Chapter 4

The Natural Gas Resource Base

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About the only thing that any estimator can say with certainty about his (resource) estimate is that it is wrong.

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The focus of this technical memorandum is on U.S. natural gas availability for the next few decades—and, specifically, on the gas supply that can be provided by production in the Lower 48 States. Some analysts have claimed that the resource base is not an important constraint to gas supply during this period because the U.S. Geological Survey (USGS) estimated resource represents over 40 years of supply at current production levels, which does not count huge resources of unconventional gas (e. g., tight sands gas and methane from geopressurized aquifers) and potential imports of liquefied natural gas (LNG) or pipeline gas from Mexico, Alaska, and Canada.

In OTA's opinion, the claim that the resource base is unimportant to "midterm" (1985-2000) supply is arguable. Most theories of resource depletion imply that the "easiest" part of the resource base—for gas, this would be the largest, most accessible fields—tends to be discovered and exploited in the early stages of development and that declines in discovery rates and production will occur well before the "last" resources are discovered and extracted. Consequently, the resource estimates of USGS and the even higher estimates of the Potential Gas Committee (PGC) do *not* necessarily imply a capability to continue gas production at current levels for decades to come. These estimates indicate that we have already produced about 40 percent of the Lower 48 gas resource obtainable within the current price technology regime. The remaining 60 percent will be more difficult and more expensive to find and eventually extract than the already produced portion. The very pessimistic recent estimates of M. King Hubbert[1] imply that the United States may have produced 70 percent of all the gas it shall *ever* produce in the Lower 48. The Hubbert estimate thus implies that the United States may encounter an almost immediate dropoff in discoveries and reserve additions, followed shortly thereafter by sharp reductions in gas production. Even the more optimistic USGS and PGC estimates do not deny the possibility of significant reductions in supply within this century. * Therefore, an understanding of resource base estimates is important to midterm as well as long-term planning regarding natural gas policy.

In this section, OTA has not attempted to create a new, independent assessment of U.S. natural gas resources nor to settle on any existing assessment as the "best. " Instead we attempted to accomplish the following four goals:

1. To give the reader an idea of how natural gas resource assessments are made.
2. To describe the problems associated with general resource assessment methods and with particular individual assessments.
3. To define the continuing areas of controversy about the size and characteristics of the remaining gas resource base.
4. To convey OTA's evaluation of these controversies and of the credibility of some of the most widely used assessments.

[1]M. K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas, " in Oil *and Gas Supply Modeling*, S. I. Gass (cd.), National Bureau of Standards Special Publication 631, May 1982.

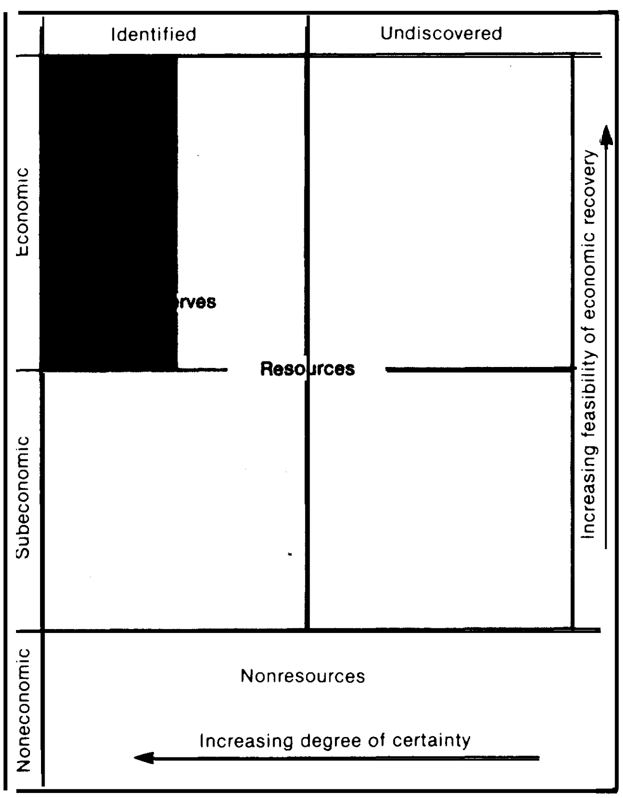
*For a discussion about the production implications of the Hubbert, USGS, and PGC assessments, see ch. 5, Approach Number 4 —Graphing the Complete Production Cycle. "

RESOURCE BASE CONCEPTS

An important source of difficulty in interpreting and comparing resource base estimates is the failure of the estimator to state and explain precisely the boundaries of his estimate—his definition of the resource base—and the failure of the client to comprehend what a resource base is, or what *a particular* resource base is.

The well-known McKelvey Box (named after its originator, the former director of USGS) is a useful tool in explaining basic resource base concepts (see fig. 8). The McKelvey Box classifies resources according to their economic feasibility of recovery and the geologic certainty of their occurrence. The outer boundaries of the box define the total amount of the material—in this case, natural gas—remaining within the crust of the Earth. The top third of the box (the proportions are NOT meant to be indicative of magnitude) represents gas that is economically producible at current prices using existing technology. The middle third represents gas that is expected at some *future* time to be producible but is currently not economically producible, either because of the absence of recovery technology or because of economic conditions. The lower third represents gas accumulations under such difficult physical conditions that they are likely never to be economically producible. Obviously, our inability to accurately project future economic conditions and future technology developments prevents us from knowing where to place the line between subeconomic resources and "nonresources."

Figure 8.—The McKelvey Box



SOURCE Adapted from V E McKelvey, "Mineral Resource Estimates and Public Policy," *American Scientist*, VOl 60, No 1, 1972, PP 32-40

The left half of the box represents identified resources—"resources whose location and quantity are known or are estimated from specific geologic evidence."[2] The economically recoverable portion of the identified resources is called "reserves" in the box, but this is not a universally accepted definition. (However, it is generally accepted that use of the term "reserves" to designate the total recoverable resource is a poor usage of the term. Reserves should always refer to gas that is in some sense within the ready inventory available for production.) *Proved or measured reserves* are the most certain portion of the recoverable identified resource, gas which has been estimated from geologic evidence *supported directly by engineering measurements.* An actual physical discovery by drilling is necessary for inclusion within this category. The remainder of the recoverable identified resource is somewhat poorly defined because of disagreement about what "identified" or "discovered" means. To USGS, for example, untapped reservoirs in discovered fields belong to the "discovered" resource,[3] whereas to the PGC, they are "undiscovered."[4]

A critical feature of the components of the resource base is that they are not static, As the production and discovery process continues, gas flows out of reserves and is processed, distributed, and consumed, and other gas moves from "undiscovered" to "identified" as geologic knowledge increases. Additionally, improved technology and economics cause gas to move from the subeconomic to the economic portion of the resource base. For example, improvements in offshore drilling technology may allow drilling in deeper waters and more hostile conditions, opening up new territories to development. Higher gas prices may allow the development of smaller reservoirs that

[2] G.L.Dolton, et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States,* U ,S. Geological Survey Circular 860, 1981.

[3] Ibid.

[4] Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of December 31, 1980),* May 1981,

were previously uneconomic, or allow known economic reservoirs to be developed more intensively and drained to lower abandonment pressures.

In the history of development of nonrenewable resources, the process of advancing technology and knowledge and of changing economic conditions has not always been smooth. Consequently, assessments of nonrenewable resources have tended to run in cycles. The discovery of resources in areas or under geologic conditions where they had not been expected or the development of new extraction and processing technologies can generate higher estimates of the remaining resource which may then taper off as that portion of the resource base is systematically depleted. For most resources, analysts assessing the remaining recoverable materials at the end of each cycle have been convinced that the most recent cycle upturn was the last and that resource depletion was imminent. They have been proven wrong time and again. *

Recognizing this, many resource estimators have confined their assessments to only a portion of the McKelvey Box, usually the top third and a small portion of the middle, subeconomic third. In doing so, they explicitly accept the possibility that changing economic and technological conditions could make their recoverable resource estimates obsolete. Unfortunately, the stated boundaries of the assessments are seldom very precise, and it is not always clear that the estimators have consistently followed their own specified rules for including and excluding portions of the total physical resource. Furthermore, besides the ambiguity of the boundary definitions, some resource assessments have chosen different boundaries than the "top third and a small portion" indicated above. Hubbert, for example, claims to capture the ultimately *recoverable resource-the* top two-thirds of the box—in his estimate, although he restricts the estimate to "conventional" gas and excludes such sources as methane in coal seams.[5]

The differences in economic technological boundary conditions between alternative gas resource assessments is one of several reasons why comparisons of assessments must be handled with caution. Table 5 lists some of the common problems encountered in comparing estimates.

*Oil has undergone such cycles of apparent depletion followed by large new discoveries and drastic upward revisions in resource estimates Two other well-known materials that have undergone similar cycles are uranium and iron ore

[5]Hubbert, op. cit.

Table 5.—Why It Is Difficult to Compare Resource Estimates

- Geographical areas (or geological limitations, such as depth) included in the estimate may be different—especially offshore boundaries.
- Assumptions about economic conditions and the state of technology may be different. Also, these assumptions are often poorly defined and appear in some cases to have been applied inconsistently.
- Some estimates may have included some unconventional resources.
- Areas that are currently legally inaccessible (e. g., wilderness areas) may or may not be included.
- Definitions of "undiscovered" may differ; they may or may not include undiscovered reservoirs in known fields,
- Degree of optimism about estimates (e.g., assigned probabilities) may differ.
- Estimates may or may not correct for liquid content and for impurities.

SOURCE Off Ice of Technology Assessment 1983

APPROACHES TO GAS RESOURCE ESTIMATION*

Although the extensive literature on oil and gas resource assessment identifies a wide variety of estimation techniques, all of the techniques fall into two basic categories. Geologic *approaches* rely on information and assumptions about the physical nature of the resource: volumes of sedimentary rock, numbers of geologic structures, presence of "source" rocks, time profiles of subsurface pressure and temperature, and the like. *Historical approaches* rely on the evaluation and extrapolation of past trends in gas production and discovery in the assumption that the size and

● This section is based largely on U.S. Geological Survey Circular *860,* "Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States, ' G.L. Dolton, et al. , 1Q81, and D. A White and H.M. Gehman, Methods of Estimating Oil and Gas Resources, " AAPG Bullet In, vol. 6.3, No. 12, December 1979.

character of the resource base, rather than transitory economic conditions and technological developments, are the most important factors controlling the discovery and production cycle. If this assumption is correct, the evidence provided by the manner in which the development cycle has unfolded can be used to ascertain the nature of the resource base.

Geologic Approaches

Geologic approaches run the gamut from simple—for example, the collection of expert geologic opinion on the size of the overall resource base—to complex procedures involving probabilistic estimates of the geochemical and geologic factors affecting the formation, migration, and accumulation of gas. The methods listed may be used in combination.

In geologic *analogy,* untested areas are examined for comparison with known producing areas. Comparisons range from simple evaluations of hydrocarbon source beds or reservoir beds to evaluation of dozens of factors. Because the use of analogy is basic to all geologic and geochemical understanding, this method in some sense is the basis for all the other methods.

In the *Delphi approach,* in its simplest form, each member of a group of geologists evaluates the geologic evidence available for an area and estimates the area's potential resources. These individual estimates are then reviewed by the group, possibly modified, and then averaged into a single estimate. This approach may also be used as a tool to assist other resource estimation approaches, as when experts are asked to jointly evaluate the hydrocarbon yield of an untested area in barrels per acre-foot as an input to a resource assessment using a volumetric yield approach (see below).

Areal-yield and volumetric-yield approaches involve the estimation of the amounts of hydrocarbon per unit area or volume of potentially productive rock in a region and the multiplication of these estimated yields by the appropriate area or volume. The yields are generally calculated by geologic analogy.

Geochemical material balances, elaborations of the *volumetric-yield approach,* attempt to account explicitly for the process of gas generation, migration, and entrapment. Rather than estimating a simple volumetric yield, for example, this approach might estimate the amount of organic matter in source beds, the fraction converted into hydrocarbons, the fraction actually able to move from the source beds into reservoirs, and finally the fraction of this amount actually trapped and concentrated and thus available for extraction.

Field *number and size approaches* attempt to count or estimate the number of prospective fields in the area being evaluated and to estimate their success rate and size distribution in order to yield an overall area resource estimate. Estimation methods include actual counting of structural traps by using seismic surveys, extrapolation from historic field size distributions (a historic approach, as discussed below), and calculation of success ratios by geologic analogy. Other levels of aggregation besides the field are also used; *play analyses,* for example, focus on groups of fields or prospects with several common geologic characteristics.

Some generalizations can be made about these approaches. The simple methods that use few factors to calculate gas resources all share the risk that key geologic factors, such as the temperature history of the rocks, may be left out. The converse is that the more complex methods, such as geochemical material balances, may assume a higher level of geologic knowledge than currently exists. Although the breakdown of the resource assessment into several individual components appears precise, the uncertainty associated with each component is quite large and the potential for error in the resource estimate is high. For example, incorporating factors such as pressure and temperature histories into resource estimation allows the estimator to account directly for the probability that petroleum actually was formed and survived. However, because the geology of most areas has changed significantly over time, it is difficult to trace these changes to reconstruct the temperature and pressures that existed during the periods of hydrocarbon formation, migration, and accumulation.

The simpler methods are most useful in the early stages of development of a basin when few data are available and the need for expert judgment and intuition is at a peak. The obvious disadvantage, however, is that documentation of the estimation process is minimal or, in the case of the simplest Delphi approach, lacking entirely. The credibility of these estimates, then, rests mainly on the reputation of the experts involved in the assessment or of the sponsoring organization.

Finally, the geographically disaggregated approaches, such as play analysis, are most useful when considerable exploration data are available. Many analysts think highly of these approaches, perhaps because the approaches deal in units that most accurately reflect the discovery process and thus allow participants in the resource assessment to draw most readily on their experience for geological analogs.

Historical Approaches

A variety of historical approaches to resource estimation rely on extrapolation of historical trends in production, reserve additions, and discovery rates as functions of time, number of wells drilled, or cumulative feet of exploratory drilling. Some of these approaches lack explicit assumptions about geology and simply search for curves that achieve the best fit to the data. Others (e. g., some of Hubbert's approaches) first assume general models of the production and discovery process and then adjust the models to fit the data.

A variety of formulations can lead to an estimate of the resource base. One simple example is shown in figure 9, which plots the rate of discovery of natural gas, in thousands of cubic feet per foot of exploratory well drilled, versus the cumulative footage drilled. An exponential or other function can be fit to the historical data and extrapolated into the future. After *f* feet have been drilled, the area under the curve is equal to the total amount of gas discovered up to that point. * The total resource base can then be estimated by measuring the area under the curve when it has been extrapolated to the point where all recoverable gas has been located. This point is assumed to be:

- when the amount of gas discovered per foot of drilling falls below some chosen lower limit, or
- when the cumulative exploratory footage is judged high enough to have allowed essentially all prospective acreage in the United States to have been explored.

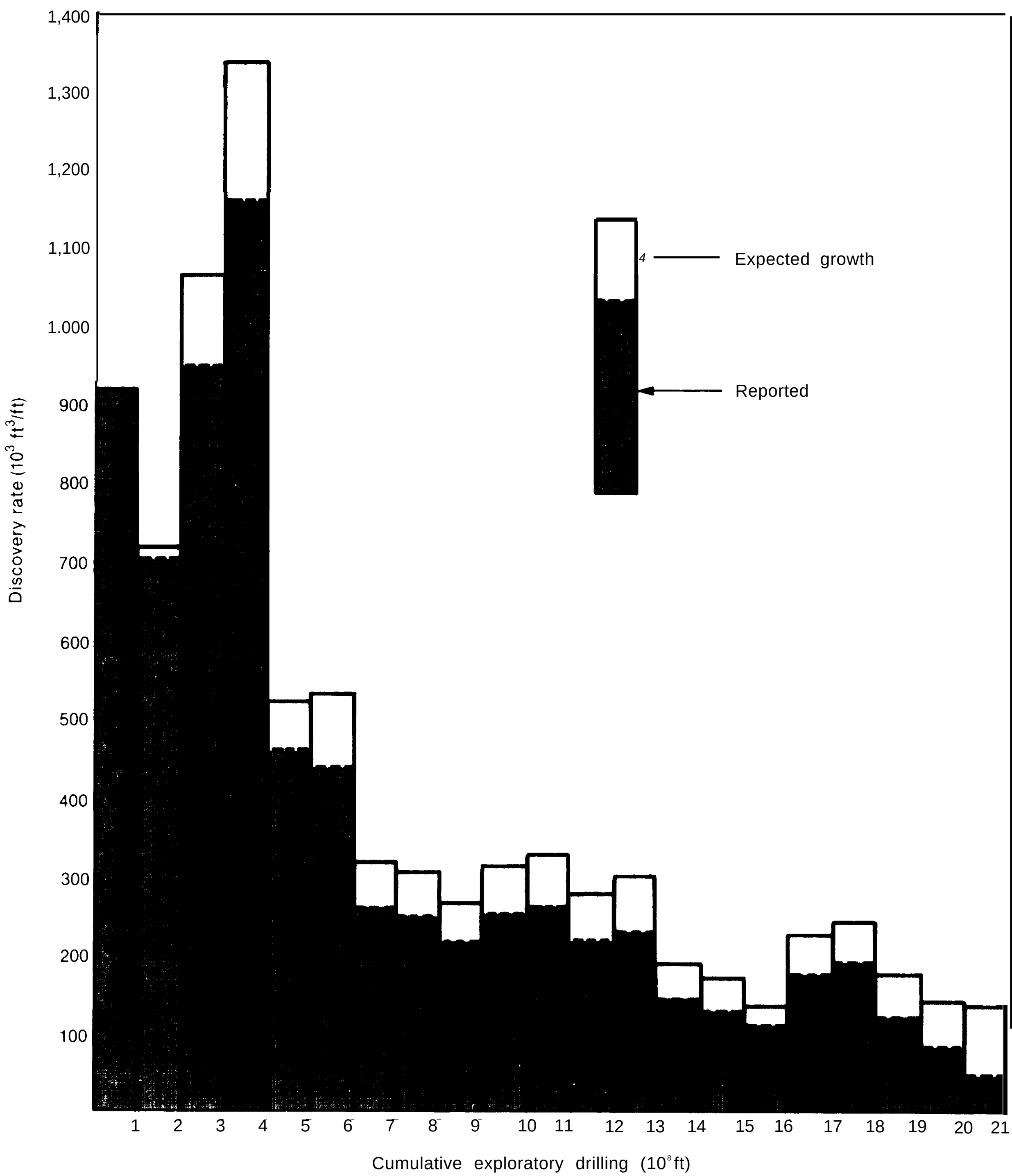
Although Hubbert's estimate of gas resources will be reviewed individually later, historical approaches to gas resource estimation *as a class* have some common limitations. First, areas that are not "mature' '-that do not have a substantial drilling or discovery history—are not represented in the historical data base and can be included in the assessment only if one is willing to assume they are part of the development process of a larger area and are not really independent. Consequently, Alaska is typically not included in the historical approaches, and the offshore areas are sometimes excluded as well. This limitation can be a problem with geologic as well as geographic categories; there is some question, for example, as to whether deep gas (below 15,000 ft) should be included in a "historical" resource estimate.

