FINAL REPORT

Assessing and Forecasting, by Play, Natural Gas Ultimate Recovery Growth and Quantifying the Role of Technology Advancements in the Texas Gulf Coast Basin and East Texas

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Abstract

A detailed natural gas ultimate recovery growth (URG) analysis of the Texas Gulf Coast Basin and East Texas has been undertaken. The key to such analysis was determined to be the disaggregation of the resource base to the play level. A play is defined as a conceptual geologic unit having one or more reservoirs that can be genetically related on the basis of depositional origin of the reservoir, structural or trap style, source rocks and hydrocarbon generation, migration mechanism, seals for entrapment, and type of hydrocarbon produced. Plays are the geologically homogeneous subdivision of the universe of petroleum pools within a basin. Therefore, individual plays have unique geological features that can be used as a conceptual model that incorporates geologic processes and depositional environments to explain the distribution of petroleum.

Play disaggregation revealed important URG trends for the major natural gas fields in the Texas Gulf Coast Basin and East Texas. Although significant growth and future potential were observed for the major fields, important URG trends were masked by total, aggregated analysis based on a broad geological province. When disaggregated by plays, significant growth and future potential were displayed for plays that were associated with relatively recently discovered fields, deeper reservoir depths, high structural complexities due to fault compartmentalization, reservoirs designated as tight gas/low-permeability, and high initial reservoir pressures. Continued technology applications and advancements are crucial in achieving URG potential in these plays.

Executive Summary

Detailed natural gas ultimate recovery growth (URG) analysis of the Texas Gulf Coast Basin and East Texas has been undertaken. The key to such analysis was determined to be the disaggregation of the resource base to the play level. The project has developed a realistic and play-specific measurement of remaining URG potential by natural gas resource volume. Through such assessment the longer term potential of natural gas URG as a contributor to future gas supply from the Texas Gulf Coast Basin and East Texas has been determined.

Within Texas itself, the Gulf Coast Basin and East Texas comprise 67 percent and 58 percent of natural gas annual production and proved reserves, respectively. The Texas Gulf Coast Basin comprises Railroad Commission of Texas (RRC) Districts 1 through 4 and Offshore State waters. A total of 7,484 fields existed in the original 1996 Energy Information Administration's (EIA) Oil and Gas Integrated Field File (OGIFF) data base. This data set was reduced to 1,372 fields that had 1996 natural gas ultimate recovery estimates greater than 10 Bcf and at least 2 years of data. This reduced data set represents 94 percent of the total 1996 natural gas ultimate recovery for the 7,484 fields. East Texas comprises RRC Districts 5 and 6 and a few fields extending into 3. A total of 1,447 fields existed in the original 1996 EIA OGIFF data base. This data set was reduced to 235 fields that had 1996 natural gas ultimate recovery estimates greater than 10 Bcf and at least 2 years of data. This reduced data set represents 96 percent of the total 1996 natural gas ultimate recovery for the 1,447 fields.

Major results include

1. Natural gas ultimate recovery estimates in the Texas Gulf Coast Basin increased approximately 30 percent (37 Tcf) within the 20-year data history frame from 1977 through 1996. Natural gas ultimate recovery estimates in East Texas increased approximately 74 percent (17 Tcf) within the same time frame.
2. Aggregated URG curves for the Texas Gulf Coast Basin and East Texas revealed significant URG. Texas Gulf Coast Basin and East Texas had an aggregated cumulative growth factor (CGF) of 8.28 and 33.5, respectively.
3. For the Texas Gulf Coast Basin, 1,369 fields were disaggregated into 30 geologically delineated plays. Only major plays with natural gas ultimate recovery greater than 1 Tcf were selected for detailed analysis. A total of 21 plays were selected for further detailed URG analysis. For East Texas, 246 fields were disaggregated into 14 individual plays. Ten major plays having significant natural gas ultimate recovery were selected for detailed analysis.
4. URG analysis by a factor of time using cumulative growth factors showed that plays WX-2, KG-2, KG-4, WX-1, WX-4, VK-1, and KG-1 in the Texas Gulf Coast Basin and the Lower Cretaceous-Jurassic Sandstone (KJ) plays in East Texas are experiencing the most growth. These plays all show URG trends above the total aggregated growth curves. These plays also show significant recent growth in terms of 1996 versus 1977 natural gas ultimate recovery ratios.
5. URG analysis by a factor of drilling activity revealed significant growth to be occurring in the Texas Gulf Coast Basin and East Texas. When yields per effort were compared, plays WX-4, WX-2, WX-1, VK-1, MC-4, KG-1, and FR-2 in the Texas Gulf Coast Basin and the Jurassic Carbonate (JC) and the Lower Cretaceous-Jurassic Sandstone (KJ) plays in East Texas were above the total aggregated yield per effort.

6. On the basis of both time and drilling activity, the top plays found to have the greatest current and future potential for natural gas URG were WX-2, WX-4, WX-1, and VK-1 in the Texas Gulf Coast Basin and the Lower Cretaceous-Jurassic Sandstone (KJ) plays in East Texas.

7. Plays experiencing the greatest URG were characterized by relatively recently discovered fields, greater reservoir depths and pressures, high structural complexities due to fault compartmentalization, and reservoirs designated as tight gas/low permeability.

8. Technologies most amenable and currently applied to plays experiencing the most URG were determined to be 3-D seismic, horizontal/directional drilling, and hydraulic fracturing techniques.

9. The Texas Gulf Coast Basin was forecast to have 43,734 future incremental well completions to contribute approximately 13 Tcf to URG by Year 2015. East Texas was forecast to have 14,655 future incremental well completions to contribute approximately 5 Tcf to URG by Year 2015. URG forecast by the Year 2030 in the Texas Gulf Coast Basin and East Texas was approximately 22 and 8 Tcf, respectively.

10. For the Texas Gulf Coast Basin, plays WX-4, VK-1, and WX-2 hold the greatest URG potential by Year 2030. These three plays comprise approximately 50 percent of the total natural gas URG potential in the Texas Gulf Coast Basin. For East Texas, the Lower Cretaceous-Jurassic Sandstone (KJ) plays account for approximately 59 percent of the total natural gas URG potential by Year 2030.

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Introduction

Estimates of ultimate recovery, the sum of the proved reserves and cumulative production up to a specific time, are initially conservative due to the lack of understanding of the geological, engineering, and production characteristics of the reservoir or field. Ultimate recovery tends on average to increase substantially over time and drilling because of better understanding of the reservoir or field and application of advanced technologies.

In recent years, ultimate recovery growth (URG)—the increase in ultimate recovery estimates from fields subsequent to discovery from extensions and infield drilling in existing fields, improved recovery of in-place resources, new pools, and intrapool completions—has become a major component of total U.S. annual natural gas reserve additions (Fisher, 1991a). URG has commonly also been referred to as reserve growth, reserve appreciation, increases in inferred reserves, probable resources, and known resources. URG is more suitable terminology than the others because it is possible for the estimate of reserves to decrease as a result of production while the estimate of ultimate recovery increases for a particular reservoir or field over a given period of time (Morehouse, 1997).

Over the past years, from 1977 through 1995, approximately 89 percent of the additions to U.S. proved reserves of crude oil and 74 percent of the additions to U.S. proved reserves of dry natural gas were due to URG rather than to the discovery of new oil or natural gas fields (Morehouse, 1997). Further, since the addition of reserves within the existing infrastructure, commonly by inexpensive recompletions in existing wells, URG has become the dominant factor in low-cost natural gas supply in the U.S. (Fisher, 1994b).

The rise of URG basically came about when reservoirs were judged much more geologically complex than generally thought and that they hold substantial quantities of natural gas in conventionally movable states that are not recovered by typical well spacing and vertical completion practices (Fisher, 1991b). Considerable evidence indicates that many reservoirs show significant geological variations and compartmentalization and that uniform spacing, unless very dense, does not efficiently tap and drain a sizable volume of the reservoir.

The increased emphasis on development drilling, an apparently increasing rate of URG from existing fields, and the increasing ratio of URG to new field discovery all indicate that the switch from wildcatting to recovery improvement has long since taken place (Fisher and Galloway, 1983). The fundamental question is whether there is sufficient remaining URG potential to contribute significantly to a sustained or increased natural gas supply and at a relatively low to moderate cost.

PREVIOUS ULTIMATE RECOVERY GROWTH ASSESSMENTS

It is well known that the estimates of ultimate recovery tend to increase with reservoir or field maturity, most commonly expressed in terms of time and drilling. However, questions on how much they increase and the variability in the URG rate for different areas have not been researched in much detail (Megill, 1989a). Most research on URG has been limited to broad geological provinces. URG rates are expected to differ according to plays because of different reservoir characteristics, field sizes, and applicability of additional recovery methods (Megill, 1989c). Disaggregation to the play level is therefore essential to determining the effects and amenability of technology and the economic sensitivity of URG.

James A. Arrington was the first to apply the concept of ultimate recovery, subsequently published in 1960, in the revision of Carter Oil's annual reserve estimates. Arrington discovered that URG varies according to the size of fields, as well as geographic locations, and that future URG can be estimated from past annual URG rates (Arrington, 1960). Arrington's URG analysis methodology utilizes the age of the field as measured by years after discovery as the variable to represent degree of field maturity.

In 1971, G. Rogge Marsh applied Arrington's URG analysis methodology to estimating U.S. national oil and natural gas URG using data from the American Petroleum Institute (API) and the American Gas Association (AGA) (Marsh, 1971). Marsh calculated annual URG rates and used these annual URG rates to calculate the volume of reserves that have actually been discovered in past years (Marsh, 1971).

In 1971, J. J. Arps and others plotted cumulative growth factors versus incremental exploratory footage since discovery for U.S. domestic oil ultimate recoveries, excluding Alaska (Arps and others, 1971). Their work was the first to use cumulative exploratory footage as the measure of maturity rather than time because it was considered a direct measure of probing the Earth's crust by drilling. Time, when considered the independent variable for measure of maturity, was thought inappropriate because time and maturity were not always linearly related (Arps and others, 1971).

M. K. Hubbert assumed a functional form for URG using the API/AGA data (Hubbert, 1962, 1967, 1974). Hubbert claimed that the unproved recoverable oil and natural gas in a field decayed exponentially with time, following a symmetrical life cycle. Similar URG assessments utilizing functional forms were performed by Pelto (1973) and Mast and Dingler (1975). In 1981, Root applied Arrington's URG analysis methodology to the API/AGA data to estimate future U.S. national oil and natural gas URG (called "inferred reserves" in his report) (Root, 1981). Subsequently, the Department of Interior (DOI) revised its national oil and natural gas estimates of future URG utilizing field reserve data from the Energy Information Administration (EIA) (Root and Mast, 1993).

A Department of Energy (DOE) panel led by the Bureau of Economic Geology (BEG), applied a geological engineering approach to calculate the amount of natural gas in compartments not in contact with the well bore in Texas and extrapolated their results to the national level in 1988 (Finley and others, 1988). In 1990, EIA utilized its Oil and Gas Integrated Field File (OGIFF) to estimate future U.S. national oil and natural gas URG by fitting URG rate functions to the data (Energy Information Administration, 1990). The National Petroleum

Council (NPC) used EIA and AGA data to estimate a functional URG form that included field age and the number of wells drilled since discovery to estimate future U.S. national oil and natural gas URG by broad, highly aggregated geological provinces (National Petroleum Council, 1992, 1999). The NPC's assessment fitted an empirical function to the data that was based both on time since discovery and a measure of drilling activity.

As a part of its 1995 national assessment of U.S. oil and natural gas resources located onshore and in Offshore State waters, the U.S. Geological Survey (USGS) performed a study on URG that was based on a factor of time using EIA's OGIFF data series. The OGIFF data series was divided into two classes: (1) a "normally behaving" field class comprising 89 percent of the total U.S. oil and natural gas ultimate recovery and (2) an "outlier" field class, which accounted for the rest. The "outlier" field class included such fields as the heavy oil fields in California that had returned to major production levels after the introduction of tertiary recovery methods and early low-permeability natural gas fields in the Appalachian Basin that were not fully developed until the advent of hydraulic fracturing technology and special pricing and tax incentives (Morehouse, 1997). For the offshore Federal waters, Minerals Management Service (MMS) applied the methodology of Arrington's URG analysis to the Gulf of Mexico Offshore Continental Shelf (GOM OCS), which was broadly disaggregated into depositional styles (Lore and others, 1996).

The Potential Gas Committee (PGC) has estimated URG, referred to as "probable resources," biennially since 1964, except for 1974 (Potential Gas Committee, 1969, 1971, 1973, 1981, 1983). The known productive area of the reservoir is used as an analog to develop a yield factor, which is then applied to an estimate of the as-yet-undeveloped reservoir volume. The resulting volume is then risked by multiplying the estimated probability of existence of the additional reservoir volume. Similar methods are used to determine the undiscovered probable gas resources, those involving new reservoir discoveries in known fields. The PGC's estimates of URG, unlike the previously mentioned empirical and statistical studies, are independent of a historical data series (Morehouse, 1997). URG research has also been undertaken in various degrees by Fisher (1987, 1988, 1991a, 1991b, 1993a, 1993b, 1993c, 1994a, 1994b, 1994c, 1995), Enron (1989), Megill (1989a, 1989b, 1989c), Tyler and Banta (1989), Gas Research Institute (GRI) (1991, 1998), Drew and Schuenemeyer (1992), Energy and Environmental Analysis, Inc. (EEA) (1992, 1998), Levey and others (1993), Root and Attanasi (1993), Attanasi and Root (1994), Drew and others (1994), Woods (1994), and Kim (1998).

Natural gas URG assessments and estimates have also been made by the agencies and individuals mentioned earlier (Figure 1). A generally increasing trend in natural gas URG estimates was made because this component of the natural gas supply, previously unrecognized, was acknowledged and better understood. However, most of these natural gas URG assessments and estimates were by broad, highly aggregated geological provinces, and even with these estimates, there remain unanswered questions with regard to the distribution of natural gas URG potential by play. An assessment of natural gas URG potential by play is the next research direction essential to quantifying the future role of natural gas URG. The Texas Gulf Coast Basin and East Texas are ideal areas in which to initiate such an assessment.

NATURAL GAS ULTIMATE RECOVERY GROWTH RESEARCH OBJECTIVES

URG is an important component of U.S. natural gas supply. However, very few URG studies have been conducted, and it is still poorly understood. As stated recently by USGS researchers, "Much work remains to be done on the phenomenon of URG, which is arguably the most significant research problem in the field of hydrocarbon resource assessment" (Schmoker and Attanasi, 1997). Through disaggregation by plays, a methodology has been developed to better quantify, forecast, and explain natural gas URG.

The large, gross estimates of remaining natural gas URG and the tremendous increases in these estimates over the past decade support the assumption that URG can continue to be a long-term, low-cost component of natural gas supply. There is also substantial evidence that

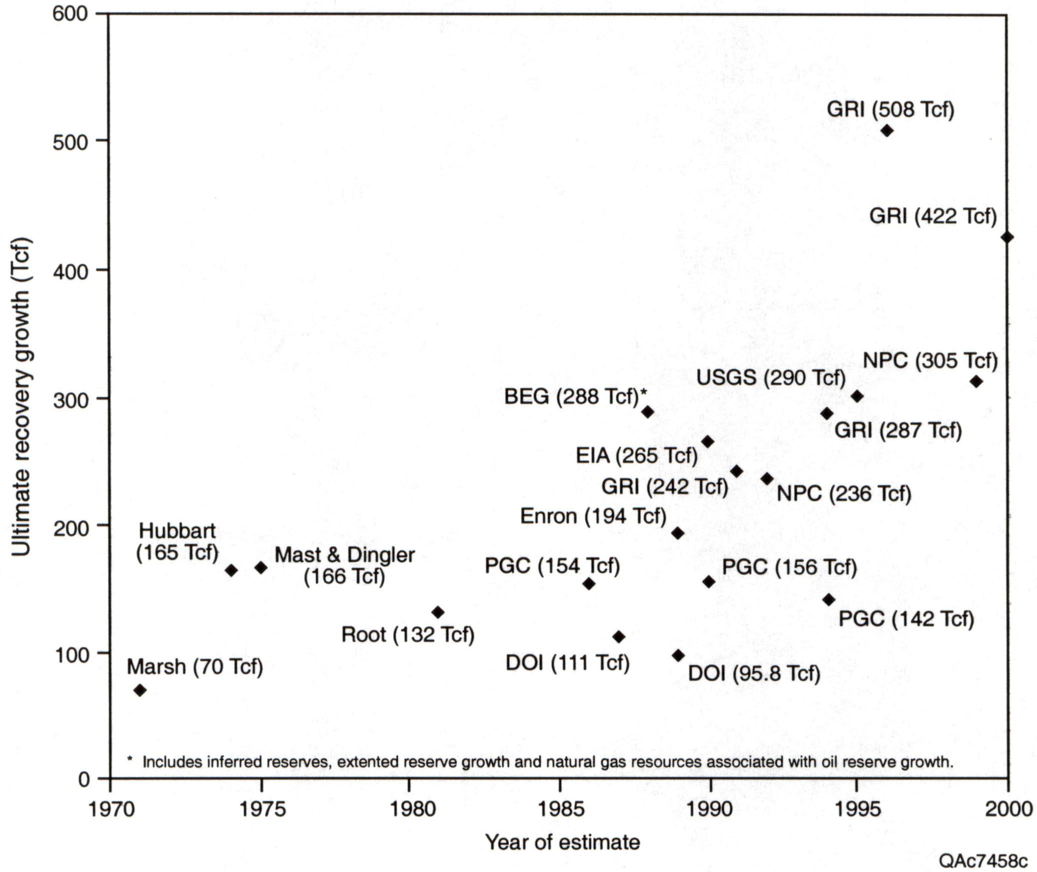


Figure 1. Estimates of natural gas URG for the U.S. Lower 48 States (modified from Fisher 1994b, 1995).

technological advancements have become a major factor in the emergence of URG as an important component of low-cost natural gas supply. But in the case of both the future volume and the role of technology, there are a number of specific elements that should be better defined, better assessed, and more finely disaggregated to facilitate the full combination of URG to future natural gas supply.

Although there is a wide range in natural gas URG potential by play, which is a function of the drilling and technology applied, current natural gas URG estimates are gross, averaging wide ranges, disaggregated by broad natural gas provinces and commonly calculated solely as a function of time. It is well known that areas that have vertically stacked reservoirs associated with growth faults and compartmentalized reservoirs associated with domal salt structures are especially amenable to several new technologies, such as horizontal drilling, directional drilling, and 3-D seismic imaging, and have been major sources of natural gas URG. It is also known that plays with few constraints to natural gas mobility have achieved high rates of conventional recovery and offer minimal URG potential, whereas plays with geologically complex reservoirs show low conventional recovery and offer large potential (Fisher, 1997). However, natural gas URG has neither been quantified by play nor ranked according to plays having the largest remaining potential.

Detection technology, locational diagnostics, horizontal drilling, directional drilling, hydraulic fracturing technology, measurement while drilling (MWD), advanced drilling bits, 3-D seismic, and amplitude versus offset (AVO) are just a few technological advances that have led to an increase in exploration and development efficiency sufficient to offset the depletion effects of declining field size, particularly in URG of older, large fields. However, neither the impacts of technology by play nor the play-specific amenability of applying advanced technologies has been assessed.

Major research objectives include (1) developing a realistic and play-specific measure of remaining URG potential by natural gas resource volume for the Texas Gulf Coast Basin and East Texas, (2) an assessment of the technology necessary and most amenable to realizing the

URG resource, and (3) assessing the economics of converting the resource to reserves. Through such assessment the longer term potential and cost of URG as a contributor to future natural gas supply from the Texas Gulf Coast Basin and East Texas can be determined. Further, the methodology for such an assessment can be verified and codified for wider extrapolation to other natural gas resource areas with significant URG potential.

NATURAL GAS ULTIMATE RECOVERY GROWTH DATA

The EIA maintains the most comprehensive and reliable historical data on proved reserves, production, and ultimate recovery by field relative to time in its OGIFF, available since 1990. The 1996 OGIFF data base provides estimates of crude oil and natural gas proved reserves, annual production, cumulative production, and ultimate recovery for most U.S. oil and natural gas fields. As of 1997, the file contained field-level estimates for each of the 20 years between 1977 and 1996. Related information concerning each field, besides the field name and standard six-digit EIA field code, includes state, state subdivision (within Alabama, Alaska, California, Louisiana, New Mexico, and Texas only), county or counties, year of field discovery, and indicators of oil and natural gas occurrence. The OGIFF data series is not releasable to the public because EIA considers the information to be proprietary.

Data sources for the OGIFF include (1) Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1977 through 1996 surveys (proved reserves, annual and cumulative production for fields, or portions of fields, operated by the largest, approximately 600 oil and natural gas well operators); (2) EIA's "Field Code Master List 1994" (FCML) (field name and code, county, year of field discovery, oil or natural gas identifiers—all of which are based on information through October 1996); (3) Petroleum Information/Dwight's Energydata lease and well files (annual and cumulative production through 1996 in approximately 22 states plus Federal offshore areas, generally having total field coverage); (4) Petroleum Information/

Dwight's Petroleum Data System (annual and cumulative production through 1996 by field, for most U.S. fields, used for states not covered in Petroleum Information/Dwight's lease and well files); and (5) API and AGA (cumulative production for states not covered by Petroleum Information/Dwight's Energydata, derived from a joint report of proved reserves on December 31, 1979).

The EIA OGIFF contains field-specific, confidential data that must be protected through aggregation by play or that must be omitted if one or two fields dominate the play. Some operators may choose to keep confidential any specific technology that might have been applied in particular fields. However, a sufficient and comprehensive data set exists or could be developed to assess natural gas URG (achieved and yet to be realized) on a play basis.

An assessment of natural gas URG potential by play is essential to quantifying the future role of natural gas URG in the Texas Gulf Coast Basin and East Texas. Disaggregation to the play level reveals current production trends and highlights areas for further exploration by identifying and emphasizing areas of potential URG (Lore and Batchelder, 1995). Plays provide the comprehensive reference needed to develop more efficient reservoirs, to extend field limits, and to better assess opportunities for intrafield exploration and development in a mature natural gas province (Seni and Desselle, 1994). Play disaggregation provides a logical basis for natural gas URG potential in the Texas Gulf Coast Basin and East Texas. The BEG, with support from GRI, has defined the major natural gas plays in the Texas Gulf Coast Basin and East Texas, as well as analyzed the main geological, engineering, and production attributes of the plays (Kosters and others, 1989; Seni and others, 1997).

The Texas Gulf Coast Basin and East Texas were selected on the basis of their role as a major natural gas producing district where significant technological advancements have been routinely applied and developed. In terms of U.S. natural gas annual production and proved reserves, Texas accounts for 27 percent and 24 percent, respectively. Within Texas itself, the Gulf Coast Basin and East Texas comprise 67 percent and 58 percent of natural gas annual production and proved reserves, respectively (Energy Information Administration, 1999).

Scientific contributions and research directions

The scientific contributions to the field of resource assessment in this report include the development of one of the first play-level, natural gas URG models for the Texas Gulf Coast Basin and East Texas. The methodology of such an assessment can be verified and applied to other natural gas resource areas with significant natural gas URG potential.

Several important questions relating to the future direction of research in URG have been raised in the most recent review of URG performed by the EIA (Morehouse, 1997): (1) Are field-level data sufficient? (2) Is the available data series representative of the area under consideration? (3) Is ultimate recovery time-invariant? and (4) Can the available data series be adequately parsed?

Questions concerning whether the data are adequately representative and whether the URG process is time-invariant are critical issues that must be resolved in future URG research. Although EIA's OGIFF is the most complete data series of U.S. national oil and natural gas reserves, production, and ultimate recovery available, only about 39,000 fields (85 percent) of the total 45,992 distinct oil and natural gas fields (as of October 1996) are represented. Moreover, out of these approximately 39,000 fields, only about 13,000 new field discoveries occurred during and after EIA's time frame of 1977 and beyond. For most oil and natural gas fields reported in the EIA's OGIFF data series only mid- to late-stage URG is included. Whether this 20-year time frame of the available data series is adequate and time-invariant also remains to be addressed (Morehouse, 1997).

Field-level data are proposed to be sufficient for adequate URG analysis if used directly, and the available data series can be adequately parsed through the use of plays. The potentially deleterious effect of utilizing aggregated data pertaining to large, broad areas was well documented in the striking differences between early USGS studies based on state-level

API/AGA data versus recent USGS studies on URG based on EIA OGIFF field-level data. USGS's URG estimates increased by 326 percent for natural gas (Morehouse, 1997). When field-level data are used at play level, the EIA's OGIFF field-level data are considered to be sufficient for natural gas URG analysis.

Fields may be included in one or more plays because a field may include different reservoirs in different plays. When a field exists within multiple plays, field-level data can be parsed by assigning data to the play level, which is done by allocating ultimate recovery to the specific reservoirs using production data maintained by the TX RRC.

Play Definitions and Summary

Historically, petroleum geologists gathered and organized data that related to reservoir rocks, structure, stratigraphy, and source rocks. As more and more data about the occurrence of petroleum accumulated, a need arose to organize and categorize ideas into conceptual models that were based on geologic processes and depositional environments. These conceptual models had to be classified so that comparative studies could be undertaken (Magoon, 1987).

Conceptual models that incorporate geologic processes and depositional environments to explain the distribution of petroleum include oil systems (Dow, 1974), petroleum zones (Bois, 1975), facies-cycle wedges (White, 1980), generative basins (Demaison, 1984), hydrocarbon machines (Meissner and others, 1984), independent petroliferous systems (Ulmishek, 1986), and petroleum systems (Magoon, 1987). All of these models are generally similar in their definitions and classifications; they differ largely in terms of scale. The concept of a play model, probably first defined by Bois as a petroleum zone, will be utilized as the unit that best incorporates geologic processes and depositional environments to explain the distribution of petroleum.

A play is defined as a conceptual geologic unit having one or more reservoirs that can be genetically related on the basis of depositional origin of the reservoir, structural or trap style, source rocks and hydrocarbon generation, migration mechanism, seals for entrapment, and type of hydrocarbon produced. Plays are the geologically homogeneous subdivision of the universe of petroleum pools within a basin (White, 1980). Therefore, individual plays have unique geological features that can be used as a conceptual model that incorporates geologic processes and depositional environments to explain the distribution of petroleum. When grouped by plays, reservoirs show great similarity in terms of geological, engineering, and production characteristics because the physical, chemical, and biological processes particular to specific plays determine the characteristics of reservoirs (Tyler and others, 1985).

Grouping reservoirs into plays offers several advantages. Because of their relatively similar geological, engineering, and production characteristics, reservoirs within the same play tend to have similar production and URG patterns. Additionally, these patterns of better known, mature reservoirs may be extrapolated with relative confidence to newly discovered reservoirs within the same play. Production and URG responses to technology may, moreover, be determined for a representative reservoir and results readily transferred to the larger family of reservoirs that constitute the play. Finally, knowledge gained from plays can assist in future exploration for similar reservoirs (Galloway and others, 1983).

Research on URG, however, has been limited to broad geological provinces instead of geologically defined plays. Historically, oil and natural gas URG assessments were prepared on a national basis or by broad geological provinces. Although Ryan (1973a, 1973b) and Ulmishek (1986) were the first to recognize different URG patterns by plays, it is only relatively recently that the importance of disaggregation to the play level for URG assessment has been recognized. Moreover, disaggregation to the play level is essential in determining (1) the quantity and future potential, (2) effects and amenability of technology, and (3) economic sensitivity of URG.

SUMMARY OF THE MAJOR GEOLOGICAL CHARACTERISTICS OF THE TEXAS GULF COAST BASIN AND EAST TEXAS

No attempt is made herein to completely describe the petroleum geology of the Texas Gulf Coast Basin or East Texas. Numerous publications that discuss the petroleum geology of the region, its plays, fields, and reservoirs exist and are constantly evolving. Major references that include geological summaries of the Texas Gulf Coast Basin and East Texas are Landes (1970), Nehring (1981, 1991), Galloway and others (1982, 1983, 1986), East Texas Geological Society (1984), Tyler and others (1985), Tyler and Ambrose (1986), Morton and others (1988), Hamlin (1989), and Kosters and others (1989).

The most notable structural features of Texas geology are the Gulf Coast Basin, Llano Uplift, and Marathon Uplift (Figure 2). The Gulf Coast Basin is the northern flank of a great salt basin now largely covered by the Gulf of Mexico. Crustal extensional deposition of Cretaceous and Tertiary sediments probably caused the seafloor to subside. The western extension of the Gulf Coast Basin is known as the Rio Grande Embayment, whereas the northward sector is known as the Houston, or East Texas, Embayment, containing the East Texas Basin. From the bottom of the East Texas Basin the strata rise gently but consistently eastward to the top of the Sabine Uplift, a large dome with its structural crest in northwestern Louisiana. A series of fault zones, including the Balcones Fault Zone and the Mexia-Talco Fault Zone, compose the continental edge of the Gulf Coast Basin (Landes, 1970).

Inland from the Gulf Coast Plain are the Marathon Uplift in the southern part of western Texas and the Llano Uplift in Central Texas. These uplifts are similar in that erosion has exposed older rocks toward the center of the uplift. North of the Llano Uplift is the Bend Flexure or Arch, in which warping took place during the Pennsylvanian, and younger Pennsylvanian and Permian sediments were deposited unconformably across the arch. To the north of the Bend Flexure or Arch is the east-west Red River Uplift overlapping a part of southern Oklahoma. West of the

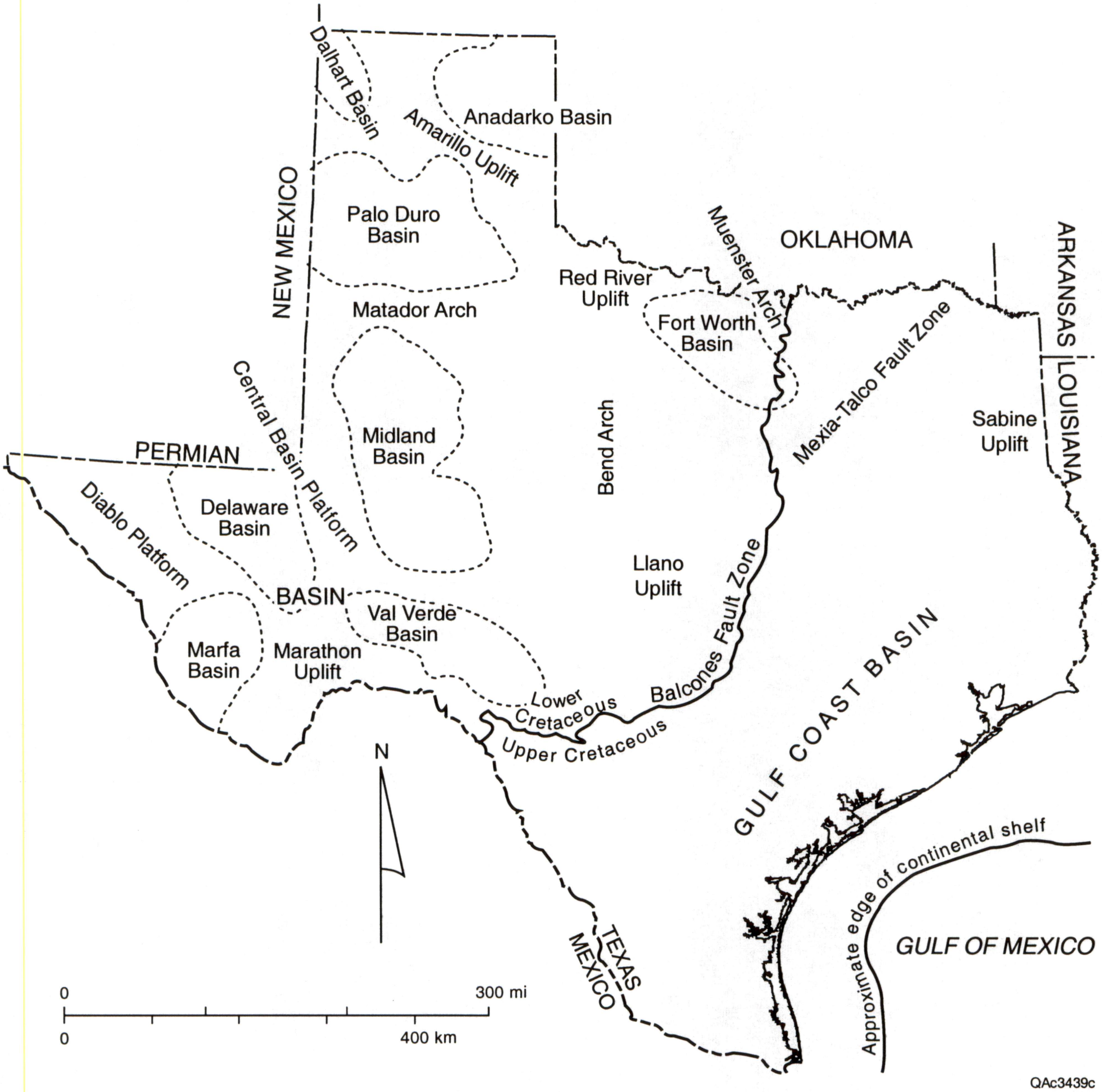


Figure 2. Major structural features of Texas geology (modified from Landes, 1970).

Llano Uplift and north of the Marathon Uplift is the Permian Basin of western Texas and southeastern New Mexico.

The Permian Basin comprises a complex series of basins and arches. The Central Basin Platform separates the Midland Basin to the northeast and the Delaware Basin to the southwest. To the west of the Delaware Basin is the Diablo Platform, and the Midland Basin is bordered on the north by the Matador Arch. The Panhandle of Texas is crossed from northwest to southeast by the Amarillo Uplift. This uplift separates the Anadarko Basin from the Palo Duro Basin (Landes, 1970).

On the geologic map of Figure 3, Texas is largely divided into Mesozoic/Cenozoic Texas and Paleozoic Texas. Mesozoic/Cenozoic Texas includes all of southern and eastern Texas, age increasing inland. Paleozoic Texas extends over the rest of Texas, covering northern and western Texas, including the Panhandle.

The stratigraphy in Paleozoic Texas includes Permian limestones, dolomites, shales, and evaporites at the top in most areas, reaching great thickness in the West Texas basins. The Pennsylvanian is especially well represented in the basins flanking the Bend Flexure or Arch. Mississippian-, Devonian-, and Silurian-age rocks occur in various areas but are less abundant. The Ordovician is also widely present. The stratigraphy in the Gulf Coast Basin has been explored more than 20,000 feet, yet there remains a great thickness yet to be explored, especially near the present shoreline and offshore. The Quaternary is represented by Pleistocene and more recent muds and sands. Abundant clastic deposition occurred in all Tertiary epochs. Upper and Lower Cretaceous sediments have been thoroughly explored in the interior of the Gulf Coast Basin. The Upper Cretaceous includes both clastic and carbonate deposits, and the Lower Cretaceous, or Comanchean, contains not only clastics and carbonates but also anhydrite. Beneath the Lower Cretaceous is a thick Jurassic section; below the Jurassic Smackover Limestone is a thick salt and red-bed section that is Jurassic or older (Landes, 1970).

Texas oil and natural gas reservoirs range in age from Pliocene to Precambrian. The Tertiary reservoirs are confined to the Gulf Coast Basin, well-known producing formations or

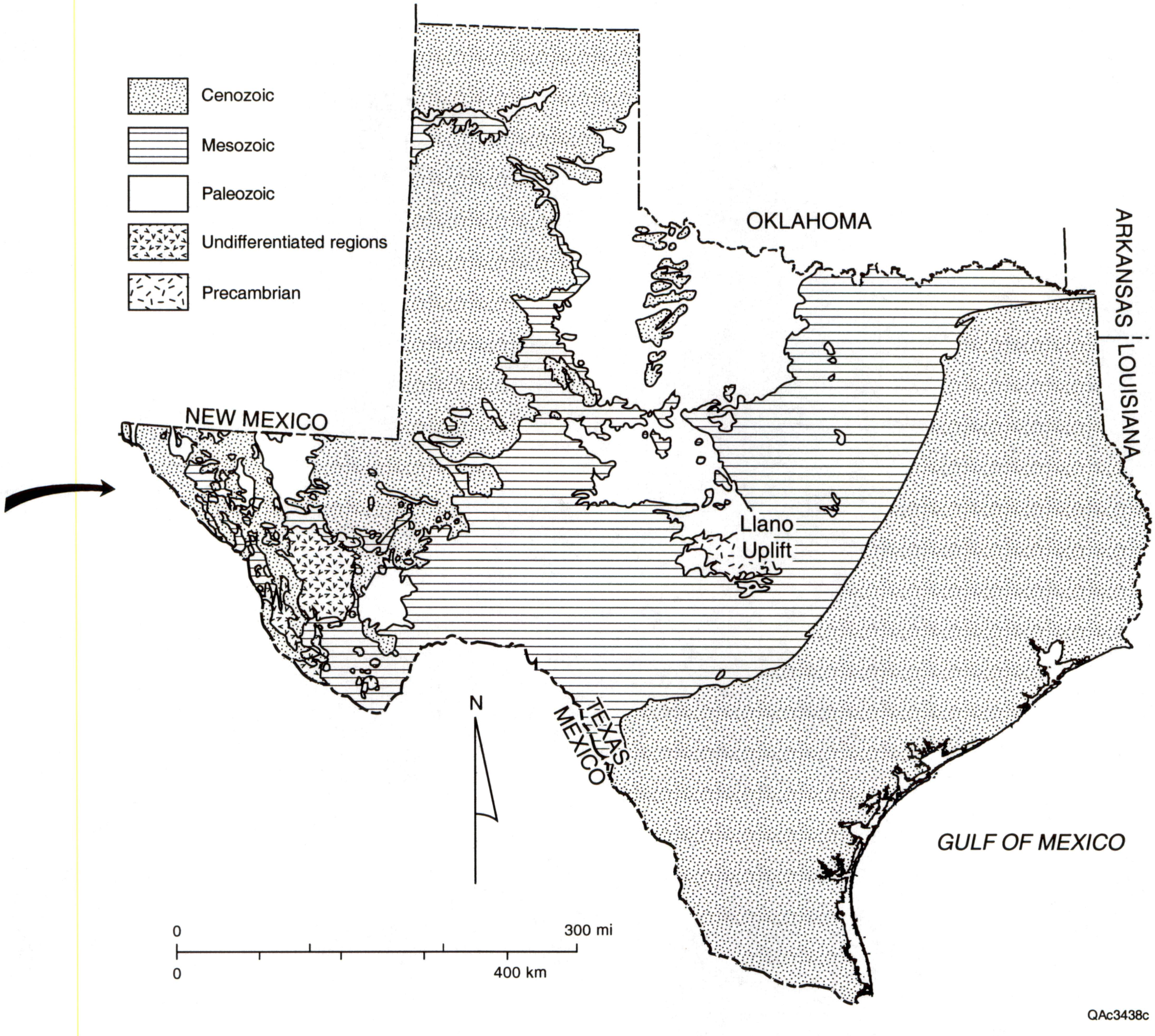


Figure 3. Geologic age map of Texas (modified from Landes, 1970).

zones including the Miocene; the Anahuac, Frio, and Vicksburg of the Oligocene; and the Jackson, Claiborne, Wilcox, and Midway of the Eocene to Paleocene. Upper Cretaceous reservoirs include the Navarro, Taylor, Olmos, and Austin. The Jurassic Cotton Valley and Smackover are productive in East Texas. Permian carbonate rocks, notably the Guadalupian Series, are the principal reservoirs in West Texas and the Panhandle. Sandstone reservoirs in the Wolfcamp are important reservoirs in West-Central Texas. The Strawn, Bend, and other Pennsylvanian formations are productive in North and West-Central Texas. Devonian, Silurian, and Ordovician, especially the Ellenburger limestone, are deep reservoirs in West Texas. Fractured Precambrian volcanic rocks are also productive in the Texas Panhandle (Landes, 1970).

The RRC divides Texas into 10 districts, including two subdivisions in Districts 7 and 8, as shown in Figure 4. The Texas Gulf Coast Basin comprises RRC Districts 1 through 4 and Offshore State waters. Major Texas Gulf Coast Basin natural gas producing fields include Katy, Old Ocean, Giddings, Stratton, Borregos, La Gloria, Seeligson, Zone 21-B Trend, Agua Dulce, Viboras, Chocolate Bayou, Pledger, and Sheridan. East Texas comprises RRC Districts 5 and 6 and a few fields extending into 3. Major East Texas natural gas fields include Carthage, Bethany, East Texas, Opelika, Trawick, Willow Springs, and Hawkins.

The Texas Gulf Coast Basin consists of three major structural provinces: the San Marcos Arch, the Houston Embayment, and the Rio Grande Embayment. The San Marcos Arch is a broad, gently sloping platform that extends from the Llano Uplift in Central Texas southeast toward the Gulf of Mexico. Greater sediment supply and greater relative subsidence north and south of the San Marcos Arch resulted in thicker sediment accumulation in the Houston Embayment and the Rio Grande Embayment, respectively (Dodge and Posey, 1981).

Within these three major structural provinces, Tertiary deposition occurred as a series of gulfward-thickening, terrigenous clastic wedges. Sediments transported by fluvial systems to the coastal margin were deposited as deltas or reworked by marine processes into strandplains and barrier bars. Extension along the shelf margin formed contemporaneous growth faults where

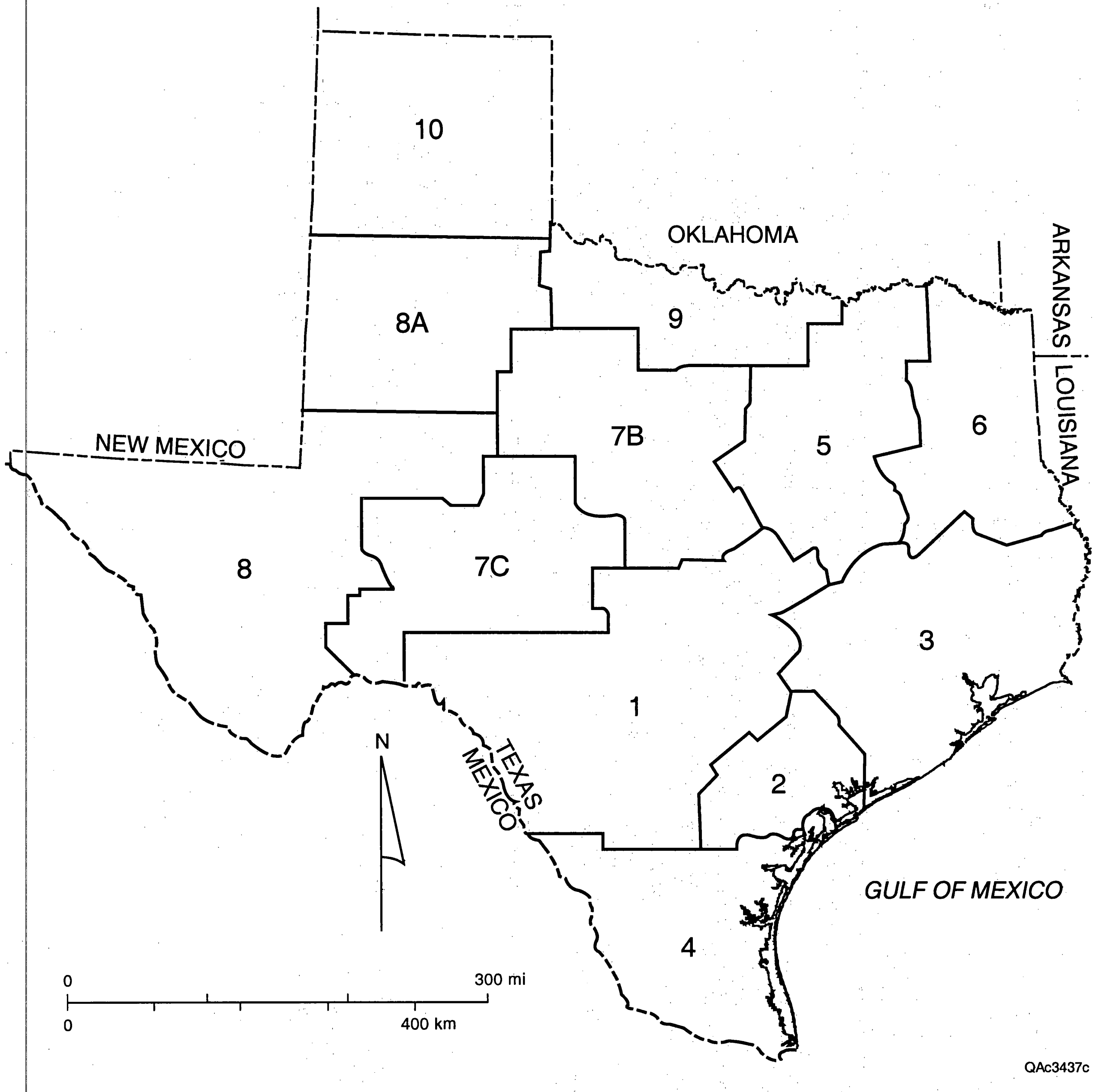


Figure 4. Ten districts defined by the RRC.

sand and mud of one sediment wedge were deposited over prodelta and shelf muds of the previous wedge (Bruce, 1973; Bebout and others, 1975). Continuous movement of growth faults accumulated and isolated thick deposits of sand and mud on the downthrown side.

In some areas, movement of the underlying Jurassic salt induced further complications (Bruce, 1973). Salt domes along the coast, prominent along the northern Gulf Coast (RRC District 3), appear to be of less importance in the southern Texas Gulf Coast Basin (RRC Districts 2 and 4). However, shale diapirs continue in the southern Texas Gulf Coast Basin and contribute to the entrapment of petroleum.

The primary oil and natural gas trapping structures of the Texas Gulf Coast Basin are coast-parallel, strike-elongate bands of growth faults, and also, to a lesser degree, salt structures (Figure 5). The growth-fault zones generally consist of several major normal faults, variably listric, and major thickening or expansion of part of the Tertiary sedimentary wedge. The downthrown strata are generally rotated into the fault, creating reversal of the regional gulfward dip and rollover anticlines. Minor reactivation of many growth faults continued long after major sedimentation and deformation ended (Tyler and others, 1985). Growth-fault zones of the southern Texas Gulf Coast Basin become younger basinward. The oldest growth-fault zone trend occurs in the Paleocene-Eocene Wilcox Group, which prograded gulfward over the Stuart City shelf margin (O'Brien and Freeman, 1979). The main trend extends southwest from De Witt to Zapata County. Increased sediment supply prograded Vicksburg deltas over the Wilcox growth-fault zone in the Texas Gulf Coast Basin, giving rise to the Vicksburg Fault Zone. The zone consists largely of a single master fault, extending from the Republic of Mexico to Wharton County. The fault, highly listric, has displaced the sand-rich Vicksburg section many miles seaward. Shale ridges pierce or deform the basal décollelment downdip (Tyler and others, 1985).

Late Oligocene progradation of the Norias delta system in the Texas Gulf Coast Basin created a broad zone of Oligocene Frio growth faulting landward of the present shoreline (Galloway and others, 1983). Early Miocene sedimentation in the Gulf Coast Basin gave rise to the Miocene Fault Zone, which is composed of two fault systems that parallel the present shoreline.

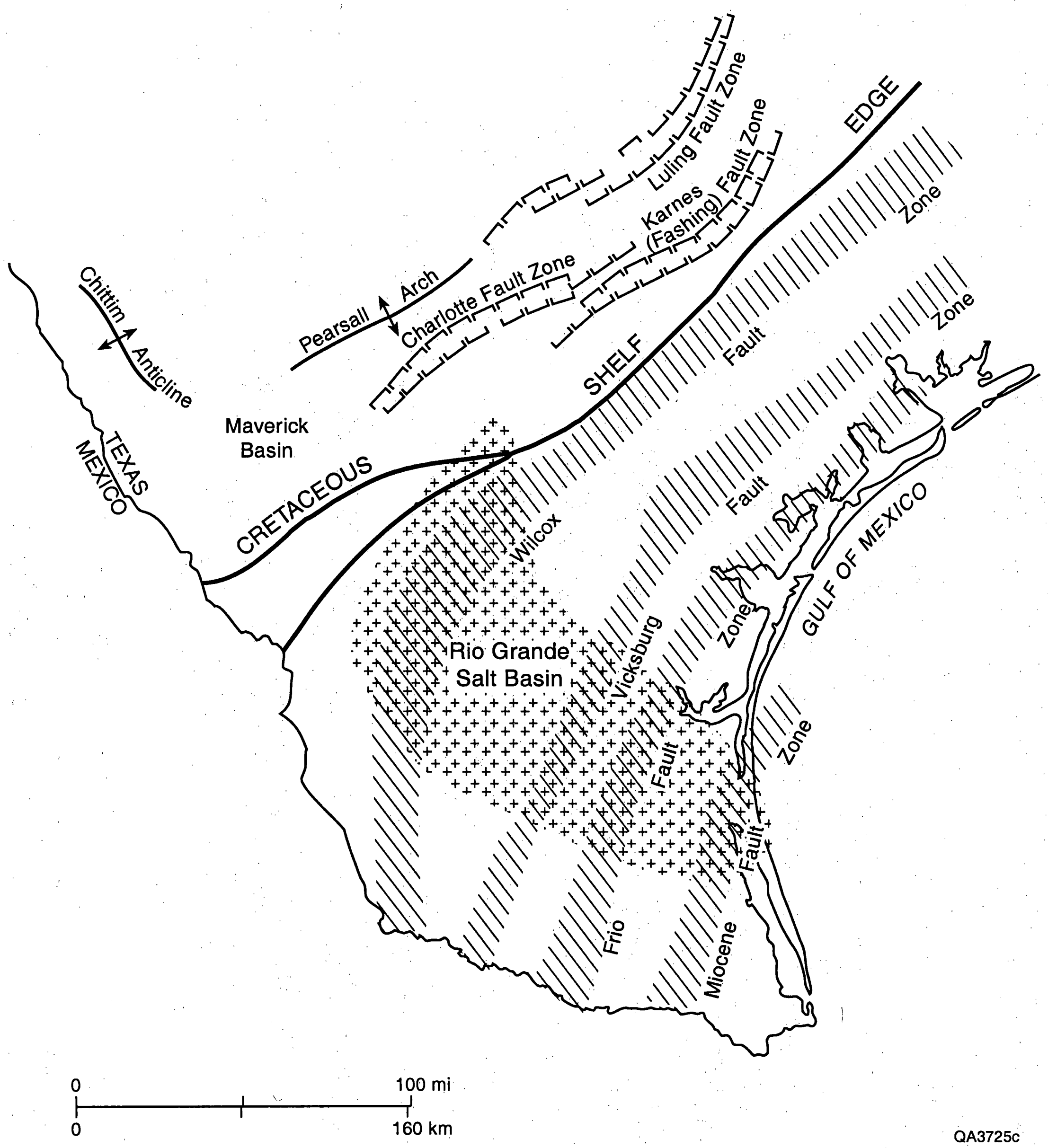


Figure 5. Major structural features of the southern Texas Gulf Coast Basin (modified from Galloway and others, 1983).

Late Miocene and Plio-Pliestocene normal fault zones developed near the present shelf edge (Bruce, 1973).

Sandstone geometry in the Tertiary formations reflects the interaction of fluvial, deltaic, and marine processes. The upper Wilcox of the southern and middle Texas Gulf Coast Basin is characterized by both strike- and dip-oriented deltaic sandstones. Along the middle and northern Texas Gulf Coast Basin, the upper Wilcox is characterized by highly destructive, wave-dominated deltas (Fisher and McGowen, 1967). Marine processes dominated sandstone deposition of the Frio Formation in the middle Texas Gulf Coast Basin. Deltaic deposits were reworked and redistributed strike parallel into strandplain and barrier-bar systems. During the Oligocene and Miocene, the major depocenters of sedimentation in the Texas Gulf Coast Basin shifted northeast from the Rio Grande Embayment to the Mississippi Embayment. These shifting depocenters define the major producing trends of the Miocene Formation. Because Claiborne Group and Jackson Formation deltas did not prograde over the underlying shelf margins, only thin sands in prodelta and shelf muds were deposited in these formations gulfward of the Wilcox growth-fault zone trend (Dodge and Posey, 1981).

The greater part of the East Texas Basin lies within the East Texas embayment, a northward tongue of the Gulf Coastal Plain. The East Texas embayment is bounded to the east by the Sabine Uplift and to the north and west by the Mexia-Talco Fault Zone. The East Texas Basin formed initially during Late Triassic rifting. Crustal extension produced thinning and heating of the lithosphere. Subsequent cooling and subsidence formed a basin in which a thick sequence of Mesozoic and Cenozoic sediments accumulated. Numerous salt domes, both piercement and nonpiercement, are present in the East Texas Basin (Landes, 1970).

After deposition of a thick upper Middle Jurassic salt layer, carbonates dominated the early phases of deposition in East Texas. The earliest progradation of terrigenous clastics in East Texas is recorded by the Upper Jurassic-Lower Cretaceous Cotton Valley Group. The Travis Peak Formation represents a second period of fluvial-deltaic progradation. In updip parts of East Texas, the Travis Peak Formation unconformably overlies the Cotton Valley Group. Downdip, the Travis Peak Formation is separated from the Cotton Valley Group by a thin, transgressive-marine deposit, the Knowles Limestone. The Travis Peak Formation is gradationally overlain by limestones of the Cretaceous Sligo Formation.

