ABANDONED WELL CHARACTERIZATION: A METHODOLOGY TO EVALUATE REGIONAL HYDRAULIC CONTROLS ON FLOW FROM HYDROCARBON RESERVOIRS INTO UNDERGROUND SOURCES OF DRINKING WATER

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Prepared for

American Petroleum Institute

Bureau of Economic Geology
W. L. Fisher, Director
The University of Texas at Austin
University Station, Box X
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EXECUTIVE SUMMARY

Between 1859 and 1990 approximately 3.3 million wells for oil and gas exploration and production were drilled in the U.S., of which nearly 2.4 million have been shut-in, temporarily abandoned, or plugged and abandoned (World Oil, 1992). Several major petroleum basins in the country contain large populations of these wells. Because drilling, completion, and abandonment practices for wells have evolved over the years, older wells that were found to be unproductive (or dry), or which had to be permanently shut-in for mechanical problems or economic reasons, may not have been adequately plugged according to modern standards or regulations. In some instances, upward movement of salt water in such abandoned wells may pose a risk of contamination to underground sources of drinking water (USDWs).

Three main conditions must exist for contamination of a USDW to occur by fluid migration from an oil and gas production zone or a waste disposal zone: (1) presence of a USDW overlying the zone; (2) presence of unplugged or inadequately plugged abandoned wells (or natural geologic pathways) that penetrate both a production or disposal zone and a USDW; and (3) an upward-directed hydraulic gradient between the zone of interest and the USDW. The first condition exists in many of the petroleum-producing areas in the U.S. However, the second and third conditions may or may not occur. In particular, the third condition depends in part upon the changes in pressure due to fluid withdrawal and injection associated with enhanced recovery or salt-water disposal (Class II wells).

Proposed changes to the U.S. Environmental Protection Agency's Underground Injection Control program would require calculating an area of review (AOR) around each Class II well and assessing the mechanical integrity of abandoned wells within that area. A screening methodology to prioritize AOR studies can allow operators and regulatory agencies to identify areas where natural hydraulic conditions may be conducive to brine migration. The Bureau of Economic Geology (BEG) has developed such a methodology that uses primarily computerized data bases and computer mapping software in a three-step process. First, bottomhole and surface tubing pressure data from oil and gas reservoirs are converted to hydraulic heads. Second, average, regional potentiometric surfaces are generated for aquifers and reservoirs. Third, differences in hydraulic heads between aquifers and reservoirs are calculated to regionally delineate residual areas of upward (positive) or downward (negative) hydraulic gradients. Locations of abandoned wells and Class II injection wells can be plotted relative to residuals to examine where waterflooding, pressure maintenance, and salt-water disposal may cause or exacerbate the potential for upward flow.

State and Federal agencies were surveyed regarding the availability of data on petroleum production and on injection for enhanced oil recovery, salt-water disposal, and storage. The results of this survey indicate that most reservoir and injection data are maintained on paper rather than in digital format, rendering mapping of data at a regional scale difficult. On the basis of this survey, we selected the San Juan Basin in New Mexico and Colorado, the greater Permian Basin in Texas and New Mexico, and the South Texas Basin as case studies to test the hydraulic screening methodology. Digital data on reservoir pressures and the locations of abandoned wells were obtained from national data bases maintained by Petroleum Information, Inc. (PI). For the Texas study areas, reservoir pressure data from PI were supplemented using data bases available at the BEG. USDW data and data on Class II injection were obtained from various State and Federal agencies. For purposes of economy and ease of data manipulation, the data obtained from PI consisted of ten-year averages of pressure measurements per reservoir and counts of abandoned wells at a 0.1° latitude × 0.1° longitude scale. Because of a lack of data on initial formation pressures, the highest available values were taken as representative of pre-production conditions.

In the San Juan Basin, the sparseness of mappable reservoir pressure data from PI led to the construction of a composite, computer-generated potentiometric surface for the oil and gas reservoirs. This surface primarily overlaps USDW aquifers in Tertiary formations in the center of the basin and, to a lesser extent, USDW aquifers in older formations at the margins of the basin, so that some mapped areas of upward hydraulic gradient are poorly constrained spatially. Some positive residuals approximately coincide with areas of upward hydraulic gradients reported by other authors, such as along the San Juan River. Pre-production hydraulic gradients appear to be directed downward where abandoned wells are most numerous.

In comparison, reservoirs were divided by age and by depth into four hydrostratigraphic units each in the greater Permian and South Texas Basins, for which reservoir pressure data are more numerous. In the greater Permian Basin, positive residuals in the Pecos River valley and along the Eastern Shelf may reflect natural discharge of basinal brines, although positive residuals in the eastern Delaware Basin, Central Basin Platform, and western Midland Basin contradict downward gradients mapped by other authors. In the South Texas Basin, the density of abandoned wells is greatest where positive residuals are concentrated. Positive residuals in the South Texas Basin appear to result from natural geopressuring in formations deeper than 6,000 ft (1,800 m), which are negligibly affected by Class II injection wells. However, given the sparseness of bottomhole pressure measurements, the linkage of mapped positive residual areas with natural hydraulic phenomena or Class II injection in the three basins is speculative.

Focusing on abandoned wells within positive residuals as a "first cut" reduces the approximate number of abandoned wells for primary examination from 6,104 to 1,000 in the San Juan Basin, from 395,176 to 80,185 in the greater Permian Basin, and from 77,050 to 21,145 in the South Texas Basin. These numbers are reduced further when other factors such as age and distance from Class II wells are taken into account. However, in this study, those factors have only been examined in a limited fashion, and other risk factors such as wellbore conditions, depth, and completion and abandonment practices have not been evaluated. Moreover, plotting the centroids of $0.1° \times 0.1°$ cells containing abandoned wells, rather than the actual locations of such wells, permits only a semi-quantitative assessment of the numbers of wells potentially at risk. The use of positive residuals is insufficient for screening in instances where Class II injection reverses a downward hydraulic gradient. Nonetheless, the method is useful in providing a regional screen to identify areas where natural hydraulic conditions favor upward brine migration.

INTRODUCTION

Between 1859 and 1990 approximately 3.3 million wells for oil and gas exploration and production were drilled in the U.S., of which nearly 2.4 million have been shut-in, temporarily abandoned, or plugged and abandoned (World Oil, 1992). Several major petroleum basins in the country contain large populations of these wells. Because drilling, completion, and abandonment practices for wells have evolved over the years, older wells that were found to be unproductive (or dry), or which had to be permanently shut-in for mechanical problems or economic reasons, may not have been adequately plugged according to modern standards or regulations. In some instances, such abandoned wells may pose a risk of contamination to underground sources of drinking water (USDWs).

Three main conditions must exist for contamination of a USDW to occur by fluid migration from an oil and gas production zone or a waste disposal zone: (1) presence of a USDW overlying the zone; (2) presence of unplugged or inadequately plugged abandoned wells (or natural geologic pathways) that penetrate both a production or disposal zone and a USDW; and (3) an upward-directed hydraulic gradient between the zone of interest and the USDW. The first condition exists in many of the petroleum-producing areas in the U.S. However, the second and third conditions may or may not occur. In particular, the third condition depends in part upon the changes in pressure due to (1) fluid withdrawal and (2) fluid injection associated with enhanced oil recovery or salt-water disposal (Class II wells).

The potential for ground-water contamination varies with the type of Class II well. Two types of injection wells are used for enhanced oil recovery (EOR): waterflooding wells, in which oil is physically swept toward producing wells, and pressure maintenance wells. Both types of wells are used in mature fields where original field pressures may have been significantly depleted because of production. The presence of adjacent producing wells limits the magnitude and areal extent of repressurization around the injectors. In contrast, because salt-water disposal (SWD) wells are not used to increase oil production, brine may not always be injected into depressurized producing reservoirs. Initial fluid pressures in the disposal reservoirs may be hydrostatic, leading to overpressured conditions and upward fluid flow potentials.

This report examines the hydraulic conditions under which abandoned oil and gas wellbores proximal to Class II wells may become conduits for the migration of brines into overlying USDWs. Proposed changes to the U.S. Environmental Protection Agency's (EPA) Underground Injection Control (UIC) program would require calculating an area of review (AOR) around each Class II injection well and assessing the mechanical integrity of abandoned wells within that area (Smith and Browning, 1993). This report describes and evaluates in case studies a screening methodology that can help operators and regulatory agencies to prioritize AOR studies by identifying areas where natural hydraulic conditions may favor brine migration.

In this study, the screening methodology uses primarily computerized data bases and computer mapping software in a three-step process. First, bottomhole pressure and surface tubing pressure data from oil and gas reservoirs are converted to hydraulic heads. Second, average, regional potentiometric surfaces are generated for aquifers and reservoirs. Third, differences in hydraulic heads between aquifers and reservoirs are calculated to delineate regional residual areas of upward (positive) or downward (negative) hydraulic gradients. Locations of abandoned wells and Class II injection wells can be plotted relative to residuals to examine where waterflooding, pressure maintenance, and salt-water disposal may cause or build on the positive residuals, exacerbating the potential for upward flow. The methodology is useful in manipulating thousands of measurements to identify and prioritize areas for further evaluation either at a local scale or on the basis of other criteria not examined here. Such criteria, which are necessary for a complete determination of the risk of contamination, include the mechanical integrity of wells; the presence of cement plugs, mud, or wellbore fluids; the mechanical competence of intervening formations; and the presence of intervening nonproductive zones that might draw water from both USDW and hydrocarbon-producing zones.

Three petroleum-producing regions were used in case studies for testing the method: the South Texas Basin, the greater Permian Basin in Texas and New Mexico, and the San Juan Basin in New Mexico and Colorado (fig. 1). The South Texas Basin is informally defined to include the Maverick Basin, part of the Rio Grande Embayment, and the Austin Chalk Trend. The greater Permian Basin is informally defined to include the Central Basin Platform, the Northwestern, Southern, and Eastern Shelves, and the

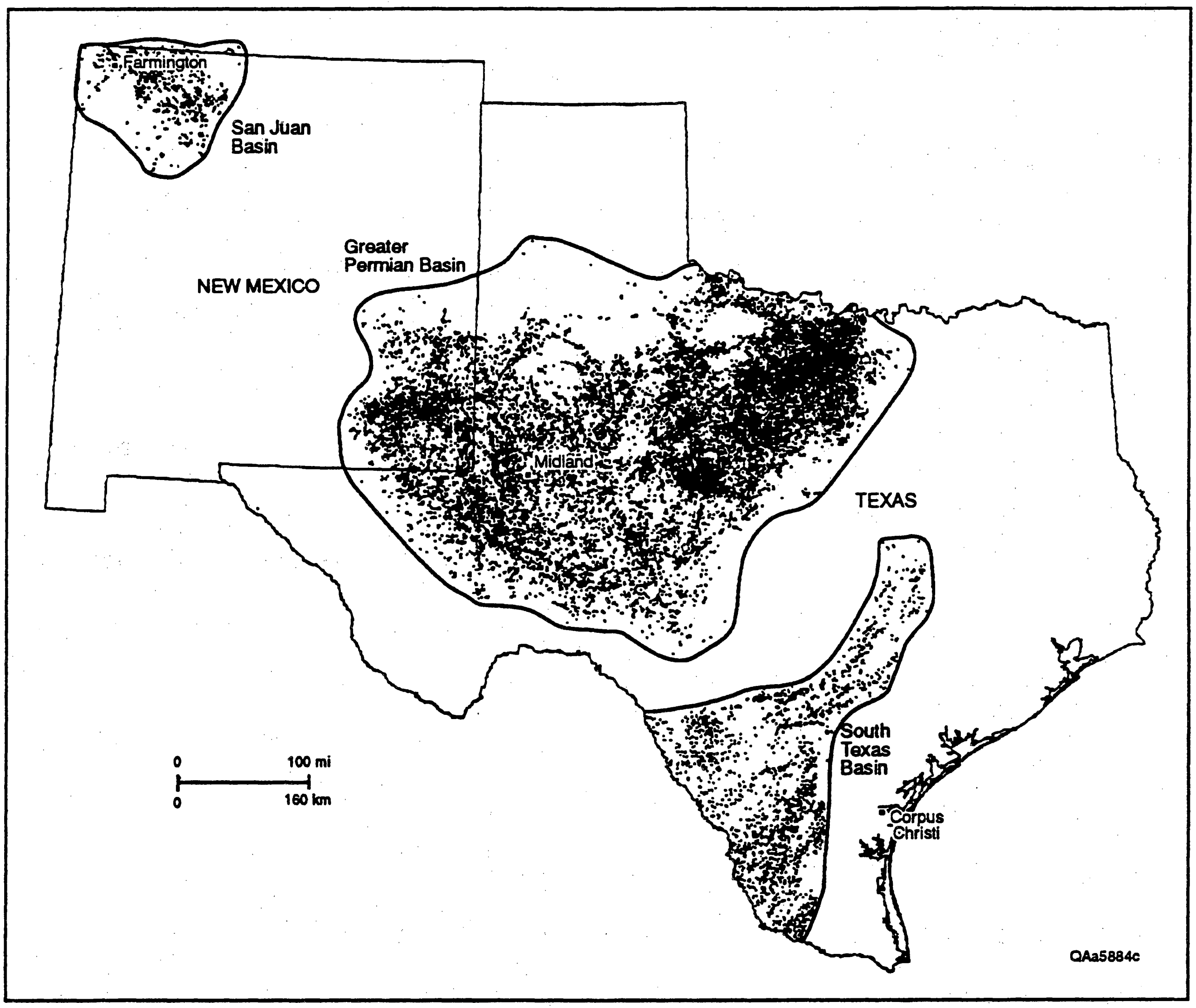


Figure 1. Outlines of study areas; dots indicate locations of individual oil and gas reservoirs.

Delaware, Midland, Val Verde, Hardeman, and Fort Worth Basins. These basins were selected because oil, gas, and ground-water data were available in digital as well as "hard-copy" format, thus making graphical manipulation of thousands of measurements feasible.

The following section outlines the fundamentals of the methodology: (1) data acquisition, review, and processing, including mapping and comparison of hydraulic head in oil- and gas-bearing zones and in USDWs, (2) determination of abandoned well distributions, and (3) analysis of pressure changes resulting from injection or disposal operations, including calculation of the area of review exposed to Class II injection wells.

METHODS

Data Acquisition, Review, and Processing

The potential for contamination of USDWs through abandoned oil and gas wells is based on the principle that fluid flows from areas of higher to lower hydraulic head (higher to lower potential energy) (Freeze and Cherry, 1979, p. 18–26). As depicted in figure 2, hydraulic head at any point in a porous medium is equal to the sum of the elevation head and the pressure head at that point:

$$h = z + \psi \qquad (1)$$

where h is hydraulic head (elevation of water column, in ft relative to sea level), z is elevation head (elevation of stratum, in ft relative to sea level), and ψ (pressure head, in ft) = p / γ, where p is fluid pressure (psi) and γ is specific weight of the fluid (psi/ft). A pressure value at a given point in a reservoir will yield different head values for fluids of different density. Fresh water has a specific weight of 0.433 psi/ft, whereas a Na-Cl brine containing 104,000 ppm (112,000 mg/L) total dissolved solids (TDS) has a specific weight of 0.465 psi/ft (Weast, 1980, p. D-262).

In descriptive terms, hydraulic head is the elevation to which a column of formation fluid (equivalent column of ground water) would rise by the force of fluid pressure in a tube connected to the formation and open to the atmosphere (as in a well). If the formation is confined (overlain by less permeable strata), the fluid might rise in a well above the top of the formation. The potentiometric surface of a formation is a plan-view representation of all hydraulic heads measured in different wells penetrating that formation. The surface is based on the assumption that hydraulic head does not vary vertically within the formation and commonly is used to infer probable direction of lateral fluid flow.

Figures 3 and 4 illustrate scenarios of downward- and upward-directed fluid flow, respectively. The unconfined USDW aquifer in both instances is isolated from an underlying hydrocarbon-bearing zone and/or target water injection zone by an intervening confining unit. In figure 3 the potentiometric surface of the hydrocarbon-bearing zone is lower than the potentiometric surface of the USDW unit, which can

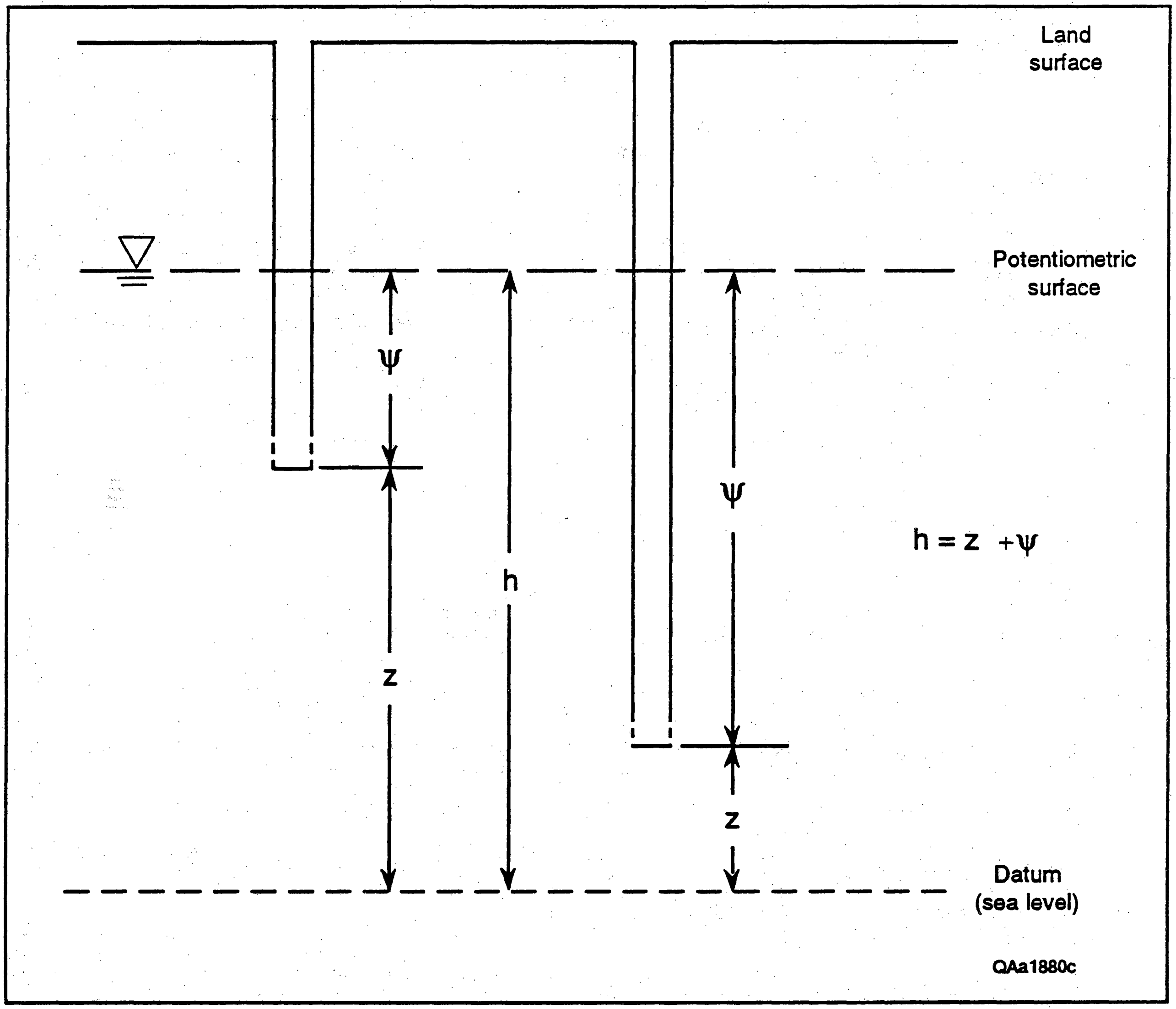


Figure 2. Schematic representation of hydraulic head (h), pressure head (Ψ), and potentiometric surface.

cause migration of fresh ground water downward through an improperly-plugged abandoned borehole toward the lower hydrocarbon-producing zone. This scenario is reversed in figure 4, where the higher potentiometric surface of the hydrocarbon zone could cause fluid to flow upward through an improperly-plugged abandoned borehole into the overlying USDW. However, contamination of a USDW by fluids from an oil and gas reservoir can occur only where (1) the hydraulic head of the fluid in the oil and gas reservoir is higher than the hydraulic head of the water in the USDW (assuming that both have been penetrated by the abandoned wellbore) and (2) the wellbore conditions and the intervening strata provide an open pathway for flow.

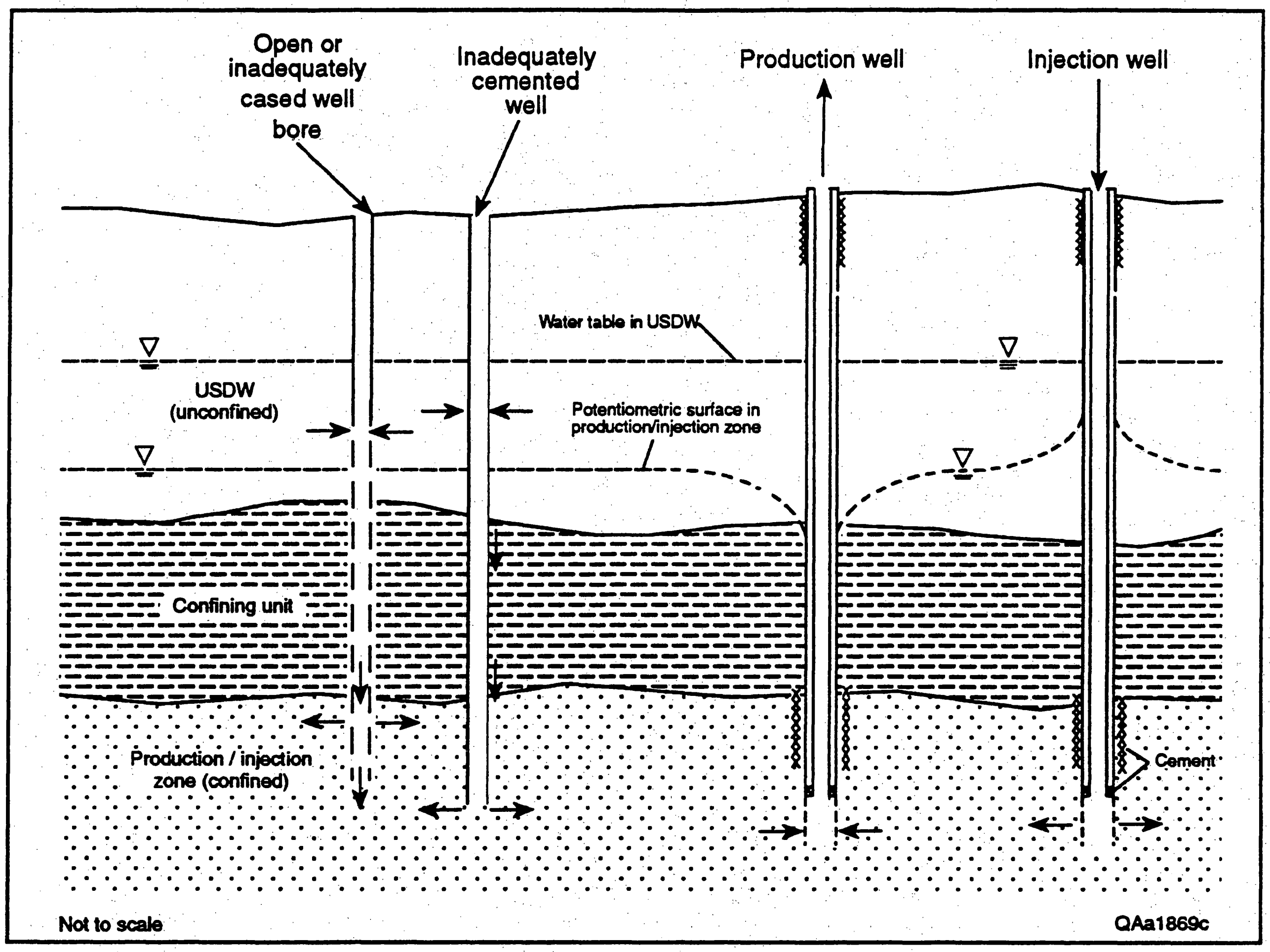


Figure 3. Schematic representation of downward flow from USDW to underlying hydrocarbon-producing zone through inadequately plugged wells.

The key to geologically characterizing areas where potentials exist regionally for contamination of USDWs from abandoned wells is the acquisition and review of reservoir pressure data. Most of the reservoir data used in this study were obtained from the national Well History Control System (WHCS) and Petroleum Data System (PDS) data bases (Petroleum Information, Inc. [PI], unpublished data, 1989). Additional pressure data for the greater Permian Basin and the South Texas Basin were extracted from other data bases (U.S. Department of Energy, Bartlesville Project Office, unpublished data, 1989; Dwight's Energydata, Inc., unpublished data, 1990; Garrett and others, 1991; Holtz and others, 1991) and combined with the PI data. Hydraulic-head measurements for USDWs were obtained from the U.S. Geological Survey (USGS) (for New Mexico and Colorado) and the Texas Water Development Board (TWDB).

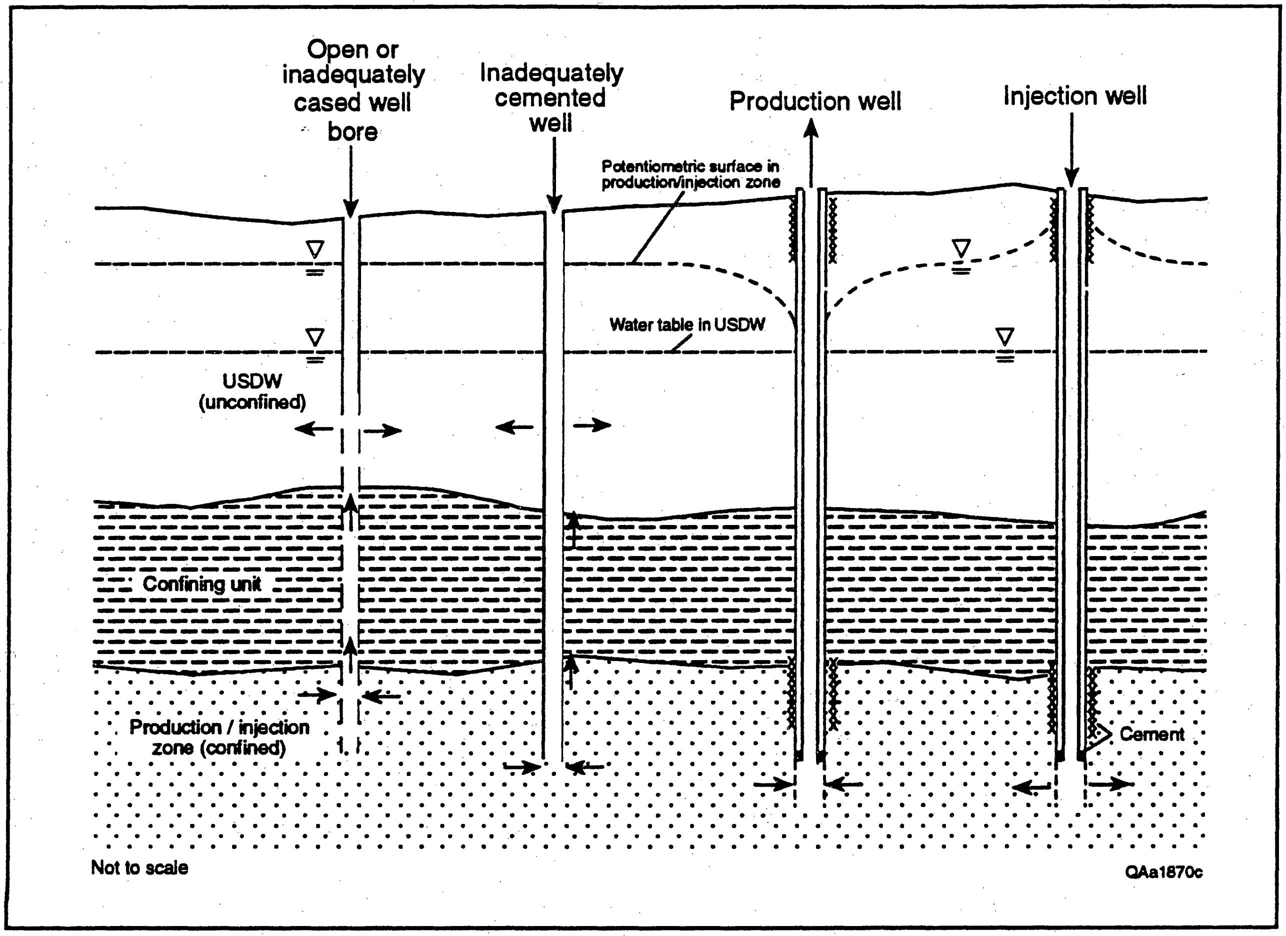


Figure 4. Schematic representation of upward flow from underlying hydrocarbon-producing zone to USDW through inadequately plugged wells.

Because of the regional scope of the case studies, each reservoir was represented by a single pressure value. For purposes of economy and ease of data manipulation, the data obtained from PI consisted of ten-year averages of pressure measurements per reservoir. We selected the maximum averaged pressure reported for each reservoir on the assumption that maximum values represent "pre-development" conditions. The Code of Federal Regulations (CFR) specifies that hydraulic-head buildup due to Class II injection shall be calculated relative to "pre-development" hydraulic head in AOR calculations (40 CFR §146.6) (U.S. Office of the Federal Register, 1987). The assumption of "pre-development" conditions can be assessed by examining pressure-depth profiles of oil and gas reservoirs. For undeveloped reservoirs in which fluid flow is predominantly horizontal (hydrostatic conditions), bottomhole pressure (BHP) ideally increases with depth along a straight line whose slope is equal to the specific weight of the fluid. Where production has depressurized a reservoir, the pressure measurements are subhydrostatic, falling below the line.

For these studies, BHP data from oil and gas production zones and enhanced recovery and saltwater disposal injection wells were converted to hydraulic head for comparison to hydraulic head in USDWs. In some instances, prior to calculating values of reservoir hydraulic head, it was necessary to calculate BHPs from shut-in tubing pressures (SITPs) measured at land surface according to the formula

$$\text{BHP (psi)} = [\text{depth (ft)} \times \text{gradient (psi/ft)}] + \text{SITP (psi)} \qquad (2)$$

where the gradient represents an empirical extrapolation between SITPs and BHPs. To determine gradients, reservoirs in the PI data base were matched to reservoirs in other data base(s) containing both the surface and bottomhole pressures. If the surface shut-in pressures were found comparable in the two data bases, then an average fluid gradient was computed from the other data base(s) and applied to the PI data for determining the bottomhole pressure. Although rigorous calculations of BHPs from SITPs require information on fluid-phase segregation in tubing, the empirical conversion factors were workable substitutes.

Maps of hydraulic head (potentiometric surfaces) in oil and gas reservoirs (combined) and in individual USDWs were contoured utilizing the graphical software package CPS-1 (Radian Corporation, 1979) installed on a VAX 11/780 mainframe computer. Although execution time is likely to be faster on a mainframe, mapping programs (including another version of CPS) are available for personal computers. Optimal values of mapping parameters such as the search radius and the grid spacing (Jones and others, 1986) were determined by trial and error for each study area, based upon how well the maps generated using various values of parameters honored the input data.

The potentiometric surface of each aquifer was subtracted from that of each oil- and gas-producing horizon, again using the CPS-1 software program. The residual difference in hydraulic head between each pair of surfaces was then contoured. On each residual (or head-difference) map, negative residuals are defined where the hydraulic head in the oil and gas horizon is lower than in the aquifer, whereas positive residuals occur where the hydraulic head in the oil and gas zone is higher than in the aquifer. The residual maps thus provide a qualitative regional indication of where USDWs may be at risk of contamination by poorly-plugged or unplugged wells. However, these maps do not indicate areas where Class II injection may reverse an initially downward-directed hydraulic gradient or areas where initially positive residuals have been changed to negative residuals by oil and gas production.

Estimates of Abandoned Wells

Abandoned well totals were mapped at a 0.1° latitude × 0.1° longitude scale on the basis of ratios relative to total wells drilled. Two sources of information were combined to determine the number and distribution of plugged and abandoned wells in the study areas. The first was a listing of dry new-field wildcat wells compiled by PI at a 0.1° × 0.1° scale for purposes of economy. The second dataset, compiled by Gruy Engineering Corp. (1989, their table 1), consisted of the total number of abandoned wells for each basin within each state. This total included infield dry holes, plugged and abandoned producers, dry new-field/pool extension wells, and dry new-field wildcats. Gruy calculated the number of currently producing oil and gas wells for various basins in each state on the basis of annual reports of state regulatory agencies and 1987 statistical review of industry (World Oil, 1988). Gruy then obtained the number of abandoned wells in each state by subtracting the number of currently producing wells from the total number of wells in each state reported by the Independent Petroleum Association of America (1987). Finally, the number of abandoned wells was estimated for the various basins within each state in direct proportion to the number of producing wells within each basin.

The data from PI and Gruy Engineering Corp. (1989) were used to estimate totals of abandoned wells at a 0.1° × 0.1° scale using one procedure for the San Juan Basin and another for the greater Permian and South Texas Basins. For the San Juan Basin, the numbers of abandoned oil and gas wells other than dry new-field wildcats were estimated separately and then totaled. For each type of well (oil and gas), we divided the sum of abandoned producers and infield dry holes in the New Mexico portion (the largest portion) of the basin (from Gruy's table 1) by the total number of active and shut-in wells for the New Mexico and Colorado portions of the basin provided by PI. The ratios thus obtained (0.31 for oil, 0.11 for gas) were then multiplied by the number of active oil and gas wells in each $0.1° \times 0.1°$ cell.

For the greater Permian and South Texas Basins, the data from Gruy's table 1 were used to calculate:

- the ratio of abandoned producers to the total number of oil and gas producers;
- the ratio of dry infield wells to the total number of producers;
- the ratio of other dry wells (including dry wildcats) to the total number of producers; and
- the ratio of other dry wells to the total plugged and abandoned well count.

Because the studies of the greater Permian and South Texas Basins were conducted later than the study of the San Juan Basin, published industry trends (World Oil, 1989, 1990) were used to update the number of oil and gas producers as of the end of 1989. The updated number of producers was then used with the ratios derived from Gruy's table 1 to update totals of abandoned producers, infield dry wells, and other dry oil and gas wells. Lastly, the ratio of other dry wells to the total abandoned well count was updated and used with the PI dataset of dry wildcats to estimate the distribution of all abandoned wells at a $0.1° \times 0.1°$ scale.

Using ratios of different categories of wells at a basinal scale to estimate the distribution of all abandoned wells at a subbasinal ($0.1° \times 0.1°$) scale is likely to overestimate the number of abandoned wells in some areas and underestimate that number in others. In areas of limited exploration, the total population of abandoned wells may consist largely of dry wildcats, so that using the basin-wide ratio of other dry wells (dry wildcats) to all abandoned wells may overestimate the number of abandoned non-wildcats. Conversely, in areas in which production is concentrated, the ratio of other dry wells to all abandoned wells may be less than the ratio for the basin as a whole, leading to underestimates of the number of abandoned non-wildcats. However, for intensively explored basins, a reasonable estimate is probably obtained.

Quantifying the Effects of Injection and Disposal

The final part of the process of determining the hydraulic potential for contamination of USDWs was to present examples of areas where increases in formation pressure (and corresponding increases in hydraulic head) due to enhanced recovery injection or salt-water disposal could result in upward hydraulic gradients. Hydraulic head buildup for selected injection and disposal wells was calculated, based on injection rate, reservoir properties, and injection time, by means of the approximate solution to the Theis (1935) equation derived by Cooper and Jacob (1946):

$$\Delta h_i = (264 \times Q / T) \times \log [0.3 \times T \times t / (r^2 \times S)] \qquad (3)$$

where Δh_i = hydraulic head change (height of cone of impression) [ft] at radius r and time t

- Q = injection rate [gpm] (gallons per minute, calculated from injection reports)
- T = transmissivity [gpd/ft] (gallons per day per ft, from reservoir properties)
- S = storativity (or storage coefficient) [dimensionless] (from reservoir and injected fluid properties)
- t = time since injection began [days]
- r = radial distance from wellbore to point of interest [ft]

This solution is valid where the ratio $(r^2 \times S)/(4 \times T \times t) < 0.01$. The hydraulic head buildup was added to the elevation of the computer-generated potentiometric surface ("natural" hydraulic head) of the oil and gas reservoirs at the location of each injection or disposal well to arrive at a total head value which was then compared to the head values in overlying USDWs.

The hydraulic head buildup can also be viewed in terms of the AOR, which is defined as the area surrounding an enhanced-recovery injection or salt-water disposal well in which there is a pressure increase sufficient to cause migration of native or injected fluids into a USDW. The AOR is also sometimes referred to as an area of endangering influence, as opposed to the area of influence, within which there is any pressure increase due to injection. The buildup of hydraulic head around an injection well can be represented by a cone of impression (fig. 5), whose position relative to the potentiometric surface of the

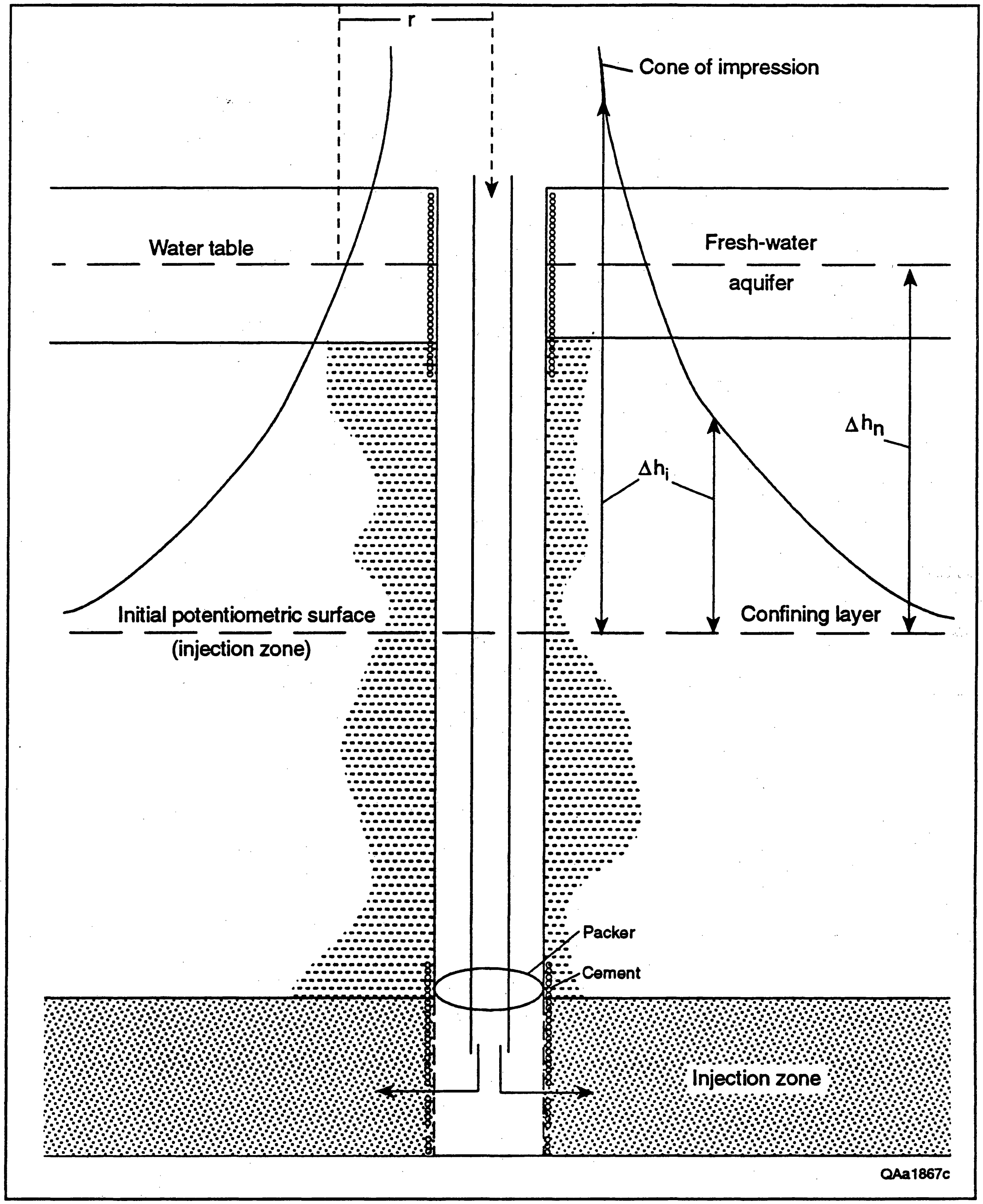


Figure 5. Schematic representation of the cone of impression around an injection well and its influence on the radius (r) of the area of review; Δh_n = "natural" (pre-injection) head difference between injection zone and USDW; Δh_i = head buildup due to injection (after Engineering Enterprises, Inc., 1988, fig. 3-1).

USDW determines the radius of the calculated AOR (r in eq. 3). In instances where the cone of impression is entirely below the USDW potentiometric surface, no upward flow can occur. If the pre-injection hydraulic head differential between the zone of injection and the overlying USDW is initially negative (downward-directed), the calculated AOR around that injection well is the area within which the head buildup is greater than the pre-injection differential. If the pre-injection differential is initially positive (upward-directed), the entire cone of impression represents the area of influence of the injection well. Appendix I summarizes the procedures described in the Code of Federal Regulations (U.S. Office of the Federal Register, 1987) for determining the AOR.

NATIONWIDE SURVEY OF DATA AVAILABILITY

Objective and Approach

The oil and gas industry in the U.S. operates more than 177,000 Class II wells, of which approximately 78 percent are used for EOR and approximately 22 percent are used for SWD (Daly and Mesing, 1993). As of 1986, 60 million barrels (bbl) of water were injected per day into subsurface formations in 39 geologic basins in 31 states (Michie & Associates, 1988). The industry also injects other types of fluids for enhanced recovery (natural gas, CO_2, air, polymers, and other chemicals), in many cases through wells that are also used for water injection. Non-water injection was excluded from this study because the total volume is much less than the volume of water injection and because the data are not as readily obtainable. The numbers of abandoned wells by state and by petroleum basin are compiled in tables 1 and 2 and illustrated in figures 6 and 7. In 1987, 21 states had programs administered directly by a state agency (primacy states), while the remaining states had UIC programs administered by EPA (direct-implementation states) (U.S. General Accounting Office, 1989, their table 1.1). Since 1987, Mississippi has also become a primacy state.

Various state agencies and EPA regional offices were queried to verify the extent of oil and gas activity and to determine the types and formats of available reservoir, injection, and disposal data. The

Table 1. Estimated numbers of abandoned wells by state, onshore U.S.A.

