Appendices to

AN ASSESSMENT OF THE NATURAL GAS RESOURCE BASE OF THE UNITED STATES

by

Bureau of Economic Geology
The University of Texas at Austin

In cooperation with

ICF-Lewin Energy Division
ICF Incorporated

and

Argonne National Laboratory

for

Office of Policy, Planning, and Analysis
U.S. Department of Energy

Bureau of Economic Geology
The University of Texas at Austin
University Station, Box X
Austin, Texas 78713-7508

May 2, 1988

This report was prepared under contract no. 80622401
between Argonne National Laboratory and The University of Texas at Austin

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by

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APPENDIX 1.

Methods in Current Use for Resource Estimation

Bureau of Economic Geology

METHODS IN CURRENT USE FOR RESOURCE ESTIMATION

For this assessment it is appropriate to review three major published resource estimates and to review the differences between them. These estimates are by the U.S. Geological Survey (USGS), as published in Circular 860 with a draft 1988 update, the Minerals Management Service (MMS) for the Outer Continental Shelf (OCS), and the Potential Gas Committee (PGC) of the Potential Gas Agency, Colorado School of Mines.

Methodology of the U.S. Geological Survey

The most recent published estimate by the USGS of "undiscovered recoverable conventional resources of crude oil and natural gas in the United States" is Circular 860 (Dolton and others, 1981). The estimates are based on work done by the USGS in 1980. Updated resource estimates prepared by the USGS and the MMS are now (1988) in review. These updated data were available to this assessment in a preliminary, or draft, format.

Estimates in Circular 860 are for those undiscovered resources recoverable at the prices and costs current at the time of the appraisal and under the "technological trends" of 1980. Not included in the estimates are any "new pay zones or extensions of existing fields" or any gas from unconventional resources such as "low permeability 'tight' reservoirs." Inferred reserves, reported separately, capture that part of the identified economic resource that will be added to known fields through extensions, revisions, or new pay zones. This is, in effect, historical field development practice.

The USGS subdivided the United States into 15 regions that include 137 provinces (80 onshore, 57 offshore). The assessments are on the basis of "analysis and review of the province petroleum geology, exploration history, finding-rate studies, and structural analyses." The basic approach, however, was a modified Delphi process in which experts discuss and individually determine a resource assessment based on a common body of data on each province. The separate subjective probability assessments are combined to produce a consensus average assessment for each province. A previous USGS assessment of the Permian Basin relied on historical performance trends and produced a smaller undiscovered resource estimate than was published later by the same group (Dolton and others, 1981) using a combination of methods and the modified Delphi process.

The main analytical methods used for the 1981 USGS study were volumetric-yield analyses and finding-rate studies. Volumetric-yield analyses were used to obtain scaling factors for application to the assessed provinces. Yields were based on basin analogs, structural analogs, and stratigraphic analogs; and high, low, and average yields were applied as scaling factors with or without geologic analogs. The finding-rate studies, which were used for some provinces, assumed a continuation of historical trends of discovery on the basis of the statistical relationship between exploration footage drilled in the past and amounts of hydrocarbons discovered.

The final estimates of resources for a region were obtained using a Monte Carlo technique to aggregate probability distributions for the provinces within the region. Probability distributions are based on assumptions of the likelihood of recoverable resources being present, the marginal probability, and assumptions of the amount of recoverable resources present (minimum amount: 95-percent probability; most likely amount: modal estimate; and greatest likely amount: 5-percent probability).

The 1988 preliminary onshore resource estimates of the USGS rely on different methods than did the earlier estimate. The USGS used a play-based procedure for approximately 250 total plays. The distribution of known fields in a play or in an analog play was used as a guide to predict the size distribution of the undiscovered fields. The undiscovered field numbers distribution was estimated independently from the field size distribution. Risk factors were applied in order to get a forward construction of the ultimate field size distribution in a play. This allowed a projection of undiscovered fields, their expected size distribution, and thus undiscovered resource. The new USGS estimates reflect current recovery efficiencies based on the sizes of the analog fields used in making the estimates. Undiscovered field sizes were increased to cover historical growth related to the continued growth in the known or analog fields. Recovery efficiencies in the Circular 860 estimates were not specified.

Methodology of the Minerals Management Service

The MMS was formed in 1982 to manage mineral and energy resources on the OCS. The MMS has responsibilities (1) to estimate the technologically and economically recoverable undiscovered petroleum energy resources of the OCS; (2) to analyze economic and engineering parameters for assessing environmental impacts and determining appropriate lease values; and (3) to conduct cost-benefit studies of leasing alternatives. Important requirements of MMS resource assessment approach include (1) flexibility in allowing leases to be included or deleted from sales; (2) flexibility in allowing various levels of knowledge of specific areas, leases, or prospects; and (3) reproducibility in allowing information to be added as it becomes available. MMS capabilities include access to industry data, as well as data MMS itself has collected in the evaluation of offshore areas.

The MMS uses a computer model called PRESTO (Probabilistic Resource Estimates-Offshore) for resource evaluation. Cooke (1985) described in detail the

MMS methodology, which is summarized below. The PRESTO model provides basin, prospect, or zone evaluation by means of a mathematical representation of an area having petroleum potential. Judgments are made in the evaluation of each variable going into the mathematical model (Cooke, 1985). PRESTO incorporates Monte Carlo simulation of ranges of values for variables, risk analysis, and economics.

The PRESTO model enables the evaluator to describe a mathematical model of each identified geologic prospect. Input values are used to define each prospect's mathematical model. Resource estimates for each prospect are derived using a volumetric formula. The following variables are needed; areal extent (acres), zone pay thickness (ft), oil recovery factor (STB/acre-ft), oil proportion of pay, solution gas-to-oil ratio (standard cubic ft/STB) gas recovery factor (Mcf/acre-ft), and condensate yield (STB/MMcf). PRESTO incorporates all relevant available data to derive estimates of undiscovered economically recoverable resources expressed as a range of values, representing all perceived outcomes. Single-point values or, more commonly, ranges of input values that define the physical properties of an area are used by PRESTO in equations to calculate volumes of oil, gas, and condensate. In PRESTO, each variable can be represented by either a fixed value or one of several distributions of values. To solve the equation, one point is randomly selected from the distribution of values for each variable during a Monte Carlo simulation. The Monte Carlo simulation is one element of PRESTO used to address the uncertainty reflected in ranges of input values.

A Monte Carlo simulation yields a single solution and represents one possible state of nature. Numerous trials are run using randomly selected values from the distribution of values for each variable. This process is repeated using the new values until a distribution of solutions has been adequately covered.

Risk analysis is incorporated in the PRESTO model with a three-level risk hierarchy at the basin, prospect, and zone levels. The risking procedure determines which prospects or zones are simulated as productive or dry for each Monte Carlo run. PRESTO calculates the quantities of oil and gas resources that may be found and developed, given the condition that economically recoverable accumulations of hydrocarbons are present. Single-point values for individual prospect-dry risks and basin- (or area-) dry risks are used to calculate conditional dry-prospect risks for each prospect.

If a prospect is found to be hydrocarbon-bearing on a Monte Carlo run, PRESTO will calculate the resources for that prospect on that trial. Economic considerations dictate whether or not the prospect's resources warrant development. Estimates of minimum economic field size are derived using another MMS computer model--MONTCAR. MONTCAR is used to compute the smallest field that would yield a prescribed minimum rate of return under the imposed conditions of positive net worth.

A PRESTO trial or model run simulates an exploratory drilling program for the area of study. On each run every prospect is "drilled" and if hydrocarbons are "discovered" the amount of resources discovered is calculated. A PRESTO run typically has from 2,000 to 5,000 trials, yielding a large number of possible outcomes. PRESTO calculates the conditional resource estimate, that is, how much resource may be found and developed given the presence of economically recoverable accumulations in the area.

The primary outputs of PRESTO are (1) the conditional 95 percent, 5 percent, and mean resource estimated for oil and gas; (2) the corresponding probability of economically recoverable accumulations of hydrocarbons existing in the area; and (3) a percentile table showing 99th percentile for all components including barrels of oil equivalent. PRESTO does not compute risked distributions. If a well is drilled and resources are discovered, the conditional estimate indicates the amount actually expected.

Preliminary MMS resource estimates made in 1988 represent an update of those published in 1985.

Methodology of the Potential Gas Committee

The PGC attempts to estimate the total natural gas resource that could be developed in the United States without regard to "the time of development of the natural gas resource, the life span of the natural gas industry, or the specific price to be paid for the produced gas." The PGC may be less conservative than the USGS in that the PGC includes gas that will be recoverable in the future as a result of the application of "foreseeable" technology. Both the 1981 USGS process and the PGC process rely on expert opinions, a Delphi process, and both attempt to sufficiently codify the assessment methods to produce uniformity in the results obtained from a large number of experts.

The PGC has divided the United States into 122 provinces that in the Lower 48 states correspond closely to the geologic province boundaries established by the AAPG Committee on Statistics of Drilling. These boundaries do not correspond to the provinces used by the USGS or to the geographic areas used by the Energy Information Administration (EIA).

The PGC has three categories of "potential supply": probable, possible, and speculative resources. Probable resources are gas estimated to exist in known fields that has not been confirmed. They include extensions of known pools and expected new pool discoveries either in known reservoirs or from shallower or deeper horizons that are productive elsewhere. They are thus comparable to USGS-MMS inferred reserves. Possible resources are from outside known fields but are estimated on the basis of the presence of productive formations in a productive province. Speculative resources are estimated for new pool or new field discoveries to be made in formations or basins that are not now productive but have potential to be productive based on geologic analogs.

PGC estimates are updated every two years. The most recent estimate was published in 1987. The expert estimators are asked to consider each prospective area in terms of the presence or absence of various factors that control known gas occurrences. Estimates of the volume of potential gas reservoirs or numbers and sizes of potential new fields and pools are multiplied by a yield factor, which is based on the amount of gas a given unit volume of rock is expected to produce, and by the estimate of the probability that the trap actually exists and, given that a trap exists, the probability that the gas accumulation actually exists. A maximum estimate is made on the basis of an assumed 10-percent probability that all factors present favor maximum resource occurrence; a minimum estimate is made on the basis of an assumed 90-percent probability that all factors present favor at least the minimum resource occurrence; and a most likely amount is similarly estimated. These estimation techniques are somewhat modified to fit data available from each prospective area and to be compatible with the three categories of potential supply.

APPENDIX 2.

Reserve Growth on Nonassociated Gas Reservoirs

Bureau of Economic Geology

RESERVE GROWTH ON NONASSOCIATED GAS RESERVOIRS

Introduction

Current procedures for reserve estimation underrepresent reserve growth in existing fields that could be tapped through a geologically directed infill and recompletion program. A typical 640-acre spacing for nonassociated gas reservoirs leaves reservoir pockets in incomplete communication or totally isolated from producing wells. This section describes both the magnitude of the resource potential and the methodology used to quantify extended reserve growth in nonassociated gas reservoirs (table 1). Resource potential within existing gas fields was analyzed for the following regions: Rocky Mountain, Gulf Mesozoic, Gulf Cenozoic, Permian, and Midcontinent (Oklahoma data were treated separately). Together these regions represent approximately 90 percent of proved gas reserves (Energy Information Administration [EIA], 1987) exclusive of Alaska and offshore areas (figure 1). The percentage of the nation's estimated ultimate recovery is more difficult to estimate accurately because of the variable quality of records of cumulative production. For this reason we extrapolated summed regional totals of nonassociated gas resources to national totals using the national and statewide reserve data from EIA (1987).

Extended reserve growth in nonassociated gas reservoirs was quantified on the basis of a reservoir-scale reserve growth factor, structural complexity, conventional versus low-permeability production, and current well spacing. The reserve growth factor is applied at the play level to all fields and reservoirs in that play. The widespread availability of this resource through infill and recompletion drilling is underscored by the predominance of gas reservoirs at 640- to 320-acre spacing. In the regions studied, 80 to 95 percent of production from nonassociated gas reservoirs is from fields with 640- to 320-acre spacing.

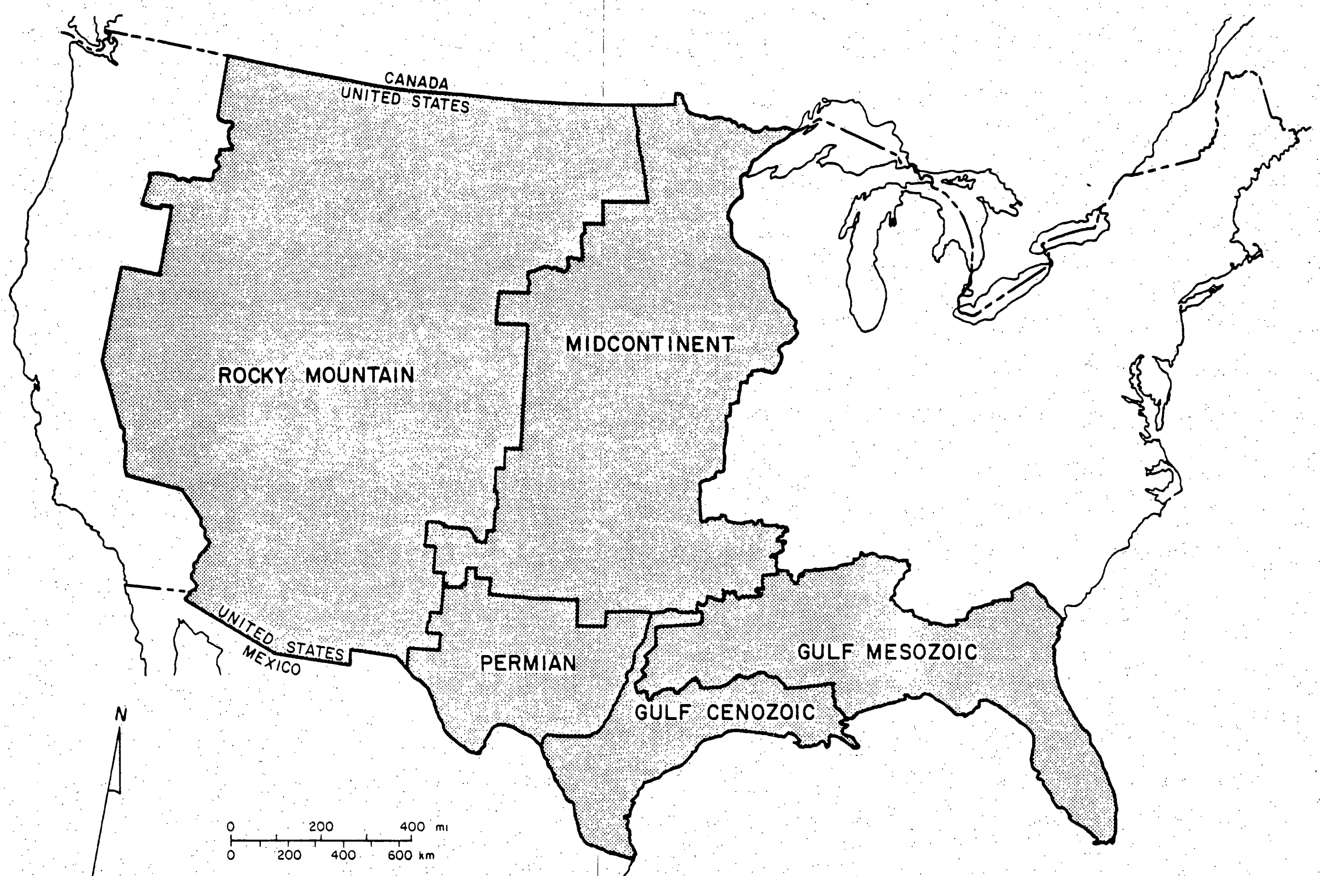


Figure 1. Nonassociated gas resource was analyzed by play in regions outlined in light stipple pattern. The regions included Gulf Cenozoic, Gulf Mesozoic, Permian, Midcontinent, and Rocky Mountain. These regions contain 90 percent of the nation's proved gas reserves.

The nonassociated advanced gas resource, available through extended reserve growth, for the five regions totals 95.56 Tcf. On the basis of appraisal of 90 percent of the nation's reserves, this implies a national advanced gas recovery resource of about 105 Tcf. This resource does not include any advanced reserve growth considered for the offshore area because of the economics dictated by production and drilling platforms.

Methodology of Advanced Gas Resource Estimation

This evaluation of nonassociated advanced gas resource is based on application of reserve growth factors to consistent patterns of geologic complexity within a play. The amount of advanced gas resource (AGR) that could be captured through geologically directed infill drilling is calculated for each play by multiplying conventional estimated ultimate recovery (EUR) by the reserve growth factor of that geologic play. The regional AGR is the EUR-weighted sum of the AGR from all plays in the region.

A play-oriented data base was developed for each region on the basis of The Significant Oil and Gas Fields of the United States (NRG Associates, 1985). All production and reserve data were tabulated through 1985. A play is defined as a group of fields and reservoirs sharing related characteristics and location. NRG Associates (1985) uses cluster as a substitute for play. The defining characteristics of each play are producing formation, lithology, depositional environment, trap type, type of hydrocarbon produced, and location of the fields. Information added to the data base at the play level included reserve growth factor, depositional system, well spacing, drive mechanism, weighted average depth, play acreage, low-permeability gas production, and advanced gas resource component. Geologic data were compiled only on the major producing formation within a play. These fields were the most productive fields within a play and constituted an average of 60 percent of the total number of fields in the play. In total, geologic data were compiled for 334 plays, which included more than 10,000 fields.

Reserve growth factors applied at the play level fell into a three-fold distribution: low, medium, and high heterogeneity. ICF-Lewin Energy (appendix 3) performed economic analysis on field size distributions within each heterogeneity range. Field size distributions were binned within 2,500-ft depth slices for each of the three reserve growth factors. Although NRG field data are not segregated on the basis of associated and nonassociated, we analyzed a population of "nonassociated" fields based on a GOR of 3000:1 or greater barrel oil ratio of conventional EUR. Generally, fields with this ratio will have a free gas cap based on the solubility of gas in oil adjusted for depth (C. Hocott, 1988, personal communication).

Data integrating information on play, reserve, and production data for Oklahoma were unavailable at the time of this study, although play and cumulative production data were available separately. The nature of Oklahoma data required a separate analysis to develop an AGR component for that state. Reserve data for 1986 were calculated on the basis of the average R/P ratio of 10.5 during 1983, 1984, and 1985 (Hugman and Vidas, 1988). This R/P ratio includes some unknown amount of production shut in during that period. Reserve growth factors were calculated for each play, but data for total EUR for each play were unavailable. Thus, a statewide average reserve growth factor was calculated. This differs from the growth factor calculated for the other regions, which had EUR available for each play. Thus, for the regions exclusive of Oklahoma, a weighted-average growth factor was calculated. Oklahoma statewide total EUR was calculated from state cumulative production and reserves. Statewide AGR was calculated on the basis of average reserve growth factor and statewide EUR.

The two key components of the analysis of gas reserve growth are reserve growth factor and well spacing. Development of reserve growth factors from reservoir heterogeneity is described in the section titled Explanation of Project Approach to Reservoir Heterogeneity, and well spacing is discussed in the following section. Nonassociated gas reserve growth is described for each region in the section titled Nonassociated Advanced Gas Resources, and additional supporting data based on case studies of significant gas reservoirs are in the section titled Heterogeneity in Gas Reservoirs.

Well Spacing

The primary means of overcoming low recovery efficiencies resulting from reservoir heterogeneity is to increase the density of producing wells to below the mean lateral extent of heterogeneity. Clearly, associated fields drilled at 20-acre spacing would have a very low reserve growth factor because most of the reservoir heterogeneity would have been captured by the dense well spacing. Although many oil fields have a 40-acre or less oil well spacing, most of the large nonassociated gas fields currently are drilled at 640-acre spacing. According to the EIA (1987), 83 percent of the proved gas reserves in the U.S. exclusive of Alaska are in nonassociated reservoirs. Well-spacing data from the five examined regions were tabulated as of 1977 to determine nonassociated gas well spacing. Table 19 shows active well spacing for nonassociated fields in Texas, Wyoming, and Kansas as of 1977. These data reveal that 80 to 94 percent of both the number of fields and the production from nonassociated gas fields are at spacings of 640 or 320 acres. About two-thirds of the fields are at 640-acre spacing. In Texas, all large (>30 Bcf) nonassociated gas reservoirs have been surveyed (Kosters and others, in preparation). Ninety-two percent of these large reservoirs have spacing at 640 to 320 acres, with 94 percent

Table 19. The distribution of 1977 well spacing in Texas, Kansas, and Wyoming. Production is predominantly from fields at 640- to 320-acre spacing. Currently, most production from the Hugoton Field in Texas, Oklahoma, and Kansas also is at 640-acre spacing.

TEXAS

- 92% of large (>30 Bcf) Non-associated Reservoirs at 640 to 320 well spacing
- 94% of Cum. Production of large (>30 Bcf) Non-associated Reservoirs at 640 to 320 acre spacing
  - 66% is at 640 acre spacing
  - 28% is at 320 acre spacing
  - 4% is at 160 acre spacing
  - 2% is <= 80 acre spacing

KANSAS

- 85% of 1986 Cum. Production from 640 acre spacing
- 80% of 1986 Annual Production from 640 acre spacing
- Hugoton Field at 640 acre spacing

WYOMING

- 246 Non-associated Gas Reservoirs
  - 73% at 640 acre spacing
  - 13% at 320 acre spacing
  - 13% at 160 acre spacing
  - 1% at 80 acre spacing

of the production at the same spacing. Sixty-six percent of the production is from the large reservoirs with spacing of 640 acres, and 28 percent have spacing of 320 acres. Only 2 percent of the production was from reservoirs at 80 acres or less. In Kansas, 85 percent of the cumulative production was from fields on 640-acre spacing. In Wyoming, 73 percent of the nonassociated gas fields were at 640-acre spacing and 13 percent were at 320 acres. Only 1 percent of the Wyoming fields were at 80-acre spacing or less. These data thus indicate that historical probable resource/inferred reserve estimates do not incorporate any significant component of gas derived from infill drilling. This is because these estimates are based on data series that ended in 1979 as formerly produced by the American Gas Association and the American Petroleum Institute.

Nonassociated Advanced Gas Resource

The nonassociated advanced gas resource (AGR), available through extended reserve growth, is tabulated for each region in table 20. In addition to AGR, conventional estimated ultimate recovery and proved reserves also are calculated. EUR is from The Significant Oil and Gas Fields of the United States (NRG Associates, 1985) and consists of fields greater than 1 million barrels of oil equivalent (boe). Nonassociated gas reserves are summed from individual state totals from the EIA (1987). The same data in table 20 are displayed graphically in figures 2 to 7. The data on gas reserves and resources are displayed on a common scale in figure 2 to facilitate comparison of reserves and resources among the regions. The AGR is related to EUR by the play-average weighted reserve growth factors. The reserve growth factors for each region are shown in figure 8. Note that for the Midcontinent region, including Oklahoma, the reserve growth factors are averaged and

Table 20. Conventional estimated ultimate recovery (EUR), advanced gas resource (AGR), and proved reserves for nonassociated gas by region. Midcontinent region includes Oklahoma data, which was analyzed using averaged heterogeneity factors.

REGION	EST. ULTIMATE RECOVERY (Tcf)	ADVANCED GAS RESOURCES (Tcf)	PROVED RESERVES (Tcf)
GULF CENOZOIC	233.06	25.58	20.17
GULF MESOZOIC	63.77	12.48	11.30
PERMIAN	73.70	15.54	8.97
MIDCONTINENT	151.48	31.18	43.11
ROCKY	51.02	10.78	24.90
TOTAL	572.93	95.56	108.45

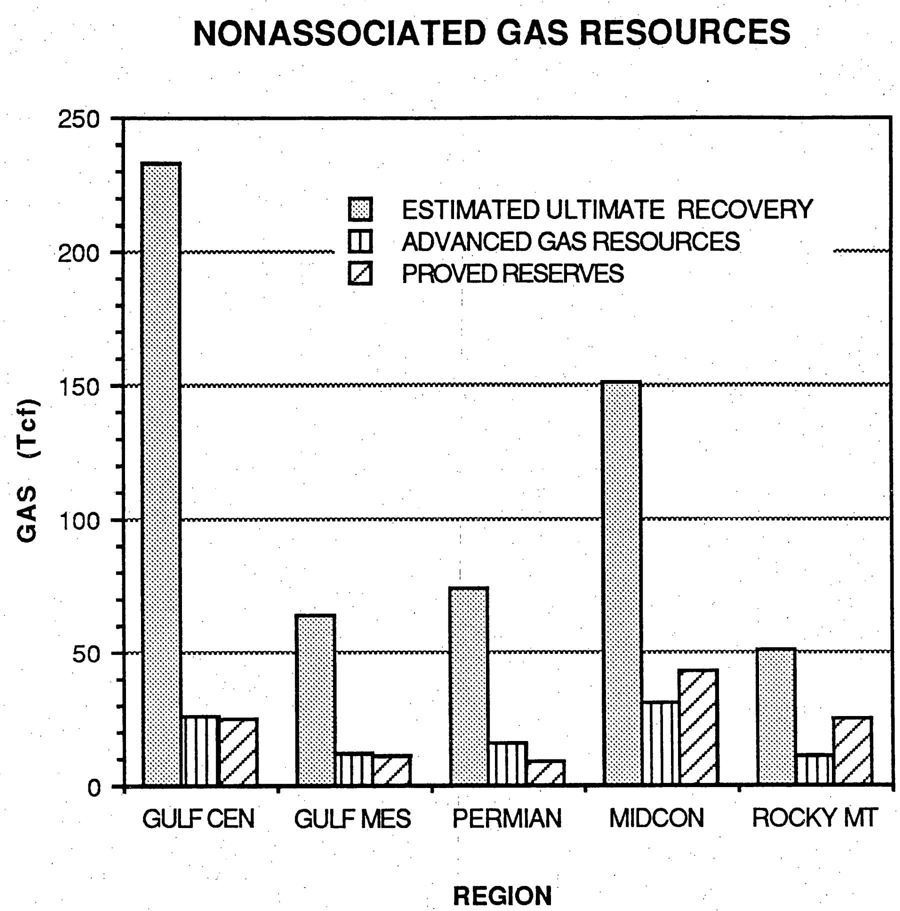


Figure 2. Nonassociated gas resources including estimated ultimate recovery (EUR), advanced gas resources (AGR), and proved reserves for the five major gas-producing regions.

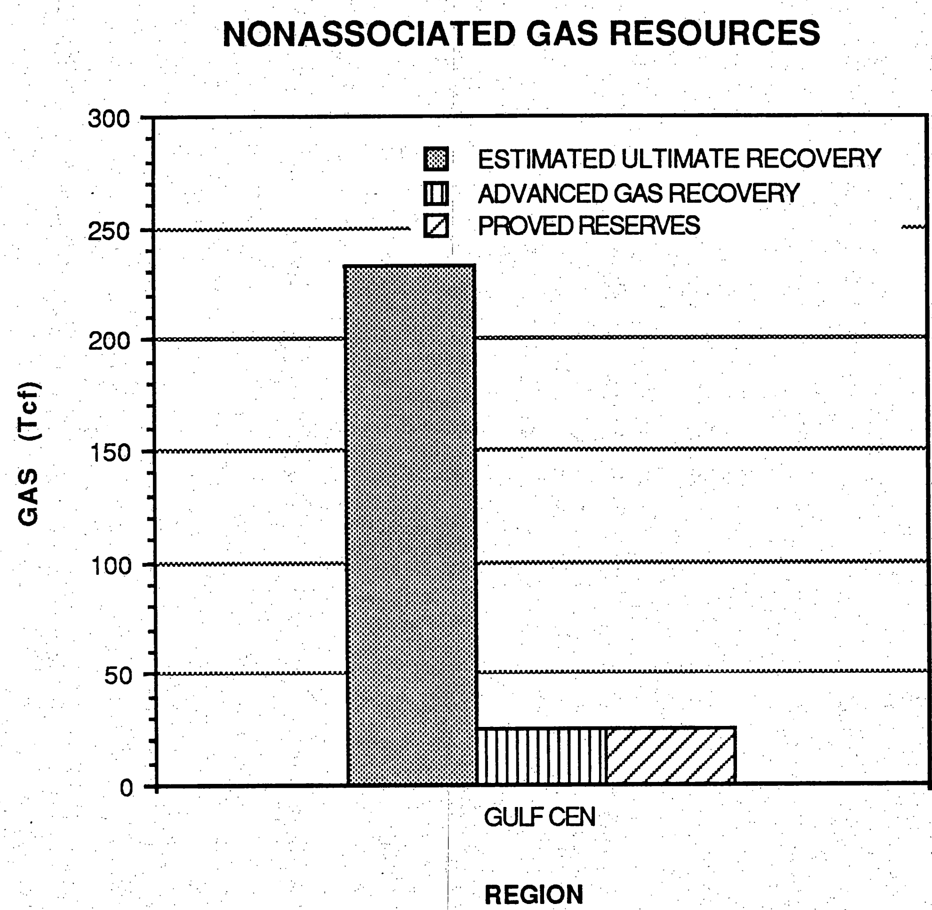


Figure 3. Nonassociated gas resources in Gulf Cenozoic region.

