Chapter 2: Assessment of Kentucky Fields for CO_2-Enhanced Oil Recovery

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Introduction

Enhanced oil recovery (EOR) using carbon dioxide (CO_2) has been successful in the United States, where the technology is recovering approximately 300,000 barrels of oil per day beyond that produced during the primary and secondary phases of field production (U.S. Department of Energy, no date a). The additional oil produced represents about 4 percent of the original oil in place nationwide and 10 to 15 percent of the original oil in place in the Permian Basin of Texas (Melzer and Miller, 2007). More recently, EOR has been viewed as a mechanism to sequester (i.e., store) some of the CO_2 used in the EOR process, thereby defraying part of the sequestration costs (Melzer and Miller, 2007; U.S. Department of Energy, 1999). Though still conceptual, over time an EOR project would be envisioned to transform into a strictly sequestration project in which sequestration costs were covered, for example, by carbon credits (U.S. Department of Energy, 1999).

In contrast to its more than 40 year history in the United States, the history of CO_2-EOR in Kentucky and surrounding regions in the Appalachian and Illinois Basins has been very limited, with only a handful of small projects implemented (see, for example, Duchscherer, 1965; Miller, 1990; Bardon and others, 1991; Miller and others, 1994; Miller and Hamilton-Smith, 1998). Remaining oil in place in Kentucky is an estimated 1.7 billion barrels, which represents 71 percent of the estimated 2.4 billion barrels of original oil in place (B.C. Nuttall, Kentucky Geological Survey, 2005, unpublished data). The proportion of remaining oil that could be recovered using CO_2-EOR is speculative because of the paucity of CO_2-EOR precedents in the region, but assuming that proportion equals 6 to 7 percent—a somewhat conservative estimate based on likely reservoir conditions in Kentucky—then 700,000 additional barrels of oil could be recovered.

Nationwide, EOR in the context of sequestration is still a very immature field; therefore, there are no historic projects that could serve as guides. Nevertheless, conventional EOR experience is providing guidelines that will allow screening of possible CO_2-sequestration projects (see, for example, Kovscek, 2002; Carr and others, 2008). What these studies suggest is that reservoir and oil properties, and surface facilities will likely exert strong influences on the efficacy and economic viability of CO_2-EOR projects within the context of sequestration.

Prior to this analysis, only a few studies have systematically examined the EOR potential in Kentucky. The Tertiary Oil Recovery Information System (TORIS) was commissioned by the U.S. Department of Energy in the 1980's to study EOR potential nationwide, including Kentucky (U.S. Department of Energy, no date b). The TORIS database system provided a compilation of geologic and engineering parameters needed to evaluate potential oil recovery. Today, the updated TORIS database provides critical reservoir data for 46 reservoirs in 33 fields in Kentucky, and it provides the basis for much of EOR analysis in this study (Nuttall, 2000). More recently, Advanced Resources International conducted EOR studies in the Appalachian Basin, where they found that 68 reservoirs were suitable for EOR, with a potential yield of 1.2 billion barrels of oil (Petroleum Technology Transfer Council, 2005).

The dearth of systematic reservoir studies focusing on EOR and actual CO_2-EOR projects in Kentucky provides the motivation for this study, in which the overarching goal is to provide a semiquantitative assessment of CO_2-EOR potential. More specifically, this study uses reservoir screening criteria described by Kovscek (2002) and Carr and others (2008) to develop an inventory and ranking of 70 oil reservoirs in 51 fields that may have favorable characteristics for CO_2-EOR. The ranking provides a high-level framework for conducting more detailed reservoir and modeling studies on selected reservoirs that can be used to predict performance during CO_2-EOR. An uncertain CO_2 supply is a significant hurdle for EOR projects in the region; therefore, the volume of CO_2 used in EOR and the volume of sequestered CO_2 are estimated. The estimated volumes will provide a basis for estimating CO_2 costs, which will be a significant part of total project costs, especially during the early period of implementation.

Methods

The 51 analyzed fields from 25 counties in eastern, central, and western Kentucky (Fig. 2.1, Table 2.1) are a small proportion of the more than 1,500 oil and gas fields that are formally recognized in Kentucky (Kentucky Division of Oil and Gas Conservation, 2008). The analyzed fields include 71 reservoirs that

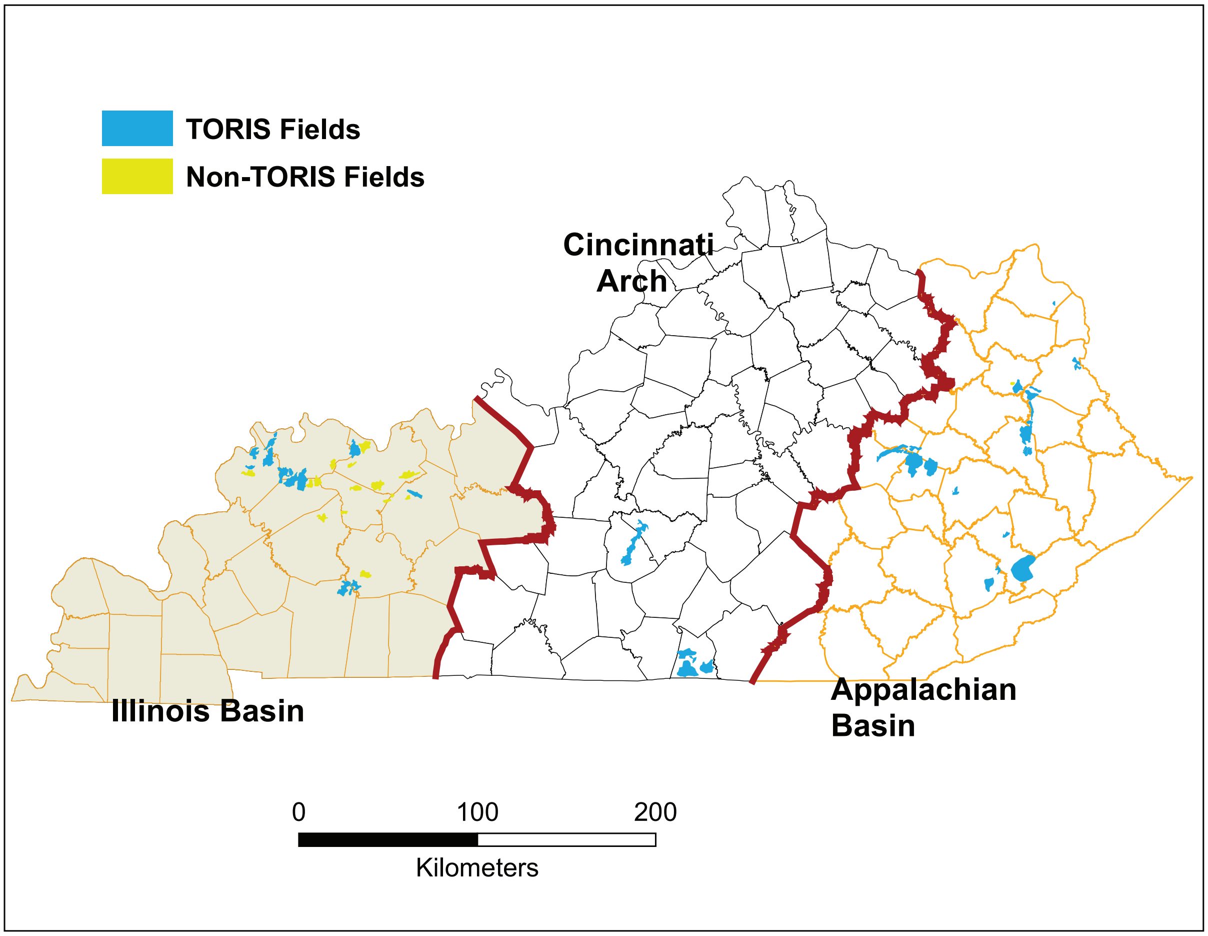

Figure 2.1. Fields evaluated for CO_2-EOR potential include those from the TORIS database (N = 33, blue areas) and non-TORIS fields (n = 18, yellow areas) having requisite characteristics discussed in the "Introduction."

range in age from Ordovician to Pennsylvanian, the majority (77 percent) of which are Mississippian (Fig. 2.2). The reservoirs include a variety of clastic (70 percent) and carbonate (30 percent) reservoirs.

TORIS data used for reservoir analysis and as inputs for screening criteria are reported by field and geologic play. Fields are administrative groupings of oil or gas wells that produce from the same or multiple (stacked) reservoirs. For example, the Dixie/Dixie West Field produces oil from the Chester, Waltersburg, and Tradewater reservoirs (see entries 11a–c, Table 2.1). Results of this study are provided primarily by field designation. The term "reservoir" refers to the body of rock—including rock matrix and pore space—that contains oil, gas, or water (or all three) in a field. It is the most fundamental subsurface volume of interest when addressing the extraction of oil and gas. Geologic plays are accumulations of oil or gas that share nearly identical characteristics of stratigraphy, reservoir type, trapping style, and seal type (Houseknecht, 1997). Oil and gas accumulations defined as plays are therefore often distributed across large areas within a sedimentary basin, and may encompass numerous fields.

To further broaden the assessment, we examined 18 fields in addition to the 33 TORIS fields. These fields, called "non-TORIS fields," have one or more of the following characteristics: (1) previously waterflooded, (2) large surface footprint, possibly indicating high potential for larger volumes of unrecovered oil, (3) large estimated original oil in place, or (4) at least four productive or previously productive wells. A waterflood is a secondary oil recovery method in which water is injected into a reservoir to displace additional oil toward producing wells.

Reservoir parameters in the TORIS database come from a variety of sources, including open-hole wireline logs, core analyses, and oil samples. These data sources are often sparse and outdated and consequently might

Table 2.1. Fields and reservoirs analyzed in this study. Based on this analysis, fields that rank in the upper quartile (n = 18) are highlighted in bold. Field ID designations are used to identify fields in subsequent tables.