State	Aband. Wells [1]	Oil Wells[2]	Gas Wells[2]	Water Injection Wells[2,3]	SWD Wells[2]	Oil Produced (mbd)[4]	Gas Produced (mmcfd)[4]	Water Produced (mbd)[4]	Water Injected (mbd)[4]	Salt-Water Disposed (mbd)[4]	Area (m acres)[5]	Acres per Aband. Well (ratio)[6]
Texas	610204	200055	46080	36117	15532	2229.1	15516	25198.9	19225.8	5973.0	16500	27
Pennsylvania	279892	24000	24000	4315	1868	10.4	412	155.5	93.3	62.2	3047	11
Oklahoma	261431	103000	24500	14895	7897	408.5	5282	7753.0	7054.0	699.0	7161	27
Kansas	177355	49906	12057	9366	5536	183.7	1274	2357.6	943.0	1411.6	6633	37
Louisiana	135734	26418	14436	1275	3149	498.0	5066	3984.0	400.0	2160.0	3789	28
Ohio	100042	29659	32721	127	3829	36.8	499	40.0	4.6	28.6	3328	33
Illinois	98528	31100	190	12631	1917	74.6	4	3135.1	2978.3	156.8	880	9
California	86417	54629	1546	14825	641	1037.1	1141	7244.7	4816.4	1507.3	427	5
Kentucky	70235	21844	9515	5311	106	17.7	200	212.9	134.1	78.8	1210	17
West Virginia	64175	15895	32500	687	74	8.6	397	25.8	18.1	7.8	7807	122
Indiana	57336	7164	1220	2919	386	13.0	1	547.6	520.2	27.4	438	8
Wyoming	38247	15122	2161	5257	679	334.9	1636	4520.1	1306.1	2578.7	2660	70
Michigan	30863	5125	755	1028	627	70.4	361	197.1	128.1	69.0	650	21
Colorado	29948	5598	4580	825	158	81.3	480	971.4	937.4	34.0	1556	52
New Mexico	26563	17557	16761	3855	307	206.8	1898	936.9	777.6	159.3	3822	144
Arkansas	22838	9700	2550	239	979	43.3	429	860.0	171.8	688.2	1032	45
Montana	22481	4680	2023	1196	256	74.4	132	445.6	434.0	40.0	984	44
Mississippi	20549	3732	717	304	677	82.2	570	910.1	273.0	637.0	700	34
Nebraska	15418	1814	16	523	98	19.4	4	205.8	80.0	123.0	335	22
North Dakota	7233	3838	98	155	252	125.1	199	217.5	77.4	182.6	643	89
Utah	6163	3773	160	456	46	107.3	653	314.4	225.2	62.5	504	82
New York	5553	4400	5038	3248	6	2.3	94	24.1	22.8	1.3	964	174
Tennessee	3893	873	921	8	3	1.8	9	3.0	2.0	1.0	560	144
Alabama	2798	861	1029	147	94	58.0	401	243.0	39.9	203.0	371	133
Missouri	1746	300	0	450	10	0.5	0	2.0	1.9	0.1	13	7
Alaska	1136	1191	104	327	9	1866.6	3788	473.6	1666.4	53.3	229	202
South Dakota	904	146	42	30	11	4.4	7	8.1	1.6	0.8	36	40
Florida	853	113	0	56	18	25.7	27	188.5	149.1	118.7	37	43
Arizona	453	23	0	0	7	0.4	1	0.9	0	0.6	6	13
Nevada	347	27	0	0	8	8.0	0	1.0	0	1.0	5	14
Virginia	201	28	581	0	0	0.1	41	0.1	0	0	147	731
TOTAL = 31	2179536	642571	236301	120572	45180	7630.4	40522	61178.2	42482.1	17066.6	66473	30 (avg.)

Notes:

(1) Number reported is the sum "total dry holes" (including infield dry holes and wildcats) + "abd prod" (oil) + "abd prod" (gas), from 1987 data in Gruy (1989, table 1).

(2) Number of wells active in 1986; data from Michie & Associates (1988, table 1).

(3) Does not include salt-water disposal wells.

(4) Average daily volume (mbd - thousands of barrels per day, mmcfd - million cubic ft per day); 1986 data from Michie & Associates (1988, table 1).

(5) Producing area (in thousands of acres); 1987 data from Gruy Engineering Corp. (1989, table 1).

(6) Number of acres (value in preceding column of this table x 1000) divided by number of abandoned wells (value in first column of data in this table).

Table 2. Estimated numbers of abandoned wells by basin, onshore U.S.A.

Basin	Aband. Wells [1]	Oil Wells[2]	Gas Wells[2]	Water Injection Wells[2,3]	SWD Wells[2]	Oil Produced (mbd)[4]	Gas Produced (mmcfd)[4]	Water Produced (mbd)[4]	Water Injected (mbd)[4]	Salt-Water Disposed (mbd)[4]	Area (m acres)[5]	Acres per Aband. Well (ratio)[6]
Appalachian	479051	80815	104527	8385	5863	64.6	1640	312.2	140.8	164.5	11975	25
North and Central Texas Area	277421	70027	13050	11619	6086	371.3	2270	2945.7	2066.4	879.4	3682	13
Illinois	163347	53555	1505	20861	2323	100.1	7	3832.0	3633.0	199.1	1730	11
Sedgwick	123884	33252	3449	6635	3804	134.4	153	1710.9	683.2	1027.0	1627	13
Permian	123845	74156	6442	21347	3669	1156.0	3282	17453.0	15651.0	1802.0	4794	39
Anadarko and Dalhart	121595	46122	22216	5151	3336	176.2	5138	2648.5	2334.3	315.2	6927	57
Sabine/Lasalle/Monroe Uplift	108500	26426	11366	1259	1504	118.7	1105	1377.0	491.8	987.2	2308	21
Central Oklahoma Platform	79825	71000	9205	10278	5449	281.4	1329	5349.0	4867.0	481.0	2762	35
South Texas Area	76273	18376	9677	2214	2301	225.1	4965	1125.6	787.9	337.7	3120	41
Gulf Coast	68349	15383	5163	732	3842	557.2	5335	5214.3	604.5	3084.0	2438	36
San Joaquin	49322	39712	223	11906	388	738.1	481	4066.1	1937.0	1122.6	200	4
Delaware	47695	17163	3686	2631	674	200.3	1241	400.7	360.7	40.1	1197	25
East Texas Salt	46385	15904	5530	765	962	277.1	2017	2123.1	387.8	1735.3	1416	31
Forest City	40002	13614	478	1416	571	18.9	15	248.5	100.3	147.9	381	10
Michigan	30863	5125	755	1028	627	70.4	361	197.1	128.1	69.0	650	21
Denver	27261	4136	3716	487	121	39.5	264	316.3	236.1	76.4	996	37
Ventura	22331	14917	28	2919	219	299.0	183	3172.5	2879.5	378.1	95	4
Hugoton Embayment	20558	4236	8130	2080	1229	40.3	1106	523.5	209.4	314.1	4765	232
Powder River	18671	6192	377	2108	336	127.3	239	427.8	223.2	217.8	1192	64
Williston	15854	5246	1019	341	335	181.7	261	434.7	224.2	195.2	1030	65
South Alberta	15019	3024	1000	73	33	12.1	67	133.0	24.0	5.2	556	37
Sacramento	14728	0	1295	0	34	0	477	6.2	0.0	6.7	131	9
Big Horn	13495	6875	632	3058	357	153.0	424	3864.1	1251.9	2194.8	881	65
Mississippi Salt Dome	13260	2076	507	143	277	44.4	346	549.8	164.9	385.0	385	29
Arkoma	8703	0	4595	0	10	0.02	663	2.0	0.0	2.0	1253	144
San Juan	6366	3070	13449	390	39	23.4	913	98.9	81.7	17.0	2491	391
Paradox	5746	1550	0	364	11	27.3	110	95.0	146.3	9.2	173	30
Findlay Arch	5084	593	654	0	3	0.7	10	0.2	0.0	0.2	665	131

(continued on next page)

Table 2. (continued).

Basin	Aband. Wells [1]	Oil Wells[2]	Gas Wells[2]	Water Injection Wells[2,3]	SWD Wells[2]	Oil Produced (mbd)[4]	Gas Produced (mmcfd)[4]	Water Produced (mbd)[4]	Water Injected (mbd)[4]	Salt-Water Disposed (mbd)[4]	Area (m acres)[5]	Acres per Aband. Well (ratio)[6]
Smackover region	4958	2262	213	337	458	109.6	434	714.6	286.0	507.8	438	88
Piceance	4559	1131	601	393	23	37.2	118	608.0	603.1	4.9	373	82
Canon City-Florence	4527	403	228	170	53	12.4	27	143.1	131.6	11.5	280	62
Uinta	2891	2300	160	92	35	83.2	550	219.4	79.0	53.3	393	136
Black Warrior	2754	303	1026	15	47	4.3	217	32.3	4.0	28.3	262	95
Green River	2163	1872	993	841	109	53.7	756	116.8	33.8	66.6	558	258
Washakie	1888	472	303	197	26	9.8	226	197.5	57.1	112.7	80	42
Beaufort Shelf	594	976	0	272	8	1818.5	3001	383.2	1555.1	53.1	175	295
South Florida	586	65	0	12	7	7.6	1	44.8	7.1	37.8	23	39
Cook Inlet	557	215	104	55	1	48.1	787	90.4	111.3	0.2	54	97
Eocene	387	27	0	0	8	7.9	0	1.0	0	1.0	6	15
Kingman	0	0	0	0	0	0	0	0	0	0	0	0
Mississippi Embayment	0	0	0	0	0	0	0	0	0	0	0	0
Ocala Uplift	0	0	0	0	0	0	0	0	0	0	0	0
Great Basin	0	0	0	0	0	0	0	0	0	0	0	0
Snake River Downwarp	0	0	0	0	0	0	0	0	0	0	0	0
Georgia	0	0	0	0	0	0	0	0	0	0	0	0
Crazy Mountain	0	0	0	0	0	0	0	0	0	0	0	0
Central Nebraska	0	0	0	0	0	0	0	0	0	0	0	0
Rio Grande Rift	0	0	0	0	0	0	0	0	0	0	0	0
Willamette Downwarp	0	0	0	0	0	0	0	0	0	0	0	0
Olympic Uplift	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL = 50	2179515	642571	236302	120574	45178	7630.9	40519	61178.8	42483.1	17070.8	62462	29 (avg.)

Notes:

(1) Number reported is the sum "infield dry holes" + wildcats + "abd prod" (oil) + "abd prod" (gas) (totalled for portions of basins which extend into more than one state), from 1987 data in Gruy Engineering Corp. (1989, table 1); number of wildcats was assumed to be the number of dry holes other than infield dry holes, and estimated for each basin by the formula: ["total dry holes" (state total) - "infield dry holes" (state total)] x "infield dry holes" (basin total) / "infield dry holes" (state total).

(2) Number of wells active in 1986; data from Michie & Associates (1988, table 2).

(3) Does not include salt-water disposal wells.

(4) Average daily volume (mbd - thousands of barrels per day, mmcfd - million cubic ft per day); 1986 data from Michie and Associates (1988, table 2).

(5) Producing area (in thousands of acres); 1987 data from Gruy Engineering Corp. (1989, table 1).

(6) Number of acres (value in preceding column of this table x 1000) divided by number of abandoned wells (value in first column of data in this table).

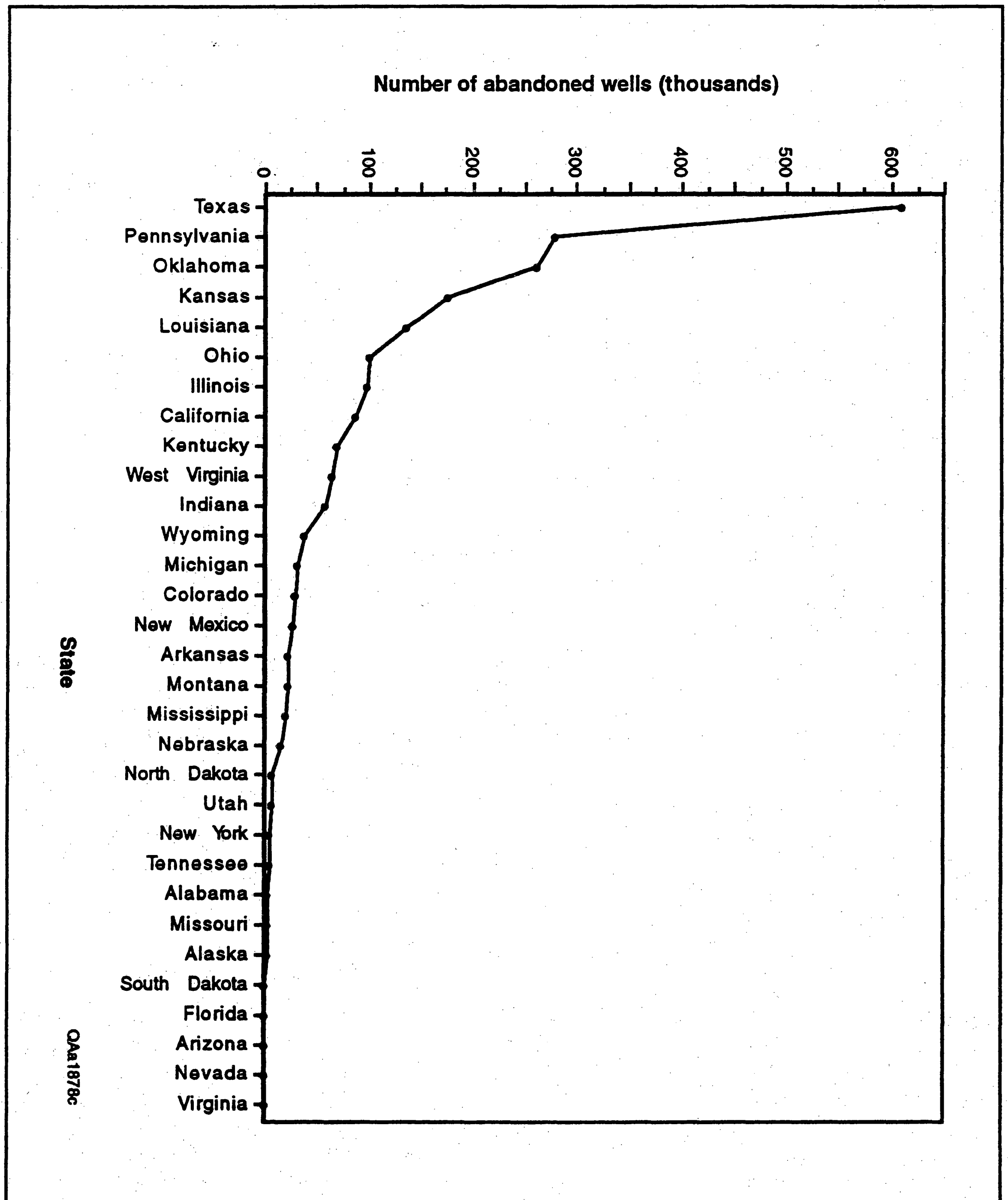


Figure 6. Estimated distribution of abandoned wells by state, onshore U.S.A.

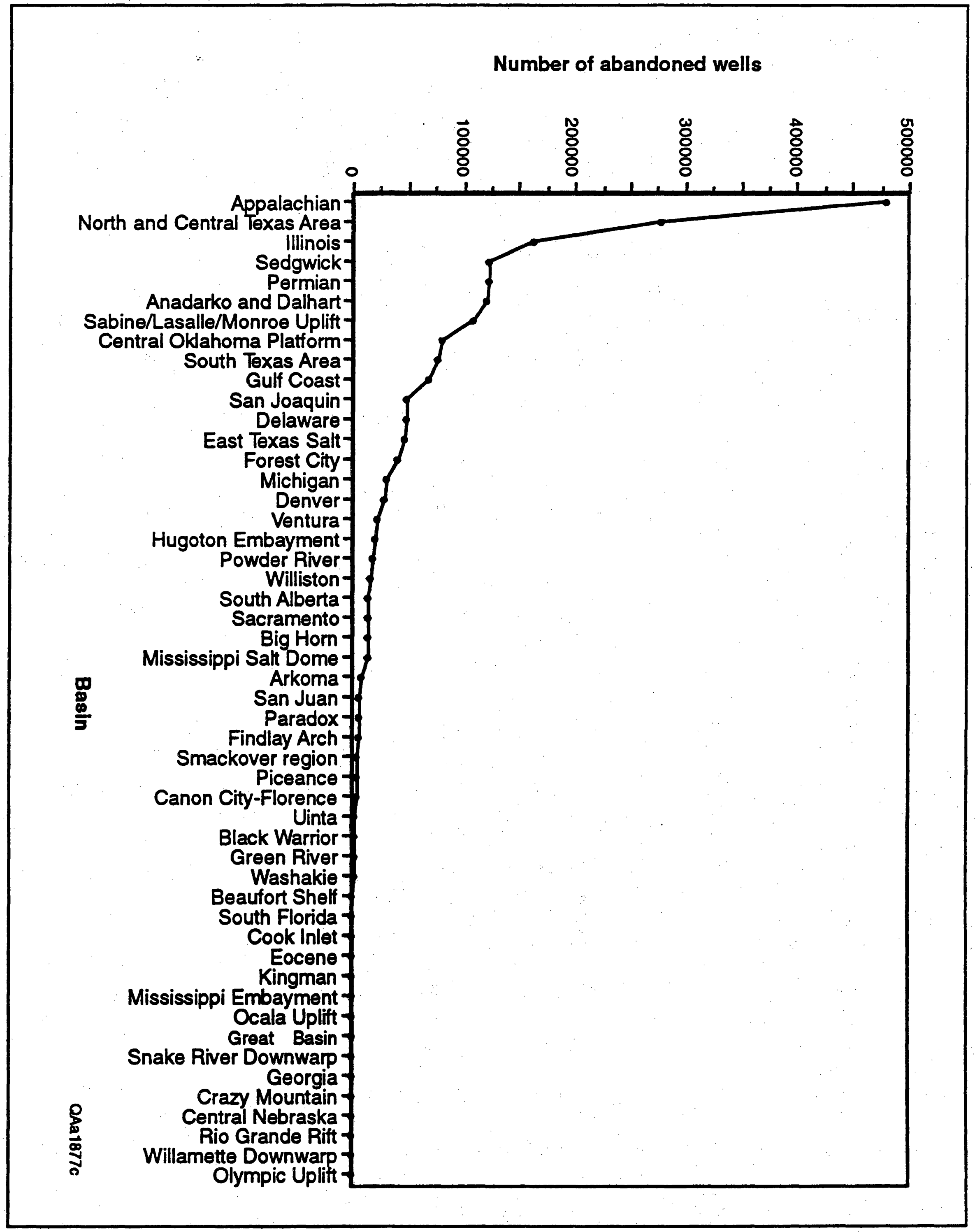


Figure 7. Estimated distribution of abandoned wells by basin, onshore U.S.A.

survey was conducted primarily through telephone conversations with individuals within the various agencies during the first half of 1990. Interviews consisted of general questions regarding the magnitude and extent of oil and gas operations in the respective state and specific questions pertaining to the actual information recorded and the formats in which it may be retrieved. The extent to which data were computerized and the type of data available in computerized format were of particular interest. Samples of typical production or injection well "hard-copy" files and/or computer files (where available) were requested at that time and later examined to define the status of data availability.

The types of information needed for comparison of potentiometric surfaces include oil and gas reservoir data (well location, elevation, perforation depths, bottomhole or other pressures, oil or gas gravity) and injection data (well location, elevation, injected/perforated interval depths, injection tubing diameter, injected fluid-specific gravity, injected formation porosity and permeability, and injection pressure, volume, and rate). Additional information such as field name and producing or injected formation are also important to overall record-keeping and for simple conveyance of information. The presence of such data in already compiled computerized data bases facilitates the analysis of potentiometric surfaces. It was beyond the scope of this study to digitize data for basins where data have not been added to computerized data bases.

A literature review was also conducted to examine sources of ground-water data. The USGS, through its National Water Data Exchange (NAWDEX) Program Office, has developed a personal-computer-based Water Data Sources Directory (WDSD) that contains information about organizations that collect, store, and disseminate water data (Green, 1991). For each organization in the WDSD, there are listings of the types of data available, the locations from which the data were collected, the periods of record, and the media on which the data are stored (i.e., whether computerized or in paper format). In surveying records on domestic (e.g., household) water wells in the U.S., Ganley (1989) tabulated the availability of data on well construction, hydrogeology, and location; assessed the extent to which the data were computerized; and listed the names of state agencies responsible for maintaining the records.

Results of Survey on Oil and Gas Data

Petroleum production, injection, disposal, and storage activities are summarized by state (or district) in table 3. In 20 states and the District of Columbia there are no or only minor activities. Significant activities occur in the remaining 30 states and the separately-administered Osage Mineral Reserve (Oklahoma). Most reservoir and injection data are collected and retained in hard-copy files (paper or microfilms/fiche) (appendices II and III). This information, although generally public, is not presently compiled in computerized data bases. Also, certain variables critical to this type of study (in particular fluid pressures) are not regularly measured or reported and so may be impossible to obtain or may be outdated.

Virtually all of the contacted agencies plan to compile computer data bases; these data bases will provide the greatest access to the data. In many cases, these data bases will include variables that are important to ensuring compliance with regulations (e.g., monthly production/injection volumes), while omitting some of the basic engineering data. Most of the state agencies contacted, while expressing hopes that ultimately all of the information would be computerized, indicated that data critical to regulations would receive priority. As of 1990, states that had computerized some engineering information on injection included Alabama, Kansas, Nebraska, Texas, and West Virginia (appendix III). In addition, several EPA regional offices indicated that some injection data are available in computerized format, though samples were not available because of computer system changes at that time. A few states (Colorado, North Dakota, South Dakota, Illinois, Texas, Utah, and Wyoming) have basic well data (such as location and depth) available in computer files (appendices II and III). Most of the other information in states with partial or no computerization is presumed to exist in hard-copy files in the agency offices, though this has not been verified in all cases.

After a preliminary literature review and communicating with state, federal, and private agencies regarding data availability, the San Juan Basin, the greater Permian Basin, and the South Texas Basin were selected as case studies for evaluating the residual potentiometric surface method. The application of the method to the San Juan Basin, as the first case study, will be reviewed most thoroughly; the two remaining case studies will be discussed in less detail in order to minimize repetition.

Table 3. Summary by state of petroleum-related production, injection, disposal, and storage activities.

State	Oil, Gas, or Other New Production (1)	Enhanced Recovery Injection	Salt-Water Disposal Injection	Gas or Other Storage Injection	Approximate Well Counts (2)		
					Active Production	Active Injection	Abandoned
Alabama	Y (3)	Y	Y	N	1890	241	2798
Alaska	Y	Y	Y	N	1295	336	1136
Arizona	Y	N	Y	N	23	7	453
Arkansas (preliminary)	Y	Y	Y	Y	12250	1218	22838
California	Y	Y	Y	Y	56175	15466	86417
Colorado	Y	Y	Y	Y	10178	983	29948
Connecticut	N	N	N	N	-	-	-
Delaware	N	N	N	N	-	-	na (4)
Dist. of Columbia	N	N	N	N	-	-	-
Florida (preliminary)	Y	Y	Y	N	113	74	853
Georgia	N	N	N	(pending)	-	-	na
Hawaii	N	N	N	N	-	-	-
Idaho	Y	N	N	N	na	-	na
Illinois	Y	Y	Y	Y	31290	14548	98528
Indiana (preliminary)	Y	Y	Y	Y	8384	3305	57336
Iowa	N	N	N	Y	-	434 (5)	na
Kansas	Y	Y	Y	Y	61963	14902	177355
Kentucky (preliminary)	Y	Y	Y	Y	31359	5417	70235
Louisiana	Y	Y	Y	Y	40854	4424	135734
Maine	N	N	N	N	-	-	-
Maryland	Y	N	N	Y	~8 (6)	82 (5)	na
Massachusetts	N	N	N	N	-	-	-
Michigan	Y	Y	Y	Y	5880	1655	30863
Minnesota	N	N	N	Y	-	66 (5)	na
Mississippi (preliminary)	Y	Y	Y	Y	4449	981	20549
Missouri (preliminary)	Y	Y	Y	Y	300	460	1746
Montana	Y	Y	Y	Y	6703	1452	22481
Nebraska	Y	Y	Y	Y	1830	621	15418
Nevada	Y	Y	N	N	27	8	347
New Hampshire	N	N	N	N	-	-	-
New Jersey	N	N	N	N	-	-	na
New Mexico	Y	Y	Y	Y	34318	4162	26563
New York	Y	Y	Y	Y	9438	3254	5553
North Carolina	N	N	N	N	-	-	na
North Dakota	Y	Y	Y	N	3936	407	7233
Ohio (preliminary)	Y	Y	Y	Y	62380	3956	100042
Oklahoma (preliminary)	Y	Y	Y	Y	127500	22792	261431
Oregon	Y	N	Y	Y	14 (6)	>1 (6)	na
Osage M. R. (Okla.) (prelim.)	Y	?	?	?	na	na	na
Pennsylvania (preliminary)	Y	Y	Y	Y	48000	6183	279892
Rhode Island	N	N	N	N	-	-	-
South Carolina	N	N	N	N	-	-	-
South Dakota	Y	Y	Y	N	188	41	904
Tennessee (preliminary)	Y	Y	Y	Y	1794	11	3893
Texas	Y	Y	Y	Y	246135	51649	610204
Utah	Y	Y	Y	Y	3933	502	6163
Vermont	N	N	N	N	-	-	-
Virginia	Y	(pending)	N	N	609	0	201
Washington	N	N	N	Y	-	77 (5)	na
West Virginia	Y	Y	Y	Y	48395	761	64175
Wisconsin	N	N	N	N	-	-	-
Wyoming	Y	Y	Y	Y	17283	5936	38247

Notes: (1) does not include withdrawal from storage;
(2) data from Michie and Associates (1988);
(3) Y - yes; N - no; ? - uncertain;
(4) not available;
(5) 1987 data from American Gas Association (1988);
(6) data from State geological survey.

CASE STUDY—SAN JUAN BASIN

Background

The San Juan Basin is a mature petroleum province in New Mexico, Colorado, and Arizona that covers about 13,000 mi^2 (34,000 km^2) and contains approximately 16,500 oil and gas wells in approximately 900 reservoir/pools (Petroleum Information Inc., unpublished data, 1989). Petroleum exploration in and around the San Juan Basin has occurred across about 22,000 mi^2 (57,000 km^2). As of 1986, the San Juan Basin produced approximately 23 thousand barrels per day (mbd) oil and 913 million cubic feet per day (mmcfd) gas from 3,070 oil wells and 13,449 gas wells (Michie & Associates, 1988). Oil is produced principally from Pennsylvanian and Cretaceous sandstone reservoirs in fields of medium depth (5,000 ft [1,500 m]). Gas has been produced for more than 60 years from Cretaceous rocks (also at approximately 5,000 ft [1,500 m] depth) (Matheny and Ullrich, 1983; Michie & Associates, 1988). In the past decade, production of coalbed methane from the Upper Cretaceous Fruitland Formation has become significant, rising from 3 billion cubic feet (Bcf) in 1985 to 67 Bcf in 1989 and finally surpassing conventional gas production in 1992 (447 Bcf coalbed methane versus 422 Bcf conventional gas) (W. R. Kaiser, Bureau of Economic Geology, personal communication, 1994). Oil and gas are also produced in smaller volumes from Devonian, Mississippian, Permian, Jurassic, and Tertiary reservoirs. Fassett and others (1978b) and Fassett (1983) reviewed the general geologic setting.

Ninety-eight percent of the water produced with oil and gas in the San Juan Basin is from Cretaceous (and to a lesser extent Pennsylvanian) reservoirs (Stone and others, 1983, p. 54; Michie & Associates, 1988). Much is reinjected in EOR operations, nearly all of which are in the Cretaceous reservoirs (New Mexico Oil Conservation Division [NMOCD], 1990a). In 1989, for example, nearly 21.5 million bbl of water were injected through some 308 EOR injection wells in ten fields in the New Mexico portion of the San Juan Basin (New Mexico Oil Conservation Division, 1990a). A considerable volume of produced water, including essentially all water produced with coalbed methane, is also injected into non-producing zones for purposes of disposal (Lawrence, 1993). In March 1990 alone, nearly

1.4 million bbl of water were injected through 34 salt-water disposal wells in the basin (New Mexico Oil Conservation Division, 1990b).

Aquifers in the San Juan Basin are predominantly confined (i.e., overlain by semi-permeable strata) and tend to occur within alluvium and sandstone, although some coal beds also act as aquifers (Kaiser and others, 1991). The numerous individual aquifers in the basin have been grouped into six hydrostratigraphic (aquifer) units by the USGS Regional Aquifer-System Analysis (RASA) Program for the San Juan Basin (Stone and others, 1983; Levings, USGS, Albuquerque, personal communication, 1990). These hydrostratigraphic units are Tertiary Undivided, Upper Cretaceous Undivided, Mesaverde Group, Gallup Sandstone, Dakota Sandstone, and Morrison Formation (table 4). The approximate base of USDWs has been delineated, along with the relative location of the oil and gas reservoirs, on a generalized geologic section across the San Juan Basin (fig. 8). Tertiary units crop out in the center of the basin and older units crop out successively farther from the center of the basin.

The stratigraphic Mesaverde Group of Upper Cretaceous age has been divided into two hydrostratigraphic units for this study: the Mesaverde Group undivided (excluding the Gallup Sandstone) and the Gallup Sandstone. The Gallup Sandstone (*sensu stricto*), the lowest stratigraphic unit of the Mesaverde Group (Beaumont and others, 1956), is an offlapping unit of Carlisle age beneath the basal Niobrara unconformity (fig. 8). This hydrostratigraphic unit should not be confused with the so-called "Gallup" unit producing oil and gas, which is technically the Tocito sandstone lentil of the Mancos shale, above the basal Niobrara unconformity. The confusion stems from locations where the true Gallup sandstone and the upper part of the lower Mancos shale are eroded, so that the "Gallup" oil and gas unit appears to be in the same position as the hydrostratigraphic unit.

Data Sources

Oil and Gas Reservoir Pressure Data

Reservoir pressures were averaged by PI from the individual well data for all active and shut-in wells in each reservoir/pool during a decade and assigned spatial coordinates of the reservoir/pool

Table 4. Characteristics of hydrostratigraphic units, San Juan Basin.

Hydrostratigraphic unit (HSU)	# Wells/# wells used to determine head	Individual units	Environment of deposition	HSU thickness (ft)	HSU depth (ft)	T(ft2/day)	Specific cond. (µS/cm) (TDS [mg/L])
Tertiary Undivided	294/241	San Jose Formation Nacimiento Formation Animas Formation Ojo Alamo Sandstone Chuska Sandstone	eolian alluvial fluvial lacustrine	72- 2700	land- 2660	40- 250	320->9000 (176->6750)
Upper Cretaceous Undivided	74/72	Kirkland Shale Farmington Sandstone Fruitland Formation Pictured Cliffs Sandstone Lewis Shale	fluvial marine	25- >2000	land- 4130	.001- <10	>2000-<41000 (>1100-<30750)
Mesaverde Group	181/149	Cliff House Sandstone Menefee Formation La Ventana Member Allison Member Cleary Coal Member Point Lookout Sandstone Crevasse Canyon Formation Gibson Coal Member Dilco Coal Member	marine coal measure	20- 1000	land- 6400	2- 240	>1500-59000 (>825-44250)
Gallup Sandstone	45/36	Gallup Sandstone	marine	93- 700	land- 4300	100- 400	<1000-4000 (<550-3000)
Dakota Sandstone	52/48	Dakota Sandstone	marine coal measure	200- 350	land- 8500	?- 100	<2000->10000 (<1100->7500)
Morrison Formation	83/68	Brushy Basin Member Westwater Canyon Sandstone Salt Wash Sandstone	alluvial fluvial	420- 900	land- 8900	?- 500	<1000->10000 (<550->7500)

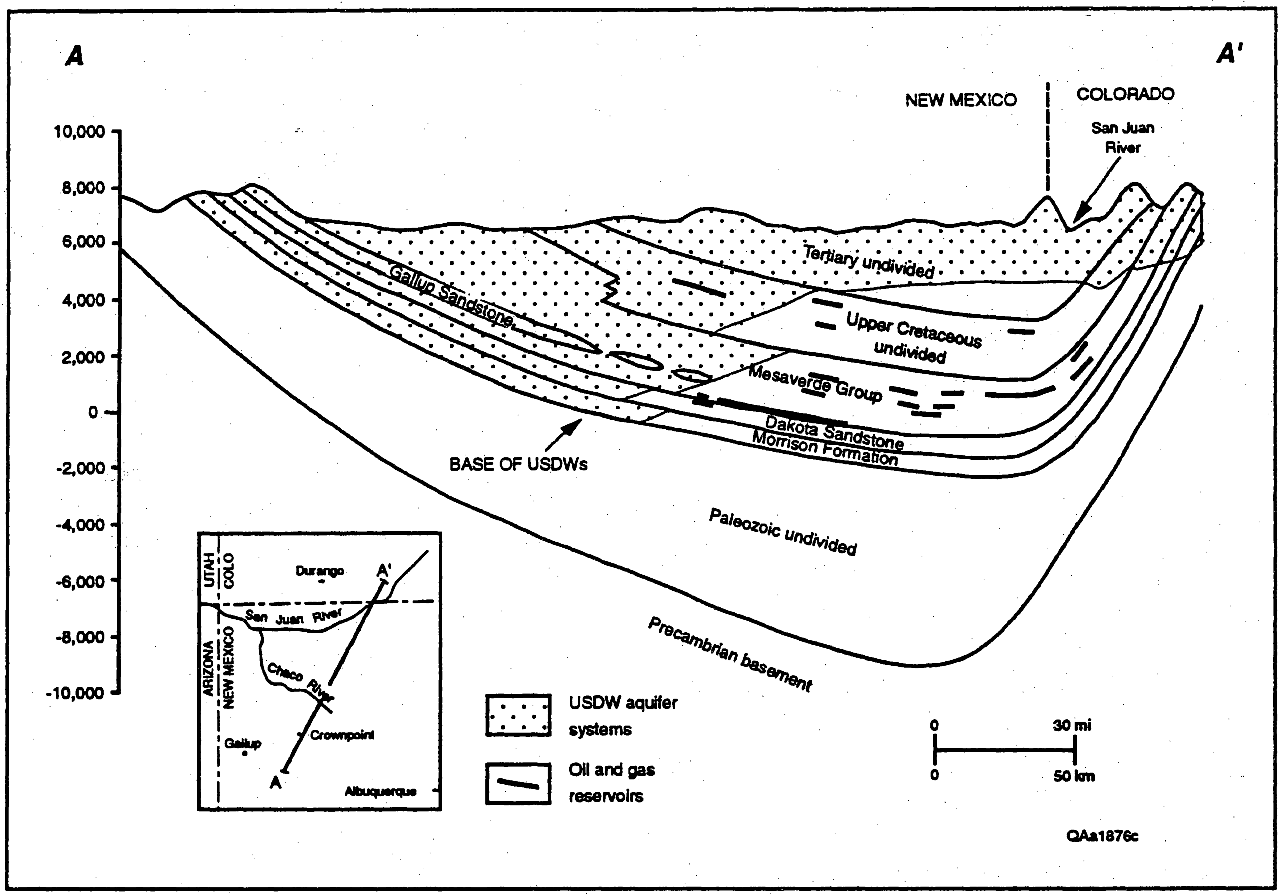


Figure 8. Generalized southwest-northeast cross section through San Juan Basin, showing major hydrostratigraphic units and oil and gas reservoirs (after Stone and others, 1983, fig. 10).

centroid. Average measured BHPs were listed for only nine of the 900 reservoir/pools in the WHCS data base from the New Mexico and Colorado portions of the basin, whereas SITP values were listed for 245 of those 900 reservoir/pools. However, information on reservoir depth and wellhead elevation were missing from 154 of the reservoir/pools for which SITP values were available. To form an internally consistent data set, the 91 reservoir/pools for which SITP values, reservoir depths, and wellhead elevations had been given were selected for potentiometric-surface mapping. One-hundred-sixty-five SITP values were listed for those 91 reservoir/pools: 51 reservoir/pools had SITP values listed for only one 10-year period, 20 had values for two periods, six had values for three periods, and 14 had values listed for four 10-year periods. Where SITPs were available for more than one 10-year period, the maximum value was selected, so that each of the 91 reservoir/pools was represented by a single SITP value. BHP values were calculated from these SITPs using a 0.07 psi/ft pressure gradient, considered to represent methane-dominated reservoirs in the San Juan Basin (Bureau of Economic Geology, unpublished data).

A different set of pressure data for 162 different reservoir/pools was compiled from State oil and gas annual reports (New Mexico Oil Conservation Division, 1952, 1954, 1957) and field summary volumes published by the Four Corners Geological Society (FCGS) (Fassett and others, 1978a, 1983). The NMOCD reports listed pressures for 41 different reservoir/pools, whereas the FCGS volumes listed discovery well or initial field pressures for 142 reservoir/pools. There are only 21 of the 162 reservoir/pools in common to NMOCD and FCGS. Fifty-four of the 162 reservoir/pools listed by NMOCD and FCGS are included in the final 91 reservoir/pools "screened" from the PI WHCS data set.

Pressure data for the 162 reservoir/pools from NMOCD and FCGS include an assortment of BHPs (in a few cases explicitly stated to be from drill-stem tests), SITPs, shut-in casing pressures, and flowing tubing pressures. In some cases, the depth of measurement was explicitly stated; in others it could only be assumed to be in the middle of the perforated interval. In addition, for some of the reservoir/pools, different values were given for discovery well pressure and initial field pressure. The quality of the NMOCD and FCGS data are unknown; it was beyond the scope of this case study to standardize and merge the NMOCD and FCGS data with the WHCS data. However, more than half (30 of 54) of the BHPs calculated from SITPs from the WHCS data base are within 25 percent of the discovery value reported by NMOCD or FCGS, and 46 of 54 calculated BHPs are within 50 percent of the reported discovery value.

USDW Data

USDW aquifer data were obtained from the USGS RASA Program data base for the San Juan Basin (Craigg and others, 1989). There are six separate data sets, each consisting of water wells producing from a single hydrostratigraphic unit; the data do not include any wells that produce from more than one hydrostratigraphic unit. This ensures that the hydraulic head recorded for each well reflects the hydraulic head in a particular aquifer at the time of measurement (if a well is perforated in more than one aquifer, it is not possible to determine which has the higher hydraulic head without additional testing). The original well records contained as many as 21 data elements, including well location, hydrostratigraphic unit, altitude of the wellhead, well depth, static water level, and altitude of the static water level.

Abandoned Well Data

Two sources of information were combined to determine the number and distribution of abandoned wells in the New Mexico and Colorado portions of the San Juan Basin. First, the distribution of 2,105 abandoned, dry new-field wildcat wells was supplied in 1989 by PI. Second, an updated number of abandoned wells other than dry new-field wildcats was estimated, as detailed in the Methods section, for each individual $0.1° \times 0.1°$ area, yielding an estimated total of 3,999 abandoned non-wildcats. The sum of 2,105 abandoned wildcats and 3,999 abandoned non-wildcats yields an estimated total of 6,104 abandoned wells for the New Mexico and Colorado portions of the basin. By comparison, Gruy Engineering Corp. (1989, their table 1) estimated 4,932 abandoned non-wildcats as of 1988 for the New Mexico and Colorado portions of the basin. The discrepancy between this study's estimates and Gruy Engineering's estimates probably reflects differences in the sources of data (PI versus State regulatory agencies).

Class II Injection Data

Injection volume data used in the quantitative analyses of head buildup around selected EOR injection wells were obtained from the NMOCD monthly injection reports for 1987 (New Mexico Oil Conservation Division, 1987). We chose the highest injection volumes to delineate the maximum areal extent of head buildup. More recent data for May 1990 (New Mexico Oil Conservation Division, 1990d) showed a similar range of injection volumes but some changes in well status. Further information for qualitative review was extracted from annual injection reports for 1988 and 1989 (New Mexico Oil Conservation Division, 1989a, 1990a). The annual reports detail maximum allowed surface injection pressures, depths, and annual injection volumes. Bottomhole injection pressures were calculated from this information (using estimates of injection rate, typical injection tubing diameter [3 in (7.62 cm)], friction losses, and the weight of water in the injection string) during the preliminary stages of the study. However, these calculated pressures were not used in the final analyses because no pre-production pressure values were obtainable for the injection locations. Instead, pre-production values of hydraulic head were determined from the composite oil and gas potentiometric surface.

The EOR injection annual report for 1989 (New Mexico Oil Conservation Division, 1990a) listed 28 fields with injection operations; 14 fields were indicated to have active injection projects in 1989, 11 fields had no active projects, and three fields were entirely abandoned. A comparison to the May 1990 monthly report (New Mexico Oil Conservation Division, 1990d) and to the November 1989 monthly report (New Mexico Oil Conservation Division, 1989b) reveals some inconsistencies in the records. For example, the data for 1989 should have listed 29 fields, Puerto Chiquito E (Mancos) having been left out. In addition, the May 1990 report listed three additional fields (Eagle Mesa–Entrada, Tocito Dome North–Pennsylvanian, and Blanco–Fruitland Sand) which may have been permitted for injection in 1990 but had not yet become active. An examination of the conflicting data suggests that of the 29 fields carried in the enhanced recovery injection records for 1989, ten had active projects (at least one active injection well), 13 had no active injection projects, and six had injection projects that had been abandoned by 1989 (including three fields entirely abandoned). There was no injection in 1989 in any of the other 225 fields in the New Mexico portion of the basin. As of May 1990, there were 119 active, 396 inactive, and 128 abandoned EOR injection wells (643 total) in the New Mexico portion of the basin.

Data on disposal volumes used in the analyses of head-buildup around selected SWD wells were extracted from the NMOCD March 1990 and April 1990 salt-water disposal reports for northwest New Mexico (New Mexico Oil Conservation Division, 1990b, 1990c). Additional SWD well data were transcribed from hard-copy well and permit files located in the NMOCD office in Santa Fe. In the salt-water disposal report for March 1990, there were 34 active wells, eight inactive wells (including one for which there was no report), and 15 abandoned or "disconnected" wells (57 total). In April 1990 there were 26 active wells, 16 inactive wells (including 11 for which there was no report), and 15 abandoned or "disconnected" wells. Well records could not be found for one disposal well listed in the monthly reports (Nassau Resources, Carracas Unit 13A/22A, no. 52—active in March 1990), but a file was found for a similarly designated well not listed in the monthly reports (Nassau Resources, Carracas Unit 27A, no. 82—activity unknown).

Initial Hydraulic Conditions

Pressure-Depth Profiles

BHPs were plotted versus measured depths in order to interpret the hydrologic environments in the hydrocarbon-bearing formations, the water injection zones, and the aquifers. Data points on the pressure-depth profile for oil and gas reservoirs (fig. 9) include fields with bottomhole pressures retrieved directly from the PI data base as well as bottomhole pressures calculated from surface shut-in tubing pressures in that data base. When more than one pressure value was available for a well, the highest value was selected under the assumption that it is a closer estimate of the initial formation pressure.

Calculated values of BHP data tend to lie along or below the line representing the fresh-water hydrostatic gradient (slope = 0.433 psi/ft [9.79 kPa/m]). This correspondence reflects relatively low salinity of formation water; with one exception, Berry (1959) reported TDS <75,000 ppm for Jurassic and Cretaceous units in the basin. Figure 9 is qualitatively similar to a plot of discovery and pre-production pressures versus depth (fig. 10), which was generated from data compiled by Fassett and others (1978a, 1983). Figure 10 suggests that, at least in some instances, underpressuring (subhydrostatic conditions) in San Juan Basin reservoirs may be natural rather than induced by hydrocarbon production. Berry (1959) attributed underpressuring in Cretaceous units in the center of the basin to osmotic flow of water downward, across shales acting as semi-permeable membranes, into the saline Entrada Formation (Jurassic). The few points that fall above the fresh-water hydrostatic line on figure 10 correspond to reservoirs in the Upper Cretaceous Fruitland and Pictured Cliffs Formations, which exhibit artesian overpressuring (Kaiser and others, 1991), and in deep Paleozoic formations.