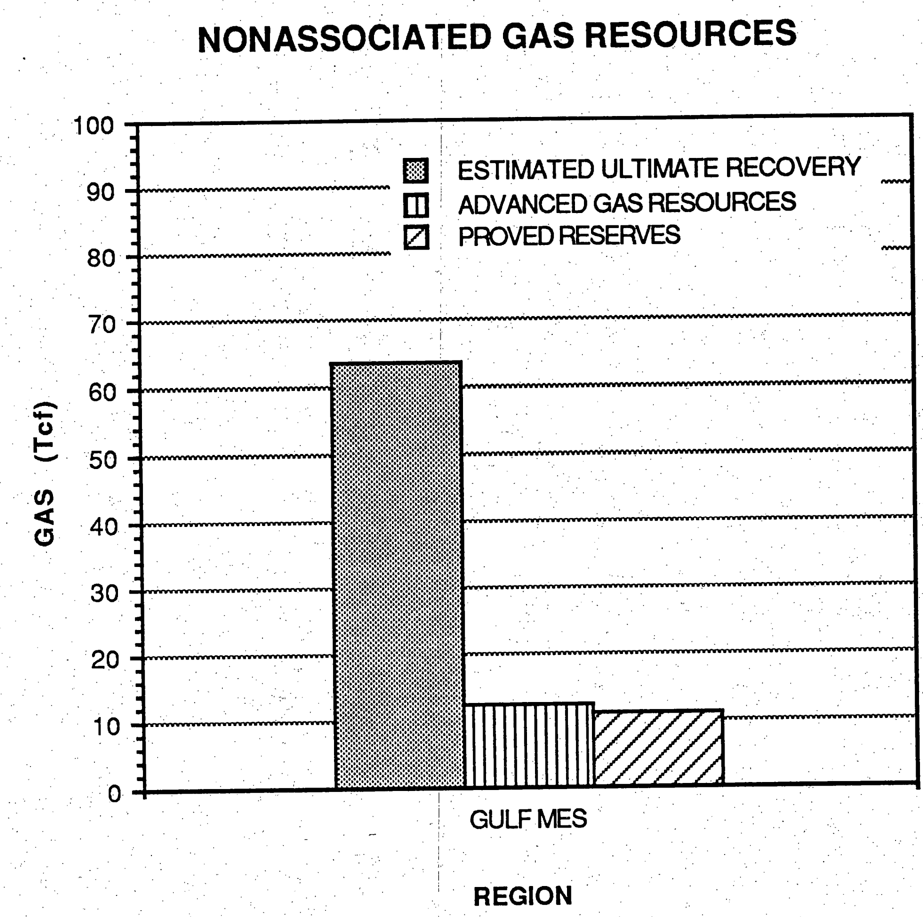


Figure 4. Nonassociated gas resources in Gulf Mesozoic region.

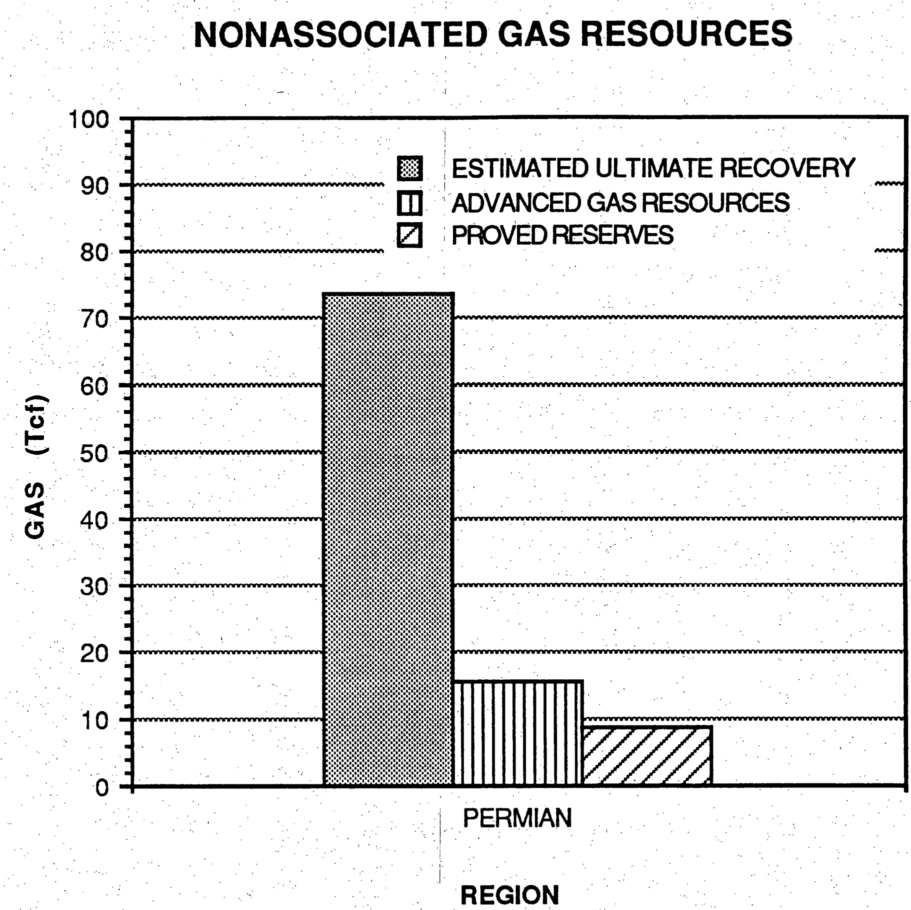


Figure 5. Nonassociated gas resources in Permian region.

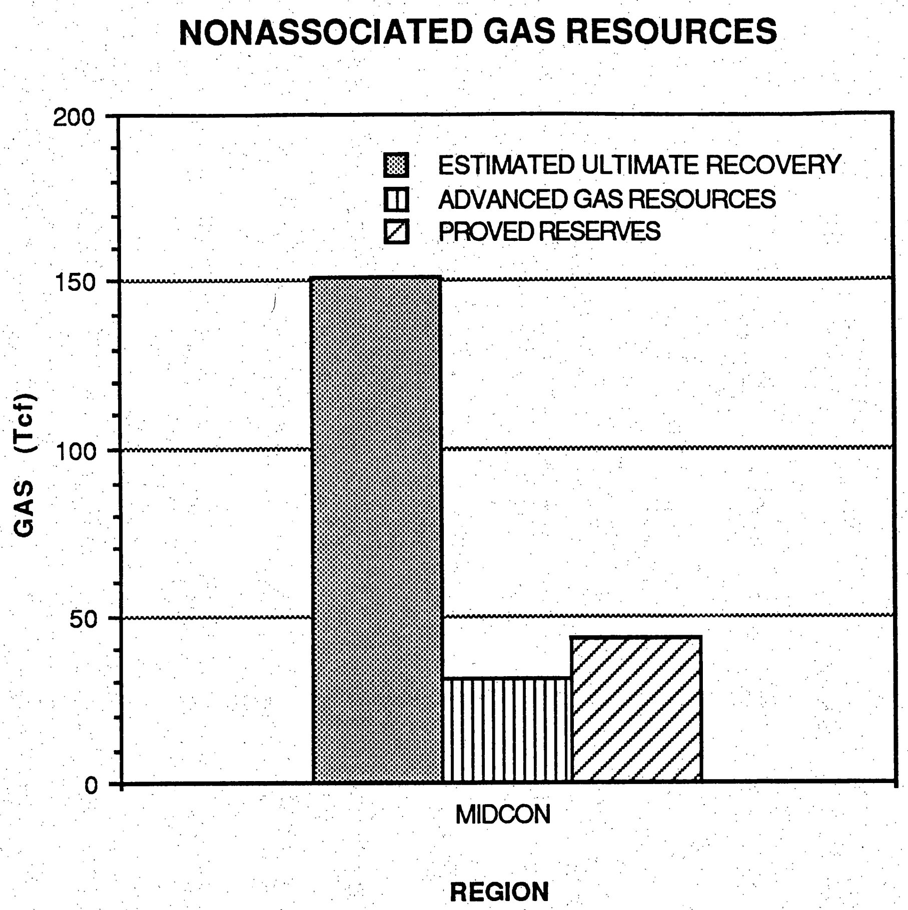


Figure 6. Nonassociated gas resources in Midcontinent region.

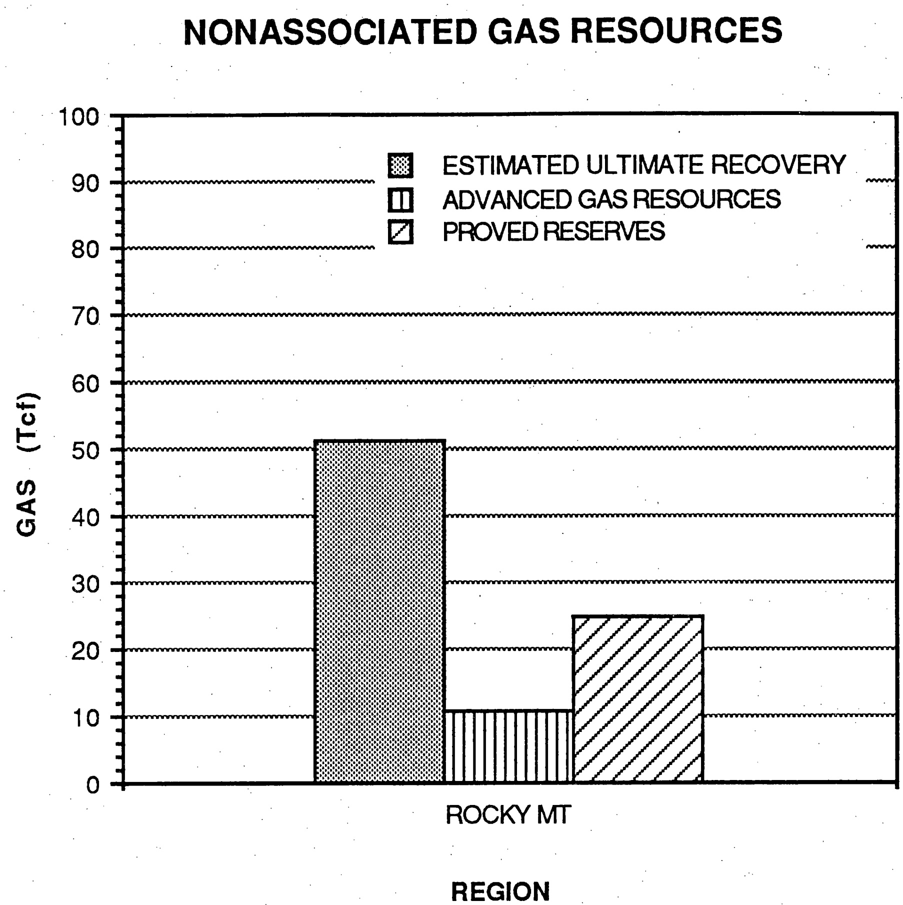


Figure 7. Nonassociated gas resources in Rocky Mountain region.

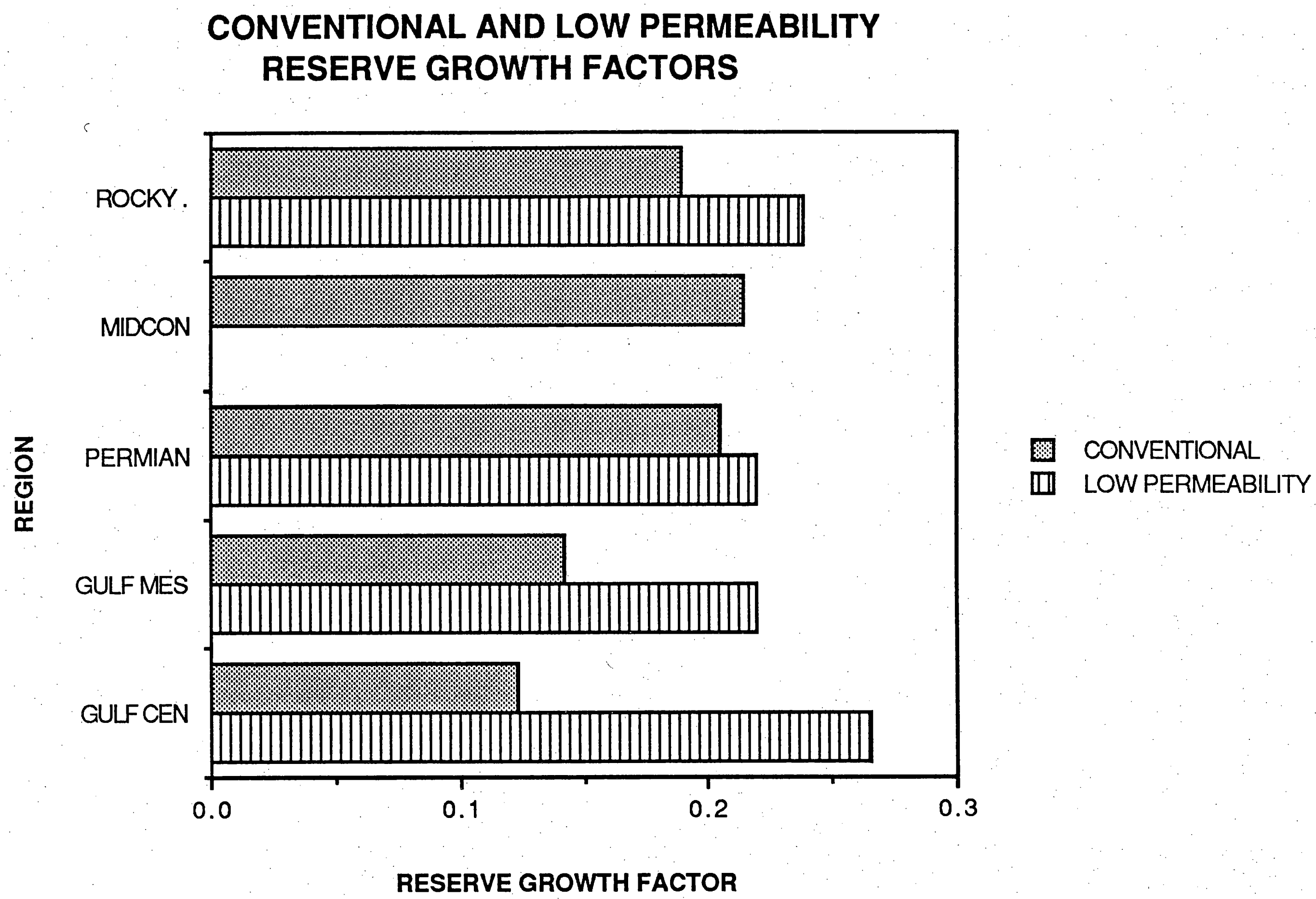


Figure 8. Regional play-weighted reserve growth factors for the five regions. Reserve growth factors are segregrated into low-permeability and conventional plays. Note the characteristic higher reserve growth associated with low-permeability plays. None of the plays in Midcontinent region have predominantly low permeability. The reserve growth factor for Midcontinent region is a simple average of all plays and thus is not weighted by the EUR of each play as are the other regions.

not weighted because EUR totals were unavailable on a play-by-play basis.

Reserve growth factors vary among regions by a factor of almost 2. Higher reserve growth factors are associated with Midcontinent and Permian regions, reflecting the dominance of heterogeneous carbonate reservoirs in those regions. In contrast, the Gulf Cenozoic region has relatively low reserve growth potential, reflecting the relatively simple clastic systems dominated by wave-dominated and modified deltas and barrier shoreface systems. Reserve growth factors for low-permeability ("tight") gas plays also are shown in figure 8. The greater geologic complexity of low-permeability gas plays is evident.

Economic analysis of the availability of the resource is affected by the depth of the resource. One component of the economic analysis required an understanding of the field size distribution by depth. Tables 21 to 24 summarize the depth distribution of the nonassociated gas resource for each region. Graphical representation of the depth distribution is illustrated for each region in figures 9 to 18. One significant pattern repeated for each region is the concentration of total resource, both EUR and AGR, at shallower depth classes for the high reserve growth factors compared with those for the lower reserve growth factors. This highlights the favorable economics associated with recovery by infill and recompletion techniques in older fields with large potential advanced gas reserves.

Table 21. Depth distribution of nonassociated gas in 2,500-ft depth slices for fields in high, medium, and low reserve growth classes in Gulf Cenozoic region.

HIGH

	DEPTH BIN (ft)	NO FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	19	38660	0.284	0.058	0.343
2	5000	60	218290	4.578	0.980	5.558
3	7500	49	1177460	7.367	1.650	9.017
4	10000	78	203756	5.152	1.219	6.371
5	12500	44	139532	3.706	0.799	4.505
6	15000	11	19080	0.531	0.107	0.638
7	17500	3	1160	0.046	0.010	0.056
8	20000	0	0	0.000	0.000	0.000
9	22500	1	2560	0.009	0.002	0.011

MED

	DEPTH BIN (ft)	NO. FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	54	98980	4.101	0.663	4.764
2	5000	163	388520	19.715	2.986	22.701
3	7500	414	992200	58.634	8.051	66.685
4	10000	425	620290	29.656	4.135	33.791
5	12500	193	281200	24.412	3.298	27.711
6	15000	39	44990	4.497	0.578	5.075
7	17500	16	13160	1.537	0.208	1.745
8	20000	8	19780	1.306	0.157	1.463

LOW

	DEPTH BIN (ft)	NO. FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	82	185360	2.426	0.111	2.537
2	5000	128	252060	9.659	0.123	9.782
3	7500	105	245640	14.495	0.383	14.878
4	10000	193	348630	22.986	0.819	23.804
5	12500	161	283261	22.249	0.967	23.216
6	15000	49	46960	3.958	0.209	4.167
7	17500	6	3300	0.389	0.018	0.407
8	20000	1	0	0.012	0.000	0.012

Table 22. Depth distribution of nonassociated gas in 2,500-ft depth slices for fields in high, medium, and low reserve growth classes in Gulf Mesozoic region.

HIGH

	DEPTH BIN (ft)	NO FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	4	281290	7.631	1.905	9.536
2	5000	8	320600	9.960	1.992	11.952
3	7500	107	754670	14.935	3.241	18.176
4	10000	114	697832	11.645	2.468	14.113
5	12500	53	296450	3.248	0.652	3.900
6	15000	17	40120	0.431	0.087	0.518
7	17500	13	28403	0.534	0.117	0.651
8	20000	7	38340	0.705	0.155	0.861
9	22500	3	3840	0.309	0.068	0.377
10	25000	1	1280	0.037	0.008	0.046

MED

	DEPTH BIN (ft)	NO. FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	15	63520	0.406	0.070	0.476
2	5000	24	126840	1.218	0.161	1.379
3	7500	27	95870	1.905	0.222	2.127
4	10000	28	61625	2.680	0.461	3.142
5	12500	34	71940	1.584	0.263	1.847
6	15000	21	36910	0.696	0.127	0.823
7	17500	16	52200	0.846	0.152	0.999

LOW

	DEPTH BIN (ft)	NO. FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	7	92792	0.801	0.059	0.860
2	5000	17	74030	0.888	0.049	0.936
3	7500	9	16920	0.679	0.035	0.714
4	10000	17	50024	1.406	0.097	1.503
5	12500	19	39960	0.480	0.034	0.514
6	15000	3	3120	0.021	0.002	0.022
7	17500	4	6240	0.127	0.010	0.137
8	20000	0	0	0.000	0.000	0.000
9	22500	1	7200	0.600	0.048	0.648

Table 23. Depth distribution of nonassociated gas in 2,500-ft depth slices for fields in high and medium reserve growth classes in Permian region.

HIGH

	DEPTH BIN (ft)	NO. FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	45	138240	3.767	0.788	4.555
2	5000	286	856279	19.863	4.202	24.065
3	7500	244	1956574	15.892	3.523	19.416
4	10000	98	290086	5.429	1.140	6.569
5	12500	71	227652	5.755	1.179	6.934
6	15000	27	104160	6.317	1.366	7.683
7	17500	19	46920	3.567	0.754	4.321
8	20000	15	115880	8.492	1.830	10.322
9	22500	8	21360	0.452	0.099	0.552

MED

	DEPTH BIN (ft)	NO. FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	13	43360	0.333	0.053	0.386
2	5000	56	132500	0.797	0.114	0.911
3	7500	19	17430	0.171	0.029	0.200
4	10000	12	58240	0.539	0.086	0.626
5	12500	26	168980	1.409	0.225	1.633
6	15000	21	41680	0.808	0.129	0.938
7	17500	3	11320	0.107	0.017	0.125

Table 24. Depth distribution of nonassociated gas in 2,500-ft depth slices for fields in high and medium reserve growth classes in Rocky Mountain region.

HIGH

	DEPTH BIN (ft)	NO FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	5000	41	1167201	7.991	1.874	9.865
2	7500	60	1594950	14.730	3.022	17.752
3	10000	72	1467053	11.922	2.656	14.578
4	12500	43	286560	2.922	0.757	3.679
5	15000	17	182960	0.808	0.204	1.012
6	17500	11	43080	3.280	0.764	4.044
7	20000	5	17320	0.134	0.031	0.165
8	22500	1	640	0.018	0.005	0.023

MED.

	DEPTH BINS (ft)	NO. FIELDS	AREA (acres)	EUR (Tcf)	AGR (Tcf)	EUR+AGR (Tcf)
1	2500	14	325760	0.804	0.144	0.948
2	5000	38	176020	1.331	0.229	1.561
3	7500	44	254470	1.668	0.264	1.932
4	10000	25	153545	2.381	0.371	2.752
5	12500	11	49880	1.429	0.219	1.648
6	15000	9	24230	0.491	0.074	0.565
7	17500	2	26800	1.110	0.167	1.277

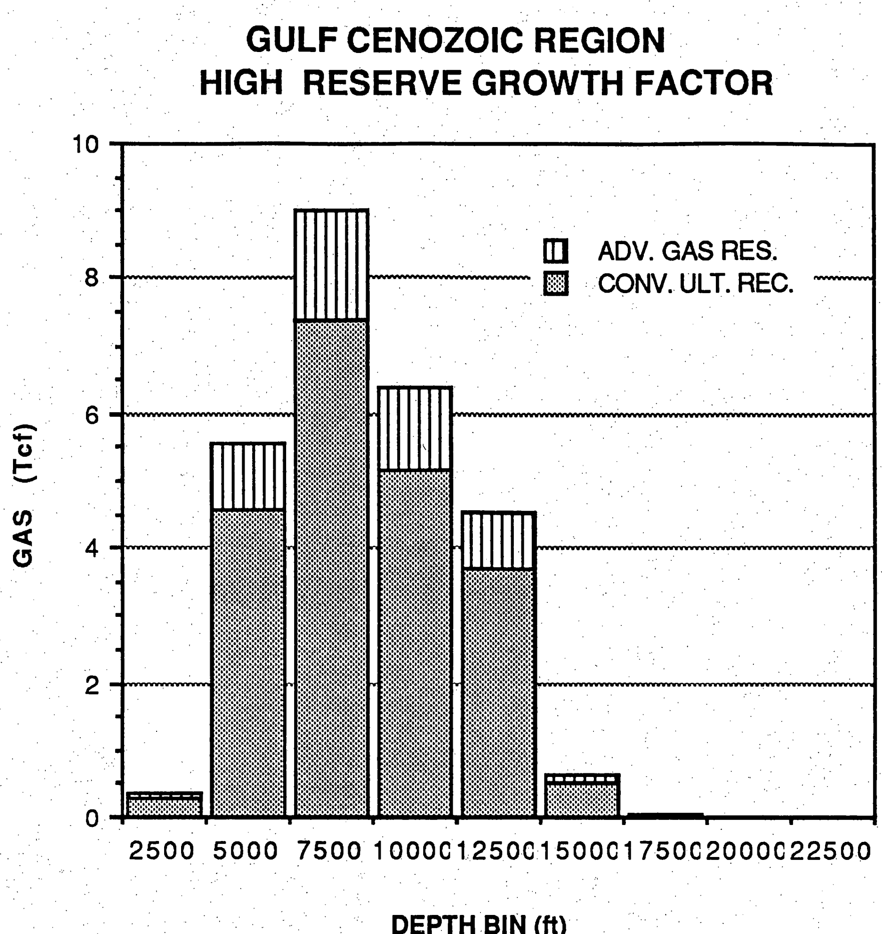


Figure 9. Depth distribution of nonassociated gas resources in Gulf Cenozoic region for high reserve growth.

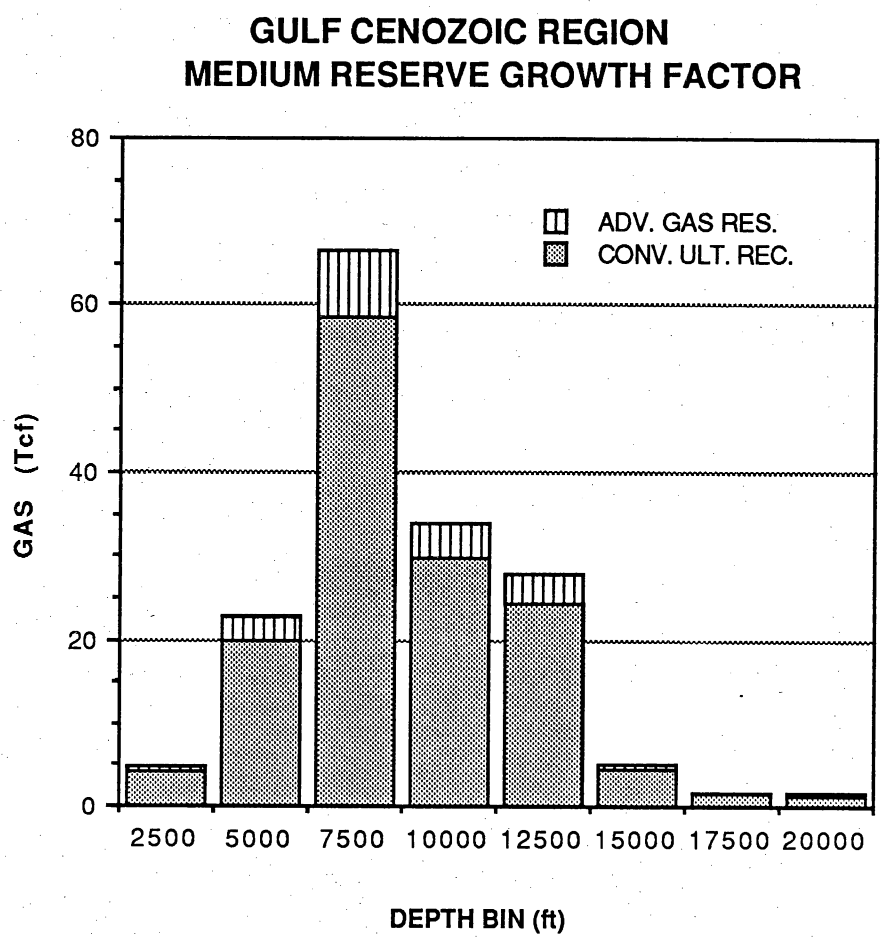


Figure 10. Depth distribution of nonassociated gas resources in Gulf Cenozoic region for medium reserve growth.