Second, since the resource estimates are totally dependent on extrapolations of the historical record, they depend heavily on the accuracy of this record. In the case of natural gas, this accuracy is probably poor. Through much *of* its discovery and production history, gas was usually a byproduct of the search for and production of oil and in the early years was often considered to be of very low value at best. Much gas was flared or otherwise wasted, production records were not kept, and gas discoveries often went unreported.

Third, all of these methods share the common assumption of all trend extrapolations: the future will be a reflection of the past. However, the "past" in the case of gas exploration and development has had interludes of radical change in the economic underpinnings and Government regulation of the industry and, to a certain extent, in the technology and geologic understanding driving the development process. Consequently, the historical approaches contain the implicit assump-

*Area $= \int^{t}$ (amount of gas discovered per foot drilled) d (cumulative feet drilled].

Figure 9.— Discoveries of Recoverable Natural Gas in the Lower 48 States v. Cumulative Exploratory Drilling



SOURCE David H Roof USGS

tion either that the process of change will continue in the same manner in the future or that the physical nature of the resource base—unchanging except for changes wrought by development itself—is the main force driving gas development. In the long run, the physical nature of the resource base is seen as overwhelming the importance of volatile and transitory events or forces such as Government regulations and gas demand and price in determining the shape of the development curves. *

Fourth, it is difficult to define the economic, technologic, geographic, and geologic boundaries of a resource assessment based on historical trends. For example, data on the development of U.S. gas resources tracks a steady expansion of geographic coverage of exploration and production, an increase over time in the depth of wells, and a radical improvement in exploration technology. Did historical assessments of the U.S. gas resource done before Anadarko deep drilling include or exclude this deep resource? Will an assessment based on historical data account for a new Overthrust Belt type of development? To the extent that the historical curves capture past change, can they account for future changes? These questions are essentially unresolved. A common criticism of historical approaches is that they do not adequately capture the effect of new technologies and other changes. However, there is little agreement on what they *do* capture: opinions range from the full capture of future economic conditions' to the capture only of gas that would be discovered and produced under the socioeconomic conditions of the last several decades[7]—in other words, from the top two-thirds of the McKelvey Box to only the top third.

It is worth noting that a substantial "surprise''—e.g., the unexpected discovery of a new geologic "horizon' '-cannot be accurately predieted by a historical approach. This is because a true surprise will not have affected the previous discovery and production history in any discernible manner. Therefore, the historical method will yield the same resource estimate no *matter how big the surprise turns out to be.* (Although the geologic approach cannot predict such a surprise, it can incorporate its effects immediately for future predictions.)

Fifth, although "historical approaches" seek to extrapolate trends that are functions primarily of the resource base and are relatively unaffected by transient economic effects, the available data may be too aggregated to allow this. Generally, the data measure processes that are made up of two or more components, some of which are sensitive to market conditions. For example, the finding rate of new field wildcats may be used to represent the success of the discovery process. * However, finding rate data measure the combined success of at least two quite different kinds of exploration. The high-risk, high-payoff wildcats represent the search for large fields in untried areas and the exploration of older areas based on new geologic interpretations. The finding rate of these wildcats is a critical determinant of the long-term replenishment of proved reserves. The low-risk, low-payoff wildcats represent the redrilling of old, formerly uneconomic areas, or the clustering of exploratory drilling around a successful new strike. Because drilling statistics do not separate new field wildcats into different risk categories, the data on low-risk, low-payoff drilling, which is very sensitive to market conditions, dilutes and distorts the data on the drilling activity most relevant to ensuring the future of gas production.

The problem of using a single data series to measure a process that has two or more dissimilar components becomes more acute as larger and larger aggregations, geographical and otherwise, are used. Compiling the data for individual provinces may be useful because, for example, exploratory drilling on a local scale is more likely to be either high or low risk rather than a combination

'In support of this view, It is worth mentioning that neither the major technical advances in exploration nor the opening of new territories since World War I I were of sufficient importance to restore the oil or gas discovery rate to pre-war levels; instead, the discovery rate continued a fairly steady downward drift for several decades, in seeming disregard of changing conditions and technology,

[6]Ibid

'R, I' Sheldon, "Estimates of Undiscovered Petroleum Resources—A Perspective, " U S. Geological Survey Annual Report, Fiscal Year 1978.

'Discover, data generally is preferred over production data in a historical approach because the discovery cycle is always a few years older than the production cycle, Extrapolation to the end of the cycle consequentl, is less severe for discovery than for production, of the two. Thus, a disaggregated approach conceivably may be more successful than a national one in appropriately interpreting implications of a changing finding rate. On the other hand, the reduction in data points may tend to cause data series for small areas to be very erratic, and aggregation over larger areas may be necessary to detect long-term trends.

Dealing With Uncertainty

It must seem obvious from past mistakes that petroleum resource assessment is a risky business. For example, tracts in the offshore South Atlantic shelf were recently leased to industry for millions of dollars (proceeds from the first two sales, lease sales 43 and 56, exceeded $400 million’) with an industry/Government consensus that large volumes of economically recoverable oil and gas were present, yet drilling results have thus far been negative.[9] Similarly, expected large fields in the Gulf of Alaska have failed to materialize under the drill. Conversely, drilling since 1975 in the Western Overthrust Belt has revealed a large, previously misunderstood potential for oil and gas. Even the calculation of proved reserves is uncertain and in some instances (e. g., Louisiana and Texas) has required extensive corrections in later years.

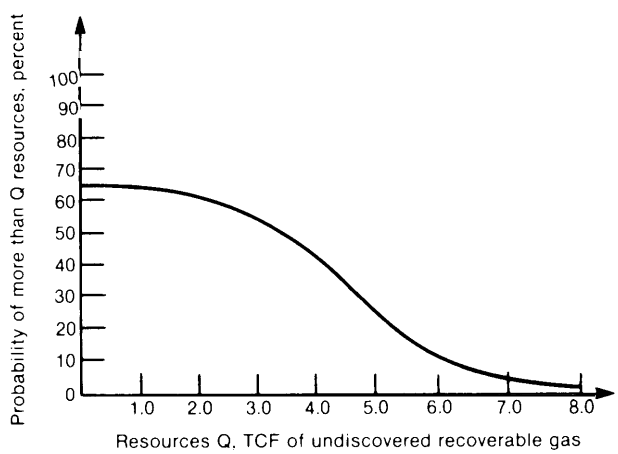
A major reason for the risk in resource assessment is that the presence of economically recoverable concentrations of petroleum requires the completion of an unbroken chain of events, each of which is difficult to predict. First, adequate amounts of source rock containing organic material must be present. Second, the temperature and pressure conditions must remain within a range capable of transforming the organic matter into petroleum. Third, geologic conditions must be right to allow the petroleum, once generated, to migrate. Fourth, permeable and porous rocks must be in the migration path to serve as a reservoir. Fifth, a geologic structure must be present to trap the petroleum so it can accumulate into commercial quantities. Not only the *availability* of the required conditions but also their *timing* are critical. The presence of an adequate trap, detectable with seismic or other search techniques, does not guarantee that the trap was present at the time of petroleum migration; if it was not, or if the trap was breached at some time after the petroleum entered the reservoir, the oil or gas would have escaped and would probably have reached the surface and dissipated.

Some estimators either (apparently) ignore uncertainty or acknowledge it only by expressing their results as an undefined or vaguely defined range (e. g., “optimistic/pessimistic”). Uncertainty *can* be dealt with explicitly and quantitatively in resource estimations, however. Resource estimates, or the individual factors used in estimating resources (e. g., volume of sedimentary rock, hydrocarbon yield factor), can be expressed as probability functions instead of point estimates or ranges. For example, figure 10 illustrates a hypothetical probability function for the undiscovered recoverable gas resources of a single province. The curve shows the probability that there are more than Q undiscovered resources in the province. * “Probabilistic estimates” such as these cannot be directly added (or, in the case of estimates for volumes and yield factors, multiplied) to form ag-

[8]USGS Open-File Report 82-15, South Atlantic Summary Report 2, May 1982.
‘Ibid.

*The probability is not 100 percent at Q = O because there is a finite probability that the province does not have “more than O resources; “ in a totally unexplored province, this probability of zero recoverable resources may be quite large.

Figure 10.— Probability Distribution for Undiscovered Recoverable Gas Resources in a Province



NOTE: "More than" cumulative distribution function.
SOURCE: David H. Root, USGS.

gregate *resource* estimates, such as an estimate of total U.S. gas resources. Instead, they are added statistically; one commonly used technique is called Monte Carlo simulation (see box A). *

Although probabilistic methods are useful for displaying some of the uncertainties associated with resource estimation, the *language* used to describe the results of these methods is often misunderstood by a lay audience. It is critical to remember that the accuracy of probabilistic estimates is limited by the extent to which the estimators' model of the physical universe is a correct one. In estimates such as those of USGS, the "95th percentile" estimate should not be interpreted as meaning that there actually is a 95 percent probability that the resource base is larger than this estimate. It should instead be interpreted to mean only that the assessors, with *whatever limitations their geologic "mindsets" and their limited data may impose on them*, believe that there is such a 95 percent probability. This difference may seem subtle, and it certainly is not kept secret by the estimators, but it is nevertheless important.

● In Monte Carlo simulation, a value is selected at random from each of the separate probability functions that are the components of the resource estimate (e. g., for a nationwide assessment, the components are the individual province assessments; for a volumetric resource assessment, the components are the volume of sedimentary rock and the hydrocarbon yield factor). These values are then combined arithmetically to form a single point estimate of the resource base (for the nationwide assessment, the values from each province are added; for the volumetric, the values selected for volume and yield are multiplied). This procedure is repeated many times, each time producing a new point estimate, until a probability function for the resource base is formed.

Box A.—Does the Monte Carlo Technique Underestimate Uncertainty?

An analytical problem with the probabilistic estimates of national gas resources is that the Monte Carlo method, when used to link individual province estimates together, usually assumes that the individual estimates are completely independent from one another. In lay language, "independence" of this sort means that any additional information gathered from one petroleum province can in no way be applied to any other province, and that a change in one province's estimate won't affect any others' estimates. In other words, independence assumes that so much is known about the geologic principles underlying petroleum formation and occurrence that the only things to be learned by additional drilling are site- or province-specific.

In reality, few if any geologists would claim such an advanced state of knowledge. Instead, it seems likely that additional knowledge of a pessimistic nature—discovery that resources in several provinces actually were leaning toward the low end of the original estimate—can cause estimates in some other provinces to be revised downwards, and vice versa. For example, geologists are currently uncertain about the number of small fields* in the resource base because past exploration ignored the discovery of such fields (they were too small to be considered producible). If the search for such fields became highly successful in one or more provinces, this *success* would probably cause geologists to reassess the significance of small fields in other provinces as well. Province-to-province dependence of this sort implies that the "optimistic" (high) national resource estimates probably aren't optimistic enough, nor are the "pessimistic" estimates pessimistic enough. In conclusion, the high-low ranges flowing from Monte Carlo-based probabilistic resource calculations that assume province-to-province independence are too narrow, that is, they understate the uncertainty associated with combining the individual province estimates into a regional or national estimate. The error introduced by the actual dependence of the estimates may be reduced, however, by careful choice of province boundaries and by making the provinces large enough.

*A small field may be defined as one with an ultimate production of less than 10 million barrels of oil, 60 billion cubic feet of natural gas, or comparable amounts of oil and gas energy expressed as barrels of oil equivalent (BOE), using 6,000 cubic feet of gas as equal to 1 barrel of oil.

COMPARISON AND REVIEW OF INDIVIDUAL ESTIMATES

Although many readers may be aware only of the work of USGS and perhaps that of M. King Hubbert, assessments of the U.S. natural gas resource base are quite numerous and use a wide variety of approaches. Table 6 lists some of the more recent estimates of the "ultimately recoverable resource''—the total amount of gas that will be produced. The table also shows estimates of the recoverable resource remaining as well as the resources not yet added to proved reserves. The wide range of mean estimates for the remaining resources in the Lower 48 States—244 to 916 trillion cubic feet (TCF)—implies, in turn, a wide range in the outlook for future gas production, especially in the longer term.

Many available resource assessments are poorly documented and cannot be evaluated. OTA has reviewed some of the more widely known estimates, however, including those of USGS, PGC, the RAND Corp., and M. King Hubbert.

U.S. Geological Survey

Recent estimates of undiscovered gas resources by USGS, as presented in 1975 in "Circular 725"[10] and more recently in 1981 in "Circular 860,"[11] are

[10] B.M. Miller, et al., *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States,* " USGS Circular 725, 1975.
[11] Dolton, et al. , op cit.

Table 6.—Alternative Estimates of Ultimately Recoverable and Remaining Natural Gas in the United States (TCF)

Estimator	Publication date	Ultimately recoverable resources: Lower 48	Ultimately recoverable resources: Total U.S.	Remaining resources Lower 48, 1983[a]	Remaining resources not yet 'added to proved reserves, Lower 48, 1983[b]
Mobil	1974	—	1,076-1,241-1,456	—	—
Garrett	1975	—	1,313	—	—
Wiorkowsky	1975	1,221 -1,289-1 ,357[c]	—	595-663-731	421-489-557
Bromberg/Hartigan	1975	966'	—	340	166
Exxon Attainable	1976	—	917-1,112-1,577	—	—
Shell	1977	946	910-1,075-1,260	320	146
IGT	1980	—	1,288-1,798	—	—
PGC	1983	1,542	1,711	916	742
Hubbert (1)	1980	870	—	244	70
Hubbert (2)	1980	989[d]	—	363	189
RAND	1981	902	989	283	109
USGS	1981	1,400	1,422-1,541-1,686	774	600

[a] Approximate cumulative Lower 48 production through 1982 was 631 TCF, of which about 5 TCF is in underground storage Remaining resource' is "Lower 48" (ultimately recoverable) column value minus 631 TCF plus 5 TCF
[b] Lower 48 proved reserves assumed to be 169 TCF at 12/31/82 (excluding underground storage)
[c] Original estimate for onshore gas only Total arrived at by adding USGS (mean) estimate for ultimately recoverable offshore gas in Lower 48 (235 TCF)
[d] Based on an analysis of finding rates by David Root, USGS

SOURCE Mobil—J D Moody an-d R E Geiger, "Petroleum Resources, How Much 011 and Where, " Technology Review, March/April 1975 Verbal comments by John Moody at a FPC presentation, Apr. 14, 1975

Garrett-R W Garrett, "Average of Some Estimates by Major Oil Companies and Others, 1975, " oral presentation at Executive Conference of the American Gas Association, June 9-11, 1975, cited in Potential Gas Committee, *A Comparison of Estimates of Ultimately **Recoverable** Quantities of Natural* Gas *in the United States,* Gas Resource Studies No 1, Potential Gas Agency, April 1977.