PLAY DELINEATION METHODOLOGY OF THE TEXAS GULF COAST BASIN AND EAST TEXAS

The BEG has applied the play approach to analysis of oil and natural gas resources of Texas. Oil and natural gas reservoirs of onshore Texas were classified into plays by Galloway and others (1983) and Kosters and others (1989). Seni and others (1997) delineated the offshore component of Texas oil and natural gas resources into plays. The play concept was also applied by Bebout and others (1992, 1993) to natural gas reservoirs of the central and eastern Gulf Coast and the Midcontinent. Various other BEG research utilizing the play concept on Texas oil and natural gas reservoirs was performed by Galloway and others (1982, 1986), Tyler and others (1985), Tyler and Ambrose (1986), Morton and others (1988), and Hamlin (1989). Delineation of plays in other U.S. regions was performed by Whitehead and others (1993), U.S. Geological Survey (1995), and Roen and Walker (1996).

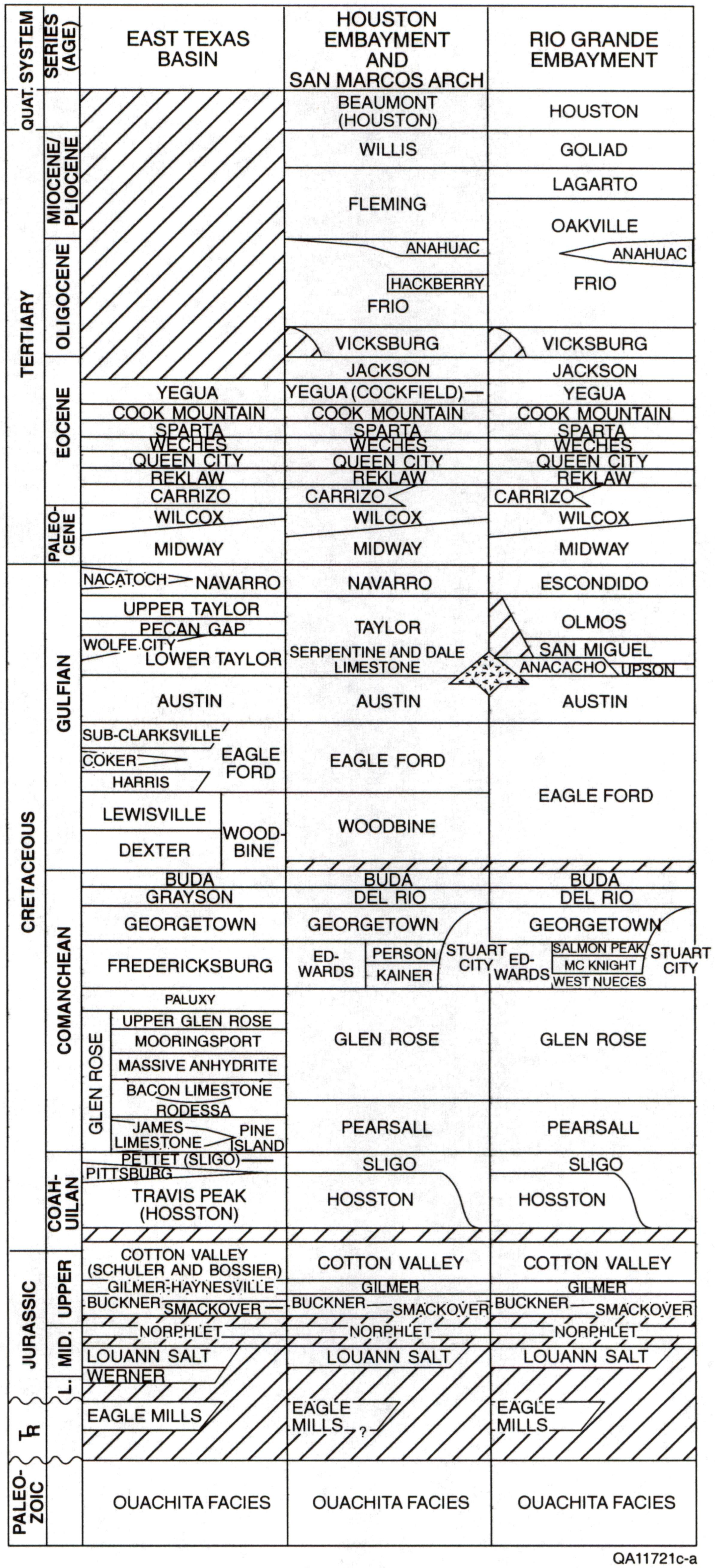
The play concept is a basic tool for organizing a vast number of data available from natural gas reservoirs of the Texas Gulf Coast Basin and East Texas. BEG's *Atlas of Major Texas Gas Reservoirs* (Kosters and others, 1989) was used as the primary guide to play delineation. The 1,828 major Texas natural gas reservoirs onshore and in State waters discovered through 1986 are represented. It characterizes these natural gas reservoirs, each of which have produced more than 10 Bcf, according to their geological, volumetric, and engineering properties. Emphasis has been placed on those 868 natural gas reservoirs that have produced more than 30 Bcf. The major natural gas reservoirs have been classified into 73 plays (Kosters and others, 1989).

In the delineation of natural gas plays in the Texas Gulf Coast Basin and East Texas, attempts to synthesize new and existing geological/engineering data and interpretations were undertaken. Few new geological interpretations of the plays were made. Compilation, updating, correction of data, and summarization of the originally defined play delineations were the major contributions. Major sources of data utilized in the compilation and updating of play delineations include annual proved reserves, production, and ultimate recovery data obtained from Energy Information Administration's OGIFF (1996); production and completion data from Lasser Inc.'s *Texas Production Database* (1999); annual field-production volume summaries and engineering and volumetric data prepared by the Railroad Commission of Texas (1996, 1997); and field summary volumes containing maps, cross sections, type logs, completion, production, and historical data published by the Bureau of Economic Geology (1951), Houston Geological Society (1962), South Texas Geological Society (1962, 1967, 1986), Corpus Christi Geological Society (1967, 1972, 1979), Beebe (1968), Halbouty (1970), Bebout and others (1978, 1982), Dodge and Posey (1981), Galloway and others (1982, 1983, 1986), East Texas Geological Society (1984, 1989), Tyler and others (1985), Hamlin (1989), Finley and others (1990), Jackson and Finley (1992), Levey and others (1993), and Holtz and Garrett (1997).

A single field may produce natural gas from several reservoirs that vary in geologic age (Figure 6), depositional environment (Figure 7), lithology, drive mechanism, traps, and many other attributes used to characterize a play. Therefore, a single field may be represented in more than one play (Figure 8). Because many natural gas fields produce from multiple reservoirs, data have been organized at a reservoir level. Reservoirs are grouped into genetically related plays that are based primarily on similar depositional settings. Individual plays have unique geological features that can be used as a conceptual model that uses geologic processes and depositional environments to explain the distribution of petroleum.

Accuracy of the available play data varies because of different sources reporting differing values and delineations for the same type of play data (Holtz and Garrett, 1997). Where great discrepancies existed, selection was based on known geologic criteria and comparison with other

Figure 6. Geologic age of Texas Gulf Coast Basin and East Texas reservoirs (Galloway and others, 1983).



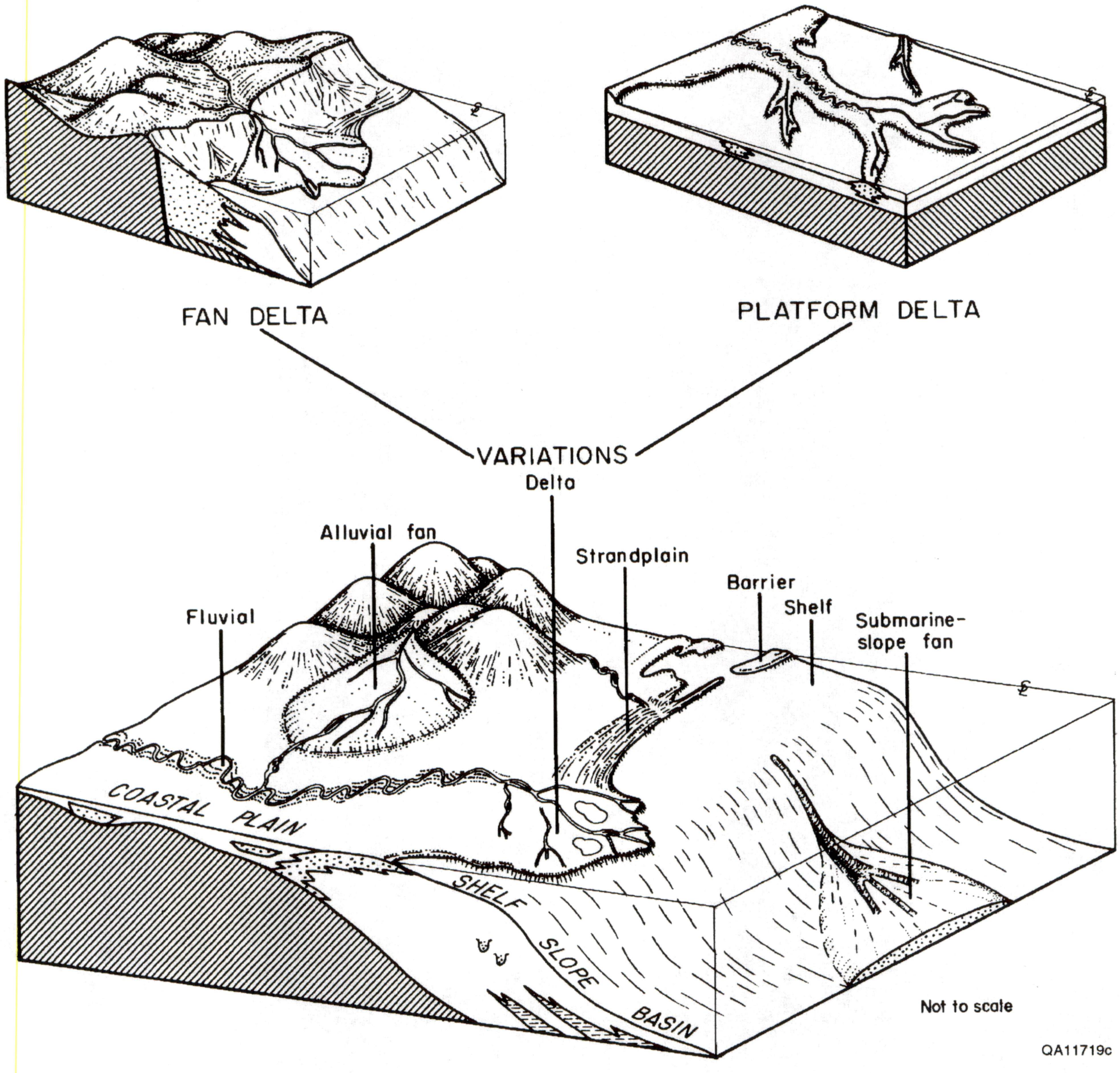


Figure 7. Depositional environments of Texas Gulf Coast Basin and East Texas reservoirs (Galloway and others, 1983).

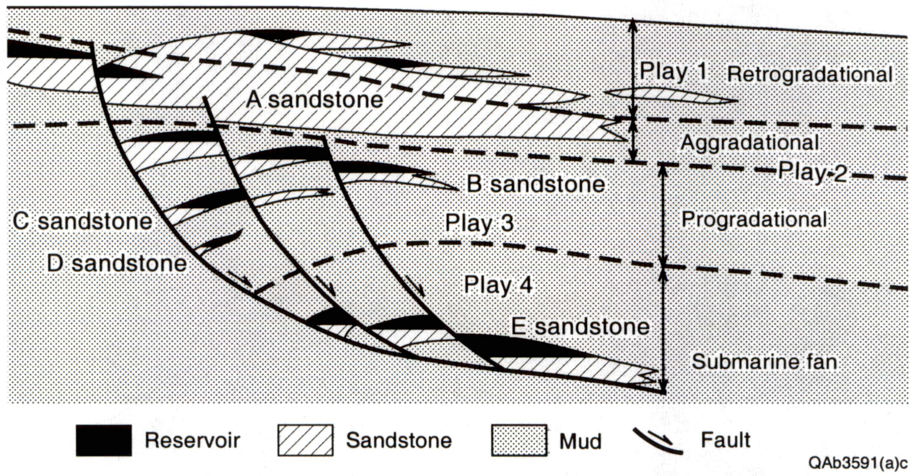


Figure 8. Play schematic and representation (Seni and others, 1997).

play data. Play data were weighted in favor of records that were most recent and from sources that were inferred to be the most reliable.

SUMMARIES OF TEXAS GULF COAST BASIN AND EAST TEXAS PLAYS

The BEG's *Atlas of Major Texas Gas Reservoirs* (Kosters and others, 1989) was used as the primary guide to play delineation in the Texas Gulf Coast Basin and East Texas. All the major Texas natural gas reservoirs discovered onshore and in State waters through 1986 were delineated into 73 geologically defined plays. Groups of the 73 plays were segregated on the basis of geographic region and RRC Districts into: Gulf Coast Basin (RRC Districts 1–4); East Texas (RRC Districts 5 and 6); North-Central Texas (RRC Districts 7B and 9); West Texas (RRC Districts 7C, 8, and 8A); and Texas Panhandle (RRC District 10) (Kosters and others, 1989).

In the delineation of plays, attempts to synthesize new and existing geological/engineering data and interpretations were undertaken rather than present new geological interpretations of the originally defined plays. Compilation, updating, corrections of play data, and summarization of the natural gas play delineations were the main tasks accomplished.

The Texas Gulf Coast Basin comprises Railroad Commission (RRC) of Texas Districts 1 through 4 and Offshore State waters. A total of 7,484 fields existed in the original 1996 Energy Information Administration's (EIA) Oil and Gas Integrated Field File (OGIFF) data base. This data set was reduced to 1,372 fields having 1996 natural gas ultimate recovery estimates greater than 10 Bcf and at least 2 years of data. The reduced data set represents 94 percent of the total 1996 natural gas ultimate recovery for the 7,484 fields. East Texas comprises RRC Districts 5 and 6 and a few fields extending into 3. A total of 1,447 fields existed in the original 1996 EIA OGIFF data base. This data set was reduced to 235 fields having 1996 natural gas ultimate recovery estimates greater than 10 Bcf and at least 2 years of data. The reduced data set represents 96 percent of the total 1996 natural gas ultimate recovery for the 1,447 fields.

For the Texas Gulf Coast Basin, RRC Districts 3 and 4 comprise the majority of natural gas ultimate recovery, production, and proved reserves (Figures 9, 10, and 11). Discovery-year histograms for the Texas Gulf Coast Basin displayed bimodal distributions of an older and younger population of fields (Figure 12). Depth histograms for the Texas Gulf Coast Basin showed a majority of fields in the 12,000- to 14,000-foot range (Figure 13). Field-size histograms for the Texas Gulf Coast Basin revealed a large population of smaller fields (Figure 14). However, several large fields (Katy, Old Ocean, Giddings, Stratton, Borregos, La Gloria, Seeligson, Zone 21-B Trend, Agua Dulce, Viboras, Chocolate Bayou, Pledger, and Sheridan) accounted for most of Texas Gulf Coast Basin 1996 natural gas ultimate recovery. In particular, Katy field was the dominant field in the Texas Gulf Coast Basin, with ultimate recovery estimates of approximately 10 Tcf. The reduced data set of 1,369 fields was disaggregated into 30 geologically delineated plays. Only major plays with natural gas ultimate recovery greater than 1 Tcf were selected for detailed analysis. A total of 21 major plays were selected for further, detailed URG analysis (Figure 15 and Table 1). Summaries of play characteristics for the 21 major plays of the Texas Gulf Coast Basin are shown in Tables 2 through 22.

Historical trends of the 21 major plays of the Texas Gulf Coast Basin in terms of natural gas ultimate recovery, production, and proved reserves are shown in Figures 16, 17, and 18. Natural gas ultimate recovery for the Lower Wilcox Lobo Trend (WX-2), Wilcox Sandstone, Rio Grande Embayment (WX-4), Vicksburg Sandstone, Rio Grande Embayment (VK-1), and Austin/Buda Chalk (KG-2) plays show prominent, increasing trends. These trends also hold true in terms of production, and excluding play VK-1, these increasing trends exists in terms of proved reserves. Judging from historical trends, these four plays hold the greatest potential for future natural gas URG.

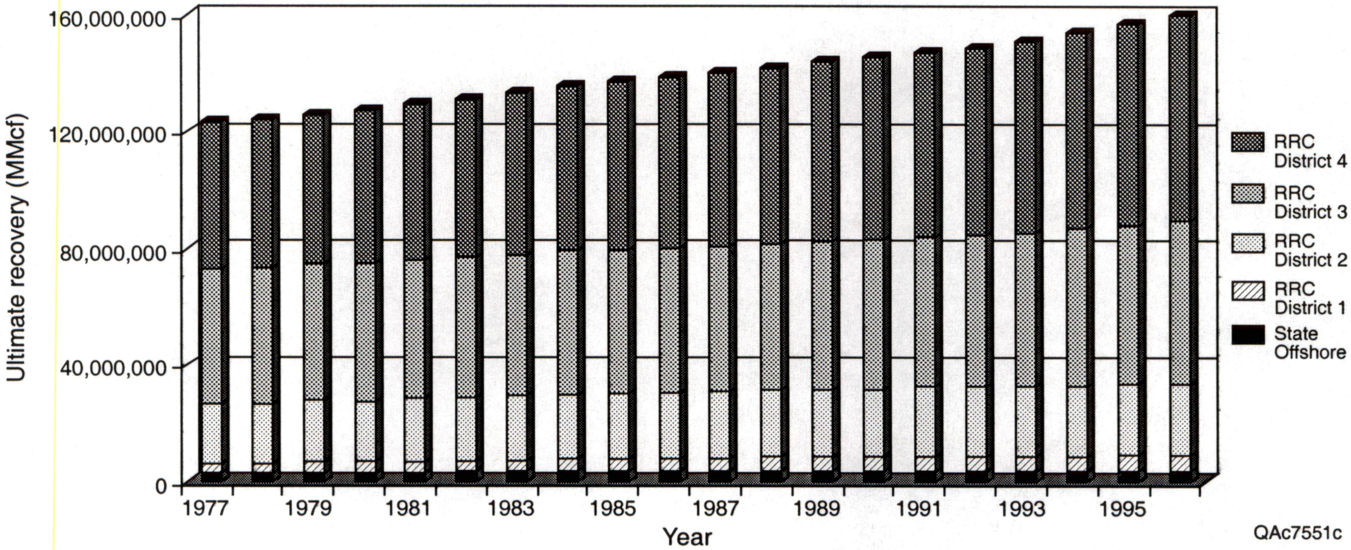


Figure 9. Natural gas ultimate recovery in major fields of the Texas Gulf Coast Basin.

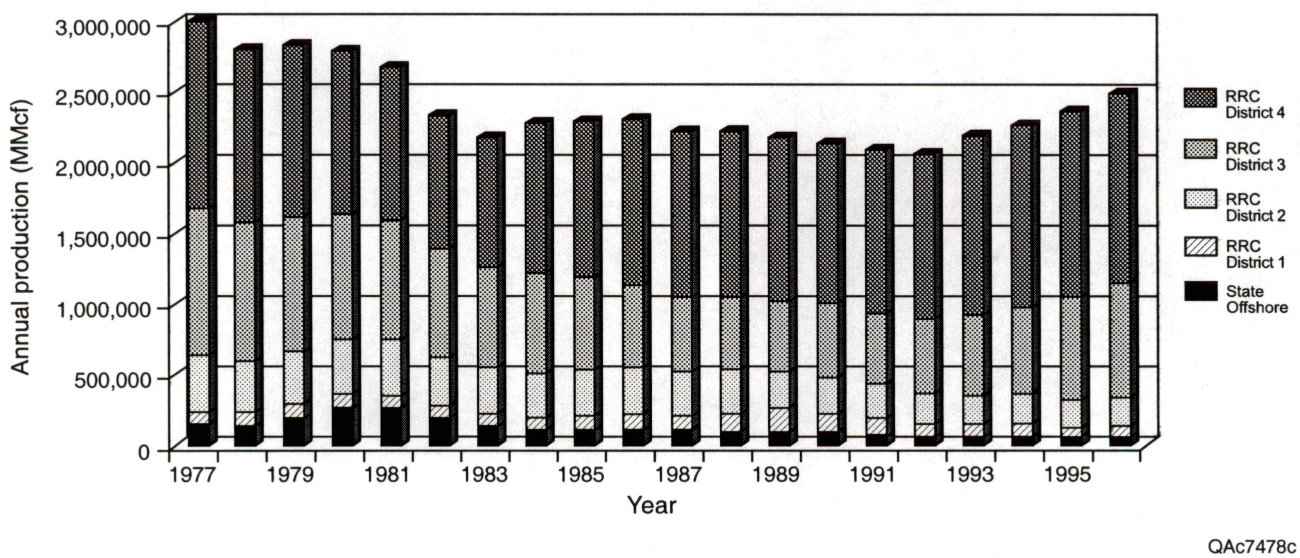


Figure 10. Natural gas production in major fields of the Texas Gulf Coast Basin.

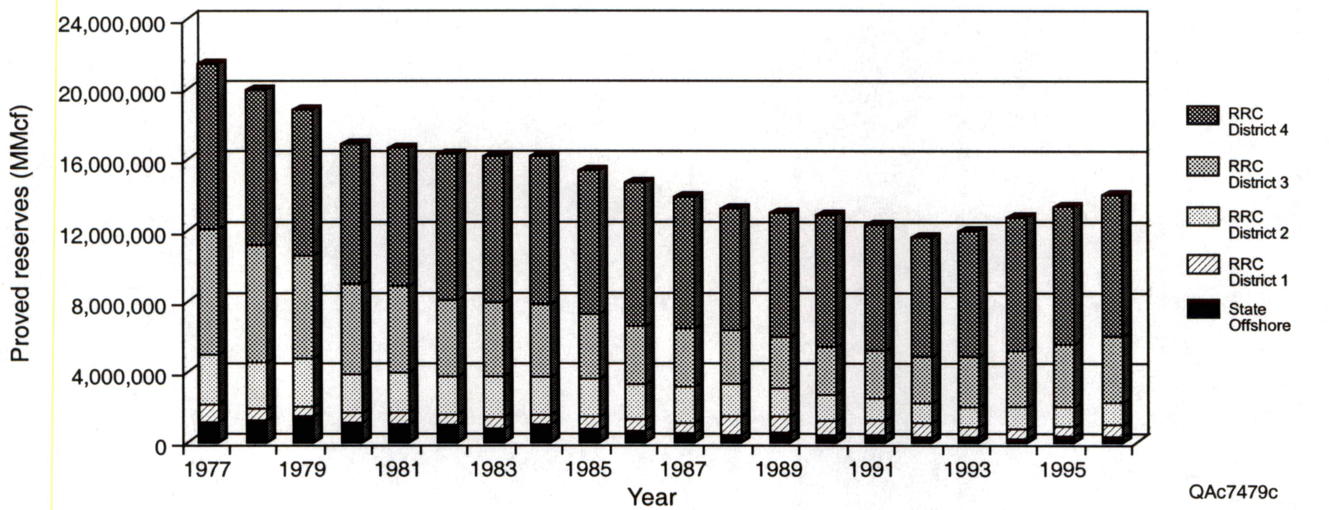


Figure 11. Natural gas proved reserves in major fields of the Texas Gulf Coast Basin.

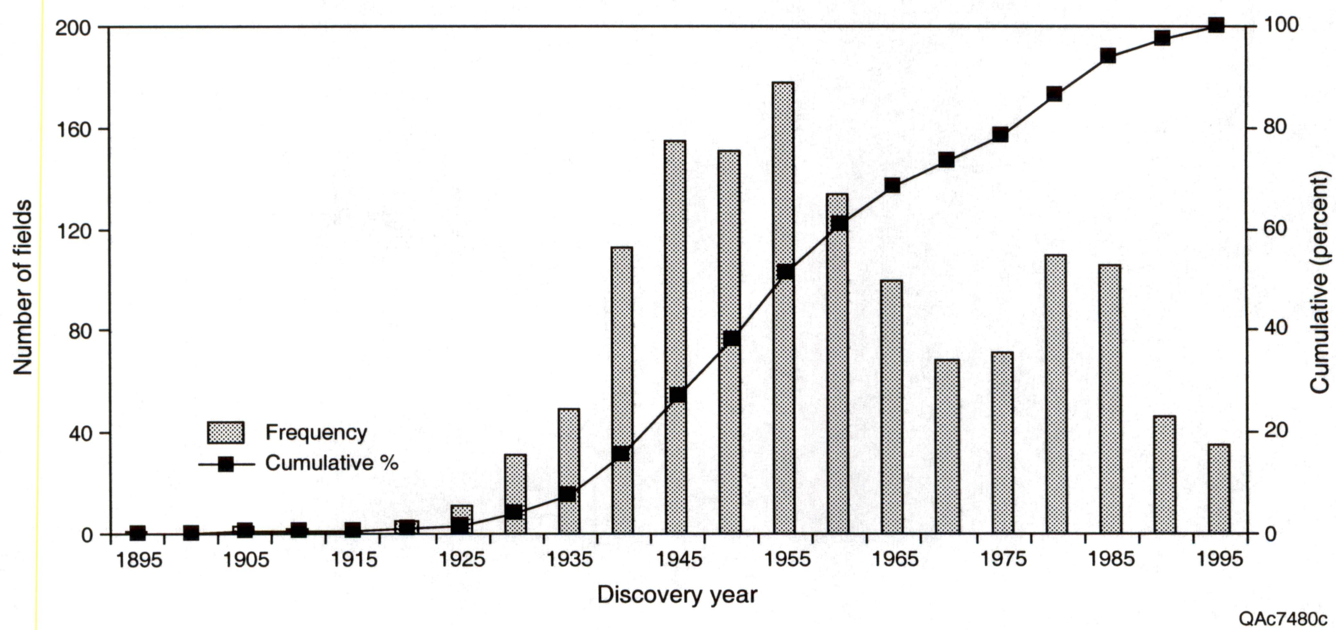


Figure 12. Discovery-year histogram for major fields in the Texas Gulf Coast Basin.

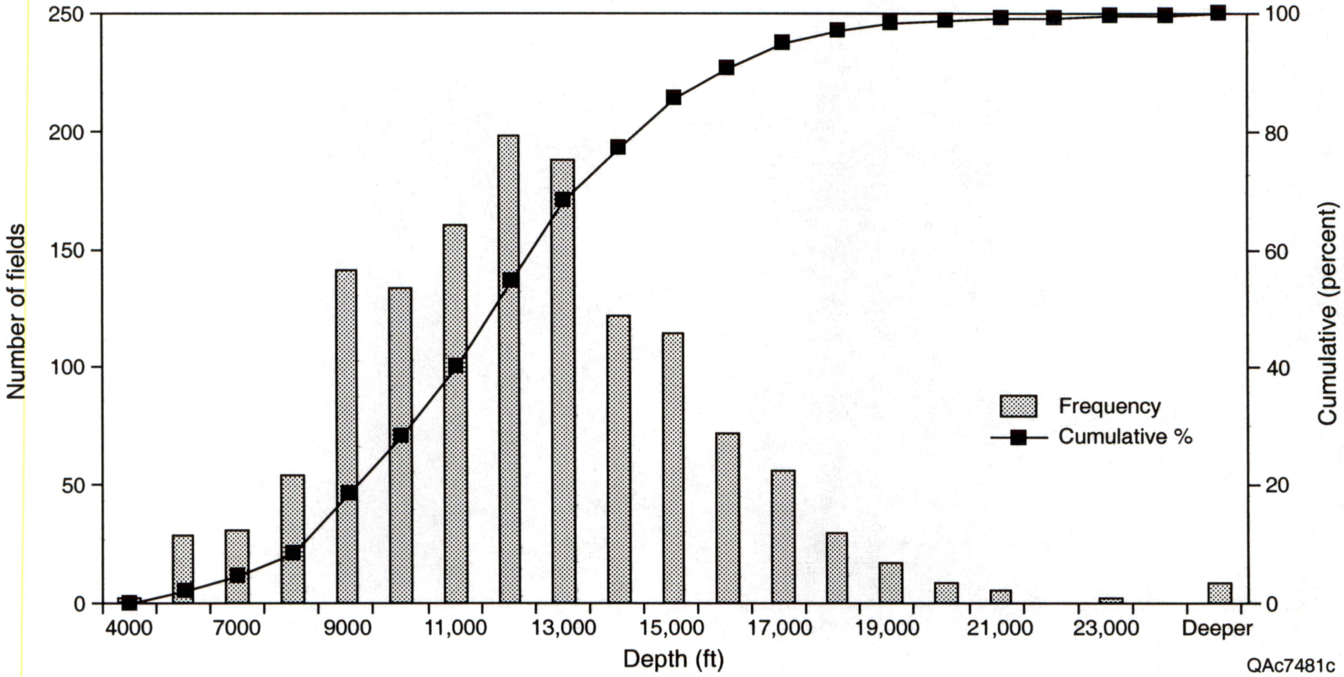


Figure 13. Depth histogram for major fields in the Texas Gulf Coast Basin.

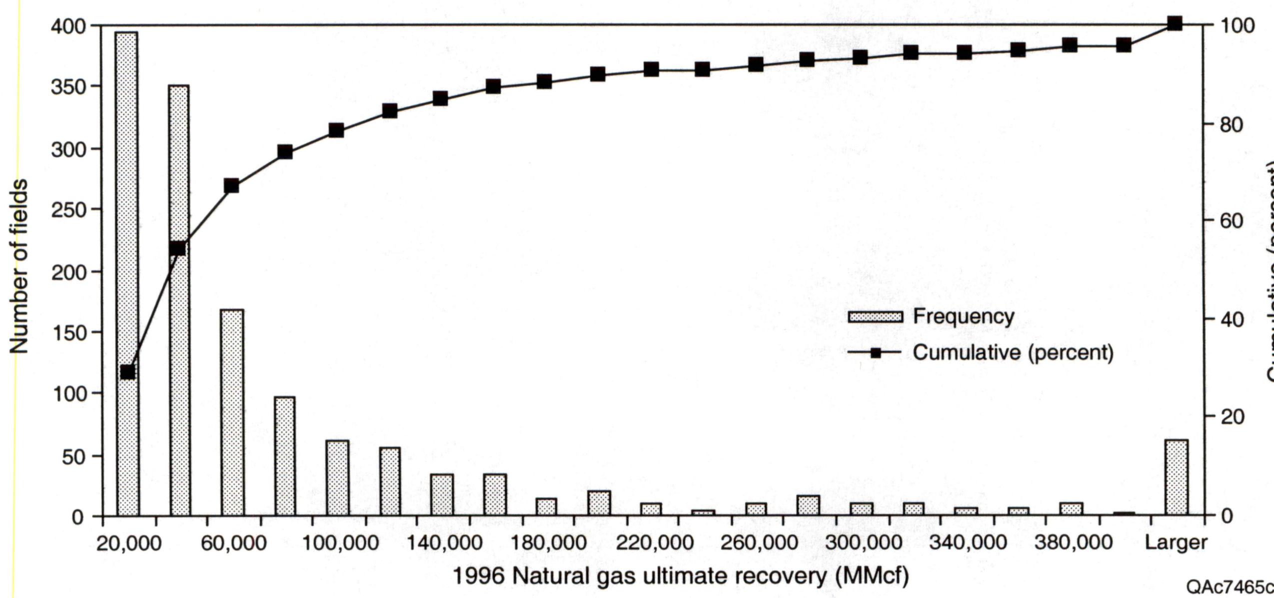


Figure 14. Size histogram for major fields in the Texas Gulf Coast Basin.

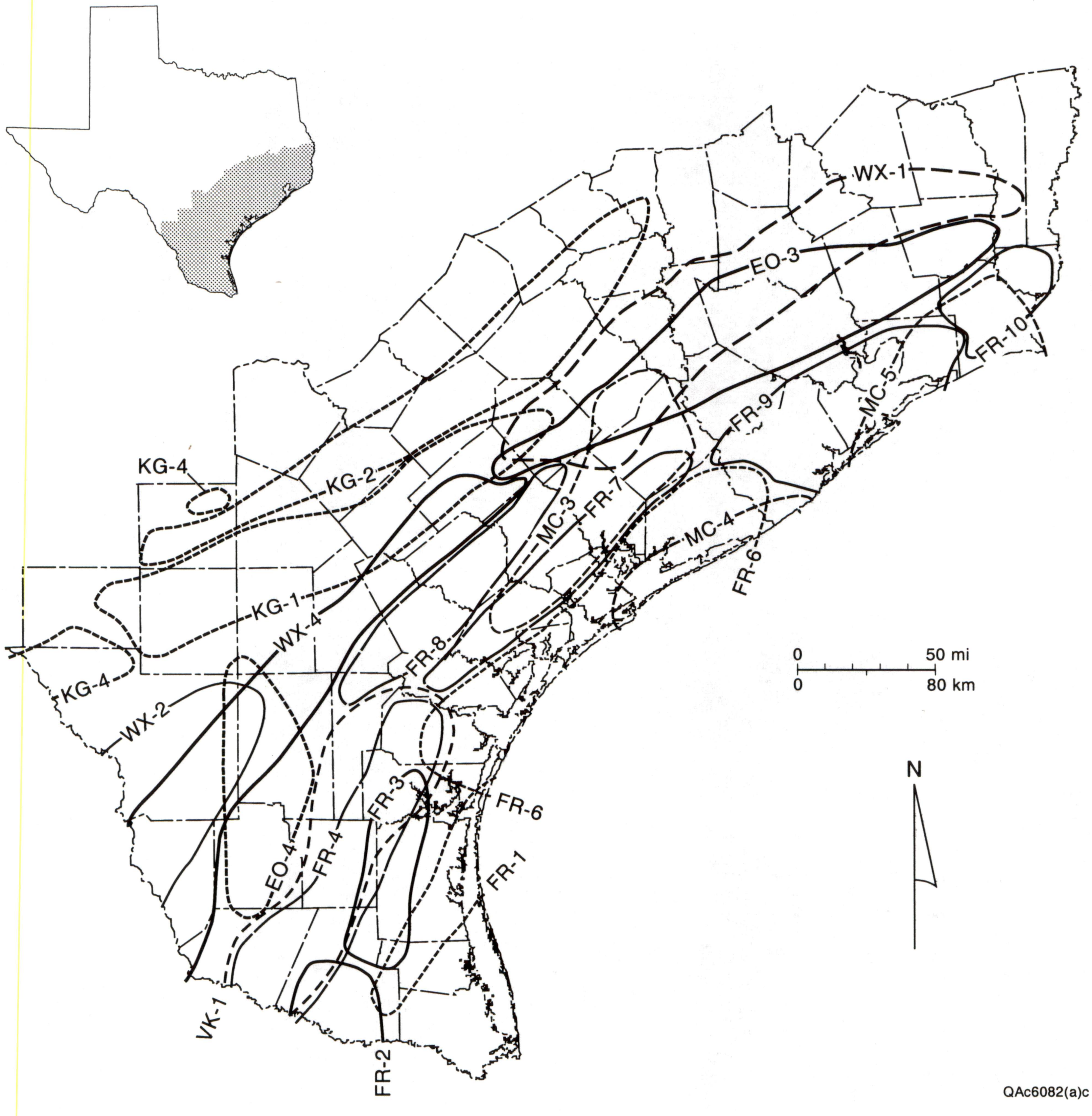


Figure 15. Major natural gas plays of the Texas Gulf Coast Basin.

Table 1. Summary of major natural gas plays of the Texas Gulf Coast Basin.

Play code	Play name	1996 Ultimate Recovery (MMcf)	1996 Production (MMcf)	1996 Reserves (MMcf)	1996 Fields
MC-3	Miocene Lower Coastal-Plain Sandstone, San Marcos Arch	3,268,895	8,398	53,553	32
MC-4	Miocene Barrier/Strandplain Sandstone, San Marcos Arch	2,900,782	42,950	140,952	38
MC-5	Miocene Sandstone, Houston Embayment	2,324,944	27,389	166,146	39
FR-1	Distal Frio Deltaic Sandstone, Rio Grande Embayment	1,173,995	6,143	32,055	18
FR-2	Frio Delta-Flank Shoreline Sandstone, Rio Grande Embayment	4,349,501	36,557	234,776	28
FR-3	Proximal Frio Sandstone, Rio Grande Embayment	7,082,121	74,577	681,766	37
FR-4	Frio Sandstone, Vicksburg Fault Zone	18,504,468	80,257	617,849	76
FR-6	Downdip Frio Barrier/Strandplain Sandstone, San Marcos Arch	17,177,887	71,828	584,795	147
FR-7	Updip Frio Barrier/Strandplain Sandstone, San Marcos Arch	9,752,358	48,043	319,272	100
FR-8	Frio Fluvial/Coastal-Plain Sandstone, San Marcos Arch	2,150,476	15,742	99,714	54
FR-9	Frio Sandstone, Houston Embayment	13,008,586	125,227	906,530	105
FR-10	Frio Sandstone, Hackberry Embayment	3,358,269	10,384	50,566	39
VK-1	Vicksburg Sandstone, Rio Grande Embayment	11,927,869	297,664	1,713,594	78
EO-3	Yegua Sandstone, Houston Embayment	16,566,819	106,482	624,435	125
EO-4	Yegua/Jackson Sandstone, Rio Grande Embayment	1,570,181	18,342	64,849	35
WX-1	Wilcox Sandstone, Houston Embayment	7,632,128	124,455	961,087	89
WX-2	Wilcox Lobo Trend	8,485,236	391,593	2,109,751	87
WX-4	Wilcox Sandstone, Rio Grande Embayment	15,555,179	440,324	2,293,522	206
KG-1	Lower Cretaceous Carbonate	3,915,183	63,124	420,875	33
KG-2	Austin/Buda Chalk	3,898,057	397,800	1,054,999	9
KG-4	Olmos Sandstone	1,401,037	39,561	430,570	23

Table 2. Summary for Miocene Lower Coastal-Plain Sandstone, San Marcos Arch (MC-3) play characteristics.

Play	Miocene Lower Coastal-Plain Sandstone, San Marcos Arch
Play code	MC-3
Lithology	Sandstone
Age	Miocene
Exploration maturity	Very mature
Structural style	Faults and anticlines inherited from underlying Frio
Frontiers	------------------
Limitations	Shallow, drilling density, lack of indigenous source rocks
Major fields	Greta, Magnet Withers, Heyser, Huff, McFaddin
Cumulative growth factor	1.76
1996/1977 ultimate recovery growth ratio	1.04
1996 ultimate recovery (MMcf)	3,268,895
1996 production (MMcf)	8,398
1996 reserves (MMcf)	53,553
Average field discovery year	1947
Average completion depth (ft)	5,101
Number of fields	32

Table 3. Summary of Miocene Barrier/Strandplain Sandstone, San Marcos Arch (MC-4) play characteristics.

Play	Miocene Barrier/Strandplain Sandstone, San Marcos Arch
Play code	MC-4
Lithology	Sandstone
Age	Miocene
Exploration maturity	Mature
Structural style	Broad rollover anticlines associated with reactivated growth faults
Frontiers	Downdip offshore
Limitations	------------------
Major fields	Collegeport, El Gordo, Brazos Blk. 440, Brazos Blk. 405, Cove
Cumulative growth factor	3.02
1996/1977 ultimate recovery growth ratio	1.36
1996 ultimate recovery (MMcf)	2,900,782
1996 production (MMcf)	42,950
1996 reserves (MMcf)	140,952
Average field discovery year	1969
Average completion depth (ft)	6,577
Number of fields	38

Table 4. Summary of Miocene Sandstone, Houston Embayment (MC-5) play characteristics.

Play	Miocene Sandstone, Houston Embayment
Play code	MC-5
Lithology	Sandstone
Age	Miocene
Exploration maturity	Mature
Structural style	Anticline, growth faults, deep-seated salt
Frontiers	Downdip offshore
Limitations	Abrupt stratigraphic changes
Major fields	High Island Blk. 24, High Island Blk. 14, High Island, Beaumont W., Shipwreck
Cumulative growth factor	2.45
1996/1977 ultimate recovery growth ratio	1.27
1996 ultimate recovery (MMcf)	2,324,944
1996 production (MMcf)	27,389
1996 reserves (MMcf)	166,146
Average field discovery year	1956
Average completion depth (ft)	6,198
Number of fields	39

Table 5. Summary of Distal Frio Deltaic Sandstone, Rio Grande Embayment (FR-1) play characteristics.

Play	Distal Frio Deltaic Sandstone, Rio Grande Embayment
Play code	FR-1
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Mature
Structural style	Growth faults and shale ridges
Frontiers	Downdip offshore
Limitations	Low source and reservoir rock quality; migration inefficiency
Major fields	Murdock Pass, Mercedes, Calandria, Lacy, La Sal Vieja
Cumulative growth factor	3.61
1996/1977 ultimate recovery growth ratio	1.25
1996 ultimate recovery (MMcf)	1,173,995
1996 production (MMcf)	6,143
1996 reserves (MMcf)	32,055
Average field discovery year	1959
Average completion depth (ft)	8,592
Number of fields	18

Table 6. Summary of Frio Delta-Flank Shoreline Sandstone, Rio Grande Embayment (FR-2) play characteristics.

Play	Frio Delta-Flank Shoreline Sandstone, Rio Grande Embayment
Play code	FR-2
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Mature
Structural style	Growth faults, shale ridges, and rollover/faulted anticlines
Frontiers	Deeper prospects
Limitations	Low reservoir quality and migration inefficiency
Major fields	McAllen, San Salvador, La Blanca, Donna, San Carlos
Cumulative growth factor	1.23
1996/1977 ultimate recovery growth ratio	1.11
1996 ultimate recovery (MMcf)	4,349,501
1996 production (MMcf)	36,557
1996 reserves (MMcf)	234,776
Average field discovery year	1952
Average completion depth (ft)	8,832
Number of fields	28

Table 7. Summary of Proximal Frio Sandstone, Rio Grande Embayment (FR-3) play characteristics.

Play	Proximal Frio Sandstone, Rio Grande Embayment
Play code	FR-3
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Very mature
Structural style	Growth faults and shale ridges; Vicksburg flexure
Frontiers	------------------
Limitations	Well density
Major fields	Viboras, Alazan N., Tordilla, Stillman, Sarita
Cumulative growth factor	0.99
1996/1977 ultimate recovery growth ratio	1.12
1996 ultimate recovery (MMcf)	7,082,121
1996 production (MMcf)	74,577
1996 reserves (MMcf)	681,766
Average field discovery year	1961
Average completion depth (ft)	8,957
Number of fields	37

Table 8. Summary of Frio Sandstone, Vicksburg Fault Zone (FR-4) play characteristics.

Play	Frio Sandstone, Vicksburg Fault Zone
Play code	FR-4
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Very mature
Structural style	Low-amplitude faults and anticlines; Vicksburg growth fault
Frontiers	------------------
Limitations	Well density, lack of indigenous mature source
Major fields	Stratton, Seeligson, Zone 21-B Trend, Agua Dulce, La Gloria
Cumulative growth factor	1.87
1996/1977 ultimate recovery growth ratio	1.09
1996 ultimate recovery (MMcf)	18,504,468
1996 production (MMcf)	80,257
1996 reserves (MMcf)	617,849
Average field discovery year	1948
Average completion depth (ft)	6,883
Number of fields	76

Table 9. Summary of Downdip Frio Barrier/Strandplain Sandstone, San Marcos Arch (FR-6) play characteristics.

Play	Downdip Frio Barrier/Strandplain Sandstone, San Marcos Arch
Play code	FR-6
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Very mature
Structural style	Frio fault zones and diapirs
Frontiers	Deeper and downdip targets
Limitations	Well density
Major fields	Old Ocean, Markham N-Bay City N., Laguna Larga, Bay City E., Red Fish Bay-Mustang Island
Cumulative growth factor	4.04
1996/1977 ultimate recovery growth ratio	1.09
1996 ultimate recovery (MMcf)	17,177,887
1996 production (MMcf)	71,828
1996 reserves (MMcf)	584,795
Average field discovery year	1958
Average completion depth (ft)	9,223
Number of fields	147

Table 10. Summary of Updip Frio Barrier/Strandplain Sandstone, San Marcos (FR-7) play characteristics.

Play	Updip Frio Barrier/Strandplain Sandstone, San Marcos Arch
Play code	FR-7
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Very mature
Structural style	Growth faults, diapirs, and shale ridges
Frontiers	------------------
Limitations	Well density
Major fields	Tom O'Connor, Magnet Withers, West Ranch, Heyser, Lake Pasture
Cumulative growth factor	1.46
1996/1977 ultimate recovery growth ratio	1.07
1996 ultimate recovery (MMcf)	9,752,358
1996 production (MMcf)	48,043
1996 reserves (MMcf)	319,272
Average field discovery year	1946
Average completion depth (ft)	6,406
Number of fields	100

Table 11. Summary of Frio Fluvial/Coastal-Plain Sandstone, San Marcos Arch (FR-8) play characteristics.

Play	Frio Fluvial/Coastal-Plain Sandstone, San Marcos Arch
Play code	FR-8
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Very mature
Structural style	Faults and low-relief anticlines inherited from underlying Wilcox
Frontiers	------------------
Limitations	Well density, lack of indigenous mature source
Major fields	Heard Ranch, Blanconia, Cologne, Sarco Creek, Morales
Cumulative growth factor	1.97
1996/1977 ultimate recovery growth ratio	1.13
1996 ultimate recovery (MMcf)	2,150,476
1996 production (MMcf)	15,742
1996 reserves (MMcf)	99,714
Average field discovery year	1950
Average completion depth (ft)	4,757
Number of fields	54

Table 12. Summary of Frio Sandstone, Houston Embayment (FR-9) play characteristics.

Play	Frio Sandstone, Houston Embayment
Play code	FR-9
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Very mature
Structural style	Salt diapirs and growth faults
Frontiers	-----------------
Limitations	Well density; deep and highly pressured
Major fields	Chocolate Bayou, Pledger, Anahuac, Red Fish Reef, Clear Lake
Cumulative growth factor	3.10
1996/1977 ultimate recovery growth ratio	1.10
1996 ultimate recovery (MMcf)	13,008,586
1996 production (MMcf)	125,227
1996 reserves (MMcf)	906,530
Average field discovery year	1954
Average completion depth (ft)	8,211
Number of fields	105

Table 13. Summary of Frio Sandstone, Hackberry Embayment (FR-10) play characteristics.

Play	Frio Sandstone, Hackberry Embayment
Play code	FR-10
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Very mature
Structural style	Salt dome and growth faults
Frontiers	------------------
Limitations	Well density; deep and highly pressured
Major fields	Port Neches N., Marrs Mclean, Lemonville, Port Acres, Big Hill
Cumulative growth factor	6.36
1996/1977 ultimate recovery growth ratio	1.09
1996 ultimate recovery (MMcf)	3,358,269
1996 production (MMcf)	10,384
1996 reserves (MMcf)	50,566
Average field discovery year	1952
Average completion depth (ft)	7,380
Number of fields	39

Table 14. Summary of Vicksburg Sandstone, Rio Grande Embayment (VK-1) play characteristics.

Play	Vicksburg Sandstone, Rio Grande Embayment
Play code	VK-1
Lithology	Sandstone
Age	Oligocene
Exploration maturity	Mature
Structural style	Vicksburg growth fault
Frontiers	------------------
Limitations	Deep and highly pressured; low permeability
Major fields	Borregos, McAllen Ranch, La Gloria, TCB, Jeffress
Cumulative growth factor	15.70
1996/1977 ultimate recovery growth ratio	1.63
1996 ultimate recovery (MMcf)	11,927,869
1996 production (MMcf)	297,664
1996 reserves (MMcf)	1,713,594
Average field discovery year	1959
Average completion depth (ft)	8,821
Number of fields	78

Table 15. Summary of Yegua Sandstone, Houston Embayment (EO-3) play characteristics.

Play	Yegua Sandstone, Houston Embayment
Play code	EO-3
Lithology	Sandstone
Age	Eocene
Exploration maturity	Very mature
Structural style	Domal structures associated with deep-seated salt diapirs
Frontiers	-----------------
Limitations	-----------------
Major fields	Katy, Conroe, Tomball, Bammel, Houston N.
Cumulative growth factor	7.23
1996/1977 ultimate recovery growth ratio	1.11
1996 ultimate recovery (MMcf)	16,566,819
1996 production (MMcf)	106,482
1996 reserves (MMcf)	624,435
Average field discovery year	1959
Average completion depth (ft)	5,931
Number of fields	125

Table 16. Summary of Yegua/Jackson Sandstone, Rio Grande Embayment (EO-4) play characteristics.

Play	Yegua/Jackson Sandstone, Rio Grande Embayment
Play code	EO-4
Lithology	Sandstone
Age	Eocene
Exploration maturity	Very mature
Structural style	Deep-seated salt domes
Frontiers	Downdip trend
Limitations	-----------------
Major fields	Sejita, Government Wells N., Conoco Driscoll, Lundell, Southland
Cumulative growth factor	6.76
1996/1977 ultimate recovery growth ratio	1.18
1996 ultimate recovery (MMcf)	1,570,181
1996 production (MMcf)	18,342
1996 reserves (MMcf)	64,849
Average field discovery year	1947
Average completion depth (ft)	3,821
Number of fields	35

Table 17. Summary of Wilcox Sandstone, Houston Embayment (WX-1) play characteristics.

Play	Wilcox Sandstone, Houston Embayment
Play code	WX-1
Lithology	Sandstone
Age	Eocene-Paleocene
Exploration maturity	Very mature
Structural style	Wilcox growth fault zone
Frontiers	Deep, downdip extension
Limitations	-----------------
Major fields	Sheridan, Provident City, Katy, Columbus, Chesterville N.
Cumulative growth factor	19.22
1996/1977 ultimate recovery growth ratio	1.37
1996 ultimate recovery (MMcf)	7,632,128
1996 production (MMcf)	124,455
1996 reserves (MMcf)	961,087
Average field discovery year	1960
Average completion depth (ft)	10,657
Number of fields	89

Table 18. Summary of Wilcox Lobo Trend (WX-2) play characteristics.

Play	Wilcox Lobo Trend
Play code	WX-2
Lithology	Sandstone
Age	Eocene-Paleocene
Exploration maturity	Relatively immature
Structural style	Gravity sliding and intense normal faulting
Frontiers	Limits of play still undetermined
Limitations	Low permeability
Major fields	Vaquillas Ranch, Laredo, JC Martin, La Perla Ranch, Benavides
Cumulative growth factor	72.37
1996/1977 ultimate recovery growth ratio	7.04
1996 ultimate recovery (MMcf)	8,485,236
1996 production (MMcf)	391,593
1996 reserves (MMcf)	2,109,751
Average field discovery year	1977
Average completion depth (ft)	9,611
Number of fields	87

Table 19. Summary of Wilcox Sandstone, Rio Grande Embayment (WX-4) play characteristics.

Play	Wilcox Sandstone, Rio Grande Embayment
Play code	WX-4
Lithology	Sandstone
Age	Eocene-Paleocene
Exploration maturity	Mature to very mature
Structural style	Closely spaced growth faults and rollover anticlines
Frontiers	Deeper and downdip targets
Limitations	Stratigraphically and structurally complex; deep and highly pressured
Major fields	Double A Wells, Brookeland, Madisonville, Iola
Cumulative growth factor	18.21
1996/1977 ultimate recovery growth ratio	1.85
1996 ultimate recovery (MMcf)	15,555,179
1996 production (MMcf)	440,324
1996 reserves (MMcf)	2,293,522
Average field discovery year	1960
Average completion depth (ft)	9,867
Number of fields	206

Table 20. Summary of Lower Cretaceous Carbonate (KG-1) play characteristics.

Play	Lower Cretaceous Carbonate
Play code	KG-1
Lithology	Carbonate
Age	Lower Cretaceous
Exploration maturity	Mature
Structural style	Reef-related modifications and faults
Frontiers	-----------------
Limitations	Low permeability
Major fields	Fashing, Word N., Jourdanton, Person, Dilworth
Cumulative growth factor	8.54
1996/1977 ultimate recovery growth ratio	1.35
1996 ultimate recovery (MMcf)	3,915,183
1996 production (MMcf)	63,124
1996 reserves (MMcf)	420,875
Average field discovery year	1962
Average completion depth (ft)	10,062
Number of fields	33

Table 21. Summary of Austin/Buda Chalk (KG-2) play characteristics.

Play	Austin/Buda Chalk
Play code	KG-2
Lithology	Carbonate
Age	Cretaceous
Exploration maturity	Relatively immature
Structural style	Irregular fracture systems that interconnect porous zones
Frontiers	------------------
Limitations	Poorly defined fracture system
Major fields	Giddings
Cumulative growth factor	21.80
1996/1977 ultimate recovery growth ratio	43.81
1996 ultimate recovery (MMcf)	3,898,057
1996 production (MMcf)	397,800
1996 reserves (MMcf)	1,054,999
Average field discovery year	1971
Average completion depth (ft)	9,385
Number of fields	9

Table 22. Summary of Olmos Sandstone (KG-4) play characteristics.

