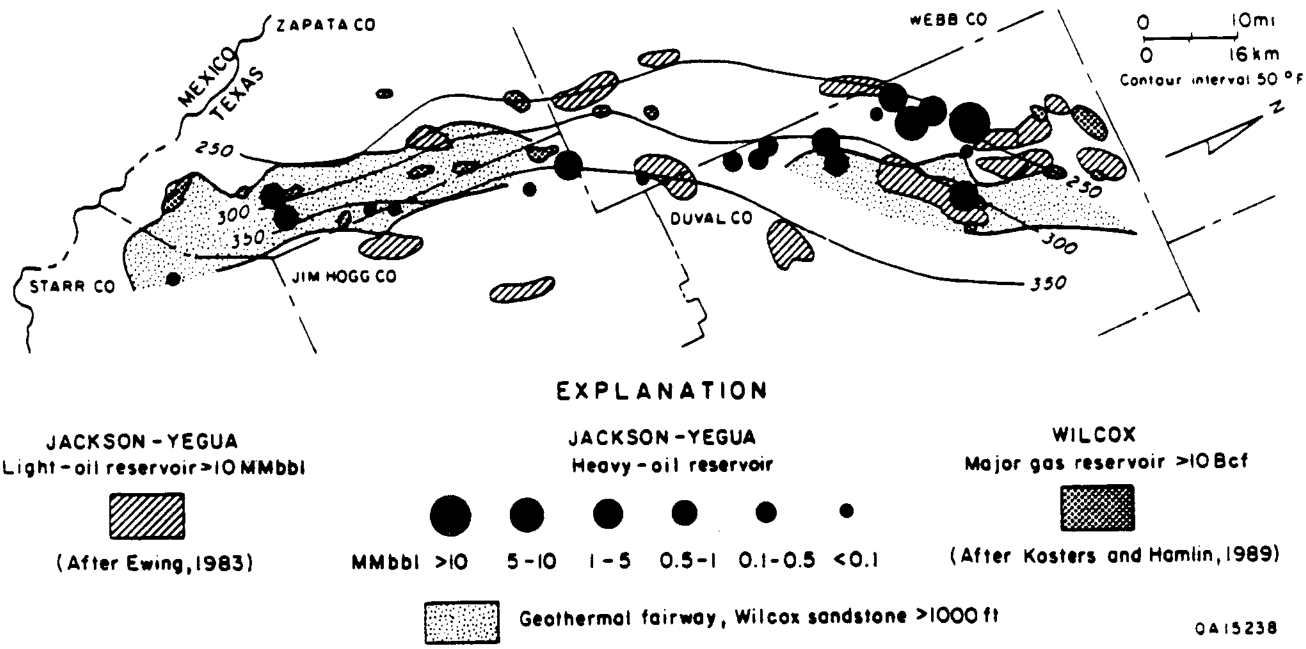

FIGURE 1. Colocation of geopressured geothermal fairways and Jackson Group heavy-oil reservoirs. Patterned area of geothermal fairway includes regions where calculated temperature of middle part of upper Wilcox exceeds 250°F (121°C) and where thickness of net sandstone in the upper Wilcox exceeds 1,000 ft (300 m). Size of circles is relative to the cumulative oil production of heavy-oil reservoirs through 1988.

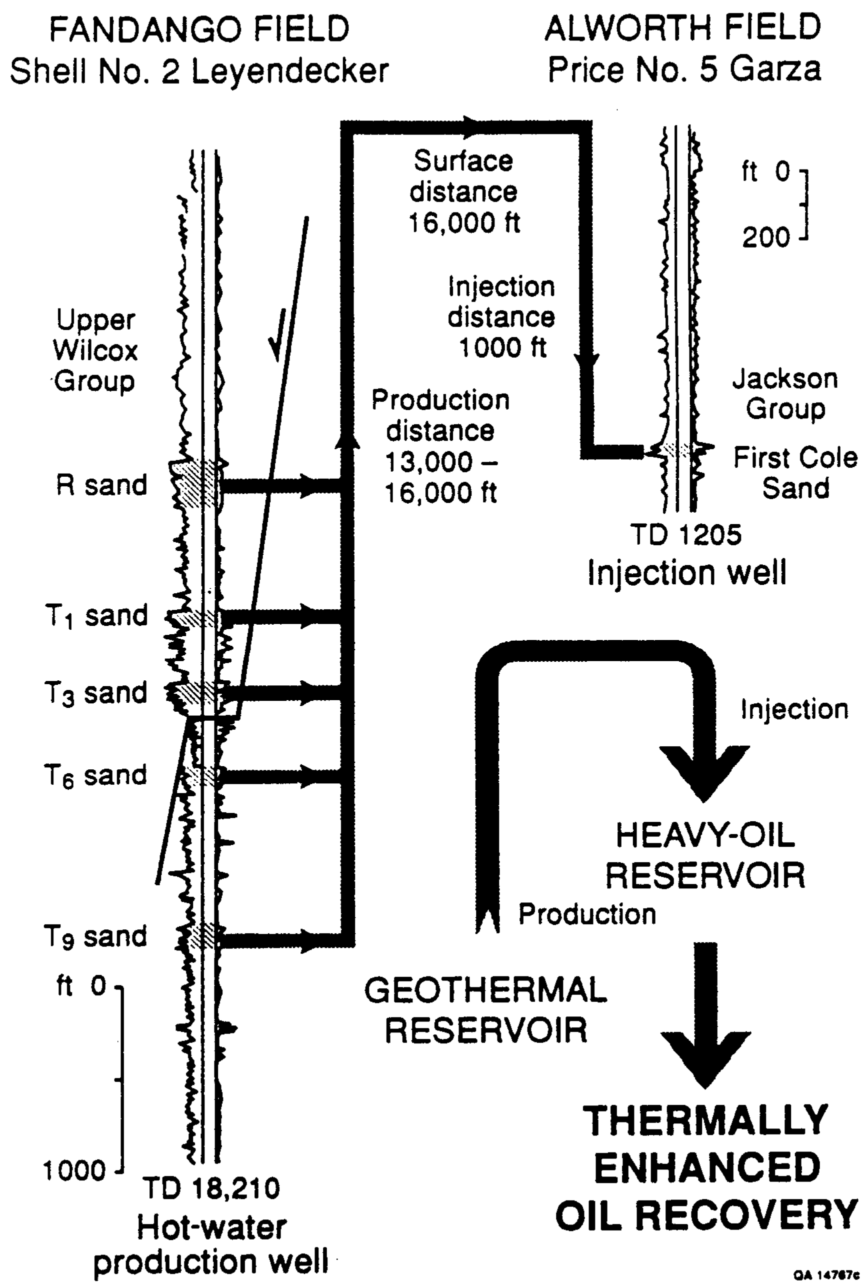

FIGURE 2. Schematic flowchart illustrating a geothermally enhanced oil-recovery method utilizing production of hot water from sandstone reservoirs in the upper Wilcox and subsequent injection into shallow heavy-oil reservoirs in the Jackson Group. The Fandango field is a typical deep upper Wilcox gas field that contains many potential hot-water reservoirs containing R and T series sandstones. Alworth is a small heavy-oil field located near Fandango field.

CHARACTERIZATION OF DEEP WILCOX GEOTHERMAL RESERVOIRS

In the early 1980's, the Bureau of Economic Geology characterized geothermal fairways in the deep Wilcox of South Texas (Bebout and others, 1982; Morton and others, 1983). Earlier, Fisher and McGowen (1967) mapped the regional depositional systems of the lower Wilcox Group, and Edwards (1981) focused on the depositional systems of the upper Wilcox in South Texas (fig. 3). Since that time, extensive exploration has discovered thick reservoir sandstones in areas previously undrilled because of extreme depth (Levin, 1983; Kimmell, 1986; Kosters and Hamlin, 1989). Through 1986, the five-county area of South Texas (Zapata, Starr, Jim Hogg, Webb, and Duval Counties) was known to contain 17 fields in the deep Upper Wilcox, with 28 reservoirs that had cumulative gas production greater than 10 Bcf (Kosters and Hamlin, 1989) (table 1). Total cumulative gas production from these fields through 1986 was 1.71 Tcf.

It is important to realize that geothermal reservoirs do not require a structural trap like an oil or gas reservoir requires four-way closure. Thus, exploration for geothermal reservoirs must concentrate not on structural highs that have four-way closure, but on thick, continuous reservoir sand bodies within large fault blocks.

The current resource-characterization study acquired well logs from recent gas-exploration wells. Deep well logs useful for investigating reservoirs in the deep upper Wilcox are concentrated in the Fandango field, Zapata and Jim Hogg Counties. In the Fandango field, temperatures of geopressured-geothermal waters locally reach 500°F (260°C), and the thickness of net sandstone in the Wilcox locally exceeds 1,000 ft (300 m). The thickness and distribution of these sandstones are being characterized to determine the extent of the geothermal resource. Net sandstone, maximum sandstone (thickest sandstone bed), and effective sandstone (cumulative sandstone in beds greater than 30 ft [>10 m] thick) are key parameters being mapped to analyze the extent of the geothermal resource.

The Wilcox growth fault zone has a tremendous influence on the distribution and thickness of reservoir-quality sandstones (fig. 4). Most growth faults are parallel to regional strike and displace strata down to the basin. Large regional growth faults have up to approximately 1,000 ft (300 m) of

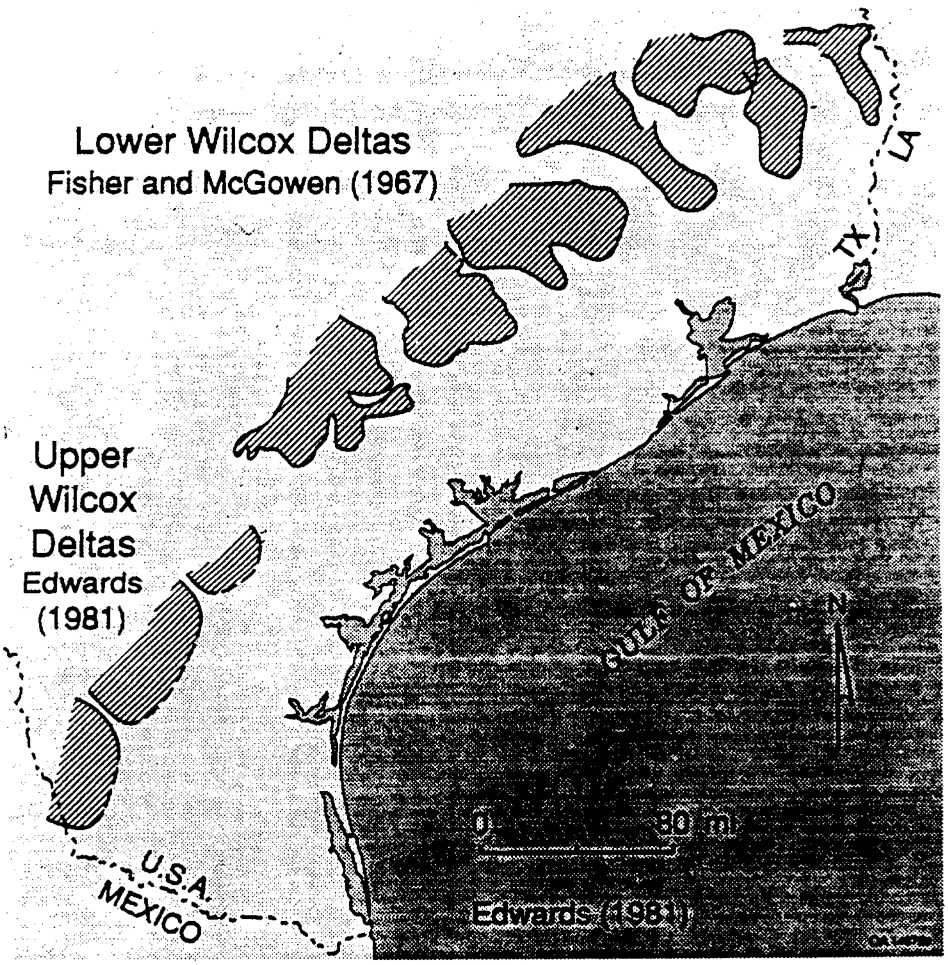

FIGURE 3. Location of Wilcox delta systems. Lower Wilcox deltas after Fisher and McGowen (1967); upper Wilcox deltas after Edwards (1981).

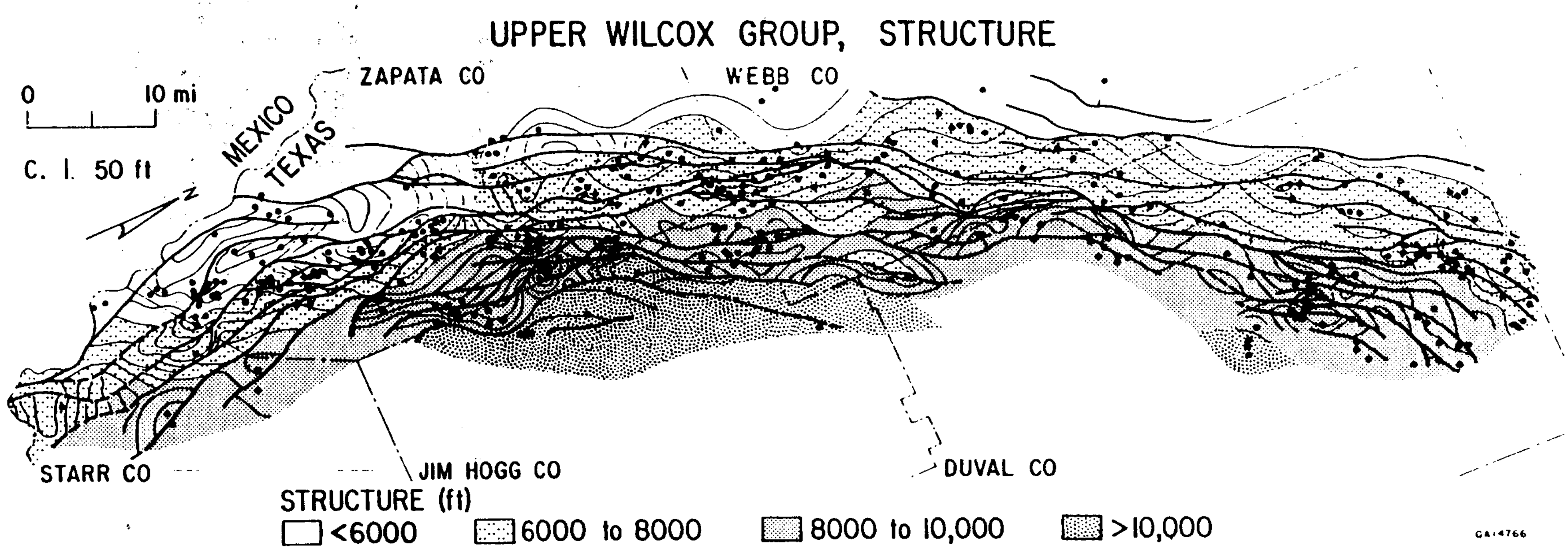

FIGURE 4. Structure map of upper Wilcox in Starr, Zapata, Jim Hogg, Webb, and Duval Counties, Texas.

TABLE 1. Geologic, engineering, and production parameters of major gas reservoirs in South Texas, deep upper Wilcox Group. Major gas reservoirs had a cumulative production greater than 10 Bcf through 1986 (after Kosters and Hamlin, 1989).