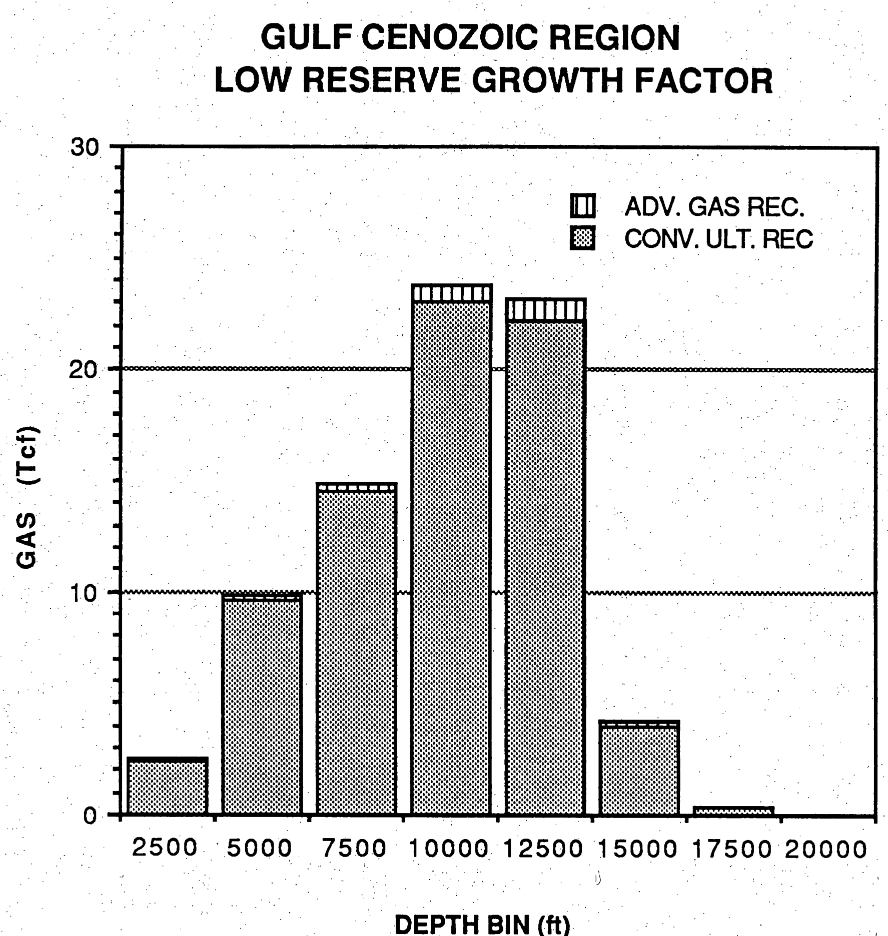


Figure 11. Depth distribution of nonassociated gas resources in Gulf Cenozoic region for low reserve growth.

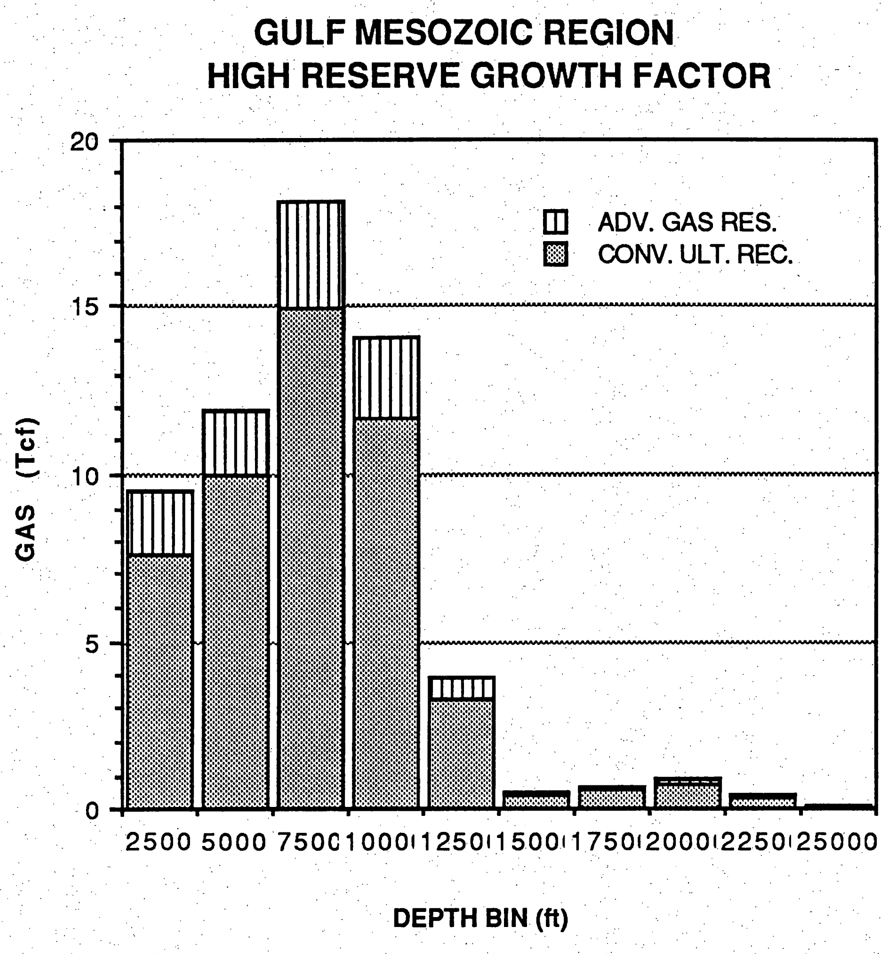


Figure 12. Depth distribution of nonassociated gas resources in Gulf Mesozoic region for high reserve growth.

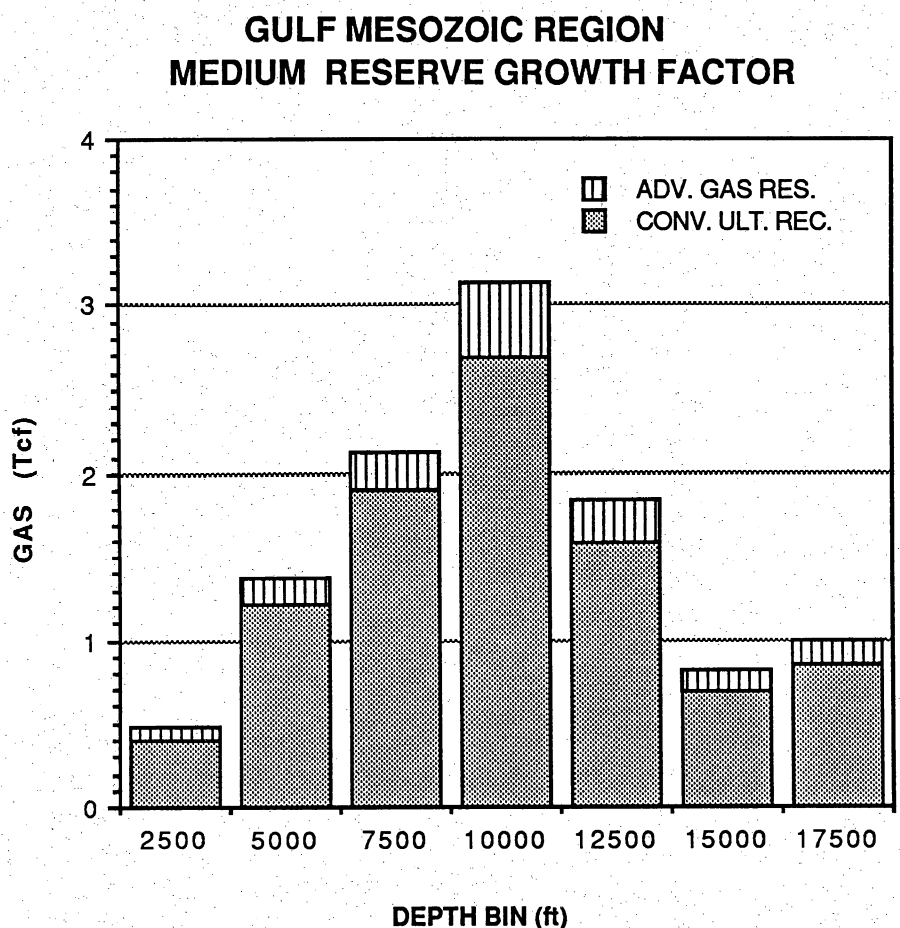


Figure 13. Depth distribution of nonassociated gas resources in Gulf Mesozoic region for medium reserve growth.

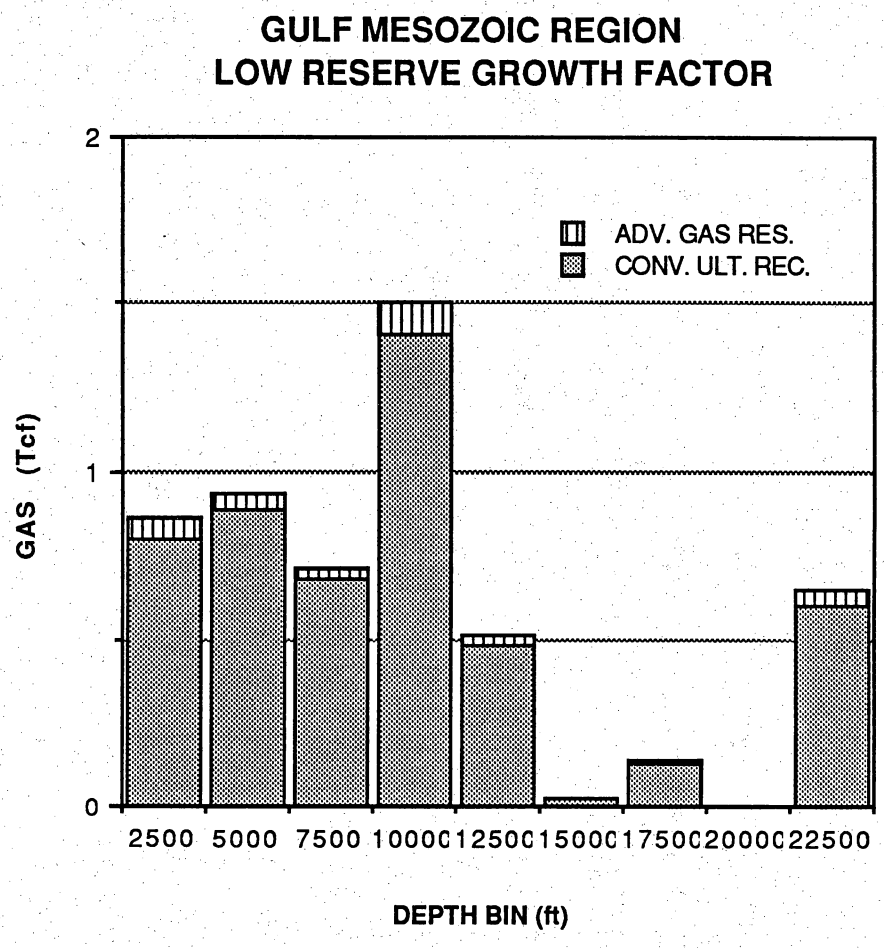


Figure 14. Depth distribution of nonassociated gas resources in Gulf Mesozoic region for low reserve growth.

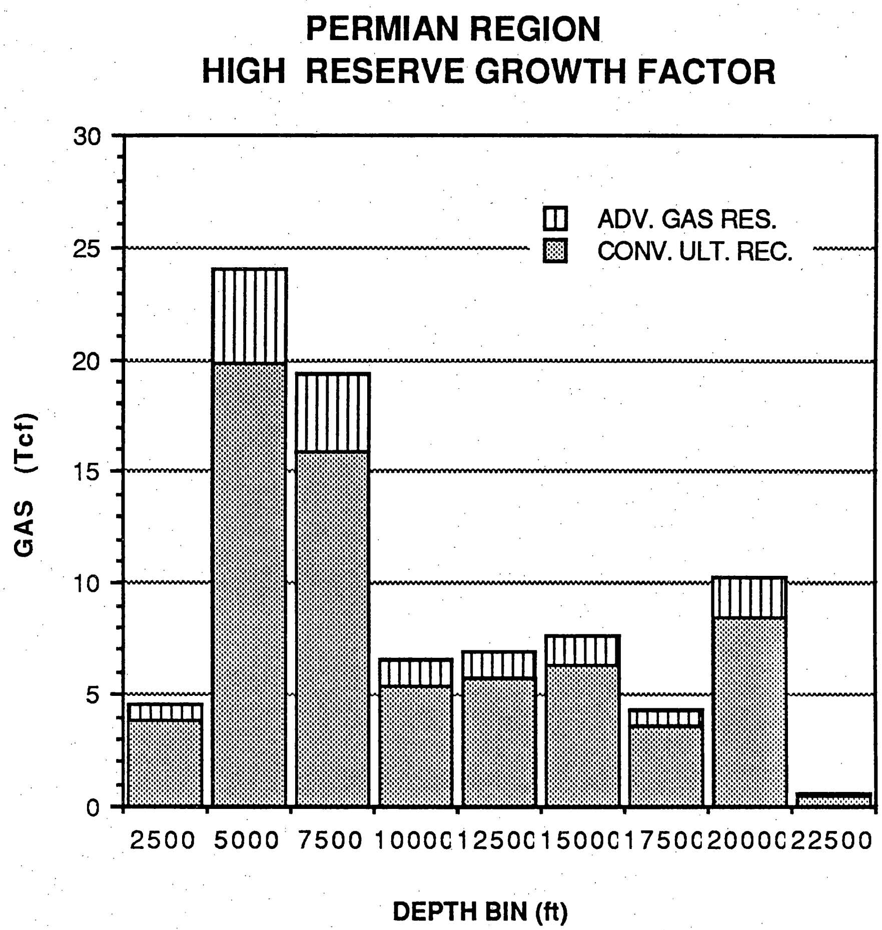


Figure 15. Depth distribution of nonassociated gas resources in Permian region for high reserve growth.

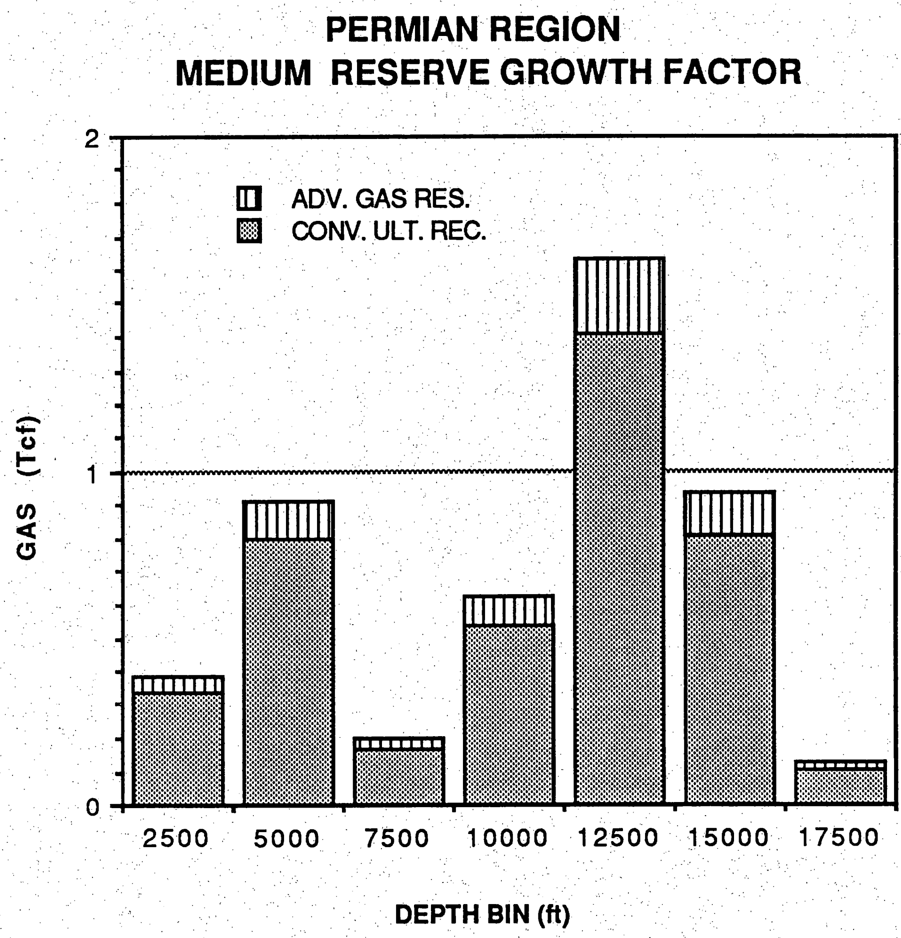


Figure 16. Depth distribution of nonassociated gas resources in Permian region for medium reserve growth.

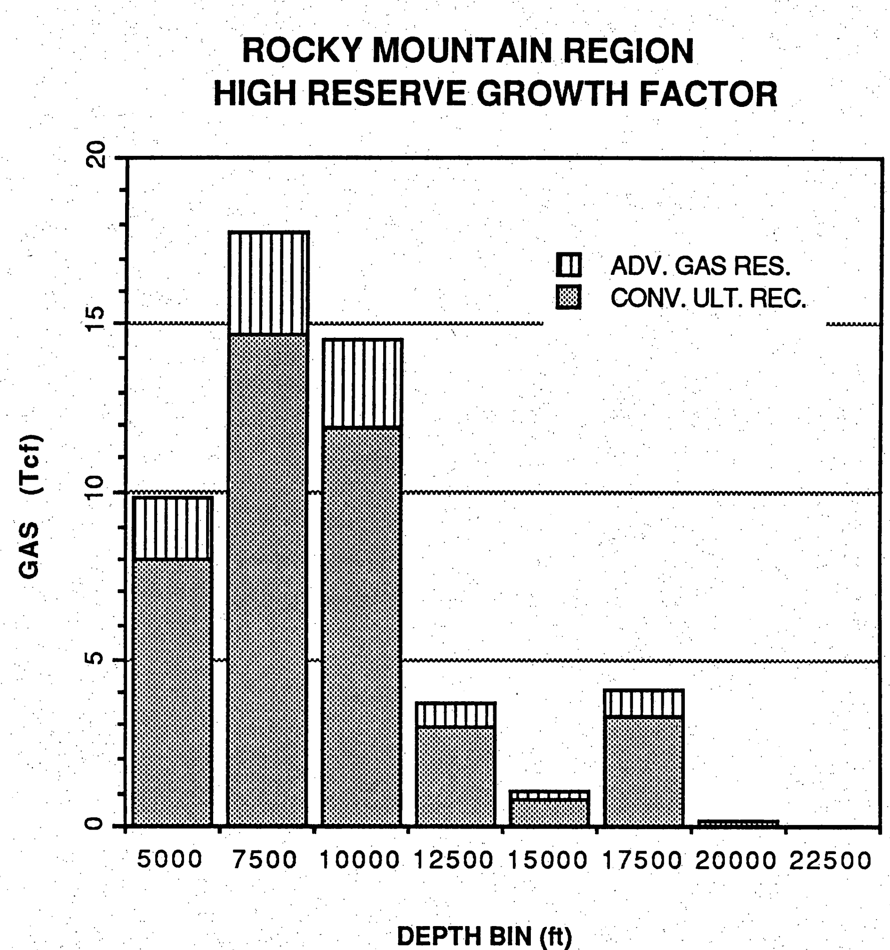


Figure 17. Depth distribution of nonassociated gas resources in Rocky Mountain region for high reserve growth.

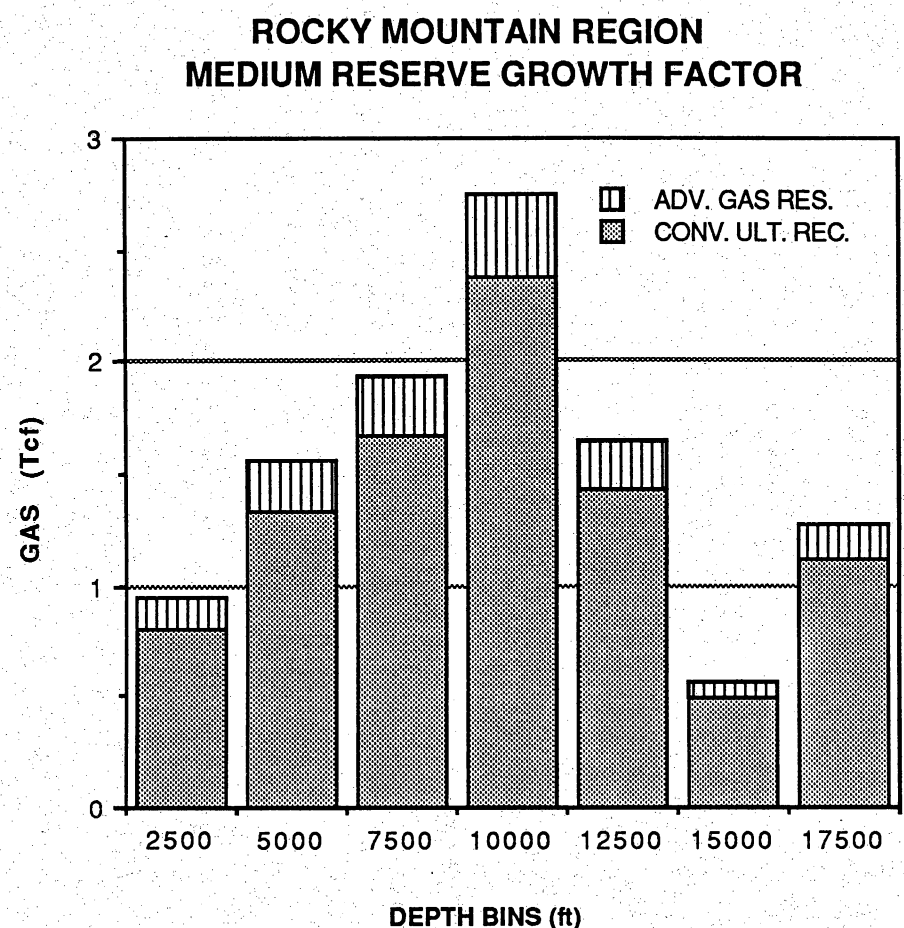


Figure 18. Depth distribution of nonassociated gas resources in Rocky Mountain region for medium reserve growth.

Heterogeneity in Gas Reservoirs
The Basis for Reserve Growth--

Examples from the Literature, Hearing Files, and Research in Progress

Siliciclastic Reservoirs

Vermilion Block 16

Seal and Gilreath (1975) documented a classic example of reservoir heterogeneity in the Vermilion Block 16 field of offshore Louisiana. Original estimates of the recoverable reserves in this Miocene deltaic sandstone reservoir totaled 20 to 25 Bcf. These estimates were derived from volumetrics calculations based on assumed laterally continuous reservoir sand bodies. Early monitoring of pressure records, however, revealed strongly disparate pressure declines among producing wells. Two wells, for example, completed at about the same time and having similar structural positions, net-sand thicknesses, and initial pressures, experienced drastically different pressure histories. Whereas one exhibited an early, steep pressure decline followed by relative stabilization suggestive of water drive, the second exhibited a continuous, rapid decline more typical of depletion drive (figure 19). These differences in well performance and those observed in other wells suggested that the reservoir was not a homogeneous system, as had been assumed.

Careful reexamination of well log data led to the recognition of 108 distinct sandstone depositional units within the field, many of which were unconnected to adjacent units. Sandstone units were interpreted to be primarily distributary-front sand bodies

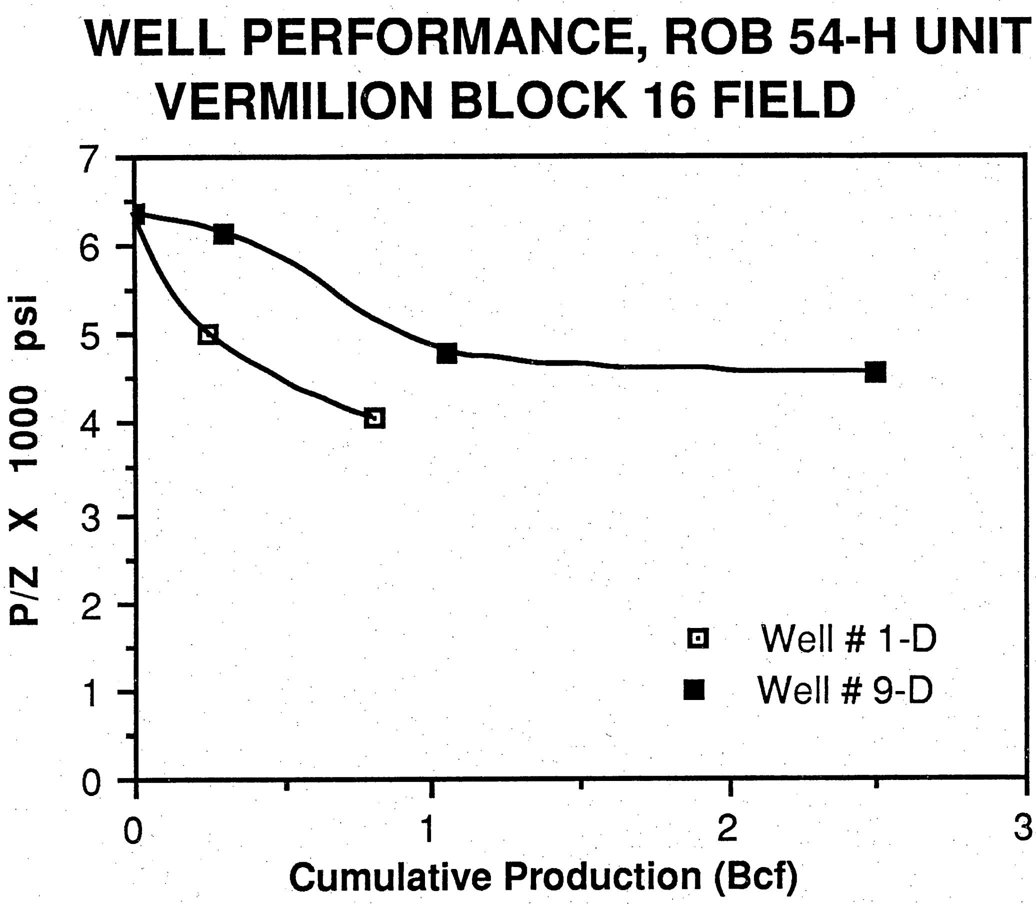


Figure 19. Pressure decline plots of two wells located approximately 1,000 ft apart in the Vermilion Block 16, offshore Louisiana Miocene field. Both wells were drilled on top of structure and have equivalent net-sand thicknesses in the Robulus 54-H reservoir horizon. Reevaluation of well log data revealed that the wells occupied different reservoir compartments owing to lithologic heterogeneities produced by variations in depositional environment. After Seal and Gilreath (1975).

but also included channel sands and minor, reworked offshore bar sands. The study indicated that some sandstone units in the field previously thought to represent a single reservoir in fact constituted as many as six or seven discrete reservoirs. Although not very sophisticated, this geologic model made it possible to design a completely new exploitation strategy for the field, based on recognition of the fact that the field was highly compartmentalized into numerous reservoir units. Subsequent development of the field, which was based on this revised geologic interpretation, resulted in confirmation of the reservoir heterogeneity predicted by the model. New completions in downdip wells now shown to be in separate reservoir units exhibited pressures essentially equal to original reservoir pressure but far less than those in nearby updip wells. In another case, a well was recompleted into a zone that had been abandoned in adjacent wells on the basis of indications from cased-hole logging that hydrocarbon saturations existed. This well, which the geologic model suggested had penetrated a separate reservoir, came in producing gas and condensate at 88 percent of original reservoir pressures and has since produced sizable quantities of gas.

