COMPARATIVE ENGINEERING FIELD STUDIES AND GAS RESOURCES OF THE TRAVIS PEAK FORMATION, EAST TEXAS BASIN

TOPICAL REPORT
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Data from eight fields producing from the Travis Peak Formation in the eastern East Texas Basin were used to define key engineering parameters for each field and to develop resource-reserve estimates. Field-average porosities range from 8 to 11 percent, and the median permeability for 191 wells is 0.088 md; field-average permeability ranges from 0.006 to 0.1 md. Gas productivity generally increases from south to north across the area studied with changes in the reservoir drive mechanism. Gas in place in the Travis Peak of the East Texas Basin is estimated to be 19.5 Tcf, assuming 12 percent of the area of the basin is ultimately productive.

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RESEARCH SUMMARY

Title	Comparative Engineering Field Studies and Gas Resources of the Travis Peak Formation, East Texas Basin
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5082-211-0708, entitled "Geologic Analysis of Travis Peak/Hosston and Corcoran-Cozzette Tight Gas Sandstones."
Principal Investigator	R. J. Finley
Report Period	February-November 1985 Topical Report
Objective	To define gas production characteristics and reservoir properties of the Travis Peak Formation in the eastern East Texas Basin using data from eight producing fields, to define regional trends in key parameters, and to refine previous resource/reserve estimates on the basis of additional information.
Technical Perspective	Previous work on the Travis Peak has defined the regional geologic framework and delineated the major depositional systems of the formation across East Texas and North Louisiana. The availability of core from cooperative well activities and additional core loaned or donated to the project by operators has resulted in an assessment of the sandstone petrography and diagenesis of the Travis Peak. This report assesses regional variations in production characteristics, such as absolute open flow potential, maximum production rate, decline rate, and gas/condensate production, and defines reservoir parameters, such as porosity and permeability, from well logs and well test data rather than from cores. Fields were selected to provide a geographic spread across the area of research emphasis.
Results	Within the area of research emphasis, field-average porosities range from 8 to 11 percent and thickness-weighted field-average permeabilities range from 0.006 md in the southeastern part of the study area to 0.1 md in the northern part, with the exception of one field that measured 2 md. The median permeability for 191 wells is 0.088 md. Because of the effects of fracture treatments, permeabilities defined from well test data are upper limits. Gas productivity was relatively high in the northern and central parts of the study area where a weak to moderate water-drive mechanism is evident; productivity is lower in the southwestern and southeastern parts of the study area where a gas-expansion production mechanism is evident. Potential fluid migration in the eastern East Texas Basin appears to be from the southwest toward the northeast; initial average formation pressure decreases from 4,540 psi in the southwestern part of the study area to 3,076 psi in the northeastern

part. Gas in place in the Travis Peak of the East Texas Basin is estimated to be 19.5 Tcf, assuming that 12 percent of the area of the basin is ultimately productive. This excludes gas reservoirs in the Travis Peak Formation having permeability greater than 0.3 md, which represent about 31 percent of the total productive area.

Technical Approach

Data from 166 wells in eight Travis Peak fields were utilized in analysis of well completion data, reservoir properties, and production characteristics. Limited data from eight additional fields, for a total of 191 wells, were used to define field-average permeabilities. Public sources, including hearing files and gas well test data (Form G-1) of the Railroad Commission of Texas, provided most of the information. A consistent tabular format was adopted to present data from each field in order to facilitate field-to-field comparison.

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ABSTRACT

The purpose of this report is to characterize production from, and to calculate reserve estimates for, low-permeability gas reservoirs in the Travis Peak Formation, East Texas Basin. The study area lies within the central and eastern parts of the East Texas Basin and includes the western flank of the Sabine Uplift. Reservoir parameters, such as permeability, porosity, water/gas saturation, and formation pressure, were calculated and analyzed. Production characteristics, such as absolute open flow potential, maximum production rate, decline rate, and gas/condensate production ratio, were examined. In addition to the results from studies of eight gas-producing fields, some data from incomplete field studies and from public records were also included in the regional interpretations and were used in resource/reserve estimates.

Thickness-weighted average permeabilities and median permeabilities, which both represent the upper limits of gas permeability in the study area, are less than 0.1 md. Thickness-weighted field-average permeabilities range from 0.006 md in the southeastern part of the study area to 0.1 md in the northern part, with the exception of one field in the central part of the study area that measured 2 md. About 53 percent of completed wells in the Travis Peak Formation have permeabilities of less than 0.1 md. In the study area, field-average porosities range from 8 percent to 11 percent, with the exception of a field in the central part of the study area that measured 14 percent. Water saturation varies from 24 percent to 43 percent and generally decreases from the northeastern part to the southwestern part of the study area.

Gas fields in the northern and central parts of the study area are characterized by relatively high productivity and a weak to moderate water-drive production mechanism; this contrasts with low productivity and a gas-expansion production mechanism in the southwestern and southeastern parts. For very low permeability gas reservoirs in the Travis Peak Formation, production decline data on a semi-logarithmic plot may be

empirically characterized as having two linear sections with different slopes. The first linear section, which represents early production (a period of three to five years), is followed by a linear section of lesser slope representing later production. The average production decline rate of the first linear section (early production) in the northern part of the study area (0.46 cycle/yr) is lower than that of the southern part (1.28 cycle/yr). Insufficient data are available for making comparisons of decline rates in later production periods because these periods are less than three to five years for several fields. For relatively high permeability reservoirs (several millidarcys) in the central part of the study area, production decline data can be characterized as having only one linear section; the average production decline rate is 0.3 cycle/yr. Maximum production rate decreases from 82,300 Mcf/mo in the northern part of the study area to 11,700 Mcf/mo in the central part, with the exception of a rate of 40,890 Mcf/mo for one field to the southeast. Almost all of the Travis Peak wells in the central part of the study area produced wet gas or condensate gas (gas to condensate ratio between 5 to 100 Mcf/bbl). About one-third of the gas wells in the northern area and more than one-half of the gas wells in the southern and western areas initially produced wet gas. Some wells in gas fields in the northern and central parts of the study area produce oil. In the study area, specific gravity of produced gas ranges from 0.62 to 0.66 (air = 1), and gravity of produced condensate ranges from 50° to 60° API. Formation temperature ranges from 200°F to 240°F and temperature gradient ranges from 18.0°F to 20.7°F/1,000 ft.

Potential fluid migration in the study area within the Travis Peak Formation appears to be from the southwest toward the northeast; initial average formation pressure decreases from 4,540 psi (pressure gradient = 0.494 psi/ft) in the southwestern part of the study area to 3,076 psi (pressure gradient = 0.384 psi/ft) in the northeastern part.

Based on all available information, including the results of this field study, gas in place in the Travis Peak Formation, East Texas Basin, is estimated to be from 19.52 to 24.39 Tcf, assuming that ultimate productive areas are 12 percent and 15 percent of the basin, respectively. These results exclude gas reservoirs in the Travis Peak Formation having permeability greater than 0.3 md, which represent about 31 percent of the total productive area.

INTRODUCTION

This work is part of an ongoing research program supported by the Gas Research Institute (GRI) aimed at improving recovery of gas from low-permeability, blanket-geometry sandstones. The GRI program began with a national survey of the geology and engineering characteristics of selected blanket-geometry formations that included basic data on the Travis Peak Formation (Finley, 1982, 1984). Reservoir engineering properties of the Travis Peak, based on applications submitted by operators to the Railroad Commission of Texas for tight sand designations, were collected and used for initial resource estimates (Lin, 1983). Based largely on these data, the Travis Peak Formation, which has more than 13 Tcf of maximum recoverable gas in the East Texas Basin (Lin, 1983), was selected by the Gas Research Institute for research aimed at (1) understanding the geology and engineering properties of tight gas sandstones and (2) improving gas recovery by more effective hydraulic fracture treatments. The ultimate goal of the GRI program is to develop the technology necessary for nationwide improvement in tight gas resource utilization, especially in the area of more effective hydraulic fracture treatment.

The purpose of this report is to characterize production from the Travis Peak and to provide data for better reserve estimates for tight sandstones within the formation. Studies of individual fields were conducted to collect and analyze engineering and production data. Gas resources and reserves were estimated based on the results from these studies and from Railroad Commission of Texas hearing-file data. In addition to gas resource/reserve estimates, this work consisted of calculating and analyzing key reservoir properties, such as permeability, porosity, water saturation, and formation pressure. Production characteristics, such as absolute open flow potential, maximum production rate, decline rate, gas/condensate production ratio, and water/gas production ratio, were examined. Related parameters, such as formation temperature, specific gas gravity, and condensate gravity, were also reviewed.

Eight fields located in the central and eastern parts of the East Texas Basin (fig. 1) that contain approximately 250 wells producing from the Travis Peak Formation were analyzed for this study. Some results from incomplete studies and data from hearing files have also been used in regional interpretations presented in this report. Information used in the engineering studies includes data obtained from Petroleum Information Corporation, Dwight's Energydata, Inc., field operators, and the Railroad Commission of Texas. These data include information on 18-year historical gas and condensate production, 31-month gas production history, p/z versus cumulative gas plots, gas well back-pressure tests and completion reports (G-1 or equivalent form), well logs, and reservoir data sheets obtained from hearing files.

Methodology

Reservoir engineering and well log analyses were applied to determine reservoir parameters and to delineate production characteristics. This section explains how key parameters were derived and utilized in this report.

Porosity and Water Saturation

Formation density and compensated neutron logs were used to derive porosity, and the gamma-ray log was used to take the shale (or clay) effect in the formation into consideration in the porosity determination. By using the calculated porosity and formation resisitivity obtained from the deep induction log, water saturation was derived by the Archie equation. The detailed methodology used in this study to derive porosity and water saturation was shown by Finley and others (1985). Water resistivity of 0.03 o-m was assumed. A tortuosity factor of 1.0 and a cementation exponent of 2.0 in the Archie equation were determined using porosity and water saturation measured from core samples.

To ensure that the methodology was appropriate, porosity and water saturation derived from well log analyses were compared with those measured from core samples.

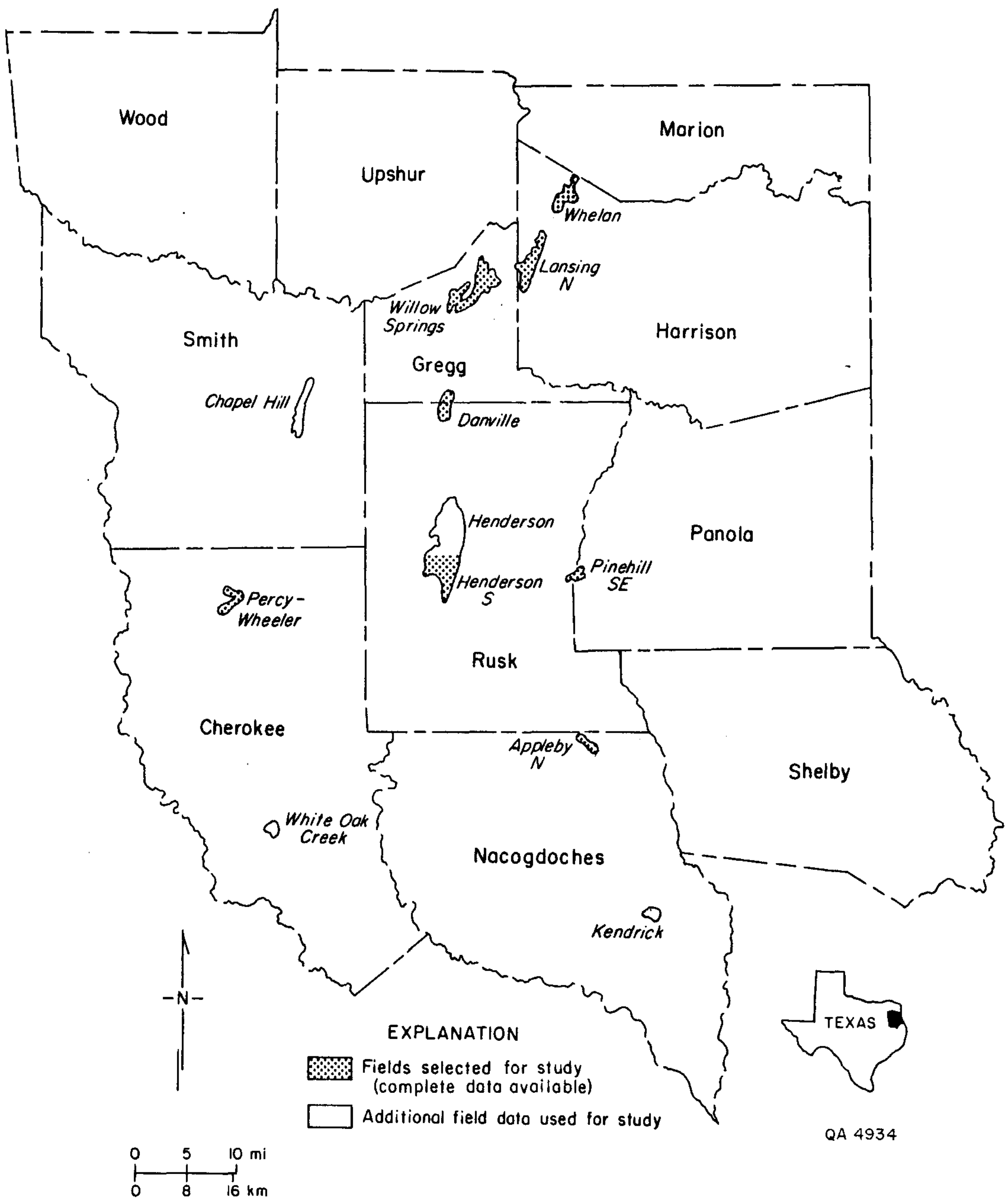

Figure 1. Selected fields in the Travis Peak Formation, East Texas Basin.

The agreements between core measurements and well log analyses for porosity (fig. 2) and water saturation (fig. 3) are reasonably good. Because porosity and water saturation are not constant in the formation in a given well, a representative value is obtained by averaging over a designated interval. For wells with only sonic logs available, instead of formation density and compensated neutron logs, the Wyllie equation was used to estimate porosity (Schlumberger, 1972). Water saturation was then calculated by the Archie equation.

Pay Thickness

Within a gross perforated interval, some sections are not expected to contain and produce gas because they have a high percentage of shaly sand and/or high water saturation as well as low porosity. Shale or shaly sand can usually be detected using the gamma-ray or spontaneous potential (SP) logs; usually, the gamma-ray log is better than the SP log in determining the shale content of a formation. Net-pay thickness used in the study is defined as a sand thickness wherein shale (or clay) content is less than 50 percent based on the gamma-ray log. The determination of shale content was described by Finley and others (1985). Effective net-pay thickness used in this study is a sand thickness that is effectively permeable to gas flow under the conditions of low water saturation and high porosity. In the present study the cutoff criteria were set at 70 percent for water saturation and 7 percent for porosity (that is, gas porosity is 2.1 percent). It is expected that the gross perforated interval, net pay, and effective net pay will generally not be the same. Accordingly, porosities and water saturations averaged from gross perforated thickness, net pay, and effective net pay will also differ.

Reservoir Boundaries

When sufficient subsurface well control is available, the gas reservoir boundary may be defined based on the gas/water contact, or from determination of zero net-pay thickness, which can be obtained from well log analysis in conjunction with structural and

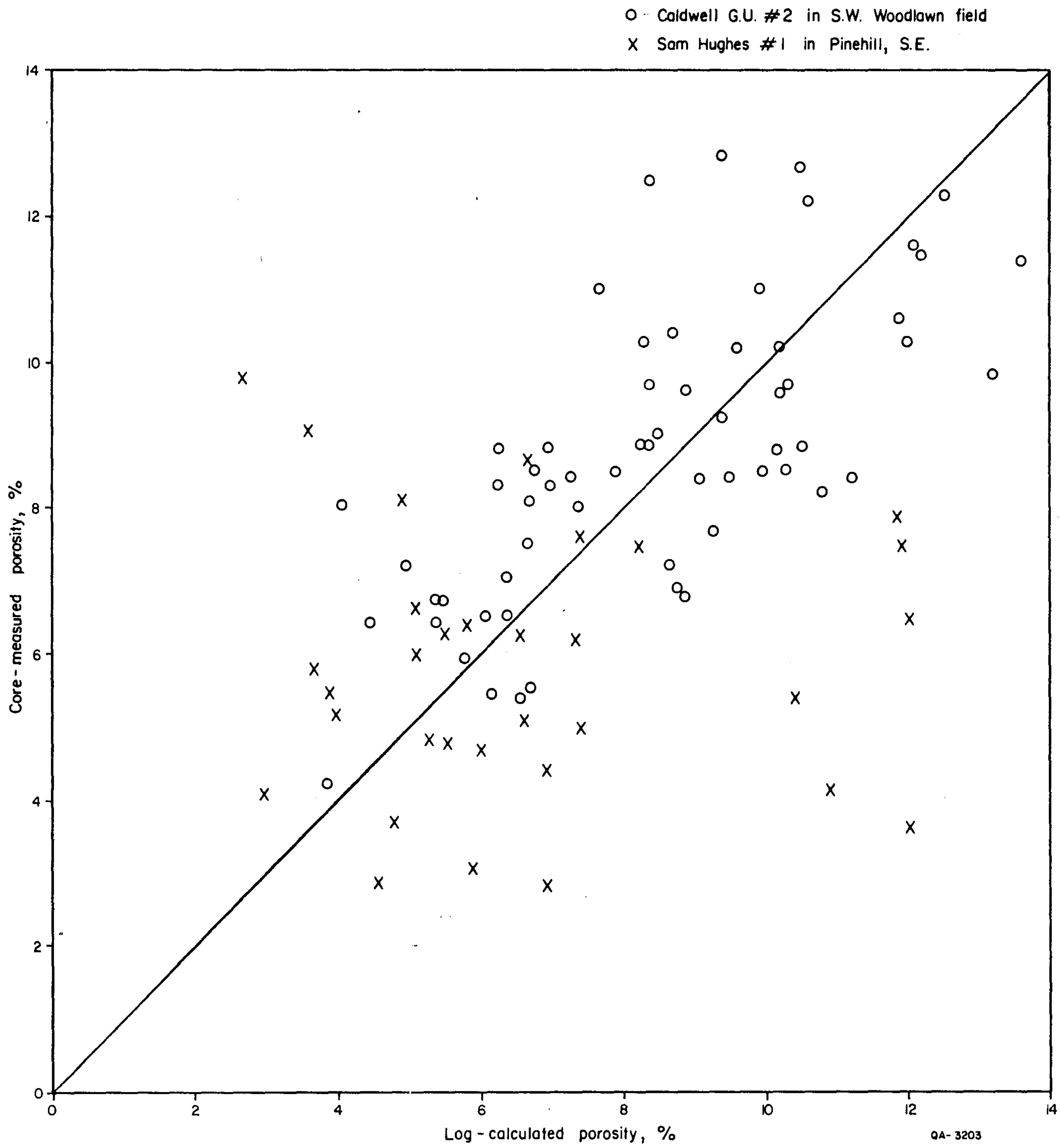

Figure 2. Comparison between core-measured porosity and log-calculated porosity for the wells completed in the Travis Peak Formation, East Texas Basin.

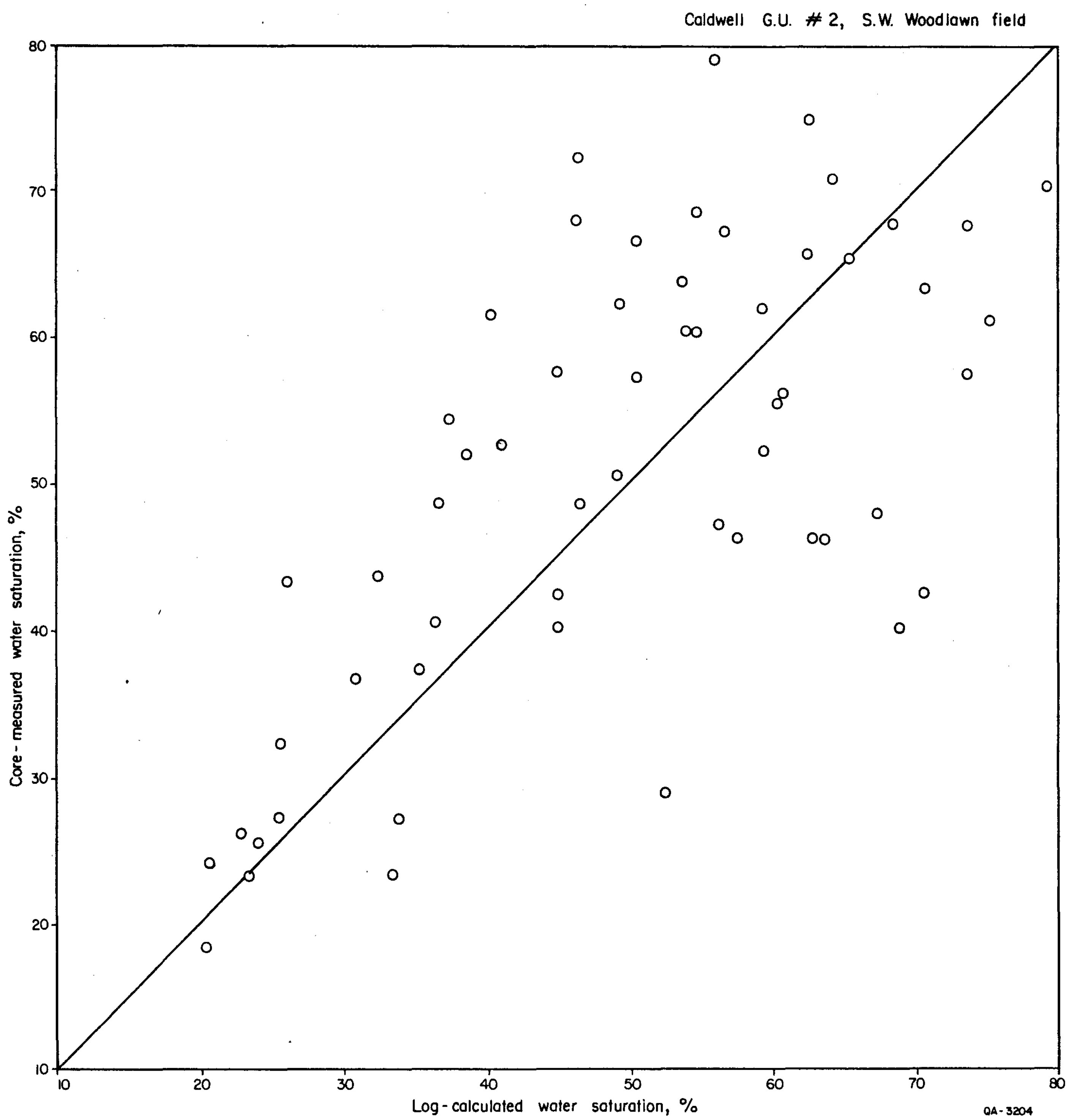

Figure 3. Comparison between core-measured water saturation and log-calculated water saturation for a well completed in the Travis Peak Formation, East Texas Basin.

isopach maps. However, sufficient well logs were not always available for analysis, and isopach maps for each field were not prepared for this study. Thus, approximate reservoir boundaries were drawn for each field. The boundaries enclose all producing wells and follow the structural contour (if the producing field/reservoir is on an anticline) and water/gas production ratio (if possible) for a given field. For the Willow Springs field, about six producing wells are not included within the reservoir boundary because some of those wells are relatively far from the top of the structural high that encloses 62 producing wells. Producing areas based on reservoir boundaries drawn in this study are probably conservative estimates.

Gas in Place

If reservoir parameters, reservoir fluid properties, and reservoir size are known, gas in place (GIP) may be calculated by a volumetric method using the following equation (Craft and Hawkins, 1959):

$$GIP = 43{,}560 \cdot A \cdot h \cdot \phi \cdot (1-S_w) \cdot Bg \quad (1)$$

where A = area of the field, acres

h = effective net-pay thickness, ft

ϕ = porosity, fraction

S_w = water saturation, fraction

Bg = gas formation volume factor, Scf/ft^3, which is a function of formation pressure, temperature, and gas composition.

Usually, the volumetric method incorporates structure and isopach maps for evaluating parameters such as area and thickness. Since field-scale structure and isopach maps were not available for this study, average values for the parameters in Equation (1) were obtained from well logs, cores, and production test data.

If reservoir parameters, reservoir fluid properties, and reservoir size are not known, the p/z (pressure, p, divided by gas compressibility factor, z) versus cumulative gas production plot, which is based on the material balance in gas reservoirs (Craft and Hawkins, 1959), may be used to estimate initial gas in place and to study the production mechanism. For a reservoir with no water encroachment and no water production, the initial gas in place may be estimated by extrapolating a straight line of data points in the plot to a zero p/z value (fig. 4). The production test data in the p/z versus cumulative gas production plot is not a straight line for a water-drive reservoir. It is impossible to estimate initial gas in place using the plot for a strong water-drive reservoir, that is, one in which almost no pressure drop in a reservoir occurs during production. There is no indication of a strong water-drive production mechanism for wells drilled in the Travis Peak Formation of East Texas. However, the pressure behavior in the plots for some fields indicates weak to moderate water drive. The initial gas in place for the wells in these fields may be approximated with some adjustment based upon pressure behavior in the adjacent wells at abandonment.

The material-balance method to estimate gas in place in a conventional reservoir is applicable only to the reservoir as a whole because of the migration of gas from one portion of the reservoir to another. However, the permeability of the fields studied is so low that a long time elapses before the drainage area of one well interferes with that of other wells, and the actual average reservoir pressure may be higher than the shut-in pressure measured during a short-duration production test. In this case, gas in place estimated using material balance from each well may be only for the drainage area of the well analyzed, and may represent the lower limit of total gas in the formation within a field.