ID	*Field Name*	*County*	*Reservoir*	*Discovery Date*	*Depth (ft)*	*Temperature (°F)*
TORIS fields						
1	Albany North	Clinton	Knox	1961	1,800	72
2a	Apex/Hardeson/Dukes Ridge CONS	Christian/ Muhlenberg	Ste. Genevieve	1954	715	76
2b	Apex/Hardeson/Dukes Ridge CONS	Christian/ Muhlenberg	Corniferous	1954	934	70
3	Ashley	Powell/Wolfe	Corniferous	1917	910	71
4	Big Sinking	Lee/Estill/Powell/ Wolfe	Corniferous	1918	1,036	70
5a	Birk City	Daviess/Henderson	Chester	1938	1,497	82
5b	Birk City	Daviess/Henderson	Ste. Genevieve	1938	1,860	84
6	**Bulan CONS**	**Perry**	**Big Lime**	**1960**	**2,350**	**76**
7	**Bull Creek CONS**	**Perry/Letcher**	**Big Lime**	**1965**	**3,030**	**88**
8	Concord CONS	Clinton	Knox	1941	1,800	74
9	Cutshin DBS	Leslie	Big Lime	1979	3,200	86
10	Daley DBS	Leslie/Perry	Big Lime	1970	3,136	87
11a	Dixie/Dixie West	Henderson/Union/ Webster	Chester	1945	2,277	86
11b	Dixie/Dixie West	Henderson/Union/ Webster	Tradewater	1945	977	76
11c	Dixie/Dixie West	Henderson/Union/ Webster	Waltersburg	1945	1,778	78
12	Elna	Johnson	Weir	1921	750	68
13	Fallsburg CONS	Lawrence	Berea	1912	1,750	73
14	Greensburg	Green/Taylor	Laurel	1955	442	79
15	Highland	Breathitt	Corniferous	1954	1,900	80
16a	**Hitesville CONS**	**Union/Henderson**	**Aux Vases & Waltersburg**	**1954**	**2,566**	**86**
16b	Hitesville CONS	Union/Henderson	Chester	1954	2,058	85
16c	Hitesville CONS	Union/Henderson	Ste. Genevieve	1954	2,592	88
17	Ida CONS	Clinton	Knox	1959	1,750	73
18	Irvine-Furnace CONS	Estill/Powell	Corniferous	1947	800	69
19	Isonville CONS	Elliott	Weir	1917	1,010	75
20	Ivyton	Magoffin	Weir	1919	1,215	80
21	Keaton-Mazie CONS	Lawrence/Johnson	Weir	1920	850	74
22	Lee Chapel	Clinton	Knox	1975	1,577	74
23	Martha	Lawrence	Weir	1922	900	70
24	Mine Fork	Johnson	Weir	1919	800	68
25a	**Morganfield CONS**	**Union**	**Caseyville**	**1943**	**1,406**	**84**
25b	**Morganfield CONS**	**Union**	**Chester**	**1943**	**2,145**	**91**

Table 2.1. Fields and reservoirs analyzed in this study. Based on this analysis, fields that rank in the upper quartile (n = 18) are highlighted in bold. Field ID designations are used to identify fields in subsequent tables.

ID	*Field Name*	*County*	*Reservoir*	*Discovery Date*	*Depth (ft)*	*Temperature (°F)*
25c	Morganfield CONS	Union	Ste. Genevieve	1943	2,616	88
25d	Morganfield CONS	Union	Waltersburg	1943	1,833	88
26	Naples	Muhlenberg	Berea	1968	1,000	71
27	Oil Springs CONS	Magoffin/Johnson	Weir	1919	1,100	80
28	Petty Knob	Clinton	Knox	1980	1,750	73
29a	Poole CONS	Webster/Henderson	Aux Vases & Waltersburg	1943	1,775	86
29b	Poole CONS	Webster/Henderson	Chester	1943	2,030	83
29c	Poole CONS	Webster/Henderson	Ste. Genevieve	1943	2,560	91
30a	**Smith Mills/Smith Mills North CONS**	**Henderson/Union**	**Chester**	**1942**	**2,341**	**85**
30b	Smith Mills/Smith Mills North CONS	Henderson/Union	Ste. Genevieve	1942	2,635	88
31	Taffy CONS	Ohio	Chester	1926	625	72
32a	**Uniontown CONS**	**Union**	**Aux Vases & Waltersburg**	**1942**	**1,784**	**80**
32b	Uniontown CONS	Union	Chester	1942	2,237	83
33	Walker Creek CONS (Big Andy)	Lee/Wolfe	Corniferous		1,275	80
Non-TORIS fields						
34	Barnett Creek CONS	Ohio	Tar Springs	1929	650	74
35a	Barrett Hill CONS	McLean/Ohio	Bethel	1929	1,161	67
35b	**Barrett Hill CONS**	**McLean/Ohio**	**Tar Springs**	**1929**	**975**	**64**
36	Bells Ferry CONS	McLean	Jackson	1952	2,340	83
37a	**Cane Run CONS**	**Daviess**	**Hardinsburg**	**1938**	**860**	**70**
37b	**Cane Run CONS**	**Daviess**	**Tar Springs**	**1938**	**778**	**64**
38	Curdsville CONS	Daviess	Palestine	1944	1,390	72
39	**Euterpe North CONS**	**Henderson**	**Hardinsburg**	**1948**	**1,735**	**74**
40	Fannin CONS	Elliott	Berea	1950	1,080	78
41a	Griffith CONS	Daviess	Jackson	1946	1,494	70
41b	Griffith CONS	Daviess	Palestine	1946	1,000	69
42a	**Guffie CONS**	**McLean**	**Big Clifty**	**1946**	**1,908**	**69**
42b	**Guffie CONS**	**McLean**	**Tar Springs**	**1946**	**1,706**	**65**
43a	Hanson CONS	Hopkins	Cypress	1962	2,385	62
43b	**Hanson CONS**	**Hopkins**	**Tar Springs**	**1962**	**2,408**	**65**
44	Hardeson CONS	Muhlenberg/ Christian	Bethel	1955	884	63
45	**Maxwell CONS**	**Ohio/McLean/ Daviess**	**Tar Springs**	**1943**	**1,860**	**67**
46	**Morganfield South CONS**	**Union**	**Hardinsburg**	**1948**	**1,930**	**79**

Table 2.1. Fields and reservoirs analyzed in this study. Based on this analysis, fields that rank in the upper quartile (n = 18) are highlighted in bold. Field ID designations are used to identify fields in subsequent tables.

ID	*Field Name*	*County*	*Reservoir*	*Discovery Date*	*Depth (ft)*	*Temperature (°F)*
47	**Pratt CONS**	**Webster**	**Tar Springs**	**1943**	**1,860**	**67**
48	Rhodes School CONS	Muhlenberg	Jackson	1952	1,359	74
49	Sebree CONS	Webster/Henderson	Tar Springs	1904	1,800	73
50	Taffy CONS	Ohio	Tar Springs	1926	620	61
51a	Utica CONS	Daviess	Cypress	1927	1,450	67
51b	Utica CONS	Daviess	Tar Springs	1927	1,200	66

not provide the desired accuracy for modern reservoir analysis. Many of the reported reservoir parameters therefore represent average values for an entire field or play and do not address potential reservoir heterogeneity, which would have to be addressed in any subsequent detailed analyses. For the non-TORIS fields, reservoir parameters were calculated or extrapolated from TORIS, based on similarity where required.

Minimum miscibility pressure (MMP) is one of the most critical parameters used to assess CO_2 interactions with oil in the reservoir and hence the effectiveness of CO_2-EOR projects. The MMP is the minimum pressure at which CO_2 will mix with oil in a reservoir to form a single fluid phase. Miscibility contributes to optimal recovery of oil. Values for MMP may be determined experimentally using slim-tube tests (Jarrell and others, 2002), or, as in the case of this study, with empirical correlations. Specifically, we used the Cronquist correlation (Bank and others, 2007), which equals:

$$\text{MMP} = 15.988 * \text{Temperature}^{(0.744206+0.0011038*\text{MW C5+})}$$

where: MW C5+ = $4247.98641*\text{API}^{(-0.87022)}$ and API is the API gravity of the oil. “MW C5+” is the molecular weight of hydrocarbons containing at least five carbon atoms in a single chain (pentane, hexane, etc.).

The ability to pressurize a reservoir to the point of achieving miscibility is, in large part, a function of the magnitude of MMP relative to the maximum pressure at which the reservoir can be pressurized during an EOR project. Accordingly, calculated MMP values were compared to initial reservoir pressures (P_i) and theoretical maximum reservoir pressures (P_{max}) (Table 2.2). In reconstructing the values for P_i, we attempted to document pressures for a reservoir in a field prior to significant production and depletion. P_i values were based on retrievals from the TORIS database or from drillstem or production test data provided at the KGS online database (kgs.uky.edu/kgsweb/DataSearching/oilsearch.asp). Test data were not found for several fields, however, and, consequently, P_i was estimated to equal hydrostatic pressure, which is the pressure exerted by a column of water whose height is proportional to the measured depth of the reservoir. Hydrostatic pressure was estimated by:

$$\text{Hydrostatic pressure } (P_{hydro}) \text{ (psi)} = 0.433*\text{depth (ft)}.$$

The value for P_{max} was taken from Environmental Protection Agency guidelines (www.epa.gov/r5water/uic/r5guid/r5_07.htm#Ia) and is defined as the maximum pressure a reservoir should attain during injection. It is equal to:

$$P_{max} \text{ (psi)} = 0.8 \text{ psi/ft} * \text{depth (ft)}.$$

The magnitude of P_{max} is intended to keep pressure below that at which fracturing of the reservoir and seal rocks might occur. In the Appalachian and Illinois Basins fracture pressures fall near a gradient of 1.0 psi/ft (Frailey and others, 2004; Nopper and others, 2005). Avoiding fracturing of the seal is important for two reasons. First, it ensures that CO_2 remains in the oil-bearing part of the reservoir, thereby increasing CO_2 interaction with the oil. Second, it facilitates monitoring the fate of the CO_2 and ensures that shallower potable groundwater remains protected.

Reservoir and fluid properties exert significant influence on the viability of reservoirs for combined EOR and sequestration. Using techniques described in Kovscek (2002) and Carr and others (2008), these properties were used to analyze and broadly screen fields in terms of their EOR and sequestration potential. The most fundamental reservoir property is porosity, φ, which is the proportion of rock volume that is open space, typically filled with gas, oil, water, or some combination. Porosity is measured directly from core samples or indirectly from open-hole logs. The initial water saturation, S_{wi}, is the fraction of porosity filled with water at the time that fluids are initially produced

