# PRESENTATION AND EXHIBITS
# for the
# SAN JUAN BASIN COALBED METHANE SPACING STUDY

*Presented at the*

*NEW MEXICO OIL CONSERVATION DIVISION*
*EXAMINER HEARING*
*CASE NO. 9420, ORDER NO. R-8768*
*FEBRUARY 21, 1991*

*Submitted by*

SAN JUAN BASIN COALBED METHANE COMMITTEE

BEFORE EXAMINER CATANACH
OIL CONSERVATION DIVISION
M/W EXHIBIT NO. 6
CASE NO. 11996

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## OUTLINE FOR PRESENTATION

OVERVIEW AND
CONCLUSIONS

# BASIN FRUITLAND COAL POOL
# COALBED METHANE RECOVERY

**6.93 BCF OGIP**

| Recovery | 1 well/320 acres | 2 wells/320 acres |
|---|---|---|
| **% OGIP** | | |
| Average | 55.5 | 56.3 |
| Range | 34.4 - 68.3 | 35.9 - 68.5 |
| **BCF** | | |
| Average | 3.85 | 3.90 |
| Range | 2.38 - 4.73 | 2.49 - 4.75 |

**Basis:** San Juan Basin Coalbed Methane Spacing Study
Exhibit 80 - Area 1 Sensitivity Analysis
100' frac, 0.25% porosity, 35' coal, 50 MCFD cutoff,
Permeability range 1-50 mds.

NMOCD Hearings
April 4, 1991
Case 9420

Amoco Exhibit No. 1

# BASIN FRUITLAND COAL POOL
# ECONOMIC ANALYSIS RESULTS

| | 1 well/320 acres | 2 wells/320 acres |
|---|---|---|
| $PV_0$ | $4.6 MM | $1.6 MM |
| $PV_{10}$ | $0.5 MM | $0.4 MM |
| $PV_{15}$ | $0.3 MM | $0.2 MM |

# ECONOMIC ASSUMPTIONS

1. **Well Cost - $300 M**
   **Facilities $175 M**
2. **Operating Cost - $20,000/yr/well**
   **w/decline to $10,000 in 5 yrs.**
   **$1.00/BBL Water Disposal**
3. **5% Inflation and Escalation**
4. **$1.00/mcf - wellhead price (netback)**
5. **Production Profile for Area 1**
   **0.25%porosity, 5 mds perm, 100 ft. frac**

NMOCD Hearings
April 4, 1991
Case 9420

Amoco Exhibit No. 2

## STUDY OVERVIEW AND CONCLUSIONS

### Introduction

In May 1989, the Coalbed Methane Committee (CMC) agreed that a reservoir engineering study of the basal Fruitland coalbed methane resources in the San Juan Basin would greatly assist the New Mexico Oil Conservation Division and the Colorado Oil and Gas Conservation Commission in developing the appropriate fieldwide rules for optimum well spacing and conservation of the resource. GRI also was interested in conducting a study to determine the relationship between reservoir properties and productivity. The CMC and GRI agreed to cooperate in a study to fulfill these mutually compatible objectives. GRI requested its contractor, ICF Resources Incorporated, to prepare a proposal outlining the methodology and requirements to perform the study. This proposal became the technical basis for the joint agreement between GRI and the CMC, the study commenced in September 1989.

The primary objective of the CMC in this effort has been to develop an appropriate methodology for evaluating well spacing in the development of the coalbed methane resources of the San Juan Basin. ICF Resources proposed meeting this stated objective by concentrating its efforts on the reservoir characterization of selected field sites and the completion of sensitivity analyses based on reservoir simulation techniques. Reservoir characterization of selected field sites under active coalbed methane development provides the means by which key reservoir parameters can be defined on a site specific basis. Once the key parameters such as cleat permeability and porosity, coal thickness, reservoir pressure, initial gas content, sorption isotherm characteristics, and initial water saturation have been determined, the sensitivity of gas and water production to a wide range in these parameters can be evaluated with an appropriate coalbed methane simulator.

As one of the most productive basins in the United States, the San Juan Basin has been the focus of active research in recent years. In order to advance the body of knowledge on all facets of commercial coalbed methane resource development in the basin, the Gas Research Institute has funded much of this research effort. The foundation of the CMC Fruitland spacing study relied extensively on contributions from two such recently completed studies[1, 13] funded by GRI.

Identification and location of coalbed methane wells in the San Juan Basin was conducted by the Texas Bureau of Economic Geology[1], under contract to GRI, and provided the foundation for the selection of areas under active coalbed methane development within the basin. On the basis of hydrodynamics and geology, the San Juan Basin was divided into three main regions having similar reservoir characteristics[1]. These are: the overpressured north-central part of the basin designated as Area 1, the underpressured regional discharge area in the west-central part of the basin designated as Area 2, and the underpressured eastern part of the basin designated as Area 3 (Exhibit 1). It should be noted that the boundaries between these areas are very complex and are not as well defined as shown in Exhibit 1. The implications of these subdivisions on reservoir characterization and performance will be discussed in detail later.

Resource Enterprises, Inc., under contract to GRI, conducted the Western Cretaceous Coal Seam Project[13] with the objectives of evaluating the areas of exploration geology, drilling, formation evaluation, completion engineering, production operations, and field development in the northern San Juan Basin. As a result of the major formation evaluation efforts performed for the study, realistic ranges in reservoir properties were identified and became invaluable in constructing and designing the sensitivity analyses for Areas 1, 2 and 3.

In addition to the public data available through GRI funded research, individual members of the Coalbed Methane Committee provided both their experience and selected data throughout this cooperative effort. Primary responsibility for the oversight of the project resided with the Gas Research

Institute and the six participants of the Steering Committee: Amoco Production Company, Arco Oil & Gas Company, Bowen Edwards & Associates, Marathon Oil Company, Meridian Oil, Inc., and Nassau Resources, Inc.

Important contributions were also provided by the other seven participants of the Coalbed Methane Committee that are currently active operators in the San Juan Basin: Devon Energy Co., Mesa Limited Partnership, Phillips Petroleum Co., Southern Ute Indian Tribe, Texaco Inc., and Union Oil Company of California.

An important component of this study was the dialogue continually maintained between the study group (GRI, CMC and ICF Resources) and the New Mexico Oil Conservation Division and the Colorado Oil and Gas Conservation Commission through the presence of their respective representatives, Ernie Busch (NMOCD) and Mark Weems (COGCC).

The purpose of this presentation is to provide a review of the results and conclusions of the San Juan Basin Coalbed Methane Spacing Study. As this research project involved the cooperative effort of the Gas Research Institute and 13 operators currently active in the basin (CMC), the results and conclusions of this study may not reflect those of any specific individual but are, however, consistent with the consensus of the members of the Coalbed Methane Committee.

In addition, it is important to note that this study does not include economics as a parameter in the evaluation of spacing considerations. Economics and the methods used to evaluate economics varies from operator to operator; and therefore, economics must necessarily be considered on a case by case basis. However, the results of the study do provide an evaluation of how key reservoir parameters impact performance to which economics can then be applied.

**Summary and Conclusions**

A. The current 320 acre temporary spacing rules provide an appropriate basis for initial development and evaluation of the Fruitland Coal pool of the San Juan Basin. However, this study indicates that there are many combinations of reservoir properties where spacing other than the existing temporary rules of 320 acres may be appropriate. There are likely to be areas of the basin where these combination of properties exist; however, there are not sufficient data at this time to properly define the location and extent of these areas. In order to prevent waste and protect correlative rights, individual operators should be afforded every opportunity to present testimony and technical data to support their application for spacing in their respective areas. This study has identified key parameters which should be considered in spacing applications which may include the following: Well Performance Data, Permeability, Porosity, Coal Thickness, Pressure, Gas Content, Sorption Isotherm and, Initial Water/Gas Saturation.

Take this data to the tables

B. Based on the results of the sensitivity analyses, gas recovery increases with (1) increasing initial free gas saturation, (2) increasing initial reservoir pressure, (3) decreasing coal cleat porosity, (4) increasing cleat permeability, (5) decreasing well spacing, (6) increasing fracture half-length, and (7) increasing initial gas content.

C. Unlike conventional wells, well interference effects may be useful in beneficially exploiting coalbed methane as a resource. Acceleration of dewatering may improve recovery within practical time limits of 25 years or so.

D. The selection of an optimum spacing is a function of both reservoir performance and economic considerations. This study only dealt with an evaluation of reservoir performance and did not address the economic analysis which must necessarily follow. It is important, however, to remember that the spacing issue is best resolved on a site-specific basis to achieve the best utilization and conservation of the coalbed methane resource.

TECHNICAL
APPROACH

## TECHNICAL APPROACH

### Study Methodology

The only reliable method currently available to determine the effects of reservoir properties and well spacing on coalbed methane recovery is reservoir simulation. This is because gas production from coalbed methane wells (Exhibit 2) is more complex than from conventional gas wells, and the traditional methods of analogy, decline curve analysis and material balance are not adequate to describe coalbed methane behavior.

Exhibit 2 reflects that the key difference between a conventional gas reservoir and a coal gas reservoir is the mechanism of gas storage and production. In a conventional reservoir, gas is stored in pore space in the rock. In a coal reservoir, methane is physically bound (adsorbed) on the solid structure of the coal itself. The methane does not become a gas and migrate to the wellbore until pressure is reduced.

Since the classical coalbed reservoir contains water, pressure reduction normally occurs by pumping water. The relationship between the amount of gas in the coal and pressure is described by the sorption isotherm (Exhibits 3 and 4). If the initial reservoir conditions lie on the isotherm (coal A), the coal is said to be saturated, and both gas and water are produced upon pumping. In this case, the desorption pressure and the initial reservoir pressure are identical. However, in some coal seams the initial gas content lies below the sorption isotherm (coal B), and significant drawdown of pressure at the wellbore, during which time only water is produced, must occur before methane can be released. In this case, the "release" or desorption pressure is somewhat lower than the initial reservoir pressure. For dry coalbeds, pressure reduction also occurs by pumpdown. However, the same arguments apply regarding the saturated or undersaturated conditions shown in Exhibits 3 and 4, except only single phase gas is produced once the desorption pressure is reached.

The result of the dewatering of a coal seam is that the effective permeability of gas, relative to water, increases. This causes a period during which gas production <u>increases</u>, that is, a "negative" decline period (Exhibit 2) which does not occur in a conventional gas well. This negative decline feature is thus a "fingerprint" of a classical coalbed methane well. For coalbeds having an initial gas saturation, the negative decline feature of the gas production rate curve may, or may not, be demonstrated.

Another significant difference is that in coal seam reservoirs, interference between wells may be beneficial. It is well known that as coal wells are drilled on closer spacing, the dewatering process provides more rapid depletion of the hydrostatic pressure and more rapid release of gas for the same coal seam permeability. This is fundamentally different from conventional gas-sand reservoirs, where wells are placed at sufficiently large spacing to minimize interference. As well spacing decreases in a coal reservoir, gas production peaks are higher and earlier in time (Exhibit 5). The impact on ultimate recovery will depend upon reservoir conditions as early time increases in production may or may not be offset by more rapid production decline in the later life of the wells. The location and magnitude of these peaks, and their effect on subsequent long term cumulative gas production are most readily assessed with a reservoir simulator, as they involve the interaction between pressure drawdown (Exhibit 6), the location of wells relative to other wells and reservoir boundaries such as faults, and many coal reservoir properties, the most important of which is permeability. Additional insight into the differences between coalbed methane reservoir and conventional reservoir behavior may be found in Remner, et al[15].

The study methodology is simulation based because simulation provides a consistent and reliable way to account for the complex mechanism of coalbed methane production and in doing so to predict actual field production, develop reservoir characterization, and assess the sensitivity of gas production to reservoir properties and operating methods.

## Model Validation

The reservoir simulator used for the study was COMETPC 3-D, a computer model developed by ICF Resources Incorporated and the Gas Research Institute[2, 3]. Before beginning the study, the CMC requested that the simulator be validated against other simulators and by matching actual field production.

ARCO Oil and Gas Co. volunteered their coal seam gas simulator for comparison with COMETPC 3-D. Three problems using data typical of the Fruitland coal formation were constructed and run by ARCO and ICF Resources on their respective simulators. For all three problems, a mathematical grid was constructed to represent a full 640 acre section with three wells located as shown in Exhibit 7. The cross-section of the reservoir for problem 1 was constructed as shown in Exhibit 8. Problems 2 and 3 used variations of this cross-section.

Agreement between the two simulators was excellent for all three problems. Comparison of the results for problem 1 are shown in Exhibits 9 - 13. The results for problems 2 and 3 and the details of the comparison are shown in the SPE paper "Validation of 3D Coalbed Simulators" (Exhibit 14).

The ICF simulator was also validated by using it to match actual production data from the Cedar Hill and Tiffany fields in the northern part of the San Juan Basin. This history matching exercise also served to develop a reservoir characterization for the sensitivity analysis work.

## Reservoir Characterization

Before the sensitivity analyses could be performed using the simulator, each of the three areas had to be investigated to discern a range of expected reservoir properties. These reservoir parameters included coal cleat permeability and porosity, initial water saturation, gas content, sorption isotherm, initial reservoir pressure, net coal thickness and zonation, and induced fracture half-length. This was accomplished by conducting a literature search, and by reviewing publically available field and laboratory data and data provided by operators on the CMC. For example, Exhibit 15 shows data from GRI's Western Cretaceous Coal Seams Project which was used in arriving at suitable ranges for the key reservoir parameters.

To further define the ranges of reservoir parameters, the simulator was used to match gas and water production rates, and bottomhole pressures from producing and pressure monitor wells for the Cedar Hill and Tiffany fields. The simultaneous matching of data from many wells in each of these fields yielded a reservoir description and further definition of values of the key parameters over which the sensitivity analyses would be performed. Procedures and results for the history matches are presented later.

## Sensitivity Analyses

Having established the validity of an appropriate reservoir simulator, and the anticipated ranges of key reservoir parameters upon which coalbed methane depends, the crux of the study is to use the simulator to determine the sensitivity of gas and water production to changes in the key parameters over their expected ranges. This is a most powerful use of reservoir simulation as simulations without actual history can be made. Systematic production predictions can be made while changing variables felt to be important or to investigate sensitivity of production to the effects of variables not actually measured in the laboratory or by well tests.

The sensitivity analyses for each of the three areas of the basin were performed by designing a "matrix" of sensitivity simulations whereby combinations of the key parameters and well spacing were varied. The resulting families of gas and water production rate versus time curves can be used by operators to determine appropriate well spacing for specific sites in the basin. In addition, the results can be used as guidelines to promulgate well spacing and water disposal rules by the NMOCD and COGCC.

# DISCUSSION OF RESULTS

# DISCUSSION OF STUDY RESULTS

## Cedar Hill Field Area History Match

### Introduction

To adequately characterize reservoir properties which are favorable to coalbed methane production, a field site should be selected on the basis of established commercial levels of gas production. The Cedar Hill area has the longest production history of any multi-well coalbed methane field in the San Juan Basin. The level of productivity and the amount of reservoir data available in the public domain make this field an excellent candidate for a detailed reservoir simulation study.

The purpose of this discussion is to provide a brief review of the geologic model developed for the Cedar Hill field area and to provide a detailed discussion of the results of the subsequent reservoir simulation study completed on a selected portion of the field area. As this work was limited to data only available in the public domain, a summary of the data sources utilized in the study is also provided. These sources consisted primarily of research funded by the Gas Research Institute (GRI) and information provided to the New Mexico Oil Conservation Division (NMOCD).

Cedar Hill is located approximately 20 miles northeast of Farmington in the northeastern part of San Juan County, New Mexico (Exhibit 1). The field covers approximately 16 square miles in Townships 31 and 32 North and Range 10 West where active coalbed methane production occurs from coal seams occurring within the basal portion of the Upper Cretaceous Fruitland Formation (Campanian). Cedar Hill is located in the overpressured north-central part of the San Juan Basin which has been designated as Area 1[1]. The implications of this will be addressed later in the reservoir model discussion of this report.

### Geologic Model

A geologic evaluation of the Cedar Hill field area was performed to provide an accurate framework for the subsequent reservoir simulation study completed on a portion of the field area. The large number of Fruitland penetrations within the area provided an accurate inventory of coal reserves as well as the basis for some stratigraphic and structural analysis.

To accomplish this task, density logs were obtained from Petroleum Information (PI) on over 75 well locations in T31-32N and R10-11W. Two coal seams were identified and correlated as the "Upper" and "Lower" Basal Fruitland coal seams. Two stratigraphic cross sections were constructed to illustrate lateral facies relationships along depositional strike (A-A') and dip (B-B') across the main part of the Cedar Hill field area (Plates 1-3, Exhibits 48-50). As indicated in the cross sections, a silty shale interval was identified as consistently occurring between the two coal seams. This shaley interval was assumed to restrict vertical fluid movement between the two seams within the area selected for detailed reservoir simulation work; that is, the absence of vertical permeability prevented communication between the two model layers.

A structure contour map showing elevations above sea level for the top of the "Upper" Basal Fruitland coal was constructed (Plate 4, Exhibit 51). Net coal isopach maps were developed for both the "Upper" and "Lower" seams using a bulk density cut-off of 1.75 gm/cc (Plates 5-6, Exhibits 52-53). In a general sense, the Fruitland coal displays a northeast-southwest dip-elongate pattern in both thickness and structural trend. Within the area mapped, the top of the Fruitland coal is characterized by structurally high noses both in the northeast and southwest dip directions while forming a structurally lower saddle in the central part of the field area (Plate 4, Exhibit 51). Similarly, along depositional strike, the Fruitland coal is structurally higher both in the northwest and southeast directions relative to the central portion of the Cedar Hill field area. Within the model area (Plate 1, Exhibit 48), the top of the Fruitland coal rises from less than 3,210 feet above mean sea level in the central part of the area to over 3,280 feet in the southwest and over 3,230 feet in the northeast, representing a structural relief in excess of 70 feet. The thickest Fruitland coal development, which is particularly evident in the "Upper" Basal Fruitland coal seam, also occurs in a dip-elongate belt trending northeast-southwest (Plate 5, Exhibit 52). Within the area mapped, the Fruitland coal attains thicknesses of almost 30 feet on the basis of a 1.75 gm/cc bulk density cut-off and displays a thinning along depositional strike to both the northwest and southeast.

## Reservoir Model

The selection of that portion of the Cedar Hill field area to be utilized for a detailed reservoir simulation study was determined by considering both the well completion dates reported on the PI scout tickets and the first gas delivery dates reported to the NMOCD. The Cedar Hill field was discovered by Amoco Production Company with the drilling and completion of the Cahn Gas Com 1 well in May 1977. In 1986, curtailments in gas sales were invoked and as a result the use of reported production volumes to accurately characterize reservoir properties becomes ineffective. Therefore, only wells completed between May 1977 and December 1985 were considered for the model area.

Exhibit 21 schematically illustrates the relative timing of other Cedar Hill wells drilled in the immediate area around the Cahn well. As can be seen in the figure, a total of seven coalbed methane wells were drilled and produced between May 1977 and December 1985. In addition, Amoco Production Company recompleted three non-commercial Pictured Cliffs wells to the basal Fruitland coal to monitor formation pressures in the Cedar Hill field area. This resulted in a total of ten wells being utilized in the simulation study.

The relative position of the simulation grid is shown on Plate 1 (Exhibit 48) with the detailed grid illustrated in Exhibit 22. The grid was designed with 19 grid blocks in the x-direction and 23 in the y-direction and utilized 2 layers; that is, one layer for each of the two basal Fruitland coal seams. Individual grid blocks varied in size from as small as 400 feet on a side to as large as 2,800 feet on a side for the coarser blocks on the outside edge of the grid.

On the basis of oriented core analysis completed on the Mesa Hamilton No. 3 well which lies approximately 2 miles west of Cahn Gas Com 1 (Plate 1, Exhibit 48), the face cleat direction in this area lies between 30 and 50 degrees east of due north[4]. To properly model the resulting anisotropy in cleat permeability, the simulation grid was rotated approximately 40 degrees east of due north (Plate 1, Exhibit 48). As Exhibit 22 indicates, the y-direction permeability then parallels the face cleat orientation, and the x-direction permeability approximates the butt cleat direction.

Once the grid design was complete, the structure and both isopach maps were digitized for input into the simulator. This was accomplished by assigning the appropriate map values for both the elevation and two layer thicknesses to the corresponding grid blocks in the simulation grid. Exhibit 16 summarizes additional reservoir parameters that were used in the simulation study and the sources of the data.

As stated previously, the Cedar Hill field is located in Area 1 of the San Juan Basin. In general terms, Area 1 is regionally characterized by pressure gradients of 0.50 to 0.60 psi/ft with bottomhole pressures in excess of 1,200 psi[1] and coalbed reservoirs which are typically fully saturated with water at initial reservoir conditions. Amoco Production Company reported the initial shut-in pressure for the Cahn Gas Com 1 well as 1562 psi[5]. This results in a calculated pressure gradient of 0.56 psi/ft for the Cahn well which is consistent with the definition of the Area 1 overpressuring. This pressure was used to initialize the model area. In addition, both coal seams were assumed to be fully water saturated at the initial reservoir conditions.

Several publically available sorption isotherms exist for Area 1 of the San Juan Basin[4, 6, 7]. This study relied upon one measured on the Mesa Hamilton No. 3 well which was felt to closely approximate the desorption characteristics at Cedar Hill[4]. Experiment No. 2 from the Mesa Hamilton No. 3 well yielded a Langmuir volume of 623 scf/ton of coal (25.74 scf/cf) and a Langmuir pressure of 330.8 psia (Exhibit 23). At an initial reservoir pressure of 1562 psi, this resulted in an initial gas content of 514 scf/ton of coal (21.24 scf/cf). This appeared to be consistent with the adsorbed gas content data reported for Amoco's Cahn Gas Com 1 well which ranged between 358 and 667 scf/ton as determined from canister tests[8].

The parameters that were the least well defined for the Cedar Hill field area were the cleat porosity, absolute cleat permeability and relative permeability curves. As a result, these variables were utilized as calibration parameters for the history matching work with the simulator. However, as a starting point, the cleat permeability and porosity were assumed to be 7 md and 3%, respectively, on the basis of some limited published data[9]. The initial relative permeability curves were taken from those developed earlier by ICF Resources for another San Juan Basin study[10].

Both gas and water production data for the seven coalbed methane wells was obtained from the monthly operator reports submitted to the NMOCD. To confirm the accuracy of the data and to supplement any missing data, Dwight's production data was also utilized.

As indicated in Exhibit 17, five of the 7 wells were placed on water rate control. That is to say, the observed average daily water rate was input into the simulator on a monthly basis and the simulator calculated the associated gas production rate and flowing bottomhole pressure. Alternatively, two of the 7 wells, the Cahn Gas Com 1 and Wood Gas Com A-1 wells were put on flowing bottomhole pressure control where both the gas and water production rates were calculated by the simulator.

The three pressure monitor wells were completed as non-producing wells to permit an accurate accounting of reservoir pressure. The observed pressure data was originally reported by Amoco in graphical form to the NMOCD[11]. This data was digitized and used to verify the accuracy of the simulated reservoir pressures calculated for the three monitor well locations.