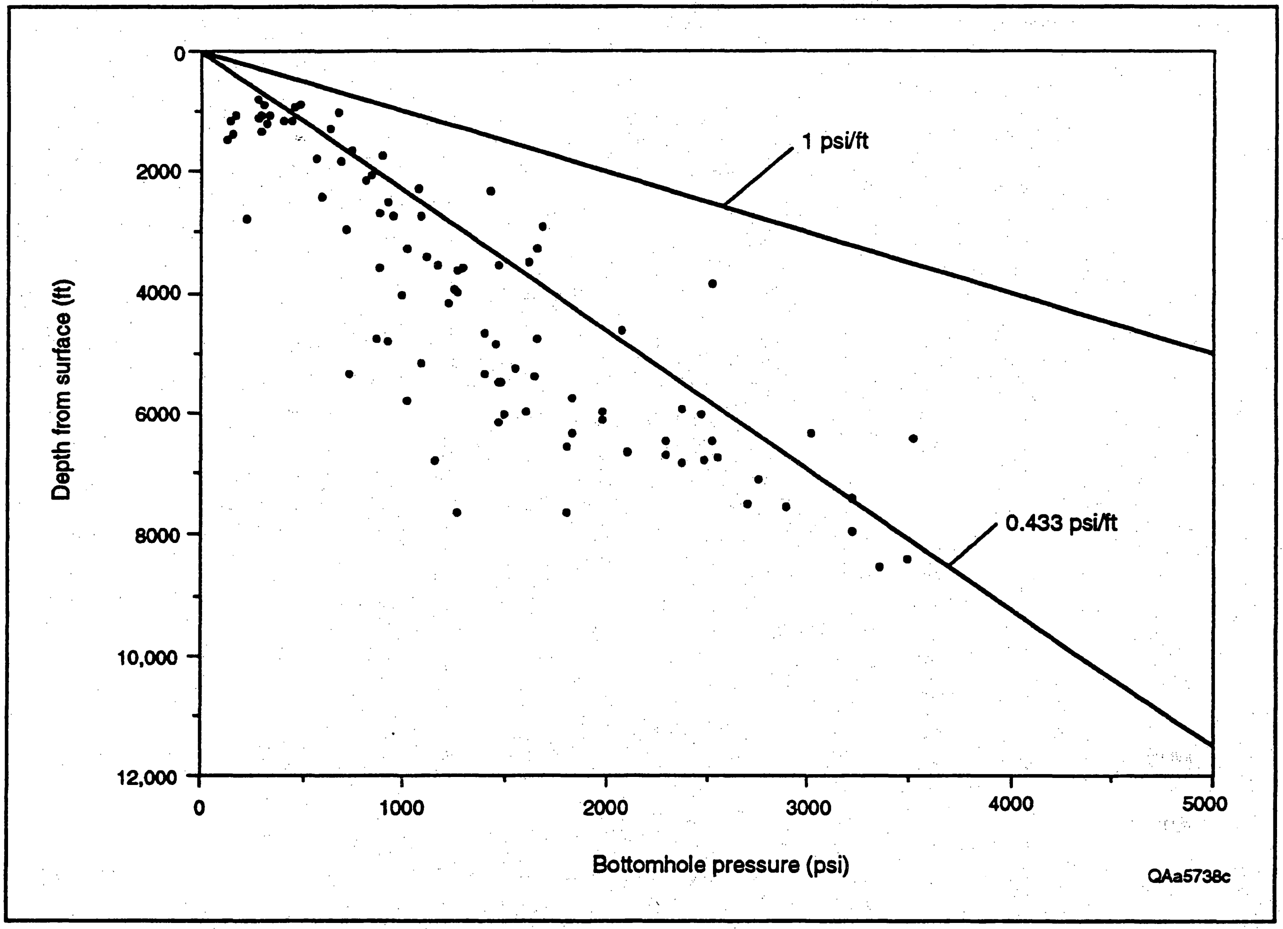


Figure 9. Current (1990) reservoir bottomhole pressure versus depth, San Juan Basin.

Hydraulic head values for each of the six USDWs were converted to equivalent BHPs and plotted versus depth (fig. 11). The subhydrostatic profiles for each of the hydrostratigraphic units may reflect depressurization due to ground-water production. Alternatively, subhydrostatic conditions may reflect downward flow. Water wells in aquifers other than the Tertiary Undivided USDW occur primarily along the margins of the basin, where recharge occurs on outcrops. Analyses of aquifer structure, surface topography, recharge and discharge areas, and historical water-level measurements would be required to assess the local controls on subhydrostatic conditions.

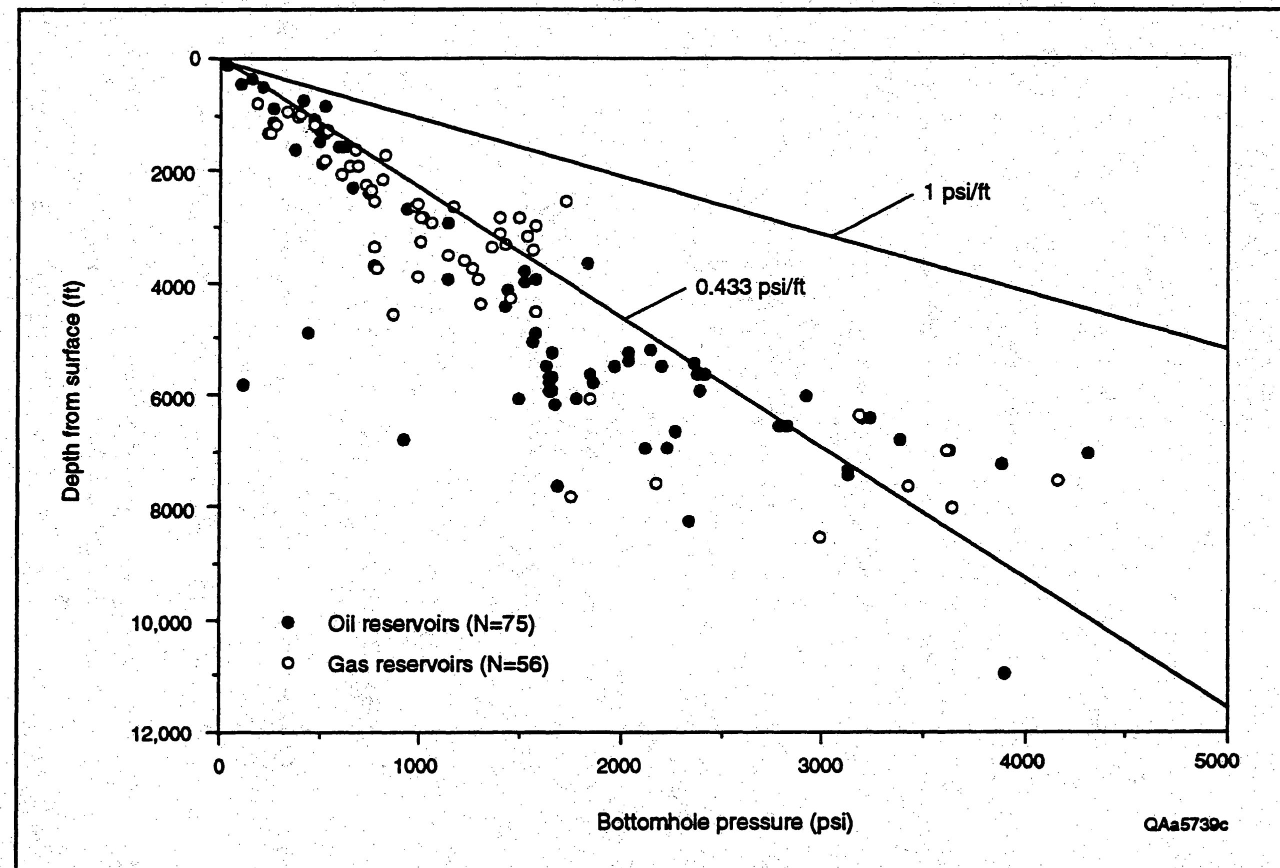
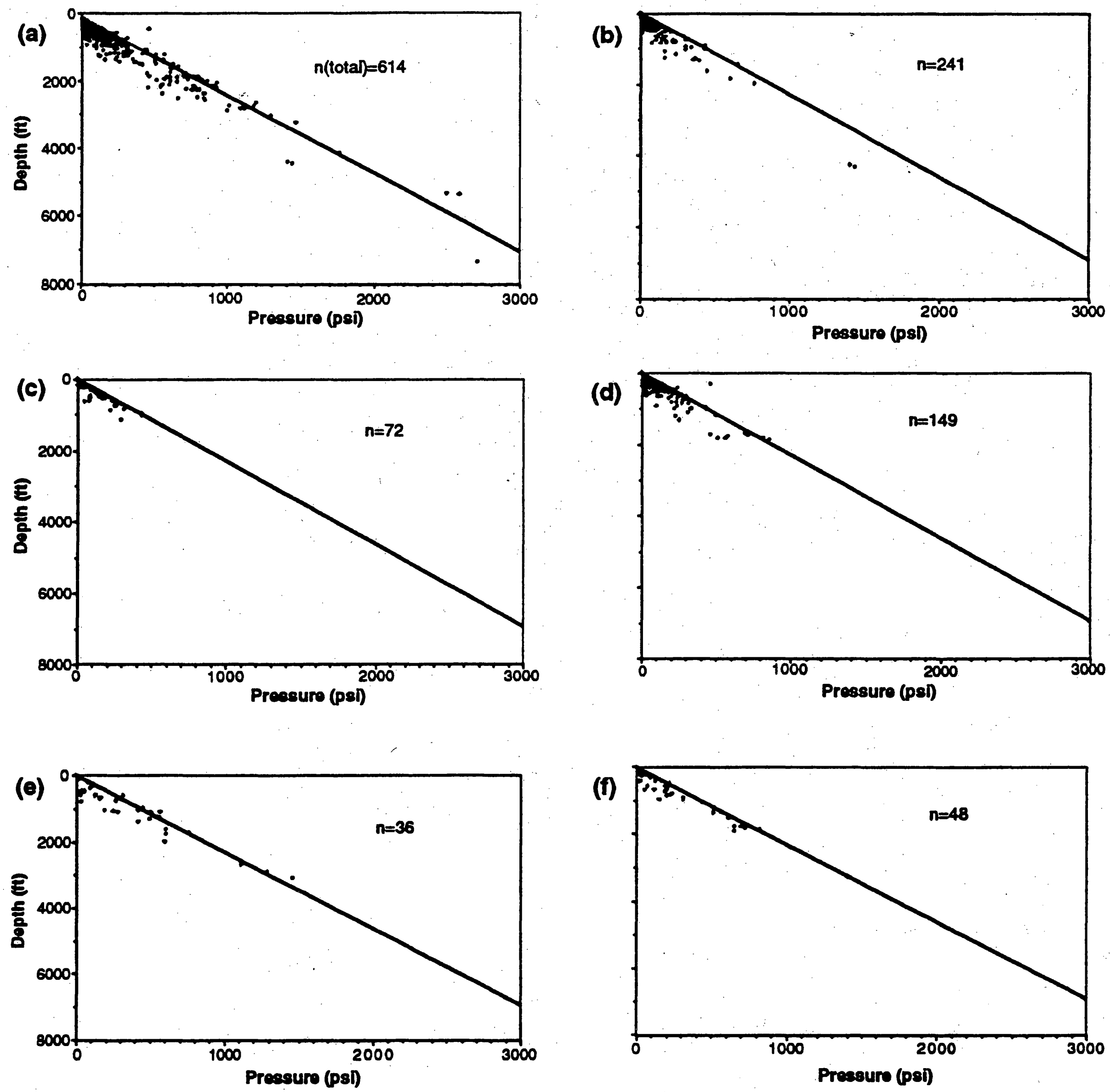


Figure 10. Initial oil and gas reservoir bottomhole pressure versus depth, San Juan Basin.

Computer-Generated Potentiometric Surfaces

Based on the distribution of reservoir pressures with depth, freshwater hydrostatic conditions were assumed in converting BHP values to hydraulic head. Berry (1959) (who used a slightly lower gradient of 0.429 psi/ft [9.70 kPa/m]) and Kaiser and others (1991) also used equivalent freshwater heads to construct potentiometric surface maps of various formations in the San Juan Basin. Reservoir elevation was taken as the elevation (relative to sea level) of the middle of the perforated interval. Because of the sparseness of the data set, the 91 hydraulic head values at reservoir centroids were mapped on a single, vertically-integrated potentiometric surface representing the hydrocarbon-producing formations (fig. 12). Because there are as many as 12 different petroleum-producing units in the San Juan Basin, the composite surface does not fully reflect the geologic complexities and distinctions between these formations. The



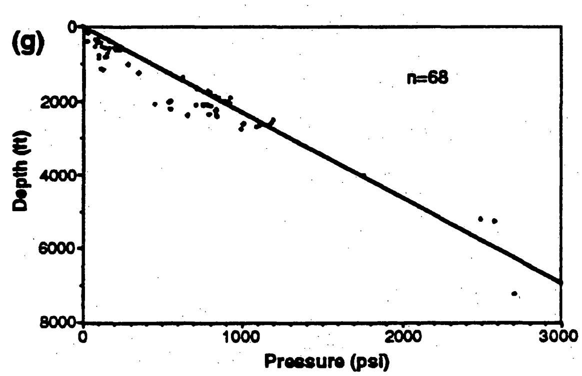


Figure 11. Bottomhole pressure versus depth in hydrostratigraphic units, San Juan Basin: (a) all combined USDWs; (b) Tertiary Undivided USDW; (c) Upper Cretaceous Undivided USDW; (d) Mesaverde Group USDW; (e) Gallup Sandstone USDW; (f) Dakota Sandstone USDW; (g) Morrison Formation USDW.

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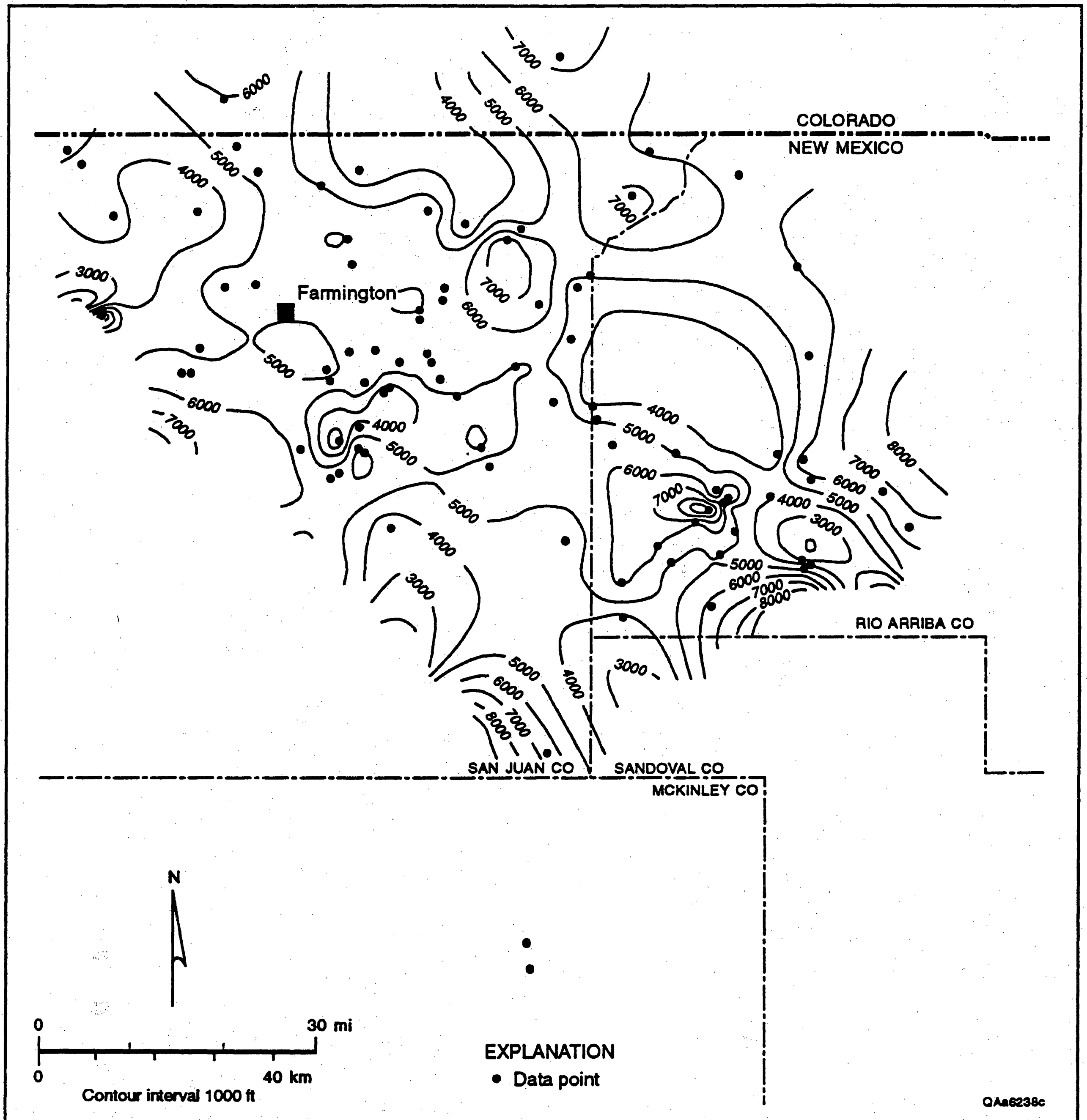


Figure 12. Computer-generated potentiometric surface of combined oil- and gas-producing formations, San Juan Basin.

composite surface nonetheless provides a usable, regional representation of the maximum hydraulic head in the oil and gas zones, which can be used for comparison in a vertical direction with the hydraulic head in the USDWs. This and other potentiometric surfaces have been redrawn for this report from the original CPS-1 printouts for the sake of legibility; however, the contours honor the computer-drawn contours.

Potentiometric surfaces were also generated for each of the USDWs, as shown for the Tertiary Undivided and Upper Cretaceous Undivided hydrostratigraphic units in figures 13 and 14. Whereas the Tertiary USDW potentiometric surface coincides with most of the composite oil and gas surface, the surfaces for the other USDWs, located on the margins of the basin, do not. The lack of overlap is an artifact of the lack of water-level data from the other USDWs in the center of the basin. The "hole" on the southern margin of the Upper Cretaceous Undivided potentiometric surface, like "bull's-eyes" on other potentiometric surfaces in this report, is an artifact of computer-guided contouring where data are sparse.

Residual Surfaces

Analysis of residual hydraulic head between the oil and gas section and each USDW is necessarily restricted to those overlapping areas where there are data for both. Because of the high degree of overlap between the Tertiary Undivided USDW and the area for which there are reliable oil and gas pressure data, relatively high confidence can be placed in most of the positive residuals resulting from subtraction of the Tertiary Undivided potentiometric surface from the composite oil and gas surface. The amount of confidence that can be placed on any residual decreases as the data points defining one surface become more widely separated from those defining the other. In the case of the Gallup sandstone, analysis of residual head is not meaningful because available aquifer data and the computer-generated potentiometric surface do not overlap with the oil and gas surface. More confidence can be placed in the analyses of residual head for the other four hydrostratigraphic units where there is greater overlap between each data set (and corresponding computer-generated potentiometric surface) and the oil and gas potentiometric surface.

Seventeen positive residual areas reasonably supported by data are scattered across the center of the basin. Five positive residual areas for the Tertiary Undivided USDW are constrained by data from both the reservoir and aquifer data sets (fig. 15). The three northernmost of these five areas approximately coincide with regional ground-water discharge areas in the San Juan River valley (Kaiser and others,

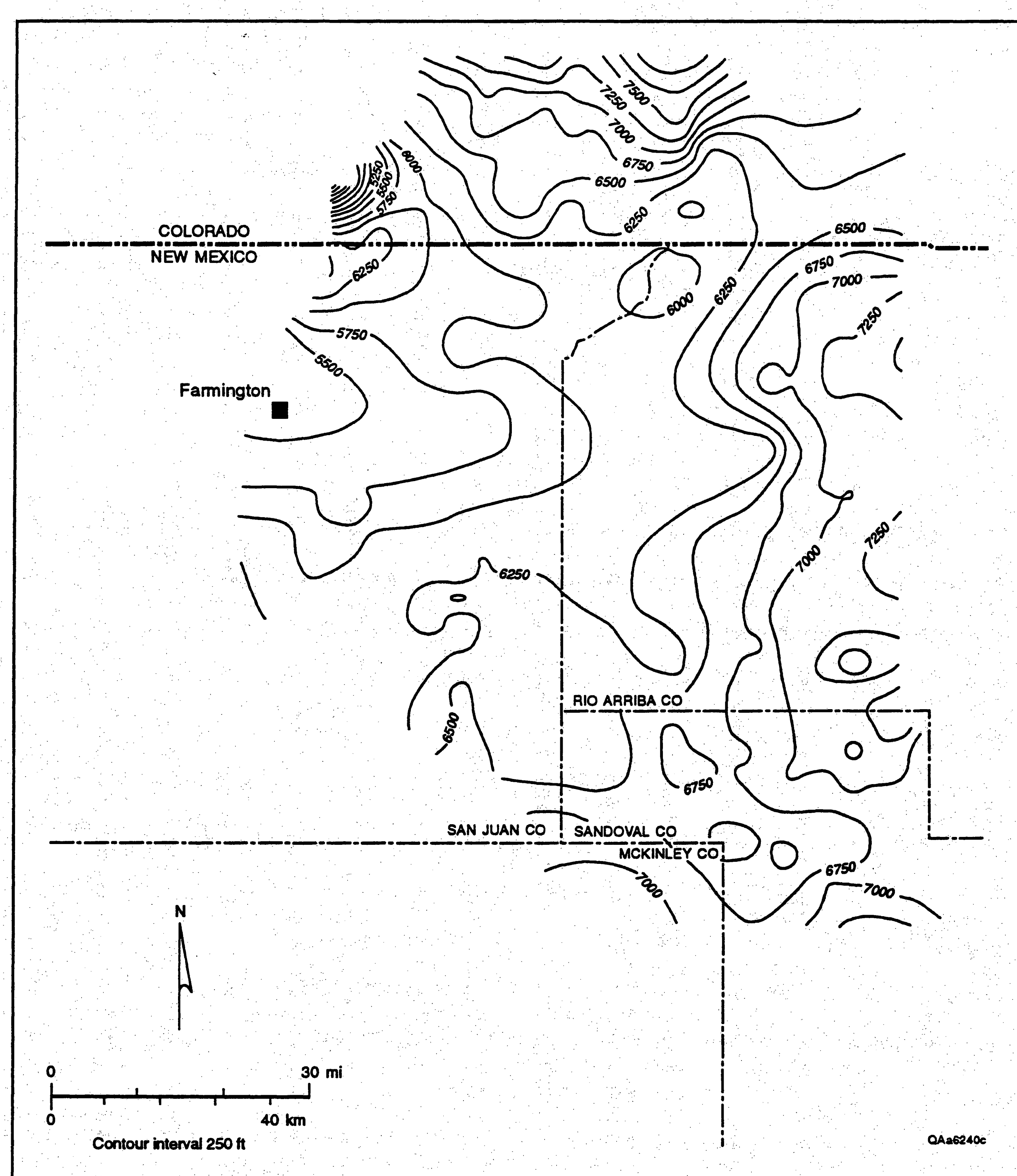


Figure 13. Computer-generated potentiometric surface of Tertiary Undivided USDW, San Juan Basin.

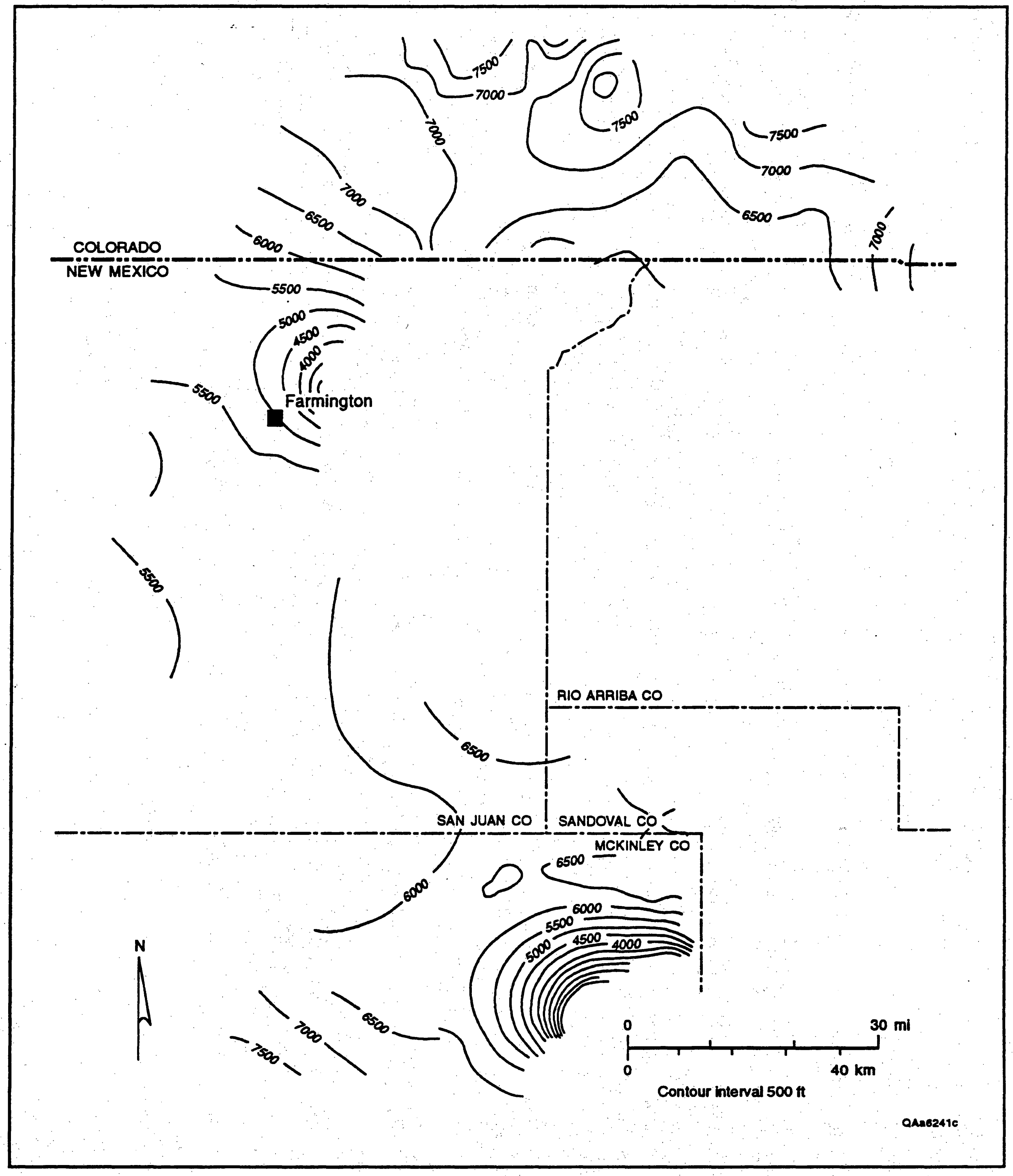


Figure 14. Computer-generated potentiometric surface of Upper Cretaceous Undivided USDW, San Juan Basin.

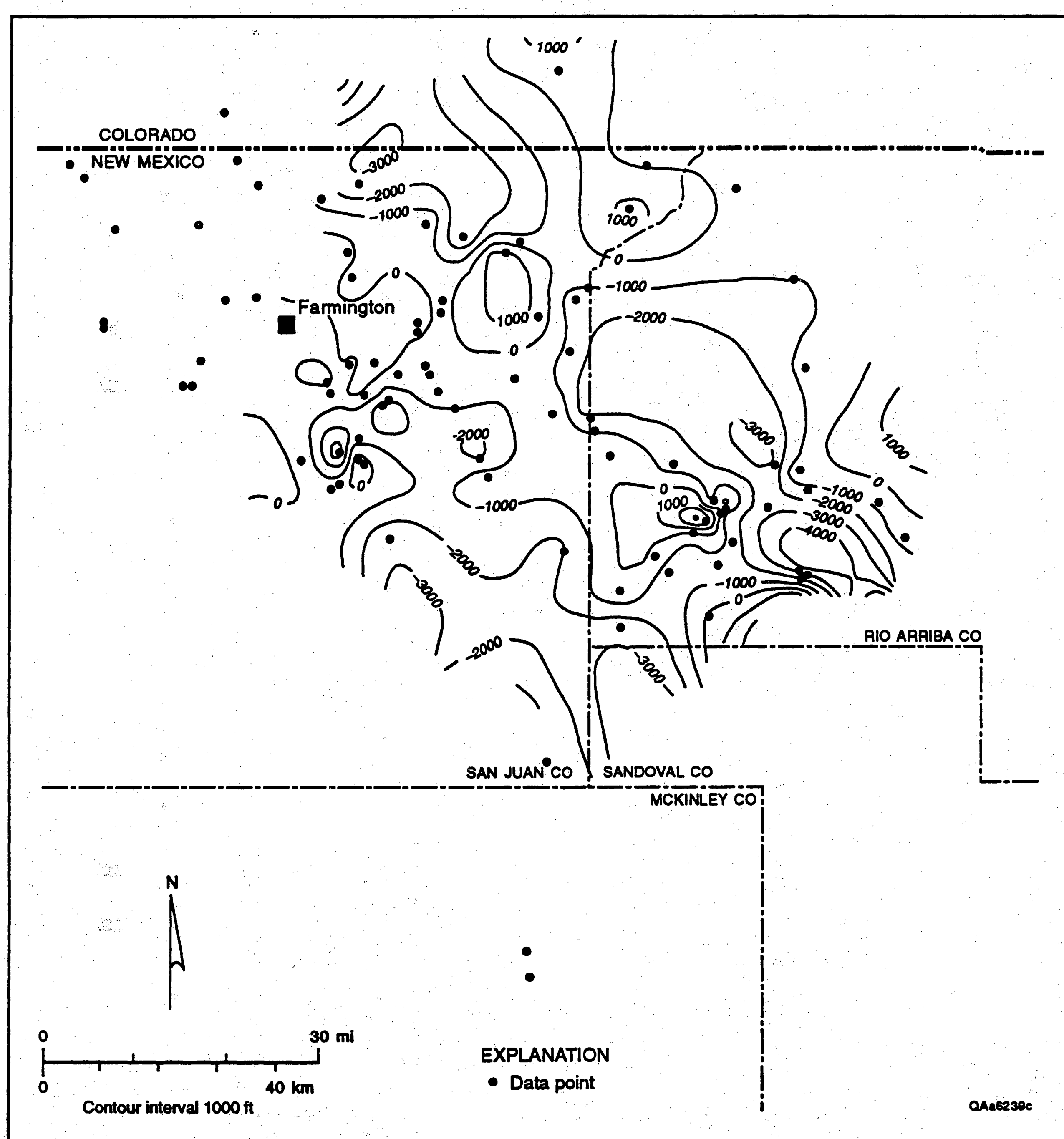


Figure 15. Residual of computer-generated potentiometric surface of combined oil- and gas-producing formations minus computer-generated potentiometric surface of Tertiary Undivided USDW, San Juan Basin. Positive residuals (differential head values >0) indicate possible areas of upward hydraulic-head gradient.

1991). Two other positive residual areas near the margins of the Tertiary Undivided system are poorly constrained by both data sets. The four positive residual areas for the Upper Cretaceous Undivided USDW are not well constrained, located where the oil and gas and aquifer data sets barely overlap (fig. 16). Likewise, none of the three positive residuals for the Mesaverde Group nor the two positive residuals for the Dakota sandstone is well constrained by data points. Potable water may be present in the non-Tertiary hydrostratigraphic units at greater depth toward the center of the basin where oil and gas data are available, but there are no water wells that produce solely from non-Tertiary USDWs in those areas. The sole positive residual area identified for the Morrison Formation USDW is constrained by several data points from the oil and gas data set and one point from the aquifer data set. This positive residual for the Morrison Formation USDW approximately coincides with less well constrained positive residuals for the Mesaverde Group and Dakota sandstone aquifer systems, suggesting that this is indeed an area of high hydraulic head in the oil and gas section.

All positive residuals have been compiled on a composite map (fig. 17); this map reduces the 17 unique positive residuals to five large and eight medium-to-small positive residuals. All positive residual areas for all hydrostratigraphic units are shown, including those that are not well constrained by nearby data points. Between the positive residuals, USDWs overlap with the zone of oil and gas production, but residual head is negative, indicating no upward flow potential based on available data. The composite map was used in combination with figure 18 in area of review analyses to determine approximate numbers of abandoned wells that are near active injection operations and salt-water disposal wells in positive residual areas.

Abandoned Well Locations

Contouring the distribution of abandoned wells at the 0.1°×0.1° scale illustrates that abandoned wells are concentrated in five areas within the region of oil and gas production (fig. 18), none of which is centered on a mapped positive residual. At the latitude of the San Juan Basin (approximately 35.5° N to 37.5° N), a 0.1°×0.1° cell is approximately 36 mi^2 (93 km^2). The greatest concentration of abandoned

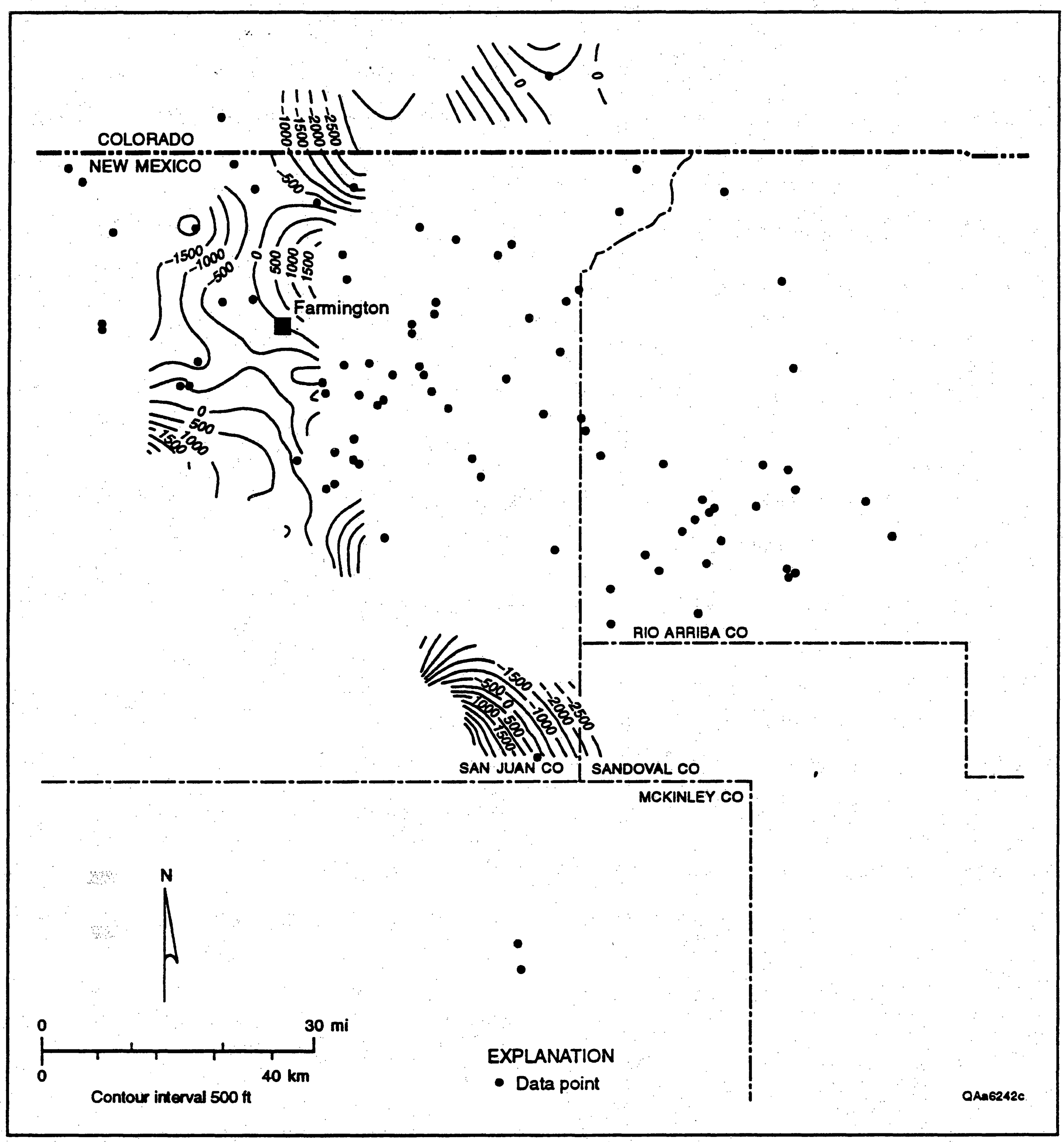


Figure 16. Residual, computer-generated potentiometric surface of combined oil- and gas-producing formations minus computer-generated potentiometric surface of Upper Cretaceous Undivided USDW, San Juan Basin. Positive residuals (differential head values >0) indicate possible areas of upward hydraulic-head gradient.

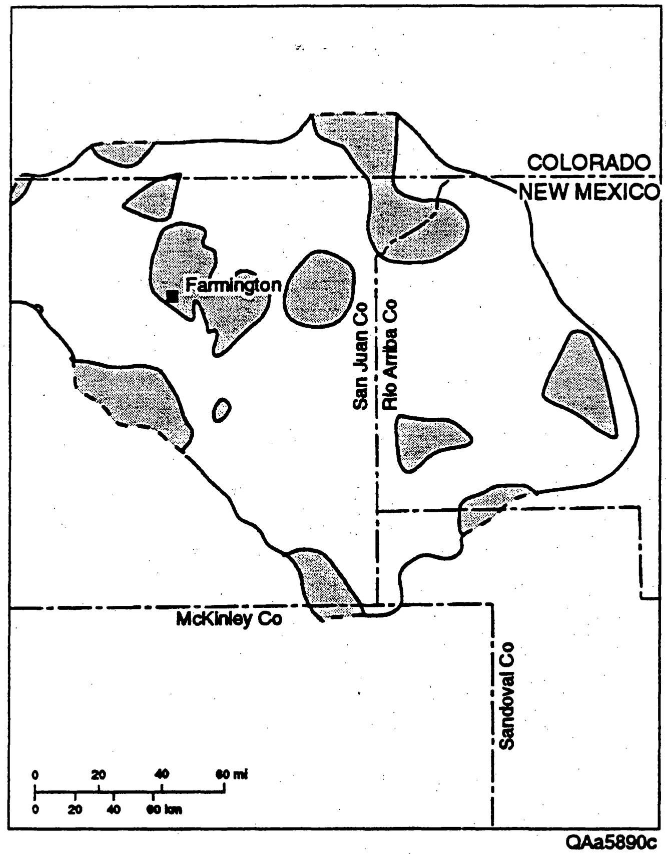


Figure 17. Composite map of all positive residuals within area of reliable reservoir pressure data (outlined) in San Juan Basin; boundaries dashed where inferred.

wells (approximately 662 within a 0.1° × 0.1° cell) occurs in the north-central part of the basin. The other four areas are located nearer the margins of the region of active production; each of those areas is estimated to contain from 100 to 150 abandoned wells per cell. The fact that the five clusters of abandoned wells coincide with negative residuals suggests that hydraulic gradients are directed downward where abandoned wells are most numerous in the basin. This potentially reduces the risk of salinization of USDWs. The numbers of abandoned wells in various areas of interest were estimated by totaling the well counts for the cells lying partially or completely within each area (table 5). This approach yielded conservatively large estimates—approximately 1,000 abandoned wells within the positive residual areas and as many as 4,000 abandoned wells within the entire region for which reliable oil and gas reservoir pressure data were available.

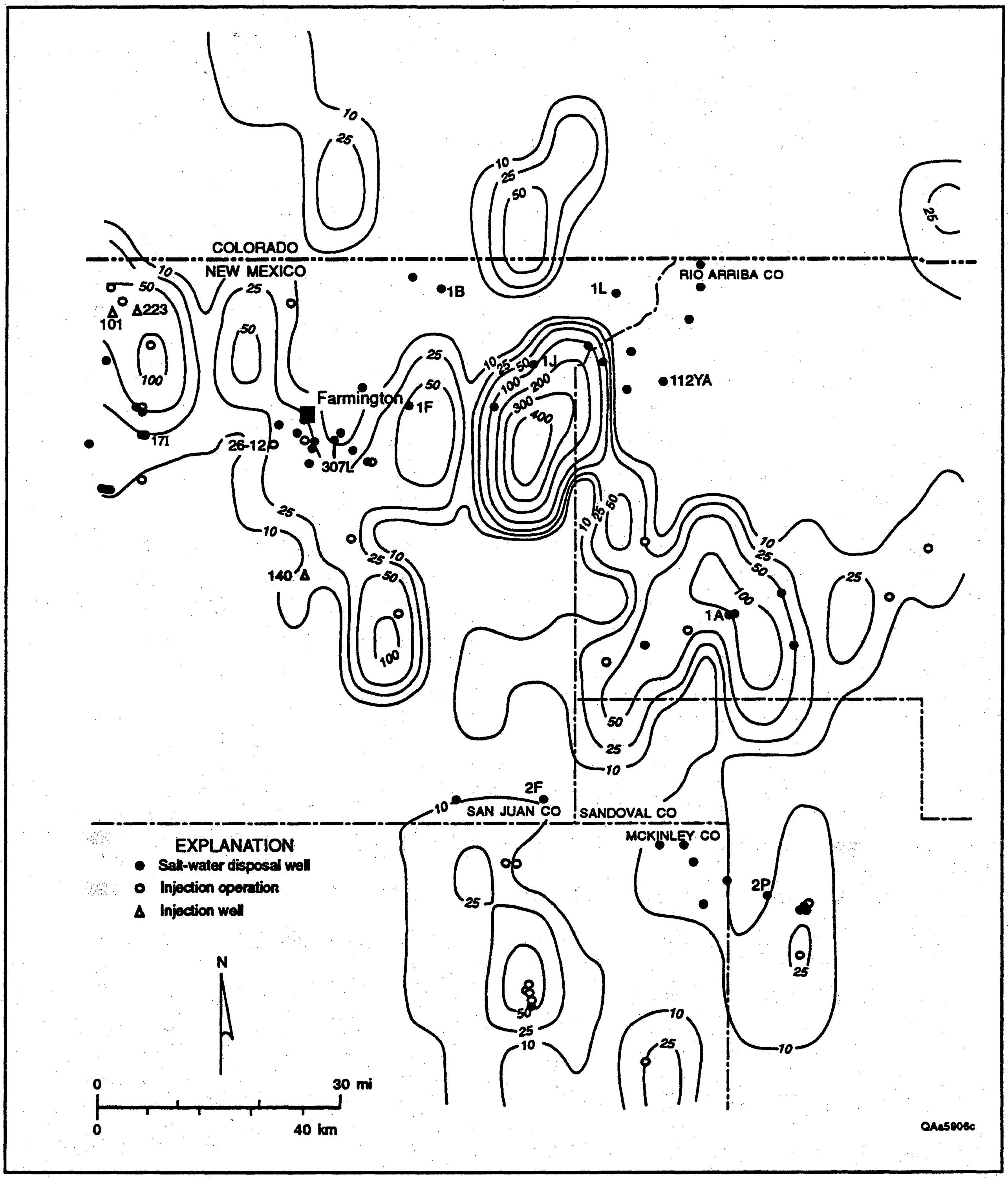


Figure 18. Contour map of the estimated distribution of abandoned wells at a 0.1° × 0.1° scale, San Juan Basin, with locations of Class II wells (as of 1989–1990) superposed. Open circles mark the centroids of injection operations.

Table 5. Estimated number of abandoned wells, San Juan Basin.

Area of interest	Number of abandoned wells [1]	Area (sq mi)	Area (sq km)	Area (thousand acres)
Entire area of petroleum operations in San Juan Basin and surrounding area	6,050	22,000	56,000	14,080
Entire area of available hydrologic data	5,700	18,500	47,900	11,840
Principal area of petroleum operations	4,500	13,000	33,700	8,320
Area of petroleum operations with reliable pressure data	4,000	8,400	21,800	5,380
All positive residual areas combined	1,000	1,000	2,600	640

Note:

(1) Sum of individual well counts of cells which lie partially or completely within the area of interest; values are approximate.

Effects of Class II Injection

Head-Buildup Calculations for Selected EOR Injection Wells

Hypothetical hydraulic head buildup in the vicinity of Class II wells was calculated to illustrate how injection may affect the natural hydraulic gradient. One high-volume injection well from each of four EOR projects in the San Juan Basin was selected as an example (table 6; fig. 18). Transmissivity and storativity values were computed on the basis of typical hydrologic properties for the injection formation ("Gallup" [Tocito] sandstone) in the vicinity of the injection project (Fassett and others, 1978a). Head buildup at various radial distances from the wellbore was calculated (eq. 3) for continuous injection over one yr, 20 yr, and 40 yr (appendix IV).

Three of the four selected EOR wells are located in negative residual areas in which the calculated pre-production hydraulic gradient is downward from the USDWs to the hydrocarbon reservoirs. The fourth well (West Bisti Pressure Maintenance Project [PMP], well no. 140) is located in a positive residual,

Table 6. Characteristics of selected enhanced-recovery injection wells, San Juan Basin.