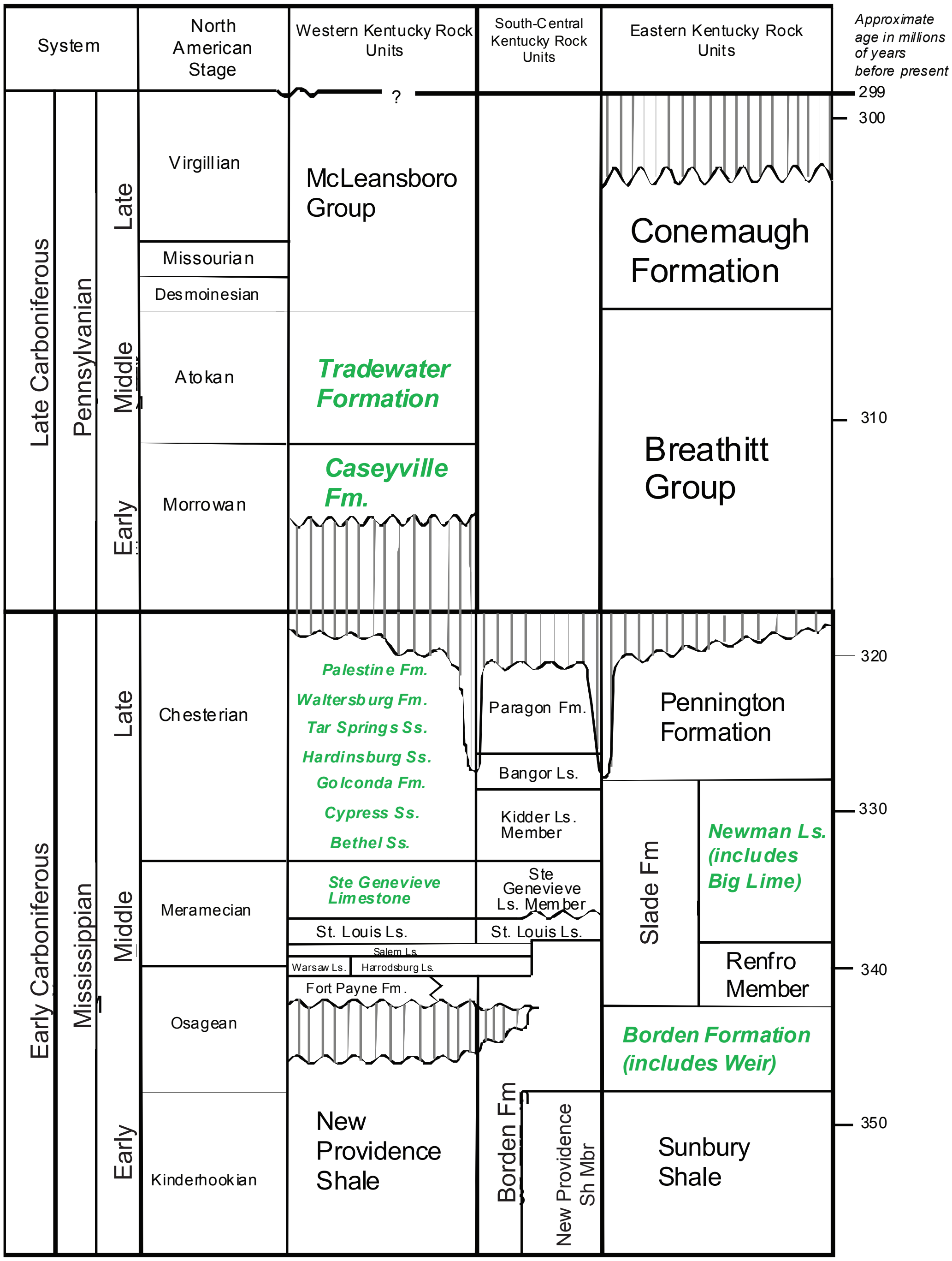

Figure 2.2a. General stratigraphic column showing Pennsylvanian and Mississippian reservoirs of Kentucky. Names in green are reservoirs examined in this study.

from the reservoir and is calculated from open-hole wireline logs. For this study, the fraction of porosity saturated with oil (S_o) was assumed to be $1–S_w$ (in some reservoirs the gas saturation, S_G, must also be considered).

The first screening criterion is the product of oil saturation and porosity, $S_o\varphi$, which is a measure of the amount of oil per unit volume of rock (Table 2.3). Reservoirs having $S_o\varphi$ values greater than 0.05 to 0.07 are often economic for EOR because they started with high initial oil saturations and therefore may have high residual oil saturations. In contrast, reservoirs having values less than 0.05 need to be closely examined for the possibility of additional costs related to EOR

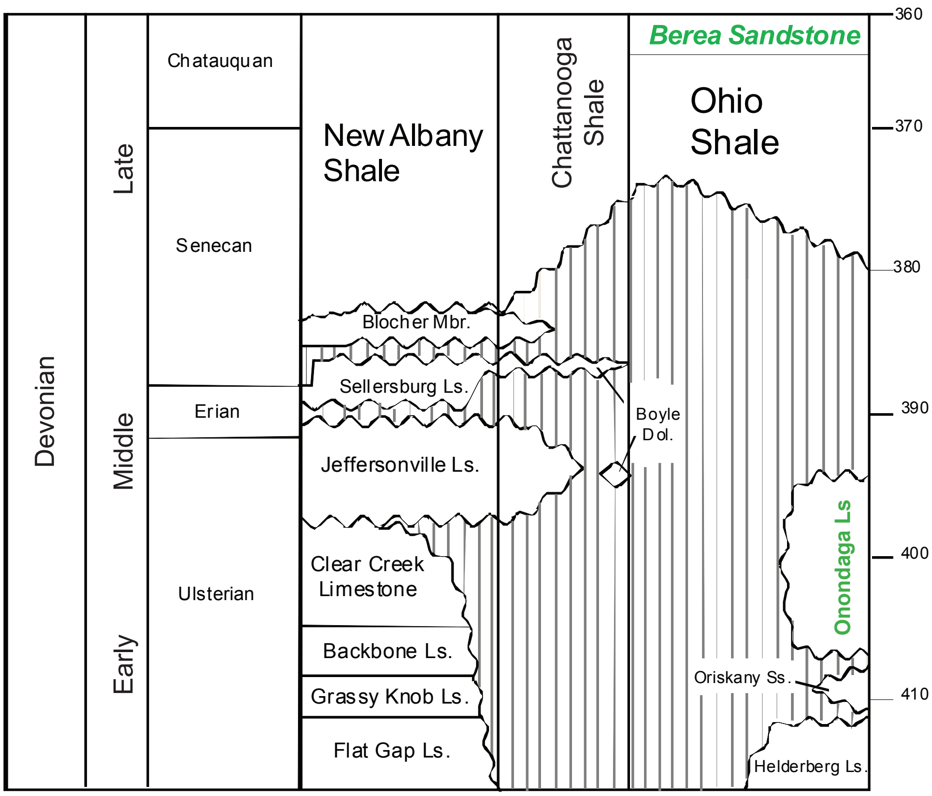

Figure 2.2b. General stratigraphy showing Devonian reservoirs of Kentucky. Names in green are reservoirs examined in this study.

(Kovscek, 2002). From a sequestration perspective, reservoirs having higher $S_o\varphi$ values are more desirable because of a greater potential for a revenue stream from oil sales to offset sequestration costs.

Whereas porosity is a measure of the fraction of pore volume in a rock, the degree to which pore spaces in the rock are interconnected is described by its permeability, *k*. Permeability is a measure of a rock's ability to conduct fluids and is therefore a main rock property influencing the ease of extracting or injecting fluids into a reservoir. To account for permeability, the second screening criterion is defined as the permeability thickness product, *k*h. The net pay thickness, h, is the reservoir thickness (measured in ft) that is sufficiently saturated with oil that it produces economic quantities of oil.[1] According to Kovscek (2002), reservoirs having *k*h values less than 10^{-14} m^3 (33.2427 md/ft) may not have economically viable flow rates for production or injection. Moreover, the product *k*h implies that thick reservoirs having lower permeability can have overall injection rates similar to thinner reservoirs having higher permeability.

The third screening criterion is oil gravity (API gravity or degree API) and provides a measure of how "light" (high API gravity) or "heavy" (low API gravity) an oil is considered. Lighter oils typically are predominated by shorter-chain and volatile hydrocarbons. Heavy oils contain fewer volatiles and are predominantly longer-chain hydrocarbons. By industry standard, API gravity is inversely proportional to the specific gravity of the oil and is determined by:

$$\text{API gravity} = 141.5/\text{specific gravity} - 131.5.$$

The equation demonstrates that oils with lower densities have higher API gravities and tend to flow more readily (have low viscosities). Moreover, miscibility with CO_2 is typically more readily attained with oils having higher API gravities (Jarrell and others, 2002). According to Kovscek (2002), reservoirs having oils with API gravities of less than 22 should be

[1]In this study, permeability is reported in millidarcys and net pay thickness in feet, yielding a permeability-thickness product expressed as md-feet (see Table 2.2). Kovscek (2002), however, used *k* expressed in m^2 and net pay thickness expressed in m. This yields a calculated permeability-thickness product in units of m^3. Multiply *k* in md by 9.869233 X 10^{-16} to obtain *k* in m^2. Multiply *k*h in md-ft by 3.008179 X 10^{-16} to obtain *k*h in m^3.

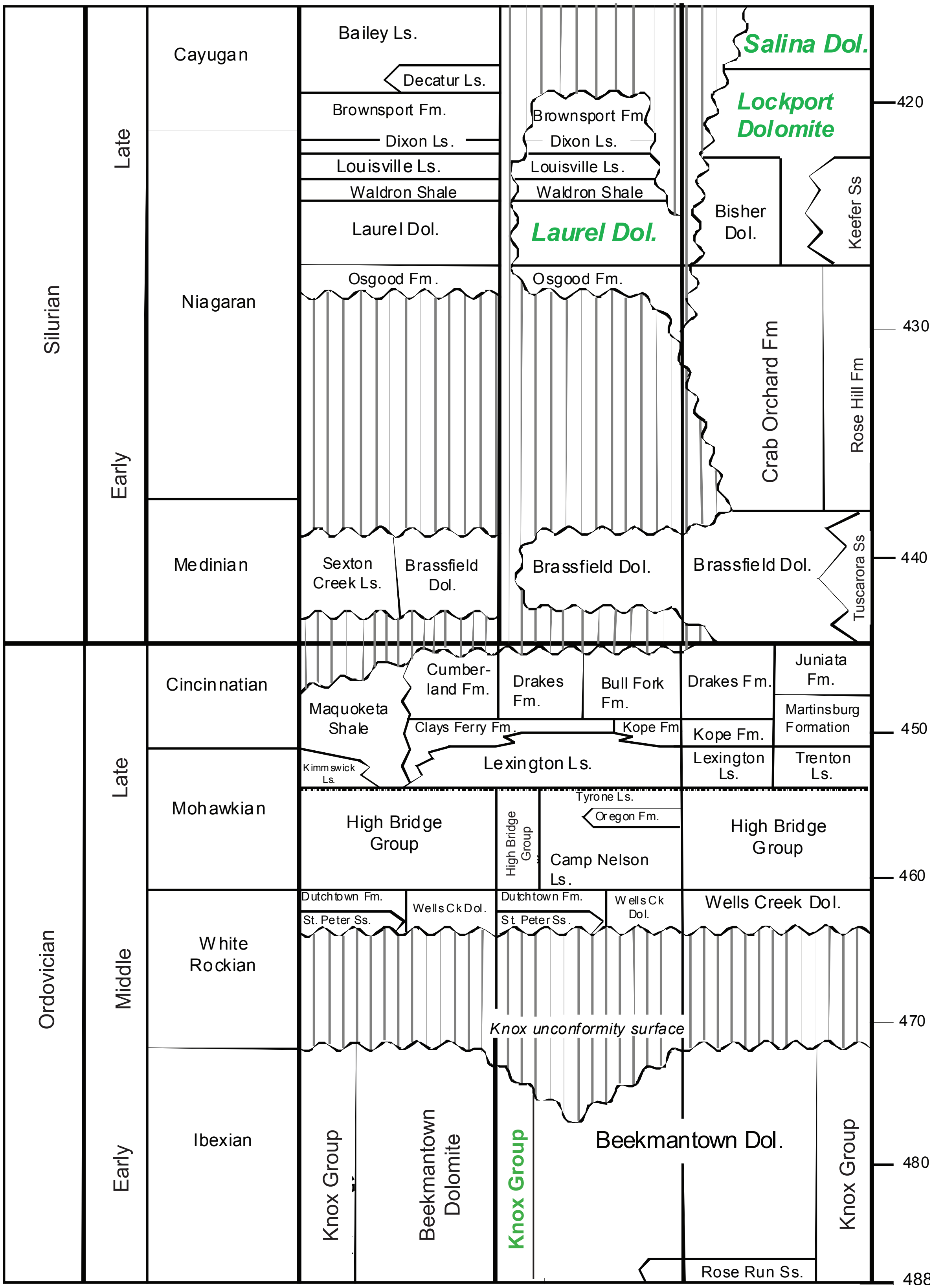

Figure 2.2c. General stratigraphy showing Silurian and Ordovician reservoirs of Kentucky. Names in green are reservoirs examined in this study.