This case history is one of the first to illustrate the presence of significant compartmentalization in deltaic sandstone reservoirs and the importance of this reservoir heterogeneity to the effective exploitation of such reservoirs. Seal and Gilreath (1975) concluded from their experience with the Vermilion Block 16 field that this kind of reservoir heterogeneity or compartmentalization is implied by (1) major deviations of actual production yields from those expected from volumetrics calculations on a per well or fieldwide basis and (2) significant variations in reservoir pressure across the field. These are important clues to recognition of the nonhomogeneity that, we believe, is the rule rather than the exception in oil and gas reservoirs of all types and ages.

Port Arthur Field

The Port Arthur field, in Jefferson County in the Gulf Coast of Texas, produced 57 Bcf of gas from the Hackberry sandstone member of the Frio Formation before being abandoned in 1981 because of excessive water production. Frio facies and depositional systems have been characterized in detail by Galloway and others (1982). In general, the Frio comprises a 15,000-ft-thick progradational wedge of interfingering nonmarine and marine sandstones and shales deposited in fluvial-deltaic and barrier-island and strandplain depositional systems. The Hackberry represents a distal equivalent composed of channel-fill and overbank sandstones deposited in a deep-water setting downdip from strandplain and barrier-bar sands of the middle Frio system (Ewing and Reed, 1984; Gregory and others, 1984). Analysis of general sandstone geometries in the Port Arthur area indicates that these sandstones were deposited in a dip-elongate, submarine channel system developed in an onlapping submarine channel fan complex. The thickest, most continuous sand bodies in this complex trend southeastward and represent submarine channel-fill sequences.

More detailed study of these sands by Tyler (1987) illustrates that the sandstone bodies in these channel and overbank systems display considerable lateral and vertical heterogeneity within the Port Arthur field (figures 20 and 21). Channel-fill sandstones, for example, which generally form the cleanest and most porous reservoir facies, are flanked by levee and overbank deposits that have lower porosities. The channel sandstones are as small as 1,000 ft in width (figure 22). These sandstone bodies are also vertically heterogeneous. Hemipelagic muds deposited during periodic interruptions in accumulations of channel-fill sands have divided each channel complex into several discrete sandstone layers (figure 21). Reservoir heterogeneity is further

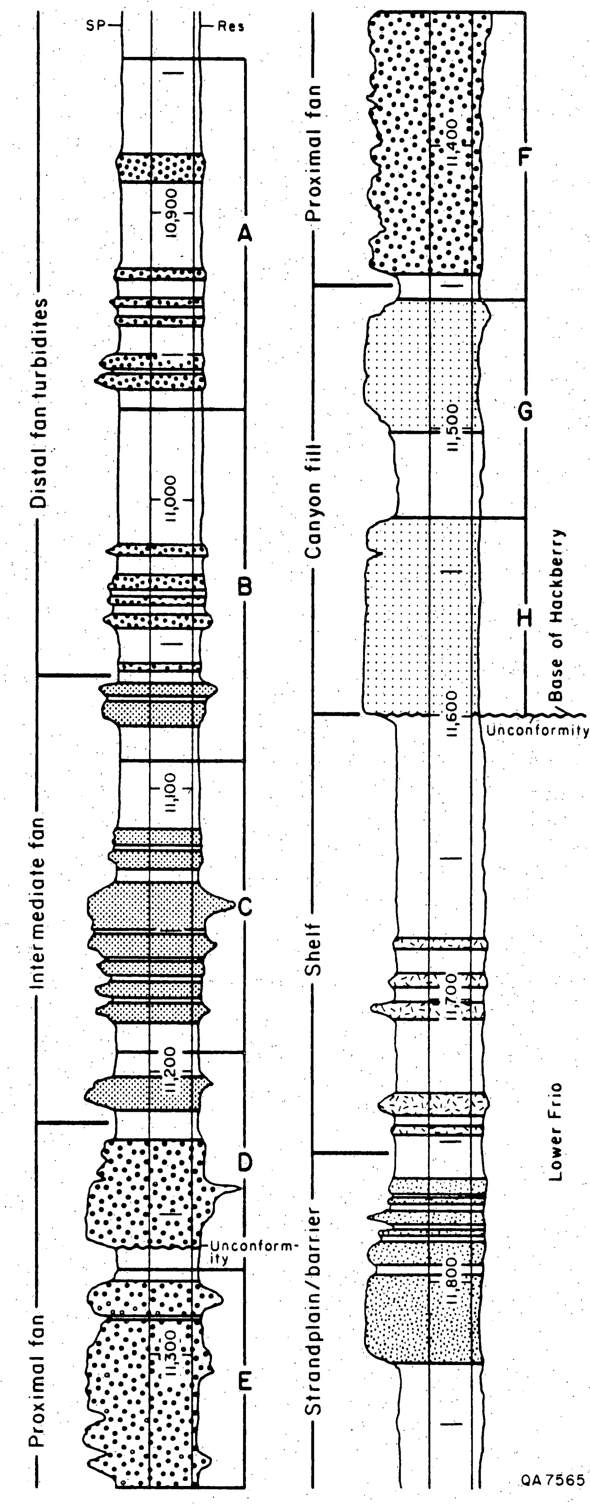


Figure 20. Typical log section through the Port Arthur Hackberry field, Gulf Coast of Texas, showing the general vertical sequence of lithologies and depositional environments. The sequence varies laterally across the area as shown in figure 21. From Tyler (1987).

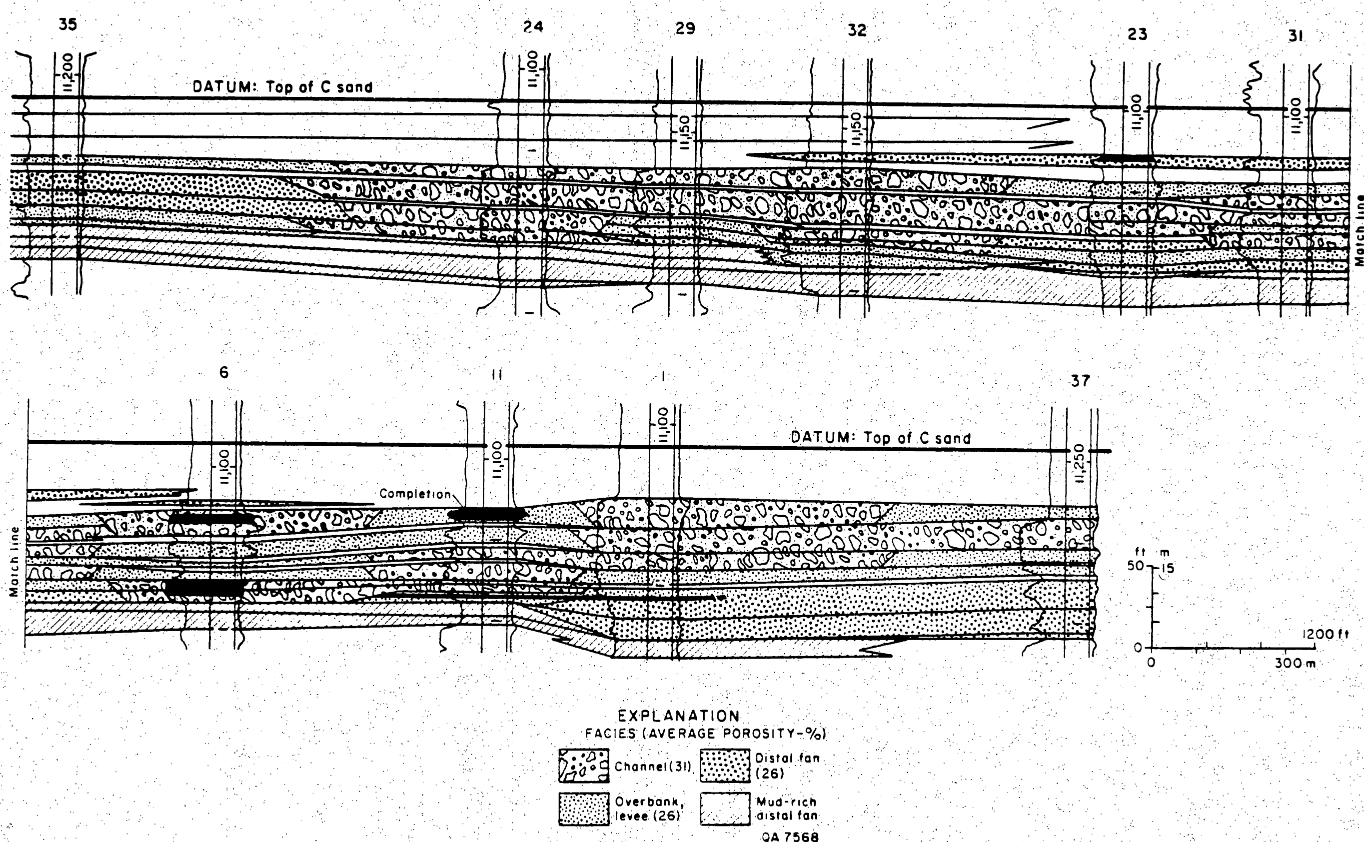


Figure 21. North-south cross section illustrating lateral facies changes in the C sand, Port Arthur field, Texas. Note that channel sandstones are separated into numerous distinct reservoir compartments by lateral facies changes and overlying and underlying thin shale beds. From Tyler (1987).

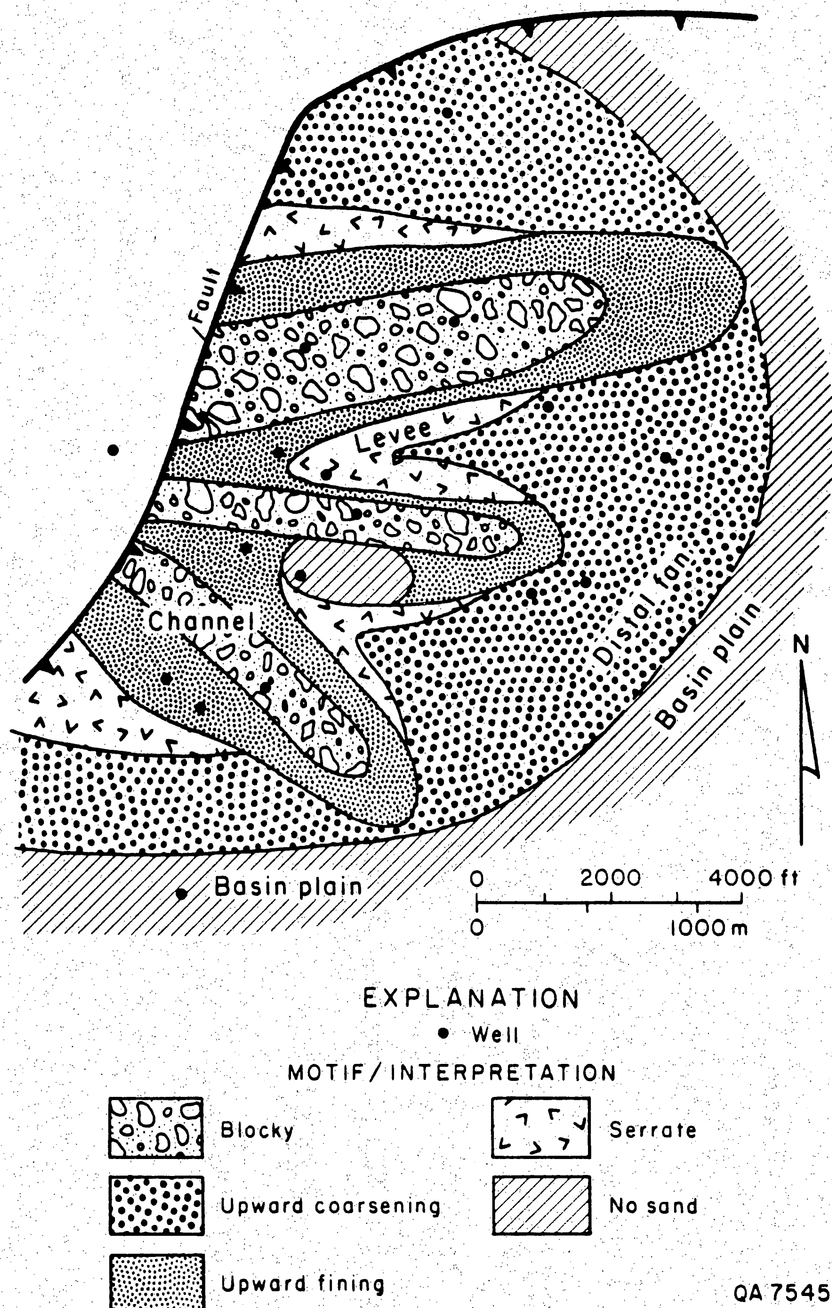


Figure 22. Facies map of the C-4 sandstone stringer in the Port Arthur field. Note that the porous channel deposits, which have a maximum width of about 2,000 ft, are separated by less porous, interchannel deposits. From Tyler (1987).

complicated by structural variations across the field. Each reservoir compartment has a separate gas/water contact determined by the field structure (figure 23). Clearly, these submarine fan sandstones form a highly compartmentalized reservoir sequence.

Testing of the Port Arthur field subsequent to its abandonment has provided additional support for the reservoir compartmentalization indicated by geologic study. Recompletion of an abandoned well in a previously untapped, lower sandstone layer (lower completion interval, well #6, figure 21) of what was considered to be a single reservoir unit resulted in an initial potential of 5.5 Mcf of gas and 300 barrels of condensate per day. This well eventually produced 144 Mcf before being shut in for reasons unrelated to production (Tyler, 1987). This new production represents an increase of about 150 percent over the total production recorded by this well from the previous completion (upper completion interval, well #6, figure 21) in what was previously considered to be the same reservoir (C sand).

Reevaluation of reservoir continuity in the Port Arthur field resulted in the recognition of 11 untapped reservoir compartments (Tyler, 1987). Estimations of remaining gas in place indicate that the Port Arthur field contains an additional resource of about 14 Bcf (20 percent of the original gas in place [OGIP]). This amounts to a potential 25-percent increase in gas recovery from this field.

La Gloria Field

The La Gloria field is developed in fluvial sandstones of the middle Frio Formation in Jim Wells and Brooks Counties, South Texas. Regional study of the Frio in this area illustrates that these deposits are part of the Gueydan fluvial system of the

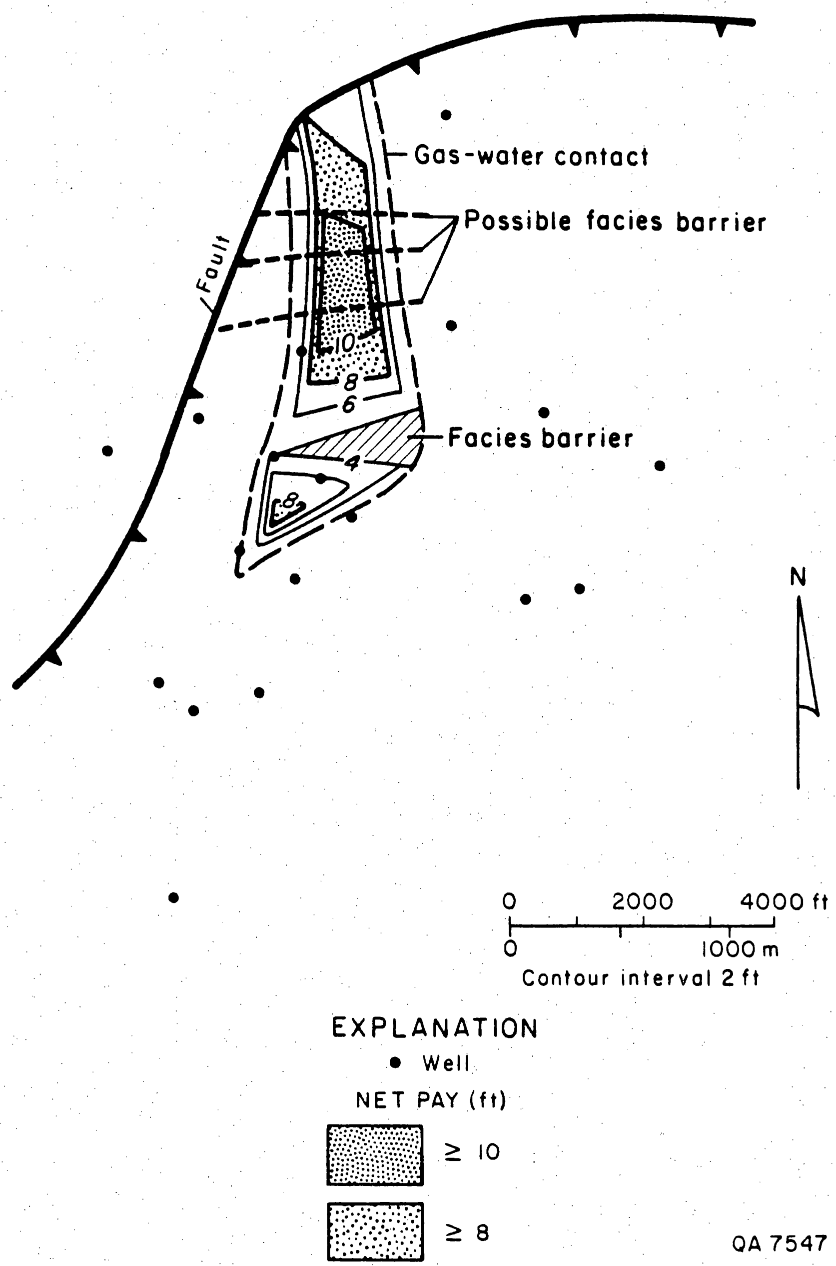


Figure 23. Net-pay map of the C-4 stringer in the Port Arthur field. Note the major reservoir compartmentalization due to sandstone geometries produced by variations in depositional environment. From Tyler (1987).

Rio Grande Embayment (Galloway, 1977; Galloway and others, 1982). The Gueydan sequence comprises (1) bed-load and mixed-load channel-fill sandstones and conglomerates, (2) crevasse splay sandstones, (3) poorly developed levee siltstones, and (4) floodplain mudstones (figure 24). Gueydan channels were generally low sinuousity; thus channel-fill deposits are typically straight and oriented parallel to depositional dip. Vertical stacking of channel sequences has produced sandstone bodies 50 to 100 ft thick. Individual channel sandstones also are commonly amalgamated laterally, producing significant lateral reservoir continuity (Galloway, 1977). Reservoir-quality facies also are developed in overbank splays, but continuity in these sandstones is considerably less than that in channel sequences.

Analysis of depositional sequences in the La Gloria field illustrates the variation in reservoir continuity. As illustrated in figure 25, sandstone continuity is markedly greater along depositional dip than along strike. These data, which are based on tabulating sandstone bed continuity among well pairs (George and Stiles, 1978) in the Brooks B unit, the most prolific of the La Gloria reservoirs, reflect the dip orientation of the Gueydan channel systems in the area. A second approach to determining reservoir heterogeneity involves measuring the widths of reservoir and nonreservoir facies belts. Figure 26 depicts the continuity of reservoir and nonreservoir facies in the lower Jim Wells unit using this technique. In both units, continuity data suggest that wells drilled on grids of 40 acres or greater are unlikely to penetrate interconnected reservoir units; the field is currently developed on about 280-acre spacing.

Pressure data recovered from the La Gloria field support the heterogeneity in reservoir facies indicated by studies of the depositional systems. Initial pressures recorded in a recent infill well were substantially higher than average pressures in the reservoir (figure 27). This indicates that this well penetrated a reservoir compartment

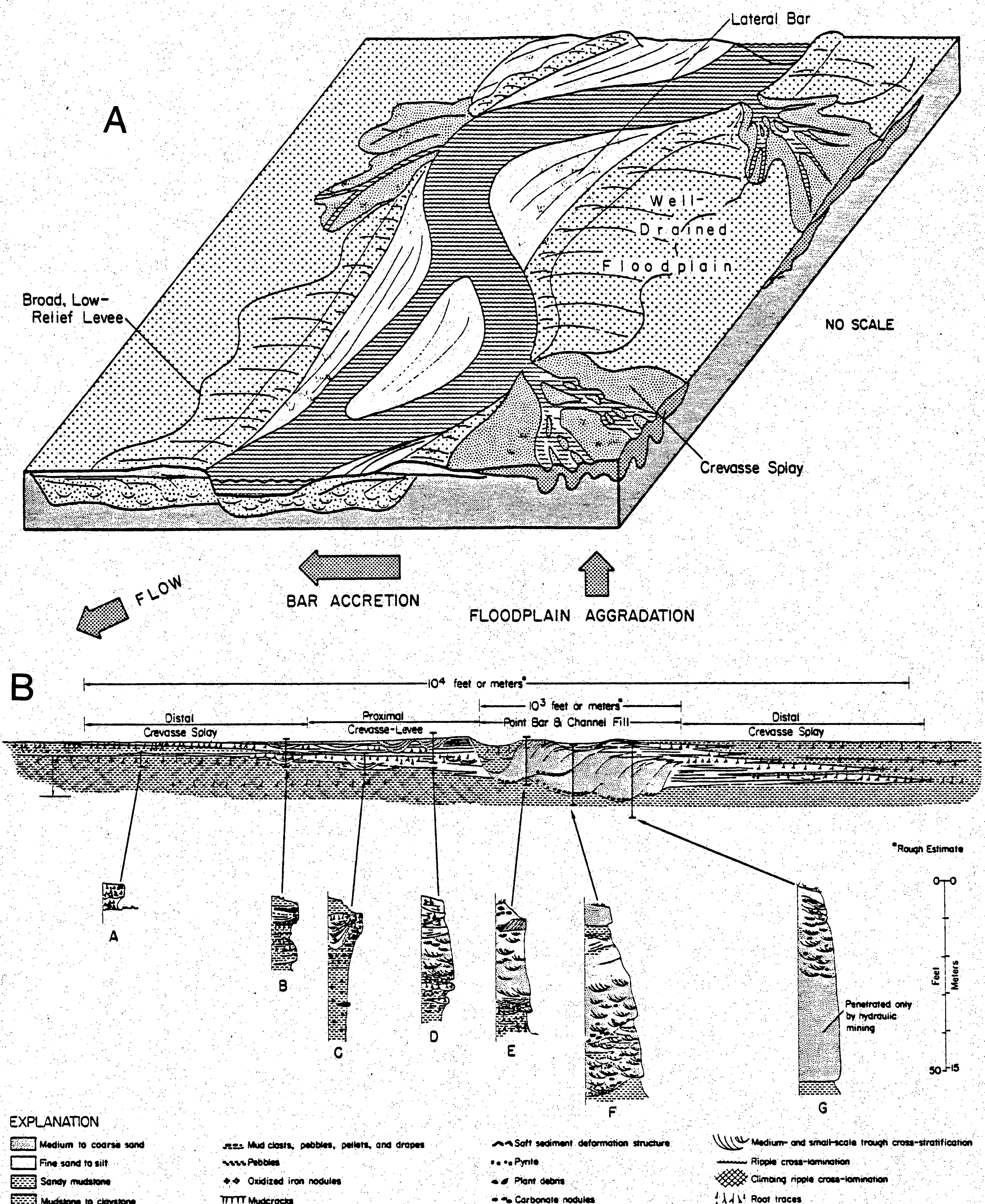


Figure 24. Facies and paleoenvironments of the Gueydan fluvial system (Frio). A. Block diagram showing low-sinuosity channels flanked by extensive crevasse splays. B. Cross section illustrating complex lateral interrelationships of channel, splay, and floodplain deposits. Note that within the channel complex, sandstone bodies are relatively thick and continuous. Continuity decreases laterally into interbedded splay sandstone and mudstones and siltstones of the surrounding floodplain. From Galloway (1977).

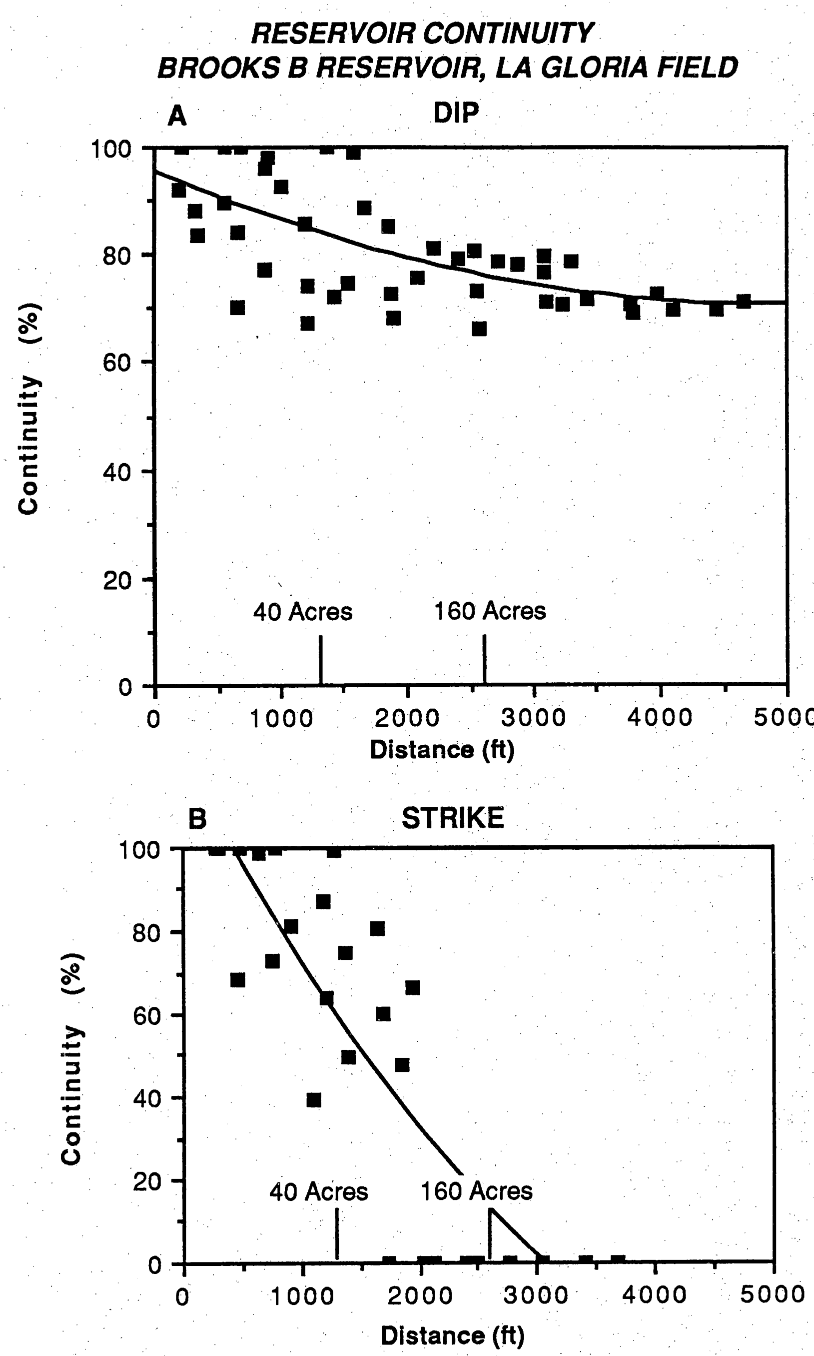


Figure 25. Continuity of reservoir facies (channel and splay sandstones) measured parallel to depositional dip (A) and strike (B) for the Brooks B reservoir interval in the La Gloria field. Note that there is little change in facies contact along dip, whereas contact along strike decreases rapidly. These data indicate that wells drilled along strike are relatively unlikely to encounter interconnnected reservoir compartments even when closely spaced. Continuity calculations are based on determining continuity of sandstone beds among well pairs according to the method outlined by George and Stiles (1978). After Ambrose and others (1988).