Wiorkowski—J J. Wiorkowski, *Estimation* of *Oil* and *Natural Gas Reserves Using Historical Data Series A Critical Review*, unpublished manuscript, 1975, cited in J J Wiorkowski, "Estimating Volumes of Remaining Fossil Fuel Resources A Critical Review, " in *J Am Stat Assoc*, VOl 76 No 875, September 1981

Bromberg/Hartigan—L Bromberg and J A Hartigan, *Report to the Federal Energy Administration*, unpublished manuscript, 1975, cited in Wiorkowski (1981), noted above

Exxon—Exxon Co , U S A Exploration Department "U. S 011 and Gas Potent ial,'' March 1976 *Oil* and Gas *Journal,* "Exxon Says U S St Ill Has Vast Potential Mar 22, 1976

Shell—C L Blackburn, Shell 011 Co., "Long-Range Potential of Domestic Oil and Gas, " presented at NAPIA/PIRA Fall Conference, Boca Raton, Fla Oct 19, 1978 *Oil and Gas Journal,* "Shell Alaska Holds 58°/0 of Future U S. 011 Finds, " Nov 20, 1978

IGT—J D Parent *A Survey of United States and Total World Product/on, Proved Reserves, and Remaining Recoverable Resources of Fossil Fuels and Uranium* Institute of Gas Technology, Chicago, August 1980, cited in American Gas Association, "Energy Analysis: A Comparison of U S and World Remaining Gas and 011 Resources, ' Aug 7, 1981

PGC— Potential Gas Agency, News *He/ease–February 26 1983*

Hubbert (1) (2)—M K Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas, " in *Oil and Gas Supply Mode//rig, S* I Gass (ed) National Bureau of Standards Special Publication 631, May 1982

RAND—R Nehring with E R Van Driest II *The Discovery of Significant Oil and* Gas *Fields in the United States*. R 2654/1 USGS/DOE, RAND Corp January 1981

USGS—G L Dolton, et al *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*. U S Geological Survey Circular 860, 1981 probably the most widely used gas resource estimates. The most recent estimate uses a Delphi-type approach whereby teams of geologists arrive directly at resource estimates for individual petroleum provinces through a subjective assessment of the available geological data and the results of a variety of estimation approaches (including volumetric, play analysis, and other geologic methods as well as finding-rate analyses and other historical methods).

The estimates are probabilistic, that is, each is presented as a curve that shows the probability that the actual resource base is larger than any particular value (see fig. 10). Thus, the 95th percentile estimate reflects the USGS assessment that there is a 95 percent probability that the actual resource base is at least this large. Because only those resources that are virtually certain to exist are included, this estimate would be considered the pessimistic extreme of the range of estimates. The individual province estimates are added statistically, using a Monte Carlo technique, to achieve a national estimate. As described previously (box A), the "high-low" range described by the 5th and 95th percentiles is narrower than would be the case if the interdependence of individual province estimates could be taken into account. However, the potential problem was described as minor by the experts OTA talked with, largely because of USGS's selection of province boundaries.

The USGS assessment is unusual in that individual probabilistic estimates are available for each of 137 provinces, providing a very fine level of detail. Also, detailed information files on individual provinces are open to the public at USGS's Denver facility. As with most geologic estimates, the USGS estimate is not meant to include all resources that may be recoverable at any time, but is instead limited to the resources that "will be recoverable under conditions represented by a continuation of price-cost relationships and technological trends that prevailed at the time of assessment (1980)."[12] Consequently, resources that are currently in fields that are too small, under too much water, under geologic conditions that are too difficult, or are otherwise not economically recoverable are not reflected in the current estimates but could be expected to enter the recoverable resource base in the future if gas prices rise and technology improves significantly.

In contrast to the approach for estimating resources in undiscovered fields, USGS calculated the remaining resources in undiscovered pools in known fields and expansion of the proved areas of known pools' by using a simple extrapolation from historical records of gas-field growth.[13] Field growth is a significant source of gas, and USGS calculated the resources in this category to be about 172 TCF, or over one-fifth of the remaining gas resources. Unfortunately, the USGS approach to assessing this source is problematical because the historical growth rates of known fields have tended to be extremely variable, and the characteristics of fields discovered recently, and calculated by this method to yield the most growth, are quite different from the fields that supplied the historical data. In OTA's opinion, there is a significant potential for error in this approach.

In USGS's 1975 resource estimate, the economic boundary of recoverable resources also proved to be a problem; a survey of the assessment team revealed considerable differences between their various interpretations of the meaning of the boundary definition. " Although OTA undertook no formal survey for the 1981 assessment, informal talks with analysts close to the assessment process lead OTA to believe this problem still exists. For example, several analysts believe that part of the offshore resource in the USGS assessment is far too expensive to be developed unless gas prices escalate substantially. If this is correct, these resources are subeconomic, according to USGS's definition, and should not be included in the estimate of recoverable resources.

Another potential problem area in the assessment is the boundary between "conventional" and "unconventional" resources. The USGS estimate

[12] Ibid

*These resources are called "inferred reserves in the USGS assessment and are equivalent to the "Probable potential resources" in the PGC assessment,

"Ibid, app. F.

"Personal communication with John Schanz, Congressional] Research Service.

is of “undiscovered recoverable *conventional* resources (our emphasis)” and excludes “gas in low permeability (’tight’) reservoirs” and other so-called unconventional resources.[15] The precise meaning of the exclusion is unclear, however. In moving towards lower and lower permeabilities, there is no general consensus about where “conventional but low permeability reservoirs” end and “unconventional ‘tight’ reservoirs” begin, and USGS has not defined a threshold value of permeability to separate the two.

Circular 860 does imply, however, that some undiscovered gas in low-permeability reservoirs was excluded from the estimated conventional resource base even though the gas could currently be defined as economically recoverable. Consequently, all else being equal, the USGS estimate should be expected to be smaller than estimates that include all economically recoverable gas resources.

It also is commonly believed that USGS’s Delphi technique, described by USGS as relying on reviews of the results of a variety of approaches, relies primarily on the results of volumetric analysis. This reliance on the volumetric approach is probably due to data limitations. The USGS data base, although substantial, is generally limited to public data.[16] Volumetric analysis has often been associated with relatively optimistic resource assessments.

Potential Gas Committee

The estimates of “potential” gas resources—recoverable resources that have not been produced or proved—by the PGC represent the gas industry counterpoint to the USGS estimate. *

PGC’s most recent estimate of the total U.S. potential resource—876 TCF for the end of 1982[17]—represents a decrease from the year-end 1980 estimate.[18] Because this decrease is balanced by additions to proved reserves during the period, the old and new estimates are similar in their estimates of total ultimately recoverable resources.

The PGC estimation procedure is generally structured like a volumetric analysis in that the PGC analysts separately estimate the volume of potential gas-bearing reservoir rock and a yield factor (amount of gas per volume of rock) and multiply the two to arrive at an initial resource estimate. The analysis combines aspects of other geologic approaches, however. It is also strengthened by the separate estimation of gas potential for 11 distinct geographical areas within the Lower 48 States, for three distinct categories of resource within the areas according to their state of development, * for offshore and onshore resources, for resources above and below a depth of 15,000 ft in the onshore portion, and for resources above and below water depths of 200 meters to a maximum of 1,000 meters offshore. The estimates “include only the natural gas resource which can be discovered and produced using current or foreseeable technology and under the condition that the price/cost ratio will be favorable.’’” These conditions are similar to those adopted by USGS, but what constitutes a “favorable price/cost ratio” remains unclear. The large proportion of deep resources incorporated in the estimate may imply, however, that PGC has included resources that will require prices above present market clearing levels. * *

The PGC volumetric estimation procedure is considerably more sophisticated than early tech-

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[15] Dolton, et al., op. Cit

[16] G. Dolton, USGS, presentation at RAND workshop on estimating U.S. natural gas resources, Washington, D. C., Mar. 1-3, 1982.

•PGC is composed of members and observers from gas producers, pipelines, and distribution companies and observers from the American Gas Association, Department of Energy, Gas Research Institute, and other public and private organizations. The actual estimating workgroups consist mainly of industry employees and consultants, but State geological surveys are well represented, and some of the groups include personnel from Federal agencies and from universities.

“News Release, Potential Gas Agency, Feb. 26, 1983.

[18] Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of December 31, 1980)*, May 1981.

*The categories are “Probable, ” “Possible, ” and “speculative” resources. Probable gas results from the growth of known fields, Possible gas is associated with the projection of plays or trends of a producing formation into a less well-explored area of the same geologic province, and Speculative gas is from formations or provinces that have not yet proven to be productive.

“Ibid.

* *On the other hand, the actual price requirements for producing deep gas under free market conditions are uncertain, and it is possible that much of PGC’s deep potential is producible at prices not far removed from today ’s.

niques that were based on total volumes of sedimentary rock. In the PGC analysis, the volumes of potential gas-bearing reservoir rock are estimated by adding up estimates of individual traps and trap sizes where sufficient data is available. According to PGC's methodology description,'" techniques such as play analysis and field number and size approaches are used to construct an areawide volume estimate based on a variety of existing geological data. Yield factors (gas volumes rock volumes) are then calculated by selecting appropriate analogs from producing areas and adjusting the yields to account for geochemical factors such as the thermal history of the source rocks. Finally, the analysts are asked to multiply the (volume) x (yield) estimates by their assessments of the probabilities that traps actually exist and that an actual accumulation of gas has occurred.

The analysts also are asked to separately estimate "optimistic," "most likely," and "pessimistic" volumes of gas in a manner similar to that of the USGS. In contrast to USGS, however, PGC publishes only the "most likely" estimates. The other estimates are apparently used for review purposes on] y.

Because PGC publishes only the results of its analyses and does not release any internal details of the resource calculations (except for general methodology descriptions), and because it is essentially a gas industry organization, the credibility of PGC's resource estimates may be questioned. In OTA's opinion, however, the PGC estimates should be taken as a serious effort at resource assessment by analysts with excellent access to exploration data. The estimating workgroups, although composed mostly of industry employees, have a sufficient number of other participants—and a sufficient divergence of incentives within different segments of the industry-to prevent any attempts to subvert the assessment process significantly. Also, the long-term professional history of the organization (since 1966) and the oversight of the Colorado School of Mines are substantial arguments for accepting the PGC estimates as honest reflections of the professional judgment of the organization.

[20]Ibid

An advantage of the PGC estimates is that the basic methodology has been applied, with evolutionary changes, for **16** years. Table 7 shows the eight estimates of ultimately recoverable gas resources in the Lower 48 States produced by PGC since 1966. The consistency of these estimates is high. In fact, given the advances in technology and the major additions to the known boundaries of conventional gas supply that have occurred in the past 16 years, * the mildness of the upward trend in the estimates over this time period implies a movement toward more conservative estimates. This conservatism is particularly interesting in light of PGC's resource estimates being among the most optimistic of the major assessments.

In its 1982 assessment, PGC attempted to isolate that portion of the estimated potential resource that occurs in tight formations—tight sands with permeability levels less than 0.1 millidarcy (conforming to the Federal Energy Regulatory Commission definition for gas eligible for incentive pricing) and Devonian shales. A series of areawide estimates were produced for depths above and below 15,000 ft. The "tight" portion of the U.S. potential gas resource was estimated to be about 20 percent of the total, or 172 TCF.

This estimate is highly significant for two reasons. First, it demonstrates graphically the

*For example, the addition of the Western Overthrust Belt due largely to advances in seismic technology, and the addition Of large amounts of gas from low-permeable formations due to advances in fracturing.

Table 7.—Comparison of Potential Gas Committee Estimates of Ultimately Recoverable Gas Resources in the Lower 48 States

Estimate as of yearend	Ultimately recoverable resources (in TCF)
1966	1<283
1968	1,426
1970	1,498
1972	1,446
1976	1,396-1,421-1,446
1978	1,550
1980	1,502
1982	1,542a

aApproximate—A portion of the difference between the 1980 and 1982 estimates is due to discrepancies between the proved reserve values computed by AGA (used for the 1980 calculation) and the EIA (used for the 1982 calculation)

SOURCE Potent [al Gas Agency, *Potential Supply of Natural Gas in the United States (as of* December 31. *1980)* May 1981 and Potential Gas Agency, News Release Feb 26 1983

24-358 0 - 83 - 4

long-term growth in the "ultimately recoverable" gas resource base and offers some support to the optimistic view that advancing technology can overcome at least some of the effects of resource depletion. Second, to the extent that other resource assessors may have excluded tight gas from their estimates, it may bring the PGC estimate closer to the "mean" of gas resource estimates in table 6. Unfortunately, the definitions of the boundary conditions of most of the assessments in table 6 are not sufficiently clear to ascertain whether tight gas *that is recoverable under the PGC boundary conditions* were excluded or included. A possible exception, however, is the USGS assessment, whose stated boundary conditions appear to be more restrictive than PGC's. It is probable that some of the tight gas included in the PGC estimate was not included in the USGS estimate.

RAND/Nehring

Richard Nehring of the RAND Corp. has produced an assessment of conventional U.S. oil and gas resources by a method that stresses an evaluation of the discovery of significant fields. [21] The assessment incorporates a variety of approaches:

1. To estimate the growth of reserves in known fields, a combination of methods were used, including extrapolating by historical field-growth factors and by more analytical approaches that used available geologic information and known production practices.
2. To estimate the amount of resource remaining to be discovered in known producing plays, an approach based on extrapolating historical trends was used. The key to this approach was the establishment of a data base containing production and reserve values, the year of discovery, discovery method, trap type, depth, and other data for virtually every petroleum field discovered in the United States by 1975 larger than class C (10 million to 25 million barrels-of-oil-equivalent). Despite the emphasis on the historical record, however, the approach also incorporates geologic methods based on play analysis.
3. Play analysis was used to estimate the resources in new plays in mature regions.
4. Depending on the availability of data, a variety of approaches were used to estimate resources in the frontier (ranging from volumetric analysis to field number and size approaches).

The estimates for new plays in mature regions and frontier areas were "risked" (i. e., the probability that there are no recoverable resources in the play is taken into account), and the assessments of undiscovered resources were expressed as probability distributions in a manner essentially identical to that used by USGS.

The RAND assessment has been criticized because of its alleged failure to define the process by which its massive data base is translated into resource base conclusions. In OTA's opinion, the description of the methodology that appears in the RAND report is indeed brief and generalized and gives no specific examples of the assessment process. However, this failure is endemic to resource assessments as a class. Even the PGC assessment, which describes its analytical process in some detail, publishes no backup data and provides only the sketchiest details of the geologic reasoning behind its regional results. In contrast, the RAND assessment explicitly defines the historical and geologic reasons for its regional assessments and identifies—and argues against—opposing views. This approach allows at least a partial evaluation of the assessment, whereas most assessments can be evaluated only to the extent of either accepting or rejecting the final estimates.

At the core of Nehring's argument for his quite pessimistic estimate is the thesis that the geologic possibilities for finding substantial new oil and gas resources in the United States have been largely exhausted. Nehring identifies four major hypotheses about where significant amounts of oil and gas may yet be found—in fields below 15,000 ft in depth (for natural gas only); in subtle, difficult-to-detect stratigraphic traps; in small fields; and in frontier areas, including the Eastern and Western Overthrust Belts—and argues against

[21] R Nehring with E. R. Van Driest II, *The Discovery of Significant Oil and Gas Fields in the United States,* RAND Corp. Report R-2654 1 -USGS DOE, January 1981.

high optimism in each, with the possible exception of the frontier areas. The four hypotheses and Nehring's countering arguments are summarized in box B. A more detailed discussion of these hypotheses is presented later in this chapter.

A second facet to this argument is that this exhaustion of geologic possibilities is reflected in the recent (disappointing) history of exploratory drilling. Nehring argues that optimistic assessments simply do not bear up under the weight of the question, "Is it likely that we will find as many large fields as this assessment implies must be there?" For example, table 8 presents a proposed field size distribution that would yield an undiscovered petroleum (oil plus gas) resource equal to that predicted in the 1975 USGS (Circular 725) onshore assessment. This distribution would also be approximately equivalent to the more recent 1981 (Circular 860) USGS assessment, although the more recent assessment is slightly more optimistic. In the table, the proposed distribution is compared to actual field discovery statistics for 1971 through 1978. The last column shows how long it would take to find the necessary number of fields of each size category if the annual discovery rates of 1971 through 1978 continued for the life of the resource. In Nehring's opinion, the number of large fields that would have to be discovered to fulfill the USGS assessment is too large

Box B.—Rand Assessment's Arguments Against a Large Undiscovered Oil and Gas Resource Base

Deep Discoveries

- Major argument: Deep sediments are relatively unexplored. The few exploratory wells that have been drilled have been highly successful.
- RAND rebuttal: Physical and chemical conditions at these depths can be poor for methane stability. Reservoir porosity is often lacking. The area with deep sediments is a small fraction of total prospective sedimentary area. Most of the potentially productive structures in several basins have already been tested.

Stratigraphic Traps

- Major-argument: Exploration has focused on structural traps, leaving significant opportunities in subtle stratigraphic traps.
- RAND rebuttal: Actually, considerable attention has been paid to stratigraphic traps in the Anadarko, Permian, and other basins. Aside from the stable interior provinces, multiple stratigraphic traps are unlikely. Because stratigraphically trapped reservoirs tend to be thin, large fields would cover large areas and would likely have been discovered. Large traps would be vulnerable to breaching and other causes of petroleum loss.

Very Small Fields

- Major argument: Because small gas fields were previously subeconomic, their discovery went unreported. Many more small fields exist than indicated by historical experience, and they form a sizable part of the recoverable gas resource.
- RAND rebuttal: Future reliance on small fields is based on assumption only; there is neither historical nor geologic argument to back it up. Also, because giant and large fields are two-to-four orders of magnitude larger than fields small enough to have been ignored in the past, there would have to be many tens of thousands of such fields to make any significant difference.

