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GEOLOGIC CONTROLS OF DEEP NATURAL GAS RESOURCES IN THE UNITED STATES

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ABSTRACT

Review and analysis of resource appraisal methodologies allows identification of several that are particularly suited for dealing with the more common types of deep gas occurrences. Choice of a particular method is ultimately dependent on the level of geologic and engineering data available and on an understanding of the geologic model for a subject occurrence, the objectives of the assessment, and the manpower and time resources available. The methodologies considered appropriate are deposit simulation, reservoir performance, discovery process and finding rate, mass balance, and volumetric or areal yield methods. An example of a deposit simulation is provided, showing sensitivity of various input parameters.

INTRODUCTION

The U.S. Geological Survey previously published an assessment of undiscovered recoverable oil and gas resources in the United States (Mast and others, 1989) but did not include unconventional resources. Deep natural gas resources were extrapolated by depth from known plays. In the present study, emphasis was placed on developing assessment methodologies that best deal with deep natural gas resources. In this paper, therefore, we (1) identify and develop quantitative resource assessment methods and models for evaluation of undiscovered deep gas resources, based on geologic models of occurrence and information developed through geologic research, and (2) present a modeled assessment of a hypothetical deep gas play in order to better understand the wide range of resources that results when geologic variables change.

Review and analysis of resource appraisal methodologies allows identification of methodologies for dealing with some of the more common types of deep gas occurrences. These methods are ultimately dependent on the level of geologic and engineering data available and on an understanding of the geologic model for specific deep gas occurrences, objectives of the assessment, and time and manpower resources available. One or more methodologies may be appropriate in a given case, and the use of multiple methodologies allows independent checks. In general, we feel that methods which lead to assessment of accumulation sizes and numbers are preferable because they allow effective modeling for economic and supply purposes. At a play level, this approach has been used by various workers and is generally described by Baker and others (1984, p. 426).

> Assessments of undiscovered oil and gas potentials for a group of geologically related, untested prospects can be effectively made from an estimate of the possible ranges in number and size of potential fields, assuming that the play exists, coupled with an evaluation of geologic risks that it might not exist. Field-size distributions are constructed from known-field reserves in geologically similar plays, from assessments of representative prospects in the play, or from simulations of distributions of the play's prospect areas, reservoir parameters and potential hydrocarbon relations***The possible range of numbers of potential fields is estimated from counted and postulated numbers of untested prospects in conjunction with the success ratio, or from look-alike field densities.

Several underlying methods used in such assessments are discussed separately in the following section, as are more general approaches.

The general methods of assessment that probably are most appropriate to assessment of undiscovered resources of deep gas include (1) deposit simulation, (2) reservoir performance, (3) analogy, (4) discovery process and finding rate models, (5) mass balance models, and (6) volumetric and areal yield determinations. For a general review of overall methodologies and their characteristics, the reader is referred to White (1978), Dolton (1984), and Charpentier and Wesley (1986). These basic methods can be applied at various levels—basin, major stratigraphic unit, play, or prospect—and, to some degree, they overlap.

The specific assessment methodology employed depends to a large extent on the intended use of the assessment, time and manpower constraints, the geologic model used, and the geologic and engineering data available for synthesis and analysis. The level of assessment that is appropriate, whether at the basin, play, petroleum system, or other level, is likewise determined by these factors and the objectives of the assessment. Geologic information in our companion studies (chapters, this volume) indicates that many deep gas occurrences should be assessed at a play level utilizing a method that provides information on the size of the deposits and their geologic characteristics, as well as an aggregate value, such that economic and supply studies can be made.

DEPOSIT SIMULATION

The deposit simulation method is a volumetric calculation of resources based on measurement or estimation of physical properties of the traps, reservoir rocks and fluids, and host environment in terms of temperatures, pressures, and fluid dynamics. This method has the advantage of working directly with the basic geologic properties of the accumulations and dealing with these properties in a rigorous, quantitative manner. It allows for simulation of the hydrocarbon deposit(s) through modeling of their geologic properties. Because the parameters are uncertain quantities, they are represented by estimates expressed as ranges of values with probabilities of occurrence (probability distributions). The approach therefore uses stochastic and probabilistic methods, as well as statistical methods. An example of input for this type of approach is shown in table 1 (later). A general resource assessment model using these inputs has been described by Canada Department of Energy, Mines, and Resources (1977), U.S. Department of Interior (1979), Dolton and others (1987), and Crovelli and Balay (1986, 1988, 1990).