Table 2.2. Measured and calculated pressures. MMP calculated from Cronquist correlation (Bank and others, 2007).

ID	*Initial Pressure, P_i (psi)*	*Current Pressure (psi)*	*MMP* (psi)*	*Fracture Pressure, P_f** (psi)*	*Pi-MMP*	*P_i-P_f*
1	*779.4*	85	839.9	1,080.0	–61	–300.6
2a	300.0	–	1,031.4	429.0	–731	–129.0
2b	*404.4*	–	944.3	560.4	–540	–156.0
3	350.0	50	957.2	546.0	–607	–196.0
4	320.0	50	944.3	621.6	–624	–301.6
5a	500.0	–	1,015.5	898.2	–516	–398.2
5b	*805.4*	–	1,196.6	1,116.0	–391	–310.6
6	460.0	110	880.2	1,410.0	–420	–950.0
7	750.0	215	1,008.0	1,818.0	–258	–1,068.0
8	200.0	174	921.9	1,080.0	–722	–880.0
9	700.0	200	986.9	1,920.0	–287	–1,220.0
10	556.0	490	997.5	1,881.6	–441	–1,325.6
11a	600.0	–	1,150.6	1,366.2	–551	–766.2
11b	*423.0*	–	1,021.8	586.2	–599	–163.2
11c	*769.9*	–	933.0	1,066.8	–163	–296.9
12	300.0	50	820.9	450.0	–521	–150.0
13	370.0	–	922.9	1,050.0	–553	–680.0
14	45.0	–	1,060.5	265.2	–1,016	–
15	450.0	300	1,034.5	1,140.0	–585	–690.0
16a	289.0	–	1,150.6	1,539.6	–862	–1,250.6
16b	632.0	–	993.1	1,234.8	–361	–602.8
16c	117.0	–	1,064.1	1,555.2	–947	–1,438.2
17	*757.8*	–	948.2	1,050.0	–190	–292.2
18	300.0	50	855.0	480.0	–555	–180.0
19	325.0	75	1,008.9	606.0	–684	–281.0
20	320.0	50	992.2	729.0	–672	–409.0
21	300.0	40	996.0	510.0	–696	–210.0
22	*682.8*	–	996.0	946.2	–313	–263.4
23	320.0	40	944.3	540.0	–624	–220.0
24	320.0	50	851.3	480.0	–531	–160.0
25a	555.0	–	1,083.7	843.6	–529	–288.6
25b	712.0	–	1,214.7	1,287.0	–503	–575.0
25c	1,000.0	–	1,132.7	1,569.6	–133	–569.6
25d	703.0	–	1,176.2	1,099.8	–473	–396.8
26	510.0	235	957.2	600.0	–447	–90.0
27	320.0	50	1,073.4	660.0	–753	–340.0
28	*757.8*	–	1,079.1	1,050.0	–321	–292.2
29a	227.0	–	1,150.6	1,065.0	–924	–838.0

Table 2.2. Measured and calculated pressures. MMP calculated from Cronquist correlation (Bank and others, 2007).

ID	*Initial Pressure, P_i (psi)*	*Current Pressure (psi)*	*MMP* (psi)*	*Fracture Pressure, P_f** (psi)*	*Pi-MMP*	*P_i-P_f*
29b	750.0	–	955.0	1,218.0	–205	–468.0
29c	700.0	–	1,214.7	1,536.0	–515	–836.0
30a	725.0	711	976.2	1,404.6	–251	–679.6
30b	*1,141.0*	–	1,085.4	1,581.0	56	–440.0
31	265.0	–	837.2	375.0	–572	–110.0
32a	725.0	–	1,034.5	1,070.4	–310	–345.4
32b	900.0	–	1,071.4	1,342.2	–171	–442.2
33	350.0	–	1,034.5	765.0	–685	–415.0
34	*281.5*	–	833.9	1,144.8	–552	–863.3
35a	*502.7*	–	900.3	696.6	–398	–193.9
35b	*422.2*	–	828.9	530.4	–407	–108.2
36	*1,013.2*	–	1,014.8	1,701.0	–2	–687.8
37a	*372.4*	–	831.6	870.0	–459	–497.6
37b	*336.9*	–	821.4	516.0	–485	–179.1
38	*601.9*	–	968.9	1,041.0	–367	–439.1
39	*751.3*	–	940.1	1,158.0	–189	–406.7
40	*467.6*	–	969.1	1,404.0	–501	–936.4
41a	*646.9*	–	910.3	896.4	–263	–249.5
41b	*433.0*	–	957.6	815.4	–525	–382.4
42a	*826.2*	–	859.6	834.0	–33	–7.8
42b	*738.7*	–	906.2	600.0	–168	138.7
43a	*1,227.6*	–	1,052.7	390.0	–175	837.6
43b	*1,042.7*	–	1,113.2	585.0	–71	457.7
44	*382.8*	–	808.3	466.8	–426	–84.0
45	*516.1*	–	841.8	1,023.6	–326	–507.5
46	*835.7*	–	964.2	1,444.8	–129	–609.1
47	*657.0*	–	990.8	715.2	–334	–58.2
48	*588.4*	–	926.0	1,116.0	–338	–527.6
49	*657.0*	–	1,073.0	1,080.0	–416	–423.0
50	*268.5*	–	902.6	372.0	–634	–103.5
51a	*627.9*	–	937.8	720.0	–310	–92.1
51b	*519.6*	–	986.4	648.0	–467	–128.4

*Italicized initial pressures are calculated hydrostatic pressures = depth (ft) X 0.433 psi/ft
**Fracture pressure (P_r) = fracture gradient (0.6 psi/ft) X depth (ft)

Table 2.3. Reservoir parameters used to evaluate fields for EOR-sequestration.

ID	*(S_o) (ϕ)*	*S_o ϕ*	*Rank $S_o\phi$*	*(k) (h)*	*k*h*	*Rank Kh*	*API Gravity*	*Rank API*	*CO_2 (tons/ac-ft)*	*Rank CO_2 (tons/ac-ft)*	*Sum of Ranks*	*Rank of Sum*	*G CO_s (tons)*
6	(0.72) (0.17)	0.1224	1	(21) (27)	567	52	42.00	1	928.44	2	56	4	2,723,555
10	(0.44) (0.13)	0.0572	44	(21) (23)	483	56	42.00	1	923.40	3	104	13	2,251,974
11b	(0.345) (0.18)	0.0621	40	(308) (10)	3,080	22	40.00	11	291.58	18	91	11	141,722
16a	(0.46) (0.16)	0.0736	25	(58) (8)	464	58	41.00	10	803.21	12	105	15	351,579
30a	(0.47) (0.18)	0.0846	15	(750) (15)	11,250	3	42.00	1	820.60	10	29	1	1,614,908
32a	(0.49) (0.17)	0.0833	19	(150) (20)	3,000	23	36.00	26	293.56	17	85	9	851,593
35a	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	37.00	24	196.65	25	81	8	1,467,482
37a	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	36.00	26	322.24	15	73	5	548,759
37b	(0.67) (0.14)	0.0938	6	(309) (16)	4,944	5	36.00	26	920.18	4	41	2	9,936,925
39	(0.67) (0.14)	0.0938	6	(309) (16)	4,944	5	36.00	26	822.76	8	45	3	1,202,734
42a	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	37.60	21	165.56	36	89	10	533,036
42b	(0.36) (0.15)	0.0540	48	(85) (16)	1,360	33	42.00	1	201.18	23	105	15	298,210
43b	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	32.50	63	822.24	9	104	13	474,985
45	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	37.80	20	131.03	39	91	11	874,483
46	(0.67) (0.14)	0.0938	6	(309) (16)	4,944	5	36.00	26	114.55	43	80	7	5,352,434
47	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	34.39	39	901.73	5	76	6	395,244
1	(0.58) (0.1)	0.0580	43	(60) (9)	540	53	41.80	9	193.06	26	131	32	57,027
2a	(0.2) (0.19)	0.0380	59	(85) (15)	1,275	42	34.00	61	73.98	57	219	70	405,893
2b	(0.21) (0.15)	0.0315	61	(450) (10)	4,500	18	34.39	39	52.98	67	185	61	98,041
3	(0.31) (0.14)	0.0434	55	(34) (20)	680	50	34.39	39	71.43	58	202	66	225,404
4	(0.3) (0.16)	0.0480	53	(45) (22)	990	47	34.39	39	84.20	51	190	64	2,320,549
5a	(0.17) (0.18)	0.0306	62	(102) (15)	1,530	31	38.00	15	185.15	28	136	34	234,841
5b	(0.37) (0.14)	0.0511	49	(1,210) (13)	15,730	1	32.00	64	131.79	38	152	47	690,542
7	(0.43) (0.13)	0.0559	45	(21) (24)	504	55	42.00	1	901.73	5	106	17	3,500,971
8	(0.5) (0.09)	0.0450	54	(60) (15)	900	48	38.00	15	189.36	27	144	42	217,231
9	(0.38) (0.1)	0.0380	59	(21) (16)	336	60	42.00	1	937.99	1	121	28	2,147,619
11a	(0.186) (0.16)	0.0298	63	(38) (16)	608	51	34.39	39	76.62	55	208	68	251,089
11c	(0.38) (0.18)	0.0684	26	(85) (15)	1,275	42	34.39	39	178.68	32	139	40	485,716

Table 2.3. Reservoir parameters used to evaluate fields for EOR-sequestration.