## Simulation Results

The process of doing a history match involves making an adjustment in one or more of the calibration parameters and then plotting the simulated production rate and pressure results against the corresponding observed data. If the results are not yet satisfactory, then an adjustment is again made and another run is made until satisfactory results are achieved. It should be noted however that no history match is completely unique; for example, a different set of relative permeability curves would necessarily produce a different solution in both porosity and absolute permeability. In spite of the fact that mathematically any solution to the "history match" problem is non-unique, multiple solutions are usually not available from which to choose. History matches can establish with some degree of certainty a "range" in values which can be reasonably expected to apply to the reservoir under investigation. As a result, the simulation results presented in the paragraphs below represent the only solution in the time frame available to the production behavior observed in the Cedar Hill field area.

As stated earlier, the porosity, absolute permeability and relative permeability curves were utilized as calibration parameters for the history matching work with the simulator because these parameters were the least well defined in the publically available literature. Estimates of these parameters were arrived at during the process of matching the simulated production and pressure data with that observed for the model area. The resulting relative permeability curves are shown in Exhibit 24 and the values for both cleat porosity and permeability are summarized for each of the ten wells in Exhibit 18.

As indicated in Exhibit 18, the y-direction permeability ($k_y$) which parallels the face cleat orientation is generally 2 to 4 times that assigned to the x-direction ($k_x$). The resulting geometric means in absolute cleat permeability ( $\bar{k}$ ) range from as low as 0.5 md for the Wood Gas Com A-1 well to as high as 10.0 md for several of the other wells in the model area. The values in cleat porosity range between 0.05 and 0.80%. It should be noted that in the areas of the reservoir not directly affected by the individual well completions, the level of cleat permeability and porosity is 10 md ($k_x$ = 5 md and $k_y$ = 20 md) and 0.25%, respectively. The distributions in the simulated anisotropic face and butt cleat permeabilities for both model layers are illustrated in Exhibits 25 and 26. Similarly, the distribution in simulated cleat porosities for model layer 1 is shown in Exhibit 27; cleat porosity for model layer 2 was assigned a uniform value of 0.05% and is not included as an exhibit.

As this discussion deals primarily with the history match results for only three of the seven coalbed methane wells utilized in the simulation study, water production rate (Bbls/D), gas production rate (Mscf/D) and flowing bottomhole pressure (psia) are presented as a function of simulated production time (days) in Exhibits 28 - 36 for the Cahn Gas Com 1, Schneider Gas Com B-1S, and State Gas Com BW-1 wells. For each of the three pressure monitor wells, the simulated reservoir pressure (psia) is presented as a function of simulation time (days) in Exhibits 37 - 39 for the Cahn Gas Com 2, Schneider Gas Com B-1, and Leeper Gas Com B-1 wells. In Exhibits 28 - 39, the simulated production rates and pressures are shown as solid lines where as the corresponding observed rates are represented by symbols.

The cumulative gas and water volumes, both simulated and observed, for the production period of May 1977 and December 1985 (3,167 days) are summarized in Exhibit 19. For the Cahn Gas Com 1 well, the observed gas and water volumes were incomplete for the early production history on the well. As a result, the 2.15 BCF of gas production observed between October 1978 and December 1985 actually corresponds to a simulated gas volume of 2.32 BCF and the 160.65 MBbls of water observed between August 1980 and December 1985 corresponds to a simulated water production volume of 175.13 MBbls.

As indicated in Exhibit 21, the Cahn Gas Com 1 well was drilled and completed in May 1977 (0 simulation days), but the early production history was not reported. However, by October 1978 (549 simulation days), gas production rates on Cahn Gas Com 1 were being reported and in August 1980 (1,219 simulation days), the first water production rates were reported to NMOCD (Exhibits 28 - 29). This resulted in the strategy of controlling this well with a flowing bottomhole pressure schedule (Exhibit 30). Through October 1981 (1,645 simulation days), the Cahn Gas Com 1 well was the only coalbed methane well producing in the model area. During this more than four year period, the Cahn Gas Com 1 well experienced two shut-in periods: (1) December 1978 through June 1979 (579 - 791 simulation days), and (2) May 1980 through June 1980 (1,127 - 1,188 simulation days).

In May 1980 (1,127 simulation days), three years of production from the Cahn Gas Com 1 well resulted in a pressure drawdown of less than 200 psia in the surrounding reservoir. Coalbed dewatering and the associated pressure drawdown accounts for the development of 5 to 7% free gas saturation observed within the area around the Cahn Gas Com 1 well. Free gas saturation in excess of 10% also developed structurally updip near the State Gas Com BX-1 and is in part the result of a boundary effect; that is, the gas is restricted from continuing to migrate updip due to the finite nature of the simulation grid. After a two month shut-in at the Cahn Gas Com 1 well, the reservoir pressure rose to within 100 psia of the initial conditions of 1,562 psia and a decrease in the simulated free gas saturation was observed in the area around the well due to gas re-adsorption.

The Schneider Gas Com B-1S and State Gas Com BW-1 wells were the next two coalbed methane wells drilled and completed in the model area (Exhibit 21). The first produced volumes reported on these wells was in November 1981 (1,675 simulation days). Since the production histories were complete, both of these wells were controlled by specifying their respective average daily water production rates on a monthly basis throughout the simulation period (Exhibit 17).

Exhibits 40 and 41 illustrate the simulated areal distribution in reservoir pressure and gas saturation for October 1981 (1,645 simulation days) after four and one-half years of unconfined production from the Cahn Gas Com 1 well and just before production begins from the Schneider Gas Com B-1S and State Gas Com BW-1 wells. The gas bubble has developed an elongate shape which reflects both the structural characteristics of the reservoir and the permeability anisotropy described earlier. It should be noted that the Cahn Gas Com 1 well has been producing only from the "Upper" Basal Fruitland coal seam (model layer 1) during this period while the "Lower" coal seam (model layer 2) has remained at initial reservoir pressure and 100% water saturated.

By December 1981 (1,706 simulation days), the Schneider Gas Com B-1S and State Gas Com BW-1 wells have been producing for two months as indicated by the development of their respective cones of pressure depression (Exhibit 42), which have resulted in the expansion of the gas bubble in the central part of the reservoir (Exhibit 43). Only the State Gas Com BW-1 well is completed in both the "Upper" and "Lower" Basal Fruitland coal seams at this point in the production history, resulting in pressure drawdown and the development of free gas saturation in the "Lower" coal seam at the State BW well location.

Through October 1981 (1,645 simulation days), the Cahn Gas Com 1 well has been producing without any pressure interference from surrounding wells; i.e., as an unconfined well (Exhibit 40). When the Schneider Gas Com B-1S and State Gas Com BW-1 wells begin production in November 1981, both wells experience a more rapid response in the gas production rate (Exhibits 32 and 35) as compared to that observed for the Cahn Gas Com 1 well (Exhibit 29). Conversely, the initial water production rates are lower for both the Schneider Gas Com B-1S and State Gas Com BW-1 wells (Exhibits 31 and 34) than those observed for the Cahn Gas Com 1 well (Exhibit 28). Exhibit 41 indicates that by October 1981, coalbed dewatering by Cahn Gas Com 1 has resulted in the development of a free gas saturation which is available for production at the Schneider Gas Com B-1S and State Gas Com BW-1 well locations.

By September 1983 (2,344 simulation days), the Cahn Gas Com 1 well has been producing for over six years and the Schneider Gas Com B-1S and State Gas Com BW-1 wells have both been producing for almost three years (Exhibit 21). Since October 1981 (1,645 simulation days), pressure interference between these three wells has resulted in approximately 600 psia of drawdown in the central part of the reservoir and free gas saturations approaching 10% due to more rapid dewatering. As indicated in Exhibits 28 and 29, the gas production rate for the Cahn Gas Com 1 well is on the incline during this period while the water production rate is declining as a result of coalbed dewatering and pressure drawdown throughout the central part of the model area.

As indicated in Exhibit 21, four additional coalbed methane wells were drilled and completed in the model area between September 1983 and December 1985 (2,344 - 3,167 simulation days). These are the Keys Gas Com G-1, State Gas Com BX-1, Ealum Gas Com C-1, and Wood Gas Com A-1 wells (Exhibit 22). With the exception of the Wood Gas Com A-1 well, each of these wells was simulated on water rate control (Exhibit 17). Due to the very low observed water production rates for the Wood Gas Com A-1 well, this well was placed on a flowing bottomhole pressure schedule. Of these four later wells, two were completed in both the "Upper" and "Lower" coal seams: (1) the Ealum Gas Com C-1 well, and (2) the Wood Gas Com A-1 well (Exhibit 17).

December 1985 (3,167 simulation days) represents the end of the simulation period for this history match. Exhibits 44 and 45 represent the simulated areal distribution in both reservoir pressure and gas saturation in December 1985. Production from a total of seven coalbed methane wells has resulted in widespread pressure drawdown and the development of gas saturations approaching 9 to 10% throughout most of the reservoir area modelled. It was also observed that the three wells completed in the "Lower" coal seam resulted in widespread pressure drawdown in model layer 2 and the corresponding development of free gas saturations.

Amoco Production Company recompleted three non-commercial Pictured Cliffs wells to the basal Fruitland coal to monitor formation pressures in the Cedar Hill field area. These three pressure monitor wells were included in the model area due in part to the unique opportunity this type of data provides in making adjustments to the calibration parameters being utilized in the history match; that is, cleat porosity, absolute cleat permeability and the relative permeability curves. Exhibits 37 through 39 illustrate the simulated and observed reservoir pressures as a function of simulation time for the Cahn Gas Com 2, Schneider Gas Com B-1 and Leeper Gas Com B-1 pressure monitor wells.

The Cahn Gas Com 2 pressure monitor well is offset from the Cahn Gas Com 1 well by approximately 933 feet (Exhibit 22), and is clearly responding to the earlier under-production of water and the corresponding over-production of water later in the Cahn Gas Com 1 well's production history (compare Exhibit 37 with 28). The Schneider Gas Com B-1 pressure monitor well is offset from the Schneider Gas Com B-1S production well by approximately 327 feet (Exhibit 22) and appears to be responding accurately to the nearby reservoir voidage conditions (Exhibit 38). The Leeper Gas Com B-1 pressure monitor well is more strongly influenced by the Keys Gas Com G-1 and Ealum Gas Com C-1 coalbed methane wells than any other wells in the model area, at least during the period for which measurements were taken on the monitor well (Exhibit 22). The reservoir characterization in this general part of the model area appears to be resulting in an accurate response in the Leeper Gas Com B-1 pressure monitor well.

## Interference Effects

Two competing mechanisms are at play during coalbed methane well interference: 1) amplification and reinforcement of pressure lowering in the interwell distance, and 2) competition for drainage of gas located in the overlapping drainage areas (interwell distance) between adjacent wells. Engineers and geologists, familiar with development of conventional oil and gas resources, are acquainted with the competition for drainage of fluids during interference. It is this competition for drainage that gives the negative connotation to well interference. However, in coalbed methane, this difference may have beneficial effects since the amplification of drawdown in the interwell distance has a direct bearing upon release of gas from the coal matrix via the sorption isotherm. Most operators agree that the pressure lowering effects which result from well interference in coalbeds accelerates production; however, the current feeling is that ultimate recovery is probably not affected to a large extent. Results of the sensitivity analyses portion of this study show that there is a difference in recovery within practical time limits of 25 years or so, and these differences can be examined in a later section of this report. Two additional comments need to be made: 1) there is some spacing that is too close even for coalbed wells and that spacing creates wasteful drilling, and 2) the requirement for interference is especially important in some reservoir settings because if dewatering is never accomplished, there will be no attendant gas production.

Reservoir characterization through the application of multi-well, three-dimensional simulation techniques provides a mechanism by which well interference effects can be examined. On this basis, an appropriate methodology to evaluate coalbed methane well spacing can be developed for specific field areas. Within the Cedar Hill model area, the proximity and timing of drilling of the Cahn Gas Com 1, Schneider Gas Com B-1S, and State Gas Com BW-1 wells afforded an excellent opportunity to evaluate well interference effects. The discussion that follows is intended only to demonstrate that interference may affect individual well production from the Cahn Gas Com 1, Schneider Gas Com B-1S, and State Gas Com

BW-1 wells. Furthermore, this analysis is in no way intended to make a recommendation regarding the well spacing utilized in developing the Cedar Hill field area.

Examination of the area selected for modelling at Cedar Hill indicates that the Cahn Gas Com 1 well is located at the center of a 320 acre five-spot pattern with the corner locations occupied by the State Gas Com BW-1, Schneider Gas Com B-1S, Ealum Gas Com C-1, and Cahn Gas Com 1S wells (Plate 1, Exhibit 48). Between May 1977 and November 1981 (0 to 1645 simulation days), the Cahn Gas Com 1 well was producing as an unconfined well; i.e., there was no pressure interference from surrounding wells. When production was initiated in the Schneider Gas Com B-1S and State Gas Com BW-1 wells in November 1981 (1645 simulation days), the drainage area of the Cahn Gas Com 1 well was reduced to a partially confined 160 acres where confinement was provided both to the north and to the west of the Cahn's location (Plate 1, Exhibit 48). Additional pattern confinement east of Cahn Gas Com 1 was not established until August 1984 (2680 simulation days) when production was initiated in the Ealum Gas Com C-1 well. The Cahn Gas Com 1S well occupies the southern corner of the five-spot pattern but was not drilled until after December 1985 (the end of the simulated period).

As the history match results indicated, when the Schneider Gas Com B-1S and State Gas Com BW-1 wells began production in November 1981, both wells experienced a more rapid response in their gas production rate apparently due to the pressure drawdown and coalbed dewatering associated with four and half years of production from the Cahn Gas Com 1 well. In addition, it was also noted that gas production from the Cahn Gas Com 1 well subsequently showed an improvement apparently in response to the pressure drawdown effects of production from the Schneider Gas Com B-1S and State Gas Com BW-1 wells.

In an attempt to further examine the well interference effects within the area modelled at Cedar Hill, three cases were simulated upon the completion of the history match, the results of which are shown in Exhibit 20. For each of the three cases, the reservoir description was assumed to be identical to that which resulted from the history match work; i.e., the distributions in cleat porosities, anisotropic face and butt cleat permeabilities, and the relative permeability behavior remained unchanged. In addition, all but three of the seven coalbed methane wells were operated assuming exactly the same well controls as described for the history match exercise (Exhibit 17). For three of the wells (Cahn Gas Com 1, Schneider Gas Com B-1S, and State Gas Com BW-1), the simulated cases utilized variations in the well production schedule and modifications to the operating conditions to determine the impact on the aggregate gas production from the model area.

Case I assumed that the Cahn Gas Com 1 well was the only active producing well in the model area throughout the simulated period of 3167 days. Alternatively, Cases II and III assumed that only the remaining six coalbed methane wells were actively producing throughout the same simulation period; i.e., the Cahn Gas Com 1 well was the only non-producing coalbed methane well in the model area. The only difference between Cases II and III was in the operating conditions assumed for two of the coalbed methane wells, Schneider Gas Com B-1S and State Gas Com BW-1.

For Case II, it was assumed that Schneider Gas Com B-1S and State Gas Com BW-1 would be operated with the same water rate controls utilized during the history match exercise. However, a convincing argument could be made that in the absence of production from the Cahn Gas Com 1 well, the Schneider Gas Com B-1S and State Gas Com BW-1 wells would not produce their observed water rates. That is, the four and half years of production from the Cahn Gas Com 1 well limited the amount of water available for the Schneider Gas Com B-1S and State Gas Com BW-1 wells to produce and therefore, in the absence of production from the Cahn Gas Com 1 well, both Schneider Gas Com B-1S and State Gas Com BW-1 would produce more water than actually observed in the field. Therefore, to dispel this argument, the assumption utilized in simulating Case III was that both the Schneider Gas Com B-1S and State Gas Com BW-1 wells were operated with a specified flowing bottomhole pressure schedule. This schedule was obtained from the results of the history match exercise where the simulator calculated flowing bottomhole pressure for both these wells. This approach to Case III assumes that the bottomhole pressure schedule determined during the history match exercise could be maintained in the absence of production from the Cahn Gas Com 1 well. The results of this analysis are summarized in Exhibit 20 and illustrated in Exhibits 46 and 47. Examination of Exhibits 20, 46 and 47 suggests that aggregate gas production from the area selected for simulation study at Cedar Hill is positively affected by the mutual interaction between the Cahn Gas Com 1 well and the other surrounding wells for the 8.7 years of simulated history (3,167 days).

The modeling of Cedar Hill is impacted by the fact that the overall area modeled is not large enough; that is to say, there is interference of pressure drawdown of the wells with the model boundary. These effects are thought to be minor insofar as the reservoir characterization of permeabilities and porosities are concerned. However, the intent to draw quantitative conclusions regarding the amount of additional gas produced due to interference effects would be improper. It should also be noted that the effects of well interference may not be the same for other possible combinations of reservoir properties.

## Conclusions

The results of the ten well history match for the Cedar Hill model area yielded coal cleat porosities in the range of 0.25 to 0.80% which are much lower than previously accepted values of 2 to 3%. In addition, the history matching process generated geometric average cleat permeabilities in the range of 0.5 to 10 md. These geometric averages have anisotropic components in the face and butt cleat directions on the order of 2-4:1; i.e., the face cleat permeability is generally 2 to 4 times that of the butt cleat permeability. Although the data is limited, these cleat permeabilities determined from the simulation work are consistent with previously reported values.

Structural relief (up to 70 feet across the model area) is an important factor influencing the simulated production behavior of coalbed methane wells in the Cedar Hill field area. In addition, the proximity and timing of drilling of the wells at Cedar Hill (particularly Cahn Gas Com 1, Schneider Gas Com B-1S, and State Gas Com BW-1) contributed to simulated pressure interference effects and the development of a free gas saturation available for production. The distribution in the free gas saturation is the result of coupling pressure interference effects with the structural relief associated with the basal Fruitland coalbed reservoir model used here.

**Tiffany Field Area History Match**

## Introduction

As with the selection of the Cedar Hill field area, the Tiffany field area was selected for a detailed reservoir simulation study due to the length of available production history and the amount of reservoir data generously made available by Amoco Production Company. The purpose of this discussion is to provide a brief review of the geologic model developed for the Tiffany field area and to provide a more detailed discussion of the results of the subsequent reservoir simulation study completed on a selected portion of the field area.

Tiffany is located approximately 20 miles southeast of Durango in the southeastern part of La Plata County, Colorado (Exhibit 1). The field covers over 20 square miles in Townships 32 and 33 North and Ranges 6 and 7 West where active coalbed methane production occurs from coal seams occurring within the basal portion of the Upper Cretaceous Fruitland Formation (Campanian). As with Cedar Hill, Tiffany is also located in the overpressured north-central part of the San Juan Basin which has been designated as Area 1[1].

## Geologic Model

A geologic evaluation of the Tiffany field area was performed to provide an accurate framework for the subsequent reservoir simulation study completed on a portion of the field area. The large number of Fruitland penetrations within the area provided an accurate inventory of coal reserves as well as the basis for some stratigraphic and structural analysis.

To accomplish this task, density logs were obtained from Petroleum Information (PI) on over 75 well locations in T32-33N and R6-7W. Two stratigraphic cross sections were constructed to illustrate lateral facies relationships along depositional strike (A-A') and dip (B-B') across the main part of the Tiffany field area (Plates 7-8, Exhibits 73-74). Three distinctive coal-bearing intervals (Coal A, B and C) were identified and correlated across the field. Coal A and B occur predominantly in the northwestern half of the mapping area, and are relatively minor contributors to coalbed methane production at Tiffany because both are thin and were generally not completed. Coal C is the lowermost and thickest of the three intervals, ranging between 23 and 49 feet in thickness. As the main producing zone in the Tiffany field, Coal C was the primary focus of the simulation study.

Distinct lateral variations in the stratigraphic integrity of Coal C occur across the Tiffany mapping area, and these changes were distilled into three gross isopleth types: (1) Type 1 is where Coal C is comprised of one thick basal coal seam or coal-dominant interval, (2) Type 2 is where Coal C is split into two distinct coal seams or coal-dominant intervals, and (3) Type 3 is where Coal C is further divided into three or more distinct coal seams or coal-dominant intervals. The main Type 1 areas are found in the northwestern half and the far southeastern corner of the Tiffany mapping area (Plate 9, Exhibit 75). Type 1 is relatively widespread and forms a backdrop for the more restricted Type 2 and Type 3 areas. Type 2 coals occur in sinuous belts that are generally less than one mile wide and parallel the wider, northeast-trending belt of Type 3 that occurs in the southern part of the mapping area. Fingers of Type 2 coal extend northward into Type 1 and occur in small discontinuous patches, suggesting that areas of Type 2 coal are developed for some distance away from the main northeast-trending belt.

The Tiffany area lies on the northeastern limb of the southeast-trending Ignacio Anticline in the northern San Juan Basin. Structural highs with approximately 300 feet of relief bound the Tiffany coalbed methane producing area on the northwest and west-southwest, which are substructures of the Ignacio Anticline (Plate 10, Exhibit 76). The Tiffany field roughly coincides with a southeast-trending structural low that is located in the central and southeastern portions of the mapping area. Within the area selected for the simulation study (Plate 7, Exhibit 73), the top of the Fruitland Coal C rises from less than 3,500 feet above mean sea level in the central and northeastern portions of the model area to over 3,750 feet along the southwestern edge, representing a structural relief in excess of 250 feet (Plate 10, Exhibit 76).

Within the area selected for detailed reservoir simulation work, Coal C primarily consists of a single thick basal coal seam typical of Type 1 with some limited development of the Type 2 coals occurring in the northwestern and southeastern portions of the model area (Plate 9, Exhibit 75). Because of the limited number of wells affected by the Type 2 coals (only four wells), the main productive horizon at the Tiffany field was represented as a single coal layer for the simulation work. Within the model area, net coal thicknesses for Coal C vary between 25 and 48 feet on the basis of a 1.75 gm/cc bulk density cut-off.

## Reservoir Model

The selection of that portion of the Tiffany field area to be utilized for a detailed reservoir simulation study was determined by considering both the first gas delivery dates provided by Amoco Production Company and the production character of the individual wells within the field area. Examination of the well spacing patterns in the southwestern corner of T33N, R6W indicates two contiguous 320 acre 5-spot patterns oriented in a northeast - southwest direction (Plate 7, Exhibit 73). The outside well locations which include the Hott 20-4, Hott 30-1, Hott 30-2, Southern Ute 29-1, Hott 29-2, and Taichert 31-1 wells were all brought on production in late 1983 - early 1984. Comparison of the production curves for each of these six wells indicates similar gas volumes and production character and suggests that the pattern axis actually approximates an isopotential surface. Of the three wells drilled along the pattern axis itself, Hott 20-2 came on production in late 1983, whereas the Hott 29-2 #2 and Hott 30-1 #2 wells were not produced until May 1989.

On the basis of this analysis, the southeastern edge of the simulation grid was selected to coincide with the pattern axis described above because it approximated a no flow boundary condition. The model area was extended to the northwest to include the Baird 18-1 well (Plate 7, Exhibit 73). It was assumed from a preliminary pattern analysis that the drainage area for the Southern Ute 17-1 and Baird 18-2 wells is approximately 160 acres and therefore, production from these two well locations would not affect the northeastern boundary of the grid. The southwestern boundary of the grid was extended to include enough reservoir pore volume to approximate the unconfined reservoir conditions existing to the west of the main area of interest.