RRC	County	Field	Reservoir	Disc	Depth	Lith	Trap	Drive	SPAC	Pay	Acres	Por	Perm	Range	Temp	Press	G/N	Grav	SW	Type	R	Cum Prod (Bcf)	OGP
4	Zapata	Alworth	Wilcox Hinnant 1st	1969	9949	SS	Comb:FC-FA			69		24					GP	0.65		T	1	11769	
4	Zapata	Charco	9200	1981	9200	SS	Struct:F			186		18					GP	0.62	45	N	2	31700	
4	Webb	Davis	Puig	1962	8678	SS	Struct:FA										NP	0.69		N	1	21996	
4	Zapata	Davis,S	4th Hinnant	1966	8404	SS	Struct:FA			19							NP	0.61		N	1	29226	
4	Zapata	Davis,S	Puig	1967	8124	SS	Struct:FA			15							NP	0.62		N	1	14512	
4	Zapata	El Grullo	7780	1977	7780	SS	Struct:FA			18							NP	0.62		N	1	10045	
4	Duval	Government Wells, N	Wilcox	1949	7400	SS	Struct:FA		80	35							NP	0.68		P	3	118200	
4	Duval	Hagist Ranch	Wilcox 9300	1976	9300	SS	Comb:FC-FA			34							NP	0.69		N	1	13644	
4	Duval	Hagist Ranch	Wilcox Basal House	1975	8566	SS	Comb:FC-FA			34							NP	0.70		N	1	11841	
4	Duval	Hagist Ranch.	Wilcox LO. 9700	1951	9700	SS	Comb:FC-FA		40	56							GP	0.68		P	2	49266	
4	Duval	Hagist Ranch	Wilcox Upper	1948	6800	SS	Comb:FC-FA		160	69							NP	0.77		P	3	354900	
4	Zapata	Lopeno	Wilxox E	1959	9100	SS	Struct:F			21					270		NP	0.59		N	1	19987	
4	Zapata	Lopeno SW	Wilcox 7380	1980	7380	SS	Struct:F			29							NP	0.65		N	1	11186	
4	Zapata	Martinez	Hinnant	1961	9950	SS	Strat:FC			5							GP	0.64		N	1	11761	
4	Duval	Petrox	Wilcox 7100	1973	7100	SS	Comb:FC-FA			20							NP	0.66		N	1	19521	
4	Duval	Piedre Lumbre	Wilcox	1954	6950	SS	Comb:FC-FA			48							NP	0.69		N	2	91903	
4	Duval	Rosita	Wilcox P	1962	9454	SS	Struct:FA			20		12	1	<2.0			GP	0.69		N	1	16006	
4	Duval	Rosita, N.W.	Wilcox R	1976	11494	SS	Struct:FA			26							GP	0.65		N	1	29385	
4	Duval	Rosita, N.W.	Wilcox U	1978	13676	SS	Struct:FA			118							GP	0.66		N	1	16504	
4	Duval	Seven Sisters, E	Howell Sand	1981	16068	SS	Struct:FA	WD	320	300		24	50	0.08-96	376		GP	0.64	45	N	2	78400	114390.
4	Duval	Seven Sisters, East	10000	1968	10000	SS	Struct:FA			101	290	22					GP	0.72		N	1	27575	
4	Duval	Seven Sisters, East	9500	1970	9500	SS	Struct:FA			31		17					GP	0.66		P	2	39322	50043
4	Duval	Seven Sisters, East	O-55	1983	14916	SS	Struct:FA	WD	320								GP	0.64		N	2	72400	93980
4	Jim Hogg	Thompsonville, NE	Wilcox 9500	1951	9500	SS	Struct:FA		640	53	7000	15	28			6855	NP	0.65		P	3	515200	
4	Jim Hogg	Thompsonville, NE	10,000	1967	10000	SS	Struct:FA			35							GP	0.68		N	1	12953	
4	Jim Hogg	Thompsonville, NE	12500	1966	12500	SS	Struct:FA		40	20		23	150				GP	0.67		P	2	54375	88244
4	Jim Hogg	Thompsonville, NE	9800	1972	9800	SS	Struct:FA			8							GP	0.66		N	1	13009	
4	Webb	Tom Shearman	10500	1978	10500	SS	Struct:FA			21							GP	0.67		N	1	15476	
				m	9671					54		19								Σ		1,712,062	

throw at the top of the Wilcox, but throw may exceed 5,000 ft (>1,500 m) at the base of the upper Wilcox. The growth faults may displace a potential reservoir zone below drillable depth within a short lateral distance. Concurrent movement of growth faults during deposition resulted in the accumulation of greater thicknesses of reservoir-quality sandstones in the downthrown block.

A small number of counterregional faults displace strata up to the basin. Counterregional faults are shorter and have less vertical displacement than the major regional growth faults. However, locally and in the Fandango field, counterregional faults are important barriers that have localized gas reservoirs.

According to Edwards (1981), depositional systems of the upper Wilcox in South Texas contain three delta complexes: the Zapata, Duval, and Live Oak (fig. 5). The deltas are inferred to be wave-dominated, shelf-margin deltas on the basis of the widespread distribution of upward-coarsening sand bodies. Sandstones within the delta complex are mostly in the delta-front and shoreface facies. The regional distribution of sandstone from the upper Wilcox illustrates both the thickening of sandstones on the downthrown side of regional growth faults and the accumulation of two areas of thick net sandstone that correspond with the Zapata and Duval delta systems (fig. 6). The areas of thick net sandstone are laterally distributed along strike, supporting the interpreted wave-dominated character of the deltas. The maximum thickness of individual sandstone bodies illustrates a dip-oriented alignment that may reflect thicker sandstone feeder axes related to fluvial systems (fig. 7).

In the Fandango field, gas is produced from a repetitive series of generally upward-coarsening sand bodies that are at a depth of 10,000 to 18,000 ft (3,650 to 5,490 m). These sand bodies include several 600- to 800-ft-thick (180- to 240-m) upward-coarsening sequences separated by uniformly thick basal shale (fig. 8, facies 1). Edwards (1981) interpreted these sequences as prodelta shales grading upward into delta-front sandstones, which accumulated along a prograding high-energy shoreline. These sandstones thicken by a factor of 3 to 7 across growth-fault expansion zones. Local-area geologists refer to these sand bodies as the R, T, and U series sandstones (C. Kimmell, personal communication). A dip-oriented cross section in the Fandango field illustrates the listric nature of a major growth fault (fig. 9). Major growth faults sole out into thick sections of highly disturbed shale.

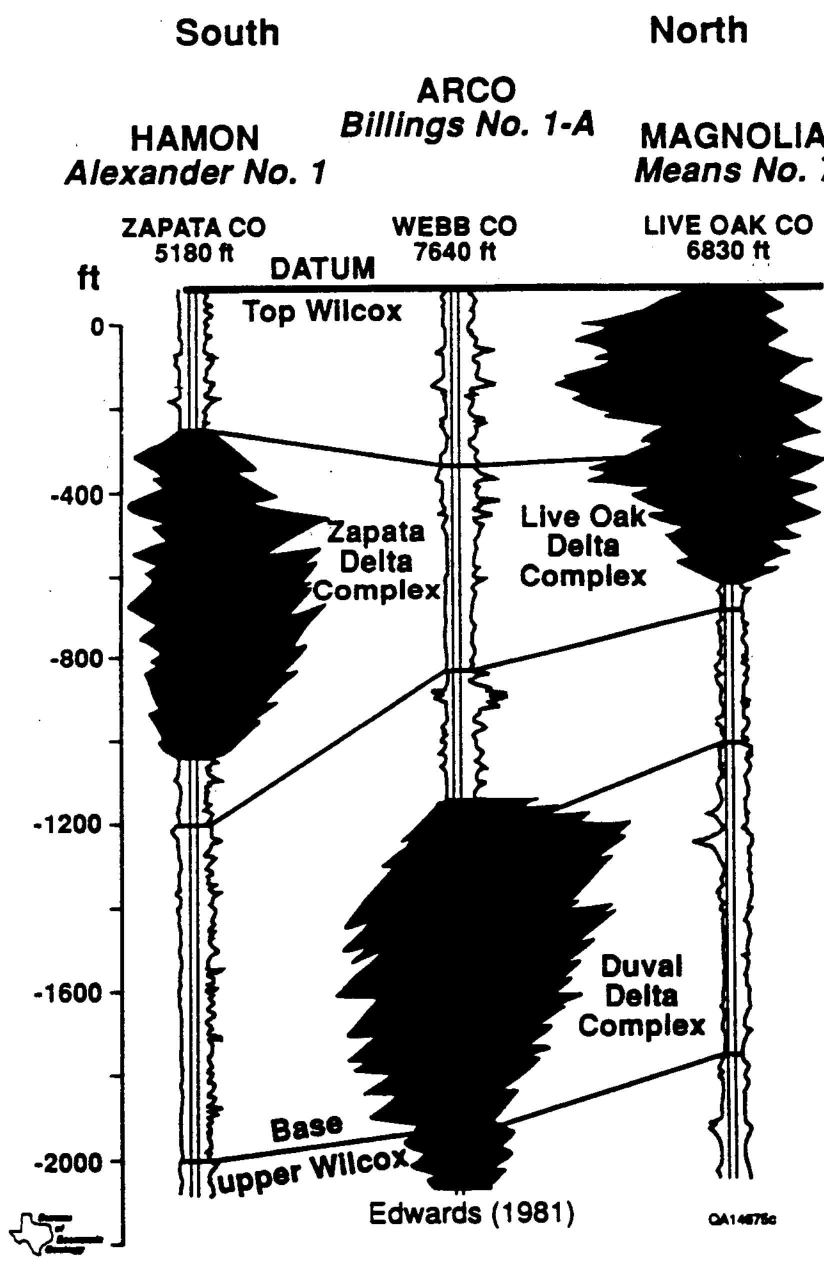

FIGURE 5. Characteristic logs from deltas of upper Wilcox in South Texas (after Edwards, 1981).

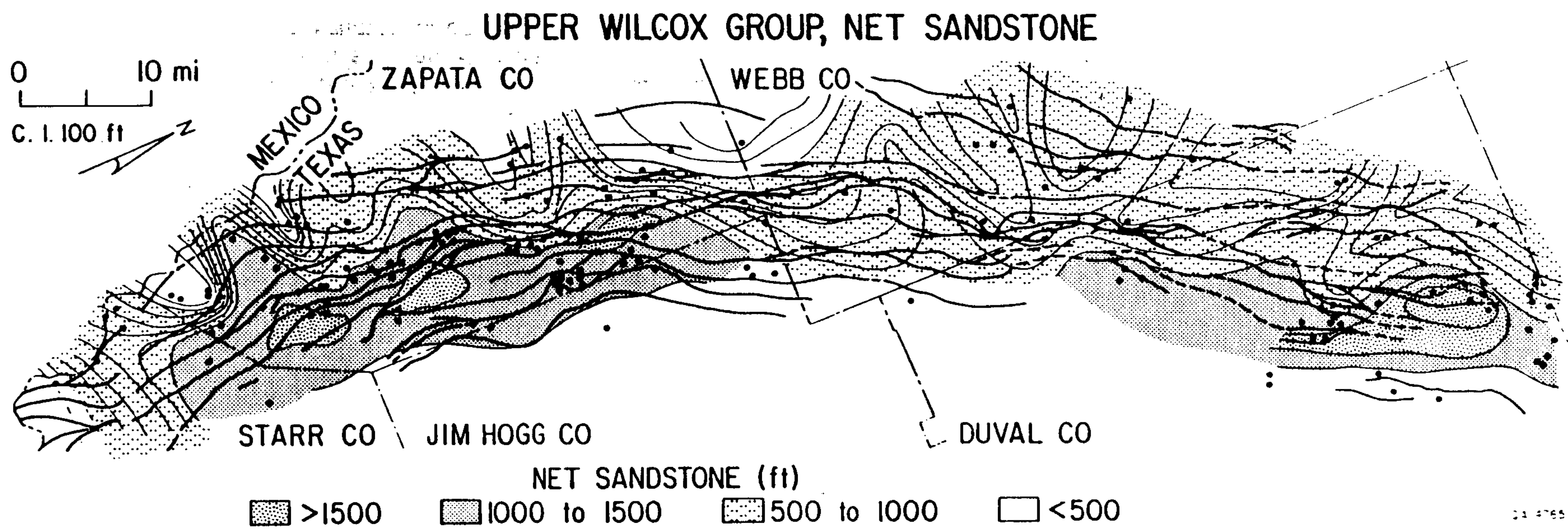

FIGURE 6. Net sandstone map of upper Wilcox in Starr, Zapata, Jim Hogg, Webb, and Duval Counties, Texas. Areas of thick net sandstone greater than 1,000 ft (>300 m) correspond with deltaic depocenters in Duval and Zapata Counties.

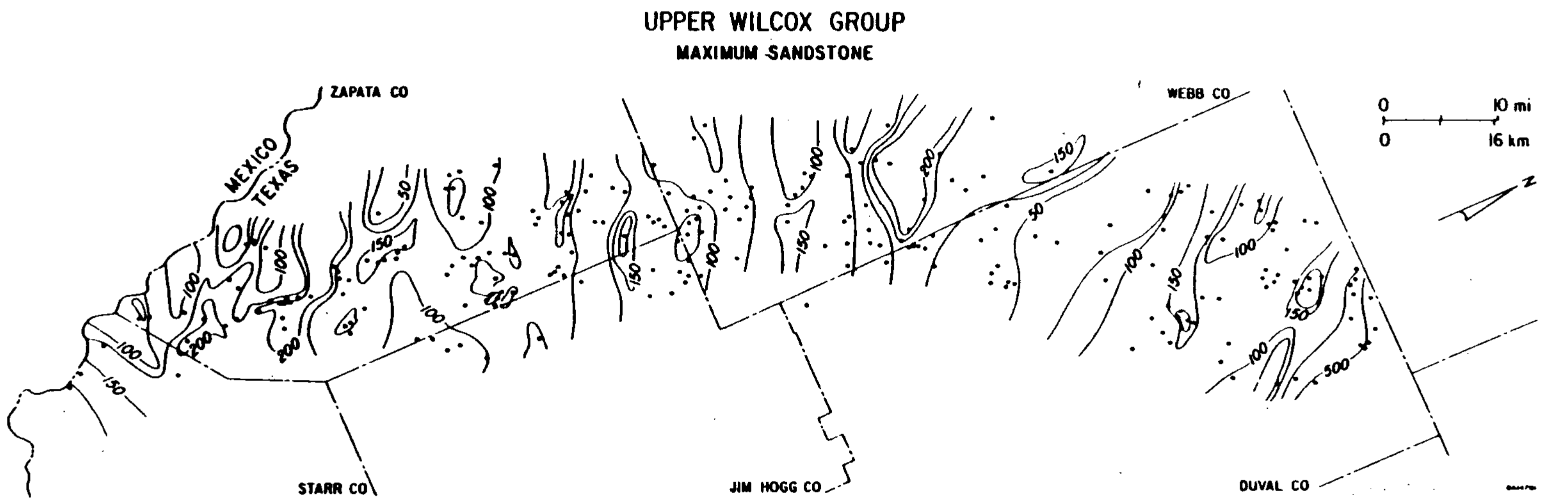

FIGURE 7. Maximum sandstone map of upper Wilcox in Starr, Zapata, Jim Hogg, Webb, and Duval Counties, Texas. Maximum sandstone is the thickest sandstone body logged in the well. Areas of thick maximum sandstones appear dip oriented and may reflect fluvial feeder axes.