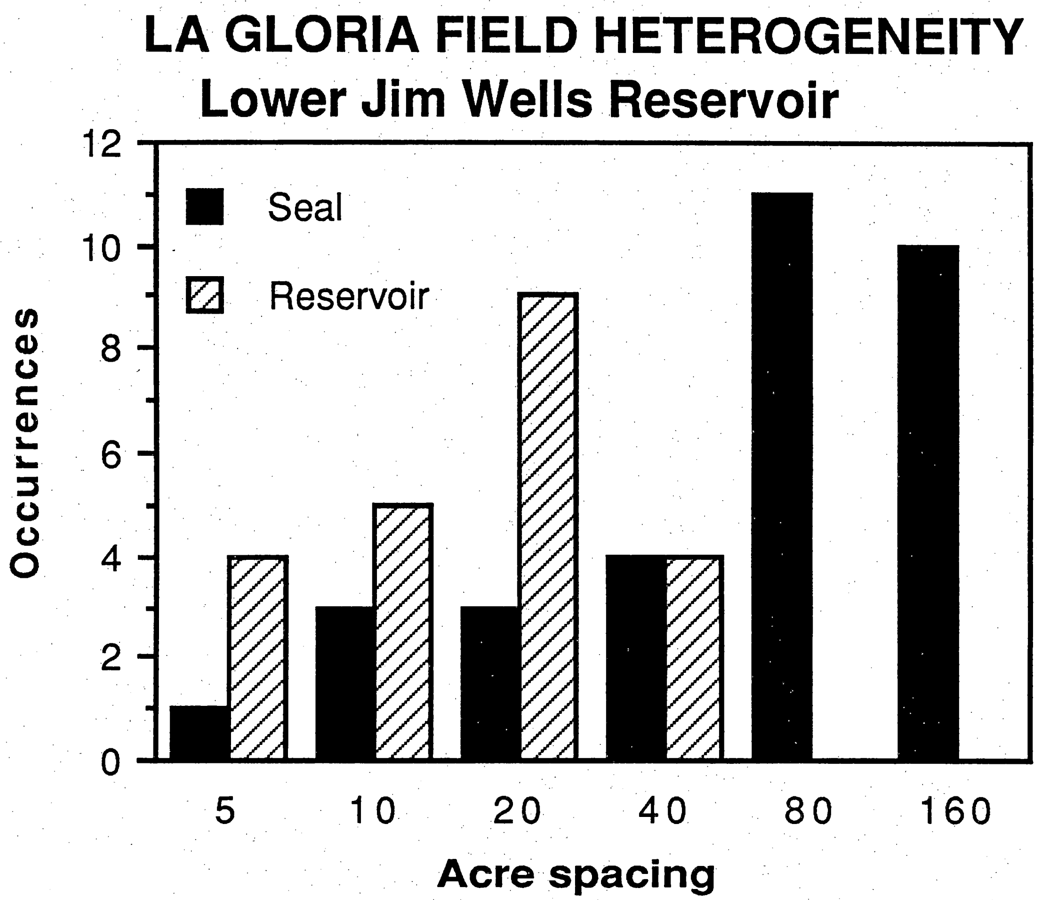


Figure 26. Continuity of reservoir and nonreservoir facies calculated for the lower Jim Wells reservoir in the La Gloria field. These data show that wells drilled on greater than 40-acre spacing will be unlikely to contact interconnected reservoir compartments. After Ambrose and others (1988).

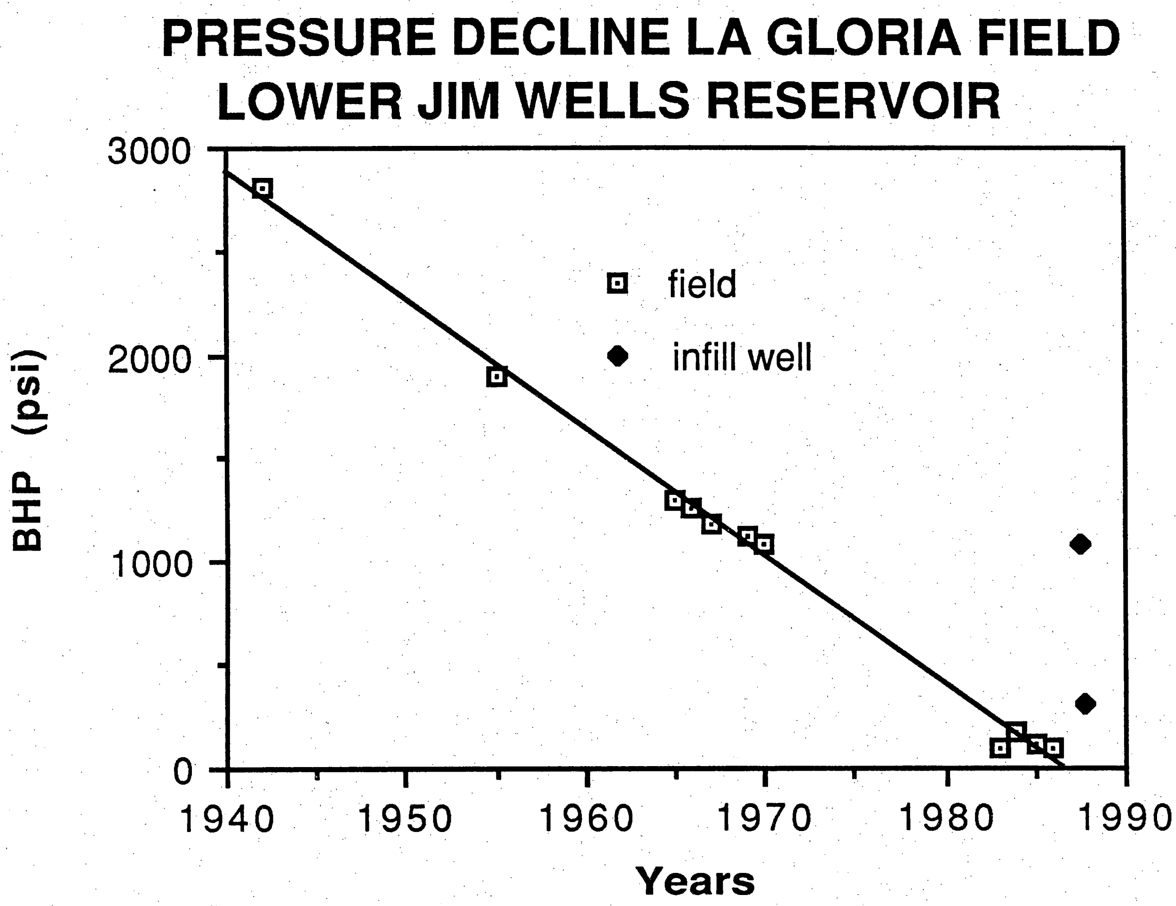


Figure 27. Pressure decline curve for the lower Jim Wells reservoir unit, La Gloria field. A recent (1987) infill well recorded initial pressures nearly five times higher than field average values. Rapid pressure decline in this well suggests that it has penetrated a small reservoir compartment that is in poor communication with the rest of this reservoir interval. After Ambrose and others (1988).

that was in poor pressure communication with the remainder of the reservoir. The rapid pressure decline exhibited by this well suggests that it is draining a rather small isolated compartment; facies analysis indicates that it is a splay sandstone of limited continuity.

The La Gloria field has produced approximately 1.5 Tcf of gas. Preliminary analysis of remaining OGIP and expected ultimate recovery (EUR) indicates that approximately 20 percent of the OGIP in the field is not being contacted by existing wells. This represents a potential for additional recovery of 25 percent of the EUR.

Julian North Field

Julian North field is located along the Vicksburg Fault Zone in South Texas (Kosters and others, in preparation), near the boundary of Brooks, Hidalgo, and Kenedy Counties. Depositionally, it lies in the Norias delta system of the Frio Formation, downdip of fluvial sediments of the middle and lower Frio Formation (Galloway and others, 1982). The Norias system consists of well-defined, vertically stacked lobes (Galloway and others, 1982), represented in the Lower Frio by thick, upward-coarsening, wave-reworked delta-front sands (Kosters and others, in preparation).

Julian North field has produced 16.8 Bcf through 1986 from two nonassociated gas reservoirs. Discovered in 1953, the Julian North field occupies part of an anticline created by rollover into a large growth fault; the Julian field lies immediately to the south in a similar structural and depositional setting (figure 28). Gas production in Julian North comes from upward-coarsening sand sequences 100 to 400 ft thick.

Sand-thickness maps of individual reservoirs show that the sand bodies are continuous along strike for 10 mi or more, but discontinuous along downdip. Facies

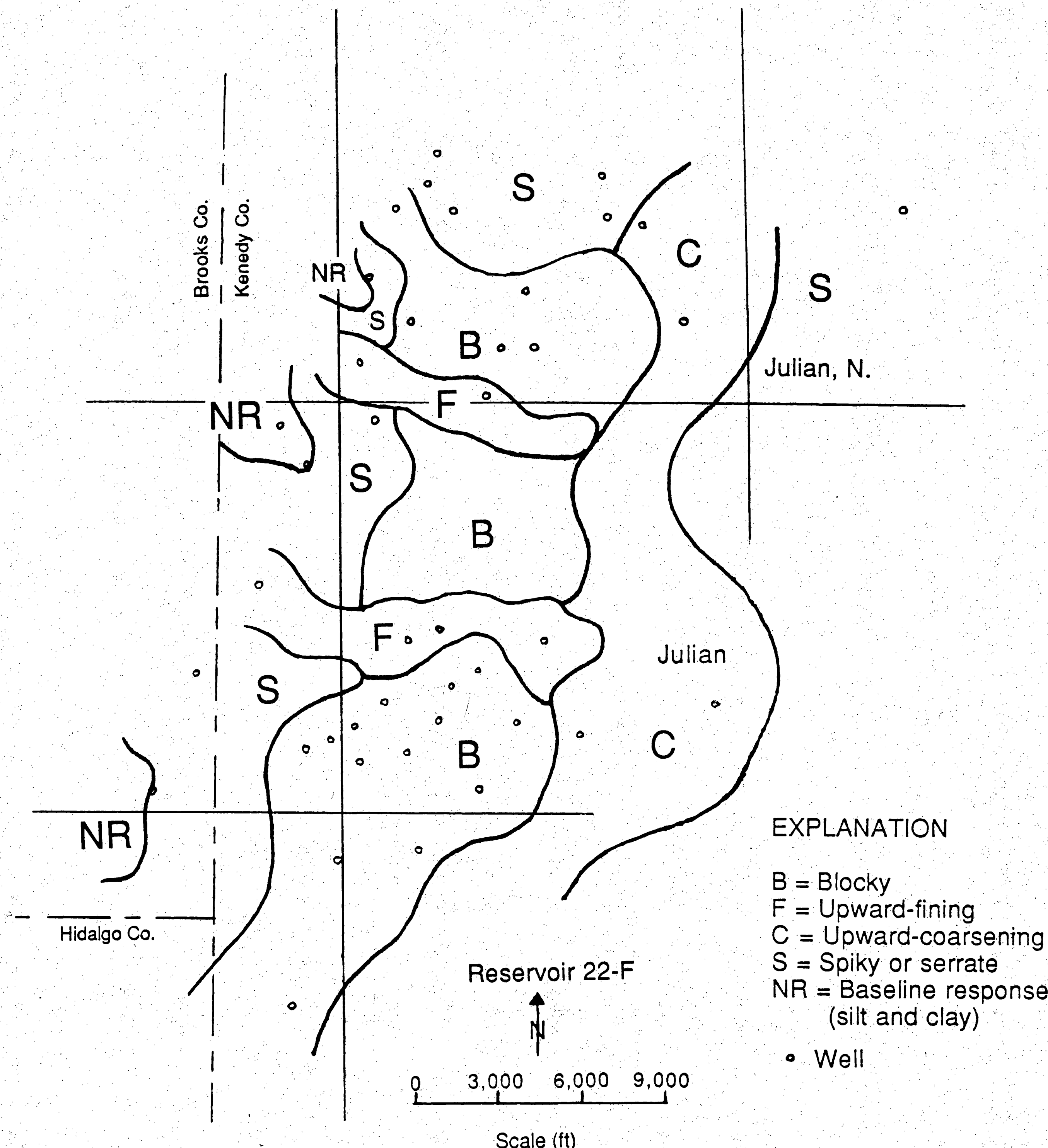


Figure 28. SP log-facies map illustrating typical geometries of depositional facies in the Julian and Julian North fields (22-F reservoir). Tidal channel facies (F) crosscut back-barrier (western S), barrier-core (B) and fore-barrier (eastern C and S) sand facies.

maps of the Julian North and Julian reservoirs reveal depositional trends characteristic of wave-dominated deltas and barrier islands. Most reservoir intervals comprise continuous, strike-elongate back-barrier, barrier-core, and fore-barrier facies, although some contain tidal channel facies that crosscut the barrier sands or dip-oriented, digitate distributary channel and channel-mouth bars less than 2 mi across (figure 28).

Continuity of reservoir facies, as measured from the widths of reservoir and nonreservoir facies, is high even in reservoirs that exhibit crosscutting tidal channel or digitate log patterns (figure 29). Despite this high continuity, reservoirs in the Julian North field need to be developed to about 320- to 160-acre spacing to assure complete contact with all reservoir compartments (figure 29). Since the field is currently drilled to only about 1280-acre spacing, considerable infill drilling will be necessary to maximize recovery.

Material balance calculations of one of the Julian North reservoir intervals (I-92) indicate an EUR of 24 Bcf. Original gas in place for this interval is estimated to be 36 Bcf, based on a volumetric estimate using detailed log analysis. These data indicate that as much as 12 Bcf, or 33 percent of the OGIP, is not in pressure communication with existing wells. This represents a potential 50-percent increase in gas reserves.

Potential new reserves calculated for the I-92 reservoir in the Julian field (50-percent increase over expected recovery) are substantially higher than those calculated for La Gloria field (26 percent), even though Julian North produces from deposits that are less heterogeneous. This discrepancy is due to the different ages and development histories of the two fields. The lower Jim Wells reservoir in the La Gloria field has experienced a long and complicated completion, cycling, and recompletion history since 1941. Initially wells were perforated near the gas/water contact to get maximum condensate production. Decades later other wells drilled

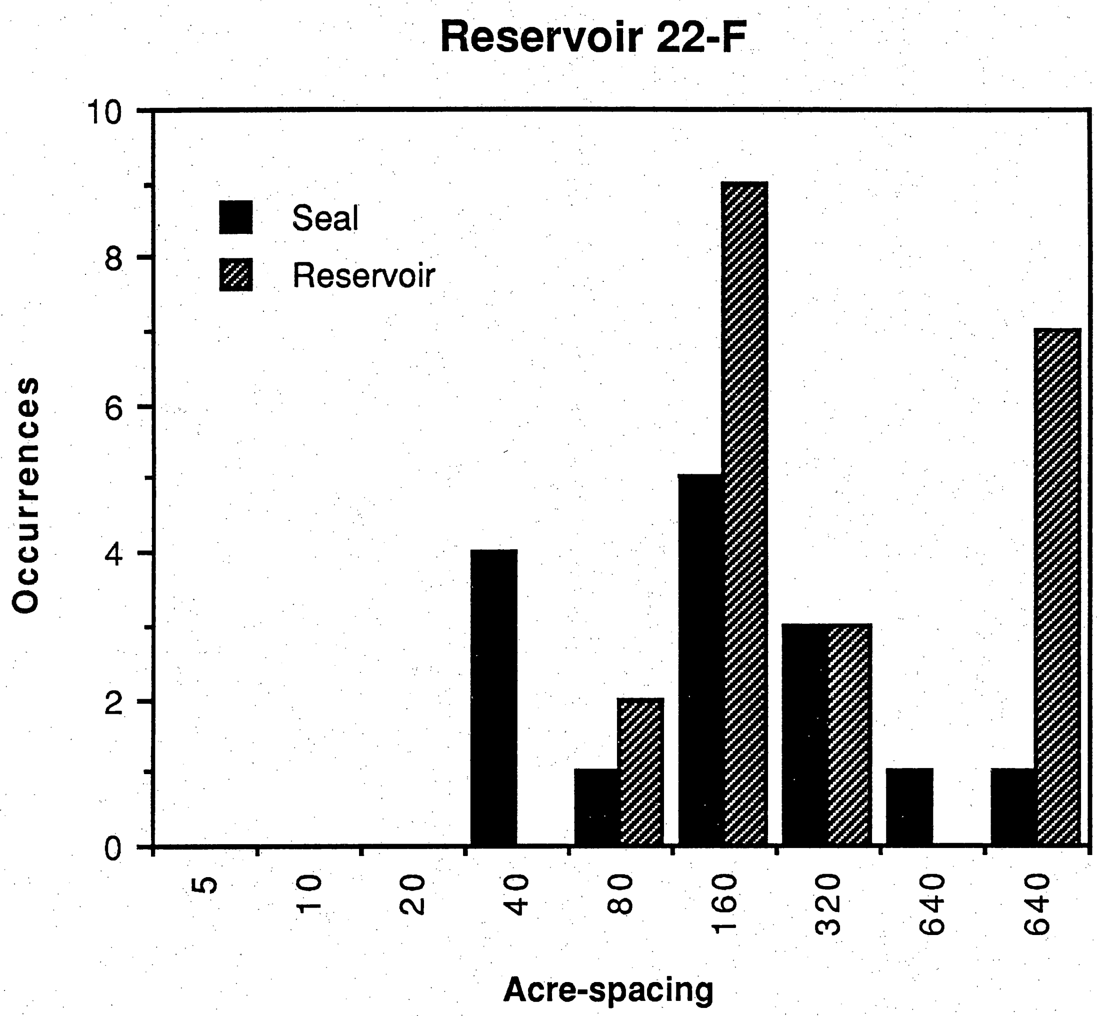


Figure 29. Continuity of reservoir and nonreservoir (seal) facies for the 22-F reservoir in the Julian and Julian North fields. Data indicate that reservoir compartments can be effectively contacted by wells spaced on about 160 to 320 acres or less.

nearby were recompleted to tap different zones within the lower Jim Wells, and at present new wells are being added on the crest of the field. The reservoir is currently developed on about 280-acre spacing.

The I-92 reservoir in Julian North field is at a much earlier stage in its development. Discovered in 1974, this reservoir is currently producing from wells drilled on about 1280-acre spacing. Continued drilling in the reservoir to 640-acre spacing will increase the EUR and decrease infill potential to 20 to 30 percent of EUR.

Carbonate Reservoirs

Hugoton Field

The Hugoton field is the largest gas-producing area in the United States, encompassing parts of Kansas, Oklahoma, and Texas (Halbouty, 1970). By the end of 1985, cumulative production in this giant field totaled 28 Tcf of gas; remaining proved reserves exceed 12 Tcf (American Gas Association, 1986). Approximately two-thirds (18 Tcf) of the cumulative production comes from the Kansas portion of the field; the Texas and Oklahoma portions of the field have each produced about 5 Tcf.

A great deal of detailed geologic and engineering data has recently become available for the Kansas portion of the field in the course of hearings held by the Kansas Corporation Commission in 1985 and 1986 to consider the application by field operators for permission to begin infill drilling. These data document significant heterogeneity within Hugoton reservoirs and illustrate that assessments of gas reserves based on material balance calculations from existing wells, which are currently on 640-acre spacing, can be far too conservative.

Geology.--The Hugoton field is a dry gas reservoir developed in Wolfcampian (lower Permian) carbonates (dolostones and limestones) and siliciclastics (quartz sandstones and siltstones) of the Chase Group at depths of 2,600 to 2,900 ft (Pippin, 1970). These rocks were deposited in nearshore, shallow-water marine environments developed on the eastern flank of the ancestral Rocky Mountains during the early Permian (Rascoe and Adler, 1983). The Hugoton is a classic stratigraphic trap. In general, permeable, shallow-marine, Chase Group dolostones pass updip into impermeable nonmarine shales and siltstones to the west; the top seal is formed by impermeable anhydrites of the overlying Wichita Group (Pippin, 1970). Detailed investigations of the Chase Group reveal complex sequences of lithologies that exhibit considerable lateral as well as vertical heterogeneity. Babcock (1985), for example, documented lithologic variability at scales ranging from regional to individual wells. This variability is due to the repeated migration of carbonate and siliciclastic depositional environments during the deposition of the Chase Group in the Hugoton field area. No less than five upward-shallowing sequences produced by relative rises and falls in sea level have been recognized in the Chase Group. The base of each sequence is composed of deposits formed following a major rise in relative sea level; these deposits are overlain by progressively shallower water deposits formed during progradation. This cyclicity, combined with the regional westward-dipping depositional slope in the area, produced complex lithologic sequences that vary across the field due to lateral migration and variations in water depth, wave energy, and proximity to sources of siliciclastics. The wide variety of carbonate and siliciclastic lithologic types encountered in the Hugoton field is illustrated in figure 30 (Babcock, 1985).

Reservoir quality is similarly variable in the Hugoton field. The most permeable rocks are (1) mud-free carbonates, which are most common at the bases of cycles and downdip, and (2) mud-free quartz sandstones deposited updip and at the top of progradational cycles in marginal marine settings. Muddy carbonates and sandstones that contain significantly less permeability are common updip in the western part of the field but are also found throughout the area in the middle and upper parts of the reservoir. The resultant variations in lithology and permeability across the field are illustrated in figure 31 (Babcock, 1985). This cross section through the Winfield sequence illustrates the dominance of massive carbonates in the section to the east, whereas siliciclastics are increasingly abundant to the west. As illustrated by porosity and permeability data depicted in figure 31, sandstones, which are especially common in the west, and dolomitized grainstones, which are abundant in the east, are the major reservoir facies.

In addition to heterogeneity caused by variations in depositional environments across the field, diagenetic changes in Chase Group carbonates have created further variability in reservoir permeability and porosity. Hinterlong (1985) recognized secondary dissolution of carbonates in the central part of the field and associated reprecipitation of carbonate cement in the easternmost part of the field. Prezbindowski and others (1988) also recognized these dissolution-reprecipitation events. They interpreted this dissolution to be the result of early influx of meteoric waters during periods of subaerial exposure that took place following at least two of the major upward-shallowing cycles during Chase Group deposition. Paleosols and evidences of dissolution in underlying carbonates formed during these periods of exposure are thickest along the western and northern margins of the field and thin to the south and east, reflecting the eastward-dipping paleoslope. Dolomitization, which is variable in its extent across the field, also has affected reservoir heterogeneity.

CHASE GROUP SEDIMENTATION PATTERNS

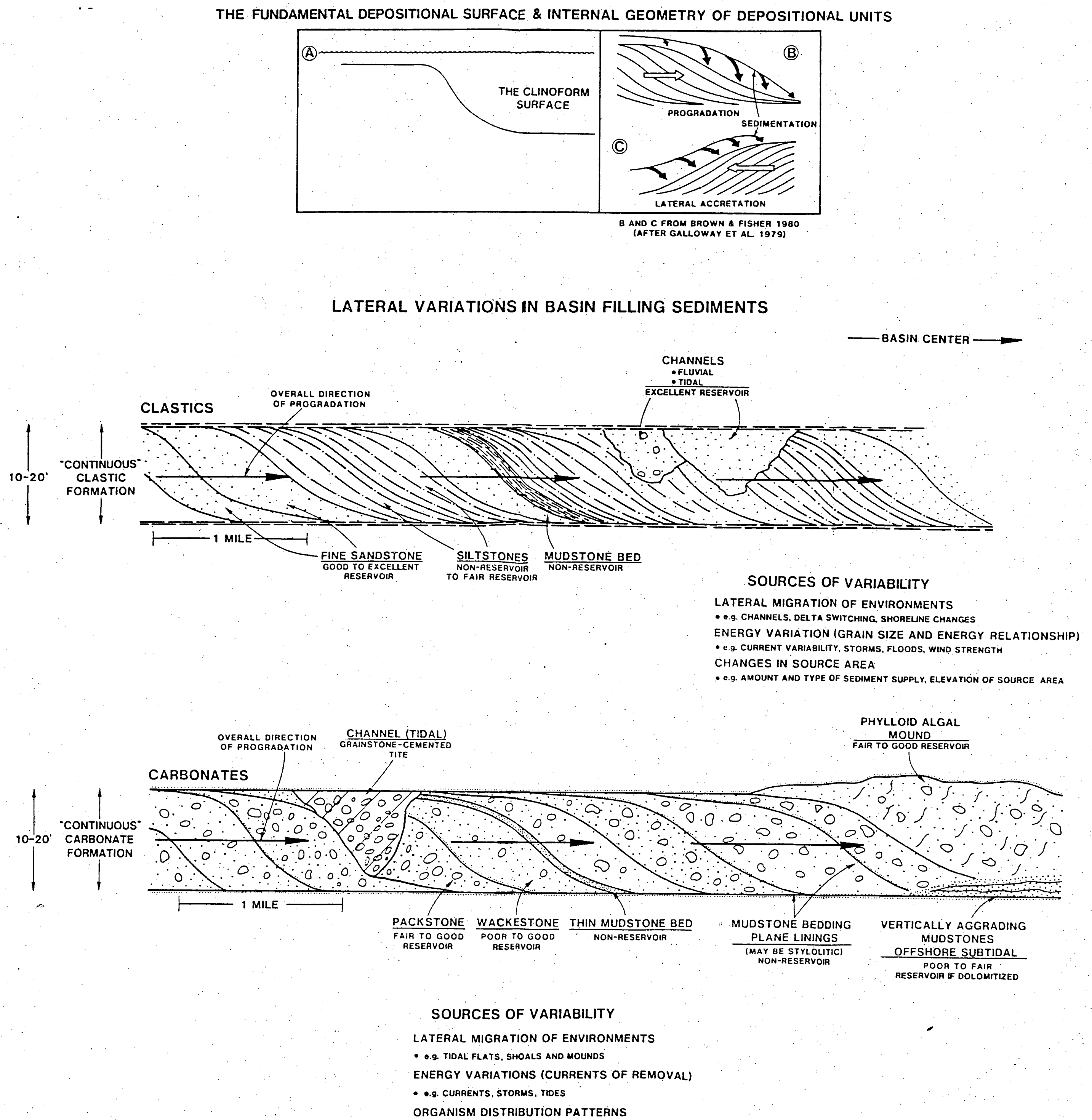


Figure 30. Styles of sedimentation and internal geometries of siliciclastics and carbonate rocks of the Lower Permian Chase Group in the Hugoton field of Kansas. The combined effects of (1) lateral migration of depositional environments, (2) variations in wave energy, (3) distribution of organisms, and (4) changes in the rate of siliciclastic sediment influx combine to produce depositional facies that are highly complex in both vertical and lateral extent. From Babcock (1985), exhibit 14.