Although gas production was reported from the Tiffany field as early as late 1982, the early drilling activity was primarily concentrated in the 1983 -1984 time period. On the basis of the production data provided by Amoco Production Company, most of the individual well production data that was provided was complete through the end of January 1990. Within the model area, there are 13 coalbed methane producing wells. However, three of these wells (State Gas Unit CB-1, State Gas Commission BZ-1 and Southern Ute Gas Unit Z-1) were not drilled and produced until November and December of 1989. With so little production data available on these three wells and to limit the size of the problem to be simulated, only wells producing between October 1983 and November 1989 were considered for the history match exercise.

Exhibit 58 schematically illustrates the relative timing of the Tiffany wells drilled within the area selected for the simulation study. As can be seen in the exhibit, a total of ten coalbed methane wells were drilled and produced between October 1983 and November 1989.

The relative position of the simulation grid is shown on Plate 7 (Exhibit 73) with the detailed grid illustrated in Exhibit 59. The grid was designed with 13 grid blocks in the x-direction and 19 grid blocks in the y-direction and utilized a single model layer; that is, one layer for the basal Fruitland Coal C. Individual grid blocks varied in size from as small as 400 feet on a side to as large as 2000 feet on a side for the coarser blocks on the outside edge of the grid.

On the basis of oriented core analysis completed on the Mobil Colorado 32-7 #9 well which lies approximately 4 to 5 miles southwest of the Hott 20-2 well in Section 4, T32N, R7W, the face cleat direction in this area lies between 40 and 50 degrees west of due north[16, 17]. To properly model the resulting anisotropy in cleat permeability, the simulation grid was rotated approximately 45 degrees west of due north (Plate 7, Exhibit 73). As Exhibit 59 indicates, the x-direction permeability then parallels the face cleat orientation, and the y-direction permeability approximates the butt cleat direction.

Once the grid design was complete, the structure and isopach maps were digitized for input into the simulator in a fashion similar to that utilized for the Cedar Hill history match exercise. Exhibit 54 summarizes the additional reservoir parameters that were used in the simulation study and the sources of the data. Wherever possible, the data supplied by Amoco Production Company was utilized in lieu of data from public sources. The sorption isotherm provided by Amoco Production Company is shown in Exhibit 60.

In contrast to the approach utilized in the Cedar Hill history match, all of the ten wells within the Tiffany model area were placed on gas rate control (Exhibit 55). That is to say, the observed average daily gas rate was input into the simulator on a monthly basis and the simulator calculated the associated water production rate and flowing bottomhole pressure. Although there are no pressure monitor wells in the Tiffany field area, bottomhole pressures were periodically measured by Amoco Production Company subsequent to their purchase of the operational rights from W. Perlman in late 1985. This observed pressure data was utilized to verify the accuracy of the simulated flowing bottomhole pressures.

**Simulation Results**

The same qualifications concerning the non-uniqueness of a history match that were enunciated in the Cedar Hill discussion apply equally as well to the Tiffany simulation results. Therefore, the simulation results presented in the following paragraphs represent the only solution to the production behavior observed in the Tiffany field area that could be determined in the time frame available. It should be noted, however, that these results seemed to be consistent with the independent findings of several members of the Coalbed Methane Committee who have operations in the nearby area.

As with the Cedar Hill field area, the reservoir parameters that were the least well defined for the Tiffany field area are the cleat porosity, absolute cleat permeability and the relative permeability curves. This data was not among the information provided by Amoco Production Company. As a result, these reservoir parameters were utilized as calibration parameters for the history matching work with the simulator. Estimates of these parameters were arrived at during the process of matching the simulated production and pressure data with that observed for the model area. The resulting relative permeability curves are shown in Exhibit 61 and the values for both cleat porosity and permeability are summarized for each of the ten wells in Exhibit 56.

As indicated in Exhibit 56, the x-direction permeability ($k_x$) which parallels the face cleat orientation is generally 1 to 4 times that assigned to the y-direction ($k_y$). The resulting geometric means in absolute cleat permeability ( $\overline{k}$ ) range from as low as 1 md for the Hott 30-2 well to as high as 2.2 md for the Hott 20-4 well. The values in cleat porosity range between 0.5 and 1%. It should be noted that in the areas of the reservoir not directly affected by the individual well completions, the level of cleat permeability and porosity is 1 md and 0.5%, respectively. The distributions in the simulated anisotropic face and butt cleat permeabilities are illustrated in Exhibit 62. Similarly, the distribution in simulated cleat porosity is shown in Exhibit 63.

Although the history match exercise utilized all ten wells that were productive in the model area during the period of time simulated, the gas production rate (Mscf/D), water production rate (Bbls/D) and flowing bottomhole pressure (psia) are presented as a function of simulated production time (days) for only two of the wells which include the Hott 20-2 and Hott 20-4 wells (Exhibits 64-69). In Exhibits 64-69, the simulated production rates and pressures are shown as solid lines where as the corresponding observed rates and pressures are represented by symbols.

The cumulative gas and water volumes, both simulated and observed, for the simulated production period of October 1983 to November 1989 (2251 days) are summarized in Exhibit 57. It should be noted that for the Hott 20-4 well, the observed gas and water volumes were incomplete for the more recent production history on the well. As a result, the 131.22 MMscf of gas production observed between October 1983 and November 1988 actually corresponds to a simulated gas volume of 130.77 MMscf and the 22.04 MBbls of water observed for the same period corresponds to a simulated water production volume of 45.73 MBbls.

## Interference Effects

The distributions in simulated gas pressure and gas saturation for the basal Fruitland coal are shown in Exhibits 70 and 71 for the end of the period simulated for the Tiffany field area. As can be seen by a review of these two exhibits, six years of production from the model area (2251 simulation days) has resulted in a pressure drawdown of more than 200 psia with the greatest effects in pressure drawdown occurring between wells which were drilled interior to the 320 acre 5-spot patterns described earlier (compare Exhibit 70 with Exhibit 73). Within this portion of the model area where wells were drilled on a closer spacing, the dewatering and pressure drawdown has resulted in the development of gas saturations approaching 10 to 12% (Exhibit 71).

An alternative way of viewing the results of accelerated dewatering and pressure drawdown is in calculating the difference between the initial matrix gas content (adsorbed gas) before production begins and the matrix gas content remaining at the end of the simulation period (Exhibit 72). Where this difference is the greatest is where the greatest amount of gas has been removed from the coal matrix into the coal cleat system where it is free to be produced. As indicated in Exhibit 72, a well like Hott 20-4 which is located interior to a 320 acre 5-spot pattern appears to have benefited from the production of surrounding wells that were producing during the same general time period (compare Exhibit 72 with Exhibit 58). Whether or not these wells will continue to benefit from early time interference remains to be seen. Alternatively, wells that are not as "confined" such as Hott 30-2 or Robertson 19-1 do not show as great a reduction in the initial matrix gas content.

## Conclusions

The results of the ten well history match for the Tiffany model area yield coal cleat porosities in the range of 0.5 to 1.0% and geometric average cleat permeabilities in the range of 1.0 to 2.2 md. These geometric averages have anisotropic components in the face and butt cleat directions on the order of 1-4:1; i.e., the face cleat permeability is generally 1 to 4 times that of the butt cleat permeability. These results are consistent with the independent findings of several members of the Coalbed Methane Committee who have interests in the general area.

Both structural relief (over 250 feet across the model area) and the proximity and timing of drilling of wells in the Tiffany area have contributed to the distribution in the gas saturation observed at the end of the simulation period. This interaction is demonstrated by an analysis of where the greatest reduction in initial matrix gas content has occurred during the six years of production history modelled for the Tiffany field area. The greatest increase in the free gas saturation available to the wells producing in the model area (alternatively, the greatest reduction in initial matrix gas content) is associated with the denser well spacings represented by the 320 acre 5-spot patterns (i.e., 160 acre well spacing).

To briefly compare the simulation results of the Tiffany model area with that of the Cedar Hill model area, the average cleat porosity simulated for Tiffany is approximately 2 to 4 times greater than that simulated for Cedar Hill (0.5-1.0% versus 0.25%, respectively) whereas the average cleat permeability simulated for Tiffany is approximately an order of magnitude less than that simulated for Cedar Hill (1 md versus 10 md, respectively). Although the average coal thickness at Tiffany is approximately twice that mapped for the two coal layers at Cedar Hill (40 ft versus 20 ft, respectively), the combination of increased cleat porosity and a reduction in cleat permeability results in the average well production in the Tiffany field area being on the order of 100 to 200 Mscf/d as compared with average well production from Cedar Hill being approximately 700 to 1000 Mscf/d for the better wells. It is also worth noting in this comparison that the initial gas content at Tiffany is somewhat higher than that used for the Cedar Hill area (572 scf/ton versus 514 scf/ton, respectively). Although the gas-in-place per 640 acres at Tiffany averages more than twice that estimated for Cedar Hill, the average gas production rate at Tiffany is lower than that at Cedar Hill. This fact results from the lower level of cleat permeability increasing the difficulty in dewatering the coal, which in turn diminishes the ability of the gas to desorb from the coal surface into the cleat system. As a result, reservoir systems characterized by higher cleat porosity (i.e., water storage capacity) and lower cleat permeability may be considered as candidates for reduced well spacings.

**Sensitivity Analyses For Areas 1, 2 And 3**

## Introduction

The purpose of the sensitivity analyses portion of the San Juan Basin Coalbed Methane Spacing Study is to determine gas production as a function of various key parameters. These parameters are well spacing, cleat permeability and porosity, coal thickness, reservoir pressure, initial gas content, sorption isotherm characteristics, initial water saturation, and fracture half-length. Other properties of importance include desorption time, gas-water relative permeability, and pore compressibility. Due to the extreme variability in the Fruitland coalbed methane reservoirs in the San Juan Basin, fields in widely spaced geographic areas had to be selected in order to maximize the representation of differing geologic and reservoir conditions in the definition of these key parameters. Once the geologic and reservoir data have been compiled and correlated through a survey of publicly available data[13] (Exhibit 15),"Type Reservoirs" can be synthesized which are, in general, representative of the more loosely defined pressure and water saturation regions within the basin. Reservoir parameters vary significantly across the basin. In order to conduct this study with a degree of consistency, certain input data used in Area 1 were also used for Areas 2 and 3. Sensitivity studies have been completed for Areas 1, 2, and 3 to examine the range of possible reservoir conditions that are expected to occur in a specific area based on the experience of the members of the Coalbed Methane Committee.

A comparison of the cases simulated for Areas 1, 2 and 3 is shown in Exhibit 82. Area 1 was investigated for variations in coal cleat porosity, well spacing, fracture half-length, and cleat permeability. Additionally, limited variations in sorption isotherm characteristics (Langmuir volume and desorption pressure), and relative permeability behavior were evaluated. Areas 2 and 3 were investigated for variations in initial free gas saturation, initial reservoir pressure, well spacing, fracture half-length, and cleat permeability. There were a total of 190 different cases simulated in the sensitivity analyses for Areas 1, 2 and 3.

Before work could progress on the sensitivity analyses, two issues impacting the sensitivity simulations needed to be resolved. These were the grid configuration to be utilized in the simulator for accurate representation of the various well spacings, and a consistent method of grid discretization for the various fracture half-lengths to be evaluated. The results of this work were presented in the Interim Report for this study dated June 18, 1990.

## Data Normalization

The performance data for all the cases simulated in Areas 1, 2 and 3 was normalized as indicated by the units utilized in presenting the results. The purpose of this exercise was to make comparisons among performance curves suitable.

All production rates and cumulative volumes for both gas and water were normalized to a 640 acre section basis regardless of the spacing being simulated for a particular case. That is to say, the production volumes for a 160 acre well spacing case were multiplied by four (4) to represent the total production from a 640 acre section developed with 160 acre well patterns. Similarly, the production volumes for a 320 acre well spacing case were multiplied by two (2) to represent the total production from a 640 acre section developed with 320 acre well patterns.

In addition, all production rates and cumulative volumes for both gas and water were further normalized by dividing by the coal thicknesses assumed for the individual simulation cases. As a result the produced volume is on a per foot of coal basis. The various coal thicknesses assumed for the sensitivity analyses are provided in Exhibits 78 (Area 1), 107 (Area 2), and 127 (Area 3).

One additional level of normalization was performed on only the simulated gas performance results. Both gas production rate and cumulative gas production were further divided by the initial gas content in scf/ton that would be calculated from the sorption isotherm at a given initial reservoir pressure. The initial reservoir pressures, Langmuir constants, and corresponding initial gas contents assumed for the sensitivity analyses are provided in Exhibits 79 (Area 1), 108 (Area 2), and 128 (Area 3).

**Area 1 Sensitivity Analyses**

A schematic of the 72 simulation cases completed for the gas and water production characteristics for Area 1 of the San Juan Basin is provided in Exhibit 83. Cases were simulated for variations in coal cleat porosity (0.25% and 3%), well spacing (160, 320 and 640 acres), fracture half-length (100, 300 and 500 feet), and cleat permeability (1, 5, 10 and 50 md). Exhibit 78 summarizes the reservoir parameters utilized in the simulation cases for Area 1. An inventory of initial fluids in place for both levels of initial free gas saturation is provided in Exhibit 79. The simulation results for all 72 cases simulated for Area 1 are summarized in Exhibit 80 for both 0.25% and 3% coal cleat porosities.

Several points are worth mentioning about how some of the data in Exhibit 78 were handled for the modelling. The Area 1 reservoir was assumed to be slightly overpressured (0.44 psi/ft), yielding an initial reservoir pressure of 1320 psia at the 3000 foot depth. The coal was assumed to be saturated, so the desorption pressure was also set to 1320 psia. The pore compressibility of $200 \times 10^{-6}$ $psi^{-1}$ is an estimated, rather than a measured value. However, this is not particularly important as it was also assumed that no stress-related change in cleat permeability occurs as the reservoir pressure is reduced at the wellbore. The gas-water relative permeability curves (Exhibit 103) used as input to the simulator were developed earlier by ICF Resources for a San Juan Basin study[10]. Finally, although the simulator is capable of handling finite conductivity induced fractures via a fine-gridding technique, the fractures simulated were of infinite conductivity.

The simulated production performance for a few selected cases are shown in figures as indicated in Exhibit 83. The presentation format includes the gas production rate [(scf/d)/(640 acres-foot of coal-scf/ton)], cumulative gas production [(mscf)/(640 acres-foot of coal-scf/ton)], gas recovery as a percentage of the initial gas-in-place, water production rate [(bbls/d)/(640 acres-foot of coal)], and cumulative water production [(mbbls)/(640 acres-foot of coal)] as a function of production time (years), with cleat permeability as the parametric variable for well spacings of 160 and 320 acres (Exhibits 85-90). Alternatively, parametric well spacing is shown in Exhibits 91 through 93 are for a cleat permeability of 10 md.

The difference in cumulative gas production [(mscf)/(640 acres-foot of coal-scf/ton)] and cumulative water production [(bbls)/(640 acres-foot of coal)] resulting from infill drilling a 320 acre well spacing to a 160 acres is illustrated in Exhibits 94 and 95 as a function of both time (years) and cleat permeability (md).

Only cases assuming a coal cleat porosity of 0.25% and a fracture half-length of 300 feet are illustrated for the Area 1 sensitivity analyses (Exhibit 83).

**Area 1 Variation Cases**

In addition to the 72 simulation cases completed for variations in cleat porosity, well spacing, fracture half-length, and cleat permeability (Exhibit 83), the sensitivity of gas production to an additional value in cleat porosity, initial gas content, and relative permeability behavior was evaluated (Exhibit 84). All of the variation cases assumed a well spacing of 320 acres, a fracture half-length of 300 feet, and a cleat permeability of 10 md. In addition to 0.25 and 3% cleat porosity, a porosity of 2% was simulated to determine the effect on gas production. The sensitivity to initial gas content was evaluated with a dual approach (Exhibit 84). First, the Langmuir volume of 427 scf/ton was allowed to vary ±75 scf/ton (approximately an 18% variation), while the initial reservoir pressure (which is equal to the desorption pressure) was held constant at 1320 psia. In the second approach, the sorption isotherm (i.e., Langmuir constants) was not varied, rather, the desorption pressure was allowed to vary higher and lower than the 1,320 psia used in the first approach. Again, the initial reservoir pressure was held equal to the desorption pressure. This twofold approach was necessary to account for differences in both gas and water production characteristics which result depending on the way gas content is varied. Relative permeability effects were evaluated by replacing the Cause 112-73[10] curves with the curves published by Kamal and Six[14]. For variations in initial gas content and relative permeability, the coal cleat porosity was assumed to remain constant at 3%.

The simulation results are illustrated for the 0.25%, 2% and 3% coal cleat porosity cases in Exhibits 96 - 97, where both gas and water production results are shown. Comparing the 2% and 3% porosity cases shows that the 33% reduction in cleat porosity yields a corresponding decrease of 33% in the initial water-in-place. This resulted in lower values for both water production rate and cumulative water production (Exhibit 97). Alternatively, the 0.01 decrease in the cleat porosity resulted in a 1% increase in the bulk volume of coal matrix. Therefore, a slight increase in the gas production rate and the cumulative gas production was observed (Exhibit 96), with a higher percentage of the initial gas-in-place being recovered for the 2% cleat porosity case. The results of the production analysis are summarized in Exhibit 81. On the basis of percent recovered, it is evident that gas production increases and water production decreases with decreasing coal cleat porosity.

Variations in the initial gas content were also evaluated. In the first approach, the Langmuir volume was allowed to vary 75 SCF/ton (approximately an 18% variation) above and below the Langmuir volume utilized in the 72 simulation cases which was 427 scf/ton, while the initial reservoir pressure (which is equal to the desorption pressure) was held constant at 1,320 psia. The variations in the desorption isotherm are shown in Exhibit 98. The results of the simulations are presented in Exhibits 99 - 100. Although gas production varies with changes in the initial gas content, the water production remains essentially the same (Exhibit 81).

Another way in which sensitivity of the production to variations in the initial gas content was evaluated was to vary the desorption pressure (set equal to the initial reservoir pressure) while the desorption isotherm (i.e., Langmuir constants) was held constant. The simulation results are shown in Exhibits 101 - 102. In these cases, both gas and water production increase with increasing initial gas content (Exhibit 81).

Variations in the relative permeability were also evaluated. The Cause 112-73 gas-water relative permeability curves[10] are shown contrasted with the San Juan Basin curves as published by Kamal and Six[14] in Exhibit 103. The $k_{rg}/k_{rw}$ ratio curves for both sets of relative permeability data are presented in Exhibit 104. The simulation results are shown in Exhibits 105 - 106 and are summarized in Exhibit 81. As would be expected from an examination of the relationship between the two $k_{rg}/k_{rw}$ curves in Exhibit 104, conditions are more favorable to the flow of gas at very high initial water saturations with the Kamal and Six curves than with the Cause 112-73 curves. Alternatively, as water saturation declines due to water production, the Cause 112-73 $k_{rg}/k_{rw}$ curve crosses over that of the Kamal and Six curve at approximately 98-99% $S_w$ (Exhibit 104). Once this occurs, conditions become more favorable to gas flow for the Cause 112-73 relative permeability curves as compared with those of Kamal and Six. The resulting gas and water production curves further illustrate this behavior (Exhibits 105 - 106). Although the gas production from the Cause 112-73 curves is initially lower, it does not decline as rapidly as that resulting from the Kamal and Six curves (Exhibit 105). The initial water production for the Kamal and Six curves is higher than that for the Cause 112-73 curves but then declines to the same level early in the production history

(Exhibit 106). The net result is that the greatest differences are seen in the cumulative water production (Exhibit 106) as contrasted to the relatively minor differences in the gas production (Exhibit 105).

## Area 2 Sensitivity Analyses

In areas 2 and 3, some of the data available to the study committee was inconsistent or of insufficient duration to be useful for history matching. The available data did provide a general indication of the expected range of several important reservoir parameters. This information, along with the general experience of the committee members, was used to establish the range of parameters considered in the sensitivity studies.

A schematic of the 64 simulation cases completed for the gas and water production characteristics for Area 2 of the San Juan Basin is provided in Exhibit 111. Cases were simulated for variations in initial free gas saturation (0 and 10%), initial reservoir pressure (200 and 300 psia), well spacing (160 and 320 acres), fracture half-length (100 and 300 feet), and cleat permeability (1, 5, 10 and 30 md). Exhibit 107 summarizes the reservoir parameters utilized in the simulation cases for Area 2. An inventory of initial fluids in place for both levels of initial free gas saturation is provided in Exhibit 108. The simulation results for all 64 cases simulated for Area 2 are summarized in Exhibits 109 (no initial free gas saturation) and 110 (10% initial free gas saturation).

The simulated production performance for a few selected cases are shown in figures as indicated in Exhibit 111. The presentation format includes the gas production rate [(scf/d)/(640 acres-foot of coal-scf/ton)], cumulative gas production [(mscf)/(640 acres-foot of coal-scf/ton)], gas recovery as a percentage of the initial gas-in-place, water production rate [(bbls/d)/(640 acres-foot of coal)], and cumulative water production [(bbls)/(640 acres-foot of coal)] as a function of production time (years), with cleat permeability as the parametric variable for well spacings of 160 and 320 acres (Exhibits 112 - 117). Alternatively, parametric well spacing is shown in Exhibits 118 through 120 are for a cleat permeability of 5 md.

The difference in cumulative gas production [(mscf)/(640 acres-foot of coal-scf/ton)] and cumulative water production [(bbls)/(640 acres-foot of coal)] resulting from infill drilling a 320 acre well spacing to a 160 acres is illustrated in Exhibits 121 and 122 as a function of both time (years) and cleat permeability (md).

To provide a basis for comparison between variations in initial free gas saturation and initial reservoir pressure, variations in initial free gas saturation at an initial reservoir pressure of 300 psia are shown in Exhibits 123 and 124, and variations in initial reservoir pressure with no initial free gas saturation are shown in Exhibits 125 and 126.

Only cases assuming no initial free gas saturation, an initial reservoir pressure of 300 psia, and a fracture half-length of 300 feet are illustrated for the Area 2 sensitivity analyses (Exhibit 111).

## Area 3 Sensitivity Analyses

A schematic of the 48 simulation cases completed for the gas and water production characteristics for Area 3 of the San Juan Basin is provided in Exhibit 131. Cases were simulated for variations in initial free gas saturation (0 and 23%), initial reservoir pressure (400 and 650 psia), well spacing (160 and 320 acres), fracture half-length (100 and 300 feet), and cleat permeability (0.1, 1 and 5 md). Exhibit 127 summarizes the reservoir parameters utilized in the simulation cases for Area 3. An inventory of initial fluids in place for both levels of initial free gas saturation is provided in Exhibit 128. The simulation results for all 48 cases simulated for Area 3 are summarized in Exhibits 129 (no initial free gas saturation) and 130 (23% initial free gas saturation).

The simulated production performance for a few selected cases are shown in figures as indicated in Exhibit 131. The presentation format includes the gas production rate [(scf/d)/(640 acres-foot of coal-scf/ton)], cumulative gas production [(mscf)/(640 acres-foot of coal-scf/ton)], gas recovery as a percentage of the initial gas-in-place, water production rate [(bbls/d)/(640 acres-foot of coal)], and cumulative water production [(bbls)/(640 acres-foot of coal)] as a function of production time (years), with cleat permeability as the parametric variable for well spacings of 160 and 320 acres (Exhibits 132 - 137). Alternatively, parametric well spacing is shown in Exhibits 138 through 140 are for a cleat permeability of 1 md.