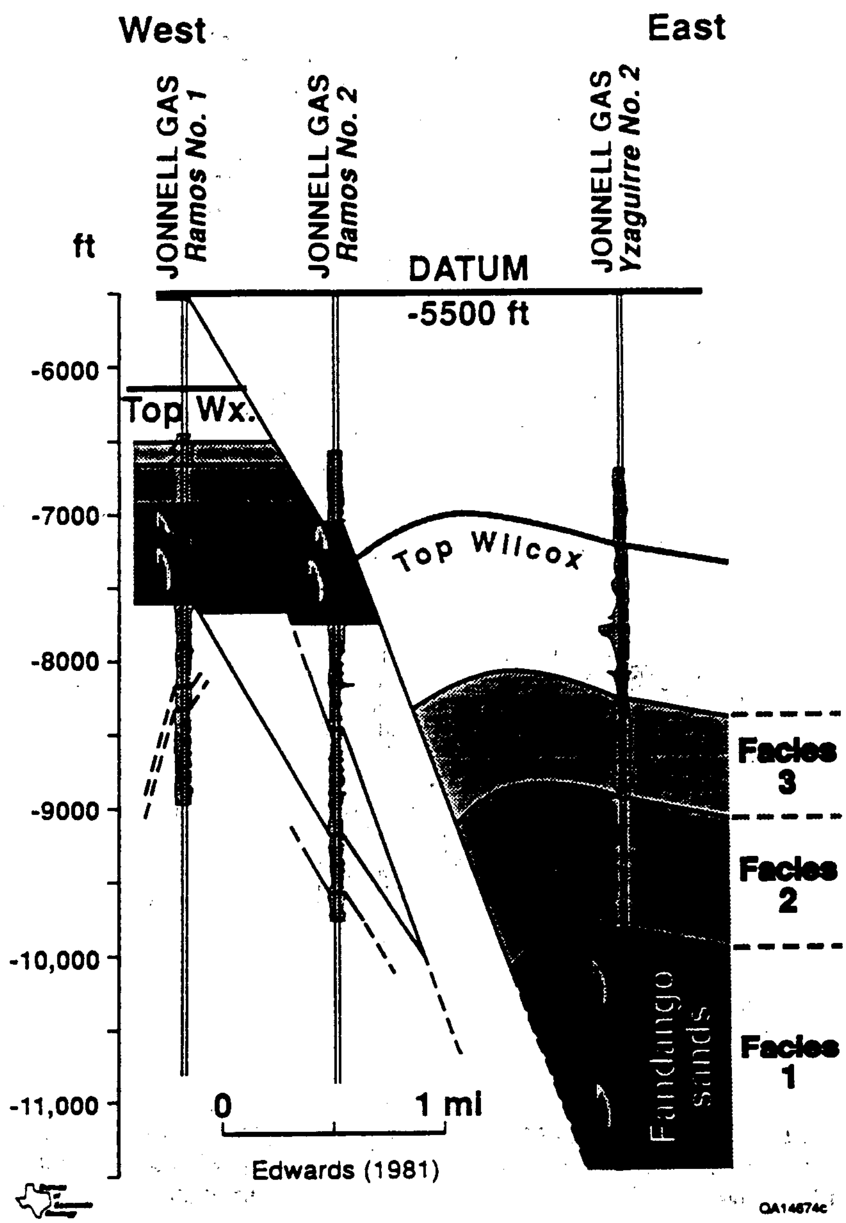

FIGURE 8. Structural dip-oriented cross section across major growth fault in Zapata delta complex, Zapata County. Log patterns and facies are similar across fault. Facies 1 is equivalent to Fandango R, T, and U series sandstones (after Edwards, 1981).

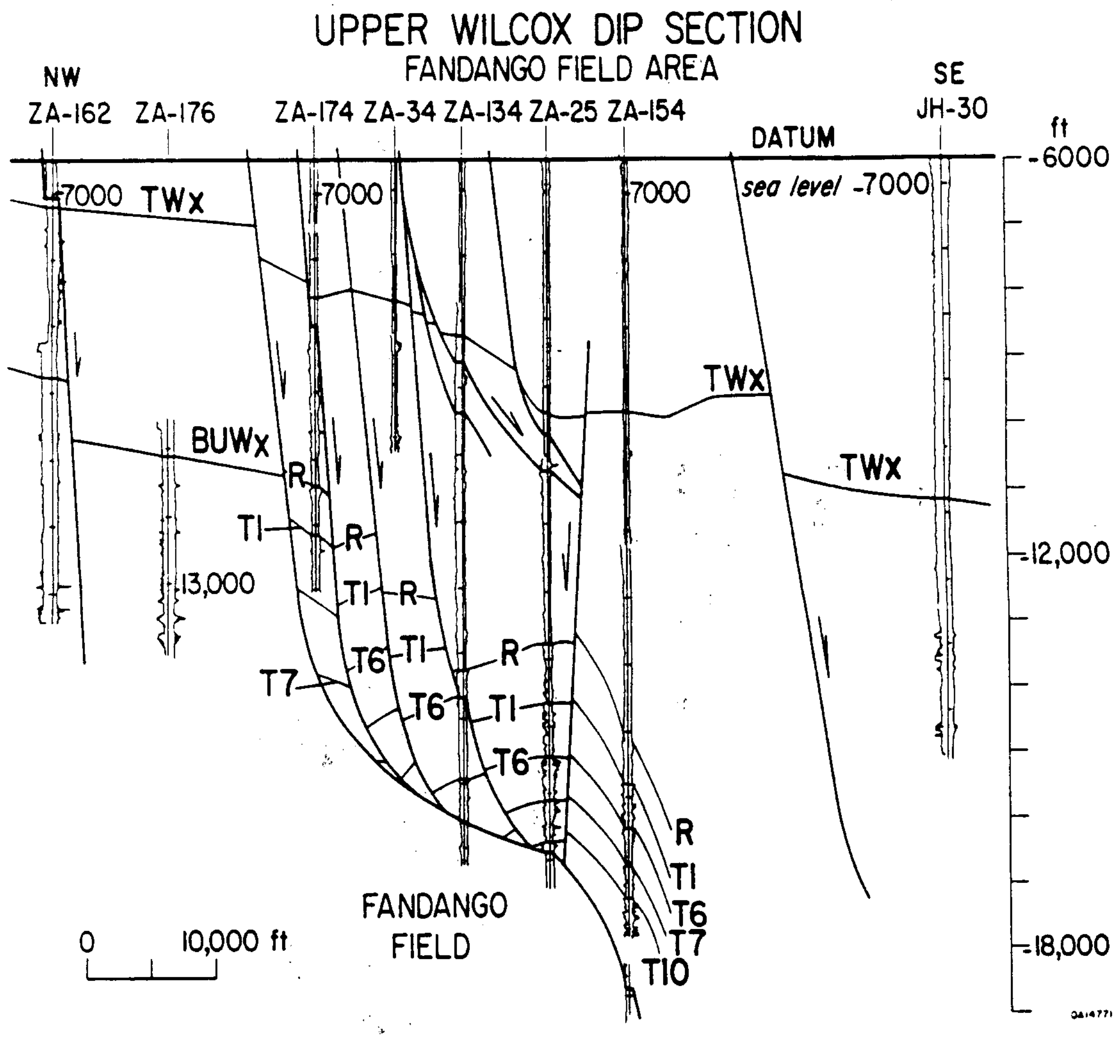

FIGURE 9. Structural dip-oriented cross section across Fandango field from Zapata to Jim Hogg County, Texas. Top and base upper Wilcox are correlated; only top Wilcox is penetrated in downdip wells. Within Fandango field, R, T, and U sandstone series are correlated.

Reservoir sandstones rollover against the fault plane. A more detailed cross section illustrates the structure and variation in sand body thickness associated with the growth faults (fig. 10).

A dip-oriented cross section across Thompsonville, NE field, Webb and Jim Hogg Counties, also illustrates thick sandstones in the upper Wilcox (fig. 11). The main productive reservoir at Thompsonville, NE field, is the first Hinnant sandstone. The Hinnant sandstone terminology is carried throughout the Thompsonville field and surrounding area (Berg and Tedford, 1977). The R through U sandstone terminology is also used farther north around Rosita field (Straccia, 1981).

R Sandstone Reservoir

The R sandstone is the thickest laterally continuous sandbody in the Fandango field and apparently is equivalent to the tenth Hinnant sandstone, which is well developed in Thompsonville, NE field. The R sandstone is an excellent sand body on which to focus attention because it could serve as a potential geothermal reservoir on the basis of its moderate depth, high temperature, great thickness, and wide distribution. Calculated reservoir temperatures and depth of water samples from individual sandstone zones in Fandango and Rosita fields are provided in table 2 (Lundegard, 1985). At a depth of 12,000 to 15,000 ft (3,660 to 4,570 m), temperatures of water in the R sandstone range from 350°F to 383°F (177°C to 195°C).

Initial characterization of the R sandstone focuses on its depth, thickness, and distribution (table 3). The geothermal-reservoir size for the R sandstone compares favorably with that calculated for the first Hinnant sandstone in the Riddell No. 1 Saldana well (table 4) (Morton and others, 1983). The elevation (below sea level) to the top of the R sandstone in the Fandango field area ranges from approximately -11,000 ft (-3,350 m) in updip fault blocks to greater than -14,000 ft (>-4,270 m) in the downdip fault block with the deepest penetrations (fig. 12). The pattern of fault traces is complex, and, with the limited well control available, the patterns are poorly constrained. A comparison of variations in the fault patterns mapped by Levin (1983), Kimmell (1986), and this study reveals significant variations in fault orientation and serves to underscore the difficulty in mapping complex structure without detailed three-dimensional seismic data.

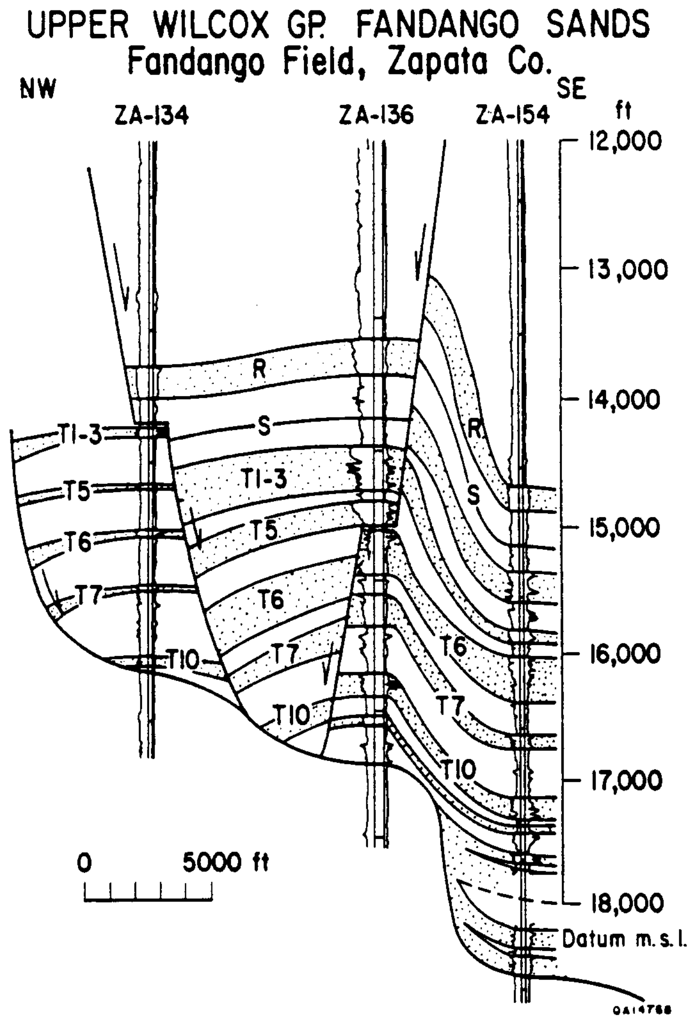

FIGURE 10. Structural dip-oriented cross section within Fandango field, Zapata County, Texas. R and T series of sandstones are readily identified across field. Major growth fault is a decollement zone that soles out in thick basal shales.

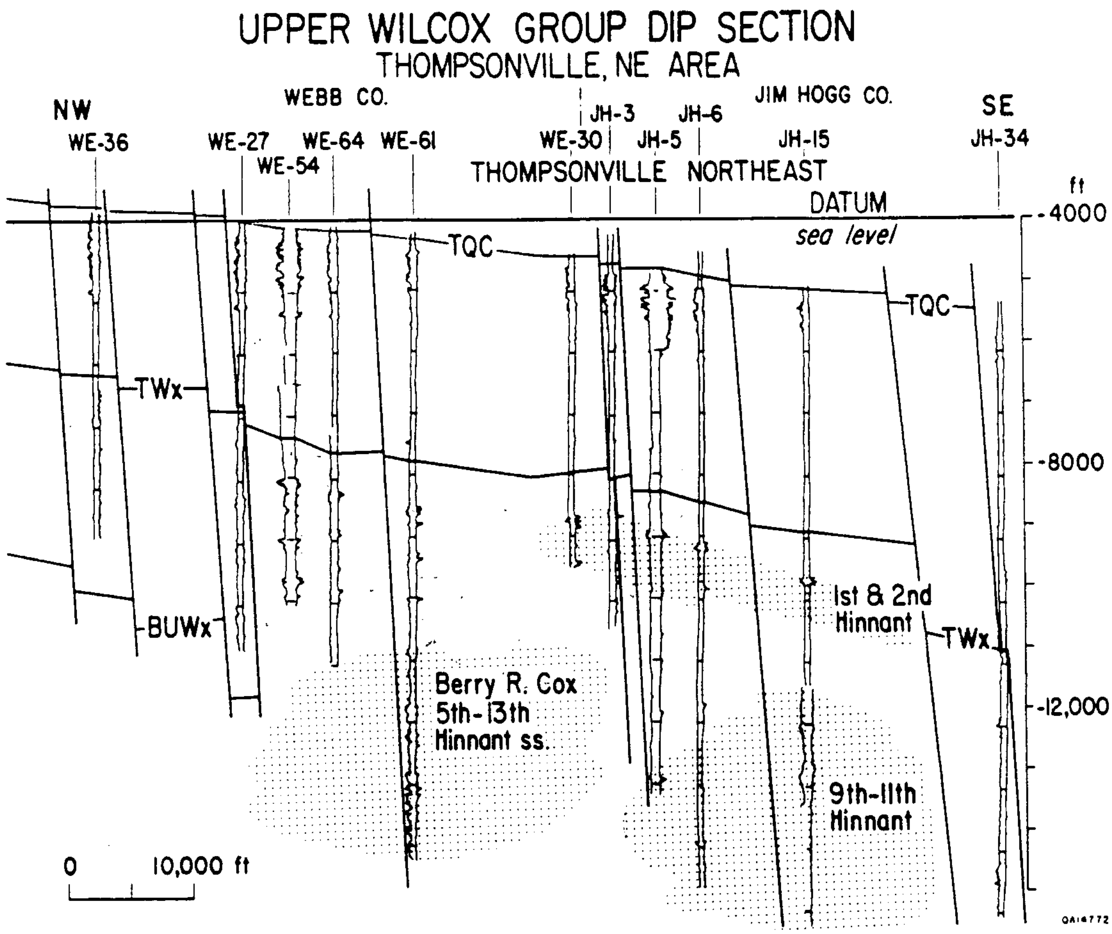

FIGURE 11. Structural dip-oriented cross section in Thompsonville, NE field, Webb and Jim Hogg Counties, Texas. Thick productive sandstones include first and fifth through thirteenth Hinnant sandstones in Berry R. Cox and Thompsonville, NE fields. Major gas reservoir at Thompsonville, NE field is first Hinnant.