Play	Olmos Sandstone
Play code	KG-4
Lithology	Sandstone
Age	Upper Cretaceous
Exploration maturity	Mature
Structural style	Down-to-coast normal faulting
Frontiers	Updip reexploration and downdip extension
Limitations	Low permeability
Major fields	AWP, Big Foot W., Tom Walsh, Dos Hermanos, Owen
Cumulative growth factor	18.76
1996/1977 ultimate recovery growth ratio	3.01
1996 ultimate recovery (MMcf)	1,401,037
1996 production (MMcf)	39,561
1996 reserves (MMcf)	430,570
Average field discovery year	1966
Average completion depth (ft)	6,429
Number of fields	23

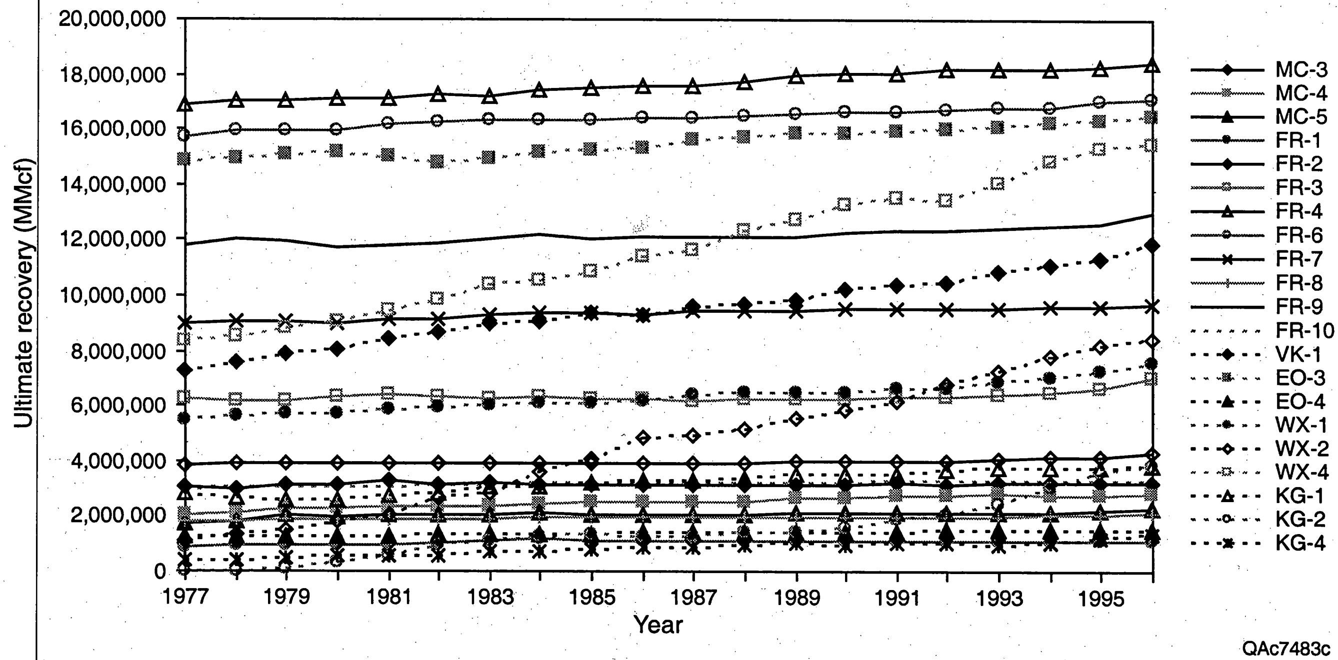


Figure 16. Historical natural gas ultimate recovery by major plays in the Texas Gulf Coast Basin.

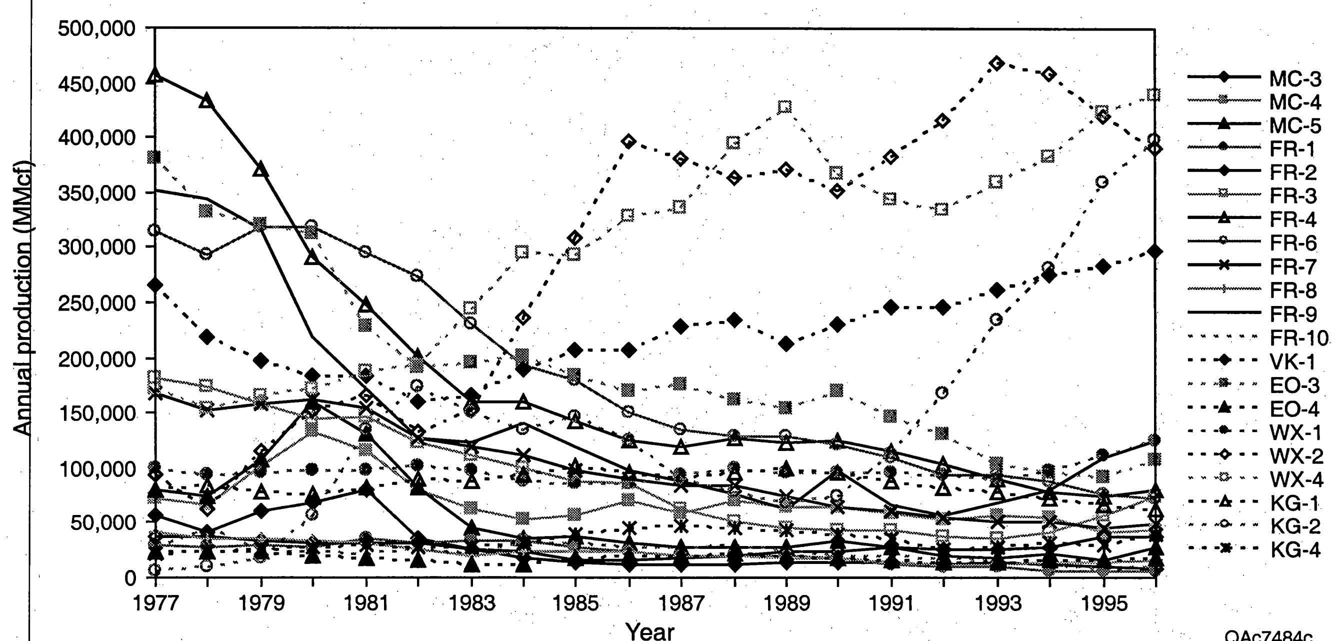


Figure 17. Historical natural gas production by major plays in the Texas Gulf Coast Basin.

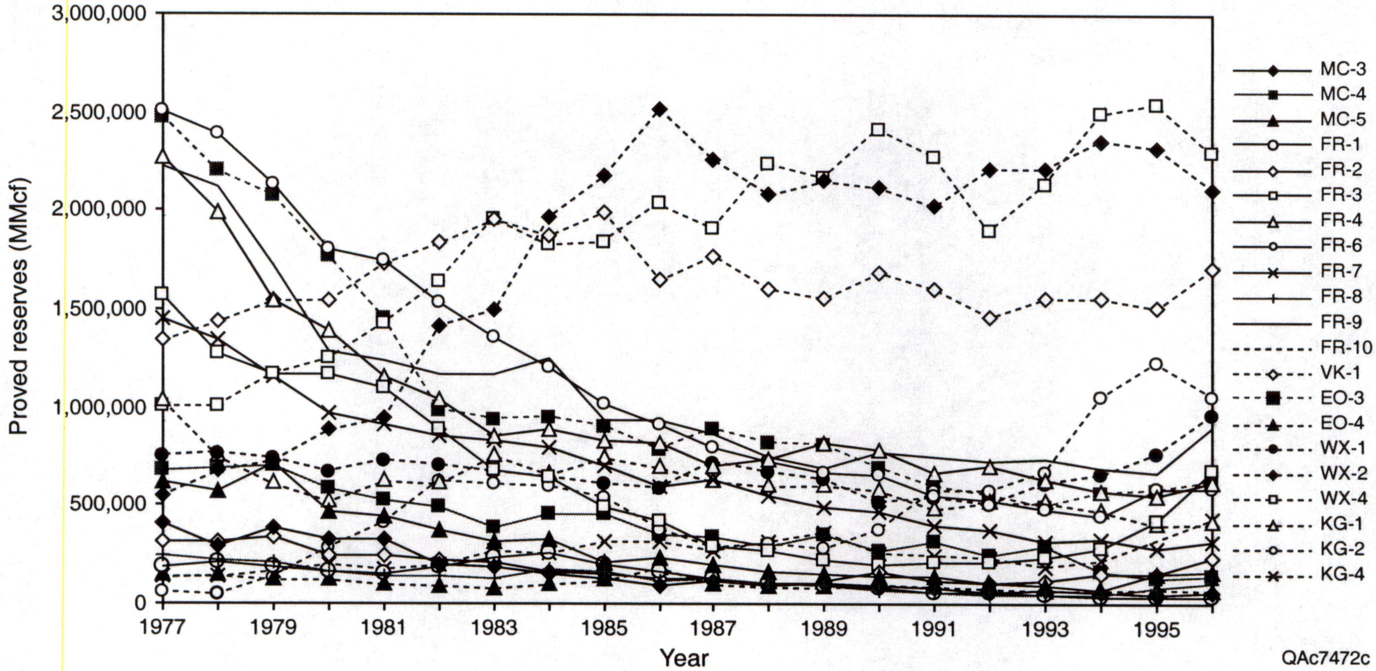


Figure 18. Historical natural gas proved reserves by major plays of the Texas Gulf Coast Basin.

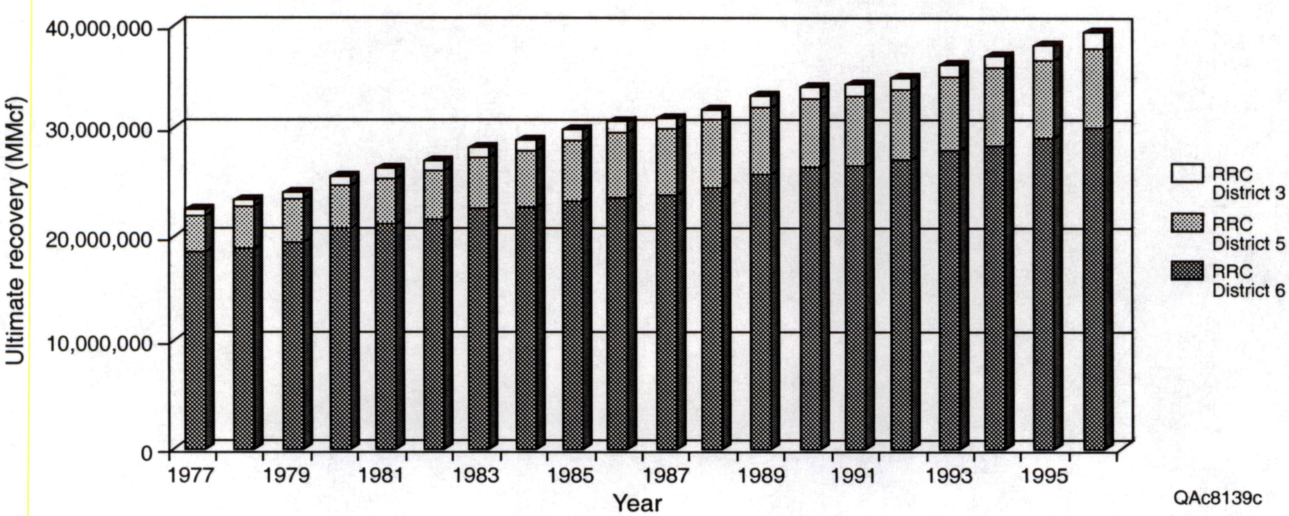


Figure 19. Natural gas ultimate recovery in major fields of East Texas.

RRC District 6 comprises the majority of natural gas ultimate recovery, production, and proved reserves (Figures 19, 20, and 21). Discovery-year histograms for East Texas display bimodal distributions of an older and younger population of fields (Figure 22). Depth histograms for East Texas showed a majority of fields in the 11,000- to 14,000-foot range (Figure 23). Field-size histograms for East Texas revealed a large population of smaller fields (Figure 24). However, several large fields (Carthage, Bethany, East Texas, Opelika, Trawick, Willow Springs, and Hawkins) accounted for most East Texas 1996 natural gas ultimate recovery. In particular, Carthage field was the dominant field in East Texas, with ultimate recovery estimates of approximately 10 Tcf. The reduced data set of 246 fields was disaggregated into 14 individual plays composing Jurassic Carbonate, Lower Cretaceous-Jurassic Sandstone, Lower Cretaceous Trinity Group Carbonate, and Upper Cretaceous Sandstone. Ten major plays having significant natural gas ultimate recovery were selected for detailed analysis (Figure 25 and Table 23). Summaries of play characteristics for the 10 major plays of East Texas are shown in Tables 24 through 33.

Historical trends of the 10 major plays of East Texas in terms of natural gas ultimate recovery, production, and proved reserves are shown in Figures 26, 27, and 28. Although several plays in East Texas show increasing historical ultimate recovery, the most noticeable trend is the enormous increases in ultimate recovery achieved by the Travis Peak Formation-Cotton Valley Group Sandstone, Sabine Uplift (KJ-1) play. It is also the dominant play in terms of recent production and proved reserves in East Texas and holds the greatest future potential for natural gas URG in East Texas. The two other Lower Cretaceous-Jurassic Sandstone plays (KJ-2, and KJ-3) also hold significant future URG potential, judging from historical trends.

Play delineations for the 31 major plays of the Texas Gulf Coast Basin and East Texas have been provided in a Geographic Information System (GIS) as ArcView poly-line files, which are overlain onto a Texas county map. Summary tables characterizing the major geological, engineering, and production data of each major play are linked to the specific poly-lines.

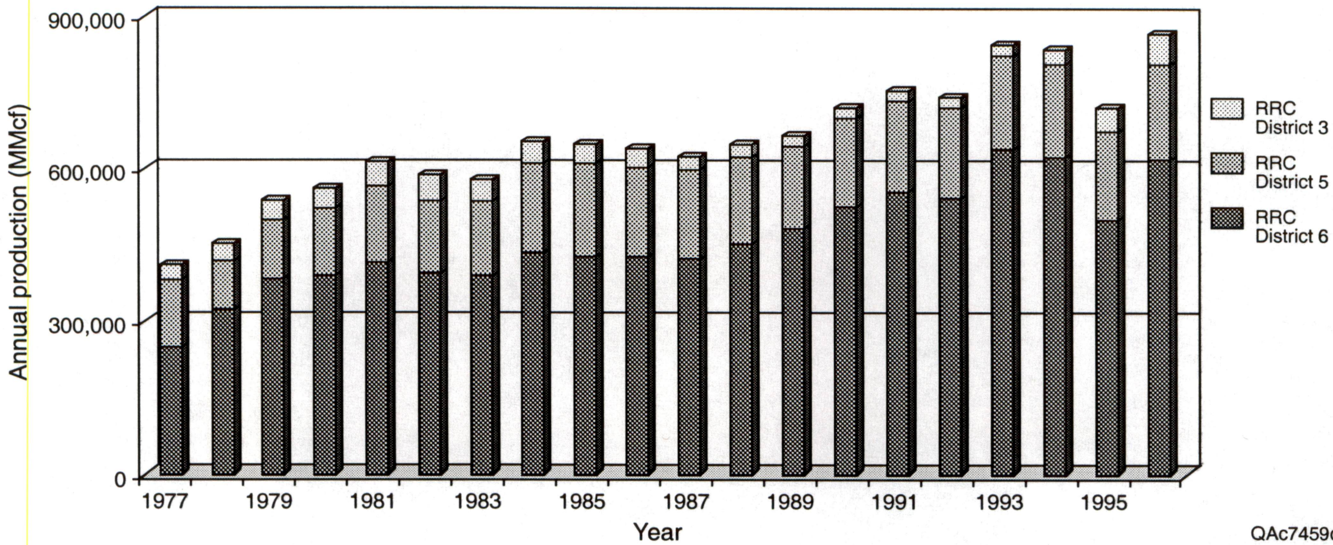


Figure 20. Natural gas production in major fields of East Texas.

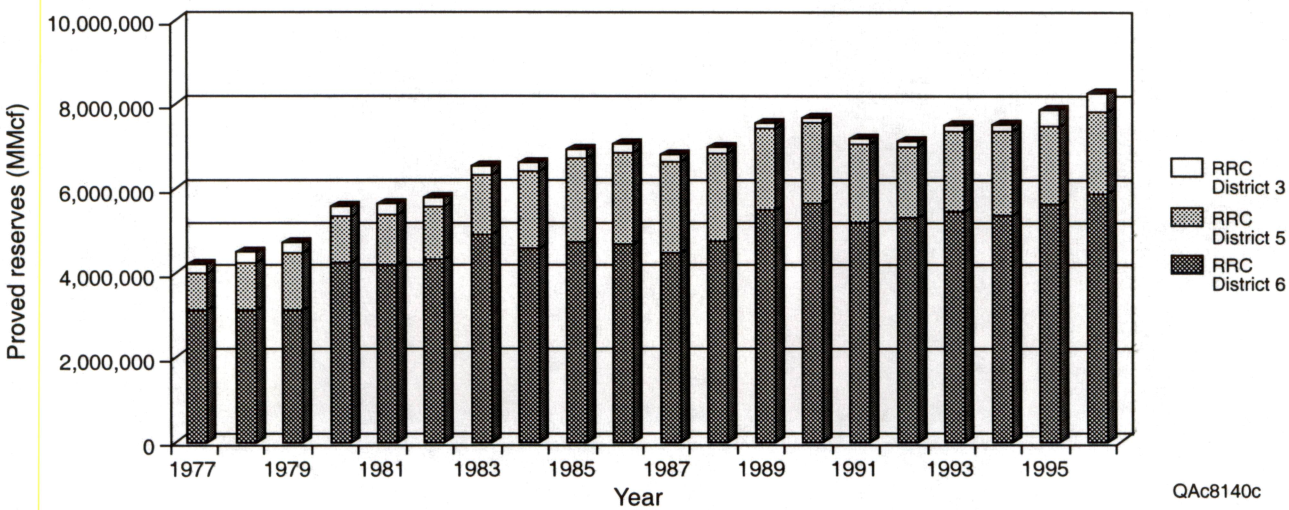


Figure 21. Natural gas proved reserves in major fields of East Texas.

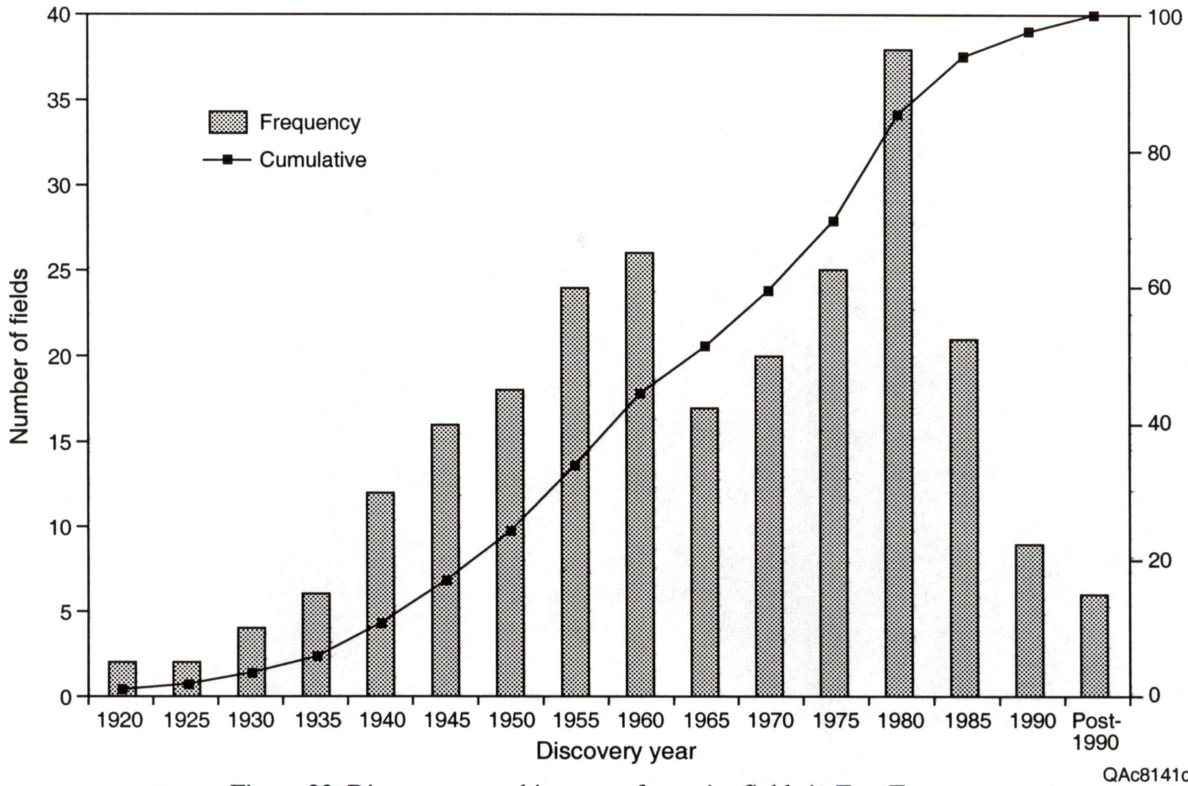


Figure 22. Discovery-year histogram for major fields in East Texas.

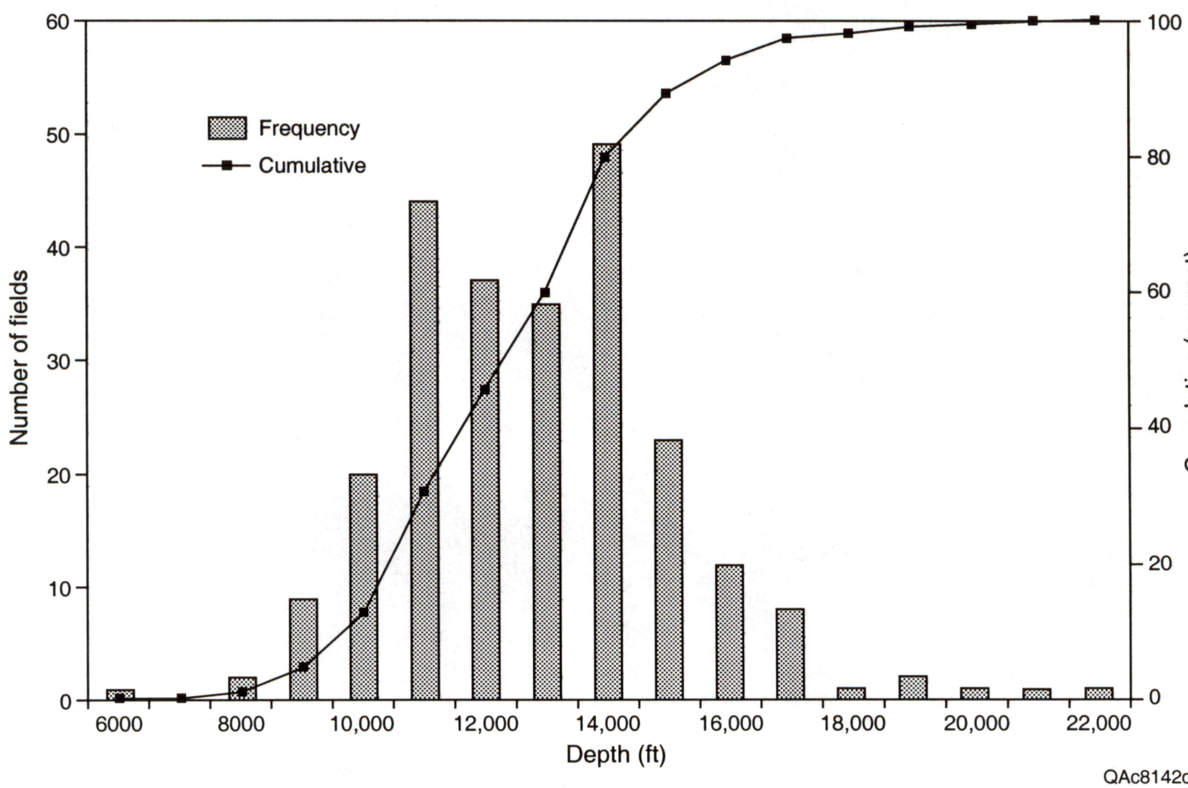


Figure 23. Depth histogram for major fields in East Texas.

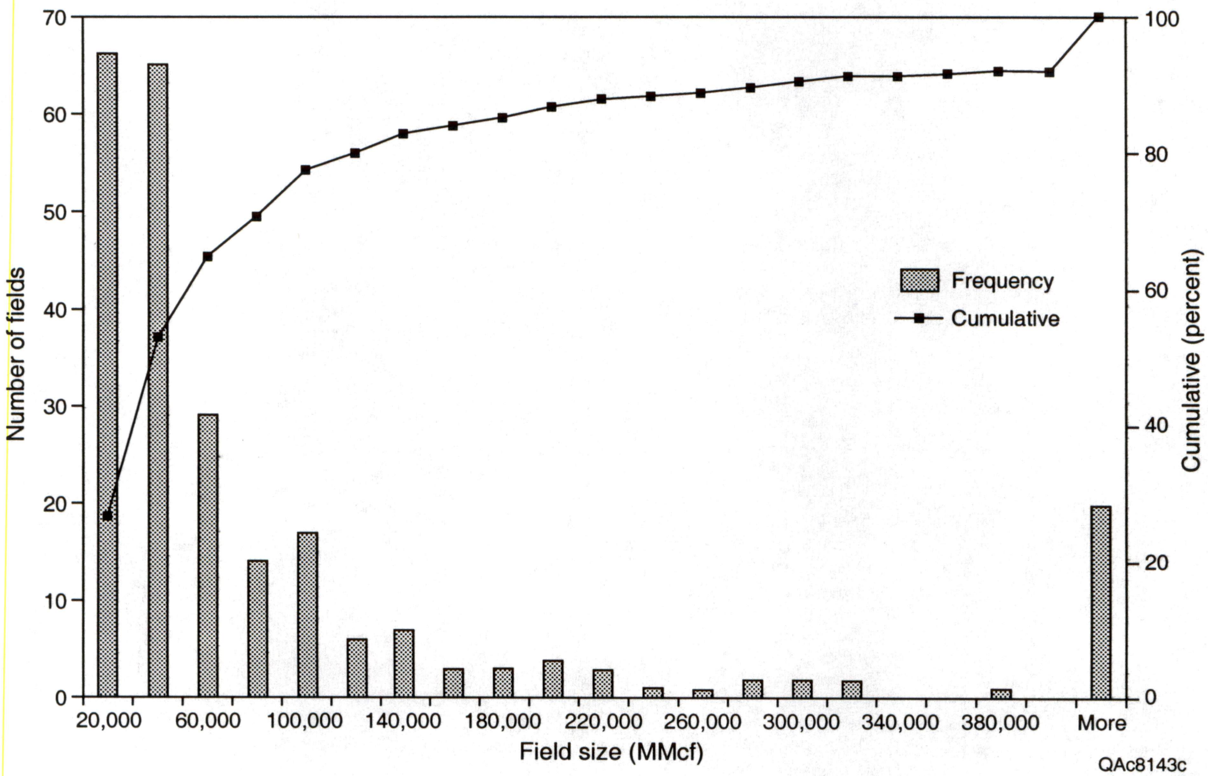


Figure 24. Size histogram of major fields in East Texas.

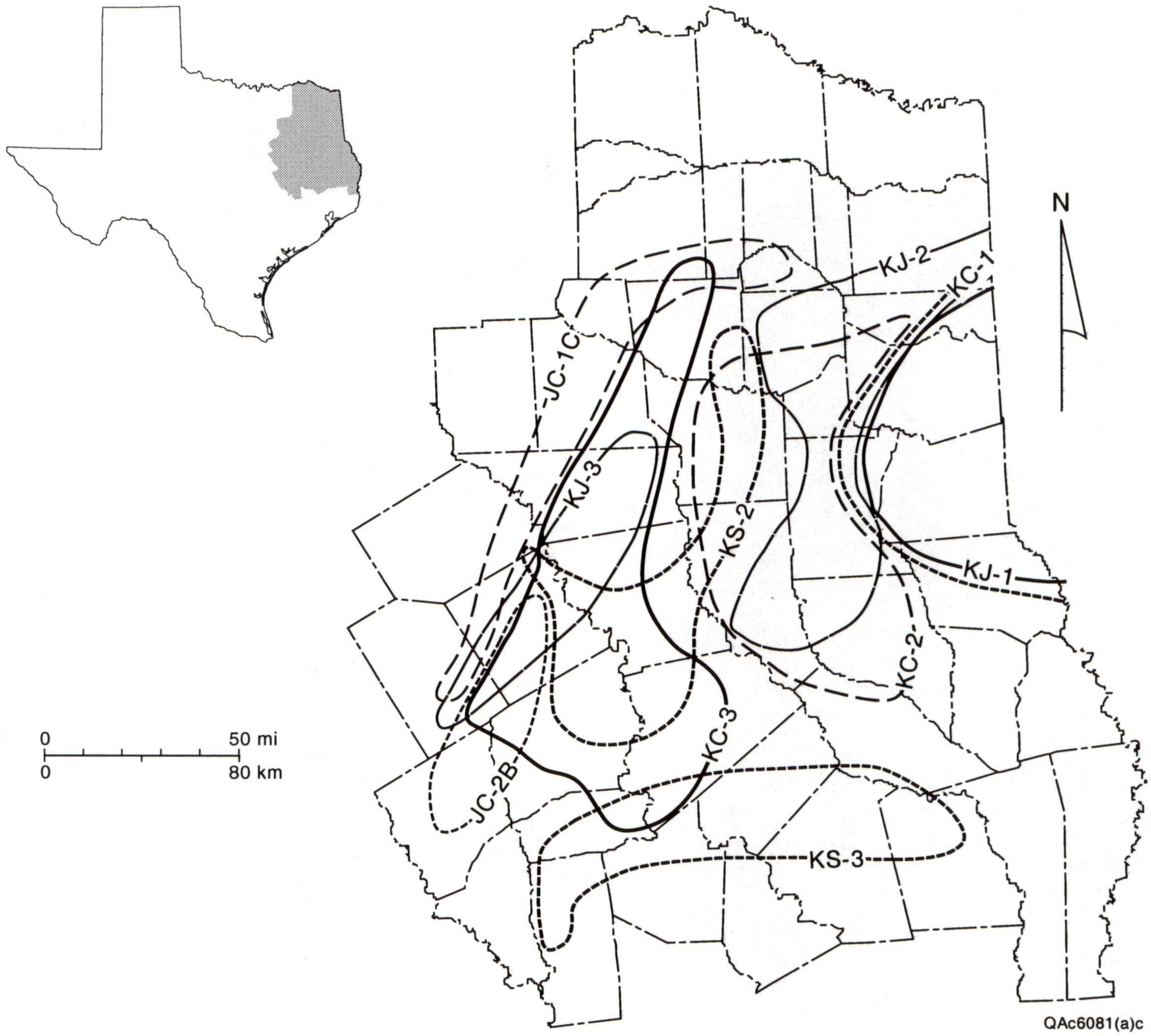


Figure 25. Major natural gas plays of East Texas.

Table 23. Summary of major natural gas plays of East Texas.

Play code	Play name	1996 Ultimate Recovery (MMcf)	1996 Production (MMcf)	1996 Reserves (MMcf)	1996 Fields
KS-2	Upper Cretaceous Sandstone, Salt Structures	2,264,767	17,738	263,650	22
KS-3	Upper Cretaceous Sandstone, Downdip Shelf Margin	1,243,381	58,669	421,217	14
KC-1	Trinity Group Carbonate, Sabine Uplift	8,051,279	36,555	308,660	23
KC-2	Trinity Group Carbonate, East	2,439,842	21,008	216,998	34
KC-3	Trinity Group Carbonate, West	3,535,674	28,644	313,367	52
KJ-1	Travis Peak Formation-Cotton Valley Group Sandstone, Sabine Uplift	9,332,676	338,874	3,177,723	29
KJ-2	Travis Peak Formation-Cotton Valley Group Sandstone, East	3,677,681	116,874	1,318,208	37
KJ-3	Travis Peak Formation-Cotton Valley Group Sandstone, West	2,689,105	74,715	932,956	30
JC-1C	Smackover Carbonate, Salt Structures	2,307,111	39,949	347,455	29
JC-2B	Cotton Valley Lime, West	1,650,581	67,590	562,689	28

Table 24. Summary of Upper Cretaceous Sandstone, Salt Structures (KS-2) play characteristics.

Play	Upper Cretaceous Sandstone, Salt Structures
Play code	KS-2
Lithology	Sandstone
Age	Upper Cretaceous
Exploration maturity	Very mature
Structural style	Intermediate- and large-amplitude salt pillows
Frontiers	------------------
Limitations	------------------
Major fields	East Texas, Hawkins, Chapel Hill, Navarro Crossing
Cumulative growth factor	15.64
1996/1977 ultimate recovery growth ratio	1.28
1996 ultimate recovery (MMcf)	2,264,767
1996 production (MMcf)	17,738
1996 reserves (MMcf)	263,650
Average field discovery year	1950
Average completion depth (ft)	4,154
Number of fields	22

Table 25. Summary of Upper Cretaceous Sandstone, Downdip Shelf Margin (KS-3) play characteristics.

Play	Upper Cretaceous Sandstone, Downdip Shelf Margin
Play code	KS-3
Lithology	Sandstone
Age	Upper Cretaceous
Exploration maturity	Relatively immature
Structural style	Porosity pinch-outs and salt-related anticlines
Frontiers	------------------
Limitations	------------------
Major fields	Double A Wells, Brookeland, Madisonville, Iola
Cumulative growth factor	14.28
1996/1977 ultimate recovery growth ratio	2.97
1996 ultimate recovery (MMcf)	1,243,381
1996 production (MMcf)	58,669
1996 reserves (MMcf)	421,217
Average field discovery year	1972
Average completion depth (ft)	9,285
Number of fields	14

Table 26. Summary of Trinity Group Carbonate, Sabine Uplift (KC-1) play characteristics.

Play	Trinity Group Carbonate, Sabine Uplift
Play code	KC-1
Lithology	Carbonate
Age	Lower Cretaceous
Exploration maturity	Very mature
Structural style	Sabine uplift
Frontiers	------------------
Limitations	------------------
Major fields	Carthage, Bethany, Waskom, Woodlawn, Joaquin
Cum.growth factor	6.09
1996/1977 URG ratio	1.08
1996 ultimate recovery (MMcf)	8,051,279
1996 production (MMcf)	36,555
1996 reserves (MMcf)	308,660
Average field discovery year	1956
Average completion depth (ft)	6,544
Number of fields	23

Table 27. Summary of Trinity Group Carbonate, East (KC-2) play characteristics.

Play	Trinity Group Carbonate, East
Play code	KC-2
Lithology	Carbonate
Age	Lower Cretaceous
Exploration maturity	Very mature
Structural style	Salt related structures
Frontiers	------------------
Limitations	------------------
Major fields	Trawick, Willow Springs, Hawkins, Lansing N., Chapel Hill
Cumulative growth factor	2.46
1996/1977 URG ratio	1.07
1996 ultimate recovery (MMcf)	2,439,842
1996 PRODUCTION (MMcf)	21,008
1996 reserves (MMcf)	216,998
Average field discovery year	1962
Average completion depth (ft)	6,501
Number of fields	34

Table 28. Summary of Trinity Group Carbonate, West (KC-3) play characteristics.

Play	Trinity Group Carbonate, West
Play code	KC-3
Lithology	Carbonate
Age	Lower Cretaceous
Exploration maturity	Very mature
Structural style	Salt related structures
Frontiers	------------------
Limitations	------------------
Major fields	Fairway, Opelika, Cayuga, Long Lake, Fort Trinidad
Cumulative growth factor	9.28
1996/1977 URG ratio	1.35
1996 ultimate recovery (MMcf)	3,535,674
1996 production (MMcf)	28,644
1996 reserves (MMcf)	313,367
Average field discovery year	1959
Average completion depth (ft)	9,184
Number of fields	52

Table 29. Summary of Travis Peak Formation-Cotton Valley Group Sandstone, Sabine Uplift (KJ-1) play characteristics.

Play	Travis Peak Formation-Cotton Valley Group Sandstone, Sabine Uplift
Play code	KJ-1
Lithology	Sandstone
Age	Lower Cretaceous-Upper Jurassic
Exploration maturity	Mature
Structural style	Sabine uplift that focused gas migration toward it
Frontiers	------------------
Limitations	Low permeability
Major fields	Carthage, Oak Hill, Waskom, Bethany, Bethany E.
Cumulative growth factor	396.28
1996/1977 URG ratio	3.55
1996 ultimate recovery (MMcf)	9,332,676
1996 production (MMcf)	338,874
1996 reserves (MMcf)	3,177,724
Average field discovery year	1960
Average completion depth (ft)	9,067
Number of fields	29

Table 30. Summary of Travis Peak formation-Cotton Valley Group Sandstone, East (KJ-2) play characteristics.

Play	Travis Peak Formation-Cotton Valley Group Sandstone, East
Play code	KJ-2
Lithology	Sandstone
Age	Lower Cretaceous-Upper Jurassic
Exploration maturity	Mature
Structural style	Salt related structures
Frontiers	------------------
Limitations	Low permeability
Major fields	Willow Springs, Trawick, Whelan, Glenwood, Rosewood
Cumulative growth factor	106.88
1996/1977 URG ratio	2.94
1996 ultimate recovery (MMcf)	3,677,681
1996 production (MMcf)	116,875
1996 reserves (MMcf)	1,318,208
Average field discovery year	1963
Average completion depth (ft)	9,610
Number of fields	37

Table 31. Summary of Travis Peak Formation-Cotton Valley Group Sandstone, West (KJ-2) play characteristics.

Play	Travis Peak Formation-Cotton Valley Group Sandstone, West
Play code	KJ-3
Lithology	Sandstone
Age	Lower Cretaceous-Upper Jurassic
Exploration maturity	Mature
Structural style	Intermediate amplitude salt structures
Frontiers	------------------
Limitations	Low permeability
Major fields	Opelika, Tri-cities, Bear Grass, Freestone
Cumulative growth factor	218.31
1996/1977 URG ratio	2.86
1996 ultimate recovery (MMcf)	2,689,105
1996 production (MMcf)	74,715
1996 reserves (MMcf)	932,956
Average field discovery year	1965
Average completion depth (ft)	10,806
Number of fields	30

Table 32. Summary of Smackover Carbonate, Salt Structures (JC-1C) play characteristics.

Play	Smackover Carbonate, Salt Structures
Play code	JC-1C
Lithology	Carbonate
Age	Upper Jurassic
Exploration maturity	Mature
Structural style	Low to intermediate amplitude salt structures
Frontiers	------------------
Limitations	------------------
Major fields	New Hope, Edgewood NE, Eustace, Ginger SE, WA Moncrief
Cumulative growth factor	9.01
1996/1977 URG ratio	1.50
1996 ultimate recovery (MMcf)	2,307,111
1996 production (MMcf)	39,949
1996 reserves (MMcf)	347,455
Average field discovery year	1966
Average completion depth (ft)	9,513
Number of fields	29

Table 33. Summary of Cotton Valley Lime, West (JC-2B) play characteristics.

Play	Cotton Valley Lime, West
Play code	JC-2B
Lithology	Carbonate
Age	Upper Jurassic
Exploration maturity	Relatively immature
Structural style	Salt related structures
Frontiers	------------------
Limitations	Low permeability
Major fields	Personville N., Teague, Reed, Bald Prairie, Teague Townsite
Cumulative growth factor	32.28
1996/1977 URG ratio	6.70
1996 ultimate recovery (MMcf)	1,650,581
1996 production (MMcf)	67,590
1996 reserves (mmcf)	562,689
Average field discovery year	1973
Average completion depth (ft)	12,275
Number of fields	28

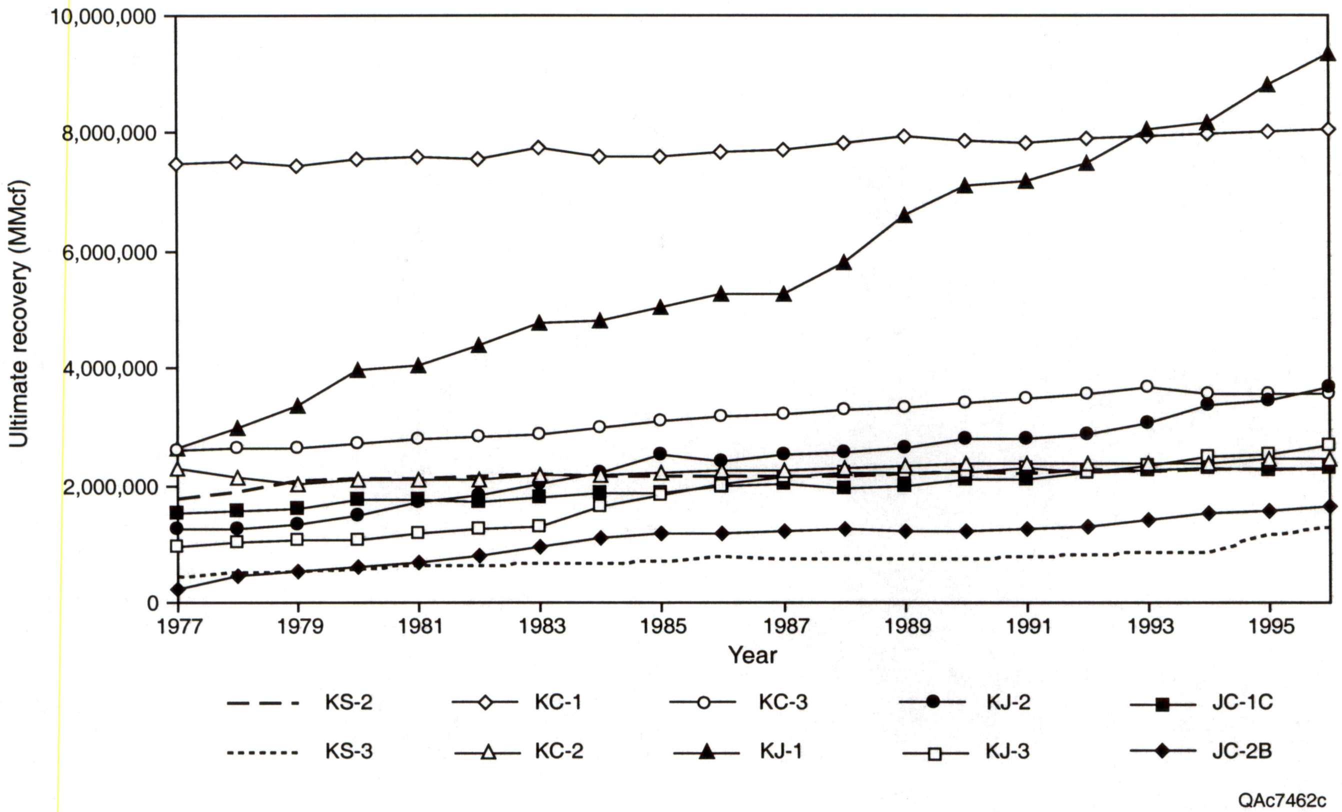


Figure 26. Historical natural gas ultimate recovery by major plays of East Texas.

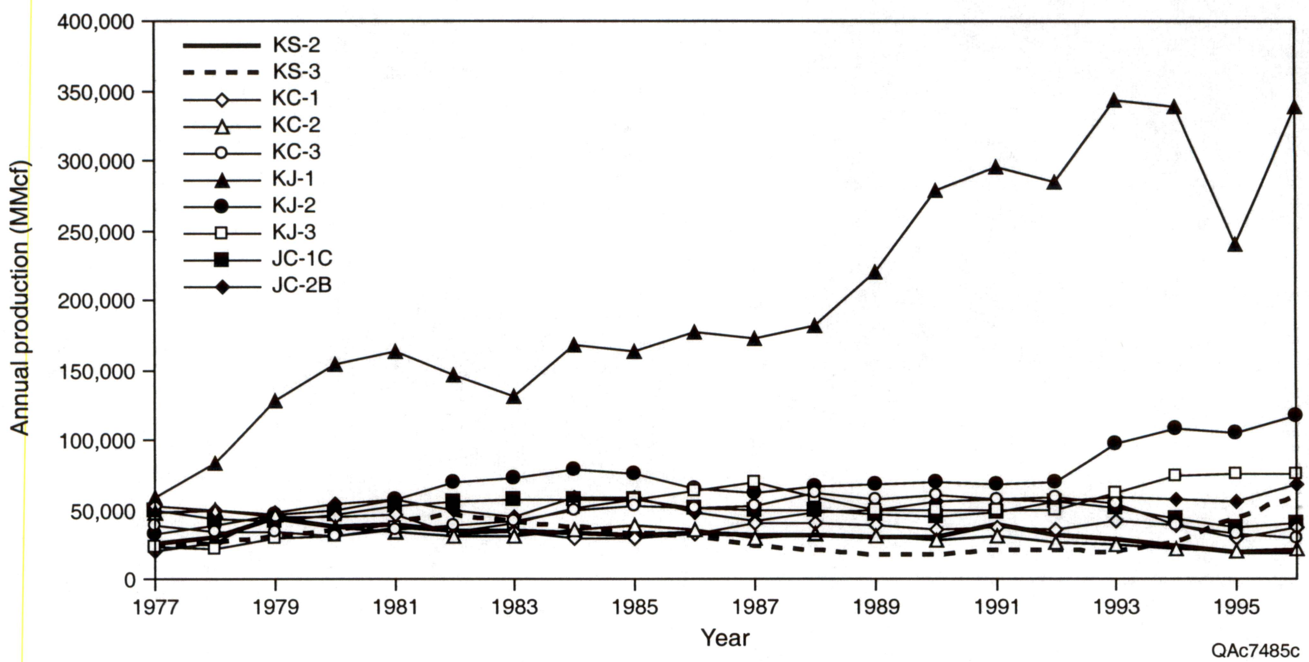


Figure 27. Historical natural gas production by major plays of East Texas.

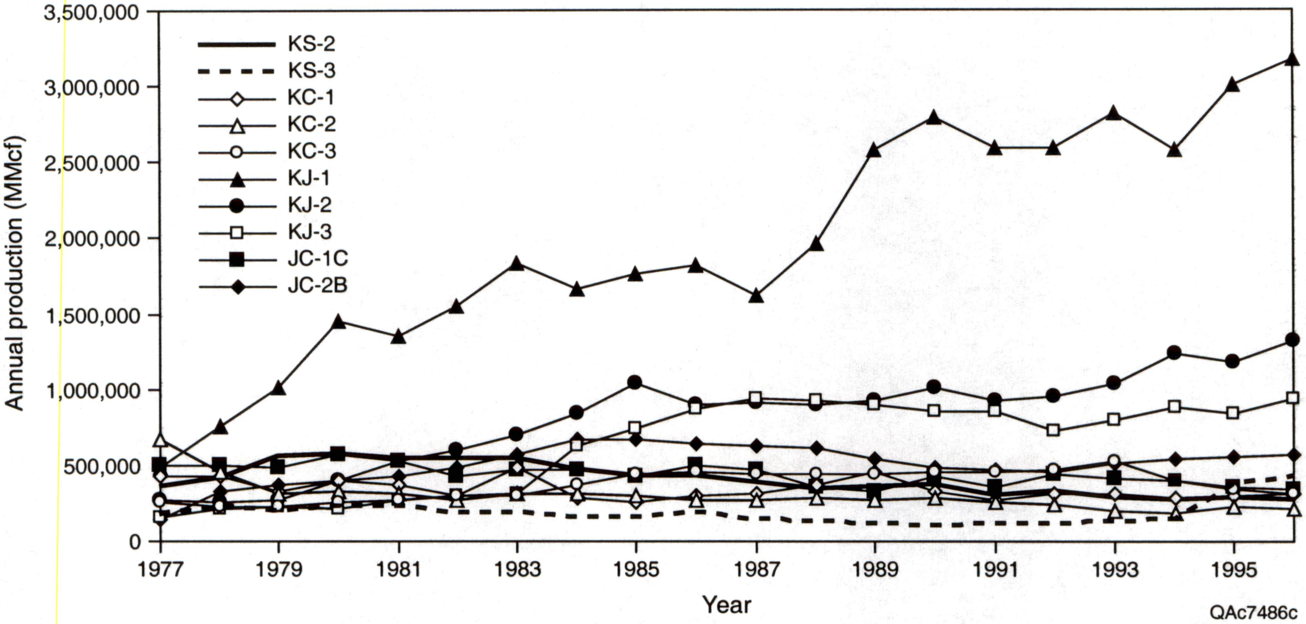


Figure 28. Historical natural gas proved reserves by major plays in East Texas.

Year of discovery	Year of revision 1	2	3	4	5	6	7	Sum	
	1987	1988	1989	1990	1991	1992	1993	1987–1992	1988–1993
1981	G	H	I	J	K	L	M		
1982	F	G	H	I	J	K	L		
1983	E	F	G	H	I	J	K		
1984	D	E	F	G	H	I	J		
1985	C	D	E	F	G	H	I		
1986	B	C	D	E	F	G	H	G1-G6	H2-H7
1987	A	B	C	D	E	F	G	F1-F6	G2-G7
1988		A	B	C	D	E	F	E1-E6	F2-F7
1989			A	B	C	D	E	D1-D6	E2-E7
1990				A	B	C	D	C1-D6	D2-D7
1991			Sum A1 to A6		A	B	C	B1-B6	C2-D7
1992						A	B	A1-A6	B2-B7
1993							A		

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Figure 29. Example of Arrington's tabular URG analysis methodology.

Individual trend plots based on data contained in these summary tables are possible. Additional information concerning the GIS digital files and their utilization can be found in the appendix.

Natural Gas Ultimate Recovery Growth as a Factor of Time

Ultimate recovery growth (URG) modeling was previously undertaken by a number of researchers who used time as the dependent factor. The use of time as a dependent factor in URG modeling came about largely as a result of the format of the available data. Data concerning production, proved reserves, and ultimate recovery are generally maintained by companies and Federal reporting agencies and largely based on time. For example, the RRC maintains production data of Texas reservoirs on monthly and annual bases, whereas the EIA maintains field production, proved reserves, and estimates of ultimate recovery on an annual basis.

The pioneer studies on URG modeling performed by Arrington (1960) utilized time as the dependent factor. Arrington's methodology uses the age of the field as measured by years after initial discovery as the variable representing the degree of field maturity. Rather than using a functional form, Arrington provided a tabular example of how to calculate URG as a factor of time. This methodology has been utilized and modified in subsequent URG analyses by Marsh (1971), Root (1981), Megill (1989a, 1989b, 1989c), Energy Information Administration (1990), National Petroleum Council (1992), Root and Attanasi (1993), Attanasi and Root (1994), Drew and others (1994), U.S. Geological Survey (1995), Lore and others (1996), and Energy and Environmental Analysis, Inc. (1992, 1998).

Arrington's tabular example of URG analysis is shown in Figure 29. URG estimates for fields of interest are grouped by year of initial discovery and summed. A record of these grouped and summed URG estimates for the particular initial discovery year is compiled during the available time frame. The initial URG estimate is shown by the letter A. The first revision to the initial URG estimate is shown as the letter B and so on. From this ultimate recovery estimate-revision compilation, the initial ultimate recovery estimates for the years 1987 through 1992

(A1–A6) and for years 1988 through 1993 (B2–B7) are summed. The percentage increase of the first revision over the prior year's ultimate recovery estimate is calculated as

$$\{(B2 \text{ to } B7)-(A1 \text{ to } A6)\}/(A1 \text{ to } A6) * 100.$$

To calculate increase in ultimate recovery at the end of the second year over the prior year's estimate, the formula becomes

$$\{(C2 \text{ to } C7)-(B1 \text{ to } B6)\}/(B1 \text{ to } B6) * 100.$$

Continuing this methodology, the percentage change over each prior year can be computed; these percentages are weighted averages. Fields with large ultimate recovery estimates carry the most weight, influencing the percentage change much more than fields with smaller ultimate recovery estimates. As more revision history of ultimate recovery estimates becomes available, a more statistical relationship can be derived. Some researchers have elected to smooth out their calculated percentage increases over prior years to compensate for the erratic nature of their limited-data time horizons. Arrington (1960) used 3-year weighted averages, whereas Megill (1989a, 1989b, 1989c) elected to use a subjective smoothing technique.

Arrington (1960), using 3-year weighted-average values for the percentage increase over prior years, calculated probable final factors (PFF) that adjusted any year's ultimate recovery estimate to its probable future estimate after a period of time. Probable final factors were calculated by acknowledging that an asymptote would be reached in the growth of ultimate recovery over a period of time. Starting with the last year of revision available for analysis, a probable final factor, which is the factor that must be multiplied to equate the percentage increase over the prior year, is calculated. This probable final factor is then multiplied by the next year's factor to be multiplied to obtain the percentage increase over the prior year to derive the next year's probable final factor. This calculation is made until the initial year of revision. Megill (1989c) used the term "revision factor" to represent this probable final factor.