The calculation of gas volume of a deposit is based on a fundamental reservoir engineering formula. Basic to calculation, therefore, is determination of reservoir volume. The dimension of this container is critical, whether it be a single homogeneous reservoir rock in a conventional trap, a compartment of lesser size within a larger heterogeneous reservoir, or a heterogeneous reservoir of great size associated with an unconventional basin-center gas occurrence.

The modeling of gas-saturated reservoir volumes is affected by various geometric constraints. White (1987) and Abrahamsen (1989) discussed some of these geometric considerations as they may be applied to reservoir thicknesses within closures. For example, reservoir thickness is a function not only of the available stratigraphic thickness of the reservoir unit and effective porosity within it but also of the position of the gas-water contact and the configuration and size of the trap and its fractional fill. Geometric considerations become particularly significant if available reservoir rock thickness is great relative to closure area (as in many fields in the gas-productive Lower Ordovician Ellenberger Group of the deep Permian Basin) or if dealing with small vertical closures, small fractional fill, or small areal trap sizes. If mapping is sufficient, thickness can be measured, or, alternatively, gross hydrocarbon-bearing reservoir volume can be calculated directly from planimetered areas (Pirson, 1950), thereby collapsing the variables of reservoir thickness, area, and trap fill into a single variable of hydrocarbon-occupied reservoir.

The internal physical characteristics of the reservoir that determine hydrocarbon volumes are porosity and water saturation. Porosity values used must meet an assigned threshold value to qualify as “effective porosity.” It is important that this same minimum value be adhered to in terms of measurement of reservoir thickness and risking of attributes. Water saturation can be estimated directly (as in the input example) or determined using an algorithm that relates water saturation to the average porosity of the reservoir.

Adjustment for nonhydrocarbon gas volumes that may occupy pore space is made simply through introduction of an estimate of the fractional percentage of hydrocarbon gas. This adjustment is an especially important element in such deep gas areas as the Delaware–Val Verde Basin of West Texas and deep gas reservoirs of southwestern Wyoming and probably is important in many other deep gas basins.

It is essential to consider engineering factors, including estimation of the thermal and pressure conditions of the simulated reservoir and trap. In addition, it is necessary to calculate the compressibility factor of the gas (Z), based on known or estimated gas composition.

Adequate framing of the basic geologic model or models of occurrence is essential to assessment in terms of assignment of risk to the variables controlling the occurrence of gas and to the assessment of volume parameters. The rock and fluid characteristics identified and investigated in companion studies are critical and include physical properties of reservoirs such as thickness; distribution; porosity amount and variation; pore geometry and dimensions; trap types and dimensions; effectiveness of seals; physical environments of accumulations including depth, present and past thermal conditions, pressure regimes, and fluid dynamics; and saturations and properties of the involved fluids, their composition and physical state. Availability of data for these characteristics and their sufficient quantification ultimately determine the adequacy of results. Development of relevant databases is a requirement for assessment.

The simulation method provides not only an overall resource assessment but also a description of the individual accumulations in terms of their geologic characteristics and their contained gas, and it affords an easily updatable assessment record. It estimates resources in situ and does not tell the user directly about the recoverability or producing characteristics of the resources, although permitting use of known or estimated recovery factor. The method is flexible in that it allows the geologist to model the geologic conditions controlling the resource and allows for a range of resource values for uncertain and variable geologic conditions.

The actual production characteristics of reservoirs that lead to recoverability are best determined by engineering studies of the reservoir rock and fluids, including reservoir drive and pressure characteristics, reservoir rock permeability and compartmentalization, and fluid properties, especially critical with reference to tight-gas reservoirs.

RESERVOIR PERFORMANCE

The somewhat empirical method of reservoir performance relies on production data that are extrapolated to permit a calculation of ultimately recoverable resources, based on certain economic and technologic assumptions. The method, including, variously, production decline extrapolation methods, cumulative production extrapolation, material balance, and others, relies heavily on a careful engineering approach, beyond the scope of this analysis. It is useful in a reservoir in which some development has occurred, as locally may be the case in an extensive but otherwise poorly defined unconventional tight-gas reservoir, or for reserve calculations within a developed field. It deals not only with the basic physical characteristics of the reservoirs and fluids but also measures, over time, how production and reservoirs respond to development controlled by both technologic and economic factors. It can be a very effective method in areas in which there is a sufficient history of production; however, the assessor commonly does not have sufficient information to satisfy the method, except on an analog basis.