Formation Permeability

Since pressure-transient data from pressure-buildup and pressure-drawdown tests, which are the best resource for permeability determination, are not usually available from public records, formation permeability was primarily estimated using back-pressure test

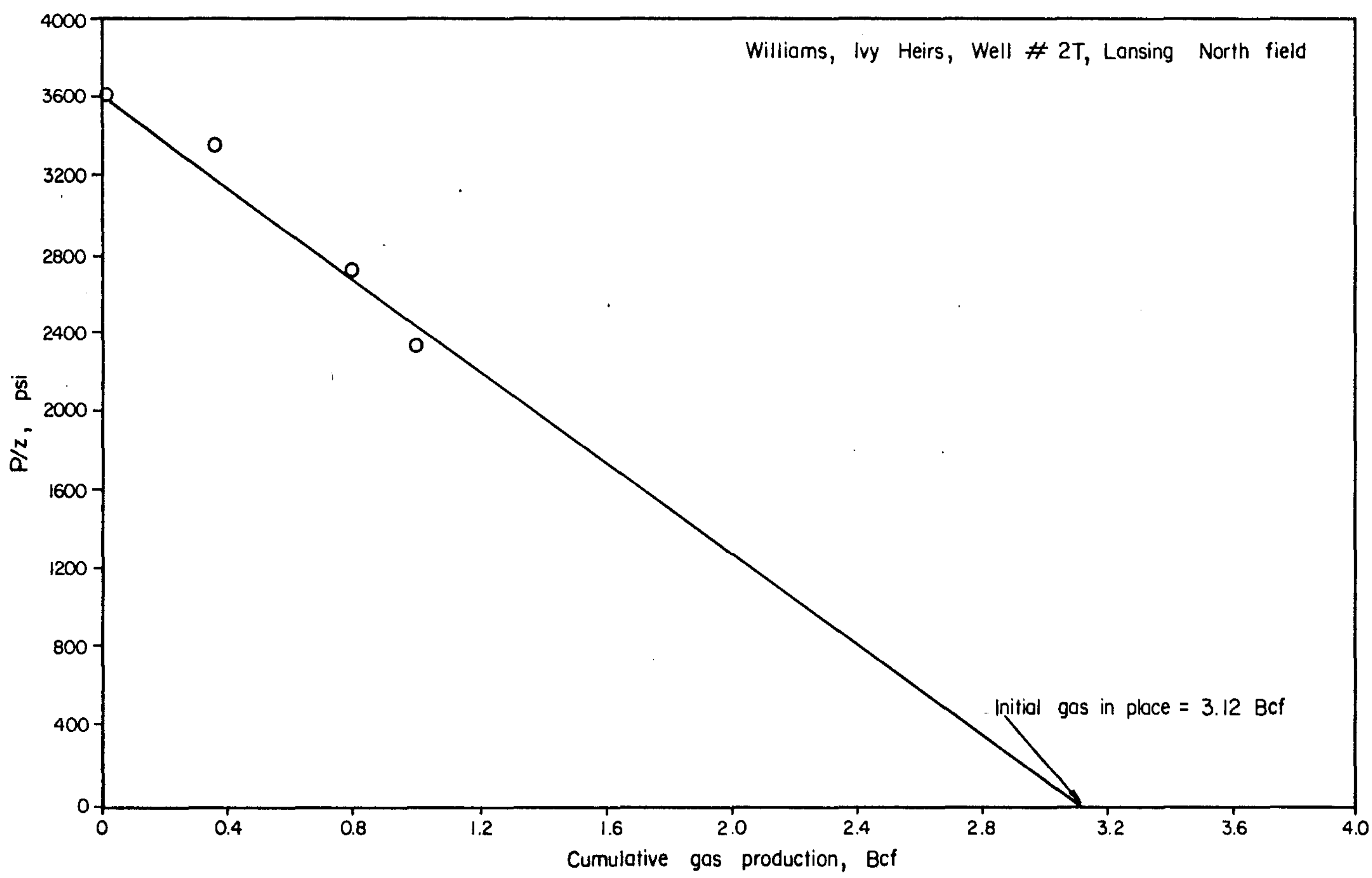

Figure 4. Plot of p/z versus cumulative gas production to estimate initial gas in place.

data (Lee and others, 1984). (Operators in Texas are required to file gas well back-pressure test data with the Railroad Commission of Texas.) This methodology has been demonstrated by Finley and others (1985) based on the work presented by Lee and others (1984). In the report by Finley and others (1985) it was shown that agreement in permeability calculated from pressure-buildup and from back-pressure tests (table 1) is sufficient for resource estimation and geologic studies. The same methodology may also be applied to analyze fractured wells if the apparent wellbore radius, which is related to fracture length, is known. Because fracture length is not available for the hydraulically stimulated wells used in this study, it has been assumed that no hydraulic fractures exist in the wells. Thus, the calculated permeabilities represent an upper limit (Jaggernauth and others, 1981).

In order to eliminate the uncertainty of formation "thickness" in the permeability determination, permeability-thickness product as a measure of the formation flow capacity was calculated before permeability was estimated.

Three averaging schemes, arithmetic, thickness-weighted, and statistical averaging, were employed to calculate the average permeabilities in a field or in an area. To calculate the arithmetic average permeability, k_{avg}, the summation of individual permeabilities, k_i, is divided by the total number of wells, N, in a field or an area considered:

$$k_{avg} = \frac{\sum_{i=1}^{N} k_i}{N} \qquad (2)$$

Average permeability from Equation (2) is calculated by weighting permeability from each well equally, and is the simplest mean value of permeability. To weight formation thickness, h_i, from each well, the thickness-weighted average permeability, k'_{avg}, can be expressed and calculated as follows:

Table 1. Comparison of permeabilities calculated from transient-pressure analysis and back-pressure test.

Field name	Well name	Calculated permeability, md: Transient-pressure analysis	Calculated permeability, md: Back-pressure test
Swanson Landing	Carl Jones Lou-Tex #3	0.0825	0.11040
Appleby North	E. A. Blount G.U. #1	0.0131	0.00434
Appleby North	Max Hart #2	0.0133	0.01189
Appleby North	D. H. Newman G.U. #1	0.0060	0.00802
Kendrick	T. J. Kendrick #1	0.0270	0.02942
White Oak Creek	Temple-Eastex G.U. #1	0.0330	1.16560
White Oak Creek	Temple-Eastex G.U. #1	0.0015	0.00133
Wildcat	George H. Henderson #1	0.0100	0.07243

$$k'_{avg} = \frac{\sum_{i=1}^{N} k_i h_i}{\sum_{i=1}^{N} h_i} \tag{3}$$

The average value derived from Equation (3) is probably more meaningful than that from Equation (2) in representing a field or an area.

In addition, a median permeability with 50 percent probability was estimated. By plotting permeability versus cumulative frequency based on a permeability histogram, a median permeability with 50 percent cumulative frequency can be obtained. Median permeability is the statistically expected value of permeability to be found in a given Travis Peak well.

Absolute Open Flow Potential

Absolute open flow potential, or calculated absolute open flow, is defined as a rate of flow that would be produced by a well if the pressure in the wellbore at the producing formation is atmospheric pressure (Smith, 1962). The value of absolute open flow potential is usually determined graphically by plotting the test flow rate against the corresponding values of pressure-square difference between initial reservoir pressure and flowing wellbore pressure (fig. 5). The straight-line relationship in the plot may be extended so that the absolute open flow potential can be read by extrapolation according to the value of the pressure-square difference between reservoir pressure and flowing wellbore pressure (when flowing wellbore pressure is at atmospheric pressure). The absolute open flow potential is directly related to deliverability of a well, and is often used by regulatory authorities as a guide in setting the maximum allowable producing rate.

Decline Rate of Production

A production decline curve, which may be obtained from a semi-logarithmic plot of production rate versus time, can be used to characterize production performance and be extrapolated to provide an estimate of the future rate of production. Decline-curve

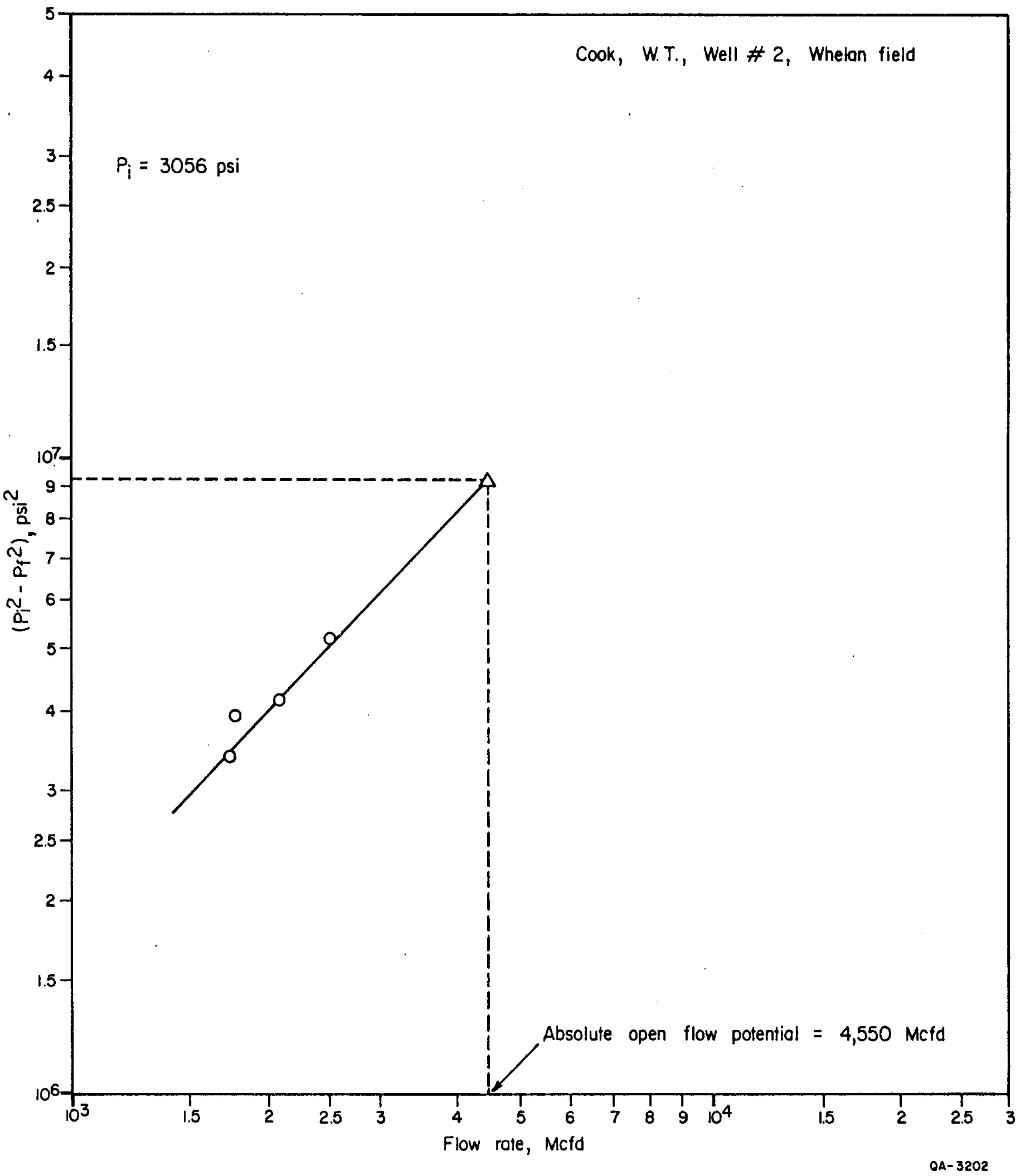

Figure 5. Plot of test flow rate versus pressure-square difference between reservoir and flowing wellbore pressure to estimate absolute open flow potential.

analysis is based on the assumptions that a well is produced at capacity and that the mechanical conditions of a producing well remain constant. The three types of curves that may be used in decline-curve analysis are exponential (or constant percentage), hyperbolic, and harmonic declines. Although hyperbolic and harmonic decline curves would give more accurate predictions, exponential decline, which is the most widely used curve type and one that projects a straight-line fit on a rate-time semi-logarithmic plot (fig. 6), will be used in the current study because of simplicity. The equation for the exponential decline curve can be expressed as follows:

$$q_t = q_i e^{-at} \tag{4}$$

where q_t = production rate at time t, Mcf/mo

q_i = initial production rate, Mcf/mo

a = decline rate (slope in semi-logarithmic plot), cycle/mo

t = production time, mo.

By rearranging Equation (4), decline rate may be calculated from an equation such as

$$a = -\frac{1}{t} \log_e \frac{q_t}{q_i} \tag{5}$$

In actual production, the linear relationship between rate and production time in a semi-logarithmic plot may not hold during the entire production period. However, decline rate and maximum production rate may be selected for analysis to delineate production characteristics. The higher the decline rate, the faster the drop in flow rate will be. A well with a lower decline rate may possess potential for a longer productive life than a well with a higher decline rate.

Resource Estimates

To estimate gas resources in the Travis Peak Formation, East Texas Basin, the methodology and procedures suggested by the National Petroleum Council (1980a) were followed. Basic data used in the estimation include permeability, net pay, gas porosity,

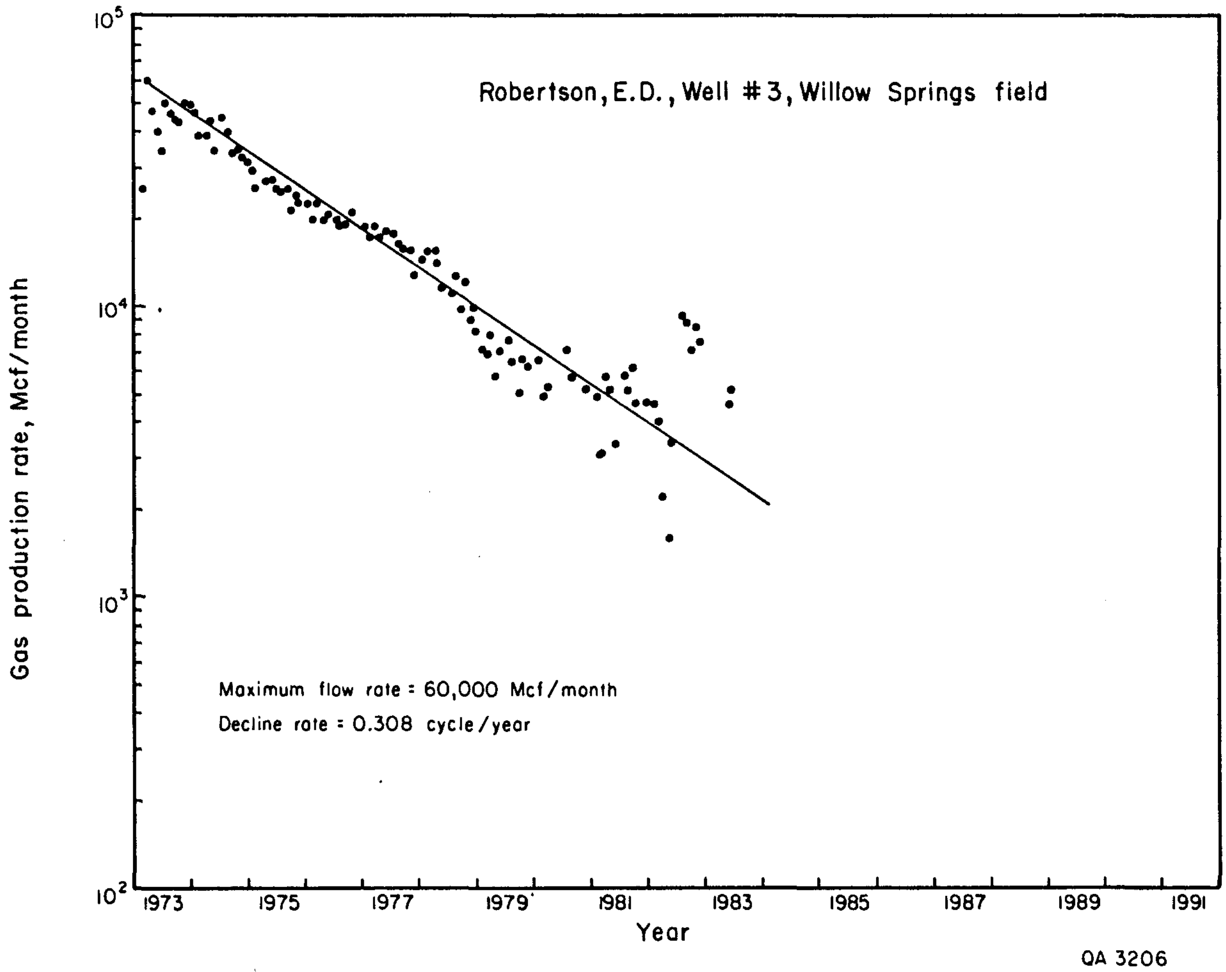

Figure 6. Exponential (or constant percentage) decline curve.

productive area, formation pressure, and formation temperature. The procedures involved in developing resource estimates can be summarized as follows:

(1) Outline a boundary for the specific formation defined by the presence of reservoir sand.

(2) Obtain values for the following parameters within a formation boundary:

 (a) net-pay thickness,

 (b) permeability,

 (c) gas porosity,

 (d) formation pressure, and

 (e) formation temperature.

(3) Establish empirical relationships of permeability versus gas porosity and permeability versus net-pay thickness. The classification of each zone within a boundary is based on the permeability grades.

(4) For each permeability grade, the following parameters were estimated or assigned based on available information: total productive area, gas-filled porosity, and net-pay thickness of a reservoir.

(5) Calculate gas in place (GIP)

 GIP = (productive area) • (net pay) • (gas porosity) • (gas formation volume factor)

 Where gas formation volume factor is a function of formation pressure, formation temperature, and specific gas gravity. In this study, specific gas gravity is assumed to be 0.65 (National Petroleum Council, 1980a).

(6) Calculate technically recoverable gas in place (TRGIP)

 TRGIP = (technical recovery factor) • (GIP)

 Where technical recovery factor can be determined from the following equation (National Petroleum Council, 1980a):

$$\text{Technical recovery factor} = 1 - \frac{P_w \cdot Z_i \cdot T_f}{Z_w \cdot P_i \cdot T_w}$$

where P_w = wellbore pressure

Z_i = gas compressibility factor at initial formation condition

T_f = formation temperature

Z_w = gas compressibility factor at wellbore condition

P_i = initial formation pressure

T_w = wellbore temperature.

The determination of technical recovery factor involves the assumption that wellbore pressure is one-tenth of the initial formation pressure.

(7) Calculate maximum recoverable gas in place (MRGIP)

MRGIP = (recovery adjustment factor) • (TRGIP)

where recovery adjustment factor is a function of permeability (table 2).

Selected Field Studies

Information obtained from the Railroad Commission of Texas and from our field studies indicate that there are multiple productive reservoirs in the Travis Peak Formation. Gas-productive reservoirs designated by the Railroad Commission of Texas are shown in figure 7. In Henderson South field, for example, one gas reservoir and two oil reservoirs exist in the Travis Peak Formation. Even though only one productive reservoir in the Travis Peak Formation in Appleby North field is designated, it probably consists of more than one gas-productive stratigraphic horizon, based on a pressure-depth relationship that will be described in the evaluation of Appleby North field. In this study, the most productive reservoir, or the reservoir with the most producing wells in each field with several productive reservoirs, was selected for detailed analysis. Fields for which engineering studies have been completed include Whelan, Lansing North, Willow Springs, Danville, Henderson South, Percy Wheeler, Pinehill Southeast, and Appleby North.

Table 2. Recovery adjustment factor (after National Petroleum Council, 1980a).

Average permeability (md)	Recovery adjustment factor
0.3	0.95
0.1	0.90
0.03	0.85
0.01	0.80
0.003	0.75
0.001	0.70
0.0003	0.65
0.0001	0.60
0.00003	0.55
0.00001	0.50

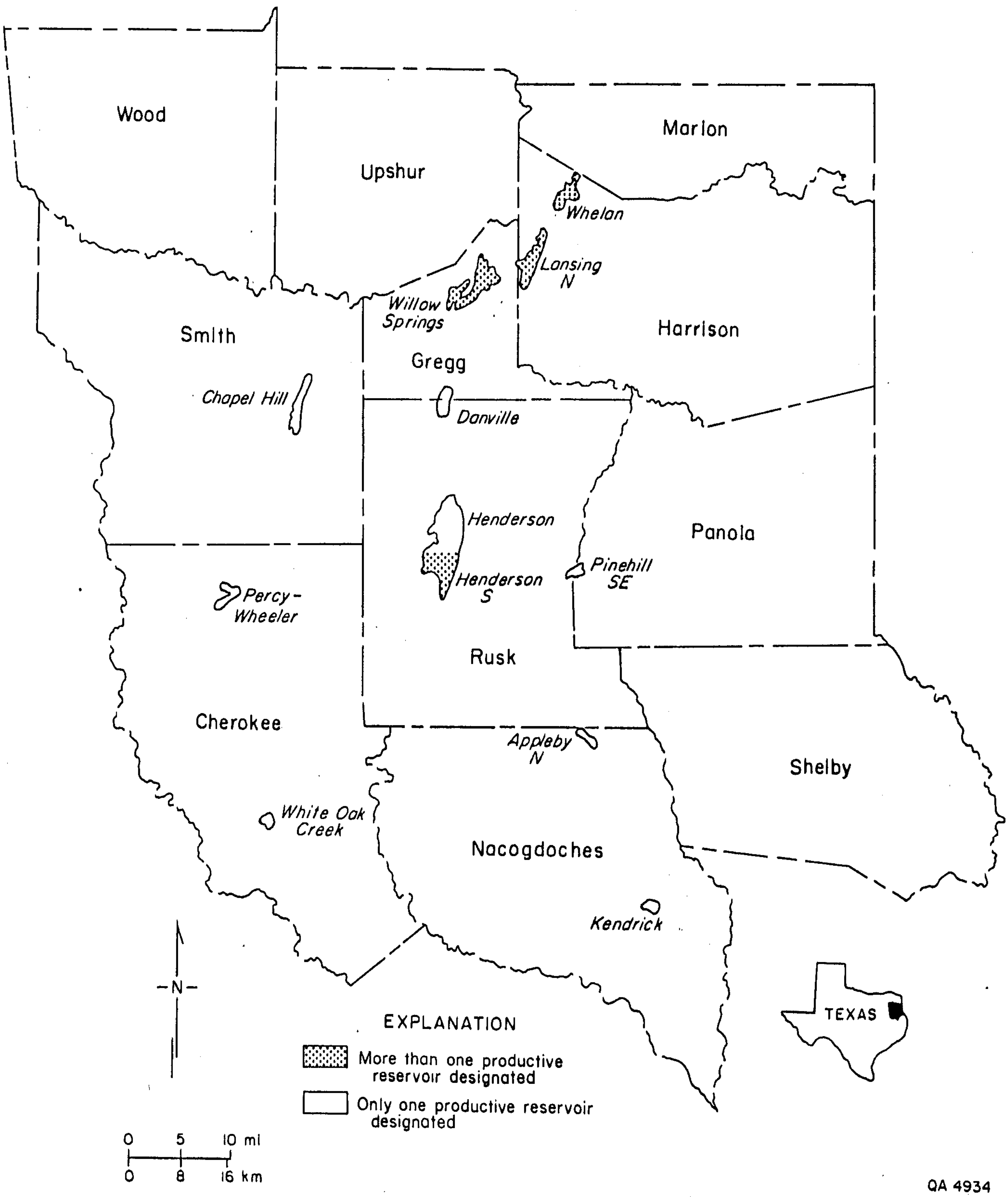

Figure 7. Gas productive reservoirs in the Travis Peak Formation designated by the Railroad Commission of Texas.

Whelan Field

Whelan field (fig. 1) was discovered on September 7, 1945, during drilling of the Roger Lacy Inc. Peteet No. 1 well on a structurally positive feature in Harrison County, Texas. As designated by the Railroad Commission of Texas, the productive zones of the Travis Peak Formation in this field are divided into the Travis Peak reservoir (perforated interval of 7,368 ft to 8,240 ft, with an average depth of 7,576 ft), and the Travis Peak prorated reservoir (perforated interval of 7,370 to 9,053 ft, with an average depth of 8,036 ft). The first producing wells from the Travis Peak reservoir and from the Travis Peak prorated reservoir are, respectively, the Roger Lacy Inc. Peteet No. 1 and the Lone Star Production Company Ledbetter Unit No. 1-T. The average gross perforated thicknesses are 295 ft and 866 ft for the Travis Peak reservoir and Travis Peak prorated reservoir, respectively. From January 1959 to July 1983, total gas production was 103 Bcf from 42 wells in the Travis Peak prorated reservoir, and 17 Bcf from 12 wells in the Travis Peak reservoir. No information is available on gas production before 1959. The Travis Peak prorated reservoir was selected for this study because it is the most prolific gas producer in the Travis Peak Formation in Whelan field. The field size measured by planimeter is 8,100 acres. The current (1985) calculated average well density, derived from acreage of the field divided by number of the producing wells, is approximately 200 acres/well. A summary of well completion data, reservoir properties, and production characteristics of the Travis Peak prorated reservoir discussed below is given in table 3.

Reservoir Properties and Gas in Place

The average reservoir temperature and reservoir temperature gradient in Whelan field are 220 °F and 18.6°F/1,000 ft, respectively; these values are expected in the East Texas area. Average initial reservoir pressure in the middle of the perforated interval is 3,076 psi and ranges from 2,193 to 3,635 psi. Within the field, initial reservoir pressure variation of 1,442 psi may be caused by reservoir compartmentalization, assuming that pressure measurements are accurate. Based on the average initial reservoir pressure of

Table 3. Summary of well completion data, reservoir properties, and production characteristics of Whelan field.

(a)	**Well completion and field data (based on 22 wells)**	
	Perforated interval	7,370-9,053 ft
	Midpoint of perforated interval	8,036 ft
	Field size	8,100 acres
	Current well density	200 acres/well
(b)	**Reservoir properties**	
	Effective net-pay thickness	238 ft
	Porosity	9.2%
	Water saturation	40%
	Permeability-thickness product	80.6 md-ft (range: 0.093-815.3 md-ft)
	Permeability	0.153 md (arithmetic average) 0.092 md (thickness-weighted average) 0.047 md (median)
	Reservoir temperature	220° F (gradient = 18.6° F/1,000 ft)
	Initial formation pressure	3,076 psi (range: 2,193-3,635 psi) (gradient = 0.383 psi/ft)
	Gas in place	675 Bcf
(c)	**Production characteristics**	
	Cumulative gas production	103 Bcf
	Absolute open flow potential	7,700 Mcfd (range: 10-59,000 Mcfd)
	Maximum production rate	82,300 Mcf/mo
	Decline rate	0.109 cycle/yr (pseudo-steady-state flow period) 0.466 cycle/yr (transient-flow period)
	Initial gas/condensate production ratio	117 Mcf/bbl
	Initial water/gas production ratio	172 bbl/MMcf
	Specific gravity of gas (air = 1)	0.63
	API gravity of condensate	54°

3,076 psi and a depth at the middle of the perforated interval of 8,036 ft, average pressure gradient is calculated to be 0.383 psi/ft, which is below the normal hydrostatic pressure gradient of 0.45 psi/ft. Possible reasons for the underpressure are (1) lack of hydrologic continuity with hydrostatically pressured aquifers surrounding the gas reservoir (Orr and others, 1985), and (2) updip gas flow (that is, from west to east) through low-permeability rock (Gies, 1982).

Based on logs available from three wells with an average gross perforated interval of 518 ft, the average porosity and water saturation in Whelan field are 8.1 percent and 43 percent, respectively, if net-pay thickness is used, and 8.9 percent and 40 percent, respectively, if effective net-pay thickness is used. It can be shown that 79 percent of the gross perforated interval forms net-pay thickness and 55 percent of the gross perforated interval forms effective net-pay thickness. With an average gross perforated interval of 866 ft over all the producing wells, net pay and effective net pay are approximately 684 ft and 476 ft, respectively, in the center of the field. An effective net-pay thickness of 476 ft is very high and should be reviewed by analyzing more well logs. The effective net pay representing the whole field should be a number between zero and 476 ft because effective net pay tapers to zero at the reservoir boundary or gas/water contact from a maximum thickness at the center of the field. In this study, one-half of the effective net pay derived from well log analysis will be used as a representative effective net-pay thickness for the field to estimate gas in place.

Based on the volumetric method, initial gas in place for the field is calculated to be approximately 675 Bcf if average reservoir properties are used. The p/z versus cumulative gas production plot, which is based on the material-balance method, was also used to estimate initial gas in place for individual wells. The summation of initial gas in place from each well will give the total gas in place for the field. The calculated initial gas in place of 240 Bcf from material-balance calculations is much less than it is from the volumetric method for one or more of the following reasons: (1) in a low-permeability reservoir, average reservoir pressure may not be obtained if shut-in time is not long enough; usually, a shut-in time of 48 hr, in a regular production test, is insufficient for a low-permeability reservoir to reach an average pressure if a well has produced for a period of time between tests; (2) some areas in the field may not be drained because of discontinuities of the reservoir and/or insufficient production time; and (3) the p/z plot was not always available for all the wells in the field to determine gas in place.

In Whelan field, the permeability-thickness product averages 80.6 md-ft and ranges from 0.093 to 815.3 md-ft. The wide variation in values of permeability-thickness product also indicates a nonhomogeneous reservoir, or discontinuities in permeability and effective net pay. If gross perforated interval is used as a formation thickness, the arithmetic average permeability in the field is 0.153 md, ranging from 0.00017 md to 1.0217 md; 70 percent of the producing wells have permeability of less than 0.1 md. Thickness-weighted average and median permeabilities are 0.092 md and 0.047 md, respectively. Even though the permeability in this reservoir is low, the productivity remains high because of high effective net-pay thickness.