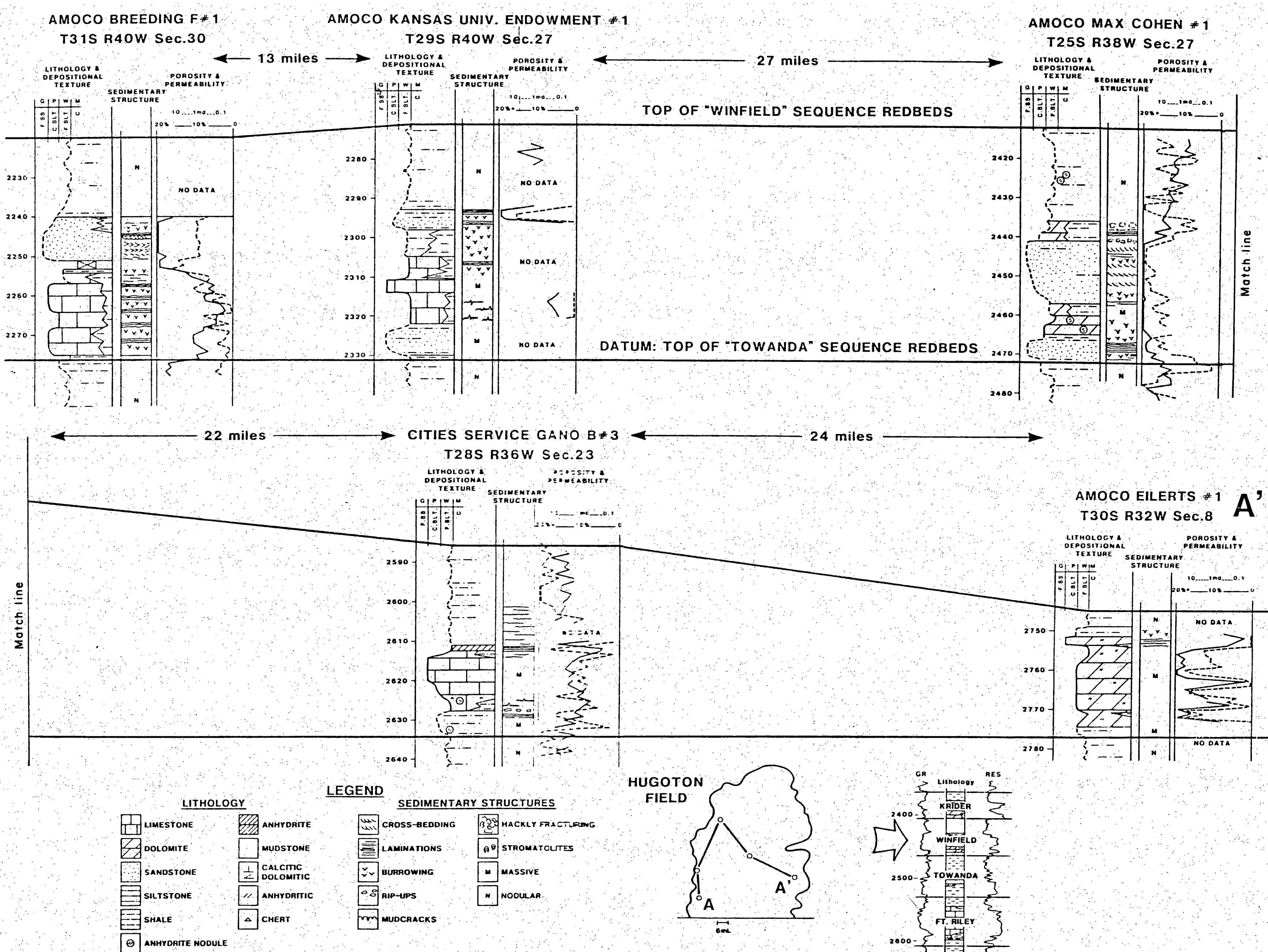


Figure 31. Cross section through the Kansas Hugoton field illustrating variations in lithology and porosity and permeability in the Winfield sequence (middle Chase Group). Note that clean carbonates dominate the eastern part of the field, whereas siliciclastics, both fine grained and coarse grained, are abundant in the west. Clean carbonates, especially dolostones, and sandstones are the most porous reservoir facies. From Babcock (1985), exhibit 142-6.

Dolomitized carbonates in the reservoir are commonly characterized by secondary porosity and enhanced permeability (Babcock, 1985).

Lateral changes in lithology have been documented on a finer scale by Hinterlong (1985) on the basis of detailed analysis of closely spaced wells using a synthesis of well log and core data. These studies reveal major changes in lithology between wells currently on 1-mi spacings and imply that no single well is in communication with all permeable zones (Hinterlong, 1985). Studies of interwell variations in lithology were further studied by Pelzmann (1985) using Schlumberger Faciologs (Wolff and Pelissier-Combescure, 1982; Widdicombe and others, 1984) produced from well log suites. These data indicate similar heterogeneity between wells as closely spaced as 0.25 mi.

Although no similarly detailed geologic studies of the Texas or Oklahoma portions of the Hugoton field have been published, available data indicate that the rocks constituting these reservoirs are very similar to those in Kansas. The Texas Hugoton differs slightly in two ways: (1) because the reservoir is developed a little basinward from the Kansas Hugoton, the volume of westwardly-derived siliciclastics deposits is less and (2) the western, or updip, margin of the field is formed by a small anticlinal structure (Pippin, 1970).

Engineering.--Engineering studies, including reservoir simulations and analyses of pressure data, by engineers from several different operating companies in the Hugoton field support interpretations of significant heterogeneity in the reservoir.

Examination of pressure data from repeat formation testers and drill-stem tests, for example, revealed wide variations in pressures, both vertically and laterally within the Chase Group in the Kansas Hugoton. Some zones showed essentially no pressure depletion after decades of production, indicating that reservoirs are not in complete pressure communication throughout the field (Sale, 1985; Brown, 1985). Figure 32 illustrates the variability in pressures and lithologies in the field. Note, for example, the marked variation in pressure values recorded in the Winfield interval from closely spaced wells.

Pressure data from recently drilled wells in the field further support heterogeneity across the field. Petzet (1988) reported that of the first 86 infill wells drilled in 1987, 75 percent had higher pressures than the most recent values obtained in initial wells. Comparison of subsequently drilled infill wells showed a similar increase, although only about 13 percent increased by more than 10 percent. Interestingly, new wells drilled in the Texas portion of the field in the late 1970's also exhibited higher than average reservoir pressures, indicating poor pressure communication throughout that portion of the field due to reservoir heterogeneity. Figure 33 is a material balance plot of the Texas Hugoton field (Tripp, 1985). Note that in 1976 the average pressure increased 10 percent over that expected by the previous rate of decline. This increase in pressure is directly related to the addition of about 30 new wells in the field at this time. This significant increase in the average recorded pressure for the field indicates that these new wells came in at significantly higher than average pressures.

All of the major operators in the Kansas Hugoton field have calculated the potential for additional gas reserves in the field (table 25). An analysis of a 25-mi^2 area within the field by Mobil engineers indicated substantial amounts of OGIP not in pressure communication with existing wells (Besly, 1985; Liveris, 1985; Robl, 1985). Both computer reservoir simulations and comparisons of calculations of OGIP on a per-well basis based on volumetrics with those derived from material balance studies (bhp/z) produced similar estimates of OGIP not likely to be recovered by current development (20 to 25 percent). On the basis of similar comparisons in a much larger

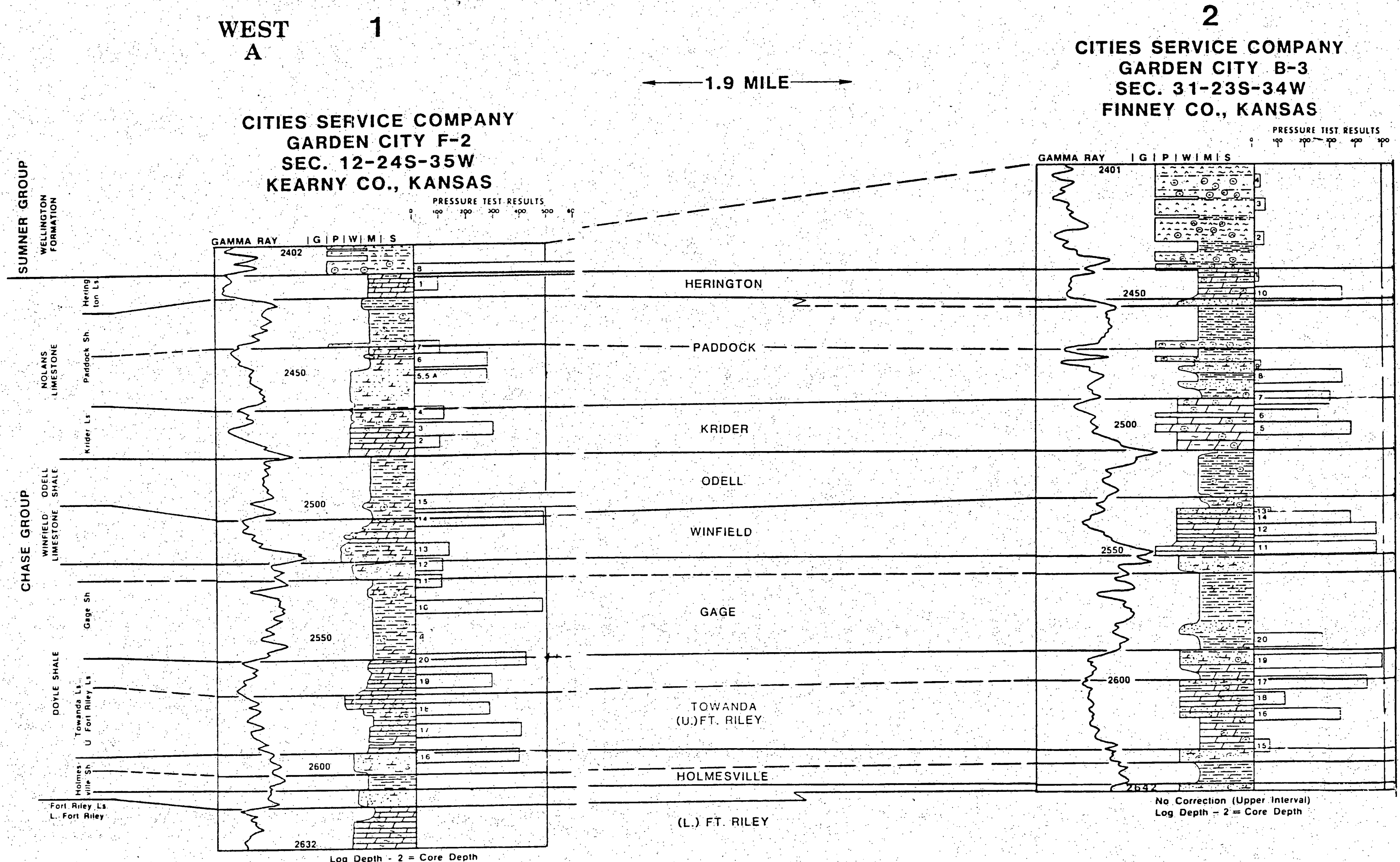


Figure 32. West-east cross section through the north-central portion of the Kansas Hugoton field illustrating marked variations in lithologies and pressures in correlative units of the Chase Group. Note especially the marked differences in pressure values (more than 100 percent) recorded within the Winfield Limestone in wells only a mile apart. From Brown (1985), exhibit 67-12.

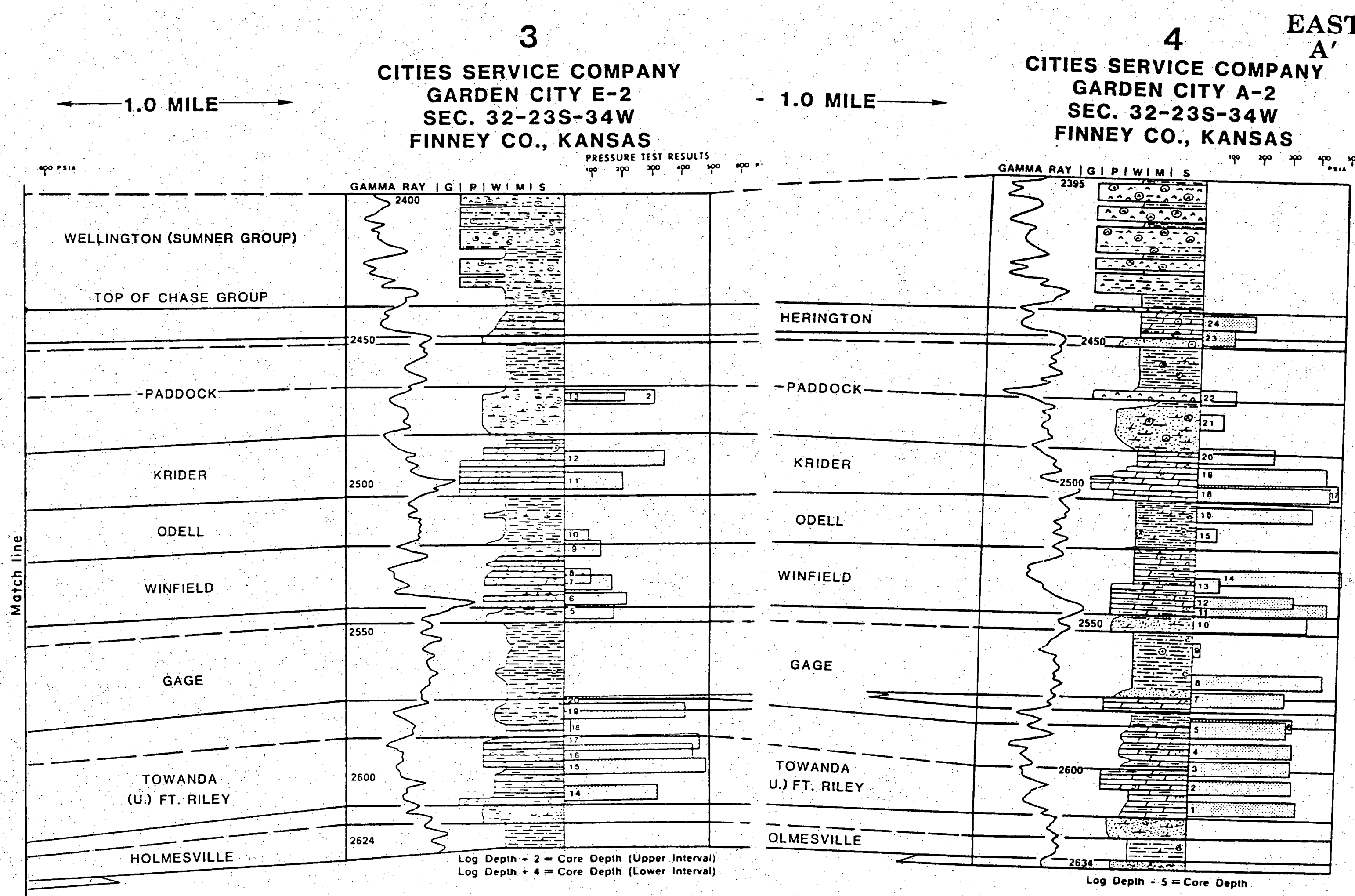


Figure 32. Continued.

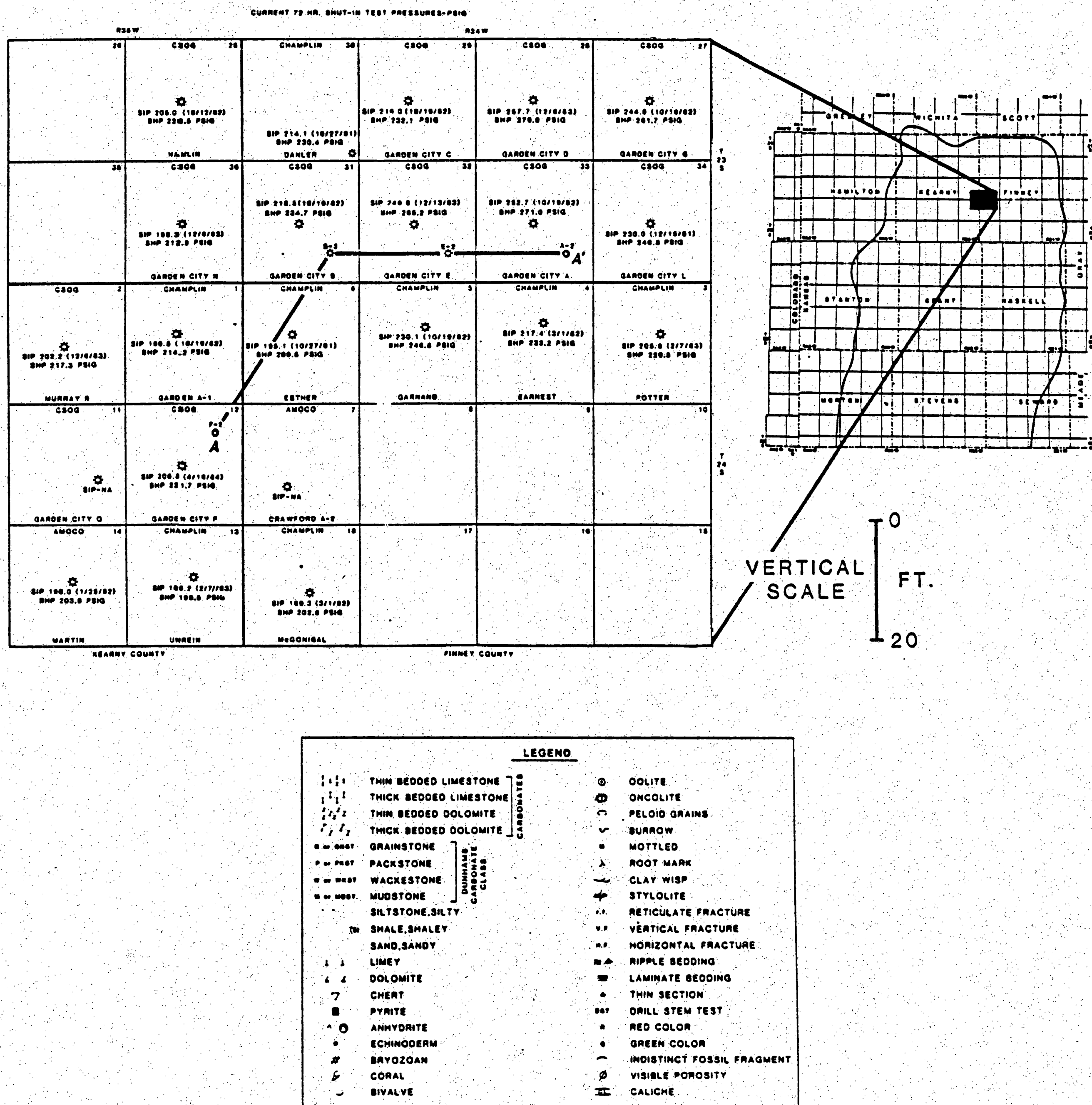


Figure 32. Continued.

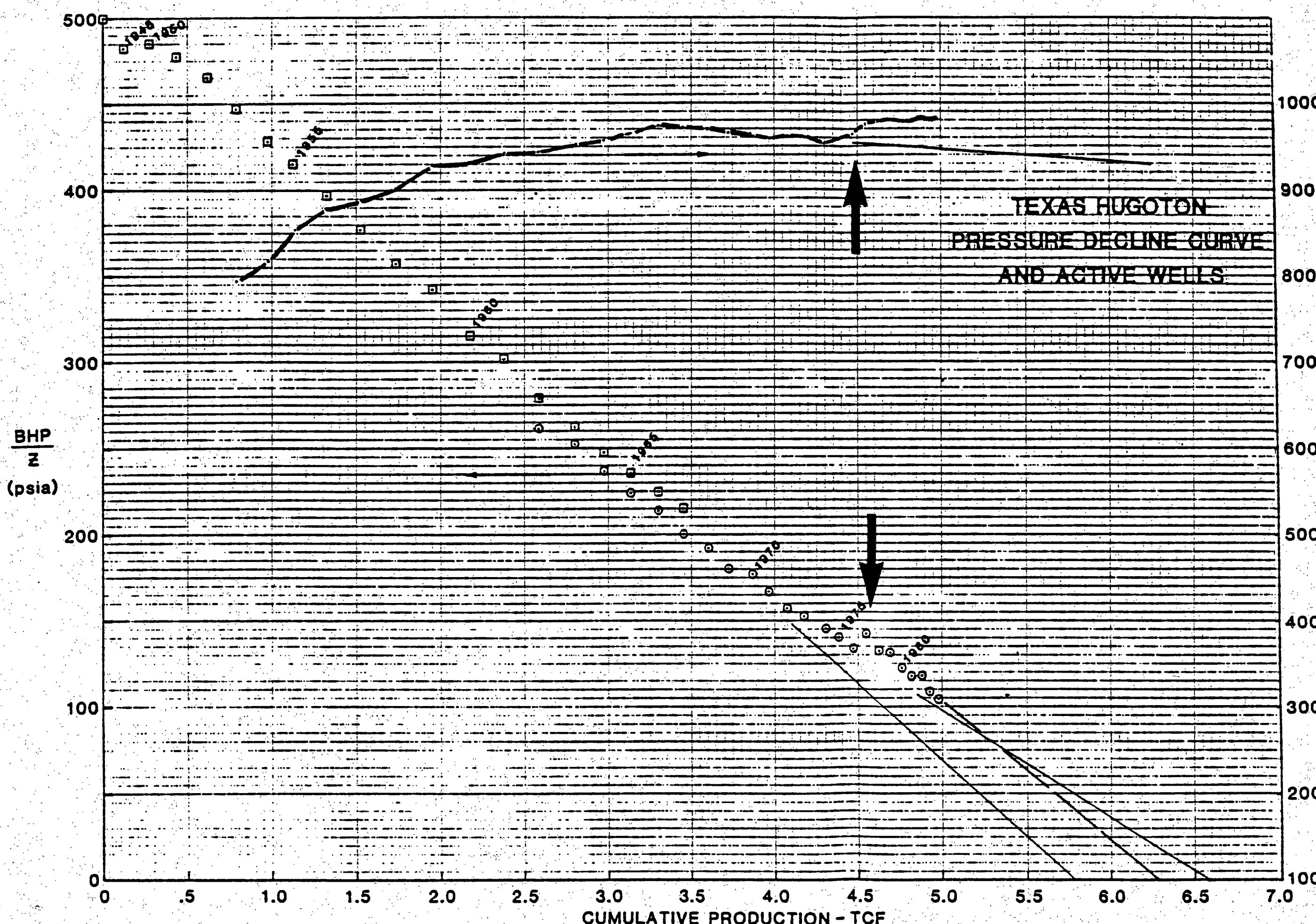


Figure 33. Material balance plot for the Texas portion of the Hugoton field. Note the significant increase in bhp/z in 1975. This increase was associated with the drilling of approximately 30 new wells in the preceding year and indicates that many of these new wells encountered significantly higher than expected pressures. From Tripp (1985).

TABLE 25. ESTIMATIONS OF UNRECOVERED GAS FROM THE HUGOTON FIELD

KANSAS

OPERATOR	REFERENCE	NUMBER OF WELLS	OGIP (Bcf)	EUR (Bcf)	REMAINING GAS (%OGIP)	REMAINING GAS (%EUR)
Cities	Vairogs, 1985	4	16	8.7	46	84
Helmerich & Payne	Keeling, 1985	8	105.3	65.4	38	61
Mobil	Besly, 1985	25	214.4	160.4	25	34
Mobil[1]	Robl, 1985	25	214.4	171.7	20	25
Tenneco	Sale, 1985	180	2467	1381	44	79

TEXAS

OPERATOR	REFERENCE	NUMBER OF WELLS	OGIP (Bcf)	EUR (Bcf)	REMAINING GAS (%OGIP)	REMAINING GAS (%EUR)
Shamrock		56	1129	635	44	78

[1] Based on computer simulation; all other calculations based on material balance versus volumetrics determinations.

study, Tenneco engineers determined that approximately 38 percent of the OGIP will not be produced by wells on 640-acre spacing due to reservoir heterogeneities (Sale, 1985). A considerable degree of variability in recovery efficiency was observed across the field, however. Gas projected to be unrecovered by single wells ranges from as little as 23 percent to as much as 62 percent. Modeling of Cities Service lease areas in the Hugoton field indicated similar ranges in recovery efficiencies. Relph (1985) determined that unrecovered gas in these areas of the field will range from a low of about 15 percent to a high of 66 percent. Estimates of uncontacted OGIP by Amoco on their lease holdings are similar, 15 to 40 percent. Such variations in recovery efficiency are expected in heterogeneous reservoirs and illustrate the importance of detailed geologic and engineering characterization of reservoirs in optimizing recovery from infill drilling techniques.

Generally similar results were obtained in the Texas Hugoton field. Diamond Shamrock engineers performed material balance calculations and plotted drainage areas for a 56-well area (figure 34). Their studies suggest that approximately 44 percent of the OGIP in this area is uncontacted. This implies a new resource potential of about 81 percent of the current EUR in the Texas Hugoton and documents a degree of reservoir heterogeneity that is similar to that observed in the Kansas Hugoton.

All of these studies document the importance of infill drilling to improved recovery of OGIP in the Hugoton field. They also, however, document the potential for new reserves. Current reserve estimates for the Hugoton field are primarily based on material balance calculations, as they are for most gas fields. The reservoir heterogeneities documented by geologic and engineering studies of the Hugoton field, however, illustrate that average pressures recorded from existing wells are not representative of the entire field. Reserve estimates derived from these data include

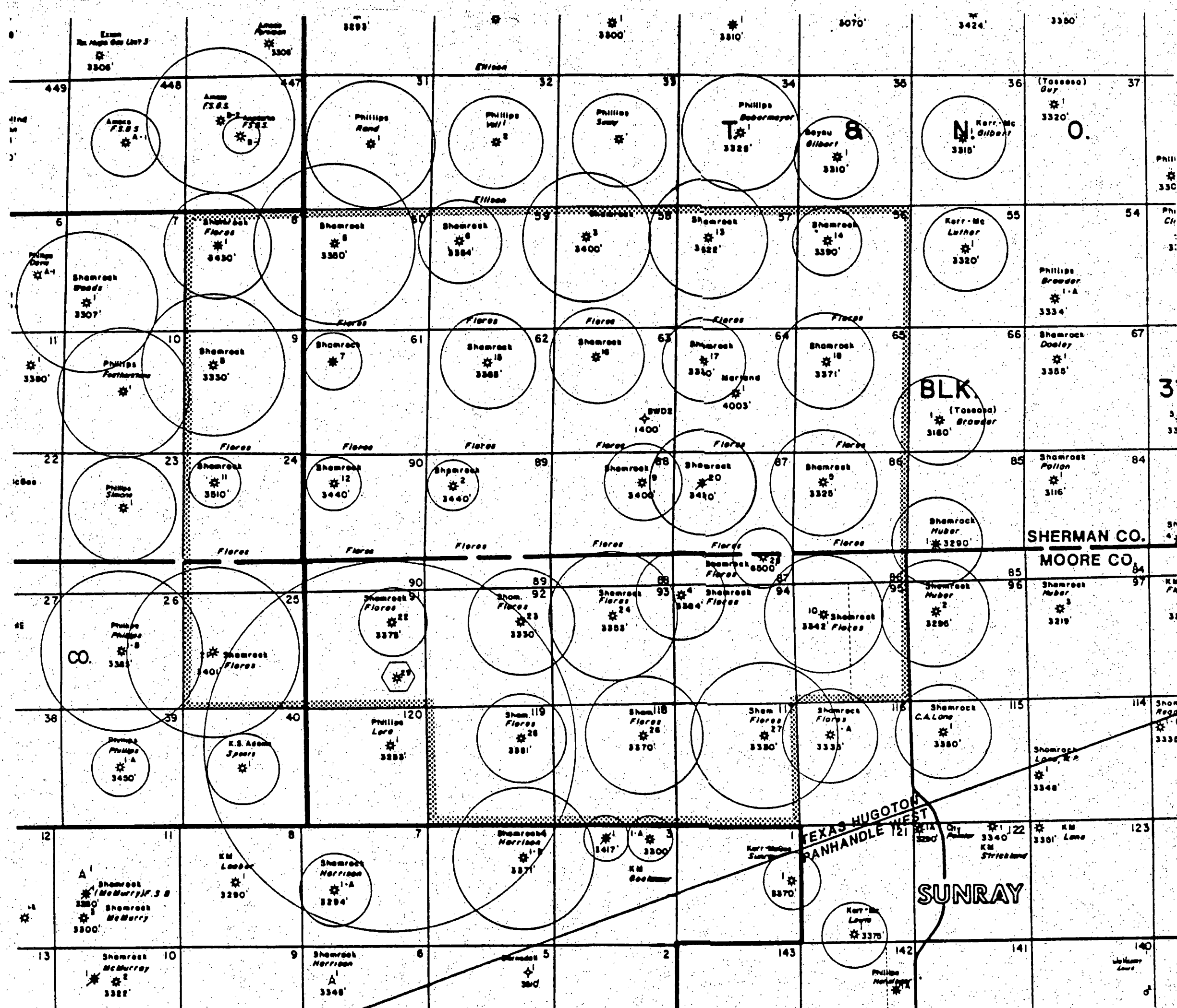


Figure 34. Map of part of the Texas Hugoton field showing calculated maximum drainage areas based on determination of expected ultimate recovery and original gas in place for 56 wells on 640-acre spacing. Data predict that approximately 44 percent of the OGIP will not be produced by current well spacings. This represents a reserve growth potential of 78 percent. From Texas Railroad Commission hearing files, docket 10-87, 871, exhibit 3.

only that fraction of the OGIP contacted by those wells; these estimates are thus low. Current estimates of remaining reserves for the Kansas Hugoton field, for example, are approximately 9.5 Tcf, giving an EUR of about 28 Tcf. Estimates of OGIP for the entire field based on volumetrics calculated for individual wells (discussed previously) range from a high of 52 Tcf (Cities Service calculations, from Relph, 1985) to about 36 Tcf (based on Mobil and Tenneco data).