The difference in cumulative gas production [(mscf)/(640 acres-foot of coal-scf/ton)] and cumulative water production [(bbls)/(640 acres-foot of coal)] resulting from infill drilling a 320 acre well spacing to a 160 acres is illustrated in Exhibits 141 and 142 as a function of both time (years) and cleat permeability (md).

To provide a basis for comparison between variations in initial free gas saturation and initial reservoir pressure, variations in initial free gas saturation at an initial reservoir pressure of 650 psia are shown in Exhibits 143 and 144, and variations in initial reservoir pressure with 23% initial free gas saturation are shown in Exhibits 145 and 146.

Only cases assuming 23% initial free gas saturation, an initial reservoir pressure of 650 psia, and a fracture half-length of 300 feet are illustrated for the Area 2 sensitivity analyses (Exhibit 131).

## Use of Performance Curves

To illustrate the use of this type of normalized performance data, an example is provided from Area 1 (Exhibit 88). In this hypothetical situation, the coalbed methane reservoir under consideration is similar in character to the coals in Area 1 and has an average cleat permeability of 5 md. Based on a 320 acre well spacing, this coal would be producing approximately 180 scf/d of gas per 640 acres per foot of coal per scf/ton of gas initially in place after three years of production. Assuming the coal thickness is 10 feet and the initial gas content is 345 scf/ton in this hypothetical case, the gas production rate would then be approximately 621 mscf/d for 640 acres or 310.5 mscf/d per 320 acre well three years into the production history. The corresponding cumulative production at three years would be approximately 552 mmscf per 640 acres or 276 mmscf per 320 acre well, which represents a recovery of approximately 18% of the initial gas in place (Exhibits 88 - 89).

To further expand on this illustration, the question might arise as to what the impact would be on the performance of this hypothetical situation if the same 640 acres were infill drilled to 160 acres; that is, how much more gas could be produced and would it be enough to justify drilling the additional two wells that would be required to achieve the higher level of production. Using Exhibit 94, the difference in production would be 130 mscf of additional cumulative gas production per 640 acres per foot of coal per scf/ton of gas initially in place three years into the production history. This translates to 448.5 mmscf per 640 acres or 112.1 mmscf per 160 acre well. Based on this result, the operator would then apply the appropriate economic criteria to the question of whether or not it would be prudent to drill the additional two wells. It is important to note that the water production associated with such a decision is equally as important an issue. Therefore, a similar exercise would necessarily be performed on the calculation of the produced water volumes.

## Conclusions

The sensitivity analyses of critical reservoir parameters for Areas 1, 2, and 3 not considering economic parameters, indicate the following:

1) For a given initial reservoir pressure and free gas saturation, gas recovery expressed as a percentage of initial gas-in-place increases with decreasing well spacing. This is particularly evident when gas recoveries are compared at a fixed point in time, such as the 25 year cutoff summarized in the attached exhibits. Alternatively, when the various cases are compared at a fixed abandonment rate such as 20 MSCF/d or 50 Mscf/d, there is very little difference in the gas recovery as a function of well spacing at a given level of both permeability and fracture half-length. However, the time required to achieve essentially the same recovery for a 320 acre well spacing generally increases by a factor of two over that of 160 acre well spacing, with the same relationship holding between 640 acre and 320 acre well spacings.

2) Gas recovery increases with both increasing permeability and increasing fracture half-length for all initial reservoir pressures and free gas saturation conditions evaluated.

3) For a fixed value in initial free gas saturation, gas recovery increases with increasing initial reservoir pressure when viewed at either a fixed abandonment rate or at a fixed point in time (Exhibits 125 and 145). This results from the fact that the increasing reservoir pressure results in a higher initial gas content, assuming the Langmuir constants remain unchanged. In addition, as reservoir pressure increases while maintaining a constant flowing bottomhole pressure, a larger drawdown is achieved resulting in a greater volume of gas being recovered.

4) Gas recovery increases with increasing initial free gas saturation. In Area 2 where initial gas saturations were varied between 0 and 10% with initial reservoir pressures of 200 and 300 psia, this increase in recovery is generally around 3% or less (compare Exhibits 109 and 110). In Area 3 where initial gas saturation ranged up to 23% and initial reservoir pressures were higher, the increase in recovery can be as high as 10% (compare Exhibits 129 and 130).

   Exhibit 143 illustrates the simulated gas production rate versus time for a 320 acre drainage area. Rate curves are shown for initial free gas saturations of 0 and 23%. For these two cases, all other reservoir parameters are the same (i.e., 300 foot fracture half-length, 1 md cleat permeability, initial reservoir pressure of 650 psia, etc.). As indicated in the figure, the difference in the gas rate curves is greatest during the 10 years of production. As production time increases, the difference in the two gas rate curves continues to diminish until ultimately the curves converge at approximately 15 years.

   When the two cases shown in Exhibit 143 are compared on the basis of gas recovery at 25 years, a difference in initial free gas saturation of 23% results in a recovery of 24.9% which is 9.5% greater than the recovery for the same case simulated without any free gas saturation (compare Exhibits 129 and 130). Using the data provided in Exhibit 128, the 9.5% difference in recovery represents 1,258.56 MMSCF per 640 acre section (0.095 * 1,150 [(mscf)/(640 ac-ft coal-scf/ton)] * 40 ft * 288 scf/ton). When this gas volume is compared with the 29.5 MMSCF per 640 acre section resulting directly from the 23% free gas saturation (2.56 * [(mscf)/(640 ac-ft coal-scf/ton)] * 40 ft * 288 scf/ton), it can be concluded that the difference in gas recovery between the two cases is attributable to more than just the difference in initial gas-in-place resulting from variations in free gas saturation alone.

   As the free gas saturation is the only reservoir parameter that was varied, these two cases were initialized at different points on the relative permeability curves; that is, a 23% initial free gas saturation results in a $k_{rw}$ = 0.0 and a $k_{rg}$ = 0.5 at $S_{wc}$ = 77%, whereas a coal system which is 100% water saturated at initial conditions results in a $k_{rw}$ = 1.0 and a $k_{rg}$ = 0.0 assuming the relative permeability curves utilized in the Area 1 sensitivity analyses (Cause 112-73). As a result, as gas and water saturations change with production time, the two cases follow distinctly different "paths" on the relative permeability curve for each phase.

This relative permeability effect also explains the earlier observation that the increase in gas recovery resulting from an increase in free gas saturation at a given initial reservoir pressure is generally less for Area 2 than for Area 3. At an initial free gas saturation of 10% (utilized in Area 2), $k_{rw}$ and $k_{rg}$ would initially be 0.1 and 0.05, respectively. Although these values are different than those resulting from a system which is initially 100% water saturated (i.e., $k_{rw}$ = 1.0 and $k_{rg}$ = 0.0), there is still some water mobility ($k_{rw}$ > 0.0) with which the gas phase has to compete. Alternatively, an initial free gas of 23% (utilized in Area 3) assumes no initial water mobility ($k_{rw}$ = 0.0) and gas phase behavior dominates the system.

This disparity in starting points on the relative permeability curves resulting from the absence or presence of free gas at least partially accounts for the variations in gas recovery increases when cases of equal initial reservoir pressure, permeability, fracture half-length, and well spacing are compared. The other component to these variations in gas recovery is the early production of additional gas reserves stored in the cleat system as initial free gas saturation increases.

The earlier observation that the difference in gas recovery resulting from increasing gas saturation diminishes with increasing permeability is also related in part to this relative permeability effect. The effective permeability ($k_{eff}$) for each phase is derived from the relative permeability function ($k_{eff}$ is the product of $k_{rg}$ or $k_{rw}$ and the absolute permeability). Lower values in absolute permeability result in lower values of effective permeability and a "tighter" system. As a result, the relative permeability effects have a relatively stronger influence on gas recovery. As the absolute permeability (and effective permeability) increases, resulting in a "looser" system, the relative permeability effects are dampened out somewhat and ultimate recovery becomes less dependent on them.

5) Cumulative gas production and recovery are greater for a 2% porosity coal than a 3% porosity coal due to lower water production rates and the shorter time required to dewater the reservoir. This effect is not significant in areas where water production is minimal or non-existent.

6) Gas production and cumulative recovery increase with increasing gas content.

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1. Ayers, W. B., Jr., Kaiser, W. R., Ambrose, W. A., Swartz, T. E., Laubach, S. E., Tremain, C. M., and Whitehead, N. H., III: "Geologic Evaluation of Critical Production Parameters for Coalbed Methane Resources, Part I, San Juan Basin," The University of Texas at Austin, Bureau of Economic Geology Annual Report GRI-90/0014.1 (August 1988 - July 1989) prepared for the Gas Research Institute under contract no. 5087-214-1544, 175 p.

2. Sawyer, W. K., Paul, G. W., and Schraufnagel, R. A.: "Development and Application of a 3D Coalbed Simulator," CIM/SPE Paper 90-119 presented at the CIM/SPE International Technical Meeting, Calgary, June 10-13, 1990.

3. Paul, G. W., Sawyer, W. K., and Dean, R. H.: "Validation of a 3D Coalbed Simulator," SPE Paper 20733 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, LA, September 23-26 (Attached as Exhibit 14).

4. Mavor, M. J., Britton, R. N., Close, J. C., Erwin, T. M., Logan, T. L., and Marshall, R. B.: "Western Cretaceous Coal Seam Project, Evaluation of the Cooperative Research Well Hamilton #3 Operated by Mesa Operating Limited Partnership", Resource Enterprises, Inc. Topical Report GRI-90/0040 (December 1, 1989) prepared for the Gas Research Institute under contract no. 5088-214-1657, 40 p.

5. Amoco Production Company Hearing before the New Mexico Oil Conservation Division, June 8, 1983, Case 7898, Exhibit 19B (Reservoir Pressures).

6. Zuber, M. D. and Boyer, C. M., II: "Methane from Coal Deposits Technical Evaluation and Data Base (Reservoir Engineering and Analysis)," Methane from Coal Seams Technology Quarterly Review, June 1989, vol. 6, nos. 3 and 4, p. 51-52.

7. Amoco Sorption Isotherm for Federal Land Bank "C" No. 1 (Sec. 36-T34N-R9W), Exhibit presented to the Colorado Oil and Gas Conservation Commission, Cause 112, February 21, 1989.

8. Amoco Production Company Hearing before the New Mexico Oil Conservation Division, June 8, 1983, Case 7900, Exhibit 8C (Gas Content Data).

9. Oldaker, P.: "Cedar Hill Field, New Mexico - Reservoir Data Analyses," Methane from Coal Seams Technology Quarterly Review, September 1987, vol. 5, no. 1, p. 42-43.

10. "Ignacio Blanco Field Fruitland Formation Coalbed Methane Gas Recovery Estimates for U. S. Exploration Company Leases", Exhibit presented to the Colorado Oil and Gas Conservation Commission, Cause 112-73, September 18, 1989.

11. Amoco Production Company Hearing before the New Mexico Oil Conservation Division, February 19, 1986, Case 8014, Exhibit 6 (Pressure Monitor Wells).

12. Amoco Production Company Hearing before the New Mexico Oil Conservation Division, June 8, 1983, Case 7898, Exhibits 15B, 16(A,B,C) and 17(A,B,C) (Gas Analyses).

13. Mavor, M.J., Britton, R.N., Close, J.C., Erwin, T.M., Logan, T.L., and Marshall, R.B.: "Western Cretaceous Coal Seam Project," Resource Enterprises, Inc. Final Report GRI-90/0044 (December 1, 1989) prepared for the Gas Research Institute under contract no. 5088-214-1657, 28p.

14. Kamal, M.M., and Six, J.L.: "Pressure Transient Testing of Methane Producing Coalbeds," SPE Paper 19789 presented at the 1989 SPE Annual Technical Conference and Exhibition, San Antonio, TX, October 8-11.

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16. Owen, L.B.: "ASR measurements for Colorado 32-7 #9," Terra Tek Core Services report submitted to Resource Enterprises, Inc., March, 1989, 40p.

17. Core Orientation Log for Colorado 32-7 #9 by Resource Enterprises, Inc., May, 1989, 2p.

EXHIBITS

**LIST OF EXHIBITS FOR THE**
**SAN JUAN BASIN COALBED METHANE SPACING STUDY**
**TO BE PRESENTED AT THE**
**NEW MEXICO OIL CONSERVATION DIVISION EXAMINER HEARING**
**CASE NO. 9420, ORDER NO. R-8768**

**FEBRUARY 21, 1991**

| EXHIBITS | TASK DESCRIPTION |
|---|---|
| 1 - 15 | Introduction and Technical Approach |
| 16 - 53 | Cedar Hill Field Area History Match<br>(Exhibits 48-53 in Supplemental Volume) |
| 54 - 77 | Tiffany Field Area History Match<br>(Exhibits 73-77 in Supplemental Volume) |
| 78 - 106 | Area 1 Sensitivity Analyses |
| 107 - 126 | Area 2 Sensitivity Analyses |
| 127 - 146 | Area 3 Sensitivity Analyses |

**DESCRIPTION OF EXHIBITS**
**FOR THE**
**INTRODUCTION AND TECHNICAL APPROACH**

## DESCRIPTION OF EXHIBITS FOR
## CEDAR HILL FIELD AREA HISTORY MATCH

**List of Plates (in Supplemental Volume)**

## DESCRIPTION OF EXHIBITS
## FOR
## TIFFANY FIELD AREA HISTORY MATCH

## List of Plates (in Supplemental Volume)

## DESCRIPTION OF EXHIBITS FOR AREA 1 SENSITIVITY ANALYSES ASSUMING A CLEAT POROSITY OF 0.25% AND A FRACTURE HALF-LENGTH OF 300 FEET

## DESCRIPTION OF EXHIBITS FOR AREA 2 SENSITIVITY ANALYSES ASSUMING NO INITIAL FREE GAS SATURATION AND AN INITIAL RESERVOIR PRESSURE OF 300 PSIA

**Exhibit No.** **List of Tables**



**List of Figures**

## DESCRIPTION OF EXHIBITS FOR AREA 3 SENSITIVITY ANALYSES ASSUMING 23% INITIAL FREE GAS SATURATION AND AN INITIAL RESERVOIR PRESSURE OF 650 PSIA

# SAN JUAN BASIN
# AREAS 1, 2 AND 3

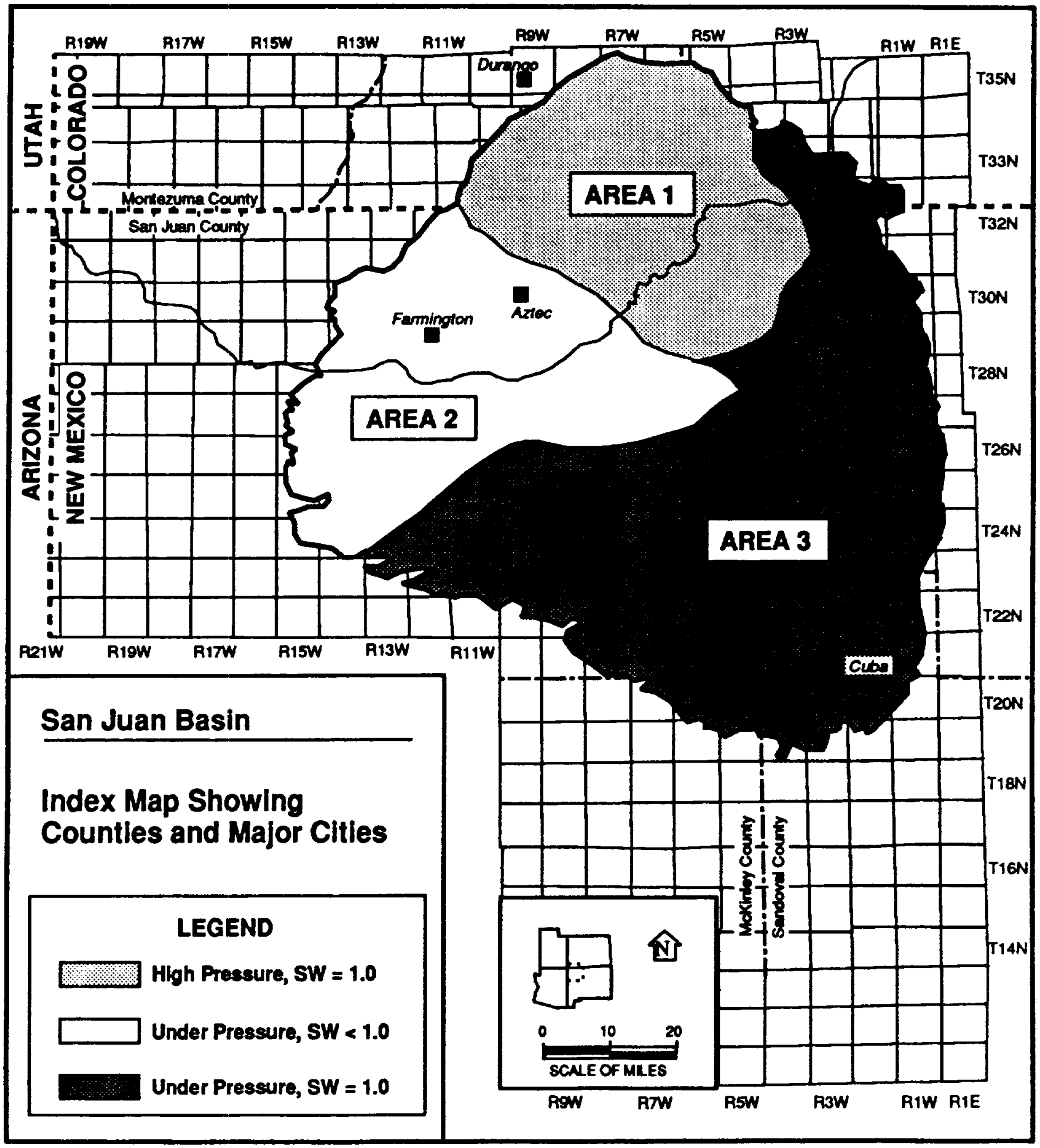
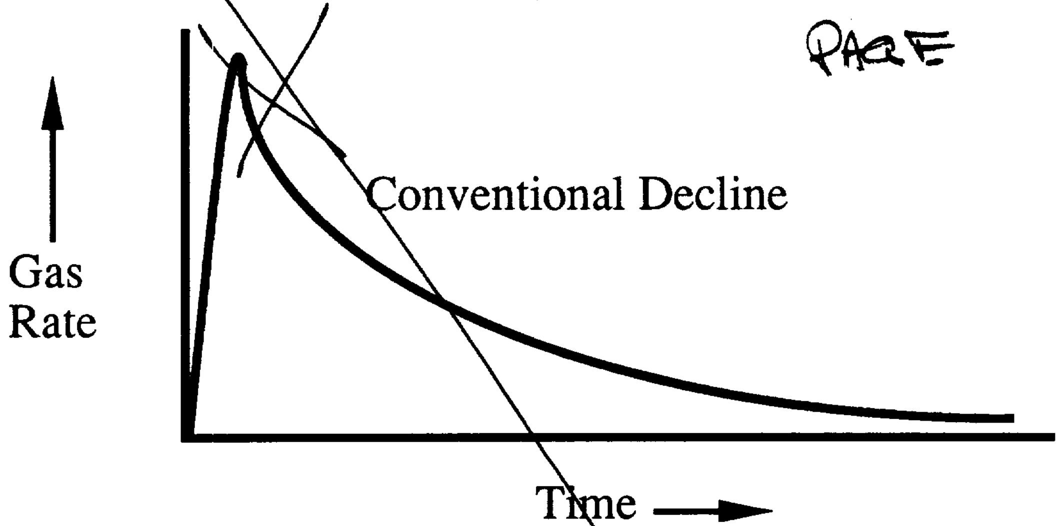


EXHIBIT 2

# San Juan Basin Coalbed Methane Spacing Study

## Schematic of Gas Recovery
## Conventional vs Coalbed Methane

REPLACE WITH SEPARATE PAGE



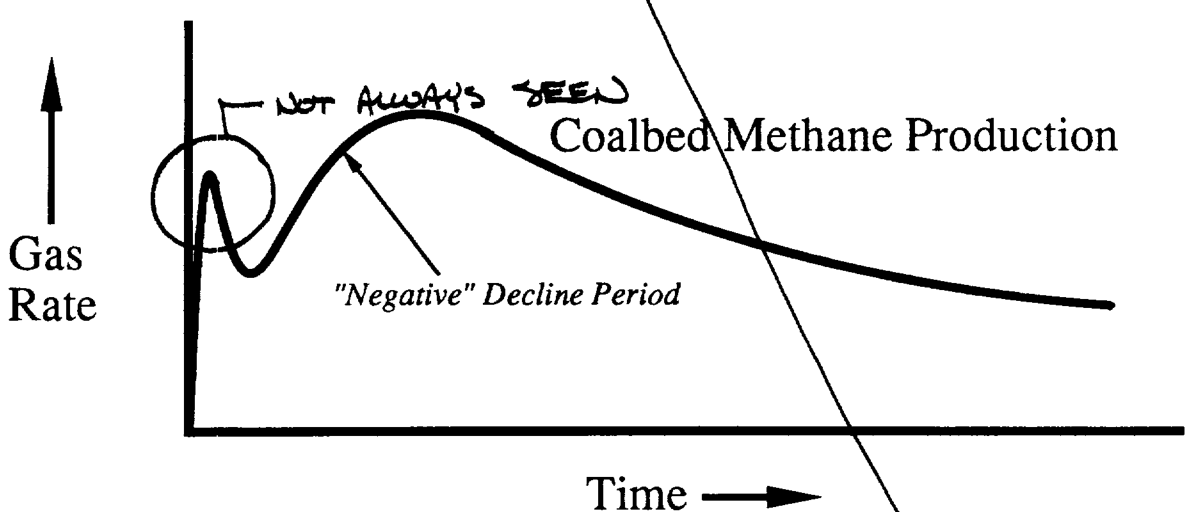
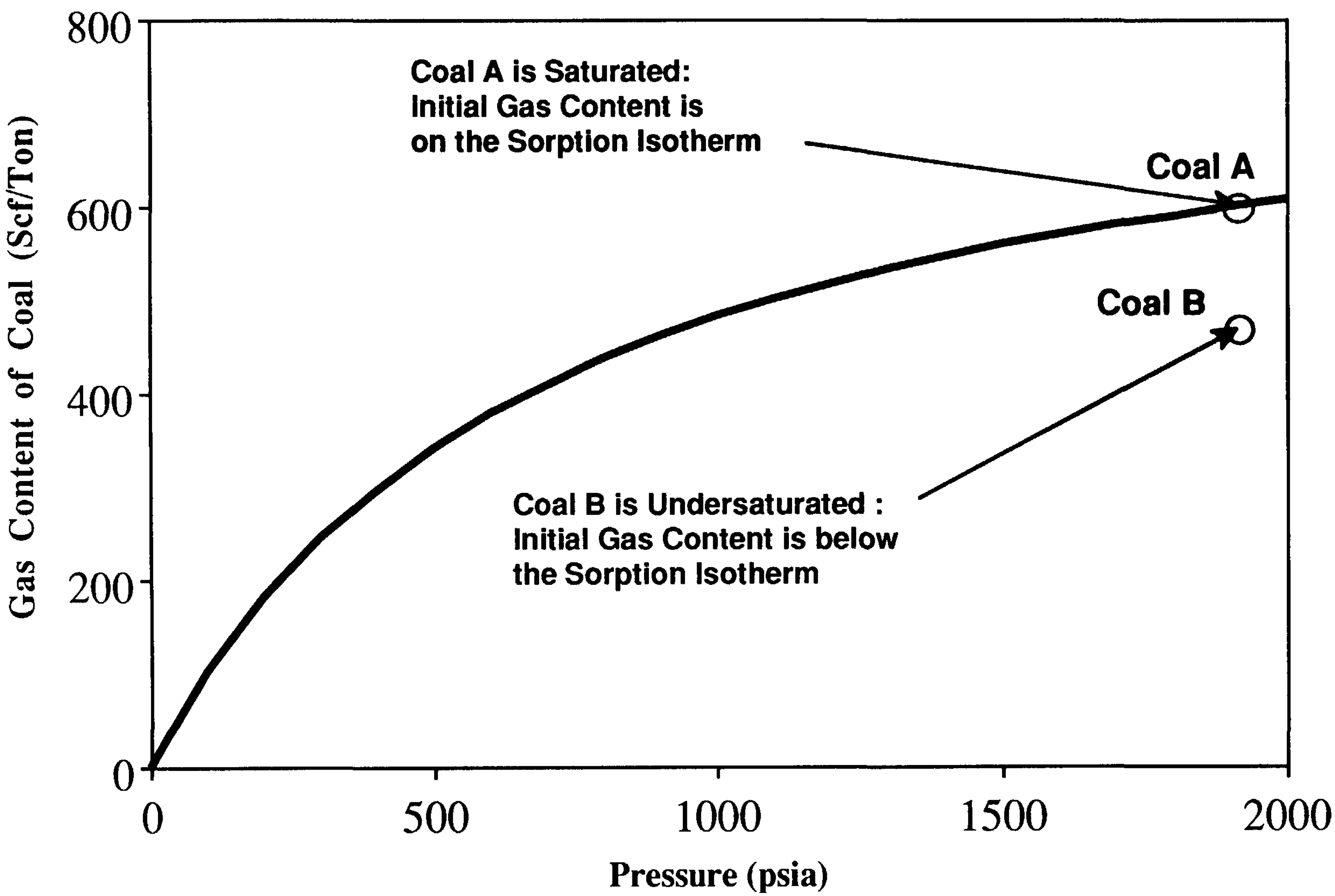