New Frontiers

- Major argument: Areas such as Alaska, the offshore Lower 48 States, and the Overthrust Belts have not been extensively explored and offer the potential for many significant discoveries.
- RAND rebuttal: Yes, but the small number of exploratory wells drilled in the Gulf of Alaska, the Outer Banks of California, the eastern Gulf of Mexico, the Southeast Georgia Embayment, and Baltimore Canyon are sufficient to severely dampen optimism for these areas. Some very promising areas do remain, however, including the deeper Gulf of Mexico, offshore Ventura Basin, and others.

SOURCE Office of Technology Assessment, based on R Nehring, *The Discovery of Significant Oil and Gas Fields m the United States*, R-2654/1-USGS/DOE, RAND Corp., January 1981

Table 8.—Field Discovery Implications of USGS Circular 725, Onshore Lower 48 Undiscovered Petroleum Resource

Field size[a]	Potential field size distribution: USGS Circular 725	Actual field discoveries 1971-75	1976-78	Implied time to find USGS undiscovered resource, constant annual discovery rate at 1971-78 average (years)
AAAA (>500/>3,000)	11	0	1	88
AAA (200-500/1,200-3,000)	44	0	0	Large but indeterminate
AA (100 -200/600-1 ,200)	94	7	1	94
A (50-100/300-600)	199	7	3	159
B (25-50/150-300)	375	15	8	130
C (10-25/60-150)	977	44	22	118
D (1-10/6-60)	6,000	455[b]	—	66
E (<1/< 6)	70,000	3,041 [b]		115

[a]Values in parenthesis are size range in millions of barrel s-of-oil equivalent (mm boe)/billions of cubic feet of gas (BCF)
[b]1972-76, Committee on Statistics of Drilling of the American Association of Petroleum Geologists

SOURCE Off Ice of Technology Assessment, based on R Nehring, *The Discovery of Significant 01/ and Gas Fields in the United States*. RAND Corp report R-2654/1-USGS/DOE, January 1981 Also, personal communication, Richard Nehring

to be credible. The long "times of discovery" in the table appear to reinforce this opinion. Unfortunately, none of the reviewed assessments defined a timeframe for complete discovery of the resource base, and an interpretation of the compatibility of a particular resource base / discovery rate combination is anything but straightforward. Also, the cessation of the American Gas Association's (AGA) reserve data (particularly reserve additions from new field wildcats) in 1979 prevents an easy check on whether post-1978 new field discoveries are ahead of discoveries during 1971-78; if they were, an argument could be made that the times in table 8 were misleadingly long because the assumed discovery rate was too low. On the other hand, the assumption in table 8 of a constant annual discovery rate for new gasfields over a 50- to 100-year period appears optimistic, even if the assumed rate is a bit low at the beginning of the period. This is because discovery rates *per foot drilled* appear likely to decline during this period, and a constant *annual* discovery rate thus implies an ever-increasing rate of new field wildcat drilling in an increasingly hostile *and expensive* environment.

One portion of the RAND assessment that now seems particularly suspect is the median estimate for field growth. The estimate (67 TCF) was only about one-third of the field growth estimates of USGS and PGC, a seemingly surprising difference considering the substantial amount of geologic knowledge available. * Recent large reserve additions from field growth make it clear that this estimate was too low. *

Hubbert

As noted earlier, M. King Hubbert is one of a considerable number of analysts who have used a historical approach—fitting curves to past trends in production, reserve growth, discoveries, etc. — to petroleum resource assessment. However, Hubbert's estimates must be accorded special attention. In 1962, Hubbert predicted that U.S. oil production would peak in 1969 and decline thereafter. He then held his ground in the face of substantial criticism until the peak actually did occur, only a year later than he said it would. From that time, his assessments of petroleum trends and resources have received considerably more attention and respect.

Hubbert's most recent estimate of the size of the natural gas resource base was made in 1980.[22] He estimates the ultimate cumulative production of conventional natural gas (Q_m) for the Lower 48 States to be approximately 870 TCF. This is a remarkably low estimate given cumulative production to date of about 631 TCF and proved reserves of about 169 TCF; * * if correct, it leaves only 70 TCF remaining to be added to reserves from the growth of known fields (calculated by

'However, the recent controversy over the magnitude of additional gas that might be obtainable from old gas decontrol demonstrates that the availability of extensive geologic knowledge does not guarantee agreement over resources present.

*Nehring acknowledged this problem to OTA in a recent telephone conversation.

[22]Hubbert, op. cit.

* *As of the beginning of 1983. Numbers are approximate because 1982 production and reserve data have not been published.

USGS to be 172 TCF) and new field discoveries. In other words, Hubbert's assessment implies that the precipitous declines of the early 1970's in Lower 48 proved reserves will resume again almost immediately, with subsequent drastic consequences for production rates within only a few years.

In his 1980 assessment, Hubbert obtained five separate estimates, using basically three approaches (table 9). In his first approach he derived equations for the magnitudes and rates of change of gas production and discoveries by noting some simple boundary conditions for the production cycle * and fitting a second order equation** to these conditions. By further manipulating the equation obtained by this exercise, Hubbert derived three separate but related methods of estimating Q_∞, two involving the curve of cumulative discoveries and one involving production rate as a function of cumulative production.

In his second approach Hubbert assumed that the ratio of the discoveries of natural gas to those of crude oil will tend to remain stable, allowing the gas resource base to be calculated as a simple function of the oil resource base.

The third approach involved extrapolating the declining finding rate for gas out to the point where exploratory drilling ceases and taking the area under the curve, as discussed in the earlier section on historical approaches to resource estimation (see fig. 8).

*Cumulative production Q is zero at the beginning of the cycle and Q_∞ at the end: the production rate $\frac{\partial Q}{\partial t}$ is zero when Q = 0 and also when $Q = Q_\infty$).

** $\frac{\partial Q}{\partial t} = C_1Q + C_2Q^2$

Table 9.— Hubbert's 1980 Estimates of Ultimately Recoverable Gas Resources in the Lower 48

Method of estimation	Q_∞ (TCF)
1. Extrapolating the plot of production rate as a function of cumulative production .	810
2. Estimating the approach of cumulative discoveries to Q_∞ as time approaches ∞ . .	871
3. Finding the equation of cumulative discoveries versus time	840
4, Using oil resource estimate and assuming stable gas/oil discovery ratio. . .	876-896
5. Fitting and extrapolating the curve of discoveries per 10^8 feet of exploratory drilling	989

SOURCE Off Ice of Technology Assessment, based on M K Hubbert, "Techniques of Production as Applied to the Product Ion of Oil and Gas, " in *Oil and Gas Supply Mode//rig*, S I Gass (ed), National Bureau of Standards Special Publication 631, May 1982

Hubbert's work has been the subject of numerous critical appraisals.[23] This discussion will not attempt to review the appraisals but will incorporate some of their key points.

Of Hubbert's five estimates, the first three involve the assumption that the curves of *declining* production and proved *reserves* will be the mirror image of the curves of the (increasing) first portion of the resource development cycle. This derives from Hubbert's satisfaction with the "fit" of the simple quadratic equation he uses to approximate the curve of $\frac{\partial Q}{\partial t}$ v. Q. Aside from the criticism associated with all historical approaches—that the future does not have to look like the past, and more often than not doesn't—Hubbert never explores the possibility that he could achieve an equal or better fit with a different equation and thereby calculate a different Q_∞. Critics have shown, for example, that the resource base values obtained from fitting a curve to oil production data are sensitive to the type of curve used, and that Hubbert's assumed curve is not the best choice." Although Hubbert's curve for oil discovery is more satisfactory, it maybe that the less mature gas discovery curve is also flawed. *

The assumption of the fourth estimate, that the ratio of gas discoveries to oil discoveries will remain stable, appears to be very weak. The great majority (85 percent) of gas discoveries today are not associated with oil, and it is the consensus of many geologists that a large portion of the remaining gas resource lies below 15,000 ft in a physical

23 For example, L.S. Mayer cites three: D. V. P. Harris, "Conventional Crude Oil Resources of the U. S.: Recent Estimates, Methods for Estimation and Policy Consideration, " *Materials* and *Society 1*, 1977; N. Uri, "A Reexamination of the Estimation of Undiscovered Oil Resources in the U.S., " DOE/TM/ES /79-03, 1979, EIA; L. Mayer, et al., "Modeling the Rates of Domestic Crude Oil Discovery and Product ion," report to the EIA, Princeton University, Department of Statistics, 1979. (In comment on J, J. Wiorkowski, "Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review, " *J. Am. Stat. Assoc.*, September 1981)

"E. g., J. J. Wiorkowski, 1981, "Estimating *Volumes* of Remaining Fossil Fuel Resources: A Critical Review, " *J.* Am. *Stat. Assoc.*, September 1981, vol. 76, No. 875,

*The reasoning here is that the oil discovery curve gives more satisfactory results than the oil production curve because discovery is more advanced in its overall cycle. The less advanced, or less "mature, " the curve, the less satisfactory will be the results.

environment hostile to the preservation of oil. A method predicated on stable gas/oil ratios would appear to guarantee an overly pessimistic gas resource base estimate.

In the last estimate, Hubbert fits an exponential curve to a historical plot of finding rate (the ultimate volume of gas to be produced from fields discovered by 10^8 ft of exploratory drilling) versus cumulative exploratory drilling, by requiring the curve to pass through the last data point and by requiring the area under the fitted curve to equal the area under the historical data plot (see fig. 8). This estimate has several serious problems. First the curve does not fit the data because it virtually ignores the "form" of the data and concentrates instead on the last data point.[25] Second, the estimate is very sensitive to this last data point, yet the magnitude of the point is the sum of a value (reported new field wildcat discoveries) that may vary with economic conditions* and with the state of depletion of the resource base plus a second value (reserve growth after the initial reporting period) that is, at best, a gross approximation. * Third, as with the first three estimates, Hubbert makes no attempt to explore the possibility that he could achieve a better "fit" with a different curve. His choice of a negative exponential curve is an assertion, made several times but unsupported by reasoning in his text.

An interesting observation about this last estimate is that despite the fact that the fitted curve is well under the trend line of the last several units of drilling—an ingredient for an overly *conservative* estimate—the estimate is considerably higher than the four other estimates in table 9.

[25] Harris, 1977, op. cit.

● For example, a period of high-risk exploratory effort—responding to economic conditions that favor this sort of activity—will tend to yield high discovery rates, whereas one of lower risk effort responding to different conditions generally will yield lower rates. This is important here because Hubbert's analysis is dependent on the finding rate being a function only of the physical resource base and its state of depletion,

● The procedure used to estimate reserve growth utilizes the average growth rate over many years, However, the year-to-year historical growth rates have tended to be quite volatile, so the average growth rate for a single year or single period of 10^8 ft of drilling is at best a rough approximation. Furthermore, there are reasons to suspect that the *long-term trend* of reserve growth may now be turning downwards, causing a further error in an estimate assuming an unchanging trend.

RECONCILING THE DIFFERENT ESTIMATES

Which of these resource assessments are to be believed? In approaching this question, OTA used three criteria:

1. Is there a consensus, or even a "central tendency, " in the scientific community?
2. How credible are the methods used by the assessors, in the abstract and in actual performance?
3. What do the different assessments imply in terms of geology and future discoveries? Are these implications credible?

Is There A Consensus?

In OTA's judgment, the range of opinion in the scientific community about the size of the natural gas resource is too wide to represent a significant consensus. Not only are there the obvious divisions along the lines of the various estimates, or simply between "optimistic" and "pessimistic, " there is also an important division between scientists who believe in a particular estimate or range of estimates and those who do not believe that the state of knowledge is adequate enough to allow *any* reliable estimate to be made. Furthermore, some scientists believe that those estimates that invoke current technology and economic relationships—the great majority—are simply irrelevant, *whether or not they are correct within the constraints of these assumptions.* These scientists believe that both the inexorable advance of technology and rising prices that reflect resource scarcity will constantly push outwards the boundaries of the recoverable resource base. As noted previously, the history of resource estimation in general tends to support this view; cycles of predictions of scarcity followed by radical upward revisions in resource assessments appear to be common for nonrenewable resources (see box C). On the other hand, the USGS oil and gas resource estimates of the past decade and a half sustained some very substantial downward revisions as estimation procedures became more sophisticated.

Tables 10 and 11 summarize some of the key arguments used by the optimists and pessimists in explaining their positions on the probable size of the gas resource base. Because each of the arguments has merit, it is obvious that an unambiguous answer to the question, "How large is the U.S. gas resource base?" is not likely. Selection of a "best" estimate is further confused by the observation that some major disagreements exist even among assessors who appear to have the same general outlook (see box D), and some of the more important disagreements occur in areas where considerable geologic data exists to aid the resource assessments (and where, consequently, the most agreement might be expected).

Given what OTA would term a lack of consensus, is there at least a "central tendency?" What

Box C.—A Very Brief History of Petroleum Exploration

The history of petroleum exploration in general, and exploration for natural gas in particular, has been one of continuous movement toward new discovery horizons and resulting reappraisals of resource potential. The "movement" encompasses new geologic theories and "ideas," new exploration and production technologies, and new geographic areas.

During the first half-century of exploration following Drake's initial discovery in 1859, exploratory drilling was essentially random drilling, drilling at oil seeps, or drilling in areas where previous strikes had been made. Then a succession of geologic insights began to open up new horizons for exploration: first, the understanding that anticlines, some with surface manifestations, could serve as traps for petroleum; then, the discovery that petroleum deposits could exist in traps on the flanks of salt domes; next, the recognition of the petroleum potential of sand lenses and stratigraphic traps; and finally, the insight that petroleum could exist in recoverable quantities *underneath* thrusting plates, leading to the opening up of the Overthrust Belts to exploration and eventual large discoveries.

Another discovery "horizon" was the growing sophistication of the tools of the trade: the advent of the gravity meter and magnetometer, allowing the locating of geologic anomalies that might signal the existence of structural traps; the addition to the explorer's tool kit of refractive and then reflective seismology, which permitted the detailed mapping of geologic structures; the introduction of rotary drilling and advanced drill bits that allowed deeper horizons to be explored; the growing use of fracturing technologies, which opened up another geologic horizon in petroleum-bearing rock of low permeability; and the engineering triumphs of offshore drilling technologies.

At the same time, exploration and development moved into new regions, sometimes driven by the new technologies (e.g., the continental shelves) or new ideas (e.g., into Texas after realization of the importance of salt domes) and sometimes driven simply by the need for new supplies and dwindling prospects in the mature regions. Thus, exploration began in the Appalachian region but moved inexorably into Ohio and Kansas, into California and the Mid-Continent Region, to the onshore Gulf of Mexico, and spilled out into the Offshore, moved to the Overthrust Belt, and drove to deeper horizons in the Anadarko.

This history of constant movement to new horizons provides grist for the mill of both the resource optimists and the pessimists. The optimists focus on the seemingly continuous ability of explorationists to find new geologic concepts and to develop new technologies that allow them to expand the petroleum resource base over and over again. The pessimists focus on the questions: Just how long can this go on? How many additional places are there to look? As noted earlier in the section on "Resource Base Concepts," this history and the ongoing controversy in the search for petroleum is a paradigm for the development of many nonrenewable resources.

SOURCE: Dr John Schanz, Senior Specialist in Energy Resources Policy, Congressional Research Service.

Table 10.—The Optimist's View of Gas Resources

- Just a few short years ago nobody had heard about the Overthrust Belt and the Tuscaloosa Trend; now everybody has jumped in. The pessimists have always been wrong about resource shortages.
- Increased prices for gas and better exploration techniques have opened up a huge new resource in small fields. Past estimates of the number of small fields relied on data from a time when a small field was likely to be abandoned as a dry hole.
- We haven't been looking for natural gas for more than a few decades, so a mature basin for oil—with little prospects for significant new finds—isn't necessarily mature at all for gas. This is especially true because the conditions that led to gas are often hostile to the formation and preservation of oil, and thus the presence of these conditions would have tended to keep explorers away. A key example of this effect is the deep gas resource.
- A good part of the lower finding rates of the recent past was due to the substantial increase in low-risk, low-yield drilling. The lower rates therefore do not necessarily imply "resource depletion."
- Most resource estimates—including optimistic ones such as those of USGS and PGC—represent only snapshots in time, reflecting current economics and technology. The resource base estimates will tend to grow over time as prices rise and technology advances.
- The decline in proved reserves of the past decade, interpreted by many as a sign of resource depletion, actually represents merely a rational response to high discount rates, that is, a reduction in inventory to the minimum amount necessary to sustain production.
- Recent price increases have opened up a large potential for new reserves from the growth of older fields. This new gas will come from closer spaced drilling, the extension of fields to lower permeability areas that were previously uneconomic, the lowering of abandonment pressures, and well workovers.

SOURCE Office of Technology Assessment.

Table 11.—The Pessimist's View of Gas Resources

- We have drilled too many holes in the Lower 48 States and tested too many ideas to believe there is much room for brand new natural gas horizons.
- If there's so much gas right here in the Lower 48, why are we testing the limits of hostile environments in the Arctic and continental slopes?
- The geologists who make industry's resource estimates tend to be the most successful ones, those who have a built-in bias toward optimism because of their experience.
- We have already found most of the "easy," giant fields. The future is in the smaller reservoirs, and there doesn't appear to be enough of these to provide the amount of resources the optimists say is there.
- The depletion effects apparent in exploratory drilling finding rates are actually *understated* because the advance of exploration technology, by increasing the success rate of exploratory drilling, has tended to hide the onset of depletion.
- The higher resource estimates, when translated into the number of fields of various sizes that must *be discovered* to yield this much gas, look very shaky when compared to the numbers of these fields that we have actually been discovering lately.