The probable final factor generally decreases with each increasing year of revision. With time, the probable final factor approaches and eventually becomes unity, because ultimate recovery estimates for any one year cannot increase infinitely. The last remaining producing field must eventually produce its last remaining barrel of oil or cubic foot of gas (Marsh, 1971).

Annual growth factors (AGF) and cumulative growth factors (CGF) can also be calculated from the tabular example. The methodology involves developing AGF's from equation 1:

$$AGF = \Sigma\, c(d,e+1)/\Sigma\, c(d,e), \tag{1}$$

where e is the early estimate year and c(d,e) is the estimate of the ultimate recovery discovered in year d, as estimated in year e. The same fields are included in both the denominator and numerator. Growth factors can also be expressed as CGF's from equation 2:

$$CGF = c(d,e+n)/c(d,e), \tag{2}$$

where n is the time in years between the early estimate year, e, and the later estimate year, e+n. CGF's represent the ratio of the size of a field n years after discovery to the initial estimate of its size in the year of its discovery (Lore and others, 1996).

Using the tabular example, we can calculate AGF's by dividing each initial discovery year's first and second summation. For example, the AGF for initial discovery year 1992 would be

B2-B7/A1-A6.

Each successive initial discovery year can be computed similarly. CGF's can be obtained by compounding all probable final factors; that is, PFF1 is multiplied by PFF2, then by the product by PFF3, and so on. If we plot the products against years elapsed since postinitial discovery year, the result is a curve that expresses the ratio of URG since initial discovery (Marsh, 1971). Subsequent research on URG as a factor of time involved fitting growth functions to the data in order to extrapolate the results and dividing the data into common and outlier fields.

Because our data set for ultimate recovery estimates has a limited time frame, URG analysis as a factor of time can also be undertaken within this time frame. For example, because complete histories exist for fields discovered since 1977 in EIA's OGIFF, we can compute AGF's and CGF's more directly within our available data time frame by using vintaging curves according to initial discovery year. Moreover, instead of using a single discovery year, the available data may be analyzed by decade of discovery and field-size classes.

Now we have a powerful statistical tool to calculate URG on the basis of elapsed postdiscovery time. Because this is a statistically dependent methodology, care must be taken in its use. Its assumptions and limitations must be clearly understood. The large overall assumption of this statistical methodology is that the revision history of older fields can apply to fields of today. Moreover, it is assumed that the rate of change in recovery technology will proceed with equal speed in the future.

Probable final factors differ from area to area because of different reservoir characteristics, field sizes, and applicability of recovery technology (Megill, 1989c). Because the probable final factor is a probability-based concept, it follows that the greater the number of data used, the greater the probability of final accuracy. Therefore, probable final factors should not be applied to a number of data smaller than the number in the group from which they were derived (Arrington, 1960). Otherwise, minor fluctuations take on too much importance, and the results become erratic (Marsh, 1971). Even if confined mostly to large groups of data, such as plays, URG analysis based on a factor of time can provide a future outlook on our remaining resource base. Being able to estimate future growth is a big step in the difficult task of learning all we can about our future natural gas supply potential.

TEXAS GULF COAST BASIN AND EAST TEXAS: ULTIMATE RECOVERY GROWTH AS A FACTOR OF TIME

URG analysis based on a factor of time was analyzed for the major plays of the Texas Gulf Coast Basin and East Texas. The data set used is derived from EIA's OGIFF, which is the most comprehensive and reliable historical data on natural gas proved reserves, production, and ultimate recovery by field relative to time currently available. Energy Information Administration's OGIFF (1996) provides estimates of crude oil and natural gas proved reserves, annual production, cumulative production, and ultimate recovery for most U.S. oil and natural gas fields. As of 1997, the file contained field-level estimates for each of the 20 years between 1977 and 1996.

Although EIA's OGIFF is the most complete data series of U.S. national oil and natural gas reserves, production, and ultimate recovery available, only about 39,000 fields of the total 45,992 distinct oil and natural gas fields (as of October 1996) are represented. Moreover, out of these approximately 39,000 fields, only about 13,000 new field discoveries occurred during and after EIA's time frame of from 1977 through 1996. For most oil and natural gas fields reported in the EIA's OGIFF data series only mid- to late-stage URG is included.

In order to apply Arrington's tabular methodology, we first grouped and summed natural gas ultimate recovery estimates according to the initial discovery year. Initial discovery years were adjusted on the basis of when the first ultimate recovery estimate was provided. We grouped 20 years of natural gas ultimate recovery estimates, for the time period between 1977 and 1996, according to initial discovery year, ranging from 1893 through 1996. Summation of the ultimate recovery estimates for the years 1977 through 1995 and 1978 through 1996 was made for each initial discovery year. The percentage change of the ultimate recovery estimate summations of the years 1978 through 1996 from the ultimate recovery estimate summations of years 1977 through 1995 were then calculated for each initial discovery year.

Natural gas ultimate recovery estimates in the Texas Gulf Coast Basin have increased approximately 30 percent (37 Tcf) within the 20-year data-history frame from 1977 through 1996 (Figure 9). An aggregated growth curve for the total 1,369 fields of the Texas Gulf Coast Basin revealed significant URG. The Texas Gulf Coast Basin had an aggregated cumulative growth factor (CGF) of 8.28 (Figure 30). Natural gas ultimate recovery estimates in East Texas have increased approximately 74 percent (17 Tcf) within the 20-year data-history frame from 1977 through 1996 (Figure 19). An aggregated growth curve for the total 246 fields of East Texas revealed significant URG. East Texas had an aggregated cumulative growth factor (CGF) of 33.5 (Figure 31). Carthage field alone, discovered in 1936, has shown tremendous URG. Its ultimate recovery estimate showed a 54-percent growth of 3.7 Tcf from 1977 through 1996 (1977 = 6.9 Tcf and 1996 = 10.6 Tcf).

Carthage field's increase is rather notable because it proves that even when using a limited, current, 20-year time frame, we still find significant URG occurring. URG is playing a dominant role even after the long period since the older, larger, natural gas fields were discovered. Continued URG in the Texas Gulf Coast Basin and East Texas is essentially derived from (1) younger fields discovered relatively recently and (2) continued growth in older fields.

The CGF curve rises very rapidly in the early years after initial discovery. Afterward, the curve generally levels off with time as the curve reaches an asymptote. An interesting observation is that the CGF curve has not yet reached an asymptote in either the Texas Gulf Coast Basin or East Texas, probably illustrating that more natural gas URG will exist in both these areas in the future. When the CGF curve is rising, ultimate recoveries from those initial discovery years are currently being revised upward. Where the CGF curve is level, upward and downward revisions are about equal, with no appreciable URG (Marsh, 1971).

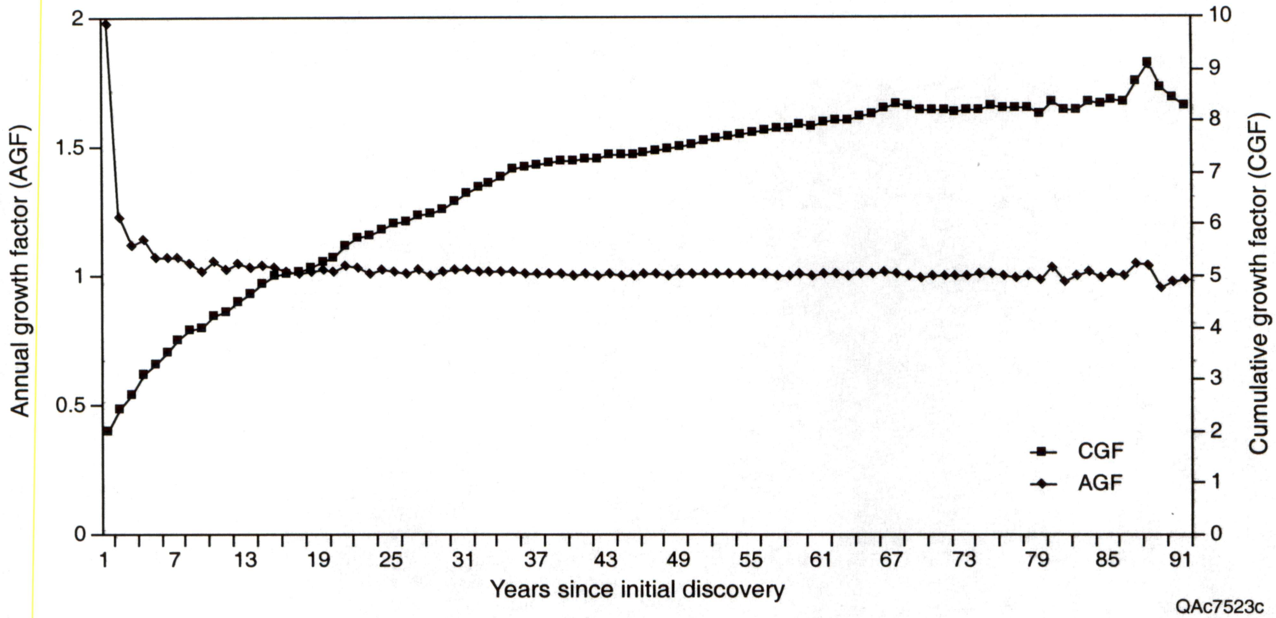


Figure 30. Texas Gulf Coast Basin aggregated natural gas URG.

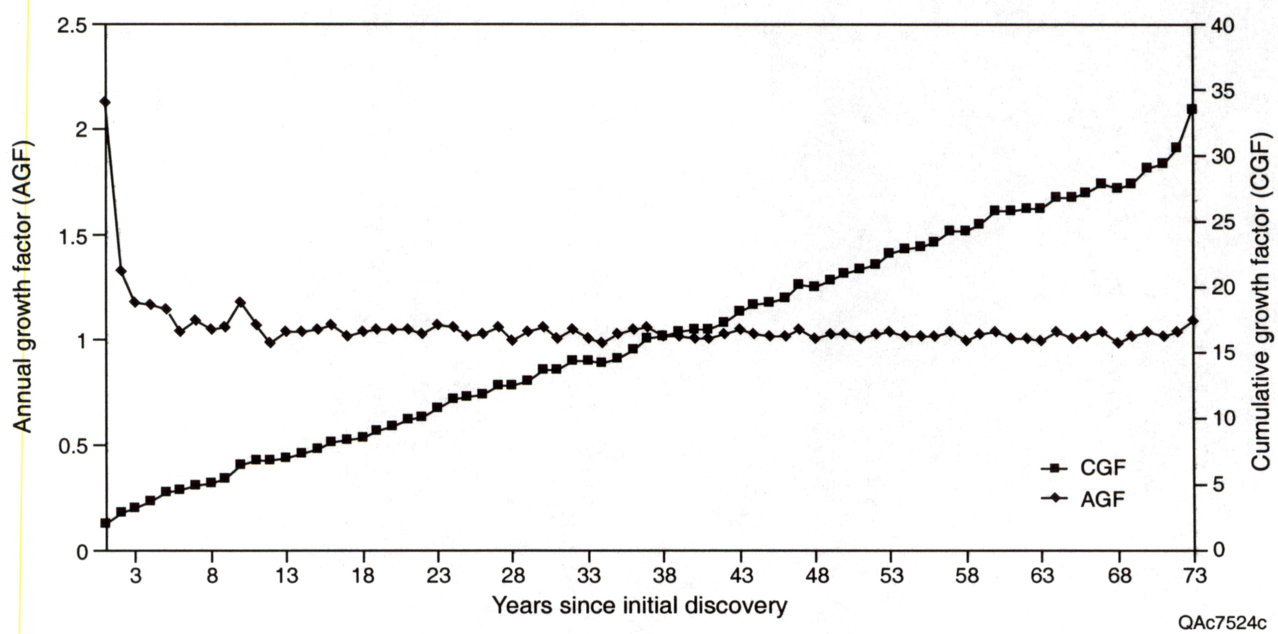


Figure 31. East Texas aggregated natural gas URG.

URG analysis as a factor of time, using cumulative growth factors, showed that plays WX-2, KG-2, KG-4, WX-1, WX-4, VK-1, and KG-1 are experiencing the most growth in the Texas Gulf Coast Basin (Figure 32). These plays all show URG trends above the aggregated curve for the 1,369 total fields. These plays also show significant recent growth in terms of 1996 versus 1977 natural gas ultimate recovery ratios. URG analysis as a factor of time, using cumulative growth factors, revealed the Lower Cretaceous-Jurassic Sandstone (KJ) plays to be experiencing the most growth in East Texas (Figure 33). These plays all show URG trends above the aggregated curve for the total 246 fields. They also show significant recent growth in terms of 1996 versus 1977 natural gas ultimate recovery ratios.

A crucial factor in calculating URG as a factor of time on the basis of the earlier methodology is the percentage change from previous years. Characteristically, the initial percentage change is high and rather erratic during the early years of the field, shifting to a more minor and uniform percentage change in its later years. Some researchers, such as Arrington (1960) and Megill (1989a, 1989b, and 1989c), smoothed out the percentage change from the previous year by either a best-fit line or subjective smoothing. Moreover, some researchers have purposely removed the first couple of years of data because of their perceptions that the percentage changes from the previous year in the earlier life of the field were abnormally high. Caution should be exercised when smoothing out the percentage change from the previous year because it can make a large difference in final calculations of the growth factors. Studies with more pessimistic views on URG potential will exclude data from earlier years or smooth out the data set for percentage change from the previous year, resulting in lower growth factors.

Previous studies conducted by EIA and USGS concerning URG analysis as a factor of time fitted growth functions to historical growth factors. EIA used a hyperbolic function, whereas USGS utilized a least-squares growth function, minimizing a subsequent error function. Moreover, USGS also utilized a monotone growth function, assuming that older fields will have a smaller percentage of growth than younger fields.

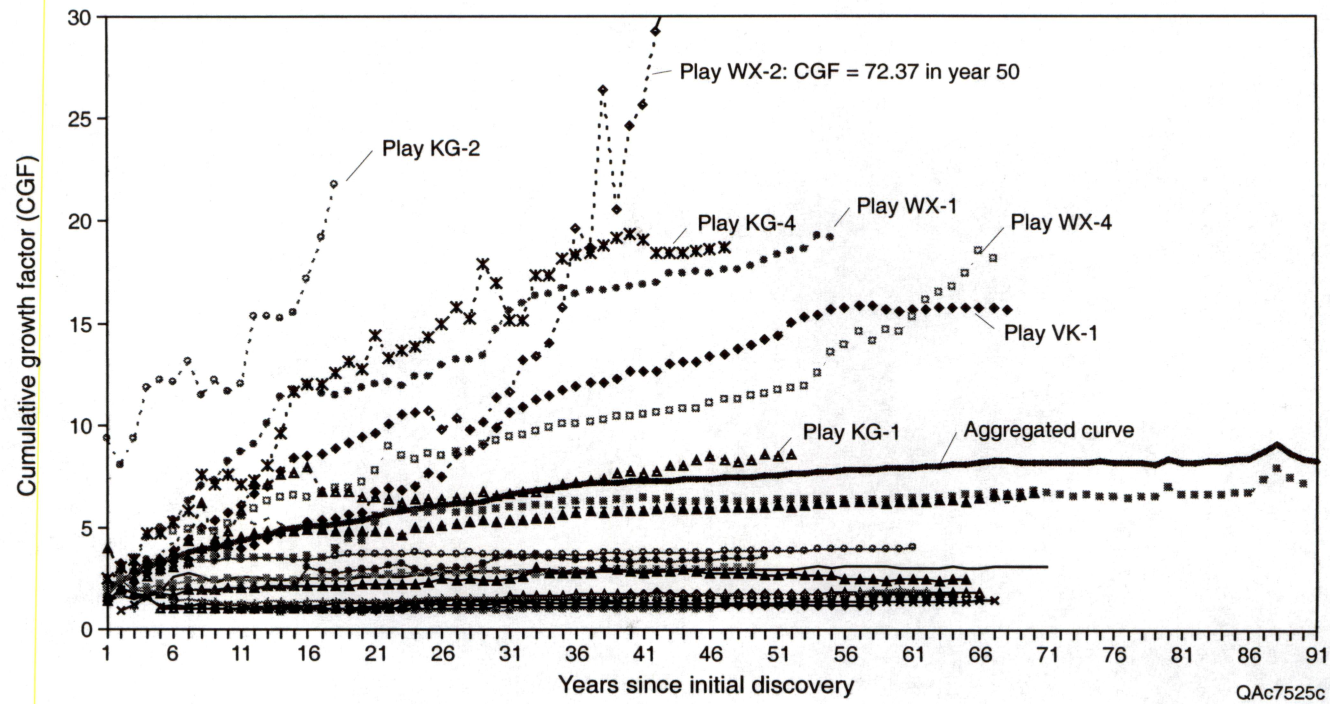


Figure 32. Natural gas URG for major plays of the Texas Gulf Coast Basin.

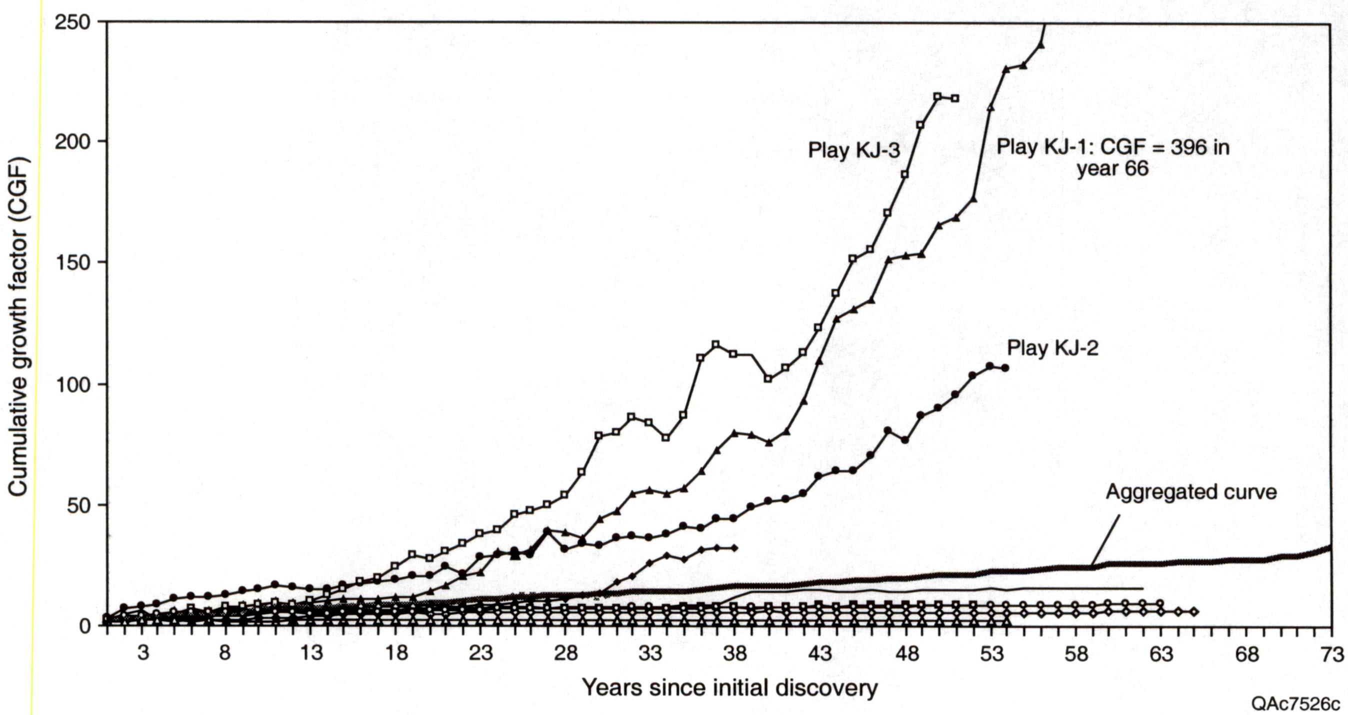


Figure 33. Natural gas URG for major plays in East Texas.

For major natural gas fields discovered in or after 1977, complete ultimate recovery histories since their initial discoveries exist. Although these more recently discovered fields make up only a minor percentage of the number of total major fields analyzed in the Texas Gulf Coast Basin and East Texas, they constitute a major percentage of current natural gas proved reserves and annual production. Observations of their URG behavior that are based on time should provide valuable insights into the future natural gas resource base in the Texas Gulf Coast Basin and East Texas.

Because complete ultimate recovery histories are available, vintage curves based on initial discovery year can be derived in terms of AGF's and CGF's. Studies using vintage curves based on discovery year were undertaken by Davis (1979), National Petroleum Council (1992), and Energy and Environmental Analysis, Inc. (1998). All fields discovered in the same discovery year are first grouped and AGF's and CGF's can be calculated directly using equations 1 and 2. Results of vintage curves based on discovery year are shown in Figures 34 and 35. Years in which the data set was minimal, in terms of number of fields or years of ultimate recovery revision history, were excluded. As can be seen in this methodology, the number of data available for analysis proves to be a crucial detrimental factor in current analysis of URG based on time. Nevertheless, key observations and trends can be deduced from URG as a function of discovery year vintage curves. As with the trend established in analysis of natural gas URG as a function of time for the total major natural gas fields of Texas Gulf Coast Basin and East Texas, significant URG is displayed. It is particularly interesting to note that fields discovered relatively recently display a significant amount of URG.

Historical URG of the major natural gas fields of the Texas Gulf Coast Basin and East Texas can also be analyzed by field age groups (Figures 36 and 37). For the Texas Gulf Coast Basin, a large proportion of relatively recently discovered fields contributed a significant amount of URG. For East Texas, older fields contributed most of the URG, so URG must be occurring regardless of field age. These findings contradict some previous views that URG is largely from older fields, and newer fields show less potential for URG. Another key observation, such as for

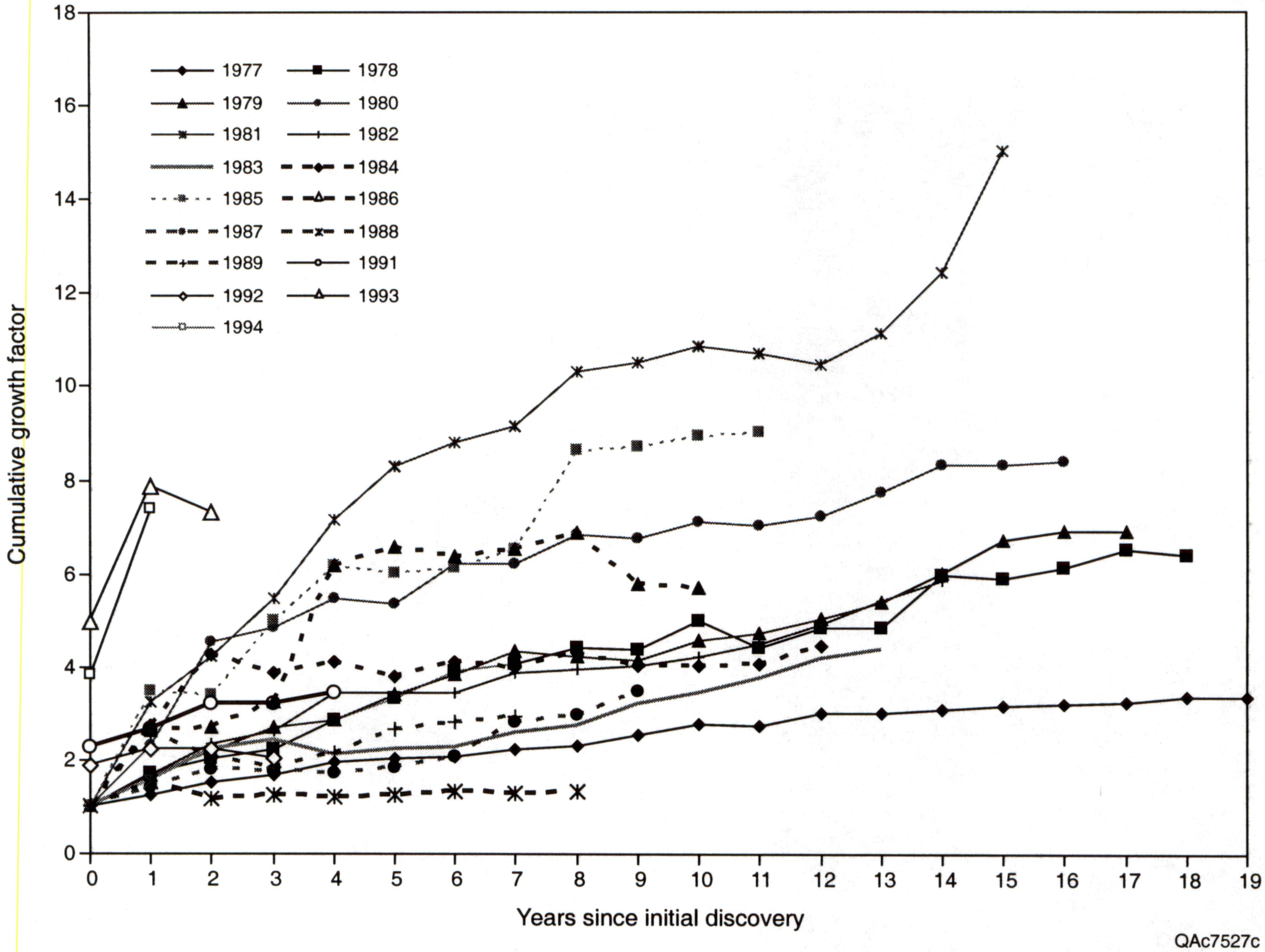


Figure 34. Natural gas URG vintage curves of post-1976 fields in the major plays of the Texas Gulf Coast Basin.

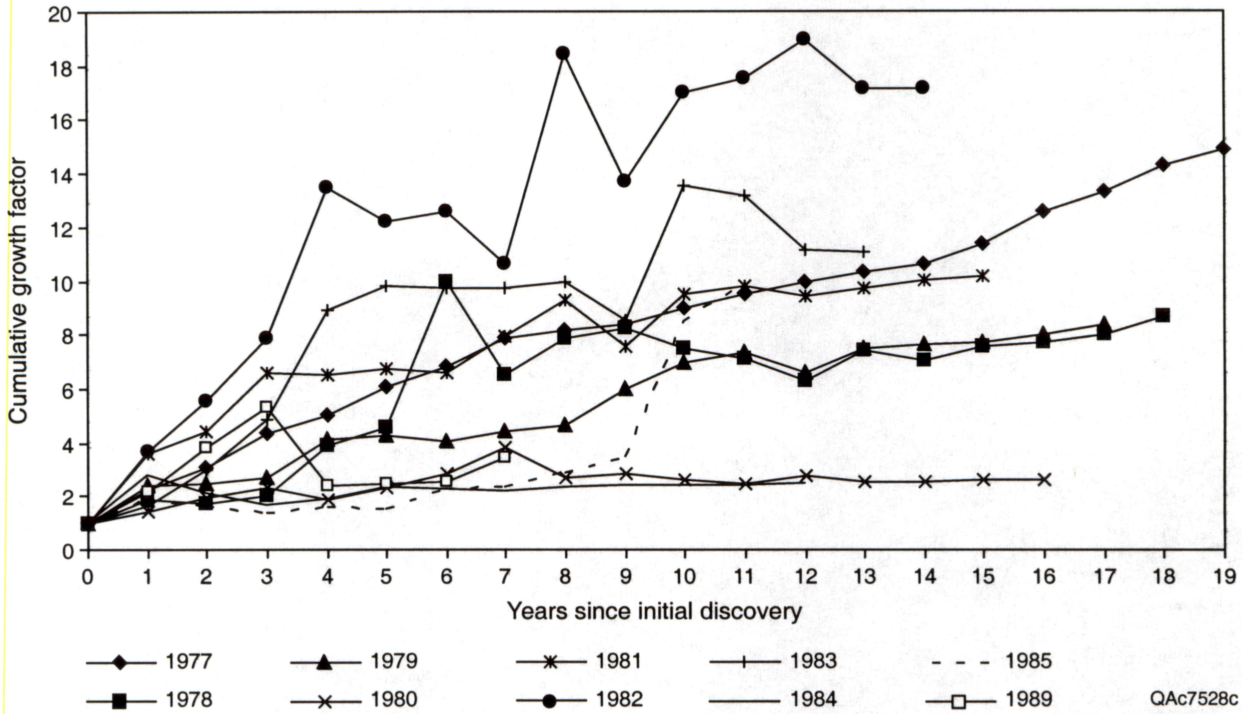


Figure 35. Natural gas URG vintage curves of post-1976 fields in the major plays of East Texas.

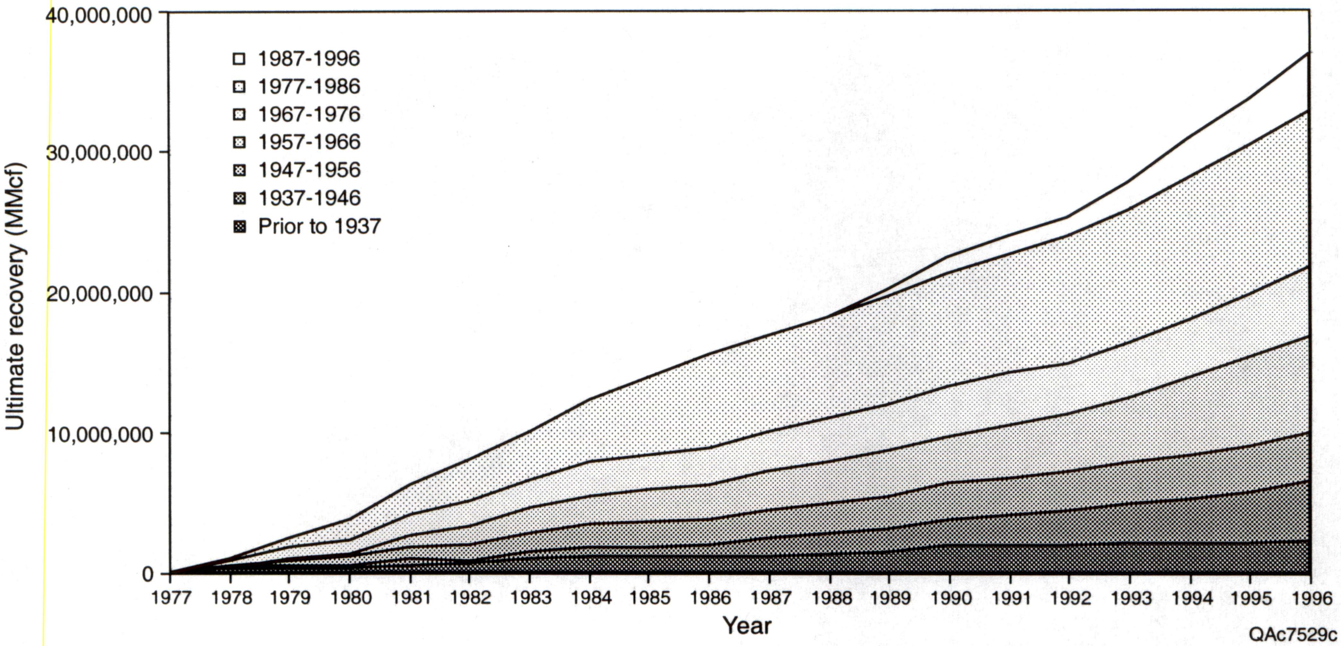


Figure 36. Natural gas URG by field-age groups in the major plays of the Texas Gulf Coast Basin.

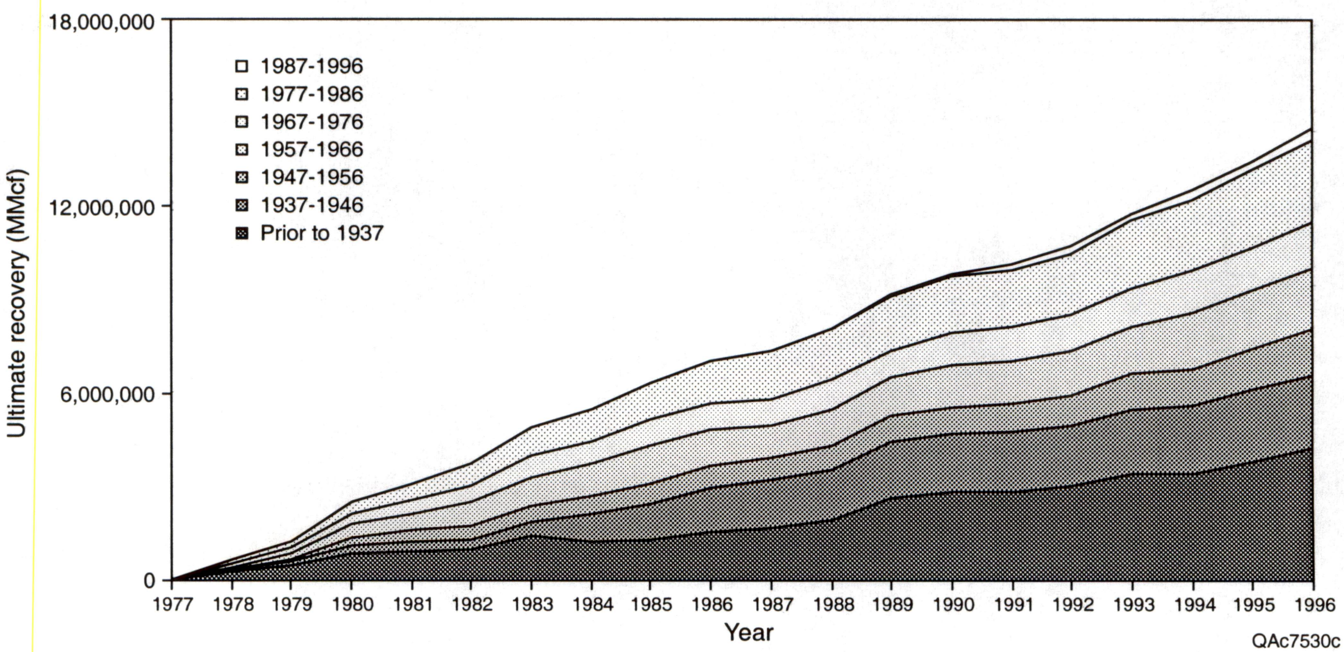


Figure 37. Natural gas URG by field-age groups in the major plays of East Texas.

East Texas, is that older fields are still displaying URG, even after several decades since their initial discovery, and growth curves for younger fields have not yet reached an asymptote.

LIMITATIONS OF ULTIMATE RECOVERY GROWTH ANALYSIS AS A FACTOR OF TIME

One of the most important limitations is that the data series available is limited with respect to time. EIA's OGIFF data file that was used for its analysis covers a period from 1977 through 1996. This is only a 20-year time frame for natural gas ultimate recovery statistics for the Texas Gulf Coast Basin and East Texas, which have been producing since 1893 and 1916, respectively. Therefore, for most fields, only mid- to late-stage ultimate recovery statistics are available. URG patterns are thus deduced from only this fraction of the data available. Previous data exist only in an aggregated form provided by the API/AGA and are not integrated with each other. An implicit assumption is made that URG is invariant over time. Therefore, recently discovered fields are assumed to show URG patterns similar to those of fields discovered earlier in time.

Moreover, historical data are affected by reporting practices and field definitions that have not been historically consistent. In some instances, a field may be reported to have been discovered in an earlier year than for when ultimate recovery data actually exist. Correcting the discovery year to the year in which actual data exist, as undertaken in the analysis, results in significant variations in URG factors. Caution should also be exercised when assigning a discovery year to multiple play fields. The field's discovery year for its reservoirs in one play may differ from those included in another play. Discovery years must be adjusted to the year in which ultimate recovery data exist for that particular play. Upward and downward revisions to URG estimates have been made through time. In some instances, smaller fields have been merged with a larger field and fields may be combined with each other with the progression of time.

Natural Gas Ultimate Recovery Growth as a Factor of Drilling Activity

Previous studies have calculated URG solely as a factor of time. Analysis of historical URG, using ultimate recovery by year of initial discovery, assumes that ultimate recovery will grow only as a function of time, regardless of drilling activity. The use of time for analyzing URG has a major limitation in that time and effort are not always linearly related. Exploratory and development efforts are not always continually applied at the field or reservoir level over time. Other external factors, such as market forces and governmental policies, can modify or disrupt the amount of exploration and development of a particular field or reservoir. Available ultimate recovery data cover a broad spectrum of drilling activity, including the "boom" days of the early 1980's and the "bust" days of the late 1980's. Moreover, backdating newly discovered production and proved reserves to the initial year of field/reservoir discovery results in exploration and development efforts being improperly credited to the time in which they actually occur.

Several measures of natural gas exploratoration and development other than time were considered, such as expenditures for exploration and development, wells drilled, footage drilled, and producing completions. A comparison of these measures led to the selection of a cumulative number of producing completions as the most appropriate measure for exploration and development because a direct measure of probing the Earth's crust is linearly related to drilling activity.

Only two previous studies of URG have employed exploration and development measures other than time as the independent variable. These include exploratory footage since new-field discovery (Arps and others, 1971) and a functional form of the number of well completions linked to time (National Petroleum Council, 1992). However, these studies also utilize aggregated data for analysis on a national level, as has URG analysis as a factor of time.

WELL-COMPLETION DATA AND ULTIMATE RECOVERY GROWTH ANALYSIS METHODOLOGY

Well-completion data were compiled for the major natural gas plays of the Texas Gulf Coast Basin and East Texas. Natural gas well-completion data for each play were obtained from Lasser Inc.'s *Texas Production Database* (1999). All producing completions within each play were compiled, along with information such as field, reservoir, county, operator name, lease name, well number, API number, status code, first production date, last production date, completion date, cumulative production, well depth, and perforation depth.

Instead of sorting the producing well completions by completion date, we used the first production date as the primary index because of slight differences between the two in some instances. When the two differed, the first production date was used because it represented when actual production was recorded in the designated well completion. In some producing-well completions, neither a first production date nor a completion date was designated. These producing-well completions made up less than 5 percent in the majority of plays analyzed and were excluded in the calculation of natural gas URG as a factor of drilling activity.

The number of producing-well completions in each play was summed on a yearly basis. Yearly and cumulative producing-well-completion data were matched to the ultimate recovery data obtained from EIA's OGIFF data base. All pre-1977 producing-well completions were summed together with the 1977 annual producing-well-completion data.

Drilling activity results, representative of exploration and development efforts, are best represented by ultimate recovery estimates. A general relationship between drilling activity and ultimate recovery is shown in Figure 38. The curve intuitively should go through the origin because no drilling activity produces no results. Furthermore, the curve for drilling activity and its ultimate recovery must rise, first steeply, and then more gently. It finally asymptotically reaches the ultimate resource recoverable as the number of producing-well completions approaches infinity.

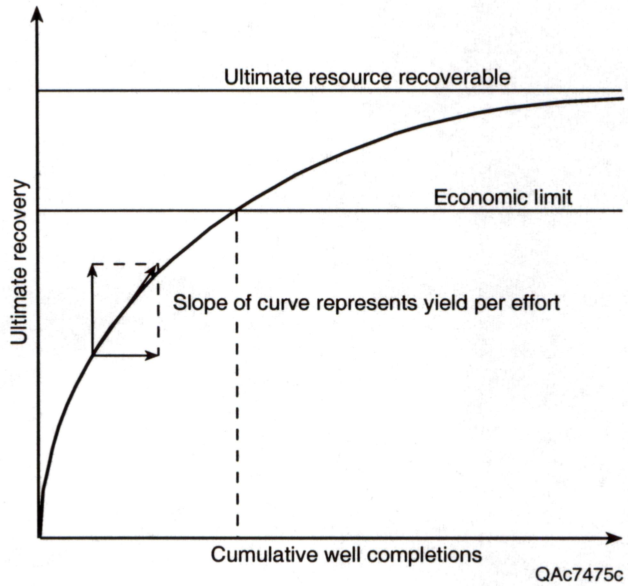


Figure 38. General relationship between drilling activity and ultimate recovery (modified from Arps and others, 1971).

The ultimate resource recoverable, being a fraction of the resource base, represents all the resources that could be recovered if there were no economic limit on the number of well completions drilled. The resource base concept includes all hydrocarbon resources within a specified geological area. The resource base represents the sum of annual reserves and production, the currently unrecoverable content of undiscovered reservoirs, and the total content of undiscovered reservoirs, without regard to present or future technological feasibility. However, long before the ultimate resource recoverable is reached, the economic limit will prevent further drilling activity. In fact, the slope of the cumulative number of well completions versus ultimate recovery represents the incremental ultimate recovery per well completion and can be used to determine the economic limit by converting ultimate recovery and well completions to their corresponding dollar values (Arps and others, 1971).

ASSESSMENT OF NATURAL GAS ULTIMATE RECOVERY GROWTH IN THE TEXAS GULF COAST BASIN AND EAST TEXAS AND ASSOCIATED PLAYS AS A FACTOR OF DRILLING ACTIVITY

In order to quantify and forecast natural gas ultimate growth in the Texas Gulf Coast Basin and East Texas and associated plays by drilling activity, past trends in exploratory and development performance are utilized to delineate current and most likely trends of URG. A plot between cumulative producing-well completions and natural gas ultimate recovery, as shown in Figures 39 and 40, is constructed for the total selected natural gas plays of the Texas Gulf Coast Basin and East Texas. An increasing ultimate recovery trend can be correlated with increasing cumulative well completions.

A logarithmic equation, most closely resembling the past performance of all of the total selected natural gas plays of the Texas Gulf Coast Basin and East Texas, was fitted to the data series. The squared correlation coefficient reveals a relatively good fit of the data to the logarithmic equation. This curve can be used to quantify natural gas URG or forecast future natural gas URG potential extrapolated by increasing the number of cumulative completions

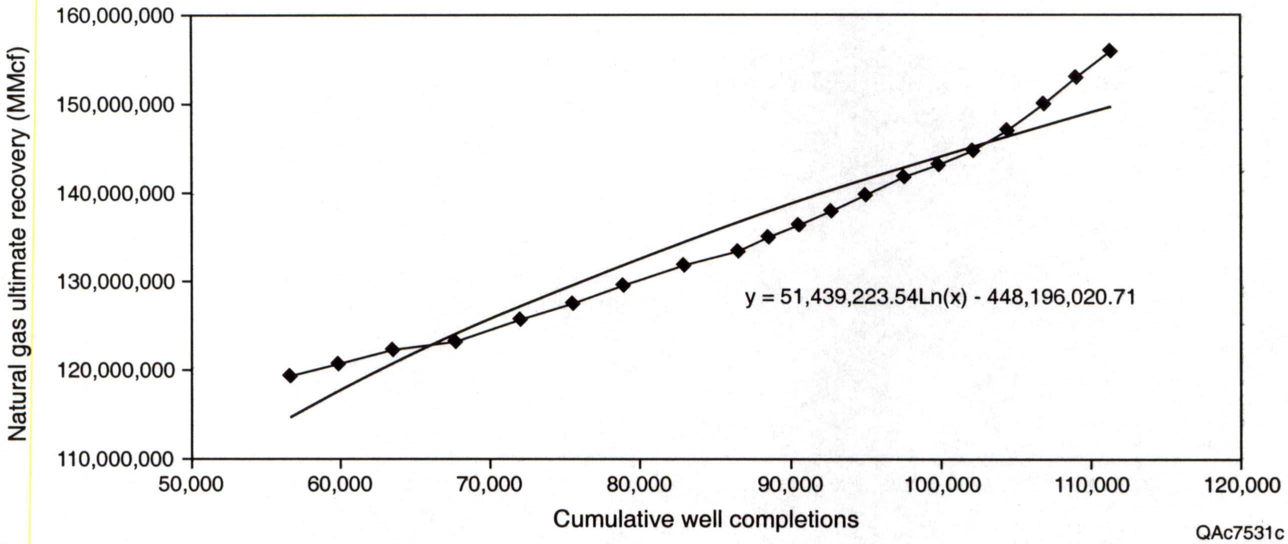


Figure 39. Cumulative well completions versus natural gas ultimate recovery in the total major plays of the Texas Gulf Coast Basin.

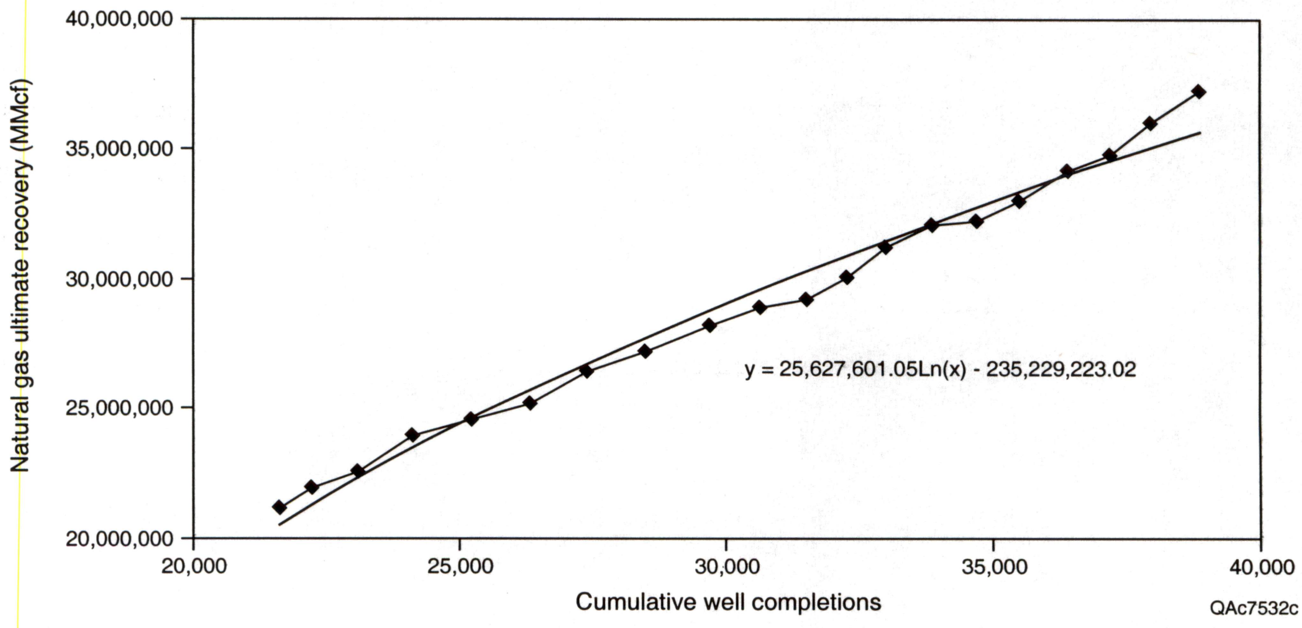


Figure 40. Cumulative well completions versus natural gas ultimate recovery in total major plays of East Texas.

until an economic limit is reached. Well completions will be made until the economic limit, where the value derived from URG is equal to the cost of incremental well completions.

A general prevailing assumption was that URG would be achieved rather linearly with an increasing number of well completions. However, natural gas URG in the total selected natural gas plays of the Texas Gulf Coast Basin and East Texas has occurred regardless of the number of annual well completions. URG is controlled not merely by the number of well completions, but by the application and development of advanced exploration and recovery technologies. Fewer well completions are needed to explore, delineate, and develop as a result of these advanced exploration and recovery technologies.

YIELD PER EFFORT OF NATURAL GAS PLAYS IN THE TEXAS GULF COAST BASIN AND EAST TEXAS

The traditional view in petroleum economics is that yield per effort (YPE) (referred to also as finding rate, discovery rate, and exploration efficiency) generally declines as the more obvious, larger geological features in a play are discovered by earlier drilling, as deeper drilling increases footage, and as exploration and development targets include more elusive and marginal reservoirs (Arps and others, 1971). The concept of declining yields per effort has prompted many researchers to represent the relationship between yield and effort by an exponential decline curve. Hubbert (1967) was the first to argue that yield per effort declined monotonically as an exponential decline function of cumulative drilling because large fields were found early during initial drilling and subsequent drilling targeted smaller and more remote fields.

However, yield per effort is controlled not only by cumulative depletion, but by a combination of variables that include technological advancements, the rate of drilling, economics, and institutional factors. Analysis of natural gas URG has shown that the exponential decline in yield per effort for specific plays has been arrested or reversed. Rather than following an exponential decline curve model, yield per effort may be better expressed in these plays through a "technological stretch" model (Fisher, 1994c; Forbes and Zampelli, 1996) (Figure 41). The "technological stretch" model assumes that technological advancements will shift the yield per effort function upward, mitigating the progression from larger to smaller fields. The advantage of this model is that it does not presuppose that cumulative depletion dominates the effect of technology and that it is possible that technology can arrest or reverse the impact of cumulative depletion on the volume of resources that are ultimately recoverable (Forbes and Zampelli, 1996). These plays are assumed to be geologically complex with high degrees of reservoir heterogeneities that require application of advanced exploration and development technologies to fully realize their potential.

Several variables can be used to determine yield per effort. Total annual reserve additions, ultimate discoveries by year of discovery, annual new-field discoveries, area of giant fields discovered, and number of fields discovered by size class have been historically used as a measure of yield. Commonly used variables of effort include total footage, productive exploratory wells, total exploratory footage, total wells, and cubic mile of sediment drilled. In this study, yield is expressed as the amount of natural gas ultimate recovery, and effort is expressed as the number of producing-well completions,

YPE = Ultimate recovery /number of producing-well completions.

The number of producing-well completions was selected as a measure of effort because it is not affected by varying drilling depths, whereas ultimate recovery was selected as a variable of yield because it measures directly the total amount recoverable through well completions.

The average annual yield per effort of the total selected natural gas plays of the Texas Gulf Coast Basin and East Texas is shown in Figures 42 and 43. However, utilizing cumulative completions to determine play-by-play average yield per effort trends may mask some of the more recent trends in natural gas URG in the Texas Gulf Coast Basin and East Texas. Past completions prior to 1977 are included in the calculation of average annual yield per effort for

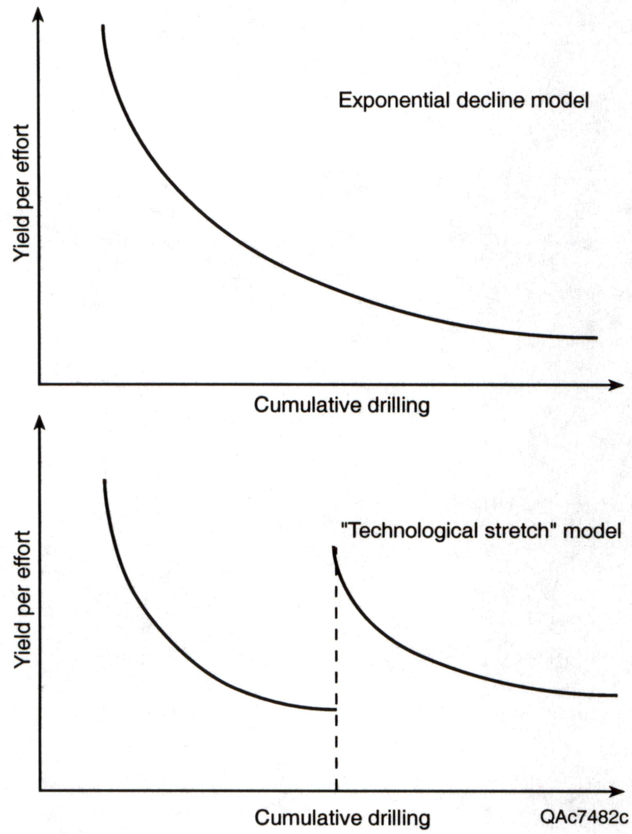


Figure 41. Exponential decline versus "technological stretch" model (modified from Cleveland and Kaufmann, 1995).

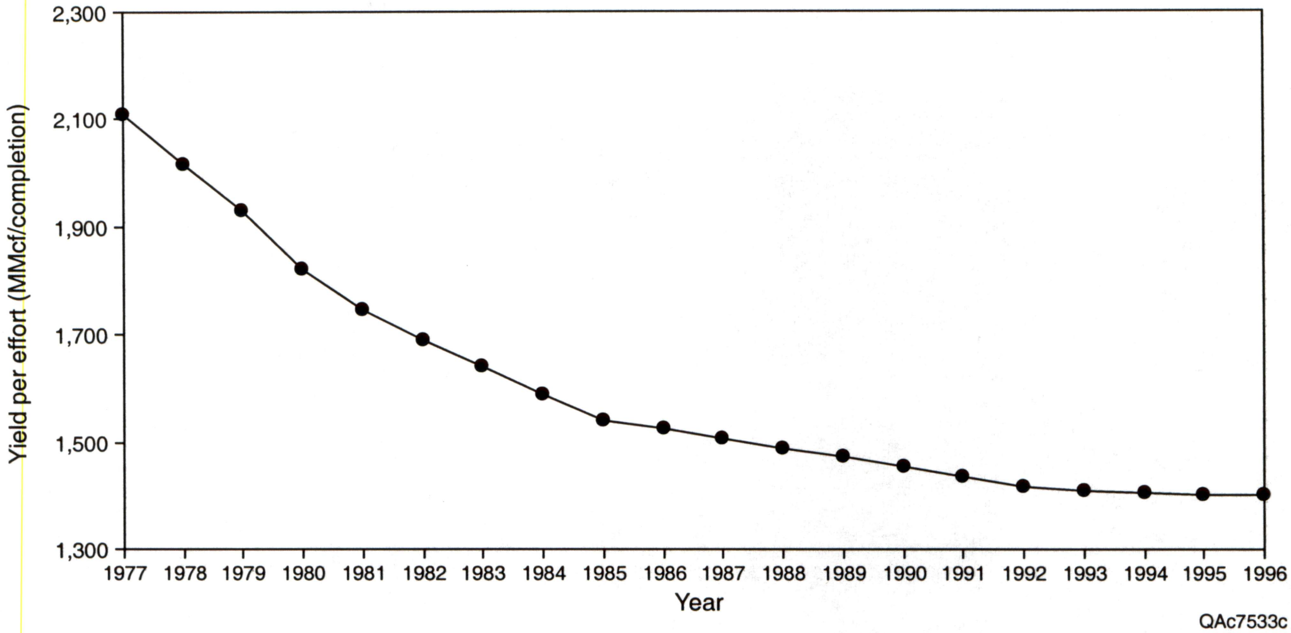


Figure 42. Yield per effort for total major plays of the Texas Gulf Coast Basin.