Reservoir Performance and Production Characteristics

Absolute open flow potential, which is directly or indirectly related to productivity and deliverability of a reservoir, ranges from 10 Mcfd to 59,000 Mcfd, and averages 7,700 Mcfd in Whelan field. The distribution of productive area with high absolute open flow potential (fig. 8) and high permeability-thickness product is generally coincident with the structurally high part of the field. The highest absolute open flow potential is not located over the axis of the structure but is shifted to the west of the axis (fig. 8). Resulting interpretations are: (1) gas might have migrated from the west to displace water and did not reach the center of the structural high because of reservoir discontinuities; and (2) movement of salt might have caused the structural crest to shift from west to east (Finley and others, 1985). Differences in diagenetic history may exist across the structure

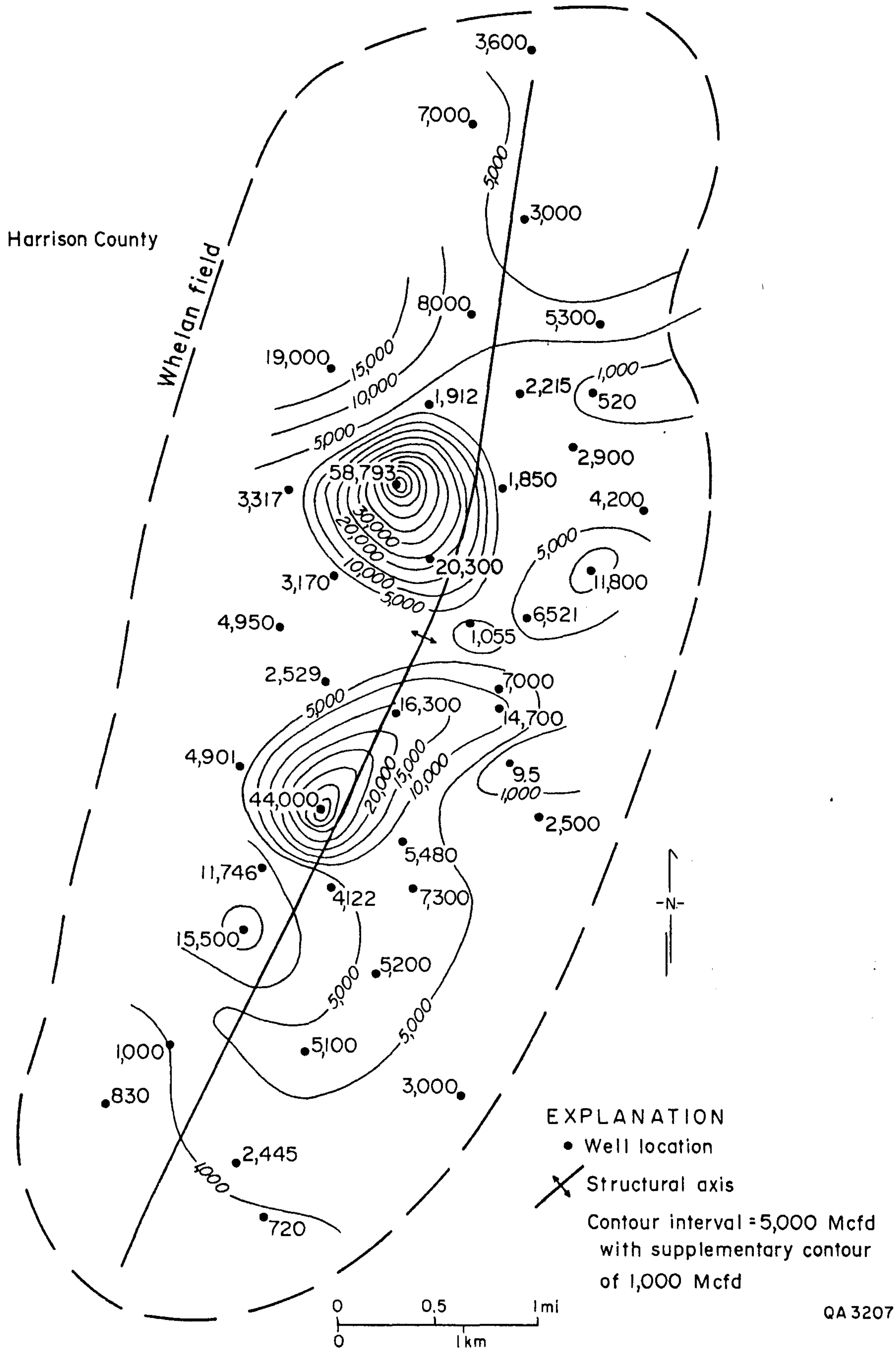

Figure 8. Distribution of absolute open flow potential in Whelan field.

and may have affected gas distribution because of variations in permeability pathways at the time of migration.

A production decline curve, which can be used to forecast oil and gas production under the assumptions described in the methodology section, characterizes the historical production performance. In Whelan field, typical production performance in the flow rate versus time plot (fig. 9) indicates two production periods characterized by two linear sections of the plot. The linear part of early production, a period of three to five years, may correspond to the transient-flow period and has the characteristics of a low-permeability well. The second linear part, which follows the transient-flow decline period, shows another fluid flow period (perhaps pseudo-steady-state) and may be used for future performance prediction. Ten wells in Whelan field were selected and used for determination of maximum production flow rate and decline rate. Maximum production rate averages 82,300 Mcf/mo. Average decline rates were 0.109 cycle/yr in the pseudo-steady-state flow and 0.466 cycle/yr in the transient-flow period.

Gas/condensate ratio, which may reflect the type of organic matter incorporated into the source sediments, has been reviewed. Production with a gas/condensate ratio greater than 100 Mcf/bbl is commonly called lean or dry gas, although there is no generally recognized cutoff for the ratio (Craft and Hawkins, 1959). Wet-gas reservoirs may be defined as those reservoirs with gas/condensate ratios in the range of 5 to 100 Mcf/bbl (Craft and Hawkins, 1959). Thus, Whelan field contains predominantly dry-gas reservoirs because the initial gas/condensate production ratio in the field averaged 117 Mcf/bbl; however, one-third of the wells in Whelan field have initial gas/condensate production ratios in the range of wet-gas or gas condensate reservoirs. Average gas/condensate production ratios in the field decreased to 60 Mcf/bbl by 1983. Specific gravity of produced gas is 0.63 and API gravity of produced condensate is 54°.

Assuming no water coning during production, the water/gas ratio is expected to be related to the water saturation surrounding the producing well and to the distance to the

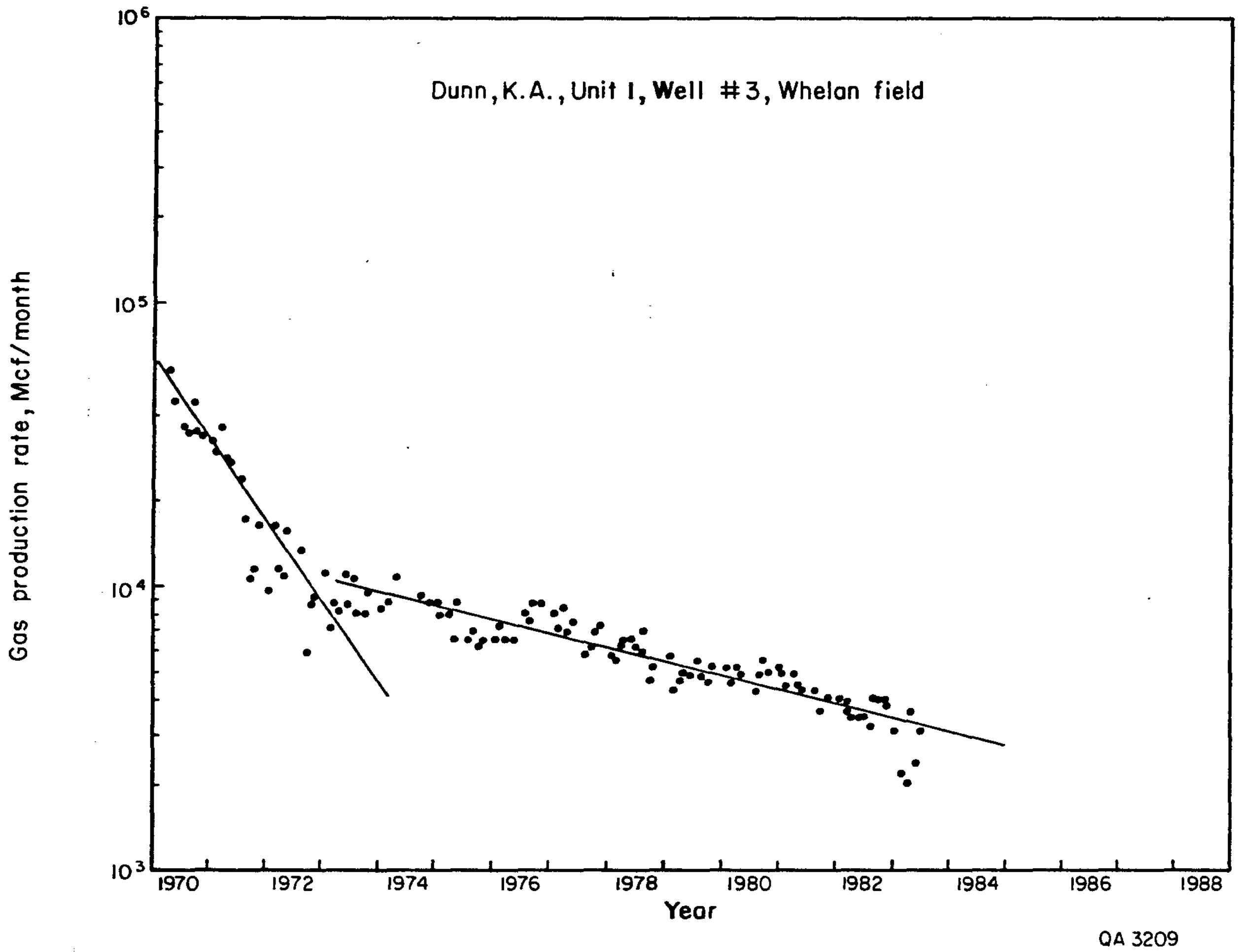

Figure 9. A typical decline curve in Whelan field.

gas/water contact zone. In Whelan field, the initial water/gas ratio, which was obtained from production test data, is low over the central part of the structure (fig. 10). It is inferred that produced water has flowed from the gas/water contact zone at the margins of the field instead of from beneath the hydrocarbon zone. From the water/gas production ratio and from a typical plot of p/z versus cumulative gas production it is concluded that the production mechanism is a weak to moderate water drive in addition to gas expansion (or pressure depletion).

For purposes of interpretation, initial pressure obtained from the back-pressure test for each well at different depths was corrected to an arbitrary datum of -8,500 ft by considering the static pressure gradient existing in the fluid (gas) column. No attempt was made to correct the pressure variations due to the effect of gas/water production, because sophisticated reservoir engineering calculations and knowledge of detailed reservoir parameters are needed. The initial pressures, at a datum of -8,500 ft, range from 2,214 to 3,600 psi in the field. Overall, the initial pressure on the west side of the field is higher than on the east side of the field. This suggests that the fluid (hydrocarbon) migration was from west to east across the field area (from basin center toward basin margin). Perhaps water displaced by hydrocarbons during migration causes higher water saturation on the east side of the field (fig. 10).

Lansing North Field

Lansing North field (fig. 1), located in Harrison County Texas, is on the same positive structural trend as Whelan field. On March 18, 1950, the first well, Landers Gas Unit No. 1-T, was completed in the Travis Peak Formation. During the period 1950 through 1977, only three wells were produced from the Travis Peak reservoir. The Travis Peak prorated reservoir was designated in the field with the drilling of the Estate Oil & Gas Corporation John K. Keasler No. 1 well on October 19, 1977. From 1977 to June 1983, 8 wells from the Travis Peak reservoir and 16 wells from the Travis Peak prorated reservoir

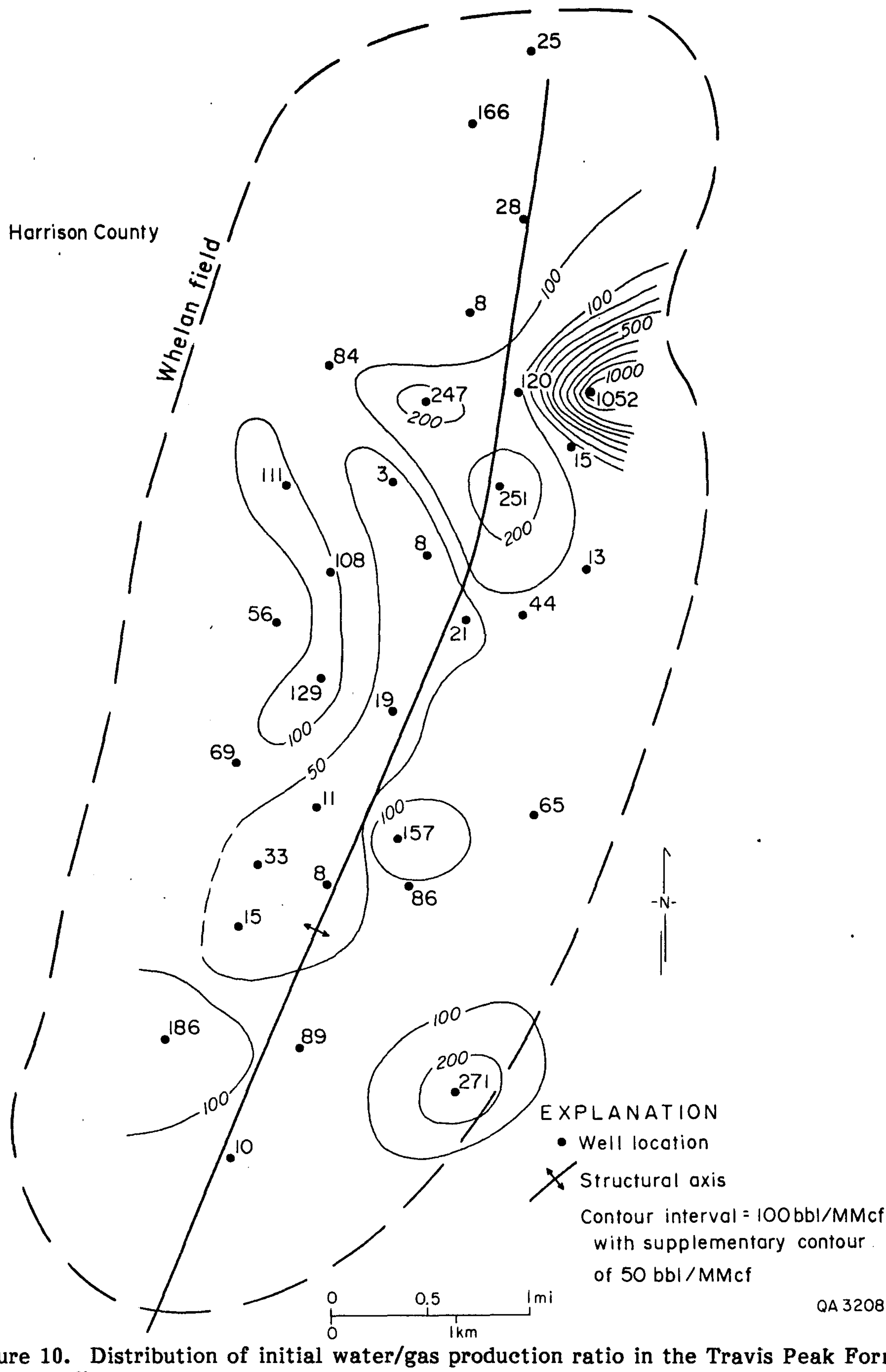

Figure 10. Distribution of initial water/gas production ratio in the Travis Peak Formation in Whelan field.

were completed and produced. The productive zones of the Travis Peak Formation in the field were divided into the Travis Peak reservoir (perforated interval of 7,306 to 8,116 ft, with an average depth of 7,608 ft) and the lower Travis Peak reservoir (perforated interval of 7,900 to 9,002 ft, with an average depth of 8,482 ft). The average gross perforated thicknesses are 265 ft and 467 ft for Travis Peak and lower Travis Peak reservoirs, respectively. Through July 1983 cumulative gas production was 6 Bcf from 11 wells in the Travis Peak reservoir and 11 Bcf from 16 wells in the lower Travis Peak reservoir. The lower Travis Peak reservoir was selected for this study because it has yielded the most prolific gas production from the Travis Peak Formation in Lansing North field. Well completion data, reservoir properties, and production characteristics of the lower Travis Peak reservoir discussed below have been summarized in table 4.

Reservoir Properties and Gas in Place

The average reservoir temperature of 239°F in Lansing North field is in the same range as in Whelan field. In Lansing North field, a pressure gradient of 0.418 psi/ft, which is slightly below a hydrostatic pressure gradient, suggests that regionally there should be a slightly updip gas flow (Gies, 1982), that is, from west to east in this area. Average pressure in Lansing North field is higher than in Whelan field, suggesting that a component of potential gas flow may exist from Lansing North field to Whelan field. In Lansing North, the initial pressure, corrected to an arbitrary datum of −8,500 ft, is higher on the west side than on the east side of the field, indicating that there exists a tendency for gas flow toward the east. Considering overall pressure distribution and regional structural gradients, gas flow direction may be southwest to northeast.

Porosity, water saturation, net pay, and effective net pay were calculated based on logs from five wells. Net pay and effective net pay within the gross perforated interval in Lansing North field are less than in Whelan field, not only because the gross perforated interval is thinner, but also because clay content appears higher in Lansing North field.

Table 4. Summary of well completion data, reservoir properties, and production characteristics of Lansing North field.

(a)	**Well completion and field data (based on 16 wells)**	
	Perforated interval	7,900-9,002 ft
	Midpoint of perforated interval	8,482 ft
	Field size	6,900 acres
	Current well density	430 acres/well
(b)	**Reservoir properties**	
	Effective net-pay thickness	182 ft
	Porosity	8.9%
	Water saturation	39%
	Permeability-thickness product	53.2 md-ft (range 0.529-431.3 md-ft)
	Permeability	0.156 md (arithmetic average) 0.114 md (thickness-weighted average) 0.027 md (median)
	Average reservoir temperature	239° F (gradient = 19.9° F/1,000 ft)
	Average initial formation pressure	3,547 psi (2,801-3,923 psi) (gradient = 0.418 psi/ft)
	Gas in place	176 Bcf
(c)	**Production characteristics**	
	Cumulative gas production	11 Bcf
	Absolute open flow potential	4,120 Mcfd (range 150-24,000 Mcfd)
	Maximum production rate	61,850 Mcf/mo
	Decline rate	0.641 cycle/yr (transient-flow period)
	Initial gas/condensate production ratio	224 Mcf/bbl
	Initial water/gas production ratio	115 bbl/MMcf
	Specific gas gravity (air = 1)	0.62
	Condensate API gravity	57°

Based on the volumetric method, initial gas in place for the field was calculated to be approximately 176 Bcf using average reservoir properties. From a p/z versus cumulative gas production plot for each well, initial gas in place was calculated to be 22 Bcf for Lansing North field. Initial gas in place calculated from the material-balance method (the p/z plot) is inconsistent with the results of the volumetric method because of low permeability and, possibly, poorly understood discontinuities of the reservoir.

The average value of the permeability-thickness product in this field is 53.2 md-ft and ranges from 0.529 to 431.3 md-ft; the arithmetic average permeability of the field is 0.156 md (with a range of 0.000907 to 1.364 md). Thickness-weighted average and median permeabilities are 0.114 and 0.027 md, respectively. Seventy-five percent of the 15 wells analyzed have permeabilities of less than 0.1 md.

Reservoir Performance and Production Characteristics

Absolute open flow potential in Lansing North field ranges from 150 to 24,000 Mcfd with an average of 4,120 Mcfd. The highest absolute open flow potentials occur near the central and northern parts of the field (fig. 11). Overall, absolute open flow potential on the west side is higher than on the east side of the structural axis. This distribution is similar to that of Whelan field.

If characterisics of production decline in Lansing North field are the same as those in Whelan field, a plot of production rate versus time (in semi-logarithmic form) will show two "linear" segments (fig. 9) for a sufficiently long production time. However, there is only one linear segment in the plot from the wells in Lansing North field, because the period of production for the wells is less than three to five years, that is, they remain in the transient-flow period characteristic of early production. The average decline rate for the early production period was 0.641 cycle/yr in the field, compared with 0.466 cycle/yr in Whelan field. The average maximum production rate was 61,850 Mcf/mo in the field compared with 82,300 Mcf/mo in Whelan field.

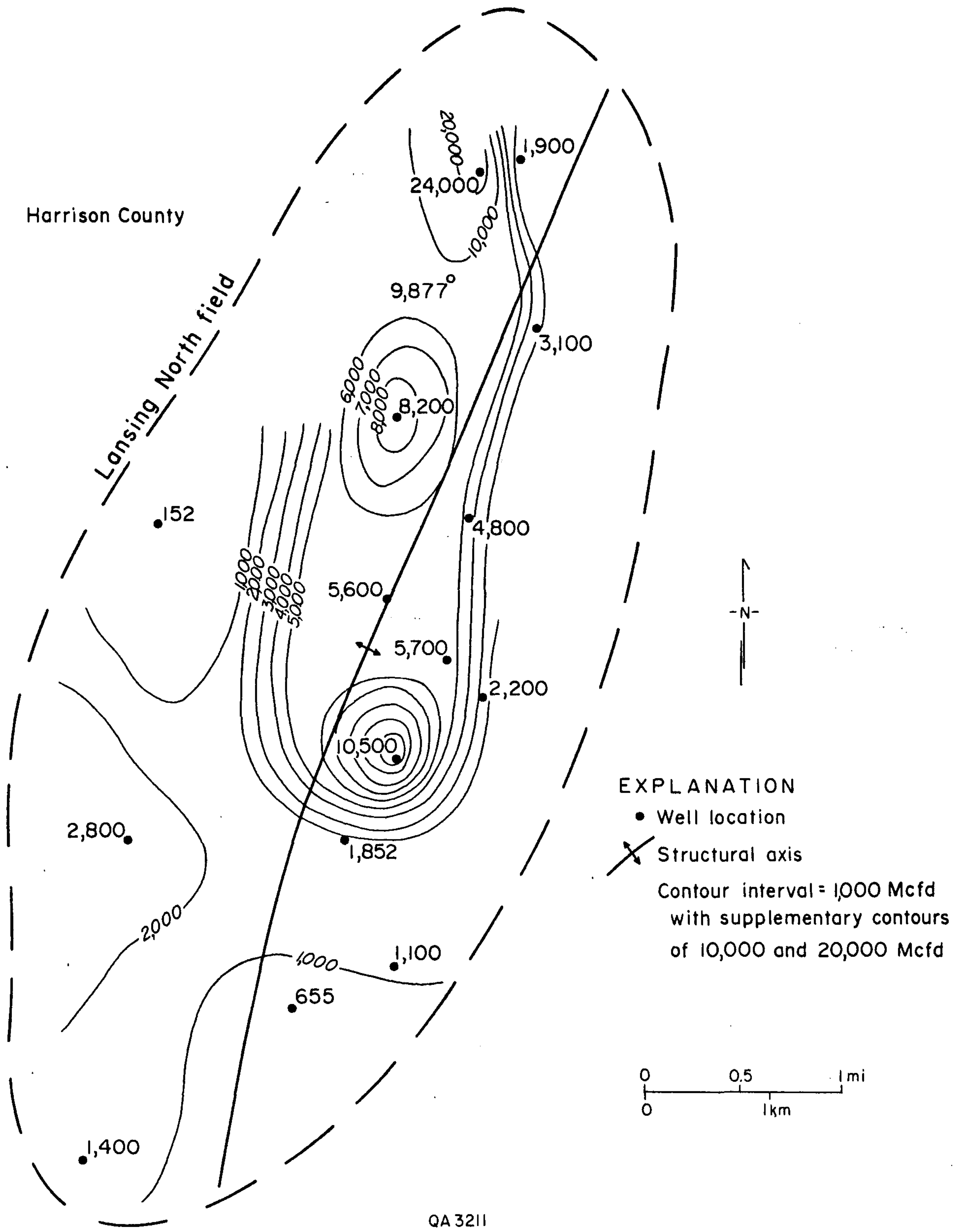

Figure 11. Distribution of absolute open flow potential in the Travis Peak Formation in Lansing North field.

The initial gas/condensate production ratio in Lansing North field is high compared with that in Whelan field. In Lansing North field, more than 90 percent of the wells in the lower Travis Peak reservoir had initial gas/condensate production ratios in the range of a dry-gas reservoir. The average gas/condensate production ratio in the field increased from 224 Mcf/bbl initially to 314 Mcf/bbl in 1983, whereas in Whelan field, it decreased from 117 Mcf/bbl to 60 Mcf/bbl. The differences in gas/condensate production ratio in both fields may reflect variations of geologic factors, such as wettability of the reservoir rock. The API gravity of condensate produced from Lansing North field is 57°, slightly higher than the 54° gravity from Whelan field.

The distribution of the intial water/gas production ratio (fig. 12) indicates low water production from the central part of the field and a probable gas/water contact zone near the field margins. A typical plot of p/z versus cumulative gas production, which is similar to that in Whelan field, shows that the production mechanism is a weak to moderate water drive in addition to gas expansion.

Willow Springs Field

Willow Springs field (fig. 1), discovered on December 19, 1955, with the drilling of the F. R. Jackson & S. H. Killingsworth James N. Adams No. 1 well, is developed over an anticline in Gregg County, Texas. Except for one well producing from a designated Travis Peak transition reservoir (perforated interval of 8,909 to 9,006 ft), all 67 wells completed in the Travis Peak Formation produced gas from the Travis Peak reservoir (perforated interval of 7,332 to 8,893 ft). The average midpoint of the perforated depth in the field is 7,812 ft, which is shallower than in Whelan and Lansing North fields. Average gross perforated thickness of 310 ft in Willow Springs field is small compared with 886 ft (Travis Peak prorated reservoir) in Whelan field and 467 ft (lower Travis Peak reservoir) in Lansing North field. The field size of 17,884 acres in the Willow Springs field is much larger than in Whelan and Lansing North fields. From January 1959 to July 1983, total gas production

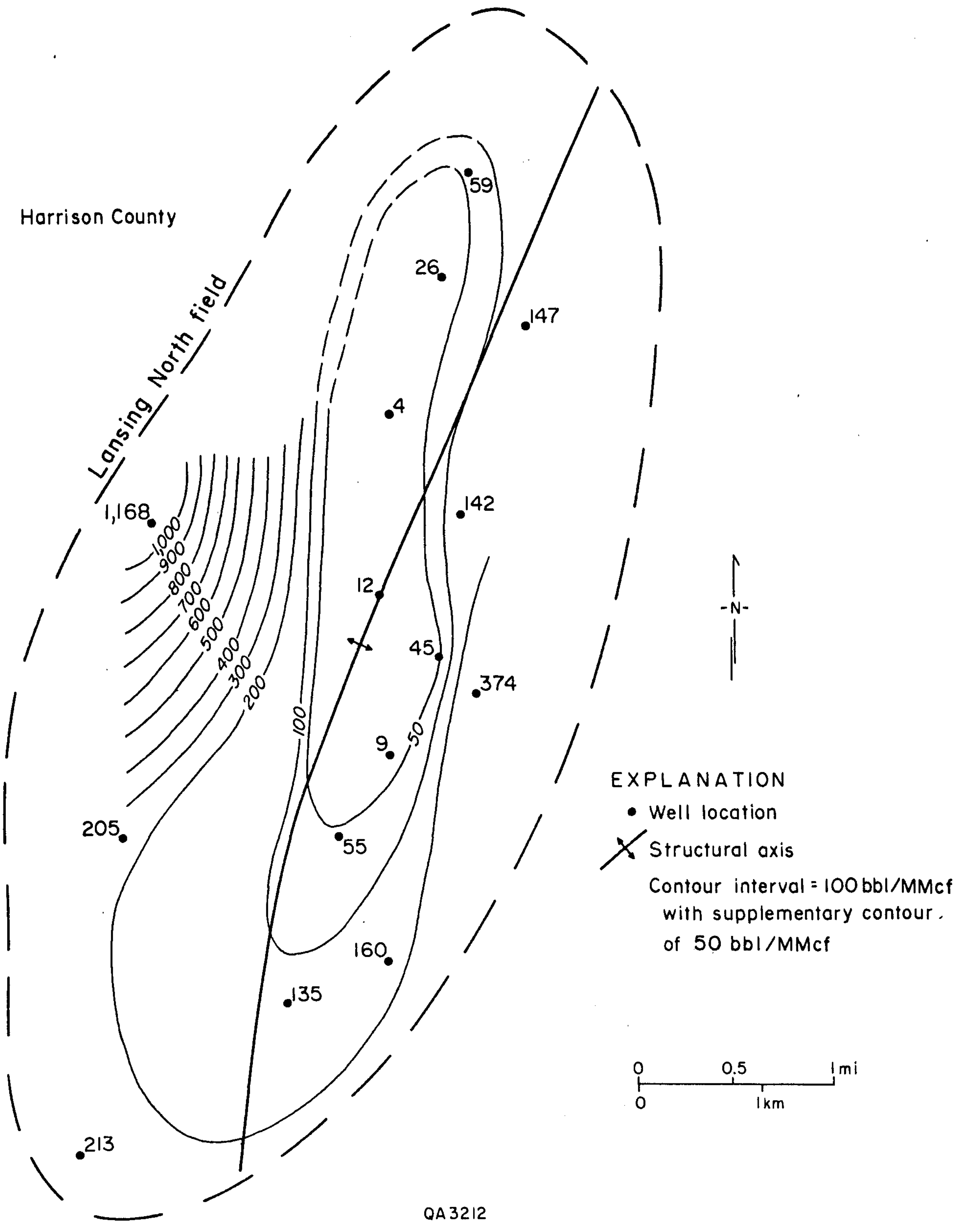

Figure 12. Distribution of initial water/gas production ratio in the Travis Peak Formation in Lansing North field.

was 106 Bcf from 67 wells in Willow Springs field. The current calculated average well density is approximately 270 acres/well. A summary of well completion data, reservoir properties, and production characteristics discussed below is given in table 5.

