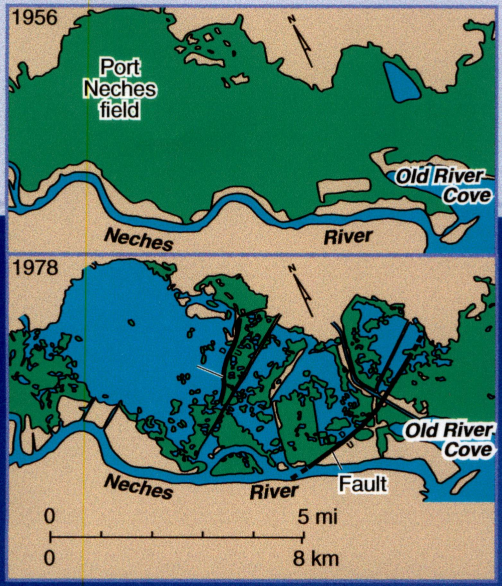
2000–2001 Annual Report

Effect of Hydrocarbon Production and Depressurization on Subsidence and Fault Reactivation



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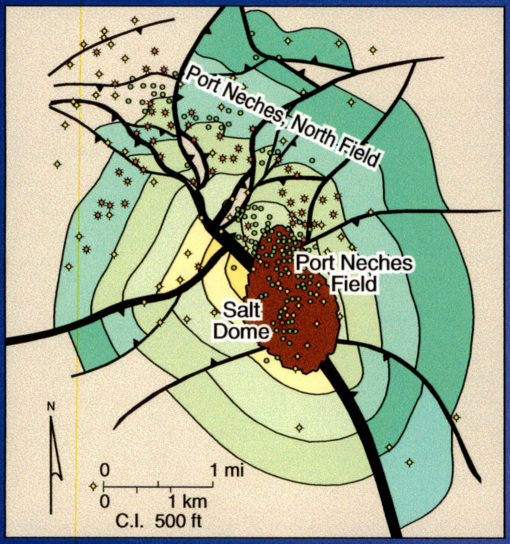
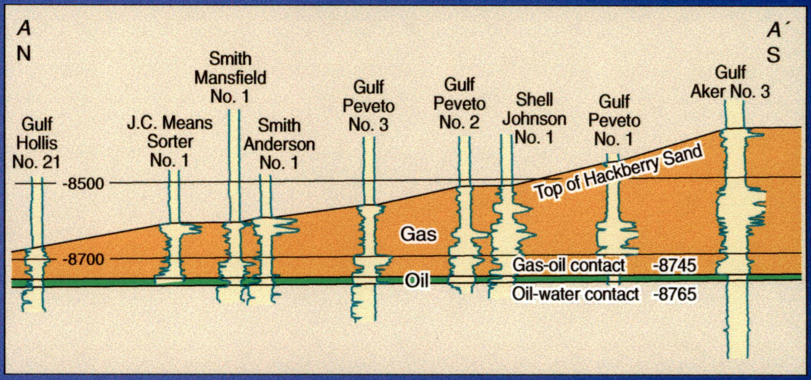
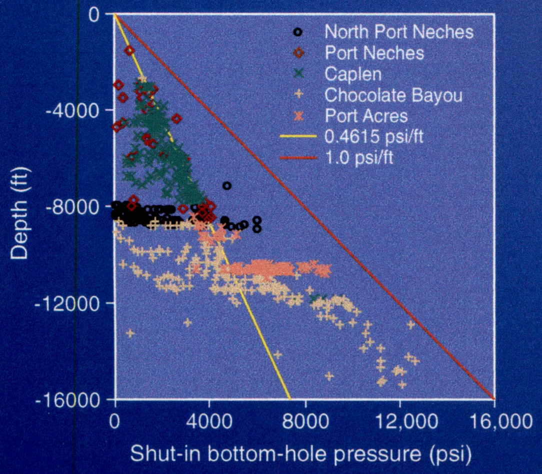
Prepared for U.S. Geological Survey







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Bureau of Economic Geology

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INTRODUCTION

Subsurface fluid withdrawal is one of the most common causes of land subsidence. Subsurface fluids include water, oil, gas, and steam. Examples of subsidence induced by groundwater withdrawal significantly outnumber those induced by hydrocarbon production. Several severe subsidence cases induced by hydrocarbon production were documented including Goose Creek field (Pratt and Johnson, 1926), Wilmington field in Long Beach, California, Lost Hill and Belridge fields in California, Bolivar coast in Venezuela (Nunez and Escojido, 1976), and Ekofisk field in the North Sea (Sulak, 1991). Ekofisk field is the most recent and costly example.

Ekofisk field was discovered in 1969, and production from the 700- to 1,000-ft-thick geopressured high-porosity chalk reservoir (top at 9,600 ft subsea) began in the 1970's. By 1984, the seabed under the Ekofisk complex had subsided about 10 ft. To stabilize platforms and facilities, an unprecedented billion-dollar project was initiated in 1987 to elevate the four platforms an additional 20 ft and to construct protective barriers around the hydrocarbon storage tank. In addition, gas and water have been injected to increase reservoir pressure and arrest active subsidence. Nevertheless, the local seabed has subsided continuously to 26 ft in 2001.

In coastal southeast Texas, land subsidence has been severe in the Houston/Galveston area. However, despite enormous oil and gas production from Frio and Miocene formations, most land subsidence and surface faults in the area have been attributed more to regional shallow groundwater withdrawal than to hydrocarbon production (Kreitler, 1976; Verbeek and Clanton, 1981; Holzer and Bluntzer, 1984; Gabrysch and Coplin, 1987). Holzer and Bluntzer (1984) showed that hydrocarbon production has caused an additional 0.1 to 0.2 m of local subsidence near some oil and gas fields.

To better quantify the impact of hydrocarbon production on subsidence and fault reactivation, we need to eliminate the effects of groundwater withdrawals by selecting fields having insignificant groundwater withdrawals relative to hydrocarbon production. Two field areas in the coastal southeast Texas—Port Neches in Orange County and Caplen in Galveston County—satisfy this prerequisite. Both areas contain active surface faults and wetlands that have been inundated by marine waters (White and Morton, 1997). Most Port Neches and Caplen hydrocarbon production occurred between 1940 and 1970.

DATA COLLECTION

Direct measurements of subsurface subsidence, such as casing-collar survey and extensometer measurement, are most valuable but seldom available for producing fields. In lieu of direct measurements, land subsidence may be correlated with hydrocarbon production data and reservoir pressure history where direct measurements of subsurface subsidence and fault movements are not available. Pressure and production data for Port Neches and North Port Neches fields and for Caplen field were collected from Railroad Commission of Texas (TRRC) files, scout tickets, and the Petroleum Information/Dwights' database.

Texas RRC

It has always been difficult to obtain accurate production data for old fields in Texas, especially old gas fields. Although oil and gas production data can be found in TRRC Annual Reports, there are time and regulatory limits. For example, oil fields produce associated gas. However, prior to 1968 associated gas was not included in the Annual Reports. The Annual Report for Texas gas fields did not begin until 1970. Therefore, for pre-1970 fields accurate production rates and cumulative production of gas cannot be derived from TRRC Annual Reports.

TRRC requires reporting of pressure test data for gas wells but not for oil wells. Therefore, most pressure data found in the public domain are from gas wells, and only a small percentage of oil-well pressure data can be found in hearing files and literature. In TRRC archives, gas-well pressure (tubing or bottom-hole) data can be found on forms reporting gas-well back-pressure tests (GWT-1 or G-1), adjustments of open flow (GWT-4), gas-well status (G-10), and proration schedules.

PI/Dwights' Databases

One of the widely used commercial production databases is the PI/Dwights' from IHS Energy Group. The PI/Dwights' database differs slightly from those in the Texas RRC archive. It is a digital database containing fairly complete post-1965 well pressure and monthly production data and many pre-1965 pressure test and cumulative production data. Note that the cumulative production data of pre-1965 gas wells were dated back to the beginning of production, but the pre-1965 yearly production rates are not. For pre-1965 gas fields, the yearly field production rates before 1965 are not reliable because the well's cumulative production between the completion date and 1965 is used as the first-year field production rate. The only reliable source of pre-1965 gas production data is the operator. However, even with operator data, the amount of flared gas might not be reported.

Casing Leak-off Test

Casing leak-off tests (or step-rate tests) are normally used to test casing cement or estimate formation fracture pressure. The rate and pressure relationship changes when the pressure exceeds the breakdown pressure of cement bond or formation fracture pressure. Casing leak-off has been used in North Sea fields to study fault reactivation (Wiprut and Zoback, 2000). However, no leak-off test data have been found for Port Neches and Caplen areas.