ID	*(S_o) (ϕ)*	S_o ϕ	*Rank* $S_o\phi$	*(k) (h)*	*k*h*	*Rank Kh*	*API Gravity*	*Rank API*	CO_2 *(tons/ ac-ft)*	*Rank* CO_2 *(tons/ ac-ft)*	*Sum of Ranks*	*Rank of Sum*	*G* CO_s *(tons)*
12	(0.46) (0.18)	0.0828	20	(8) (20)	160	66	40.00	11	57.29	66	163	53	113,435
13	(0.51) (0.12)	0.0612	41	(2) (15)	30	70	37.30	23	180.77	29	163	53	715,836
14	(0.09) (0.12)	0.0108	69	(642) (12)	7,704	4	34.39	39	30.89	70	182	59	139,656
15	(0.43) (0.1)	0.0430	57	(100) (16)	1,600	29	36.00	26	199.64	24	136	34	319,422
16b	(0.18) (0.14)	0.0252	66	(75) (14)	1,050	44	34.39	39	835.68	7	156	51	1,431,560
16c	(0.12) (0.12)	0.0144	67	(105) (10)	1,050	44	39.00	13	224.86	20	144	42	1,214,352
17	(0.54) (0.1)	0.0540	47	(60) (9)	540	53	36.00	26	180.77	29	155	50	164,641
18	(0.31) (0.14)	0.0434	55	(300) (14)	4,200	19	38.50	14	61.61	64	152	47	526,615
19	(0.38) (0.16)	0.0608	42	(4) (25)	100	67	34.39	39	80.10	53	201	65	397,314
20	(0.44) (0.2)	0.0880	13	(11) (25)	275	64	38.00	15	99.58	45	137	37	549,662
21	(0.45) (0.17)	0.0765	24	(5) (56)	280	63	34.39	39	65.18	61	187	62	2,327,046
22	(0.55) (0.1)	0.0550	46	(60) (15)	900	48	34.39	39	149.40	37	170	57	486,696
23	(0.48) (0.17)	0.0816	22	(8) (36)	288	62	34.39	39	70.71	59	182	59	380,819
24	(0.5) (0.18)	0.0900	12	(12) (30)	360	59	38.00	15	61.80	63	149	45	180,209
25a	(0.46) (0.17)	0.0782	23	(309) (12)	3,708	20	36.00	26	119.32	41	110	20	84,490
25b	(0.46) (0.18)	0.0828	20	(184) (14)	2,576	25	34.39	39	175.19	34	118	23	518,190
25c	(0.42) (0.16)	0.0672	37	(58) (23)	1,334	41	34.39	39	230.78	19	136	34	409,135
25d	(0.35) (0.14)	0.0490	52	(105) (15)	1,575	30	36.00	26	813.44	11	119	25	638,742
26	(0.36) (0.14)	0.0504	51	(2) (30)	60	68	34.39	39	80.23	52	210	69	137,153
27	(0.46) (0.19)	0.0874	14	(10) (25)	250	65	34.39	39	87.59	49	167	56	2,357,058
28	(0.551) (0.1)	0.0510	50	(60) (8)	480	57	30.80	70	180.77	29	206	67	37,310
29a	(0.17) (0.17)	0.0289	64	(200) (17)	3,400	21	34.39	39	223.01	22	146	44	401,607
29b	(0.16) (0.16)	0.0256	65	(24) (14)	336	60	42.00	1	168.14	35	161	52	1,351,488
29c	(0.1) (0.14)	0.0140	68	(800) (15)	12,000	2	34.39	39	492.01	13	122	29	816,154
30b	(0.066) (0.15)	0.0099	70	(105) (13)	1,365	32	38.00	15	339.36	14	131	32	805,044
31	(0.44) (0.21)	0.0924	11	(95) (19)	1,805	28	42.00	1	45.98	69	109	18	310,051
32b	(0.37) (0.18)	0.0666	38	(150) (20)	3,000	23	36.00	26	177.00	33	120	26	1,087,450
33	(0.3) (0.14)	0.0420	58	(25) (40)	1,000	46	36.00	26	106.17	44	174	58	2,217,125

Table 2.3. Reservoir parameters used to evaluate fields for EOR-sequestration.

ID	*(S_o) (ϕ)*	*S_o ϕ*	*Rank $S_o\phi$*	*(k) (h)*	*k*h*	*Rank Kh*	*API Gravity*	*Rank API*	*CO_2 (tons/ac-ft)*	*Rank CO_2 (tons/ac-ft)*	*Sum of Ranks*	*Rank of Sum*	*G CO_s (tons)*
34	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	34.39	39	92.31	47	118	23	121,248
35b	(0.7) (0.16)	0.1120	2	(85) (16)	1,360	33	34.39	39	92.96	46	120	26	578,078
36	(0.67) (0.14)	0.0840	16	(85) (16)	1,360	33	36.00	26	92.31	47	122	29	649,158
38	(0.67) (0.14)	0.0938	6	(150) (16)	2,400	26	32.70	62	224.15	21	115	21	522,818
40	(0.45) (0.14)	0.0630	39	(2) (23)	46	69	31.00	65	297.00	16	189	63	73,843
41a	(0.67) (0.14)	0.0938	6	(150) (16)	2,400	26	31.00	65	125.48	40	137	37	2,057,343
41b	(0.67) (0.14)	0.0840	16	(85) (16)	1,360	33	36.00	26	64.40	62	137	37	1,149,154
43a	(0.7) (0.16)	0.1120	2	(85) (16)	1,360	33	37.00	24	84.83	50	109	18	630,443
44	(0.7) (0.16)	0.1120	2	(85) (16)	1,360	33	37.60	21	70.10	60	116	22	686,672
48	(0.67) (0.14)	0.0840	16	(85) (16)	1,360	33	34.39	39	118.19	42	130	31	406,466
49	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	31.00	65	77.14	54	151	46	361,224
50	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	31.00	65	46.73	68	165	55	220,330
51a	(0.34) (0.2)	0.0680	27	(309) (16)	4,944	5	31	65	74.80	56	153	49	563,167
51b	(0.7) (0.16)	0.1120	2	(85) (16)	1,360	33	34.39	39	57.31	65	139	40	3,996,011

scrutinized because miscibility with CO_2 and flow rates will be diminished.

The final ranking criterion is a measure of the theoretical effective storage capacity (ESC) in short tons of CO_2 per acre-ft of volume of each reservoir, expressed as:

$$\text{ESC (kilotons)} = 43{,}560 * \varphi * \rho * S_o * 0.001$$

where 43,560 is a constant equal to the volume of 1 acre of reservoir 1 ft thick and is used to convert density in short tons/ft^3 to density in short tons/acre-ft, ρ is the density of CO_2 in short tons/ft^3 at estimated reservoir conditions, and 0.001 is a conversion to kilotons. CO_2 in a reservoir may occur in any one of three phases (gaseous, liquid, and supercritical fluid), depending upon reservoir pressure and temperature, which are, in turn, proportional to depth. Given a unit volume of reservoir rock (an acre-ft), the storage capacity is an important function of CO_2 density and thus, by means of the hydrostatic and geothermal gradients, is an indicator of the relationship between ultimate storage capacity and reservoir depth.

To describe the total amount of CO_2 that can be stored in oil and gas reservoirs during and after the main phase of EOR, the mass was calculated using the equation adopted by the Capacity and Fairways Subgroup of the Geologic Working Group for the U.S. Department of Energy Regional Carbon Sequestration Partnerships (Carr and others, 2008):

$$G_{CO2} = A * h_n * \varphi * S_o * \rho * B * E, \text{ or effectively}$$
$$G_{CO2} = A * h_n * ESC * B * E$$

where A = area (acres), h_n = height of oil and gas column in the reservoir (i.e., net pay), φ = average reservoir porosity, S_o = oil saturation (i.e., total reservoir volume available for CO_2 storage assuming 100 percent displacement of oil), ρ = density of CO_2 at expected reservoir conditions (short tons/acre-ft), B = formation volume factor, which converts standard oil or gas subsurface volume at formation pressure and temperature (a value of 1 was used in this study), and E = estimated displacement efficiency of CO_2 with respect to all pore fluids. The density of CO_2 (ρ) was calculated using the National Institute of Standards and Technology (2008) online webbook for thermophysical properties (webbook.nist.gov/chemistry/fluid/). The displacement efficiency, E, and formation volume factor, B, were both assumed to equal 100 percent (i.e., 1.0) for all reservoirs considered; therefore, values for G_{CO2} represent theoretical maxima.

By definition, there is a direct relation between the ESC and G_{C02} for a reservoir. The effective storage capacity was selected as a comparison and evaluation criteria because the gross reservoir capacity, can be misleading. A reservoir with a large areal extent and large gross capacity is not necessarily superior to a smaller reservoir in which higher-density phases of CO_2 may be stored.

In this analysis, larger values for each of the screening criterion correspond to reservoir properties that are more favorable for CO_2-EOR. This relationship was used to rank the fields for each of the screening criteria. For example, the highest API gravity observed in the study was 42°, and fields having oils with this value were assigned a rank of 1 for this criterion (Table 2.1). The ranking values for each screening criteria were summed (Table 2.3, Sum of Ranks) to provide an aggregate ranking of the 70 reservoirs. Reservoirs having low sum of rank values should accordingly be more favorable for CO_2-EOR. For analysis and plotting purposes, fields were divided into quartiles based on their sum of rank values.

Results

The majority of fields and reservoirs in this study are shallow, with 87 percent at 2,500 ft or shallower. When analyzed versus depth, 90 percent of the fields have pressures less than hydrostatic and are therefore underpressured (Fig. 2.3). The apparent widespread distribution of underpressured fields underscores the importance of the relationship among P_i, MMP, and P_{max} within the context of evaluating fields for EOR potential. The relationship between P_i and MMP is shown schematically in Fig. 2.4, in which the black reference line represents the condition of P_i being equal to MMP. The fields show a wide range of values for P_i, but MMP values plot in a relatively narrow interval of 800 to 1,200 psi. The narrow range for MMP is accounted for by the relatively narrow range of temperatures (68–92°F) and API oil gravities (31–42°) that were input into the Cronquist correlation. The critical point demonstrated by Fig. 2.4 is that, with the exception of the Birk City field–Ste. Genevieve reservoir in Daviess and Henderson Counties, all of the fields plot in the area in which P_i is less than MMP; that is, above and to the left of the one-to-one line. The corollary to this observation is that practically all of the fields would not reach pressures sufficient for miscibility if the reservoirs were simply repressurized to the values for P_i (negative values for P_i-MMP in Table 2.2). If, however,