SOURCE Office of Technology Assessment

is an acceptable range of estimates for the size of the recoverable resource base that excludes "unconventional gas"* and gas that cannot be exploited profitably at gas prices in the same range as today's and with technology that is well within reach in the next few decades? OTA believes that a substantial majority of scientists concerned about the gas resource base would feel comfortable *somewhere within* ** a range that included Nehring's estimate as the extremely pessimistic minimum and the PGC estimate as not quite the maximum, but close to it, This range is about 280 to 915 TCF for the remaining conventional gas resource (including proved reserves and the growth of known fields) recoverable with readily foreseeable technology and given today's economics, for the Lower 48 States.

OTA believes that the minority who might like the range extended would consist mainly of those who believe that the upper end should be higher. Furthermore, OTA suspects that a thorough review of the production implications of the *lower* end of the range—as discussed in the next chapter—would tend to push many scientists away from this end of the range. * It should be added, however, that some of those who are considerably less optimistic than PGC, and even USGS, are major oil and gas producers—e.g., Exxon** —who are very familiar with most of the areas that are supposed to supply the United States with the "optimistic" levels of new gas discoveries.

* Gas from very tight formations, geopressurized zones, coal beds, and Devonian shales. However, gas that arguably could be placed in these categories but that is commonly produced today, would be considered conventional.

** Many would no doubt disagree strongly with values near one extreme or the other, however.

*As shown in chapter 5, a 280-TCF remaining resource implies that the year 2000 production of Lower 48 conventional gas, recoverable with existing or foreseeable technology and at the current cost/price relationships, cannot be much greater than 4 TCF/yr.

**OTA has been told informally by Exxon geologists that Exxon's most recent internal estimates of the U.S. gas resource base are considerably below those of USGS and PGC. The major disagreements are with estimates for the Lower 48 onshore gas potential.

Box D.—Are the USGS and PGC Gas Resource Assessments Really Similar?

Two widely referenced gas resource assessments—those of the USGS and the PGC—have similar estimates for the ultimately recoverable gas in the Lower 48 (1,400 TCF and 1,542 TCF, respectively) and are often used to illustrate what some feel is a wide consensus for an optimistic gas future. Are these two assessments really so similar? The table below compares the *regional* assessments of undiscovered gas from both groups, * based on the PGC reporting areas.

	Onshore		Offshore	
PGC reporting area	*PGC*	*USGS*	*PGC*	*USGS*
A	41	11	16	24
B	13	21	30	3
C	3	6		
D	39	24		
E&G	34	101	52	69
H	159	124		
I	4	8		
J-N	99	43		
J-S	34	33		
L	16	19	18	7
Total**	442	390	116	102

The table shows some substantial disagreements about where the major undiscovered gas resources lie, but it also shows that, ***on the average,*** the region-by-region assessments agree quite well,

Important areas where the two agencies differ are:

- J-N–the mid-continent region (Kansas, Oklahoma, parts of Texas), where PGC is far more optimistic about deep gas.
- E&G onshore—the gulf coast.
- A—the Eastern Appalachian States.
- B offshore—Mississippi, Alabama, and Florida, where PGC remains optimistic about gas in the eastern Gulf of Mexico.
- D—Arkansas, north Louisiana, and central Texas.

The *average level* of agreement can be checked by conducting a linear regression of the two data sets. This yields a correlation coefficient of 0.74, which is a good agreement for two resource assessments conducted somewhat independently of each other.*** Also, removing the two worst disagreements—the offshore gulf coast and mid-continent estimates—increases the correlation coefficient to 0.92, a high value.

Consequently, the differences in no way "discredit" either of these assessments. The differences do illustrate, however, the substantial disagreements that can exist between two groups considered optimistic, and thus they illustrate the considerable uncertainty associated with these resource assessments.

* The PGC values **exclude "Probable" resources, which include new pools in discovered fields. Strictly speaking,** PGC **defines these pools as undiscovered;** USGS **does not, and includes them** in its "inferred reserves" category.

Excludes cumulative production, proved **reserves, and growth of known fields,

*****The estimators have too much access to the same studies and estimates, and to each other, to allow a claim of strict independence between the** two assessments.

How Credible Are the Methods?

How credible the methods are is generally difficult to determine because few resource assessments using geologic approaches reveal many details of their assessment processes. Generally, more details are available for the assessments based on historical, extrapolative approaches; *in* addition, USGS makes available to the public its open-file reports and data. OTA did not attempt to review the extensive USGS backup information because of time and budget constraints. Historical approaches have been reviewed in a number of reports,[26] and for the most part OTA chose to use them instead of conducting a totally independent review.

In general, OTA is skeptical of historical approaches to resource assessment when they are based on national data and when they are the sole means of estimation. The substantial data problems associated with natural gas exploration (especially during those years when gas was valued as little more than a byproduct of oil production), the broad range of activity covered by any single data series, and the distorting effects of Government controls are important sources of this skepticism.

The most important estimate based strictly on a historical approach is Hubbert's because he has gained substantial credibility from his successful predictions of declining U.S. oil production. As discussed earlier in this chapter, OTA notes substantial problems with Hubbert's approach and believes that his extremely pessimistic estimate (870 TCF) of ultimately recoverable conventional gas is too low.

Of the assessments using geologic approaches, only the assessments of USGS and PGC are reviewable in any sense because details of the others are not public information. In OTA's opinion, both assessment processes are serious attempts to wrestle with a most difficult problem. One problem with both assessments is the failure to include the detailed assumptions behind, and implications of, the assessment, thus precluding much opportunity for useful feedback from those outside the assessment process. The USGS assessment may also be hampered by lack of access to proprietary industry data; PGC, on the other hand, apparently has access to excellent data but *appears* to ignore the insight that might be gained from analyses of discovery trends (i. e., the historic approach).

Are the Physical Implications of the Assessments Plausible?

Most gas resource assessments do not provide descriptions of either the direct physical implications of their resource estimates (e. g., the number and size of fields implied by the estimate) or, conversely, the initial physical model used to derive the estimate. Nevertheless, some physical implications can be drawn directly from the estimates. This is especially true when the estimates are separated into components: onshore and offshore (quite common), deep and shallow (e.g., the PGC assessment), and individual regions or even smaller provinces (USGS divides the United States into **137** separate provinces). Consequently, it is clear that PGC believes that the deep resource below 15,000 ft represents a massive source; fully 39 percent of the onshore undiscovered resource of the Lower 48 States is projected to be deep gas. In a similar vein, USGS clearly appears to have given up on the eastern Gulf of Mexico but has great hope—as does PGC—for another "frontier" area, the Western Overthrust Belt.

Rather than carrying out a detailed "translation" of each assessment, OTA chose to examine two basic physical issues that appear to cut across virtually all of the assessments. These issues, as stated by Nehring,[27] are:

- Does the assessment imply a substantial break with past and recent discovery trends and patterns?
- If the assessment does imply such a break, what is the explanation for it? Is it credible?

A Break With Past Trends?*

The most obvious ties between past trends and the magnitude of the resource base are the analyses performed in the "historic approaches" to resource assessment. In general, these approaches have given relatively pessimistic results when used with U.S. gas production and exploration data. For example, all four of the estimates using pure data-tracking techniques (two by Hubbert, one each by Wiorkowsky and Bromberg/Hartigan) in table 6 are below the USGS estimate, with three

[26]For example, Wiorkowski, op. cit.

[27]R Nehring, The *Discovery of Significant Oil and Gas Fields in the United States,* op. cit.

*Readers interested in past trends in petroleum exploration may also wish to read *Exploration for Oil and Gas in the United States: An Analysis of Trends and Opportunity,* by John J. Schanz, Jr. and Joseph P. Riva, Jr., of the Congressional Research Service (CRS report No. 82-138 S, Sept. 16, 1982).

of the four at least **400** TCF below. In addition, the RAND estimate, which is at least partly dependent on past discovery trends, is nearly 500 TCF below the USGS estimates.

This series of pessimistic resource estimates based on trend analysis, when coupled with the very low rates of reserve additions in the Lower 48 States from 1968 to 1978 (average yearly AGA reserve additions were 9.6 TCF v. average production of 20.6 TCF yr), represent a strong initial argument that the more optimistic resource estimates do represent a break with past trends, while the pessimistic estimates do not. However, as noted in the discussion of historical approaches to resource assessment, the available data used to measure trends in exploratory success (or trends in other factors that may be used to form judgments about the probable size of the resource base) tend to measure multiple rather than single processes; for example, measures of the success of drilling for new fields are, in fact, measuring a range of activities from the high-risk testing of new geological ideas to the low-risk redrilling of formerly uneconomic dry holes. Consequently, none of these trends can be interpreted in an unambiguous manner. The discussions in chapter 5 about the factors that affect the various components of reserve additions give a sense of the complexity of individual trends and of the difficulties in interpreting the trends.

Trends in the discovery of new fields appear likely to be most closely associated with the remaining recoverable resource base; these trends are examined in the following paragraphs.

Table 12 displays the returns to new field wildcat drilling in the onshore Lower 48 States from 1966 to 1981. The patterns displayed in the table demand careful deciphering. The gas volumes found per successful gas new field wildcat show a startling decline during the period, from 18.56 billion cubic feet (BCF) per well in 1966 to 1.85 BCF per well in 1979 (use of EIA data moderates this trend somewhat, but the EIA and AGA data are not strictly comparable). This *means that the average field size found by a successful gas wildcat declined by a factor of 10 during 1966-79.*

Because the larger fields in a basin are generally found early in the discovery process, a sharply declining average field size is often interpreted as a sign that the discovery cycle is winding down. However, the data shown in the table are collected from multiple basins, and during the time period in question, the pattern of gas exploration may have been influenced by increased gas prices and other factors. For example, it is widely believed that deliberate exploration for small gas targets (e.g., in areas where past exploration identified then uneconomic gas deposits) increased sharply

Table 12.– Returns **to New Field Wildcat Drilling in the Onshore Lower 48 States, 1966-81** (BCF/well)

Year	New field discoveries: Per all NFWs	New field discoveries: Per new field discovery well	New field discoveries: Per new gasfield discovery well	Percent of new field discovery wells that find gas
1966	0.46	4.56	18.56	25
1967	0.42	3.96	11.93	33
1968	0.24	2.66	10.25	27
1969	0.24	2.66	7,47	36
1970	0,29	3.01	8.20	37
1971	0.16	1.67	3.70	45
1972	0.24	2.11	4.46	47
1973	0.34	2.30	3.89	59
1974	0,24	1.60	2.88	56
1975	0,22	1.47	2.91	51
1976	0.18	1.02	1.85	55
1977	0.20 (.32)[a]	1.15 (1 .86)	2.23 (3,61)	52
1978	0,17 (0.36)	1.07 (2.27)	1.96 (4,17)	55
1979	0.20 (0.26)	1.07 (1 .40)	1,85 (2.48)	58
1980	(0.27)	(1 .37)	(2.69)	51
1981	(0.34)	(1 .88)	(3.95)	48

[a]AGA data (EIA data)

SOURCE R Nehring 'Problems in Natural Gas Reserve, Drilling, and Discovery Date, " contractor report to the Off Ice of Technology Assessment, 1983 during this period. Such an increase in the willingness of explorationists to go after small targets would tend to reduce field size averages even *if high-risk exploration for large fields maintained a steady success record*. Consequently, the decline in average field size may not fairly represent the actual condition of the resource base.

The record of returns to wildcat drilling per well *drilled* tends to support this view. These returns per well drilled have exhibited only a slight decline since 1968; the success rate, which varies from a low of 2.3 percent in 1968 to a high of 10.8 percent in 1979, essentially compensates for the declining field size. In other words, *while each gas wildcat well completed returned far less gas in 1979 than in 1966, the actual number of wildcat wells drilled to find each trillion cubic feet of gas did not increase very much during this period.* This relatively optimistic result should be tempered, however, by the observation that the percentage of wildcats aimed deliberately at gas targets probably increased during this period. Consequently, it is likely that the actual gas-directed effort—as distinct from the total *petroleum*-directed effort—that was needed to find a unit of gas probably did increase during the period.

Although the data in table 12 look more optimistic than might have been initially expected, the history of natural gas development implies that, in order to sustain successful levels of reserve additions for the long-term, efforts must be made to open new geologic horizons and find the large fields that are the cornerstone of reserve growth in later years. Consequently, it is useful to examine the pattern of discovery of different-sized fields.

The American Association of Petroleum Geologists (AAPG) publishes the primary public record of the discovery of petroleum fields by size and discovery year, and this record may be used to examine patterns of discovery. The record must be used cautiously, however, because AAPG appears to have undercounted the number of fields discovered. * For example, from 1971 to 1975, AAPG reports only 49 gas discoveries of a size greater than 60 BCF. In comparison, the RAND data base reports 141 fields in this size range during the same time period.[28] Consequently, the AAPG data should be examined for trends rather than absolute magnitude, and even the trends may be skewed if undercounting and other problems were not consistent over time.

Table 13 presents the historical record of new gasfield discoveries by field size, for 1945-75, as compiled by AAPG. * In parallel with the trends shown in table 12, the percent of significant (size class A through D) gasfields in all gas discoveries decreased over the 30-year period, while the effort required to find a significant field increased through the 1960's but then declined to earlier levels.

The data in the table can be used to examine the discovery trends of larger fields. Figures 11 and 12 show trends in, respectively, the number of fields discovered as a percentage of new field wildcats drilled, and the number of fields discovered per year. Figure 11 shows that the apparent effort (in wells drilled)** required to find fields of size C or larger, B or larger, and A grew sharply during the early 1950's but then leveled off between 1955 and 1975. However, these trends would look considerably more pessimistic if "total footage" rather than "wells drilled" were the measure of effort. This is because the average depth of new field wildcats grew steadily during this period, from 4,007 ft in 1946 to 6,071 ft in 1975.[29]

Figure 12 shows that, starting about 1950, the number of moderate-to-large gasfields declined steadily through 1975. These larger fields may be particularly important for continued reserve additions because of the general belief that the larger fields generate the majority of field growth (from extensions, new pool discoveries, and revisions).

*Part of this problem may arise from simple disagreements over field boundaries; the EIA data base, for example, treats the Hugoton field as three separate large fields, whereas other analysts might count it as one. Also, field reserve estimates are not consistent across data bases.

[28] R. Nehring, *Problems in Natural Gas Reserve, Drilling, and Discovery Data*, contractor report to OTA, 1983.

*The record stops in 1975 because AAPG classifies fields as gas or oil fields only after the passage of 6 years past the discovery report.

**"Apparent" because some of the wells were aimed deliberately at small targets and should not be included in the "effort" involved in finding large fields. As noted, however, there is no way to separate data about these wells from the overall data.

[29] R. R. Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin*, vol. 66/11, November 1982.