ANALOGY

A fundamental approach to assessment is geologic analogy, and, in fact, this method underlies elements of several of the other methods. As an explicit assessment method, analogy relies on identification of an appropriate and adequately documented analog model for use in a subject assessment area. If well-understood models of deep gas occurrences are adequately documented, analog comparisons and calculations can be used to approximate resource values of subject areas. The method is relatively unsophisticated, although flexible in the sense that it can be readily modified to incorporate adjustments for geologic differences between analog and subject areas. It is particularly useful in areas lacking detailed information other than a broad geologic setting. In somewhat more sophisticated forms it is used to model not only geologic properties but also hydrocarbon accumulations and populations for use in resource procedures dealing with evaluation of field sizes and numbers (White and Gehman, 1978; Mast and others, 1989). We believe that analogy is a particularly useful method for assessing deep gas resources in basins for which reasonable analogs can be established.

DISCOVERY PROCESS AND FINDING RATES

If there is a sufficient exploration history, an effective assessment technique is that of extrapolating from the sequence of field discoveries to derive what remains to be discovered, both in terms of field size and aggregate resource value. These techniques are variously termed discovery process models or finding rate models and, in their more sophisticated forms, were pioneered by Arps and Roberts (1958), Drew (1974), and Barouch and Kaufman (1975). At their best, they are done at a play level, by identifying and using natural populations of fields that are identifiable by common geologic characteristics of trap, reservoir, seal, and source (Canada Department of Energy, Mines, and Resources, 1977; Lee and Wang, 1986; Podruski and others, 1988). In a subjective format, the method was part of the analysis of field sizes employed in the 1989 U.S. Geological Survey national assessment (Mast and others, 1989; Houghton and others, 1989). Various specific methodologic approaches can be used and are commonly highly statistical in nature. The reader is referred to White (1978) and Miller (1986) for further discussion of methods of this class. Because development of deep gas in most areas is relatively new and has not yet proceeded to a point to allow this kind of analysis, use of the method has been limited, although the method was successfully employed in the Permian Basin of West Texas and southeastern New Mexico by Drew and others (1979). To employ the method, sufficient data are needed concerning exploration effort and discovery.

The more basic models of this class of historical extrapolations deal simply with overall resources discovered as a function of exploratory footage or exploration wells drilled, without reference to the underlying field size population, and are not considered appropriate for deep gas assessment.

MASS BALANCE

Mass balance calculations have been used as a tool for estimation of resources. The method deals with the amount of hydrocarbon generated, based on geochemical data, the amount expelled and migrated, and the amount finally retained in traps. Because of the difficulty and uncertainty in quantitatively assessing several of these variables, the method has been useful mostly in a qualitative sense, that is, in identifying the probable hydrocarbon composition, the migration history and adequacy of charge, and the general resource potential. The method is particularly useful in identifying critical geologic elements and processes needed for resource evaluation. In very well studied areas containing the requisite information, it can be applied as an estimation method.

AREAL OR VOLUMETRIC YIELD METHODS

These methods use basic geologic data and areas or volumes of rock for calculation of resources. Yields of hydrocarbons per unit of rock, obtained from analog areas, are used as the basis for calculation of resources in a subject area. The method can be used on a basin, play, or stratigraphic unit scale. The result is only as good as the analogy, which can be either internal or external, and the information regarding its hydrocarbons. Comparability factors are commonly used in modifying the yield factors to more closely model the subject area. If a strong analogy can be established, a useful estimate can be obtained in areas for which detailed geologic data may be lacking. These methods might be particularly useful in assessment of deep gas resources of some areas of the Rocky Mountains.