Reservoir Properties and Gas in Place

The average temperature of 229 °F in Willow Springs field is lower than in Whelan and Lansing North fields, but the temperature gradient of 20.4 °F/1,000 ft is slightly higher than in the latter two fields, probably owing to regional variations in temperature gradient distribution. Initial reservoir pressure at the midpoint of the perforated interval averages 3,421 psi and ranges from 2,042 to 4,100 psi. The high initial reservoir pressure variation of 2,058 psi indicates reservoir compartmentalization necessary to sustain such differences. Pressure gradient decreases from 0.437 psi/ft in Willow Springs field to 0.418 psi/ft in Lansing North field and to 0.383 psi/ft in Whelan field, suggesting fluid flow from southwest to northeast.

Well logs were not utilized to determine porosity and water saturation for the field in the present study. Based on the data sheet for the MER (maximum efficient rate) hearing submitted to the Railroad Commission of Texas by Lone Star Producing Company, the average porosity and water saturation are 9.5 percent and 35 percent, respectively, and "average effective net-pay thickness" is 46 ft. Thus, based on the volumetric method, initial gas in place was calculated to be approximately 417 Bcf using average reservoir properties. Initial gas in place calculated from the p/z plot could not be adequately defined because the plots were only available for 38 percent of the wells in the field.

In Willow Springs field, the permeability-thickness product averages 39.8 md-ft, and ranges from 0.612 to 217.7 md-ft. If gross perforated interval is used as a formation thickness, permeability ranges from 0.001 to 13.2 md and the arithmetic average permeability of the field is 1.483 md. Thickness-weighted average and median permeabilities are 0.106 md and 0.25 md, respectively. About one-third of the total producing wells have

Table 5. Summary of well completion data, reservoir properties, and production characteristics of Willow Springs field.

(a) Well completion and field data (based on 67 wells)	
Perforated interval	7,332-8,983 ft
Midpoint of perforated interval	7,812 ft
Field size	17,884 acres
Current well density	270 acres/well
(b) Reservoir properties	
Effective net-pay thickness	46 ft
Porosity	9.5%
Water saturation	35%
Permeability-thickness product	39.8 md-ft (range: 0.612-217.7 md-ft)
Permeability	1.483 md (arithmetic average) 0.106 md (thickness-weighted average) 0.25 md (median)
Reservoir temperature	229° F (gradient = 20.4° F/1,000 ft)
Initial formation pressure	3,421 psi (range: 2,042-4,100 psi) (gradient = 0.437 psi/ft)
Gas in place	417 Bcf
(c) Production characteristics	
Cumulative gas production	106 Bcf
Absolute open flow potential	4,552 Mcfd (range: 82-18,600 Mcfd)
Maximum production rate	55,200 Mcf/mo
Decline rate	0.172 cycle/yr (pseudo-steady-state flow period) 0.898 cycle/yr (transient-flow period)
Initial gas/condensate production ratio	110 Mcf/bbl
Initial water/gas production ratio	114 bbl/MMcf
Specific gravity of gas (air = 1)	0.64
API gravity of condensate	58°

permeabilities of less than 0.1 md. The average formation flow capacity, or permeability-thickness product, in the field is similar to Lansing North field.

Reservoir Performance and Production Characteristics

Absolute open flow potential in Willow Springs field averages 4,552 Mcfd and ranges from 82 to 18,600 Mcfd. Areas of high flow potential are scattered within the area enclosed by the field boundary (fig. 13). This distribution suggests reservoir compartmentalization or variations in diagenetic history that affect reservoir quality.

The decline curves of some wells show that production characteristics in the field are the same as in Whelan field, that is, there are two distinct flow periods, transient- and pseudo-steady-state flow, in the historical production data. However, some wells with more than 10 years of production have had only one flow period, probably in pseudo-steady-state. Twenty-two wells from the field were used in the decline-curve analysis to obtain maximum production flow rate and to determine decline rate. Average maximum production rate in the field is 55,000 Mcf/mo. Average decline rates in the pseudo-steady-state and transient-flow periods in the field are 0.172 cycle/yr and 0.898 cycle/yr, respectively, which are higher than those in Whelan field.

Gas/condensate production ratio in Willow Springs field is at the same level as in Lansing North field; the average gas/condensate production ratio increased from 110 Mcf/bbl initially to 430 Mcf/bbl in 1983. A possible cause of this change is either that (1) condensate adheres to the walls of the pore spaces of the rock, or (2) vaporization of condensate occurs during pressure drop due to gas production. About 30 percent of the wells producing from the Travis Peak reservoir in this field had initial gas/condensate ratios in the dry-gas range.

The distribution of the water/gas production ratio (fig. 14) in the field indicates relatively high water production from the structurally high part of the field. This differs from relatively low water production from the central part of the field in both Whelan and Lansing fields. A possible reason for this abnormal distribution may be the variation in

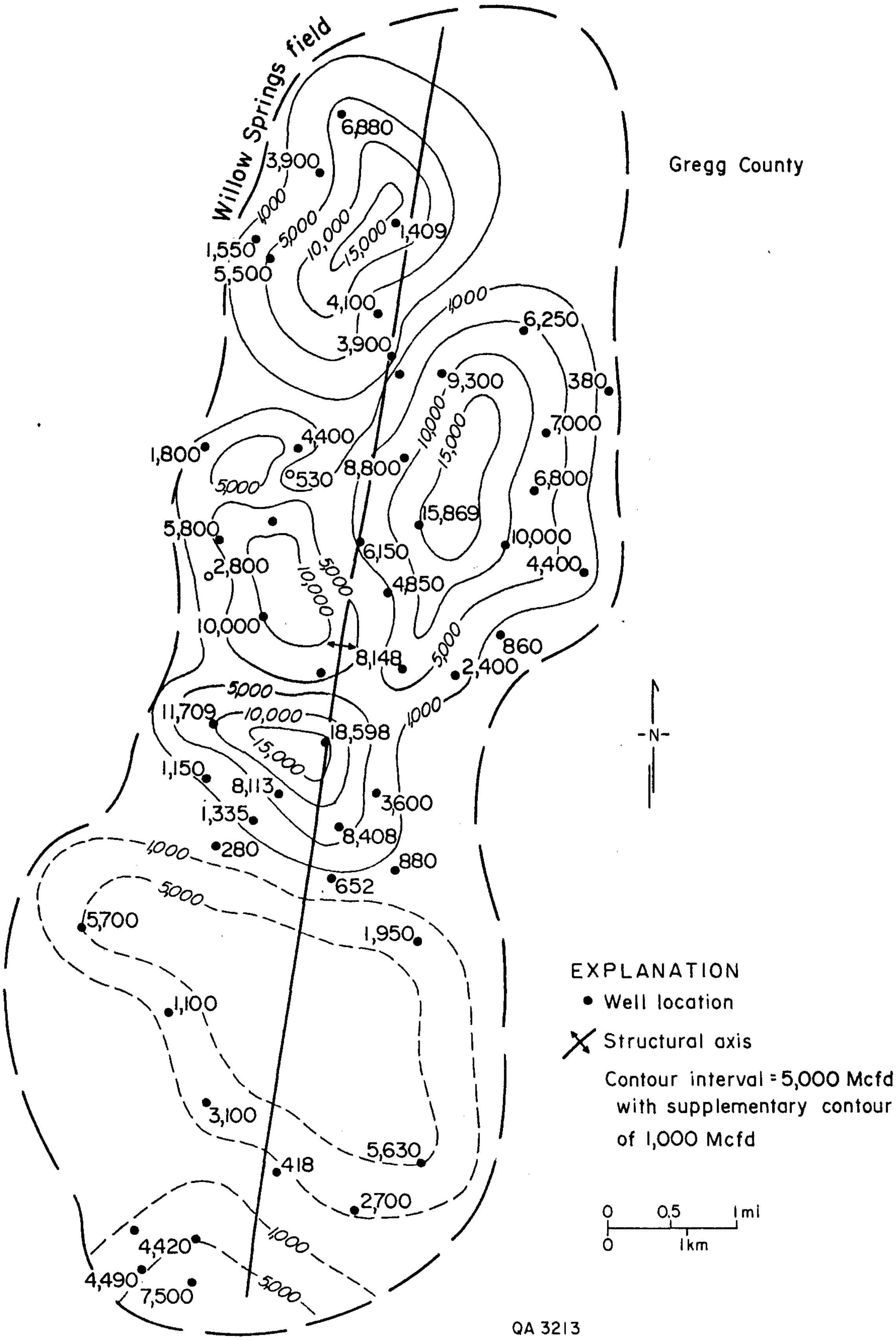

Figure 13. Distribution of absolute open flow potential in the Travis Peak Formation in Willow Springs field.

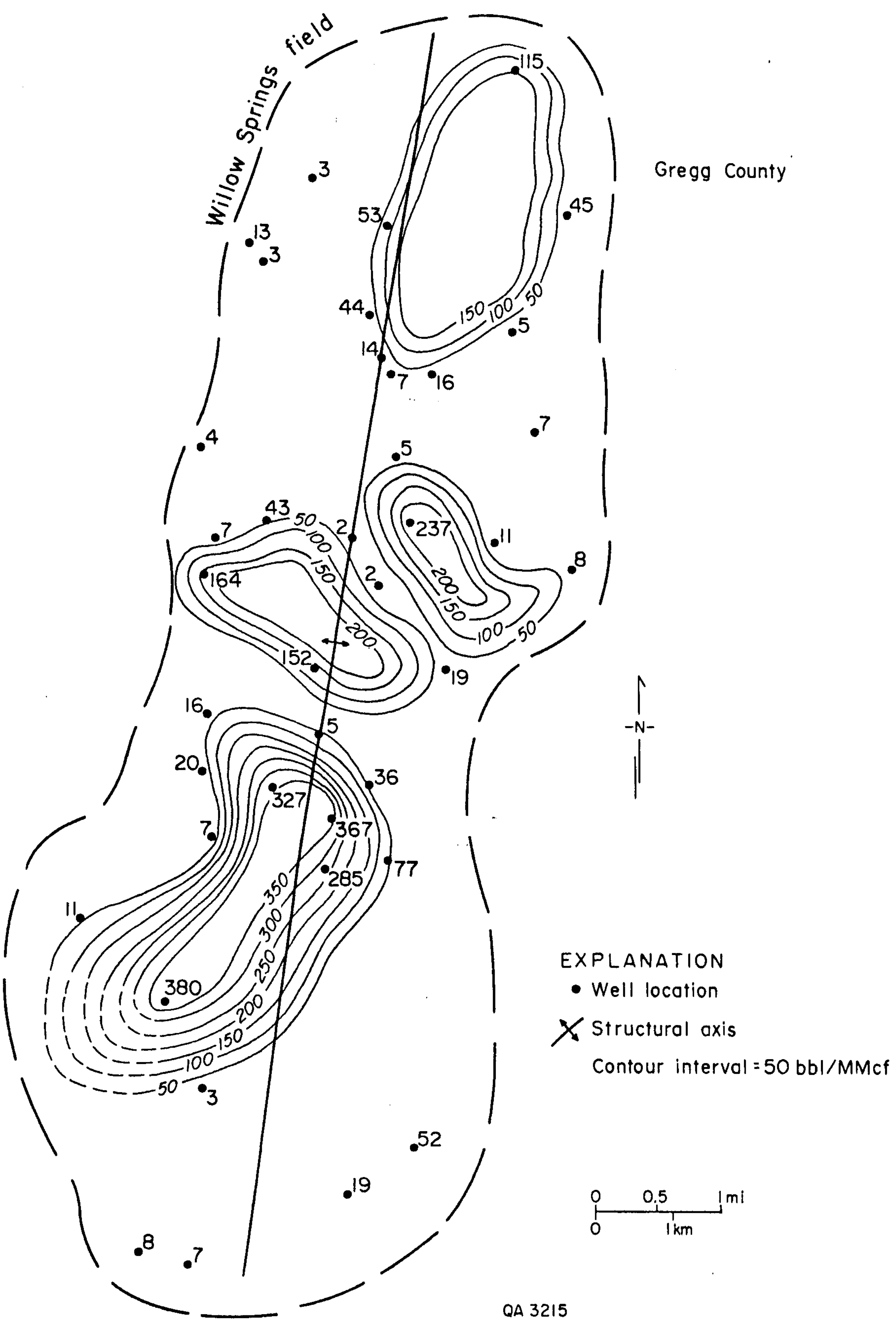

Figure 14. Distribution of initial water/gas production ratio in the Travis Peak Formation in Willow Springs field.

wettability of reservoir rock with different constituents or different grain size. Patterns of diagenesis may also vary. The water/gas production ratio in this field is small overall compared with Whelan and Lansing North fields. Based on the plot of p/z versus cumulative gas production, the production mechanism in the field is gas expansion with a very weak to negligible water drive.

Danville Field

Danville field (fig. 1), located in Rusk and Gregg Counties, is on a structurally positive feature. The Travis Peak reservoir in Danville field was discovered on July 31, 1959, with the drilling of the International Helium Inc. W. O. Compton No. 1 well. Eleven wells produce from the Travis Peak reservoir, in which the perforated interval is from 7,458 to 7,745 ft and the average midpoint of the perforated interval is 7,574 ft. The average gross perforated thickness of 59 ft is very thin compared with Whelan, Lansing North, and Willow Springs fields. Through July 1983, total cumulative gas production was 9.79 Bcf from eleven wells with a well density of 898 acres/well. The field size (estimated by planimeter) is approximately 9,877 acres. A summary of well completion data, reservoir properties, and production characteristics discussed below is given in table 6.

Reservoir Properties and Gas in Place

The average reservoir temperature and reservoir temperature gradient in the field are 213 °F and 18.3 °F/1,000 ft, respectively. Average initial reservoir pressure at the midpoint of the perforated interval is 3,491 psi, and ranges from 2,962 to 3,758 psi. Average pressure gradient is 0.460 psi/ft, which is essentially the normal hydrostatic pressure gradient. In this field, the distribution of pressure indicates that initial formation pressures decrease from southwest to northeast (fig. 15). This may imply that the direction of potential fluid flow is also from southwest to northeast.

Sonic and resistivity well log analysis for three wells shows that all of the gross perforated interval is equivalent to net pay and 96 percent of the gross perforated interval

Table 6. Summary of well completion data, reservoir properties, and production characteristics of Danville field.

(a)	**Well completion and field data (based on 11 wells)**	
	Perforated interval	7,458-7,745 ft
	Midpoint of perforated interval	7,574 ft
	Field size	9,877 acres
	Current well density	898 acres/well
(b)	**Reservoir properties**	
	Effective net-pay thickness	57 ft
	Porosity	12.8%
	Water saturation	28.8%
	Permeability-thickness product	41.2 md-ft (range 55-239.0 md-ft)
	Permeability	0.915 md (arithmetic average) 1.041 md (thickness-weighted average) 1.00 md (median)
	Average reservoir temperature	213°F (gradient = 18.3°F/1,000 ft)
	Average initial formation pressure	3,491 psi (gradient = 0.460 psi/ft)
	Gas in place	110 Bcf
(c)	**Production characteristics**	
	Cumulative gas production	9.79 Bcf
	Absolute open flow potential	2,784 Mcfd (range 345-16,500 Mcfd)
	Maximum production rate	13,460 Mcf/mo
	Decline rate	0.296 cycle/yr (whole production period)
	Initial gas/condensate production ratio	55 Mcf/bbl
	Initial water/gas production ratio	22 bbl/MMcf
	Specific gas gravity (air = 1)	0.66
	Condensate API gravity	58°

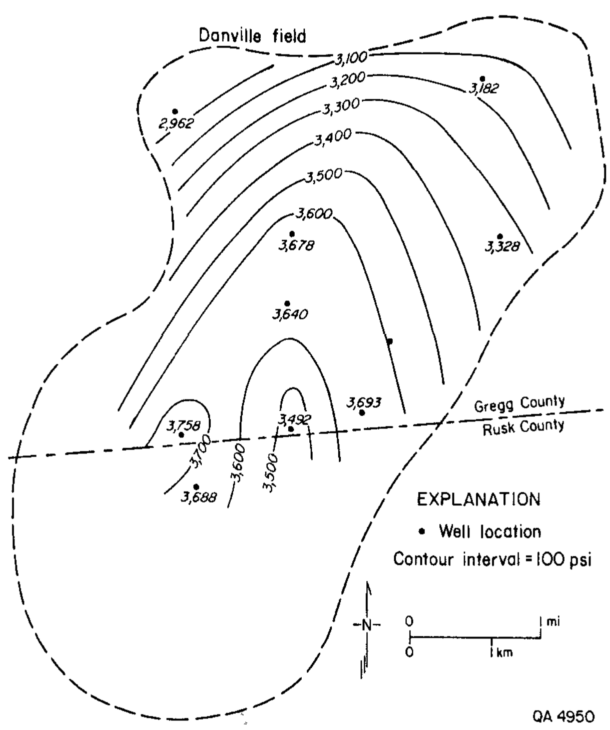

Figure 15. Distribution of initial formation pressure in the Travis Peak Formation in Danville field.

is also effective net pay. Average porosity and water saturation within the effective net-pay thickness are 12.8 percent and 28.8 percent, respectively. With a field-average gross perforated interval of 59 ft from all producing wells, net pay and effective net pay are approximately 59 ft and 57 ft, respectively.

Based on the volumetric method, initial gas in place for the field is calculated to be approximately 100 Bcf using average reservoir properties. There are insufficient p/z data to estimate gas in place; however, available p/z plots show that the production mechanism is gas expansion with no indication of any degree of water drive.

The average value of permeability-thickness product in this field is 41.2 md-ft, which is smaller than in Whelan, Lansing North, and Willow Springs fields. Thickness-weighted and median permeability in the field are about 1 md and are greater than in the fields previously discussed. It is likely that operators have perforated only the most permeable zones in the formation, which results in productive wells without hydraulic fracturing. Only one well out of the seven wells analyzed shows permeability of less than 0.1 md.

Reservoir Performance and Production Characteristics

Even though permeability in this field is relatively high compared with other fields of this study, average absolute open flow potential of 2,784 Mcfd in Danville field is relatively low. This may be because flow capacity, or permeability-thickness product, in the field is small, and also because no well has been fractured in this field.

Characteristics of production decline curves of wells in Danville field differ from those in other fields reviewed. In Danville field, the semi-logarithmic plot of production rate versus time shows only one straight line, which may correspond to only one dominant flow period. This may be related to the relatively high permeability of the reservoir. Based on the decline curve analysis of five wells from the field, average maximum production rate in the field is 13,460 Mcf/mo and average decline rate is 0.296 cycle/yr. The field-average decline rate in this field is the lowest for the fields studied.

Average gas/condensate production ratio for wells producing from the Travis Peak Formation in this field is 55 Mcf/bbl initially to 40 Mcf/bbl most recently, and is essentially constant over the entire production history. The Travis Peak gas reservoir in this field is a wet-gas (or gas condensate) reservoir in which specific gravity of gas is 0.66 (air = 1) and condensate gravity is 58 °API. A well drilled in 1960 produced oil from a depth of 7,406 ft, and has a gas/oil ratio of 0.03 Mcf/bbl and oil gravity of 43 °API. The water/gas production ratios from the production tests indicate low water production averaging 22 to 59 bbl/MMcf during the production period.

Henderson South Field

Henderson South field (fig. 1), located in Rusk County, is on the flank of a structurally positive feature. Two productive intervals within the Travis Peak Formation, the Travis Peak reservoir (discovered in 1955) and the Travis Peak-A reservoir (discovered in 1965), have been designated by the Railroad Commission of Texas. The first production from the Travis Peak reservoir was from the Traham-J.C. Drilling Dowdon No. 1-T well operated by Traham-J. C. Drilling; the Travis Peak-A reservoir was discovered on April 21, 1961, with the drilling of the Sesco Production Company Richardson No. 1-C well. For the Travis Peak reservoir (perforated interval from 7,323 ft to 7,529 ft), field-average perforated depth is 7,435 ft; in the Travis Peak-A reservoir (perforated interval from 7,399 ft to 7,540 ft) the average perforated depth is 7,469 ft. The average gross perforated thicknesses are 25 ft and 6 ft for the Travis Peak reservoir and the Travis Peak-A reservoir, respectively. From January 1959 to July 1983, total gas production was 9.3 Bcf from 13 wells in the Travis Peak reservoir, and 11.5 Bcf from 9 wells in the Travis Peak-A reservoir. The Travis Peak reservoir was selected for this study because it has more wells producing from the Travis Peak Formation than the Travis Peak-A reservoir. The field size (measured by planimeter) to enclose the producing wells is 11,945 acres. The calculated average well density, derived from acreage of the field divided by number of the producing wells (1985), is approximately 900 acres/well. A summary of well completion data, reservoir properties, and production characteristics of the Travis Peak reservoir discussed below is given in table 7.

Reservoir Properties and Gas in Place

The average reservoir temperature and reservoir temperature gradient in Henderson South field are 223 °F and 20.6 °F/1,000 ft, respectively. Temperature gradient of this field is relatively high compared with other fields in the study area. An average initial reservoir pressure at the midpoint of the perforated interval is 3,427 psi and ranges from 3,234 psi to 3,730 psi, with the exception of one well having pressure less than 3,000 psi. The initial formation pressure distribution in this field is fairly even throughout the field, indicating good reservoir continuity. The field-average pressure gradient of 0.461 psi/ft in the field is the normal hydrostatic pressure gradient. Both Danville and Henderson South fields, which are located in the center of the study area, have normal hydrostatic pressure gradients.

Based on logs (sonic and resistivity) available from five wells with an average gross perforated interval of 28 ft, the average porosity and water saturation are 13.4 percent and 34.2 percent, respectively. Also, 94 percent of the gross perforated interval forms net-pay thickness. The values obtained for both net pay and effective net pay are the same in this field. With an average gross perforated interval of 24.7 ft from all the producing wells, field average net-pay thickness, as well as effective net-pay thickness, is 23.2 ft (table 7).

Initial gas in place for the field was calculated, based on the volumetric method, to be approximately 102 Bcf using average reservoir properties. Insufficient p/z data were available to estimate gas in place.

In Henderson South field, the permeability-thickness product averages 39.6 md-ft and ranges from 8.9 to 139.2 md. The arithmetic average permeability in the field is 6.34 md, ranging from 0.30 md to 19.1 md. All the producing wells in this field have permeability of greater than 0.1 md. Thickness-weighted average and median permeabilities are 2.01 and

Table 7. Summary of well completion data, reservoir properties, and production characteristics of Henderson South field.

(a)	**Well completion and field data (based on 13 wells)**	
	Perforated interval	7,323-7,529 ft
	Midpoint of perforated interval	7,435 ft
	Field size	11,945 acres
	Current well density	900 acres/well
(b)	**Reservoir properties**	
	Effective net-pay thickness	23.2 ft
	Porosity	13.4%
	Water saturation	34.1%
	Permeability-thickness product	39.6 md-ft (range: 8.9-139.2 md-ft)
	Permeability	6.34 md (arithmetic average) 2.01 md (thickness-weighted average) 3.20 md (median)
	Average reservoir temperature	22.3° F (gradient = 20.6 °F/1,000 ft)
	Average initial formation pressure	3,427 psi (gradient = 0.461 psi/ft)
	Gas in place	102 Bcf
(c)	**Production characteristics**	
	Cumulative gas production	9.3 Bcf
	Absolute open flow potential	3,626 Mcfd (range: 800-12,100 Mcfd)
	Maximum production rate	2,992 Mcf/mo
	Decline rate	0.178 cycle/yr (whole production period)
	Initial gas/condensate production ratio	40.1 Mcf/bbl
	Initial water/gas production ratio	53 bbl/MMcf
	Specific gas gravity (air = 1)	0.64
	Condensate API gravity	59°

3.20 md, respectively. Even though the permeability in this field is relatively high in the study area, the permeability-thickness product is relatively low because of low net-pay thickness.

Reservoir Performance and Production Characteristics

Absolute open flow potential in Henderson South ranges from 800 to 12,100 Mcfd, with an average of 3,626 Mcfd. High absolute open flow potential occurs at the center of the field (fig. 16). The average value of absolute open flow potential in this field is relatively low compared with other fields in the study area, perhaps because of the relatively low permeability-thickness product and of no wells being fractured.

The characteristics of production decline in Henderson South are the same as those in Danville field; that is, semi-logarithmic production rate versus time plots show only one "linear" segment, even over a relatively long production time. This may be a characteristic of a higher permeability gas reservoir in the Travis Peak Formation. The average maximum production rate was 2,992 Mcf/mo in this field compared with 82,300 Mcf/mo in Whelan field and 2,784 Mcf/mo in Danville field. An average decline rate in Henderson South field was 0.178 cycle/yr, the lowest for the fields selected for this study, indicating relatively long expected production life.

The initial gas/condensate production ratio in Henderson South is 40.1 Mcf/bbl, which is similar to Danville field, and is the lowest in the selected gas fields studied. Thus, the Travis Peak reservoir in both Henderson South and Danville fields is a wet-gas or gas condensate reservoir, because gas/condensate production ratios in these fields were in the range of 5 to 100 Mcf/bbl. The average gravity of condensate produced from this field is 59 °API, which is the highest in the fields selected.

Water production from the field is very low; it has a gas/water production ratio of 53 bbl/MMcf, which is similar to the 22 bbl/MMcf value for the Danville field.