Reservoir, project, operator; well [1]	Injection zone(s)	Overlying USDW	Perforated interval thickness (ft) [2]	Maximum injection rate (bpd) [3]	Surface injection pressure (psi) [4]	Transmissivity (gpd/ft) [5]	Storage coefficient (dimensionless) [6]	Residual head (oil & gas head - USDW head) (ft) [7]	Radius of area where inj. head + residual head > 0 (ft) [8] 1 yr	20 yrs	40 yrs
Bisti - Lower Gallup, West Bisti PMP, Chevron U.S.A. Inc.; Well No. 140	Lower "Gallup" sandstone	Tertiary Undivided	29	1198 (May 1987)	500 (May 1987)	13.20	0.000050	+50	Total residual always positive		
		Upper Cretaceous Undivided						+390	Total residual always positive		
Cha Cha Gallup Humble Northwest Cha Cha-Gallup PMP, Mountain States Petroleum Corp. (previously operated by Suburban Propane Gas Corp.); Well No. 26-12	"Gallup" sandstone	Tertiary Undivided	10	29 (July 1987)	800 (July 1987)	10.37	0.000018	-445	Total residual always negative		
		Upper Cretaceous Undivided						-485	Total residual always negative		
Horseshoe Gallup Humble Horseshoe Gallup PMP No. 2, Marmac Petroleum Co. (formerly Solar Petroleum, Inc.); Well No. 101	"Gallup" sandstone	Dakota Sandstone	13	292 (October 1987)	760 (October 1987)	21.29	0.000024	-750	2.8	12	18
Many Rocks Gallup Many Rocks-Gallup PMP No. 1, Marmac Petroleum Co. (formerly Solar Petroleum, Inc.); Well No. 223	"Gallup" sandstone	Dakota Sandstone	8	148 (March 1987)	710 (March 1987)	21.11	0.000015	-1165	Total residual always negative		

Notes:

(1) Reservoir, operator, project, and well as shown in May 1990 injection report (New Mexico Oil Conservation Division, 1990d).
(2) Data from "hard-copy" well files of New Mexico Oil Conservation Division, Santa Fe, NM.
(3) Barrels per day, calculated from injection volume of month indicated, divided by 31; data from March, May, July, and October 1987 monthly injection reports (New Mexico Oil Conservation Division, 1987).
(4) Average injection pressure for month indicated (data from same sources as in note 3).
(5) Transmissivity in gallons per day per foot.
(6) Storage coefficient is dimensionless.
(7) Head difference (Δhn) determined from residual potentiometric surface maps at approximate location of injection well.
(8) Determined by adding head due to injection (Δhi - read from buildup plots) to residual head in vicinity of injection well (Δhn - from residual potentiometric surface maps; see note 7).

which suggests that upward flow from reservoirs to the Upper Cretaceous USDW could occur without injection. Among the wells in negative residuals, the calculated head buildup in the well with the highest injection volume (Humble Horseshoe Gallup PMP no. 2, well no. 101) would be great enough to reverse the hydraulic gradient (fig. 19). However, the maximum radius of the area of induced upward flow (the area of review) would be only 18 ft (5.5 m) after 40 yr of injection (table 6), far less than the typical 1,320-ft (402-m) spacing between injectors and producing wells (appendix I). Still, this example illustrates that the use of positive residuals is insufficient for screening in instances where Class II injection reverses a downward hydraulic gradient.

Calculating hydraulic head or reservoir pressure buildup relative to pre-production conditions, which is mandated by the CFR (U. S. Office of the Federal Register, 1987), may overestimate the actual hydraulic head or reservoir pressure in instances of injection for EOR. In three of the four EOR injection wells considered here, recent bottomhole pressures obtained from PI are less than the initial field and/or discovery well pressures (Fassett and others, 1978a, 1983). For the fourth, the Humble Northwest Cha Cha-Gallup PMP, initial (1,630 psi [11.24 MPa]) and recent (1,637 psi [11.29 MPa]) BHPs were similar. Given that the pressure maintenance projects probably would not have been needed had the original formation pressures persisted, the existence of lower-than-calculated reservoir pressures following injection is logical.

Head-Buildup Calculations for Selected Salt-Water Disposal Wells

Ten of the 34 SWD wells which were active in March and/or April 1990 were selected for head-buildup calculations on the basis of high surface-injection pressures, high injection volumes, and geographic distribution (table 7; fig. 18). Transmissivity and storativity values were determined in the same fashion as for the EOR examples. Head buildup due to injection was calculated for a range of transmissivity values for each formation (appendix V); an increase in transmissivity reduces the head buildup at a particular distance from the well but increases the radius of impression, that is, the maximum distance at which any head buildup occurs.

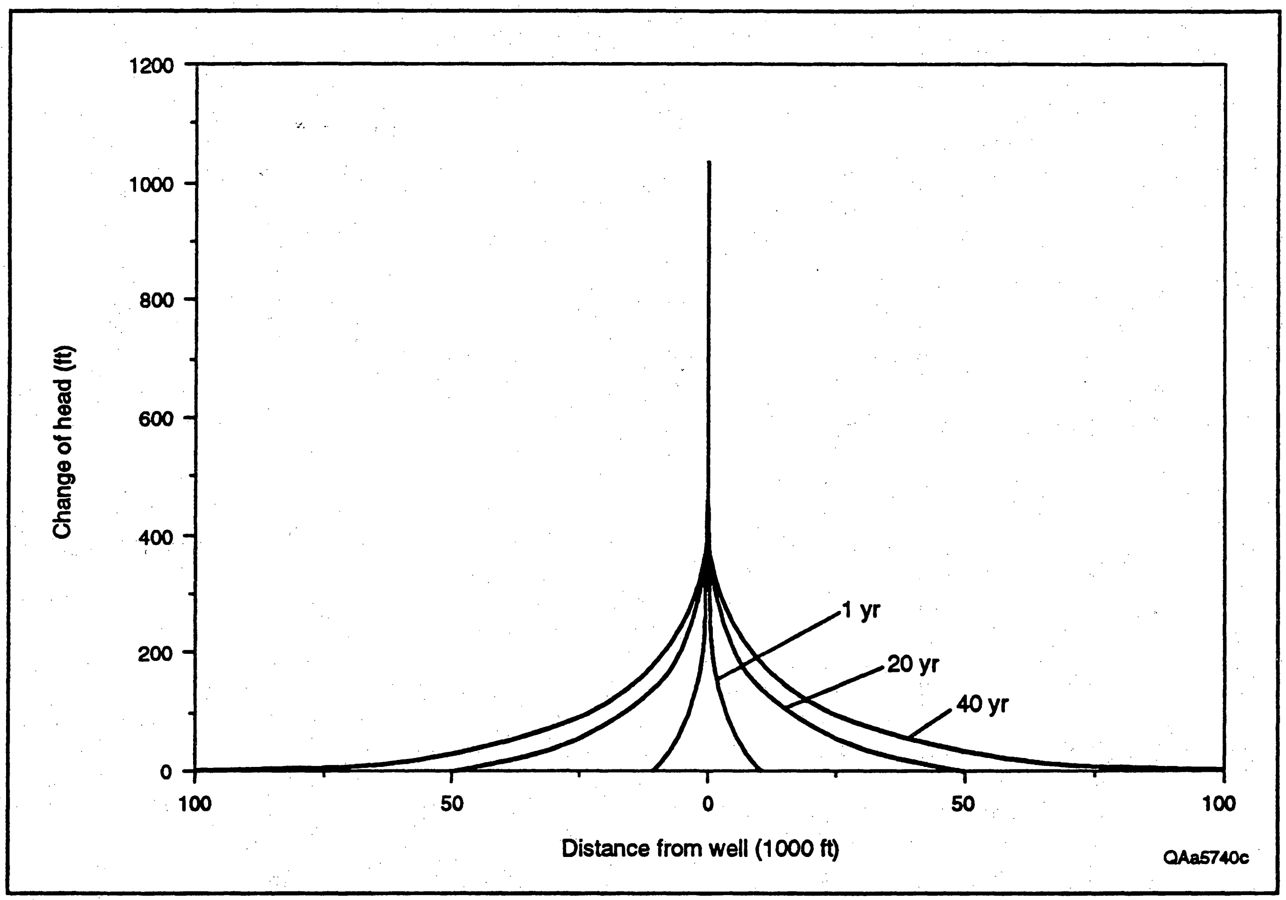


Figure 19. Calculated hydraulic-head buildup around well no. 101, Humble Horseshoe Gallup Pressure Maintenance Project No. 2, Horseshoe Gallup reservoir, San Juan Basin.

Of the ten SWD wells, the "natural" head difference between the composite oil and gas section and each of the overlying USDWs is negative (downward-directed) in five cases and positive in four cases. The remaining disposal well is located in an area for which no oil and gas pressure data were available. The calculated head buildup due to disposal would be sufficient to reverse the inferred negative head differential in two cases (BHP Petroleum well no. 307L and Meridian Oil well no. 1J); for well no. 307L, the reversal in gradient is calculated assuming a low estimate of injection-zone transmissivity (table 7).

The accuracy of regional positive residuals in the San Juan Basin was evaluated by comparison with local hydraulic gradients calculated from non-PI data in the vicinity of the disposal wells. Bottomhole pressures (calculated from surface injection pressures) in the ten SWD wells selected for study were compared with pressure distributions in the overlying USDWs using the following procedures. The SWD

Table 7. Characteristics of selected salt-water disposal wells, San Juan Basin.

Operator, lease, well [1]	Injection zone(s) [2]	Overlying USDW(s)	Perforated interval thickness (ft) [2]	Maximum injection rate (bpd) [3]	Surface injection pressure (psi) [4]	Transmissivity (gpd/ft) [5]	Storage coefficient (dimensionless) [6]	Residual head (oil & gas head - USDW head) (ft) [7]	Radius of area where inj. head + residual head > 0 (ft) [8]: min. T, 1 yr	min. T, 40 yrs	max. T, 1 yr	max. T, 40 yrs
Basin Disposal, Inc., Disposal, Well 1 F	Cliff House Ss. of Mesaverde Gp.	Tertiary Und.	46	1440 (April 1990)	1,080 (April 1990)	14.96 min 1795 max	0.00009	+437	Total residual always positive			
BHP Petroleum, Inc., Gallegos Canyon Unit, Well 307 L	Cliff House Ss. of Mesaverde Gp.	Tertiary Und.	815	288 (April 1990)	929 (April 1990)	14.96 min 1795 max	0.00153	-403	45	290	Total residual always negative	
Conoco, Inc., Jicarilla 30, Well 1 A	Cliff House Ss., Menefee Fm., and Pt. Lookout Ss. of Mesaverde Gp.	Tertiary Und.	265	136 (March 1990)	1,510 (March 1990)	14.96 min 1795 max	0.00048	-3365	Total residual always negative			
Meridian Oil, Inc., Cedar Hill SWD, Well 1 B	Morrison Fm., Bluff Ss., Summerville Fm., and Entrada Ss.	Tertiary Und.	947	2330 (March 1990)	1,778 (March 1990)	748 min 3748 max	0.00182	-2385	Total residual always negative			
Meridian Oil, Inc., Middle Mesa SWD, Well 1 L	Bluff Ss. and Entrada Ss.	Tertiary Und.	371	4399 (March 1990)	710 (March 1990)	1000 min 2500 max	0.00071	+365	Total residual always positive			
Meridian Oil, Inc., Pump Canyon SWD, Well 1 J	Morrison Fm. and Entrada Ss.	Tertiary Und.	230	4482 (March 1990)	1,340 (March 1990)	748 min 3748 max	0.00044	-30	6,500	41,000	720	4,500
Meridian Oil, Inc., San Juan 30-6 Unit, Well 112Y A	Morrison Fm. and Entrada Ss.	Tertiary Und.	1024	6584 (April 1990)	1,053 (April 1990)	1000 min 2500 max	0.00199	-895	Total residual always negative			
Merrion Oil and Gas Corp., Federal 11C, Well 2 P	Gallup Ss.	Tertiary Und.	548	4487 (March 1990)	1,250 (March 1990)	748 min 2992 max	0.00100	No oil and gas pressure data in this area	Not applicable			
Merrion Oil and Gas Corp., Santa Fe 20, Well 2 F	Morrison Fm. and Entrada Ss.	Tertiary Und. Mesaverde Gp.	994	4294 (March 1990)	850 (March 1990)	748 min 2500 max	0.00192	+730	Total residual always positive			
Tiffany Gas Co., USG Section 19, Well 17 I	Entrada Ss. and Chinle Fm.	Mesaverde Gp.	1055	702 (March 1990)	550 (March 1990)	500 min 2500 max	0.00201	+1300	Total residual always positive			

Notes:

(1) Operator, project, and well number as shown in April 1990 saltwater disposal report (New Mexico Oil Conservation Division, 1990c).
(2) Data from "hard-copy" well files of New Mexico Oil Conservation Division, Santa Fe, NM.
(3) Barrels per day, calculated from monthly disposal volume divided by 31 (March) or 30 (April) (New Mexico Oil Conservation Division, 1990b, 1990c).
(4) Average injection pressure for the month (data from same sources as in note 3).
(5) Transmissivity range, in gallons per day, per foot; from ranges reported by Stone and others (1983) using conversion T(gpd/ft) = T(square-ft/day) x 7.48(gal/cubic-ft).
(6) Storage coefficient is dimensionless; calculated from typical formation parameters.
(7) Head difference (Δhn) determined from residual potentiometric surface maps at approximate location of disposal wells.
(8) Determined by adding head due to injection (Δhi - read from head-buildup plots) to residual head in vicinity of disposal well (Δhn - read from residual potentiometric surface maps; see note 7); values shown correspond to minimum and maximum transmissivities (see note 5).

wells were first located on the computer-generated potentiometric surfaces of the six USDW aquifer systems to determine which USDWs directly overlie disposal areas. Pressure-depth graphs were then constructed for each overlying USDW from four to ten water wells near each SWD well. These profiles (not shown) illustrate that the USDWs in the vicinity of nine of the ten SWD wells (all but Tiffany Gas no. 17 I) are subhydrostatic to varying degrees. It is uncertain whether these subhydrostatic conditions reflect natural underpressuring, ground-water production, or a combination of the two.

In contrast to the USDWs, the injection zones were overpressured for the five SWD wells (out of ten studied) for which initial formation pressures were available from NMOCD (table 8). Values of hydraulic head in the five injection zones (converted from BHP using a specific weight of 0.433 psi/ft) were 3,100 ft to 4,270 ft (945 m to 1,301 m) above land surface, whereas water levels in the USDWs tended to be below land surface, indicating upward hydraulic gradients between the injection zones and the USDWs. However, on the basis of the contoured PI reservoir pressures, four of these five SWD wells were located within negative residuals, which indicates that regional residual mapping may be inaccurate in some instances. Bottomhole pressure values in the injection zones were converted to hydraulic head without accounting for friction losses associated with injection. However, the example of Meridian Oil well no. 112YA suggests that friction losses are minor in situations where there is a significant head difference between an injection zone and a USDW. Neglecting friction losses resulted in the BHP being overestimated by only 12 percent, that is, the head values in the disposal zone would still be 1,350 ft to 2,050 ft (411 m to 625 m) above land surface.

Abandoned Wells Affected by Injection and Disposal Operations

Each of the two forms of area of review determination, fixed radius and calculated radius (appendix I), offers certain advantages and disadvantages. The fixed radius method may require review of unnecessarily large areas but can be accomplished with minimal data. The calculated radius may result in a much smaller AOR but requires more data and analysis. We have made approximate estimates of numbers of abandoned wells affected by injection and disposal operations using both methods. Because

Table 8. Hydraulic head in injection zones of selected salt-water disposal wells, San Juan Basin.

Unit	Well #	Land surface (LS) elevation (ft above msl)	SITP (psi)	Reservoir interval (ft below LS)	BHP (psi)	Head (fresh-water) (ft)	(Head) - (LS elevation) (ft)
Basin Disposal Inc.	Disposal #1F	5710	1850	3652-3698	3440	9980	4270
BHP Petroleum Inc.	Gallegos Canyon Unit #307L	5360	1400	2592-3500	2720	8590	3230
Conoco Inc.	Jicarilla 30 #1A	6990 (kelly)		4846-5585	3600	10090	3100
Meridian Oil Inc.	Cedar Hill SWD #1B	6059		8180	4910	9220	3160
Meridian Oil Inc.	San Juan 30-6 Unit #112YA	6675		8200	4974	9960	3290

the calculated-radius AOR analyses were limited to selected Class II wells, the total abandoned well count is smaller than the upper estimate of abandoned wells based on fixed-radius AOR analyses, which include all Class II wells in the basin.

The number of abandoned wells which lie within 0.5 mi (0.8 km) of EOR injection wells (the fixed radius prescribed by NMOCD) was difficult to estimate accurately because (1) it was not practical in the present scope of work to consider the exact distribution of all EOR wells within the fields and (2) the precise location of abandoned wells was not provided by PI. To simplify analysis, EOR injection wells were assumed to be uniformly distributed throughout each of the fields with injection operations. This reduces the task to one of counting the number of abandoned wells that lie interior to or within 0.5 mi (0.8 km) of each field. In practice, we used producing-unit boundaries to approximate outlines of fields which were larger than the Class II well symbols used on the maps (extracted from field summaries in Fassett and others, 1978a, 1983) and used the well symbols themselves for fields which were smaller (fig. 18). Each well symbol has an area of approximately 0.78 mi^2 (2.0 km^2). The difficulty in determining the precise distribution of abandoned wells within each $0.1° \times 0.1°$ cell was minimized by calculating a high and low estimate for each field of interest. The high estimate assumes that all of the abandoned wells within each cell are located within the boundaries of the field(s) within that cell; the low estimate assumes that the abandoned wells are evenly distributed throughout each cell, so that the number is directly proportional to the area of the cell occupied by the field(s). If a field or map symbol extends into more than one cell, then a factor representing the percentage of the AOR in each cell must be incorporated into the computations.

The number of abandoned wells which lie within 0.5 mi (0.8 km) of a salt-water disposal well was estimated using the same approach as was used for EOR injection wells. The only difference is that the disposal wells are single points with precise locations, so that the circular portion of the map symbol itself could be used directly to represent the AOR.

Thus, approximately 200 to 800 of the 6,104 plugged and abandoned wells in the basin are located within 0.5 mi (0.8 km) of a field with an EOR injection operation active in 1989 (approximately 5,304 to 5,904 are more than 0.5 mi [0.8 km] from an active EOR operation) (table 9). As few as 20 to as many as 800 plugged and abandoned wells in the San Juan Basin were within 0.5 mi (0.8 km) of a SWD well active in 1989 (approximately 5,304 to 6,084 wells are beyond the 0.5-mi [0.8-km] radius) (table 9). Approximately 20 to 120 plugged and abandoned wells are within 0.5 mi (0.8 km) of both a field with an active EOR injection operation and an active SWD well (table 9).

Similar counting techniques were used to estimate the number of abandoned wells within the area of head buildup of the four EOR wells and ten SWD wells examined previously. The calculated AOR radii were read from the head-buildup plots and the areas of the corresponding circles were computed. The estimate of the number of abandoned wells, as with the high estimate for the fixed radius method, assumes that all abandoned wells for a particular cell are located within the AOR in that cell. Again, if an AOR extends into more than one cell, then a factor representing the percentage of the AOR in each cell must be incorporated into the computations. As shown in table 10, as many as 695 abandoned wells (rounded to nearest multiple of five) could lie within areas of head buildup for selected EOR injection wells and as many as 329 abandoned wells could lie within areas of head buildup for selected SWD wells after 40 yr of injection. Because the ages of the EOR and SWD wells vary, the totals do not reflect the numbers of abandoned wells within areas of head buildup at a single time. As noted previously, the head-buildup calculations are likely to overestimate the actual head buildup in instances of EOR injection. In addition, the calculations assume continuous injection at a constant (reported) rate, which is probably not accurate.

Table 9. Estimated number of abandoned wells within 0.5-mi (0.8-km) fixed radius of Class II wells, San Juan Basin.

	Abandoned wells in the vicinity of injection operations and disposal wells	
	Low estimate	High estimate
Number of abandoned wells within 0.5 mi of fields with EOR injection projects active or inactive in 1989	300	1,200
Number of abandoned wells within 0.5 mi of fields with EOR injection projects active in 1989	200	800
Number of abandoned wells within 0.5 mi of fields with EOR injection projects active in 1989 and within positive residual areas	10	30
Number of abandoned wells within 0.5 mi of SWD wells active or inactive in 1989	20	1,000
Number of abandoned wells within 0.5 mi of SWD wells active in 1989	20	800
Number of abandoned wells within 0.5 mi of SWD wells active in 1989 and within positive residual areas	10	360
Number of abandoned wells within 0.5 mi of both an EOR injection project and an SWD well active in 1989	20	120

Table 10. Estimated number of abandoned wells within calculated head buildup of selected Class II wells, San Juan Basin.

EOR Injection Reservoir, project, operator; well [1]	Number of abandoned wells within area of review [3]
Bisti - Lower Gallup, West Bisti PMP, Chevron U.S.A. Inc.; Well No. 140	305
Cha Cha Gallup Humble Northwest Cha Cha-Gallup PMP, Mountain States Petroleum Corp. (previously operated by Suburban Propane Gas Corp.); Well No. 26-12	90
Horseshoe Gallup Humble Horseshoe Gallup PMP No. 2, Marmac Petroleum Co. (formerly Solar Petroleum, Inc.); Well No. 101	230
Many Rocks Gallup Many Rocks-Gallup PMP No. 1, Marmac Petroleum Co. (formerly Solar Petroleum, Inc.); Well No. 223	70
total	695

Salt-Water Disposal Operator, lease, well No. [2]	Number of abandoned wells within area of review [3]
Basin Disposal, Inc., Disposal, Well 1F	83
BHP Petroleum, Inc., Gallegos Canyon Unit, Well 307 L	4
Conoco, Inc., Jicarilla 30, Well 1 A	138
Meridian Oil, Inc., Cedar Hill SWD, Well 1 B	1
Meridian Oil, Inc., Middle Mesa SWD, Well 1 L	4
Meridian Oil, Inc., Pump Canyon SWD, Well 1 J	23
Meridian Oil, Inc., San Juan 30-6 Unit, Well 112Y A	2
Merrion Oil and Gas Corp., Federal 11C, Well 2 P	6
Merrion Oil and Gas Corp., Santa Fe 20, Well 2 F	17
Tiffany Gas Co., USG Section 19, Well 171	51
total	329

Notes:
(1) Reservoir, operator, project, and well as shown in May 1990 EOR report (New Mexico Oil Conservation Division, 1990d).
(2) Operator, project, and well number as shown in April 1990 SWD report (New Mexico Oil Conservation Division, 1990c).
(3) Estimated from abandoned well distribution map using technique described in text.

Total Number of Abandoned Wells in Potential Risk Areas

The total population of abandoned wells in the San Juan Basin potentially at risk based on hydraulic factors is determined by first adding (1) the number of abandoned wells within the positive residual areas (table 9) and (2) the numbers of abandoned wells within the AORs of injection operations or disposal wells that are outside the positive residual areas. The number of wells that fall within multiple categories (such as wells within a positive residual area and an AOR, or wells within the AORs of both an EOR injection well and a SWD well) are then subtracted to avoid double counting. Based on a 0.5-mi (0.8-km) fixed radius and considering only EOR injection operations and SWD wells active in 1989, an approximate estimate of the number of abandoned wells in potential risk areas is 1,180 to 2,090, derived as follows:

	1,000	abandoned wells within positive residual areas
+	200 to 800	within 0.5 mi (0.8 km) of active EOR injection wells
+	20 to 800	within 0.5 mi (0.8 km) of active SWD wells
	1,220 to 2,600	abandoned wells
−	10 to 30	within 0.5 mi (0.8 km) of EOR injection wells and within positive residuals
	1,210 to 2,570	abandoned wells
−	10 to 360	within 0.5 mi (0.8 km) of SWD wells and within positive residuals
	1,200 to 2,210	abandoned wells
−	20 to 120	wells within 0.5 mi (0.8 km) of both an EOR injection well and SWD well
	1,180 to 2,090	abandoned wells in potential risk areas

Although this total would probably be different if a calculated radius were used, it appears that only a fraction of the 6,104 abandoned wells in the San Juan Basin lie within areas of natural or induced upward hydraulic gradients.

CASE STUDY—GREATER PERMIAN BASIN

Background

The greater Permian Basin is a mature petroleum province covering an area of approximately 110,000 mi^2 (280,000 km^2) in central and west Texas and southeastern New Mexico. In 1990, the basin produced nearly 1,530 mbd oil and 5,700 mmcfd gas from an estimated 135,850 oil wells and 21,400 gas wells (table 11), a significant contribution to the total U.S. production of 7,300 mbd oil and 46,600 mmcfd gas from 587,800 oil and 264,600 gas wells (data from Gruy Engineering Corp. [1989], updated with industry trends from World Oil [1989, 1990]). Oil and gas are produced from Ordovician- to Permian-age reservoirs; the most productive formations in the basin range in depth from 2,000 ft to 7,000 ft (600 m to 2,100 m). However, significant volumes of gas (nearly 10.5 Tcf [297 million m^3] through the end of 1986) have also been produced from formations deeper than 15,000 ft (4,600 m).

Ground water in the greater Permian Basin is produced primarily from aquifers in Cretaceous (Trinity and Edwards-Trinity [Plateau]), Tertiary (Ogallala), and Quaternary (Seymour) and indeterminate Cenozoic (Pecos alluvium) units. Minor aquifers occur in Cambrian-Ordovician (Hickory and Ellenburger-San Saba), Permian (Capitan Reef Complex, Rustler, and Blaine), Triassic (Dockum), and Quaternary (Lipan) units (Ashworth and Flores, 1991).

Data Sources

Reservoir Pressure and Aquifer Water-Level Data

Data on oil and gas reservoir locations, completion depths, and pressures were primarily obtained from the WHCS data base maintained by PI. Table 12 summarizes the well counts and the number of pressure data values retrieved from this data base. It should be noted that the numbers of wells in table 12 do not agree with those in table 11, reflecting the differences in sources of data (values updated from

Table 11. Estimated numbers of producing and abandoned oil and gas wells as of the end of 1989, greater Permian Basin.

		Oil				Gas				Total	Total	Class II Injectors	
State	RRC Dist.	Producers [1]	Abandoned Producers [2]	Infield Dry [2]	Other Dry [2,3]	Producers [1]	Abandoned Producers [2]	Infield Dry [2]	Other Dry [2,3]	O & G Producers	O & G Dry & Abandoned	EOR [4]	SWD [4]
N. Mexico		15,500	12,000	6,800	3,400	4,000	350	1,050	500	19,500	24,100	4,600	600
Texas	7b	14,800	22,500	21,650	7,900	5,900	4,000	8,650	3,150	20,700	67,850	4,700	2,700
	7c	12,700	19,300	18,600	6,800	5,000	3,400	7,300	2,650	17,700	58,050	1,000	900
	8	42,100	63,150	31,600	10,750	2,600	1,750	1,950	650	44,700	109,850	15,200	3,300
	8a	23,600	35,400	8,500	3,100	250	200	100	50	23,850	47,350	12,700	1,300
	9	27,150	40,750	38,000	12,900	3,650	2,400	5,100	1,750	30,800	100,900	7,900	4,600
TOTAL =		**135,850**	**193,100**	**125,150**	**44,850**	**21,400**	**12,100**	**24,150**	**8,750**	**157,250**	**408,100**	**46,100**	**13,400**
Total (Texas)[5] =		**186,200**	**281,100**	**185,200**	**65,300**	**46,800**	**31,500**	**47,700**	**17,000**	**233,000**	**627,800**	**48,600**	**21,250**
% covered (TX) =		64.6	64.4	63.9	63.5	37.2	37.3	48.4	48.5	59.1	61.2	85.4	60.2

Notes:

1. Producing well counts are from table 1 in Gruy Engineering Corp., 1989, updated with published industry trends.
2. The population of abandoned producers, infield and other dry wells is a calculated fraction of the producers using Gruy table.
3. The Other Dry category includes wildcat, new pool/field extension and test wells.
4. Class II injection wells include all permitted wells (source: RRC UIC & NMOCD data bases).
5. Total (Texas) well populations include all RRC districts.

Table 12. Well populations and pressure data counts from Petroleum Information Inc., greater Permian Basin.

Category	Permian N. Mexico	Permian Texas	Totals
Oil wells	48307	226151	274458
Gas wells	6819	21868	28687
W.I. wells	3839	15034	18873
Dry New Field wildcats	not available	39371	39371
Dry Outposts & Extensions	730	894	1624
Dry Shallower Pool Tests	752	1095	1847
Dry Deeper Pool Tests	2656	4607	7263
Dry New Pool Wildcats	775	442	1217
Dry Development Wells	7162	30808	37970
Subtotal	12075	77217	89292
# Avg. Shut-in Tubing Pressures: pre-1950	6	33	39
# Avg. Shut-in Tubing Pressures: 1950-59	50	240	290
# Avg. Shut-in Tubing Pressures: 1960-69	91	582	673
# Avg. Shut-in Tubing Pressures: 1970-79	120	461	581
# Avg. Shut-in Tubing Pressures: 1980-89	254	1564	1818
Subtotal	521	2880	3401
# Avg. Bottomhole Pressures: pre-1950	2	5	7
# Avg. Bottomhole Pressures: 1950-59	8	21	29
# Avg. Bottomhole Pressures: 1960-69	36	371	407
# Avg. Bottomhole Pressures: 1970-79	27	327	354
# Avg. Bottomhole Pressures: 1980-89	21	31	52
Subtotal	94	755	849
# Avg. DST FSIPs: pre-1950	5	26	31
# Avg. DST FSIPs: 1950-59	67	452	519
# Avg. DST FSIPs: 1960-69	100	500	600
# Avg. DST FSIPs: 1970-79	111	392	503
# Avg. DST FSIPs: 1980-89	82	251	333
Subtotal	365	1621	1986

(1) Oil and gas well counts include producers and infield dry, but not abandoned producers.
(2) DST FSIPs are final shut-in formation pressures during drillstem tests.

Gruy Engineering [1989] versus PI). Of the 6,236 average pressure values obtained from PI, 3,401 were average surface shut-in tubing pressures, 849 were bottomhole pressures, and 1,986 were bottomhole-drillstem test pressures.

As in the San Juan Basin study, not all of these pressure values could be used. In the absence of measured bottomhole pressures, bottomhole pressures were calculated from surface SITPs using pressure gradients obtained from Dwight's Natural Gas Well Production Histories data base (Dwight's Energydata Inc., unpublished data, 1990). To determine gradients, reservoirs in the PI data base were matched to the same or equivalent (in location, depth, and formation) reservoirs in the Dwight's data base, which contains both the surface and bottomhole pressures. If the surface shut-in pressures were comparable in the two data bases, then an average fluid gradient was computed from the Dwight's data and applied to the PI data for determining the bottomhole pressure. Approximately 900 gradient values for the greater Permian Basin were calculated and applied in this fashion. Overall, 2,077 pressure values (one per reservoir) for the greater Permian Basin were used for mapping, including 220 values extracted from other data bases maintained at the Bureau of Economic Geology. Of the 2,077 values, 1,793 represented reservoirs shallower than 10,000 ft (3,000 m) (436 Permian reservoirs, 1,205 Pennsylvanian, and 152 lower- to middle-Paleozoic [Ordovician, Silurian-Devonian, and Mississippian]). The remaining 284 values represented reservoirs deeper than 10,000 ft (3,000 m).

Water-level data for the USDW aquifers were obtained from the TWDB and the USGS (for New Mexico). Only those wells in which the static water level had been measured between 1980 and 1990 were used.

Abandoned Well Data

In the same fashion as the San Juan Basin case study, the numbers of abandoned wells were updated from Gruy Engineering (1989) by incorporating trends in U.S. well drilling and completions (World Oil, 1989, 1990). A total of 43,290 abandoned wildcats was estimated based on data provided by PI. An updated total of 351,886 abandoned wells other than dry new-field wildcats was estimated as detailed in the Methods section. The sum of the 43,290 abandoned wildcats and 351,886 abandoned non-wildcats yields an overall total of 395,176 abandoned wells for the greater Permian Basin. In comparison, Gruy Engineering Corp. (1989, their table 1) estimated a 1988 total of 390,051 abandoned non-wildcats for the Delaware Basin, Permian Basin, and North and Central Texas regions (basins 34, 42, and 43 defined by Michie & Associates [1988]), a somewhat larger area.

Class II Injection Data

Information on Class II injection well locations and injection volumes and pressures was obtained from State agencies in Texas and New Mexico. During the period March–May 1990, 40,720 of the 59,416 SWD and EOR injection wells in the greater Permian Basin were active or shut-in (data from Railroad Commission of Texas [RRC] and NMOCD files) (table 13); the remaining 18,696 Class II wells were abandoned. Additional data processing was required to convert the available injection well data into a usable format for mapping. Because injection-well locations were listed with reference to section and block boundaries, latitude and longitude coordinates had to be calculated. Locations of Class II wells in southeast New Mexico were converted from township-range-section-unit format to latitude-longitude coordinates using a computer program. Latitude-longitude coordinates for 35,088 active, shut-in, and abandoned Class II wells in the Texas portion of the basin were obtained from PI by matching their API numbers to wells in the PI data base. Coordinates for the remaining Texas injection wells could not be exactly determined; their distribution was compiled simply by county (table 14).

Of the 40,720 active or shut-in SWD and EOR injection wells, complete records on well locations, depths, and injection volumes and pressures existed for 18,293 (4,146 in New Mexico and 14,147 in Texas). These wells with complete records consisted largely of EOR injection wells (15,857 versus 2,436 SWD wells). Two broad areas in the greater Permian Basin exhibit relatively high populations of Class II wells for which complete records were available (fig. 20). The first area extends from Cochran and Hockley Counties south to Ward and Crane Counties, Texas, and west to Chaves and Eddy Counties, New Mexico. The other area is a narrower band in Garza, Scurry, Mitchell, and Howard Counties in

Table 13a. Number of Class II SWD and EOR injection wells, greater Permian Basin.

TX RRC Dist.	N of SWD & EOR wells	N of active and shut-in SWD & EOR wells	N of lat/long coordinates obtained	N of wells used in study*
7B	7,387	3,968	2,244	1,259
7C	1,889	1,024	1,597	532
8	18,487	13,517	16,802	5,819
8A	14,007	11,079	13,182	5,559
9	12,503	6,986	1,263	978
Total	54,273	36,574	35,088	14,147

* See table 13b.

Table 13b. Number of active and shut-in Class II SWD and EOR injection wells used for analysis, greater Permian Basin. Wells in this study include only active or shut-in wells for which data indicating the top <u>and/or</u> the bottom of the injection zone as well as permitted injection pressure <u>and</u> volume are given, <u>and</u> for which latitude-longitude location coordinates could be obtained.

TX RRC Dist.	Total N of wells used in study	N of SWD wells		N of EOR wells	
		active	shut-in	active	shut-in
7B	1,259	348	69	732	110
7C	532	194	19	267	52
8	5,819	609	130	4,383	697
8A	5,559	328	50	4,712	469
9	978	271	32	550	125
Total	14,147	1,750	300	10,644	1,453

Table 13c. Number of Class II EOR injection wells in southeastern New Mexico portion, greater Permian Basin (data from May 1990 injection report).

N of EOR injection wells active or shut-in during May 1990 (used in study)	**3,760***
N of plugged and abandoned EOR injection wells	795
N of 'CONVERTED' wells (cumulative injection volume given, but pressure blank; wells converted to production)	18
Total N of EOR injection wells in May 1990 inj. report (includes abandoned, active, and shut-in)	4,573

*82% of all EOR injection wells in southeast New Mexico were active or shut-in in May 1990 - all were used in this study.

Table 13d. Number of Class II SWD injection wells in southeastern New Mexico portion, greater Permian Basin (data from May 1990 injection report).

N of SWD injection wells active or shut-in in April 1990 (used in study)	**386***
N of plugged and abandoned SWD injection wells	140
N of disconnected SWD injection wells	44
Total N of SWD wells in April 1990 disposal report (includes abandoned, active, and shut-in)	570

*68% of all SWD wells in southeast New Mexico were active or shut-in in April 1990 - all were used in this study.

Table 14. Number of Class II wells by county, Texas portion, greater Permian Basin.

County	# of wells	County	# of wells	County	# of wells
Andrews	3448	Gaines	2061	Nolan	357
Archer	2015	Garza	526	Palo Pinto	171
Baylor	201	Glasscock	228	Parker	17
Borden	299	Grayson	323	Pecos	1498
Brown	342	Hale	149	Reagan	248
Callahan	786	Hamilton	5	Reeves	223
Clay	771	Hardeman	44	Runnels	188
Cochran	1371	Haskell	266	Schleicher	75
Coke	234	Hockley	2747	Scurry	1709
Coleman	385	Hood	4	Shackelford	1057
Comanche	28	Howard	1621	Stephens	1157
Concho	24	Irion	132	Sterling	112
Cooke	1304	Jack	725	Stonewall	491
Cottle	10	Jones	418	Sutton	32
Crane	1992	Kent	277	Taylor	337
Crockett	479	King	225	Terrell	1
Crosby	73	Knox	272	Terry	638
Culberson	223	Lamb	86	Throckmorton	638
Dawson	623	Loving	177	Tom Green	145
Denton	21	Lubbock	224	Upton	646
Dickens	16	Lynn	75	Ward	2083
Eastland	572	Martin	186	Wichita	3787
Ector	4183	McCulloch	18	Wilbarger	876
Edwards	5	Menard	30	Winkler	1368
Erath	13	Midland	357	Wise	216
Fisher	323	Mitchell	986	Val Verde	18
Floyd	2	Montague	644	Yoakum	2488
Foard	39	Motley	14	Young	1361

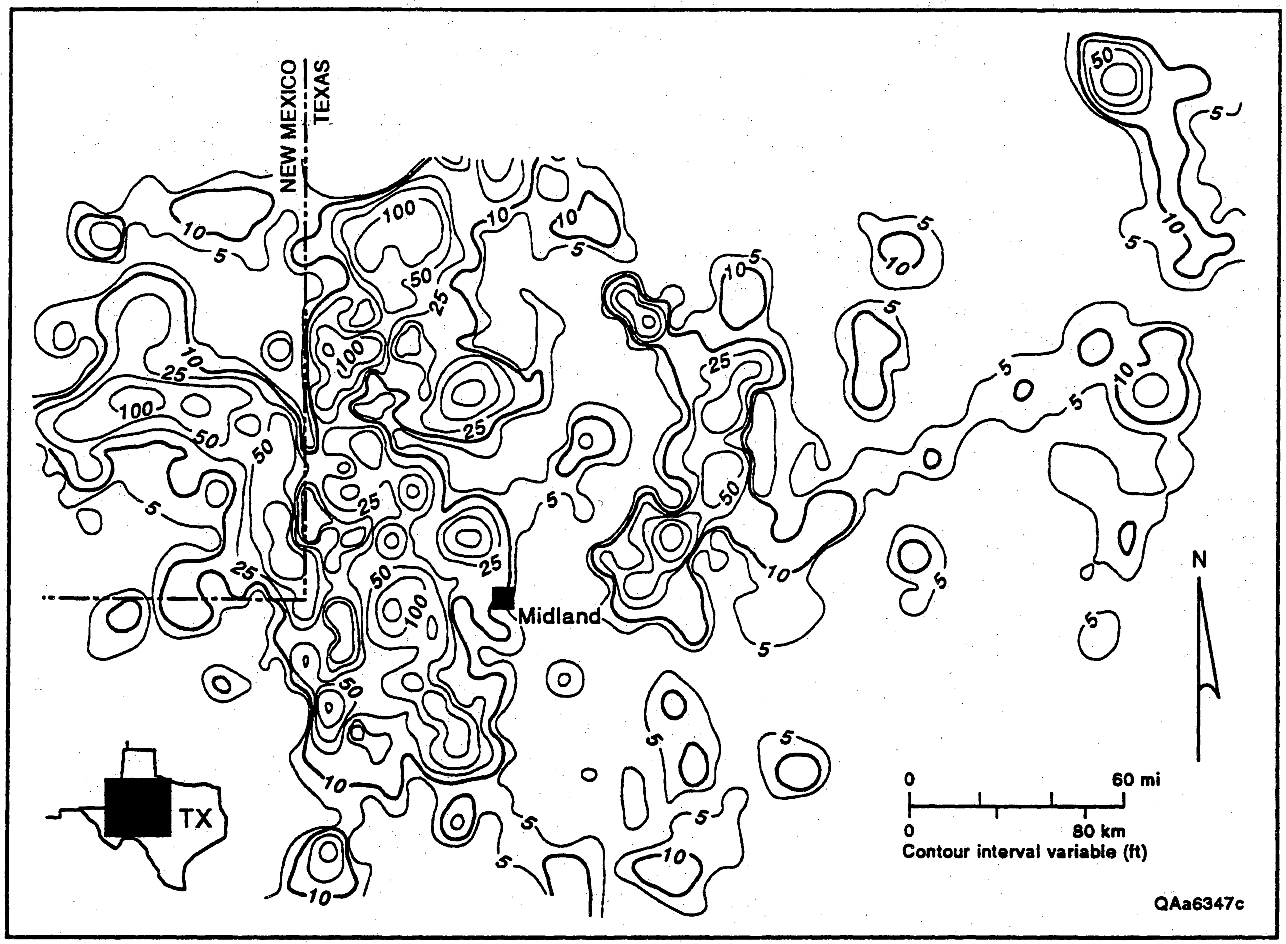


Figure 20. Contour map of Class II wells at a 0.1° × 0.1° scale, greater Permian Basin; 10-injection-well per cell contour delineated with bold outline.

west-central Texas. Injection well densities in these areas range from 100 to over 400 wells per 0.1° × 0.1° grid cell, that is, approximately 2.6 to 10 wells per mi^2 (1 to 4 wells per km^2).

Initial Hydraulic Conditions

Pressure-Depth Profiles

Figure 21 shows the variation of maximum bottomhole pressures with depth for 329 lower- to middle-Paleozoic, 1,347 Pennsylvanian, and 481 Permian reservoirs in the greater Permian Basin. It

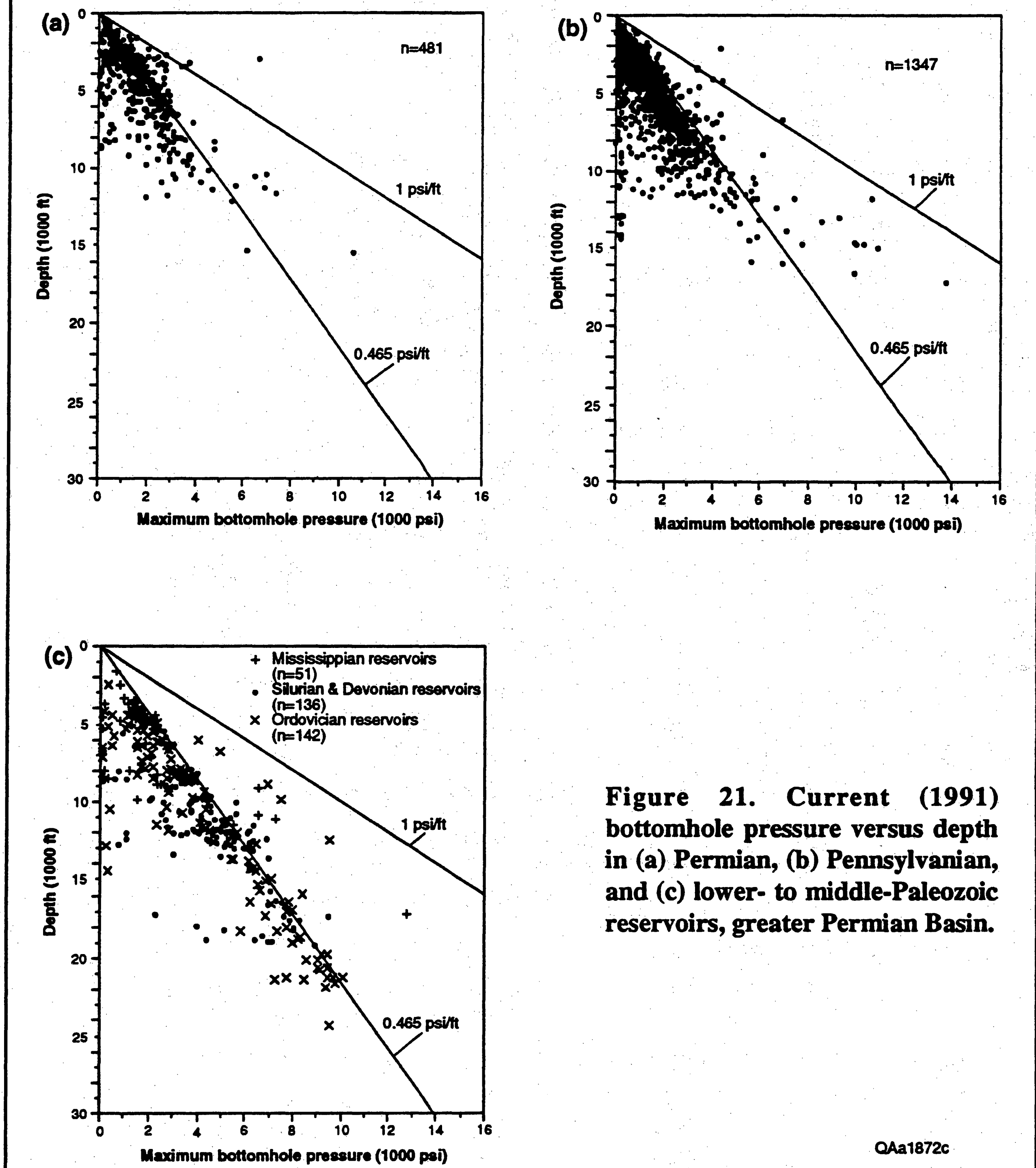


Figure 21. Current (1991) bottomhole pressure versus depth in (a) Permian, (b) Pennsylvanian, and (c) lower- to middle-Paleozoic reservoirs, greater Permian Basin.

should be noted that more data points were used for constructing the pressure-depth plots than for mapping because of unknown locations and other reasons previously mentioned. BHP values tend to lie along or below the line representing the brine hydrostatic gradient (slope = 0.465 psi/ft [10.5 kPa/m]). The TDS concentration corresponding to this specific weight (approximately 112,000 mg/L) lies within the range of TDS values in Permian Basin formation waters (45,000–385,000 mg/L) reported by Bein and Dutton (1993). Initial and current reservoir pressures from the Tertiary Oil Recovery Information System (TORIS) (U.S. Department of Energy, Bartlesville Project Office, unpublished data, 1989) (fig. 22) and Oil Atlas (fig. 23) data bases for the Permian Basin are shown for comparison. Initial pressure values, while not necessarily from the same reservoirs, were closer to hydrostatic than the maximum pressure values from the WHCS data base, which suggests that those data were affected in part by hydrocarbon production. Some overpressuring is suggested in the pressure-depth plots of figure 21, especially in Pennsylvanian and Permian reservoirs deeper than 10,000 ft (3,000 m).