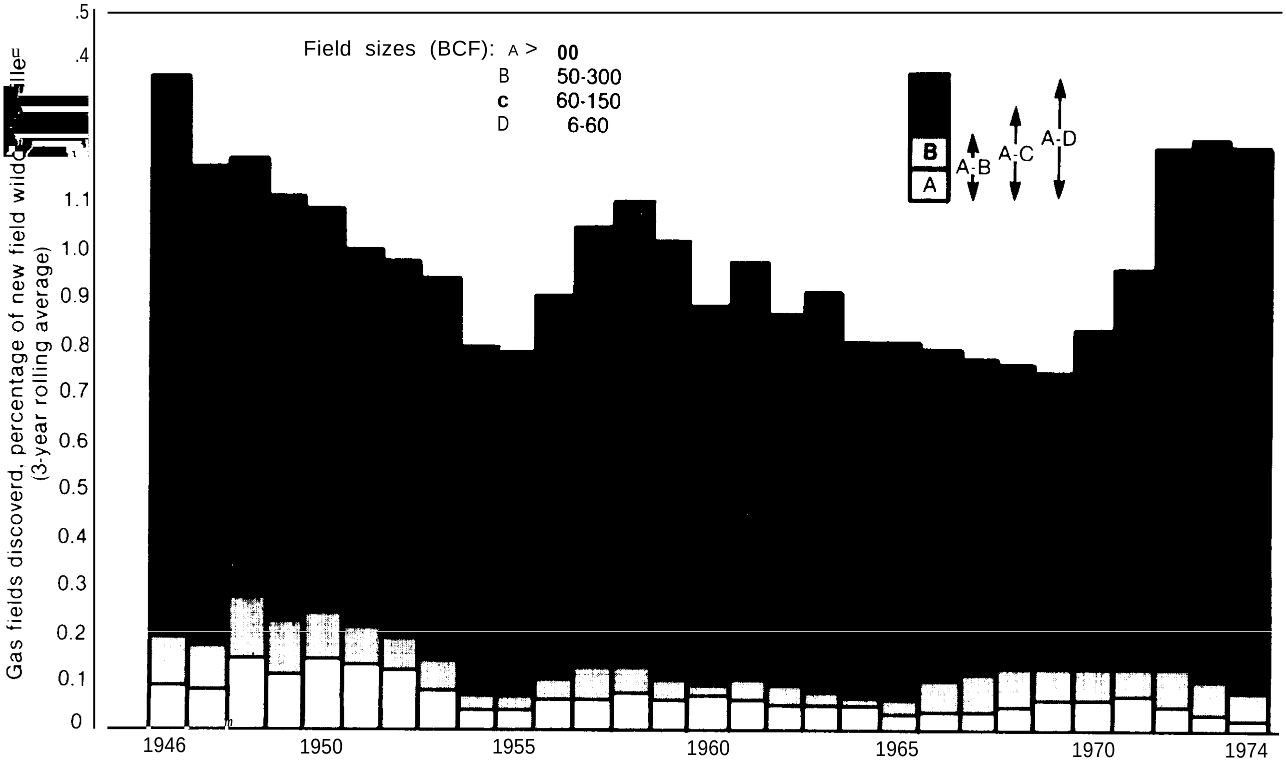
Table 13.—Historical Record: Number of New Gasfield Discoveries Proved After Six Years To Be of Significant Size

Year drilled	Total wells reported as gas wells at end of year of completion	Number of fields in each size classification[a] after 6 years development history: A	B (Significant)	C (Significant)	D	E	F	Total	Total significant size gasfields: A-D Inclusive (A + B + C + D)	Percent of significant gasfields in all gas discoveries	Total new field wildcats drilled	Percent of significant gas finds in total new field wildcats drilled
1945	193	3	2	11	33	24	20	93	49	52.69	2,905	1.69
1946	78	1	2	7	22	29	12	73	32	43.84	2,995	1.07
1947	106	5	5	4	30	35	19	98	44	44.90	3,325	1.32
1948	116	3	3	7	33	35	19	100	46	46.00	4,087	1.13
1949	121	8	7	8	34	43	12	112	57	50.89	4,238	1.34
1950	118	4	4	8	28	44	19	107	44	41.12	5,149	0.85
1951	155	10	4	10	41	57	16	138	65	47.10	6,044	1.08
1952	171	10	7	7	44	65	15	148	48	45.95	6,440	1.06
1953	177	3	3	6	40	89	18	159	52	32.70	6,634	0.78
1954	248	4	1	12	51	104	39	211	68	32.23	7,033	0.97
1955	228	2	3	11	33	107	43	199	49	24.62	7,743	0.63
1956	230	2	4	5	52	92	26	181	63	34.81	8,436	0.75
1957	247	9	5	15	70	105	30	234	99	42.31	7,556	1.31
1958	262	3	6	9	55	143	25	241	73	39.29	6,618	1.10
1959	308	4	1	6	51	135	28	225	62	20.13	7,031	0.88
1960	240	6	2	9	63	135	22	237	80	33.76	7,320	1.09
1961	316	4	3	4	35	156	40	242	46	18.59	6,909	0.66
1962	317	3	4	11	61	161	52	292	79	27.05	6,794	1.16
1963	240	4	1	7	38	124	41	215	50	23.26	6,570	0.76
1964	252	4	1	11	37	136	37	226	53	23.45	6,623	0.80
1965	234	1	3	10	38	142	30	224	52	23.21	6,175	0.84
1966	232	1	3	7	36	142	12	201	47	23.38	6,158	0.76
1967	179	4	5	6	26	111	12	164	41	25.00	5,271	0.78
1968	126	1	5	7	27	83	14	137	40	29.20	5,205	0.77
1969	190	3	2	4	35	116	14	174	44	25.28	5,956	0.74
1970	184	5	4	3	25	79	14	130	37	28.46	5,069	0.72
1971	202	2	3	3	38	102	12	160	46	28.75	4,463	1.03
1972	273	3	2	6	47	187	0	245	58	23.67	5,086	1.14
1973	416	2	6	10	57	284	0	359	75	20.89	4,989	1.50
1974	445	0	2	6	51	329	0	388	59	15.21	5,652	1.04
1975	448	3	0	1	64	336	0	404	68	16.83	6,104	1.11

[a]Size classifications: A = >300 BCF
B = 150-300 BCF
C = 60-150 BCF
D = 6-60 BCF
E = <6 BCF
F = noncommercial

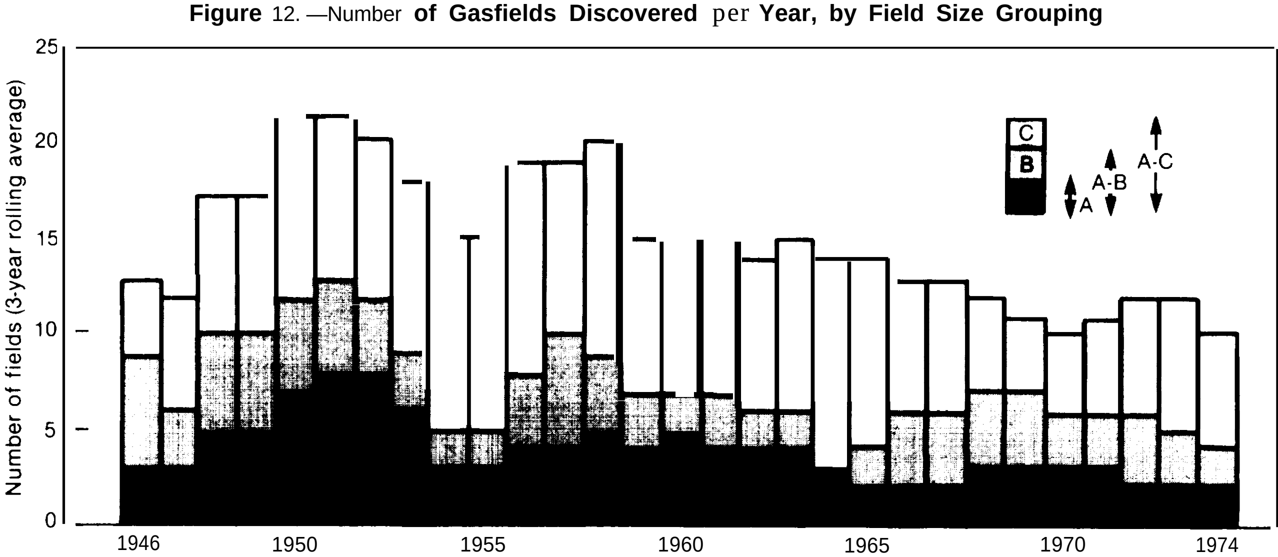
SOURCE: R. R. Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin*, vol. 66/11 November 1982.

Figure 11.— Number of Gasfields Discovered As a Percentage of New Field Wildcats Drilled, by Field Size Grouping



SOURCE Off Ice of Technology Assessment, based on data from table 16 in R R Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin*, vol 66/11, November 1982

Figure 12. —Number **of Gasfields Discovered** per **Year, by Field Size Grouping**



SOURCE Off Ice of Technology Assessment, based on data from table 16 in R R Johnston, "North American Drilling Activity in 1981, *AAPG Bulletin* vol 66/11, November 1982

The impression gained from table 12 and figures 11 and 12—that finding rates for the small-to-moderate sized fields have held up very well and even increased, but that rates of finding the larger fields have declined somewhat over the past few decades—is reinforced by an examination of Lower 48 gasfield discoveries of 1 TCF and larger. Such discoveries were scattered throughout the 1916 through 1966 period, with particularly large discoveries* in 1916 (Monroe, La., 9 TCF), 1918 (Hugoton, Kans./Tex./Okla., 36 TCF and panhandle, Tex., 31 TCF), 1921 (San Juan, N. Mex., 18 TCF), 1928 (Jalmat, N. Mex., 6 TCF), 1934 (Katy, Tex., 7 TCF), 1936 (Carthage, Tex., 6 TCF), and 1952 (Puckett, Tex., 4 TCF).[30] However, according to the 1977 International Petroleum Encyclopedia,[31] no gasfields larger that 4 TCF were found between 1953 and 1967, and no gasfields larger than 1 TCF were found between 1967 and 1975. * *

The trends in discovery up to the middle 1970's, although rendered somewhat ambiguous by the nature of the data, appear to support two conclusions. First, they show that exploration trends for gas have not nearly been as much a cause for pessimism as have oil exploration trends; in short, they do not show why the resource pessimists such as Hubbert predict such a radical drop in new discoveries. The rate of discovery of significant fields (fields of sizes A through D) did not experience the kind of steep decline that would seem to be a prerequisite for predicting—as the Hubbert resource estimate does—that undiscovered resources now total only 100 TCF. Second, the trends indicate that the type of fields usually associated with opening up major new horizons were not being discovered and that more and more of the new fields appeared to be coming from further along in the discovery cycle. The limited number of giant fields discovered in this period gives some cause to question the relatively optimistic estimates of USGS and PGC.

As to recent trends, the recent upsurge in total reserve additions has been the common centerpiece in arguments that the "resource optimists" have been right all along. Questions are raised about whether recent large discoveries in the deep Anadarko Basin and in the Overthrust Belt signify a reversal of the long-term, more pessimistic trends.

In OTA's opinion, responsibility for the reserve additions of the past few years—and therefore the implications for *future* reserve additions and production—cannot be assigned to a particular cause without a detailed investigation, at the level of individual fields and entrepreneurs, of the precise nature of the increases. Such an investigation would attempt to determine whether the new reserve additions represent a true turnaround in the exploratory process or a one-time surge of reserve development caused by the sudden movement from the subeconomic into the economic range of a limited inventory of known prospects and an acceleration of the normal pace of field development. OTA has not seen any convincing analyses arguing one side or the other.

As for the Overthrust Belt and Anadarko, the future of these areas is uncertain. The Overthrust Belt did produce some very large new fields in the late 1970's (the Whitney Canyon/Carter Creek and East Anschutz Ranch fields appear to have resources greater than 1 TCF), and its potential is substantial, However, despite continued searching, no new giant fields have been discovered in the past few years. In the Anadarko, the recent declines in prices for deep gas may have moved some gas from "economic" to "subeconomic," although the earlier superheated market for this gas and the resulting distortions in prices and production costs make it difficult to predict where the economic/subeconomic boundary might lie in the future. Also, recent engineering difficulties and rapid pressure declines in some fields imply that some overestimates may have been made in calculating reserves and estimating resources.

In conclusion, in OTA's opinion the gas discovery trends of the past several decades, while

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• Some of these fields—Hugoton, Panhandle, San Juan —are considered multiple fields by some analysts, one field by others, Also, there is considerable variation in reserve estimates from one source to another

[30] 'Oil and Gas Resources Data System, Energy Information Administration; and J. McCaslin (ed), *International Petroleum Encyclopedia*, vol. 10 (Tulsa, Okla Petroleum Publishing Co, 1977)

[31] McCaslin, op cit

* *It is possible, however, that further growth of fields that were below the 1 TCF level in 1977 could have moved them into the greater than 1 TCF category in later years

not supporting the most pessimistic of the recent gas resource estimates, also do not support the relatively optimistic estimates of PGC and, possibly, USGS.

Some Alternative Explanations

The (until recently) moderately pessimistic discovery trends and optimistic resource base estimates can be reconciled by two possible arguments:

- It is not the resource base but the market distortions caused by Government regulations that have caused discovery trends to be disappointing. Exploratory incentives have been skewed toward low-risk, low-payoff gas prospects.
- The historical trends do represent the depletion of traditional sources of natural gas. Now, however, improved technology and higher prices will allow explorers to find large quantities of gas from:
  —small fields;
  —reworking of older fields;
  —new frontiers, including deep gas; and
  —subtle stratigraphic traps.

The Causes of Past Trends

Is it the *nature of the remaining resource base* that has been the primary influence on historical declining trends in new field discoveries, or was it instead the *economic and regulatory environment* that provided the controlling influence? Does the relatively low rate of discovery of large new gasfields during the last decade and a half reflect resource depletion, or are these rates an artifact of the erratic price and regulatory history of natural gas? If gas resources are substantially depleted, it appears unlikely that gas finding rates and discoveries of large new fields will rebound to levels that would sustain high production rates. If the economic/regulatory history of gas is the cause, then optimism about future production potential may be well founded, assuming that economic and regulatory conditions can be made favorable to the gas discovery process.

The basic argument that low finding rates for new fields and other warning signals do *not* reflect resource depletion centers around the idea that the rigid price controls of the period before passage of the Natural Gas Policy Act of 1978 (NGPA) locked drilling into lower cost and risk areas that do not coincide with where the major gas potential resides. The "culprit" for this is said to be the method used by the old Federal Power Commission (FPC) to calculate allowable "area" and "national" gas prices. FPC assumed that future exploratory and development costs would be similar to past average costs, and by basing the allowable price on this assumption, essentially *guaranteed* that drilling would be confined to areas where costs were expected to be low.

A past proponent of this view has been the American Gas Association. AGA has conducted a series of studies[32] comparing total gas well completions to estimates of gas resource potential* in the Outer Continental Shelf, Alaska, the shallow Lower 48 area, and deep (below 15,000 ft) horizons. Their September 1979 analysis, which includes drilling data through 1977, concludes that "the drilling data suggested that *the decline in proved reserves was not due to a depletion of gas sources but rather to a lack of economic incentives for drilling under an artificially constrained, regulated environment [emphasis added].* "[33] This conclusion was based on the poor correlation of gas well completions to gas resource potential detected in the study** (see the first two circle charts in fig. 13). However, a more recent (January 1981) analysis added a comparison of gas well *expenditures* to gas resource potential (third circle chart in fig. 13). Noticing a *good* correlation of expenditures to resource potential,*** AGA omitted the earlier conclusion and attributed the imbalance between drilling and potential to "the much lower cost-per-well and cost-per-foot figures for the shallow, Lower 48 wells."[34] The very high drill-

[32]The latest is AGA, "Gas Well Drilling Activity and Expenditures in Relation to Potential Resources, " *Gas Energy Review*, vol. 9, No. 1, January 1981.

*The measure used for "Resource Potential" was PGC's estimates of potential supply.

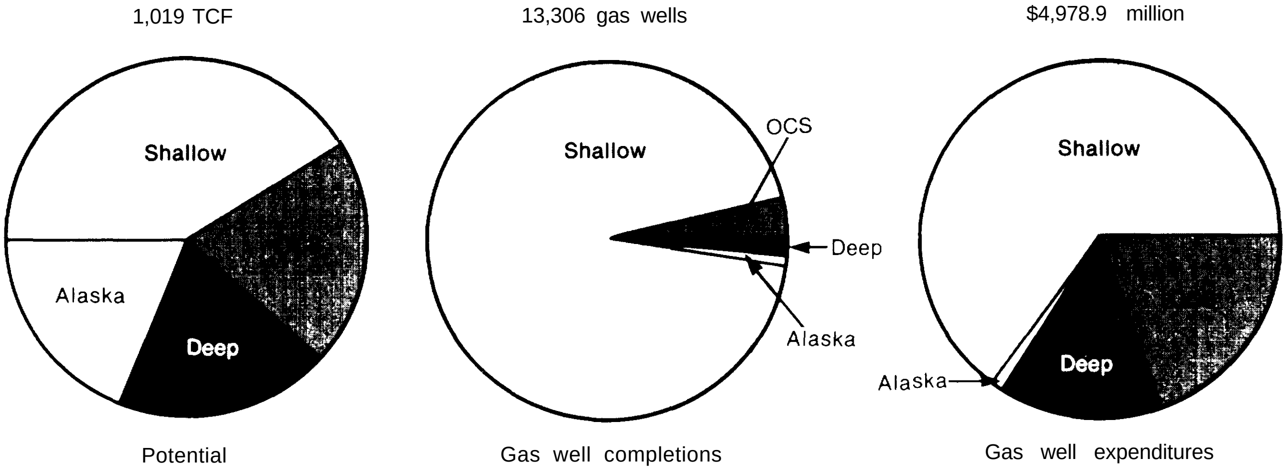
[33]AGA, "Drilling Activity and Potential Gas Resources, " Gas Energy Review, vol. 7, No, 11, September 1979.

**Of course, an alternative reason for the poor correlation could be that gas entrepreneurs do not agree with AGA's view about where the resource potential lies.

***Except for Alaska, where lack of a transportation system blocks gasfield development,

[34]AGA "Gas Well Drilling and Expenditures . .," *Op. cit.*

Figure 13.—Gas Potential, Gas Well Completions, and Expenditures—1978



NOTE Shallow and 'deep refer to Lower 48 States onshore potential is based on PGC's estimates of the undiscovered gas resource

SOURCE Gas Well Drilling Activity and Expenditures in Relation to Potential Resource in Gas *Energy Review* vol 9, No 1 (Arlington Va American Gas Association January 1981)

ing costs and risks of the high gas potential frontier areas necessitate a very cautious attitude toward drilling, whereas the lower costs in developed onshore areas encourage closely spaced development drilling and exploratory drilling for small reservoirs and other marginal targets.