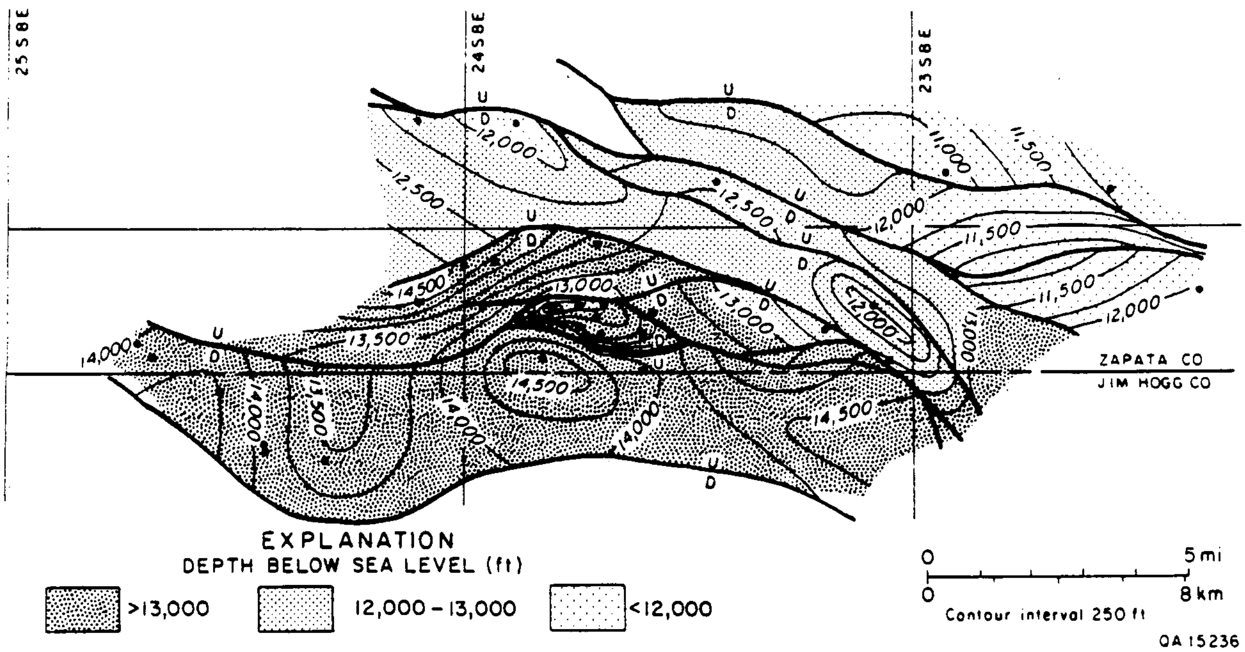

FIGURE 12. Structure map of tenth Hinnant, or R sandstone, in Fandango field, Zapata and Jim Hogg Counties, Texas.

TABLE 2. Calculated temperature and depth of geothermal waters of upper Wilcox from selected wells in Fandango and Rosita fields, South Texas (after Lundegard, 1985).

Well Number	Field	Well	Sample depth (ft)	Temperature (°F)	Horizon
1	Fandango	Shell Hinojosa No. 8	17,057	432	U sand
2	Fandango	Shell Garza No. 2	14,774	383	R sand
3	Fandango	Shell Zachry A No. 2	16,079	408	T_5 sand
4	Fandando	Shell Muzza No. 4	14,331	374	T_1 sand
			m 15,560	399	
5	Rosita	Shell Hubbard-Frost No. 169	13,425	387	
6	Rosita	Shell Hubbard No. 2	12,110	354	S sand
7	Rosita	Shell Weathery A No. 2	13,914	394	U sand
8	Rosita	Shell Travis McGee No. 1	11,890	352	R sand
			m 12,835	372	

TABLE 3. Significant attributes of a favorable geothermal reservoir.

UPPER WILCOX - 10th HINNANT (R SAND)

Locally productive: Fandango, Thompsonville, NE fields

Locally continuous: Multiple fault blocks in Zapata, Jim Hogg, and Webb Counties

Thick sandstone: Maximum sandstone 50-250 ft thick

Depth: 11,000-15,000 ft

Temperature: 300-400°F

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TABLE 4. Comparison of sizes of geothermal reservoirs in upper Wilcox sandstones. Data from Riddle No. 2 Saldana (Morton and others, 1983).

Area	Reservoir	Area (mi^2)	Thickness (ft)	V_{res} (Bcf)	Porosity (%)
Riddle #2 Saldana	First Hinnant	3.6	70	7	16
Fandango	10th Hinnant (R Sd)	4.4	200	24.5	5-10

QA14844c

The pattern of net thickness for the R sandstone illustrates a large area of thick net sandstone at Fandango field and a smaller area of thick net sandstone in updip fault blocks located 10 mi (16 km) north of Fandango field (fig. 13). Broad areas of low net sandstone bracket the area of thick net sandstone around Fandango field. Net sandstone thins along strike to the south and north, and downdip to the east. Within individual fault blocks, net sandstone is generally greatest against the updip fault. The maximum thickness of an individual sandstone body in the R sandstone more sharply defines a dip-oriented feeder (fig. 14). Apparently fluvial systems west and west-northwest of Fandango field fed small lobate deltas that prograded across the Fandango field and foundered along the rapidly subsiding shelf margin.

Although the R sandstone has a number of favorable factors, including great thickness and lateral extent, its shallow depth relative to underlying sandstones indicates that it will have lower temperatures than fluids in underlying reservoir sandstones (table 2). Calculated temperatures for the R sandstone range from 350°F to 383°F (177°C to 195°C). Although the temperatures are respectably hot, underlying reservoirs are hotter by 50°F (27°C) to greater than 100°F (>55°C).

JACKSON GROUP HEAVY-OIL RESERVOIRS

The five nty area of South Texas (Zapata, Starr, Jim Hogg, Webb, and Duval Counties) contains both heavy- and light-oil reservoirs that produce from the Jackson Group Mirando trend (tables 5 and 6). Unlike the deep upper Wilcox trend, the Mirando trend is supermature from an exploration standpoint. The major light-oil reservoirs (API gravity greater than or equal to 21) listed in table 4 are larger and more continuous than the heavy-oil reservoirs. However, the 20-API cutoff between heavy- and light-oil reservoirs is arbitrary, and the light-oil reservoirs as a group are relatively heavy (mean oil gravity equals 26 API). In the five-county area of South Texas, 21 heavy-oil fields (API less than or equal to 20) with 26 reservoirs, having a miminum cumulative production of 1 Mbbl, are directly above the Wilcox fairway, where subsurface temperatures exceed 250°F (121°C) (table 6). Total cumulative production from these fields is 33 MMbbl. Heavy-oil reservoirs constitute 9 percent of the cumulative production of the major light-oil reservoirs in the Mirando trend in the five-county area (tables 4 and 5).

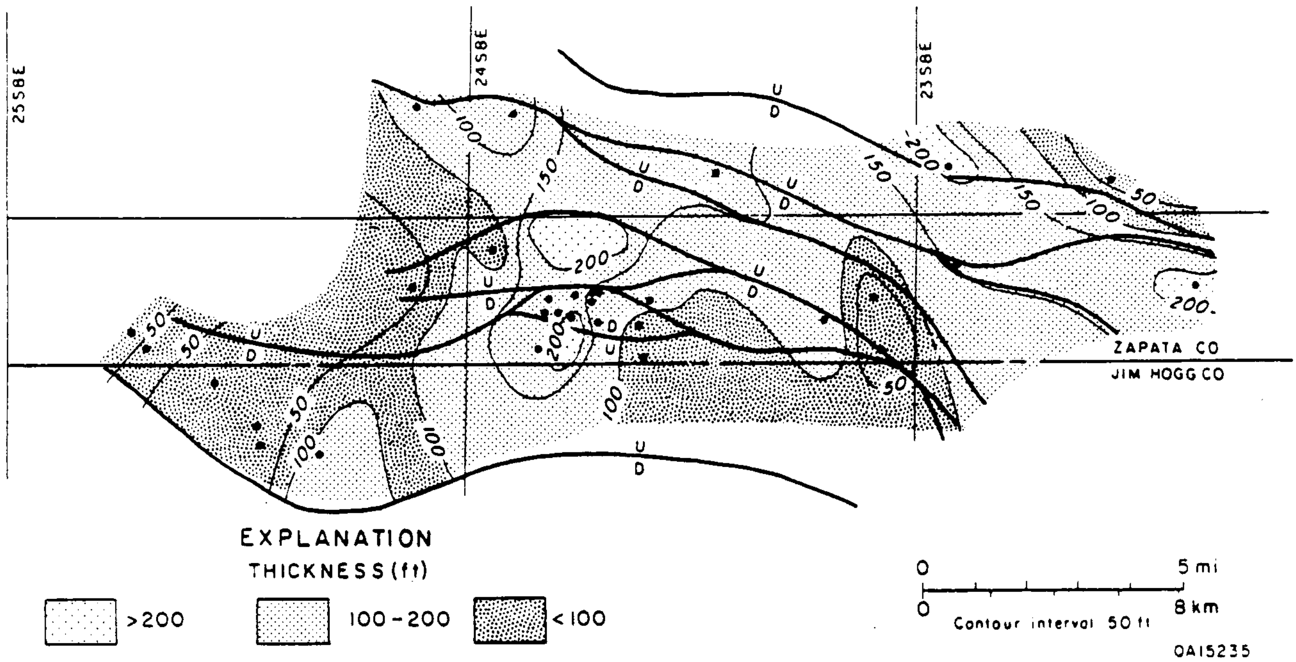

FIGURE 13. Net sandstone map of tenth Hinnant, or R sandstone, in Fandango field, Zapata and Jim Hogg Counties, Texas.

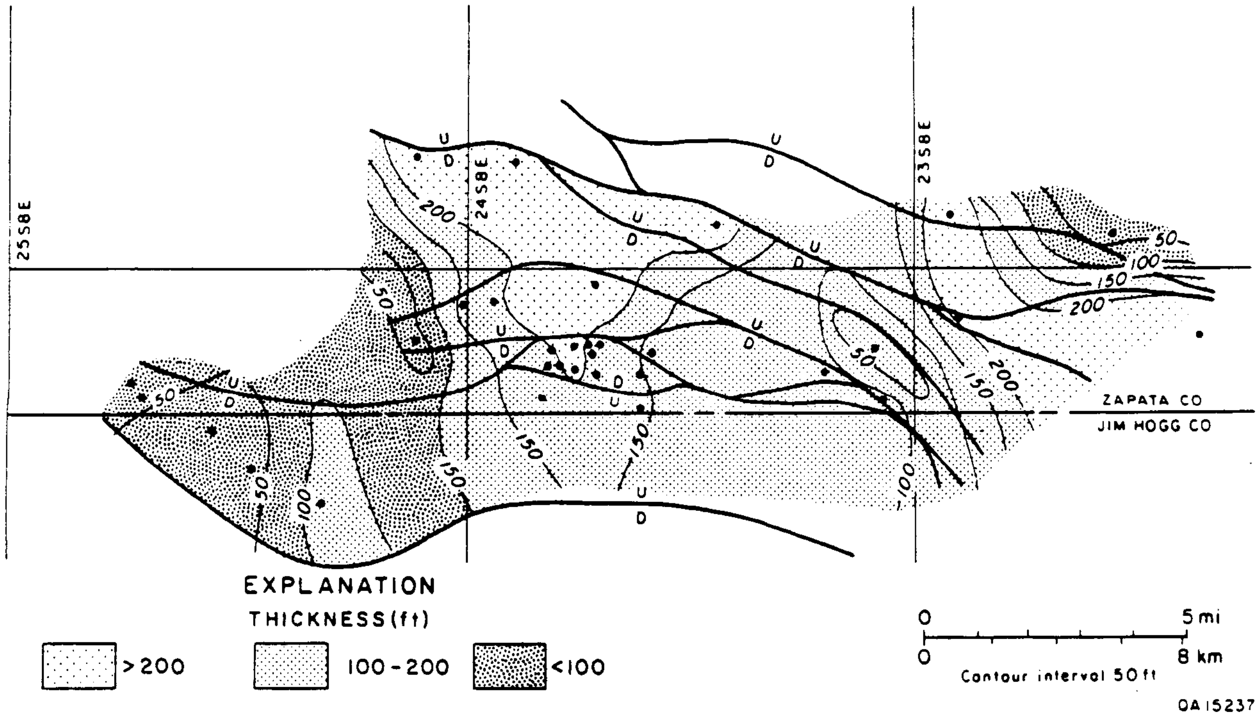

FIGURE 14. Maximum net sandstone map of tenth Hinnant, or R sandstone, in Fandango field, Zapata and Jim Hogg Counties, Texas. Maximum net sandstone is the thickest sandstone logged in the well.

TABLE 5. Geologic, engineering, and production parameters of major oil reservoirs in South Texas Jackson Group trend. Major oil reservoirs had a cumulative production greater than 10 MMbbl through 1981 (after Galloway and others, 1983).

RRC Dist	Field and Reservoir	Disc. Date	Lithology	Trap	Drive	Depth (ft)	Oil Col. (ft)	Por. (%)	Permeability Avg. (md)	Permeability Log Range	H_2O Sat.	API Grav.	Init. Gor.	Init. Pres.	Temp. (ft)	Production Technology	Unit Date	Well Spacing (acres)	Ros (%)	OIP (MMbbl	CUM Prod. (MMbbl)	ULT Recov. (MMbbl)	Rec. Eff. (%)
4	Aviators, Mirando	1922	SS	UPP	SG + WD	1700	51	32	357	1 3	37	21		700	107	WF	1966	10	25	37	10 1	10 3	28
4	Colorado, Cockfield	1936	SS	UPP	SG	2600	300	28	800	2 3	25	45	287	1125	145	WF		10-40	31	52	21.7	21 8	42
4	Conoco Driscoll, U 1GW	1937	SS	NPP	GCE	2800	54	31	458		32	33	139	1290	153	PMG	1937	20	9	69	20 0	23 7	34
4	Escobas, Mirando	1928	SS	NPP	SG	1200	70	30	500	1 3	40	23		575	100	WF,T		10	30	28	12 8	12 9	46
4	Govt. Wells, North G W.	1928	SS	UPP	SG + WD	2200	60	32	800	2 3	30	21	800	875	114	WF,P,T		10	36	150	77.3	78 0	52
4	Govt Wells, South G.W.	1928	SS	UPP	SG	2300	89	30	600	2 3	35	21	880	850		PMG,WF		10	20	40	16 6	18 0	45
4	Hoffman, Dougherty	1947	SS	NPP	SG	2000	250	34	757		40	23	85	795	131	WF,P		16	18	55	20 5	21 0	38
4	Loma Novia, Loma Novia	1935	SS	UPP	SG	2600	240	26	800	1 3	25	26	40	1003	114	WF,PMG		10	35	176	47 7	48 0	27
4	Lopez, First Mirando	1935	SS	UPP	Combined	2200	70	35	250.	1 3	40	22		780	111	PMG,WF,T	1955	10	25	75	30 4	33 0	44
4	Mirando City, Mirando	1921	SS	UPP	Combined	1600	35	33	1600	2 3	40	21	125	665		WF,T			25	46	12 1	12.1	26
4	O'Hern, Pettus	1930	SS	NPP	SG	2700	200	28	286	1 3	20	28		990	136	PMG,WF,T	1957	10	20	83	22 2	30 0	36
4	Piedre Lumbre, G.W.	1935	SS	NPP	WD + SG	1900	65	30	300	1 3	30	22		820	100	PMG,WF,LPG		10	25	95	20 7	22 0	23
4	Prado Middle, Loma Novia	1956	SS	UPP	SG + GCE	3700	65	32	850	1 4	26	40	600	1407	109	PMG,WF	1957	10	30	38	10 4	23 7	62
4	Seven Sisters, G.W.	1935	SS	NPP	SG + WD	2330	75	28	225	1 2	55	20	___	1150	132	PMG,WF		10	15	142	35 0	56 0	39
					m	2273	1110	31	613		34	26	370	930	121				25	Σ 1086	367.5	440.5	39

TABLE 6. Geologic, engineering, and production parameters of heavy-oil reservoirs in South Texas Jackson Group through 1988.