Water-level measurements from across Texas and southeastern New Mexico (including areas outside the greater Permian Basin) were converted to BHPs using a fresh-water hydrostatic gradient (0.433 psi/ft [9.79 kPa/m]), then plotted versus depth. The aquifers were grouped into hydrostratigraphic units based on the ages of the host formations; pressure-depth plots are shown for the lower Paleozoic (Cambrian-Ordovician), Permian, Triassic, Cretaceous, and Tertiary units in the greater Permian Basin and adjoining areas (fig. 24). In general, the pressures in the aquifers are fresh-water hydrostatic or slightly subhydrostatic. As discussed for the San Juan Basin, subhydrostatic conditions may reflect depressurization, particularly in the Ogallala (Tertiary) aquifer, which has been drawn down due to intensive pumpage for irrigation and municipal use (Nativ, 1988).

Computer-Generated Potentiometric Surfaces

Potentiometric surfaces were constructed for four combined hydrocarbon-producing intervals: three hydrostratigraphic units at depths of <10,000 ft (<3,000 m) (lower to middle Paleozoic, Pennsylvanian, and Permian) and a fourth unit representing all reservoirs at depths of >10,000 ft

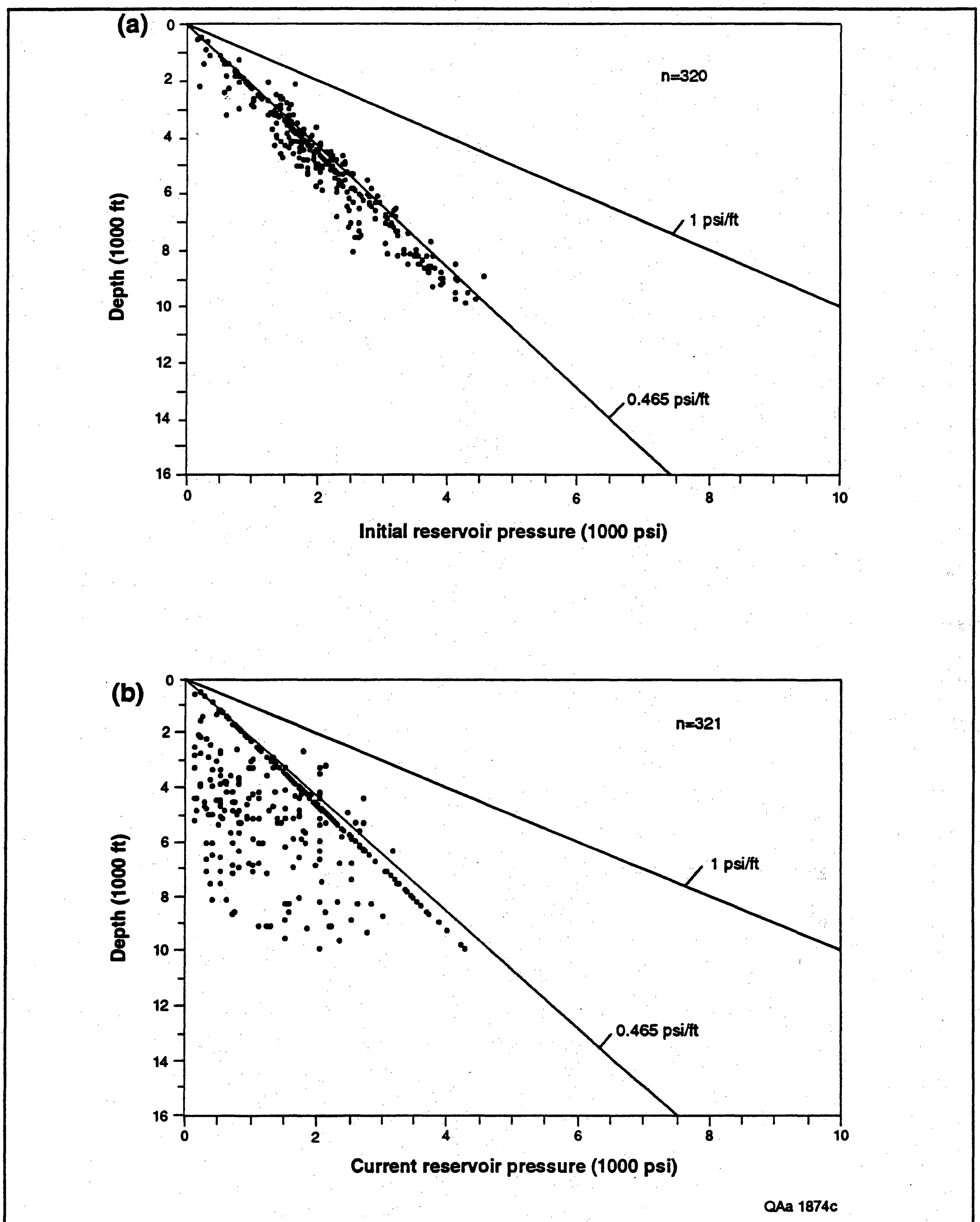


Figure 22. Plots of (a) initial and (b) current bottomhole pressure versus depth, greater Permian Basin, from Tertiary Oil Recovery Information System data base. The line of points subparallel to the 0.465 psi/ft line may reflect calculated rather than measured values.

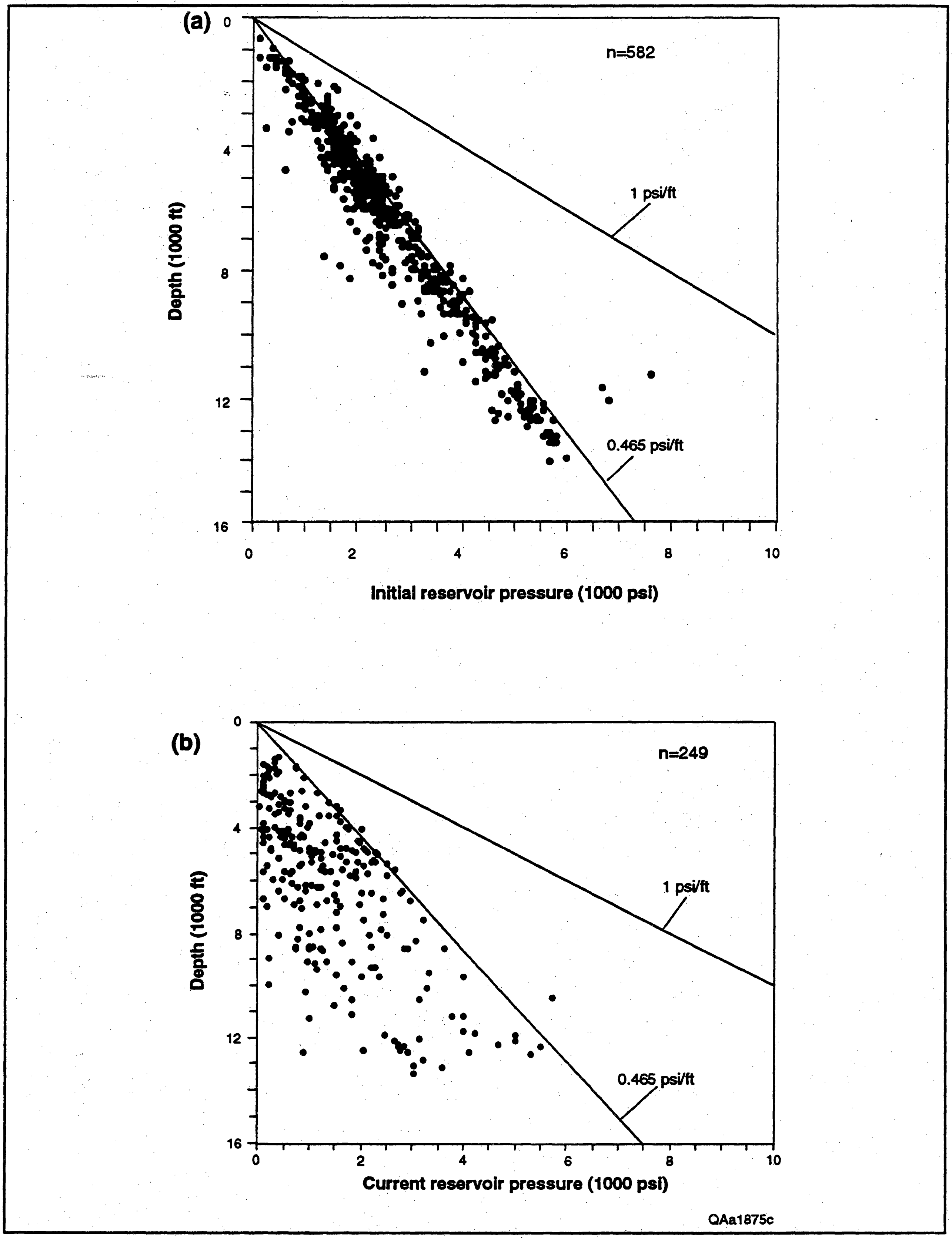
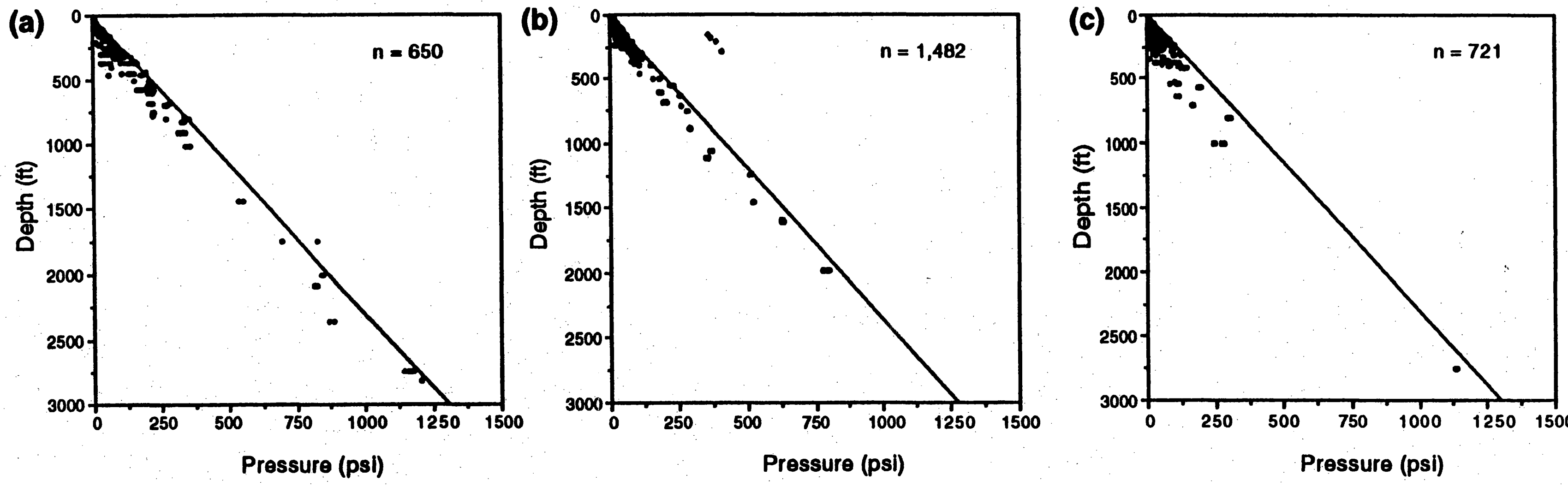


Figure 23. Plots of (a) initial and (b) current bottomhole pressure versus depth, greater Permian Basin, from Oil Atlas data base.



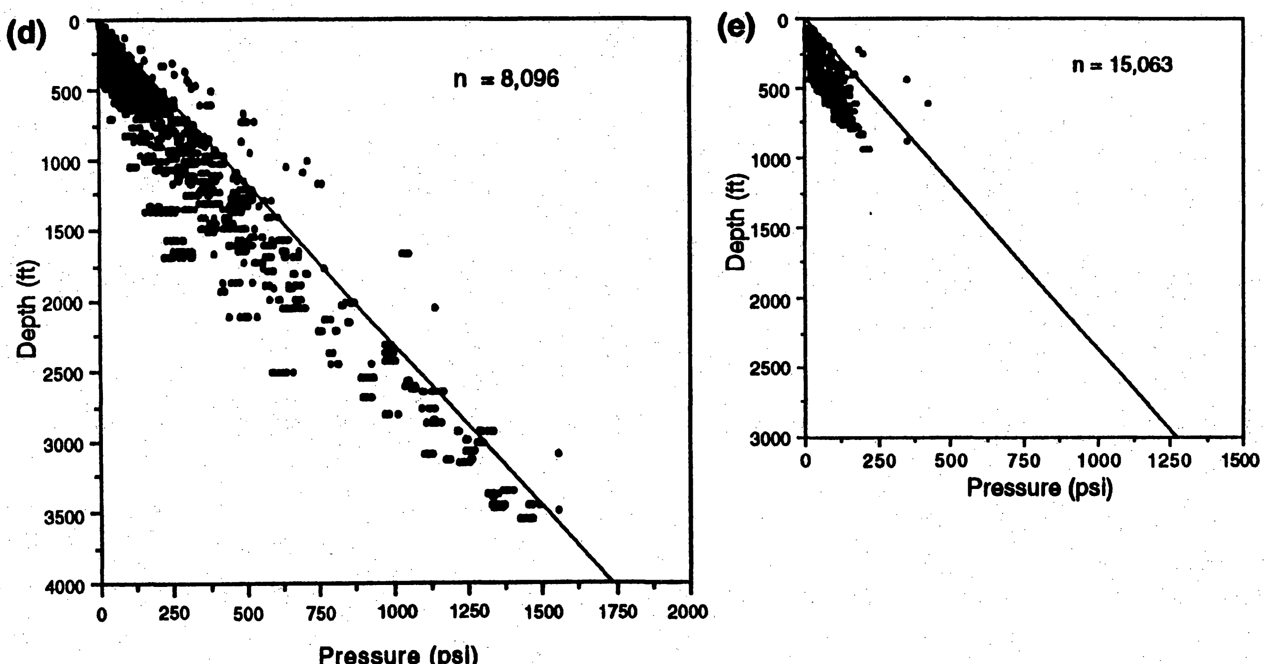


Figure 24. Bottomhole pressure versus depth in hydrostratigraphic units, greater Permian Basin: (a) Cambrian-Ordovician; (b) Permian; (c) Triassic; (d) Cretaceous; (e) Tertiary (Ogallala). Reference line represents fresh-water hydrostatic gradient (0.433 psi/ft).

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(>3,000 m). BHP data were converted to hydraulic head for each unit using a specific formation-fluid weight of 0.465 psi/ft. Potentiometric surfaces for all Permian reservoirs <10,000 ft (<3,000 m) deep and deep reservoirs are shown as examples in figures 25 and 26. In general, these surfaces reflect hydrostatic and subhydrostatic pressure environments. For reservoirs <10,000 ft (<3,000 m) deep, small overpressured areas are observed in the Permian unit along the Northwestern Shelf (fig. 25), in the Pennsylvanian unit in the northern part of the Central Basin Platform, and in the lower- to middle-Paleozoic unit near the center of the Midland Basin. Overpressuring in reservoirs >10,000 ft (>3,000 m) deep is observed in the Delaware Basin beneath the Pecos River Valley (fig. 26).

USDWs in the greater Permian Basin were grouped into four hydrostratigraphic units by age (Permian, Triassic, Cretaceous, and Cenozoic), for which potentiometric surfaces were constructed. The Cenozoic USDW potentiometric surface, which largely represents the Ogallala aquifer beneath the Southern High Plains, is shown as an example in figure 27. This surface exhibits regional highs in New Mexico and west Texas; in general, the USDW surfaces are subdued replicas of the regional topography, with flow directed from higher elevations toward lower elevations.

Residual Surfaces

Residual surfaces were generated for overlapping pairs of reservoir and USDW potentiometric surfaces, as shown for the Permian reservoirs (<10,000 ft [<3,000 m] deep) and Cenozoic USDW pair (fig. 28) and reservoirs >10,000 ft– (>3,000 m–) Cenozoic USDW pair (fig. 29). Positive residuals from all pairs of potentiometric surfaces, including those not shown, are superposed in figure 30. This map depicts the maximum extent of areas of upward hydraulic gradient from reservoirs to USDWs.

Upward hydraulic gradients are evident between the shallow Permian reservoir surface and the Triassic, Cretaceous, and Cenozoic USDW potentiometric surfaces in the middle Pecos River valley. Through numerical modeling, Senger (1991) showed that ground water discharges from Pennsylvanian and Permian units in the Pecos River valley farther north, to the west of the Palo Duro Basin. The hydrogeologic cross-sections of Summers (1981) also indicated that ground water discharges from

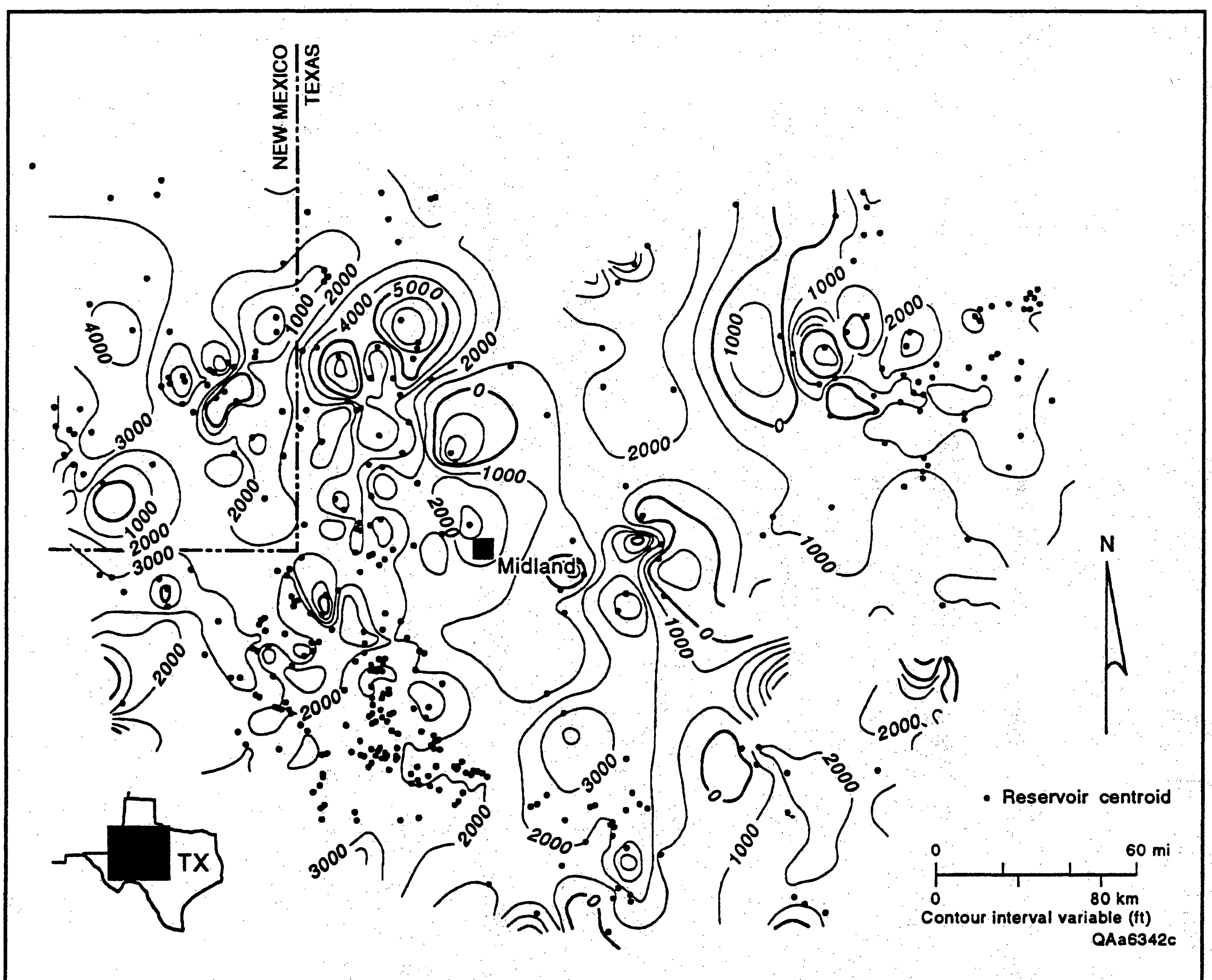

Figure 25. Computer-generated potentiometric surface of Permian reservoirs <10,000 ft (<3,000 m) deep, greater Permian Basin.

Permian units at depths of 1,000–2,000 ft (300–600 m) in the Pecos River valley near Roswell and Carlsbad, New Mexico. Although positive residuals were also mapped between reservoirs >10,000 ft (>3,000 m) deep and the Cenozoic, Cretaceous, and Triassic USDWs in the valley, both Senger (1991) and Summers (1981) indicated that some underflow occurs beneath the Pecos within Permian units <10,000 ft (<3,000 m) deep. Therefore, the occurrence of upward hydraulic gradients between the deep reservoirs and the USDWs is open to question.

Along the Eastern Shelf, scattered positive residuals occur between the shallow (<10,000-ft [<3,000-m] deep) Permian reservoir potentiometric surface and the Cenozoic and Permian USDW

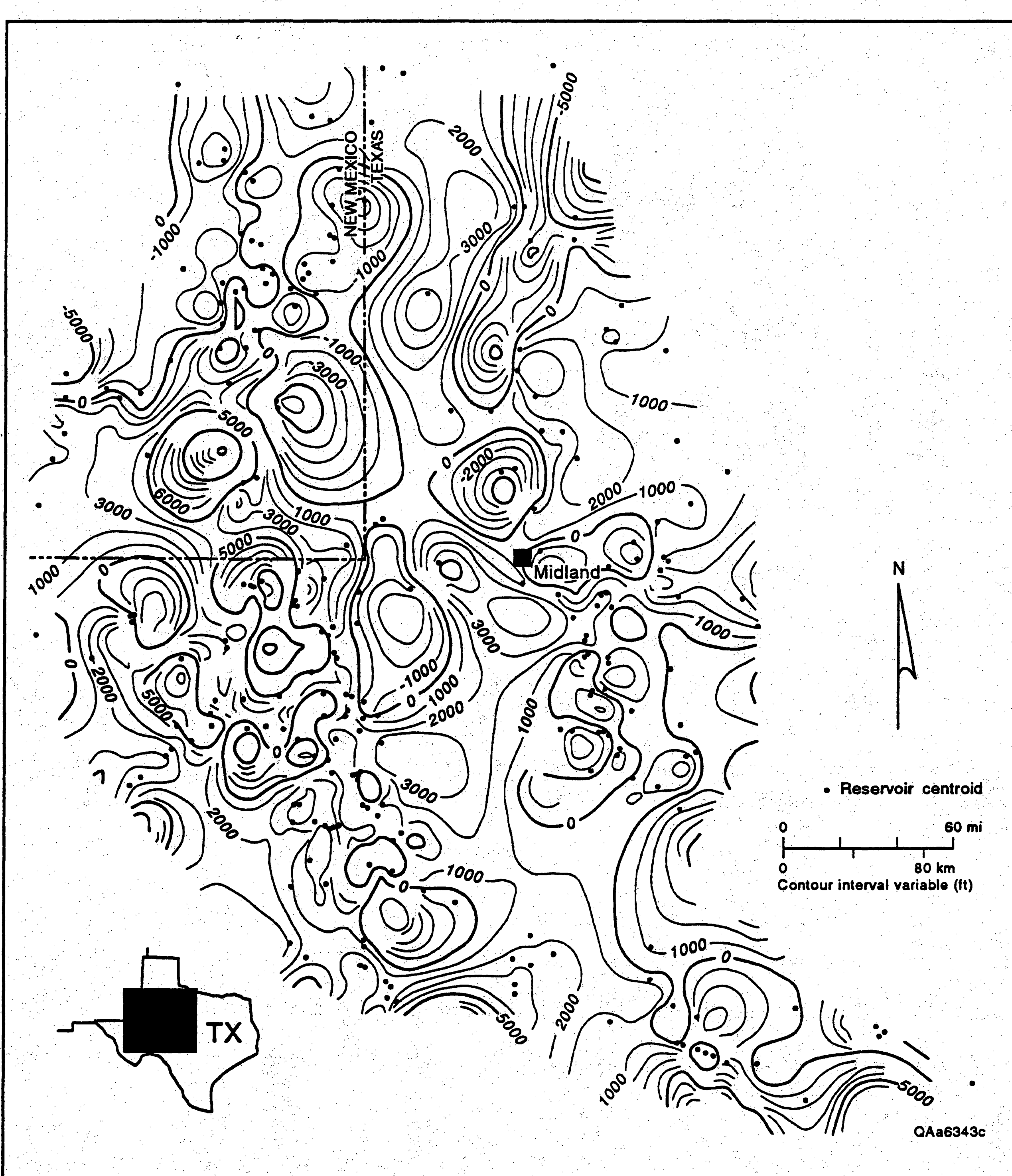

Figure 26. Computer-generated potentiometric surface of all reservoirs >10,000 ft (>3,000 m) deep, greater Permian Basin.

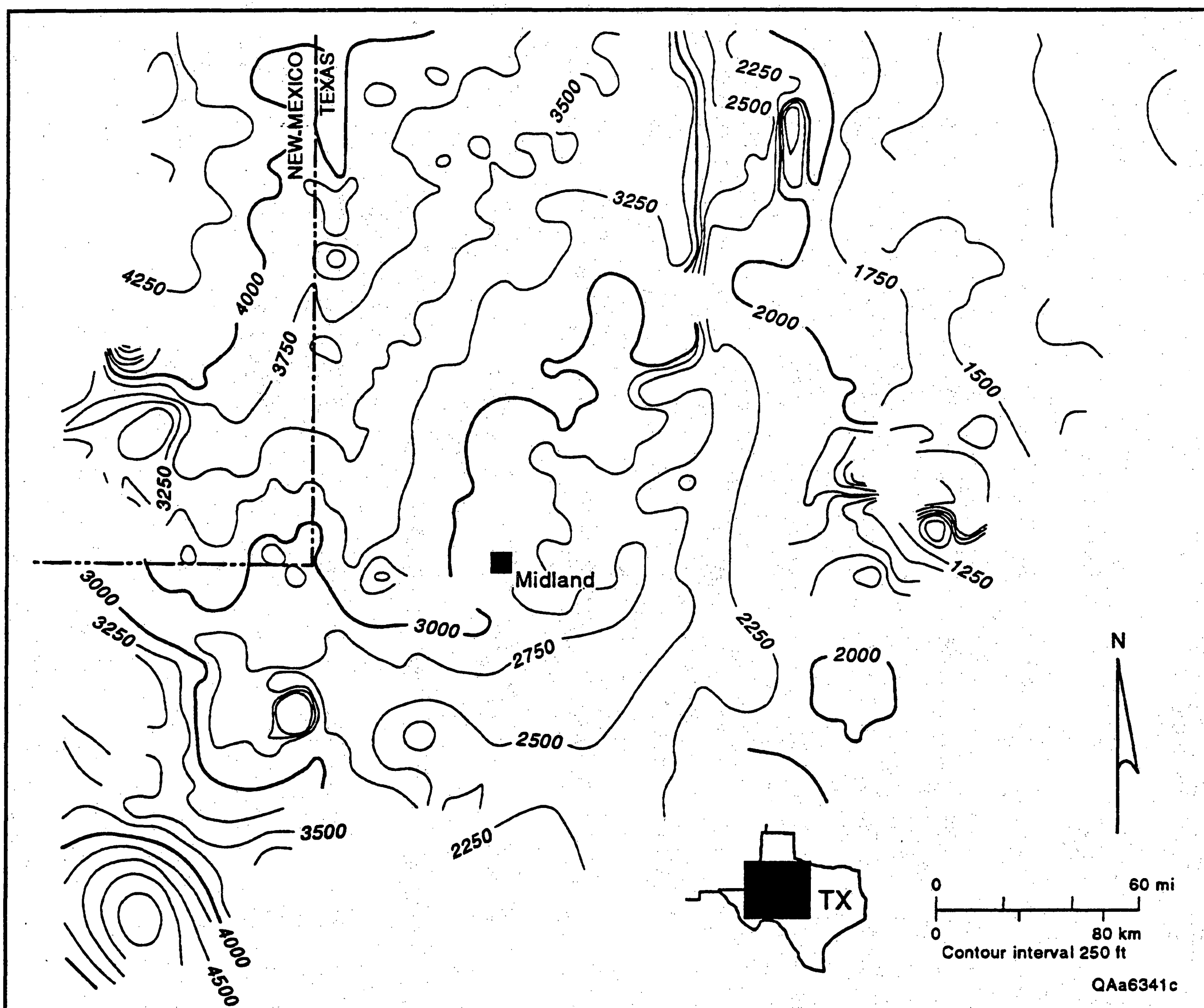

Figure 27. Computer-generated potentiometric surface of combined Cenozoic USDWs, greater Permian Basin.

potentiometric surfaces and between the shallow Pennsylvanian reservoir potentiometric surface and the Cretaceous and Permian USDW potentiometric surfaces. These positive residuals may in part reflect natural, basin-scale fluid circulation. Deep brines in the Permian Basin flow under natural potentiometric gradient from the west to the east, where they discharge upward (Dutton and others, 1989; Richter and others, 1990; Bein and Dutton, 1993).

The most extensive area of positive residuals occurs in the eastern Delaware Basin, Central Basin Platform, and western Midland Basin. Residual mapping indicates areas of upward gradient from each of the reservoir potentiometric surfaces to each of the USDW potentiometric surfaces, with hydraulic

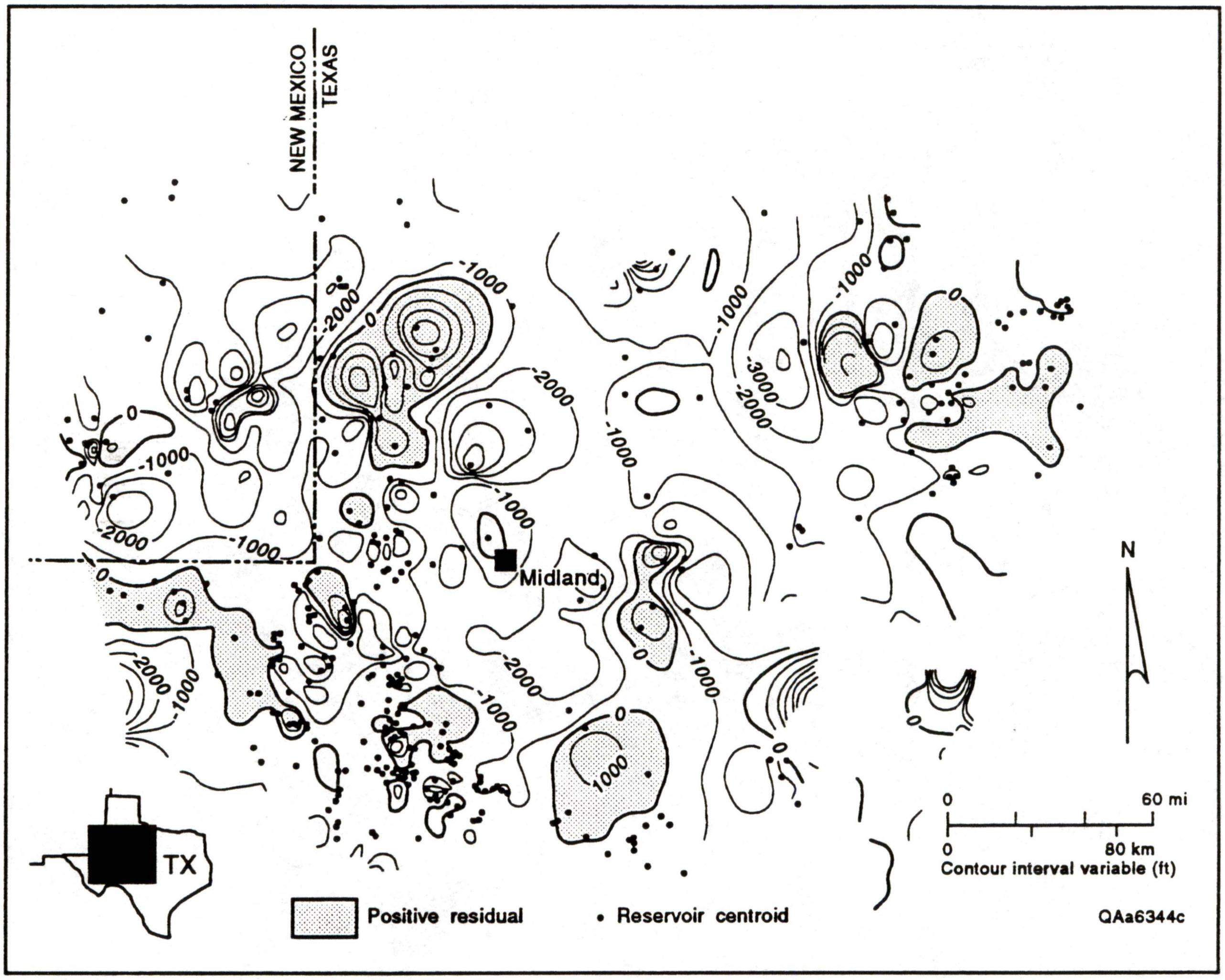

Figure 28. Residual of computer-generated potentiometric surface of Permian reservoirs <10,000 ft (<3,000 m) deep minus computer-generated potentiometric surface of Cenozoic USDWs, greater Permian Basin. Stippled areas represent positive residuals adequately supported by nearby data points.

head differentials as large as 6,000 ft (1,800 m). Although Nativ (1988) and Nativ and Gutierrez (1988) mapped some areas of upward flow from the Dockum aquifer into the Ogallala aquifer beneath the Southern High Plains, the hydrogeologic cross-sections of Summers (1981), Dutton and Simpkins (1989), and Senger (1991) indicated that flow is primarily directed downward from the Ogallala to the Dockum. In theory, upward gradients could possibly be induced by drawdown of the Ogallala water table and overpressuring due to Class II injection. However, drawdown due to irrigation was generally <50 ft (<15 m) in the southern Panhandle of Texas as of 1980 (Nativ, 1988). Moreover, the pressure changes

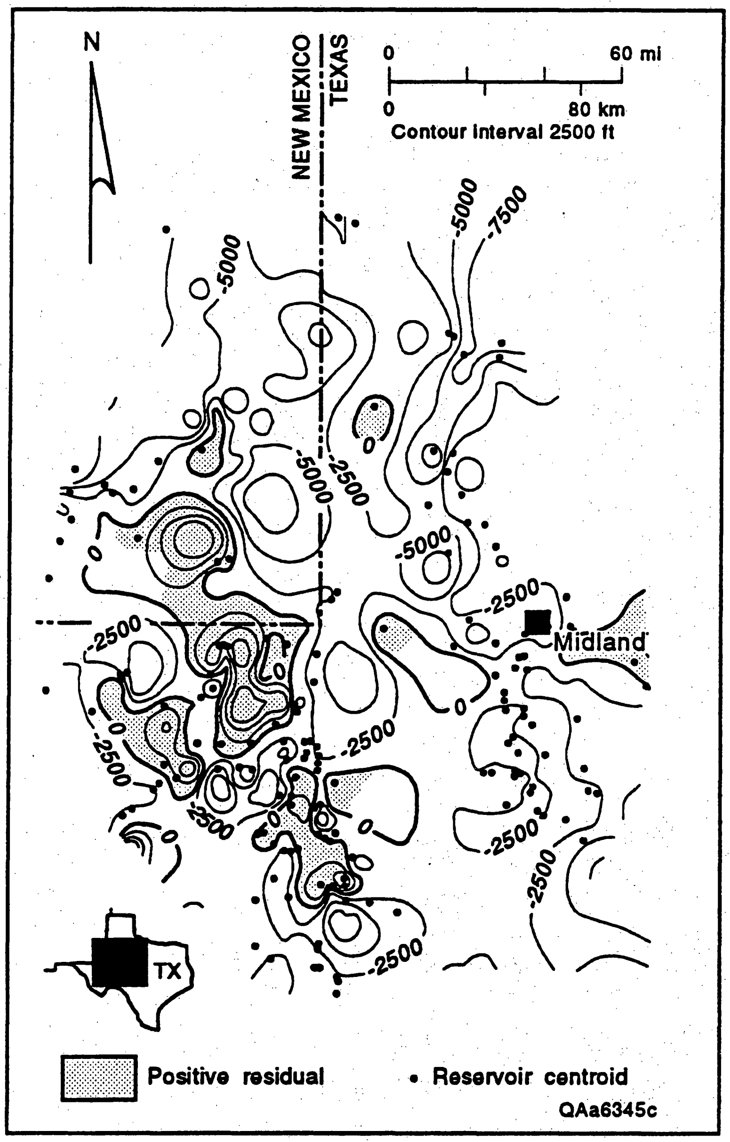

Figure 29. Residual of computer-generated potentiometric surface of all reservoirs >10,000 ft (>3,000 m) deep minus computer-generated potentiometric surface of Cenozoic USDWs, greater Permian Basin. Stippled areas represent positive residuals adequately supported by nearby data points.

associated with drawdown of the water table and Class II injection are unlikely to propagate through several thousand feet of intervening strata. Therefore, the positive residuals mapped in this area may be fictitious. Using a 0.465 psi/ft gradient may have overestimated hydraulic head in reservoirs with TDS >112,000 mg/L, such as in the Wolfcampian (Permian) section (Bein and Dutton, 1993).

Abandoned Well Locations

Figure 31 depicts the distribution of all plugged and abandoned wells at a 0.1° × 0.1° scale. The majority of these areas are clustered in the northeastern part of the greater Permian Basin, with smaller

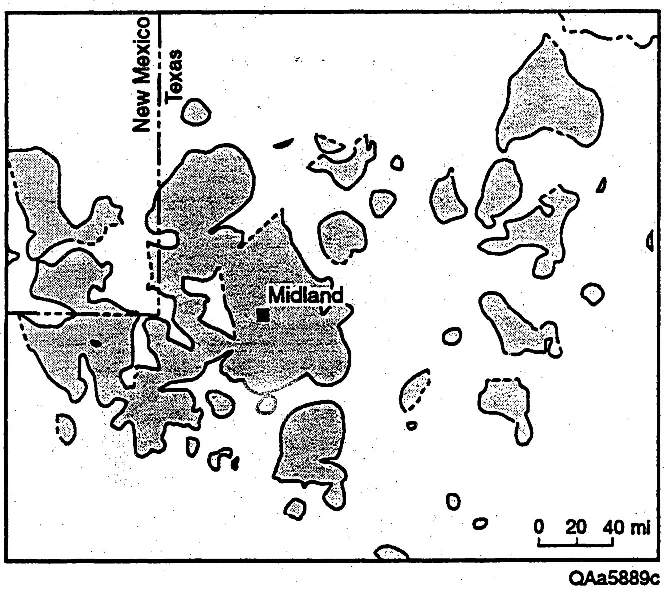

Figure 30. Composite map of all positive residuals in greater Permian Basin; boundaries dashed where inferred.

clusters farther west. Table 15 sorts the estimated abandoned well populations by age (in 10-yr intervals) and by total depth. The total number of abandoned wells in the greater Permian Basin that can be derived from table 15 (395,176) is slightly less than that given in table 11 (408,100); the total in table 15 was derived in part using data from PI, whereas the total in table 11 was not.

The mechanical integrity of older wells might be of concern due to, among other factors, less stringent construction and abandonment standards in past decades and lengthy periods of exposure to corrosive brines. Of 395,176 abandoned wells (other than Class II wells) estimated to exist in the basin as of 1990, 194,760 wells (49 percent) were abandoned prior to 1960. Deeper wells are of potential concern because of the larger number of saline units encountered; however, only 5,560 abandoned wells (1.4 percent) are deeper than 10,000 ft (3,000 m).

The extent of positive residual areas was constrained by eliminating those areas in which data from reservoirs and USDWs were deemed insufficient. The remaining positive residuals were superimposed on the abandoned well distribution map to estimate the number of abandoned wells in areas of upward hydraulic gradient (table 15). Approximately 80,185 abandoned wells are located within constrained positive residuals.