APPLICATION OF A DEPOSIT SIMULATION MODEL—HYPOTHETICAL PLAY EXAMPLE

Several of the preceding methods meet criteria for evaluation of undiscovered deep gas resources. If sufficient information is available concerning the geologic characteristics of known or suspected deposits of deep gas, we believe that a *deposit simulation based on a geologic model of reservoir volume is effective*. As discussed previously, this method is based on measurement of known or estimated physical properties of the traps, reservoir rocks and fluids, and host environment in terms of temperature, pressure, and fluid dynamics. It has the advantage of working with the basic geologic properties of the accumulations and dealing with them in a rigorous, quantitative manner, and it allows for simulation of the hydrocarbon deposit(s) through estimation of properties if data are lacking or incomplete.

The calculation of gas resources is based on a fundamental reservoir engineering formula, expressed as

Gas volume (ft^3)=

$43{,}560\ A \times F \times H \times Por \times (1-Sw)(Pr/Tr)(1/Z)(Tsc/Psc)$

where

A=area of closure (acres)

F=trap fill (decimal fraction)

H=reservoir thickness (feet)

Por=porosity (decimal fraction)

Sw=water saturation (decimal fraction)

Pr=original reservoir pressure (pounds per square inch)

Tr=reservoir temperature (degrees Rankine)

Psc=pressure, standard conditions (pounds per square inch)

Tsc=temperature (degrees Rankine)

Z=gas compressibility factor.

Simulation of properties of the accumulation, or an aggregate of accumulations, requires that the parameters are represented as estimates expressed as ranges of values, accompanied by probabilities of occurrence (probability distributions), representing the natural geologic variability of geologic characteristics and our uncertainty about them. Hence, the values shown represent the range of possibilities that might be encountered at a randomly selected prospect within a population. The model can be used either at the scale of a single prospect or for an aggregate of prospects within a common geologic setting or play.

We present an example of a deep gas occurrence in a hypothetical basin and use of this model. Several basins in the United States meet the requirements for the conditions for this model including the Anadarko Basin, the Gulf Coast Basin, and several deep Rocky Mountain basins. This exercise is intended to demonstrate the use and flexibility of this model rather than to provide an actual assessment of recoverable resources. In this case, we assume a population of drillable prospects, which have been identified geologically or geophysically or are hypothesized to exist, that we believe have common geologic characteristics. We estimate that we are dealing with a sandstone reservoir in structural traps at depths ranging from 5,486 to 6,706 m (18,000–22,000 ft).

The input used for this example is shown in figure 1. In this case, we assume that the various play attributes for hydrocarbon occurrence have been met; hence, no risk has been assigned. If questionable, then a probability of occurrence of less than one would be assigned.

In the case of the prospect attributes, we believe that there is a possibility that they may not be present or favorable at a randomly selected prospect. For instance, we consider that, on an individual prospect basis or at a randomly selected prospect, the trapping mechanism or trapping configuration we envision has a 6 in 10 chance of existence (probability of trapping mechanism=0.6) and also that the necessary migration paths from source rocks to the trap have a 7 in 10 chance of existence (probability of hydrocarbon accumulation=0.7). Each attribute is assessed conditioned on the other attributes being favorable and also on the basis of being sufficient to meet the minimum values for hydrocarbon volume parameters of the deposits to be considered (indicated in the lower part of the form, fig. 1).

For the hydrocarbon volume parameters, we use the general characteristics and properties of deep gas deposits or occurrences, which are documented elsewhere in the companion chapters. In this case, we require minimum values to be area of closure=300 acres; reservoir thickness=10 ft; effective porosity=5 percent; trap fill=10 percent; and hydrocarbon saturation=60 percent. The program FASPU (Crovelli and Balay, 1990) was used to calculate the estimates.

Results from calculation of the modeled play are shown in table 1. Several interesting relationships emerge from this calculation. First, a relatively modest amount of gas is calculated, given the given prospect areal sizes. This result is

	ATTRIBUTE		PROBABILITY OF FAVORABLE OR PRESENT
Play Attributes	Hydrocarbon Source		*1.0*
	Timing		*1.0*
	Migration		*1.0*
	Potential Reservoir Facies		*1.0*
	Marginal Play Probability		*1.0*
Prospect Attributes	Trapping Mechanism		*0.6*
	Effective Porosity (>3%)		*1.0*
	Hydrocarbon Accumulation		*0.7*
	Conditional Deposit Probability		*0.42*
Hydrocarbon, Volume Parameters	Reservoir Lithology	Sand	*X*
		Carbonate	
	Hydrocarbon type	Gas	*1.0*
		Oil	*0*