RRC Dist	Field and Reservoir	Disc. Date	Lithology	Trap	Drive	Depth (ft)	Oil Col. (ft)	Por. (%)	Permeability Avg. (md)	Permeability Log Range	H_2O Sat.	API Grav.	Init. Gor	Init Pres	Temp (ft)	Production Technology	Unit Date	Well Spacing (acres)	Ros (%)	OIP (MMbbl	CUM Prod. (MMbbl)	ULT Recov. (MMbbl)	Rec. Eff. (%)	Producing SS
4	Alworth, Cole Sand	1965	SS	Comb.	WD	1040	6	29	511		31	19		191		WF		63			.078			Cole
4	Bruni, S.	1944	SS			1804		31	600			19									.001			Cole
4	Bruja Vieja, Cole Sand	1950	SS			1755						18									.001			Cole
4	Cedro Hill	1938	SS	Strat	SG + WD	1440	12	31	700		42	19		400		WF			13.65		6.569			Cole
4	Charco Redondo	1913	SS	Strat	SG	339	14	33	1659	518-2900	25	17		30		AF			7.7		659			Cole
4	Colema	1936	SS	Strat	SG + WD	1500	20	32	650		40	19		600		WF					3.868			Cole
4	Dinn	1949	SS	Strat	WD	1805	5					19									.319			Cole
4	Edlasater, W., Cole 950	1968	SS			950						20									.013			Cole
4	El Puerto, N., O'Hern	1965	SS			760						20									.001			4th Mirando
4	Govt. wells, N., 900 Sand	1948	SS			918						20									.315			
4	Govt. wells, N., 1000 Sand	1950	SS			1062						19									.080			
4	Govt. wells, N., 1150	1978	SS			1167						20									.023			
4	Govt. wells, No., 1550	1949	SS			1547						20									.030			
4	Govt. wells, S., Hockley 1900	1965	SS			1919						19									.030			Taracahuas
4	Hoffman, E.	1950	SS	Strat	SG	2038	20					20									1.387			
4	Joe Moss, 500 Sand	1952	SS			500						20									.557			2nd Mirando
4	Kohler, NE., Mirando #2	1980	SS		S	2633						19									1.217			Cole
4	Las Animas-Lefevre	1937	SS	Strat	SG	1793	20	31	800		35	19		620							3.402			1st Mirando
4	Lopez, N., (Lopez)	1951	SS	Strat	SG	2084	10	35	428		33	20		960		WF			3.600		2.225			Cole
4	Lundell	1937	SS	Strat	SG	1528	10					19		700		WF					10.358			Cole
4	Orlee	1949	SS	Strat	WD	1697	10	25	200		35	20		765		WF					.266			1st Cole
4	Peters, N., Cole First Sand	1959	SS	Fault		1746						20									.042			Cole
4	Rancho Solo	1937	SS	Comb.		1849						19									.465			
4	Rancho Solo, Cole Second	1959	SS	Fault		1840		31				20									.030			2nd Cole
4	Rancho Solo, Extension	1939	SS	Strat		1836						19									.520			
4	Richardson	1944	SS			1784						18									.147			Cole
	21 Fields 26 Reservoirs			m		1512	12.7	31.	694		34	19		533						Σ	32.92			

However, it is estimated that 70 percent of the heavy oil has not been recovered by primary and secondary recovery operations (C. Kimmell, personal communication, 1990).

The largest reservoirs in the trend (Government Wells with a cumulative production through 1988 of 97 MMbbl and Loma Novia, with a cumulative production through 1988 of 55 MMbbl are most productive from conventional, low-viscosity reservoirs. Although these reservoirs are a part of the Mirando trend, they do not produce heavy oil with API gravities less than or equal to 20. The recovery efficiencies of the largest nonheavy-oil reservoirs are also rather low, averaging 38 percent (Galloway and others, 1983). Lundell (first Cole) is the largest heavy-oil field (cumulative production 10 MMbbl through 1988) whose reservoir produces oil with API gravities less than 20.

The updip pinch-out of strike-oriented sand bodies in the Jackson Group largely controls the distribution of Mirando-trend heavy-oil reservoirs (West, 1963). Four-way closure results from subtle structure, small faults, and local variations in strandline orientation. Although as many as 50 separate sand bodies are productive, principal producing sands are Government Wells, Loma Novia, Mirando, Lopez, Cole, and Pettus. The Cole sandstones, which are near the top of the Jackson Group, have the greatest number of reservoirs of heavy oil, whereas the Mirando and equivalent sandstones near the base of the Jackson Group have the greatest number of major light-oil reservoirs.

The linear strike-oriented sandstones characteristic of the Jackson Group are interpreted to represent strandplain/barrier bar sands (West, 1963; Fisher and others, 1970; Kaiser and others, 1978; Kaiser and others, 1980; Hopf, 1986; Schultz, 1986). They form a sand-rich belt 20 to 25 mi (32 to 40 km) wide bounded by mudstone both updip and downdip. A sand-percent map of the lower part of the Jackson Group illustrates the strongly linear strike orientation of the sandstone belt (fig. 15) (Kaiser and others, 1980). In addition, the size and distribution of Mirando-trend heavy-oil fields are indicated on the percent-sand map of the lower Jackson. In Starr and Zapata Counties, heavy-oil fields are clearly associated with the updip pinch-out of sandstone into lagoonal mudstones, where sandstone percentage approaches 15 percent. In Webb and Duval Counties, the heavy-oil fields are characteristically trapped in updip pinch-outs of individual sandstones, in the upper Jackson Cole sands, which are not mapped in figure 15.

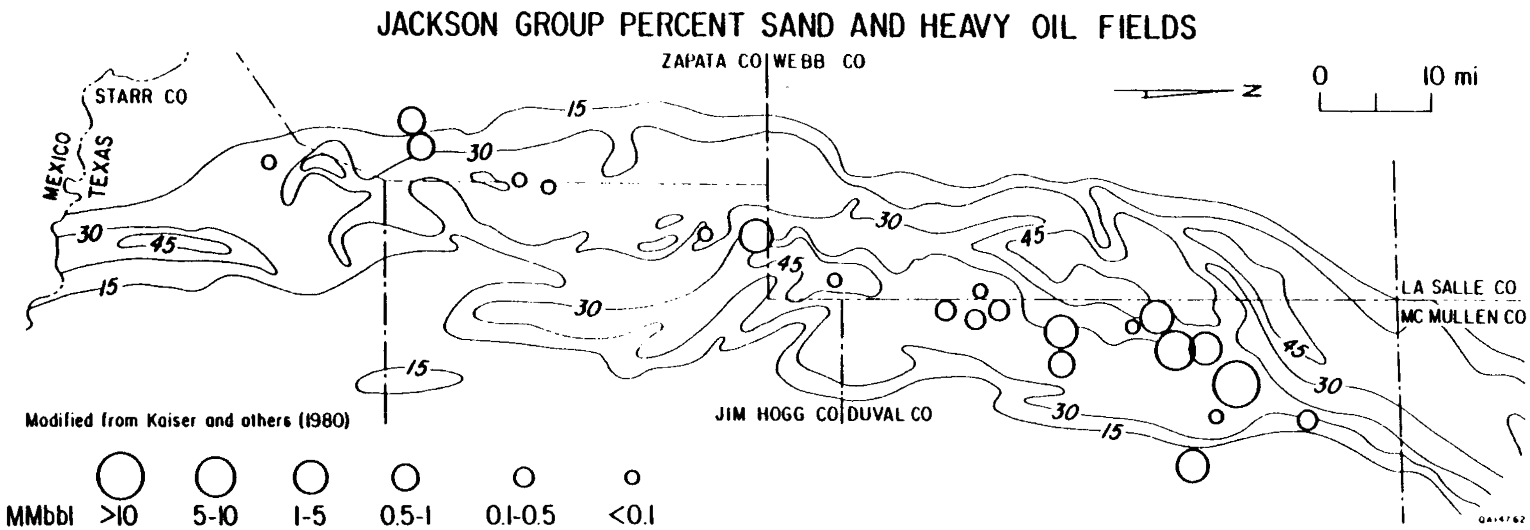

FIGURE 15. Percentage-sand map of lower part of Jackson Group in Starr, Zapata, Jim Hogg, Webb, and Duval Counties, Texas (Kaiser and others, 1980). Distribution and size of heavy-oil reservoirs in Jackson Group are indicated on percentage-sand map. Most heavy-oil reservoirs produce from the Cole sandstone. The Cole sandstones occur in the upper part of the Jackson Group and are not represented on the percentage-sand map, which emphasized the distribution of the Mirando sands.

The updip pinch-out of Cole sandstones in Zapata County, across Dinn and Richardson fields, is represented in figure 16. Production is from first Cole sandstones at a depth of 1,500 to 1,900 ft (457 to 579 m). Sandstone bodies are of two genetic types: (1) laterally continuous, upward-coarsening barrier-bar and shoreface sandstones and (2) laterally discontinuous, upward-fining fluvial or tidal-channel sandstone. The Mirando sandstones pinch out farther updip.

Production from Rancho Solo reservoirs is associated with updip pinch-out of Cole sandstones in Duval County (fig. 17). Heavy-oil production from Kohler, NE field is associated with the second Mirando sandstone.

A deep Wilcox log is illustrated on both of the cross sections shown in figures 16 and 17. Upper Wilcox sandstones greater than 50 ft (>15 m) thick are present between -12,000 and -14,000 ft (-3,658 and -4,267 m). Production of hot waters from such reservoirs would require only short-distance transport (intrafield) on the surface.

Some characteristics of Jackson Group heavy-oil reservoir sands are shown in table 7. Conditions of special significance for possible GTEOR include (1) relatively shallow heavy-oil reservoirs, (2) excellent porosity and permeability, and (3) thin oil column in thin reservoir sandstones. The relatively shallow depths of heavy-oil reservoirs (mean depth of 1,512 ft [461 m]) and low reservoir pressures constrain the upper limit of injection pressures to prevent fracture of the reservoir. However, even at these relatively low pressures, injected geothermal fluids will still be hot water and not steam. The excellent porosity and permeability of the heavy-oil reservoirs suggest that the low recovery efficiencies of heavy-oil reservoirs result from the high viscosity of the oil and from depleted reservoir energies, not from reservoir heterogeneities or low permeabilities. Heavy-oil reservoirs are significantly shallower than major light-oil reservoirs (mean depth of 1,512 ft [461 m] for heavy reservoirs vs. 2,273 ft [693 m] for light reservoirs) raising the possibility that reservoir depth also influences oil viscosity.

Mirando-trend heavy-oil reservoirs are characterized by thin, strike-elongate sandstone bodies in which the primary trapping mechanism is updip stratigraphic pinch-out of reservoir sandstone. Also, a thin oil column in a thin reservoir that pinches out updip is an ideal geometry for favorable sweep efficiencies of injected fluids. Although the laterally continuous sand-body geometry of heavy-oil

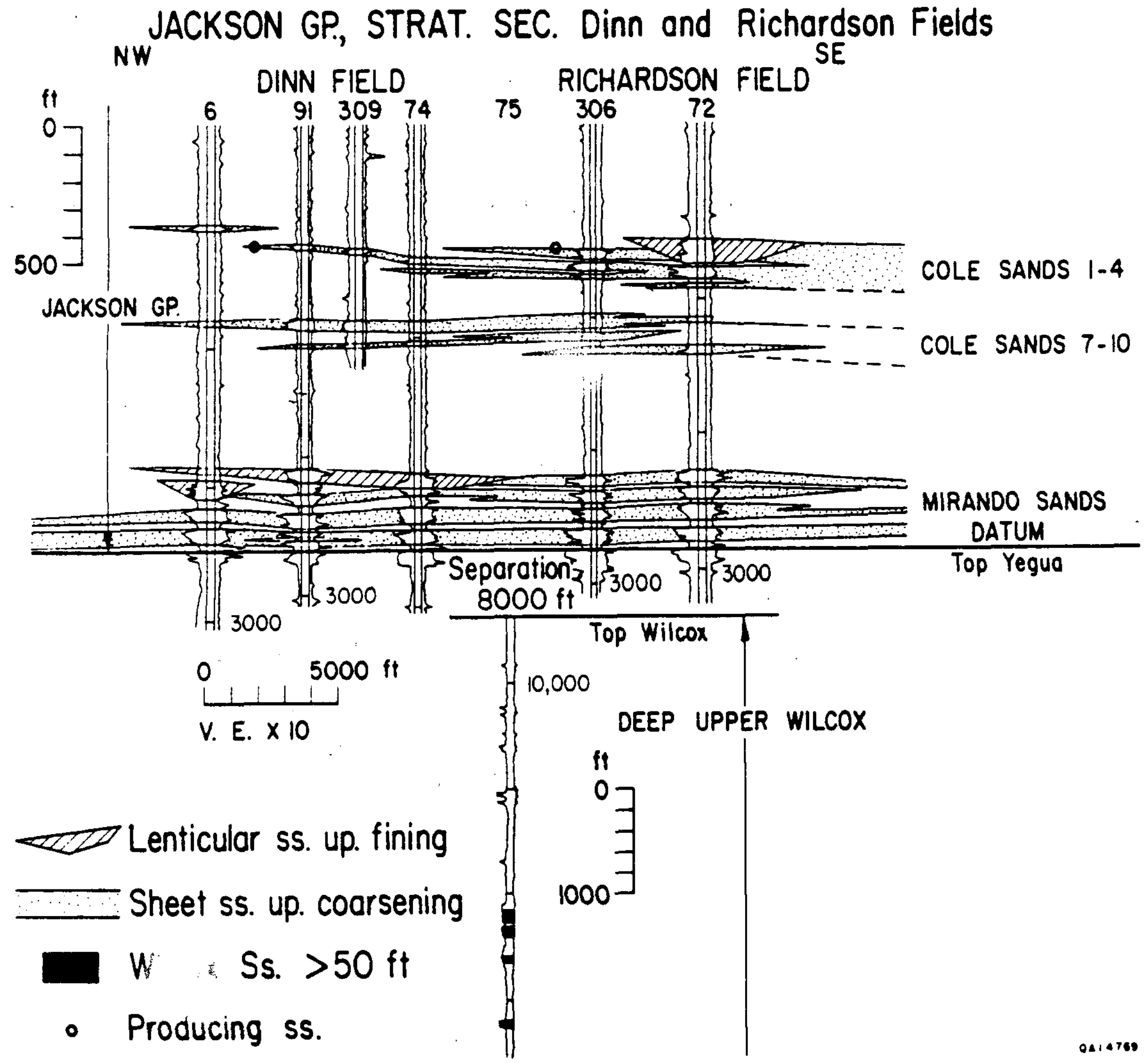

FIGURE 16. Stratigraphic cross section of Jackson Group, Dinn and Richardson fields, Webb and Duval Counties, Texas. Datum is top Yegua. Mirando sandstones are continuous across area of section. Cole sandstones pinch out toward the northwest near Webb-Jim Hogg county line. Primary trapping mechanism in Dinn and Richardson fields is updip pinch-out of barrier bar/shoreface sandstones. Deep upper Wilcox reservoirs in Dinn Deep field are vertically separated by 8,000 ft (2,438 m) from heavy-oil reservoirs.