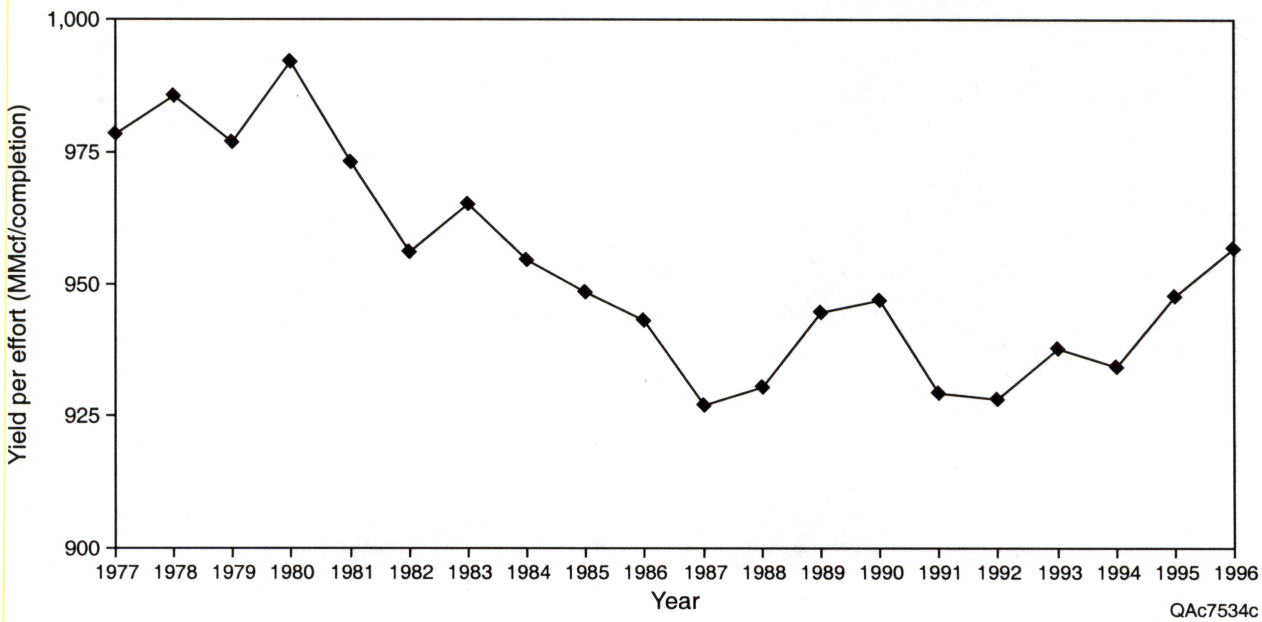


Figure 43. Yield per effort for total major plays of East Texas.

each year from 1977 through 1996. Therefore, average annual yield per effort values are not truly attributable to each year from 1977 through 1996.

When considering only the completions made during the time period from 1977 through 1996, more meaningful play-by-play yield per effort analysis may be obtained. The calculation of yield per effort for this method is simply obtained by dividing the natural gas ultimate recovery of 1996 minus that of 1977 by the cumulative completions made in 1996 minus that of 1977. A major assumption is that URG from 1977 to 1996 is attributable mostly to recent completions made. Yield per effort relying on only recent data and trends can be achieved by considering only data from 1977 through 1996. Disaggregating yield per effort by plays in this method, we find that Wilcox (WX) plays have the greatest yield per effort in the Texas Gulf Coast Basin (Figure 44). For East Texas, the Jurassic Carbonate (JC) and Lower Cretaceous-Jurassic Sandstone (KJ) plays have significantly higher yield per effort in recent years as compared with that of the Trinity Group Carbonate (KC) and Upper Cretaceous Sandstone (KS) plays (Figure 45).

Correlation to Major Geological, Engineering, and Production Parameters

Plays WX-1, WX-2, WX-4, and VK-1 in the Texas Gulf Coast Basin and plays KJ-1, KJ-2, and KJ-3 in East Texas are ranked as the top plays that have significant current URG and that hold the greatest future potential both as a factor of time and drilling activity. These plays warrant further detailed investigation of their major geological, engineering, and production parameters in order to postulate possible correlations between their significant current URG and future potential.

The Wilcox Deltaic Sandstone in the Houston Embayment (WX-1), Lower Wilcox Lobo Trend (WX-2), and Wilcox Deltaic Sandstone in the Rio Grande Embayment (WX-4) plays

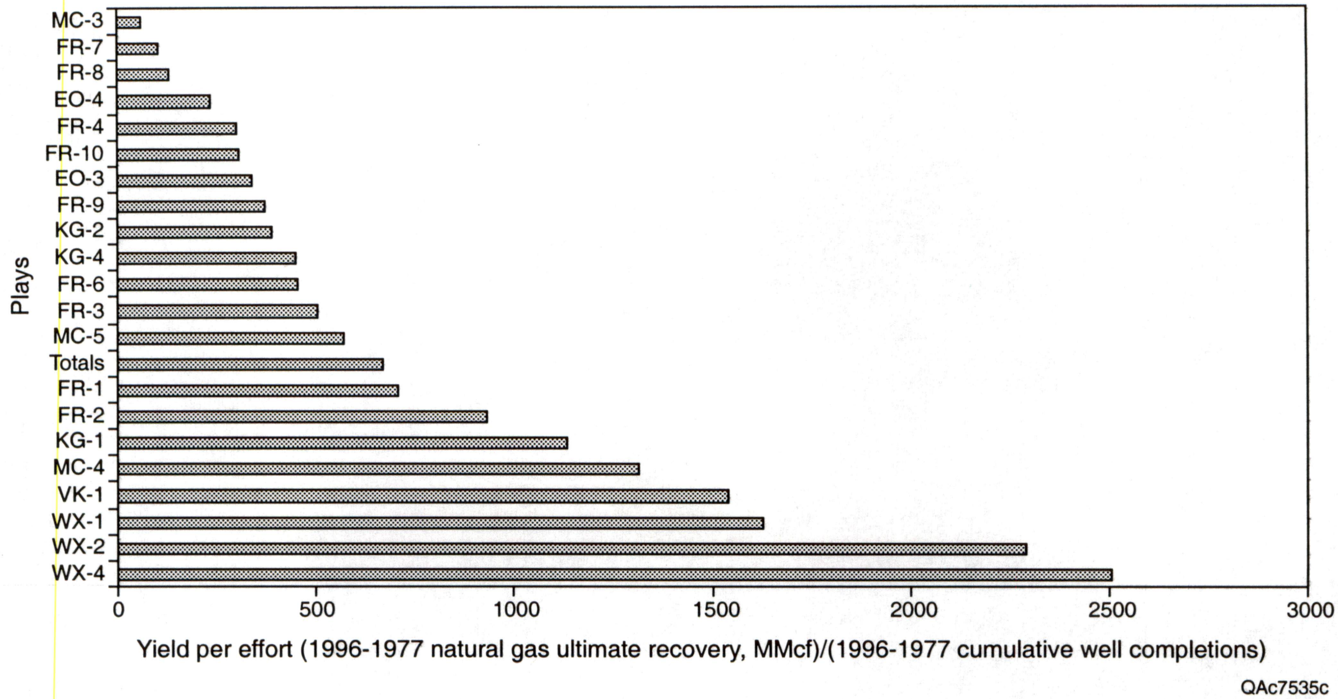


Figure 44. Recent yield per effort of major plays in the Texas Gulf Coast Basin.

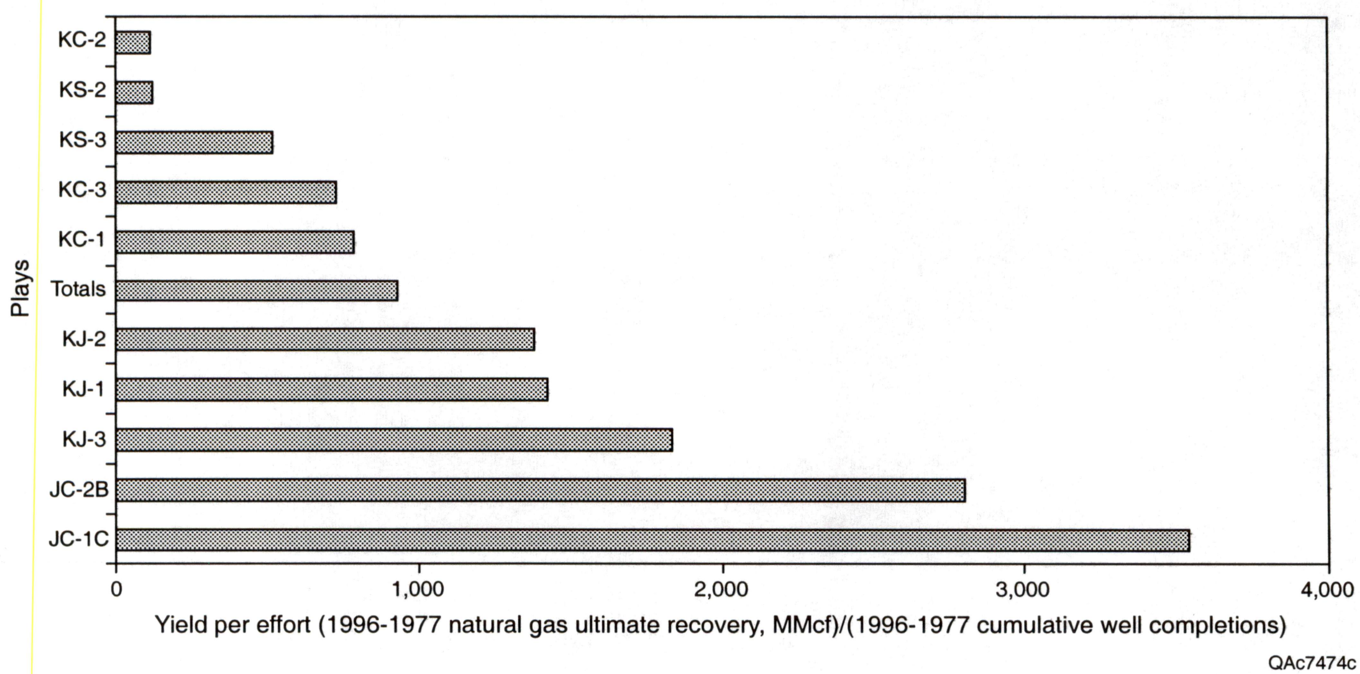


Figure 45. Recent yield per effort of major plays in East Texas.

comprise sediments of the Wilcox Group (Paleocene to lower Eocene), a major natural gas productive formation and the first major Tertiary progradational episode in the Tertiary System of the Texas Gulf Coast Basin. This major progradational sequence of terrigenous clastic sediments is separated into upper and lower progradational phases by a retrogradational phase in the middle of the sequence. Within each of these phases are transgressive-regressive cycles of deposition of more limited areal extent.

Most Wilcox reservoirs are small and natural-gas prone. Intensive exploration and development began in the late 1930's, and since then the focus has been toward even deeper reservoirs. Downdip limits of the Wilcox productive sandstones have yet to be fully determined. In outcrop and the shallow subsurface, the Wilcox was deposited primarily in fluvial environments. Downdip, the main Wilcox productive reservoirs were deposited by large deltas and associated barrier-bar and strandplain systems (Fisher and McGowen, 1967).

The extensive Wilcox growth-fault zone of syndepositional normal faults, with associated dip reversals and rollover anticlines, that developed along the unstable Wilcox shelf margin, is the main structural feature responsible for the formation of major natural gas trapping mechanisms (Figure 46) (Kosters and others, 1989). Because Wilcox deltaic reservoirs lie in the distal parts of delta-front and delta-flank shoreface facies, they are commonly thinly bedded shaly sandstones (Dutton and others, 1993). Numerous studies of the Wilcox Group have been published (Fisher and McGowen, 1967; O'Brien and Freeman, 1979; Edwards, 1981; Bebout and others, 1982; Alexander and others, 1985; Garbis and others, 1985; Long, 1986; Loucks and others, 1986; Robinson and others, 1986; Kosters and others, 1989), as well as numerous documents submitted to the RRC for designation as tight gas reservoirs.

Play WX-1 is a large natural gas play situated in the middle to upper Texas Gulf Coast Basin, predominately in RRC District 3. Current production in play WX-1 is from relatively deep reservoirs. Major fields of play WX-1 include Sheridan, Provident City, Katy, Columbus, Chesterville North, Lake Creek, Cooley, and Milton North. Almost all fields in play WX-1 lie in the Wilcox growth-fault zone, which extends downdip from the Cretaceous Stuart City shelf

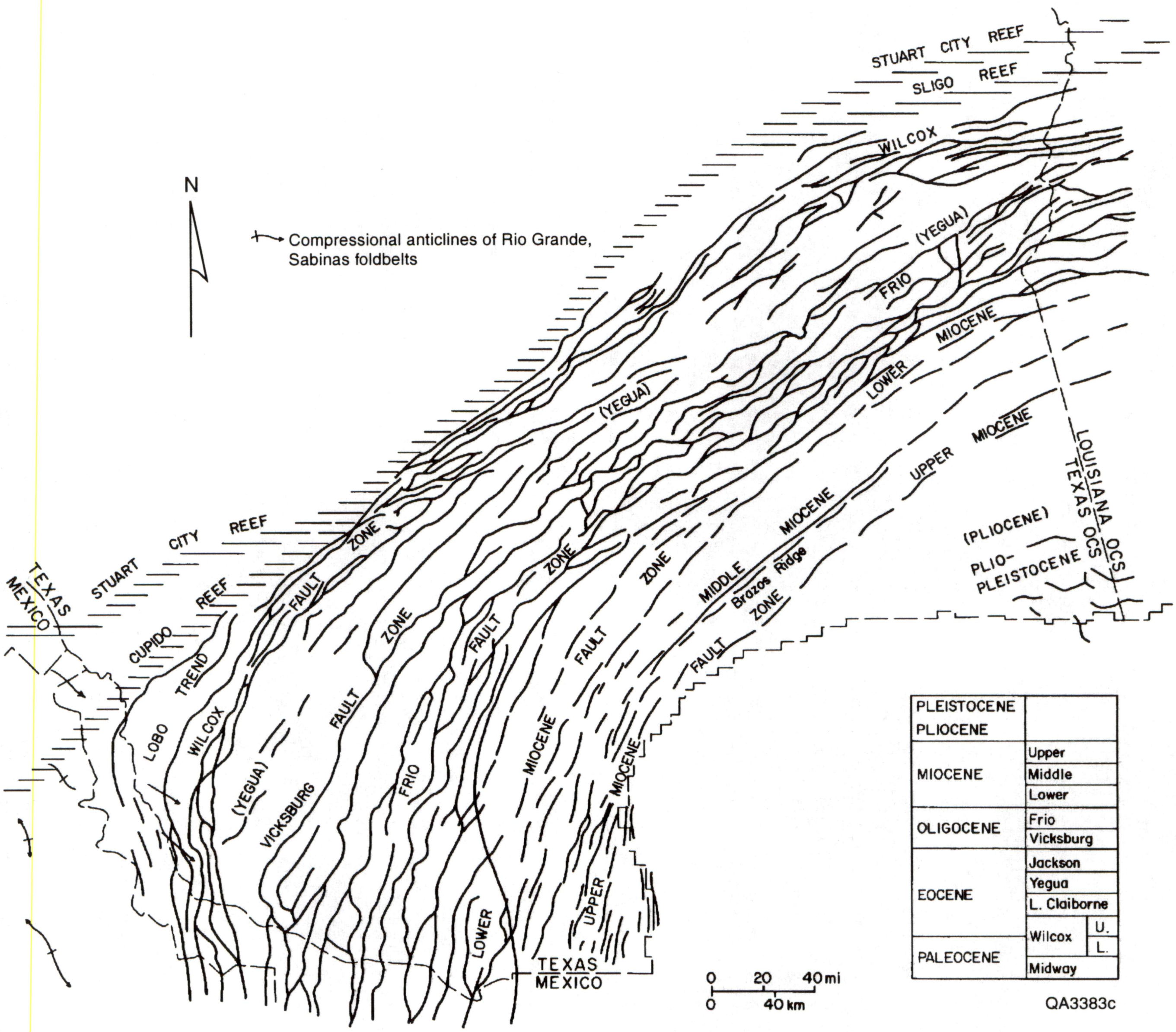


Figure 46. Regional fault zones of the Cenozoic Texas Gulf Coast Basin (Ewing, 1986).

margin. Traps formed primarily in anticlines and faulted anticlines on the downthrown sides of growth faults. In a few of the more updip fields, closure occurs against faults, and in the prolific Katy field, reservoirs are arched over a deep-seated salt structure. Most reservoirs in play WX-1 are deep and have pressures.

Depositional heterogeneities are introduced in play WX-1 reservoirs because of the differing styles of deltaic deposition that characterize the Wilcox episode in the Houston Embayment. Distinctive patterns of sandstone distribution and facies assemblages can be found in reservoirs of play WX-1. The lower Wilcox was deposited by lobate to dip-elongate, fluvially dominated deltas (Fisher and McGowen, 1967). The main reservoirs in fluvially dominated deltas are distributary-channel and channel-mouth-bar sandstones updip and thinner but more widespread delta-front sandstones downdip. In contrast, the upper Wilcox was deposited primarily by more strike-elongate, wave-dominated deltas (Fisher, 1969), where most sand is reworked by waves and deposited along the delta-flank shoreface. Possible source rocks of play WX-1 include prodeltaic mudstone interbedded with the reservoir sandstone, deep-marine Wilcox mudstone deeply buried downdip from shallow-marine reservoir facies, and underlying Upper Cretaceous to lower Paleocene marine mudstone.

The lower and upper parts of the Wilcox in play WX-1 are separated by a mudstone-rich middle Wilcox interval (Bebout and others, 1982). On the southwest margin of play WX-1, a series of submarine canyons were excavated into the lower Wilcox shelf and slope and were filled primarily by lower and middle Wilcox fine-grained deep-marine facies (Galloway and others, 1988). Gas producing zones have been found in isolated sandstones enclosed in canyon-fill mudstone (Hallettsville, South) and in erosionally truncated, underlying sandstone (Yoakum). Wilcox slope systems and deep, downdip extensions are potentially productive exploration targets in play WX-1.

Play WX-2 is a relatively new play in RRC District 4. Major fields of play WX-2 include Vaquillas Ranch, Laredo, JC Martin, La Perla Ranch, Benavides, McMurrey, and Bashara-Herford. Play WX-2 has displayed rapid increases in terms of natural gas annual production, proved reserves, and estimated ultimate recovery during a relatively short period of time. Natural gas ultimate recovery has increased severalfold just within the 1977 through 1996 time frame, directly showing the tremendous natural gas URG occurring within this play. The number of fields discovered has also increased correspondingly, but most of the major field discoveries were in the late 1970's and early 1980's.

The lower Wilcox is defined as the generally progradational, marine, and transitional (marginal marine) stratigraphic sequence between the Midway Group below and the middle Wilcox and Wilcox Shale unit above (Hargis, 1962). The name "Lobo" was introduced by O'Brien (1975) for the sequence of sandstones in the lower Wilcox in South Laredo field. A series of lowermost Wilcox deltas prograded across an unstable shelf margin composed of thick, undercompacted mud in the Midway Group. Gravity sliding and intense faulting of the entire Lobo section into numerous fault blocks over the Midway muds occurred soon after Lobo sandstone deposition. This structural activity was followed by a period of erosion that removed or reworked upper Lobo sands in many of the higher fault blocks. The faulted and erosionally limited Lobo sands were finally covered by thick middle Wilcox shales, which acted as a major trapping mechanism (Long, 1986).

The Lobo sandstones consist of progradational delta-front sand derived primarily from a local fluvial source interbedded with prodelta shales (Fisher and McGowen, 1967; Long, 1986). However, longshore currents reworking deltaic sands from the northeast could have contributed to a more wave dominated, shorezone origin for Lobo sands (Xue and Galloway, 1995). Deposition of as much as 1,500 feet of Midway Shale on a broad, flat shelf preceded the Lobo sequence.

The Lobo consists of seven sands, generally referred to as the Walker sand and the Lobo 1 through 6 sands (Figures 47 and 48). The Lobo, including the Walker sand, as well as some overlying sediments, is called the Lopeno by Bornhauser (1979). The overlying Stray section is unlike the Lobo section and is rarely productive of hydrocarbons. Claughton (1977) referred to the Stray section as the upper Lobo, and to the Walker and Lobo sands as the lower

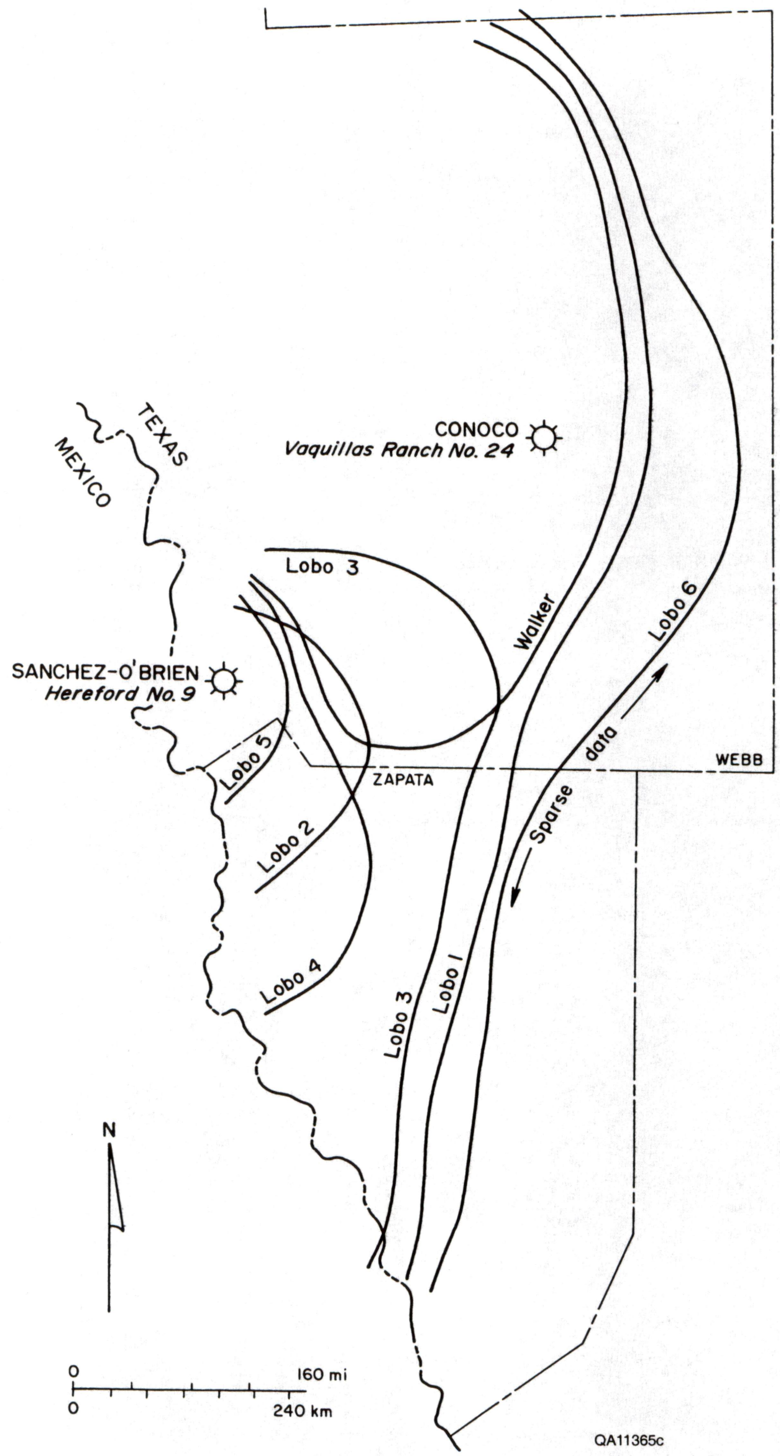


Figure 47. Lateral extents of the lower Wilcox Lobo productive sandstones (Long, 1986).

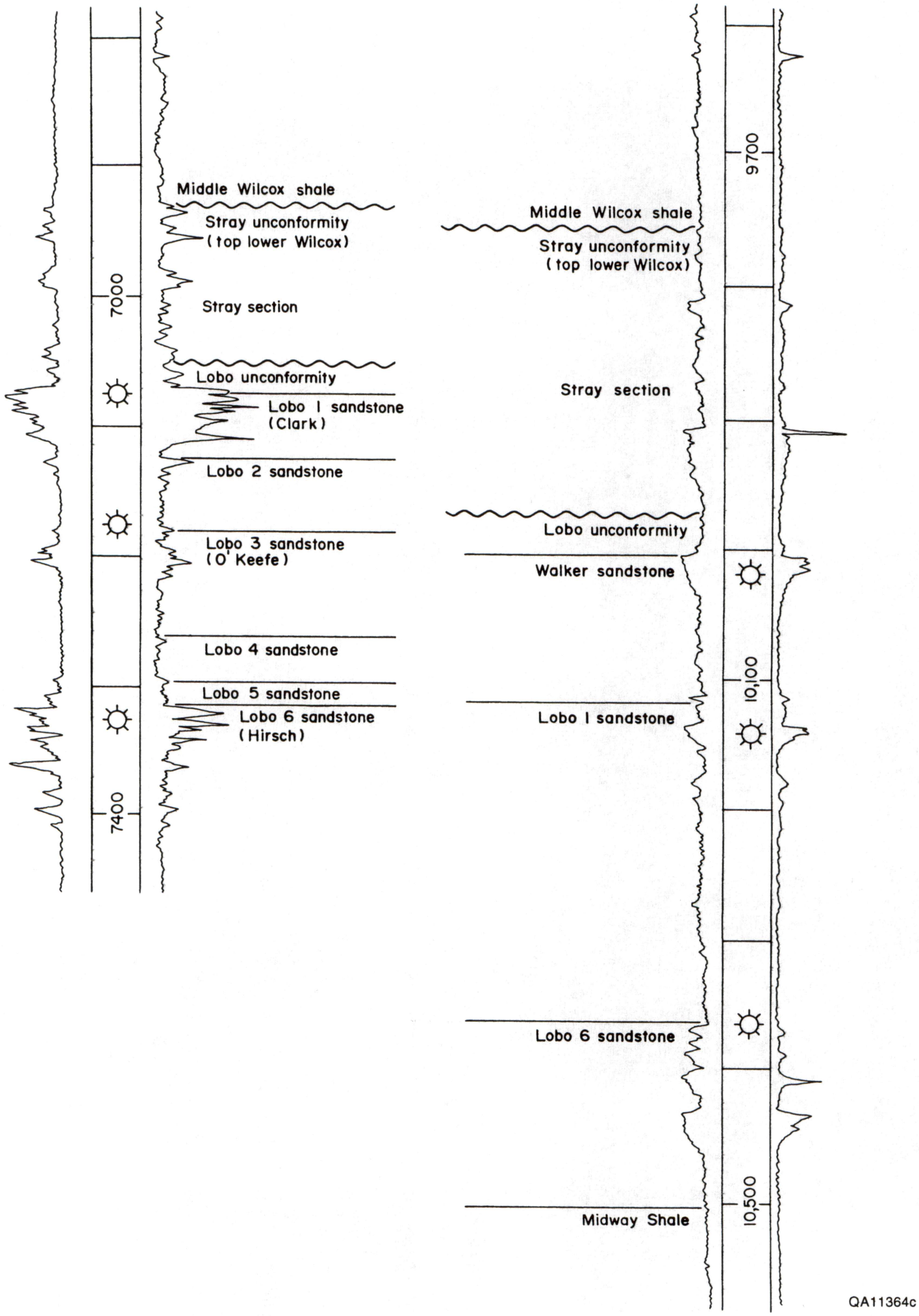


Figure 48. Typical logs from the lower Wilcox Lobo trend showing productive sandstones and unconformities (Long, 1986).

Lobo. The Lobo 6 (Hirsch) sand is the oldest, the most extensive, and the most consistently thick of all Lobo sands. The Lobo 4 and 5 sands are thin, poorly recognized, areally restricted, and generally nonproductive. The Lobo 3 (O'Keefe) sand has a greater lateral distribution than that of the Lobo 4 and 5 sands but is the least extensive and thinnest of productive Lobo sands. Like the Lobo 4 and 5 sands, the Lobo 2 sand is poorly developed, isolated, thin, and generally nonproductive. The Lobo 1 (Clark) sand is locally the thickest and most productive of the Lobo sands. To the south, the Lobo 1 sand thins in central Zapata County and is called the McMurrey sand by industry. The Walker sand, the youngest of the Lobo sands, occurs mainly in Webb County and is very productive (Long, 1986).

The lower Wilcox Lobo sandstones are the major low-permeability natural gas producers of the Texas Gulf Coast Basin and are formally designated as tight gas sandstones in Webb and Zapata Counties. Porosity and permeability ranges of 12 to 25 percent and 0.0003 to 0.5 md., respectively, are common for producing sandstones (Robinson and others, 1986). Almost all Lobo sandstones must be stimulated by fracture techniques. Typical fracture stimulation treatments averaged 101,800 gal of gel and 207,000 lb of proppant. Recently, smaller fracture treatments and more technologically advanced fracture designs have reflected an effort to optimize fracture length (Dutton and others, 1993). Lobo reservoirs generally yield little or no water, producing from gas expansion drive within each fault block (Long, 1986).

The complex configuration of faults and unconformities that compartmentalize Lobo reservoirs, as well as its characteristics of geopressured, tight gas reservoirs, has imparted high degrees of reservoir heterogeneity in play WX-2 (Figure 49). These reservoir heterogeneities require state-of-the-art reservoir characterization techniques, as well as advanced recovery techniques, in order to fully recover play WX-2's natural gas URG potential.

Play WX-4 is a large natural gas play in RRC Districts 1, 2, and 4. Within RRC District 4, play WX-4 lies primarily in Duval, Zapata, and Webb Counties. Production in play WX-4 has shifted in the last 20 years from the shallowest upper Wilcox depositional sequence to the deepest sequences. Major fields of play WX-4 include Tulsita-Wilcox, Bob West, Burnell,

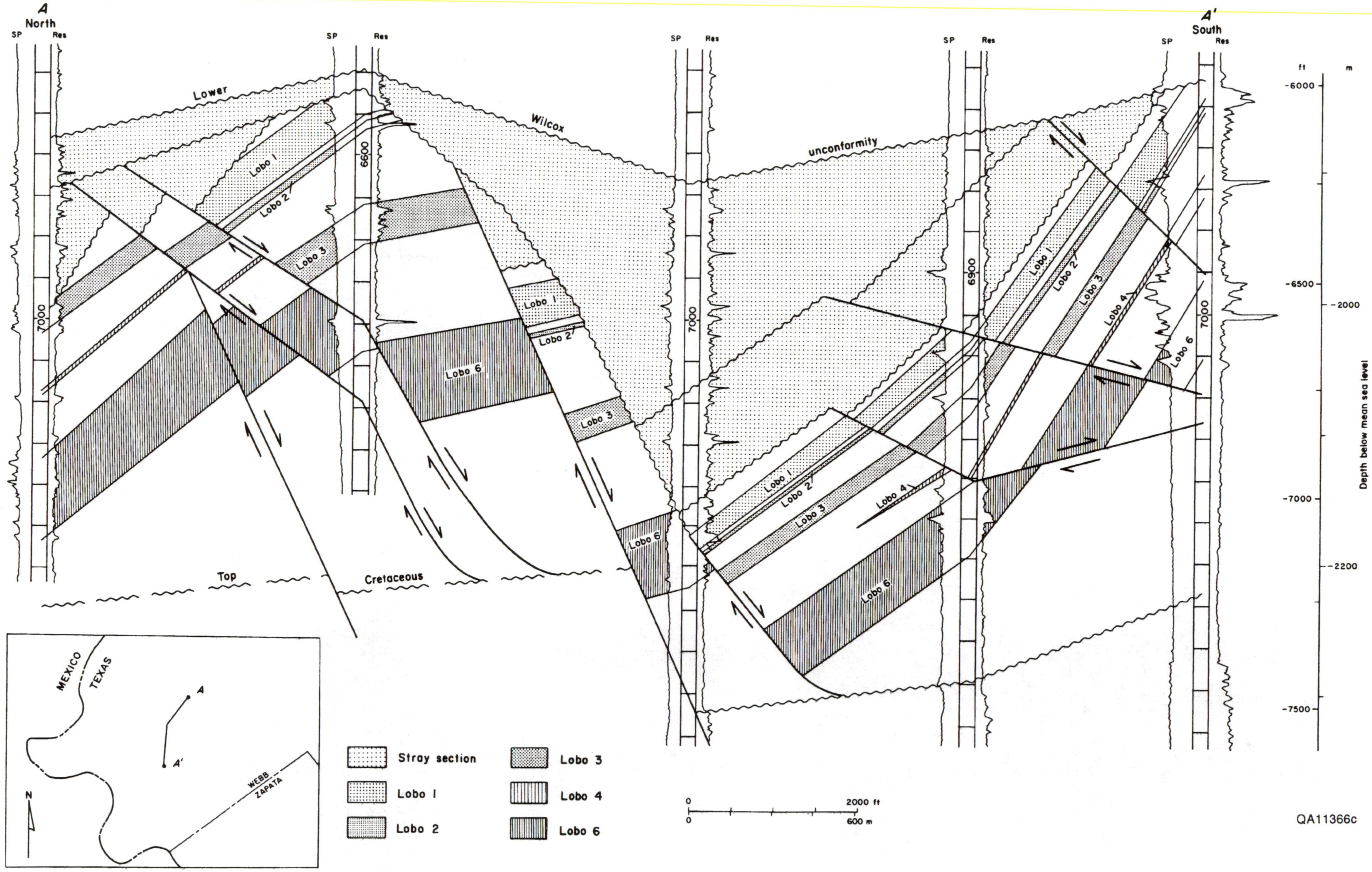


Figure 49. North-south cross section of Laredo (Lobo) field, Webb County, RRC District 4, showing complex configuration of faults and unconformities that compartmentalize lower Wilcox Lobo reservoirs (Dutton and others, 1993).

Thompsonville NE, Hagist Ranch, and Seven Sisters East. Play WX-4 is characterized by growth-faulted, deltaic sandstone reservoirs. Many of the deeper reservoirs are geopressured and typically have pressure-depletion drives, but the most prolific reservoirs are normally pressured and have solution-gas and water drives. Isolated areas in the middle Wilcox in Webb County and the upper Wilcox in Duval, Jim Hogg, and Starr Counties have been formally designated as tight gas sandstones by the RRC.

Natural gas reservoirs in play WX-4 appear in a variety of deltaic facies, primarily in the upper Wilcox. Upper Wilcox wave-dominated delta systems include thick sequences of strike-aligned delta-front and delta-flank (barrier/strandplain) sandstone (Edwards, 1981), whereas dip-oriented distributary-channel-fill and channel-mouth-bar sandstone is more prominent in lower Wilcox fluvial-dominated delta systems (Fisher and McGowen, 1967). Field-scale facies assemblages, however, are diverse and include channel-fill and crevasse splay sandstone interbedded with delta-plain mudstone that grades basinward into channel-mouth-bar and delta-front shoreface sandstone interbedded with prodelta mudstone. Delta abandonment was followed by transgressive reworking and deposition of marine mudstone over sandstone facies. Therefore, Wilcox deltaic natural gas reservoirs in the Texas Gulf Coast Basin are typically stratigraphically complex and display variable lateral continuities. Abundant prodelta, shelf, and slope mudstones in the deep Wilcox Formation form both source and seals for natural gas reservoirs in play WX-4. Additionally, the deep Wilcox Formation is overlain and underlain by thick mudstones of the Reklaw Formation and Midway Group, respectively, which were deposited during regional transgressions.

Deep Wilcox natural gas reservoirs in play WX-4 are highly faulted because of deposition along an unstable shelf margin. Closely spaced growth faults having thousands of feet of cumulative displacement, and associated stratigraphic thickness and facies changes characterize the deep Wilcox Formation. Traps formed primarily in faulted rollover anticlines on the downthrown sides of growth faults. Simple fault-plane traps are also common. Unraveling the faulting history is critical in positioning wells to penetrate fault blocks that were trapped at the time of sand deposition and not later. The vast majority of fields produce from highside closures against down-to-the-coast faults. Even apparently faulted anticlines produce primarily from the highside closure. There are some rare examples of downside closures and some minor production trapped against up-to-the-coast faults (Debus and Debus, 1998).

Play VK-1 was deposited in the Oligocene Vicksburg Formation, a major natural gas producing trend in the Texas Gulf Coast Basin. Major natural gas fields of play VK-1 include Borregos, McAllen Ranch, La Gloria, Tijerina-Canales-Blucher, Jeffress, Javelina, La Copita, Flores, McCook East, and Monte Christo. Many fields included in play VK-1 are also fields within the Frio Fluvial/Deltaic Sandstone along the Vicksburg Fault Zone (FR-4) play.

Deltaic sandstone reservoirs are downfaulted along the Vicksburg Fault Zone, also known as the Vicksburg Flexure or the Sam Fordyce-Vanderbilt Fault Zone, a regionally continuous, relatively narrow, syndepositional growth-fault system. The main Vicksburg growth fault displays regional continuity along strike, low-angle décollement, and pronounced dip reversal. Updip from the Vicksburg Fault Zone, the Vicksburg Formation averages less than 1,000 feet in thickness, but 5,000 to 10,000 feet of Vicksburg sediments accumulated on the downthrown side (Kosters and others, 1989). Stratigraphic thickening across the Vicksburg growth faults and increasing fault density with depth is well displayed in Figure 50.

The Rio Grande Embayment in the Texas Gulf Coast Basin is the principal depocenter for the thick sequences of Vicksburg deltaic sandstones. Fluvial-dominated, lower Vicksburg deltas had high rates of progradation and subsidence but only minor reworking by marine processes. During deposition of the middle Vicksburg, fluvial and marine processes interacted to produce thick, strike-oriented, delta-front sandstones. Wave-dominated, upper Vicksburg deltas formed during a period of reduced progradation and increased marine reworking (Han, 1981; Han and Scott, 1981). Progradation onto the underlying, unstable Jackson Group shales caused large-scale slope failure along listric glide planes, deformation of underlying shales into ridges and diapirs, and regional extension that provided space for large volumes of Vicksburg sediments (Picou, 1981; Winker and Edwards, 1983). The upper part of the Vicksburg is shale

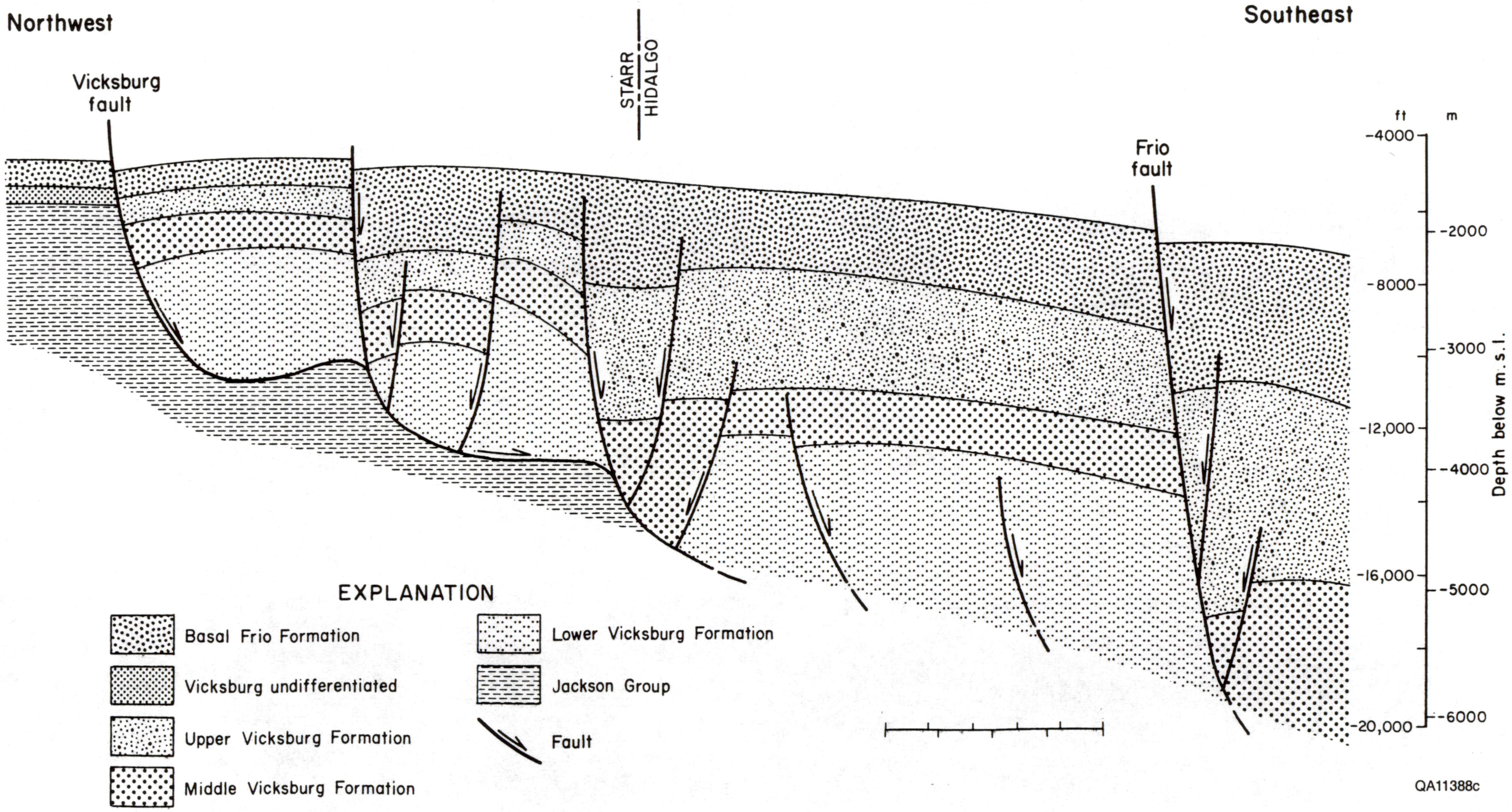


Figure 50. Northwest-southeast dip-oriented cross section of the Vicksburg Formation in Starr and Hidalgo Counties, RRC District 4 (Han, 1981).

dominated, the middle part contains several largely conventional reservoir sandstones, and the lower part comprises a thick sequence of sandstones that include most of the low-permeability reservoirs (Dutton and others, 1993).

Trapping mechanisms occur mainly in rollover anticlines that are segmented by faults (Han, 1981; Han and Scott, 1981). Stratigraphic traps are also important locally, where sandstones pinch out toward structural highs (Hill and others, 1991). The Vicksburg Formation has been the subject of numerous studies, such as Loucks (1978), Berg and others (1979), Richman and others (1980), Dramis (1981), Han (1981), Han and Scott (1981), Klass and others (1981), Marshall (1981), Picou (1981), Kosters and others (1989), Coleman (1990), Coleman and Galloway (1990), Finley and others (1990), Hill and others (1991), and Langford and others (1992, 1994).

Play VK-1 is the dominant Vicksburg play in the Texas Gulf Coast Basin. It extends from Nueces County southwest to Starr and Hidalgo Counties. Almost all reservoirs in play VK-1 are located downdip from the Vicksburg fault zone. Historically, distributary-channel-fill and channel-mouth-bar sandstones have formed the most productive reservoir facies. Generally oriented perpendicular to structure and displaying considerable internal heterogeneity, distributary-channel-fill and channel-mouth-bar sandstones form the principal reservoir facies in the fluvial-dominated lower Vicksburg. Greater field-scale continuity and internal homogeneity are displayed in the generally strike-oriented, delta-flank shoreface and beach-ridge sandstones that form the principal reservoir facies in the wave-dominated, upper and middle Vicksburg (Kosters and others, 1989).

Vicksburg reservoirs are compartmentalized by closely spaced faults, facies heterogeneities, and diagenetic barriers (Langford and others, 1992). Most of the Vicksburg sandstone reservoirs are geopressured, with reservoir pressure gradients ranging from 0.86 to 0.92 psi/ft. Fracture stimulation treatments are common in Vicksburg sandstones, particularly the tight gas sandstones in McAllen Ranch field. Typical fracture stimulation treatments involve 150,000 gal of crosslinked gel and 450,000 lb of proppant (Dutton and others, 1993).

In East Texas, the Lower Cretaceous-Jurassic Sandstone (KJ) plays are experiencing significant current URG and hold the greatest future potential both as a factor of time and drilling. The Lower Cretaceous Travis Peak (Hosston) Formation and the Upper Jurassic Cotton Valley Group (Schuler and Bossier Formations) represent the first major siliclastic influx in East Texas. Three plays produce gas from the Lower Cretaceous-Jurassic Sandstone: KJ-1, KJ-2, and KJ-3. These three plays are differentiated not by producing formation, but by major trap type. Large natural gas reservoirs are concentrated over the Sabine Uplift and nonpiercement salt structures. Reservoirs of play KJ-1 are situated over the Sabine Uplift. Reservoirs of play KJ-2 are associated with salt structures located on the boundary between the Sabine Uplift on the east and the currently deeper parts of East Texas Basin to the west. Reservoirs of play KJ-3 are located on the southwest margin of East Texas Basin and are similarly localized over the crest of intermediate-amplitude salt pillows.

The areas covered by the three KJ plays coincide with the historically prolific Lower Cretaceous Trinity Group Carbonate (KC) plays because of their distribution controlled by similar structural settings. Current natural gas production trends display a shift from these historically prolific, shallower natural gas plays to the deeper KJ plays.

Production from KJ plays is both from low-permeability reservoirs and higher permeability zones that produce natural gas without stimulation (Finley, 1984). Early production in the Cotton Valley Group was from shallow porous and permeable blanket sandstone along the updip basin margin in Louisiana (Collins, 1980). More recent production is from relatively low permeability reservoirs that lie downdip of basin-margin areas. Typically, massive hydraulic fracturing treatments are required to stimulate commercial production from both Travis Peak and Cotton Valley low-permeability reservoirs (Figure 51).

In the early 1980's, reservoirs in some Travis Peak and Cotton Valley sandstone fields throughout East Texas were designated as "tight" (low permeability) by the Federal Energy Regulatory Commission, allowing incentive pricing of natural gas to recover the high cost of hydraulic fracturing treatments. This action increased drilling activity in the early 1980's.

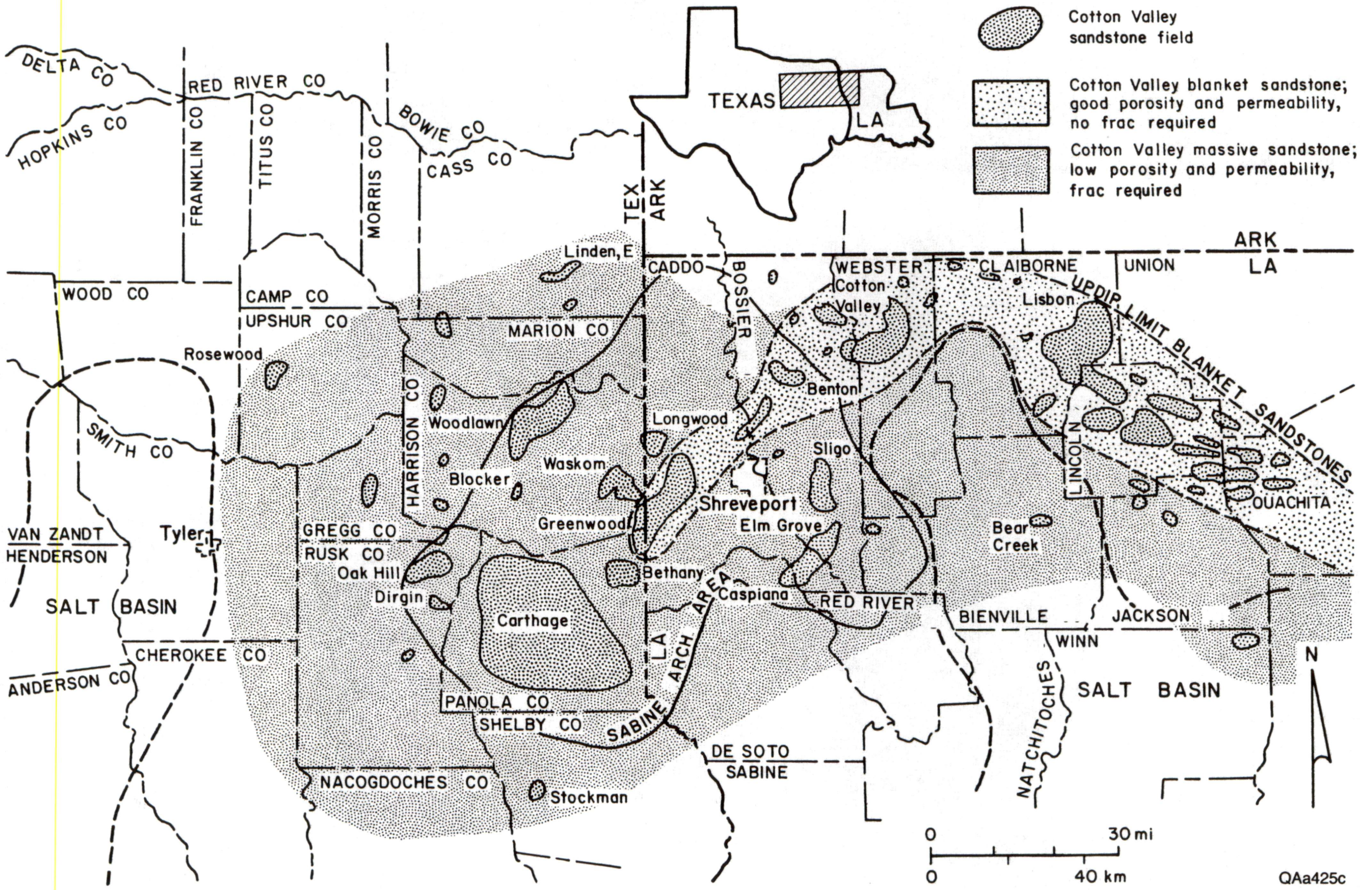


Figure 51. Distribution of Cotton Valley reservoir trends (modified from Collins, 1980).

However, the decline in natural gas prices in the middle 1980's lowered subsequent drilling activity in the low-permeability areas. With advances in hydraulic fracturing technology, which has lowered its cost of application, current production and development from these areas have been significantly revitalized. Major natural gas fields in the KJ plays include Carthage, Oak Hill, Opelika, Willow Springs, Waskom, and Bethany.

The top plays in terms of natural gas ultimate growth both by factors of time and drilling activity in the Texas Gulf Coast Basin and East Texas have several common characteristics: production trends toward deeper reservoirs, bimodal discovery-year histograms, high structural complexities due to fault compartmentalization, reservoirs designated as tight gas/low permeability, and relatively high initial reservoir pressures. A probable important control on high structural complexity, tight gas reservoirs, and high initial reservoir pressures is reservoir depths. Deeper reservoirs tend to exhibit more complex structures, cementation, and high volumes of natural gas. These geologically complex plays require steady application of advanced technologies, such as 3-D seismic, hydraulic fracturing, and horizontal drilling, in order to achieve their URG potential.

Effective Technologies Deployed and Amenability of Plays to Deployment of Existing and Future Technologies

With a few exceptions, natural gas resources have been historically underestimated largely because technology and human ingenuity have been ignored, undervalued, or thought to be irrelevant to finite natural gas resources. Changed perceptions about U.S. domestic natural gas resources provide an excellent example of the impact of rigorously applied technology and human ingenuity (Fisher, 1994a). During the 1970's and into the early 1980's, the consensus was that U.S. domestic natural gas resources were being exhausted rapidly. Prospects were for long-term natural gas supply to increasingly rely on foreign sources and remote domestic locations at significantly higher prices. Today, real natural gas prices are only about half of what they were in the mid-1980's; however, U.S. domestic natural gas production is at a record. Expectations are for continued future growth in U.S. domestic natural gas supply.

Technological advances have reduced the risks and costs associated with reserve additions. Notably, this technological impact came during a period of inordinately low natural gas prices, when technological application was the only alternative. Natural gas activity was, perhaps for the first time in U.S. natural gas exploration and development history, pure, technological play. As a direct result, natural gas supplies, curtailed in the 1970's, have exceeded demand. Moreover, natural gas resource estimates made in the 1970's are now exceeded by at least an order of magnitude (Fisher, 1994a).