DATABASE

Databases for Caplen, Port Neches, and North Port Neches areas have been compiled. Table 1 summarizes data for numbers of wells, completions, and pressure measurements among the primary producing reservoirs. Table 2 summarizes the variation in cumulative production for oil and gas for the three areas as a function of data sources.

Table 1. Inventory of Wells, Reservoir Types, Completions, and Pressure Data

Reservoir Designation	Caplen Miocene/*Discorbis*/Frio	Port Neches Miocene/Frio	N. Port Neches Frio (Hackberry)
Oil reservoirs	~100	2	2
Gas reservoirs	60	7	5
Wells	69	142	82
Completions	215	181	108
Pressure data[1]	208	42	152

1 Bottom-hole or tubing pressure.

Table 2. Summary of Cumulative Production

Field	Caplen		Port Neches	North Port Neches		
Data source	TRRC (1998)	TRRC (1965)	TRRC (1998)	TRRC (1998)	PI/Dwights'	Kiatta (1984)
Oil/condensate (MMSTB)	18.2	8.6	32.3	4.8	4.4	4.8/6
Pre-1970 gas (Bcf)		12				
Post-1970 dry gas (Bcf)	14.5		4.6	49		
Total gas (Bcf)	>26.5		>4.6	>49	555	594

REGIONAL DEPRESSURIZATION

In coastal southeast Texas, enormous amounts of hydrocarbons have been produced from Frio and Miocene formations. Most gas fields have been depleted, but the degree of depressurization varies with the strength of water drive. Figure 1 plots bottom-hole pressure data from Caplen, Port Neches, Port Acres, and Chocolate Bayou fields as a function of depth. More than 95 percent of these pressure data are from gas wells. Bottom-hole pressures were either measured or calculated from tubing pressures. The two straight lines represent the lithostatic and hydrostatic pressure trends. Data between the lithostatic and hydrostatic lines are from geopressured reservoirs that are seen in reservoirs deeper than 8,000 ft in Gulf of Mexico coastal fields. Reservoir pressures in Port Neches and Chocolate Bayou (intervals shallower than 11,000 ft) are extremely low.

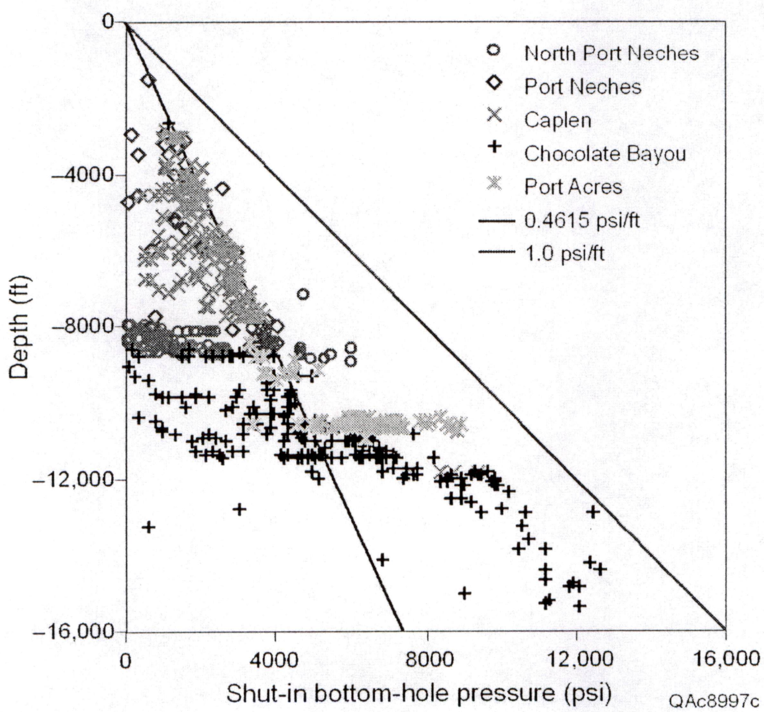


Figure 1. Bottom-hole pressure vs. depth in Capien, Port Neches, North Port Neches, Port Acres, and Chocolate Bayou fields.

PORT NECHES AREA

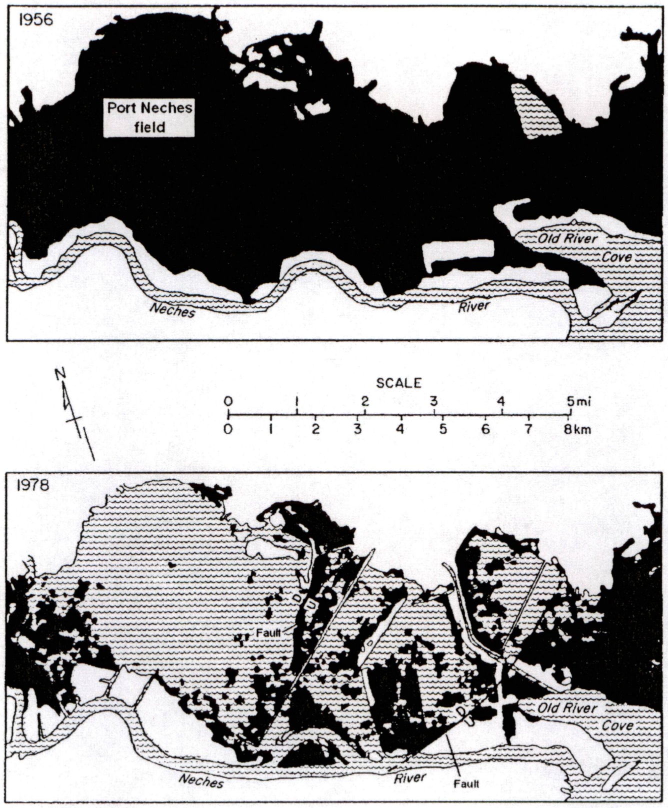
Subsidence and Surface Faulting

Port Neches field is located on the northern side of the Port Neches River, Orange County, Texas. Ratzlaff (1982) reported as much as 3 ft (0.9 m) of subsidence around the Port Acres field on the south side of the Port Neches River and concluded that subsidence was most likely caused by oil and gas production from the nearby fields. In a study on wetland losses, White and Morton (1997) observed significant changes in surface landscape in the Port Neches area—a loss of 9,410 acres of wetlands between 1956 and 1978. Several surface faults were seen in 1978, but none were observed in 1956 (fig. 2). Unlike the Galveston/Houston area, groundwater pumpage from shallow aquifers is not significant in the Port Neches area.

White and Morton (1997) attributed the wetland losses more to local subsidence than to eustatic sea-level change. A recent study by Morton and Purcell (2001) shows 0.6 m of subsidence at the downthrown side of the surface fault near Port Neches field. The estimated subsidence rate of 3 cm/yr is three times higher than the regional subsidence rate of 1 cm/yr.

Production and Pressure Histories

In the Port Neches area, hydrocarbons have come from two fields—Port Neches and North Port Neches. Port Neches field comprises 10 separate reservoirs within the Miocene to Frio section (table 3). Except for Port Neches (*Marg* Area 1), values of cumulative gas production of gas fields are listed as zero in the TRRC Annual Report. This suggests that there is no post-1968 gas production from these gas fields. Since the production of West Port Neches field has been transferred to the Port Neches field, Port Neches and Port Neches (*Marg* Area 1) are the two major producing fields.



Map Unit	1956		1978		Net Change*	
	Acres	Hectares	Acres	Hectares	Acres	Hectares
Water	2,560	1,037	11,070	4,483	+8,510	+3,446
Marsh	15,740	6,375	6,330	2,564	−9,410	−3,811

* Loss of additional 900acres (365 hectares) of marsh primarily due to spoil disposal.

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Figure 2. Surface faults and wetland loss in Port Neches area. From White and Morton (1997).