The significant variation in estimates of remaining gas in the Hugoton field, which are based on determination of recovery efficiency by individual operators on a per-well basis in their own producing areas, illustrates the considerable heterogeneity across the field but certainly also suggests that significant new reserves will be added as infill drilling proceeds. We have used the most conservative of these estimates (that by Mobil) as a basis for assessing the potential for reserve growth in the Kansas Hugoton and geologically similar gas reservoirs across the country.

Application of Case Studies to Reserve Growth Estimation

In five of the six gas reservoirs described above, estimates have been made of the amount of gas that is not currently being contacted by existing wells by comparing EUR with OGIP (table 26). This gas, which will not be produced from these fields with existing well spacings and conventional recovery techniques, constitutes a sizable potential gas resource that we have designated Advanced Reserve Growth (AGR) potential. We have used the data obtained from these gas reservoir case studies to help assign reserve growth factors to heterogeneity rankings already established for specific depositional settings from study of both oil and gas reservoirs. In all cases, factors are conservative relative to actual calculations of resource

TABLE 26. RESERVE GROWTH POTENTIAL

CARBONATE

FIELD	DEPOSITIONAL SETTING	RESERVE GROWTH POTENTIAL (%OGIP)	RESERVE GROWTH POTENTIAL (%EUR)
Hugoton	Restricted platform, dolomitized	20	25

SILICICLASTIC

FIELD	DEPOSITIONAL SETTING	RESERVE GROWTH POTENTIAL (%OGIP)	RESERVE GROWTH POTENTIAL (%EUR)
Julian North	Wave-dominated delta	33	50 *
La Gloria	Coarse-grained meanderbelt	21	26
Port Arthur	Submarine channel	20	25

* Field incompletely developed; final value will be 20% - 30%

potential made for these reservoirs. For example, in the Hugoton field, estimates of noncontacted OGIP range from about 25 to 84 percent (table 25). We have taken the most conservative of these estimates, 25 percent, as a reasonable indication of the AGR potential across this field. The reserve growth factor assigned to restricted platform dolomite reservoirs based on the Hugoton example is even more conservative (0.20). Thus our growth factors allow for variations in heterogeneity and reserve growth potential within depositional types and uncertainties regarding the maximum recovery efficiency possible in gas reservoirs (commonly estimated between 80 and 92 percent).

APPENDIX 3.

Economic Modeling

ICF Lewin Energy

ECONOMIC ASSESSMENT OF THE U.S. NATURAL GAS RESOURCE BASE

ICF-LEWIN ENERGY

MAY 1988

ECONOMIC RECOVERY FROM RESERVE GROWTH

NON-ASSOCIATED NATURAL GAS

20S00149

ECONOMIC RECOVERY FROM RESERVE GROWTH NON-ASSOCIATED GAS — BACKGROUND

OBJECTIVE: ASSESS THE ECONOMIC POTENTIAL OF NON-ASSOCIATED NATURAL GAS RESERVE GROWTH AND DEVELOP PRICE/SUPPLY TABLES FOR U.S.

METHODOLOGY:

- ESTABLISH ADVANCED RESERVE GROWTH TARGET GAS FOR SELECTED PROVINCES
- USE ICF-LEWIN GAS ECONOMICS MODEL TO ASSESS INDIVIDUAL PROVINCE POTENTIAL BY FIELD-SIZE CATEGORY, 2,500 FOOT DEPTH INCREMENT, AND HETEROGENEITY CATEGORY
  - — DEVELOP TYPICAL DECLINE CURVES BY PROVINCE, DEPTH INCREMENT AND HETEROGENEITY CATEGORY
  - — APPLY DECLINE CURVES TO PROVINCE TARGET GAS TO DEVELOP PRODUCTION PROFILES FOR TYPICAL WELLS
  - — ASSESS FULL GAS WELL ECONOMICS FOR INFILL WELLS FOR EACH PROVINCE AT VARIOUS WELL SPACINGS
  - — TABULATE RESULTS FOR OVERALL PRICE/SUPPLY TABLE

FOR MORE DETAILED INFORMATION, SEE METHODOLOGY CHAPTER.

20S00149

ECONOMIC RECOVERY FROM RESERVE GROWTH — NON-ASSOCIATED GAS

(10% REAL RATE OF RETURN)

PROVINCE	EUR (TCF)	TARGET GAS (TCF)	ECONOMIC RECOVERY (TCF)* <\$3/MCF	\$3-5/MCF	>\$5/MCF	UNCONTACTED (TCF)
GULF COAST (CENOZOIC)	240	27.5	11.7	1.3	9.1	5.4
GULF COAST (MESOZOIC)	64	12.5	6.0	0.6	2.4	3.5
PERMIAN BASIN	90	15.5	4.2	0.3	6.3	4.7
ROCKY MOUNTAIN	50	10.8	1.2	0.3	6.3	3.0
TOTAL	**444**	**66.3**	**23.1**	**2.5**	**24.1**	**16.6**

* BLANKET INFILL DRILLING TO 80-160 ACRES PER WELL

20S00149

ECONOMIC RECOVERY FROM RESERVE GROWTH

ASSOCIATED NATURAL GAS

20S00149

ECONOMIC RECOVERY OF GAS RESOURCES ASSOCIATED WITH OIL RESERVE GROWTH — BACKGROUND

<u>OBJECTIVE:</u> ESTABLISH RELATIONSHIP BETWEEN GAS PRICE AND RECOVERY OF ASSOCIATED GAS WHICH IS REPRESENTATIVE OF THE DOMESTIC RESERVE GROWTH RESOURCE BASE.

<u>METHODOLOGY:</u>

- DEVELOP DETAILED GEOLOGIC MODELS FOR THE SOUTH CENTRAL BASIN PLATFORM PLAY, PERMIAN BASIN
- ESTABLISH RELATIONSHIP BETWEEN NUMBER OF WELLS DRILLED AND IMPROVED RESERVOIR CONTACT
- USE RESERVOIR MODELING, DETAILED GOR DATA AND ECONOMIC ANALYSIS TO DEVELOP AGGREGATE PRICE/SUPPLY CURVE FOR THE 19 FIELDS OF THE PLAY
- DEVELOP RELATIONSHIP BETWEEN PRICE AND GAS RECOVERY AS PERCENTAGE OF TARGET GAS AND EXTRAPOLATE TO U.S.

FOR MORE DETAILED INFORMATION, SEE METHODOLOGY CHAPTER.

20S00149

A GEOLOGIC ASSESSMENT OF RESERVE GROWTH IN TEXAS

FINAL REPORT
SOUTH CENTRAL BASIN PLATFORM PLAY

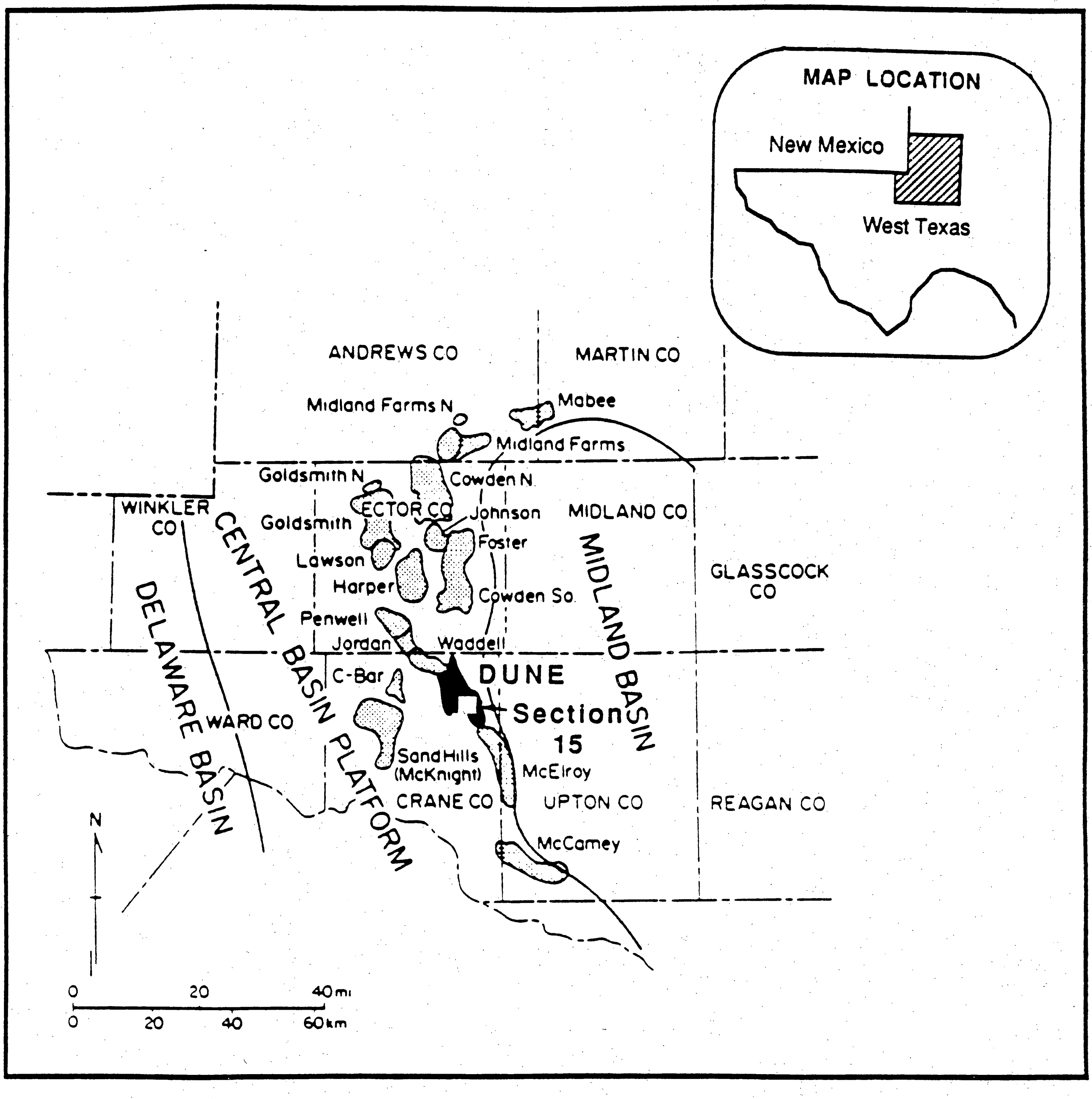
PREPARED FOR: **U.S. DEPARTMENT OF ENERGY/ FOSSIL ENERGY**

PREPARED BY: V.A. KUUSKRAA
K.S. MCFALL
ICF-LEWIN ENERGY DIVISION

N. TYLER
W.A. AMBROSE
BUREAU OF ECONOMIC GEOLOGY
THE UNIVERSITY OF TEXAS AT AUSTIN

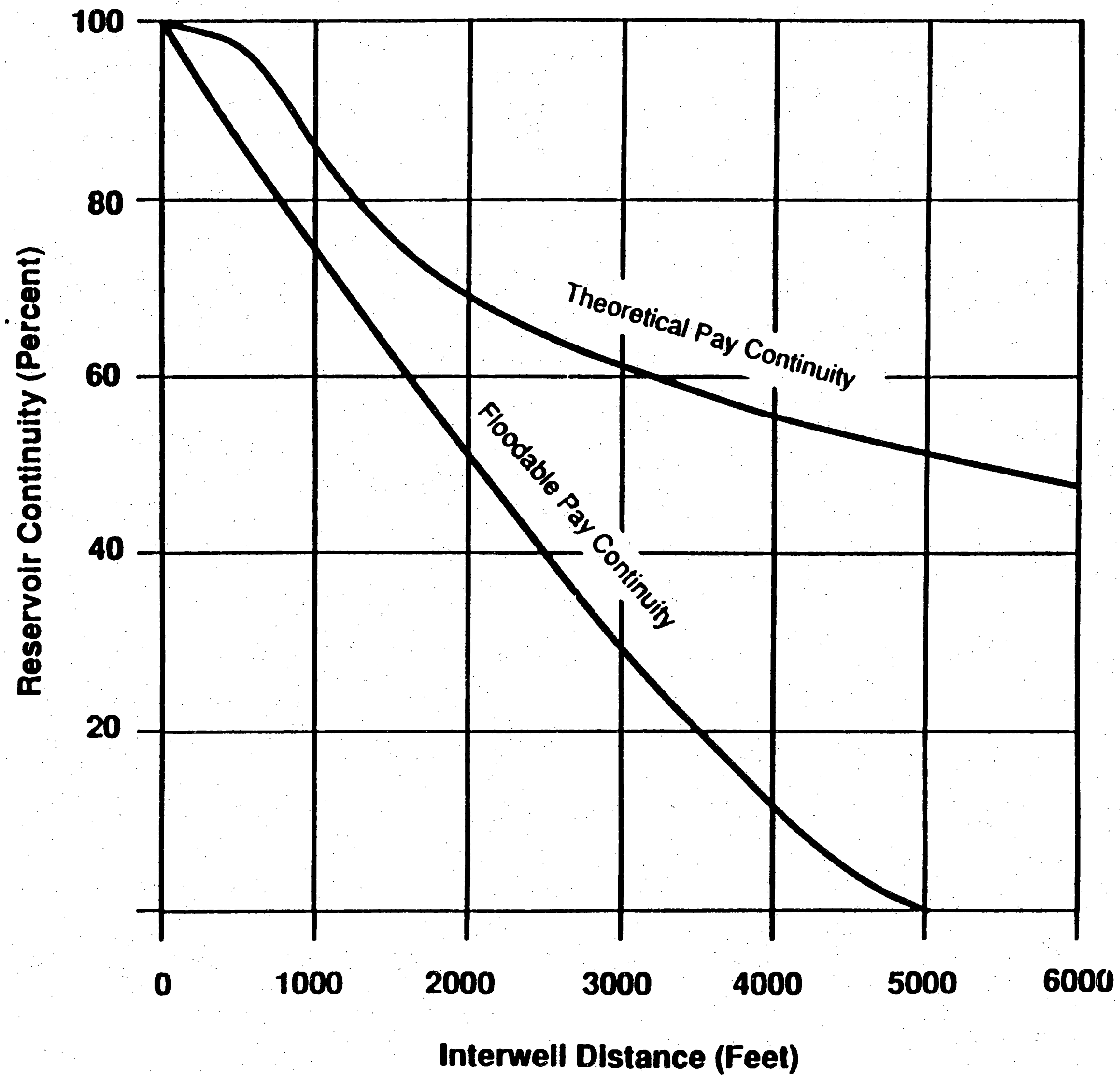
MARCH 1988

Location of South Central Basin Platform Fields
Dune Field and Study Area



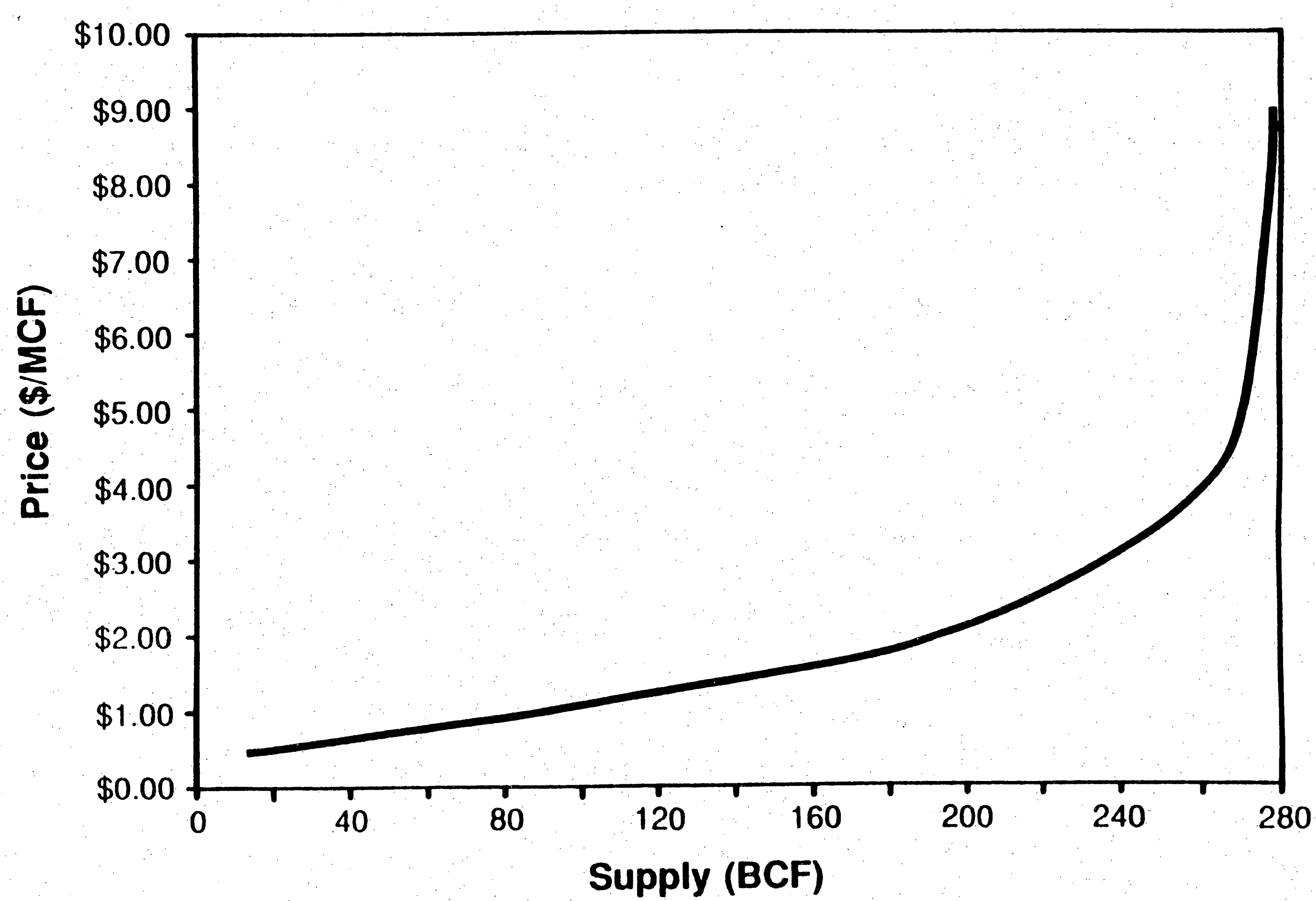
Prepared by: ICF-Lewin Energy, 1988 (after Galloway and others, 1983)

Reservoir Continuity vs Interwell Distance
Dune Field -- Section 15 Study Area



Prepared by: ICF-Lewin Energy, 1988

Price/Supply Curve
Natural Gas Recovery from Blanket Infill Drilling
South Central Basin Platform Play



Prepared by: ICF-Lewin Energy, 1988

ECONOMIC RECOVERY FROM RESERVE GROWTH — ASSOCIATED NATURAL GAS

(10% REAL RATE OF RETURN)

	COST/SUPPLY TABLE*			
	<$3.00/MCF	$3.00-$5.00/MCF	>$5.00/MCF	UNCONTACTED** (BCF)
• ASSOCIATED GAS RECOVERY (BCF)	236	34	41	107
• PERCENT TARGET GAS (418 BCF)	56	8	10	26

* ASSUMING A VALUE OF NATURAL GAS OF 0.75 RELATIVE TO OIL (ON AN ENERGY EQUIVALENT BASIS).

** BLANKET INFILL DRILLING TO 10 ACRES PER PRODUCTION WELL.

20S00149

ECONOMIC RECOVERY OF UNCONVENTIONAL NATURAL GAS

20S00149

ESTIMATED UNCONVENTIONAL NATURAL GAS POTENTIAL — TECHNOLOGY ASSUMPTIONS

RESOURCE	CURRENT TECHNOLOGY: CASE A	CURRENT TECHNOLOGY: CASE B	ADVANCED TECHNOLOGY
TIGHT GAS SANDS	• FRACTURE HALF LENGTH = 400' • FRACTURE CONDUCTIVITY = 400 MD-FT. • WELL SPACING = 160 ACRES	• SAME AS CASE A	• FRACTURE HALF-LENGTH = 1,000' • FRACTURE CONDUCTIVITY = 800 MD-FT. • 30% OF REMOTE LENTICULAR LENSES DRAINED • WELL SPACING = 80 ACRES
DEVONIAN SHALE	• SINGLE ZONE COMPLETION (HURON SHALE ONLY) • 20 FOOT HYDRAULIC FRACTURE	• CASE A ASSUMPTIONS APPLIED TO ALL FOUR TARGET SHALES* IN APPRAISED AREA	• MULTIPLE COMPLETION IN FOUR ZONES • FRACTURE HALF-LENGTH = 300' TO 600'
COALBED METHANE	• FRACTURE HALF-LENGTH = 150' TO 300' • 1 TO 3 COMPLETIONS • PROVED/PROBABLE DESIGNATED AREA ONLY	• CASE A ASSUMPTIONS APPLIED TO ALL COAL INTERVALS IN PROVED/PROBABLE AND SPECULATIVE AREA	• FRACTURE HALF-LENGTH = 500 TO 1,000' • 2 TO 3 COMPLETIONS • PROVED/PROBABLE AND SPECULATIVE AREA

* CLEVELAND/CHAGRIN, HURON, RHINESTREET, AND MARCELLUS SHALES.

FOR MORE DETAILED INFORMATION, SEE METHODOLOGY CHAPTER.

20S00149

ESTIMATED UNCONVENTIONAL NATURAL GAS POTENTIAL — CURRENT (CASE A) TECHNOLOGY

(10% REAL RATE OF RETURN)

RESOURCE	GIP (TCF)	ECONOMICALLY RECOVERABLE RESOURCE <$3/MCF (TCF)	$3-5/MCF (TCF)	$5-10/MCF (TCF)	TOTAL (TCF)
TIGHT GAS SANDS*					
• APPRAISED	295	9	12	24	45
• EXTRAPOLATED	512	49	38	47	134
• TOTAL	807	58	50	71	179
DEVONIAN SHALE**					
• APPRAISED	84	12	3	3	18
• EXTRAPOLATED	760-1,777	NO RESOURCE RECOVERED WITH CURRENT TECHNOLOGY			
• TOTAL	844-1,861				
COALBED METHANE**					
• APPRAISED	215	5	1	0	6
• EXTRAPOLATED	218	NO RESOURCE RECOVERED WITH CURRENT TECHNOLOGY			
• TOTAL	433				

* THE RESOURCE ESTIMATE FOR THE NORTHERN GREAT PLAINS IS EXCLUDED FROM THIS ASSESSMENT. THE ECONOMIC POTENTIAL OF THIS AREA MAY BE HIGH, BUT THIS RESOURCE IS CURRENTLY POORLY UNDERSTOOD DUE TO LACK OF DRILLING DATA(POOR PIPELINE INFRASTRUCTURE AND LACK OF TIGHT DESIGNATION (FERC).

** THE VALUES PRESENTED FOR CASE A REPRESENT THE RESULTS OF A DETAILED TOWNSHIP-BY-TOWNSHIP ANALYSIS USING RESERVOIR SIMULATION TO ESTABLISH TECHNICALLY RECOVERABLE GAS, AND ECONOMIC MODELING TO DEVELOP PRICE/SUPPLY TABLE.

20S00149

ESTIMATED UNCONVENTIONAL NATURAL GAS POTENTIAL — CURRENT AND ADVANCED TECHNOLOGY

(10% REAL RATE OF RETURN)

RESOURCE	GIP (TCF)	RECOVERABLE GAS (<$10/MCF) (TCF) Current (Case A)	Current (Case B)	Advanced
TIGHT GAS SANDS*				
• APPRAISED	295	45	45	76
• EXTRAPOLATED	512	134	134	228
• TOTAL	807	179	179	304
DEVONIAN SHALE**				
• APPRAISED	84	18	31	44
• EXTRAPOLATED	760-1,777	NOT AVAILABLE		
• TOTAL	844-1,861			
COALBED METHANE**				
• APPRAISED	215	6	48	90
• EXTRAPOLATED	218	NOT AVAILABLE		
• TOTAL	433			

* THE RESOURCE ESTIMATE FOR THE NORTHERN GREAT PLAINS IS EXCLUDED FROM THIS ASSESSMENT. THE ECONOMIC POTENTIAL OF THIS AREA MAY BE HIGH, BUT THIS RESOURCE IS CURRENTLY POORLY UNDERSTOOD DUE TO LACK OF DRILLING DATA (POOR PIPELINE INFRASTRUCTURE AND LACK OF TIGHT DESIGNATION (FERC).

** CASE A AND THE ADVANCED SCENARIO ARE RESULTS OF DETAILED RESERVOIR SIMULATION AND ECONOMIC EVALUATION BY ICF-LEWIN ENERGY.

ECONOMIC ASSESSMENT OF THE U.S. NATURAL GAS RESOURCE BASE

BACKGROUND AND METHODOLOGY

ICF-Lewin Energy

20S00149

ICF-LEWIN GAS ECONOMICS MODEL

Background

The ICF-Lewin Energy Gas Economics Model was used to evaluate the economic recovery of natural gas from reserve growth and unconventional sources (tight gas, coalbed methane, and Devonian shale) for the Department of Energy's Natural Gas Initiative. The model has been widely used by DOE and others to assess the economic potential of a variety of natural gas resources.

The following sections provide background information on the ICF-Lewin model. The model consists of two primary components, which will be discussed individually. Section A describes the Engineering Costing and Field Development Model and Section B discusses the Economic and Financial Analysis Model.

A. <u>Engineering Costing and Field Development Model</u>

The Engineering Costing and Field Development Model simulates the development of a gas field, pattern, or well by linking gas recovery* with well drilling, equipment, and operating costs and the timing of development. The model includes:

1) Front-end costs for seismic, logging, coring and other G&G and data acquisition and analysis activities

2) Drilling and well completion costs by province and well depth for gas wells and associated dry holes

3) Well and lease equipment costs, including costs for site preparation, by province, well depth, and maximum gas flow rate

4) Special well and lease equipment costs for operation of low pressure or high water volume gas wells, including compression, dehydration, high volume pumping equipment, and disposal

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* Gas recovery is that component of a geologically assessed resource which is technically recoverable. For unconventional gas, this is determined by detailed reservoir simulation based on specific assumptions concerning the performance of advanced fracturing technologies. Decline curve analysis and/or reservoir modeling were used to assess technically recoverable volumes of non-associated and associated gas.

5) Well stimulation costs (as appropriate) by type and volume of fracture fluid, well depth, and concentration (and type) of proppant

6) Well operating and maintenance costs by province, well depth, and gas flow rate.

The cost data and algorithms are based on widely used and publicly available sources (Table 1) and include data from the Department of Energy, the Department of Commerce, and the American Petroleum Institute. The costs are modified for the specific technological criteria required for the recovery of particular natural gas resources.