A corollary to the argument about the effects of low allowable gas prices is used to explain why the sharp price increases of the past several years have not improved the rate of new field discoveries. According to this view, drilling priorities will not immediately be corrected by rising prices because the long period of controls has created a large backlog of low-risk, previously marginal exploration prospects that are now commercially viable. Until this backlog is reduced, the argument goes, exploratory drilling will stay away from the high-risk, high-payoff wells that could find the large fields[35] that now only appear to be scarce. Furthermore, because price increases expand the boundaries of the "economically recoverable" resource base and thus add to the inventory of low-risk prospects, it is claimed that the trend toward low-risk, low-payoff drilling is likely to continue if prices continue rising.[36]

High-risk, high-payoff drilling may be expected to yield low success rates. Consequently, the sharply *improved* success ratios of both total exploratory drilling and new field wildcat drilling during the past decade and a half, shown in table 14 and figure 14, has been used to support the thesis that drilling is skewed toward the low-risk targets. The overall success rate of these drilling categories may be affected by a variety of factors, however, that cannot be separated out. For example, substantial progress in improving exploration techniques and computer technology during this period undoubtedly acted to increase success rates, but to an unknown degree. * Also, the success rate is automatically elevated by the decrease in minimum acceptable field sizes and gas flow rates associated with increased gas prices; small fields and low-permeability reservoirs that in the past would have been considered "dry" are now being developed as producers. Therefore, it is quite conceivable that an increase in *overall* success rates could be accompanied by an increase in high-risk drilling if the other factors affecting success rate were strong enough to overcome the negative effects of the shift in risk.

In addition to arguments about the effects of price controls, some analysts point out that

[35] Jensen Associates, Inc., "Early Effects of the Natural Gas Policy Act of 1978 on U.S. Gas Supply, " report to the Office of Oil and Natural Gas, U.S. DOE, April 1981,

[36] R. P. O'Neill, "Issues in Forecasting Conventional Oil and Gas Production, " in *Oil and Gas Supply Modeling,* National Bureau of Standards Special Publication *631,* May 1982.

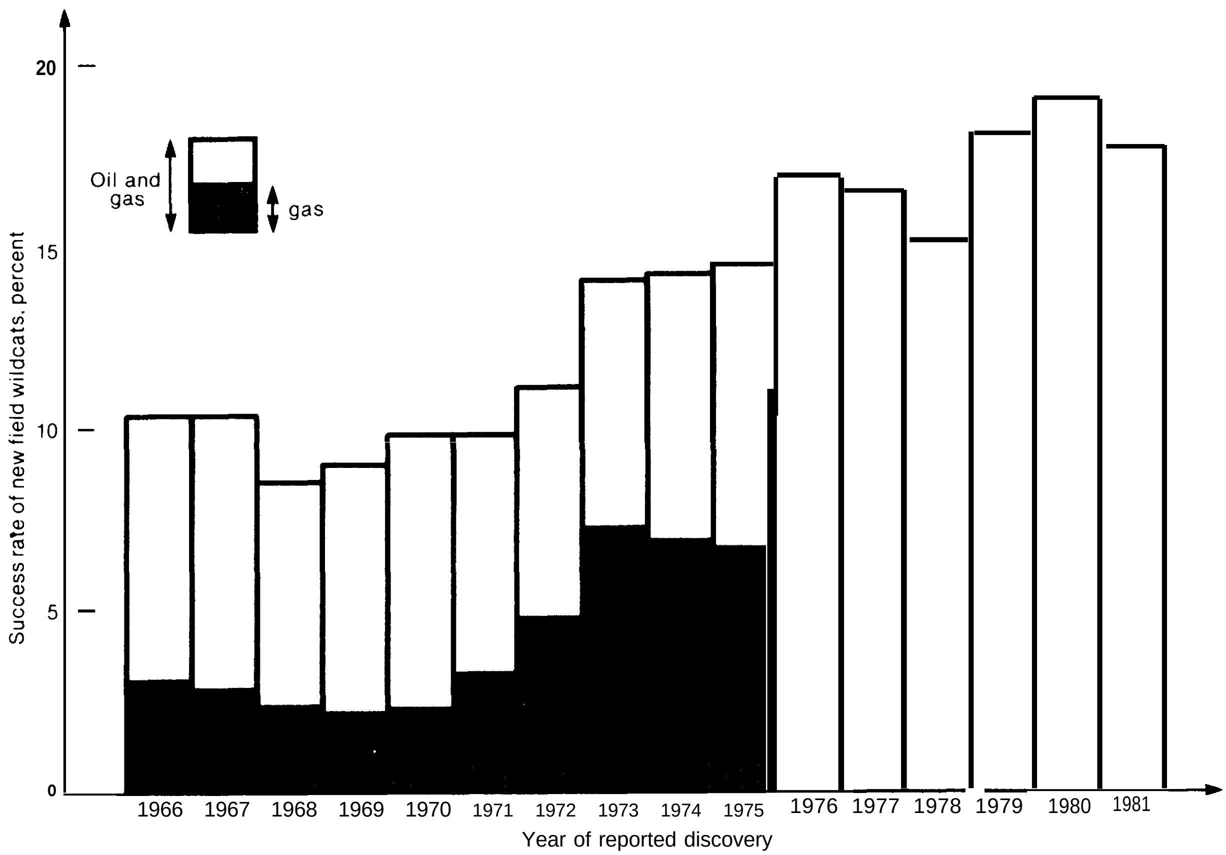
*The extensive investigation of the effects of new technology by the National Petroleum Council in 1965 could find no credible quantitative measurement of these effects.

Table 14.—Oil and Gas Drilling Success Rates
(discoveries as a percentage of exploratory drilling effort)

	Exploratory wells			"Wildcats"		
Year	Completed	Total	Rate	Completed	Total	Rate
1966	1,894	10,313	18.40/o	635	6,158	10.3 "/0
1967	1,518	8,878	17,1	544	5,271	10.3
1968	1,440	8,879	16.2	442	5,205	8.5
1969.	1,700	9,701	17,5	535	5,956	9.0
1970	1,271	7,693	16.5	493	5,069	9.7
1971	1,088	6,922	15.7	436	4,463	9.7
1972.	1,285	7,539	17.0	566	5,086	11.1
1973.	1,519	7,466	20.3	701	4,989	14.1
1974.	2,009	8,619	23.3	805	5,652	14.2
1975.	2,143	9,214	23,3	876	6,104	14.4
1976.	2,449	9,234	26.5	986	5,840	16.9
1977.	2,686	9,961	27.0	1,004	6,101	16.5
1978.	2,728	10,677	25.6	983	6,505	15.1
1979.	3,024	10,484	28,8	1,162	6,413	18.1
1980.	3,574	11,916	30.0	1,340	7,034	19,0
1981 ...., ...	4,585	15,168	30.2	1,423	8,052	17.7
1982.	4,847	16,470	29.4	1,400	7,912	17,7

SOURCE American Petroleum Institute, "Quarterly Review of Drilling Statistics"

Figure 14.— New Field Wildcat Success Rate, 1966-81



NOTE Gas success rate data not available after 1975 because gasfields and oilfields are separated out only after a 6-year review by AAPG

SOURCE Office of Technology Assessment, based on data from American petroleum Institute, Quarterly Review of Drilling Statistics maintenance of high levels of proved reserves in relationship to production would not be compatible with good business practices. According to this argument, high-interest rates made it sensible for gas producers to reduce their standing inventory—i.e., proved reserves—by maximizing deliverability and reducing exploration. Consequently, from the drilling low point of 1971 to 1982, developmental drilling rose by a factor of 3.66 (18,929 wells drilled v. 69,330), whereas total exploratory drilling rose by only a factor of 2.38 and new field wildcats rose by only 1.77.[37] Carrying this argument further, the economic incentive to increase reserves will occur only when the cost of reducing R/P ratios—of adding to the deliverability of current reserves—outweighs the cost of adding new reserves.

Although the argument about the lack of an economic incentive to increase reserves is a fair one, it does not take into account the incentive for exploration provided by a number of factors, including the perception in the industry that the rapid declines in reserve levels were dangerous and should be halted if possible, the continued profitability of most larger gasfields even at low prices, and the former inseparability of gas and oil exploration, which allowed gas discovery to benefit from exploration incentives provided by oil.

The argument about the real cause of the downward trends of past decades is difficult to resolve because the opposing sides are generally arguing less about the data themselves than about their interpretation. Both sides agree, for example, that onshore gas exploration has become increasingly oriented to prospects with less "dry-hole" risk but with smaller reservoirs with poorer producing characteristics. Those arguing for resource depletion believe, however, that this trend has occurred primarily because *that is the nature of the remaining resource base;* those arguing for a more optimistic view of resources argue that the trend reflects a natural market response to early controlled prices, recent price increases, and high discount rates that favor production over inventory. Undoubtedly, both arguments are valid to some degree; the problem is in determining the relative importance of each.

[37]American Petroleum Institute, 'Quarterly Review of Drilling Statistics."

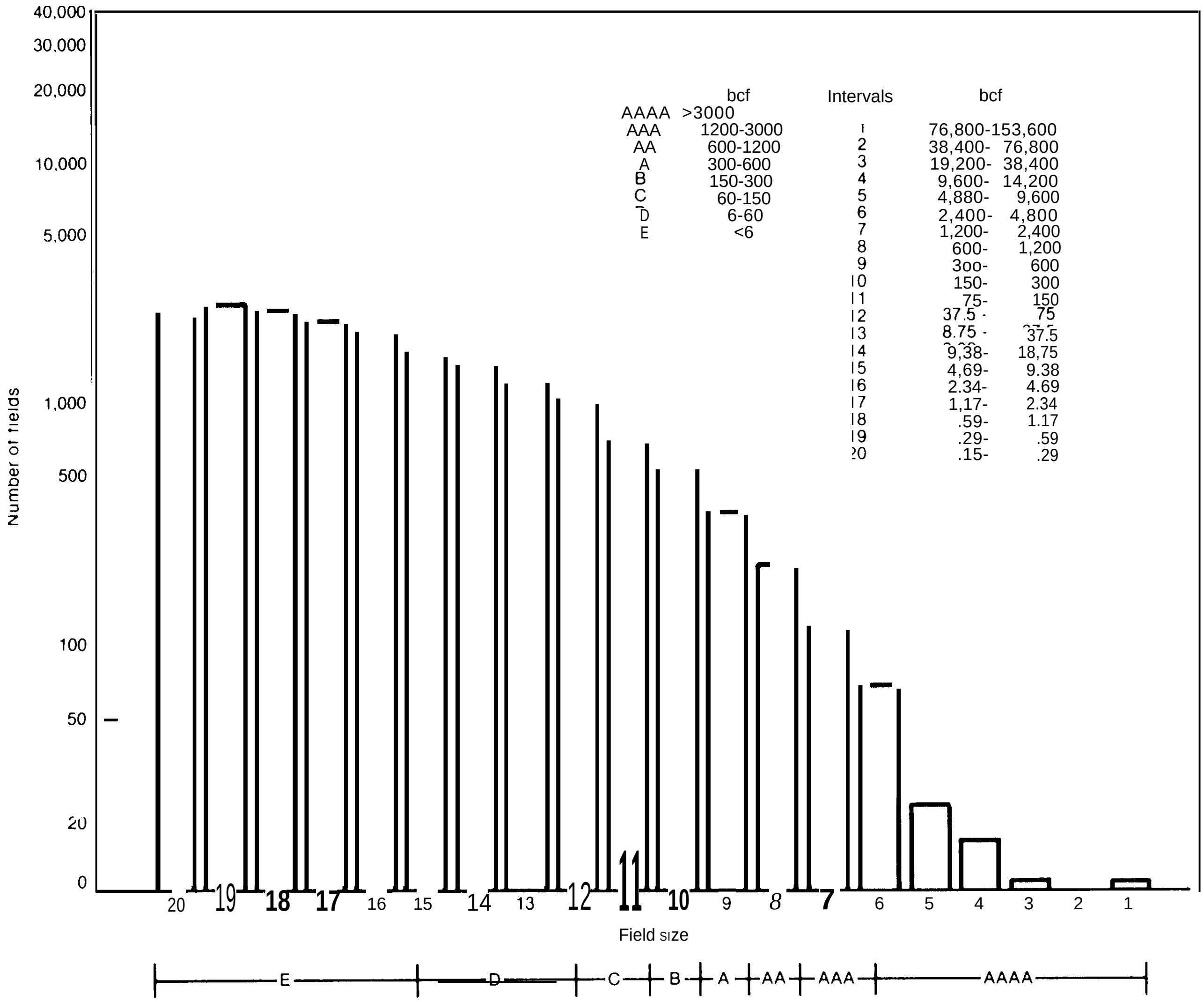
Potential Major Sources of Additional Gas

Small Fields.—One basic argument revolves around the question of whether or not a sizable resource—large enough to support continued high rates of production—lies in fields containing 60 BCF of gas or less. The *source* of the *argument* lies in the shape of the field size distribution curve.

Historically, the cumulative number of gas and oil fields are distributed according to size in a manner shown in figure 15. In this figure, the size classes 1 through 20 (on the x axis) are scaled so that the upper limit of size class 20 is one-half the upper limit of 19, and so on. As shown in the figure, the cumulative number of fields increases with decreasing size class as a geometric series, down to about size class 13 (or class D in the AAPG notation), and then rapidly levels off. At least a portion of this "truncation," or leveling-off, of the field size distribution is undoubtedly due to past economics; many small finds were too small to be economically developed and consequently were reported as dry holes rather than added to the historical record as a class D or E field. Because pipeline gathering systems are required in order to develop gasfields no matter what the field size, and also because the price (per unit of energy) of gas has historically been lower than that of oil, the minimum field size suitable for development is larger—and thus the truncation described above is more severe—for gas than for oil. The crux of the current argument is, simply, what will the shape of the field size distribution curve look like when the effects of higher gas prices run their course? An important corollary to this argument is, how expensive will it be to discover and develop these small fields, and, consequently, how many of them can appropriately be included in the recoverable gas resource base?

Proponents of the thesis that small fields represent a very sizable resource argue that the trend observed for fields larger than size class D— i.e., a progressive increase in the number of fields discovered in each size class as one moves from the larger field sizes to the smaller—will be continued into the small field sizes below class D once these fields are made the target of intensive exploratory efforts. This argument maintains that the tailing-

Figure 15.—Size Distribution of Discovered Oil and Gas Fields in the Lower 48 States



SOURCE: R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983.

off of the curve in figure 15 is almost entirely the result of economics and that there are no geologic reasons for the drop in the number of very small fields. Scheunemeyer and Drew,[38] in examining field size distributions in the Gulf of Mexico and the Denver Basin and at three depth intervals in the Permian Basin, show that the "truncation point" of the field size distribution moves to larger field sizes when exploration and development costs are higher, which would be expected if the truncation were economically determined. Also, they note that the point moved to smaller field sizes after gas prices rose and the minimum profitable field size became smaller.

A straightforward argument against the "small fields thesis" is that estimates of large resources from small fields cannot be based on more than an assumption or extrapolation—because no petroleum basin has experienced the intensity of drilling that would be required to find the postulated number of small fields. This argument appears to be a powerful one, but it works equally

[38] J. H. Scheunemeyer and L.J. Drew, "A Procedure to Estimate the Parent Population of the Size of Oil and Gas Fields as Revealed by a Study of Economic Truncation," *Mathematical Geology,* vol. 15, No. 1, 1983.

well against those who might deny the possibility of large numbers of small fields. It probably is not possible at this time to estimate credibly the ultimate number of small gasfields remaining to be discovered in the United States and the resources these fields represent.

A second argument that has been presented is that, in some basins, the field size truncation does not appear to be generated by economics and is more likely to have been caused by geology—the simple lack of sufficient small fields. For example, Nehring[39] identifies subduction and delta provinces, * that account for more than one-quarter of U.S. oil and gas resources, as an example of basins where the number of fields in each size category begins to drop at a size level considerably above any historical field size minimum. Nehring argues that only a portion of U.S. provinces act according to Scheunemeyer and Drew's thesis and that there are four distinct groupings of field size distributions, ranging from one with a rapid increase in the number of fields with decreasing field size (similar to those discussed by Scheunemeyer and Drew), to one with a single peak at about size class D, to one with little increase in the number of fields at field sizes below A or B.

A third argument notes that it takes about 1,000 class E fields to equal three class A fields,[40] and that even a sharp increase in the number of small fields discovered may not be of major significance to the overall resource base. Figure **16** shows the known field size distribution, as in figure 15, and two projected distributions for the ultimately recoverable resource base—one that assumes a doubling of the approximately 24,000 fields known as of 1975, with most of the increase at the smaller sizes, and a second that assumes a much larger increase at the smaller field sizes, essentially by assuming that the truncation of the number of fields at smaller sizes is entirely an effect of economics and that the actual number of fields continues to increase logarithmically with decreasing field size. * The first projection produces **48,000** fields, the second about **115,000.** Of critical importance is the *difference in resources* between the two projections, all of which arises from different assumptions about how the existing truncation of small fields will "fill in" with future discoveries; it is about 7 percent of the total resource base represented by the second projection. Extrapolating to the gas resource base (and assuming the "central tendency" range of **902** to 1,542 TCF of ultimately recoverable resources), the assumption that the *ultimate* number of small gasfields found will be much larger than indicated by the historical field size distribution might lead to an increase in OTA's estimates of potential gas resources of approximately 60 to 110 TCF.

A fourth argument notes that the small size of the fields makes them only marginally economic at best. For gasfields, especially, many of the fields in the projected distributions may not be economic at current and projected gas prices and therefore may not belong in the recoverable resource base at this time. * * In partial support of this argument, USGS studies the effect of gas price and other economic variables on recoverable gas resources in the Permian Basin indicate considerable sensitivity of the size of the remaining resource to these variables. Table 15 presents estimates of the amount of exploratory drilling that could profitably be pursued and the gas resources that would be discovered by this drilling as a function of wellhead price. *If the model used by the study is correct*, the size of the recoverable resource in small fields is sharply sensitive to price (also rate-of-return), although the sensitivity declines at gas prices above $5 to $6 per MCF.