U.S. NATURAL GAS STATISTICS AND TECHNOLOGY

U.S. natural gas field numbers, production, and ultimate recovery have shown a steady increase with a relatively stable proved reserve base (Figure 52). With the exception of the abnormally high USGS estimates of the early 1970's, estimates of remaining U.S. natural gas resources have increased steadily (Figure 53). The turning point of the perception of remaining U.S. natural gas resources came with the DOE estimate published in 1988 that doubled an earlier DOI estimate made in 1987. The doubled DOE natural gas resource estimate was largely influenced by improvements in yield per effort in gas drilling, nonconventionals, and new perceptions on ultimate gas recovery growth based on the extrapolated experience in oil reserve growth. Subsequent estimates of remaining U.S. domestic natural gas resources from a variety of industry, professional, and governmental agencies increased substantially. In addition to the new perceptions of a much greater natural gas resource base, historical projections of natural gas production and prices also reflected rising expectations (Figures 54, 55, and 56). Thus, the

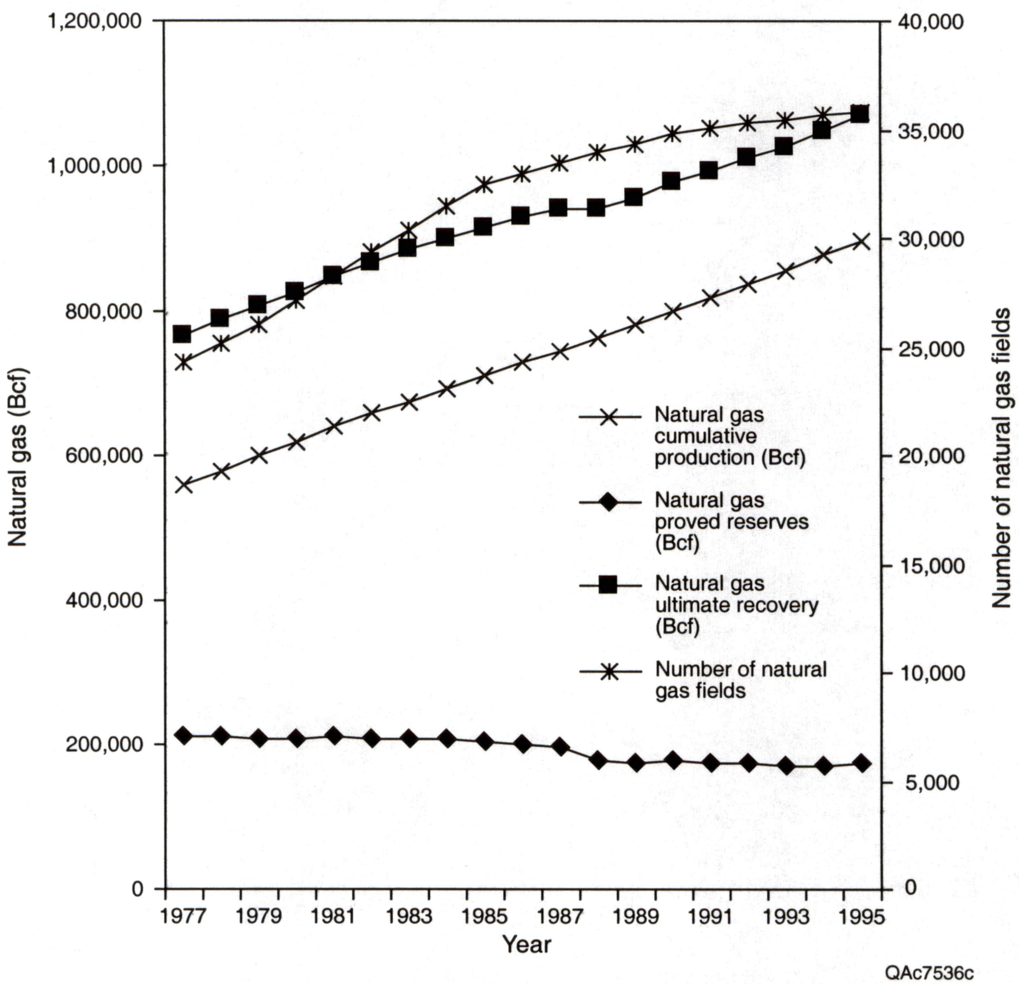


Figure 52. U.S. natural gas cumulative production, proved reserves, ultimate recovery, and field counts, 1977–1995 (Energy Information Administration, 1997a).

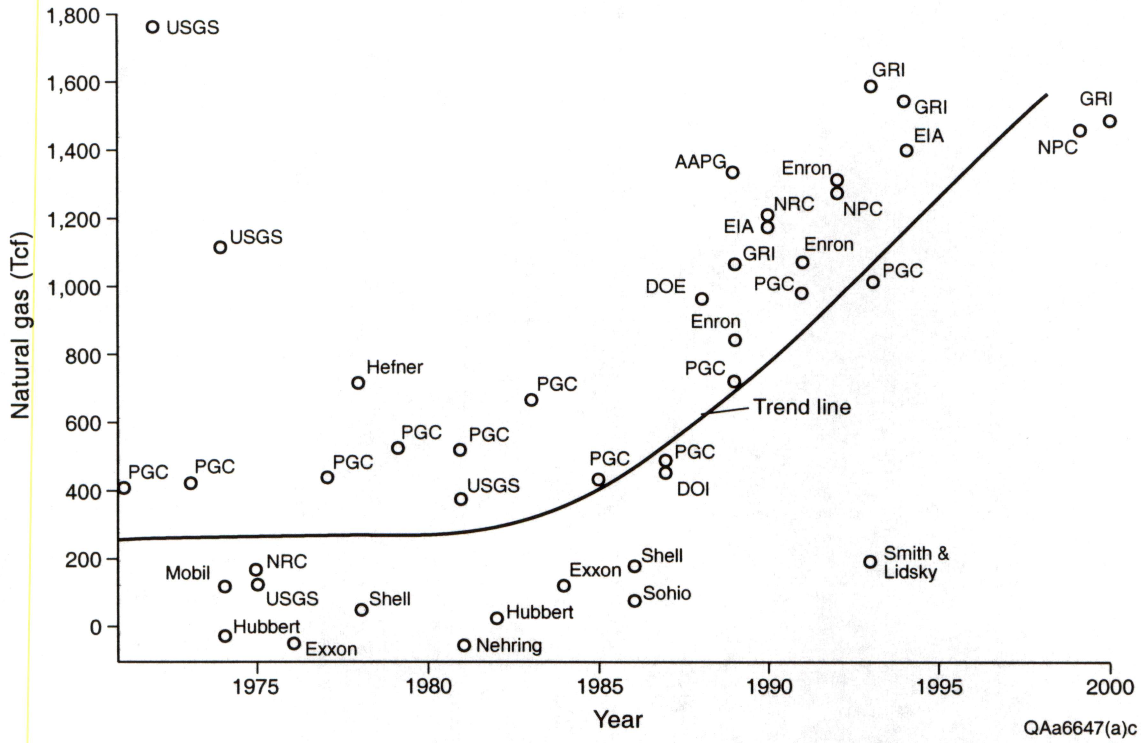


Figure 53. Estimates of remaining U.S. natural gas resources (modified from Fisher, 1994b).

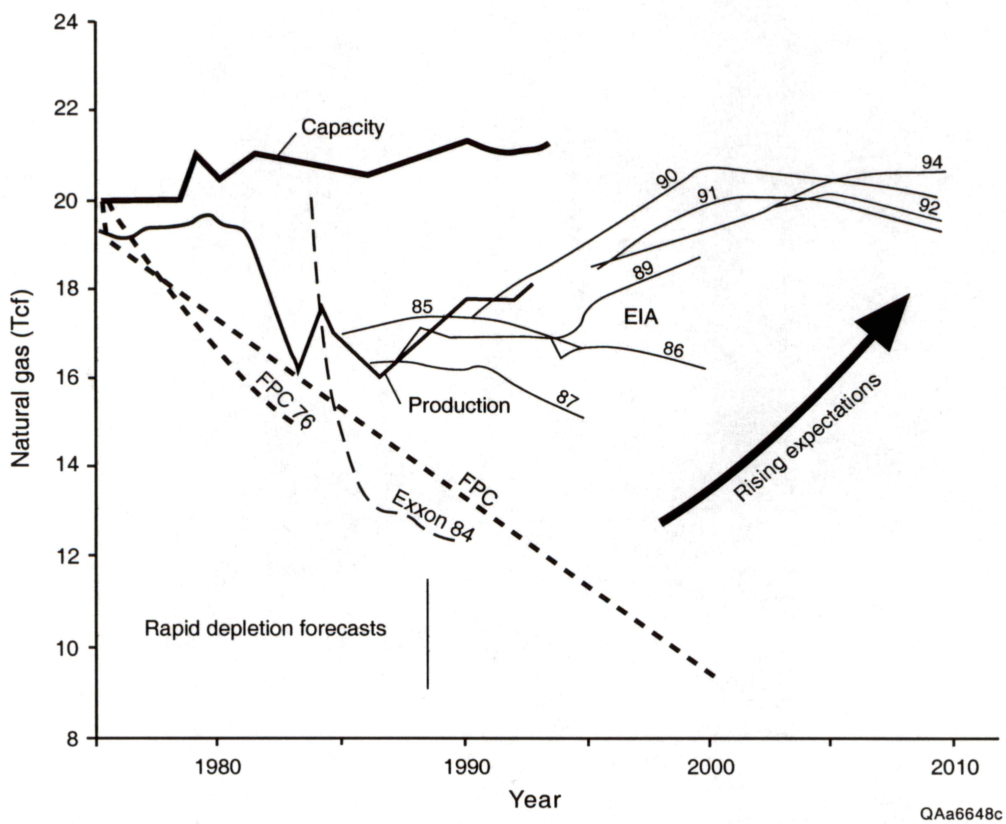


Figure 54. Historical projection of natural gas production in the United States (Hefner, 1993).

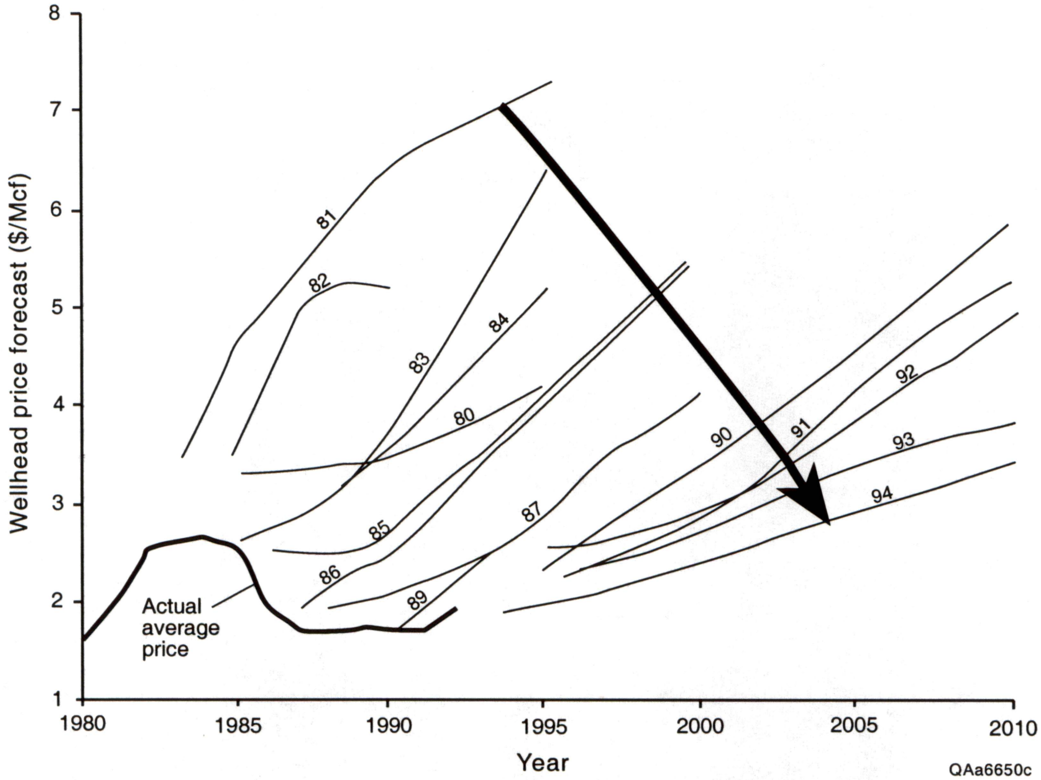


Figure 55. EIA future projections of natural gas wellhead prices in the United States, 1981–1994 (Hefner, 1993).

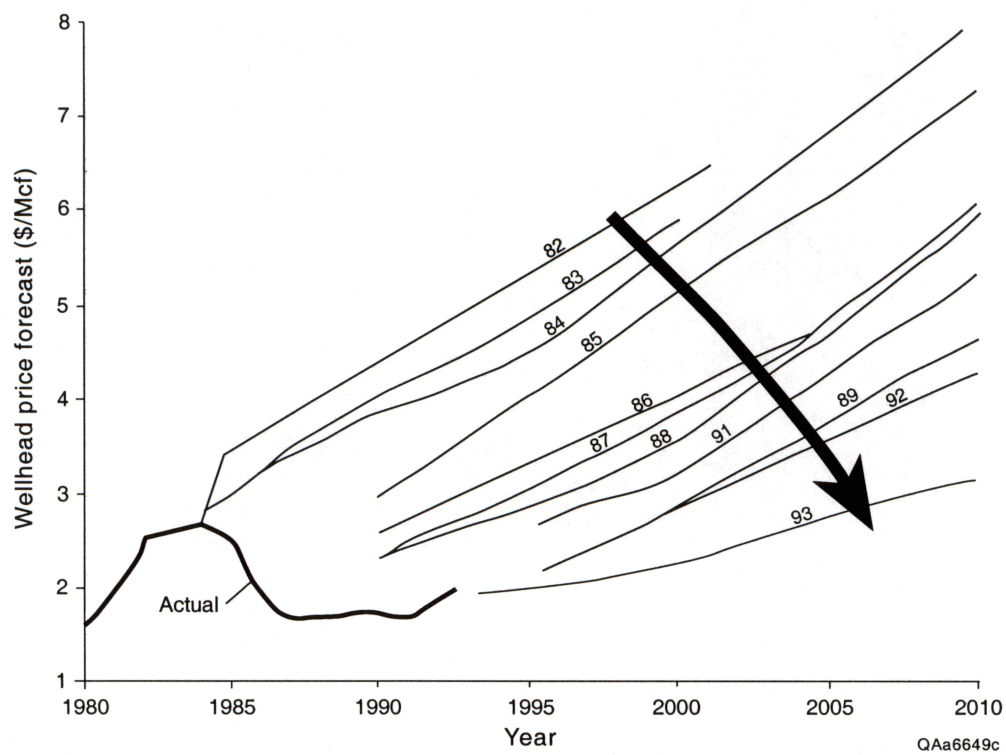


Figure 56. GRI future projections of natural gas wellhead prices in the United States, 1982–1993 (Hefner, 1993).

natural gas resource base was judged to be not only substantially greater than was earlier thought, but also more accessible at lower prices (Fisher, 1994a).

Although present views indicate an ample remaining U.S. natural gas resource base, many factors have constantly changed its future outlook. U.S. Lower 48 States natural gas production peaked in the early 1970's, with a stabilized decline through the early 1980's (Figure 57). As average wellhead prices and drilling costs increased severalfold in a decade, demand for U.S. natural gas production declined in the early 1980's, creating a surplus (Figures 58 and 59). From the late 1980's to the present, U.S. natural gas production has increased steadily. Driven by widespread perception of scarcity in the late 1970's and early 1980's, average wellhead natural gas prices have risen dramatically. In the face of a persistent surplus in the late 1980's, average natural gas wellhead prices dropped substantially. With an increase in natural gas wellhead prices, natural gas drilling responded comparably but fell dramatically in the face of falling demand and prices in the middle 1980's (Figure 60). Success rates and average well depths increased with the drop in drilling (Figures 61 and 62).

Except for negative reserve additions in 1988, arising because of the large negative revision from the decrease to North Slope dry natural gas reserves made in 1988 (due to economic and market conditions), in terms of U.S. dry natural gas annual production, proved reserves, and reserve additions, a fairly stable trend has been established since the middle 1980's (Figures 63 and 64). A drop in drilling in relation to price decreases was expected. However, maintaining relatively stable annual production, proved reserves, and reserve additions under lower levels of drilling and reduced prices was an unanticipated phenomenon. This phenomenon over the past few years has become critical to assessing future U.S. natural gas supply and deliverability.

Was the phenomenon an anomaly or a has a trend of substance been established? The answer may be revealed by taking a closer look at reserve additions. Early in the late 1980's, the fact that reserve additions were maintained or even increased with declines in both drilling and price was argued by some to be due to increase in revisions that were judged to be only "paper"

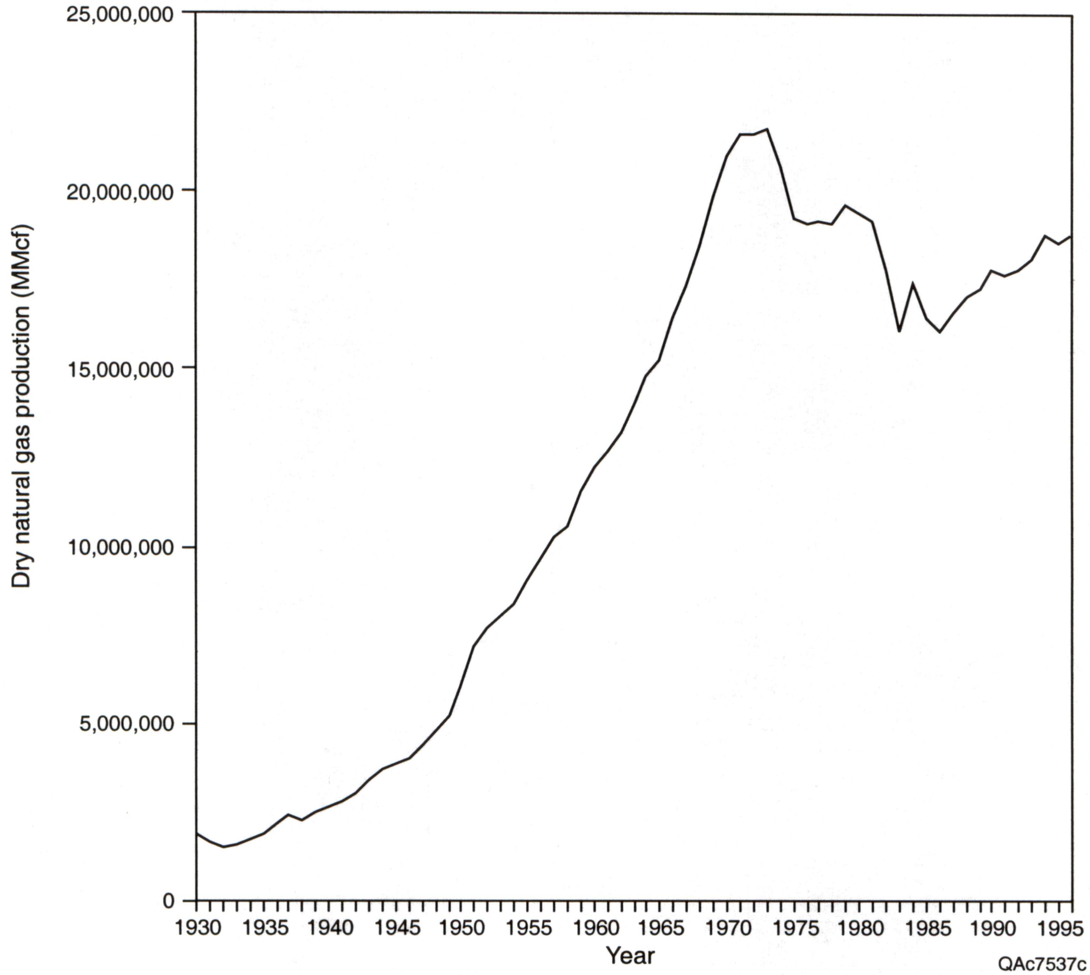


Figure 57. U.S. dry natural gas production, 1930–1996 (Energy Information Administration, 1997a).

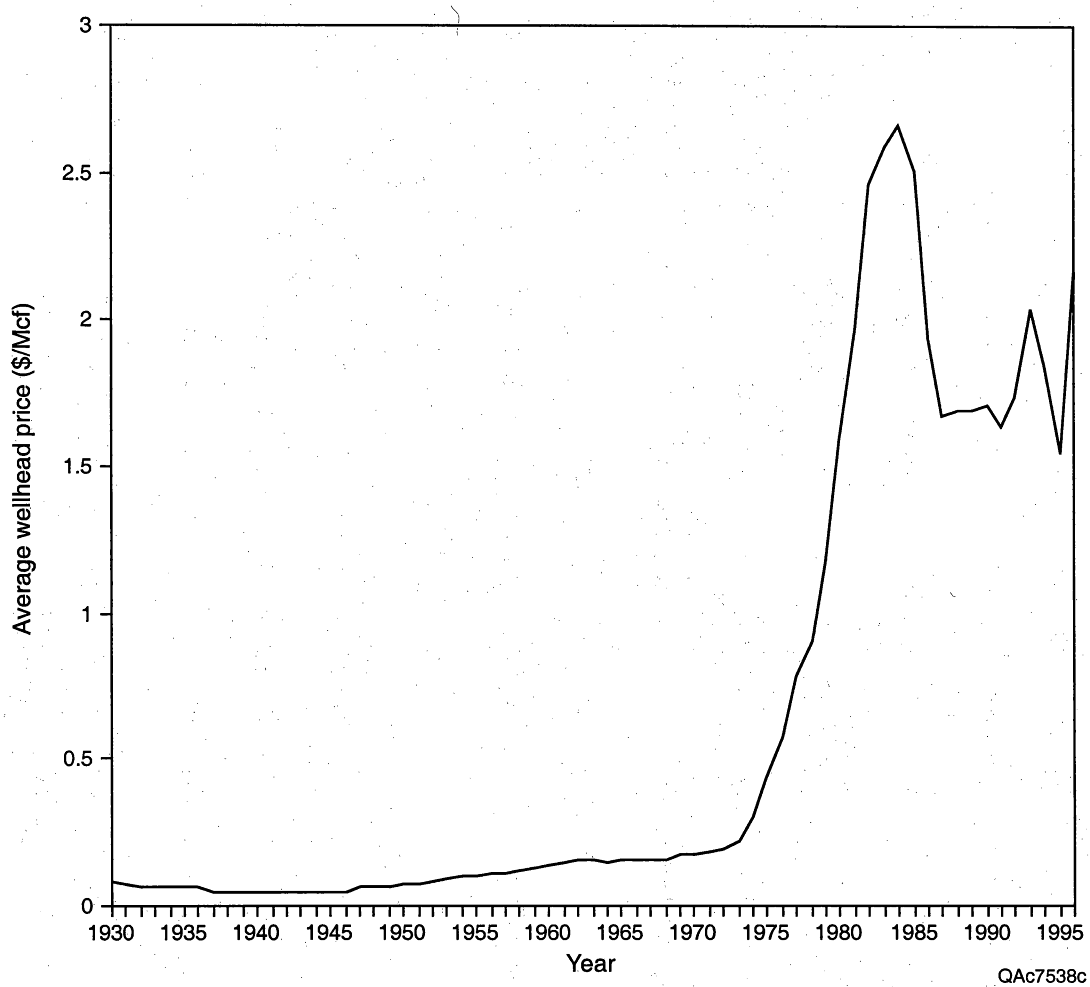


Figure 58. U.S. average wellhead price of natural gas in current dollars, 1930–1996 (Energy Information Administration, 1997a).

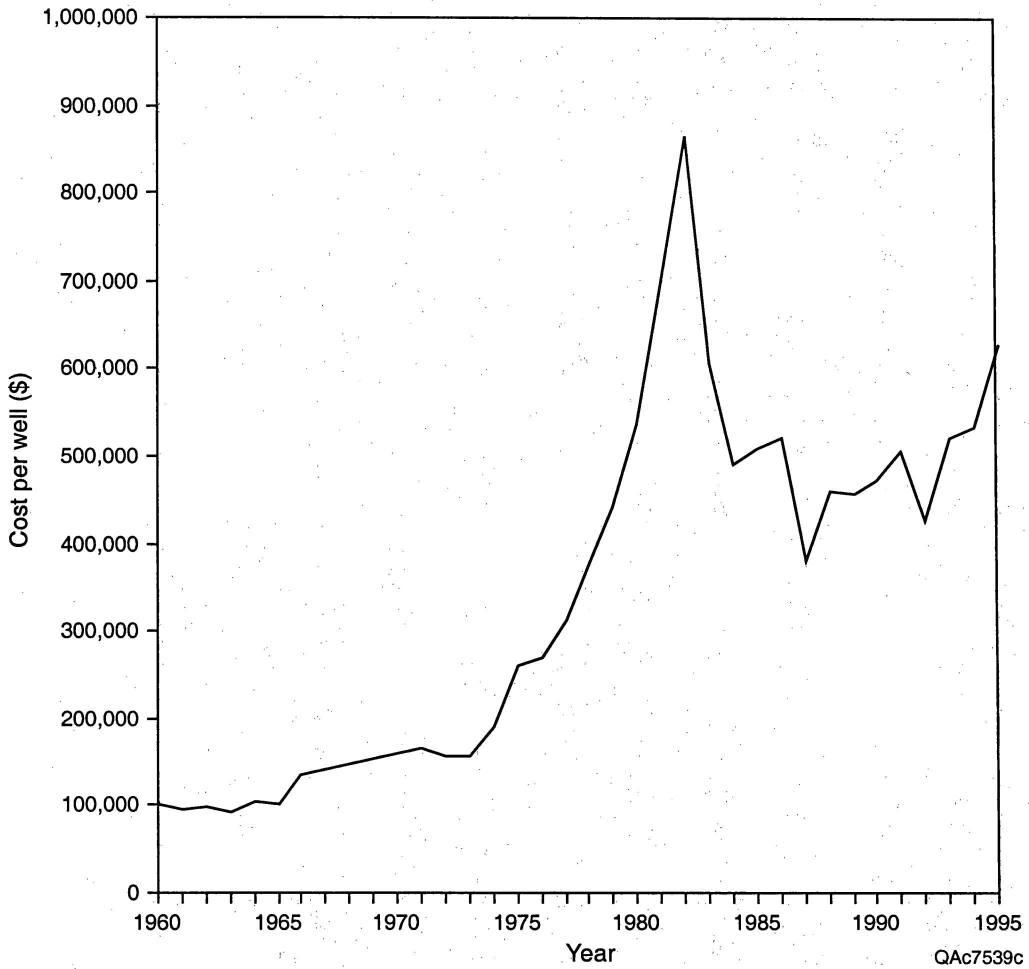


Figure 59. U.S. drilled natural gas well costs, 1960–1995 (Energy Information Administration, 1997a).

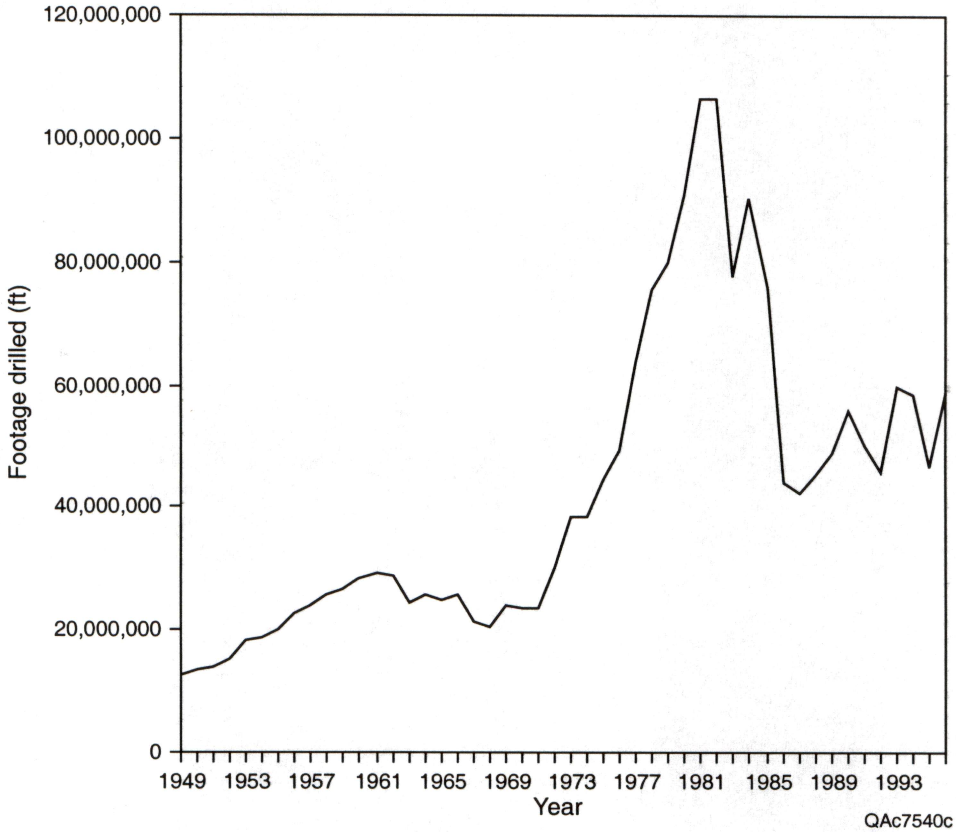


Figure 60. U.S. natural gas well footage drilled, 1949–1996 (Energy Information Administration, 1997a).

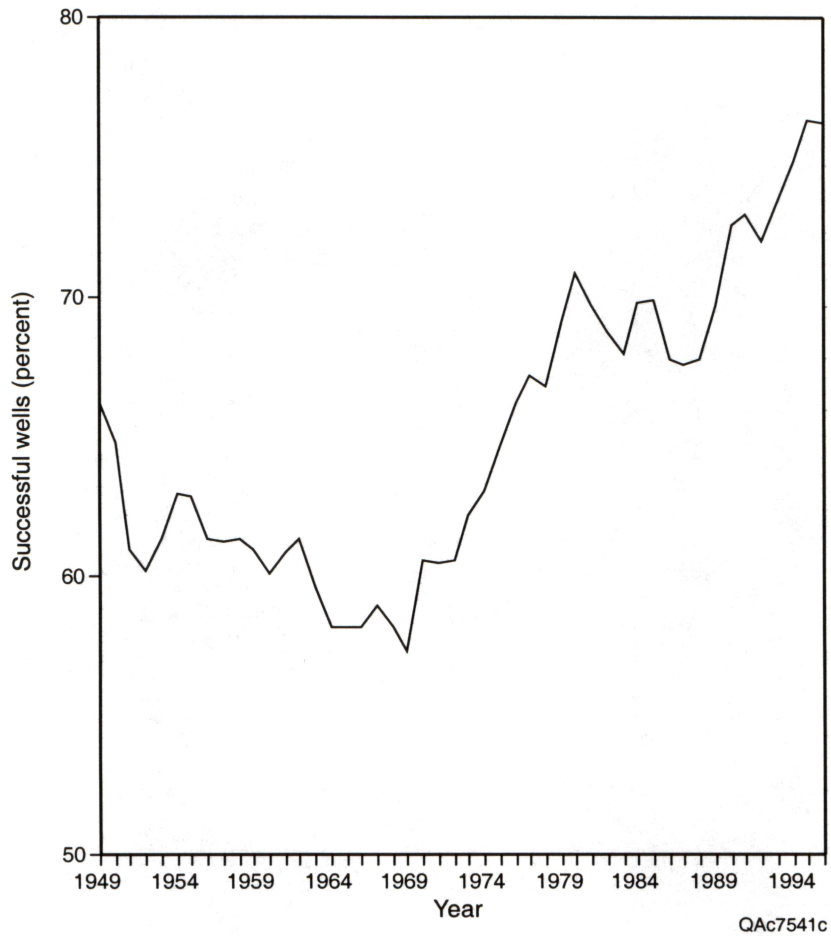


Figure 61. U.S. oil and natural gas exploratory and development successful wells drilled, 1949–1996 (Energy Information Administration, 1997a).

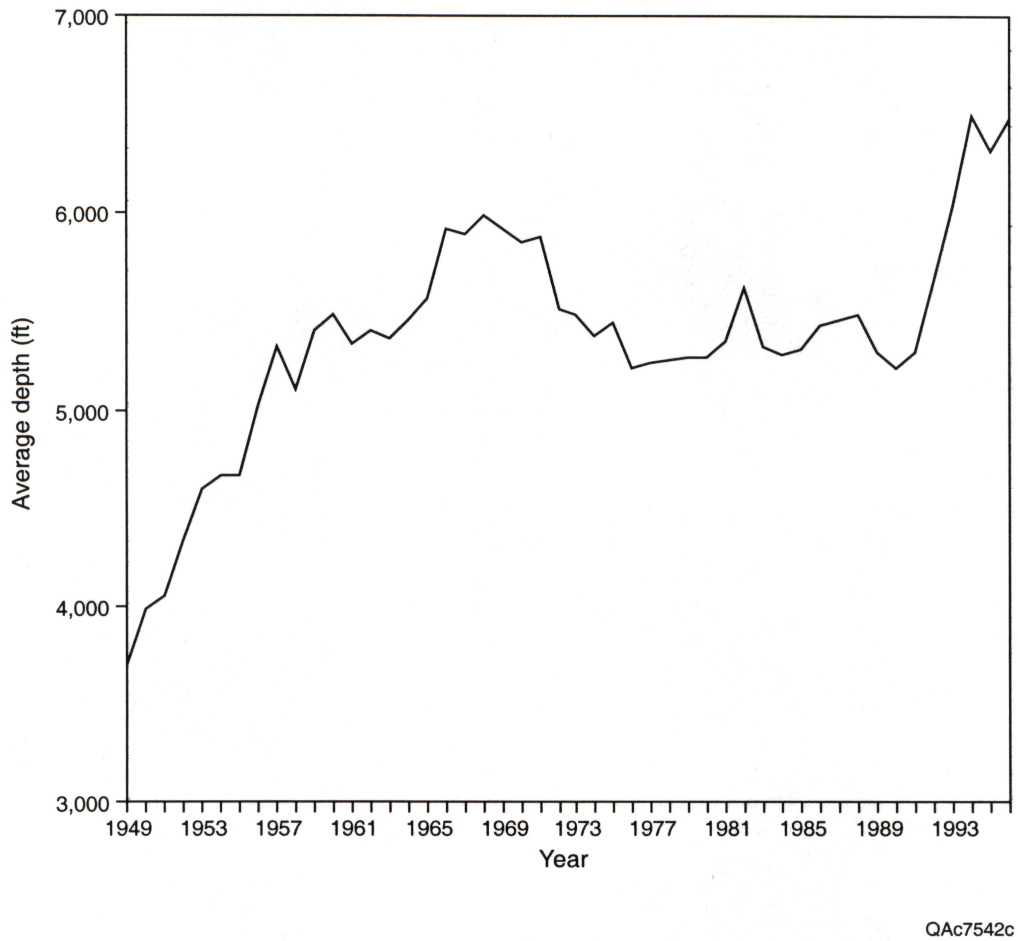


Figure 62. U.S. natural gas well average depths, 1949–1996 (Energy Information Administration, 1997a).

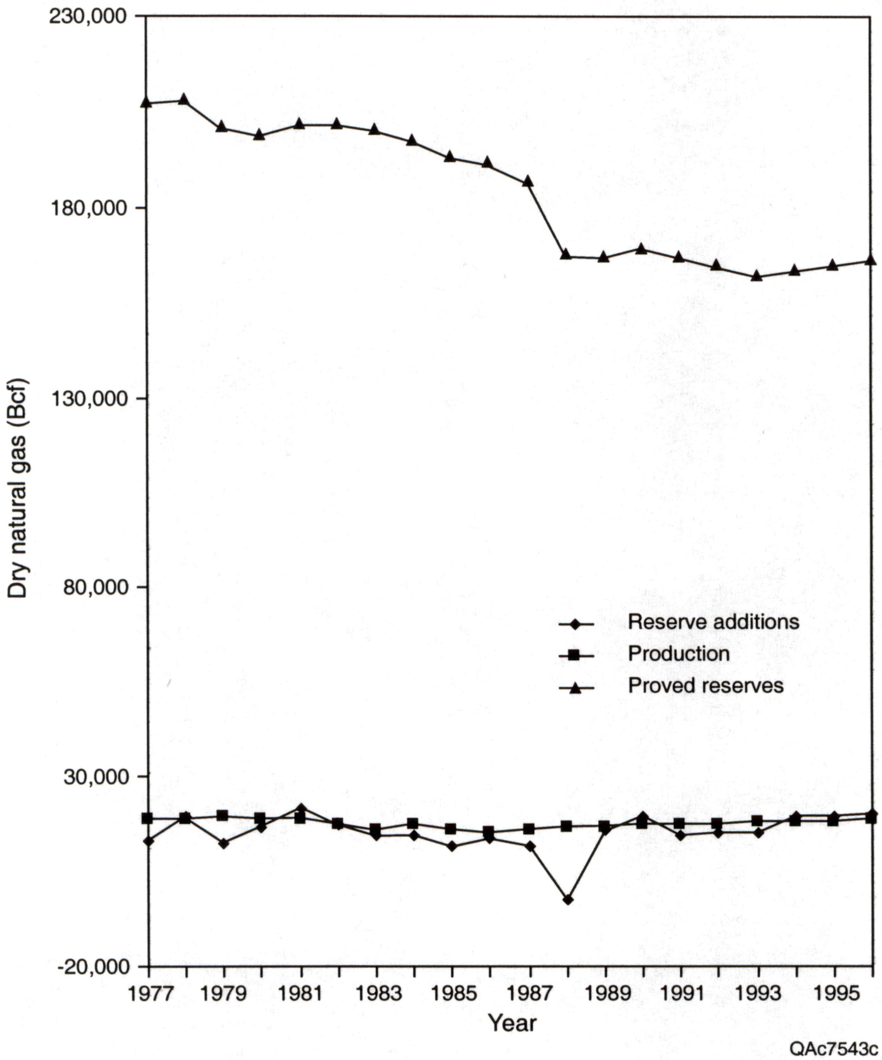


Figure 63. U.S. dry natural gas reserve additions, production, and proved reserves, 1977–1996 (Energy Information Administration, 1997b).

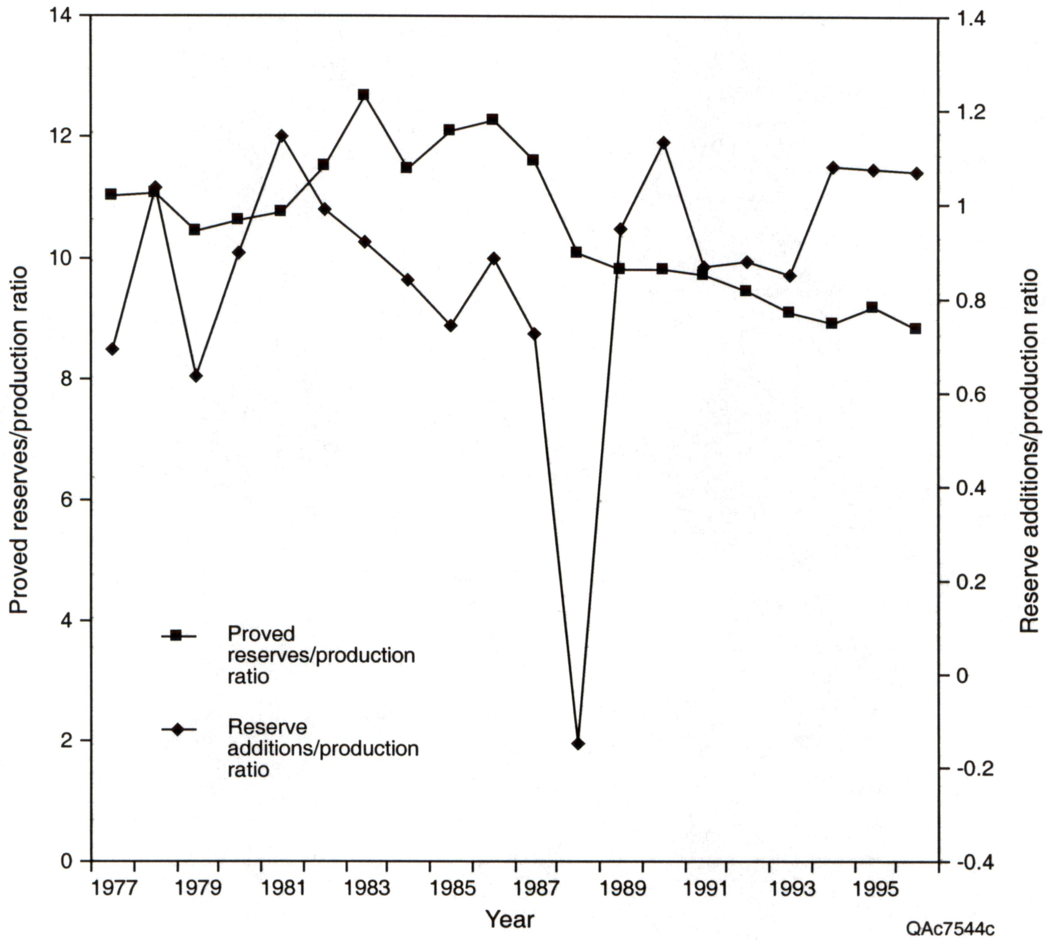


Figure 64. U.S. dry natural gas proved reserves/production ratio and reserve additions/production ratio, 1977–1996 (Energy Information Administration, 1997b).

reserves. However, the sustained natural gas supply made this argument less persuasive. Subsequently, arguments have been raised that the extra margin of reserve additions may be real but short lived. And yet this argument is also losing ground because natural gas reserve additions have actually replaced annual production since 1994 (Figures 65 and 66).

A trend of substance has been established since the middle 1980's. Essentially, necessity has proven to be the mother of invention and ingenuity. Survival during a period of low prices induced changed perceptions and strategies, and technology was vigorously applied as a substitute for price in increasing yields and reducing costs. High grading prospects and reduced drilling costs by a rig surplus probably played a role in the current trend. However, the current trend in U.S. natural gas supply has occurred and will continue for three fundamental reasons: (1) increased efficiency of exploration and development, as can be seen in the general maintenance or increase of reserve additions and discoveries with decreases in number of well completions (Figure 67) or in the steadily increasing gas-well-completion success rates (Figure 61) and yield per gas completion (Figure 68); (2) the realization that natural gas URG is much greater than was earlier thought and quite amenable to advanced technology, low-cost recovery, and rapid production response (Figure 69); and (3) steady advances of technology and its applications to nonconventional natural gas resources such as tight gas sands and coalbed methane (Fisher, 1993b).

ADVANCED TECHNOLOGIES APPLIED IN TEXAS GULF COAST BASIN AND EAST TEXAS PLAYS HAVING SIGNIFICANT ULTIMATE RECOVERY GROWTH POTENTIAL

Analysis has revealed that there is a wide range in URG potential by play and that the realization of that potential is a function of drilling and technology applied. Detection technology, locational diagnostics, horizontal drilling, directional drilling, hydraulic fracturing technology, measurement while drilling (MWD), advanced drilling bits, 3-D seismic, and

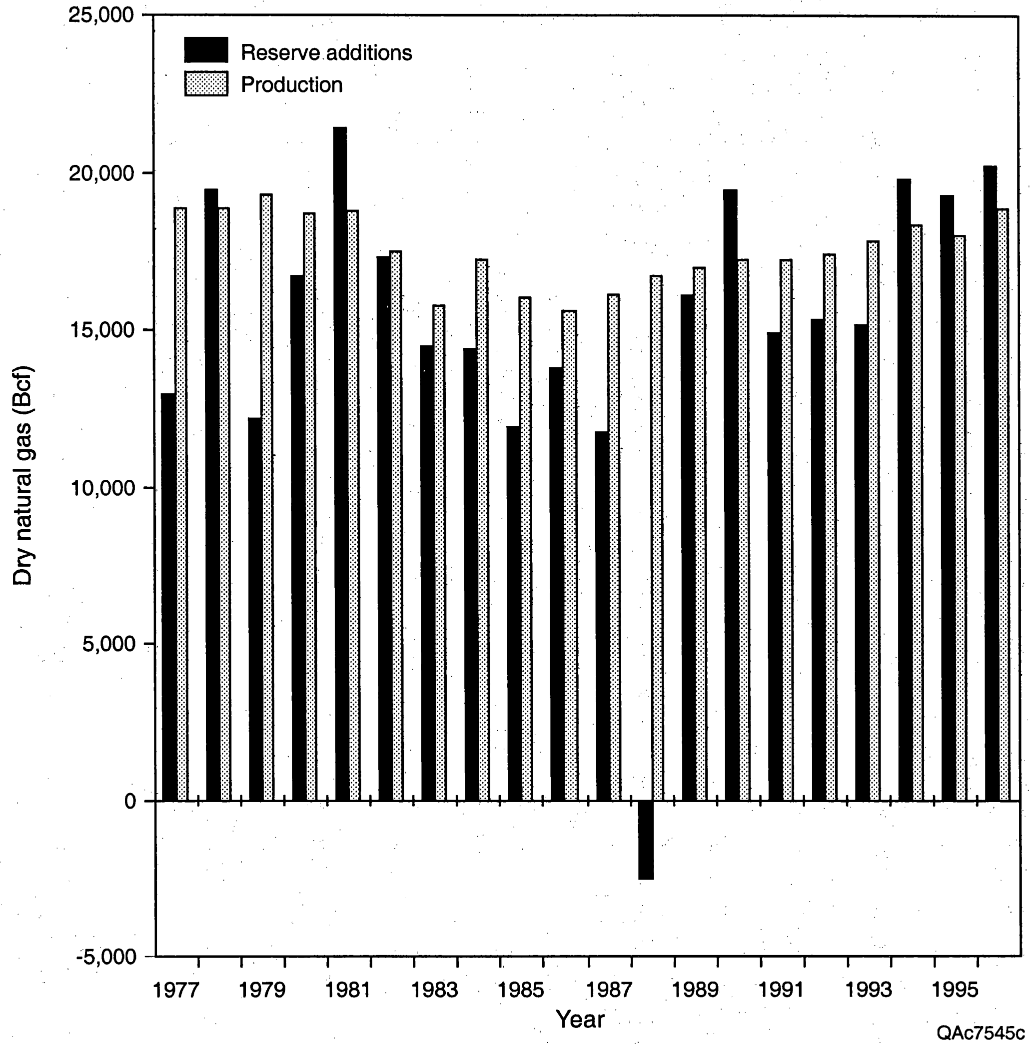


Figure 65. U.S. replacement of annual dry natural gas production through reserve additions, 1977–1996 (Energy Information Administration, 1997b).

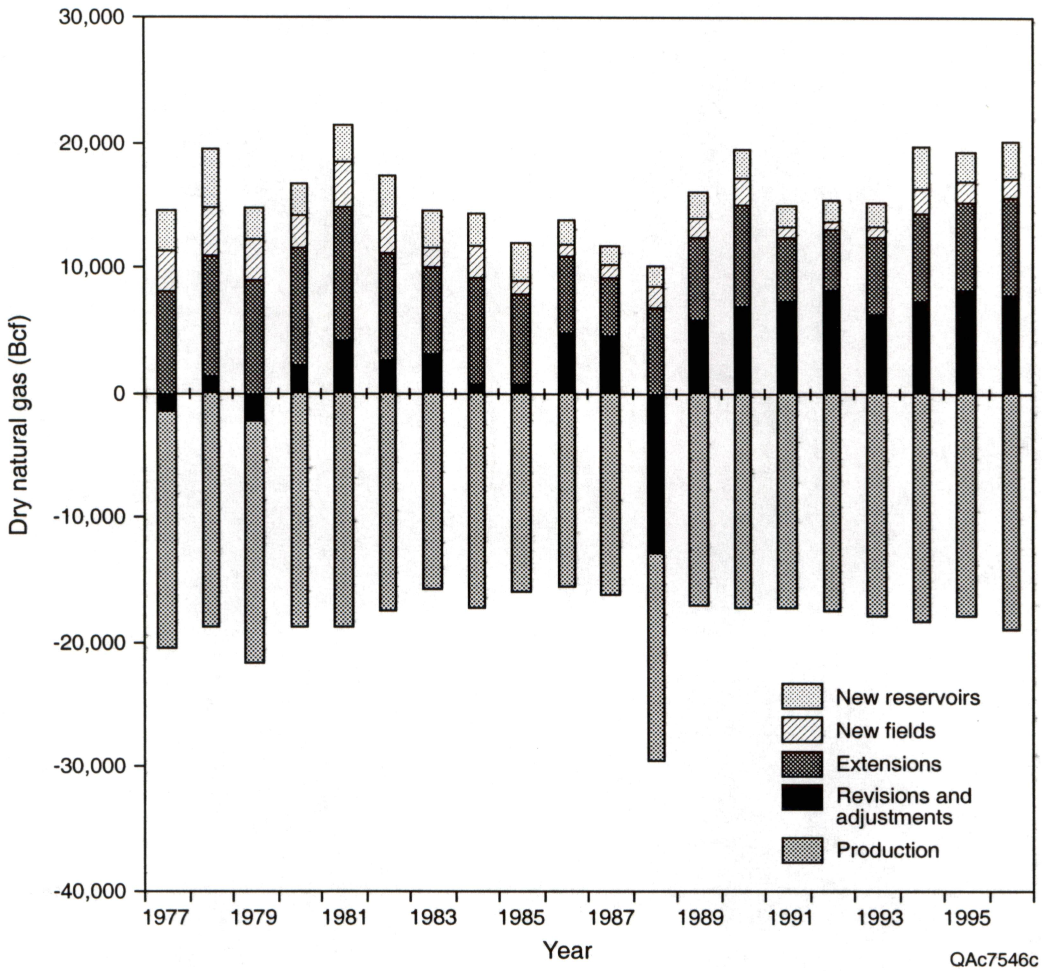


Figure 66. U.S. composition of dry natural gas proved reserve changes, 1977–1996 (Energy Information Administration, 1997b).

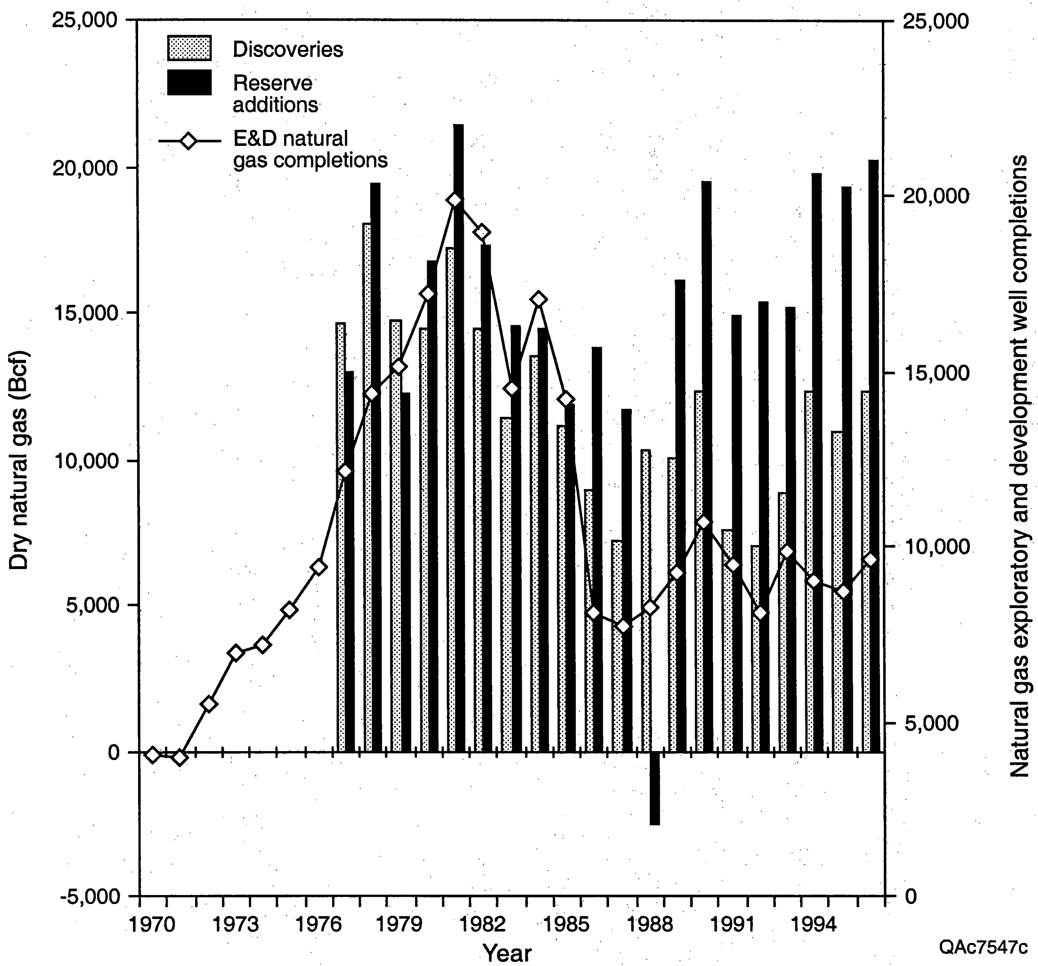


Figure 67. U.S. annual dry natural gas discoveries, reserve additions, and exploratory and development well completions, 1970–1996 (Energy Information Administration, 1997b).