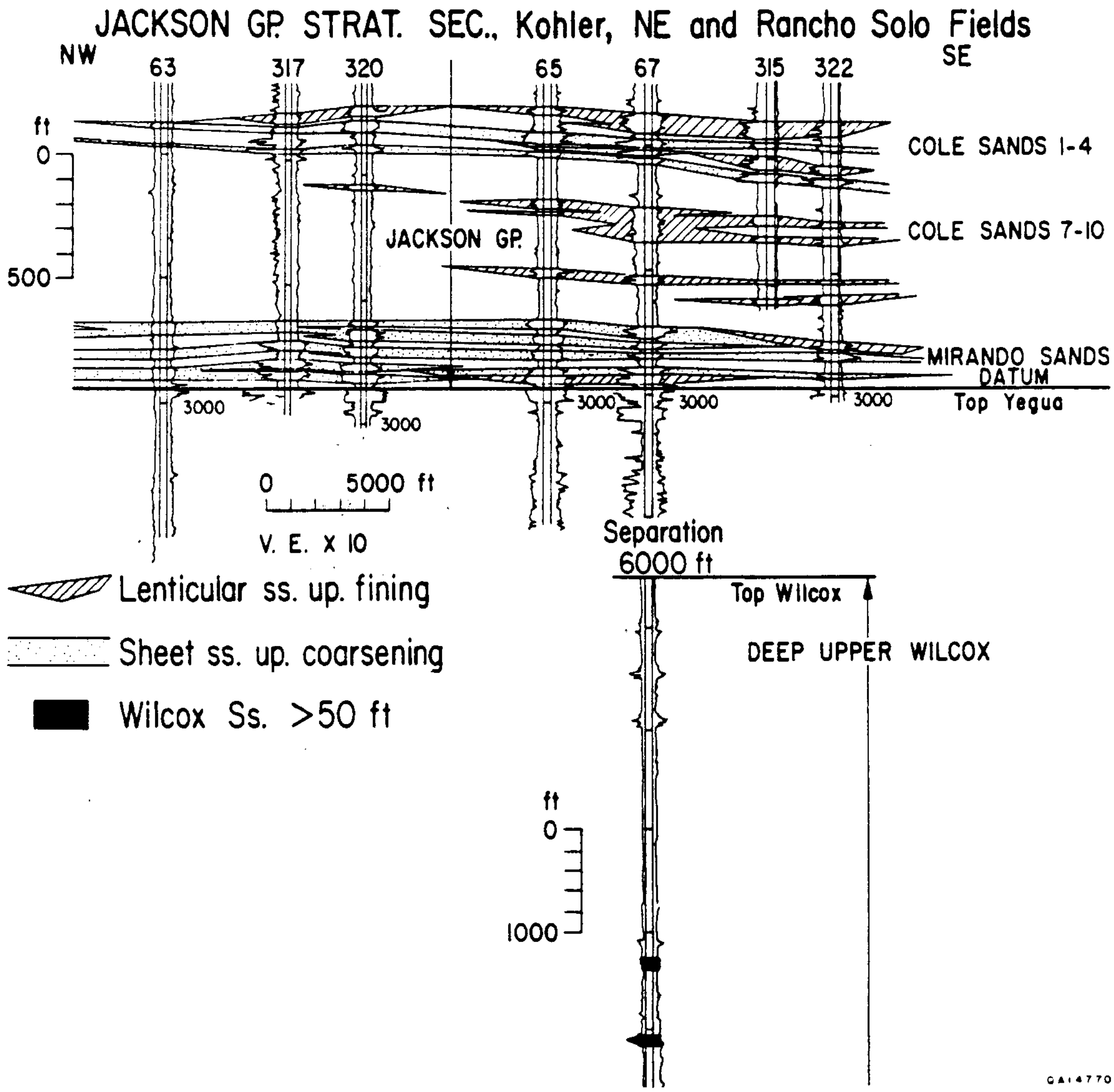

FIGURE 17. Stratigraphic cross section of Jackson Group, Kohler, NE, and Rancho Solo fields, Duval County, Texas. Datum is top Yegua. Mirando sandstones are continuous across area of section. Cole sandstones pinch out toward the northwest. Primary reservoir in Kohler, NE field, is second Mirando sandstone. The reservoirs in Rancho Solo field are the first and second Cole sandstones.

TABLE 7. Significant attributes of favorable heavy-oil reservoirs.

JACKSON GROUP - COLE SAND

Locally productive: Alworth, Charco Redondo, Cedar Hill, Lundell fields

Locally continuous: Laterally persistent with updip pinch out

Thickness: Reservoir 0-50 ft; oil column 0-10 ft

Depth: Less than 2,000 ft

Crude: Sweet crude, low gravity 17-20 API

Reservoir characteristics: Porosity 25-41%; avg. 31%
Permeability 70-2,800 md; avg. 700 md

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reservoirs is favorable for minimizing reservoir compartmentalization that could disrupt injected fluid flow paths, the thinness of the reservoir is unfavorable because of relatively high rates of heat loss (Martin and others, 1968).

CONCLUSION

In South Texas, the colocation of geothermal resources below heavy-oil reservoirs and the character of the heavy-oil and geothermal energy resources suggest thermally enhanced oil recovery could be economically viable (fig. 1). The heavy-oil reservoirs of the Jackson Group--Mirando trend have notoriously poor recoveries of oil in place using conventional and secondary recovery methodologies, despite favorable characteristics of the reservoir strata. Using geothermal waters as a source of hot water to mobilize the oil could greatly improve recovery efficiencies and prevent premature abandonment of reservoirs that still have as much as 70 percent oil remaining in place (C. Kimmell, personal communication). Major points of comparison between heavy-oil and geothermal reservoirs are listed in table 8. The thickness and lateral extent of the geothermal reservoirs appears to be much larger than that of the smaller heavy-oil reservoirs. A range of technical issues remains to be resolved, including the (1) chemical compatibility of injected fluids and heavy-oil reservoirs, (2) geometry and size of hot-water reservoirs that may be determined through detailed field studies, (3) geometry and size of heavy-oil reservoirs that may be determined through detailed field studies, and (4) temperature of injected fluids into heavy-oil reservoirs.

The R sandstone has the regional distribution and thickness that would make it an excellent candidate for production of geothermal waters (table 4). The area of fault blocks in the vicinity of the Fandango field is approximately 4.4 mi^2 (11.4 km^2), an area that is comparable to those of fault blocks from other Tertiary units (Morton and others, 1983). The area of fault blocks is poorly constrained and is largely dependent on map scale and density of control (Morton and others, 1983). Small faults that may create additional smaller compartments within fault blocks are difficult to detect with current density of well control. The individual sandstone bodies with thicknesses greater than 100 ft (>30 m) and with continuous lateral distribution indicate that reservoir volume in individual fault blocks ranges from 12 Bcf

TABLE 8. Comparison of significant attributes of Wilcox geothermal reservoirs and Jackson heavy-oil reservoirs.

WILCOX GEOTHERMAL RESERVOIRS	JACKSON HEAVY-OIL RESERVOIRS
Prolific gas reservoirs (1.8 Tcf)	Small, heavy-oil reservoirs (<10 MMbbl)
Reservoirs are deep (12,000-18,000 ft) and hot (up to 500°F)	Reservoirs are thin (<50 ft) and shallow (<2,000 ft deep)
Laterally extensive reservoirs	Laterally extensive reservoirs pinch out updip
Complex structure	Simple structure

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(for 100 ft- [30-m] sandstone) to 25 Bcf (for 200-ft [61-m] sandstone). Using a porosity of 19 percent, which is the mean porosity for major Wilcox gas reservoirs (table 1), geothermal aquifer volume ranges from 2.3 to 4.7 Bcf. The great thickness of the R sandstone increases the probability that the small faults, with throws less than the thickness of the R sandstone, would not act as barriers to fluid migration. More detailed reservoir characterization requires additional information on porosity, permeability, drive mechanism, z factor, temperature, pressure, and other variables.

ACKNOWLEDGMENTS

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Section II

Hot-water Flooding: Its Role in the Mobilization of Heavy Oil

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ABSTRACT

The effectiveness of hot-water flooding as a mechanism for improved recovery in heavy-oil reservoirs was investigated through a literature survey. There have been relatively few field applications designed to assess the effectiveness of hot-water floods to improve recovery from heavy-oil reservoirs. Hot-water flooding of heavy-oil reservoirs is more effective than conventional isothermal water flooding, but markedly less efficient than steam for recovery of heavy oil. Hot water improves recovery of heavy oil through a variety of poorly understood displacement mechanisms including (1) thermal expansion, (2) viscosity reduction, (3) decreased wettability, and (4) reduced oil/water tension. Improvement in recovery of viscous crudes by hot-water floods relative to conventional isothermal water floods may be largely due to (1) the improvement of oil mobility through reduction of oil viscosity and (2) reduction in residual oil at high temperatures. The economic disadvantages of hot-water flooding would be substantially mitigated if an ample supply of relatively inexpensive geopressured-geothermal waters was located near heavy-oil reservoirs.

INTRODUCTION

This report is a summary of a literature survey conducted to determine the role of hot-water injection in the thermal recovery of heavy oil. There have been relatively few field applications designed to assess the effectiveness of hot-water floods to mobilize heavy crude and most of these are not adequately documented in the literature. The most important exceptions are the pilot test in the Schoonebeek field, The Netherlands (1957-1966), and the Loco Field in southern Oklahoma (1961-1967). These two tests demonstrated that, although the process is more complicated than originally anticipated, hot-water flooding can both mobilize heavy oil and increase production. However, the economic feasibility of the method, especially compared to steam drives, remains unresolved.

HEAVY OIL

An excellent summary of heavy-oil resources of the United States has been prepared by Nehring and others (1983). These authors estimated that there are 46 to 49 billion barrels of original heavy oil in place in the contiguous states and that gross recovery potential should be at least 20.2 billion barrels. With recovery prior to thermal stimulation of 9.1 billion barrels, the gross incremental thermal recovery potential is between 11.1 and 16.8 billion barrels.

Definitions

"Heavy oil" has many definitions; however, none is universally accepted. Heaviness of an oil can be expressed in terms of its density or its viscosity. Generally, any oil with a gravity below 25° API is considered heavy. Crude with a density of 10° API or less, a viscosity greater than 100,000 cP (centipoise), and which does not permit in situ primary reservoir recovery is called an asphalt, a bitumen, or an extra heavy oil (World Oil, 1982).

HOT-WATER DRIVE

In its simplest form a hot-water drive involves the flow of only two phases: water and oil. Steam and combustion processes always include a third phase: gas. Hot-water flooding is basically a displacement process in which oil is displaced by both hot and cold water. Thus, the primary role of the heated water is to reduce the oil viscosity and thereby improve the displacement efficiency over that obtainable from conventional waterflood. Hot-water floods have many elements in common with conventional floods (Craig, 1971).

Hot-water flooding has not been a popular thermal recovery process. Only a few field projects and commercial-size operations have been described or even mentioned in the literature (Prats, 1986). Several of these field applications are discussed below. The Schoonebeek Project has been described by Dietz (1972) and the Loco Pilot Test by Martin and others (1972).

Hot-water injection has never proved as efficient as steam. The displacement efficiency of hot water is much less than that for steam (fig. 1). Hot water has lower transport capacity than steam and studies indicate that it is necessary to inject more than two PV (pore volumes) for the hot water to sweep a unit column of the reservoir. Also, the sweep efficiency of hot water is much less than that of steam injection (Burger and others, 1985).

Mechanisms of Displacement

Hot water injected into a formation cools upon contact with the matrix and in-place fluids. When sufficient time has passed it is possible to distinguish three principal zones (Burger and others, 1985) (fig. 2).

Zone 1. At each point in this heated zone the temperature increases with time, which generally induces a reduction of the residual oil saturation. In addition, the expansion of the fluids and the rock matrix leads, for the same saturation, to a reduction of the specific gravity of the oil left in the pore space. If the oil is very volatile some light components will be displaced by a vaporization-condensation process and, in fact, a gas phase may exist in a small part of this zone. (After Burger and others, 1985).

Zone 2. In this zone, the oil is being displaced by water that has cooled down essentially to the temperature of the formation; the oil saturation at any point in this zone will decrease with time and under certain conditions may reach residual saturation corresponding to the prevailing temperature in this zone.

Zone 3. This unaffected zone represents reservoir conditions as they exist before the injection of the hot fluid.

In contrast to the three zones that exist during injection of hot water, four zones exist during steam injection (Burger and others, 1985) (fig. 3).

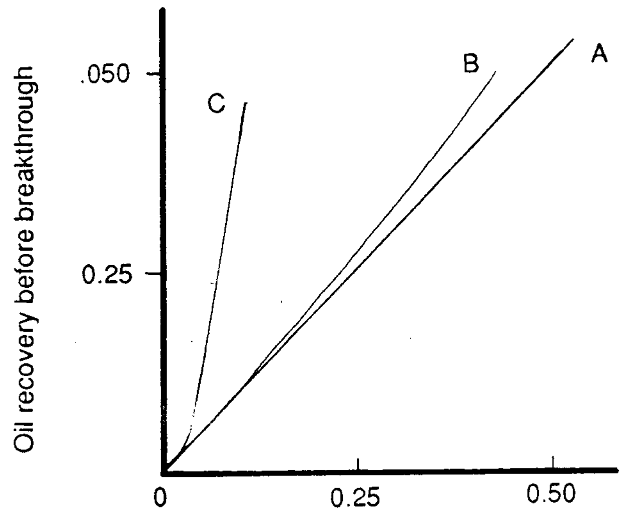


FIGURE 1. Oil recovery before the breakthrough of water versus the amount of water injected: Curve A--conventional isothermal water flood, Curve B--hot-water flood, and Curve C--steam flood. After Burger and others (1985).

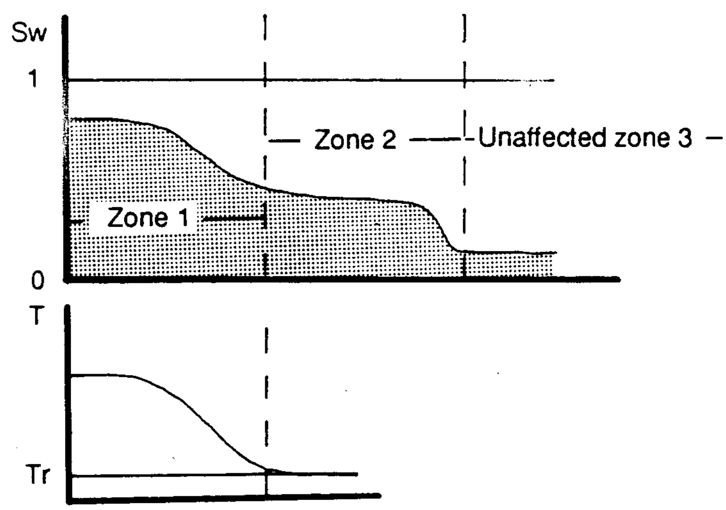


FIGURE 2. Water saturation and temperature profiles during one-dimensional displacement of oil by hot water without vaporization of the light fractions of oil: Zone 1--heated zone, Zone 2--cool zone, and Zone 3--unaffected zone.

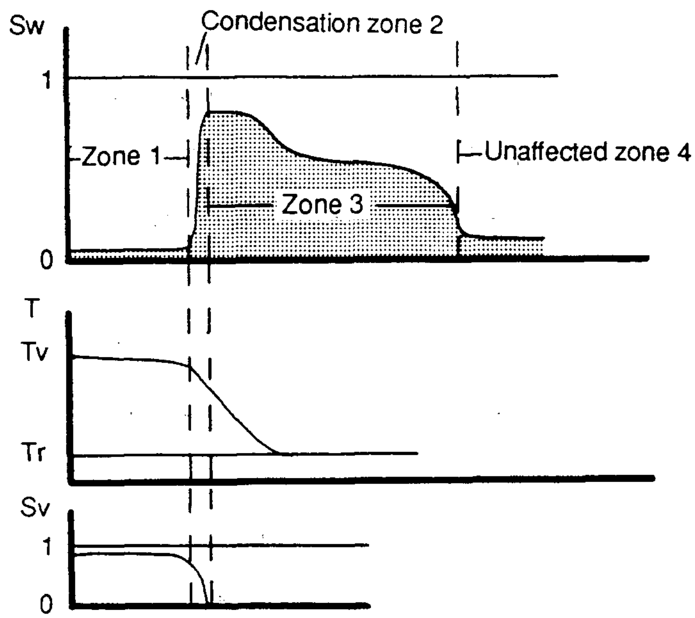


FIGURE 3. Temperature, steam, and liquid water saturation profiles during one-dimensional displacement of oil by steam: Zone 1--steam zone, Zone 2--condensation zone, Zone 3--hot-water zone, and Zone 4--unaffected zone. After Burger and others (1985).

Zone 1. In the steam zone around the injection wells three fluids coexist; water, liquid hydrocarbon, and a gas phase. The temperature is high and reasonably uniform, and the temperature decreases slowly away from the injection well but continuously in accordance with the dependence of the saturation temperature versus pressure. The liquid oil saturation is also reasonably uniform because the oil has been flushed out of this zone by hydrodynamic displacement as well as by vaporization of the more volatile compounds.