Table 3. Production Data of Port Neches Field from Texas Railroad Commission

Field Name	HC Type	Discovery Year	Depth (ft)	OilCum (STB)	GasCum[1] (Mcf)	WatCum (STB)
Port Neches (2500)	Gas		2500			
Port Neches (Miocene 3660)	Gas	3/26/63	3558			
Port Neches (Miocene 4170)	Gas	2/8/66	4173			
Port Neches (*Marg* Area 1)	Oil	1934		5,869,473	4,451,311	11,260,196
Port Neches (Frio-1)	Gas	6/11/64	5870			
Port Neches	Oil	1929	6000	26,436,018		
Port Neches (Frio-7)	Gas	9/27/64	6680			
Port Neches (Hackberry 8000)	Gas	2/5/57	7852			
Port Neches, West	Oil	9/1/48	6000	3,157,265		
Port Neches, S (*Marg*)	Oil	12/26/73	5725	382,792		
				35,845,548	4,610,452	11,260,196

1. Post-1968 cumulative dry gas production.

Port Neches field, discovered in 1929, has produced more than 26 MMSTB oil from the Frio Formation at about 6,000 ft. The production history (fig. 3) indicates that the most production occurred between 1950 and 1970 (White and Morton, 1997) when surface subsidence and faulting were active. Pressure data are not available. The second largest reservoir is the Port Neches (*Marginulina*), which has 5 MMSTB of cumulative production. The *Marginulina* is a high-quality reservoir having 33 percent porosity (table 4) and 400 to 2,500 md permeability.

North Port Neches field is located on the north and west flanks of Port Neches field. Discovered in 1946, the field produces from the Frio Lower Hackberry sandstone at a depth of about 8,745 ft (fig. 4). The Lower Hackberry sandstone is an elongated southeast-trending submarine channel sand (fig. 5) in North Port Neches field. It is best developed along the north and northwest flanks and thins updip toward the salt dome (fig. 5). However, hydrocarbon column thickness decreases toward the northwest and is controlled by structure and the oil-water contact (fig. 6).

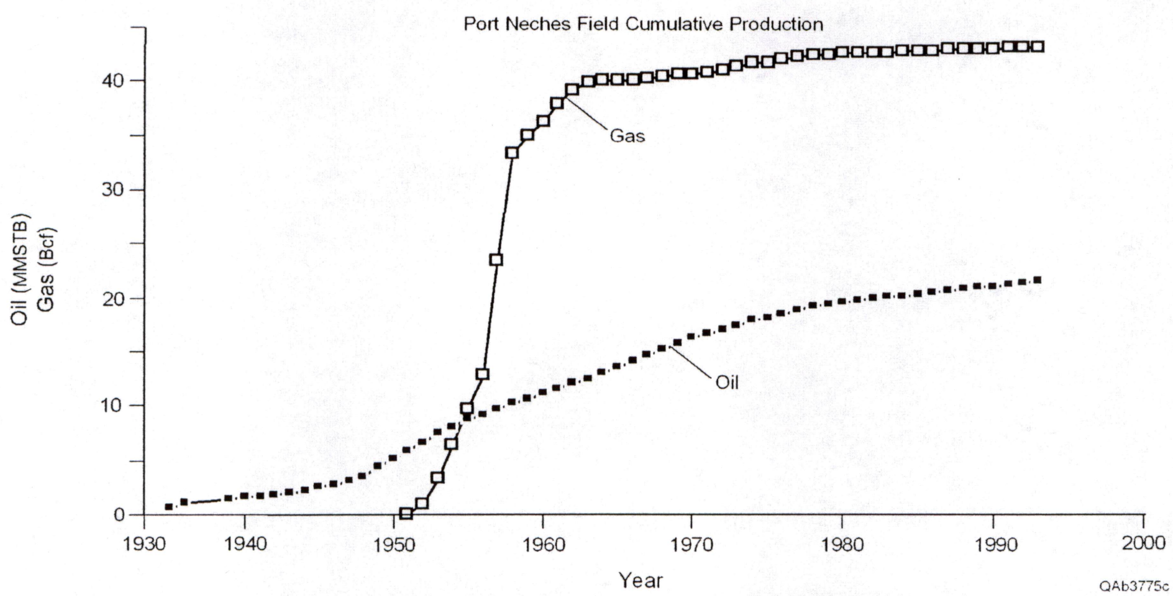

Figure 3. Production history of Port Neches field. From White and Morton (1997).

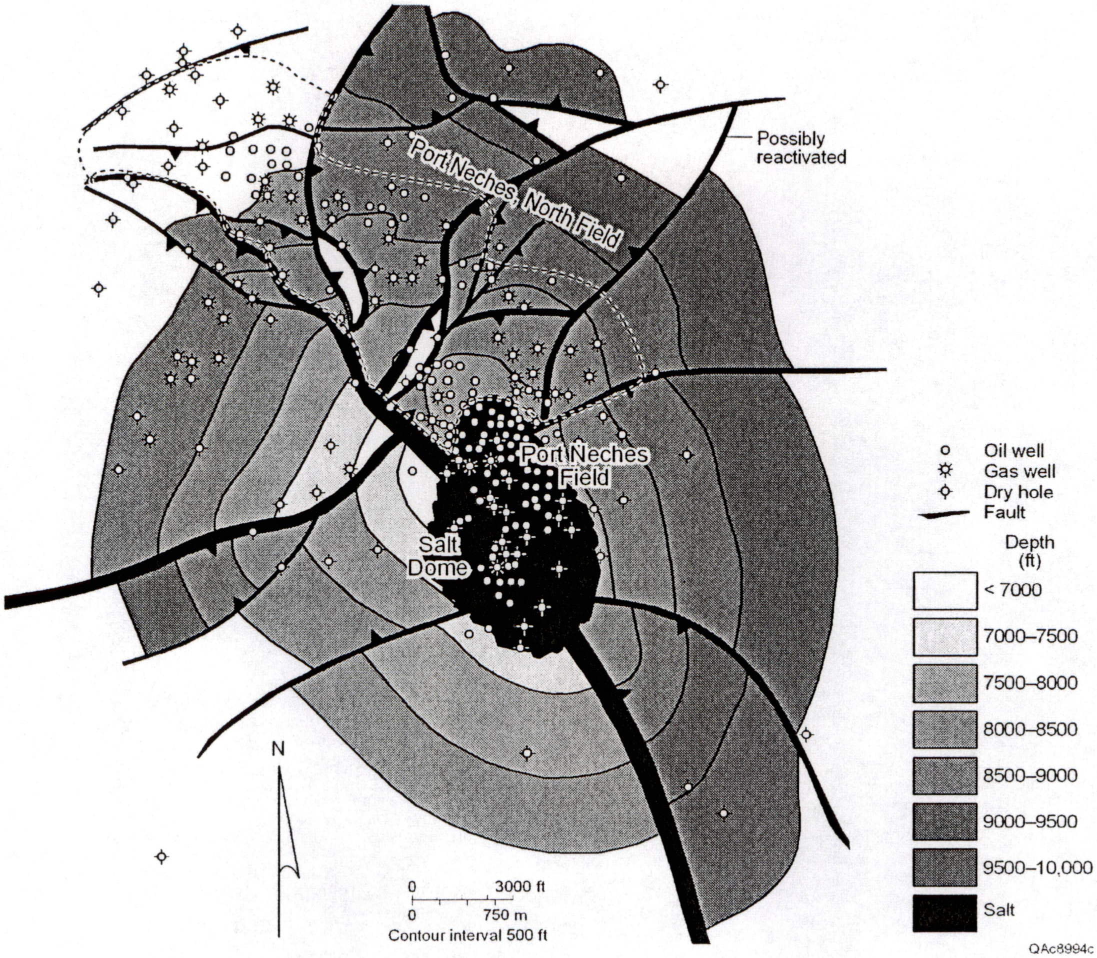

Figure 4. Structure map of Hackberry reservoir, North Port Neches field. From Kiatta (1984).