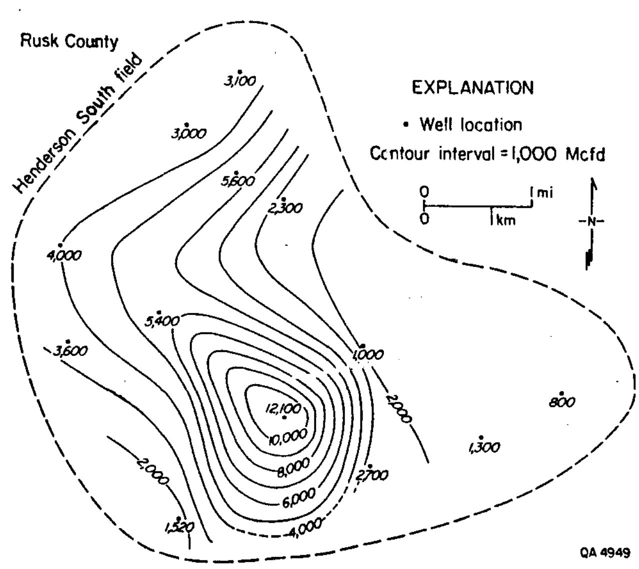

Figure 16. Distribution of absolute open flow potential in the Travis Peak Formation in Henderson South field.

Percy Wheeler Field

Percy Wheeler field (fig. 1), located in Cherokee County, Texas, consists of a faulted, structural trap. The field was discovered on July 20, 1979, with the drilling of the Jones-O'Brien B. M. Smith No. 1 well. All the wells completed in the Travis Peak Formation are producing from a Travis Peak reservoir, the perforated interval of which is from 8,863 to 9,607 ft, with an average midpoint of 9,202 ft. The average gross perforated thickness is 182 ft. Since development of the field began, through July 1983, total gas production was 5.6 Bcf from 15 wells with a well density of 640 acres/well. The field size measured by planimeter is approximately 9,384 acres. A summary of well completion data, reservoir properties, and production characteristics discussed below is given in table 8.

Reservoir Properties and Gas in Place

The average reservoir temperature and reservoir temperature gradient in the field are 245 °F and 19.0°F/1,000 ft, respectively. An average initial reservoir pressure at the midpoint of the perforated interval is 4,543 psi, and ranges from 2,631 to 5,135 psi. Average pressure gradient is 0.494 psi/ft, which is somewhat above the normal hydrostatic pressure gradient of 0.45 psi/ft. Both pressure and pressure gradient in this field are higher than in other fields selected for this study. Possibly, this distribution occurs because the field is nearer to the source of fluid flow in the vicinity of the basin center.

Based on logs available from five wells with an average gross perforated interval of 147 ft, the average porosity and water saturation in Percy Wheeler field are 7.8 percent and 53.7 percent, respectively, if net-pay thickness is used, and 10.3 percent and 32.7 percent, respectively, if effective net-pay thickness is used. It can be shown that net pay and effective net pay are 54.6 percent and 30.7 percent of the gross perforated interval, respectively. Using the average reservoir properties, initial gas in place for the field is estimated to be 148 Bcf based on the volumetric method.

Table 8. Summary of well completion data, reservoir properties, and production characteristics of Percy Wheeler field.

(a)	**Well completion and field data (based on 15 wells)**	
	Perforated interval	8,863-9,607 ft
	Midpoint of perforated interval	9,202 ft
	Field size	9,384 acres
	Current well density	640 acres/well
(b)	**Reservoir properties**	
	Effective net-pay thickness	23 ft
	Porosity	10.3%
	Water saturation	32.7%
	Permeability-thickness product	9.3 md-ft (range: 0.197-35.8 md-ft)
	Permeability	0.076 md (arithmetic average) 0.052 md (thickness-weighted average) 0.046 md (median)
	Reservoir temperature	245° F (gradient = 19.0° F/1,000 ft)
	Initial formation pressure	4,543 psi (range: 2,631-5,135 psi) (gradient = 0.494 psi/ft)
	Gas in place	148 Bcf
(c)	**Production characteristics**	
	Cumulative gas production	5.6 Bcf
	Absolute open flow potential	1,910 Mcfd (range: 310-6,500 Mcfd)
	Maximum production rate	39,857 Mcf/mo
	Decline rate	0.705 cycle/yr (transient-flow period)
	Initial gas/condensate production ratio	114 Mcf/bbl
	Initial water/gas production ratio	40 bbl/MMcf
	Specific gravity of gas (air = 1)	0.62
	API gravity of condensate	57°

Because Percy Wheeler field was developed so recently, gas in place derived from the p/z plot may not be valid. However, p/z plots may be used to evaluate the production mechanism. Most of the wells in Percy Wheeler field do not show a linear trend in the p/z plot. Instead, pressures either drop slightly or not at all in the beginning of the production period and then drop rapidly. Possible reasons for this abnormal pattern in the p/z plot are as follows: (1) gas/condensate production ratio is relatively low in the field, so that gas and condensate may be flowing at the same time in the formation, or (2) hydrocarobon phase change may be occurring during production.

In Percy Wheeler field, permeability-thickness product averages 9.3 md-ft and ranges from 0.197 to 35.8 md-ft. If gross perforated interval is used as a formation thickness, the permeability of the field averages 0.076 md, and ranges from 0.00116 to 0.354 md. Thickness-weighted average and median permeabilities are 0.052 md and 0.046 md, respectively. Approximately 80 percent of the producing wells show permeabilities of less than 0.1 md.

Reservoir Performance and Production Characteristics

Absolute open flow potential, which is related to productivity, ranges from 310 to 6,500 Mcfd with an average of 1,910 Mcfd. The productive area with high flow potential (fig. 17) is approximately coincident with the structural high. The distribution of flow potential suggests that there are no rapid spatial changes in reservoir properties (fig. 17).

If production decline curves in Percy Wheeler field are ultimately similar to those of Whelan and Willow Springs fields, then production at Percy Wheeler field is still in a period of transient flow. The average decline rate in the field is 0.705 cycle/yr, which is close to, but slightly higher than, the decline rate of 0.641 cycle/yr in Lansing North field, which was also developed in the late 1970's. The average maximum production rate in the Percy Wheeler field has been 39,857 Mcf/mo, which is small compared with 82,300 Mcf/mo in Whelan field, 61,850 Mcf/mo in Lansing North field, and 55,200 Mcf/mo in Willow Springs field; this is in part a reflection of the lower permeabilities.

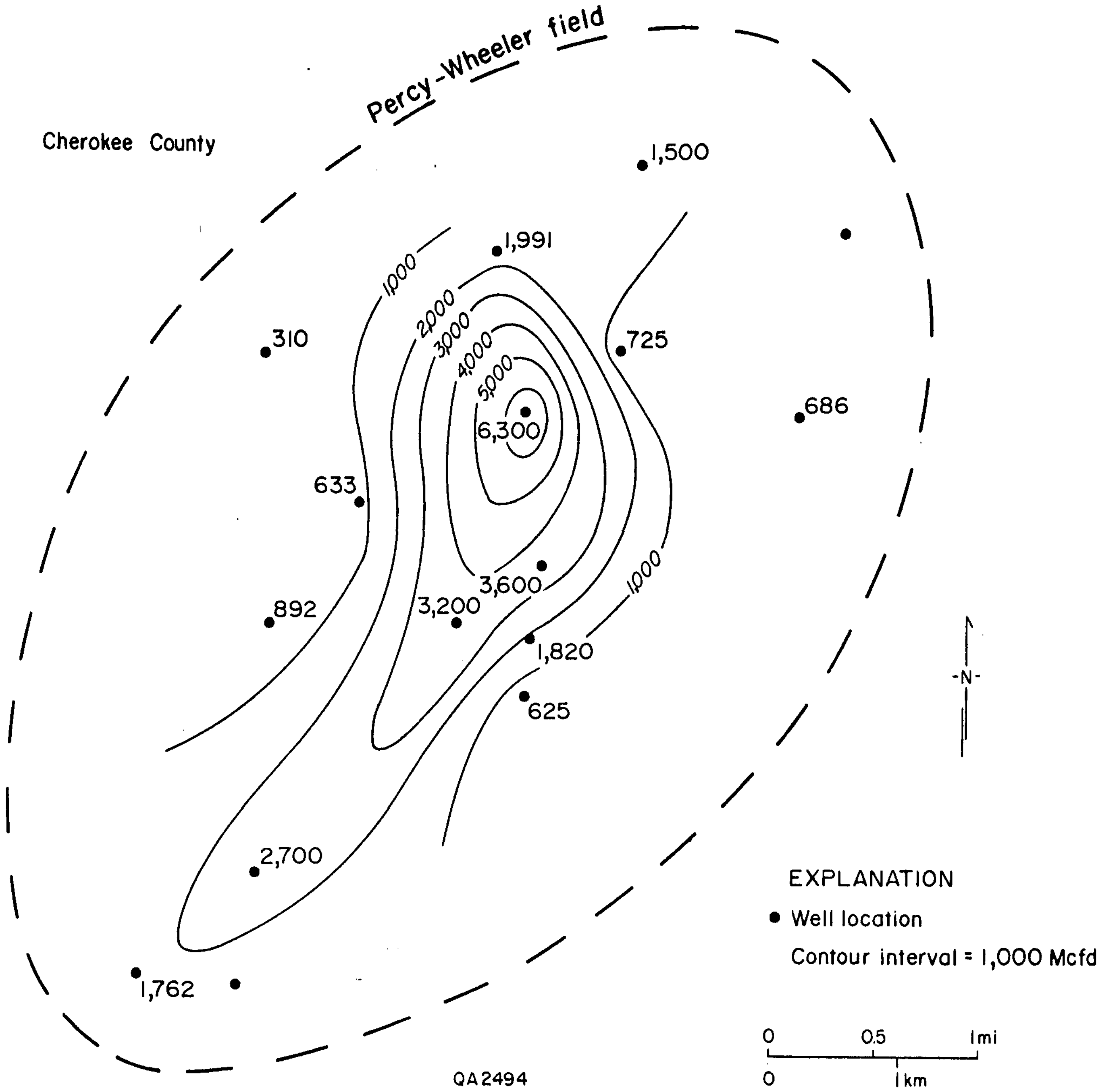

Figure 17. Distribution of absolute open flow potential in the Travis Peak Formation in Percy Wheeler field.

Average gas/condensate production ratio in the field has decreased from 114 Mcf/bbl (dry-gas reservoir) initially to 45 Mcf/bbl (wet-gas reservoir) in 1983. Note that the average gas/condensate production ratios in both Whelan and Willow Springs fields were also decreasing during the production history. Approximately 70 percent of the producing wells in both Percy Wheeler and Willow Springs fields had initial gas/condensate production ratios below 100 Mcf/bbl. In Percy Wheeler field, API gravity of produced condensate is 57° and specific gravity of produced gas is 0.624.

Initial water/gas production ratios in the field have been relatively low, with an average of 44 bbl/MMcf; one well at the western edge of Percy Wheeler field has an abnormally high ratio of 6,230 bbl/MMcf. The distribution of the water/gas production ratio (fig. 18) generally shows low water production from the central part of the field. However, it does indicate one small area with relatively high water/gas ratio, perhaps due to nonhomogeneity of the reservoir and possible extension of hydraulic fracture treatments into zones of high water saturation.

Pinehill Southeast Field

Development of Pinehill Southeast field (fig. 1) began after it was discovered on October 10, 1979, with the drilling of the Seagull International Exploration Inc. Virgil Smith Gas Unit No. 1 well; the field is a stratigraphic gas trap located in Rusk and Panola Counties, Texas. Ten wells produce from the Travis Peak reservoir, the perforated interval of which is from 6,830 to 7,408 ft, with an average midpoint of 7,155 ft. Average gross perforated thickness is 43 ft and is thin compared with other fields in this study. Through July 1983, total gas production was 0.942 Bcf. The current (1985) calculated average well density is approximately 850 acres/well. A summary of well completion data, reservoir properties, and production characteristics discussed below is given in table 9.

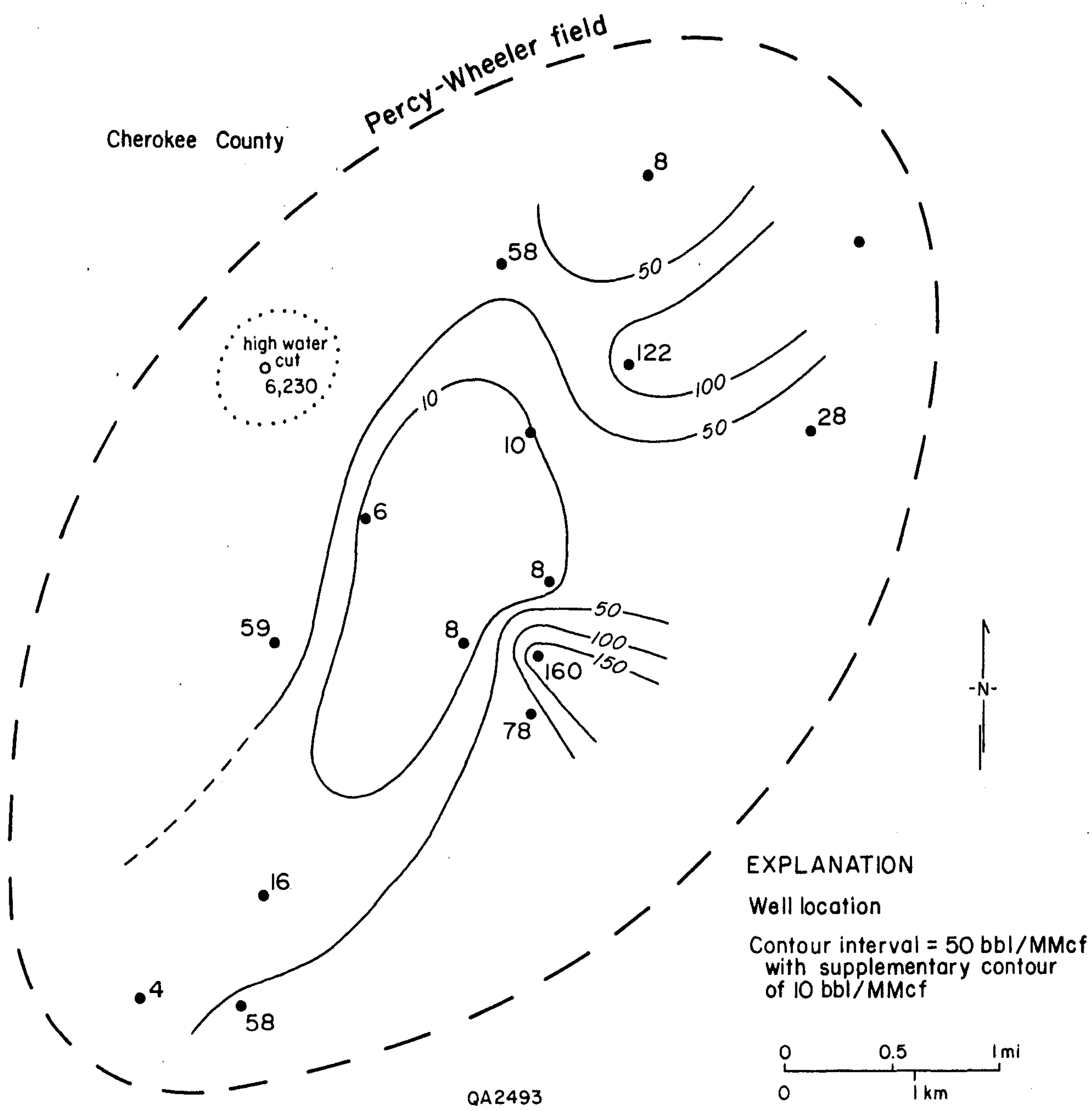

Figure 18. Distribution of initial water/gas production ratio in the Travis Peak Formation in Percy Wheeler field.

Table 9. Summary of well completion data, reservoir properties, and production characteristics of Pinehill Southeast field.

(a)	**Well completion and field data (based on 10 wells)**	
	Perforated interval	6,830-7,408 ft
	Midpoint of perforated interval	7,155 ft
	Field size	8,521 acres
	Current well density	850 acres/well
(b)	**Reservoir properties**	
	Effective net-pay thickness	25 ft
	Porosity	8.3%
	Water saturation	42.4%
	Permeability-thickness product	11.0 md-ft (range: 1.7-22 md-ft)
	Permeability	1.3 md (arithmetic average) 0.269 md (thickness-weighted average) 0.66 md (median)
	Reservoir temperature	199°F (gradient = 18.0°F/1,000 ft)
	Initial formation pressure	3,071 psi (range: 2,135-3,495 psi) (gradient = 0.429 psi/ft)
	Gas in place	42 Bcf
(c)	**Production characteristics**	
	Cumulative gas production	0.942 Bcf
	Absolute open flow potential	1,462 Mcfd (range: 315-2,722 Mcfd)
	Maximum production rate	11,700 Mcf/mo
	Decline rate	0.748 cycle/yr (transient-flow period)
	Initial gas/condensate production ratio	359 Mcf/bbl
	Initial water/gas production ratio	42 bbl/MMcf
	Specific gas gravity of gas (air = 1)	0.65
	API gravity of condensate	55°

Reservoir Properties and Gas in Place

The average reservoir temperature and reservoir temperature gradient in the field are 199 °F and 18.0°F/1,000 ft, respectively. Among the fields selected for this study, the temperature gradient in this field is the lowest. An average initial reservoir pressure at the midpoint of the perforated interval is 3,071 psi and ranges from 2,135 to 3,495 psi. Average pressure gradient is 0.429 psi/ft, which is slightly below a hydrostatic pressure gradient of 0.45 psi/ft. Both initial pressure and pressure gradient in Pinehill Southeast field are less than in Percy Wheeler field and are about the same as those in Willow Springs field. It is suggested that regional fluid flow in a west-to-east direction is more likely than a north-to-south direction.

The average porosity and water saturation in the field are 7.2 percent and 51.3 percent, respectively, if net-pay thickness is used, and 8.3 percent and 42.4 percent, respectively, if effective net-pay thickness is used. Net pay and effective net pay are 100 percent and 57 percent of the gross perforated interval, respectively. These results are based on logs available from only two wells. Based on the volumetric method and using average reservoir properties, initial gas in place in the Travis Peak Formation for the field is calculated to be approximately 42 Bcf. Note that effective net-pay thickness used in these calculations is very thin compared with other fields selected in the study. The p/z plot was not used to estimate gas in place because few data are available owing to only recent development of the field.

The average value of the permeability-thickness product is 11.0 md-ft and ranges from 1.7 to 22.0 md-ft. The arithmetic average permeability of the field is 1.3 md (0.035 to 5.5 md) and is high compared with other fields. Thickness-weighted average and median permeabilities are 0.269 md and 0.66 md, respectively. Approximately 10 percent of the total producing wells have permeabilities of less than 0.1 md. The average formation flow capacity or permeability-thickness product in Pinehill Southeast field is about the same as it is in Percy Wheeler field.

Reservoir Performance and Production Characteristics

Absolute open flow potential in Pinehill Southeast field ranges from 315 to 2,722 Mcfd with an average of 1,462 Mcfd, which is small compared with 1,910 Mcfd in Percy Wheeler field, 4,552 Mcfd in Willow Springs field, 4,120 Mcfd in Lansing North field, and 7,700 Mcfd in Whelan field. In general, high absolute open flow potential in Pinehill Southeast is on the updip part of the productive area, and the distribution of absolute open flow potentials (fig. 19) is approximately parallel to the structural contours.

Decline-curve analysis shows an average decline rate for two wells of 0.748 cycle/yr; these wells may be in a period of transient flow because the duration of production has been short. Average maximum production rate of 11,700 Mcf/mo is low compared with other fields.

In Pinehill Southeast field, the average gas/condensate ratio decreased from 359 Mcf/bbl initially to 64 Mcf/bbl in the first six months of production, and then increased to 100 Mcf/bbl most recently. These changes in gas/condensate ratios during production can be explained qualitatively. As pressure declines because of production, the gas/condensate production ratio may remain constant until the dew-point pressure, which is below the initial reservoir pressure, is reached. Below dew-point pressure, hydrocarbon liquids condense out of the reservoir fluid, and the gas/condensate production ratio decreases. As pressure continues to decline, the liquid condensate may adhere to the walls of the pore spaces of the reservoir and become immobile. At that point, gas produced at the surface would have a higher gas/condensate production ratio.

The distribution of initial water/gas production ratio (fig. 20) shows high and low water production from the northern and southwestern parts of the field, respectively. The water/gas production ratio in the Pinehill Southeast field is relatively low, averaging 42 bbl/MMcf initially and increasing to 175 bbl/MMcf most recently. The reason for the increasing water/gas production ratio may be a change of gas saturation in the reservoir, wherein increased relative permeability to water favors water flow to the wellbore.

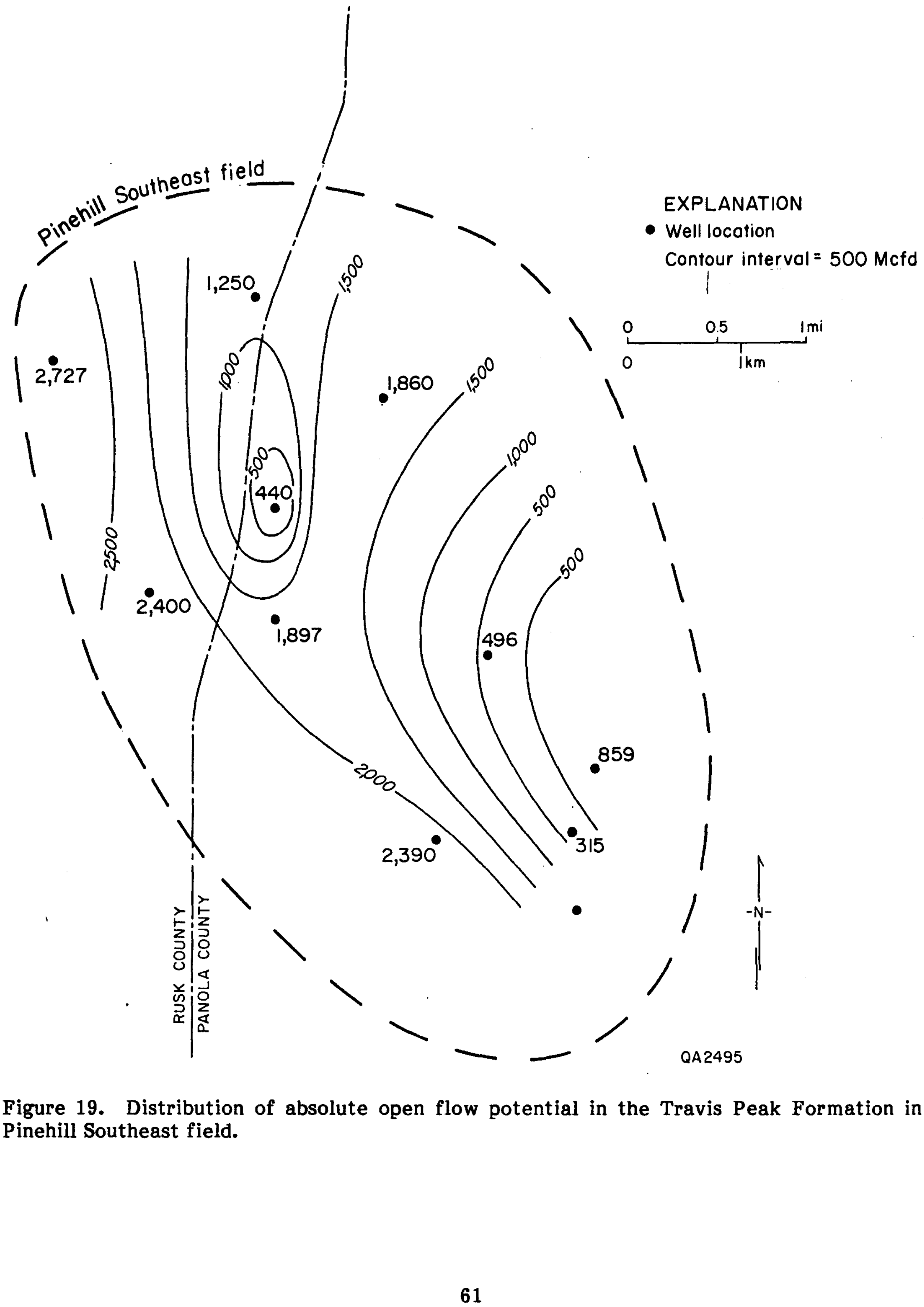

Figure 19. Distribution of absolute open flow potential in the Travis Peak Formation in Pinehill Southeast field.

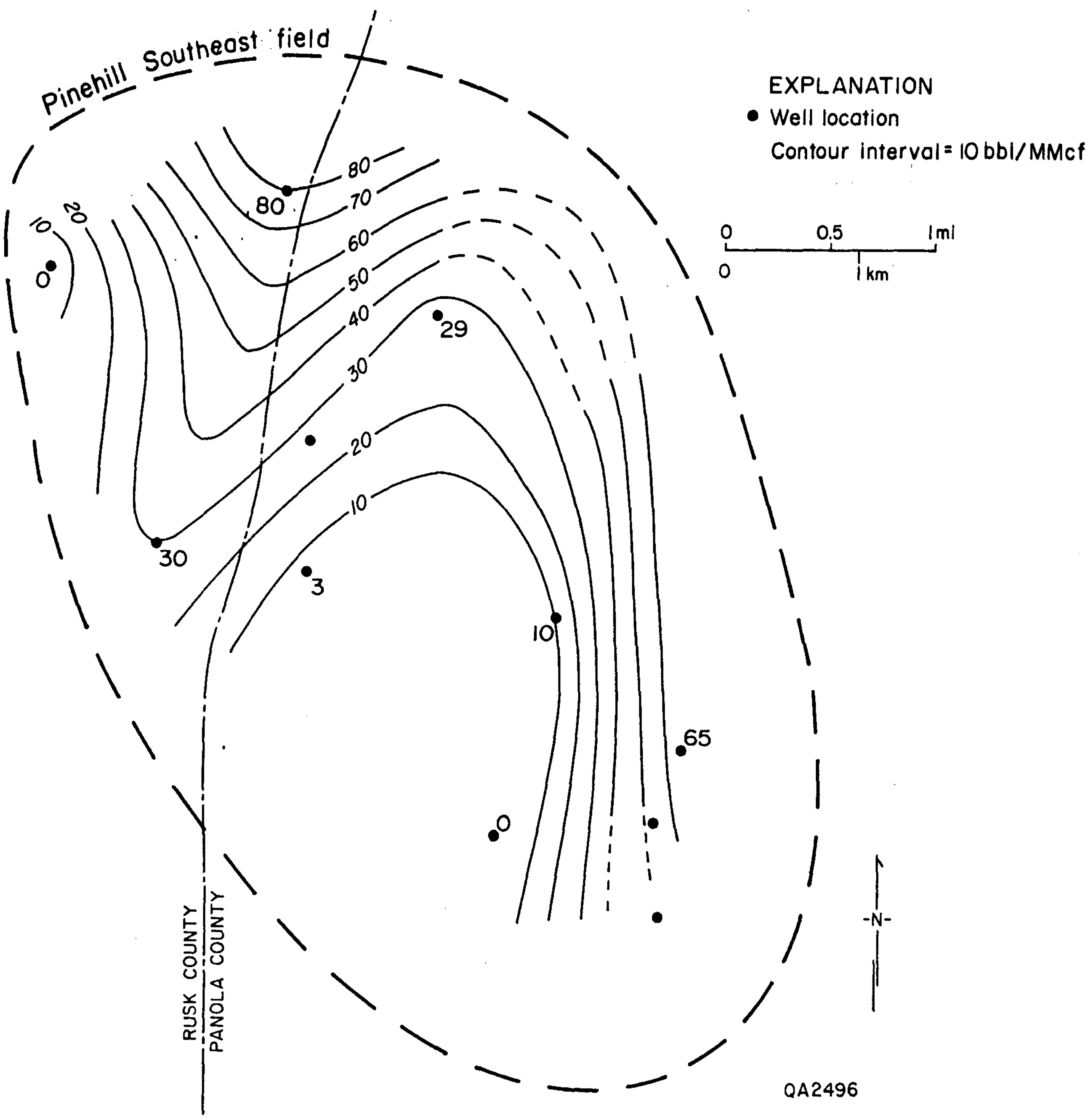

Figure 20. Distribution of initial water/gas production ratio in the Travis Peak Formation in Pinehill Southeast field.