EXHIBIT 3

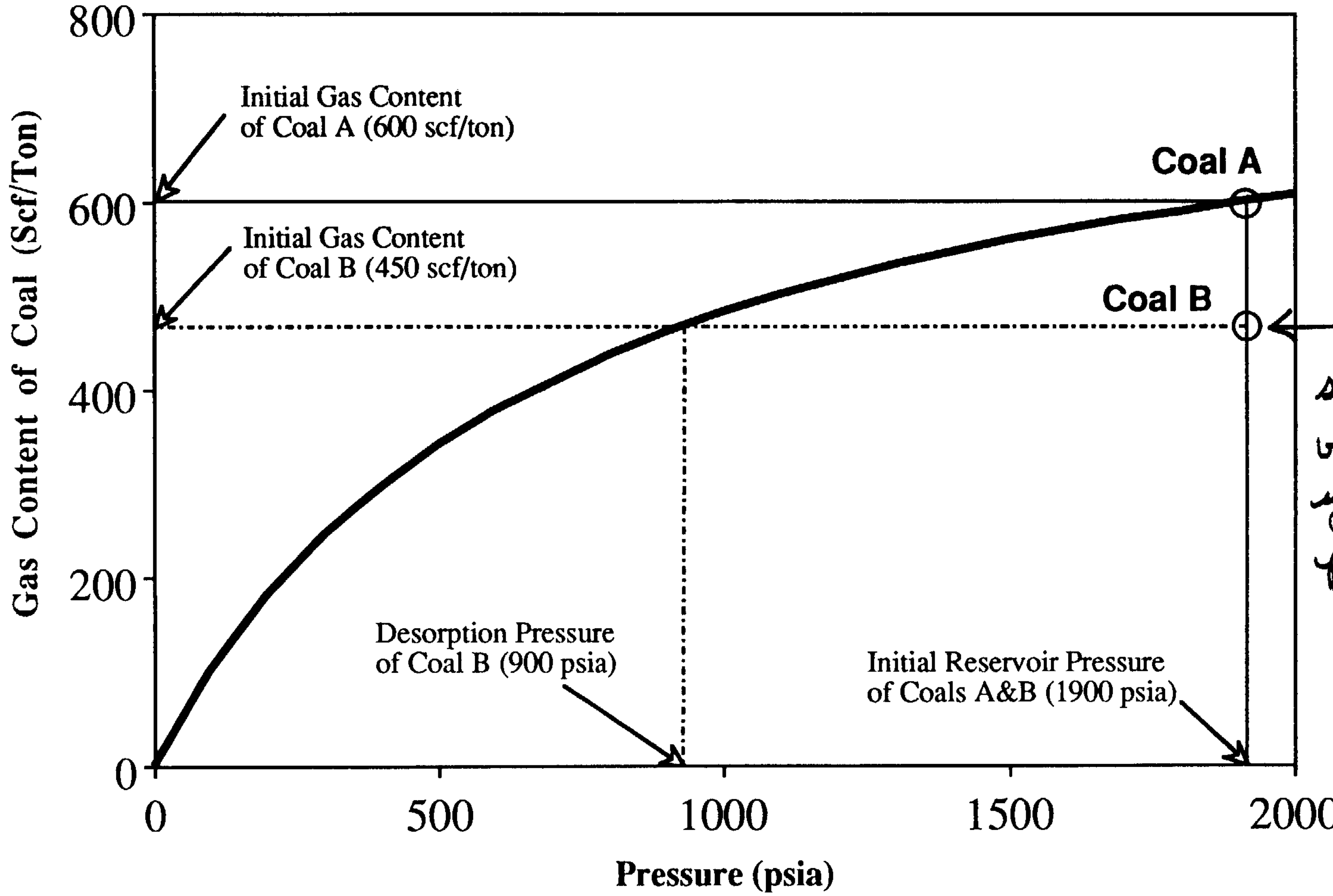
## San Juan Basin Coalbed Methane Spacing Study

**Relationship Between Sorption Isotherm and Coal Saturation**



## San Juan Basin Coalbed Methane Spacing Study

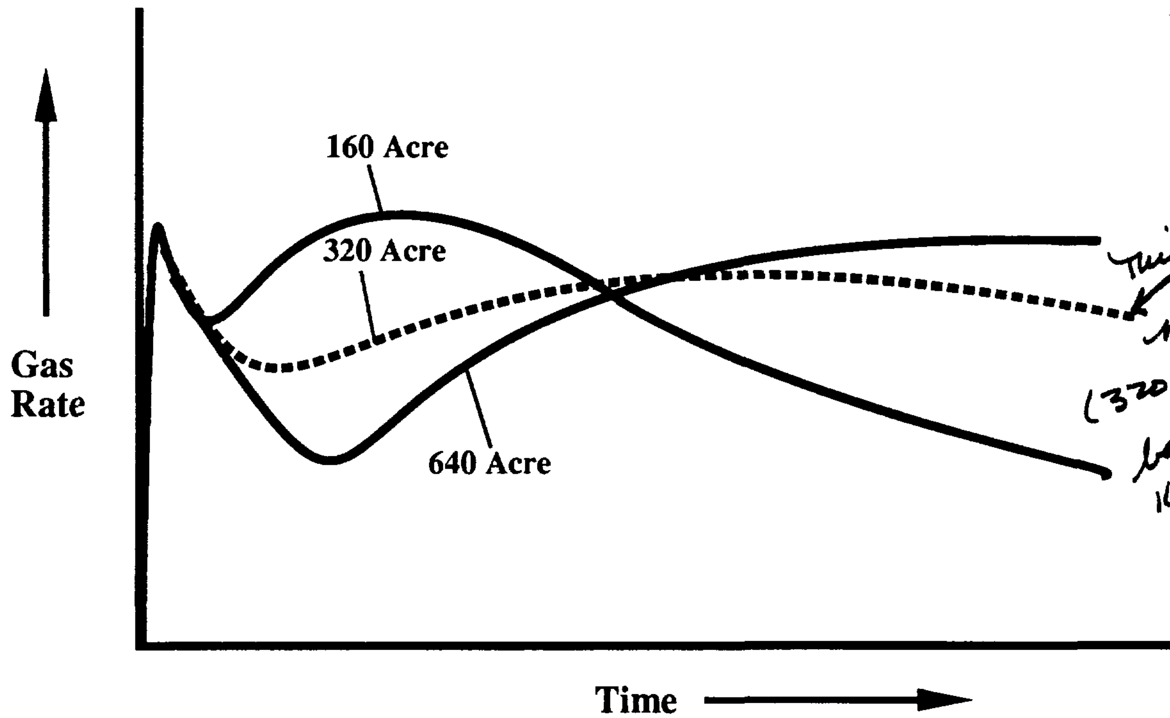
### Examples of Saturated and Undersaturated Coals




produce substantail volumes before you obtain production

# San Juan Basin Coalbed Methane Study

## Schematic Showing Well Deliverability as a Function of Well Spacing




This may be misleading (320 spacing below both 160 and 640)

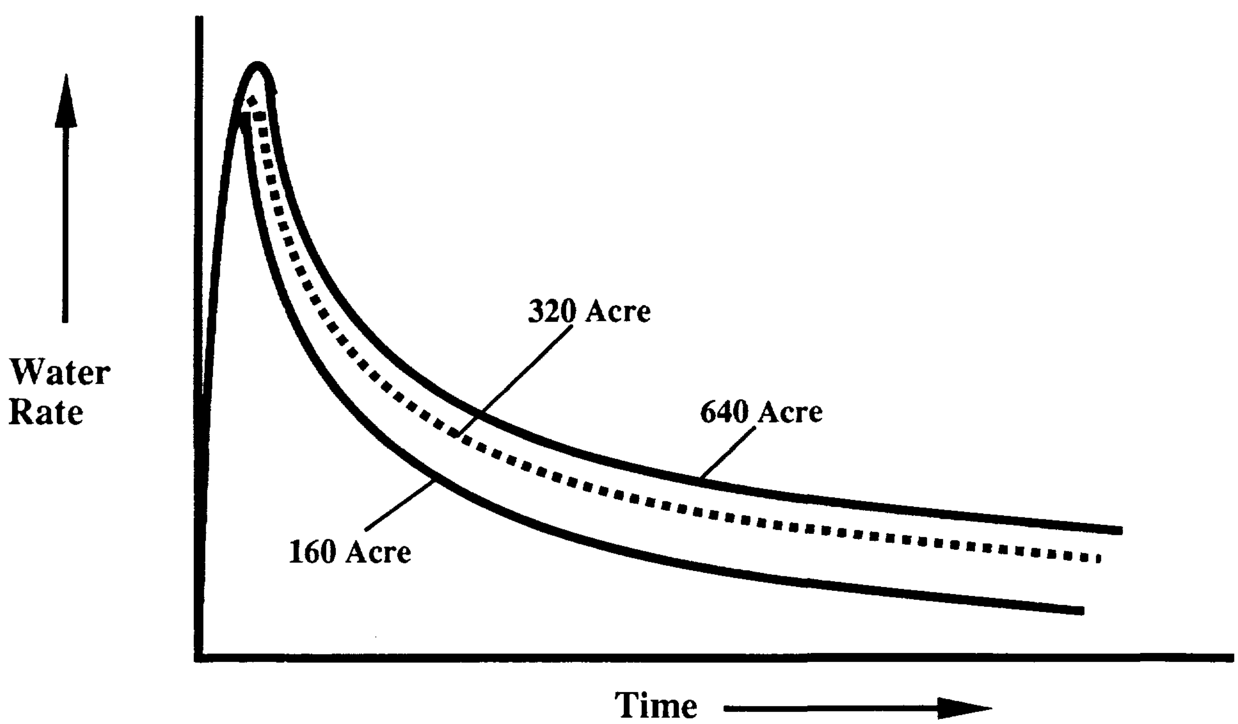


EXHIBIT 6

# San Juan Basin Coalbed Methane Spacing Study

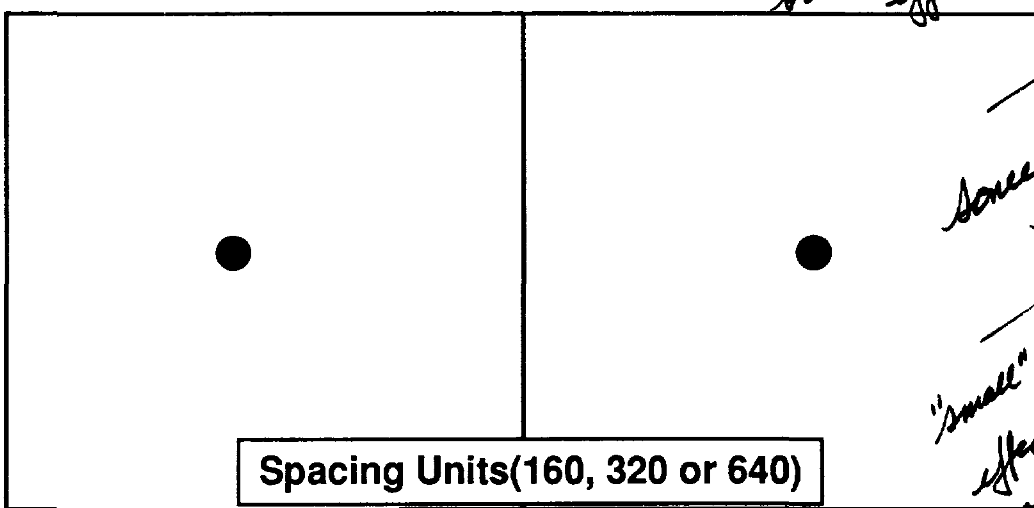
## Schematic Showing Well Interference Effects on Pressure Drawdown

some beneficial effect from interference in coal beds

Some dispute on this point.