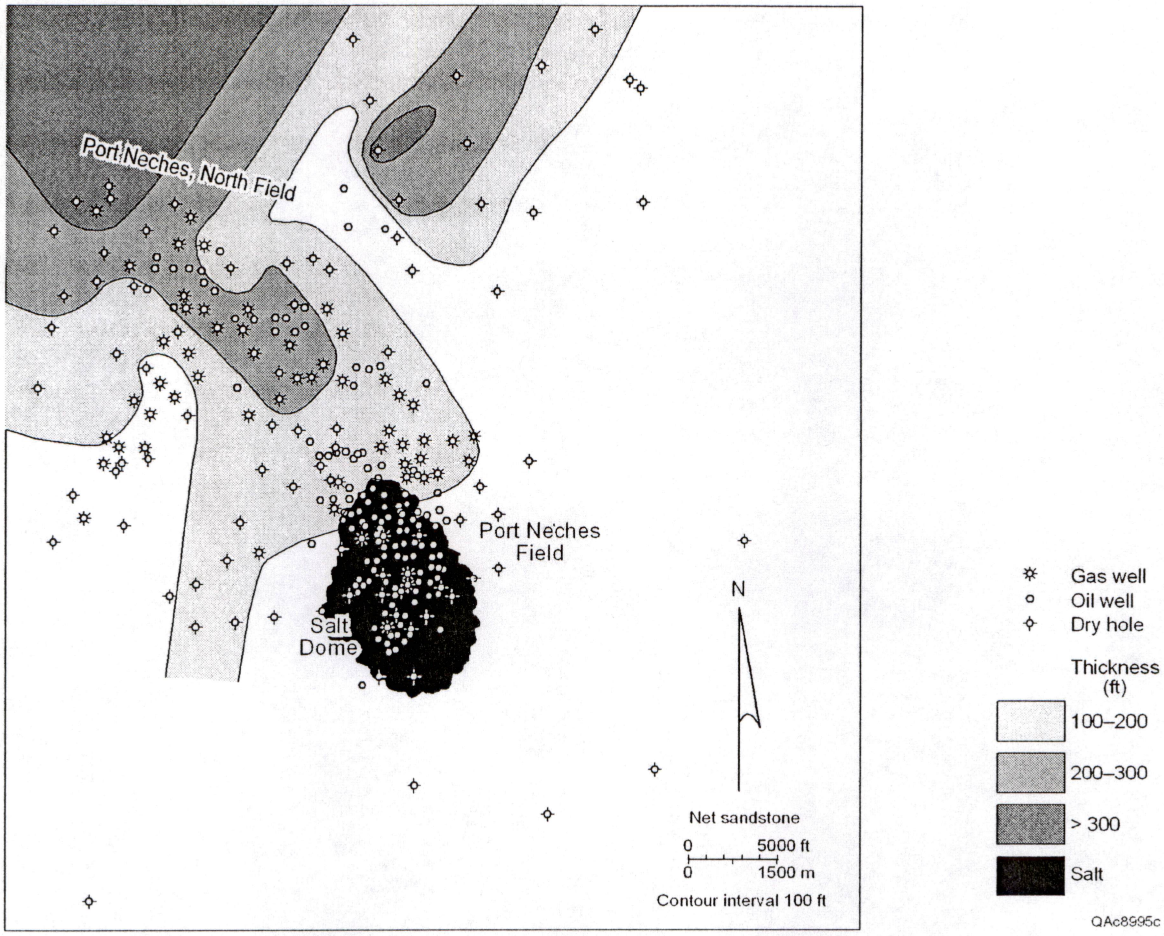

Figure 5. Net-sand map of Hackberry reservoir, North Port Neches field. Modified from Kiatta (1984).

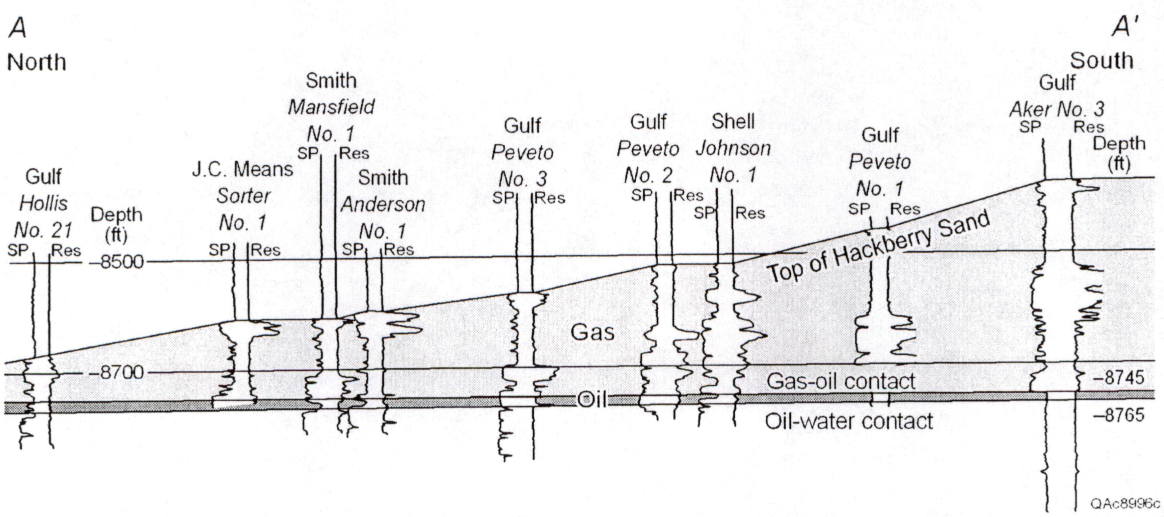

Figure 6. North-south structure cross section of Lower Hackberry reservoir, North Port Neches field. Modified from Railroad Commission of Texas, 1949, Docket No. 3-14451.

Structurally, the North Port Neches field is the extension of Port Neches field. With porosity of 28 to 30 percent and permeability ranging from 500 to 3,500 md (table 4), the Lower Hackberry sandstone is a high-quality turbidite reservoir. The reservoir comprises a 20-ft-thick oil rim having an estimated 150-ft-thick gas cap (fig. 6). The cumulative gas production varies highly with data sources (table 2). The low value of 49 Bcf from the Texas Railroad Commission Annual Report is the post-1970 cumulative gas production. Kiatta (1984) estimated that total production from Hackberry reservoir was 594 Bcf of gas and 4.8 MMSTB of oil. The 594 Bcf value is equivalent to a volume of 460 million reservoir barrels in the Hackberry reservoir, about 10 times larger than the reservoir volume in Port Neches field.

Table 4. Reservoir Parameters of Port Neches (*Marginulina*) and North Port Neches (Hackberry) Reservoirs

Field name	Port Neches	North Port Neches
Reservoir name	*Marginulina*	Hackberry
HC type	Oil	Oil and gas
Discovery year	1934	1946
Depositional system		Submarine fan
Trap	Fault trap	Structural/stratigraphic
Formation	Frio	Frio
Depth (ft)		7,700-8,900
GOC (ft)	5,825	8,745
WOC (ft)	5,975	8,765
Initial pressure (psia)	2,265	4,000 est.
Gas-cap/oil zone	0.1	Large
Drive mechanism	WD	Gas cap/WD
Net oil-sand thickness (ft)	30	20
Porosity (%)	33	28-30
Permeability (md)	250-4,000	500-3,500
Water saturation (%)	19	
Oil gravity (°API)	36.9	39
Gas gravity		
Formation volume factor (rb/STB)	1.216	
Oil in place (MMSTB)	10.4	

Figure 7 shows that reservoir pressure at North Port Neches Hackberry declined from 4,000 psi to less than 1,000 psi by 1970 and to less than 200 psi by the 1980's. There are six reservoirs (table 5) separated laterally by faults and vertically by shale. The pressure decline trend of the Adcock No. 6 well is significantly different from those of other Hackberry wells because it produces from the shallower Hackberry reservoir at 8,200 ft. The Hackberry in the west fault segment is slightly overpressured (data above the hydrostatic pressure line in fig. 8). The clear trend of initial pressure decline with time suggests that this part of the Hackberry reservoir has fairly good lateral and vertical communication and lack of strong water drive.

Table 5. Production Data of North Port Neches Field from the Texas Railroad Commission

Field Name	HC Type	Discovery Year	Depth (ft)	OilCum (STB)	GasCum (Mcf)
North Port Neches	Gas/oil	9/27/46	8,744	4,756,042	48,046,219
Port Neches, N (Seg East)	Gas	11/27/53	8,654	13,641	
Port Neches, N (Seg East 8300)	Gas	12/2/48	8,316		993,967
Port Neches, N (Seg West 8600)	Gas	10/10/50	8,655		
Port Neches, N (Seg West 8800)	Gas	5/24/50	8,838		
Port Neches, N (Frio 8800)	Gas	1/16/54	8,786		
Total				4,769,683	49,040,186