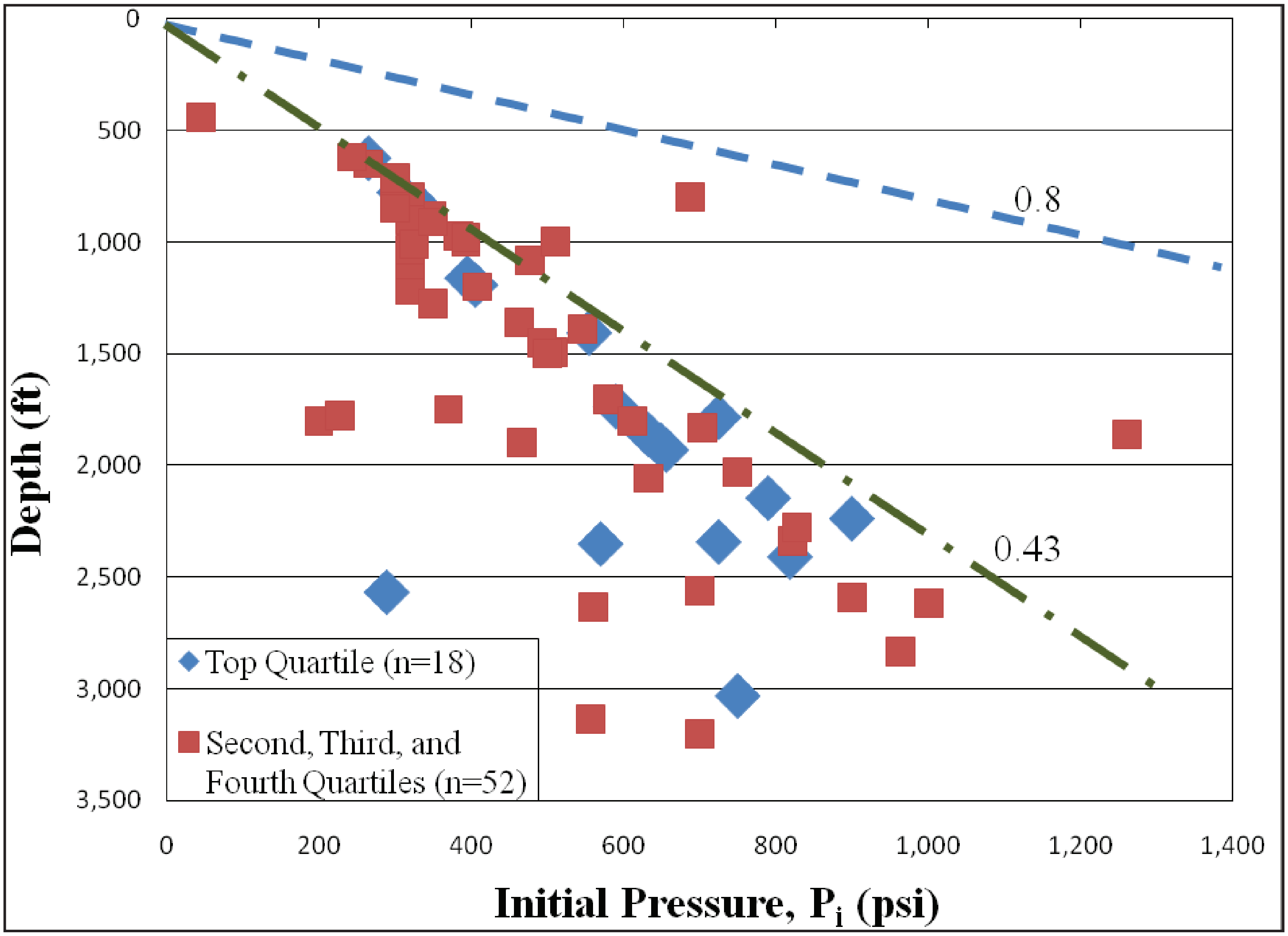

Figure 2.3. Initial reservoir pressure versus measured depth for fields (n = 40) in which pressures were documented before significant depletion.

the magnitude of repressurization equaled P_{max}, then 63 percent of the fields would have pressures that exceeded the MMP values (Fig. 2.5, positive values for P_{max} – MMP in Table 2.2). Importantly, pressurization in the fields where P_{max} is greater than MMP would produce reservoir conditions conducive to miscibility between CO_2 and oil.

Our analysis shows that 18 fields-reservoirs make up the upper quartile in terms of their aggregate score ("Sum of Ranks," Table 2.3), based on reservoir and oil properties favorable for CO_2-EOR sequestration. The Big Lime reservoir in the Bulan and Bull Creek Fields in eastern Kentucky is the only carbonate reservoir represented in the upper quartile. Of the remaining clastic fields, 83 percent are Mississippian Chester sandstones belonging to the Waltersburg, Hardinsburg, Bethel, and other reservoirs in western Kentucky.

Nearly 67 percent of the reservoirs in the upper-quartile fields occur at 1,500 ft or deeper (Fig. 2.3). Within the context of potential miscibility, all of the fields, except three, have values for P_{max} that exceed MMP (Fig. 2.3, Table 2.2). The three fields-reservoirs for which this relative pressure relation does not hold include the Chester sandstones in the Taffy and Cane Run Fields in western Kentucky. The Chester sandstone reservoirs in these fields are less than 1,000 ft deep.

Discussion

The analysis and ranking of fields into quartiles represents the composite influence of multiple reservoir and fluid properties (Table 2.3). Because the ranking criteria were taken from sources (Kovscek, 2002; Carr and others, 2008) that analyzed EOR and sequestration in a broader and more general context, we felt it

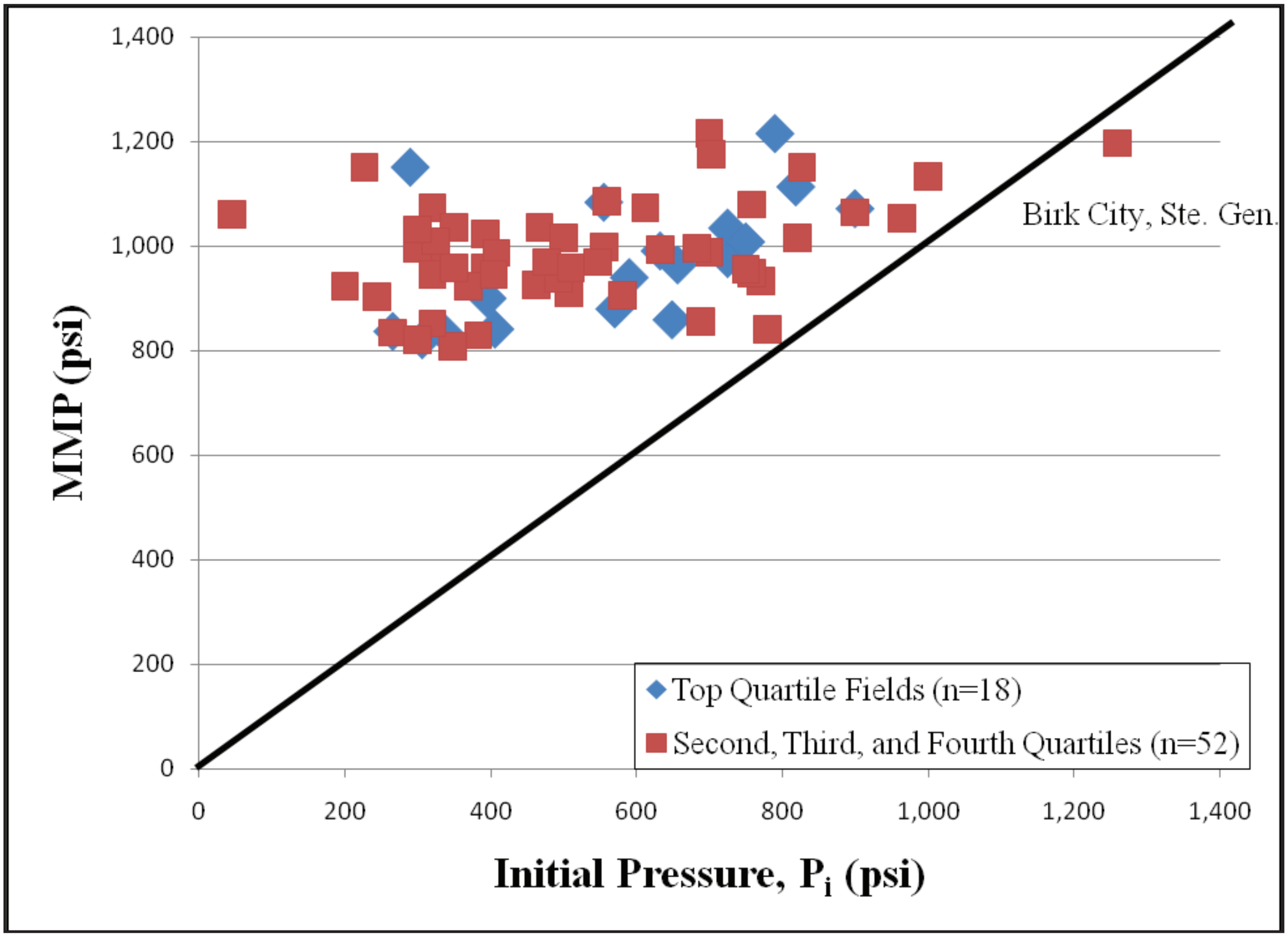

Figure 2.4. Relative relationship between P_i and MMP for fields-reservoirs. The black line is a one-to-one relationship between P_i and MMP. Only one reservoir lies below this line, suggesting that it may be near-miscible. Fields that lie above the line are likely immiscible.

was important to determine which criterion or criteria tended to characterize fields in the upper versus lower quartiles. Going forward, recognition of such criteria might assist in analysis of other fields in and outside of Kentucky not analyzed in this study. The distributions of fields in the upper versus lower three quartiles were first analyzed for each of the four screening criteria (Table 2.3). The distribution of the criterion, ln(kh), provides a representative example in which fields-reservoirs in the upper quartile plot at higher values, whereas fields-reservoirs in the lower three quartiles tend to be distributed across the full range of values (Fig. 2.5). If the distribution of ln(kh) is truly representative of the other screening criteria, this suggests that no single criterion can be used to define fields-reservoirs most prospective for EOR-sequestration. Alternatively, if pairs of screening criteria are related, then cross-plots of those criteria might exhibit distinct clusters that group into quartile populations. To investigate this hypothesis, the covariance of each of the screening criteria was calculated. The variances along the main diagonal of that matrix were used to calculate the correlation coefficients between each pair of parameters (Davis, 1986, p. 34–41). Table 2.4 is the lower half of the correlation coefficient matrix, the main diagonal of which indicates the perfect correlation of each individual parameter distribution with itself. Table 7 of Crow and others (1960, p. 241) indicates that the only statistically valid correlation ($r=0.3235$) is between the natural log of the CO_2 storage capacity in short tons/acre-ft and the API gravity (significant at the 95 percent level of confidence, $\alpha=0.05$). Figure 2.6 shows the distribution of the natural log of the permeability thickness product in the top quartile. Figure 2.7 is a cross-plot of these parameters, and although the top-quartile-ranked fields generally occur to the upper right