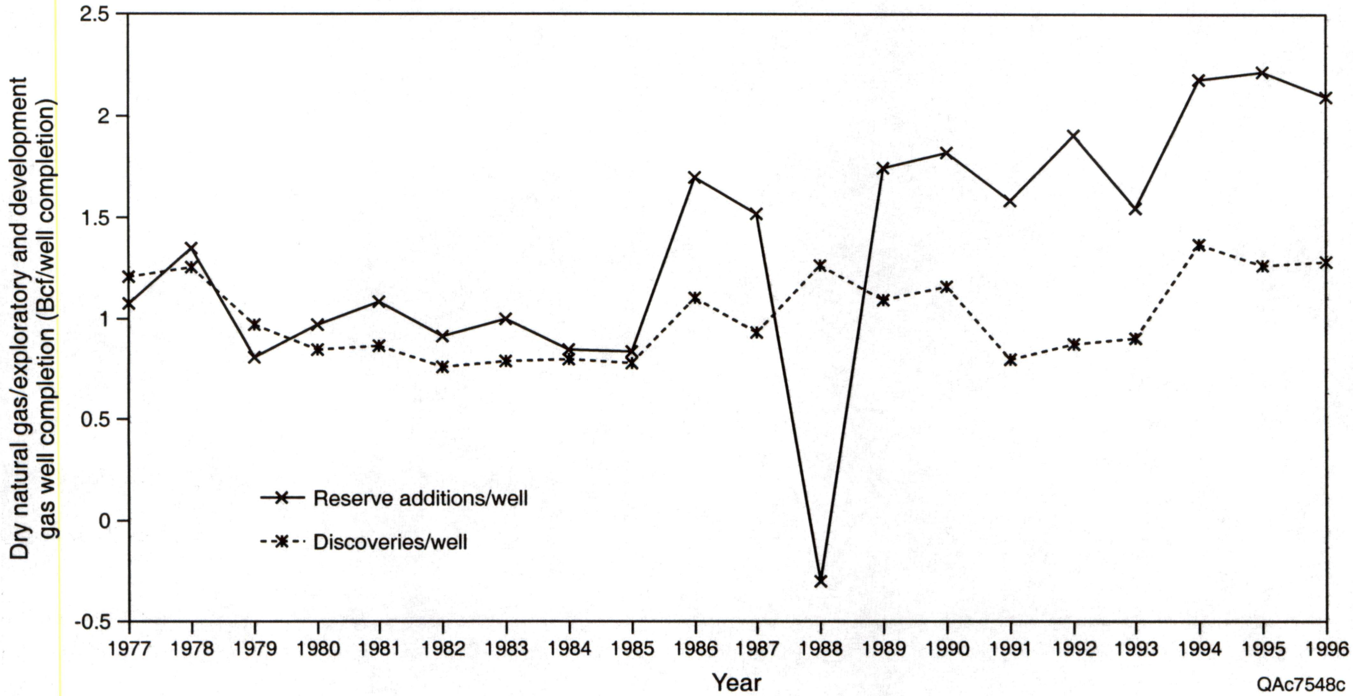


Figure 68. U.S. dry natural gas reserve additions and discoveries per exploratory and development well completion, 1977–1996 (Energy Information Administration, 1997b).

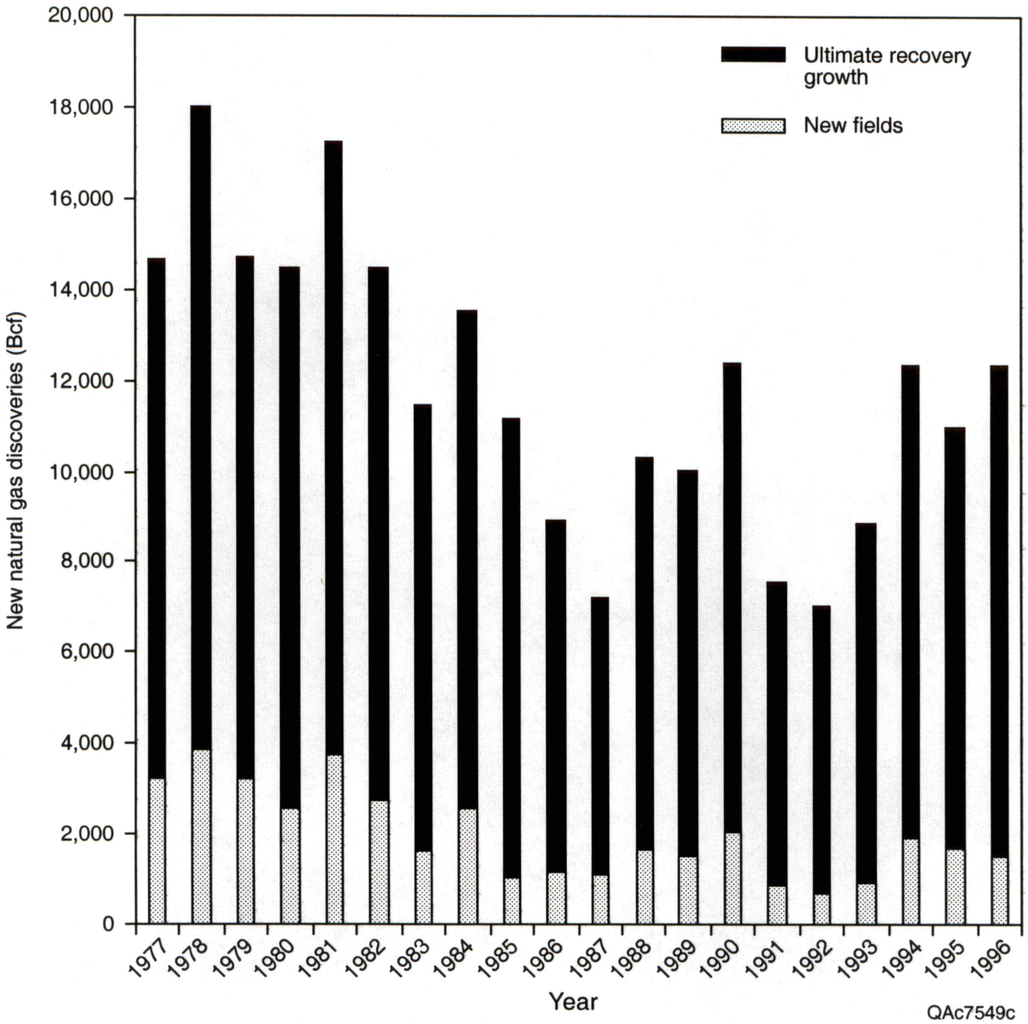


Figure 69. U.S. composition of new dry natural gas discoveries, 1977–1996 (Energy Information Administration, 1997b).

amplitude versus offset (AVO) are just a few technological advances that have led to an increase in exploration and development efficiency.

Advances in geophysical detection technology and modern basin analysis have led to an increase in exploration efficiency sufficient to offset the depletion effects of declining field size, and we see the initial impacts of detection and other technologies in field development, particularly in URG, of older, large fields. These impacts include improved economics through reducing dry-hole risks, lowering the unit cost of exploration and development, and improving knowledge and understanding of the applications of advanced technologies to particular reservoirs. A better understanding of current advanced technologies, their impacts, and play-specific amenability must be sought. Although various advanced technologies are currently being applied in the Texas Gulf Coast Basin and East Texas to increase ultimate recovery of oil and natural gas, the three most crucial—3-D seismic imaging, hydraulic fracturing technology, and horizontal/directional drilling—will be specifically analyzed.

3-D SEISMIC IMAGING

One of the most significant technologies applied in the Gulf Coast Basin and East Texas to increase ultimate recovery is 3-D seismic imaging. Its primary function is to reduce exploration and development risk by gaining a clearer image of the reservoir, trapping mechanisms, and fluid contents. Major applications have occurred in exploring for small structures, resolution of complex structures, and direct detection of oil and natural gas.

Reflection seismology uses sound waves propagated into the Earth and reflected back to the surface to infer the structure and properties of the subsurface. Such techniques have been utilized since the 1920's in two dimensions (2-D), but their true value has just recently been realized in the 1980's through the development and application of the technique in three dimensions (3-D). Compared with 2-D seismic, 3-D seismic imaging provides a better picture of the composition and structure of the subsurface. Higher resolutions of the subsurface improve our ability to locate oil and natural gas, to determine the characteristics of reservoirs for optimal development, and to help determine the best methodology for development. Moreover, exploration of smaller reservoirs and identification of isolated traps not yet exploited in mature fields and reservoirs beneath salt layers are improved as compared with results obtained with 2-D seismic.

The major difference between 2-D and 3-D seismic imaging technology is that a 2-D seismic survey collects data along a given azimuth of the Earth's surface to interpret a vertical cross section of the Earth beneath the azimuth and a 3-D seismic survey collects data over an area of the Earth's surface to interpret a volume of Earth beneath that surface area. The multiple receivers utilized to collect data over the area in 3-D seismic survey record an enormously increased number of data as compared with those in 2-D seismic surveys. Increased data results in the improved resolution of 3-D seismic imaging. Although the concept of 3-D seismic imaging was developed prior to the 1980's, it wasn't until the early 1980's that its potential was fully realized. This realization and application came along with the complementary development of sufficient computing power and analytical software able to process and interpret the increased data volumes of 3-D seismic surveys (Bohi, 1997).

Utilizing 3-D seismic data, we can construct a three-dimensional model of the Earth's subsurface. A vertical section results in an improved cross section of the subsurface. Horizontal sections, referred to as time slices because they represent different time periods in which the sediments were deposited, can reveal depositional elements and events through time that are not possible to interpret through 2-D seismic data alone.

Furthermore, 4-D seismic monitoring is an emerging technological application of 3-D seismic imaging that holds great potential as a production management system. 4-D seismic monitoring of oil and natural gas drainage from the reservoir is an integrated exploration and production technology. It requires not only the static description of reservoir geometry, but also the dynamic description of fluid and pressure changes in the reservoir that occur during production activities. To delineate these changes and introduce time dependence, the geological, geophysical, and engineering data obtained during both exploration and production phases need to be integrated. On the basis of changes in that data over time, a quantitative reservoir simulation is constructed through use of both inverse and forward seismic models of 4-D seismic differences that can be iteratively recomputed and compared with the reservoir simulations. Dynamic changes in the reservoir can be monitored and simulated efficiently, and the results can then be used to explain and predict drainage occurring during production. New wells can then be placed to maximize the lives of oil and natural gas fields in order to achieve the highest recovery rates possible (He and others, 1996; Anderson, 1998).

Although the benefits of 3-D seismic over 2-D seismic are enormous, its application was slowly realized owing to the costs involved in acquiring and interpreting 3-D seismic data. Initially the cost associated with 3-D seismic surveys was at least three times that of a 2-D survey because of increased acquisition and computing costs. 2-D seismic surveys were utilized to survey broad areas, and 3-D seismic was limited to development applications. However, the cost of 3-D seismic surveys has been decreasing as a result of improvements in technology, increased competition, and as the benefits to exploration are becoming better appreciated. Furthermore, additional reserves identified and the reduction of dry-hole and completion costs have more then leveled the economics related to 3-D seismic application in both exploration and development.

Although comprehensive data to calculate the precise technological impacts of 3-D seismic-imaging technology do not exist, several anecdotal experiences compiled and published by companies do exist (Fuller and Major, 1982; Nestvold, 1992; Jeffers and others 1993; Aylor, 1995; Koen, 1995; McWhorter and Torguson, 1995; Fisher, 1996; Shirley, 1998). Combining these experiences provides a good measure of the technological impacts of 3-D seismic imaging. Moreover, in addition to the increased benefits in exploration and development, 3-D seismic imaging provides the necessary resolution for directional drilling, horizontal drilling, and hydraulic fracturing technology to be applied more efficiently.

A comparison of results from 2-D and 3-D seismic data of relatively low risk development drilling in the South Texas Lower Wilcox Trend (equivalent to play WX-2) was compiled by Mobil. Of the 69 wells drilled during 1991–2, 32 were based on 2-D seismic data and 37 on 3-D seismic data. Historic success rates for development drilling in this area were 72 percent when drilling was based on 2-D seismic data. With the utilization of 3-D seismic data, development drilling success rates rose to 84 percent. The increased accuracy of 3-D seismic led to better drilling locations and reduced dry-hole costs. The average 3-D seismic well resulted in 14 percent more reserves than that of an average 2-D seismic well, not counting dry holes, or 37 percent more reserves, including dry holes. After deduction of the added costs of the 3-D seismic, the net present value from 3-D seismic wells was double that of 2-D seismic wells (Jeffers and others, 1993).

In 1992, Mitchell Energy decided to supplement its 2-D seismic survey of Palacios field (play FR-6) in the Texas Gulf Coast Basin with 3-D seismic. 3-D seismic imaging revealed a much different fault pattern than that thought to exist on the basis of 2-D seismic data and earlier experience. The new information enabled a reconstruction of the geological history of the field and its depositional structure, thereby enabling the operator to avoid drilling more unsuccessful wells. Through the structural characteristics of the newly discovered fault pattern, it was realized that much of the area under consideration for additional drilling was subject to drainage and pressure depletion from wells already drilled. Therefore, plans to drill more wells were avoided, at a savings of three times the cost of the 3-D seismic survey (McWhorter and Torguson, 1995).

On the basis of 2-D seismic information, we found that prospective development of Seeligson field (play FR-4) in the Texas Gulf Coast Basin would involve 31 wells at a cost of $18.6 million. On the basis of a 3-D seismic-interpreted reservoir characterization model, we found that optimal development could be accomplished with only eight wells at a cost of $5.4 million. Moreover, under the new model, 10 percent more of the hydrocarbons in place would be recovered at one-fourth the average cost of the original development plan, which was based only on 2-D seismic (Fisher, 1996).

The Cotton Valley reef play (equivalent to play JC-2B) in East Texas has been one of the hottest exploration plays, and 3-D seismic has driven the play since the very beginning. Until the emergence of 3-D seismic-imaging technology, the relatively small, steep-sided reefs were virtually impossible to image in the subsurface. After several years of drilling in the play, operators are now finding innovative ways to apply 3-D seismic and other state-of-the-art techniques. Sonat Exploration, one of the earliest participants in the Cotton Valley reef play, has developed a method of combining surface 3-D seismic with offset vertical seismic profiling to define the reef structures more precisely and increase drilling success rates. Utilizing such techniques, Sonat has been successful on 13 out of 14 wells in Bear Grass field, equivalent to a 92-percent success rate (Shirley, 1998).

HYDRAULIC FRACTURING TECHNOLOGY

Hydraulic fracturing technology is utilized to increase access of the well bore to the formation. Major applications have been in low-permeability (tight) natural gas formations. Low-permeability (tight) natural gas reservoirs usually have an in situ permeability to natural gas, exclusive of fracture permeability, of less than 0.1 millidarcy (md). In contrast to conventional natural gas accumulations where natural gas is concentrated in structural or stratigraphic traps, natural gas in tight reservoirs occurs as regionally pervasive accumulations that are usually abnormally pressured and are mostly independent of structural and stratigraphic traps. Artificial stimulation, such as hydraulic fracturing, is usually needed in order to produce natural gas unless extensive fracturing is present. As a consequence of improved hydraulic fracturing technology and knowledge of tight gas reservoirs, natural gas from these reservoirs is rapidly emerging as a major source component in the U.S., particularly in certain plays of the Texas Gulf Coast Basin and East Texas. Other applications of hydraulic fracturing technology are for areas near well-bore damage, for reducing skin damage and for connecting heterogeneities (Law and Spencer, 1993).

Hydraulic fracturing involves injecting a slurry of a proppant, usually well-sorted, clean sand, suspended in a liquid medium. The mixture is injected at a pressure higher than the natural fracture gradient of the reservoir rock so that cracks will propagate away from the well bore in two directions oriented 90° to the minimum stress direction. The ideal hydraulic fracturing technology is one that will connect the well bore to the natural fracture system in the least damaging manner (Law and Spencer, 1993).

Although hydraulic fracturing technology works well in blanket reservoirs and near-tight reservoirs, lenticular sandstone reservoirs pose problems. One of the problems associated with lenticular sandstone reservoirs during hydraulic fracturing was the inability to create cross fractures that effectively connect the dominant, through-going fracture set. This inability results in an anisotropic drainage pattern with little or no natural gas production perpendicular to the dominant fracture direction. The general recognition of the importance of natural fractures to natural gas recovery has focused attention on attempts to intersect the fracture system with horizontal or slant (inclined) wells. Horizontal and slant well bores can intersect more open, vertical fractures than a vertical well can (Lorenz and Hill, 1991).

The Lobo tight-gas trend (equivalent to play WX-2) in the Texas Gulf Coast Basin is a major area of low-permeability (tight) natural gas resources in the U.S. Initial hydraulic fracturing methodologies applied were massive. These methodologies were intended to create fractures that would propagate in lengths of 2,000 to 4,000 feet, utilizing proppant volumes of more than 300,000 lb. Such methodologies worked fairly well in blanket reservoirs where the reservoir is bounded above and below by shales that have a much higher fracture gradient than the objective reservoir. However, in other types of reservoirs, such methodologies have not worked well because the fractures propagate unpredictably. Moreover, proppant embedment into the interbedded shales during fracturing reduced natural gas flow rates (Spencer, 1989). Improved hydraulic fracturing technology and better understanding of the natural fracture system enabled Mobil to reduce well costs by 35 to 40 percent in the Lobo tight-gas trend and increase recovery efficiencies to 1 to 2 Bcf per well (Kuuskraa, 1994).

Pearsall field in the Austin Chalk trend (equivalent to play KG-2) produces via a complex system of vertically oriented natural fractures. The advent of hydraulic fracturing technology allowed a mechanism for connecting the well bore to the fracture system. Compared with the past when wells were drilled using open-hole completions, today hydraulic fracturing has lowered the risk of drilling a dry hole. Hydraulic fracturing technology was responsible for the additional development in Pearsall field, increasing recovery efficiencies in reservoirs (Caldwell and Heather, 1997). Moreover, used in conjunction with horizontal drilling, hydraulic fracturing has continued production and development in a mature play once thought to have little opportunity for URG.

HORIZONTAL/DIRECTIONAL DRILLING

Horizontal/directional drilling increases access and exposure to the reservoir. Its major applications have been in fracture finding, water/gas coning control, recovery rate improvement, and thin oil columns. Current drilling technology enables drillers to guide a drill string, with a motor at the end to turn a drill bit at all angles from vertical, including a 90° angle, so that the well bore intersects the reservoir from the side rather than above as with traditional vertical wells.

The potential advantages of horizontal/directional drilling have been appreciated for many years. However, its application was dependent on the development of several complementary technologies such as advances in downhole drilling motors, drill bits, downhole sensors, telemetry equipment, and 3-D seismic imaging. Current, sophisticated, downhole drilling motors are usually accompanied by a variety of sensors located behind the drill motor, which are called the "measurement-while-drilling" (MWD) package. In the MWD package, sensors are included that measure bottom-hole temperature and pressure, drill-bit rotation speed and torque, and physical characteristics of the surrounding rock such as fluid content and radioactivity. Radiation readings are utilized to determine the location of the drill bit in the rock layers, and fluid content is determined by the resistivity of rocks and their accompanying fluids. The information can be transmitted to the surface by fluid pulse telemetry in which the data are recorded in fluid pulses that are transmitted up the well bore through the drilling mud (Bohi, 1997). Moreover, 3-D seismic imaging allows the subsurface to be revealed in scales of resolution sufficient for such "steering" of the drill bit.

Horizontal/directional drilling is most advantageous when reservoir conditions require greater contact between the well bore and the reservoir formation. For example, a reservoir may contain a thin pay zone, low-permeability formations, vertically fractured formations, or heavy oil. Horizontal/directional drilling is also used for reentry into depleted and abandoned reservoirs. Economics and risks associated with the application have been impediments to horizontal/directional drilling. Costs of horizontal/directional wells are generally higher than those of vertical wells. However, on a per-footage basis, they cost approximately 10 to 20 percent more than vertical wells (Bohi, 1997). Although added costs are associated with horizontal/directional drilling, these costs have been more than justified through increased recovery efficiencies. Costs of horizontal/directional drilling have been falling as the recognized benefits have been rising.

Greater risks are associated with horizontal/directional drilling because it requires the use of more sophisticated techniques than does vertical drilling. The primary risk deals with the buildup of compression that causes increased contact with the walls of the borehole, leading to higher friction, drag, rotating torque, sinusoidal buckling, and lockup. Risks are also increased for reservoir damage that results in drilling mud leaving the formation less permeable to the flow of oil and natural gas.

The impacts of horizontal/directional drilling technology have been seen in recovery rate increases and cost reduction. Horizontal/directional drilling has higher associated costs, but on average will produce two to five times the rate of output of a conventionally drilled well in the same area (Butler, 1988; Offshore 1995). Moreover, one horizontal/directional well frequently replaces between two and five vertical wells in suitable reservoirs (Offshore, 1993). Reduction in cost premium, combined with reduction of number of wells, has led to a significant increase in the application of horizontal/directional drilling.

The Austin Chalk trend (equivalent to play KG-2), has been a traditional "hotspot" for horizontal/directional drilling applications. The Austin Chalk trend is an extensive oil- and natural-gas-bearing limestone formation characterized by vertical fractures that allowed oil and natural gas to migrate from below the formation up into the limestone. The fractures can be accessed one at a time by conventional, vertical wells targeting relatively small reservoirs. A horizontal/directional well drilled to intersect several vertical fractures at the same time offers more opportunities to offset its higher associated costs.

Giddings field has been the most prolific field in the Austin Chalk trend. Although the field was discovered in 1961, major URG occurred in the mid-1980's with the advent of horizontal/directional drilling technology applications to connect multiple vertical fracture systems with the same well bore. Amoco drilled eight horizontal/directional wells into Giddings field in 1987–1989 and compared its recovery rates with the production histories of vertical wells completed in the same time period and with equal pressure conditions. Horizontal/directional wells had recovery rates between two and one-half and seven times higher than those of vertical wells (Shelkkholeslami and others, 1991). Other operators also reported higher recovery rates, rapid payback on investments, and higher rate of internal returns for projects involving horizontal/directional drilling in Giddings field (Maloy, 1992; Koen, 1996).

PLAY-SPECIFIC AMENABILITY OF ADVANCED TECHNOLOGIES

Various advanced technologies are currently being applied in the Texas Gulf Coast Basin and East Texas to increase ultimate recovery of oil and natural gas. The three most crucial advanced technologies are 3-D seismic imaging, hydraulic fracturing technology, and horizontal/directional drilling. Play-specific amenability of these advanced technologies depends largely on the play's geological complexity. Geological complexity arises because both structural and stratigraphic heterogeneities induce natural gas mobility constraints.

We know, for instance, that areas such as the northern margin of the Texas Gulf Coast Basin have vertically stacked reservoirs associated with growth faults and compartmentalized reservoirs associated with domal salt structures. These producing environments are especially amenable to several new technologies, such as directional drilling and 3-D seismic imaging, and have been major sources of URG. We also know that pervasively saturated, low-permeability (tight) formations are amenable to hydraulic fracture technology and horizontal/directional drilling and have shown remarkable URG. Certain plays with little natural gas mobility constraint have achieved high rates of conventional recovery and offer little URG potential, whereas plays with geologically complex reservoirs show low conventional recovery and offer large potential.

Play-specific amenability of application of advanced technologies, such as 3-D seismic imaging, hydraulic fracturing technology, and horizontal/directional drilling to achieve URG in the Texas Gulf Coast Basin and East Texas, is shown in Table 34. A scale of 1 (low) to 5 (high) was assessed to the major plays of the Texas Gulf Coast Basin and East Texas after review of their geology in terms of depositional environments and the current status of the technological applications utilized by operators in successful fields.

Table 34. Play-specific amenability of application of advanced technology to achieve ultimate recovery growth (1 = low, 5 = high).

	Play	Play name	3-D seismic	Hyraulic fracturing	Horizontal/directional
Texas Gulf Coast Basin:	MC-3	Miocene Lower Coastal-Plain Sandstone, San Marcos Arch	1	1	1
	MC-4	Miocene Barrier/Strandplain Sandstone, San Marcos Arch	1	1	1
	MC-5	Miocene Sandstone, Houston Embayment	1	1	1
	FR-1	Distal Frio Deltaic Sandstone, Rio Grande Embayment	2	1	1
	FR-2	Frio Delta-Flank Shoreline Sandstone, Rio Grande Embayment	2	1	1
	FR-3	Proximal Frio Sandstone, Rio Grande Embayment	1	1	1
	FR-4	Frio Sandstone, Vicksburg Fault Zone	3	1	1
	FR-6	Downdip Frio Barrier/Strandplain Sandstone, San Marcos Arch	2	1	1
	FR-7	Updip Frio Barrier/Strandplain Sandstone, San Marcos Arch	2	1	1
	FR-8	Frio Fluvial/Coastal-Plain Sandstone, San Marcos Arch	1	1	1
	FR-9	Frio Sandstone, Houston Embayment	2	1	1
	FR-10	Frio Sandstone, Hackberry Embayment	2	1	1
	VK-1	Vicksburg Sandstone, Rio Grande Embayment	4	3	3
	EO-3	Yegua Sandstone, Houston Embayment	3	2	2
	EO-4	Yegua/Jackson Sandstone, Rio Grande Embayment	3	2	2
	WX-1	Wilcox Sandstone, Houston Embayment	4	3	3
	WX-2	Wilcox Lobo Trend	5	5	5
	WX-4	Wilcox Sandstone, Rio Grande Embayment	4	3	3
	KG-1	Lower Cretaceous Carbonate	2	2	2
	KG-2	Austin/Buda Chalk	4	5	5
	KG-4	Olmos Sandstone	3	3	3
East Texas:					
	KS-2	Upper Cretaceous Sandstone, Salt Structures	3	1	1
	KS-3	Upper Cretaceous Sandstone, Downdip Shelf Margin	1	1	1
	KC-1	Trinity Group Carbonate, Sabine Uplift	1	1	1
	KC-2	Trinity Group Carbonate, East	1	1	1
	KC-3	Trinity Group Carbonate, West	1	1	1
	KJ-1	Travis Peak Formation-Cotton Valley Group Sandstone, Sabine Uplift	4	5	4
	KJ-2	Travis Peak Formation-Cotton Valley Group Sandstone, East	4	5	4
	KJ-3	Travis Peak Formation-Cotton Valley Group Sandstone, West	4	5	4
	JC-1C	Smackover Carbonate, Salt Structures	3	1	2
	JC-2B	Cotton Valley Lime, West	4	4	4

Economic Limits of Ultimate Recovery Growth Potential

Significant natural gas URG potential exists in the Texas Gulf Coast Basin and East Texas. Specific plays have been identified as holding significant URG potential, whereas others show little or no growth. Plays that hold significant URG potential are largely technology-driven plays. Play-specific amenability of advanced technologies such as 3-D seismic, hydraulic fracturing, and horizontal/directional drilling has been determined. Although certain plays hold significant URG potential, they are bounded by economic limits.

As discussed previously in Figure 38, a general relationship exists between drilling activity and ultimate recovery. Intuitively the curve should go through the origin because no drilling activity produces no results. Furthermore, the curve for drilling activity and its ultimate recovery must rise, first steeply, and then more gently. Finally asymptotically it reaches the ultimate resource recoverable as the number of producing well completions approaches infinity. The ultimate resource recoverable, being a fraction of the resource base, represents all the resources that could be recovered if there were no economic limit on the number of well completions drilled. However, long before the ultimate resource recoverable is reached, the economic limit will prevent further drilling activity. The slope of the cumulative number of well completions versus ultimate recovery represents the incremental ultimate recovery per well completion and can be used to determine the economic limit by converting ultimate recovery and well completions to their corresponding dollar values. Well completions will be made until the economic limit is reached, where the value derived from URG is equal to the cost of incremental well completions.

The value of incremental recovery was calculated utilizing a natural gas price of $2.50 in the year 2000, escalating at 1 percent per year. EIA's 1998 U.S. well equipment and operating costs were utilized as the incremental cost per well completion (Table 35). These well costs were

Table 35. 1998 EIA U.S. well equipment and operating costs (EIA, 1999).

Depth (ft)	Equipment Cost	Operating Cost	Total Per Well Cost
2,000	$20,600	$11,800	$32,400
4,000	$28,100	$16,600	$44,700
8,000	$47,100	$26,900	$74,000
12,000	$64,000	$33,800	$97,800
16,000	$80,800	$40,500	$121,300
Average	$48,120	$25,920	$74,040

escalated at 2 percent per year for the future forecasts. Play-specific average depths of historical well completions were utilized to assign a well-completion, depth-related incremental well cost (Table 36). As expected, plays with deeper historical well completions have higher incremental well costs.

One aspect of technology advancement is its role in reducing well costs. A reduction in well costs is achieved both by the actual reduction in the per-well costs, and by a reduced number of well completions required to exploit the URG potential. Reduced well costs in turn increase the economic limit, thereby allowing more resources to be converted to reserves. Another aspect of the role of technology is its shifting of the curves developed for URG as a factor of drilling. Because fewer wells are required, the slope of the curve, which is an expression of yield per effort, increases. The total volume of URG thereby increases, as well as its rate.

Extrapolation of historical drilling trends was utilized to forecast future well completions. Data of cumulative well completions plotted by time were fitted to a logarithmic curve and extrapolated to the year 2030. These extrapolations are based on the assumption that the rate of technology advancements will continue in the future as the historical record. Play-specific extrapolations of the cumulative well completions in the Texas Gulf Coast Basin and East Texas (Figures 70 and 71) were performed.

Forecast well completions per year from 2000 through 2030 were input into the equations derived for the growth curves as a factor of drilling to determine URG achievable in the Texas Gulf Coast Basin and East Texas (Figures 39 and 40). Play-specific calculation was also performed (Table 37). By converting incremental ultimate recovery and well completions to their corresponding dollar values, we determined economic limits. The value of incremental recovery was calculated utilizing a natural gas price of $2.50 in the year 2000, escalating at 1 percent per year. Economic limits for play MC-3 (Miocene Lower Coastal-Plain Sandstone, San Marcos Arch) and KG-2 (Austin/Buda Chalk) existed prior to the year 2030 under the set assumptions. These two plays were forecast to have no URG potential beyond their economic limits. The

Table 36. Average well-completion depths by play and associated EIA 1998 U.S. well equipment and operating costs.

Play	Depth	Cost
Texas Gulf Coast Basin:		
MC-3	5,101	$74,000
MC-4	6,577	$74,000
MC-5	6,198	$74,000
FR-1	8,592	$97,800
FR-2	8,832	$97,800
FR-3	8,957	$97,800
FR-4	6,883	$74,000
FR-6	9,223	$97,800
FR-7	6,406	$74,000
FR-8	4,757	$74,000
FR-9	8,211	$97,800
FR-10	7,380	$74,000
VK-1	8,821	$97,800
EO-3	5,931	$74,000
EO-4	3,821	$44,700
WX-1	10,657	$97,800
WX-2	9,611	$97,800
WX-4	9,867	$97,800
KG-1	10,062	$97,800
KG-2	9,385	$97,800
KG-4	6,429	$74,000
East Texas:		
KS-2	4,154	$74,000
KS-3	9,285	$97,800
KC-1	6,544	$74,000
KC-2	6,501	$74,000
KC-3	9,184	$97,800
KJ-1	9,067	$97,800
KJ-2	9,610	$97,800
KJ-3	10,806	$97,800
JC-1C	9,513	$97,800
JC-2B	12,275	$121,300

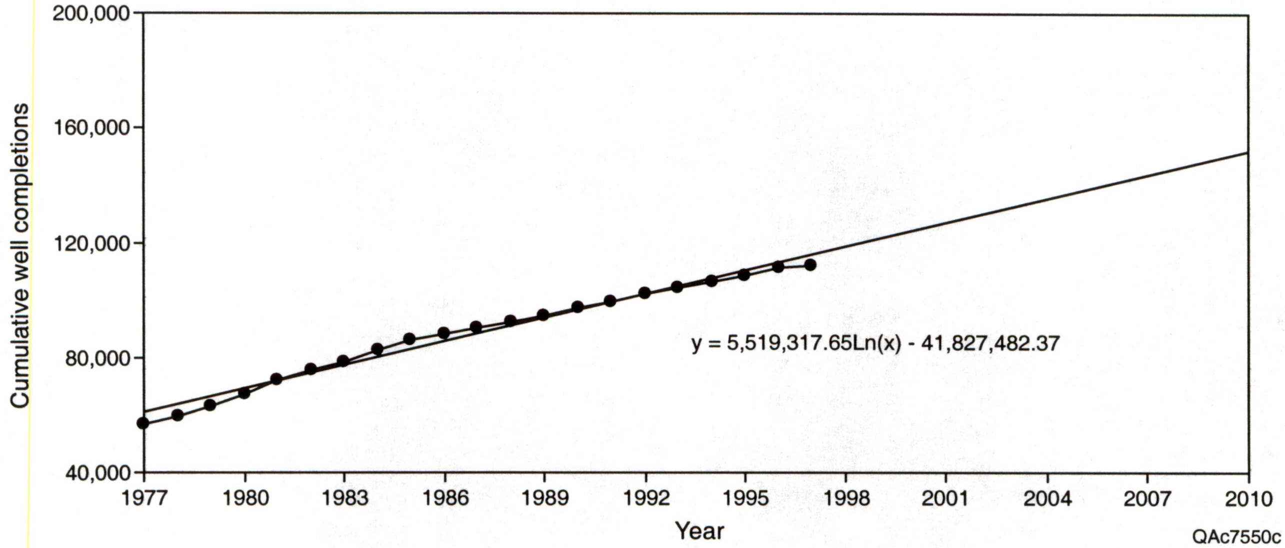


Figure 70. Historical and forecast cumulative well completions in total selected plays of the Texas Gulf Coast Basin.

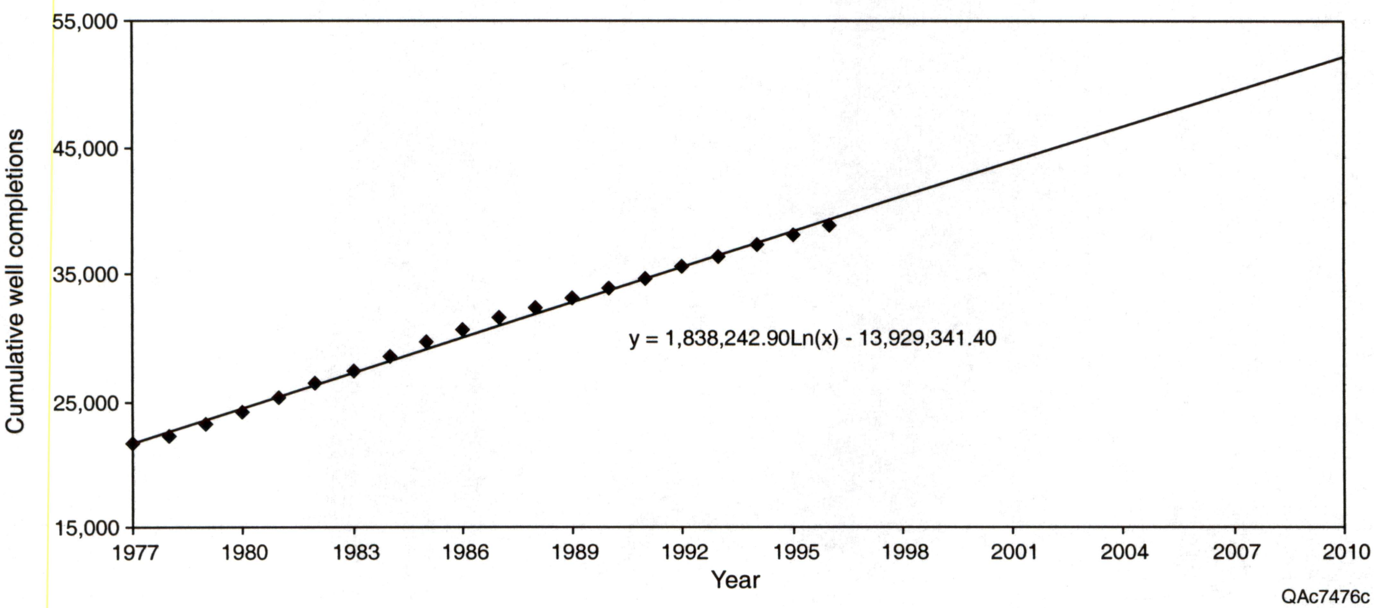


Figure 71. Historical and forecast cumulative well completions in total selected plays of East Texas.

Table 37. Economic summary of forecast incremental well completions and natural gas ultimate recovery growth by the years 2015 and 2030 in the Texas Gulf Coast Basin and East Texas.

Play	Inc. well comp. (2000-2015)	% of sum	2000-2015 URG	% of sum	Inc. well comp. (2000-2030)	% of sum	2000-2030 URG	% of sum	Economic limit
MC-3	282	0.64	9,162	0.07	282	0.33	9,162	0.04	Year 2002
MC-4	485	1.10	313,931	2.36	936	1.10	529,044	2.37	
MC-5	687	1.56	177,141	1.33	1,326	1.56	312,485	1.40	
FR-1	282	0.64	106,079	0.80	543	0.64	180,928	0.81	
FR-2	342	0.78	169,595	1.28	660	0.78	296,500	1.33	
FR-3	1,137	2.58	116,265	0.88	2,194	2.58	200,479	0.90	
FR-4	4,285	9.74	836,502	6.30	8,271	9.74	1,455,760	6.52	
FR-6	2,383	5.42	624,232	4.70	4,600	5.42	1,098,225	4.92	
FR-7	5,329	12.11	351,663	2.65	10,286	12.11	611,854	2.74	
FR-8	1,644	3.74	100,844	0.76	3,173	3.74	172,476	0.77	
FR-9	2,529	5.75	413,653	3.11	4,882	5.75	719,900	3.23	
FR-10	741	1.68	164,365	1.24	1,430	1.68	288,818	1.29	
VK-1	2,426	5.51	1,737,553	13.08	4,682	5.51	2,932,776	13.14	
EO-3	3,991	9.07	800,582	6.03	7,703	9.07	1,389,783	6.23	
EO-4	870	1.98	153,108	1.15	1,679	1.98	270,593	1.21	
WX-1	1,012	2.30	812,203	6.12	1,953	2.30	1,384,919	6.21	
WX-2	2,663	6.05	1,793,937	13.51	5,140	6.05	2,888,660	12.95	
WX-4	2,338	5.31	3,162,322	23.81	4,513	5.31	5,315,362	23.82	
KG-1	713	1.62	482,410	3.63	1,377	1.62	813,007	3.64	
KG-2	7,878	17.90	614,555	4.63	12,281	14.46	862,664	3.87	Year 2024
KG-4	1,721	3.91	341,506	2.57	3,321	3.91	578,549	2.59	
Total TX GCB	43,734	100.00	13,281,608	100.00	81,234	100.00	22,311,944	100.00	
KS-2	3,783	25.82	217,880	4.48	7,303	25.82	392,357	4.86	
KS-3	1,331	9.08	123,253	2.53	2,569	9.08	203,368	2.52	
KC-1	618	4.22	353,884	7.27	1,193	4.22	625,116	7.74	
KC-2	1,280	8.73	154,370	3.17	2,470	8.73	262,575	3.25	
KC-3	1,266	8.64	444,671	9.14	2,444	8.64	746,848	9.25	
KJ-1	3,705	25.28	1,766,647	36.31	7,151	25.28	2,870,226	35.53	
KJ-2	1,365	9.32	638,543	13.12	2,635	9.32	1,045,001	12.94	
KJ-3	717	4.89	498,686	10.25	1,385	4.89	813,267	10.07	
JC-1C	200	1.37	375,868	7.73	386	1.37	641,434	7.94	
JC-2B	389	2.65	291,365	5.99	751	2.65	477,444	5.91	
Total E TX	14,655	100.00	4,865,167	100.00	28,288	100.00	8,077,639	100.00	

Texas Gulf Coast Basin was forecast with 43,734 future incremental well completions, contributing to approximately 13 Tcf of URG by the year 2015. East Texas was forecast, with 14,655 future incremental well completions, contributing to approximately 5 Tcf of URG by the year 2015. URG forecast by the year 2030 in the Texas Gulf Coast Basin and East Texas was approximately 22 Tcf and 8 Tcf, respectively.

For the Texas Gulf Coast Basin, plays WX-4, VK-1, and WX-2 hold the greatest URG potential by the year 2030. These three plays comprise approximately 50 percent of the total natural gas URG potential in the Texas Gulf Coast Basin. For East Texas, the three Lower Cretaceous-Jurassic Sandstone (KJ) plays account for approximately 59 percent of the total natural gas URG potential by the year 2030.

Preliminary Plan for Extrapolation of Results

A realistic and play-specific measure of remaining URG potential by natural gas resource volume has been developed. Results obtained through the detailed natural gas URG analysis of the Texas Gulf Coast Basin and East Texas provide a tool for extrapolating the developed methodology to other oil and natural gas resource areas having significant growth potential. Areas of possible extrapolation include West Texas and North-Central Texas because these would complete the analysis of Texas, one of the major provinces of oil and natural gas resources in the U.S. Extrapolation to the Federal Offshore Gulf of Mexico (GOM) is also under consideration because of its importance in terms of oil and natural gas production, as well as its current industry activity and interest.

Texas and the Federal Offshore GOM are major natural gas provinces in the United States. In terms of natural gas proved reserves and annual production, Texas and the Federal Offshore GOM account for approximately 40 and 52 percent, respectively (Figures 72 and 73).

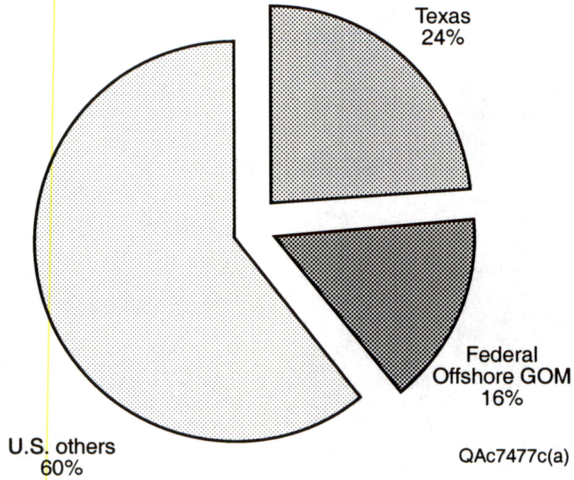


Figure 72. Composition of U.S. natural gas proved reserves, as of 12/31/98 = 172,443 Bcf (Energy Information Administration, 1999).

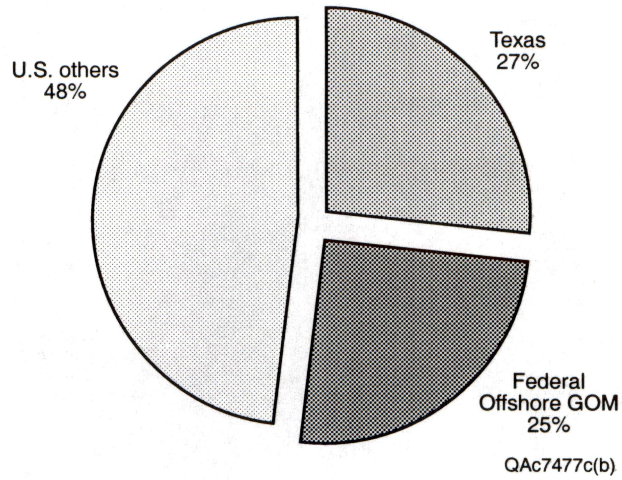


Figure 73. Composition of natural gas production in the U.S., 1998 = 19,622 Bcf (Energy Information Administration, 1999).

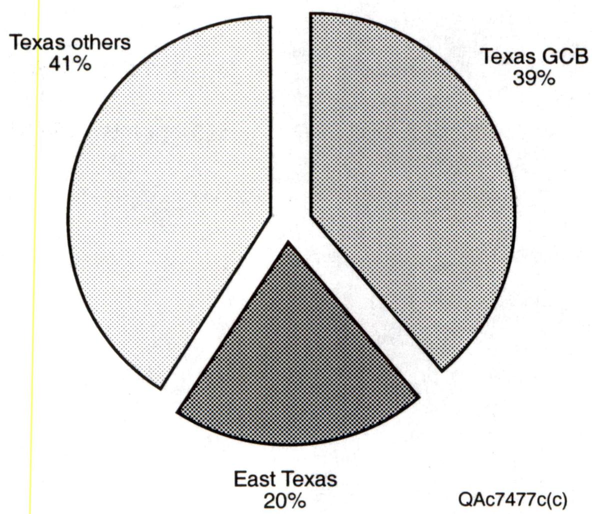


Figure 74. Composition of Texas natural gas proved reserves as of 12/31/98 = 40,793 Bcf (Energy Information Administration, 1999).

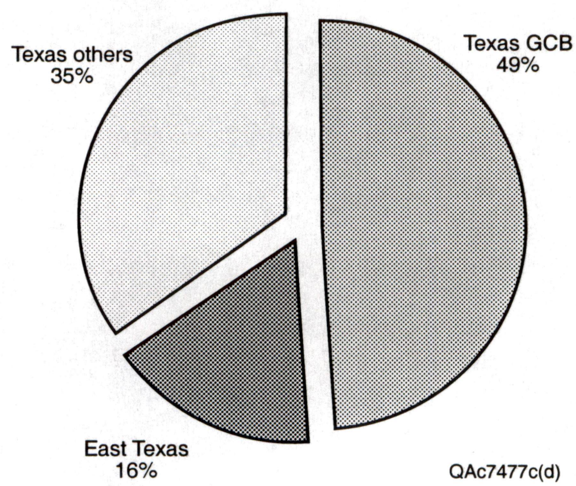


Figure 75. Composition of Texas natural gas production, 1998 = 5,242 Bcf (Energy Information Administration, 1999).

Within Texas, excluding the Texas Gulf Coast Basin and East Texas, 41 and 35 percent of natural gas proved reserves and annual production are made up of West Texas and North-Central Texas (Figures 74 and 75). Other potential areas of extrapolation due to their important natural gas reserves and production are New Mexico, Oklahoma, Louisiana, and Wyoming.

Remaining unstudied areas of Texas and the Federal Offshore GOM were chosen as primary targets for future extrapolation of developed URG analysis methodologies because these are areas currently displaying significant reserve additions. Reserve additions can originate from adjustments, revisions, extensions, new field discoveries, and new reservoir discoveries in old fields. In particular, URG is largely attributable to extensions and new reservoir discoveries in old fields. Areas within the United States with the largest extensions in terms of their percentage of total extensions were Texas (41 percent) and Federal Offshore GOM (13 percent). Among the areas with the largest new reservoir discoveries in old fields in terms of percentage of total were Federal Offshore GOM (49 percent) and Texas (24 percent). Moreover, the largest supply of future increased natural gas production in the United States was found to be attributable to the Federal Offshore GOM in a recent National Petroleum Council study (National Petroleum Council, 1999).

URG analysis methodology for future extrapolations includes

1. Play selection and definition.
2. Compilation of annual ultimate recovery by field/reservoir and aggregation to defined plays.
3. Calculation of historical URG as a factor of time and drilling.
4. Determination of the most effective kind of technologies deployed to date and definition of the amenability of plays to the deployment of existing and future technologies.

5. Determination on a play-by-play basis of the economic sensitivity of remaining URG potential.

Comparison of the Current Study's Ultimate Recovery Growth Forecast with That of Previous Studies

The results and methodology of the current study's URG forecast were compared with those of previous studies. The effect of the use of aggregated versus disaggregated data on forecasts of URG was examined in detail. We found in the current study that if disaggregated data by play are used, a measure of URG is possible that is more realistic than that reached by aggregating different plays according to various geological, engineering, and production characteristics, as occurred in previous studies.

In the current study, URG analysis was based on a factor of time, as well as drilling activity. Forecasts were made by using both aggregated and disaggregated data for the Texas Gulf Coast Basin and East Texas. Based on a factor of time, disaggregated data by play revealed a more robust forecast than did aggregated data in the Texas Gulf Coast Basin and East Texas (Table 38). This difference occurred because URG rates for plays such as the Wilcox Lobo Trend (WX-2), Wilcox Sandstone, Rio Grande Embayment (WX-4), and Travis Peak Formation-Cotton Valley Group Sandstone, Sabine Uplift (KJ-1) are much greater than the aggregated growth rate calculated for the Texas Gulf Coast Basin and East Texas as single units.

Data utilized were based on URG data for the 20 years covering 1977 through 1996. Both 91 years (1905–1996) and 73 years (1923–1996) of revision history were available for the Texas Gulf Coast Basin and East Texas, respectively. For individual plays, earliest revision year and historical amount varied. Plays with longer revision histories and number of field/reservoirs are more likely to resemble the probable final URG forecast. Moreover, the general trends rather than the exact forecast figures should be observed. For example, the results for the Austin/Buda

Table 38. Forecast of URG by play in the Texas Gulf Coast Basin and East Texas as a factor of time (natural gas in MMcf).

Play	1996 Ultimate recovery	Probable final ultimate recovery	Ultimate recovery growth	Revision year	Earliest revision year
Texas GCB					
MC-3	3,268,895	3,315,260	46,365	64	1932
MC-4	2,900,782	3,151,094	250,312	49	1947
MC-5	2,324,944	2,417,408	92,464	65	1931
FR-1	1,173,995	1,289,907	115,912	50	1946
FR-2	4,349,501	4,501,948	152,447	58	1938
FR-3	7,082,121	7,173,767	91,646	46	1950
FR-4	18,504,468	21,161,412	2,656,944	66	1930
FR-6	17,177,887	17,963,138	785,251	61	1935
FR-7	9,752,358	10,543,789	791,431	67	1929
FR-8	2,150,476	2,385,323	234,847	62	1934
FR-9	13,008,586	13,351,298	342,712	71	1925
FR-10	3,358,269	3,524,803	166,534	69	1927
VK-1	11,927,869	16,948,619	5,020,750	68	1928
EO-3	16,566,819	19,871,848	3,305,029	90	1906
EO-4	1,570,181	1,752,155	181,974	70	1926
WX-1	7,632,128	9,902,155	2,270,027	55	1941
WX-2	8,485,236	67,353,689	58,868,453	50	1946
WX-4	15,555,179	32,561,199	17,006,020	67	1929
KG-1	3,915,183	4,458,900	543,717	52	1944
KG-2	3,898,057	4,285,116	387,059	18	1978
KG-4	1,401,037	1,897,657	496,620	47	1949
Agg. Plays	*156,003,971*	*249,810,485*	*93,806,514*		
East Texas					
KS-2	2,264,767	2,441,497	176,730	62	1934
KS-3	1,243,381	1,856,640	613,259	35	1961
KC-1	8,051,279	8,290,556	239,277	65	1931
KC-2	2,439,842	2,534,259	94,417	54	1942
KC-3	3,535,674	4,156,411	620,737	63	1933
KJ-1	9,332,676	36,363,392	27,030,716	66	1930
KJ-2	3,677,681	7,229,914	3,552,233	54	1942
KJ-3	2,689,105	7,962,924	5,273,819	51	1944
JC-1C	2,307,111	2,665,368	358,257	52	1944
JC-2B	1,650,581	6,623,171	4,972,590	38	1958
Agg. Plays	*37,192,097*	*80,124,132*	*42,932,035*		
Totals					
Texas GCB	160,327,185	191,487,520	31,160,335	91	1905
East Texas	39,255,592	74,626,168	35,370,576	73	1923

Chalk (KG-2) play should be utilized with caution because only 18 years of revision history are available, and it consists of nine field/reservoirs, one of which, the Giddings/Austin Chalk, comprises 88 percent of the total play in terms of 1996 ultimate recovery. Each field/reservoir was grown completely by using cumulative growth factors (CGF) based on its revision history.

Based on a factor of drilling activity, aggregated data for the Texas Gulf Coast Basin and East Texas revealed more robust forecasts than did the play's disaggregated data (Table 39). This difference arises because the aggregated data utilize well completion costs that are lower than those of particular plays. Plays with significant URG potential, such as the WX-2, WX-4, and KJ-1, involve greater completion costs because of their having deeper drilling depths. Logarithmic extrapolations of historically established well completion versus ultimate recovery were used to forecast URG to 2015, 2030, and to the economic limit of the play (that is, the point where the value of incremental ultimate recovery equals cost of incremental well completion). For the Texas Gulf Coast Basin, the WX-4, VK-1 (Vicksburg Sandstone, Rio Grande Embayment), and WX-2 plays were forecast to have the greatest URG potential. This forecast is based on a factor of drilling activity. For East Texas, the KJ-1 play was forecast to have the greatest URG potential, a forecast also based on a factor of drilling activity.