Costs are specific to each province for representative well depths and gas flow rates. These costs are expressed in 1986 dollars and have been updated using the Bureau of Labor Statistics (BLS) inflation indices for each major cost component. In addition, algorithms exist in the model that relate costs to oil prices and rig utilization. These cost/price algorithms are based on previous work performed for DOE/FE and published in the Society for Petroleum Engineer's literature (Kuuskraa and others, 1986 and 1987).**

The costs associated with developmental dry holes are allocated on a per well basis. Region-specific developmental drilling success rates are based on historical gas well drilling over the 1981 through 1986 time period, as reported annually by the American Association of Petroleum Geologists.

B. Economic and Financial Analysis Model

The Economic and Financial Analysis Model links natural gas production, investment and operating costs, and gas prices and considers royalties,

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** Kuuskraa, V.A., M.L. Godec, and F. Morra, Jr., "Replacement Costs of Domestic Oil and Gas Reserves," SPE Paper No. 15352, presented at the 61st Annual Technical Conference and Exhibition of the SPE, New Orleans, Louisiana, October 5-9, 1986.

Kuuskraa, V.A., F. Morra, Jr., and M.L. Godec, "Importance of Cost/Price Relationships for Lease Cost Oil and Gas Reserves," SPE Paper No. 16289, presented at the SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, Texas, March 2-3, 1987.

Table 1

Sources for Onshore Costs of
Exploration, Drilling, and Production

Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations, Washington, D.C., DOE/EIA, April 1986, DOE/DIA, April 1986, DOE/EIA-0185(85). Gives cost indices and an engineering breakout of costs for a few selected depth classes on a regional basis.

Current Industrial Reports, Annual Survey of Oil and Gas, U.S. Department of Commerce, Bureau of the Census, 1981 (MA-13K-(79)-1), published annually.

Indexes and Estimates of Domestic Well Drillings Costs, Washington, D.C.. DOE/EIA-0347 (1984 and 1985). Gives indices and an engineering breakout of costs for a few selected depth classes on a regional basis.

Joint Association Survey of Drilling Costs, Washington, D.C., API/AGA, December 1986. Gives drilling costs for successful and dry wells by state and depth classes.

Survey of Oil and Gas Expenditures, American Petroleum Institute, published annually since 1982. Gives total industry expenditures by region for a wide variety of items.

severance taxes, income taxes, and return on investment. The key features of the model include the following:

1) Optional means for incorporating gas price versus time (e.g., constant price, escalating price, user-established price by year) that link with annual gas production to establish gross revenues

2) Provision for royalty, severance tax, and ad valorem taxes as customary for the gas production industry to establish net revenues

3) Proper timing of investment and operating costs (particularly the effect of front-end dryhole and other capital outlays) to establish before-tax cash flows and operating net revenues

4) Accounting conventions, such as depreciation, tax credits, etc., for establishing taxable income and tax obligations, using the current 1987 federal/state tax code, to establish after-tax cash flows and operating profits

5) Standard internal rate of return, net present value, payback and minimum required selling price financial measures by which to appraise the relative economic attractiveness of a non-traditional gas recovery venture versus its competing alternatives.

The model develops year-by-year undiscounted and discounted cash flows and provides:

- The net present value of a project, at the specified discount rate and price
- The minimum required gas sales price, at specified rates of return
- The payback time for the project
- The investment and operating costs per Mcf of natural gas recovered.

For all of the economic assessments of natural gas from unconventional sources and reserve growth performed a part of the DOE Natural Gas Initiative, no unconventional gas tax credits or Natural Gas Policy Act incentive prices were considered. Therefore, the economic assessments may be somewhat conservative, since some of the resources considered would likely be eligible for these benefits.

Non-associated Natural Gas Reserve Growth from Discovered Fields

The economic assessment of the potential of natural gas from reserve growth of discovered fields relied on the BEG assessment of the "advanced gas resources" of over 200 plays in the Lower-48 states. The advanced gas resource defines the maximum target gas that remains in discovered fields due to reservoir heterogeneity. From this, ICF-Lewin Energy estimated the component of this target gas that is economically recoverable at various prices. The methodology for the economic analysis is discussed in the following paragraphs.

The results of the BEG play analysis were aggregated to a province level, the unit of analysis for the economic assessment. For each province (and for 2,500 foot depth increments within each province), BEG developed the following data set:

- Field size distribution using estimated ultimate recovery plus maximum reserve growth target ("advanced gas resources") as the basis for the distribution
- Productive areal extent by field size category
- Current well spacing (number of wells per square mile), on average, for each field size category
- Recovery function relating number of infill wells drilled per section to percent incremental reservoir contact, by estimated extent of reservoir heterogeneity.

Using the data supplied by BEG, ICF-Lewin developed a cost/supply summary table for gas reserve growth for each province. The cost categories are: <$3.00/Mcf, $3.00-5.00/Mcf, and >$5.00/MCF. This was accomplished through five subtasks, described below.

Task 1. Update Gas Economics Model to Correspond to Provinces Selected by BEG. This step involved updating the cost data of the ICF-Lewin Gas Economics Model to account for the provinces and depth categories designated by the BEG.

Task 2. Develop Typical Decline Curves for Each Province. ICF-Lewin developed normalized well production curves and typical reservoir properties by province using historical production data for a set of representative fields. These curves were used to represent the incremental gas recovery from improved reservoir contact through infill drilling.

Task 3. Apply Typical Decline Curves to Each Province. Using the data provided by BEG (recovery function, current well spacing, and areal extent) the normalized production decline curves were applied to the recoverable volume of incremental gas to develop a typical per well production history for each province. This was performed for each depth and field size category for various well spacings and served as input for the economics model.

Task 4. Determine Minimum Economic Price for Incremental Gas Recovery for Various Well Spacings, Regions, Depth Categories and Field Sizes. The ICF-Lewin Gas Economics Model was used to determine the minimum gas price, for each region, depth category, well spacing, and field size, that is required to achieve a ten percent (real) return on investment from incremental gas recovery resulting from infill drilling. For each province and depth category, this price was assumed to apply for all fields of that size.

Task 5. Aggregate Results into Cost Table for Each Province. The results of the individual field size and well spacing economic analyses were aggregated to develop a cost/supply table representative of the U.S. gas reserve growth potential for the provinces assessed.

Gas Resources Associated with Oil Reserve Growth

The economic evaluation of the associated natural gas reserve growth relied on preliminary analyses currently being conducted for DOE/FE by ICF-Lewin Energy and the Bureau of Economic Geology (BEG).

The purpose of this study is to develop a geologic/engineering based approach to estimating the potential contribution of reserve growth to domestic oil supplies. To date, the study has estimated the economically recoverable hydrocarbons from the San Andres/Grayburg South Central Basin Platform Play, a collection of 19 fields in the Permian Basin of West Texas. This study developed a geologic methodology to establish the increased volume of reservoir in contact with more closely drilled infill wells, calculated recoverable oil and associated gas, and concluded with an economic analysis of the reserve growth potential of the South Central Basin Platform Play.

The results of this study were used as an approximation of the potential for economic recovery from domestic associated gas reserve growth. For this, ICF-Lewin Energy developed a cost/supply table relating recoverable gas from infill drilling to price per Mcf of gas. This table is an aggregation of a field-by-field analysis of South Central Basin Platform Play. Detailed gas-oil ratio data for individual fields were used to assess the volumes of associated gas recoverable from infill drilling as a function of oil recovery.

Tight Gas Sands

The estimates of potential natural gas from tight gas sands are based on geologic data compiled by the National Petroleum Council (NPC) in its study of unconventional gas published in 1980. Lewin and Associates automated the data and the NPC analysis methodology in the Tight Gas Analysis System (TGAS) systems model in 1984. The model has been updated to account for current tax and cost charges and the production, stimulation, and financial analysis routines have been improved over time.

The NPC organized the overall tight gas resource into two categories: appraised and extrapolated. The appraised resource consists of 102 formations located in ten basins that were studied in detail by the NPC. Each appraised formation is specified in terms of 5 to 10 average levels of permeability, with each permeability "grade" associated with an explicit productive area, gas-filled porosity, net pay, probability that traps contain hydrocarbons, and probability that wildcat wells are productive. From this, the economic potential of the appraised tight gas resource was estimated.

The remaining basins/formations, for which there was insufficient data for detailed analysis, were grouped into four extrapolated regions: Western, Greater Southwest, Mid-Continent, and Eastern. Geologic analogs were used to establish the economic tight gas potential in these regions. For example, tight formations in the Eastern region are represented by the Northern Great Plains (Mowry, Greenhorn, Carlile, Niobrara, and Eagle formations), the Piceance (Corcoran-Cozzette, Fort Union, Lower Cretaceous, and Mesaverde formations), the Cotton Valley and the San Juan (Dakota) basins.

Coalbed Methane

The appraised gas in place estimate for methane from coal seams is comprised of detailed resource study estimates completed for four basins by ICF-Lewin Energy. The extrapolated gas in place estimate extends the appraised resource estimate by including gross estimates for the remaining domestic coal basins. For most of the basins, the estimates are taken from the TRW basin reports.

Technically recoverable resource estimates were derived for the appraised basins using reservoir simulation on a township-by-township basis. The reservoir simulation was based on specific assumptions concerning the performance of advanced technologies, and was conducted using a two-phase, dual porosity finite difference reservoir simulator for coalbed methane.

Economically recoverable resource estimates were determined by running the technically recoverable production results through the ICF-Lewin Gas Economics Model, and solving for a minimum gas price at a 10 percent rate of return.

Devonian Shale

The gas in place estimate for Devonian shales was determined by examining four productive Devonian shale zones: the Cleveland/Chagrin, Huron, Rhinestreet, and Marcellus shales of the Appalachian Basin. Gas in place was computed for each zone in the historically productive area of the basin and these values were accumulated to derive the total gas in place estimate.

The extrapolated gas in place estimates were taken from the following sources:

1. Estimates of Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin (USGS Open File Report 82-474). The U.S. Geological Survey estimates 577 to 1,131 Tcf of natural gas in the organically-rich (black) shales of the basin, with a mean of 844 Tcf. Subtracting the appraised value of 84 Tcf from this value yields the extrapolated estimate of 760 Tcf.

2. The upper figure of 1861 Tcf is taken from Unconventional Gas Sources - Devonian Shale, National Petroleum Council, 1980. Subtracting the appraised value of 84 Tcf from this value yields the extrapolated estimate of 1777 Tcf.

Technically recoverable resource estimates were derived by applying a set of technology assumptions to the geologic and reservoir data developed through extensive review of previously published geologic and reservoir studies, analysis of well logs, and the history matching of actual Devonian shale well production using a two phase, dual porosity finite difference gas reservoir simulator.

Economically recoverable resource estimates were determined by running the simulated production streams (technically recoverable gas) through the ICF-Lewin Gas Economics Model, solving for a minimum gas price at a 10 percent (real) rate of return.

APPENDIX 4.

Gas Recovery Technologies

Argonne National Laboratory

REVIEW OF MAJOR EXISTING AND "NEW" GAS EXTRACTION TECHNOLOGIES

Introduction

It has been shown in this study that there is an incremental component of reserve growth in current gas reservoirs. It has also been shown that this reserve growth is tied to reservoir heterogeneity and compartmentalization and that with a better understanding of the reservoir we can access these additional reserves with approximately the same capital outlay. Thus, the major gas reserve growth potential in this study is tied to the wider implementation of extended conventional recovery techniques aimed at improved recovery efficiency and is not dependent on foreseeable research breakthroughs. Such implementations are cost-effective and readily applied extensions of current gas recovery technology coupled with improved geologically based site selection and full integration of reservoir geology and engineering.

On the other hand, there are improved recovery technologies in various states of research and development which could add an additional increment of both gas reserve growth and deliverability. Such new or improved technologies would not only impact reserve growth in known fields but could have a significant impact on the ultimate recoveries in newly discovered fields and on the exploitation of unconventional resources. Although components of these technologies can now be directly applied within the current understanding of the geologic and engineering reservoir framework, the maximum impact will be felt when such technology improvements can be combined with a better understanding of the heterogeneities of both gas and oil reservoirs. One of the major challenges of the development function in the oil and gas industry will be the early on accurate characterization of the reservoir and the adoption of an optimal engineering design for drilling and completing the reservoir. An early accurate characterization will optimize the placement of infill or development wells and assure a minimum of dry holes.

The current state of development of some of the improved technologies is such that it is difficult at the present time to assess the quantitative impact of implementation on gas reserve growth and deliverability but enough information is available to suggest that such technologies can play an increasing, perhaps very significant, future role in developing additional gas resources. It is also difficult to associate a given technology with a percentage component of reserve growth. The amount of reserve growth and deliverability is directly dependent on the degree to which a better understanding of geologic and engineering controls on production in specific reservoirs is applied to the placement and utilization of extant and improved gas extraction technologies.

Infill Drilling

One of the most important yet conventional technologies which can contribute to an increase in gas reserve growth is the strategic placement of infill wells within the productive limits of existing fields and in evolving a development drilling program associated with new field or pool discoveries. At the current time, most operators recognize that there is a certain amount of gas that is not going to be accessed with the current spacings (typically 640 acre and/or 320 acre) in many fields and that additional infill wells are required to access these reserves. For example, in the Hugoton field, one current infill drilling program has increased gas deliverabilities by as much as 40% over earlier wells in the field and well test results thus far support contentions that infill drilling may add an additional 70% increase to reserves that remained before infill drilling was begun. In addition, shut-in pressures at 75% of the infill wells tested have been higher than the pressure at the existing well in the unit at a time of recent test.

However, most of the infill programs are designed around a pattern which increases drilling density in a systematic fashion, i.e. in a regular geometric grid. Such programs cannot, by their very nature, take into account the fundamentally nongeometric lateral heterogeneities present in many reservoirs and although they can and often do add additional producibility and reserve growth, they do not necessarily maximize the potential for accessing all the recoverable gas in a given field. Strategic or selective placement of infill or development wells based on an understanding of lateral and vertical reservoir variations can take advantage of the known heterogeneities in the reservoir and maximize producibility and reserve growth. The strategic placement of vertical wells assumes that the drainage geometry can be only partially modified (e.g., through fracture stimulation). Therefore, implicit in the rationale for strategic well placement is a degree of improvement in reservoir characterization which will allow the operator to take advantage of existing variations in reservoir geometry and lithologic variations controlling porosity and permeability.

Improved Reservoir Analysis Combining 3-D Seismic with Cores and Log Analysis

Historically, the description of reservoirs has been primarily based on well and core data interpretation and the petrophysical properties derived from such data have been smoothly interpolated between well locations. In addition, the contribution of seismic data in building reservoir models has primarily been one of mapping discontinuities and seismic markers in and near the reservoir rock. The emerging role of modern three-dimensional (3D) seismic data is based on its ability to provide a greater understanding of the structural and stratigraphic relationships in the subsurface. Not only can it assist in delineating reservoir geometry but it can also play a role in predicting porosity and lithology variations away from well control. 3D seismic data when integrated with subsurface well data can provide spatially continuous estimates of rock parameters across the reservoir. Such reservoir characterization is a must if additional increments of compartmentalized gas reserves are to be accessed through selective strategic drilling. Better reservoir management as represented in fewer dry holes, better well placement, earlier production, and greater recovery of gas are all benefits to be derived from the use of this integrated technology.

Better Use of Advanced Computer Technology

Computers will obviously play a major role in any task that involves complex calculations, the examination of alternatives, and the processing of large amounts of data. Reservoir modeling, based on an increased understanding of reservoir characterization, is important for the purpose of achieving maximum primary recovery through efficient development. Defining reservoir properties from computer processing of a combination of surface measurements and downhole measurements are particularly important. Borehole to borehole and borehole to surface transmission of seismic signals and electrical signals as well as tomographic probing require extensive interdisciplinary research utilizing computers.

Advanced computer technology is also very important for precise engineering design and analysis for the optimization of the well established technology of hydraulic fracturing to increase producibility. More realistic fracture treatment designs and better quality control are only two of the end results of model analysis by computer and computer-based monitoring of fracture operations in the field.

Computerized data bases, knowledge bases/expert systems and artificial intelligence which were nonexistent a few years back are playing an increasing role in both probabilistic and deterministic solutions to engineering problems associated with the efficient development of reservoirs. The explosive data growth associated with an increase in reservoir characterization necessary to bring maximum growth in reserve potential absolutely requires the use of advanced computer technology.

Horizontal Drilling

One of the most promising technologies that is currently being brought to bear on the exploitation of oil and gas reservoirs is horizontal drilling. Although the concept of nonvertical or deviated drilling for exploration and exploitation of petroleum resources has been with us for a long time, horizontal well drilling (defined as a drilled well in which the portion of the well bore that penetrates the reservoir is horizontal) and horizontal well production (defined as production that is systematically produced through horizontal wells) had their initial beginnings in the 1950's. Continued advances in horizontal drilling and MWD (measurement while drilling) technology have brought the state-of the art to the point that there are now many active and proposed projects world-wide including several in the United States.

Horizontal drilling was first introduced during the 1950's by the Soviet Union and subsequent activity in the 1960's by the Chinese indicated that horizontal drilling was technically feasible but uneconomical. Developments during the 1970's further established the feasibility of the method but it was not until the 1980's that the economic viability of the method began to be established by projects in Canada, Italy, Indonesia, and Prudhoe Bay. Today, horizontal holes have been drilled to depths greater than 10,000 feet and with horizontal lengths as great as 4100 feet. Horizontal lengths of 500 feet while not routine do not appear to present any significant technological drilling or production problems. Typical completion practices involve sidetracking previously drilled vertical holes and producing through uncemented perforated liners. In addition production histories from two to five years are now available to demonstrate the viability of the methodology.

The basic rationale for adoption of the methodology is that it allows the operator to modify the drainage geometry through directional control, a modification that is only partially realized with vertical drilling. It thus allows selective placement and orientation of the productive string to take advantage of more favorable zones within the reservoir. In addition, it allows for an increase in productivity by allowing longer completion intervals and by allowing selective placement across latent and preexisting fracture systems. Thin beds not amenable to vertical completions can be accessed with the horizontal completion. Producing problems can also be reduced by allowing the operator to remain further away from fluid interfaces as well as allowing more complete development of down structure portions of fields.

Potential increases in ultimate recovery are one of the most important benefits in terms of incremental growth in reproducible reserves although there is no current agreement as to the magnitude of this growth. Horizontal drilling allows the operator to target those areas of compartmentalized or bypassed lateral preferred orientation resource that might not be accessed with blanket geometric infill drilling. In some cases, there could even be a potential reduction in the number of wells required to develop the resource. A better geologic understanding of the lateral heterogeneities within the reservoir through the use of horizontal drilling technology allows for better reservoir management following partial development.

The downside of utilizing horizontal drilling technology is the increased costs and risks associated with the method. In addition to the possibility of the well bore exiting the reservoir, there are the increased pressure losses with length, borehole stability problems, and the increasing risk of losing the well with greater horizontal distance. Although early attempts at horizontal drilling were marked by costs that were several times greater than vertical well costs, current technology has brought the drilling and completion costs down considerably. Although the costs of drilling and completing a horizontal hole are 30% - 100% greater than the costs of drilling and completing a vertical hole the productivity increases documented on projects to date suggest a productivity increase of 2 to 6 times that of a conventional vertical completion. This increase in productivity certainly impacts the economics of a project in a positive manner.

Not all reservoirs are suited to use of horizontal drilling technology. Reservoirs with strong compartmentalization tendencies due to reservoir rock heterogeneities are certainly excellent candidates along with reservoirs with widely spaced vertical fractures and reservoirs with thin pay zones. Among the unconventional gas sources, the fractured tight gas sand reservoirs and coalbed methane reservoirs are certainly candidates for the technology. On the other hand homogeneous reservoirs, reservoirs with thick pay zones, and reservoirs with dense intense fracturing are less likely candidates.

Certain research needs still remain with this promising new technology. It is obvious that we need a more complete and better understanding of reservoir heterogeneities if we are going to target the ideal portions of a reservoir for exploitation. The flow characteristics of a horizontal completion are largely unknown and therefore a predictable flow model has not yet been developed. The optimal length of the horizontal borehole must be determined to maximize production and minimize risk. The further development of measurement while drilling (MWD) techniques and the development of simultaneous drilling and casing methodology will serve to further enhance the technology.

Measurement While Drilling (MWD) Techniques

An important evolution in drilling involves measurements while drilling, i.e. the downhole measurement of important parameters and the simultaneous transmission of those measurements to the surface while drilling. Although the first patents on such technology were issued in the 1930's, the methodology has only been commercial for the last seven years and at the current time, considerable research is being carried out to further understand and improve available technology.

One of the major benefits of MWD techniques to reserve growth is its benefit to directional drilling. Its impact has been significant because of more and better surveys and better success with downhole motors in directional applications. High angle/horizontal wells are particular candidates for this technology because of the importance of knowing the position of the bit relative to the adjacent bed boundaries. Oriented formation resistivity or other formation measurements can provide a useful measure of relative bit location.

Formation evaluation based on MWD is also proving itself particularly in those cases where MWD logs have been substituted for wireline logs in high angle holes. The use of multiple logs over a span of time (time lapse logging) constitute an additional facet to formation evaluation which can contribute to our understanding of the reservoir. Although not directly applicable to reserve growth, the technology contributes indirectly through improved drilling efficiency, trouble avoidance, and drilling safety.

TECHNICAL AND ECONOMIC IMPEDIMENTS TO GAS RESOURCE DEVELOPMENT (NON-PRICE/SUPPLY/DEMAND DRIVEN)

Introduction

The potential for incremental reserve growth in current gas reservoirs analyzed in this study and the exploration for new gas supplies can only be realized under more favorable economic conditions than are currently extant today. It is recognized that there is considerable interaction between price, supply, and demand in setting the tone for gas resource development. A change in any one of these major driving factors can impact on the other two, and the overall impact on the supply side can be positive or negative. Certainly an increase in demand and/or price will have a significant actual and perceptual positive impact on gas exploration and exploitation activities.

However, even under conditions that can allow stimulation of the supply side, i.e. increased demand and/or price, there are certain additional negative factors that can impede exploration and development programs for bringing additional gas reserves and producibility on line. Some of these negative factors are ever present; others can be attributed to the decline in vitality of the oil and gas industry brought on by extreme product price erosion in recent years.

A positive move in demand and/or price can serve to overcome, at least in part, some of these negative factors almost immediately; others will respond only over an extended period of time and will constitute a drag on any recovery of exploration and exploitation of additional gas supplies. Some of the impediments are technical, some institutional, others economic, and certainly one of the more important is perceptual. All are from difficult to impossible to quantify. Nonetheless, they must be taken into account and do represent an inelastic component which may not necessarily respond immediately to any positive turnaround in price and/or demand for natural gas. None of the impediments are in and of themselves necessarily capable of stifling any turnaround driven by price and/or demand but in a collective sense they do represent an inhibitor to the magnitude and timing of any recovery.

Drilling/Production/Service Impediments

Any possible pickup in gas demand will definitely have a positive impact on the service and supply side of the industry. There will, however, be a decided reluctance on the part of this segment of the industry to tool up to a higher level of activity in the face of recent past profitability and the uncertainty of future compensation. In addition, any major change in the mix of U.S. drilling between oil and gas or a sharp increase in rig demand will be difficult to meet without shortages in personnel or equipment or both. Shallow depth programs will be easier to handle because of a lesser need for specialty personnel but any expansion of deep gas drilling will impact heavily, particularly in terms of both specialty personnel and tubular goods.

In a recovery mode the most likely constraint will be one of personnel. Overall employment in the service sector has fallen from an early 80's peak of over 475,000 to a 1987 low of slightly more than 200,000. While the drop has not been as severe from a percentage standpoint in the drilling/production sector (275,000 to just over 200,000), this is still a significant decrease. Specialized personnel such as mud engineers, directional drillers and measurement-while-drilling (MWD) engineers will particularly be in short supply. This shortage of specialty personnel will be even more acute in the presence of expanded deep gas drilling because of the need for more expertise.

Specialty personnel shortages will take longer to eliminate than will potential materials shortages. Many companies will find it difficult to justify the wage increases needed to attract new employees under current economic conditions. No doubt part of the problem can be alleviated by shifting personnel or by hiring consultants but certainly any kind of vigorous recovery will result in shortages of adequately trained individuals.

Potential materials shortages will not likely persist as long as personnel shortages but there is, nonetheless, reason for concern. Although there is currently a surplus of both onshore and offshore rigs which is expected to hold for the next year or two, there may be some regional shortages of quality rigs. Of more concern is the potential lack of spare parts for both current and future operating rig requirements. Many spare parts manufacturers have closed their doors and those that remain can now operate at only a fraction of their previous level. Tubular goods are also likely to be in short supply in the future and the supply of serviceable used drill pipe is essentially gone. New supplies of drill pipe are tight at the present time and can only be alleviated by some confidence in a significant pickup of drilling activity.

Economic Impediments

There are several real and/or perceptual economic impediments to bringing additional supplies of gas on line. These impediments, are, in most cases, a holdover from the severe economic depression that the oil and gas industry has undergone during the last few years. The net result is that even if we have a sharp positive turnaround in price of product, there may be a delay in the ability of the financial infrastructure to respond to any increased activity.

Of concern, particularly to the smaller independent operators, is the negative effect of the 1986 tax reform act on outside investors. Basically the independent is now faced with a more restrictive tax code for both retiring debt and raising outside capital. Passive loss rules have severely curtailed the use of limited partnerships to raise money and although several new innovative vehicles for raising money have surfaced, the restrictions are such that their magnitude is but a fraction of what it was in the past and in addition can only be directed toward certain projects. Finally, there is considerable competition for investment funds by other segments of the economy which are currently more robust than the oil and gas industry. Bank funding is also now more restrictive than in the past. Not only is most of the available bank funding concentrated on the large stable borrowers but also the collateral requirements are considerably more stringent. All of the above factors could serve as a drag on any price or demand driven exploration or exploitation activity aimed at bringing additional reserves on line.

An additional problem which is difficult to define but nonetheless real is the perception that the oil and gas industry is no longer very successful in their exploration programs. Part of this perception can be directly related to the marginal quality of some of the prospects drilling during the latter part of the "boom" period, partly from the fact that indeed large accumulations are becoming harder to find domestically, and partly from the unrealistic financial projections that were factored into past exploration programs and probability of success ratios. The net result of this perception is that the wide appeal that oil and gas had to investors has now been diminished and the pool of available dollars has shrunk. In an industry which depends heavily on both borrowed and outside investment dollars for its day to day operations the impact can be significant.

Regulatory and Institutional Impediments

It is recognized that Federal and state regulations, contractual obligations and abrogations, access to pipeline transport, etc. can serve as additional impediments to the timely and efficient development of gas resources. However, these complex subjects while very important are considered to be peripheral to the assessment of gas resource potential which is the main thrust of this study.

APPENDIX 5.

Deliverability Assessment

Bureau of Economic Geology

RESOURCES AND PRODUCTIVE CAPACITY: QUESTIONS OF DELIVERABILITY

In addition to the assessment of natural gas resources it is important to consider productive capacity and our capability to move gas to market. It appears that it would be appropriate to conduct a survey of productive capacity and then update that survey periodically. Specific parameters and approaches to that survey are not delineated herein, but the survey should at least consider some major areas of study:

1. Analysis of peak load demand requirements. There should be measurement of supply requirements to meet normal peak load demand during the calendar year.

2. Survey of storage reservoir capacity throughout the nation. Storage deliverability should be measured and compared with total industry deliverability as well as in terms of excess producibility needed for peak load requirements.

3. Renewal of R/P ratio studies conducted by the Federal Power Commission. Technological advances in improved deliverability should be reviewed and compared with traditional maximum efficient recovery requirements that serve conservation objectives.

4. Determination of the likely supply path for casinghead gas and its expected availability. Considerations should be made of how future oil production levels impact associated gas supply.

A study of these parameters would clearly be useful in assessing gas availability in the marketplace and could effectively complement the understanding of gas resource distribution gained in this assessment.