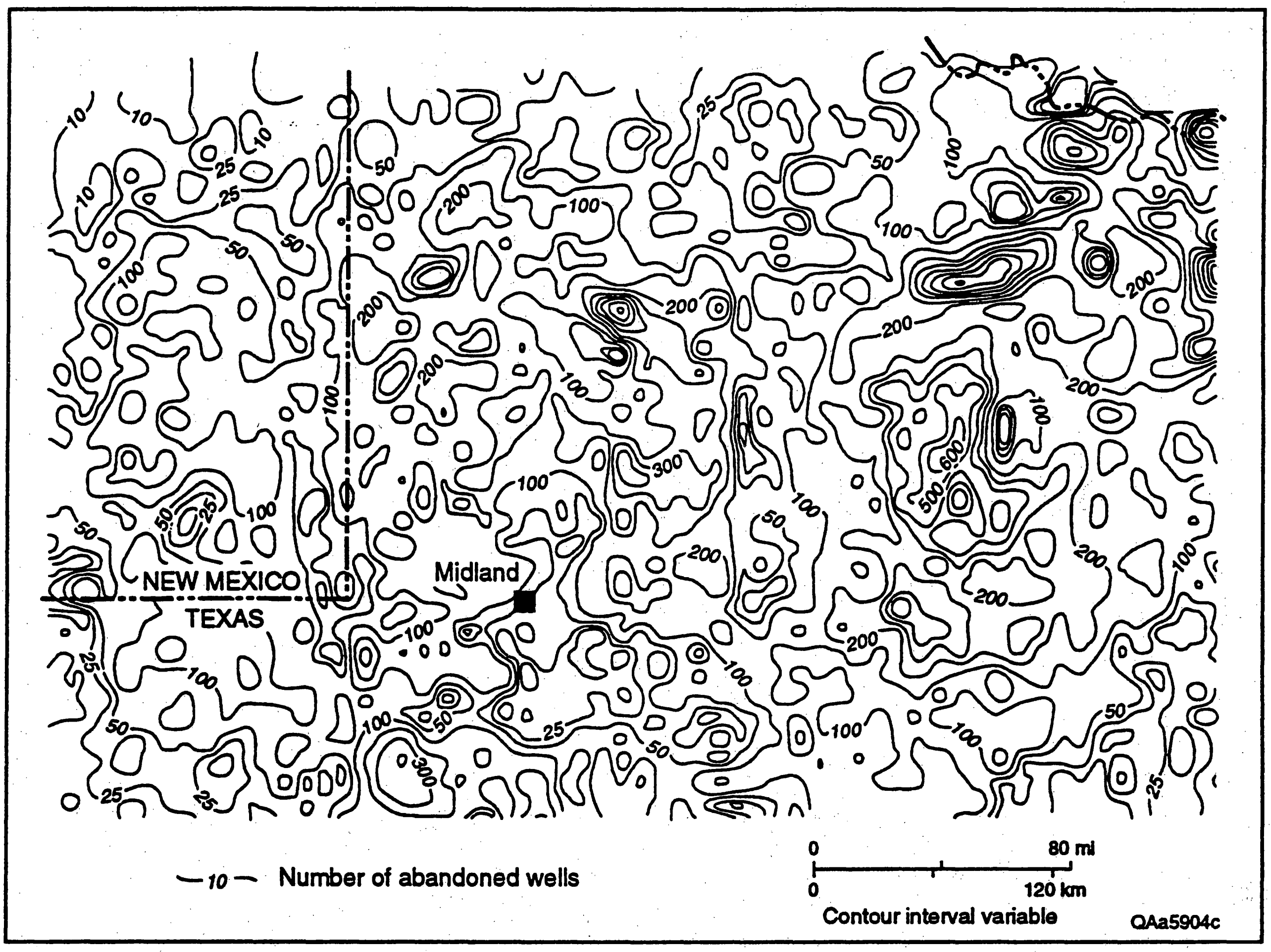

Figure 31. Contour map of the estimated distribution of abandoned wells at a 0.1°×0.1° scale, greater Permian Basin.

Effects of Class II Injection

Head-Buildup Calculations for Selected EOR Injection Well

Head-buildup calculations were conducted for an injection well in a high-volume EOR pressure maintenance project (F0694) in the greater Permian Basin for comparison with actual reservoir conditions. Injection data (table 16) were taken from a survey of EOR operations by the RRC (Texas Petroleum Research Committee, 1976). The calculated hydraulic-head buildup due to continuous injection is shown as a function of distance from the well in figure 32. The differential between the potentiometric surface of Pennsylvanian reservoirs <10,000 ft (<3,000 m) deep and the potentiometric surface of Triassic

Table 15. Estimated numbers of (a) abandoned wells, (b) abandoned wells within constrained positive residuals, and (c) abandoned wells within constrained positive residuals in areas containing approximately one Class II well per km², greater Permian Basin. Numbers of abandoned wildcats based on PI data; total numbers of abandoned wells computed from wildcat data using factors from Gruy's table 1.

(a)	New Mexico				Texas			
Avg. total depth (ft) / Year	<10000 #wildcats	<10000 #all aband.	>10000 #wildcats	>10000 #all aband.	<10000 #wildcats	<10000 #all aband.	>10000 #wildcats	>10000 #all aband.
<1950	737	5,099	19	131	8,870	78,324	38	480
1950-59	775	5,361	79	547	13,786	104,077	57	741
1960-69	859	5,943	62	429	6,764	66,776	65	778
1970-79	484	3,348	29	201	5,588	65,890	106	1,144
1980-89	324	2,241	19	131	4,547	52,557	82	978
All Years	3,179	21,992	208	1,439	39,555	367,624	348	4,121

(b)	New Mexico				Texas			
Avg. total depth (ft) / Year	<3000	3000-10000	>10000	Totals	<3000	3000-10000	>10000	Totals
<1950	104	804	0	908	7,788	11,359	129	19,276
1950-59	272	863	21	1,156	8,594	18,627	796	28,017
1960-69	146	1,444	7	1,597	4,140	9,568	723	14,431
1970-79	334	217	28	579	1,715	5,807	666	8,188
1980-89	63	105	56	224	1,095	3,659	1,055	5,809
All Years	919	3,433	112	4,464	23,332	49,020	3,369	75,721

(c)	New Mexico				Texas			
Avg. total depth (ft) / Year	<3000	3000-10000	>10000	Totals	<3000	3000-10000	>10000	Totals
<1950	104	1,117	0	1,221	1,411	5,705	103	7,219
1950-59	160	424	21	605	1,392	5,236	662	7,290
1960-69	132	715	7	854	435	2,926	441	3,802
1970-79	264	28	21	313	80	1,552	241	1,873
1980-89	14	7	35	56	30	978	626	1,634
All Years	674	2,291	84	3,049	3,348	16,397	2,073	21,818

Table 16. Characteristics of selected enhanced-recovery injection projection F0694, greater Permian Basin.

Proj. #	RRC dist.	Reservoir, county, centroid location	Depth (ft)	Inj. rate (BPD/well)	Project type	# inj. wells	Project area (acres)	Perm. (md)	Poros. (%)	Ave. net pay (ft)	Surface inj. press. (psi)	Reservoir pressure (date) original (psi)	Reservoir pressure (date) first injection (psi)	Reservoir pressure (date) latest (psi)	Volume of fluid injected, from first inj. to 1/76, all wells (mbbl)	Oil prod. from project area from disc. to first inj. (mbbs)	Oil prod. from project area from first inj. to 1/76 (mbbl)
F0694	7B	Canyon Lm., Fisher Co., Lat. 32.623N, Long. 100.542W	5900	3850	PM	6	3213	10	0.05	155	1400	2335 (1/52)	2027 (6/60)	2031 (1/76)	19,797	6,912	37,690

Project type: PM - pressure maintenance

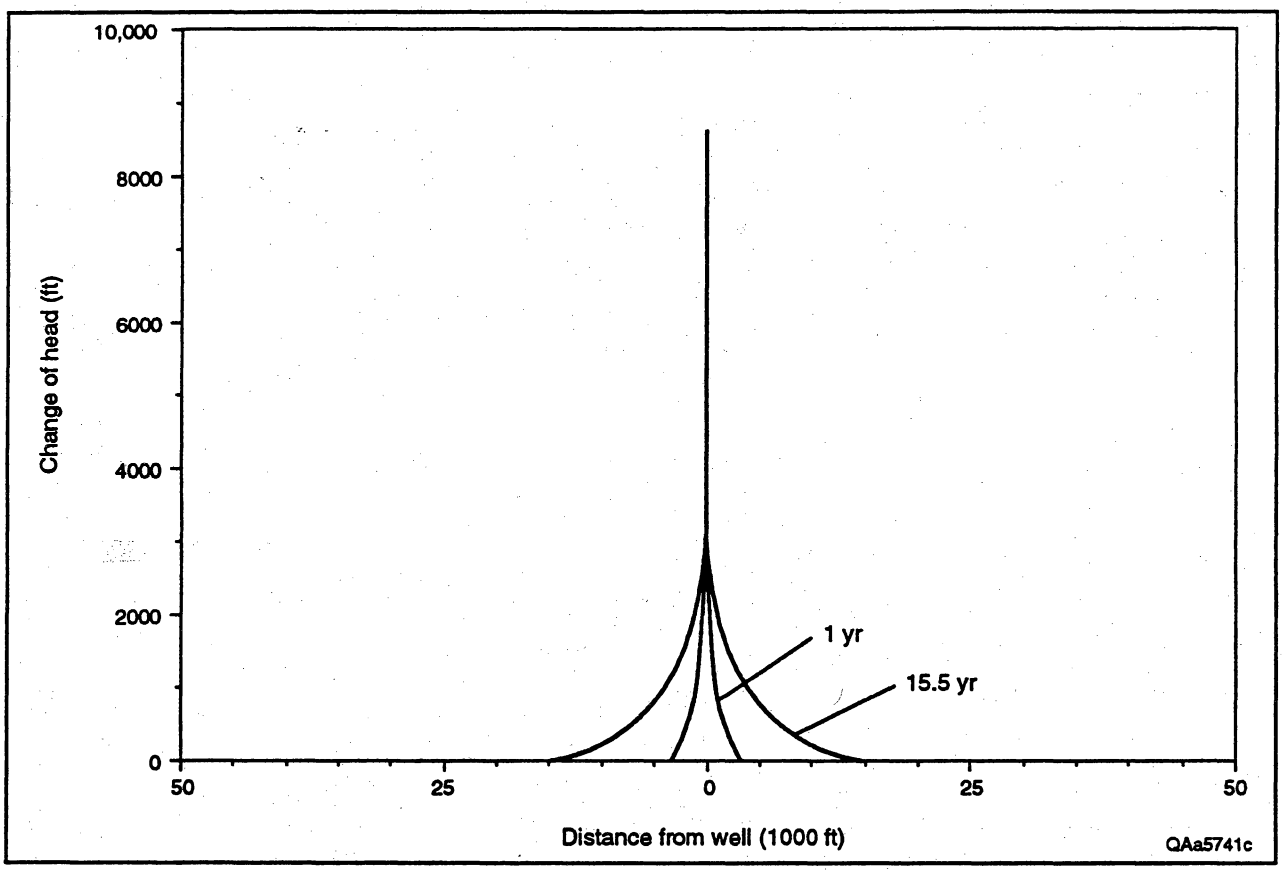

Figure 32. Calculated hydraulic-head buildup around well in enhanced-recovery injection project F0694, greater Permian Basin.

USDWs is approximately –1,333 ft (–410 m), that is, there is a potential for downward-directed flow. Without accounting for depressurization of the reservoir due to production, the hydraulic gradient could be reversed by the effects of injection, leading to upward flow within a radius of 780 ft (240 m) after 1 yr and 3,090 ft (940 m) after 15.5 yr (appendix VI). However, the actual reservoir pressure following 15.5 yr of injection (2,031 psi [14.0 MPa]) was less than the initial reservoir pressure (2,335 psi [16.1 MPa]), which most likely is due to hydrocarbon and brine production.

Total Number of Abandoned Wells in Potential Risk Areas

Of the 18,293 active or shut-in Class II wells for which complete records existed, 7,669 were within positive residual areas constrained by adequate data: 722 in the New Mexico portion of the basin and 6,947 in the Texas portion (including 30 deeper than 10,000 ft [3,000 m]). The number of abandoned wells within constrained positive residuals containing (for example) ten or more Class II wells per cell (approximately one Class II well per 3.85 mi^2 [10 km^2]) was 24,867. Of those, 16,335 were plugged before 1960, a reduction of nearly 96 percent from the total population of abandoned wells in the basin. Therefore, prioritizing abandoned wells for further evaluation based on multiple criteria such as location within positive residuals, proximity to injection wells, and age significantly reduces the number of abandoned wells to be examined at the field scale.

CASE STUDY—SOUTH TEXAS BASIN

Background

The South Texas Basin occupies an area of approximately 30,000 mi^2 (78,000 km^2). As defined by Michie & Associates (1988) and Gruy Engineering Corp. (1989), the basin includes all of RRC District 4, whereas this study excludes the ten counties nearest the Gulf Coast (Cameron, Willacy, Kenedy, Kleberg, Nueces, San Patricio, Aransas, Hidalgo, Brooks, and Jim Wells) in that district. However, this study includes reservoirs along the San Marcos Arch in RRC District 1, whereas Michie & Associates (1988) and Gruy Engineering Corp. (1989) did not. Significant hydrocarbon production occurs at depths from 1,000 ft to 14,000 ft (300 m to 4,300 m) in Tertiary formations, which are compartmentalized by faults and low-permeability strata. Cretaceous carbonate and clastic rocks along the San Marcos Arch and in the Rio Grande Embayment also contain major oil and gas reservoirs (Galloway and others, 1983; Kosters and others, 1989). As of 1990, the basin contained approximately 20,600 oil-producing wells, 5,300 gas-producing wells, and 77,050 plugged and abandoned wells (table 17) (data from Gruy Engineering Corp. [1989], updated with industry trends from World Oil [1989, 1990]).

Ground water in the South Texas Basin is produced primarily from Tertiary units overlying the hydrocarbon-producing formations. In the northern and northwestern portions of the study area, the

Table 17. Estimated numbers of producing and abandoned oil and gas wells at the end of 1989, South Texas Basin.

	Oil				Gas				Total	Total	Class II Injectors	
RRC Dist.	Producers [1]	Abandoned Producers [2]	Infield Dry [2]	Other Dry [2,3]	Producers [1]	Abandoned Producers [2]	Infield Dry [2]	Other Dry [2,3]	O & G Producers	O & G Dry & Abandoned	EOR [4]	SWD [4]
1	18,900	28,750	25,100	9,150	1,300	900	1,700	650	20,200	66,250	1,850	800
4	1,700	2,600	1,200	450	4,000	2,700	2,850	1,000	5,700	10,800	1,450	1,400
Total=	20,600	31,350	26,300	9,600	5,300	3,600	4,550	1,650	25,900	77,050	3,300	2,200

Notes:

1. Producing well counts are from table 1 in Gruy Engineering Corp., 1989, updated with published industry trends.
2. The population of abandoned producers, infield and other dry wells is a calculated fraction of the producers using Gruy table.
3. The Other Dry category includes wildcat, new pool/field extension and test wells.
4. Class II injection wells include all permitted wells (source: RRC UIC database).

Eocene-age Wilcox Group and Carrizo Formation are major aquifers and the overlying, Eocene-age Queen City and Sparta Formations are minor aquifers (Ashworth and Flores, 1991). To the south, Miocene/Pliocene-age units, including the Oakville, Goliad, Willis, and Lissie Formations, constitute the Gulf Coast aquifer (Ashworth and Flores, 1991).

Data Sources

Reservoir Pressure and Aquifer Water-Level Data

Data on oil and gas reservoir locations, completion depths, and pressures were primarily obtained from the WHCS data base (table 18). As in the case of the greater Permian Basin, the numbers of wells in table 18 do not agree with those in table 17, reflecting differences between the updated counts from Gruy Engineering Corp. (1989) and the PI (WHCS) data. More than 96 percent of the WHCS reservoir pressure measurements from the South Texas Basin (3,027 of 3,143 values) were surface shut-in tubing pressures. In the same fashion as for the greater Permian Basin, SITPs were converted to BHPs using approximately 1,550 calculated pressure-gradient values. Overall, 1,332 pressure values (one per reservoir) for the South Texas Basin were used for mapping, including 220 values extracted from other data bases maintained at the Bureau of Economic Geology. These values represented 987 Tertiary reservoirs and 345 Cretaceous reservoirs.

Water-level data for the USDW aquifers were obtained from TWDB; as in the greater Permian Basin, only those wells in which the static water level had been measured between 1980 and 1990 were used.

Abandoned Well Data

As in the first two case studies, the numbers of plugged and abandoned wells were updated from Gruy Engineering Corp. (1989) by incorporating trends in U.S. well drilling and completions (World Oil,

Table 18. Well populations and pressure data counts from Petroleum Information Inc., South Texas Basin.

Category	South Texas
Oil wells	36678
Gas wells	11039
W.I. wells	204
Dry New Field wildcats	16388
Dry Outposts & Extensions	820
Dry Shallower Pool Tests	123
Dry Deeper Pool Tests	254
Dry New Pool Wildcats	177
Dry Development Wells	11069
Subtotal	28831
# Avg. Shut-in Tubing Pressures: pre-1950	78
# Avg. Shut-in Tubing Pressures: 1950-59	388
# Avg. Shut-in Tubing Pressures: 1960-69	516
# Avg. Shut-in Tubing Pressures: 1970-79	923
# Avg. Shut-in Tubing Pressures: 1980-89	1122
Subtotal	3027
# Avg. Bottomhole Pressures: pre-1950	1
# Avg. Bottomhole Pressures: 1950-59	2
# Avg. Bottomhole Pressures: 1960-69	7
# Avg. Bottomhole Pressures: 1970-79	4
# Avg. Bottomhole Pressures: 1980-89	7
Subtotal	21
# Avg. DST FSIPs: pre-1950	10
# Avg. DST FSIPs: 1950-59	46
# Avg. DST FSIPs: 1960-69	32
# Avg. DST FSIPs: 1970-79	4
# Avg. DST FSIPs: 1980-89	3
Subtotal	95

(1) Oil and gas well counts include producers and infield dry, but not abandoned producers.
(2) DST FSIPs are final shut-in formation pressures during drillstem tests.

1989, 1990). Based on data provided by PI, an estimated 23,455 abandoned wildcats occur in the study area plus the remainder of RRC District 4 and a portion of RRC District 2. A total of 68,002 abandoned non-wildcats as of 1990 was then estimated, so that the sum of all abandoned wells was 91,457 for this larger area. In comparison, Gruy Engineering Corp. (1989) estimated a total of 67,502 abandoned non-wildcats for their differently-defined South Texas study area.

Class II Injection Data

The number of SWD and EOR injection wells in the South Texas Basin plus the coastal counties of RRC District 4 (5,449 [table 19]) is only one-tenth as great as the number of those wells in the greater Permian Basin. Latitude-longitude coordinates for 2,232 active, shut-in, and abandoned Class II wells in this area were obtained, as for the greater Permian Basin, by matching their API numbers to wells in the PI data base. The county-by-county distribution of the wells for which coordinates could not be obtained is given in table 20. Of 2,944 Class II wells that were active or shut-in during March–May 1990, complete records were available for 1,177 (853 EOR injection wells and 324 SWD wells). Those wells are primarily located along the trend of Cretaceous reservoirs in the northern part of the basin, extending from Guadalupe County in the northeast to Maverick County in the west (fig. 33). Injection wells in this region are generally fewer than 100 per grid cell (approximately 2.6 wells per mi^2 [1 well per km^2]).

Initial Hydraulic Conditions

Pressure-Depth Profiles

The distribution of maximum bottomhole pressures with depth for 328 Cretaceous and 978 Tertiary reservoirs is shown in figure 34. At depths shallower than approximately 6,000 ft (1,800 m), BHP values tend to fall along or below the brine-hydrostatic gradient line with slope of 0.465 psi/ft (10.5 kPa/m). The TDS concentration upon which this line is based (approximately 112,000 mg/L) is

Table 19a. Number of Class II SWD and EOR injection wells, South Texas Basin.

TX RRC Dist.	N of SWD & EOR wells	N of active and shut-in SWD & EOR wells	N of lat/long coordinates obtained	N of wells used in study*
1	2,618	1,753	1,689	805
4**	2,831	1,191	543	372
Total	5,449	2,944	2,232	1,177

* See table 19b.
** Includes all of District 4.

Table 19b. Number of active and shut-in SWD and EOR injection wells used for analysis of South Texas Basin. Wells used in this study include only active or shut-in wells for which data indicating the top and/or the bottom of the injection zone as well as permitted injection pressure and volume are given, and for which latitude-longitude location coordinates could be obtained.

TX RRC Dist.	Total N of wells used in study	N of SWD wells		N of EOR wells	
		active	shut-in	active	shut-in
1	805	82	14	502	207
4	372	179	49	107	37
Total	1,177	261	63	609	244

Table 20. Number of Class II wells by county, South Texas Basin.

County	# of wells	County	# of wells	County	# of wells
Aransas	12	Guadalupe	106	Nueces	211
Atascosa	314	Hidalgo	75	Refugio	2
Bastrop	19	Jim Hogg	113	San Patricio	233
Bexar	219	Jim Wells	197	Starr	220
Brooks	88	Kenedy	38	Travis	1
Burleson	1	Kleberg	171	Webb	295
Caldwell	211	LaSalle	19	Williamson	3
Cameron	1	Live Oak	3	Wilson	109
Dimmit	289	Maverick	649	Zapata	206
Duval	854	McMullen	128	Zavala	65
Frio	379	Milam	27		

generally greater than the TDS values for Tertiary formation waters from the basin. Bebout and others (1982) reported a TDS range of 10,000–75,000 ppm (as NaCl, calculated from electric logs) in the Wilcox Formation. Morton and Land (1987) mapped TDS values generally <35,000 mg/L in the Frio Formation, although TDS levels >105,000 mg/L were shown for a small area in northeastern Starr County. Therefore, apparent underpressuring may to some extent reflect lower salinity rather than hydrocarbon production. At depths >6,000 ft (>1,800 m), pressures fall above the brine-hydrostatic line, consistent with the regional occurrence of geopressures associated with relatively rapid sedimentation along the Gulf Coast during Tertiary time (Harrison and Summa, 1991).

As in the previous case studies, water-level measurements were converted to BHPs using a fresh-water hydrostatic gradient (0.433 psi/ft [9.79 kPa/m]) and plotted versus depth. Pressure-depth plots are shown for the Eocene, Miocene, and Pliocene hydrostratigraphic units in the basin and adjoining areas to the east and northeast (fig. 35). Pressures in the aquifers are fresh-water hydrostatic or (especially in the Pliocene unit) subhydrostatic. Subhydrostatic conditions may reflect pumpage or downward (downdip) flow toward the coast (Harrison and Summa, 1991).

Computer-Generated Potentiometric Surfaces

Reservoirs were divided by age (Cretaceous and Tertiary) and by depth (<6,000 ft and >6,000 ft [<1,800 m and >1,800 m]) into four hydrostratigraphic units for which potentiometric surfaces were

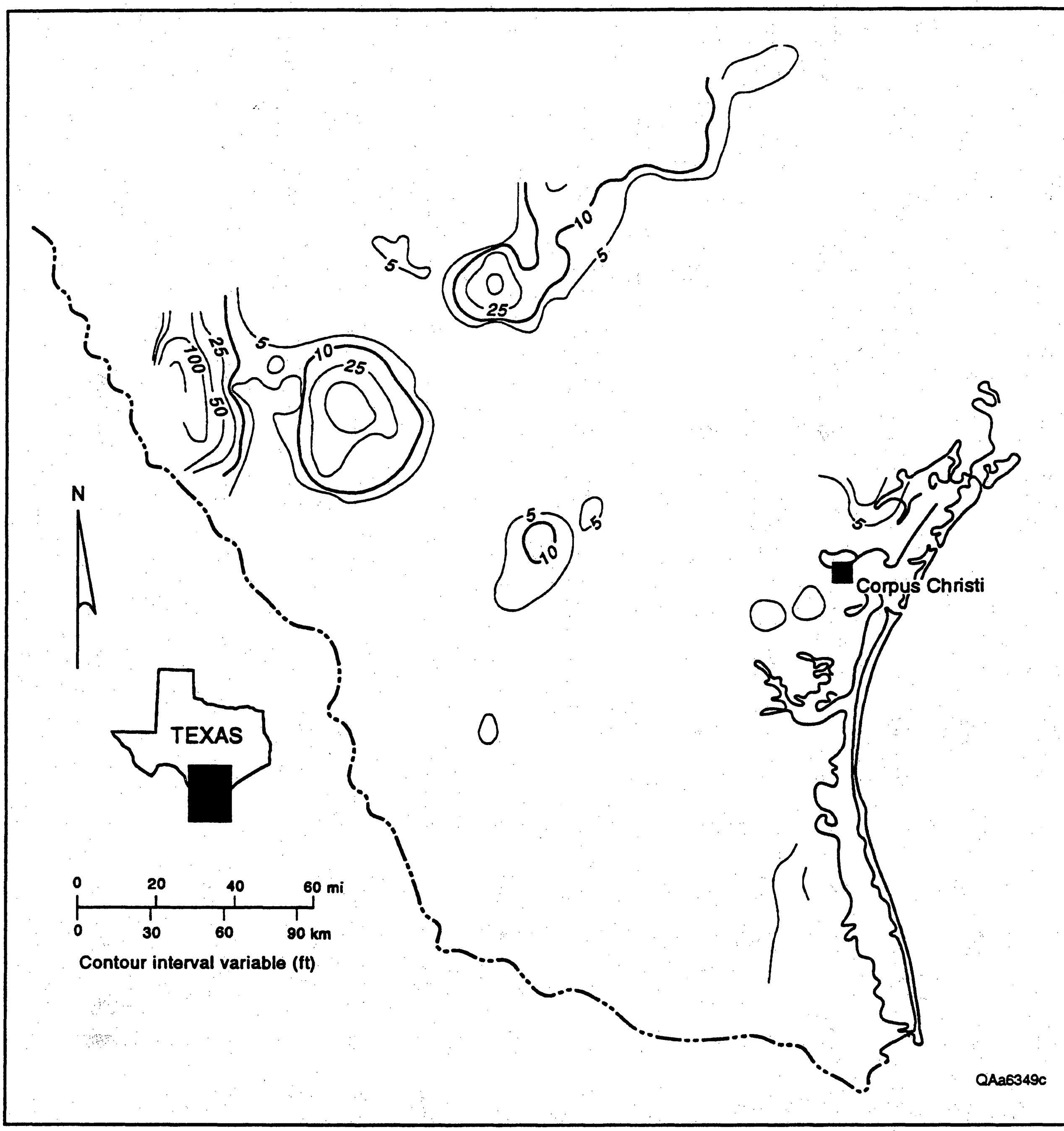

Figure 33. Contour map of Class II wells at a 0.1° × 0.1° scale, South Texas Basin; 10-injection-well per cell contour delineated with bold outline.

constructed. Pressure data were available from 908 reservoirs shallower than 6,000 ft (1,800 m) and 618 deeper reservoirs. BHP data were converted to hydraulic head using a specific weight of 0.465 psi/ft. Potentiometric surfaces for shallow and deep Tertiary reservoirs and deep reservoirs of various ages are shown as examples. The deep Tertiary surface (fig. 36) is predominantly above land surface (0 to

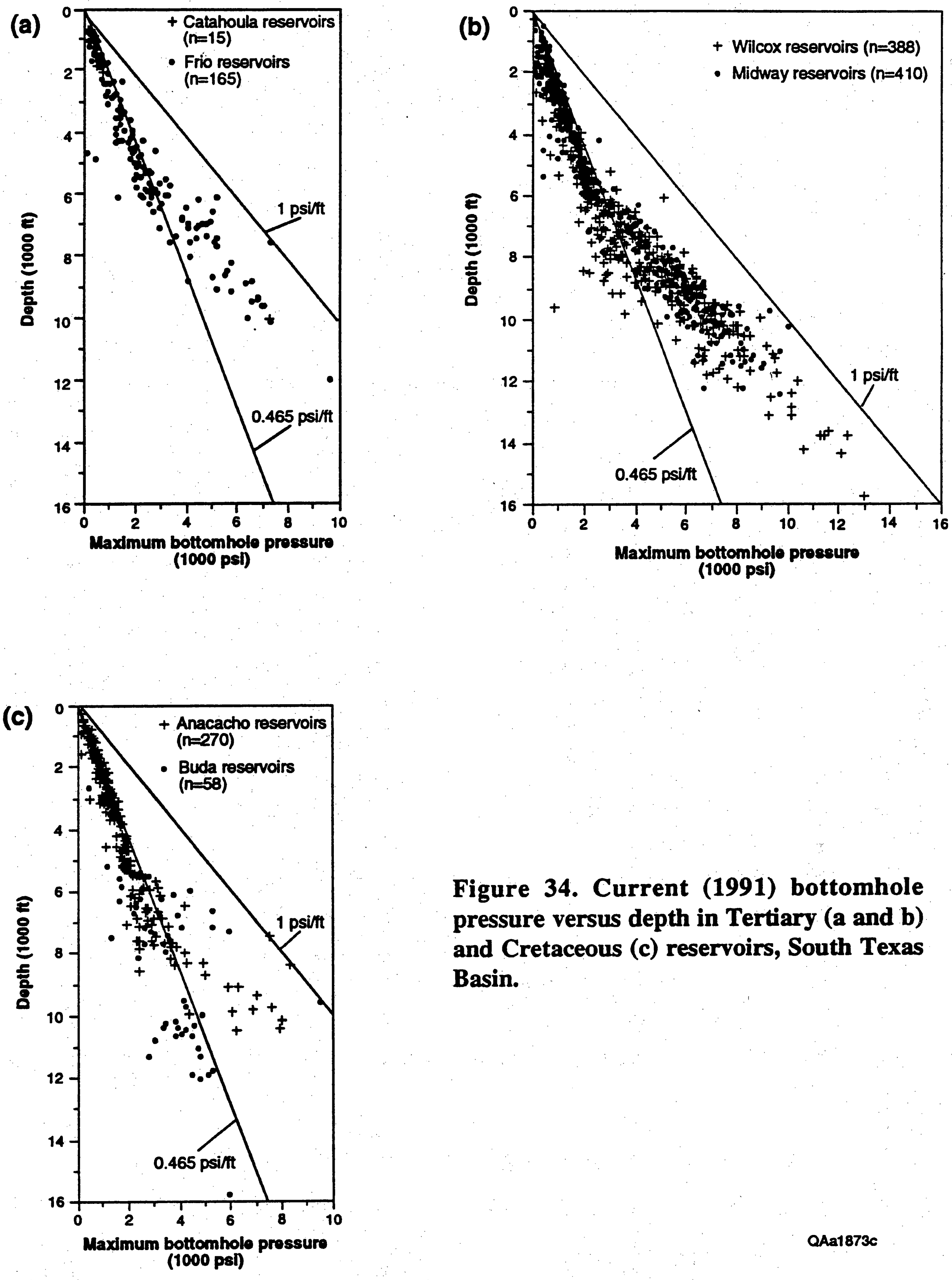

Figure 34. Current (1991) bottomhole pressure versus depth in Tertiary (a and b) and Cretaceous (c) reservoirs, South Texas Basin.

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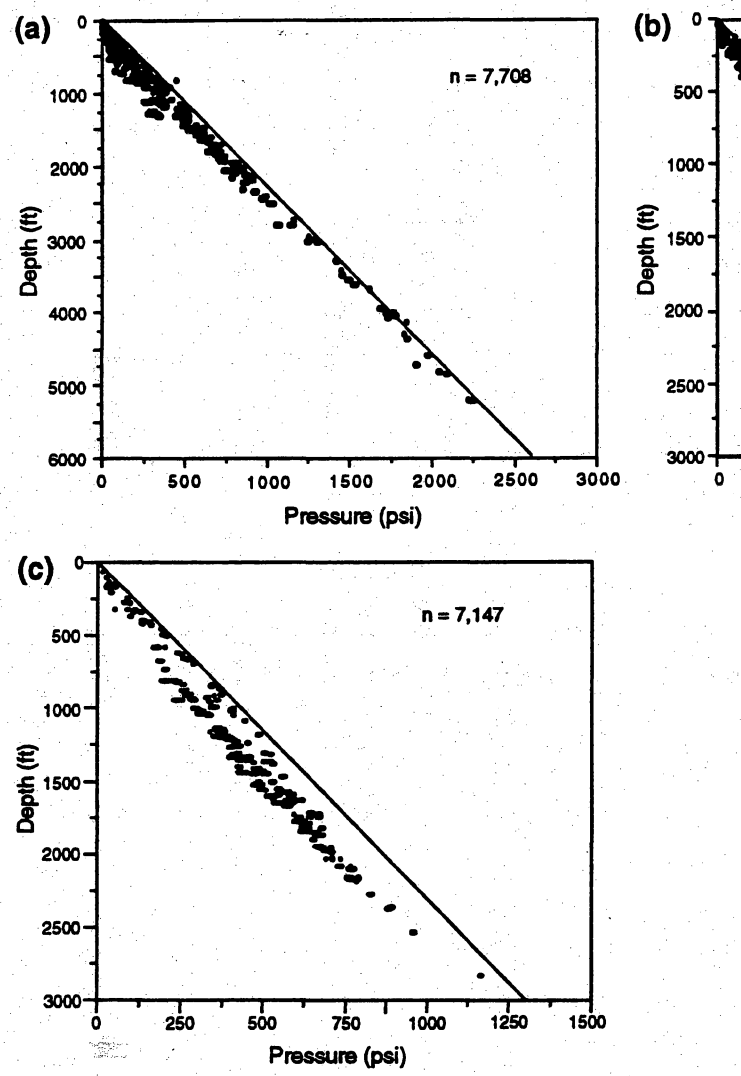

Figure 35. Bottomhole pressure versus depth in hydrostratigraphic units, South Texas Basin: (a) Eocene; (b) Miocene; (c) Pliocene. Reference line represents fresh-water hydrostatic gradient (0.433 psi/ft).

>5,000 ft [1,500 m] above sea level), whereas the shallow Tertiary surface (fig. 37) generally is <500 ft (150 m) above sea level.

Water-level data from the various Cenozoic (Tertiary and Quaternary) formations containing USDWs were combined and contoured to obtain a single potentiometric surface (fig. 38) whose elevation is close to that of land surface. It ranges from <250 ft (76 m) above sea level in the southeast to >1,000 ft (300 m) above sea level in the northwest.

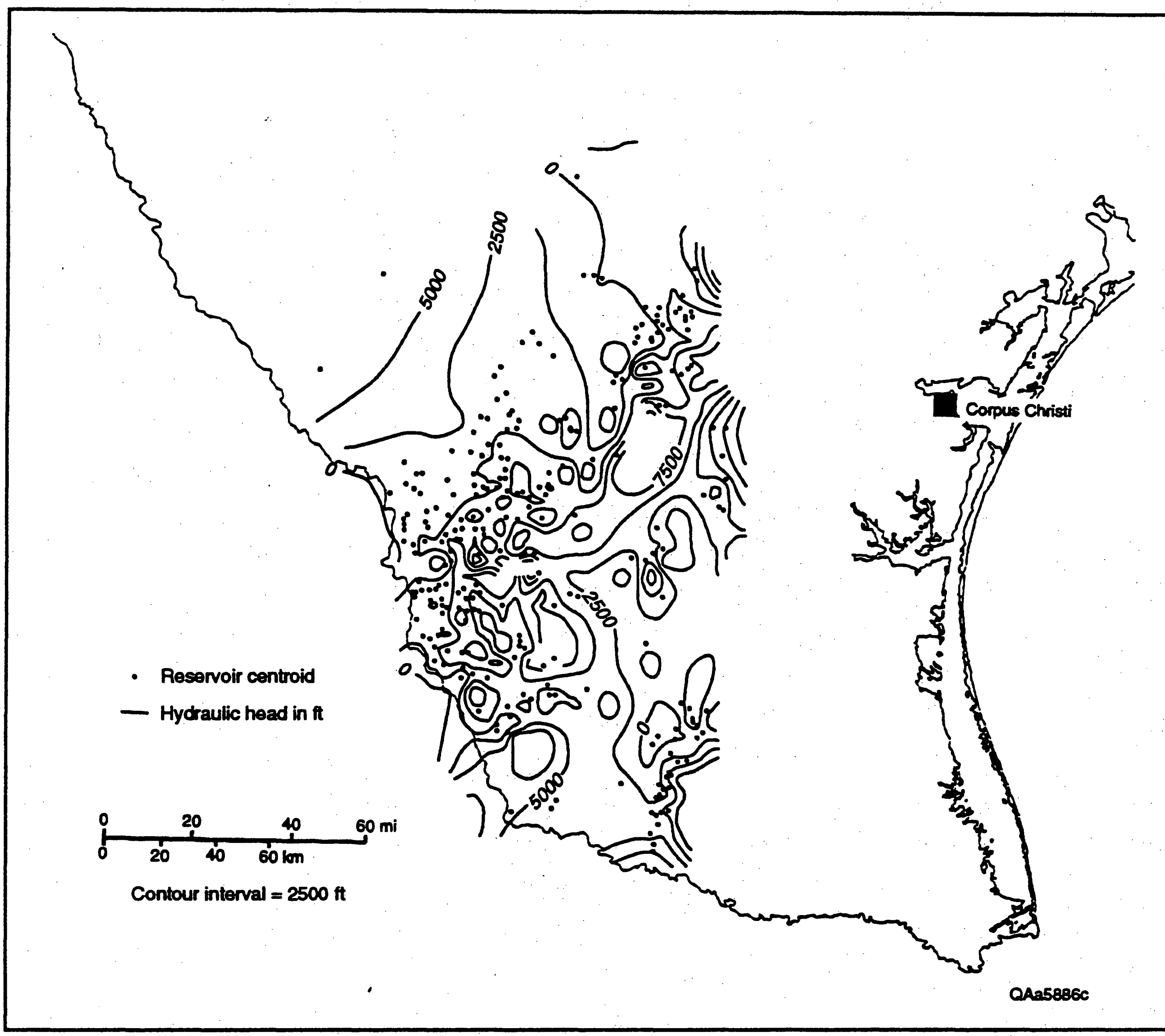

Figure 36. Computer-generated potentiometric surface of Tertiary reservoirs >6,000 ft (>1,800 m) deep, South Texas Basin.

Positive Residual Surfaces

There are extensive areas where hydraulic head in Tertiary reservoirs at depths >6,000 ft (>1,800 m) deep is higher than hydraulic head in the combined Cenozoic USDWs. Positive residuals between the deep Tertiary reservoirs and the USDWs (fig. 39) occur in a southwest–northeast band in the southern portion of the study area, aligned with geopressured zones along the Wilcox trend (Bebout and others, 1982). In comparison, positive residuals between Cretaceous reservoirs >6,000 ft (>1,800 m)

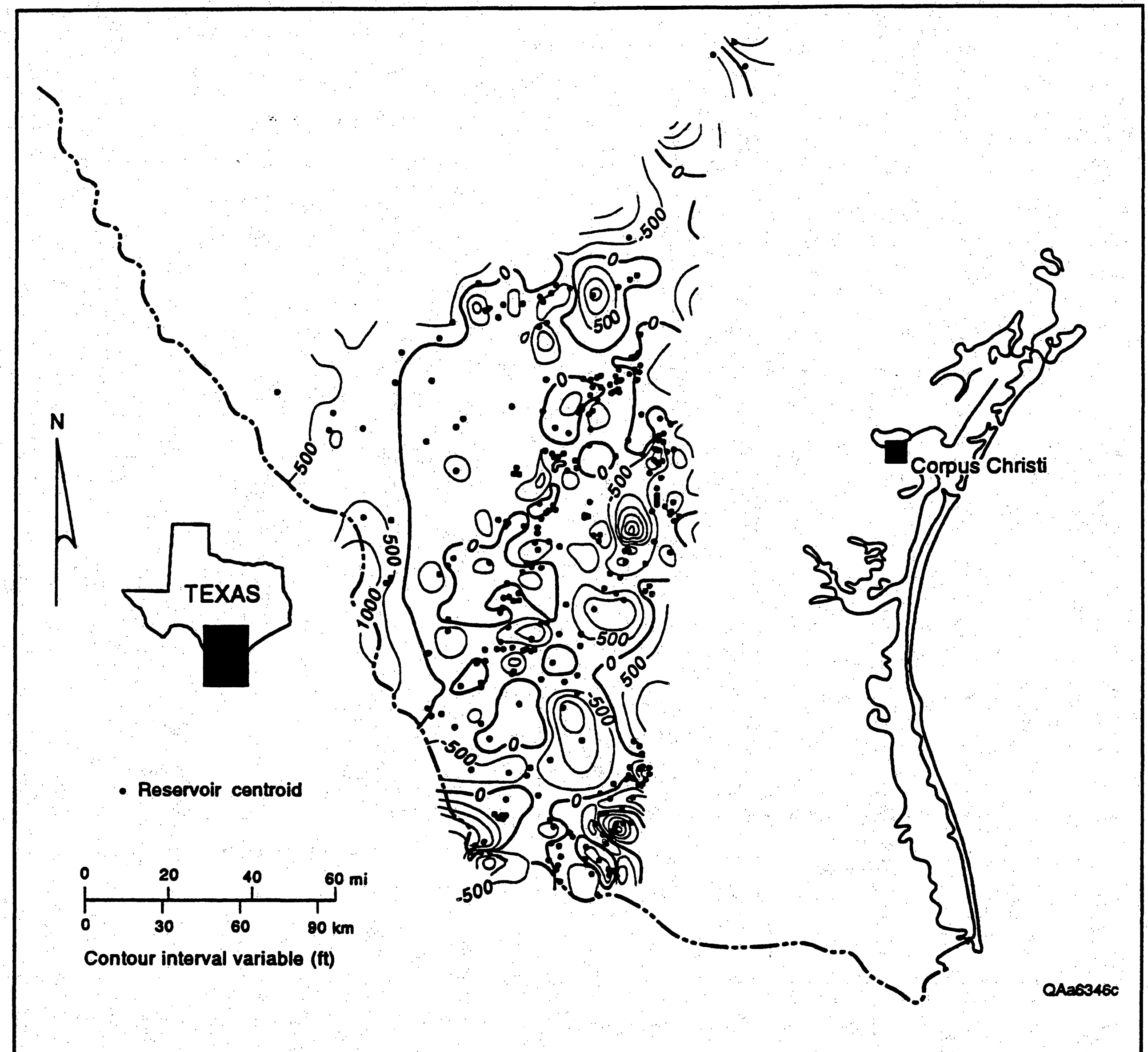

Figure 37. Computer-generated potentiometric surface of Tertiary reservoirs <6,000 ft (<1,800 m) deep, South Texas Basin.

deep and the Cenozoic USDW surface are less extensive, perhaps because the Cretaceous reservoirs are further inland and thus more distant from depocenters than are the Tertiary reservoirs. No positive residuals were identified between reservoirs <6,000 ft (<1,800 m) deep and the Cenozoic USDW surface (fig. 40). Therefore, the composite map of positive residuals (fig. 41) largely corresponds to the deep Tertiary reservoirs.

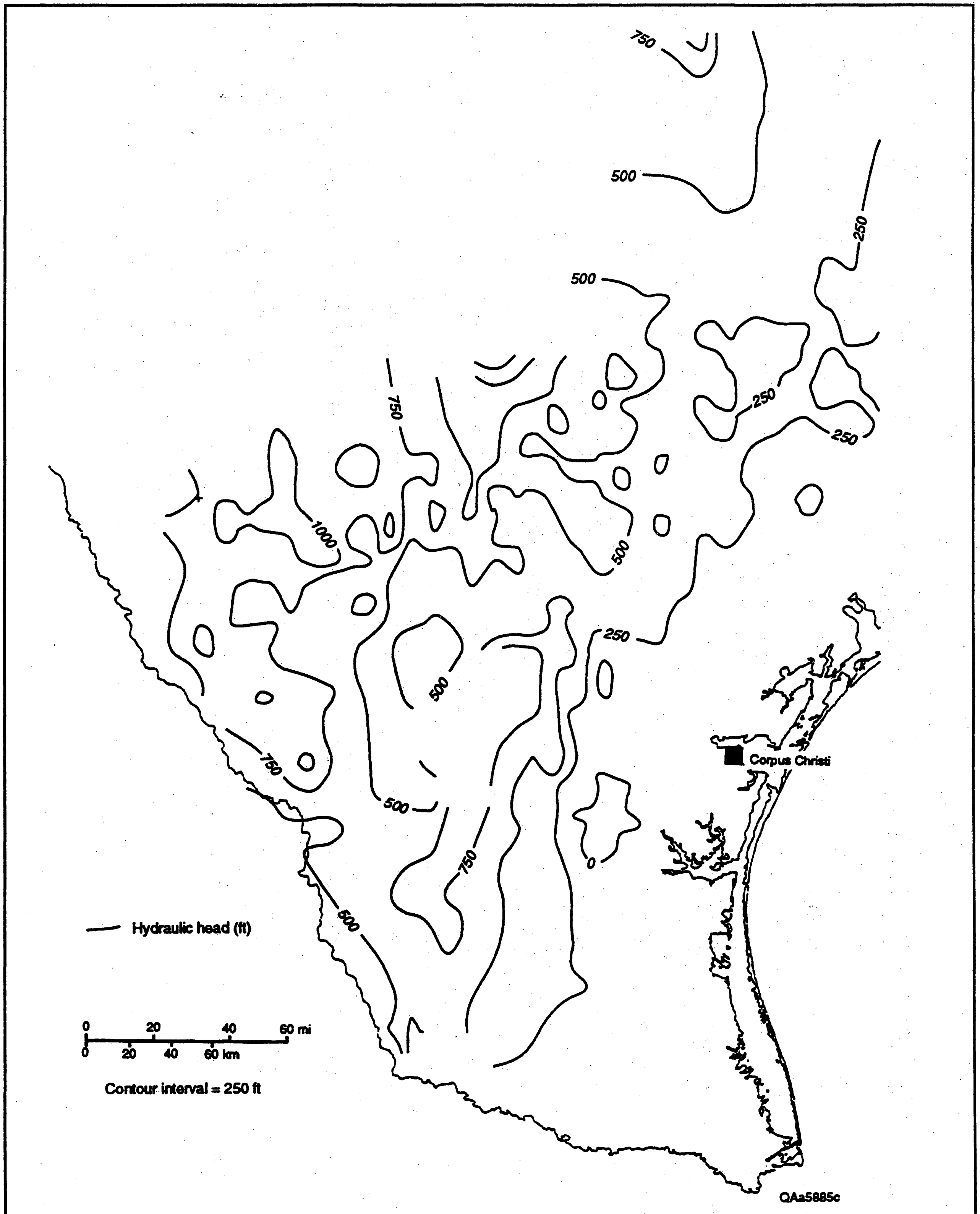

Figure 38. Computer-generated potentiometric surface of combined Cenozoic USDWs, South Texas Basin.