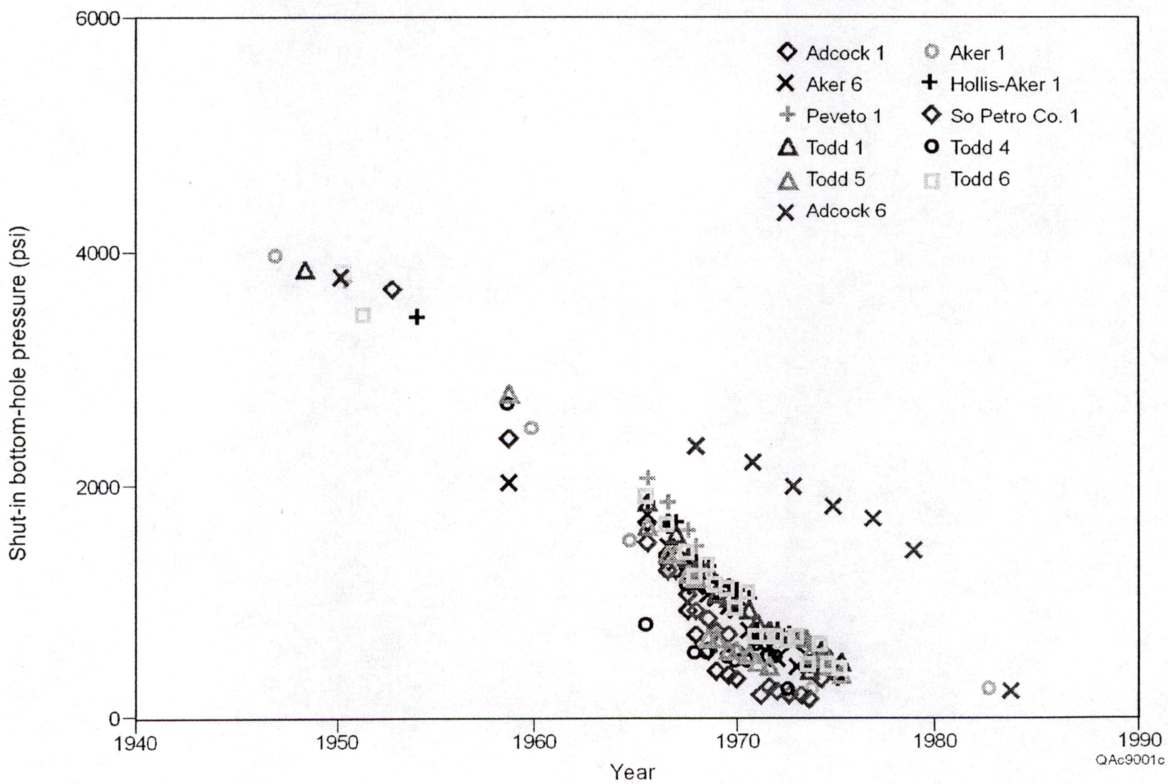

Figure 7. Pressure decline history of wells in North Port Neches (Hackberry) field.

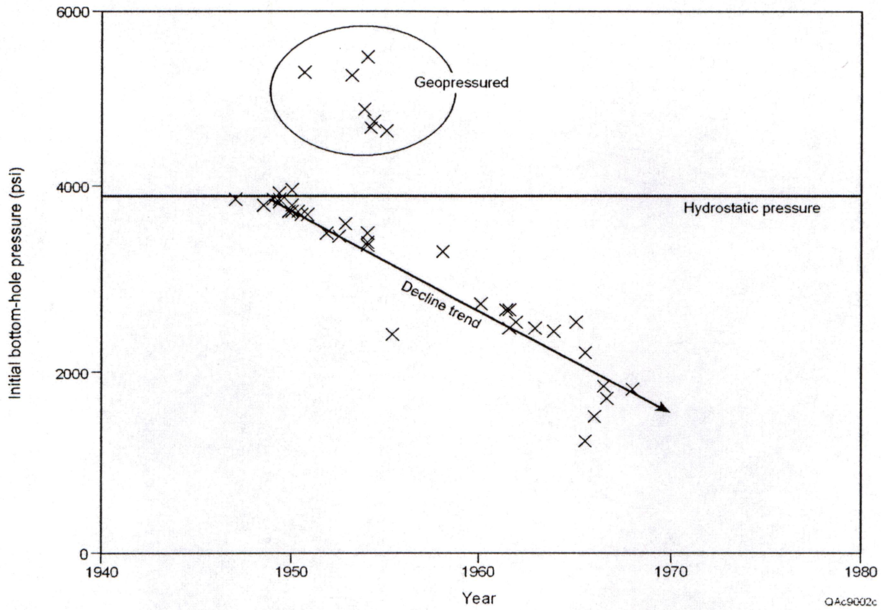

Figure 8. Decline trend of initial bottom-hole pressure in North Port Neches (Hackberry) field.

Reservoir Compaction

Land subsidence is caused by compaction of reservoir sand and shale that overlie the reservoir. The compaction of shale, called shale dewatering or aquitard drainage, was introduced by Pratt and Johnson (1926) for the subsidence at Goose Creek field. Subsequently, Snider (1927) concluded that the mechanism of subsidence at Goose Creek was from compaction of producing sands. Shale and sand compaction was measured in Wilmington field, California (Allen and Mayuga, 1969). The oil-well-collar surveys in the Wilmington field showed that 67.7 percent of the compaction had occurred in the sands and only 32.4 percent had occurred in the shales.

Reservoir compaction induces land subsidence but also increases oil and gas recovery, referred to as “compaction drive” in the petroleum industry. Figure 9a shows the relationships between formation compressibility and effective stress for unconsolidated, friable, and consolidated sandstones (Yale and others, 1993). Figure 9b shows the relationships between formation compressibility and reservoir pressure for unconsolidated and consolidated sandstones.

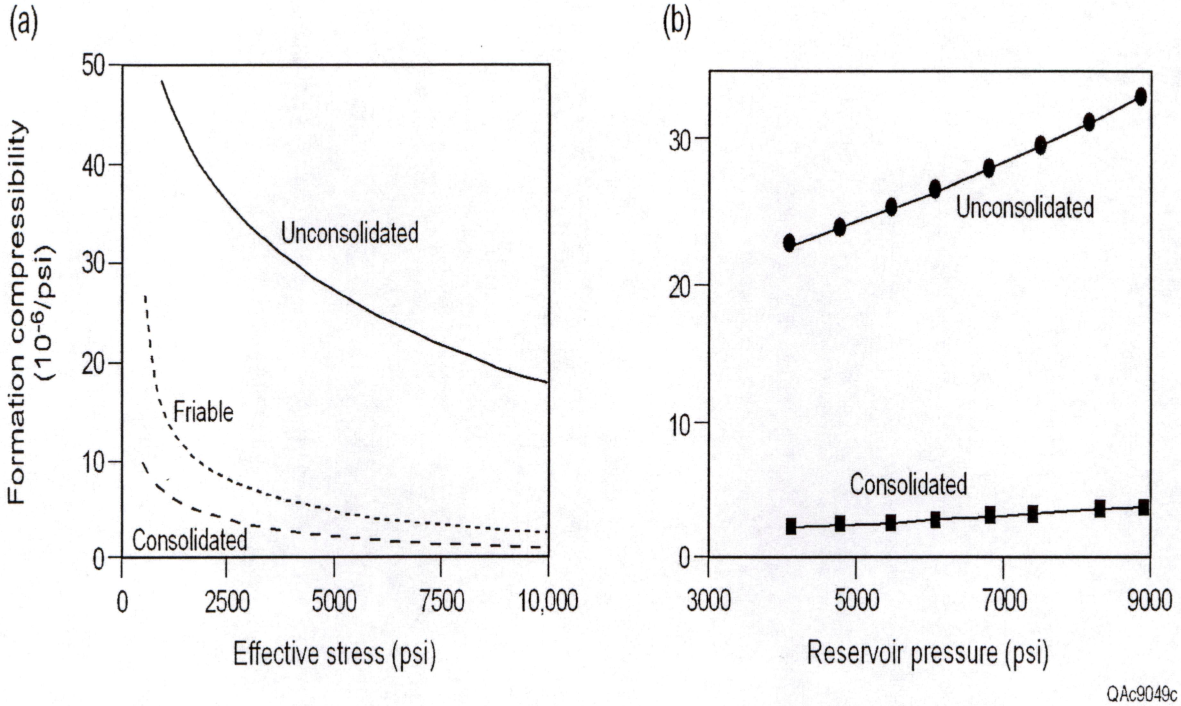

Figure 9. Effect of pressure on formation compressibility: (a) formation compressibility *vs.* effective stress and (b) formation compressibility *vs.* pore pressure. From Yale and others (1993).