Appleby North Field

Appleby North field (fig. 1) is a stratigraphic gas trap located in Nacogdoches County, Texas. The field was discovered on March 17, 1980, with the drilling of the Amoco Production Company Lois Foster Blount Gas Unit "A" No. 1 well. The perforated interval of the producing wells in this field ranges from 7,690 to 9,862 ft with an average midpoint of 8,872 ft. The average gross perforated thickness is 891 ft. During field development, through July 1983, total gas production was 2.965 Bcf from 12 wells with current (1985) calculated well density of 700 acres/well. The field size is approximately 8,355 acres. A summary of well completion data, reservoir properties, and production characteristics discussed below is given in table 10.

Reservoir Properties and Gas in Place

The average reservoir temperature and reservoir temperature gradient in the field are 254 °F and 20.7°F/1,000 ft, respectively. An average initial reservoir pressure at the midpoint of the perforated interval is 3,890 psi (ranging from 2,887 psi to 4,880 psi). An average pressure gradient in the field is 0.438 psi/ft, which is slightly below a hydrostatic pressure gradient, and is about the same as it is in Pinehill Southeast field.

The wells in Appleby North field are operated by AMOCO Production Company and by Cities Service Company. AMOCO has conducted multiple tests on its wells, that is, fracturing and testing in each subzone within the Travis Peak Formation. Therefore, pressure versus depth information is available for some wells and is plotted (fig. 21) from two adjacent wells drilled in this field. Data in the figure show that there are two non-communicating zones (or reservoirs) in the Travis Peak Formation. The pressures in the upper zone are higher than those in the lower zone. This is an indication of vertical and lateral discontinuity of discrete reservoirs within the Travis Peak Formation in Appleby North field.

Table 10. Summary of well completion data, reservoir properties, and production characteristics of Appleby North field.

(a)	**Well completion and field data (based on 12 wells)**	
	Perforated interval	7,690-9,862 ft
	Midpoint of perforated interval	8,872 ft
	Field size	8,355 acres
	Current well density	700 acres/well
(b)	**Reservoir properties**	
	Effective net-pay thickness	62 ft
	Porosity	10.8%
	Water saturation	28.2%
	Permeability-thickness product	6.2 md-ft (range: 0.156-16.6 md-ft)
	Permeability	0.015 md (arithmetic average) 0.0064 md (thickness-weighted average) 0.007 md (median)
	Reservoir temperature	254°F (gradient = 20.7 °F/1,000 ft)
	Initial formation pressure	3,890 psi (range: 2,887-4,880 psi) (gradient = 0.438 psi/ft)
	Gas in place	344 Bcf
(c)	**Production characteristics**	
	Cumulative gas production	3 Bcf
	Absolute open flow potential	1,606 Mcfd (range: 54-4,410 Mcfd)
	Maximum production rate	40,890 Mcf/mo
	Decline rate	1.285 cycle/yr (transient-flow period)
	Initial gas/condensate production ratio	121 Mcf/bbl
	Initial water/gas production ratio	197 bbl/MMcf
	Specific gravity of gas (air = 1)	0.61
	API gravity of condensate	50°

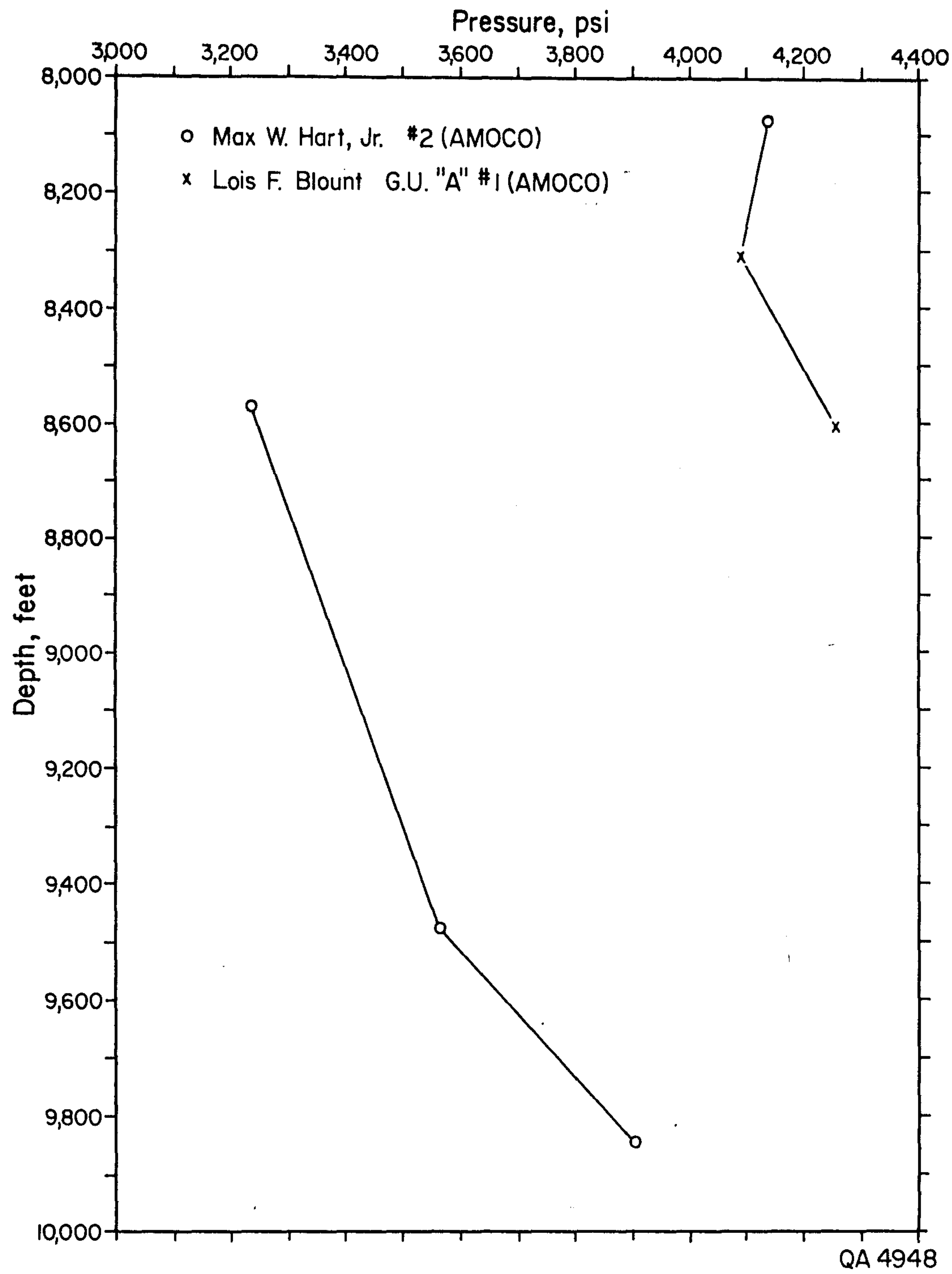

Figure 21. Pressure-depth plot for the data from two wells completed in the Travis Peak Formation in Appleby North field.

The average porosity and water saturation in the field are 7.6 percent and 51.3 percent, respectively, if net-pay thickness is used, and 10.8 percent and 28.2 percent, respectively, if effective net-pay thickness is used. Net pay and effective net pay are 28 percent and 14 percent of the gross perforated interval, respectively. The ratio of effective net pay and gross perforated interval in Appleby North field is the smallest among the fields included in this study. These results are based on logs available from two wells and agree reasonably well with the reservoir data sheet submitted for a Railroad Commission of Texas hearing by Cities Service Company. Cities Service reports that the average porosity and water saturation are 11 percent and 22 percent, respectively.

Based on the volumetric method, initial gas in place for the field is calculated to be approximately 344 Bcf if average reservoir properties are used. Even though the productive area in Appleby North field is almost the same as it is in Pinehill Southeast field, which is located to the north of Appleby North field, the calculated gas in place for Appleby North field is much more because of differences in effective net-pay thickness.

The average permeability-thickness product in the field is 6.2 md-ft and ranges from 0.156 to 16.6 md-ft. If the gross perforated interval is used as a formation thickness, the arithmetic average permeability of the field is calculated to be 0.015 md (with a range of 0.0011 to 0.085 md). Thickness-weighted average and median permeabilities are 0.006 md and 0.007 md, respectively. All calculated permeabilities are less than 0.1 md.

Reservoir Performance and Production Characteristics

Absolute open flow potential in the field ranges from 54 to 4,410 Mcfd with an average of 1,606 Mcfd. The distribution of this parameter (fig. 22) indicates that there are three local areas of high absolute open flow potential near the reservoir boundary, that is, in separate reservoir compartments. Local variations in the absolute open flow potential are approximately parallel to structural contours.

Decline-curve analysis shows an average decline rate of 1.285 cycle/yr; the field may still be in a period of transient flow because the field has been developed only since 1981.

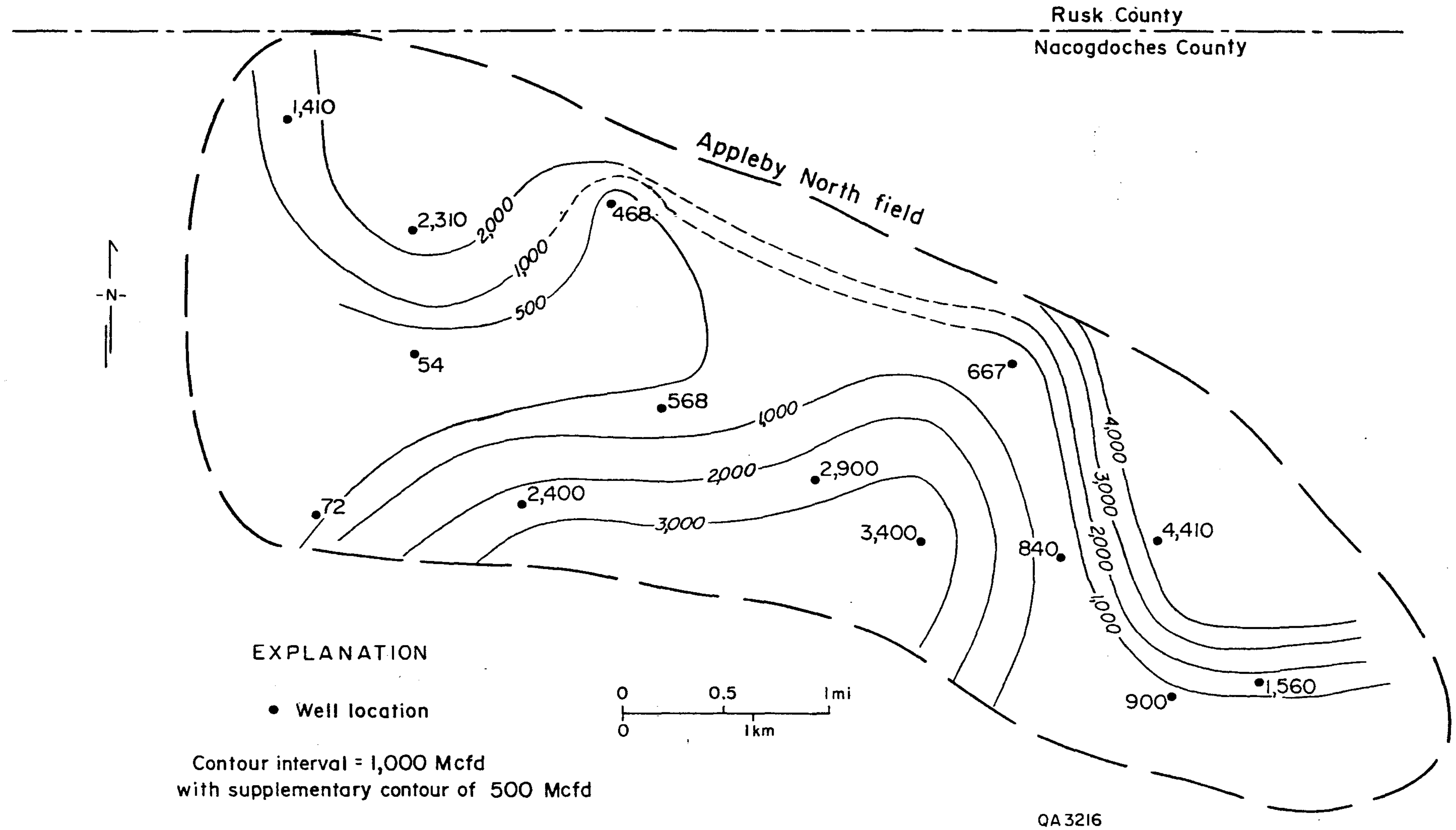

Figure 22. Distribution of absolute open flow potential in the Travis Peak Formation in Appleby North field.

The decline rate in this field is the highest among the fields selected in this study, suggesting that the economic productive life may be potentially shorter than other fields. The average maximum production rate of 40,890 Mcf/mo is low compared with other fields, except for Pinehill Southeast field.

The gas/condensate production ratio in Appleby North field decreased from 121 Mcf/bbl initially to 64 Mcf/bbl most recently. The specific produced gas gravity is 0.614. API gravity of produced condensate is 50 °, which is low compared with other fields.

The distribution of initial water/gas production ratio (fig. 23) shows an area of high water production located in the northern part of the field. However, it should be noted that part of the produced water was probably coming from water injected during well stimulation (R. F. West, personal communication, 1984). Based on the pressure behavior shown in p/z plots, the production mechanism is gas expansion.

DISCUSSION AND GAS RESOURCE DETERMINATION

Perforated Depth and Thickness

In the area of study within the East Texas Basin (fig. 1), the average depth of the producing interval (fig. 24) is generally parallel with regional structural configuration (fig. 25) in that the depths of perforated intervals are shallower toward the Sabine Uplift. The producing fields that have an anticlinal structure, such as Whelan, Lansing North, Willow Springs, Percy Wheeler, Danville, Henderson, and Henderson South, are located in the western, central, and northern parts of the study area. The fields that are predominantly stratigraphic traps, such as Appleby North and Pinehill Southeast, are located in the southern part of the study area.

Producing wells in the northern and southern parts of the study area had gross perforated thicknesses averaging more than 800 ft, whereas fields in the center of the area had intervals less than 30 ft thick (fig. 26). Generally, producing intervals in the Travis

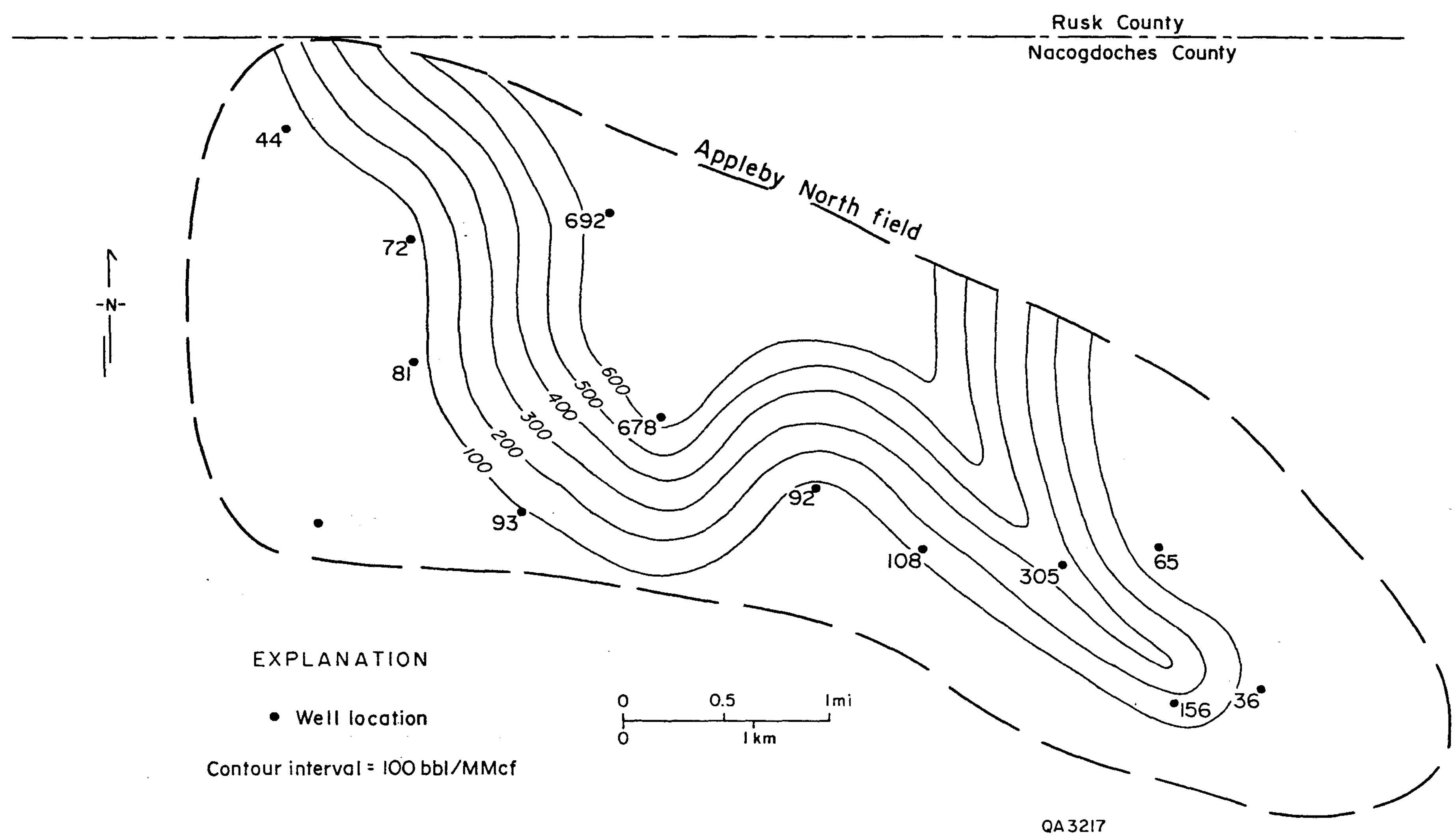

Figure 23. Distribution of initial water/gas production ratio in the Travis Peak Formation in Appleby North field.

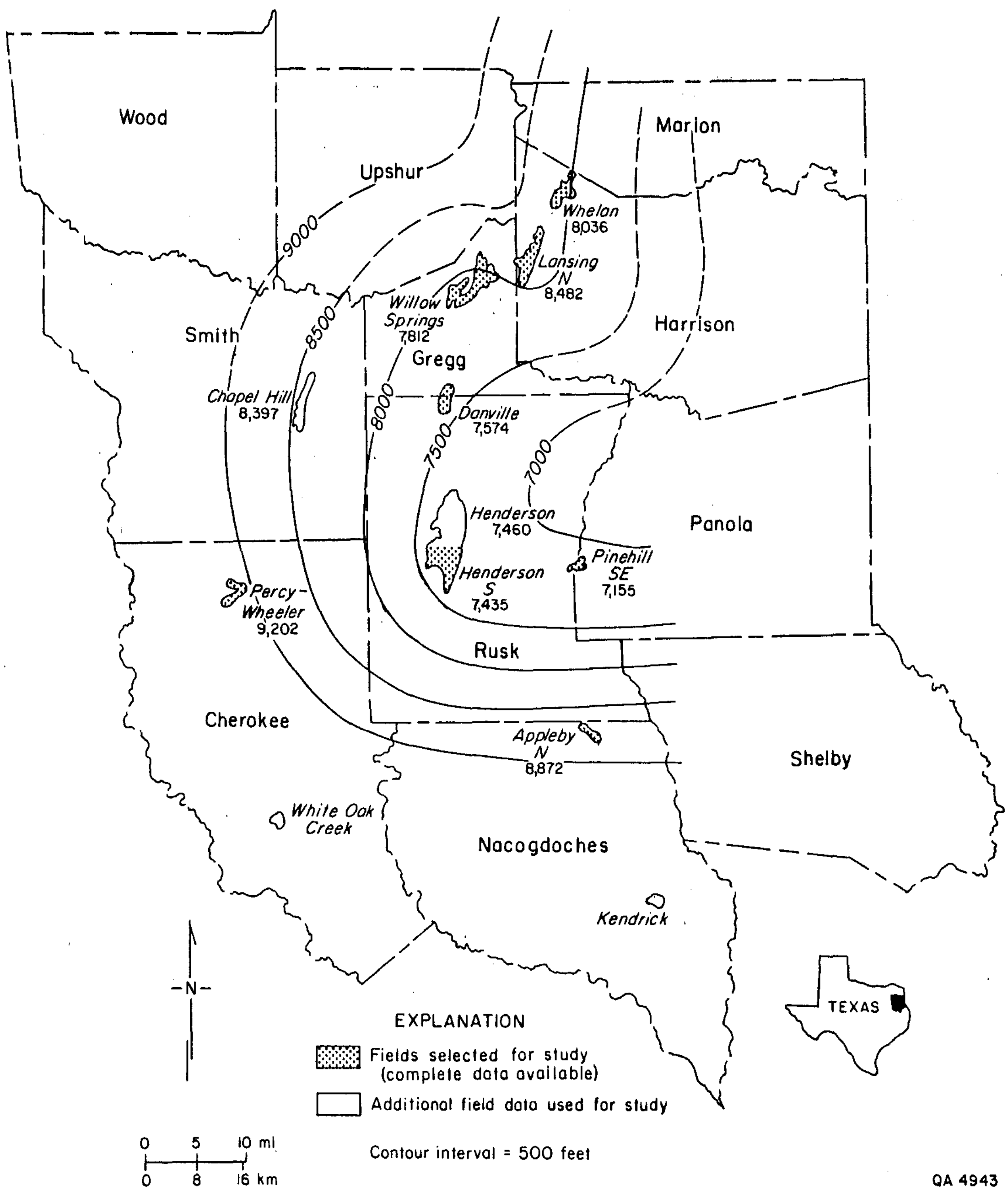

Figure 24. Distribution of field-average midpoint of perforated interval in the Travis Peak Formation, East Texas Basin.

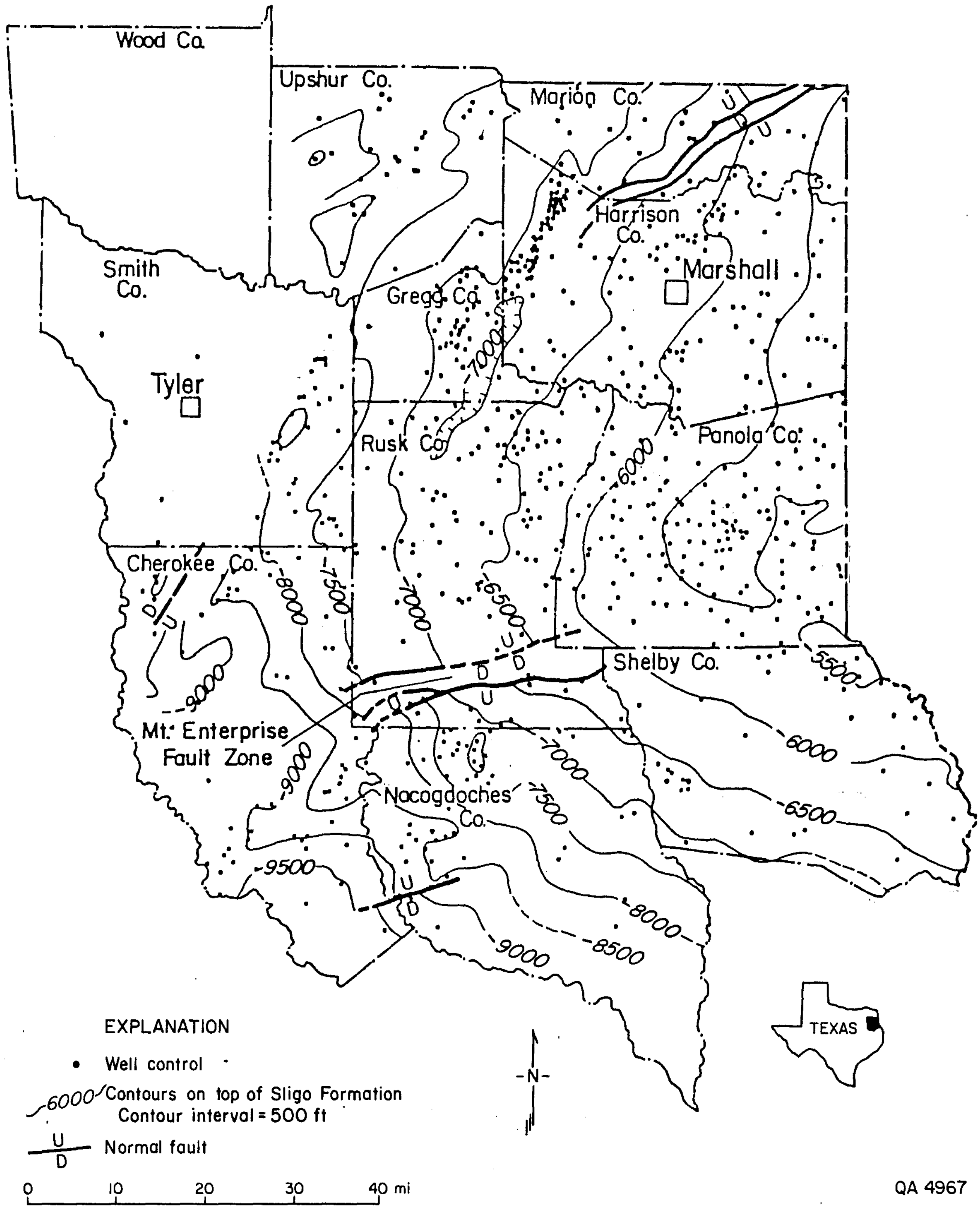

Figure 25. Generalized structure-contour map on the top of the Sligo Formation (after Saucier, 1985).