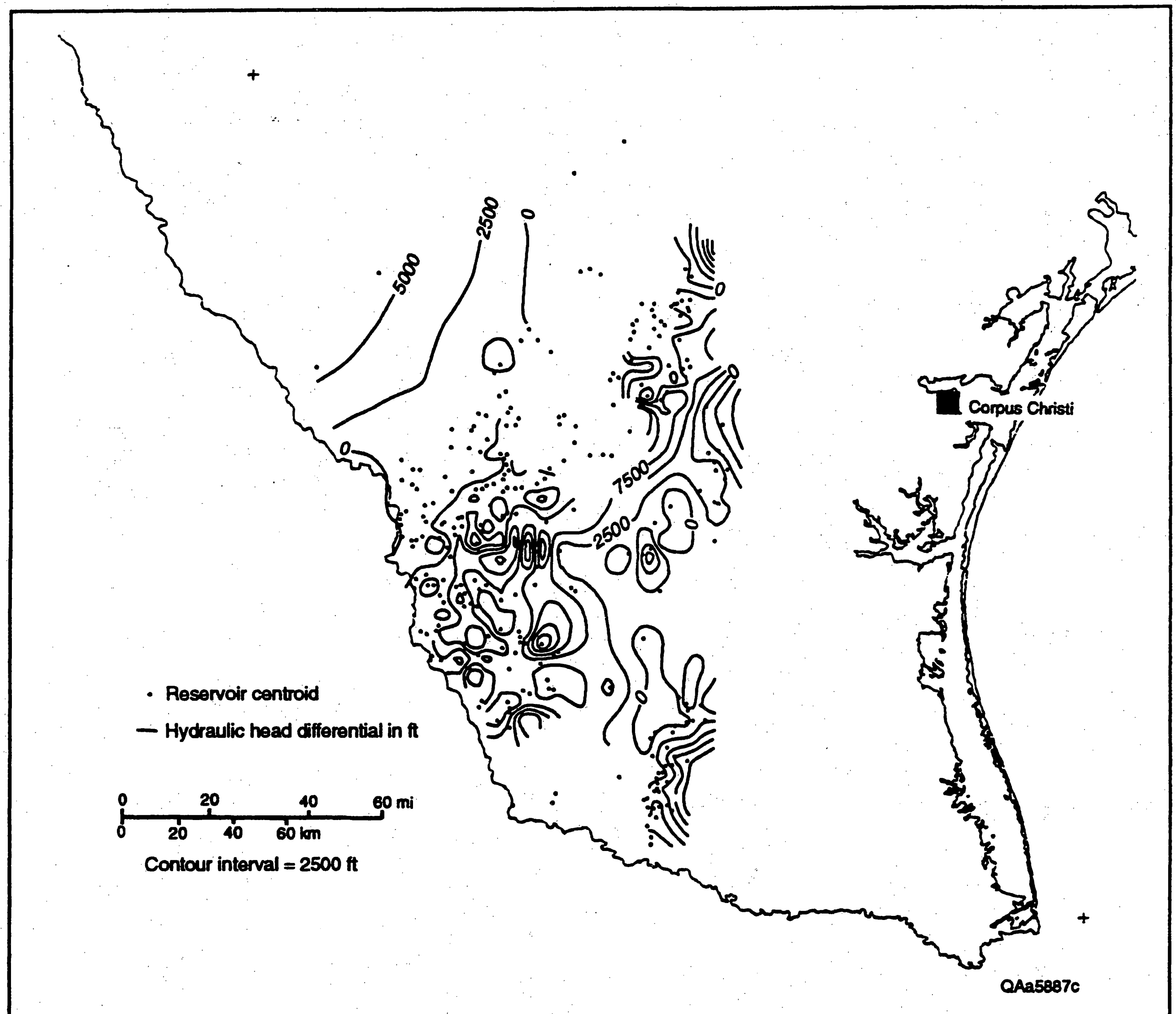

Figure 39. Residual of computer-generated potentiometric surface of Tertiary reservoirs >6,000 ft (>1,800 m) deep minus computer-generated potentiometric surface of Cenozoic USDWs, South Texas Basin. Positive residual areas not stippled.

Abandoned Well Locations

The distribution of all abandoned wells at a 0.1° × 0.1° scale is shown in figure 42. In contrast to the greater Permian Basin, only five small areas in the South Texas Basin contain >400 wells per cell. The density of abandoned wells is greatest in the northeastern part of the basin and in the south-central part of the basin, where positive residuals are concentrated. The population of all abandoned wells estimated from

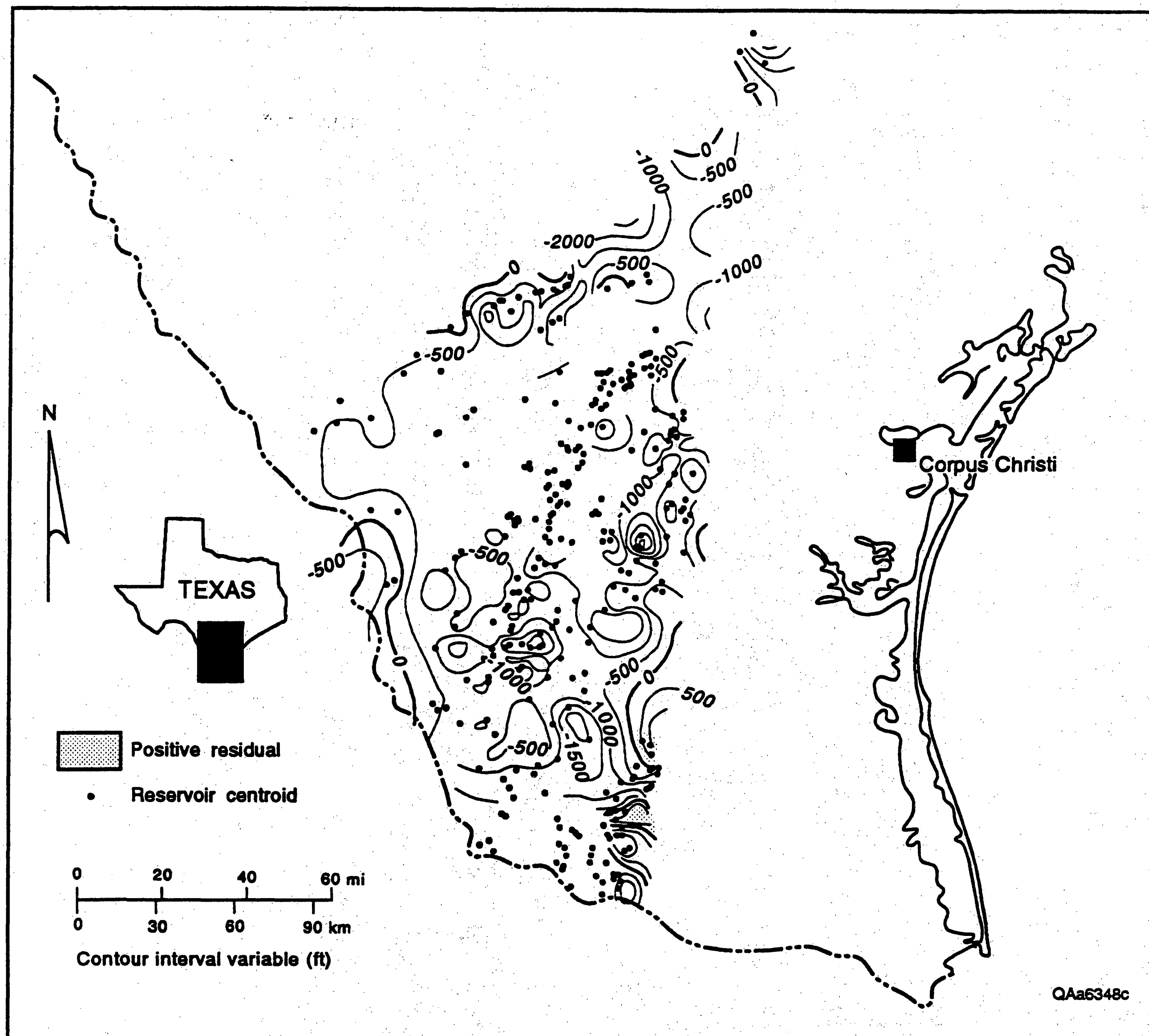

Figure 40. Residual of computer-generated potentiometric surface of Tertiary reservoirs <6,000 ft (<1,800 m) deep minus computer-generated potentiometric surface of Cenozoic USDWs, South Texas Basin. Stippled areas represent positive residuals adequately supported by nearby data points.

PI data (table 21) is approximately 19 percent larger than the population estimated in table 17 for the South Texas Basin, which corresponds to the study area outlined in figure 1. Of the 91,457 wells (other than Class II wells) abandoned through 1989 in the larger area for which PI provided data, 51,894 (57 percent) were abandoned prior to 1960 (table 21). Of the wells abandoned prior to 1960, 7,432 are deeper than 6,000 ft (1,800 m); the total number of abandoned wells deeper than 6,000 ft (1,800 m) is 21,987.

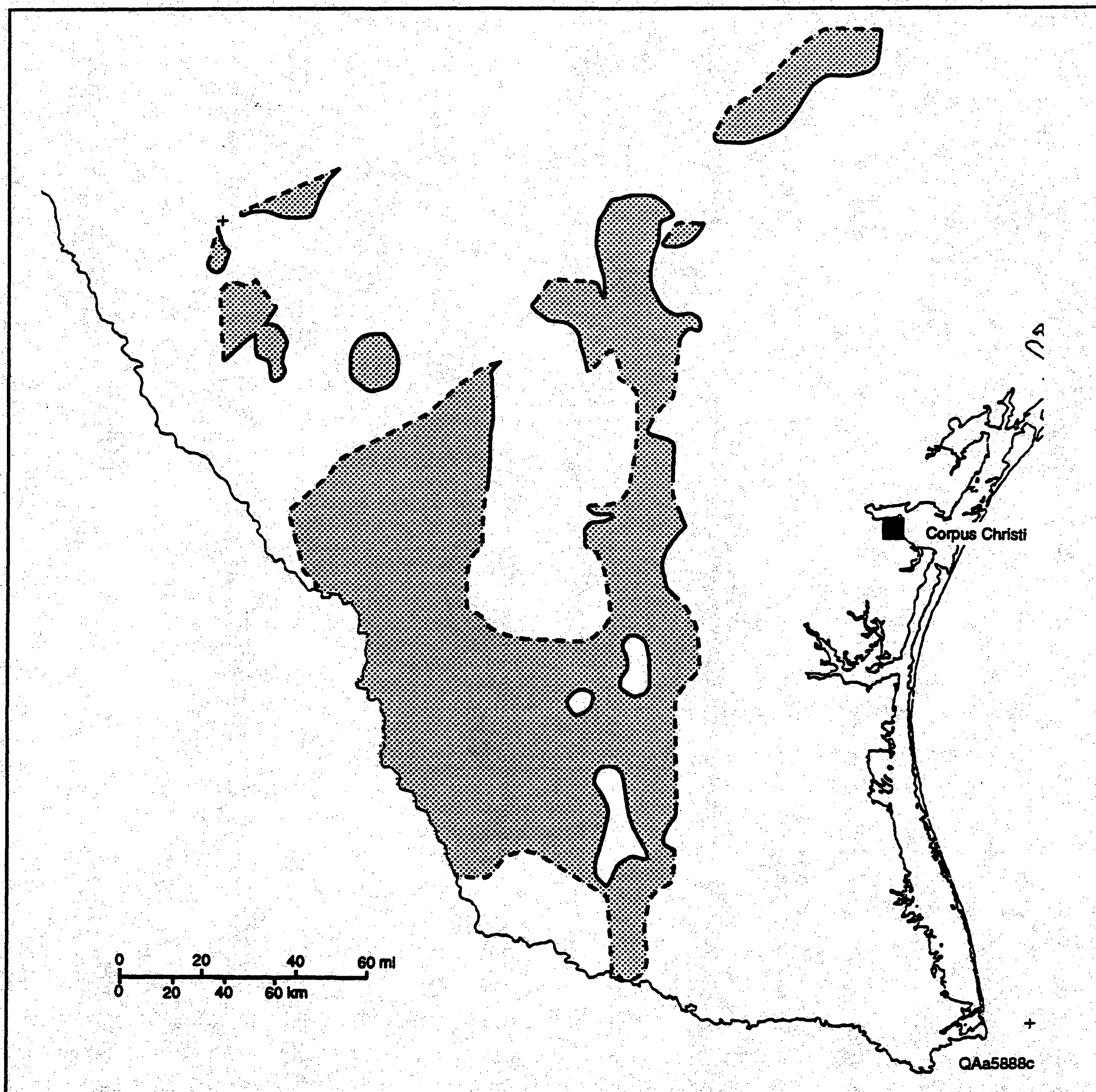

Figure 41. Composite map of all positive residuals in South Texas Basin; boundaries dashed where inferred.

The extent of positive residual areas was again constrained by eliminating areas in which data from reservoirs and USDWs were deemed insufficient. The remaining positive residuals were superimposed on the abandoned well distribution map to estimate the number of abandoned wells in areas of upward hydraulic gradient (table 21). Of approximately 21,145 wells located within constrained positive residuals, only 3,466 are deeper than 6,000 ft (1,800 m).

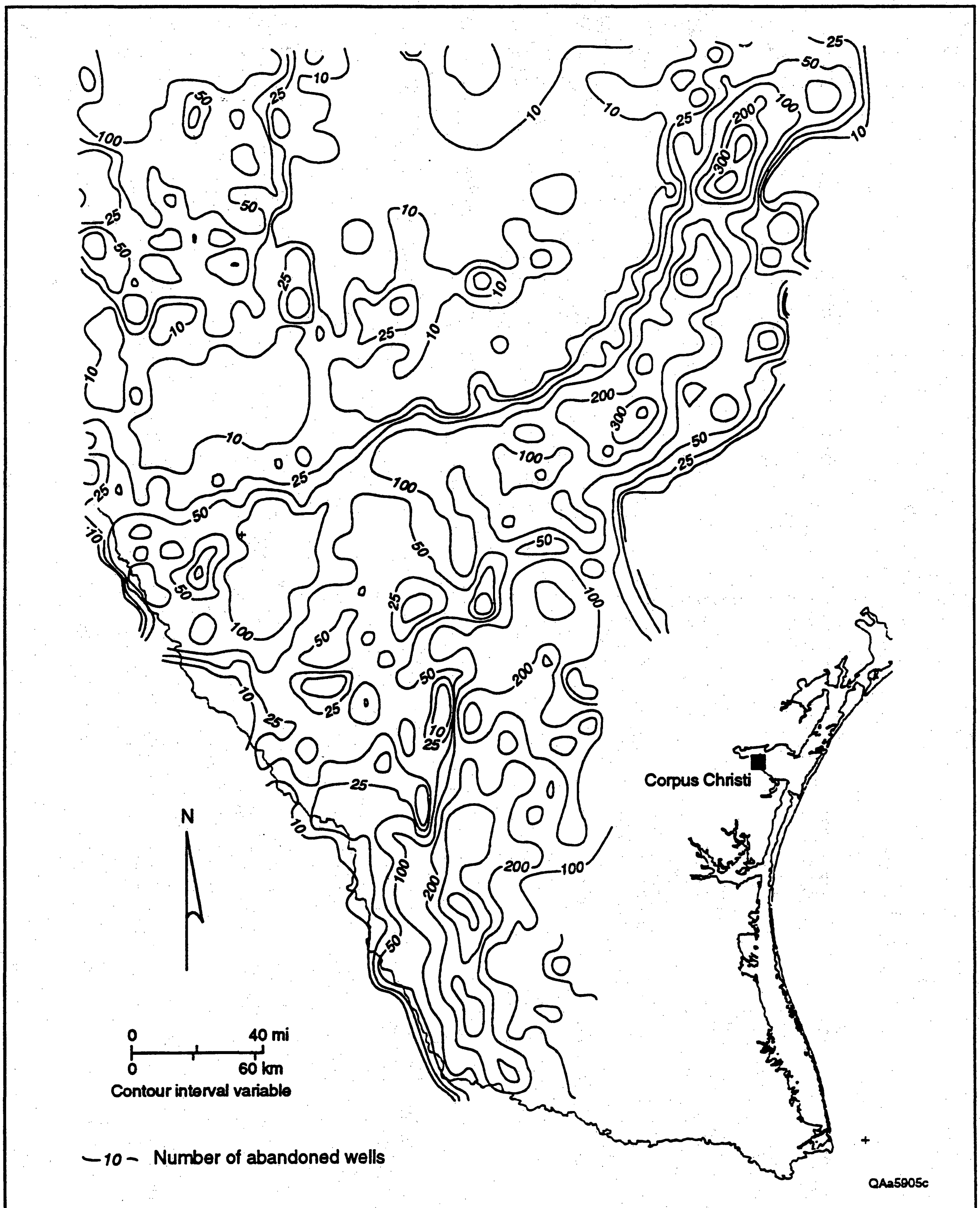

Figure 42. Contour map of the estimated distribution of abandoned wells at a 0.1° × 0.1° scale, South Texas Basin.

Table 21. Estimated numbers of (a) abandoned wells, (b) abandoned wells within constrained positive residuals, and (c) abandoned wells within constrained positive residuals in areas containing approximately one Class II well per km^2, South Texas Basin. Numbers of abandoned wildcats based on PI data; total numbers of abandoned wells computed from wildcat data using factors from Gruy's table 1.

(a)

Avg. total depth (ft) / Year	<6000 #wildcats	<6000 #all aband.	>6000 #wildcats	>6000 #all aband.
<1950	6,507	25,307	868	3,397
1950-59	4,927	19,155	1,030	4,035
1960-69	3,242	12,629	1,024	4,003
1970-79	2,330	9,094	828	3,257
1980-89	1,981	7,753	718	2,827
All Years	18,987	73,938	4,468	17,519

(b)

Avg. total depth (ft) / Year	<3000	3000-6000	>6000	Totals
<1950	3,925	3,473	301	7,699
1950-59	1,875	2,993	377	5,245
1960-69	680	2,240	640	3,560
1970-79	315	1,280	816	2,411
1980-89	94	804	1,332	2,230
All Years	6,889	10,790	3,466	21,145

(c)

Avg. total depth (ft) / Year	<3000	3000-6000	>6000	Totals
<1950	35	8	0	43
1950-59	50	16	0	66
1960-69	31	0	0	31
1970-79	0	19	8	27
1980-89	0	19	0	19
All Years	116	62	8	186

Effects of Class II Injection

Head-Buildup Calculations for Selected EOR Injection Wells

Sample calculations were conducted for two high-volume EOR injection projects in the South Texas Basin to evaluate the hydraulic-head buildups from individual injectors relative to the residual surfaces (appendix VII). Injection data were taken from the EOR survey of the Texas Petroleum Research Committee (1976) (table 22).

For well F0394, the pre-production hydraulic-head differential between the Tertiary reservoir potentiometric surface and the Cenozoic USDW potentiometric surface is approximately –1,162 ft (–354 m), whereas the maximum head buildup 1 ft (0.3 m) from the well is 769 ft (234 m). Therefore, injection over a 13-yr period would not have reversed the downward, pre-production hydraulic gradient between the Tertiary USDWs and the Tertiary reservoir. Moreover, the actual hydraulic gradient was greater than the pre-production gradient due to depressurization (868 psi [5.98 MPa] original pressure, 600 psi [4.14 MPa] after 13 yr of injection).

For well F0004, the pre-production hydraulic-head differential between the potentiometric surface for Tertiary reservoirs <6,000 ft (<1,800 m) and the Cenozoic USDW potentiometric surface is approximately –835 ft (–255 m). The injection rate in well F0004 (2,320 bbl water/day [368,000 L/day]) was four times that of well F0394. The pre-production hydraulic gradient could be reversed by injection, leading to upward flow within a radius of 2,850 ft (869 m) after 1 yr and 8,060 ft (2,460 m) after 8 yr (appendix VII; fig. 43). However, depressurization associated with production would have prevented the reversal of hydraulic gradient by injection: the initial reservoir pressure of 1,195 psi (4.22 MPa) was greater than the actual reservoir pressure following 8 yr of injection (750 psi [5.17 MPa]).

Total Number of Abandoned Wells in Potential Risk Areas

The identification of abandoned wells proximal to Class II injection wells within positive residual areas is relatively simple in the South Texas Basin. Of the 5,449 Class II wells in RRC Districts 1 and 4

Table 22. Characteristics of selected enhanced-recovery injection wells, South Texas Basin.

Proj. no.	RRC dist.	Reservoir, county, centroid location	Depth (ft)	Inj. rate (BPD/well)	Project type	N inj. wells	Project area (acres)	Perm. (md)	Por. (%)	Avg. net pay (ft)	Surface inj. P (psi)	Reservoir pressure (date): original (psi)	Reservoir pressure (date): first injection (psi)	Reservoir pressure (date): latest (psi)	Volume of fluid injected, from first inj. to 1/76, all wells (mbbl)	Oil prod. from project area: from disc. to first inj. (mbbl)	Oil prod. from project area: from first inj. to 1/76 (mbbl)
F0004	1	Pettus, McMullen Co., Lat. 28.096N, Long. 98.441W	3000	2320	PM	2	496	300	0.32	6	600	1195 (7/41)	500 (3/68)	750 (1/76)	8,960	959	1,137
F0394	4	Loma Novia (2nd sand), Duval Co., Lat. 27.882N, Long. 98.586W	2500	580	WF	6	565	276	0.31	11	950	868 (5/58)	270 (11/62)	600 (1/76)	6,225	522	1,226

Project type:
PM - pressure maintenance
WF - water flood

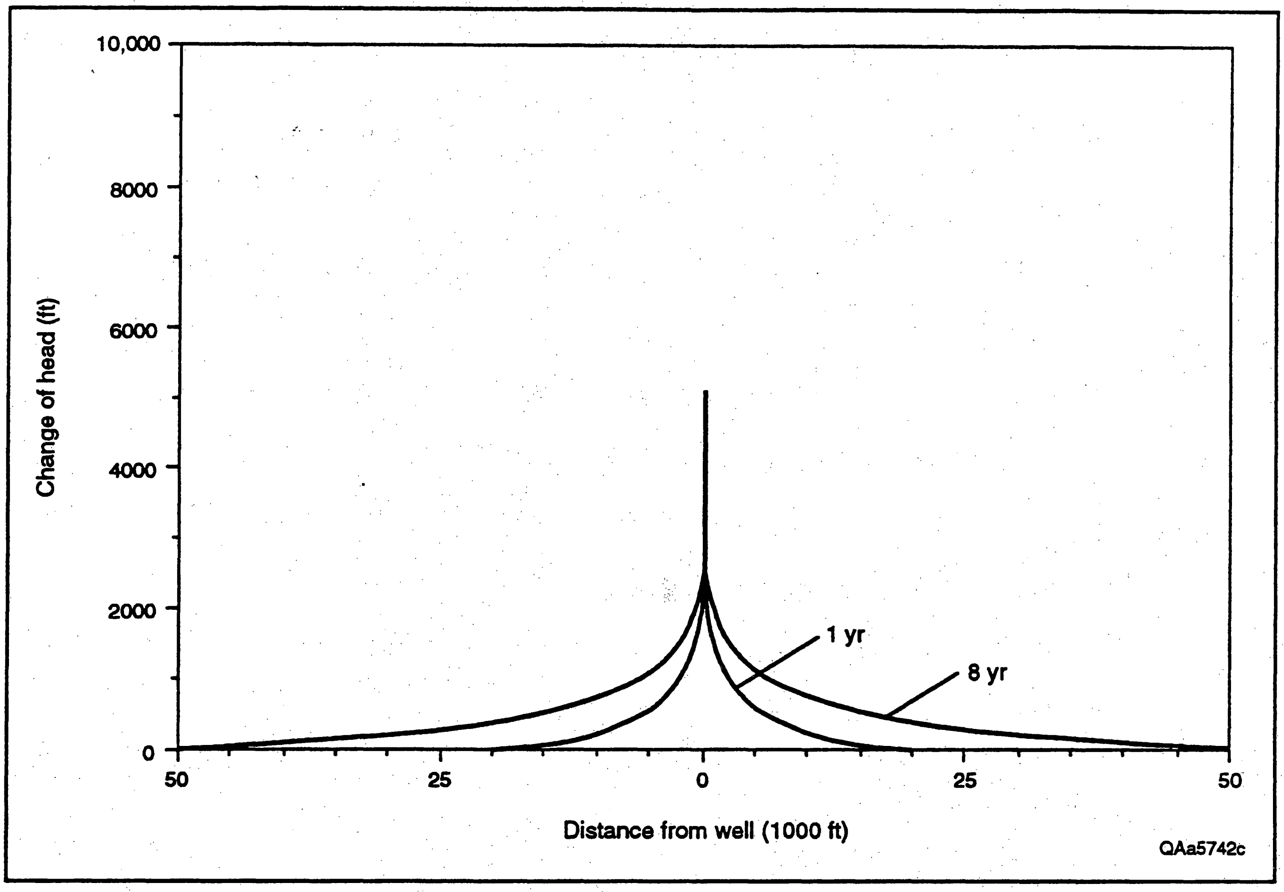

Figure 43. Calculated hydraulic-head buildup around well in enhanced-recovery injection project F0004, South Texas Basin.

(slightly larger than the basin area) as of 1990, only 115 were located in positive residual areas constrained by adequate data, and only four were deeper than 6,000 ft (1,800 m). Very high pressures at depths >6,000 ft (>1,800 m) hinder EOR injection and salt-water disposal, although there are normally-pressured zones deeper than 6,000 ft (1,800 m) in some areas of the basin (Bebout and others, 1982) where Class II injection may be feasible. Of the 21,145 abandoned wells in the positive residual areas, 3,466 were deeper than 6,000 ft (1,800 m) (table 21). The number of abandoned wells within constrained positive residuals containing (for example) ten or more Class II wells per cell (approximately one Class II well per 3.85 mi^2 [10 km^2]) was 186. Of those 186, none were plugged before 1960, and only eight were deeper than 6,000 ft (1,800 m). By extension, abandoned wells in the South Texas Basin are unlikely to penetrate a formation in which Class II injection builds on natural overpressures.

DISCUSSION

Limitations of Methodology

The usefulness of this methodology as a screening tool depends upon the accuracy of mapping the potentiometric surfaces, residuals, and distributions of Class II wells and abandoned wells. One possible source of error is the use of sparse or unrepresentative pressure data. Using a single pressure value per reservoir masks local spatial heterogeneities in the flow field, particularly where the value represents a single measurement from a single well. In addition, the pressure values used may not consistently represent pre-production (maximum) conditions; the present extent of positive residuals might be smaller than mapped because of reservoir depressurization. Lumping various formations into hydrostratigraphic units may obscure vertical gradients between formations. This was particularly true for the San Juan Basin, for which the lack of mappable pressure data from PI necessitated the construction of a single potentiometric surface for oil and gas reservoirs. Pressure data for non-petroleum-productive saline formations are not generally compiled, even though such units may cause salinization of USDWs through improperly abandoned wells. Richter and others (1990) documented this phenomenon in Tom Green County, Texas, in the greater Permian Basin. Brine was upwelling from the naturally overpressured Coleman Junction Formation (above the petroleum-productive units) into shallow ground water, apparently through an abandoned exploration hole that was plugged above the base of the USDW.

A second possible source of error is the use of inaccurate conversion factors to obtain values of hydraulic head in reservoirs. Using empirical pressure gradients to convert SITPs to BHPs is probably an oversimplification: in particular, the 0.07 psi/ft gradient used in the San Juan Basin pertains to coalbed methane wells, whereas pressure data from PI were also collected from conventional gas and oil wells. As noted in the case study for the greater Permian Basin, use of a 0.465 psi/ft specific weight to convert bottomhole pressures to hydraulic head may lead to erroneous conclusions of overpressuring in areas where TDS of brine exceeds 112,000 mg/L. In addition, the assumption of hydrostatic conditions in converting bottomhole pressures to hydraulic head, whether fresh water or brine, neglects vertical components of flow and differences in fluid density that may drive flow (Kaiser and others, 1991).

A third possible source of error is intrinsic to contouring: interpolation and extrapolation between data points. Closed contours on the computer-generated potentiometric surfaces not supported by data ("bull's-eyes") may be artifacts of the contouring algorithm. Subtracting the gridded surfaces and contouring head differences introduces additional error.

Class II Injection and Implications for AOR

Sample head-buildup calculations presented for selected EOR injection and SWD wells illustrate how injection can reverse a downward-directed hydraulic gradient as well as magnify a natural upward-directed hydraulic gradient. As illustrated by the examples of the San Juan Basin SWD wells, some disposal may occur in initially overpressured, non-producing formations, which increases the potential for upward flow. However, for EOR injection wells, which tend to be more numerous, the calculated buildups typically overestimate the actual buildups because the impact of hydrocarbon production on reservoir pressures is neglected. Even if all produced water were to be reinjected for EOR, the net loss of fluid due to hydrocarbon withdrawal would be likely to lower reservoir pressures. Head buildups for both EOR and SWD wells may also be overestimated because of the assumption, implicit in the Theis equation (eq. 3), that injection occurs continuously at a constant rate over the lifetime of the injection or disposal project. Both the use of pre-production reservoir pressures and the assumption of continuous, constant injection are mandated by the Code of Federal Regulations for calculating areas of review (U.S. Office of the Federal Register, 1987). Realistically, however, the use of ambient reservoir pressures would allow more accuracy in mapping positive residuals and in determining areas where injection could cause or build on an upward hydraulic gradient.

CONCLUSIONS

This study defined an approach and developed procedures to identify areas where hydraulic conditions in hydrocarbon reservoirs and injection zones create a potential risk to USDWs through certain abandoned wells. A screening methodology to prioritize AOR studies can allow operators and regulatory agencies to identify areas where natural hydraulic conditions may be conducive to brine migration through abandoned wells that do not meet current regulatory standards. Nationwide, most reservoir and injection data needed for such an analysis are maintained on paper rather than in digital format, rendering mapping of data and comparison of potentiometric surfaces at a regional scale difficult. Based on data availability, we selected the San Juan Basin in New Mexico and Colorado, the greater Permian Basin in Texas and New Mexico, and the South Texas Basin as case studies to test the hydraulic screening methodology. Digital data on reservoir pressures and the locations of abandoned wells were obtained from national data bases maintained by PI and supplemented by data from other sources.

The three basins selected are of different sizes and located in different geologic settings. The San Juan and greater Permian Basins have been uplifted and subjected to meteoric flushing, leading to artesian overpressuring in areas of ground-water discharge (Senger and others, 1987; Kaiser and others, 1991; Bein and Dutton, 1993). In contrast, in the South Texas Basin, circulation of meteoric water is restricted to depths approximately <6,000 ft (<1,800 m) and deeper sediments are overpressured by compaction (Harrison and Summa, 1991). Some of the mapped positive residuals approximately coincide with these areas of upward hydraulic gradient in each basin, although others do not. Pressure data from selected SWD wells in the San Juan Basin indicate an upward hydraulic gradient between the injection zones and USDWs, in contrast to the delineation of negative residuals around those wells based on reservoir pressures from the basin as a whole. The discrepancies may result from sparse or inaccurate pressure data, inaccurate conversion factors, and interpolation between or extrapolation from these data during contouring.

Focusing on abandoned wells within positive residuals as a "first cut" reduces the approximate numbers of abandoned wells for primary examination from 6,104 to 1,000 in the San Juan Basin, from 395,176 to 80,185 in the greater Permian Basin, and from 77,050 to 21,145 in the South Texas Basin. These numbers are reduced further when other factors such as age and distance of abandoned wells from Class II wells are taken into account. In the San Juan Basin, pre-production hydraulic gradients appear to be directed downward where abandoned wells are most numerous. However, in the South Texas Basin, the density of abandoned wells is greatest in the south-central region where positive residuals are concentrated.

This study found inconsistencies in data (specifically counts of abandoned wells) obtained from different sources. Where feasible, data should be collected from all available sources, including operators and regulatory agencies, and evaluated for completeness and quality prior to mapping. Using averaged pressure values and plotting the distribution of wells at a $0.1° \times 0.1°$ scale permits only a semi-quantitative assessment of the numbers of wells potentially at risk. For greater accuracy, potentiometric surfaces should be constructed for individual formations at specific times and the actual geographic location of wells should be plotted.

Where possible, computer-generated residual surfaces were compared to previously collected, independent field data. The results of this study, however, do not provide absolute confirmation of areas where upward flow through improperly abandoned wells may endanger USDWs. Field validation of local hydraulic conditions is necessary. In areas of confirmed upward hydraulic gradient from hydrocarbon reservoirs to USDWs, the risk of salinization of USDWs needs to be quantified by evaluating factors such as wellbore conditions, depth, and completion and abandonment practices, which were beyond the scope of this study. Sample AOR analyses illustrated that the use of positive residuals is insufficient for screening in instances where Class II injection reverses a downward hydraulic gradient. Nonetheless, the method is useful in providing a regional screen to identify areas where natural hydraulic conditions favor upward brine migration.

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APPENDIX I

PROCEDURE FOR DETERMINATION OF AREA OF REVIEW AROUND INJECTION WELLS AND DISPOSAL WELLS

APPENDIX I

PROCEDURE FOR DETERMINATION OF AREA OF REVIEW AROUND INJECTION WELLS AND DISPOSAL WELLS

The procedure is to find the radius of the area within which the pressure increase due to injection raises the hydraulic head (potentiometric surface) of injection formation water above the head in an overlying source of drinking water. Differences in fluid density may be taken into account. Two methods are specified in the Federal regulations for determining the area of review (AOR) for each injection well, field, project, or area (U.S. Office of the Federal Register, 1987). First, a zone of endangering influence can be calculated on a case by case basis. For a single well permit, the AOR of this zone is the area determined by a radius within which the injection zone pressures may cause the migration of injection and/or formation fluids into a USDW. For an area permit, the AOR of the zone is the project area plus a circumscribing area the width of which is the lateral distance from the perimeter of the project area, in which injection zone pressures may result in fluid migration from the injection zone into USDW horizons. Computation of the zone of endangering influence may be based upon reservoir and operating parameters such as (1) hydraulic conductivity of the injection zone, (2) thickness of the injection zone, (3) injection rate, (4) injection duration, (5) hydrostatic head in the injection zone, (6) hydrostatic head in the overlying USDW zones, and (7) specific gravity of fluid in the injection zone. The modified Theis equation is acceptable as a mathematical model in the regulations for calculating the zone of endangering influence.

The second, alternative approach involves defining a circular AOR using a fixed radius of not less than 0.25 mi (0.40 km) around a single well. In the case of an area permit, a circumscribing area having a fixed width not less than 0.25 mi (1,320 ft [400 m]) may be used. The 0.25 mi (0.40 km) radius is equal to the sides of a square of 40 acre area, which is commonly the minimum field spacing for oil wells. Factors to be considered when determining the fixed area are (1) hydrogeology of injection zone, (2) chemistry of formation and injected fluids, (3) population and ground-water usage in the area, and (4) historical practices in the area.

The pressure distribution in the injection zone is calculated using the nonequilibrium method of Theis (1935). This method uses the solution to the transient radial flow equation of a compressible fluid from a line source in a homogeneous, isotropic, confined reservoir of infinite areal extent. The aquifer parameters needed for calculation of pressure distribution are the transmissivity (the multiplicative product of hydraulic conductivity and thickness) and storativity, which are equivalent to the permeability-thickness product and porosity-compressibility product used in petroleum reservoir engineering. When the AOR is determined using an acceptable mathematical model, the radius of the AOR is deemed to be the applicable radius, even if it is less than 0.25 mi.

According to Theis (1935), the response of an aquifer to single well injection is described by the equation

$$\Delta h_i = (Q / 4\pi \times T) \times (-0.577216 - \log_e u + u - (u^2 / (2 \times 2!)) + (u^3 / (3 \times 3!)) - \ldots) \quad (I.1)$$

where Δh_i = hydraulic head change (height of cone of impression) (L)
- Q = volumetric injection rate (L^3/t)
- T = transmissivity (L^2/t)
  - = $K \times h$, where
    - K = hydraulic conductivity (L/t)
    - h = thickness of the injection zone (L)
- S = storativity (storage coefficient)
  - = $\rho gh(\alpha + \beta\phi)$, where
    - ρ = density of injection fluid (M/L^3)
    - g = acceleration due to gravity (L/t^2)
    - α = compressibility of injection zone matrix ($L \times t^2/M$)
    - β = compressibility of injection fluid ($L \times t^2/M$)
    - ϕ = porosity of injection zone (L^3/L^3)
- u = $(r^2 \times S)/(4 \times T \times t)$, where
  - r = radial distance from wellbore to point of interest (L)
  - t = time since injection began

For $u < 0.01$, equation I.1 becomes (Cooper and Jacob, 1946)

$$\Delta h_i = (2.3 \times Q / (4\pi \times T)) \times \log (2.25 \times T \times t / (r^2 \times S)) \quad (I.2)$$

Equation I.2 is expressed in the Federal regulations in the form

$$r = [2.25 \times K \times H \times t / (S \times 10^x)]^{1/2} \quad \text{(I.3)}$$

where r = radius of endangering influence from injection well
K = hydraulic conductivity of injection zone
H = thickness of the injection zone
t = time of injection
S = storativity (or storage coefficient)
x = $4\pi \times K \times H \times [h_w - (h_{bo} \times S_p \times G_b)] / (2.3 \times Q)$, where
h_w = hydrostatic head of USDW measured from the base of the lowermost USDW
h_{bo} = observed original hydrostatic head of injection zone measured from the base of the lowermost USDW
$S_p \times G_b$ = specific gravity of fluid in injection zone
Q = injection rate

Equation I.2 is also used in petroleum reservoir engineering in the form

$$\Delta p = (162.6 \times Q \times \mu \times B / (k \times b) \times (\log(k \times t \times \Phi \times \mu \times C \times r^2) - 3.23) \quad \text{(I.4)}$$

where Δp = reservoir pressure change at radius r and time t (psi)
Q = injection rate (bbl / day)
μ = viscosity (cP [centipoise])
B = formation fluid volume factor (dimensionless)
(ratio of liquid volume at bottomhole conditions to liquid volume at surface conditions; typically >1 for oil containing dissolved gas, <1 for oil under very high formation pressure and lacking dissolved gas, ≈1 for fresh water)
k = average reservoir permeability (md [millidarcies])
b = reservoir thickness (ft)
t = time since injection began (hrs)
Φ = reservoir porosity (fraction)
C = reservoir compressibility (psi^{-1})
r = radial distance from wellbore to point of interest (ft)

APPENDIX II

OIL AND GAS FIELD DATA BY PRODUCING STATE

STATE	UIC PROGRAM AUTHORITY	OIL AND GAS FIELD DATA									
		Active Oil and Gas Wells*	Aband. Wells (all types)**	Field Name	Pool or Formation	Year of Discovery	Field Location	Surface Elevation	Prod. Depth/ Perfs.	Field Press.	Source of Oil and Gas Data
ALABAMA	State	~2600 (incl. TA & SI)		F	F	F	F	F	F	F (BHP's, see comments)	AL State Oil and Gas Board (205) 349-2852 monthly reports for Black Warrior Basin only see also AL Oil and Gas Report 11 1985-86 (Black Warrior Basin)
ALASKA (combined onshore and offshore)	State	1386 oil 108 gas 108 gas (Pm)	(see comments)	C (Pa, Pm)	C (Pa, Pm)						AK Oil and Gas Conservation Commission (907) 279-1433 1989 annual report included in Feb. 1990 monthly report ("Bulletin").
ARKANSAS	State										
CALIFORNIA	State	C (by field) 51,269 (Pa) 43,715 (Pm)	C (by field) 23,905 SI (Pa) 32,251 SI (Pm)	C (Pm)	C (Pa, Pm)						CA Dept. of Conservation, Div. of Oil & Gas (916) 445-9686; Pub. PR06: "74th Annual Report of the State Oil & Gas Supervisor 1988"; Pub. PR04: "Monthly oil and gas production and injection report, Sept. 1969"
COLORADO	State (Indian lands regulated by EPA, Rgn. 8; see Montana)	C (by field) 10,923 (Pa)	C (by field) 2488 SI (Pa)	C (Pa)	C (Pa)	C (Pa)	C (STR) (Pa)				CO Department of Natural Resources Oil and Gas Conservation Commission (303) 894-2100; "1988 Oil and Gas Statistics".
FLORIDA	Federal (EPA Rgn. 4)										
ILLINOIS	State	Total of ~150,000 oil, gas, injection, and all other related wells in state; nearly complete geographical information for most of these; additional geologic information for ~40,000 of the 150,000.									IL State Geological Survey (217) 333-4747 or 244-2387
INDIANA	Federal (EPA Rgn. 5)										
KANSAS	State	~9-10,000 ER & 6-7000 SWD in all of Kansas	(GAO: 14,009 Class II/GRUY: 14,861)	Tm				Gas well pressure test data is available for certain wells each year, for the Hugoton Field (e.g., Oct. 1989 monthly report) and for the Pamona - Council Grove Pool (e.g., Nov. 1989 monthly report)		Tm	KS Corp. Commission Conservation Division (Oil, Gas, & Water) - misc. monthly reports (316) 263-3238
KENTUCKY	Federal (EPA Rgn. 4)										
LOUISIANA	State										LA Office of Conservation, Injection and Mining (production audit & engineering sections) (504) 342-1959, 342-1972
MARYLAND	State	F (no oil, 8 gas leases)	F?	F (Pa)	F (Pa) (Oriskany sand)	F (Pa) (1951 and later)	F Allegheny Co., western Maryland.				MD Department of Natural Resources Geological Survey, (301) 554-5525 "Review of 1989 Oil and Gas Activities in Maryland"; see also MD Geol. Survey Basic Data Rept. 11 (1980) (lists all wells).