[39] R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United* **States,** R-2654 / 1-USGS 'DOE, RAND Corp., January 1981, pp, 78-94. Excursus, The Distribution of Petroleum Resources by Field Size in the Geologic Provinces of the United States,

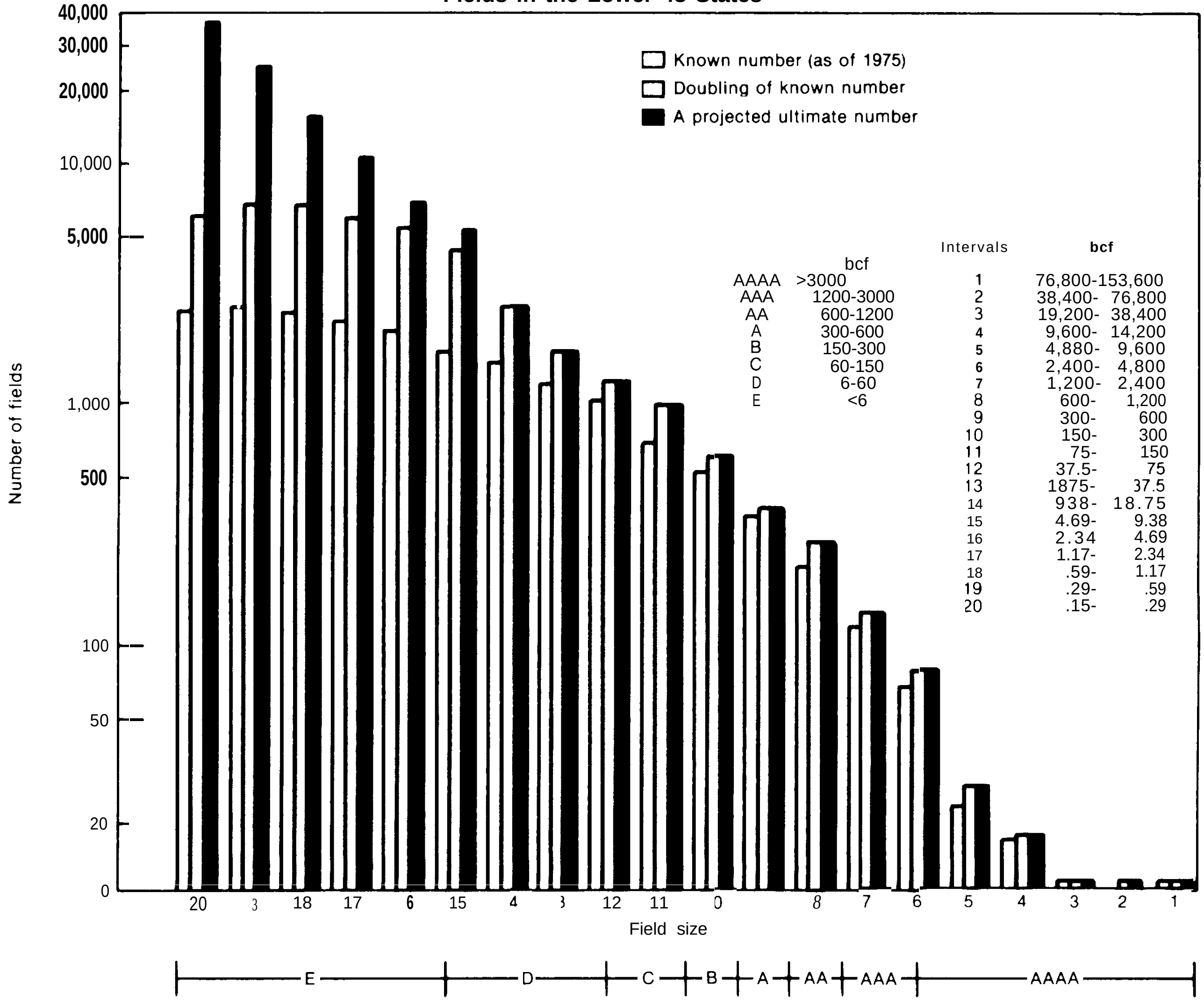
● Subduction provinces are small, linear basins located along the converging margins of plates. They account for about 11 percent of U.S. oil and gas resources in the RAND assessment. The three largest are the San Joaquin, Los Angeles, and Ventura provinces on the west coast. Delta provinces are small-to-medium sized, circular-shaped, and derived from major continental drainage centers. The one producing delta province in the United States is the Mississippi Delta, which accounts for about 17 percent of U.S. oil and gas resources in the RAND assessment,

[40] R. Nehring, *Problems in Natural Gas Reserve, Drilling, and Discovery Data,* op. cit.

● The projected distribution is drawn by assuming that the number of fields in each size interval smaller than 100 million BOE (0. 6 TCF) is 50-percent greater than the number of fields in the next larger interval.

' *In other words, they are subeconomic resources in the McKelvey Box (fig 8).

Figure 16.—Known and Projected Size Distributions of Discovered Oil and Gas Fields in the Lower 48 States



SOURCE: Office of Technology Assessment, based on data from R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983.

Table 15.—Potential Recoverable Gas Resources From New Discoveries in the Permian Basin (assumed 15 percent of return)

Wellhead price $/BOE ($/MMBtu)[a]	Exploration wells drilled (thousands)	New discoveries (TCF)
10 (1.50)	5	4.98
15 (2.40)	12	9.17
20 (3.20)	18	11.38
25 (4.00)	24	13.02
30 (4.80)	29	14.12
35 (5.60)	34	15.13
40 (6.40)	38	15.81

[a]Dollars per barrel of oil equivalent (dollars per million Btu).

SOURCE: Geological Survey Circular 828—Future Supply of Oil and Gas From the Permian Basin of West Texas and Southeastern New Mexico, Interagency Oil and Gas Supply Project, 1980

New **Gas** From Old Fields.—Over the lifetime of a field, from initial discovery to depletion, estimates of the field's ultimately recoverable resources generally increase with time as normal development probes the full extent of the field and as improved technology and rising prices bring subeconomic portions of the field into the economically recoverable range. * Although the effects of improved technology and prices have long been acknowledged as critical for increasing oil

● Reserve estimates in some fields will decrease with time. Small fields are generally considered to be more susceptible than large fields to such reserve "shrinkage."

recovery, gas recovery rates have long been considered to be very high under most conditions and thus somewhat insensitive to price and technology.* Consequently, increases in reserve estimates from known gasfields were generally considered to be primarily an effect of the normal process of exploring for new pools and enlarging the proved area of known pools. This view is now being challenged, as reserve additions are being credited to lowering of the abandonment pressure of depleting reservoirs, to extension of field boundaries into areas of low permeability, to well stimulations and well reworking, and to infill drilling to well spacings lower than the old norm of 640-acre spacing (see box E). For example, from 1969 to 1979, ultimate recovery in the Hugoton-Panhandle field (discovered around 1920) in Kansas, Oklahoma, and Texas Railroad Commission District 10 increased from 71.0 to 84.0 TCF, * * and ultimate recovery in the Blanco-Basin fields (discovered from 1927 to 1950) in the San Juan Basin increased from 15.2 to 21.7 TCF.[41] Although growth rates of known fields have varied considerably across different geographic areas, these substantial increases in known recovery from quite old fields are well beyond what might have been predicted by the historic data on growth of old fields.

Industry opinion about the importance of "new gas from old fields" is quite varied. One reason for this variation of opinion is the anecdotal nature of much of the available evidence and the very mixed experiences of different companies. For example, one source reports claims of 40-percent increases in proved reserves with infill drilling," while another, based on interviews with 14 major production and pipeline companies, reports that infill drilling has "not provided the large reserve additions needed to reverse the long-term decline in proved reserves, " and that "relatively small reserve additions were believed to have been provided by extension of the economic life of pro-

* However, the *rate* of recovery is extremely sensitive to these factors, as is the economic threshold of development for a field.

** This field is not considered a single field by all analysts, nor are its reserve levels completely agreed on. As noted previously, these are not uncommon problems, especially with large fields.

[41] *Ibid.*

[42] Personal communication, William Fisher, University of Texas at Austin, Feb. 9, 1982.

Box E.—Sources of "New Gas From Old Fields"

- *Lowering of abandonment pressure.* —Wells are abandoned when operating and maintenance costs are not balanced by sufficient revenues from gas sales. Because gas-flow rates can generally be associated with wellhead pressures, an "abandonment pressure" can be specified for a given gas price. When gas prices rise, the abandonment pressure is lowered and total recovery efficiency of the reservoir is increased.

- *Infill drilling.* —The original premise of requirements for wide-well spacing was that gas reservoirs were sufficiently homogeneous so that very high-recovery efficiencies could be obtained with only a few wells, except in fields that had low permeability. More recently, it has been recognized that many reservoirs are heterogeneous in character and are compartmentalized, i.e., composed of relatively small, discontinuous interlaid pockets of gas-bearing rock. Drilling at higher density can intercept pockets that would otherwise not have been drained at traditional wide spacing.

- *Fracturing and acidizing.* —These well-stimulation technologies, which have wider application with increased gas prices, are used to speed gas flows and can add to resources by allowing completion of wells in low-permeability sands that otherwise would have been considered as "dry." They do this by allowing a higher recovery during the limited life of the well (at low-flow rates, the well may not last long enough to allow full recovery) and by opening up new "pay zones" too small to be economically developed by a new well.

- *Well workovers.* —Marginal wells may also be abandoned because of water encroachment, physical aging of well equipment, and accumulation of sand in the well bore. At higher gas prices, well workovers to correct these problems become possible.

ducing reservoirs (by lowering abandonment pressures)."[43]

Unfortunately, it is difficult to translate this anecdotal evidence into credible estimates of past increases in recoverable resources available from this "new gas" effect. No collected set of data separates out this effect because the associated changes in reserve estimates are combined with the growth caused by normal development in the "revisions" and "extensions" data now published by EIA. Also, as discussed in chapter 5, the pace of "normal" development has quickened with rising prices and improved seismic technology, preventing any attempt to measure the effect as the difference between current and historical *rates* of field growth.

Attempts have been made to measure *future* growth of older fields that might be caused by higher prices. For example, a recent report has claimed that an increase in the price of "old gas''—gas controlled to prices well below market-clearing levels—could make an additional 52 TCF available: 27 TCF from lower abandonment pressures, 18 TCF from additional infill drilling, and 7 TCF from a combination of fracturing and other well-stimulation treatments, well workovers, and other measures. 44 This estimate is, to our knowledge, the highest of any released to date.

A major controversy surrounding this and other studies involves the extent to which the "additional" resources may already have been added to reserves or else may be developed at current prices (and, consequently, may already be a part of the "economic" portion of the recoverable resource base).

New Frontiers, Including Deep Areas.—Even though recent exploratory drilling in the frontier areas has had mixed success and several severe disappointments, considerable areas of untested or inadequately tested sedimentary rock remain that may hold considerable potential. Even extreme pessimists view areas such as the deepwater Gulf of Mexico, the Anadarko Basin, and the Western Overthrust Belt as having considerable potential. However, it is also inarguably true that areas such as the Gulf of Alaska, eastern Gulf of Mexico, the Southeast Georgia Embayment, and the Baltimore Canyon have been expensive failures[45] thus far. Unfortunately, it is not easy to document the opinions of the major oil companies—who traditionally are leaders in frontier exploration—because few details of their most recent resource assessments are available to the public. It is clear, however, that some of the majors, notably Exxon and Shell, are pessimistic about the overall Lower 48 potential and the Lower 48 onshore frontier areas. Given the speculative nature of these resources, the range of credible estimates of frontier undiscovered gas must be considered quite wide.

An important part of the controversy over the resource potential of frontier areas involves the economic viability of the potential resources rather than their physical presence. For example, much of the intense deep-drilling activity of the early 1980's in basins such as the Anadarko appears to have been a direct response to the very high prices for deep gas (as much as three times the market-clearing price) resulting from the price-controlled market. Prices for deep gas and other categories of gas entitled to special incentive pricing under NGPA have now dropped sharply, and drilling activity has dropped sharply as well. Consequently, some analysts question whether these expensive resources still belong in the economically recoverable resource base. Similar questions have arisen over some of the gas under the deep waters of the continental slope, now included in the USGS assessment and others.

The appropriate placement of these resources inside or outside of the recoverable resource base is complicated by several factors. First, uncertainty about the precise geologic conditions of these resources combined with the recent rapid fluctuations in drilling costs create substantial uncertainty about the cost of producing the resources using today's technology. Second, the present hesitancy of the industry to drill for these resources may not necessarily reflect the resources' lack of long-term economic viability but rather the current lack

[43]Jensen Associates, Inc., "Early Effects of the Natural Gas Policy Act ., op. cit.

"C. S. Matthews, *Increase in United States "Old Gas" Reserves Due to Deregulation*, Shell Oil Co., April 1983.

[45]R. Nehring, "The Discovery of .,., " op. cit.

of gas demand and regulatory uncertainties about decontrol, Third, uncertainty is added by ambiguities in the common definitions of "recoverable resource base, " some of which, e.g., allow the possibility of technological improvements that are in line with trends prevailing at the time of the assessment (this is USGS's boundary condition). This greatly complicates the evaluation of resources whose production may involve technological difficulties. Because of these factors, in OTA's opinion the boundary between economic and subeconomic, and consequently the magnitude of the recoverable resource base, is not well defined for the frontier resources.

Stratigraphic Traps.—Over the cycle of gas exploration, structural traps have tended to be the most favored drilling prospects. As possibilities for finding new large structures have declined, many explorers have shifted their strategy toward locating subtle stratigraphic traps, i.e., potential reservoirs whose main trapping mechanism is a gradation of the reservoir rock into layers of rock of low permeability laid down by the sedimentation process. Resource optimists expect to find large amounts of resources in these traps,

There are two major arguments against such expectations. First, there have been significant past efforts aimed at finding stratigraphic traps, especially in the Anadarko, Permian, Denver, and Powder River basins. " Second, it is argued: 1) that very large stratigraphic gasfields are unlikely to have remained undiscovered in the explored basins of the Lower **48** States because of the fields' large areal extent and the very high density of drilling in these basins, and 2) that most of the stratigraphic traps remaining to be discovered will be small. Nehring[47] also cites geologic arguments against the possibility y of finding many large new stratigraphic traps, including the vulnerability of such traps to degradation or dissipation and Nehring's contention that the presence of multiple structural trapping possibilities in basins outside of the stable interior provinces makes it unlikely that many stratigraphic traps will exist outside of these provinces, the source of most past discoveries.

These are strong but not conclusive arguments. New efforts to locate stratigraphic traps can use seismic exploratory techniques not available to the earlier efforts. It is possible, though speculative, that several sizable traps that were "invisible" to earlier techniques could now be located. Similarly, arguments about drilling density are valid but must be tempered by the depth limitations of much of this earlier drilling and the clustering of such drilling around areas considered prospective by earlier standards.

Even if the arguments against finding large stratigraphic traps are correct, there remains significant uncertainty about the number of smaller fields that might exist and the actual potential for finding and exploiting these fields—the same uncertainty that affects assessment of the resource potential of small fields in general. Key factors affecting the potential for producing significant quantities of gas from these fields include gas prices and reductions in the costs of effective exploration techniques.

Conclusions

Based on the previous discussion, OTA accepts the possibility that discovery trends may have been sufficiently distorted by past regulatory and economic conditions and that sufficient resource possibilities exist in small fields, growth of old fields, and other sources to allow us to accept the estimates of PGC as possible, but very optimistic--a reasonable upper bound to the probable magnitude of the conventional gas resource base. On the other hand, we consider the extremely pessimistic estimate of Hubbert to be unlikely, and to a lesser extent we are also skeptical of the RAND estimate. Both come very close to the analogy of "running into a brick wall. " Looking ahead to chapter 5, we can see that the Hubbert estimate implies a "conventional gas" production rate of about 3 or 4 TCF in **2000,** an astoundingly low value. The RAND estimate implies that there will beat best only a handful of new exploration plays in the Lower 48, that these will be only moderate in size (2 to 10 TCF), and that there will be no really large "surprises" left; we believe this is possible, although quite pessimistic. However, the RAND assessment appears to have underestimated the potential for reserve growth in known

[46]Ibid
[47]Ibid

fields, and it apparently has excluded some gas in low-permeability reservoirs that is currently economically recoverable. Therefore, we consider a credible lower bound to be somewhat higher than the RAND estimate.

In conclusion, our best guess—and we chose this word carefully—is that a reasonable range for the magnitude of remaining conventional natural gas resources, *recoverable under technological and economic conditions not far-removed from today's,* * is about **400** *to* 900 TCF as of the end of 1982. This is not really a very wide range, given the basic uncertainty associated with resource assessment, but it *is* a wide range with respect to future production potential. The two ends of the range have very different implications about how difficult it is going to be to continue to replenish our current inventory of gas reserves over the next decade or two, and they have profound implications about what the role of natural gas in our energy economy will be in 2000. OTA believes that if the lower end is correct, reserve additions will fall off drastically within a few years, with production rates dropping in response. On the other hand, the upper range implies the potential for a very positive future for conventional gas production during this century. The next chapter explores these production issues in greater detail.

* Including gas in low-permeability reservoirs that otherwise satisfies the conditions. This recognizes the ambiguous boundary between "conventional" and 'unconventional" gas in such reservoirs.