No other previous study's URG forecast has been disaggregated by plays. Only aggregated analysis on a national and regional scale has been performed. Moreover, very few studies include forecasts based on a factor of drilling activity. Two of the most current and widely referenced URG forecasts include the estimates of inferred reserves in the United States Geological Survey (USGS) 1995 *National Assessment of United States Oil and Gas Resources* and the National Petroleum Council (NPC) (1999) *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand*. The results and methodologies of these two studies, as compared with those of the current study, are given.

Table 39. Forecast of URG by play in the Texas Gulf Coast Basin and East Texas as a factor of drilling activity (natural gas in MMcf).

Play	2015 Completions	2015 Ultimate recovery growth	2030 Completions	2030 Ultimate recovery growth	Remaining completions	Remaining ultimate recovery growth	Economic limit
Texas GCB							
MC-3	282	9,162	282	9,162	282	9,162	2002
MC-4	485	313,931	936	529,044	4,682	1,424,684	2159
MC-5	687	177,141	1,326	312,485	5,064	828,212	2120
FR-1	282	106,079	543	180,928	1,925	419,645	2111
FR-2	342	169,595	660	296,500	2,944	838,610	2141
FR-3	1,137	116,265	2,194	200,479	3,034	256,638	2042
FR-4	4,285	836,502	8,271	1,455,760	25,467	3,257,328	2096
FR-6	2,383	624,232	4,600	1,098,225	15,017	2,617,902	2102
FR-7	5,329	351,663	10,286	611,854	12,259	702,702	2036
FR-8	1,644	100,844	3,173	172,476	3,173	172,476	2030
FR-9	2,529	413,653	4,882	719,900	10,918	1,308,058	2069
FR-10	741	164,365	1,430	288,818	4,935	710,696	2108
VK-1	2,426	1,737,553	4,682	2,932,776	21,874	7,668,298	2148
EO-3	3,991	800,582	7,703	1,389,783	23,958	3,111,287	2097
EO-4	870	153,108	1,679	270,593	6,875	752,865	2129
WX-1	1,012	812,203	1,953	1,384,919	9,833	3,871,190	2160
WX-2	2,663	1,793,937	5,140	2,888,660	26,414	6,247,057	2125
WX-4	2,338	3,162,322	4,513	5,315,362	26,763	15,393,355	2190
KG-1	713	482,410	1,377	813,007	6,225	2,082,301	2143
KG-2	7,878	614,555	12,281	862,664	12,281	862,664	2024
KG-4	1,721	341,506	3,321	578,549	9,298	1,155,563	2087
Agg. Plays	*43,734*	*13,281,608*	*81,234*	*22,311,944*	*233,221*	*53,690,693*	
East Texas							
KS-2	3,783	217,880	7,303	392,357	8,704	455,779	2036
KS-3	1,331	123,253	2,569	203,368	2,652	207,957	2031
KC-1	618	353,884	1,193	625,116	6,614	2,073,992	2177
KC-2	1,280	154,370	2,470	262,575	4,903	426,558	2061
KC-3	1,266	444,671	2,444	746,848	7,904	1,591,466	2101
KJ-1	3,705	1,766,647	7,151	2,870,226	24,452	5,889,092	2107
KJ-2	1,365	638,543	2,635	1,045,001	9,092	2,184,682	2108
KJ-3	717	498,686	1,385	813,267	5,753	1,845,600	2131
JC-1C	200	375,868	386	641,434	2,654	2,090,198	2222
JC-2B	389	291,365	751	477,444	2,958	1,068,070	2124
Agg. Plays	*8,279*	*1,294,058*	*15,980*	*2,230,265*	*30,777*	*4,755,752*	

USGS 1995 National Assessment of United States Oil and Gas Resources

The USGS utilized a method similar to that of the current study in assessing URG by a factor of time. The available 15-year data set spanned 1977 through 1991, and URG was assessed for 1991 through 2071. Forecasts were made on the basis of aggregated U.S. ultimate recovery data and disaggregation into eight regions (Table 40). Aggregate U.S. total data forecasts were more robust than regionally grown data, differing from that of our current study, which has a more robust disaggregated forecast. For comparison with the results of our current study, we looked at data from Region 6 (Gulf Coast), which includes the Texas Gulf Coast Basin and East Texas, as well as Louisiana, Mississippi, Alabama, and Florida. A total of 102.4 Tcf was forecast for Region 6 by the USGS. According to production ratios of 1996 dry natural gas production, the Texas Gulf Coast Basin and East Texas comprise 63.8 percent of Region 6, or 65.3 Tcf. This value resembles that of the ultimate recovery forecast (66.5 Tcf), which is based on a factor of time in the current study, which uses aggregated data.

NPC 1999 Study on Natural Gas

URG was forecast by the NPC on the basis of two methodologies employed by Energy and Environmental Analysis, Inc. (EEA), and the Energy Information Administration (EIA).

Energy and Environmental Analysis, Inc. (EEA)

EEA utilized a methodology based on the observation that successive increments of drilling in fields of a certain age show declining estimated ultimate recovery (EUR). By extrapolating those declining per-completion recoveries, EEA estimated how many reserves could be added by additional natural gas completions and, thus, the growth potential of the fields.

Table 40. URG according to the USGS *1995 National Assessment of United States Oil and Gas Resources* (U.S. Geological Survey, 1995)

	Geographic location	Dry natural gas (Tcf)
Region 1	Alaska	32
Region 2	Pacific Coast	13.5
Region 3	Colorado Plateau and Basin Ridge	11.8
Region 4	Rocky Mountains and Northern Great Plains	19.2
Region 5	West Texas and Eastern New Mexico	51.2
Region 6	Gulf Coast	102.4
Region 7	Mid-Continent	88.3
Region 8	Eastern	3.7
Lower 48		290
U.S. Total		322

Using this methodology, EEA estimated ultimate recoveries of each natural gas completion and then fit a statistical curve over the historical data and projected what the ultimate recoveries would be for hypothetical future completions. Future completions were made until their productivity fell below a minimum threshold that was based on drilling depth. Analysis was done in several regions, including the Texas Gulf Onshore and Arkla-East Texas (Table 41). For the Texas Gulf Onshore (inclusive of the Texas Gulf Coast Basin) and Arkla-East Texas (inclusive of East Texas), the URG forecast was 54.3 Tcf and 25.9 Tcf, respectively. East Texas comprises approximately 71 percent of the Arkla-East Texas forecast, or 18.4 Tcf. These figures are approximately equivalent to the 53.7- and 17.8-Tcf forecast of the current study that was based on a factor of drilling activity and the play's aggregated forecasts.

Energy Information Administration (EIA)

EIA grouped data by vintage (year of field discovery) and modeled growth on the basis of well completion and, to a lesser extent, time. Growth was forecast to an economic limit (ultimate recovery per completion) and data were grouped according to major supply regions, as well as classification on the basis of shallow, deep, tight, and Gulf (Table 42). Region 2 comprised the Gulf Coast Onshore, including the Texas Gulf Onshore, South Louisiana, Arkla-East Texas, and Eastern Gulf Onshore. Total remaining ultimate recovery was assessed at 74.3 Tcf from shallow, 40.2 Tcf from deep, and 58.7 Tcf from tight categories. Assuming that the Texas Gulf Coast Basin and East Texas comprised approximately of 44.7 percent of the total 173.2 Tcf in terms of 1996 dry natural gas production, 77.5 Tcf was forecast. This total is approximately equivalent to the 71.5 Tcf forecast for the combined Texas Gulf Coast Basin and East Texas URG, which was based on a factor of drilling activity by using aggregated play forecasts.

Table 41. URG analysis performed by EEA for the NPC 1999 study on natural gas (National Petroleum Council, 1999)

Model region	**Old field appreciation (Bcf)**
A: Appalachia	2,301
B: Eastern Gulf Onshore	5,069
C: North Central	2,718
D: Arkla - East Texas	25,864
E: South Louisiana	20,361
G: Texas Gulf Onshore	54,341
WL: Williston Basin	2,653
FR: Rocky Mtn. Foreland	28,949
SJB: San Juan Basin	11,673
OV: Overthrust Belt	702
JN: Mid-Continent	48,430
JS: Permian Basin	22,319
L: West Coast Onshore	5,717
BO: Eastern Gulf of Mexico	2,160
EGO: Cent. & West. Gulf of Me:	70,661
LO: West Coast Offshore	1,039
AO: Atlantic Offshore	0
Lower 48 total	**304,957**

Table 42. URG analysis performed by EIA for NPC 1999 study on natural gas (natural gas in MMcf) (National Petroleum Council, 1999)

SHALLOW	**Region 2**	**Region 3**	**Region 4**	**Region 5**	**Region 1**	**Region 6**	**U.S. Total**
PULT 1996	232,887,226	157,285,334	66,562,614	33,144,565			489,879,739
URAss	307,126,136	208,343,794	93,088,707	69,929,801			678,488,438
URAssRem	74,277,650	56,563,853	26,962,310	36,975,243			194,779,056
Econ5000	0	978,555	4,961,352	4,203,779			10,143,686
Econ3000	986,971	3,568,527	7,759,401	8,438,234			20,753,133
Econ2000	3,665,736	8,450,097	9,886,348	11,746,666			33,748,847
Econ1500	6,584,067	11,299,160	11,753,027	14,062,793			43,699,047
Econ1000	13,736,728	17,884,934	14,064,725	16,955,218			62,641,605
Econ750	20,993,785	22,143,607	15,870,768	19,117,242			78,125,402
Econ500	33,462,131	28,563,365	18,217,336	21,914,728			102,157,560
Econ300	***48,247,094***	***33,702,983***	***20,644,941***	***24,992,190***			***127,587,208***
Econ100	66,426,522	38,174,995	21,576,524	29,333,397			155,511,438

DEEP	**Region 2**	**Region 3**	**Region 4**	**Region 5**	**Region 1**	**Region 6**	**U.S. Total**
PULT 1996	57,294,330	11,343,707	3,095,423	894,389			72,627,849
URAss	96,912,177	23,603,812		1,839,525			122,355,514
URAssRem	40,240,461	13,996,982		945,136			55,182,579
Econ5000	2,905,432	2,670,835		164,091			5,740,358
Econ3000	3,770,251	4,709,648		383,004			8,862,903
Econ2000	4,702,003	5,467,354		522,026			10,691,383
Econ1500	6,137,164	5,610,510		599,269			12,346,943
Econ1000	9,560,690	5,831,930		684,291			16,076,911
Econ750	12,663,173	6,111,139		727,091			19,501,403
Econ600	***15,218,463***	***6,246,546***	***989,128***	***753,754***			***23,207,891***
Econ500	17,401,854	6,613,101		772,823			24,787,778
Econ300	23,279,349	8,386,116		812,455			32,477,920
Econ100	32,660,888	10,715,428		824,091			44,200,407

TIGHT	**Region 2**	**Region 3**	**Region 4**	**Region 5**	**Region 1**	**Region 6**	**U.S. Total**
PULT 1996	35,660,496	6,604,685	8,232,872	67,545,742			118,043,795
URAss	92,623,118			159,959,452			252,582,570
URAssRem	58,681,686			95,600,763			154,282,449
Econ5000	18,803,086			2,496,888			21,299,974
Econ3000	23,902,140			6,197,742			30,099,882
Econ2000	27,828,375			16,900,516			44,728,891
Econ1500	33,230,495			26,663,129			59,893,624
Econ1000	36,279,943			40,613,721			76,893,664
Econ750	39,628,859			47,912,140			87,540,999
Econ500	42,183,379			57,759,682			99,943,061
Econ300	***45,775,520***	***7,229,738***	***9,012,014***	***67,197,939***			***129,215,211***
Econ100	50,637,442			80,559,984			131,197,426

GULF	**Gulf**
PULT 1996	163,205,881
URAss	267,478,022
URAssRem	104,910,287
Econ5000	6,690,823
Econ3000	25,391,881
Econ2000	44,554,532
Econ1500	56,968,781
Econ1000	***71,230,180***
Econ750	78,777,752
Econ500	86,657,620
Econ300	88,337,103
Econ100	88,980,176

Selected economic URA target: ***351,240,490***

Region 2	Gulf Coast Onshore
Region 3	Mid-Continent
Region 4	Permian Basin
Region 5	Rocky Mountains
Region 1	Appalachia
Region 6	West Coast

Metrics: Economic Benefits and Importance of Current Study

The current study's metrics, or economic benefits and importance, result directly from the development of a detailed regional study that outlines major natural gas URG trends and future resource availability in the Texas Gulf Coast Basin and East Texas. The detailed regional study can assist in better identification of natural gas prospects for explorers through disaggregation to the play level. URG trends are quantified and ranked by plays having the largest remaining future potential. Targeted technological applications for continued URG can be achieved through play-specific advanced technology, such as 3-D seismic, hydraulic fracturing, and horizontal/directional drilling.

URG analysis disaggregated by plays provides a more accurate and detailed assessment of the total natural gas resource base in the Texas Gulf Coast Basin and East Texas. Significant additions to the recoverable reserves are achieved through a disaggregated analysis of URG as opposed to an aggregated analysis. Aggregated analysis of URG as a factor of time, utilizing aggregated data for the Texas Gulf Coast Basin and East Texas, yields a future potential of 31,160,335 MMcf and 35,370,576 MMcf, respectively. However, aggregated data mask the tremendous growth occurring in specific plays that are amenable to the application of advanced technologies.

Disaggregation by play captures play-specific natural gas ultimate growth trends. When disaggregated data play are used, the potential remaining in the Texas Gulf Coast Basin and East Texas is calculated at 93,806,514 MMcf and 42,932,035 MMcf, respectively. An increased projection of URG also results in the Texas Gulf Coast Basin and East Texas of 62,646,179 MMcf and 7,561,459 MMcf, respectively. Major URG in the WX-2 and WX-4 plays of the Texas Gulf Coast Basin and the KJ-1 play in East Texas are more accurately forecast. A total of approximately 70 Tcf of natural gas URG is added to recoverable reserves by disaggregation of data to the play level. Assuming a constant natural gas price of $3/Mcf during the period of recovery, the undiscounted dollar value of additional URG forecast through disaggregated play analysis equals $210 billion.

Indicators of industry activity and technological applications, such as historical completions; total drilling permits issued; horizontal, directional, and sidetrack drilling permits issued; and tight gas applications approved, were collected to support URG by play. Analyses of such indicators were utilized to determine whether they coincided with areas experiencing and holding the greatest potential for natural gas URG in the Texas Gulf Coast Basin and East Texas. Direct, play-specific correlation with the indicators was not possible because of organization of data by RRC districts and counties. However, through the use of RRC districts, a general observation and correlation of indicators of industry activity and technological applications in plays can be made.

Table 43 represents the distribution of plays among RRC districts. The KG-1 and KG-4 plays dominate RRC District 1; the WX-4, FR-7, MC-3 and FR-8 plays dominate RRC District 2; the EO-3, FR-9, and WX-1 plays dominate RRC District 3; the FR-4, VK-1, WX-2, and WX-4 plays dominate Texas RRC District 4; the KJ-3, JC-2B, KC-3, and JC-1C plays dominate RRC District 5; the KJ-1, KJ-2, KC-1, and KC-2 plays dominate RRC District 6; and the MC-4, MC-5, and FR-6 plays dominate the Texas Offshore State waters. Table 44 represents the distribution of RRC districts among plays. Major natural gas plays experiencing and holding the most URG potential are in RRC Districts 4 and 6. The WX-2, WX-4, VK-1, and FR-4 plays are dominantly in RRC District 4, whereas the KJ-1 and KJ-2 plays are dominantly in RRC District 6. Plays experiencing relatively minor or no growth dominate in RRC District 2 (FR-7, FR-8, and MC-3), District 3 (FR-9 and FR-10), and the Texas Offshore State waters (MC-4, MC-5, and FR-6).

Historical completion data for the Texas Gulf Coast Basin and East Texas were compiled through RRC Oil and Gas Annual Reports (Railroad Commission of Texas, 1980 through 1999). Historical completion data provide a good barometer of past industry activity and interest. Total completions in the Texas Gulf Coast Basin and East Texas declined in the mid-1980's because of

Table 43. Distribution of plays among RRC districts (natural gas in MMcf).

TX RRC district	Play	1996 ultimate recovery	Number of fields	Major fields	Percentage of district 1996 ultimate recovery	Percentage of district fields
1	EO-2	7,109	1		0.1	1.6
1	EO-4	24,476	1		0.5	1.6
1	WX-3	113,907	4		2.4	6.6
1	WX-4	891,960	18		18.6	29.5
1	KG-1	2,384,132	15	Fashing (1,218,793)	49.8	24.6
1	KG-2	150,808	4		3.1	6.6
1	KG-3	255,299	5		5.3	8.2
1	KG-4	960,088	13	AWP (531,173)	20.1	21.3
2	MC-3	2,477,100	16	Greta (1,044,139)	10.0	4.7
2	MC-4	309,546	5		1.3	1.5
2	FR-6	1,682,672	22		6.8	6.4
2	FR-7	7,243,999	66	Tom O'Conner (1,400,915)	29.3	19.2
2	FR-8	1,731,711	43		7.0	12.5
2	VK-2	188,997	9		0.8	2.6
2	EO-1	257,461	10		1.0	2.9
2	EO-2	195,180	4		0.8	1.2
2	EO-3	507,797	19		2.1	5.5
2	EO-4	59,671	2		0.2	0.6
2	WX-1	1,399,897	18	Provident City (618,593)	5.7	5.2
2	WX-4	7,627,852	119	Tulsita-Wilcox (893,256)	30.9	34.6
2	KG-1	1,017,558	11		4.1	3.2
3	MC-3	791,795	16		1.4	3.5
3	MC-4	893,981	10	Collegeport (584,671)	1.6	2.2
3	MC-5	898,983	20		1.6	4.3
3	FR-6	8,217,646	35	Old Ocean (4,777,946)	14.4	7.6
3	FR-7	1,714,275	22	Magnet Withers (966,195)	3.0	4.8
3	FR-8	68,665	2		0.1	0.4
3	FR-9	12,968,718	104	Chocolate Bayou (2,074,726), Pledger (2,029,985)	22.7	22.6
3	FR-10	3,358,269	39	Port Neches, N. (578,668)	5.9	8.5
3	VK-3	347,859	7		0.6	1.5
3	EO-3	16,059,023	106	Katy (9,513,159)	28.1	23.0
3	WX-1	6,232,232	71	Sheridan (1,892,553)	10.9	15.4
3	KG-1	288,100	3		0.5	0.7
3	KG-2	3,826,057	8	Giddings (3,440,018)	6.7	1.7
3	KS-3	1,243,381	14		2.2	3.0
3	KC-3	297,796	3		0.5	0.7

Table 43. Cont.

TX RRC district	Play	1996 ultimate recovery	Number of fields	Major fields	Percentage of district 1996 ultimate recovery	Percentage of district fields
4	MC-1	661,758	15		0.9	2.6
4	MC-2	915,020	17		1.3	2.9
4	FR-1	1,101,320	17		1.6	2.9
4	FR-2	4,349,501	28	McAllen (779,999), San Salvador (776,338)	6.2	4.8
4	FR-3	7,082,121	37	Voboras (2,137,785), Alazan N. (1,815,507)	10.0	6.3
4	FR-4	18,504,468	76	Stratton (3,231,705), Seeligson (2,845,600)	26.2	13.0
4	FR-5	217,998	9		0.3	1.5
4	FR-6	6,467,369	76	Laguna Larga (743,110), Red Fish Bay-MI (656,086)	9.2	13.0
4	FR-7	794,084	12		1.1	2.1
4	FR-8	350,100	9		0.5	1.5
4	VK-1	11,927,869	78	Borregos (2,617,563), McAllen Ranch (1,752,691)	16.9	13.3
4	EO-2	733,428	11		1.0	1.9
4	EO-4	1,486,034	32	Sejita (518,859)	2.1	5.5
4	WX-2	8,485,236	87	Vaquillas Ranch (1,153,253), Laredo (903,595)	12.0	14.9
4	WX-3	57,225	2		0.1	0.3
4	WX-4	7,035,366	69	Bob West (857,778), Thompsonville NE (709,279)	10.0	11.8
4	KG-4	440,949	10		0.6	1.7
5	KS-2	375,019	9		5.1	8.0
5	KC-3	1,312,310	28	Opelika (472,693)	17.9	24.8
5	KJ-3	2,628,121	26	Opelika (1,092,191)	35.9	23.0
5	JC-1C	1,348,875	22		18.4	19.5
5	JC-2B	1,650,581	28	Personville N.(481,638)	22.6	24.8
6	KS-2	1,889,748	13	East Texas (820,704)	6.7	7.7
6	KC-1	8,051,279	23	Carthage (5,811,922)	28.4	13.7
6	KC-2	2,439,842	34	Trawick (686,789)	8.6	20.2
6	KC-3	1,925,569	21	Fairway (568,305)	6.8	12.5
6	KJ-1	9,332,676	29	Carthage (4,719,741)	32.9	17.3
6	KJ-2	3,677,681	37	Willow Springs (933,913)	13.0	22.0
6	KJ-3	60,984	4		0.2	2.4
6	JC-1C	958,236	7	New Hope (568,022)	3.4	4.2
995	MC-1	242,451	6		5.7	9.4
995	MC-4	1,697,255	23		39.6	35.9
995	MC-5	1,425,961	19		33.3	29.7
995	FR-1	72,675	1		1.7	1.6
995	FR-6	810,199	14		18.9	21.9
995	FR-9	39,868	1		0.9	1.6

Table 44. Distribution of RRC districts among plays (natural gas in MMcf).

Play	TX RRC district	1996 ultimate recovery	Number of fields	Major fields	Percentage of 1996 ultimate recovery in district	Percentage of fields in district
MC-1	4	661,758	15		73.2	71.4
MC-1	995	242,451	6		26.8	28.6
MC-2	4	915,020	17		*100.0*	*100.0*
MC-3	2	2,477,100	16	Greta (1,044,139)	75.8	50.0
MC-3	3	791,795	16		24.2	50.0
MC-4	2	309,546	5		10.7	13.2
MC-4	3	893,981	10	Collegeport (584,671)	30.8	26.3
MC-4	995	1,697,255	23		58.5	60.5
MC-5	3	898,983	20		38.7	51.3
MC-5	995	1,425,961	19		61.3	48.7
FR-1	4	1,101,320	17		93.8	94.4
FR-1	995	72,675	1		6.2	5.6
FR-2	4	4,349,501	28	McAllen (779,999), San Salvador (776,338)	*100.0*	*100.0*
FR-3	4	7,082,121	37	Voboras (2,137,785), Alazan N. (1,815,507)	*100.0*	*100.0*
FR-4	4	18,504,468	76	Stratton (3,231,705), Seeligson (2,845,600)	*100.0*	*100.0*
FR-5	4	217,998	9		*100.0*	*100.0*
FR-6	2	1,682,672	22		9.8	15.0
FR-6	3	8,217,646	35	Old Ocean (4,777,946)	47.8	23.8
FR-6	4	6,467,369	76	Laguna Larga (743,110), Red Fish Bay-MI (656,086)	37.6	51.7
FR-6	995	810,199	14		4.7	9.5
FR-7	2	7,243,999	66	Tom O'Conner (1,400,915)	74.3	66.0
FR-7	3	1,714,275	22	Magnet Withers (966,195)	17.6	22.0
FR-7	4	794,084	12		8.1	12.0
FR-8	2	1,731,711	43		80.5	79.6
FR-8	3	68,665	2		3.2	3.7
FR-8	4	350,100	9		16.3	16.7
FR-9	3	12,968,718	104	Chocolate Bayou (2,074,726), Pledger (2,029,985)	99.7	99.0
FR-9	995	39,868	1		0.3	1.0
FR-10	3	3,358,269	39	Port Neches, N. (578,668)	*100.0*	*100.0*
VK-1	4	11,927,869	78	Borregos (2,617,563), McAllen Ranch (1,752,691)	*100.0*	*100.0*
VK-2	2	188,997	9		*100.0*	*100.0*
VK-3	3	347,859	7		*100.0*	*100.0*
EO-1	2	257,461	10		*100.0*	*100.0*
EO-2	1	7,109	1		0.8	6.3
EO-2	2	195,180	4		20.9	25.0
EO-2	4	733,428	11		78.4	68.8

Table 44. Cont.

EO-3	2	507,797	19		3.1	15.2
EO-3	3	16,059,023	106	Katy (9,513,159)	96.9	84.8
EO-4	1	24,476	1		1.6	2.9
EO-4	2	59,671	2		3.8	5.7
EO-4	4	1,486,034	32	Sejita (518,859)	94.6	91.4
WX-1	2	1,399,897	18	Provident City (618,593)	18.3	20.2
WX-1	3	6,232,232	71	Sheridan (1,892,553)	81.7	79.8
WX-2	4	8,485,236	87	Vaquillas Ranch (1,153,253), Laredo (903,595)	*100.0*	*100.0*
WX-3	1	113,907	4		66.6	66.7
WX-3	4	57,225	2		33.4	33.3
WX-4	1	891,960	18		5.7	8.7
WX-4	2	7,627,852	119	Tulsita-Wilcox (893,256)	49.0	57.8
WX-4	4	7,035,366	69	Bob West (857,778), Thompsonville NE (709,279)	45.2	33.5
KG-1	1	2,384,132	15	Fashing (1,218,793)	64.6	51.7
KG-1	2	1,017,558	11		27.6	37.9
KG-1	3	288,100	3		7.8	10.3
KG-2	1	150,808	4		3.8	33.3
KG-2	3	3,826,057	8	Giddings (3,440,018)	96.2	66.7
KG-3	1	255,299	5		*100.0*	*100.0*
KG-4	1	960,088	13	AWP (531,173)	68.5	56.5
KG-4	4	440,949	10		31.5	43.5
KS-2	5	375,019	9		16.6	40.9
KS-2	6	1,889,748	13	East Texas (820,704)	83.4	59.1
KS-3	3	1,243,381	14		*100.0*	*100.0*
KC-1	6	8,051,279	23	Carthage (5,811,922)	*100.0*	*100.0*
KC-2	6	2,439,842	34	Trawick (686,789)	*100.0*	*100.0*
KC-3	3	297,796	3		8.4	5.8
KC-3	5	1,312,310	28	Opelika (472,693)	37.1	53.8
KC-3	6	1,925,569	21	Fairway (568,305)	54.5	40.4
KJ-1	6	9,332,676	29	Carthage (4,719,741)	*100.0*	*100.0*
KJ-2	6	3,677,681	37	Willow Springs (933,913)	*100.0*	*100.0*
KJ-3	5	2,628,121	26	Opelika (1,092,191)	97.7	86.7
KJ-3	6	60,984	4		2.3	13.3
JC-1C	5	1,348,875	22		58.5	75.9
JC-1C	6	958,236	7	New Hope (568,022)	41.5	24.1
JC-2B	5	1,650,581	28	Personville N.(481,638)	*100.0*	*100.0*

price collapse and have steadily increased thereafter (Figures 76 and 77). RRC District 4 in the Texas Gulf Coast Basin and RRC District 6 in East Texas displayed the most total completions. These two RRC districts are composed mostly of plays experiencing and holding the greatest URG potential. Similar results are obtained when dividing new-hole completions and recompletions by total completions.

A barometer of more current and future industry activity and interests can be approximated using data compiled from the Drilling Permit Master file (Railroad Commission of Texas, 2000a). The Drilling Permit Master file contains drilling permit applications and those approved each year. A general lag time of a couple of years may exist between drilling permit applications and actual well completion. The percentage of drilling permits from 1990 through the present is shown in Figure 78. As with historical completion data, RRC Districts 4 and 6 comprise the most drilling permits for the Texas Gulf Coast Basin and East Texas, respectively.

The Drilling Permit Master file also contains information on whether the permit was for a horizontal, directional, or sidetrack well. These drilling technologies are one of the advanced technological applications responsible for current natural gas URG. As seen in Figure 79, RRC District 3 comprises nearly half of the total horizontal, directional, and sidetrack drilling permits from 1990 through the present. This fact is largely due to Giddings field, which dominates production in the Austin/Buda Chalk (KG-2) play. This play has shown tremendous URG in terms of its cumulative growth factor and its 1996/1977 URG ratio. As seen in Figure 80, this advanced technological application, highly amenable to plays such as the KG-2 play, has been relatively recently applied within the past 10 years. A notable peak in the early 1990's shown in the data for RRC District 1 is due largely to permits received in similar Austin/Buda fractured chalk areas, such as Pearsall field and areas adjacent to Giddings field.

Another indicator of advanced technological applications responsible for current natural gas URG in the Texas Gulf Coast Basin and East Texas that can be correlated with specific plays is the number of tight gas applications approved. These data were compiled from the High Cost Gas file (Railroad Commission of Texas, 2000b). As seen in Figure 81, RRC Districts 4 and 6

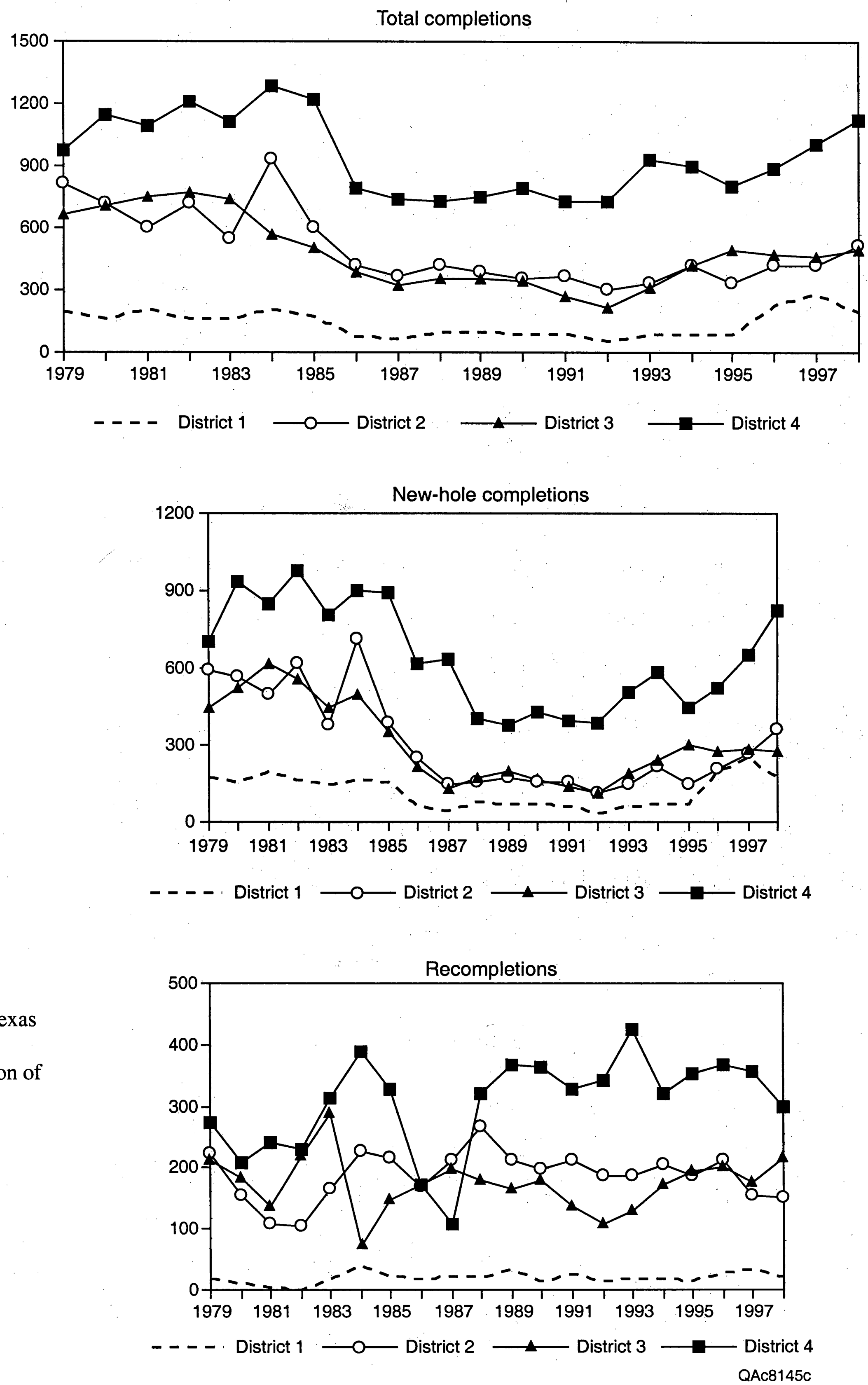


Figure 76. Historical completions in the Texas Gulf Coast Basin (Railroad Commission of Texas, 1980–1999).

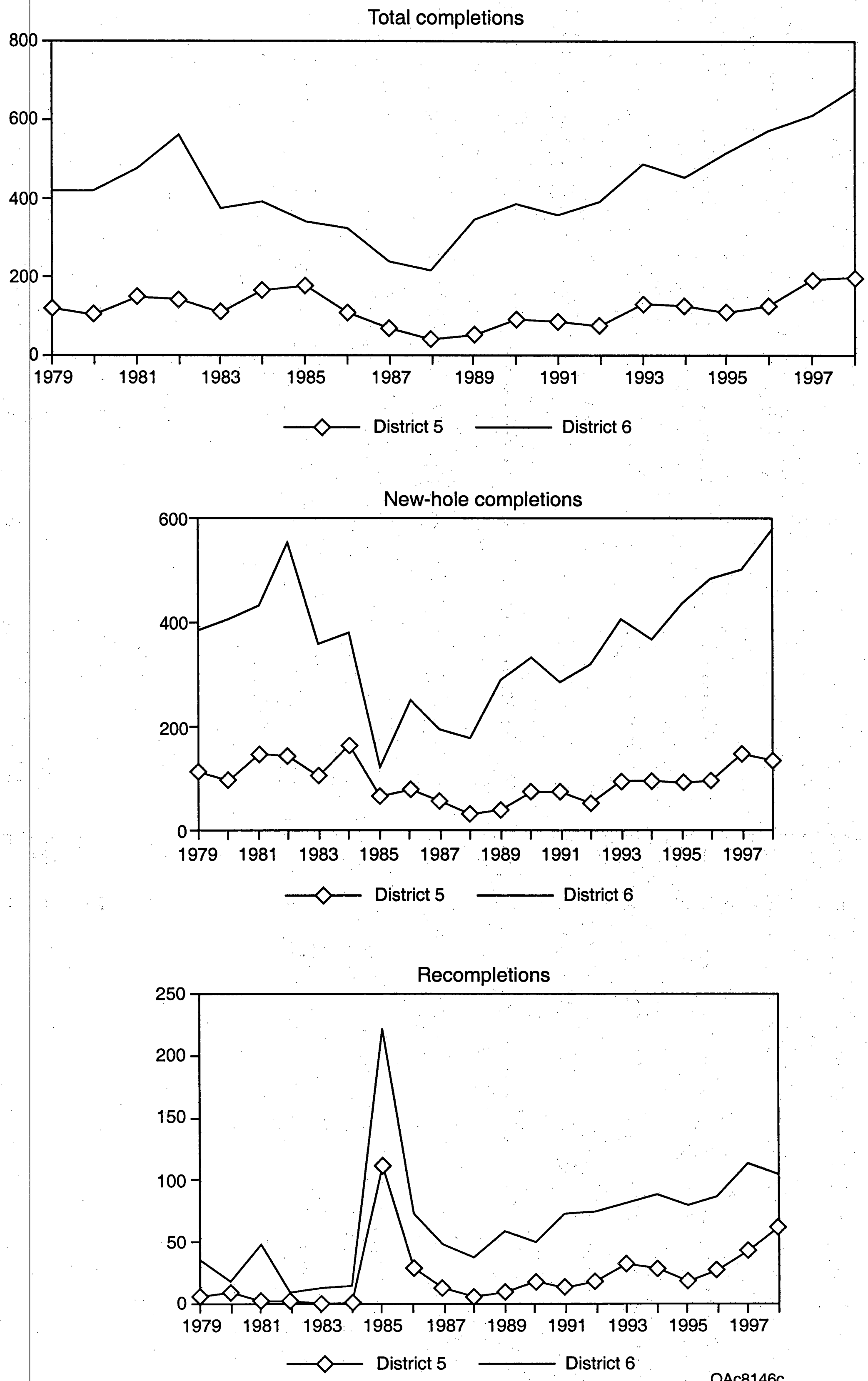


Figure 77. Historical completions in East Texas (Railroad Commission of Texas, 1980–1999).

Figure 78. Percentage of drilling permits from 1990 through the present (cumulative = 64,466) (Railroad Commission of Texas, 2000a).

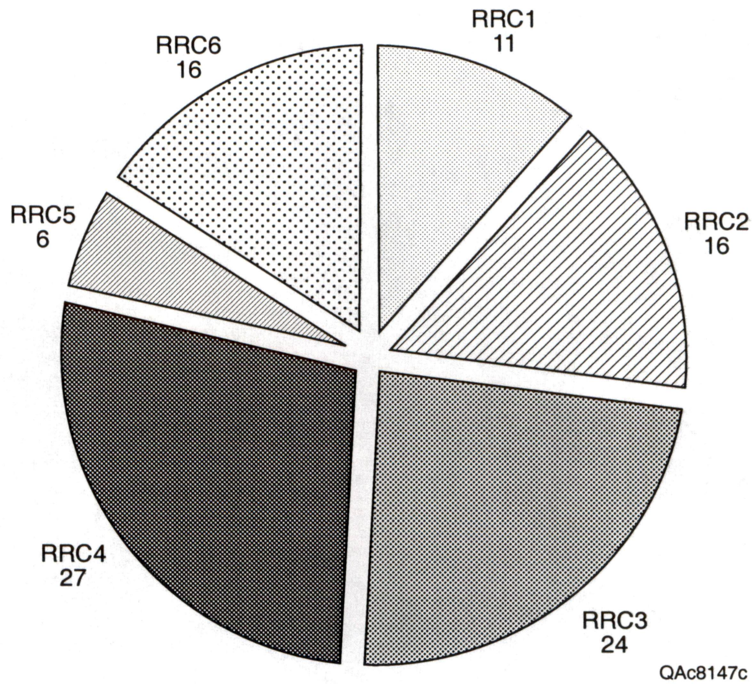
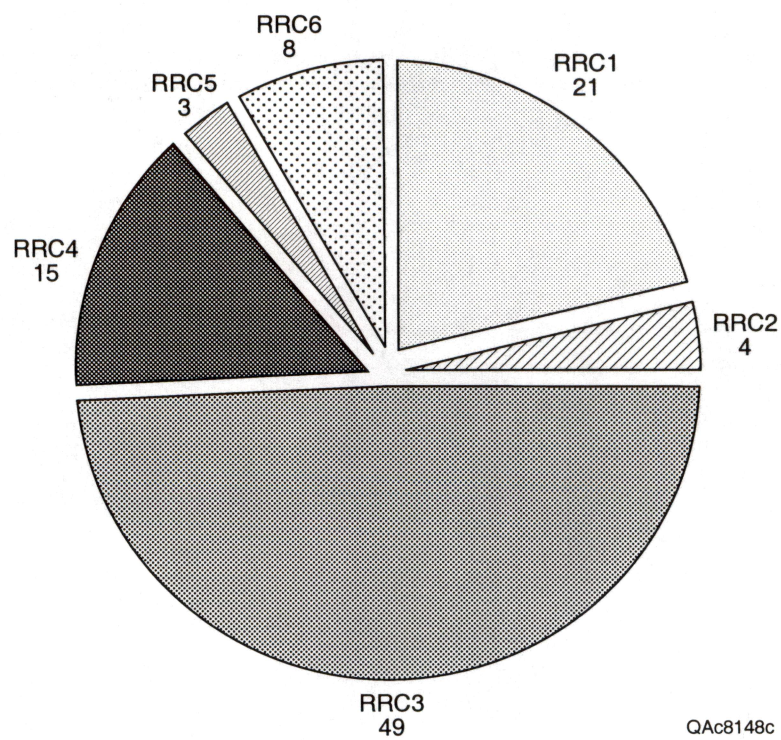


Figure 79. Percentage of horizontal, directional, and sidetrack drilling permits from 1990 through the present (cumulative = 12,486) (Railroad Commission of Texas, 2000a).



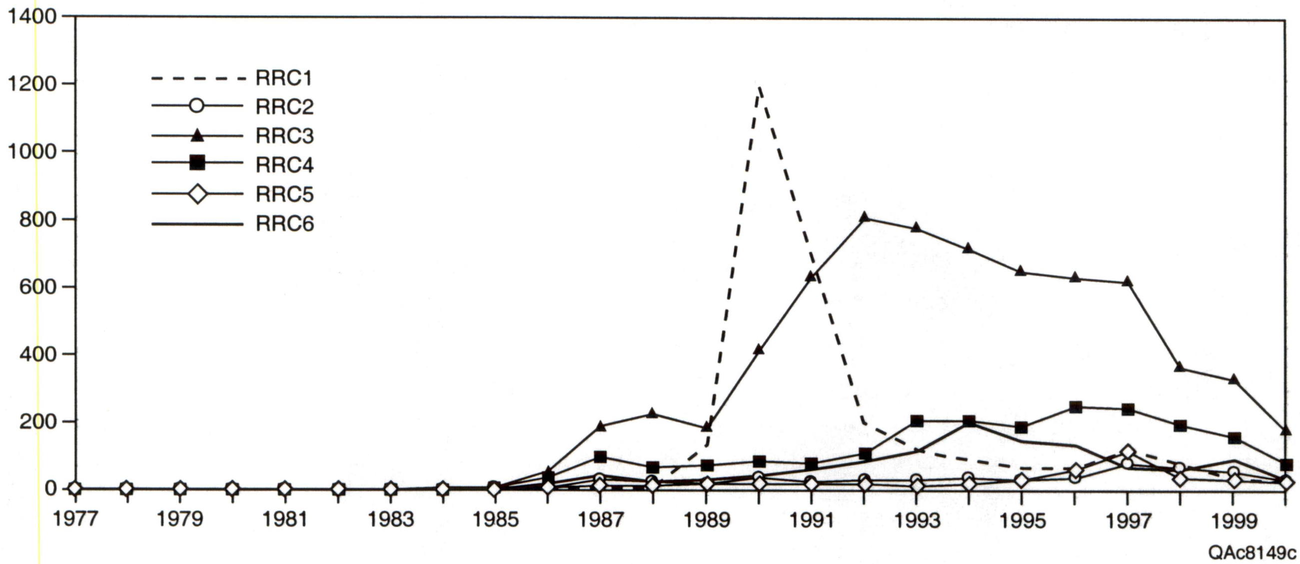


Figure 80. Horizontal, directional, and sidetrack drilling permits in the Texas Gulf Coast Basin and East Texas (Railroad Commission of Texas, 2000a).

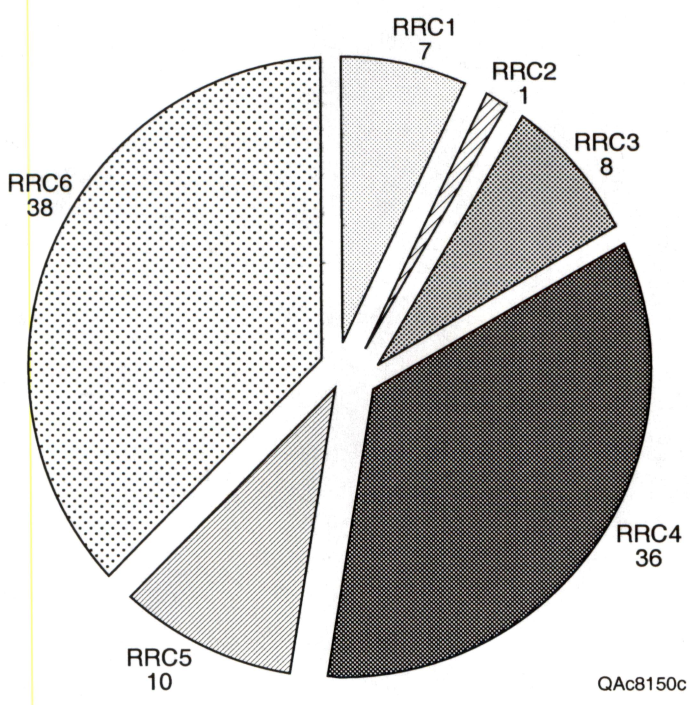


Figure 81. Percentage of tight gas applications approved from 1990 through the present (cumulative = 9,532) (Railroad Commission of Texas, 2000b).

consist of a dominant percentage of tight gas applications approved from 1990 through the present. Tight gas applications in RRC Districts 4 and 6 can mainly be attributable to the Wilcox Lobo Trend (WX-2) play and the Travis Peak Formation-Cotton Valley Group Sandstone (KJ-1 and KJ-2) plays, respectively. These plays are the most prolific in terms of current and future natural gas URG in the Texas Gulf Coast Basin and East Texas.

Conclusions and Future Research Directions

Natural gas URG in the Texas Gulf Coast Basin and East Texas was quantified, ranked, and forecast by plays, both as a factor of time and drilling activity. Play controls on natural gas URG were determined, and the play-specific amenability of advanced technologies to achieve URG was assessed. Economic limits of achieving the future URG potential were determined.

The key conclusion was that natural gas URG is occurring in the Texas Gulf Coast Basin and East Texas. Certain plays, moreover, held significant future potential because reservoirs that are in their early stage of development, structurally and stratigraphically complex, are in tight gas/low permeability, at greater depths, and with higher initial pressures. For the Texas Gulf Coast Basin, plays WX-4, VK-1, and WX-2 hold the greatest URG potential by the year 2030. For East Texas, the three Lower Cretaceous-Jurassic Sandstone (KJ) plays account for most of the total natural gas URG potential by the year 2030. Play disaggregation unmasked important play-by-play trend variations in natural gas URG obscured by aggregated analysis of broad geological provinces.

Future research directions include detailed case studies, postmortem analysis, incorporation of a GIS data-base system, and detailed case studies of fields within plays showing the most potential for URG. Such studies may reveal additional information concerning the geological, engineering, and production controls on growth. Moreover, field case studies may be better suited for detailed economic analysis and determination of the effects and amenability of technology. Postmortem comparison of predicted URG with that of actual reported URG as a verification of methodology developed is also warranted. Current analysis utilized data from 1977 through 1996. Forecasts of URG during the preceding years can be compared with the actual growth that has occurred.

Moreover, future research directions include development of a readily accessible database system and trend-analysis technique by incorporating geographic information system (GIS). Plots and overlays of plays with data such as discovery year, depths, production, and depositional systems may reveal possible controls on URG. A data base through a GIS-based system will provide for more efficient data management, interpretation, and future additional updates. Major updates of the *Atlas of Major Texas Oil Reservoirs* (1983) and *Atlas of Major Texas Gas Reservoirs* (1989) warranted owing to new production and plays, can be incorporated into the data-base system. The Bureau of Economic Geology has developed such a system, as demonstrated in the two-volume *Atlas of Northern Gulf of Mexico Gas and Oil Reservoirs* (Seni and others, 1997). A basic GIS data set for the plays studied in the Texas Gulf Coast Basin and East Texas is included with this project report (appendix). Play outlines for the 31 major plays are given, along with linked summary tables describing major geological, engineering, and production characteristics. A much more complete and detailed GIS system would greatly enhance URG analysis and provide an excellent means of annual updates.

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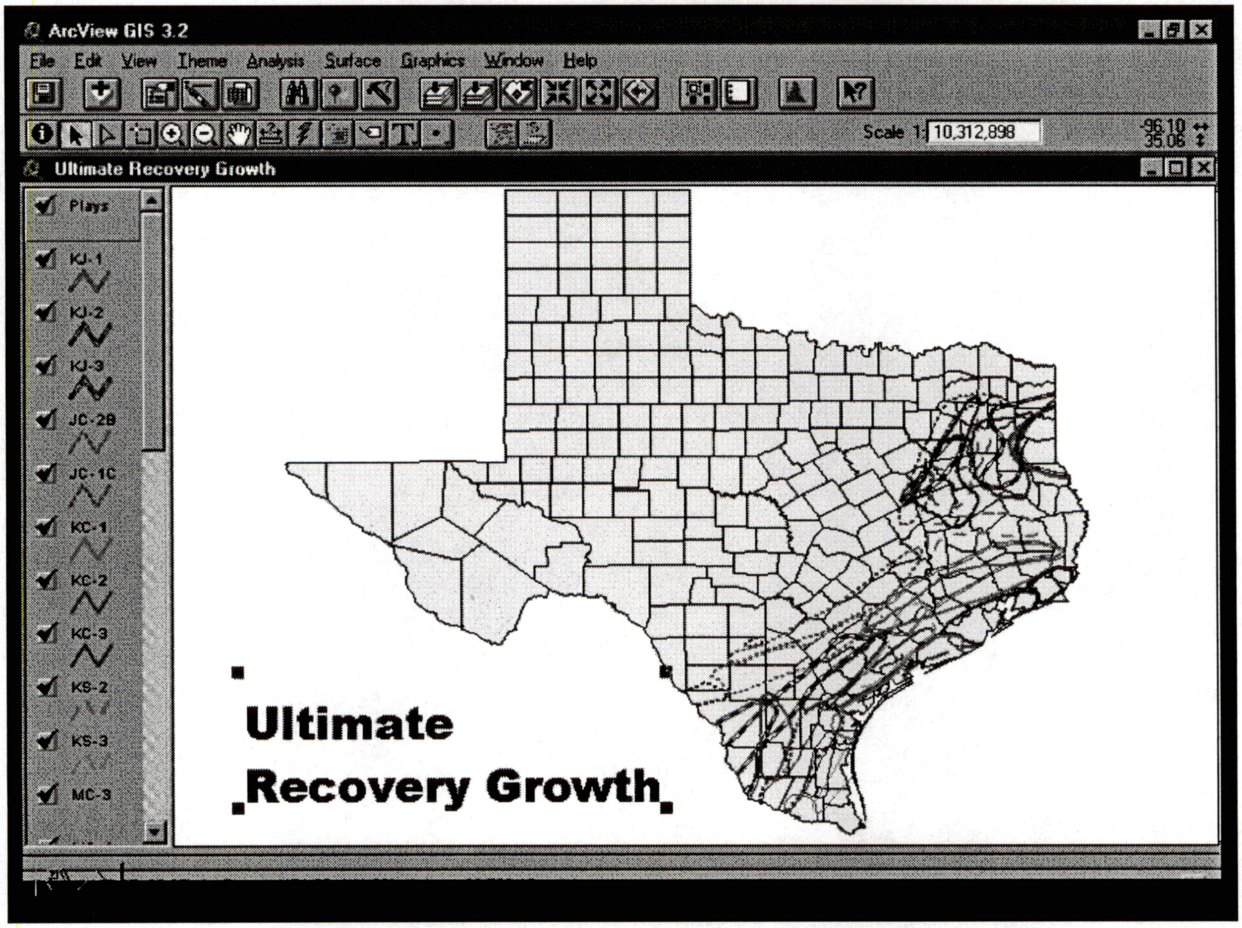
Appendix



The URG geographic information system (GIS) enables the user to visualize, explore, query and analyze data of the different natural gas plays in the Texas Gulf Coast Basin and East Texas. It is an integrated data base designed to give direct access to natural gas play information. The data were organized by linking map graphics and tabular data together in a digital project.

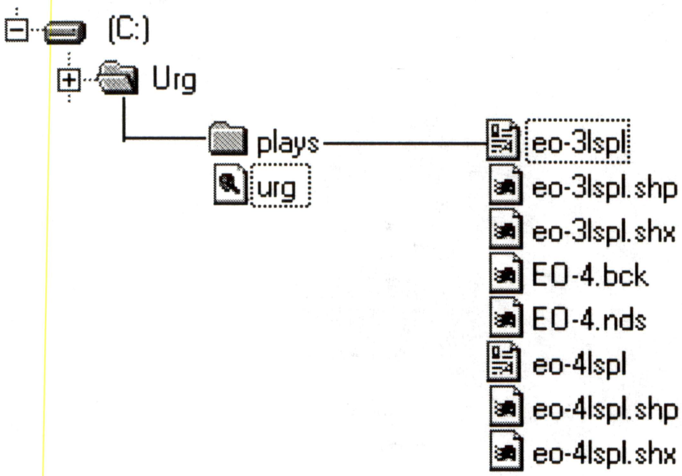
The URG GIS includes:

1. Geographic location of the natural gas plays.
2. The geological, engineering, and production attribute data of each play.

The URG GIS was built on an ArcView GIS, Version 3.2, software platform, with the following hardware requirements:

1. Pentium PC.
2. Minimum of 64 MB physical memory.
3. Color monitor (preferably with 256 colors or higher).

The URG GIS digital files are included in the file folder called “Urg.” This folder has one APR file and one additional folder. The APR file “Urg” is the project executable file. The additional folder “plays” has the graphic files and information.



The “Urg” file has an extension “.apr” in which the project stores all the views, tables, charts, and scripts. The play folder contains images, information tables, and default program files. Each play has a “bcl,” “nds,” “dbf,” “shx,” and “shp” file. In addition, the folder contains the following files: “play,” “texaslatlong,” and “rgdata.” The “play” file condenses the plays information, “texaslatlong” has the Texas county lines, and “rgdata” has the play attribute data. The files should be saved with the exact file names and root directories as shown. Upon first use, the ArcView program will ask for file locations. After pinpointing to the correct file locations, the program will correctly run the GIS files.