"small" beneficial effects may be outweighed by economic considerations

***Plan View***




***Cross Section***

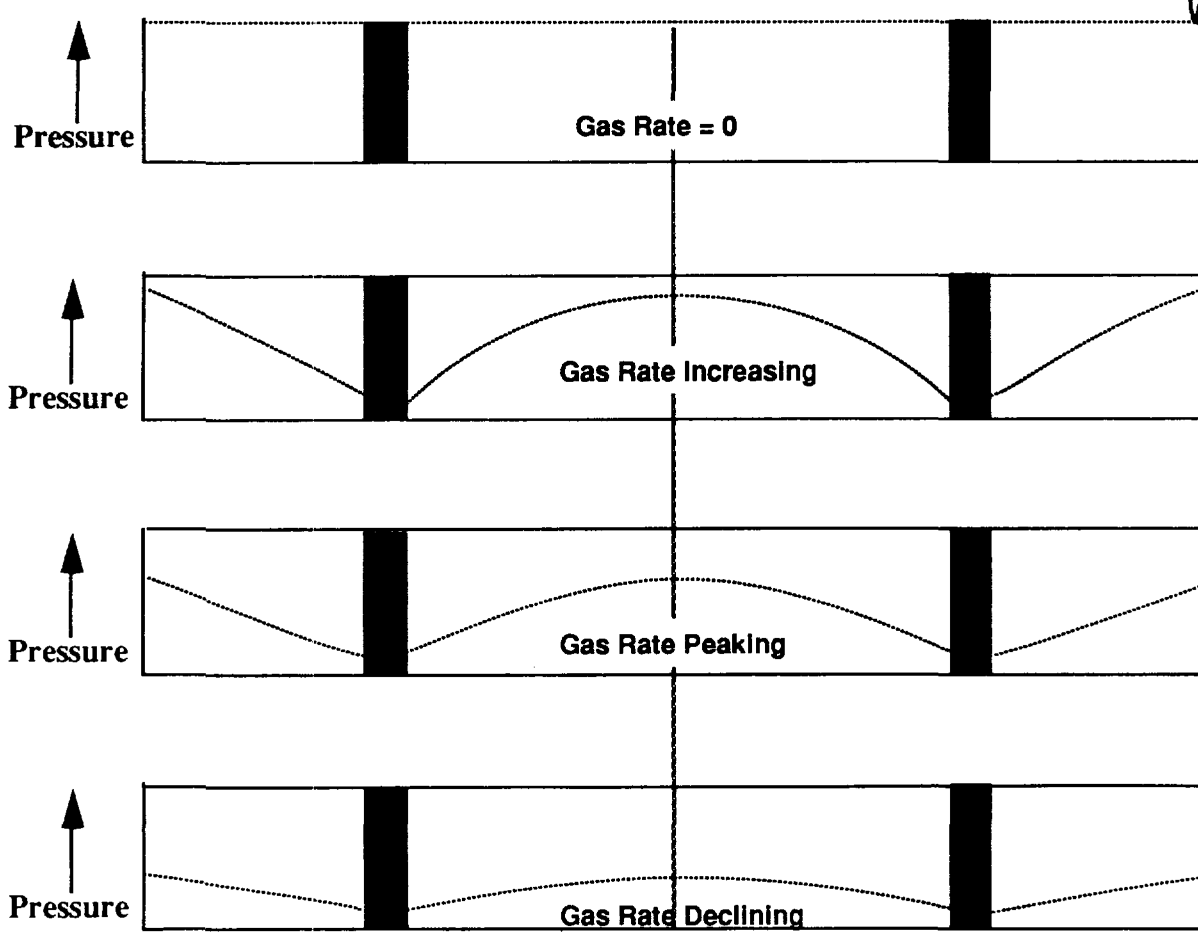


EXHIBIT 7

# SIMULATION GRID REPRESENTING 640 ACRES
## Utilized in the Model Validation Problem

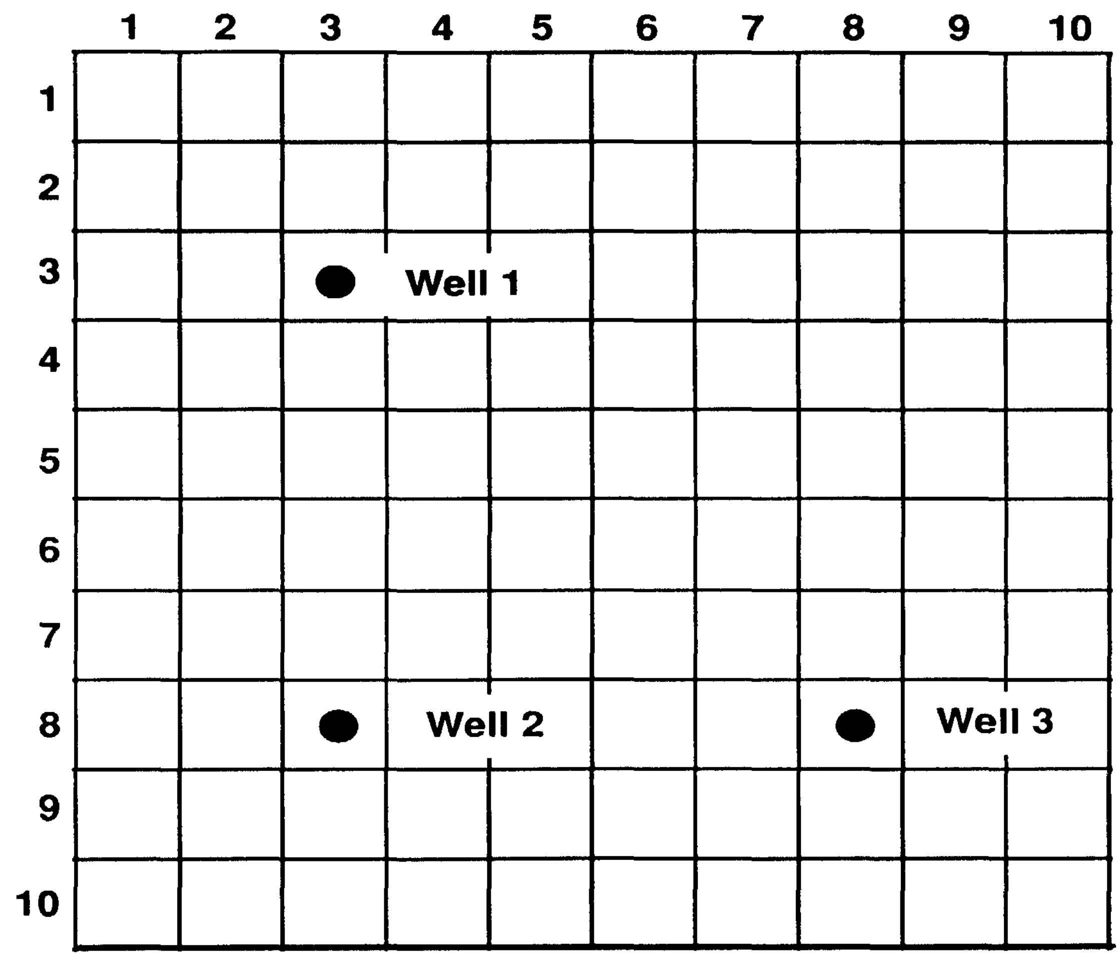


EXHIBIT 8

# WELLBORE COMPLETION SCHEMATIC for the Model Validation Problem

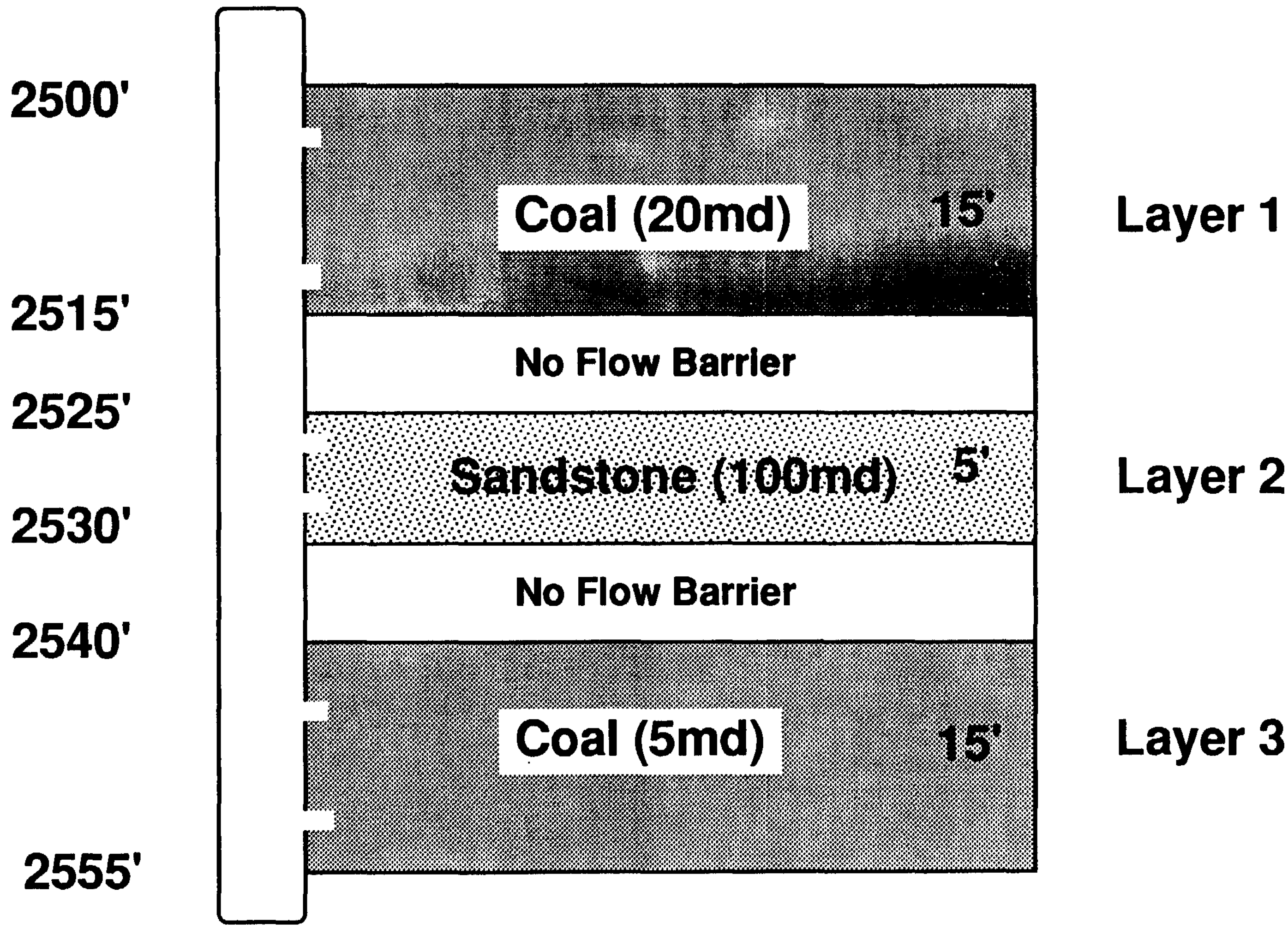
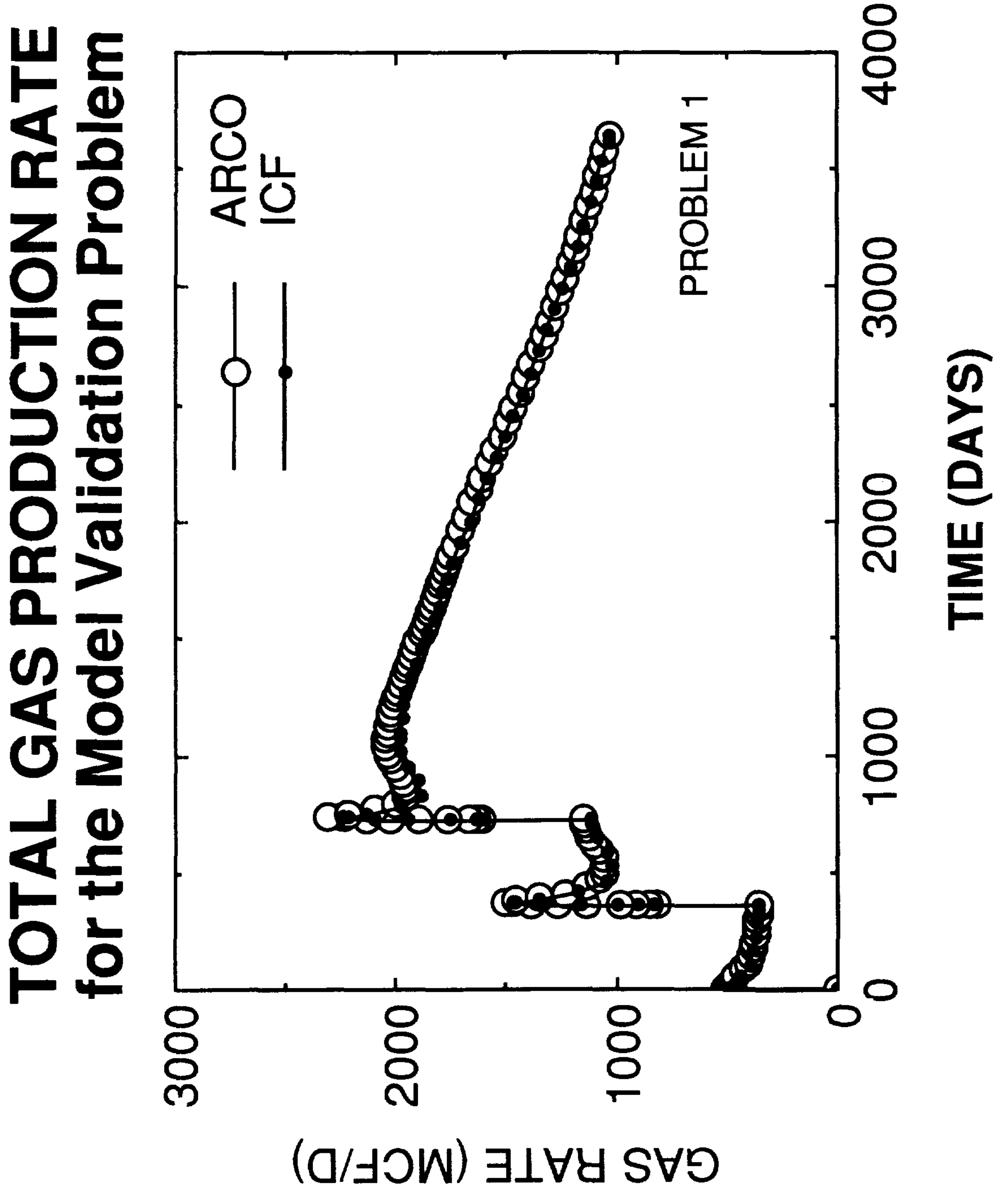


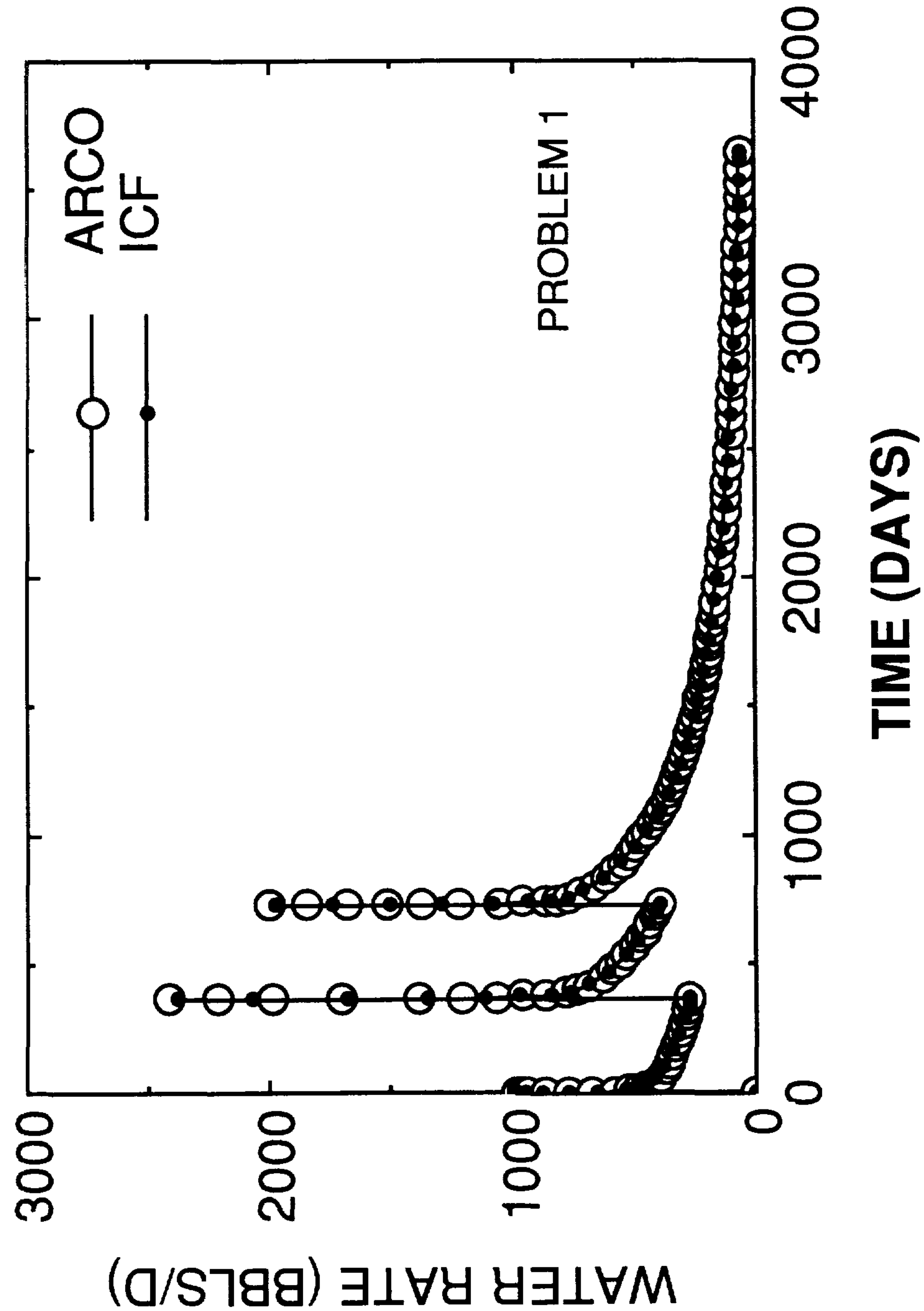
EXHIBIT 9



TOTAL GAS PRODUCTION RATE
for the Model Validation Problem
ARCO
ICF
PROBLEM 1
GAS RATE (MCF/D)
TIME (DAYS)
0
1000
2000
3000
4000

EXHIBIT 10

# TOTAL WATER PRODUCTION RATE for the Model Validation Problem



**GAS PRODUCTION RATE FOR WELL 1**
**in The Model Validation Problem**

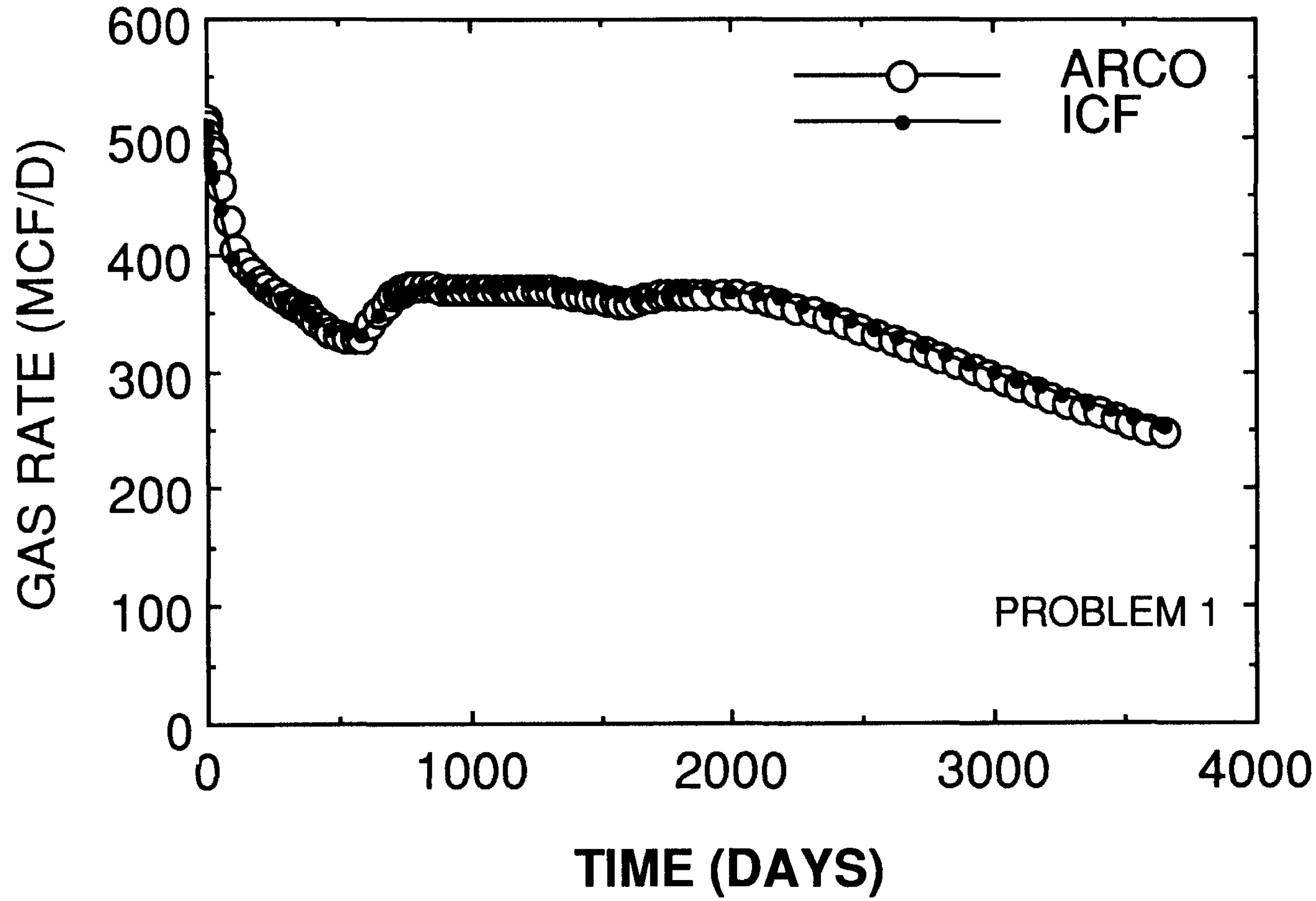



EXHIBIT 11

EXHIBIT 12

# GAS PRODUCTION RATE FOR WELL 2
## in The Model Validation Problem

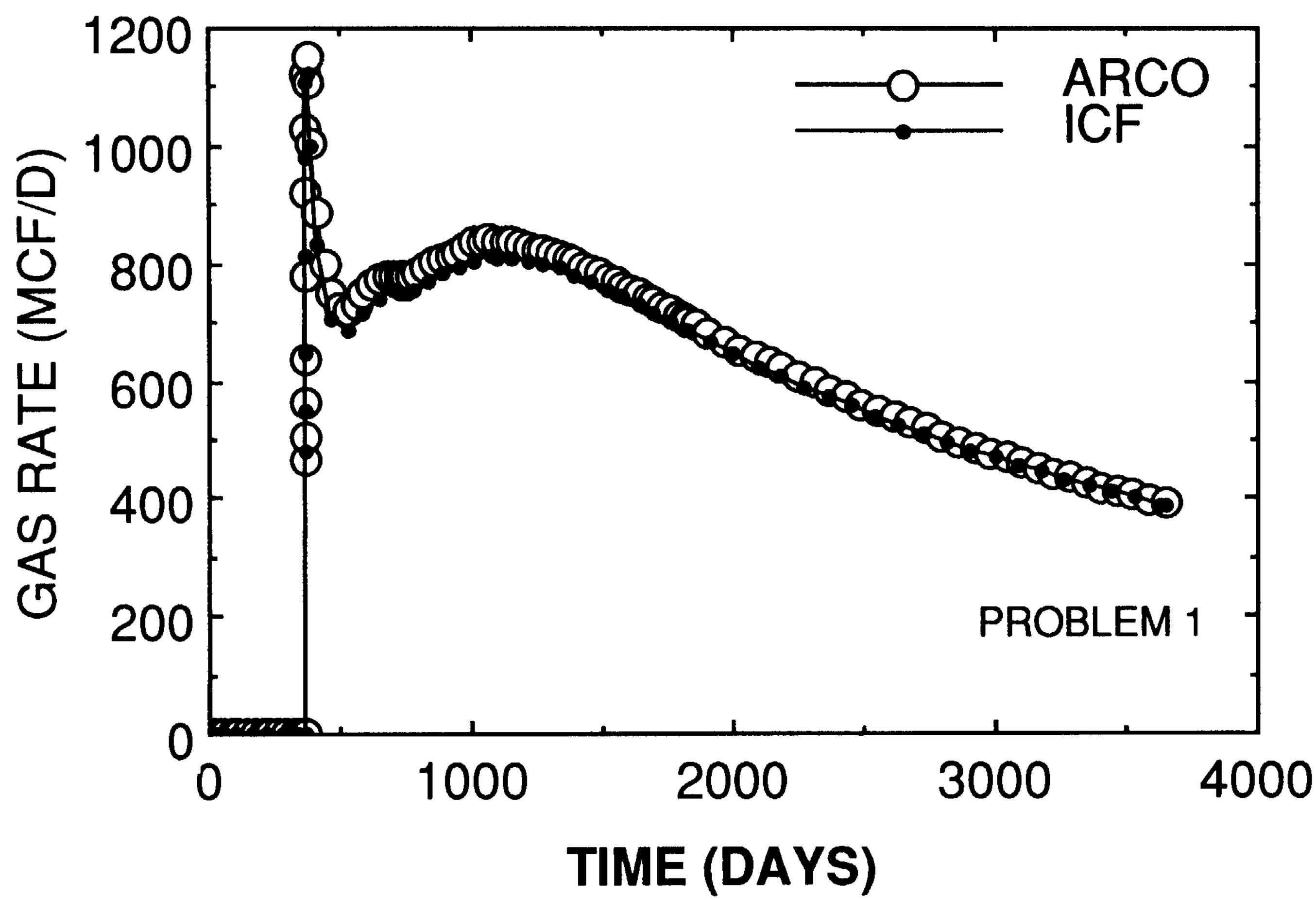


EXHIBIT 13

# GAS PRODUCTION RATE FOR WELL 3 in The Model Validation Problem

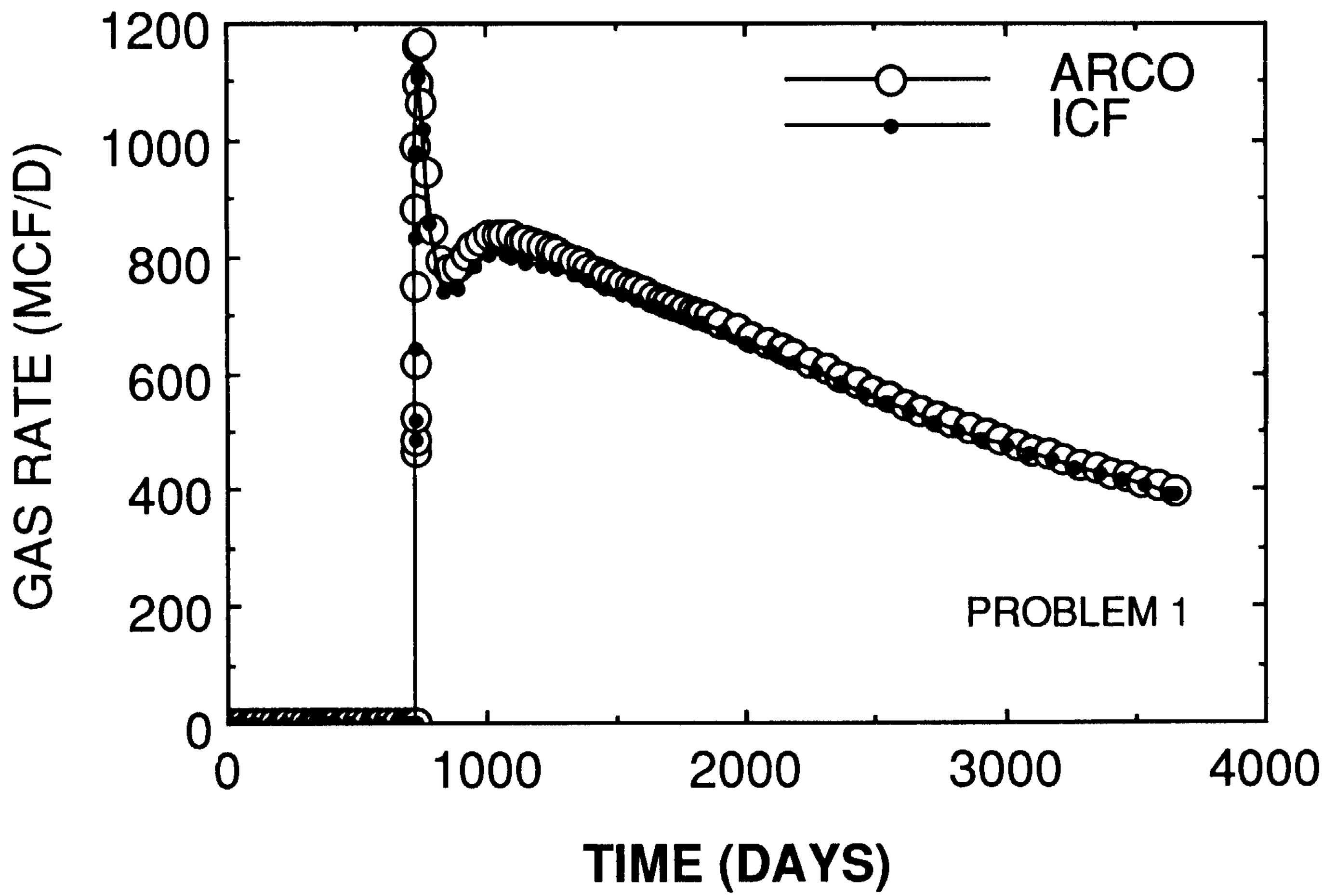


EXHIBIT 14

SPE

Society of Petroleum Engineers

SPE 20733

# Validation of 3D Coalbed Simulators

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SPE Members

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## ABSTRACT

Simulation results for three coal seam gas problems are compared for models developed by ICF Resources Inc. and ARCO Oil and Gas Company. Excellent agreement between the two simulators is obtained.

## INTRODUCTION

As part of a well spacing study being conducted by the Gas Research Institute for a committee of coalbed methane operators in the San Juan Basin, ICF Resources was asked to compare its coalbed simulator with the general purpose black-oil simulator, as modified for coal seam gas, developed by ARCO Oil and Gas Company. The comparative problems were designed to 1) illustrate some of the unique features of methane recovery from coal seams, 2) utilize data typical of the Fruitland coal formation, and 3) be easily replicable with other models.

The ICF model was also benchmarked against the first SPE black-oil comparative problem[1] as described in the appendix.

## PROBLEM STATEMENT

The three coal seam gas problems used the same areal simulation grid and locations for three vertical production wells as shown in Fig. 1. The grid in Fig. 1 represents 640 acres, so each block is 528 x 528 ft. A different layering scheme was used in each problem. For problem 1, communication was restricted to the wellbore which was completed in both coal layers and in the interbedded sandstone as shown in Fig. 2. In the second problem, the two no-flow barriers were not present and the layers were allowed to communicate with vertical permeabilities as given in Table 1. For problem 3, the sandstone layer was also removed, leaving two coal layers in communication.

Other differences among the problems in both reservoir and coal desorption properties are shown in Tables 1 and 2. Additional data for all problems are zero pore volume compressibility, no solution gas in water, zero capillary pressure, a natural fracture (cleat) spacing of 0.2 in., and wellbore radius of 0.3 ft. All wells were unstimulated in the sandstone layer, while wells 2 and 3 were provided with a negative skin (-4.5) to represent a hydraulic fracture in the coal seams. Well schedules and BHP's are given in Table 3, gas and water PVT data in Table 4, and gas-water relative permeabilities for the coal and sandstone in Table 5. Ten-year simulations were made for all three problems.