It is noted that the formation compressibility of unconsolidated rocks is an order of magnitude higher than that of consolidated rocks. For geopressured, unconsolidated sands the formation compressibility can be reduced by 25 percent when reservoir pressure decreases from 9,000 to 4,000 psi. The formation compressibility is defined as a function of pore volume

$$C_f = \frac{1}{V_p}\frac{\partial V_p}{\partial p} = \frac{1}{\phi h}\frac{\partial(\phi h)}{\partial p} \tag{1}$$

$$= \frac{1}{\phi}\frac{\partial \phi}{\partial p} \qquad \text{when } h \text{ is constant} \tag{1a}$$

and solving equation 1 for □*h* by integration yields

$$\phi h = (\phi h)_i e^{c_f (p - p_i)} \tag{2}$$

where

C_f	=	formation compressibility in psi^{-1}
V_p	=	pore volume in ft^3
P	=	pore pressure in psi
□	=	porosity
h	=	reservoir thickness.

When *h* is assumed to be constant, equation 1 reduces to equation 1a, which is commonly used in the compaction-drive analysis (Docket No. 3-93626, 1989; Sulak and others, 1991; Yale and others, 1993). Equation 2 can be used to estimate the product of porosity and thickness (□*h*) at a specific reservoir pressure. When reservoir pressure decreases, both porosity and thickness decrease. Net compaction increases with reservoir thickness, formation compressibility, and pressure change. Although formation compressibility measurements are not available for North Port Neches (Hackberry) reservoir, the theory of compaction drive has been applied to calculate the recovery factor for the nearby Port Acres (L. Hackberry) reservoir, where porosity decreased from 29 to 17.5 percent when pressure declined from 9,015 psia in 1957 to 2,900 psia in 1989 (TRRC Docket No. 3-93626, 1989). Using the compressibility in figure 9b for the Hackberry reservoir in North Port Neches field, the estimated reduction in pore volume, or □*h*, is 6 percent when pressure decreases from 4,000 to 1,000 psi. Assuming a 100- to 200-ft gas column, the estimated compaction was 2 to 4 ft (0.7 to 1.4 m) at the top of the Hackberry reservoir, which is consistent with Morton and Purcell's observation (2001) of 0.6 m of subsidence at the edge of the Port Neches fault block.

Similarly, one can apply equation 2 to estimating thickness reduction by compaction for the thick Ekofisk reservoir in the North Sea. Because the Ekofisk reservoir is a geopressured, soft chalk ranging from 700 to 1,000 ft thick (table 6, Sulak, 1991) and having high formation compressibility ranging from 10 to 90 $\times 10^{-6}$ psi^{-1} (Sulak and others, 1991), the estimated thickness reduction by compaction is more than 30 ft at the top of the reservoir when pressure decreases from 7,120 to 3,000 psi. This value agrees with the 26-ft subsidence observed in Ekofisk in 2001. Therefore, subsidence is more serious in very thick, soft reservoirs having large pressure reduction such as Ekofisk and Wilmington than in those relatively thinner reservoirs, such as North Port Neches (Hackberry).

Table 6 Parameters Used in Compaction Estimations for North Port Neches (Hackberry) Field, Texas and Ekofisk Field, North Sea

Parameter	North Port Neches	Ekofisk
Porosity (%)	28 to 30 (29)	25 to 48 (33)
Reservoir thickness (ft)	50 to 300	700 to 1,000
Pressure range (psi)	100 to 4,000	2,000 to 7,120
Formation compressibility (1/psi)	32×10^{-6}	40×10^{-6}

Subsurface and Surface Faults

North Port Neches (Hackberry) field is bounded by the major northwest-trending fault to the west, a minor east-trending fault and the salt dome to the south (fig. 4), and a stratigraphic pinch-out to the east (fig. 5). The field can be divided into at least five major fault blocks. The uncertainty in correlating small surface faults to subsurface faults in North Port Neches (Hackberry) is high because major faults either dip in the opposite direction of the surface fault or are too far from the depleted Hackberry reservoir. Additionally, surface faults can be induced by subsidence alone. In the southeast part of the field, most faults dip to the south and southeast. The relatively minor fault (shown by the arrow in fig. 4) next to the east-trending boundary fault dips to the northwest and suggests that this minor fault and the surface fault reported by White and Morton (1997) are most likely connected.

CAPLEN AREA

Surface Faulting

Caplen field, discovered in 1939, is located at the edge of Bolivar Peninsula in Galveston County, Texas. White and Morton (1997) reported a wetland loss of 600 hectares in the area. Comparing 1930's and 1980's aerial photomosaics, they observed several active surface faults (fig. 10). Because groundwater withdrawal is minimal in the area, it was speculated that surface faults were caused by hydrocarbon production.

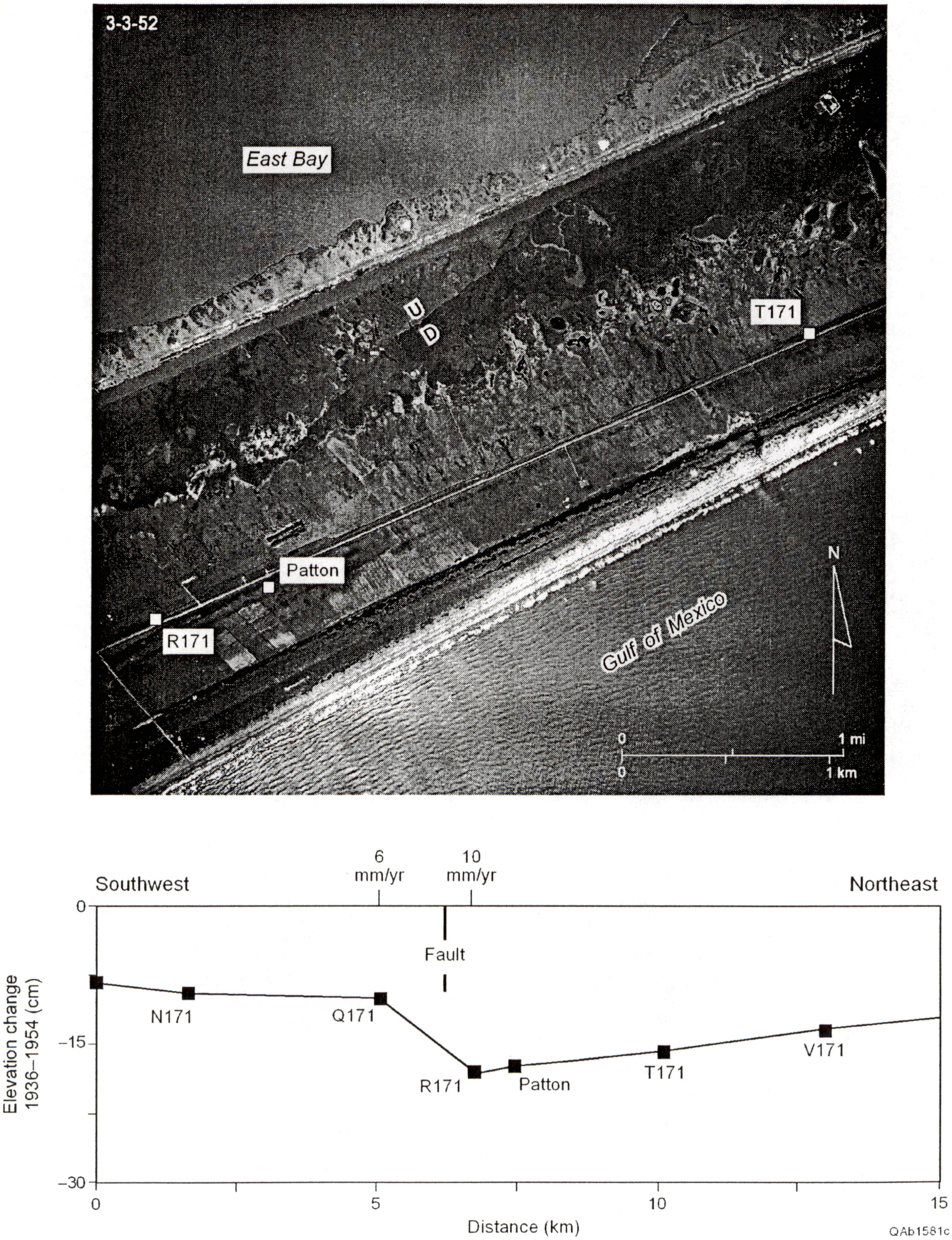

Figure 10. Aerial photo and profile of fault on Bolivar Peninsula near Caplen field. From White and Morton, 1997.