STATE	UIC PROGRAM AUTHORITY	OIL AND GAS FIELD DATA									
		Active Oil and Gas Wells*	Aband. Wells (all types)**	Field Name	Pool or Formation	Year of Discovery	Field Location	Surface Elevation	Prod. Depth/ Perfs.	Field Press.	Source of Oil and Gas Data
MICHIGAN	Federal (EPA Rgn. 5)	About 42,000 wells drilled in the state since 1939; about 7,000 active (and temp. abandoned) of all types. Of the 42,000 wells, information for only about 5,000 (~12%) is available in computerized format.									MI Geological Survey (517) 373-1220
MISSISSIPPI	State										
MISSOURI	State										
MONTANA	Federal (EPA Region 8)	CP '88 AC & SI tabl'd but not totalled	CP Indicates SI fields, but no totals	CP	CP for oil	CP for oil	(API gravity reported for oil; also some eng'g data - perm., etc.)		CP for oil		MT Department of Natural Resources Conservation-Oil and Gas Conservation Division "Annual Review for the Year 1988 Relating to Oil and Gas", vol. 32 (406) 656-0040
NEBRASKA	State	P 1702	P 798 (TA & SI)								NB Oil and Gas Conservation Commission "Nebraska Oil Activity Summary-1989"
NEW MEXICO	State	See preliminary report for San Juan Basin study.									
NEW YORK	Federal (EPA Rgn. 2)	4350 oil 5145 gas (Pa)	1478 SI oil 856 SI gas (Pa)	F (Pa)			F (Pa) (generalized map)				NY Department of Environmental Conservation Division of Mineral Resources (518) 457-9341 "New York State Oil and Gas Drilling and Production 1988".
NORTH DAKOTA	State	CP 3809	?	CP	CP	CP (well completion dates)	CP (for each well)				ND Industrial Commission-Oil and Gas Division Bismarck; "Oil in North Dakota - 1988 Production Statistics" (701) 224-2969
OHIO	State										
OKLAHOMA	State										
OSAGE MINERAL RESERVE (OKLAHOMA)	Federal (EPA Rgn. 6)										
PENNSYLVANIA	Federal (EPA Rgn. 3)										
SOUTH DAKOTA	State	CP 207 (1st half of 1989)		CP Also field well ct., API gravity, net pay ft, porosity, & spacing	CP	CP	CP (fld by co.; each well by STR)		CP	CP Initial reservoir pressure	SD Department of Water and Natural Resources Western Field Office - Oil & Gas, Rapid City (605) 394-2229 "Oil, gas and water production figures for South Dakota, first half, 1989"

STATE	UIC PROGRAM AUTHORITY	OIL AND GAS FIELD DATA									
		Active Oil and Gas Wells*	Aband. Wells (all types)**	Field Name	Pool or Formation	Year of Discovery	Field Location	Surface Elevation	Prod. Depth/ Perfs.	Field Press.	Source of Oil and Gas Data
TENNESSEE	Federal (EPA Rgn. 4)										
TEXAS	State			Anticipated completion of digitizing and plotting of oil and gas wells by late 1995 (Texas Railroad Commission).							TX Railroad Commission
UTAH	State (Indian lands regulated by EPA, Rgn. 8; see Montana)	CP 4099	CP 5507	CP	CP		CP (STR, well by well)			C	UT Division of Oil, Gas & Mining "Annual Oil and Gas Production Rept" (801) 538-5340
VIRGINIA	Federal (EPA Rgn. 3; see Penna.)	P 28 oil 26 cond. 728 gas	?	P	P AAPG (general discussion)		P AAPG (general map)		P		VA Department of Mines, Minerals, and Energy Division of Gas and Oil, Abingdon "1988 Summary of Oil and Gas Activity in Virginia" (703) 628-8115
WEST VIRGINIA	State	>50,000 since 1930									WV Geol. Survey, Morgantown
WYOMING	State (Indian lands regulated by EPA, Rgn. 8; see Montana)	CP 14,941		CP		CP	CP (TR & co.)	CP: Active well counts, by field CP: Avg. gravity listed for each active field			WY Oil and Gas Conservation Commission-Casper "Wyoming Oil and Gas Stat's 1988" (307) 234-7147

EXPLANATION OF ABBREVIATIONS

Data Availability:

C	Data are maintained in computerized database Data are maintained in EPA well inventory computerized database
F	Data are confirmed to exist in hard-copy data files
P	Data are published in production or production/injection report
(blank)	Availability of data not verified(most data elements do exist in some form in hard-copy paper files)

Source of Information:

(blank)	State oil and gas agency
AAPG	Discussions of North American oil and gas developments in World Energy Developments, in the Bulletin of the American Association of Petroleum Geologists (normally Part B of October issue of year following year of review)
GAO	U.S. General Accounting Office, 1989
GRUY	Gruy Engineering Corp., 1989

Other abbreviations:

Well status:
AC,TA,SI — Active, temporarily abandoned, shut-in

Location information:
STR — Section-township-range

Data reporting cycle:
m,y,cum — Monthly,yearly,cumulative

Footnotes:

* Includes oil, associated gas, non-associated (dry) gas, gas condensate, coal bed methane, and natural gas and LP gas storage withdrawal

** Unless otherwise specified, includes abandoned dry holes (wildcats, extensions, in-field, new), abandoned producing wells (wildcats, extensions, in-field, new), plugged or unplugged.

APPENDIX III

INJECTION DATA COMPILED BY PRODUCING STATES

STATE	INJECTION DATA																		Source of Information
	Active ER Wells	Active SWD Wells	Total Ann. Inj. Vol.	Field Name	Pool or Formation	Operator/ Project	Inj. Type	Date Begun	Surface Elevation	Inj. Depth/ Perfs.	Inj. Well Count	Inj. Well Location	Inj. Fluid Spec. Gr.	Tubing Diameter	Injection Pressure Rptd. Ave.	Injection Pressure Max. Auth.	Injection Rate	Injection Volume	
ALABAMA	162 (incl. under constr. & TA)	92 (incl. under constr. & TA)		C	C	C	C	C (partial)	C	C	C (listed well by well)	C (LL & STR+ offset)	C (also viscosity)	C	C (m, y)	C (see comments)	C (see comments)	C (m, y, cum)	AL State Oil and Gas Board (205) 349-2852 sample database output
ALASKA (combined onshore and offshore)	500 (Pm) (see comments)	20 (Pm) (see comments)	733x10*6 bbl water, 1.6x10*9 mcf gas (Pa)	C (Pa, Pm)	C (Pa, Pm)		C (Pa, Pm)				C (Pm) (listed by field)							C (Pa, Pm) (y, cum; by field)	AK Oil and Gas Conservation Commission (907) 279-1433 1989 annual report included in Feb. 1990 monthly report ("Bulletin").
ARKANSAS																			
CALIFORNIA	15,145 AC 3217 SI (Pa) 6705 AC 5408 SI (Pm)	679 AC 468 SI (Pa) 548 AC 595 SI (Pm)	2.1x10*9 bbl water 123x10*6 mcf gas (Pa; see comments)	C (Pa, Pm)	C (Pa, Pm)	C (Pa, Pm)	C (Pa, Pm)	C (Pa) (partial)			C (Pa, Pm)							C (Pa, Pm) (m, y, cum; by field)	CA Dept. of Conservation Div. of Oil & Gas, (916) 445-9686; Pub. PR06: "74th Annual report of the state oil & gas supervisor 1988"; Pub. PR04: "Monthly oil and gas production and injection report Sept. 1989".
COLORADO	56 projects (Pa)	140 (Pa)	Tabulated, but not totaled (Pa)	C (Pa)	C (Pa)	C (Pa)	C (Pa)	C (Pa)				C (Pa) (SWD by STR + Q/Q)			C (Pa, Pm) (min. and max.) (by well for SWD, by proj. for ER)			C (Pa) (m, y, cum; by field) (by well for SWD)	CO Department of Natural Resources Oil and Gas Conservation Commission (303) 894-2100 "1988 Oil and Gas Statistics"
FLORIDA																			
ILLINOIS					C		C		C		well by well	C (Lambert coord's)							IL State Geological Survey (217) 333-4747 or 244-2387
INDIANA																			
KANSAS				Data by lease and well	C	C	C		C?		C (each well is a separate record)	C	C		C	C	C (max. auth'z'd)	C (last reptd annual volume)	KS Corp. Commission Conservation Division UIC Section (316) 263-3238
KENTUCKY	(GAO: 5399 Class II/GRUY: 5417)																		
LOUISIANA	~3700 ER & SWD (Walter) (GAO: 4212 Class II/GRUY: 4150)			C	C	C	C	C (pmt)	C		C (each well is a separate record)	C (lat/long, STR, & Lambert)	C (since 1983?)	In hard-copy files?	In hard-copy files?	In hard-copy files?	In hard-copy files?	In hard-copy files?	LA Office of Conservation, Inj. and Mining (UIC section), Baton Rouge sample from computerized database (504) 342-5515, or 5562
MARYLAND	0	0																	MD Department of Natural Resources Geological Survey, (301) 554-5525

STATE	Active ER Wells	Active SWD Wells	Total Ann. Inj. Vol.	Field Name	Pool or Formation	Operator/ Project	Inj. Type	Date Begun	Surface Elevation	Inj. Depth/ Perfs.	Inj. Well Count	Inj. Well Location	Inj. Fluid Spec. Gr.	Tubing Diameter	Injection Pressure Rptd. Ave.	Injection Pressure Max. Auth.	Injection Rate	Injection Volume	Source of Information
	INJECTION DATA																		
MICHIGAN	(GAO: 1631 Class II/GRUY: 1657)			C	C		C		C (partial)		well by well	C (LL)		C	F	F	F	F	MI Geological Survey (517) 373-1220
MISSISSIPPI	(GAO: 936 Class II/GRUY: 961)																		
MISSOURI	(GAO: 275 Class II/GRUY: 402)																		
MONTANA	P 519 (GAO: 1449 Class II/GRUY: 1330)		P '88 ER inj. tab't'd but not totaled	CEW P	CEW (partial, in well name) P	CEW P	P	P	?		CEW (by well) P	CEW	P (fluid source reported)				P (avg. daily)	P (annual)	MT Dept. of Natural Resources and Conservation Oil and Gas Conservation Div. (406) 656-0040 U.S. EPA Region 8, Denver (303) 293-1544 ext. 1251; Injection pressures ext. 1416
NEBRASKA	C 658 (~20% SI) IEm 381 active (GAO: 624 Class II/GRUY: 717)	C 75		C IEm	C IEm	C (data by well) IEm (project summary)	C	IEm	C		C (data by well) IEm	C IEm		C		C	C (max. auth'z'd) IEm (avg. daily rate)	IEm (cum. total)	NB Oil and Gas Conservation Comm. Mar. '90 printout of Class II database. Dec. '88 & Dec. '89 ER Injection Report (308) 254-4595
NEW MEXICO	(GAO: 3913 Class II/GRUY: 4451)			C	C	C	C	C	C		C				C			C	NM Oil Conservation Division (505) 827-5807
NEW YORK	1382 water ER & SWD 854 strg. (Pa) (GAO: 3254 Class II/GRUY: 3254)	10 LP gas													500-1000 psi (SITP)				U.S. EPA Region 2 (New York City Office) UIC Section, (212) 264-1339, or 264-1800 (main); EPA has abandoned well survey for PA w/maps, etc. - they believe 50% of wells have been found.
NORTH DAKOTA (first well drilled in 1951)	~400 (Rygh) (GAO: 595 Class II/GRUY: 529)	~300 (Rygh)		CP	CP	CP	CP (by well)				CP (by well)	CP (by well)						CP (monthly, yearly cum., total cum.)	ND Industrial Commission- Oil and Gas Div. Bismarck; "Oil in North Dakota - 1988 Production Statistics" (701) 224-2969
OHIO	(GAO: 3952 Class II/GRUY: 3956)																		
OKLAHOMA	(GAO: 22,579 Class II/GRUY: 24,916)																		
OSAGE MINERAL RESERVE (OKLAHOMA)	(GAO: 4298 Class II)																		U.S. EPA Region 6, Dallas HQ Office (214) 655-7165
PENNSYLVANIA	(GAO: 4788 Class II/GRUY: 6183)																		U.S. EPA Region 3, Philadelphia HQ (215) 597-2537
SOUTH DAKOTA	40-50 mostly air inj. (GAO: 40 Class II/GRUY: 41)	SWD in Williston Basin		Only 40-50 injectors in South Dakota - most are air injector for in situ combustion in the northwest (Harding Co.); 1 waterflood in southwest (Fall River Co.), 1 in Harding Co. (Steece, files in Rapid City)															SD Dept. of Water and Natural Resources, Division of Land and Water Quality, Pierre (605) 773-3151

STATE	INJECTION DATA																		
	Active ER Wells	Active SWD Wells	Total Ann. Inj. Vol.	Field Name	Pool or Formation	Operator/ Project	Inj. Type	Date Begun	Surface Elevation	Inj. Depth/ Perfs.	Inj. Well Count	Inj. Well Location	Inj. Fluid Spec. Gr.	Tubing Diameter	Injection Pressure Rptd. Ave.	Injection Pressure Max. Auth.	Injection Rate	Injection Volume	Source of Information
TENNESSEE	(GAO: 9 Class II/GRUY: 10)																		
TEXAS	(GAO: 49,476 Class II/GRUY: 52,740)			C	C	C	C				C	Anticipated completion of digitizing and plotting of injection wells by late 1992 (Texas Railroad Commission).		C	C	C	C	C	TX Railroad Commission, UIC Sect.
UTAH	I 518 (GAO: 664 Class II/GRUY: 654)	I 52	I 113.2 x 10*6 bbl 234.8 x 10*6 mcf	I	I	I	I	F	F	F	I	I (county)	I (fluid source, no analysis)	most are 2 7/8" tubing (Hunt)	I (avg. inj. pressure) (monthly)		I (avg. daily rate) (monthly)	I (monthly, yearly, avg. bbl/day & mcf/day)	UT Dept. of Nat. Resources, Div. of Oil, Gas & Mining, UIC Prog. "1988 Annual Injection Report" (801) 538-5340
VIRGINIA	0 (permits pending)	0		No Class II injection wells in Virginia; several permits pending															VA Division of Gas and Oil, Abingdon (703) 628-8115 U.S. EPA, Region 3 (Philadelphia) (215) 597-2537
WEST VIRGINIA	~350 (Lewis) (GAO: 760 Class II/GRUY: 572)	~50 (Lewis)		C	C	C	C	C	C	C	well by well	C	C	C?	C (max)	C	C (max rate)		WV Department of Energy Division of Oil and Gas Charleston (304) 348-3500
WYOMING	CP 2WI: 2779 3RI: 476 GI: 36 Air: 2 Stm: 24 GS: 18 GD:2 (GAO: 5749 Class II/GRUY: 4979)	CP 192		CP	CP	CP	CP	CP			CP	CP (by Co.)	CP (fluid source)						WY Oil and Gas Conservation Comm., Casper "Wyoming Oil and Gas Stat's 1988" (307) 234-7147

EXPLANATION OF ABBREVIATIONS

Data Availability:

C	Data are maintained in computerized database
EW	Data are maintained in EPA well inventory computerized database
F	Data are confirmed to exist in hard-copy data files
P	Data are published in production or production/injection report
I	Data are published in combined injection report
E	Data are published in enhanced recovery injection report
m	Monthly report
(blank)	Availability of data not verified (most data elements do exist in some form in hard-copy paper files)

Source of Information:

(blank)	State oil and gas agency
AAPG	Discussions of North American oil and gas developments in World Energy Developments, in the Bulletin of the American Association of Petroleum Geologists(normally Part B of October issue of year following year of review)
GAO	U.S. General Accounting Office, 1989
GRUY	Gruy Engineering Corp., 1989

Other abbreviations:

Well status:

AC,TA,SI	Active, temporarily abandoned, shut-in

Location information:

LL	Latitude and longitude
STR	Section-township-range
+offset	Distance of well from section line(s)
+Q/Q	Quarter of quarter section

Data reporting cycle:

m,y,cum	Monthly,yearly,cumulative

APPENDIX IV

HEAD-BUILDUP DATA FOR SELECTED ENHANCED-RECOVERY INJECTION WELLS, SAN JUAN BASIN

1. Bisti - Lower Gallup, West Bisti PMP, Chevron USA, Inc., Well No. 140
(injection volume 37,143 bbl in May 1987 = 1198 bbls/day = 0.832 bpm = 34.95 gpm)

Q (injection rate in gpm)	Transmis-sivity (gpd/ft)	Storativity (dimension-less)	Radial Distance from Well (ft)	Injection Time (days) time 1	time 2	time 3	Head-buildup (Δh) time 1	time 2	time 3
34.95	13.20	0.000053	1	365	7300	14600	5198	6107	6317
34.95	13.20	0.000053	100	365	7300	14600	2402	3311	3521
34.95	13.20	0.000053	250	365	7300	14600	1845	2755	2965
34.95	13.20	0.000053	500	365	7300	14600	1424	2334	2544
34.95	13.20	0.000053	1000	365	7300	14600	1004	1913	2123
34.95	13.20	0.000053	1320	365	7300	14600	835	1744	1955
34.95	13.20	0.000053	2000	365	7300	14600	583	1492	1703
34.95	13.20	0.000053	3500	365	7300	14600	243	1152	1363
34.95	13.20	0.000053	5000	365	7300	14600	26	936	1146
34.95	13.20	0.000053	7500	365	7300	14600	0	690	900
34.95	13.20	0.000053	10000	365	7300	14600	0	515	725
34.95	13.20	0.000053	15000	365	7300	14600	0	269	479
34.95	13.20	0.000053	20000	365	7300	14600	0	94	305
34.95	13.20	0.000053	30000	365	7300	14600	0	0	58
34.95	13.20	0.000053	50000	365	7300	14600	0	0	0
34.95	13.20	0.000053	100000	365	7300	14600	0	0	0

2. Cha Cha Gallup, Humble Northwest Cha Cha - Gallup PMP, Mountain States Petroleum Corp. (previously operated by Suburban Propane Gas Corp.), Well No. 26-12
(injection volume 900 bbl in July 1987 = 29 bbls/day = 0.020 bpm = 0.85 gpm)

Q (injection rate in gpm)	Transmis-sivity (gpd/ft)	Storativity (dimension-less)	Radial Distance from Well (ft)	Injection Time (days) time 1	time 2	time 3	Head-buildup (Δh) time 1	time 2	time 3
0.85	10.37	0.000018	1	365	7300	14600	169	197	203
0.85	10.37	0.000018	100	365	7300	14600	82	110	117
0.85	10.37	0.000018	250	365	7300	14600	65	93	100
0.85	10.37	0.000018	500	365	7300	14600	52	80	87
0.85	10.37	0.000018	1000	365	7300	14600	39	67	74
0.85	10.37	0.000018	1320	365	7300	14600	34	62	68
0.85	10.37	0.000018	2000	365	7300	14600	26	54	61
0.85	10.37	0.000018	3500	365	7300	14600	15	44	50
0.85	10.37	0.000018	5000	365	7300	14600	9	37	43
0.85	10.37	0.000018	7500	365	7300	14600	1	29	36
0.85	10.37	0.000018	10000	365	7300	14600	0	24	30
0.85	10.37	0.000018	15000	365	7300	14600	0	16	23
0.85	10.37	0.000018	20000	365	7300	14600	0	11	17
0.85	10.37	0.000018	30000	365	7300	14600	0	3	10
0.85	10.37	0.000018	50000	365	7300	14600	0	0	0
0.85	10.37	0.000018	100000	365	7300	14600	0	0	0

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3. Horseshoe Gallup (lower), Humble Horseshoe Gallup PMP No. 2,
Marmac Petroleum Co. (formerly Solar Petroleum, Inc.), Well No. 101
(injection volume 9052 bbl in October 1987 = 292 bbls/day = 0.203 bpm = 8.52 gpm)

Q (injection rate in gpm)	Transmis-sivity (gpd/ft)	Storativity (dimension-less)	Radial Dis-tance from Well (ft)	Injection Time (days)			Head-buildup (Δh)		
				time 1	time 2	time 3	time 1	time 2	time 3
8.52	21.29	0.000024	1	365	7300	14600	844	981	1013
8.52	21.29	0.000024	100	365	7300	14600	421	559	591
8.52	21.29	0.000024	250	365	7300	14600	337	475	506
8.52	21.29	0.000024	500	365	7300	14600	274	411	443
8.52	21.29	0.000024	1000	365	7300	14600	210	347	379
8.52	21.29	0.000024	1320	365	7300	14600	184	322	354
8.52	21.29	0.000024	2000	365	7300	14600	146	284	316
8.52	21.29	0.000024	3500	365	7300	14600	95	232	264
8.52	21.29	0.000024	5000	365	7300	14600	62	200	232
8.52	21.29	0.000024	7500	365	7300	14600	25	163	194
8.52	21.29	0.000024	10000	365	7300	14600	0	136	168
8.52	21.29	0.000024	15000	365	7300	14600	0	99	131
8.52	21.29	0.000024	20000	365	7300	14600	0	73	104
8.52	21.29	0.000024	30000	365	7300	14600	0	35	67
8.52	21.29	0.000024	50000	365	7300	14600	0	0	20
8.52	21.29	0.000024	100000	365	7300	14600	0	0	0

4. Many Rocks Gallup, Many Rocks - Gallup PMP 1,
Marmac Petroleum Co. (formerly Solar Petroleum, Inc.), Well No. 223
(injection volume 4588 bbl in March 1987 = 148 bbls/day = .103 bpm = 4.32 gpm)

Q (injection rate in gpm)	Transmis-sivity (gpd/ft)	Storativity (dimension-less)	Radial Dis-tance from Well (ft)	Injection Time (days)			Head-buildup (Δh)		
				time 1	time 2	time 3	time 1	time 2	time 3
4.32	21.11	0.000015	1	365	7300	14600	442	513	529
4.32	21.11	0.000015	100	365	7300	14600	226	297	313
4.32	21.11	0.000015	250	365	7300	14600	183	254	270
4.32	21.11	0.000015	500	365	7300	14600	151	221	237
4.32	21.11	0.000015	1000	365	7300	14600	118	188	205
4.32	21.11	0.000015	1320	365	7300	14600	105	175	192
4.32	21.11	0.000015	2000	365	7300	14600	86	156	172
4.32	21.11	0.000015	3500	365	7300	14600	59	130	146
4.32	21.11	0.000015	5000	365	7300	14600	43	113	129
4.32	21.11	0.000015	7500	365	7300	14600	24	94	110
4.32	21.11	0.000015	10000	365	7300	14600	10	80	97
4.32	21.11	0.000015	15000	365	7300	14600	0	61	78
4.32	21.11	0.000015	20000	365	7300	14600	0	48	64
4.32	21.11	0.000015	30000	365	7300	14600	0	29	45
4.32	21.11	0.000015	50000	365	7300	14600	0	5	21
4.32	21.11	0.000015	100000	365	7300	14600	0	0	0

APPENDIX V

HEAD-BUILDUP DATA FOR SELECTED SALT-WATER DISPOSAL WELLS, SAN JUAN BASIN

1. Basin Disposal, Inc., San Juan Co., Well No. 1 F

(injection volume 43209 bbl in April 1990 = 1440 bbls/day = 1.00 bpm = 42 gpm; fluid density = 1.014, porosity = 0.17)

Q (injection rate in gpm)	Transmissivity (gpd/ft) low	Transmissivity (gpd/ft) high	Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days) time 1	Injection Time (days) time 2	Head-buildup (Δh) low transmissivity time 1	low transmissivity time 2	high transmissivity time 1	high transmissivity time 2
42	14.96	1795.00	0.00009	1	365	14600	5381	6568	58	68
42	14.96	1795.00	0.00009	100	365	14600	2416	3604	33	43
42	14.96	1795.00	0.00009	250	365	14600	1826	3014	28	38
42	14.96	1795.00	0.00009	500	365	14600	1380	2568	24	34
42	14.96	1795.00	0.00009	1000	365	14600	934	2121	21	31
42	14.96	1795.00	0.00009	1320	365	14600	755	1943	19	29
42	14.96	1795.00	0.00009	2000	365	14600	488	1675	17	27
42	14.96	1795.00	0.00009	3500	365	14600	127	1315	14	24
42	14.96	1795.00	0.00009	5000	365	14600	0	1085	12	22
42	14.96	1795.00	0.00009	7500	365	14600	0	824	10	20
42	14.96	1795.00	0.00009	10000	365	14600	0	639	8	18
42	14.96	1795.00	0.00009	15000	365	14600	0	378	6	16
42	14.96	1795.00	0.00009	20000	365	14600	0	193	5	15
42	14.96	1795.00	0.00009	30000	365	14600	0	0	3	12
42	14.96	1795.00	0.00009	50000	365	14600	0	0	0	10
42	14.96	1795.00	0.00009	100000	365	14600	0	0	0	6

2. BHP Petroleum, Inc., San Juan Co., Gallegos Canyon Unit, Well No. 307 L

(injection volume 8640 bbl in April 1990 = 288 bbls/day = 0.20 bpm = 8.4 gpm; fluid density = 1.043, porosity = 0.17)

Q (injection rate in gpm)	Transmissivity (gpd/ft) low	Transmissivity (gpd/ft) high	Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days) time 1	Injection Time (days) time 2	Head-buildup (Δh) low transmissivity time 1	low transmissivity time 2	high transmissivity time 1	high transmissivity time 2
8.4	14.96	1795.00	0.00153	1	365	14600	894	1131	10	12
8.4	14.96	1795.00	0.00153	100	365	14600	301	538	5	7
8.4	14.96	1795.00	0.00153	250	365	14600	183	420	4	6
8.4	14.96	1795.00	0.00153	500	365	14600	93	331	3	5
8.4	14.96	1795.00	0.00153	1000	365	14600	4	242	3	5
8.4	14.96	1795.00	0.00153	1320	365	14600	0	206	2	4
8.4	14.96	1795.00	0.00153	2000	365	14600	0	152	2	4
8.4	14.96	1795.00	0.00153	3500	365	14600	0	80	1	3
8.4	14.96	1795.00	0.00153	5000	365	14600	0	34	1	3
8.4	14.96	1795.00	0.00153	7500	365	14600	0	0	0	2
8.4	14.96	1795.00	0.00153	10000	365	14600	0	0	0	2
8.4	14.96	1795.00	0.00153	15000	365	14600	0	0	0	2
8.4	14.96	1795.00	0.00153	20000	365	14600	0	0	0	1
8.4	14.96	1795.00	0.00153	30000	365	14600	0	0	0	1
8.4	14.96	1795.00	0.00153	50000	365	14600	0	0	0	0
8.4	14.96	1795.00	0.00153	100000	365	14600	0	0	0	0

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APPENDIX V (continued)

3. Conoco, Inc., Rio Arriba Co., Jicarilla 30, Well No. 1 A

(injection volume 4208 bbl in March 1990 = 136 bbls/day = 0.094 bpm = 4 gpm; fluid density = 1.002, porosity = 0.16)

Q (injection rate in gpm)	Transmissivity (gpd/ft) low	Transmissivity (gpd/ft) high	Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days) time 1	Injection Time (days) time 2	Head-buildup (Δh) low transmissivity time 1	Head-buildup (Δh) low transmissivity time 2	Head-buildup (Δh) high transmissivity time 1	Head-buildup (Δh) high transmissivity time 2
4	14.96	1795.00	0.00048	1	365	14600	461	575	5	6
4	14.96	1795.00	0.00048	100	365	14600	179	292	3	4
4	14.96	1795.00	0.00048	250	365	14600	123	236	2	3
4	14.96	1795.00	0.00048	500	365	14600	80	194	2	3
4	14.96	1795.00	0.00048	1000	365	14600	38	151	2	2
4	14.96	1795.00	0.00048	1320	365	14600	21	134	1	2
4	14.96	1795.00	0.00048	2000	365	14600	0	109	1	2
4	14.96	1795.00	0.00048	3500	365	14600	0	74	1	2
4	14.96	1795.00	0.00048	5000	365	14600	0	52	1	2
4	14.96	1795.00	0.00048	7500	365	14600	0	28	1	1
4	14.96	1795.00	0.00048	10000	365	14600	0	10	0	1
4	14.96	1795.00	0.00048	15000	365	14600	0	0	0	1
4	14.96	1795.00	0.00048	20000	365	14600	0	0	0	1
4	14.96	1795.00	0.00048	30000	365	14600	0	0	0	1
4	14.96	1795.00	0.00048	50000	365	14600	0	0	0	0
4	14.96	1795.00	0.00048	100000	365	14600	0	0	0	0

4. Meridian Oil, Inc., San Juan Co., Cedar Hill SWD, Well No. 1 B

(injection volume 72,245 bbl in March 1990 = 2330 bbls/day = 1.62 bpm = 68 gpm; fluid density = 1.009, porosity = 0.24)

Q (injection rate in gpm)	Transmissivity (gpd/ft) low	Transmissivity (gpd/ft) high	Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days) time 1	Injection Time (days) time 2	Head-buildup (Δh) low transmissivity time 1	Head-buildup (Δh) low transmissivity time 2	Head-buildup (Δh) high transmissivity time 1	Head-buildup (Δh) high transmissivity time 2
68	748	3748	0.00182	1	365	14600	184	222	40	48
68	748	3748	0.00182	100	365	14600	88	126	21	29
68	748	3748	0.00182	250	365	14600	69	107	17	25
68	748	3748	0.00182	500	365	14600	54	93	14	22
68	748	3748	0.00182	1000	365	14600	40	78	11	19
68	748	3748	0.00182	1320	365	14600	34	72	10	18
68	748	3748	0.00182	2000	365	14600	25	64	8	16
68	748	3748	0.00182	3500	365	14600	14	52	6	14
68	748	3748	0.00182	5000	365	14600	6	45	5	12
68	748	3748	0.00182	7500	365	14600	0	36	3	11
68	748	3748	0.00182	10000	365	14600	0	30	2	9
68	748	3748	0.00182	15000	365	14600	0	22	0	8
68	748	3748	0.00182	20000	365	14600	0	16	0	6
68	748	3748	0.00182	30000	365	14600	0	7	0	5
68	748	3748	0.00182	50000	365	14600	0	0	0	3
68	748	3748	0.00182	100000	365	14600	0	0	0	0

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5. Meridian Oil, Inc., San Juan Co., Middle Mesa SWD, Well No. 1 L
(injection volume 136,383 bbl in March 1990 = 4399 bbls/day = 3.06 bpm = 128.3 gpm; fluid density = 1.011, porosity = 0.24)

Q (injection rate in gpm)	Transmissivity (gpd/ft) low	Transmissivity (gpd/ft) high	Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days) time 1	Injection Time (days) time 2	Head-buildup (Δh) low transmissivity time 1	Head-buildup (Δh) low transmissivity time 2	Head-buildup (Δh) high transmissivity time 1	Head-buildup (Δh) high transmissivity time 2
128.3	1000	2500	0.00071	1	365	14600	277	332	116	138
128.3	1000	2500	0.00071	100	365	14600	142	196	62	84
128.3	1000	2500	0.00071	250	365	14600	115	169	51	73
128.3	1000	2500	0.00071	500	365	14600	94	149	43	65
128.3	1000	2500	0.00071	1000	365	14600	74	128	35	57
128.3	1000	2500	0.00071	1320	365	14600	66	120	32	53
128.3	1000	2500	0.00071	2000	365	14600	54	108	27	49
128.3	1000	2500	0.00071	3500	365	14600	37	91	20	42
128.3	1000	2500	0.00071	5000	365	14600	27	81	16	38
128.3	1000	2500	0.00071	7500	365	14600	15	69	11	33
128.3	1000	2500	0.00071	10000	365	14600	6	61	8	30
128.3	1000	2500	0.00071	15000	365	14600	0	49	3	25
128.3	1000	2500	0.00071	20000	365	14600	0	40	0	21
128.3	1000	2500	0.00071	30000	365	14600	0	28	0	17
128.3	1000	2500	0.00071	50000	365	14600	0	13	0	11
128.3	1000	2500	0.00071	100000	365	14600	0	0	0	3

6. Meridian Oil, Inc., San Juan Co., Pump Canyon SWD, Well No. 1 J
(injection volume 138,940 bbl in March 1990 = 4482 bbls/day = 3.11 bpm = 130.7 gpm; fluid density = 1.011, porosity = 0.24)

Q (injection rate in gpm)	Transmissivity (gpd/ft) low	Transmissivity (gpd/ft) high	Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days) time 1	Injection Time (days) time 2	Head-buildup (Δh) low transmissivity time 1	Head-buildup (Δh) low transmissivity time 2	Head-buildup (Δh) high transmissivity time 1	Head-buildup (Δh) high transmissivity time 2
130.7	748	3748	0.00044	1	365	14600	381	455	83	97
130.7	748	3748	0.00044	100	365	14600	197	271	46	60
130.7	748	3748	0.00044	250	365	14600	160	234	38	53
130.7	748	3748	0.00044	500	365	14600	132	206	33	48
130.7	748	3748	0.00044	1000	365	14600	105	179	27	42
130.7	748	3748	0.00044	1320	365	14600	93	167	25	40
130.7	748	3748	0.00044	2000	365	14600	77	151	22	37
130.7	748	3748	0.00044	3500	365	14600	54	128	17	32
130.7	748	3748	0.00044	5000	365	14600	40	114	14	29
130.7	748	3748	0.00044	7500	365	14600	24	98	11	26
130.7	748	3748	0.00044	10000	365	14600	12	86	9	24
130.7	748	3748	0.00044	15000	365	14600	0	70	6	20
130.7	748	3748	0.00044	20000	365	14600	0	58	3	18
130.7	748	3748	0.00044	30000	365	14600	0	42	0	15
130.7	748	3748	0.00044	50000	365	14600	0	22	0	11
130.7	748	3748	0.00044	100000	365	14600	0	0	0	5

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APPENDIX V (continued)

7. Meridian Oil, Inc., Rio Arriba Co., San Juan 30-6 Unit, Well No. 112Y A

(injection volume 197,508 bbl in April 1990 = 6854 bbls/day = 4.57 bpm = 192 gpm; fluid density = 1.018, porosity = 0.24)

Q (injection rate in gpm)	Transmissivity (gpd/ft)		Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days)		Head-buildup (Δh)			
							low transmissivity		high transmissivity	
	low	high			time 1	time 2	time 1	time 2	time 1	time 2
192	1000	2500	0.00199	1	365	14600	392	474	165	198
192	1000	2500	0.00199	100	365	14600	190	271	84	116
192	1000	2500	0.00199	250	365	14600	149	231	68	100
192	1000	2500	0.00199	500	365	14600	119	200	56	88
192	1000	2500	0.00199	1000	365	14600	88	169	43	76
192	1000	2500	0.00199	1320	365	14600	76	157	38	71
192	1000	2500	0.00199	2000	365	14600	58	139	31	64
192	1000	2500	0.00199	3500	365	14600	33	114	21	54
192	1000	2500	0.00199	5000	365	14600	17	99	15	48
192	1000	2500	0.00199	7500	365	14600	0	81	8	40
192	1000	2500	0.00199	10000	365	14600	0	68	3	35
192	1000	2500	0.00199	15000	365	14600	0	50	0	28
192	1000	2500	0.00199	20000	365	14600	0	38	0	23
192	1000	2500	0.00199	30000	365	14600	0	20	0	16
192	1000	2500	0.00199	50000	365	14600	0	0	0	7
192	1000	2500	0.00199	100000	365	14600	0	0	0	0

8. Merrion Oil & Gas Corp., Sandoval Co., Federal 11C, Well No. 2 P

(injection volume 139,100 bbl in March 1990 = 4487 bbls/day = 3.12 bpm = 130.9 gpm; fluid density = 1.016, porosity = 0.16)

Q (injection rate in gpm)	Transmissivity (gpd/ft)		Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days)		Head-buildup (Δh)			
							low transmissivity		high transmissivity	
	low	high			time 1	time 2	time 1	time 2	time 1	time 2
130.9	748	2992	0.00100	1	365	14600	366	440	98	117
130.9	748	2992	0.00100	100	365	14600	181	255	52	71
130.9	748	2992	0.00100	250	365	14600	144	218	43	61
130.9	748	2992	0.00100	500	365	14600	116	190	36	55
130.9	748	2992	0.00100	1000	365	14600	88	162	29	48
130.9	748	2992	0.00100	1320	365	14600	77	151	26	45
130.9	748	2992	0.00100	2000	365	14600	61	135	22	41
130.9	748	2992	0.00100	3500	365	14600	38	112	17	35
130.9	748	2992	0.00100	5000	365	14600	24	98	13	31
130.9	748	2992	0.00100	7500	365	14600	8	82	9	27
130.9	748	2992	0.00100	10000	365	14600	0	70	6	24
130.9	748	2992	0.00100	15000	365	14600	0	54	2	20
130.9	748	2992	0.00100	20000	365	14600	0	42	0	18
130.9	748	2992	0.00100	30000	365	14600	0	26	0	13
130.9	748	2992	0.00100	50000	365	14600	0	6	0	8
130.9	748	2992	0.00100	100000	365	14600	0	0	0	1

(continued on next page)

9. Merrion Oil and Gas Corp., San Juan Co., Santa Fe 20, Well No. 2 F
(injection volume 133,121 bbl in March 1990 = 4294 bbls/day = 2.98 bpm = 125.2 gpm; fluid density = 1.015, porosity = 0.24)

Q (injection rate in gpm)	Transmissivity (gpd/ft)		Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days)		Head-buildup (Δh)			
							low transmissivity		high transmissivity	
	low	high			time 1	time 2	time 1	time 2	time 1	time 2
125.2	748	2500	0.00192	1	365	14600	337	408	108	129
125.2	748	2500	0.00192	100	365	14600	160	231	55	76
125.2	748	2500	0.00192	250	365	14600	125	196	44	66
125.2	748	2500	0.00192	500	365	14600	99	169	36	58
125.2	748	2500	0.00192	1000	365	14600	72	143	28	50
125.2	748	2500	0.00192	1320	365	14600	61	132	25	46
125.2	748	2500	0.00192	2000	365	14600	45	116	21	42
125.2	748	2500	0.00192	3500	365	14600	24	95	14	35
125.2	748	2500	0.00192	5000	365	14600	10	81	10	31
125.2	748	2500	0.00192	7500	365	14600	0	65	5	27
125.2	748	2500	0.00192	10000	365	14600	0	54	2	23
125.2	748	2500	0.00192	15000	365	14600	0	39	0	19
125.2	748	2500	0.00192	20000	365	14600	0	28	0	15
125.2	748	2500	0.00192	30000	365	14600	0	12	0	11
125.2	748	2500	0.00192	50000	365	14600	0	0	0	5
125.2	748	2500	0.00192	100000	365	14600	0	0	0	0

10. Tiffany Gas Co., San Juan Co., USG Section 19, Well No. 17 I
(injection volume 133,121 bbl in March 1990 = 4294 bbls/day = 2.98 bpm = 125.2 gpm; fluid density = 1.003, porosity = 0.24)

Q (injection rate in gpm)	Transmissivity (gpd/ft)		Storage Coefficient (unitless)	Radial Distance from Well (ft)	Injection Time (days)		Head-buildup (Δh)			
							low transmissivity		high transmissivity	
	low	high			time 1	time 2	time 1	time 2	time 1	time 2
20.5	500	2500	0.00201	1	365	14600	80	98	18	21
20.5	500	2500	0.00201	100	365	14600	37	55	9	12
20.5	500	2500	0.00201	250	365	14600	29	46	7	11
20.5	500	2500	0.00201	500	365	14600	22	39	6	9
20.5	500	2500	0.00201	1000	365	14600	16	33	5	8
20.5	500	2500	0.00201	1320	365	14600	13	30	4	8
20.5	500	2500	0.00201	2000	365	14600	9	26	3	7
20.5	500	2500	0.00201	3500	365	14600	4	21	2	6
20.5	500	2500	0.00201	5000	365	14600	0	18	2	5
20.5	500	2500	0.00201	7500	365	14600	0	14	1	4
20.5	500	2500	0.00201	10000	365	14600	0	11	0	4
20.5	500	2500	0.00201	15000	365	14600	0	7	0	3
20.5	500	2500	0.00201	20000	365	14600	0	5	0	2
20.5	500	2500	0.00201	30000	365	14600	0	1	0	2
20.5	500	2500	0.00201	50000	365	14600	0	0	0	1
20.5	500	2500	0.00201	100000	365	14600	0	0	0	0

APPENDIX VI

HEAD-BUILDUP DATA FOR SELECTED ENHANCED-RECOVERY INJECTION WELLS, GREATER PERMIAN BASIN

Fisher Co., RRC Dist. 7B, Claytonville field, General Crude Oil Co.,
Project No. F0694, at 5900 ft depth.

Inj. rate Q=3850 BPD gpm	T gpd/ft	S (Dimensionless)	r ft	t1=1yr days	t2=15.5yrs days	t1= 1 yr Δh ft	t1= 1 yr Δp psi	t2= 15.5 yrs Δh ft	t2= 15.5 yrs Δp psi
112.29	28.21	0.000272	1	365	5658	7415	3448	8666	4029
112.29	28.21	0.000272	100	365	5658	3211	1493	4462	2075
112.29	28.21	0.000272	250	365	5658	2375	1104	3626	1686
112.29	28.21	0.000272	500	365	5658	1742	810	2993	1392
112.29	28.21	0.000272	1000	365	5658	1109	516	2360	1098
112.29	28.21	0.000272	1320	365	5658	856	398	2107	980
112.29	28.21	0.000272	2000	365	5658	477	222	1728	803
112.29	28.21	0.000272	3500	365	5658	0	0	1217	566
112.29	28.21	0.000272	5000	365	5658	0	0	891	414
112.29	28.21	0.000272	7500	365	5658	0	0	521	242
112.29	28.21	0.000272	10000	365	5658	0	0	259	120
112.29	28.21	0.000272	15000	365	5658	0	0	0	0
112.29	28.21	0.000272	20000	365	5658	0	0	0	0
112.29	28.21	0.000272	30000	365	5658	0	0	0	0
112.29	28.21	0.000272	50000	365	5658	0	0	0	0
112.29	28.21	0.000272	100000	365	5658	0	0	0	0

Variables: Q - injection rate; T - transmissivity; S - storage coefficient; r - radial distance from well bore; t1 & t2 - time;
Δh - change of hydraulic head (function of injection rate, transmissivity, storage, distance, and time).

APPENDIX VII

HEAD-BUILDUP DATA FOR SELECTED ENHANCED-RECOVERY INJECTION WELLS, SOUTH TEXAS BASIN

1. McMullen Co., RRC Dist. 1, Compana So. field, Mobil,
Project No. F004, at 3000 ft depth.

Inj. rate Q=2320 BPD gpm	T gpd/ft	S (Dimensionless)	r ft	t1=1yr days	t2=8yrs days	t1= 1 yr Δh ft	t1= 1 yr Δp psi	t2= 8 yrs Δh ft	t2= 8 yrs Δp psi
67.67	32.76	0.000013	1	365	2920	4603	2140	5095	2369
67.67	32.76	0.000013	100	365	2920	2422	1126	2914	1355
67.67	32.76	0.000013	250	365	2920	1988	924	2480	1153
67.67	32.76	0.000013	500	365	2920	1659	772	2152	1001
67.67	32.76	0.000013	1000	365	2920	1331	619	1824	848
67.67	32.76	0.000013	1320	365	2920	1200	558	1692	787
67.67	32.76	0.000013	2000	365	2920	1003	466	1495	695
67.67	32.76	0.000013	3500	365	2920	738	343	1230	572
67.67	32.76	0.000013	5000	365	2920	569	264	1061	493
67.67	32.76	0.000013	7500	365	2920	377	175	869	404
67.67	32.76	0.000013	10000	365	2920	240	112	733	341
67.67	32.76	0.000013	15000	365	2920	48	22	541	251
67.67	32.76	0.000013	20000	365	2920	0	0	405	188
67.67	32.76	0.000013	30000	365	2920	0	0	212	99
67.67	32.76	0.000013	50000	365	2920	0	0	0	0
67.67	32.76	0.000013	100000	365	2920	0	0	0	0

2. Duval Co., RRC Dist. 4, Loma Novia field, Weco Dev. Corp.,
Project No. F0394, at 2500 ft depth.

Inj. rate Q=580 BPD gpm	T gpd/ft	S (Dimensionless)	r ft	t1=1yr days	t2=13yrs days	t1= 1 yr Δh ft	t1= 1 yr Δp psi	t2= 13 yrs Δh ft	t2= 13 yrs Δp psi
16.92	55.26	0.000024	1	365	4745	679	316	769	358
16.92	55.26	0.000024	100	365	4745	356	166	446	207
16.92	55.26	0.000024	250	365	4745	292	136	382	178
16.92	55.26	0.000024	500	365	4745	243	113	333	155
16.92	55.26	0.000024	1000	365	4745	194	90	285	132
16.92	55.26	0.000024	1320	365	4745	175	81	265	123
16.92	55.26	0.000024	2000	365	4745	146	68	236	110
16.92	55.26	0.000024	3500	365	4745	107	50	197	91
16.92	55.26	0.000024	5000	365	4745	81	38	172	80
16.92	55.26	0.000024	7500	365	4745	53	25	143	67
16.92	55.26	0.000024	10000	365	4745	33	15	123	57
16.92	55.26	0.000024	15000	365	4745	4	2	94	44
16.92	55.26	0.000024	20000	365	4745	0	0	74	35
16.92	55.26	0.000024	30000	365	4745	0	0	46	21
16.92	55.26	0.000024	50000	365	4745	0	0	10	5
16.92	55.26	0.000024	100000	365	4745	0	0	0	0

Variables: Q - injection rate; T - transmissivity; S - storage coefficient; r - radial distance from well bore; t1 & t2 - time;
Δh - change of hydraulic head (function of injection rate, transmissivity, storage, distance, and time).