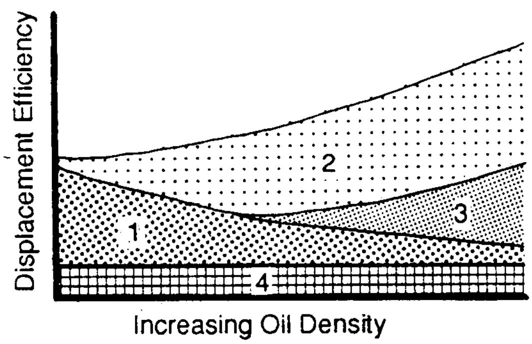
Zone 2. In this condensation zone, water and volatile hydrocarbon fractions condense upon contact with the cold matrix. On a microscopic scale the temperatures are different in the solid phase and the liquid phase, and consequently applying the effective thermal conductivity concept is not rigorously valid. Significant local thermal disequilibrium has been shown to exist in a laboratory study of displacement of water by steam: a gas-phase saturation has been detected at a local mean temperature, measured with the aid of a thermocouple, which is definitely lower than the saturation temperature at test pressure. However this phenomenon is considerably enhanced by the conditions of the reported test, namely low pressure (close to atmospheric) and high flow rate (310 kg m^{-2} h^{-1}).

Zone 3. All the phenomena occurring in this zone are similar to those involved in a hot water displacement. However, as the steam zone (zone 1) moves ahead and since the volume per unit mass for the vapor is very much greater than that of the hot or cold water, the velocity of the liquid water in this zone 3 is considerably higher than what it would have been if liquid water had been injected into the formation at the same temperature and with the same mass injection rate.

Zone 4. This is the zone that has not been affected by heat and essentially contains the original fluid saturations.

Figure 4 shows schematically how (1) thermal expansion, (2) viscosity reduction, (3) wettability, and (4) oil/water interfacial tension affect displacement efficiency of crudes of different densities. Qualitatively, thermal expansion is more important in light crudes, whereas viscosity reduction and wettability changes are more important for heavy crudes (Prats, 1986).

Burger and others (1985) recommend that hot-water injection be used when steam injection cannot be applied. These conditions are (1) when reservoir contains clays, which may swell and lead to reservoir



1 Thermal expansion
2 Viscosity reduction
3 Wettability
4 Oil-water interfacial tension

FIGURE 4. Relative contributions of mechanisms on the displacement efficiency of oil by hot water. After Prats (1986).

deterioration in the presence of freshwater, (2) where hot water is preferred to steam in deep reservoirs which require high injection pressure, and (3) where, because of increasing pressure, latent heat markedly declines.

The amount of oil displaced in a hot-water drive is always greater than that produced. The oil that is displaced but not produced is held in unswept parts of the reservoir. With viscous crudes, the mobility ratio between the advancing oil and gas or water in the reservoir is favorable. Mobile oil tends to fill regions of the reservoir initially containing free gas and water before it is produced. Where an oil bank forms, consideration of these effects permit estimation of the recovery history from estimates of the oil displacement history (Prats, 1986).

Improvement in recovery of viscous crudes by hot-water floods relative to unheated water floods may be largely due to (1) the improvement of oil mobility through reduction in oil viscosity and (2) the reduction in residual oil at high temperature (Willman and others, 1961). A 500°F (260°C) rise in temperature would reduce residual oil saturation by 10 to 30 percent of that at original reservoir temperature. Reductions in residual oil with increasing temperature greater than those attributable to thermal expansion (up to 50 percent) perhaps are due to changes in surface forces at high temperatures. Such surface forces include interfacial ones between oil and water phases, and the forces between mineral surfaces and liquids, especially those that may tend to hold complex organic compounds on the mineral surfaces.

These changes in surface forces do not necessarily reduce the capillary forces because some rock/fluid systems become more water wet as temperatures increase. Shifting capillary pressures and relative permeabilities toward increases in water wetness and higher temperatures have been reported (Sinnokrot and others, 1971; Poston and others, 1970).

Figure 5 shows examples of calculated saturation and temperature distributions in a hot-water flood. In this figure the total amount of cold and hot water is assumed to be the same. Temperature of the hot water was 380°F (193°C). Note the reduction in distance between the 0.35 and 0.65 oil saturation contours after hot-water flooding. This is considered evidence of improved displacement efficiency tending toward more piston-like displacement as temperature increases. Also, note the underrunning of

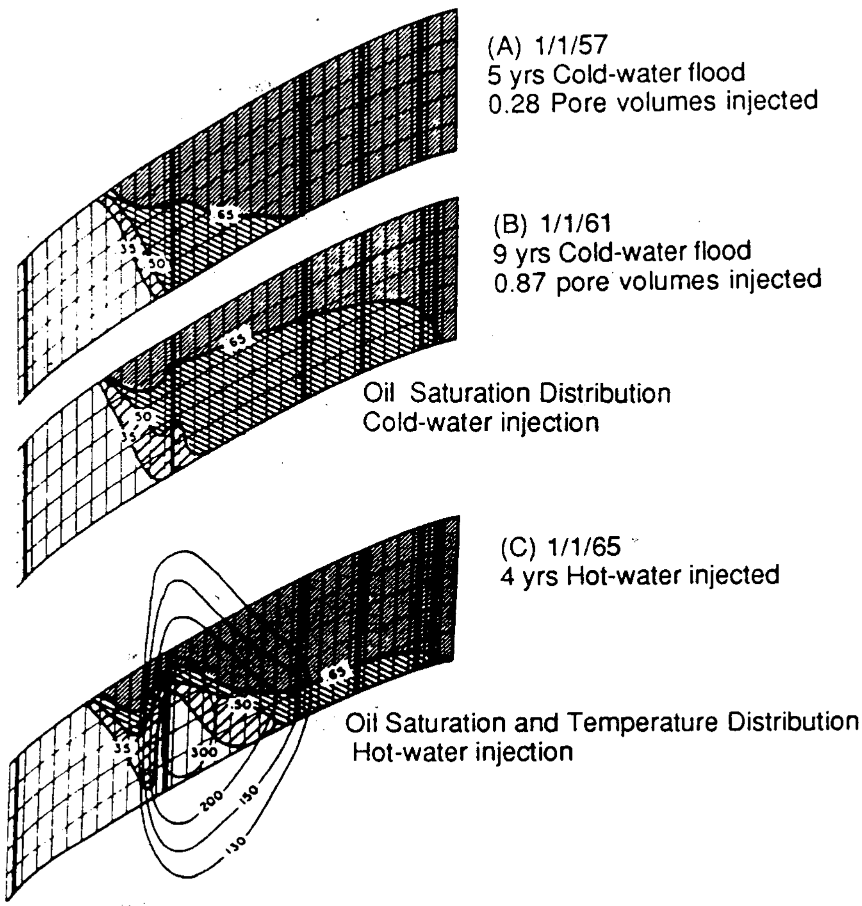


FIGURE 5. **Calculated saturation and temperature distributions. After Prats (1986).**

the water near the base of the sand even in conventional waterflood. This is the result of buoyancy forces between the water and the oil. Because of buoyancy and other factors, the contours of equal temperature and saturation are not vertical within the reservoir sand.

After injection of 0.59 PV of hot water, only about 30 percent of the reservoir shown in cross section has been heated, and that the average temperature rise in the heated zone is well below that of the injection well. Also, most of the oil already has been displaced. All thermal drives are characterized by the presence of large amounts of heat in oil-depleted parts of the reservoir. The latter has prompted modifications aimed at scavenging, or recycling the heat to improve the efficiency of the process. For hot-water drives some of this heat can be scavenged by injecting unheated water near the end of the project.

Studies by Combarnous and Pavan (1969) reveal that the higher the temperature of the water the earlier the water breakthrough. This suggests that viscous instabilities may grow faster in hot-water floods than in conventional waterfloods. This may be true because the part of a water finger that is heated has less flow resistance than that of a cold finger. The lowered flow resistance would accentuate the rate of growth of the most advanced fingers.

As oil is heated, however, its reduced viscosity and increased volume enhance displacement of the bypassed oil. Thus, although the fraction of the reservoir swept at breakthrough appears slightly less, at least some experimental hot-water floods improved displacement of the heated by-passed oil so the process has the potential of yielding higher recoveries.

Where results of multidimensional scaled experiments of the hot-water process have been reported (Harmson, 1967) it appears that hot water follows paths created by the instabilities of the preceding cold-water flood (fig. 6). Because hot water cools faster in the smaller fingers, the higher temperatures occur in the few larger channels from which the intervening spaces are heated slowly.

Model experiments indicate that cold water does not advance through the reservoir over a wide front. Varying degrees of wettability and capillarity lead to development of tongues and fingers that protrude from the frontal wall and move forward over the bottom of the reservoir. The thickness and width of a tongue does not influence production. It is the cross-sectional area of a tongue that is important. A hot-water flood acts much as that of cold water either because of a preceding cold water flood, or

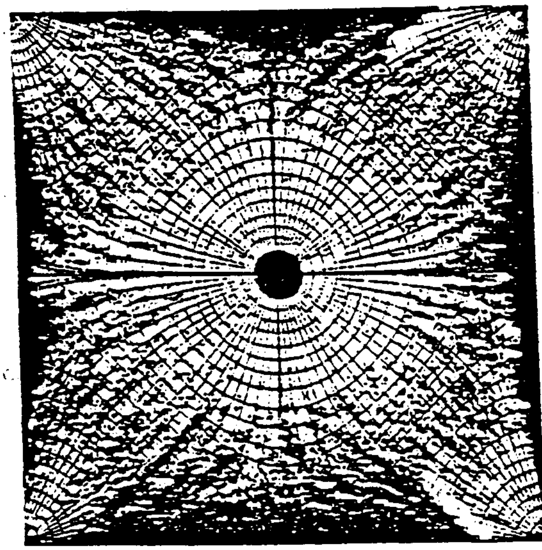


FIGURE 6. Cold-water fingers. After Dietz (1972).

because hot water, as it is injected, is soon cooled. Water in the smallest tongues cools first. These tongues will continue to push forward against cold oil, while the largest hot tongues reduce the resistance of heated oil at the front.

The hot-water tongues are so widely spaced that much of the reservoir remains cold for a long time. Locally the full height of the reservoir is heated and rapidly watered out. Widening of the tongues until they coalesce theoretically would be a slow process (Dietz, 1972).

The following conclusions can be drawn about hot-water floods:

1. There are two recognizable displacement fronts: (a) the leading front (cold-water front) is at original reservoir temperature; and (b) the hot-water front, which lags the cold front.

2. Large volumes of injected hot water may be required to bring the oil saturation to its residual value even near an injection well.

3. Oil is displaced throughout the entire zone swept by the injected water.

4. The effect of instabilities appears to be quite important even in homogeneous formations.

Items two through four are expected to be more pronounced the higher the oil viscosity. Also, they are not inconsistent with reported field observations (Prats, 1986).

Examples of Hot-Water Flood Operations

Hot-water flooding has not been a popular thermal recovery process. Only a few field pilots and commercial-size operations have been described. Some of these field applications are listed below:

Project	Location
Loco	Oklahoma
Kern River	California
Schoonebeek	Holland
N.E. Butterly	Oklahoma
Emilchheim	Germany
Arlansk	USSR

The first four of these projects are reported to be discontinued, and little information is readily available on the USSR and German operations (primary units are consistent with those reported). Severe channeling and high water-oil ratios (WOR's), which are indicative of poor sweep efficiencies, characterize the first four projects. Heat recuperation by cold-water follow-up has not been reported. At the Loco pilot, total thermal recovery after the 1-year hot-water flood in a previously waterflooded thin sand (12.9 ft net, 1100 bbl/acre-ft) amounted to 156 bbl/acre-ft. Heat losses from this thin reservoir were reported to be about 60 percent of the injected heat. At the Northeast Butterly Creek Unit, the hot-water drive phase of the project lasted about 4 years and produced less than 150,000 barrels of oil. Most of the 375,000 barrels of thermal oil produced from the project resulted from cyclic hot-water stimulation, which included converting the injector in the original hot-water drive to production. At Kern River, injection of 2.23×10^6 barrels of hot water in about a year at an average temperature of 300°F (149°C) resulted in an oil recovery of 40,260 barrels. The pilot was terminated because of its poor performance. (Prats, 1986)

The Schoonebeek field (fig. 7) is located in the Netherlands close to the German border. Details of the hot-water procedure used in the Schoonebeek field were presented by Dietz (1972).

On January 1, 1957, a small hot water pilot test (HWI-I) was initiated in the Schoonebeek field (fig. 8). Reservoir data for HWI-I are listed below:

1. Area: 500 x 550 m^3
2. Sand thickness: 18 m
3. Average depth to reservoir: 850 m
4. Grain size: 60-250 µ
5. Permeability: 3 darcys
6. Porosity: 0.33 percent
7. Oil in place: 1.5×10^6 m^3
8. Gas/Oil ratio (GOR): 10 m^3/m^3
9. Oil viscosity: 175 cP at 40°C
10. Oil density: 890 Kg/m^3
11. Water chemistry

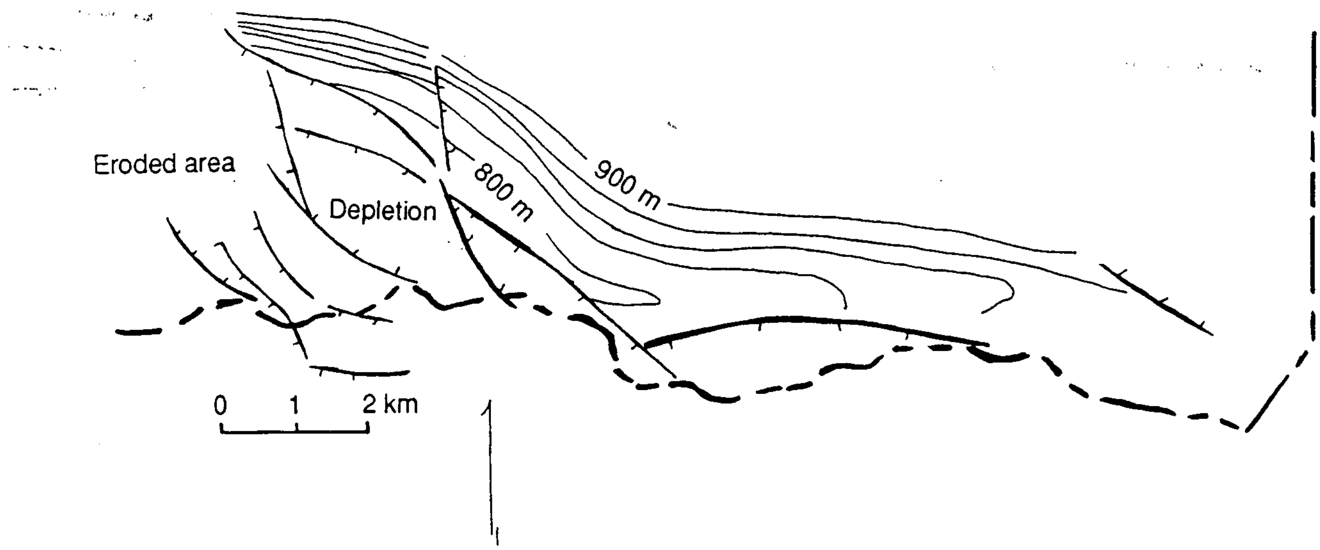


FIGURE 7. Structure map, Schoonebeek field. After Dietz (1972).