*References and illustrations at end of paper.*

## DESCRIPTION OF SIMULATORS USED

### ICF Resources Inc.

ICF used COMETPC 3-D, a three-dimensional (3D), two-phase, single or dual porosity simulator for modeling gas and water production from coal seams, devonian shales, and conventional reservoirs. The model can simulate black-oil problems for gas-oil systems. The coalbed methane formulation is based on the non-equilibrium, pseudo-steady state approach discussed by King et al[2]. Options are available to model stress-sensitive permeability, matrix shrinkage, and gas readsorption to coal. The finite-difference formulation is fully implicit, and an implicit wellbore algorithm adds stability and preserves user-specified rate and pressure constraints. Each well may be vertical, horizontal or deviated, with appropriate productivity indices internally calculated for either induced fracture or unstimulated conditions. The matrix equations are solved in 3D by a combined direct (D4) - slice SOR method. Additional details are given by Sawyer et al[3].

### ARCO Oil and Gas Company

ARCO used a general purpose black-oil simulator developed initially for modelling naturally fractured reservoirs. An early version of the simulator is described by Dean and Lo[4]. The simulator can perform fully-implicit, sequential, or IMPES calculations for 3D systems, and models multi-phase flow for single or dual porosity reservoirs. In dual porosity mode, the simulator can model the production of water, oil, and gas from naturally fractured reservoirs, and the production of water and gas from coal seams. Special options for coal seams include generation of curvilinear grids to model finite conductivity hydraulic fractures as discussed by

Fleming[5], generation of elliptical grids for infinite conductivity hydraulic fractures, deviated or horizontal wells, and allowance for user-specified wellbore hydraulics. In addition, the simulator models pressure-dependent permeabilities and gas lift-systems, accounts for aquifer influx, and allows user-specified or internally generated gas-water PVT properties.

The coal seam option in the ARCO simulator is similar to ICF's implementation as described by Sawyer et al[3]. The ARCO simulator solves the coal seam equations fully implicitly using a finite-difference grid with the three independent variables in each grid block being gas pressure and water saturation in cleat, and the gas concentration in the coal. The latter is defined as the volume of gas (in surface units) adsorbed on the coal per unit volume of reservoir.

The ARCO simulator models flow through the coal cleat system using conventional (darcy) two-phase flow equations which include an additional term representing gas exchange between the cleat system and coal. If C is the gas concentration in the coal, then the rate at which gas enters the cleat system from the coal, $-\partial C/\partial t$, is assumed to obey a first-order rate equation of the form

$$-\partial C/\partial t = (1/\tau)(C-C_w), \qquad (1)$$

where $\tau$ is the sorption time which determines how quickly gas desorbs from the coal. The variable $C_w$ is a function of the gas pressure, P, and can be calculated from

$$C_w = C_L P/(P_L + P), \qquad (2)$$

where $C_L$ and $P_L$ are constants. The simulator models both gas desorption and adsorption, and allows the coal to be undersaturated.

Eqs. (1) and (2) are combined with conventional reservoir equations to model production from coal seams. The non-linear equations are linearized with the variation in the independent variable C expressed in terms of the variation in gas pressure and water saturation. The resulting global set of linear equations contains only the gas pressure and water saturation. This approach is analogous to that used in conventional dual porosity simulations[6], and reduces the size of the linear system of equations which must be solved. The non-linear set of equations is solved with a Newton-Raphson technique, while the linearized equations are solved using an ILU(0) preconditioner with orthomin acceleration[7].

## RESULTS

Results from the ICF and ARCO simulators for the three coal seam gas problems are compared in Figs. 3-17. The ICF and ARCO results are very similar with slight differences being due to differences in well PI's and in selection of time-step sizes. The coal seam gas problems were solved with both simulators with nonlinear iteration tolerances of 0.2 psi in pressure and 0.001 (fraction) in water saturation. Small time steps were required at 0, 365, and 730 days in order to accurately model the rapidly changing well rates at those times. The ARCO simulations presented here took approximately ten seconds on a Cray-XMP. The ICF simulations required 20 min. for problem 3, 43 min. for problem 2, and 60 min. for problem 1 on a Compaq 386/20 PC with an 80387 math co-processor.

Figs. 3-7 compare simulator predictions for problem 1. The ICF and ARCO simulators predict very similar results for field-wide gas rates (Fig. 3), field-wide water rates (Fig. 4), and individual well gas rates (Figs. 5-7). The field-wide gas and water rates exhibit dramatic rate increases at 0, 365, and 730 days because wells 1 through 3 begin production at 0, 365, and 730 days, respectively. The wells are placed immediately on bottomhole pressure control when they begin production and this causes dramatic jumps in the gas and water rates. If wells were placed on production using a prescribed water production limit or if wellbore hydraulics were incorporated into the calculations, then the gas rates would build up gradually for a well and one would not see such dramatic increases in the gas rates.

Figs. 8-12 compare simulator predictions for problem 2. Problem 2 is similar to problem 1 with the major difference being that problem 2 allows vertical communication between the reservoir layers, while problem 1 has permeability barriers between the layers. As in problem 1, the ICF and ARCO simulators predict similar results for field-wide gas rates (Fig. 8), field-wide water rates (Fig. 9), and individual well gas rates (Figs. 10-12). It is interesting to note that the cumulative gas production and cumulative water production in problem 2 are approximately 85% higher than the cumulative gas production and cumulative water production in problem 1. This increased production in problem 2 occurs for two reasons: vertical communication allows the water and gas to segregate which reduces relative permeability effects, and vertical communication allows the fluids to move to the wellbore through the high permeability layers. For problem 2, over 95% of the gas production comes the top reservoir layer (coal) which has a permeability of 20 md, while the majority of the water production comes from the middle reservoir layer (sandstone) which has a permeability of 100 md.

Figs. 13-17 compare simulator predictions for problem 3. Problem 3 has only two reservoir layers and the coal seam properties are somewhat different for the two layers. In addition, all wells are placed on production at the beginning of the simulation so one does not see the dramatic production rate increases at 365 and 730 days which are present in problems 1 and 2. Once again, the ICF and ARCO simulators predict very similar results for field-wide gas rates (Fig. 13), field-wide water rates (Fig. 14), and individual well gas rates (Figs. 15-17).

## CONCLUSIONS

Simulators developed by ICF Resources Inc. and ARCO Oil and Gas Company were compared for three related coal seam gas problems. Results from the two models were in close agreement. The problems and associated results presented here can serve as benchmarks for verification of other coalbed simulators.

## NOMENCLATURE

| | | |
|---|---|---|
| C | = | gas concentration in coal, MCF gas/CF reservoir |
| $C_L$ | = | constant in Eq. (1), MCF gas/CF reservoir |
| $C_w$ | = | equilibrium isotherm gas concentration at pressure P, MCF gas/CF reservoir |
| P | = | coal cleat pressure, psi |
| $P_L$ | = | constant in Eq. (2), psi |
| t | = | time, days |
| $\tau$ | = | sorption time, days |

## ACKNOWLEDGEMENTS

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5. Fleming, G.C.: "Modeling the Performance of Fractured Wells in Pattern Floods Using Orthogonal, Curvilinear Coordinates," paper SPE 16973 presented at the 1987 SPE Annual Technical Conference and Exhibition, Dallas, Sept. 27-30.

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## APPENDIX

### Black-Oil Problem

Case 1 of the SPE black-oil comparative problem [1] was run with ICF's model. In Case 1, gas is continually injected into a well in one corner of a 10 x 10 x 3 grid representing an undersaturated oil reservoir; a production well is located in the diagonal corner. The simulation was to be terminated either at the end of ten years, or when GOR exceeds 20,000 scf/bbl, or when oil production rate drops below 1,000 bbl/d, whichever occurs first. Further details of the black-oil problem are given in Ref. 1.

ICF's model is compared to the results from seven industry simulators in Figs. 18-25. In general, ICF's results fall within the envelope of results from the industry models. The SPE black-oil problem as published is a two-phase gas-oil case. However, a third phase consisting of a 12 percent connate water saturation is present. Although this water is immobile, data input to the two-phase ICF simulator had to be modified to account for this 12 percent unused pore space in comparative three-phase models. The approach taken was to reduce the original porosity of 0.30 to (1 - 0.12) (0.30) = 0.264, with a corresponding increase in initial oil saturation from 0.88 to 1.0; this yields the identical original oil-in-place as in the three-phase system. The gas saturations in the original relative permeability table were increased by the factor 1/0.88, with a corresponding increase in the oil saturation, in order to preserve phase mobilities. Finally, computed saturations from the ICF model had to be reduced by the porosity adjustment for comparison with the results of the three-phase simulators.

**TABLE 1 - RESERVOIR DATA FOR COAL SEAM PROBLEMS 1 AND 2[1]**

| | Layer 1 (Coal) | Layer 2 (Sandstone) | Layer 3 (Coal) |
|---|---|---|---|
| Thickness, ft | 15.0 | 5.0 | 15.0 |
| Horizontal permeability, md | 20.0 | 100.0 | 5.0 |
| Vertical permeability, md | 0(2.0)[1] | 0(20.0)[1] | 0(1.75)[1] |
| Porosity, fr | 0.02 | 0.20 | 0.02 |
| Initial water saturation, fr | 1.00 | 0.85 (1.00)[1] | 1.00 |
| Initial pressure, psia | 1100.0 (1103.2)[2] | 1108.0 (1107.6)[2] | 1115.0 (1111.9)[2] |
| Desorption pressure, psia | 1000.0 (1103.2)[2] | - | 1115.0 (1111.9)[2] |
| Sorption time, days | 10.0 | - | 10.0 |
| Langmuir volume, scf gas/cf coal | 28.8 | - | 28.8 |
| Langmuir pressure, psia | 571.0 | - | 571.0 |

[1] Data are same for problems 1 and 2 except entries in ( ) which are for problem 2.

[2] For problem 2, initial pressures calculated at center of each layer assuming gradient of 0.433 psi/ft.

**TABLE 2 - RESERVOIR DATA FOR COAL SEAM PROBLEM 3**

| | Layer 1 (Coal) | Layer 2 (Coal) |
|---|---|---|
| Thickness, ft | 15.0 | 15.0 |
| Horizontal permeability, md | 20.0 | 5.0 |
| Vertical permeability, md | 2.0 | 1.75 |
| Porosity, fr | 0.02 | 0.02 |
| Initial water saturation, fr | 1.00 | 1.00 |
| Initial pressure, psia | 1103.2 | 1109.7 |
| Desorption pressure, psia | 1103.2 | 800.0 |
| Sorption time, days | 20.0 | 5.0 |
| Langmuir volume, scf/cf | 20.0 | 28.8 |
| Langmuir pressure, psia | 400.0 | 571.0 |

## TABLE 3 - WELL SCHEDULES AND CONTROLS FOR COAL SEAM PROBLEMS

| | Well No. | Layer | BHP (psia) | Time on Production (days) |
|---|---|---|---|---|
| Problem 1 | 1 | 1, 2, and 3 | 50.0 | 0 - 3650 |
| | 2 | 1, 2, and 3 | 50.0 | 365 - 3650 |
| | 3 | 1, 2, and 3 | 50.0 | 730 - 3650 |
| Problem 2 | 1, 2, and 3 | 1 | 46.55[1] | Same as Problem 1 |
| | 1, 2, and 3 | 2 | 50.88 | |
| | 1, 2, and 3 | 3 | 55.21 | |
| Problem 3 | 1, 2, and 3 | 1 | 46.55[1] | 0 - 3650 |
| | 1, 2, and 3 | 2 | 53.04 | 0 - 3650 |

[1] For problems 2 and 3, BHP's calculated at center of each layer assuming gradient of 0.433 psi/ft.

## TABLE 4 - PVT DATA FOR COAL SEAM PROBLEMS

| | |
|---|---|
| Reservoir temperature, °F | 95.0 |
| Gas specific gravity | 0.60 |
| Stock tank water density, 1bm/cu ft | 62.4 |
| Water viscosity, cp | 0.73 |

| Pressure (psia) | Gas Shrinkage Factor (MCF/RB) | Gas Viscosity (cp) | Water Shrinkage Factor (STB/RB) |
|---|---|---|---|
| 14.7 | 0.00538 | 0.0110 | 0.9940 |
| 500.0 | 0.19162 | 0.0110 | 0.9947 |
| 1000.0 | 0.40904 | 0.0124 | 0.9953 |
| 1400.0 | 0.59885 | 0.0142 | 0.9959 |

## TABLE 5 - RELATIVE PERMEABILITY DATA FOR COAL SEAM GAS PROBLEMS

Relative Permeability for Coal

| $S_w$ | $k_{rw}$ | $k_{rg}$ |
|---|---|---|
| 0.70 | 0.000 | 1.000 |
| 0.75 | 0.005 | 0.580 |
| 0.80 | 0.010 | 0.300 |
| 0.85 | 0.080 | 0.120 |
| 0.90 | 0.180 | 0.035 |
| 0.95 | 0.350 | 0.010 |
| 1.00 | 1.000 | 0.000 |

Relative Permeability for Sandstone

| $S_w$ | $k_{rw}$ | $k_{rg}$ |
|---|---|---|
| 0.40 | 0.000 | 1.000 |
| 0.50 | 0.045 | 0.400 |
| 0.60 | 0.110 | 0.210 |
| 0.70 | 0.215 | 0.105 |
| 0.80 | 0.370 | 0.035 |
| 0.90 | 0.595 | 0.010 |
| 1.00 | 1.000 | 0.000 |

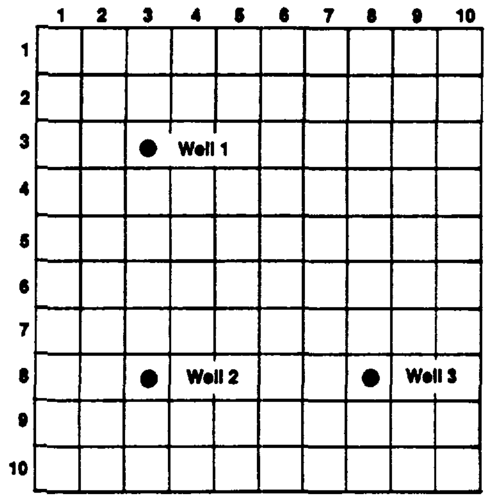



Fig. 1—Simulation grid.

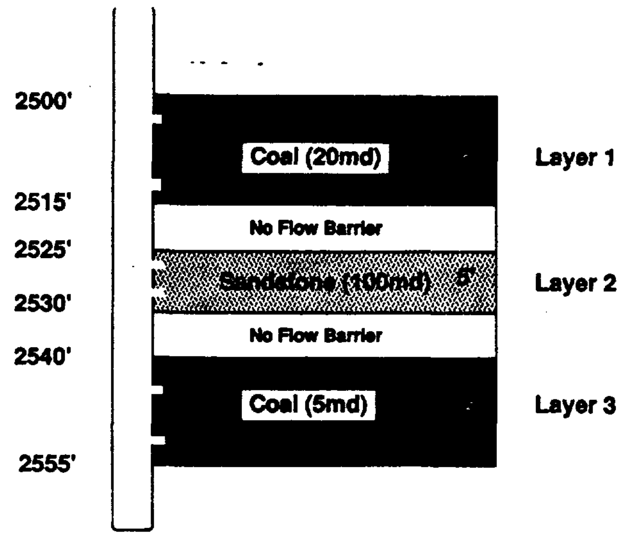



Fig. 2—Well completion schematic for Problem 1.

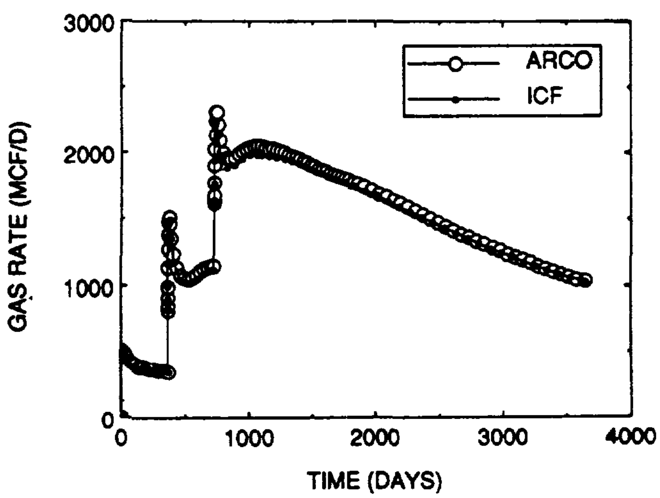



Fig. 3—Total gas production rate vs. time.

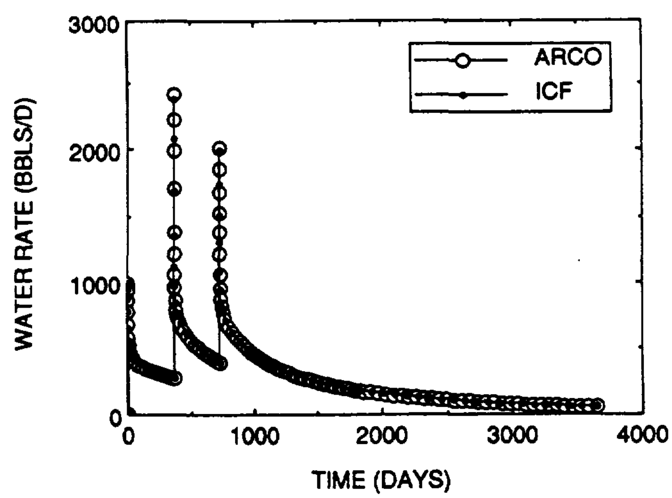



Fig. 4—Total water production rate vs. time.

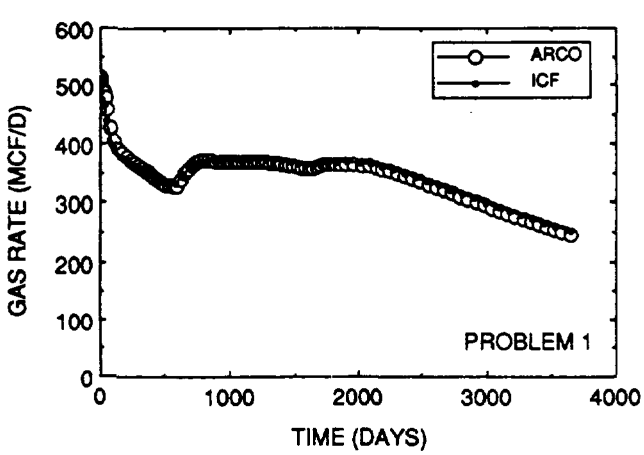



Fig. 5—Gas production rate for Well 1.

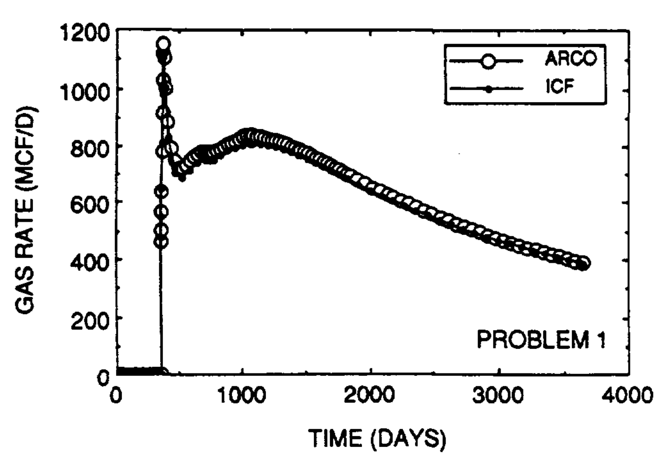



Fig. 6—Gas production rate for Well 2.

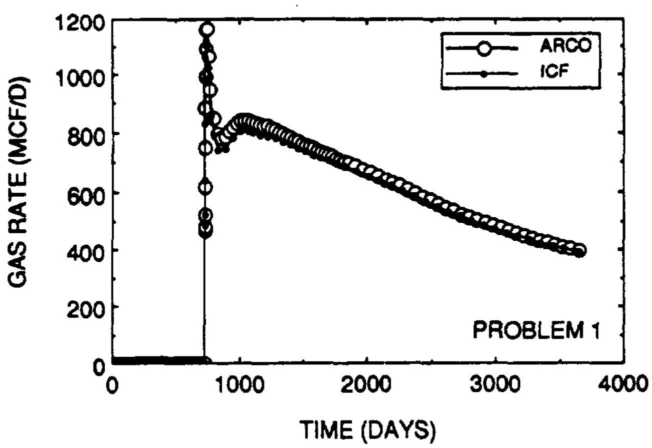



Fig. 7—Gas production rate for Well 3.

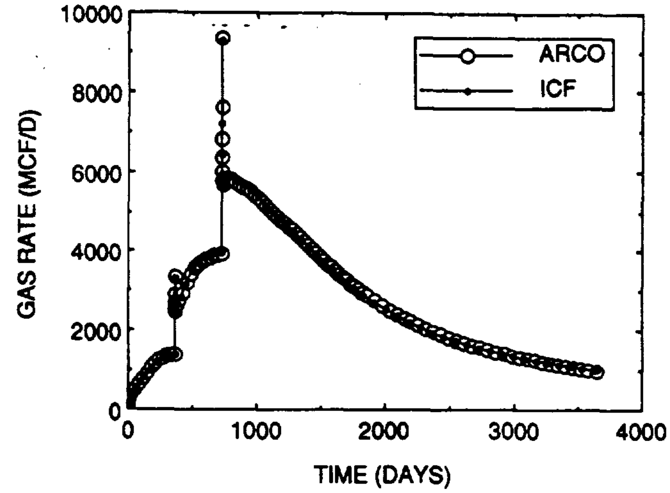



Fig. 8—Total gas production rate vs. time.

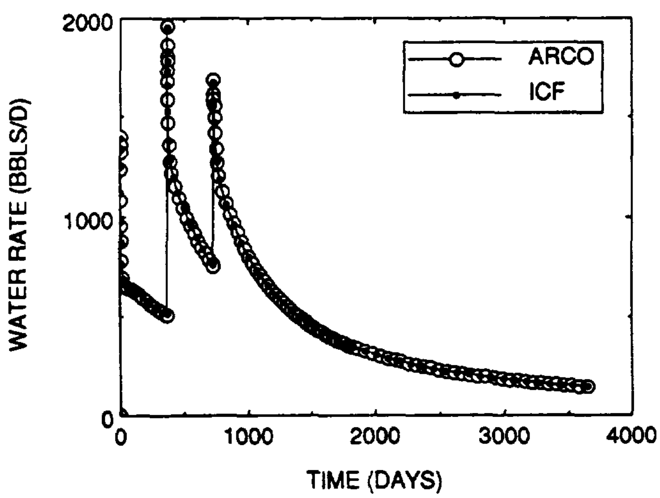



Fig. 9—Total water production rate vs. time.

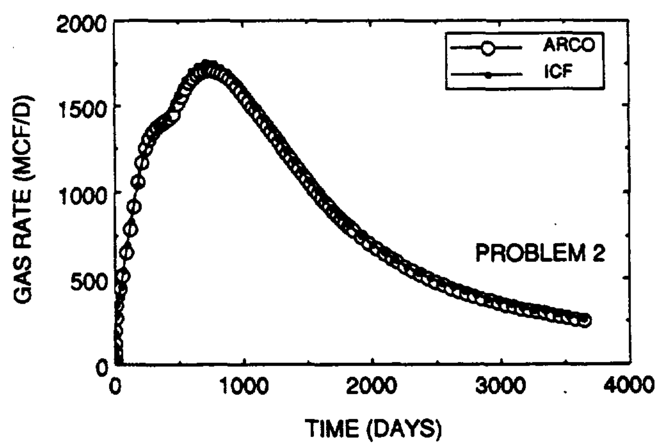



Fig. 10—Gas production rate for Well 1.