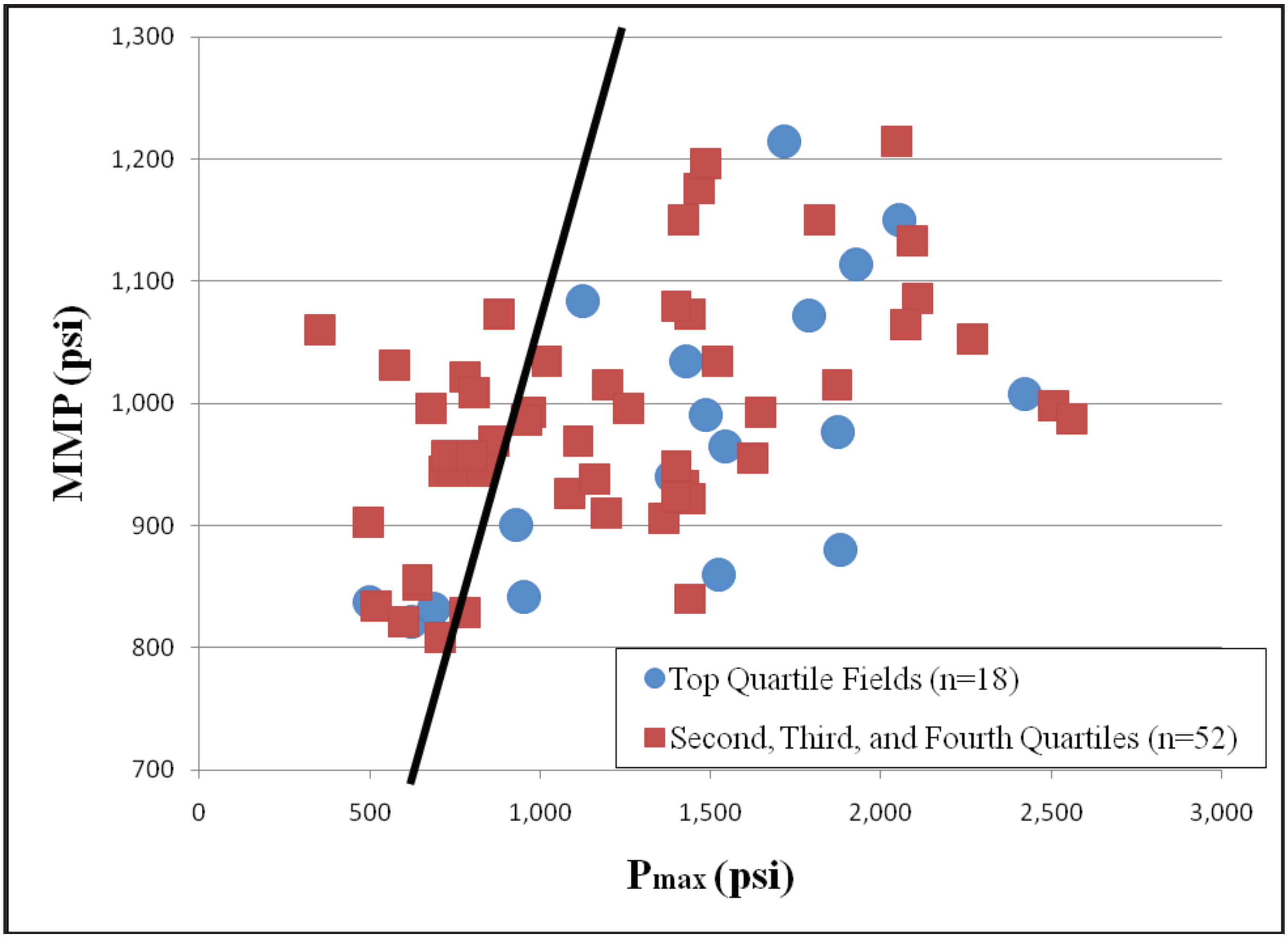

Figure 2.5. Relative relationship between P_i and P_f for fields-reservoirs. The black line is a one-to-one relationship between P_i and P_f. Note that three reservoirs fall below this line and one lies on the line, indicating these reservoirs may be brought up to the initial pressure without fracturing the reservoir rock (their P_i < Pf), whereas the other reservoirs lie above the line, indicating they cannot be brought up to initial reservoir pressure without fracturing the reservoir rock (their $P_i > P_f$).

of the chart, the scatter is a clear indication of the generally poor correlation.

In the absence of screening criteria that individually or as pairs clearly distinguish a particular oil field as being better than another for CO_2-EOR, all of the assessed parameters must be evaluated subjectively. If each of the four main screening criteria is divided along quartile boundaries, the higher-ranked fields tend to have two or more assessed criteria in the top quartile of the distribution, whereas the other fields have two or fewer criteria in their respective top quartiles. The top-quartile fields also tend to have zero or one criterion in the lowermost (less than 25 percent) quartile for that criterion. The ranking of a field (Table 2.3, Rank of Sums) thus represents the composite and complex influence of the four screening criteria. Because of this, we recommend that not too much emphasis be put on the absolute score of any given field, but rather on where that field falls in the broader quartile distribution.

Estimation of CO_2 storage capacity was one of the study objectives (Table 2.3, GCO_2). Because storage capacity was not used in the ranking process, many fields with large estimated capacities relative to the other fields did not fall into the upper quartile; for example, the Tar Springs reservoir in the Utica Field (ID 51b) equals 4,405,000 short tons. For all fields in the upper quartile, total estimated CO_2 storage capacity equals 35,088,000 short tons. This mass represents 44 percent of the capacity (79,134,000 short tons) for all of the analyzed fields. The values for GCO_2 in Table 2.3, however, represent theoretical maxima, and actual storage capacities could be significantly lower by half or more. The reason for the large potential error is because of the efficiency factor, E, which was assumed to equal 1.0, representing 100 percent displacement efficiency of the oil. We recognize that this assumption is grossly overly simplistic, but more meaningful measures of E will require determination of factors such as irreducible water saturation, partitioning of CO_2 between the free phase and dissolution in water, and sweep efficiency.

The complex interplay among the screening criteria in deciphering which fields are most prospective for CO_2-EOR and sequestration underscores the importance of reservoir pressure relative to MMP. As noted, approximately 63 percent of the analyzed fields have values of P_{max} that are greater than MMP and therefore could attain miscible or near-miscible conditions if the reservoirs were pressurized to values equal to P_{max} (Fig. 2.5). Over the course of an EOR project, the increase to pressures equal to P_{max} will be transient, with a pressure decay occurring upon cessation of CO_2 injection. Nevertheless, care should be taken that during injection reservoir pressures do not exceed values for P_{max} and certainly not pressures equal to those at a lithostatic gradient at 1.0 psi/ft, along which reservoir and seal rocks are more likely to be fractured. Improved characterization of reservoir pressure can be attained using pressure transient tests on injection and production wells (Jarrell and others, 2002).

Many fields in Kentucky have used waterfloods as a method to recover additional oil. The response of the reservoir during the waterflood may provide important information on how it will respond using CO_2 as a tertiary recovery method. Specifically, waterflood response can provide information on reservoir heterogeneity related to facies changes or structural discontinuities. Such heterogeneities will affect sweep efficiency of the injected CO_2, and placement of injection and production wells should be guided by this information along with other pertinent geologic and engineering data (e.g., geologic structure). As a rule of thumb, good waterfloods may indicate a good CO_2-EOR project; however, a bad waterflood will most likely produce an even worse CO_2 flood (Jarrell and others, 2002). The potentially significant difference between the performance of a waterflood and CO_2-EOR projects results from the lower viscosity and density of CO_2, which make it buoyant and more mobile in the reservoir.

Because fields in Kentucky tend to be underpressured and below the MMP values needed to attain miscibility (Fig. 2.5), it might be appropriate to implement a waterflood prior to CO_2 injection. In doing so, the reservoir would be largely pressurized with water, allowing subsequently injected CO_2 to better interact with the oil. Injection of water before or after CO_2 injection (water-alternating-gas; WAG) should be done with caution inasmuch as it might change the formation wettability characteristics and prevent CO_2 from contacting oil in the reservoir (Jarrell and others, 2002).

Other factors that should be considered and tasks to be undertaken when evaluating a CO_2-EOR project include, for example, source of CO_2, reservoir modeling to predict incremental oil recovery, economic forecasting, infrastructure, and logistics. Consideration of these factors is beyond the scope of this report; refer to Jarrell and others (2002) for a comprehensive treatment. Plugging standards have changed over time; many wells considered properly abandoned for their time may not meet modern standards. Moreover, there is the issue of wells that were illegally or improperly abandoned. Improperly plugged and abandoned wells, along with producing wells with poor cement jobs, represent possible pathways for injected or stored CO_2 to migrate to the surface. This is an issue for the obvious reasons of project safety and protecting groundwater quality, but also because fugitive CO_2 is not available to enhance oil recovery. The issue of leaking wellbores is especially critical for CO_2-EOR projects that might be conducted as pattern floods with multiple producing wells. The issue is less critical for single-well cyclic projects, although with a large-volume CO_2 injection it is possible that the radius of influence could extend into the surrounding wells. Thus, confirmation of good wellbore integrity should be a fundamental part of any planned CO_2-EOR project, and contingencies should be made for possible wellbore remediation.

Summary

1. Seventy oil reservoirs in 51 oil fields from the Illinois Basin, Appalachian Basin, and central Kentucky were analyzed for their potential for CO_2-EOR and CO_2 storage.
2. Analysis of initial reservoir pressures (P_i) using data mostly from the TORIS database, and drillstem and production test data from the KGS online database, show that most (90 percent) Kentucky oil reservoirs were under-pressured (that is, below hydrostatic pressure) even before pressures were reduced as a result of production, Moreover, initial

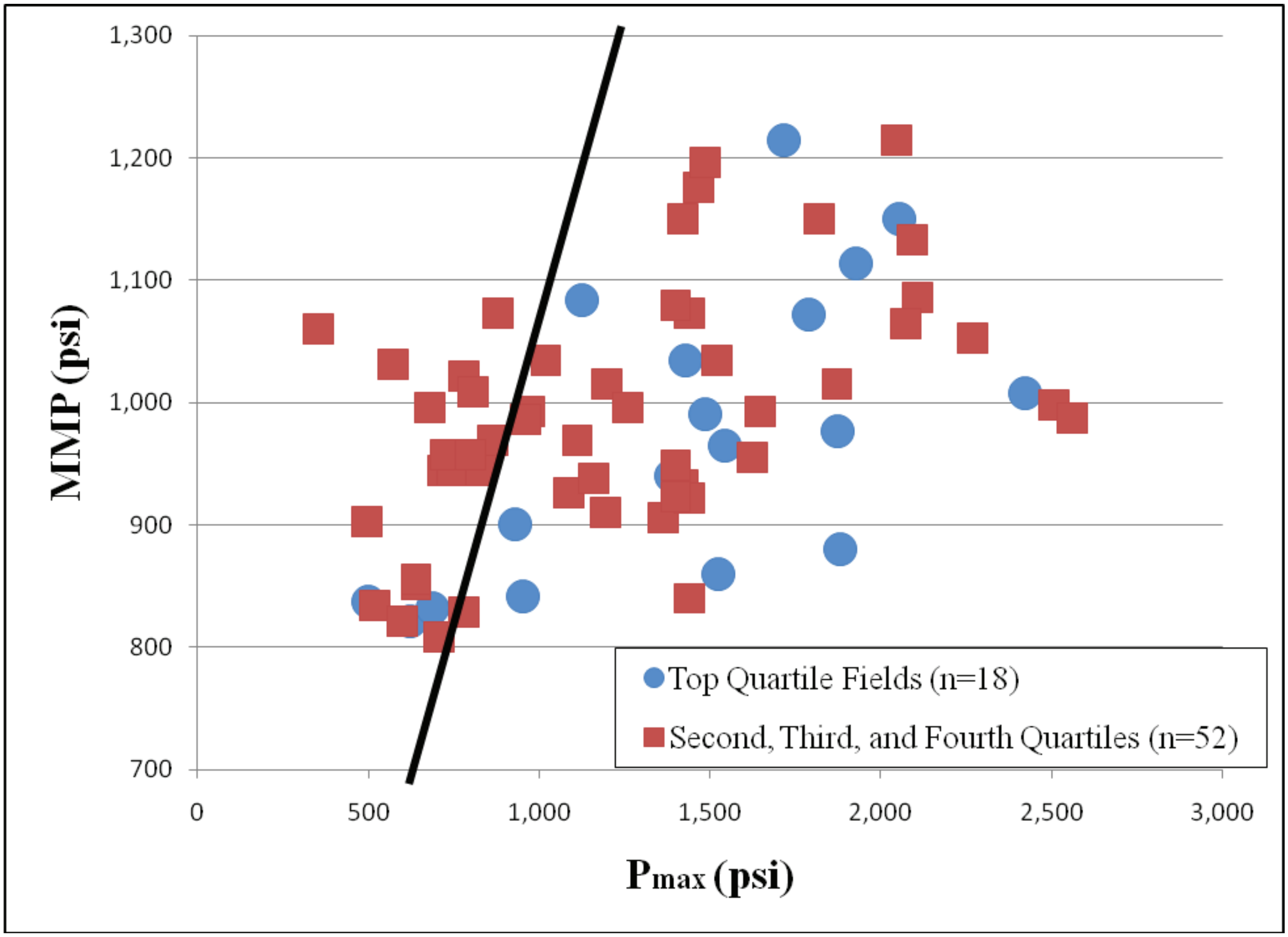

Figure 2.6. Relative relationship between P_{max} and MMP for fields-reservoirs. The black line is a one-to-one relationship between P_{max} and MMP. Fields to the right of the black line might reach miscible or near-miscible conditions with pressurization to P_{max}, whereas fields to the left will mostly remain immiscible.