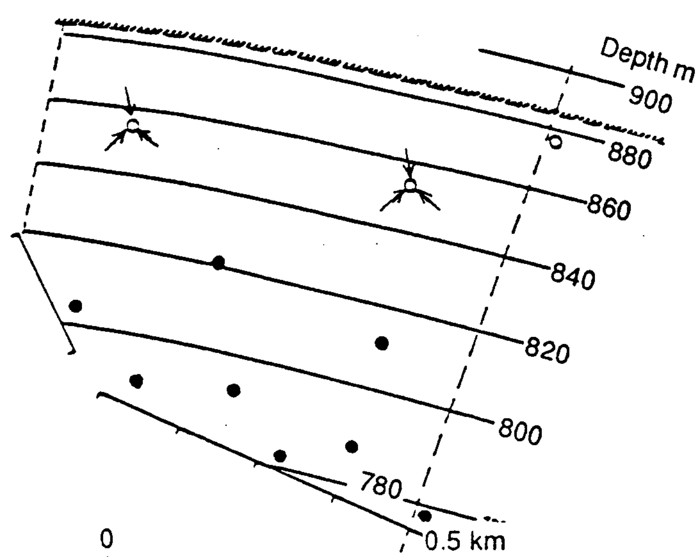


FIGURE 8. Local structure map, Schoonebeek field showing well locations for hot-water injection pilot test. After Dietz (1972).

Injection originally was 2 x 400 m^3 (2,533 bbls) water/day at 200°C (392°F) bottom hole temperature. Water was pumped through two injection wells placed 400 m (1,312 ft) apart; there were 7 production wells. Simple once-through heaters were used. Injection wells carried no special insulation. The annulus was kept dry by a trickle of high-pressure gas. To minimize the risk of clay swelling, saltwater from a closed treatment plant was used. Initial boiler problems were overcome by a minor adjustment of pH to 7.4-7.5 (at lower values corrosion occurs and at higher values scale is deposited). Only rare boiler and injection well cleaning was necessary; producing wells were pumped and gas-lifted trouble free.

For the first year injection was limited to about 500 m^3/day (3,167 bbls/day) to balance the maximum gross product and avoid loss of hot water along the water flank. When, because of higher water cuts and increased temperature, gross capacity increased beyond full injection capacity of 800 m^3/day (5,067 bbls/day) production was limited to this rate to avoid cold water influx. Injection/production balance was maintained until January 1, 1964; production was increased at that time.

In about two years, when 15 percent PV had been injected, production temperature began to increase and oil rates rose above that extrapolated for cold water drive. This was earlier than anticipated assuming that the lateral sweep would have been complete. Tracer-tests indicated that travel time to the producers was about one year.

A heat balance equation shows that the heat capacity of the water in the pores being nearly as much as that of the matrix, the velocity of a heat wave should be less than half the actual water velocity. The measured travel time of the heat wave and tracer water therefore agrees fairly closely.

By 1966 other projects had been added to HWI-I so that the total injection capacity had risen to 15,000 m^3/day (95,000 bbl/day). In 1966, following 10 years of operation the oil recovery attributable to the hot-water drives was 1.97 x 10^5 m (1.25 x 10^6 bbl). This represents an improvement in recovery from 25 percent for cold water to 43 percent of STOIIP for hot water.

In summary of this study, Dietz (1972, p. 81-82) stated:

> "... traced water has swept through slightly more than half the water present in the formation and that the other water has become stagnant. Direct field evidence of possible improved sweep efficiency is not yet available."

Figure 9 shows the production performances of model and the Schoonebeek field pilot. The curves have been plotted against time. Similar data have been used in construction of the cross-sections shown in figure 10. Figure 11 shows isotherms along the top and bottom of the formation after injection of 2.1 PV hot water and seems confirmation of incomplete lateral sweep efficiency. Figure 12 shows the isotherms updip at the same moment and figure 13 shows the growth of the 100°C (212°F) isotherm with cumulative injection. Figure 14 shows reservoir performance, 1952-1966. (Dietz, 1972)

Performance Prediction

There are three essentially different approaches to estimating performance of a hot-water drive. (Prats, 1986)

1. The effect of oil viscosity on isothermal recoveries (VanHeiningen, and Schwartz, 1955).

The method calls for shifting from one viscosity ratio curve to another of lower value in a manner corresponding to the changes in the average temperature of the reservoir (which increases with time). In applying this procedure, the oil/water viscosity ratio as a function of temperature and the average reservoir temperature as a function of time are the principal items required. The procedure clearly considers only viscosity effects, although the effect of thermal expansion of the fluids on the recovery could be included easily.

The procedure is easy to apply but it is valid only where recovery curves are representative of the formation being considered. This is true of all predictive methods; the recoveries must be reduced to account for variation in sweep efficiency resulting from well patterns and for the adverse effect of reservoir heterogeneity.

2. Buckley-Leverett calculations. This approach is also borrowed from waterflood technology and is based on the Buckley-Leverett displacement equations (Buckley and Leverett, 1942). Modified forms of this equation have been used frequently as a relatively simple way of estimating the recovery performance of hot-water drives in linear and radial systems (Jordan and others, 1957; Farouq, 1970). The estimate of recoveries from linear and radial flow systems must be reduced to allow for well-pattern and heterogeneity effects. For cold-water floods, the effect of well patterns can be taken into account by

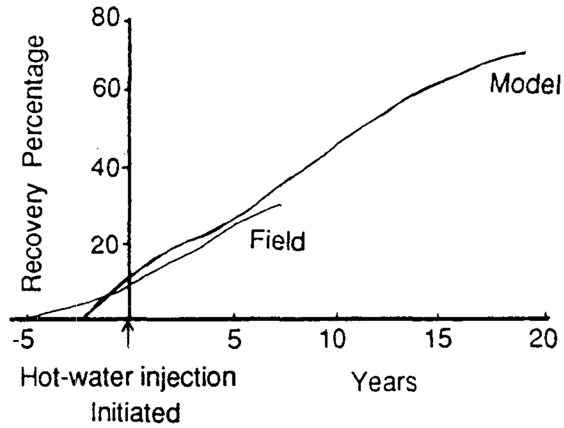


FIGURE 9. Production performances of field pilot and of model projections. After Dietz (1972).

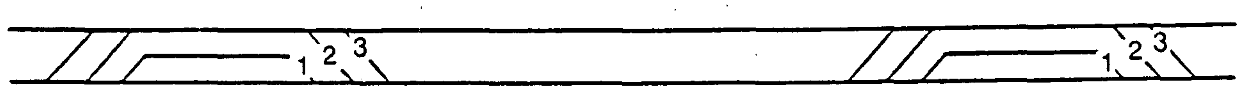


FIGURE 10. Hypothetical cross section of hot-water tongues. After Dietz (1972).

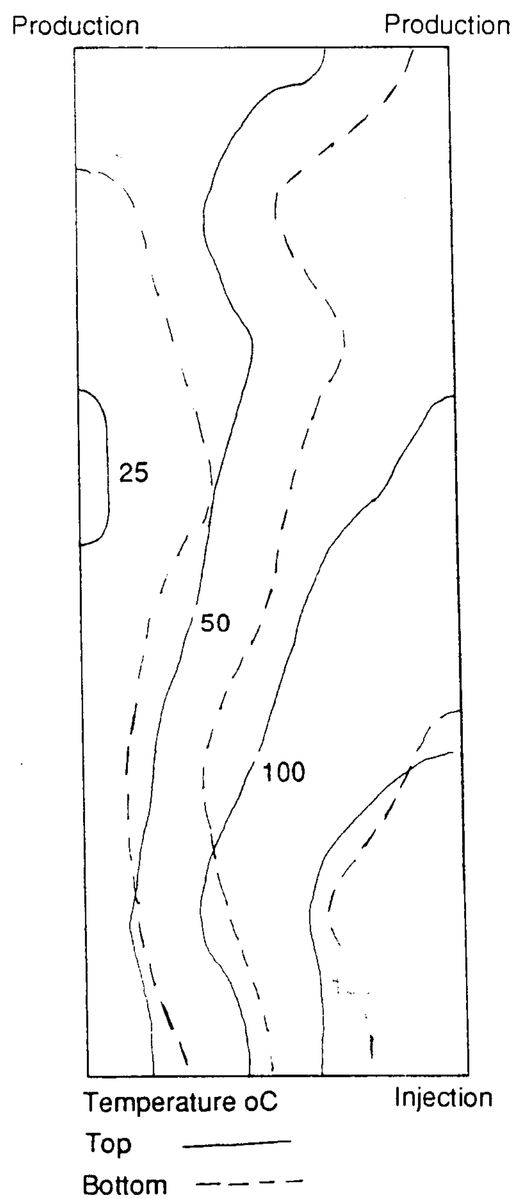


FIGURE 11. Temperature contours after injection of 2.1 pore volumes of hot water. After Dietz (1972).

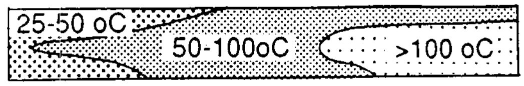


FIGURE 12. Cross section of temperature distribution after injection of 2.1 pore volumes of hot water. After Dietz (1972).

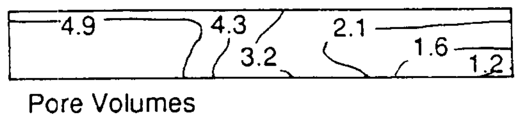


FIGURE 13. Growth of 100°C isotherms with cumulative injection in pore volumes. After Dietz (1972).

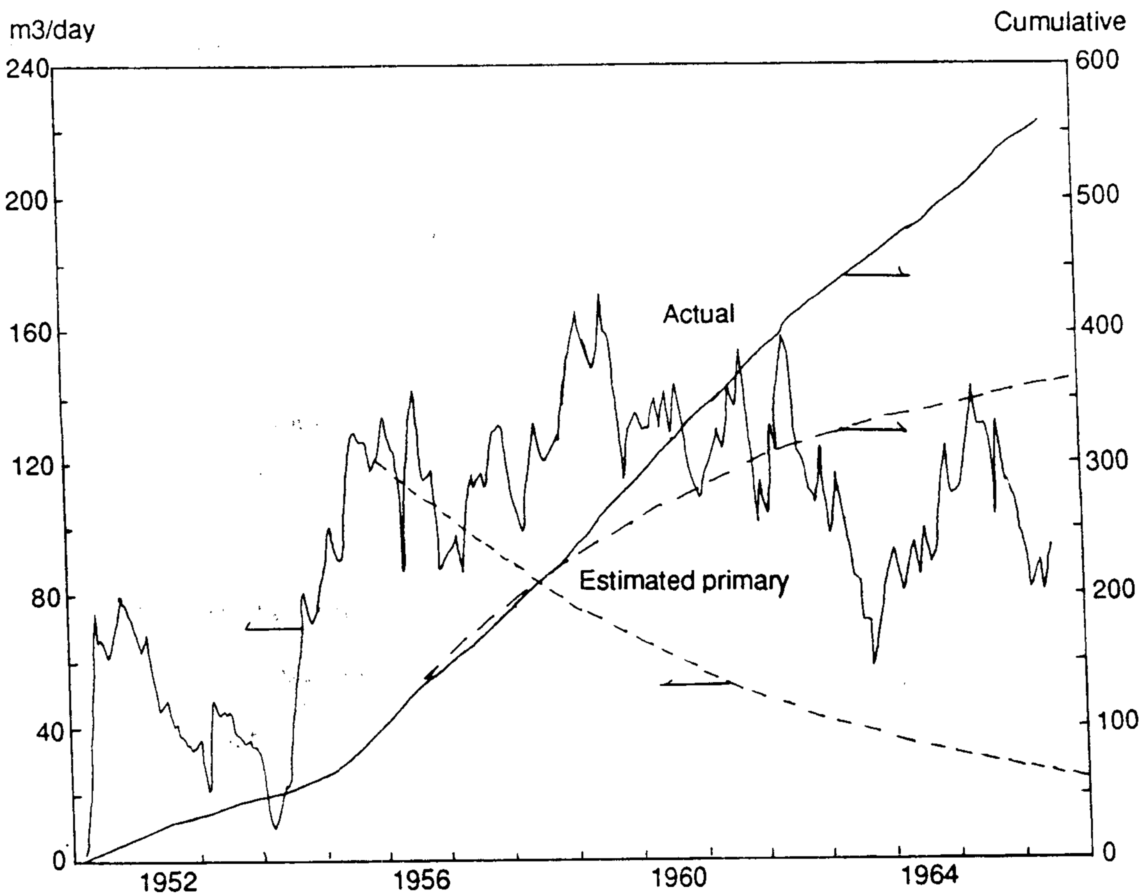


FIGURE 14. Reservoir performance, Schoonebeek field. After Dietz (1972).

applying the Buckley-Leverett displacement along the stream channels characteristic of the well pattern at least for isothermal water floods and a similar approach should work for hot-water floods.

3. Use of thermal numerical simulators. The simulators are capable of calculating more accurate recovery performances than can be achieved by the two simpler methods (above). However, they have two limitations: high cost and the quality of the input data.

Hot-Water Models

Model experiments designed to find the best way to operate a hot-water flood were discussed by Dietz (1972). A three-dimensional study box 20 x 150 x 400 cm^2 was fitted with 1001 thermophiles. The box contained a homogeneous sand body and wells with rigid geometric spacing. Tentative conclusions based on these experiments follow:

1) Early sweep efficiency is improved by a preceding cold-water flood, which ensures that the entire reservoir is interlaced with low-resistance water channels before the hot-water flood starts. The tendency of hot water to flow preferentially through the largest channels will thus be enhanced and a more efficient lateral sweep will be assured.
2) Better distribution of hot channels results with close-spacing between injection wells.
3) Efficiency of both of the above is limited basically to the downdip half of the reservoir.
4) Near updip side of reservoir the situation can be improved by closer spacing of producers and by forcing gross production ratios from them regardless of drawdown.

CONCLUSIONS

Generally, hot-water flooding of heavy-oil (but not light oil) reservoirs is more effective than conventional water flooding. In hot-water floods, the mobility ratio of the fluids is more favorable than in cold-water floods. This results in greater displacement efficiency from the heated zone, and improvement in the ultimate recovery.

Hot-water flooding, an intrinsically unstable process, is much less efficient than steam drives, and under usual circumstances is not economically competitive with steam. Steam can carry much more heat than can hot water in the operating pressure range of most projects.

There are economic drawbacks to use of steam in thermal recovery projects. Foremost among these is that much steam is generated by burning lease crude. More than one-third of the gross recovery potential is consumed to produce the steam. Natural gas is also commonly burned instead of lease crude. Burning of the crude is commonly accompanied by the creation of air pollutants such as sulfur compounds and nitrogen oxides. Harmful impurities must be removed by scrubbing and other relatively expensive techniques. Another disadvantage shared by both steam and hot water is the common problem of scale and corrosion.

It seems possible that the economic disadvantages of a hot-water flood might be substantially mitigated if there were an ample supply of naturally heated water available in the vicinity of a heavy-oil reservoir.

Such a situation seems to exist in South Texas where deeply buried (8,000 to 18,000 ft [2,440 to 5,490 m]) Wilcox geopressured-geothermal reservoirs directly underlie the heavy-oil fields of the Mirando Trend. The heavy-oil reservoirs are mainly in the Jackson and Yegua formations at depths of 100 to 5,000 ft (30 to 1,524 m). Original-heavy-oil-in-place in the Mirando Trend is about 200 million barrels (31.6 million m^3), of which about 30 percent has been produced. Water temperatures in the Wilcox reservoirs range from about 250°F (121°C) to greater than 350°F (>177°C), pressure gradients are typically greater than 0.7 psi/ft (15.83 kPa/m), sandstone porosities range from 9 to 17 percent and pore-fluid salinities from 70,000 to 20,000 ppm NaCl (Hamlin and others, 1989).

In this situation, it first must be ascertained that sufficiently large quantities of naturally heated water will sustain a multi-year hot-water project in a designated part of one of the shallow heavy-oil reservoirs. It would also be essential to demonstrate that, because of its innate purity or subsequent treatment, the hot water will not contain dissolved solids at a level likely to promote scaling or corrosion or otherwise contribute to deterioration of reservoir properties, for example through swelling clays. In addition, it is crucial that heat loss be minimized in the transfer of water from the Wilcox reservoirs to the heavy-oil reservoirs.

Should such a colocation hot-water project (as described above) prove unfeasible, serious consideration might be given to use of the geopressured-geothermal water in a hot-water flood or in a preheating role for possible steam flood projects.

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