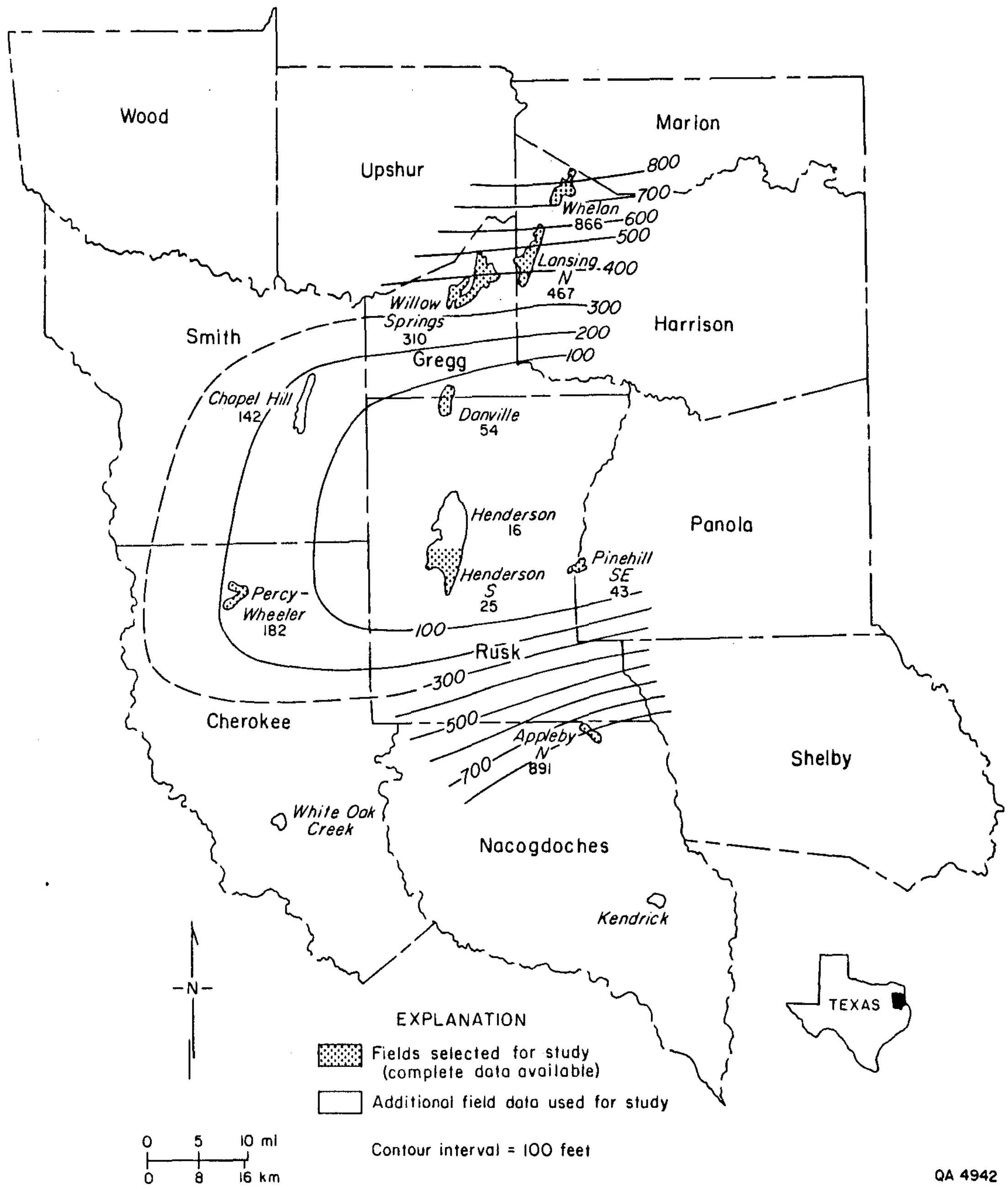

Figure 26. Distribution of field-average perforated thickness in the Travis Peak Formation, East Texas Basin.

Peak Formation in the northern part of the study area have been differentiated into producing reservoirs by the Railroad Commission of Texas (fig. 7). These reservoirs include the Travis Peak and Travis Peak prorated reservoirs in Whelan field, the Travis Peak and lower Travis Peak in Lansing North field, and the upper Travis Peak and Travis Peak in Henderson South field, which are all located in the the northern and central parts of the study area. In the southern part of the study area, even though some wells are completed in several different reservoirs and one well (in Appleby North field) has produced from two different reservoirs, only one reservoir was listed in well completion files of the Railroad Commission of Texas. This is possibly because reservoir discontinuities make it difficult to trace a single discrete reservoir throughout the whole field. Therefore, the Travis Peak Formation may consist of several distinct productive reservoir intervals even in existing fields, and some of these intervals would certainly hold unrealized gas resources. The prospect of incentive pricing in the period 1979-1982 under the Natural Gas Policy Act certainly led to the extension of Travis Peak exploration into less well known trends and into lower permeability reservoir rock, thereby adding to the variability in the total group of Travis Peak reservoirs.

Permeability

Average permeability-thickness product increases from 6.2 md-ft in the southern part of the study area to 80.6 md-ft in the northern part within the Travis Peak of the eastern East Texas Basin. Using gross perforated interval as the thickness value in permeability calculations, field-average permeabilities (arithmetic average, thickness-weighted average, and median) were calculated from 176 wells (table 1). For the study area as a whole, both thickness-weighted and median permeabilities are less than 0.1 md, and arithmetic average permeability is greater than 0.1 md (table 11). The median permeability in the study area is 0.074 md, which is slightly higher than the 0.04 md obtained for the entire East Texas area by Core Laboratories, Inc. (1981). Although 70 percent of the wells used in the

Table 11. Average permeabilities of selected fields in the Travis Peak Formation, East Texas Basin.*

Field Name/County	Permeability, md Arithmetic average	Thickness-weighted average	Median	Number of wells used
Whelan/Harrison	0.153	0.092	0.047	42
Lansing North/Harrison	0.156	0.114	0.027	16
Willow Springs/Gregg	0.148	0.106	0.250	62
Percy Wheeler/Cherokee	0.076	0.052	0.046	14
Pinehill Southeast/ Rusk-Panola	1.302	0.269	0.660	10
Appleby North/ Nacogdoches	0.015	0.006	0.007	13
Danville/Rusk-Gregg	0.915	1.041	1.000	8
Henderson South/Rusk	6.343	2.008	3.200	11
†Swanson Landing/Harrison	0.082	0.082	0.082	1
†Kendrick/Nacogdoches	0.027	0.027	0.027	1
†Douglas West/Nacogdoches	0.001	0.001	0.001	2
†Trawick/Nacogdoches	0.313	0.003	0.313	2
†Sym-Jac West/Cherokee	0.073	0.002	0.006	3
†White Oak Creek/Cherokee	0.017	0.001	0.017	2
†Southern Pine/Cherokee	0.033	0.025	0.005	3
†Rayburn Lake/Angelina	0.010	0.010	0.010	1
overall	0.578	0.092	0.088	191

* Actual in situ permeabilities are less because data are derived predominantly from hydraulically fractured wells.

† Data obtained from Railroad Commission of Texas hearing files.

permeability determinations were hydraulically fractured before back-pressure testing, no data were available on fracture length, and estimates of permeability were made assuming no fractures existed. Resulting calculated permeability values are therefore expected to be toward the upper limit of actual values. The median permeability of 0.074 md for the entire East Texas study area shows statistically that the expected value of permeability in a well drilled to and completed in Travis Peak Formation in the study area is less than 0.1 md.

Even though an arithmetic average permeability is also calculated for comparison, a thickness-weighted average permeability is a better mean value to represent permeability in a field or in an area because the arithmetic average gives a mean value that is strongly influenced by a few high values. The thickness-weighted average permeability in all the producing fields analyzed is 0.084 md (table 11). Thickness-weighted average permeability (fig. 27) increases from 0.0064 md in Appleby North field (southern part of the study area) to about 2 md in Henderson South field (central part of the study area) and decreases to 0.092 md in Whelan field (northern part of the study area) and to 0.052 md in Percy Wheeler field (western part of the study area). The trend of this permeability distribution suggests that operators have completed wells in the most permeable parts of the Travis Peak in central Rusk County, Texas (fig. 27). The data for Henderson South field are influenced by thin, high-permeability sandstone stringers that occur in the uppermost part of the Travis Peak.

Porosity, Water Saturation, and Effective Thickness in Perforated Interval

Within the gross perforated interval of wells studied--excluding zones having clay content of more than 50 percent, porosity of less than 7 percent, and water saturation greater than 70 percent--the average porosity in the study area ranges from 8 percent to 11 percent, with the exception of relatively high porosity (about 14 percent) in Henderson South field (fig. 28). The percentage of net-pay thickness in the gross perforated interval

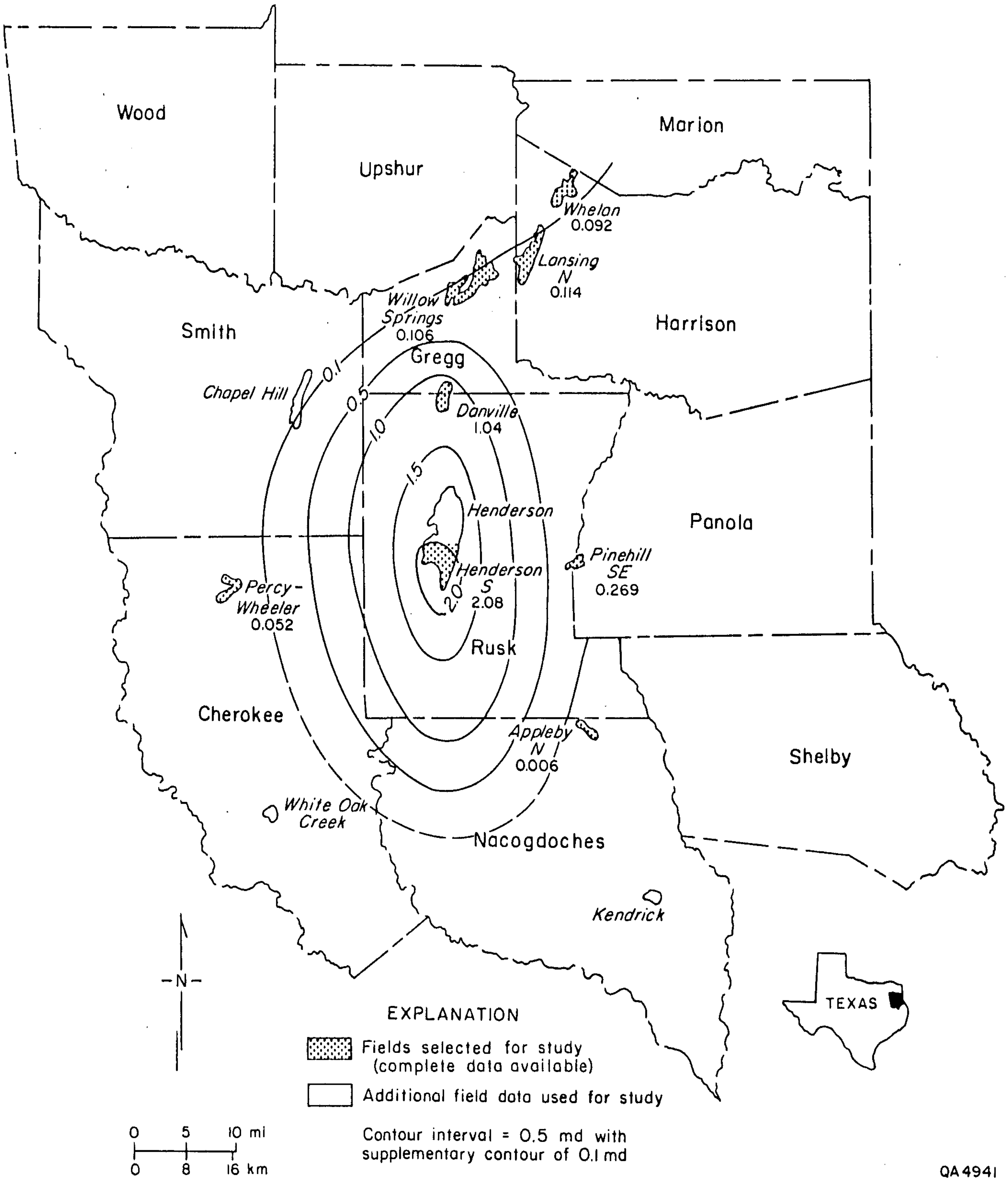

Figure 27. Distribution of field-average permeability (thickness-weighted) in the Travis Peak Formation, East Texas Basin.

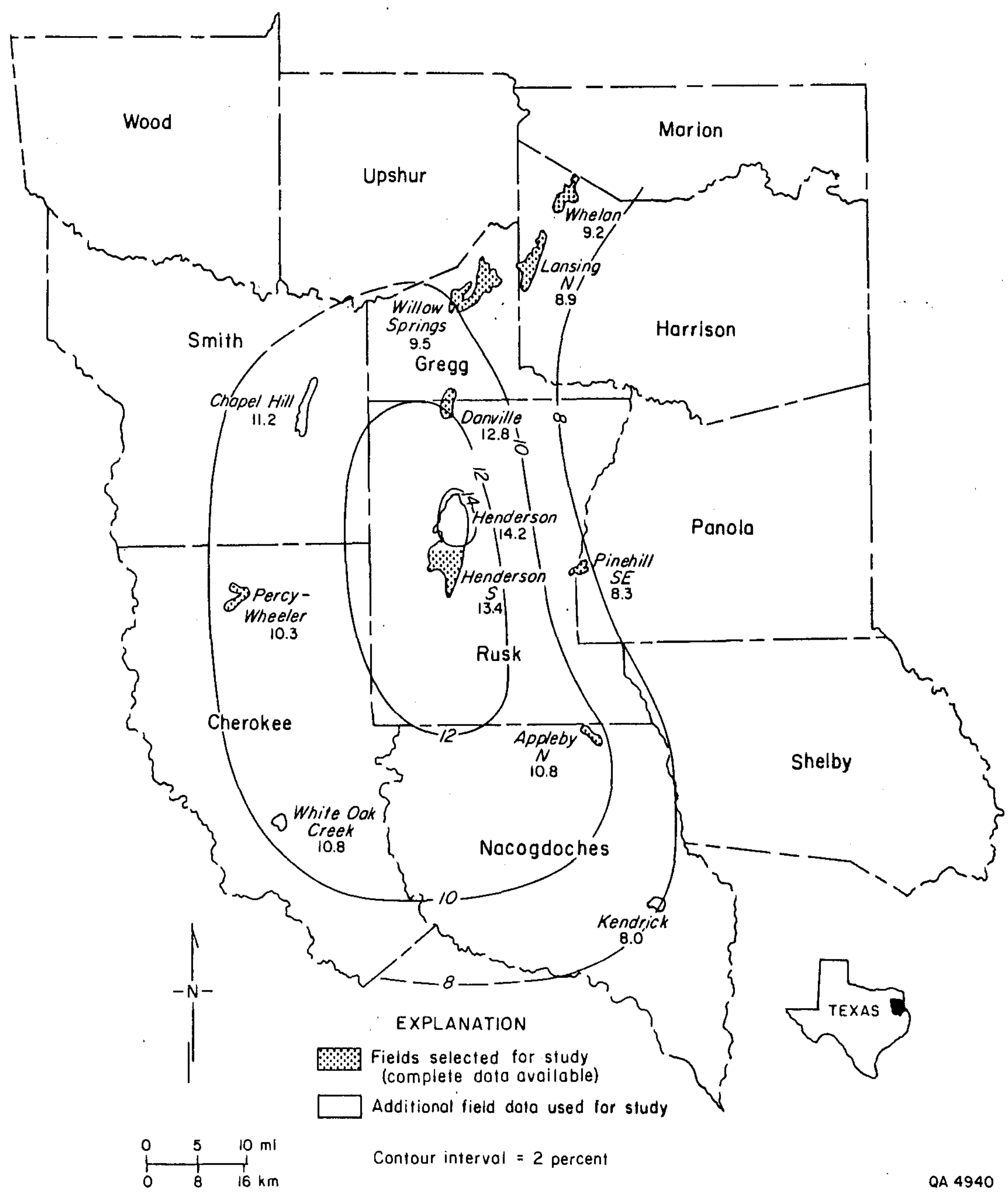

Figure 28. Distribution of field-average porosity in the Travis Peak Formation, East Texas Basin.

decreases from 55 percent in the northern part of the study area to 14 percent in the south. Effective net-pay thicknesses obtained in this study are calculated within the gross perforated intervals because no detailed, correlatable geologic subunits of the Travis Peak can be defined in multiple fields. It will be instructive to compare effective net-pay thickness with different genetic depositional units in the Travis Peak Formation. Within parts of Chapel Hill field, specific sandstone types have been identified that have different sequences of sedimentary structures, reservoir quality, and distributions of net sandstone thickness (Finley and others, 1984). This effort is now being extended to the entire field with additional efforts to relate reservoir quality to origin of the depositional unit.

Field-average water saturation within producing intervals in the study area varies from 24 percent to 43 percent, and increases from southwest to northeast (fig. 29); therefore, productive reservoirs in regionally updip positions toward the northeast margin of the East Texas Basin have high water saturations.

Production Characteristics

The older Travis Peak producing fields that have high absolute open flow potential, such as Whelan, Willow Springs, Danville, and Henderson fields, are located in the central and the northern segments of the study area (fig. 30); in most of these fields development was started before 1970. These fields are primarily developed over well-defined, salt-cored, positive structures. Sandstones within these fields have low, but not excessively low, permeability, and were developed and economically produced prior to tight gas pricing incentives. New fields with relatively low total production, such as Pinehill Southeast and Appleby North, are in the southern area; most of these fields were discovered after the late 1970's. Appleby North field in particular, a more risky stratigraphic-structural trap, was developed with the potential for higher tight gas prices, an incentive that largely disappeared in the period 1983 through the present (1985). A weak water drive in addition to gas expansion is the production mechanism for the fields in the northern part of study

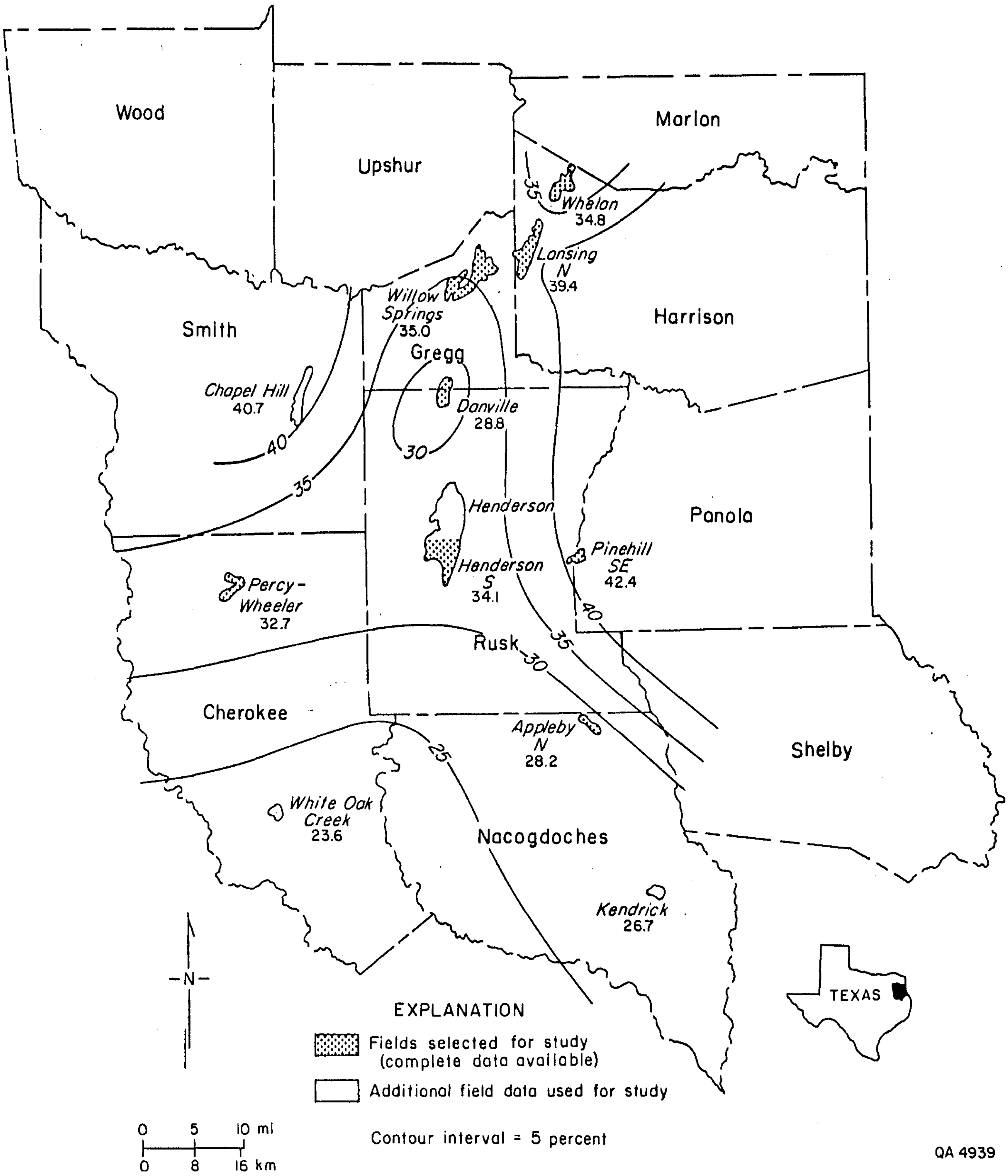

Figure 29. Distribution of field-average water saturation in the Travis Peak Formation, East Texas Basin.

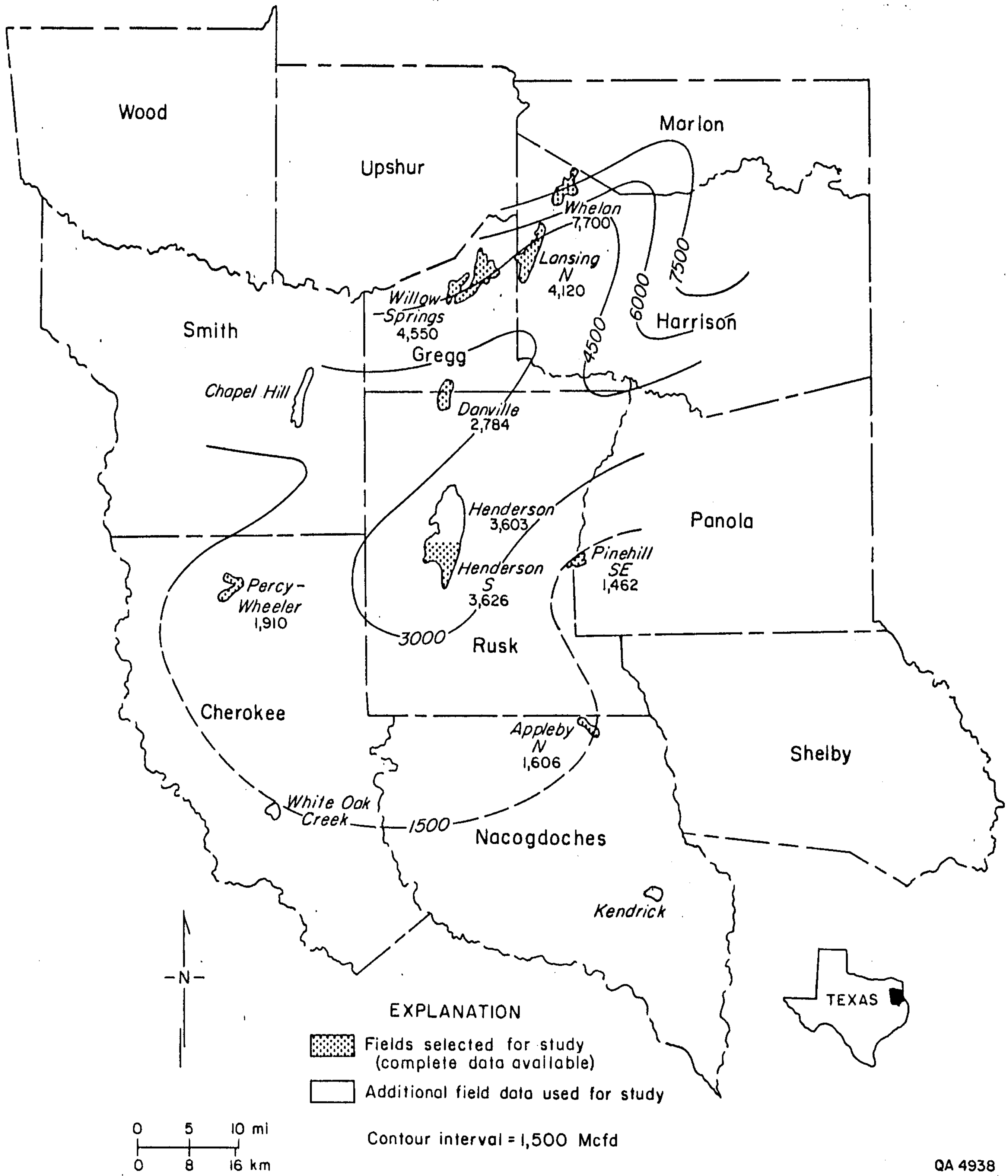

Figure 30. Distribution of field-average open-flow potential in the Travis Peak Formation, East Texas Basin.

area. Maximum production rates (fig. 31) decrease from north (82,300 Mcf/mo in Whelan field) to south (11,700 Mcf/mo in Pinehill Southeast field). A relatively high maximum production rate in Appleby North field compared with Pinehill Southeast field (fig. 31) may be attributed to the success of well stimulation in Appleby North field. Production decline rate (fig. 32) was smaller in the northern areas than in the southern areas and was low in the central part of the study area. Therefore, the potential economically productive life of wells within structural plays in the north appears to be somewhat longer than within stratigraphic-structural plays in the south. However, additional production experience is necessary before it can be determined if stratigraphic traps, or other types of traps in combination with stratigraphic trapping, will yield sustained but low-level production, as has occurred in other tight gas provinces.

Fields in the central part of the study area, such as Danville, Henderson, and Henderson South, produce not only gas but also oil from the Travis Peak Formation. The Chapel Hill field in the northwestern part of the study area (fig. 1) is an oil-producing field that has only one or two wells classified as gas wells. Even though Whelan, Lansing North, and Willow Springs fields in the north produce predominantly gas, several wells in each of these fields also produce oil. Fields located in the southern part of the study area, such as Percy Wheeler, Appleby North, and Pinehill Southeast, produce only gas and condensate. Whole-oil gas chromatography, reservoir kerogen analysis, and other geochemical techniques are currently being applied in Chapel Hill field to evaluate the relationship between gas and oil distribution in the Travis Peak Formation.

Gas/condensate production ratio in the fields studied changed during the production period. Overall, initial gas/condensate production ratio increased from the northwestern to the southeastern part of the study area. The field-average specific gravity of produced gas ranges from 0.62 to 0.66 (air = 1), and the API gravity of condensate ranges from 50° to 62°. The API gravity of oil at Chapel Hill is 45°, but high-gravity hydrocarbon liquids

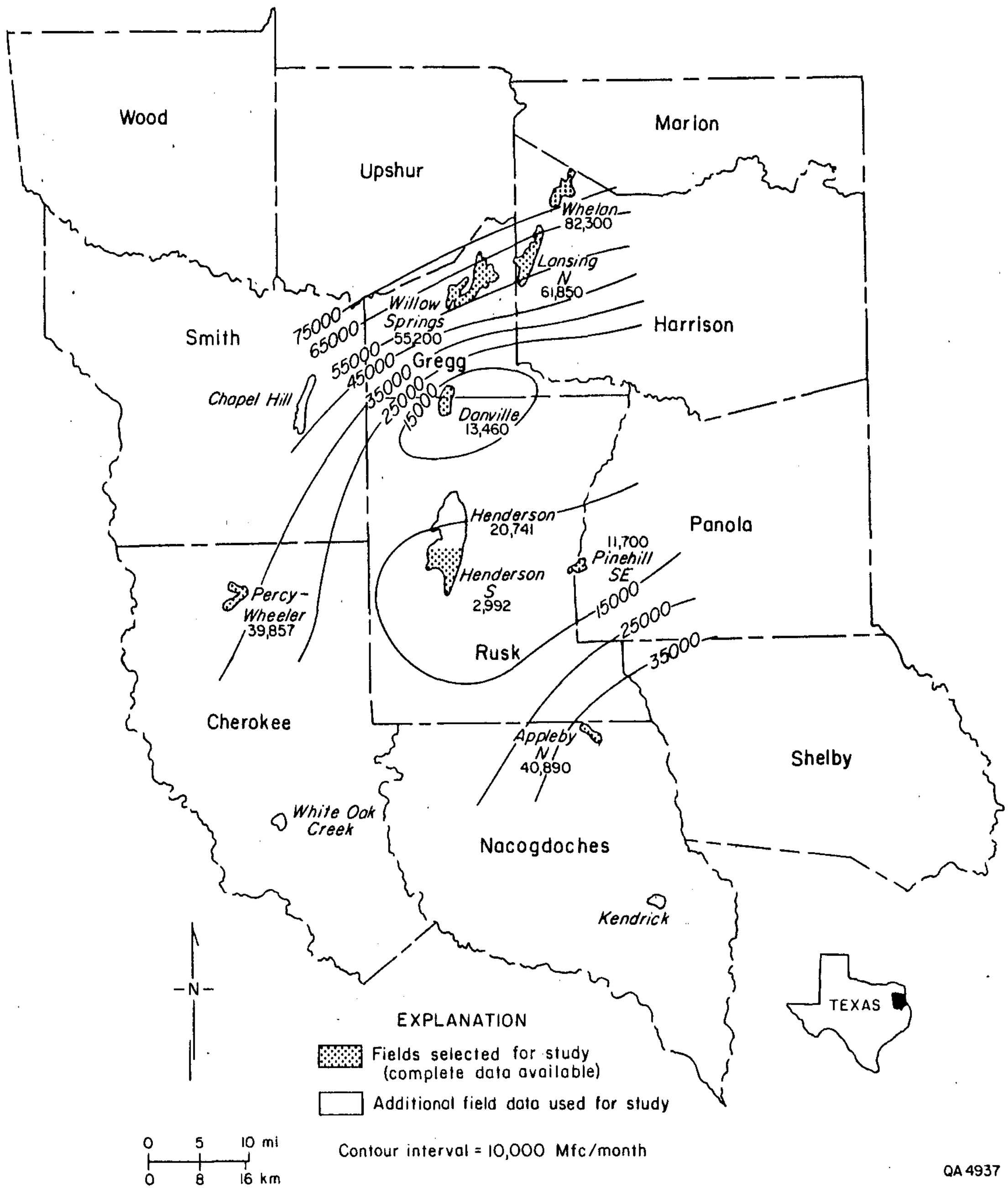

Figure 31. Distribution of field-average maximum production rate in the Travis Peak Formation, East Texas Basin.