Production and Pressure Histories

Fields in the Caplen area are highly compartmentalized within numerous stratigraphic intervals and fault-bounded blocks (figs. 11 and 12). More than 160 producing Caplen reservoirs are listed in TRRC Annual Reports. Pressure and production data are more scattered among the various reservoirs and less regularly reported on a per-reservoir basis than for the Port Neches area. Reservoir data (table 7) and subsurface structural maps were also collected from TRRC hearing files.

Figure 11. Structure map of Frio 5-W Sand in Caplen field. From Railroad Commission of Texas, 1996, Docket No. 3-15491.

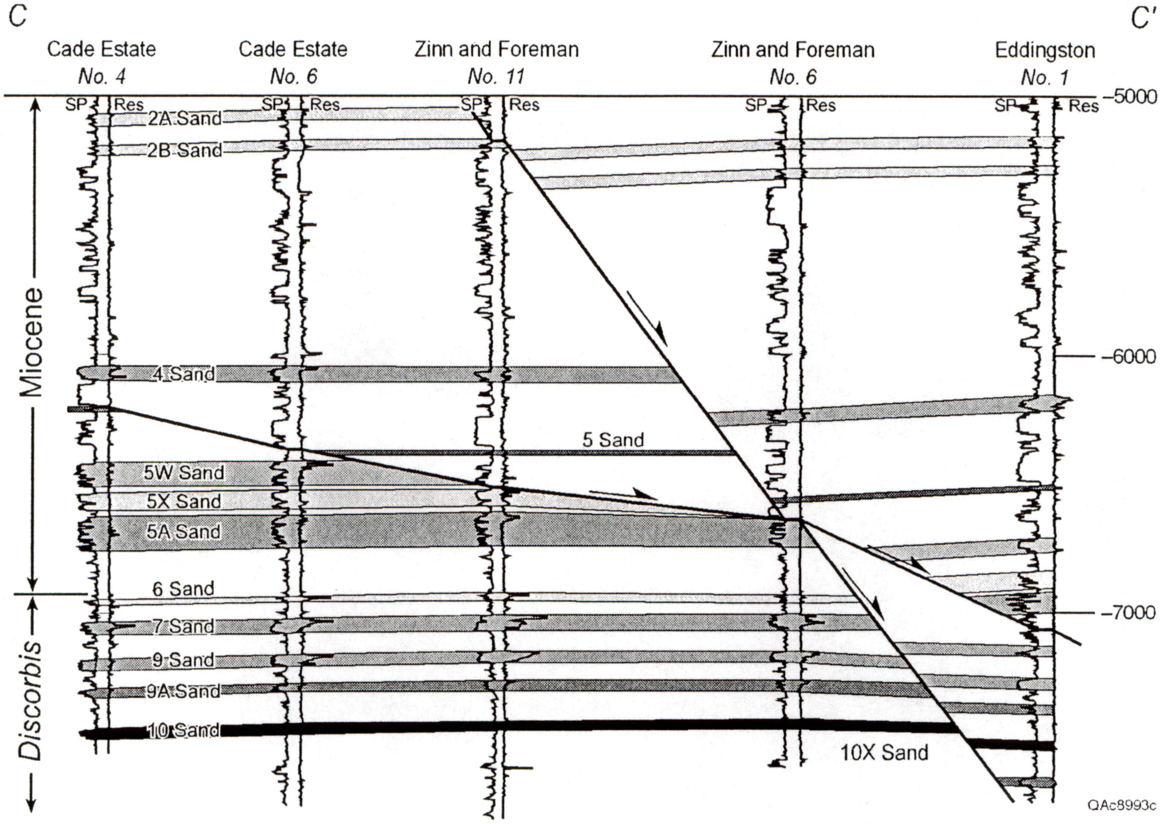

Figure 12. West-east structure cross section of Caplen field. Modified from Railroad Commission of Texas, 1953, Docket No. 3-26999.

The Caplen area has produced oil and gas from more than 60 gas reservoirs and 100 oil reservoirs. Cumulative oil production is greater than 27 MMSTB, and cumulative gas production is greater than 26 Bcf. The total amount of gas produced prior to 1970 is not known, but as of 1962 about 10 Bcf of casinghead gas and 2.3 Bcf of dry gas were produced (Musolff, 1962). Many reservoirs have fairly high water cuts (table 7) as a result of a moderate to strong water drive (Musolff, 1962; RRC Docket No. 3-55000, 1965). The largest Caplen reservoir (*Discorbis*) is an oil reservoir at subsea 7,500 ft that has a cumulative production of 7.9 MMSTB (fig. 13a). Because bottom-hole pressures of oil wells were not mandated to be submitted to TRRC, the only bottom-hole pressure data found were for four small fault blocks discovered in 1953 (fig. 13b). Oil-well pressures dropped quickly in the first two years but thereafter were stabilized by the strong water drive. The maximum pressure declines were about 600 psi in oil wells and 1,000 psi in gas wells.

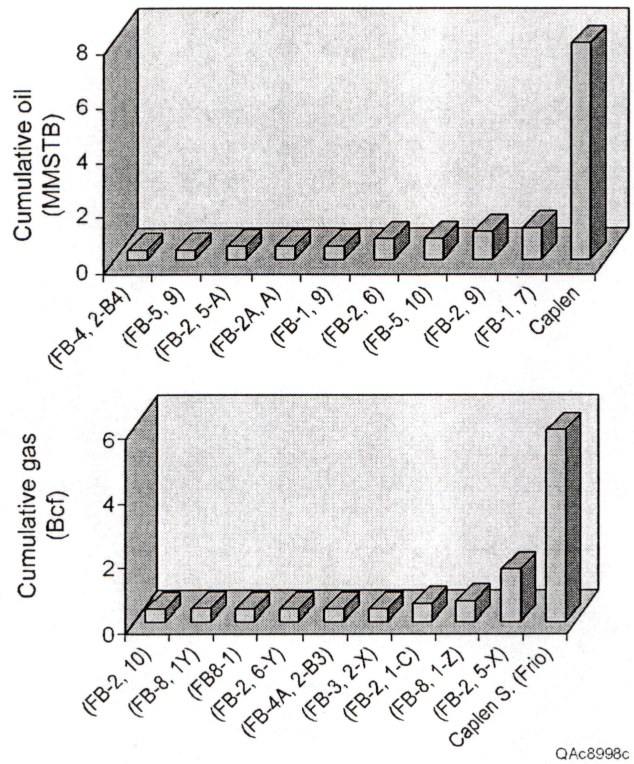

Figure 13. Production from reservoirs in Caplen field: (a) oil reservoirs and (b) gas reservoirs.

The largest gas field is South Caplen, an overpressured reservoir that has produced 5 Bcf of gas (fig. 13a) since 1979 after the appearance of surface faults. Most gas reservoirs in the area are small and have only one or two producing wells and very short producing lives (fig. 14). That initial pressures in many wells completed after 1970 (for example, Cade Estate 14, Humphreys 7 and 8, and Zinn & Foreman 9) were still close to hydrostatic pressure suggests that interfault block communications are limited or absent.