	Fractiles / Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
Hydrocarbon, Volume Parameters	Area of Closure (1000 acres)	*0.3*	*0.4*	*0.9*	*1.7*	*3.0*	*4.6*	*6.2*
	Reservoir Thickness/ vertical closure (feet)	*10*	*20*	*35*	*50*	*70*	*100*	*120*
	Effective Porosity (%)	*5*	*5.2*	*6*	*8*	*10*	*14*	*20*
	Trap Fill (%)	*10*	*25*	*45*	*60*	*75*	*90*	*100*
	Reservoir Depth (1000 feet)	*18*	*18.75*	*19.5*	*20*	*20.5*	*21.25*	*22*
	HC Saturation (%)	*60*	*65*	*70*	*75*	*80*	*85*	*90*
Number of drillable prospects (a play characteristic)		*10*	*12*	*14*	*15*	*17*	*20*	*22*

Figure 1. Oil and gas appraisal data form completed for hypothetical deep natural gas play. Geologic variables: *Pr* (original reservoir pressure [psi])=0.46 psi/ft (depth)+14.7 psi; *Tr* (reservoir temperature [˚Rankine])=surface temperature+0.013˚/ft (depth)+515˚; *Z* (gas compressibility factor)=1.2; gas recovery factor 0.80. From Crovelli and Balay (1988).

Table 1. Results of calculation of modeled deep natural gas play based on input in this report—conservative case.
[See figure 1 for input]

	Mean	F95	F75	F50	F25	F05
Number of accumulations	6.3	3	5	6	8	10
Accumulation size (BCF)	55	8	19	35	66	164
Unconditional play potential (BCF)	345	122	207	298	430	726

Table 2. Results of calculation of modeled deep natural gas play based on input in this report—optimistic case.
[Figure 1 modified to increased porosity (mean value 18 percent) and pressure (0.75 psi per foot); all other variables constant]

	Mean	F95	F75	F50	F25	F05
Number of accumulations	6.3	3	5	6	8	10
Accumulation size (BCF)	185	27	66	122	226	547
Unconditional play potential (BCF)	1,169	425	712	1,017	1,454	2,431

mostly the function of small amounts of effective matrix porosity assumed. Should porosity of less than 5 percent contribute gas to the reservoir, then such volumes should be included and the effective porosity cut-off adjusted. Porosity loss is viewed as a significant factor in many deep gas reservoirs. It affects producibility, as well as the amount of resource, as a consequence of associated low permeability. In many cases, the presence of natural fractures is necessary for economic production. In such reservoirs, adjustment of reservoir porosity values must be made to include fracture porosity for volume calculations. Situations in which porosity is retained at great depth, as in some geopressured reservoirs, need to be considered in exploration, development, and assessment scenarios. This recoverable resource estimate represents the conservative case.

Note that in this calculation we assumed independence of volume parameters, other than a positive correlation between porosity and gas saturation; however, dependencies may exist and can be dealt with. For instance, one might assume that a positive correlation or dependency exists between trap size and fill, effectively collapsing the container size parameters into a single variable; in that case, the field size possible at the 5th fractile (the largest reported field size) increases from about 160 BCFG to approximately 200 BCFG. Alternatively, if we assume an overpressured reservoir mode, in which reservoir conditions are better, as in some of the clastic reservoirs of the Gulf Coast Basin (for example, Upper Jurassic Norphlet Formation and Upper Cretaceous Tuscaloosa Formation), and use these variables in place of the original data set, resources calculated increase significantly. Table 2 shows the recoverable gas estimated for the improved reservoir conditions. For this case, we assume an average reservoir porosity of 18 percent, and a pressure gradient of 0.75 psi/ft (clearly an overpressured reservoir, as is commonly associated with deep natural gas accumulations). In the original case (table 1), the mean resource value in these prospects was 345 BCFG. In the second, more optimistic case, the mean resource value was 1,169 BCFG, a threefold increase due entirely to the increase in porosity and pressure. Other variables that particularly affect overall reservoir volume include reservoir thickness and size of prospects. Pore space occupied by nonhydrocarbon gas may be accommodated by a percentage reduction of the total gas calculated or incorporated within a recovery factor. This flexibility of the assessment method allows the geologist to model the geologic conditions controlling the resource values to reflect a wide range of geologic conditions.

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