Table 2.4. Correlation coefficients, r, of each pair of assessment parameters (Kovscek, 2002).

r	*So*ϕ*	*ln (tons/ac-ft)*	*ln (kh)*	*API*
*So*ϕ*	1.0000			
ln (tons/ac-ft)	–0.0743	1.0000		
ln (kh)	–0.0064	0.0827	1.0000	
API	0.0050	0.3235	–0.1721	1.0000

reservoir pressures were well below the calculated minimum miscibility pressures.

3. If, however, reservoir pressures are increased to a magnitude equal to the recommended maximum allowable injection pressure (P_{max}) as defined by the U.S. Environmental Protection Agency, 53 percent of the fields would have pressures sufficient to attain miscible or near-miscible conditions.
4. The reservoir and fluid parameters $S_o\varphi$, *k*h, API oil gravity, and CO_2 storage capacity, as defined by Kovscek (2002) and Carr and others (2008), were used to assess and rank fields into quartiles based on their potential for CO_2-EOR and CO_2 storage.

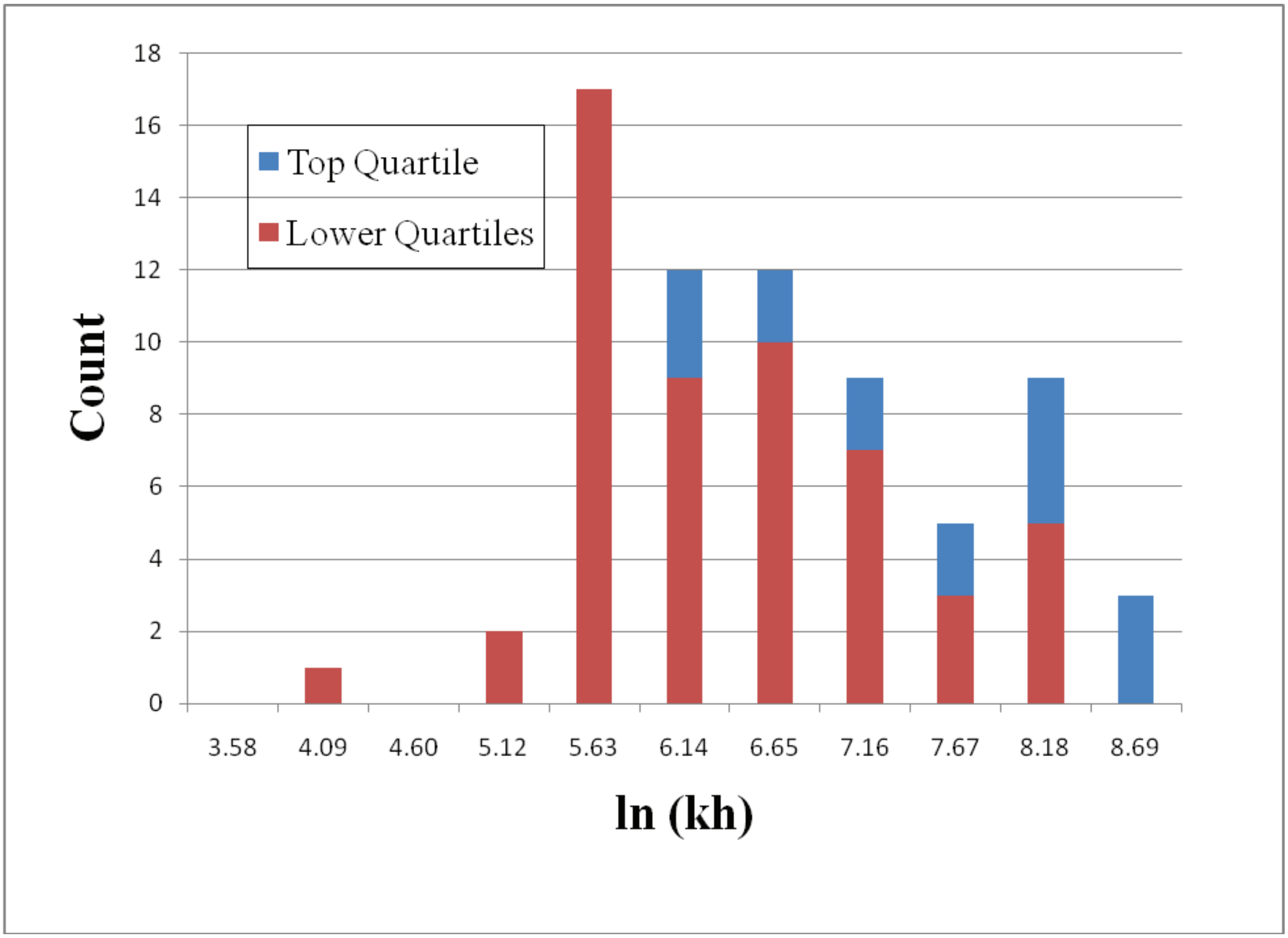

Figure 2.7. Distribution of the natural log of the permeability thickness product showing counts of top-quartile values.

5. Of the 18 fields-reservoirs in the upper quartile, 83 percent are in Mississippian Chesterian sandstone reservoirs in western Kentucky. Sixty-seven percent of the upper quartile fields occur at depths of 1,500 ft or deeper and 83 percent have values for P_{max} that exceed MMP.
6. Statistical analysis of the ranking parameters shows that no single parameter or combination of two parameters accounts for fields being ranked in the top quartile. Instead, top-quartile ranking appears to result from the composite influence of all ranking parameters.
7. Gross estimated CO_2 storage capacity in all analyzed fields-reservoirs (n=70) equals 79,134,000 short tons, of which 44 percent (35,088,000 short tons) occurs in the upper-quartile fields.

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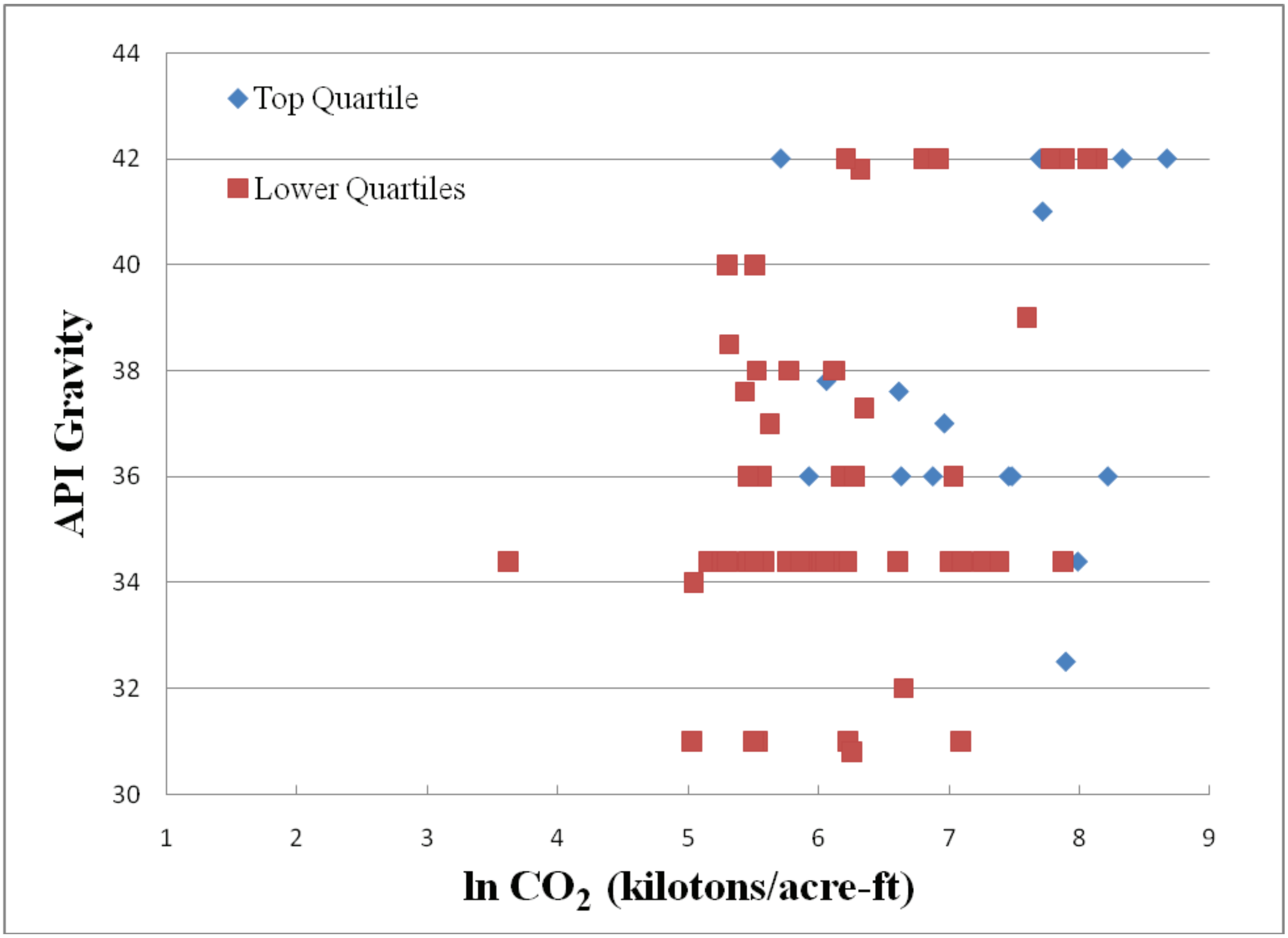

Figure 2.8. Cross-plot of CO_2 storage capacity (short tons/acre-foot) and API gravity.

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