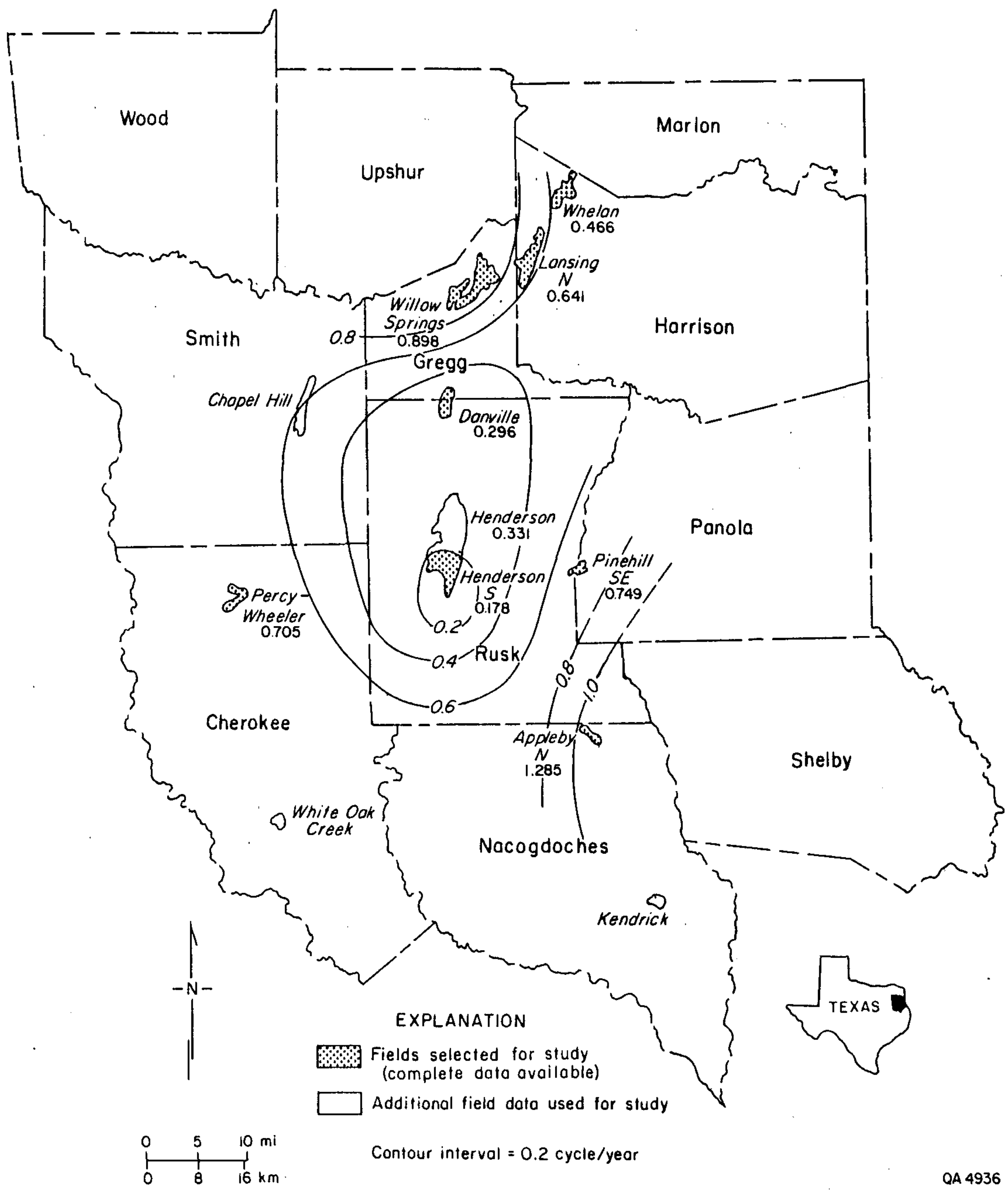

Figure 32. Distribution of field-average decline rate (in early production period) in the Travis Peak Formation, East Texas Basin.

(58° API) are present and the controls on distribution of these different liquids is not well understood.

Formation Pressure

The field with the highest reservoir pressure and pressure gradient, which may indicate proximity to the source of fluid migration, is Percy Wheeler (fig. 33). The fields with the lowest reservoir pressure and a pressure gradient below normal hydrostatic pressure, which may be caused by updip (west to east) gas flow (Gies, 1982), are Whelan and Lansing North. Regionally, reservoir pressure is higher to the southwest than to the northeast (fig. 33). This pressure distribution suggests that the direction of fluid flow was from southwest to northeast in the study area.

Reservoir compartmentalization in the fields studied was indicated by high and irregular variations in reservoir pressure and productivity. This may be caused either by internal reservoir discontinuities or by completion of producing wells in different geologic units within the Travis Peak Formation. Studies are currently underway at Chapel Hill field to define the interconnectedness of producing sandstones and sandstone packages.

Gas Resource

Based on the reservoir parameters obtained from the field studies and data acquired from hearing files of the Railroad Commission of Texas, the volumetric method (National Petroleum Council, 1980) was used to estimate the gas resource of the Travis Peak Formation in Texas but not in North Louisiana. In gas resource estimates, cumulative frequency versus permeability (fig. 34) was first plotted to show the distribution of in situ gas permeability in the area of data availability. In the productive area, permeabilities as high as 0.3 md are not likely (fig. 34); only 7.5 percent of the area attains this value. The minimum permeability is 0.0003 md, representing approximately 5.0 percent of data collected, and the median permeability, with 50 percent probability, is 0.012 md.

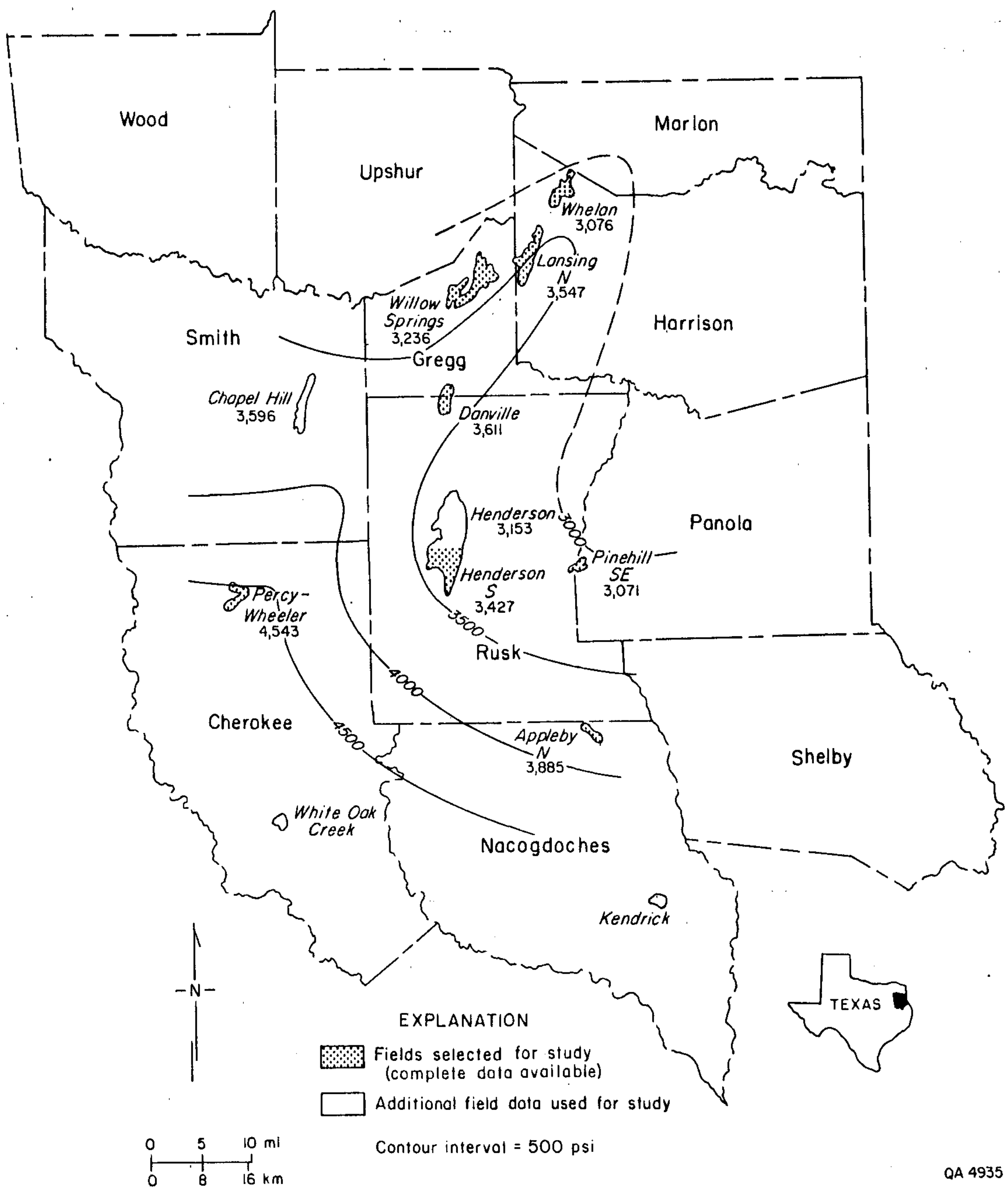

Figure 33. Distribution of field-average formation pressure in the Travis Peak Formation, East Texas Basin.

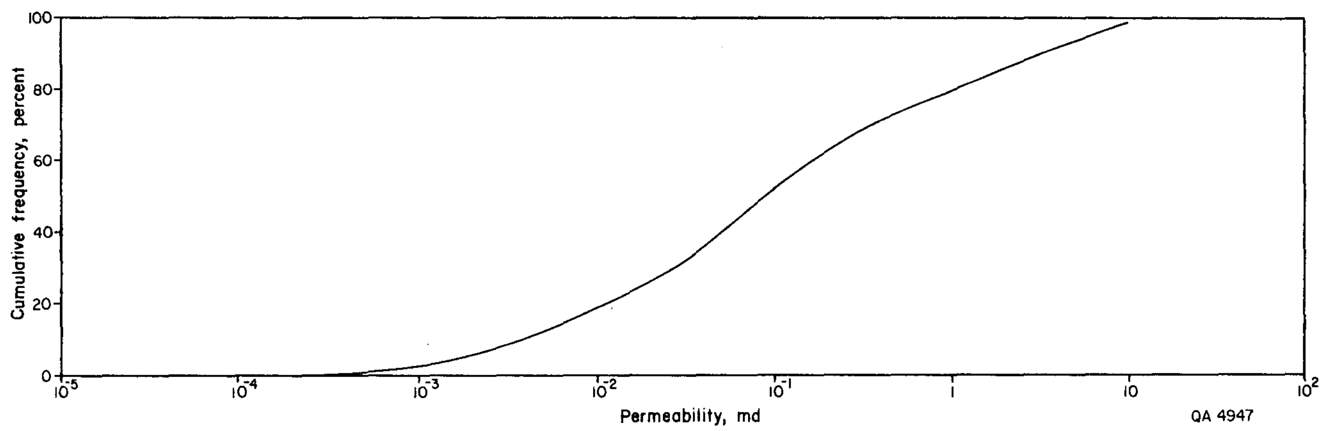

Figure 34. Cumulative frequency versus in situ permeability in the Travis Peak Formation, East Texas Basin.

No strong correlation exists between permeability and porosity, but for the purposes of resource estimation, permeability versus porosity values from available information were displayed on a semi-logarithmic plot. A line through these data allows porosity and permeability values to be generally related (fig. 35) and used in the resource estimation. A similar plot is used to relate net pay and permeability (fig. 36). In addition, a line drawn to relate gas permeability and net pay is based on the assumption that when a well encounters a high permeability zone, the net pay tends to be thin, whereas low-permeability zones will tend to be thicker. This relationship is not strong enough to warrant quantitative treatment, but it is commonly used in resource estimation.

A plot of area versus permeability (fig. 37) shows the distribution of in situ gas permeability in the Travis Peak Formation. When the total productive area is known, each productive area with a given permeability can be estimated by using figure 37. Values obtained from these plots were used to compute a resource estimate for the Travis Peak (table 12). It is assumed that data collected from hearing files of the Railroad Commission of Texas and results obtained from this field study are generally representative of the engineering and geologic characteristics of the whole basin. Using the assumption that 15 percent of the area of a tight gas basin may ultimately be productive (National Petroleum Council, 1980a), the estimated gas in place and maximum recoverable gas in place in the Travis Peak Formation in the East Texas Basin are 24.6 Tcf and 17.3 Tcf, respectively (table 12). In addition to the assumption that 15 percent of total basin area will be productive, gas resource estimates were also made for productive areas of 5 percent, 12 percent, and 20 percent of the total basin (table 13). These estimates exclude the gas reservoirs in the Travis Peak Formation having permeability greater than 0.3 md, which represent about 31 percent of the productive area (fig. 34). Thus, the actual productive area used in the estimates are 3.45 percent, 8.28 percent, 10.35 percent, and 13.8 percent of the total area in the East Texas Basin (table 13).

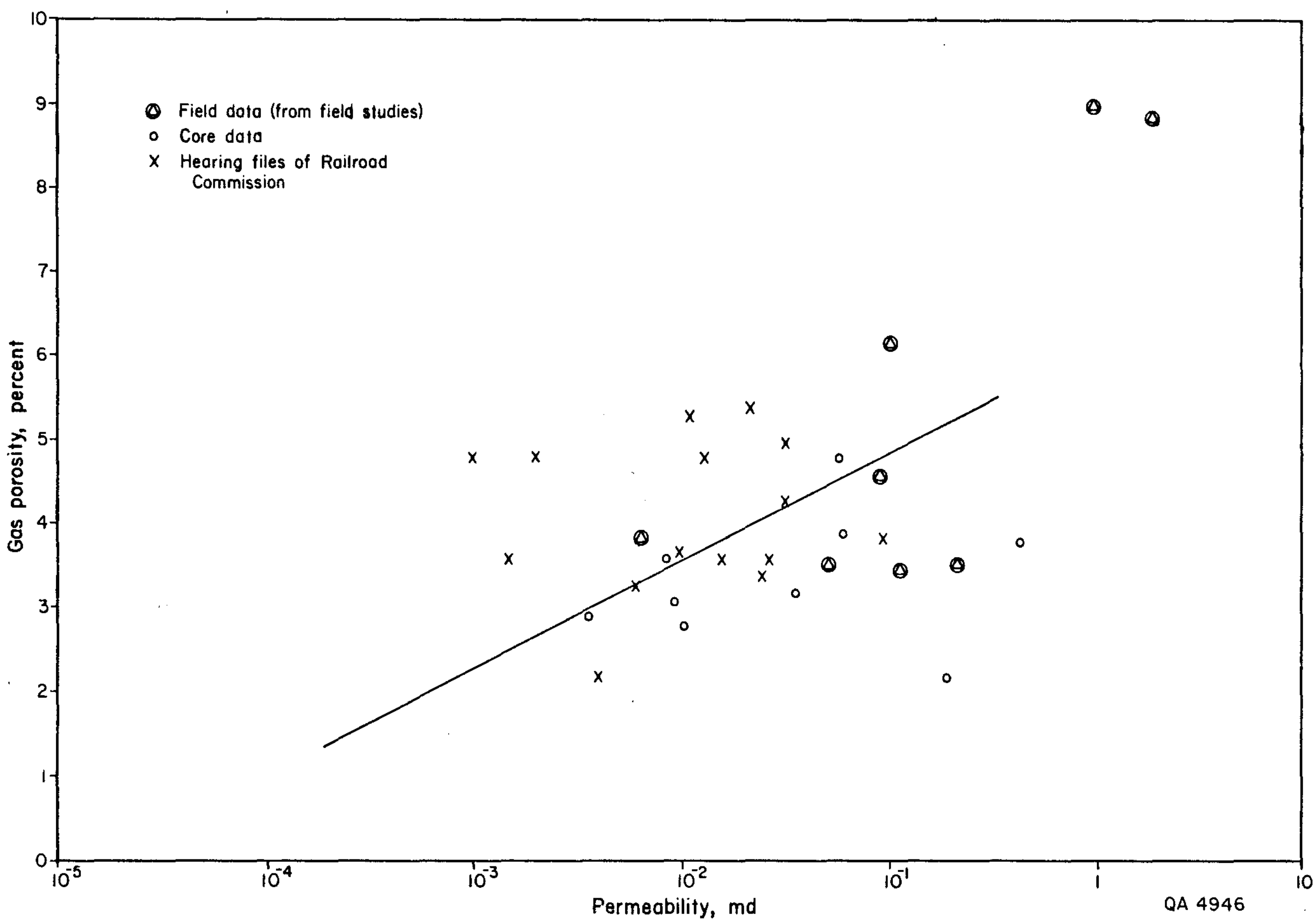

Figure 35. Gas porosity versus in situ permeability in the Travis Peak Formation, East Texas Basin.

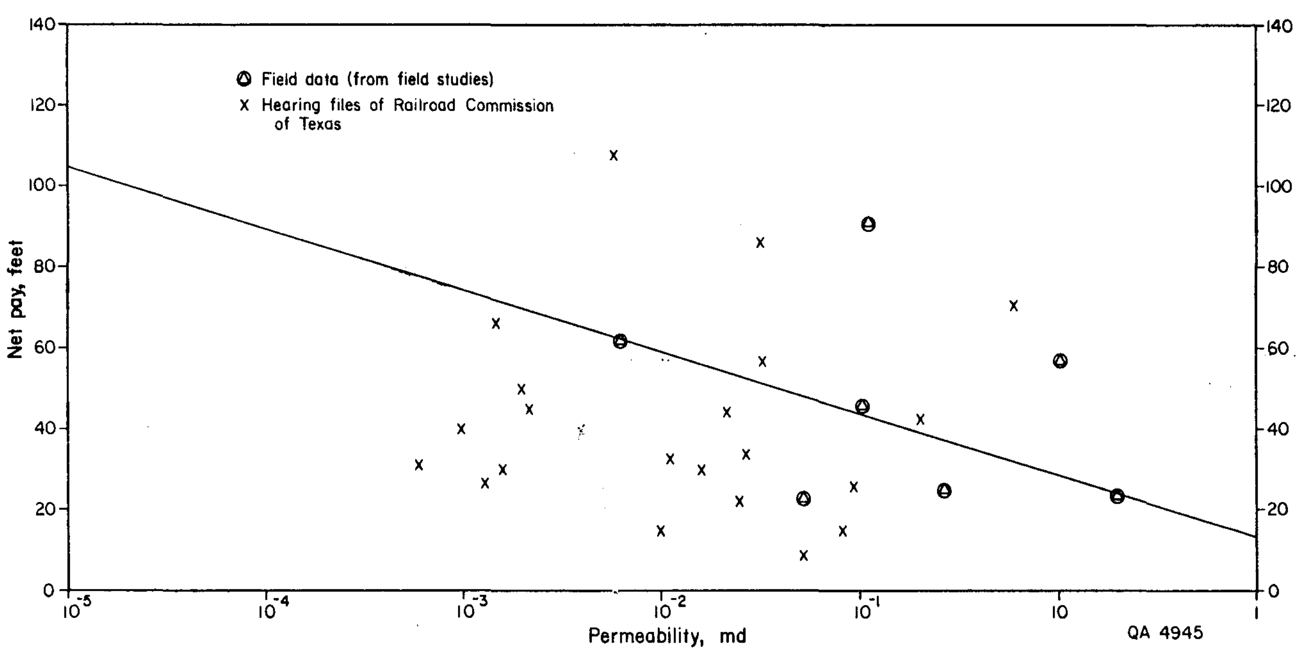

Figure 36. Net pay versus in situ permeability in the Travis Peak Formation, East Texas Basin.

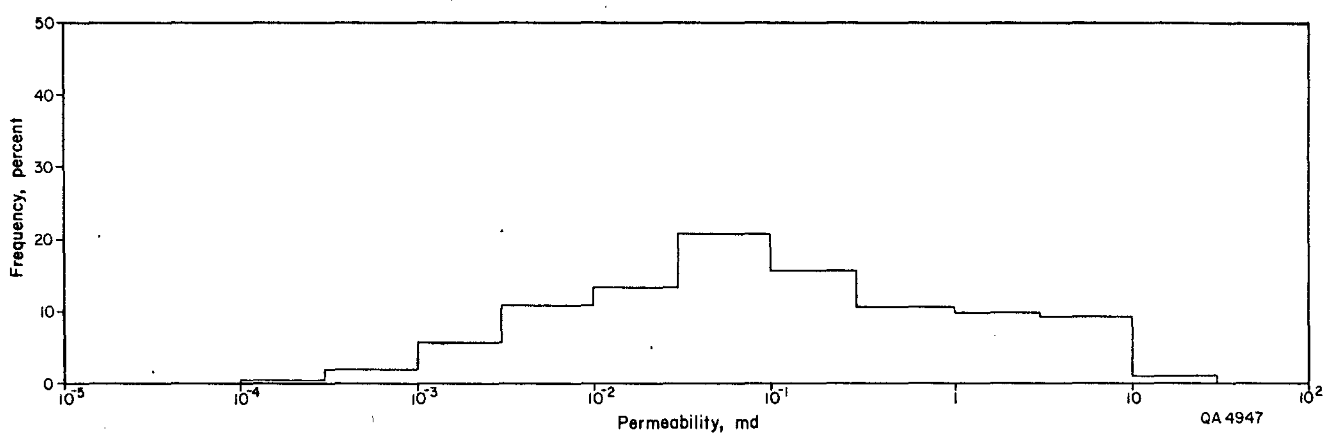

Figure 37. Distribution of in situ permeability in the Travis Peak Formation, East Texas Basin.

Table 12. Calculation of recoverable gas in place for the Travis Peak Formation in East Texas Basin (assuming 15% of total area to be productive).

Permeability (md)	Net pay (ft)	Gas porosity (fraction)	Area (mi^2)	Gas in place (Tcf)	Technical recoverable gas in place (Tcf)	Maximum recoverable gas in place (Tcf)
0.3000	36.	0.055	425.	5.27	4.74	4.50
0.1000	44.	0.048	566.	7.49	6.73	6.06
0.0300	52.	0.042	368.	5.03	4.53	3.85
0.0100	59.	0.036	298.	3.96	3.57	2.85
0.0030	67.	0.029	157.	1.91	1.72	1.29
0.0010	74.	0.023	57.	0.61	0.55	0.38
0.0003	82.	0.016	14.	0.12	0.10	0.07
			Total	24.39	Total	19.00

Initial reservoir pressure = 4,357 psi

Formation temperature = 241°F

Table 13. Gas resource estimates for the Travis Peak Formation in the East Texas Basin (assuming 5%, 12%, 15%, and 20% of total area to be productive).

Percent of total area to be productive	Percent of total area to be tight gas productive	Gas in Place (Tcf)	Maximum recoverable gas in place (Tcf)
5	3.45	8.12	6.33
12	8.28	19.52	15.21
15	10.35	24.39	19.00
20	13.80	32.52	25.34

CONCLUSIONS

The Travis Peak Formation contains between 19.52 Tcf and 32.52 Tcf of gas in place, assuming that total tight gas productive areas are 8.28 percent and 13.80 percent, respectively, in the entire East Texas Basin. The corresponding maximum recoverable gas-in-place values are 15.21 Tcf and 25.34 Tcf.

The Travis Peak is characterized by low permeability, well-developed net-pay thickness, and sandstone packages with a moderate degree of interconnection. The formation in the study area contains several discrete productive reservoirs, or zones, but some reservoirs in the existing fields no doubt remain to be developed and produced. Thickness-weighted average permeabilities and median permeabilities, both of which represent the upper limits of in situ permeability, are less than 0.1 md. The field-average porosity ranges from 8 percent to 11 percent, with the exception of one field in the central part of the study area that measures 14 percent. Water saturation varies from 24 percent to 43 percent in the productive intervals.

Gas fields in the northern and central parts of the study area are characterized by relatively high productivity, in terms of absolute open flow potential, and have weak to moderate water drives. This contrasts with low productivity and only a gas-expansion production mechanism toward the southeast and southwest. With the exception of Appleby North field, maximum production rate decreases from north to south. Production decline rate is smaller in the northern area than in the southern area and is lowest in the central part of the study area. Field-average specific gravity of produced gas ranges from 0.62 to 0.66, and API gravity of produced condensate ranges from 50° to 60°. Formation temperature ranges from 200°F to 245°F; temperature gradient ranges from 17°F/1,000 ft to 21°F/1,000 ft.

The pressure distribution, ranging from 4,540 psi (with a pressure gradient of 0.494 psi/ft) in the southeast to 3,076 psi (with a pressure gradient of 0.384 psi/ft) in the northeast, suggests that the direction of potential fluid flow is from southwest to northeast.

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Figure Captions

Figure 1. Selected fields in the Travis Peak Formation, East Texas Basin.

Figure 2. Comparison between core-measured porosity and log-calculated porosity for the wells completed in the Travis Peak Formation, East Texas Basin.

Figure 3. Comparison between core-measured water saturation and log-calculated water saturation for a well completed in the Travis Peak Formation, East Texas Basin.

Figure 4. Plot of p/z versus cumulative gas production to estimate initial gas in place.

Figure 5. Plot of test flow rate versus pressure-square difference between reservoir and flowing wellbore pressure to estimate absolute open flow potential.

Figure 6. Exponential (or constant percentage) decline curve.

Figure 7. Gas productive reservoirs in the Travis Peak Formation designated by the Railroad Commission of Texas.

Figure 8. Distribution of absolute open flow potential in Whelan field.

Figure 9. A typical decline curve in Whelan field.

Figure 10. Distribution of initial water/gas production ratio in the Travis Peak Formation in Whelan field.

Figure 11. Distribution of absolute open flow potential in the Travis Peak Formation in Lansing North field.

Figure 12. Distribution of initial water/gas production ratio in the Travis Peak Formation in Lansing North field.

Figure 13. Distribution of absolute open flow potential in the Travis Peak Formation in Willow Springs field.

Figure 14. Distribution of initial water/gas production ratio in the Travis Peak Formation in Willow Springs field.

Figure 15. Distribution of initial formation pressure in the Travis Peak Formation in Danville field.

Figure 16. Distribution of absolute open flow potential in the Travis Peak Formation in Henderson South field.

Figure 17. Distribution of absolute open flow potential in the Travis Peak Formation in Percy Wheeler field.

Figure 18. Distribution of initial water/gas production ratio in the Travis Peak Formation in Percy Wheeler field.

Figure 19. Distribution of absolute open flow potential in the Travis Peak Formation in Pinehill Southeast field.

Table Captions