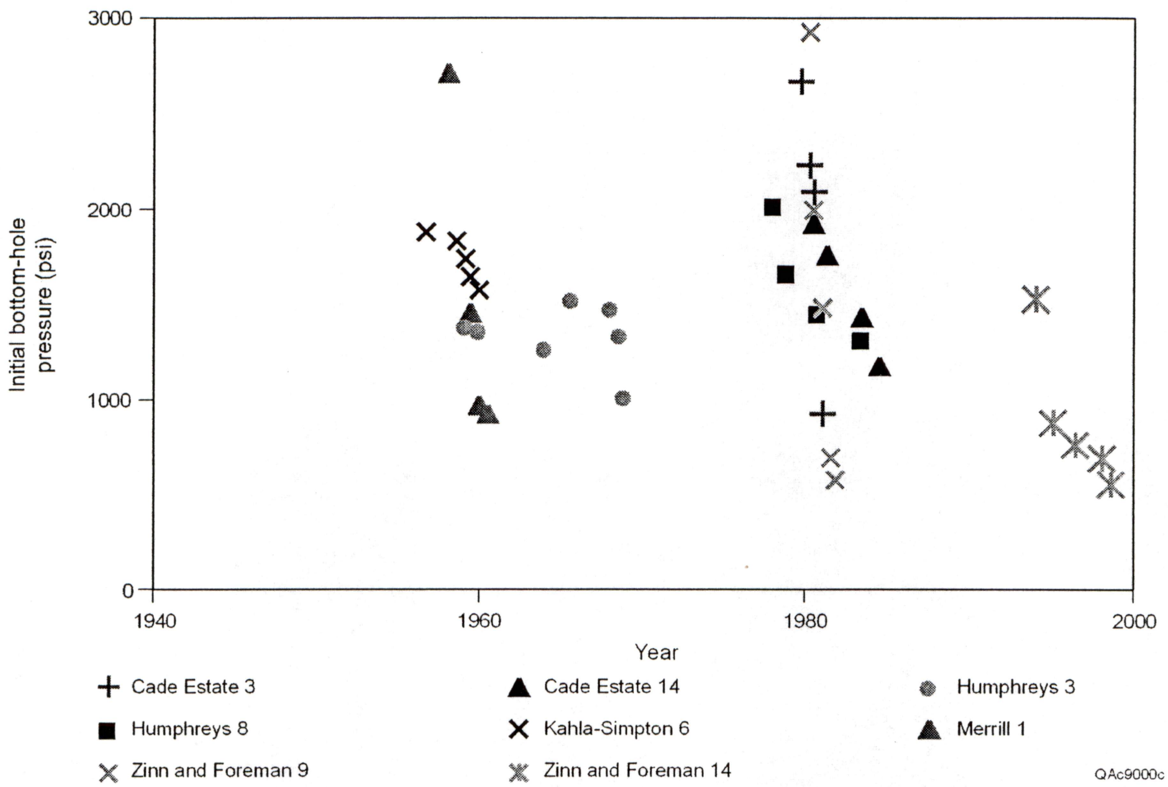

Figure 14. Well pressure decline histories of Caplen field.

Table 7. Reservoir Parameters of Caplen Field

Reservoir name	Caplen field	FB 2, 5-A	FB 2, 5-A	FB 1, 5-W	FB 2, 7	FB 1, 9-A	FB 2, 9-A	FB 2, 10-X	FB V, 9
Discovery year	1939	1953	1955	1962	1959	1953	1953	1953	1952
Depth (ft)	7000-8000								
Trap	Anticline								
Formation	*Discorbis*	*Discorbis*	*Discorbis*	*Discorbis*	*Discorbis*	*Discorbis*	*Discorbis*	*Discorbis*	*Discorbis*
Petrophysical type	Low resistivity	low resistivity	Low resistivity	low resistivity	low resistivity	Low resistivity	low resistivity	Low resistivity	low resistivity
Dip (ft/mi)		234	234	176	263	176	210	351	158
Pi (psi)	3330	3069	3100	3030	3179	3360	3332	3733	3357
T_i (°F)	190	160	162	161	168	169	172	176	169
Gas-cap/oil zone		0.33					0.33	0.2	0.33
Drive mechanism	SWD	SWD	SWD	SWD	SWD	SWD	SWD	WD	SWD
Net oil-sand thickness (ft)		14	12	8	9	8	10	10	7.5
WOC (ft)								-7777	
Porosity (%)		26	26	23	29	25	25	26	25
Permeability (md)		775.8	775.8	775.8	775.8	775.8	775.8	1500	1500
Connate water saturation (%)		32	27	25	44	42	32	30	30
Oil gravity (°API)	33	31.8	33	28.4	31.8	32	33.3	33.3	33.1
Gas gravity								0.6	
Formation volume factor (r_b/STB)								1.31	
Water cut in 12/64			81	87	88	89		98	91

Figure 15 plots initial pressures as a function of time. Initial pressures in *Discorbia* reservoirs decline gradually from 3,500 to 2,600 psi. The relatively high initial bottom-hole pressure of 2,600 psi after more than 35 years of production indicates that the *Discorbis* reservoirs are under water drives. Because there are more than 50 small sands within a 3,000-ft-thick vertical section in Caplen, initial pressures in Miocene reservoirs are too scattered to derive any decline trend. This pattern suggests that the Miocene reservoirs are highly compartmentalized.

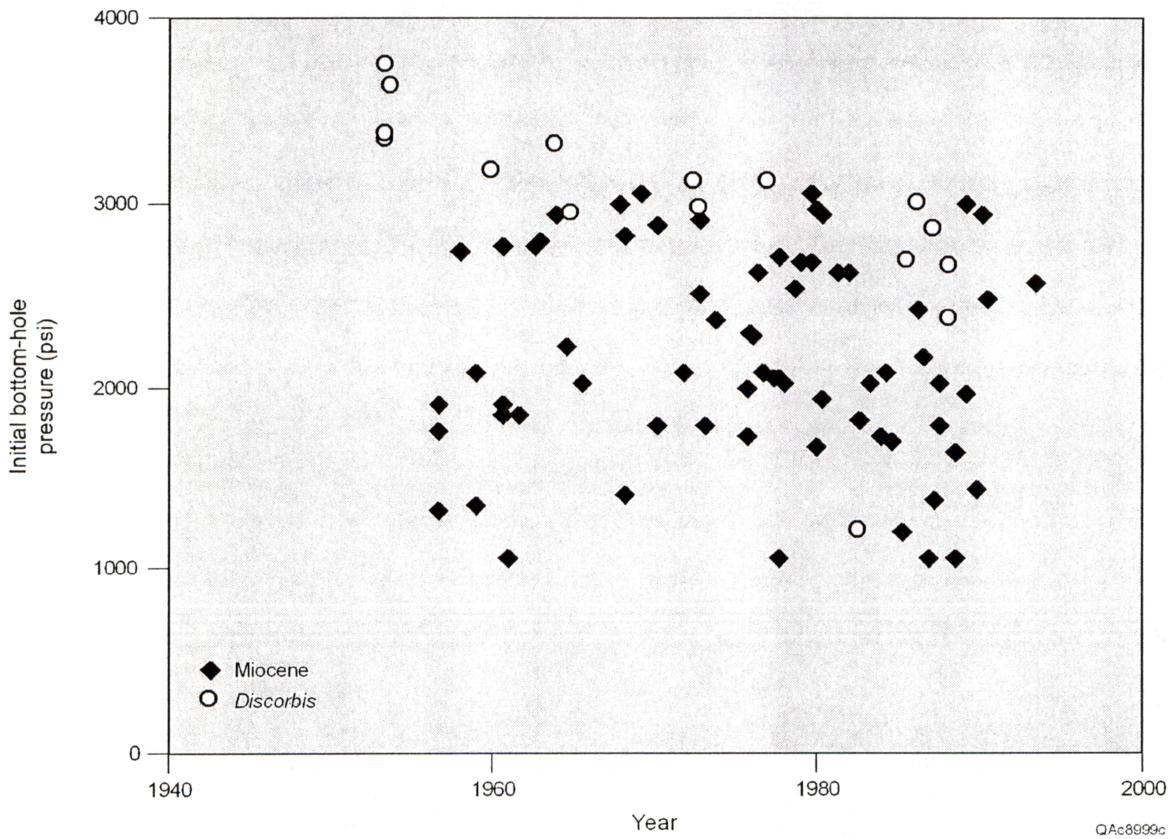

Figure 15. Initial pressure decline trends in Miocene and *Discorbis* intervals in Caplen field.

Net-sand thickness of most producing sands in the Caplen area is less than 20 ft (table 7 and fig. 12). Pressure drops were less than 1,000 psi because these thin sands are under moderate or strong water drives. From equation 2, thickness reductions by reservoir compaction are small and subsidence induced by hydrocarbon production is not significant in Caplen field. R.

A. Morton (personal communication, 2001) examined cores from updip and downdip blocks at the surface fault and found that displacement is caused more by erosion than by subsidence.

SUMMARY

Subsidence is strongly related to reservoir compaction. Reservoir compaction is a function of porosity, thickness, and degree of depressurization of the reservoir. Both porosity and thickness reduce by reservoir depressurization. Compaction as well as subsidence is severe in thick and soft reservoirs having high porosity.

Port Neches field is an oil field having several gas producing intervals, and North Port Neches (Hackberry) field is a major gas producing field. With an estimate of 594 Bcf of gas produced from the North Port Neches (Hackberry) field, the reservoir has been fully depleted from about 4,000 to 100 psi. With 29 percent porosity and high formation compressibility, the estimated thickness reduction by compaction is 2 to 4 ft at the top of Hackberry. The 2- to 4-ft thickness reduction agrees with the 2 ft of subsidence indicated by core data. The surface fault is most likely connected to a subordinate fault next to the southern boundary fault at Hackberry depth.

The Caplen area is a highly compartmentalized field that has stacks of thin sandstones. Because reservoirs are thin and small and under medium to strong water drive, production and pressure decline at Caplen are small. Consequently, hydrocarbon production probably has only a minor effect on subsidence and surface faulting.

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