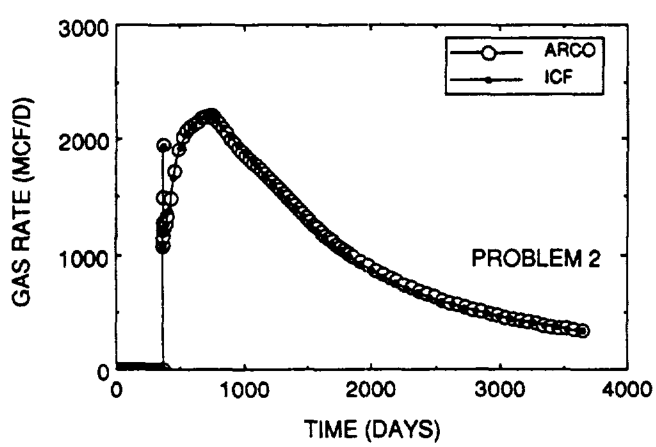



Fig. 11—Gas production rate for Well 2.

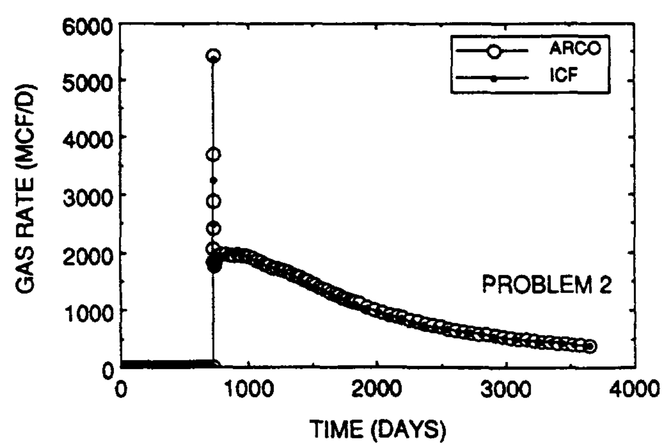



Fig. 12—Gas production rate for Well 3.

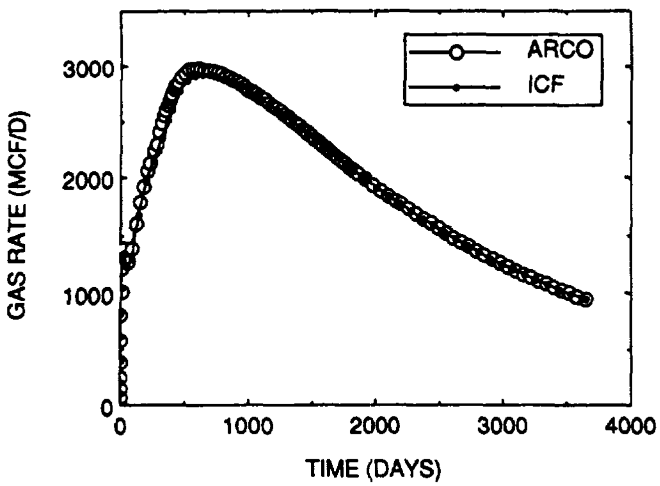



Fig. 13—Total gas production rate vs. time.

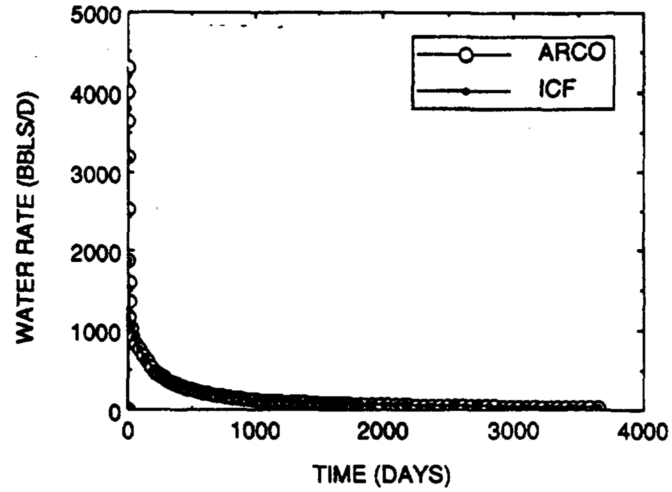



Fig. 14—Total water production rate vs. time.

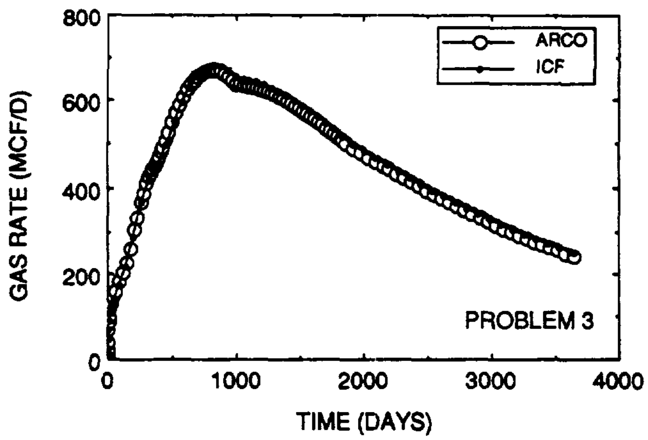



Fig. 15—Gas production rate for Well 1.

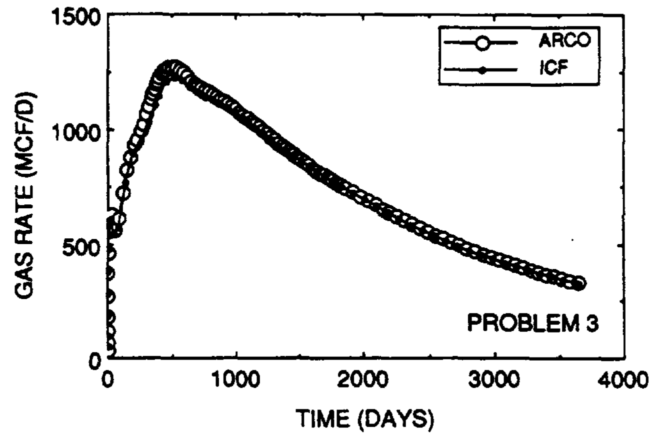



Fig. 16—Gas production rate for Well 2.

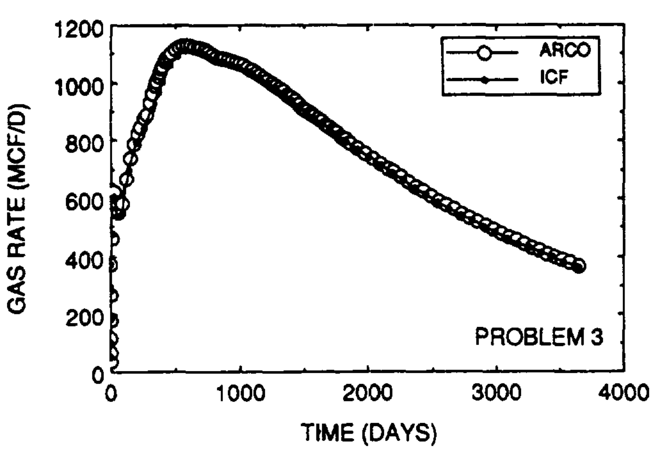



Fig. 17—Gas production rate for Well 3.

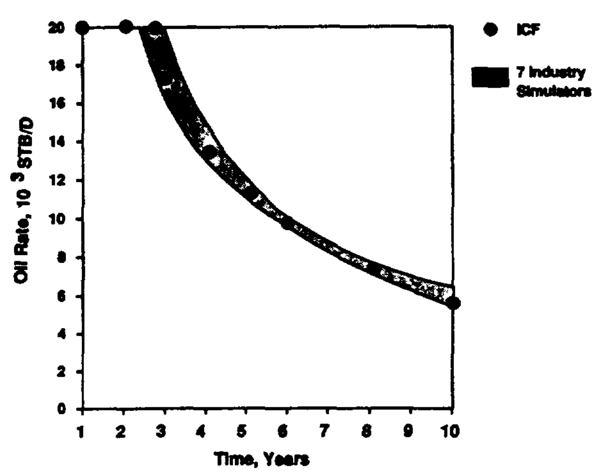



Fig. 18—Oil rate vs. time.

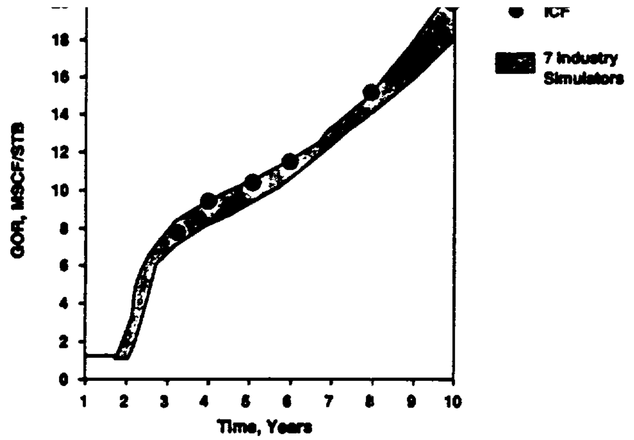


Fig. 19—GOR vs. time.

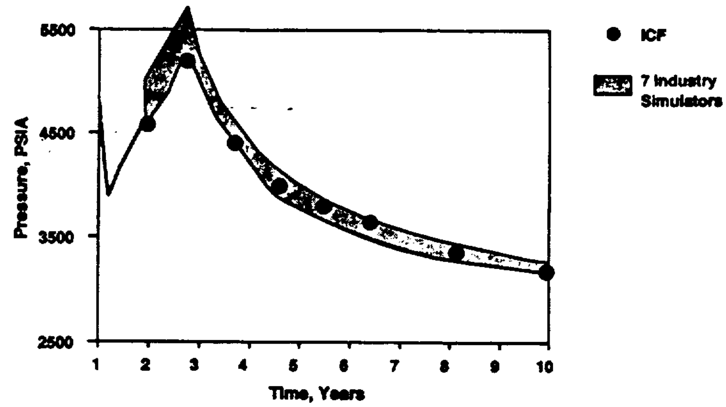


Fig. 20—Pressure vs. time for producing Well Cell 10,10,3.

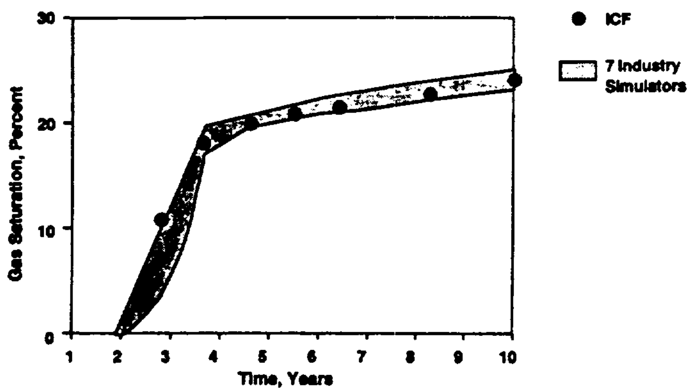


Fig. 21—Gas saturation vs. time for producing Well Cell 10,10,3.

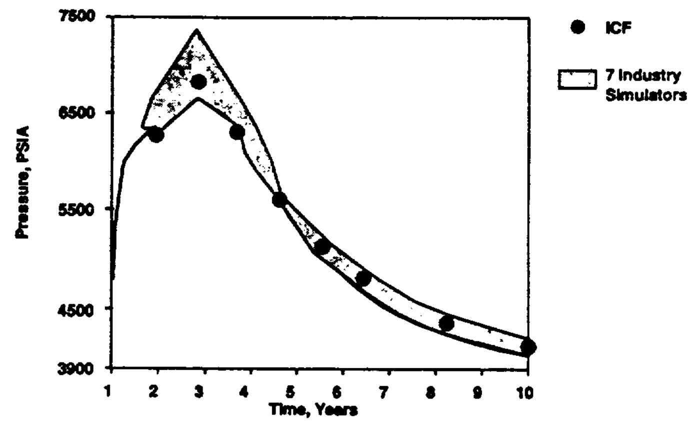


Fig. 22—Pressure vs. time for injection Well Cell 1,1,1.

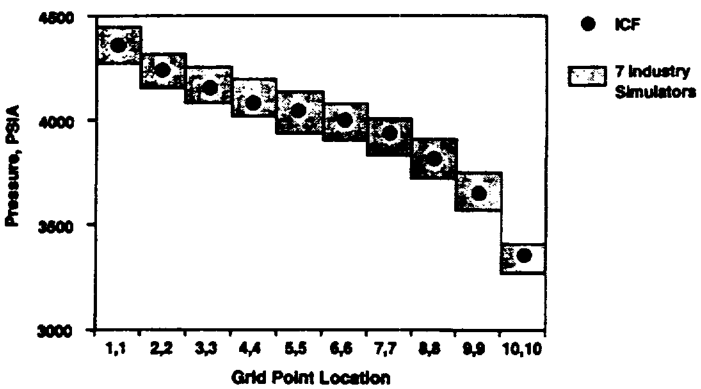


Fig. 23—Pressure vs. grid-point location, time = 8 years, top layer.

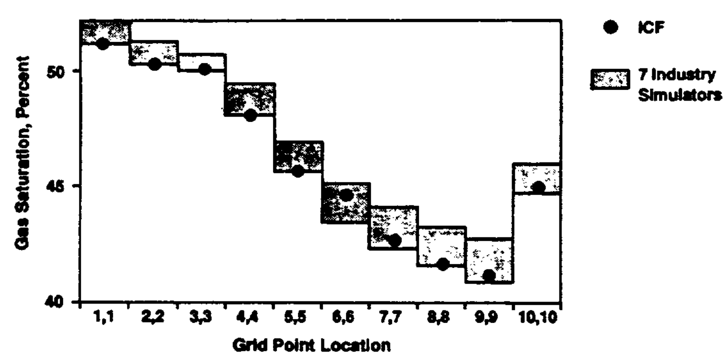


Fig. 24—Gas saturation vs. grid-point location, time = 8 years, top layer.

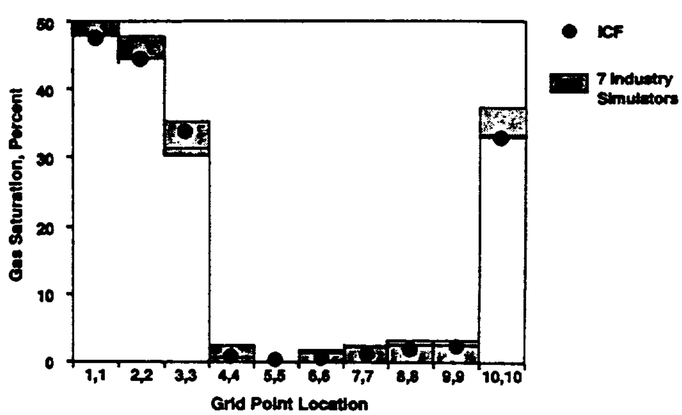


Fig. 25—Gas saturation vs. grid-point location, time = 8 years, middle layer.

EXHIBIT 15

## GRI WESTERN CRETACEOUS COAL SEAM PROJECT

### RANGE OF RESERVOIR PROPERTIES FOR THE MAJOR FORMATION EVALUATION EFFORTS

| Reservoir Property | WELL VALUE | | | |
|---|---|---|---|---|
| | Hamilton #3 | NEBU #403 | S. Ute 36-1 | Co. 32-7 #9 |
| Average Gas Content, scf/ton | 365.1 | 308.4 | 374.0 | 344.3 |
| Average Ash Free Gas Content, scf/ton | 538.0 | 500.3 | 537.3 | 513.8 |
| Average Sorption Time, hours | 9.8 | 6.4 | 22.6 | 10.1 |
| Langmuir Volume, scf/ton | 625 | 592 | NA | NA |
| Langmuir Pressure, psia | 325 | 302 | NA | NA |
| Coal Thickness, feet | 45.5 | 50.5 | 66.6 | 41.3 |
| Average Ash Content, % | 32.1 | 37.7 | 30.4 | 33.0 |
| Well Test Absolute Permeability, md | 2.4 | 1.5 | 48.7 | 3.2 |
| Core Absolute Permeability, md | 3.1 | 1.3 | NA | NA |
| Initial Reservoir Pressure, psia | 1,559 | 1,635 | 1,366 | 1,620 |
| Pressure Datum, feet | 2,748 | 2,980 | 2,345 | 2,830 |
| Initial Hydrostatic Gradient, psi/ft | 0.57 | 0.55 | 0.58 | 0.57 |
| Porosity, % | NA | NA | NA | NA |
| Initial Water Saturation, % | <100 | <100 | 100 | 100 |
| Temperature, °F | 115 | 116 | 125 | 115 |
| Vitrinite Reflectance, % | 0.78 | 0.88 | NA | NA |
| Coal Rank | Hi Vol A | Hi Vol A | NA | NA |

NA = Not Available at the present time.

← averaged these for sensitivity analysis on area I (note wide disparity)

| SAN JUAN BASIN COALBED METHANE SPACING STUDY<br><br>CEDAR HILL FIELD AREA HISTORY MATCH<br>SUMMARY OF RESERVOIR PARAMETERS | | |
|---|---|---|
| **FIXED PARAMETERS** | **VALUE** | **SOURCE** |
| Coal Depth | Plate 4 | Density logs |
| Net Pay | Plates 5 and 6 | Density logs |
| Initial Pressure | 1,562 psi @ +3,259' msl | Measured[5] |
| Langmuir Volume | 623 scf/ton | Measured[4] |
| Langmuir Pressure | 330.8 psia | Measured[4] |
| Desorption Pressure | $P_i$ | Estimated[1] |
| Initial Gas Content | 514 scf/ton | Calculated |
| Temperature | 114°F | Well logs |
| Pore Volume Compressibility | $200 \times 10^{-6}$ $psi^{-1}$ | Estimated |
| Initial Water Saturation | 100% | Estimated[1] |
| Cleat Spacing | 0.25 inches | Measured[4] |
| Sorption Time | 10 days | Estimated[13] |
| Gas Gravity | 0.6064 | Measured[12] |
| Water FVF | 1.006 RB/STB | Estimated[4] |
| Water Viscosity | 0.565 cp | Estimated[4] |
| | | |
| **HISTORY MATCH PARAMETERS** | | |
| Porosity | 0.05 - 0.80% | Exhibits 18 and 27 |
| Permeability | 0.5 - 10.0 md | Exhibits 18, 25-26 |
| Relative Permeability Curves | | Exhibit 24 |

| SAN JUAN BASIN COALBED METHANE SPACING STUDY<br><br>CEDAR HILL FIELD AREA HISTORY MATCH<br>SUMMARY OF WELL PRODUCTION CONTROLS | | | | |
|---|---|---|---|---|
| **Well Name** | **Simulation Time (Days)** | **Calendar Date** | **Perforated Layers** | **Well Control** |
| Cahn Gas Com 1 | 0 | 05/77 | 1 | FBHP |
| Cahn Gas Com 2 | 822 | 07/79 | 1 | Pressure Monitor |
| Schneider Gas Com B-1 | 822 | 07/79 | 1 | Pressure Monitor |
| Schneider Gas Com B-1S | 1645 | 10/81 | 1 | Water Rate |
| State Gas Com BW-1 | 1645 | 10/81 | 1 and 2 | Water Rate |
| Leeper Gas Com B-1 | 2283 | 07/83 | 1 | Pressure Monitor |
| Keys Gas Com G-1 | 2283 | 07/83 | 1 | Water Rate |
| State Gas Com BX-1 | 2375 | 10/83 | 1 | Water Rate |
| Ealum Gas Com C-1 | 2680 | 08/84 | 1 and 2 | Water Rate |
| Wood Gas Com A-1 | 2680 | 08/84 | 1 and 2 | FBHP |
| | | | | |
| End of Simulation | 3167 | 12/85 | | |

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

## CEDAR HILL FIELD AREA HISTORY MATCH
## SUMMARY OF POROSITY AND PERMEABILITY FOR THE MODEL AREA

| Well Name | Model Layer | Porosity (%) | Permeability (md) | | |
|---|---|---|---|---|---|
| | | | $\bar{k}$ | $k_x$ | $k_y$ |
| Cahn Gas Com 1 | 1 | 0.25 | 6.9 | 4.0 | 12.0 |
| Cahn Gas Com 2 | 1 | 0.25 | 10.0 | 5.0 | 20.0 |
| Schneider Gas Com B-1 | 1 | 0.75 | 6.9 | 4.0 | 12.0 |
| Schneider Gas Com B-1S | 1 | 0.75 | 6.9 | 4.0 | 12.0 |
| State Gas Com BW-1 | 1 | 0.25 | 4.9 | 3.0 | 8.0 |
| | 2 | 0.05 | 10.0 | 5.0 | 20.0 |
| Leeper Gas Com B-1 | 1 | 0.80 | 4.9 | 3.0 | 8.0 |
| Keys Gas Com G-1 | 1 | 0.80 | 4.9 | 3.0 | 8.0 |
| State Gas Com BX-1 | 1 | 0.05 | 4.9 | 3.0 | 8.0 |
| Ealum Gas Com C-1 | 1 | 0.25 | 2.0 | 1.0 | 4.0 |
| | 2 | 0.05 | 10.0 | 5.0 | 20.0 |
| Wood Gas Com A-1 | 1 | 0.25 | 0.5 | 0.5 | 0.5 |
| | 2 | 0.05 | 1.0 | 1.0 | 1.0 |

**SAN JUAN BASIN COALBED METHANE SPACING STUDY**

**CEDAR HILL FIELD AREA HISTORY MATCH**
**SIMULATED AND OBSERVED CUMULATIVE VOLUMES**
**FOR THE PERIOD OF MAY 1977 TO DECEMBER 1985**

| Well Name | Cumulative Gas Production (Bcf) | | Cumulative Water Production (MBbls) | |
|---|---|---|---|---|
| | Simulated | Observed | Simulated | Observed |
| Cahn Gas Com 1 | 2.33 | 2.15* | 240.56 | 160.65** |
| Schneider Gas Com B-1S | 0.69 | 0.76 | 87.09 | 76.58 |
| State Gas Com BW-1 | 1.35 | 1.11 | 40.34 | 36.25 |
| Keys Gas Com G-1 | 0.18 | 0.19 | 33.77 | 32.39 |
| State Gas Com BX-1 | 0.45 | 0.62 | 4.53 | 4.09 |
| Ealum Gas Com C-1 | 0.36 | 0.36 | 11.57 | 10.75 |
| Wood Gas Com A-1 | 0.04 | 0.04 | 0.89 | 0.02 |
| TOTAL MODEL AREA | 5.39 | 5.23 | 418.75 | 320.73 |
| RECOVERY (%) | 5.73 | 5.56 | 14.89 | 11.41 |

* For Cahn only, 2.32 BCF was simulated vs. 2.15 BCF observed between October 1978 - December 1985

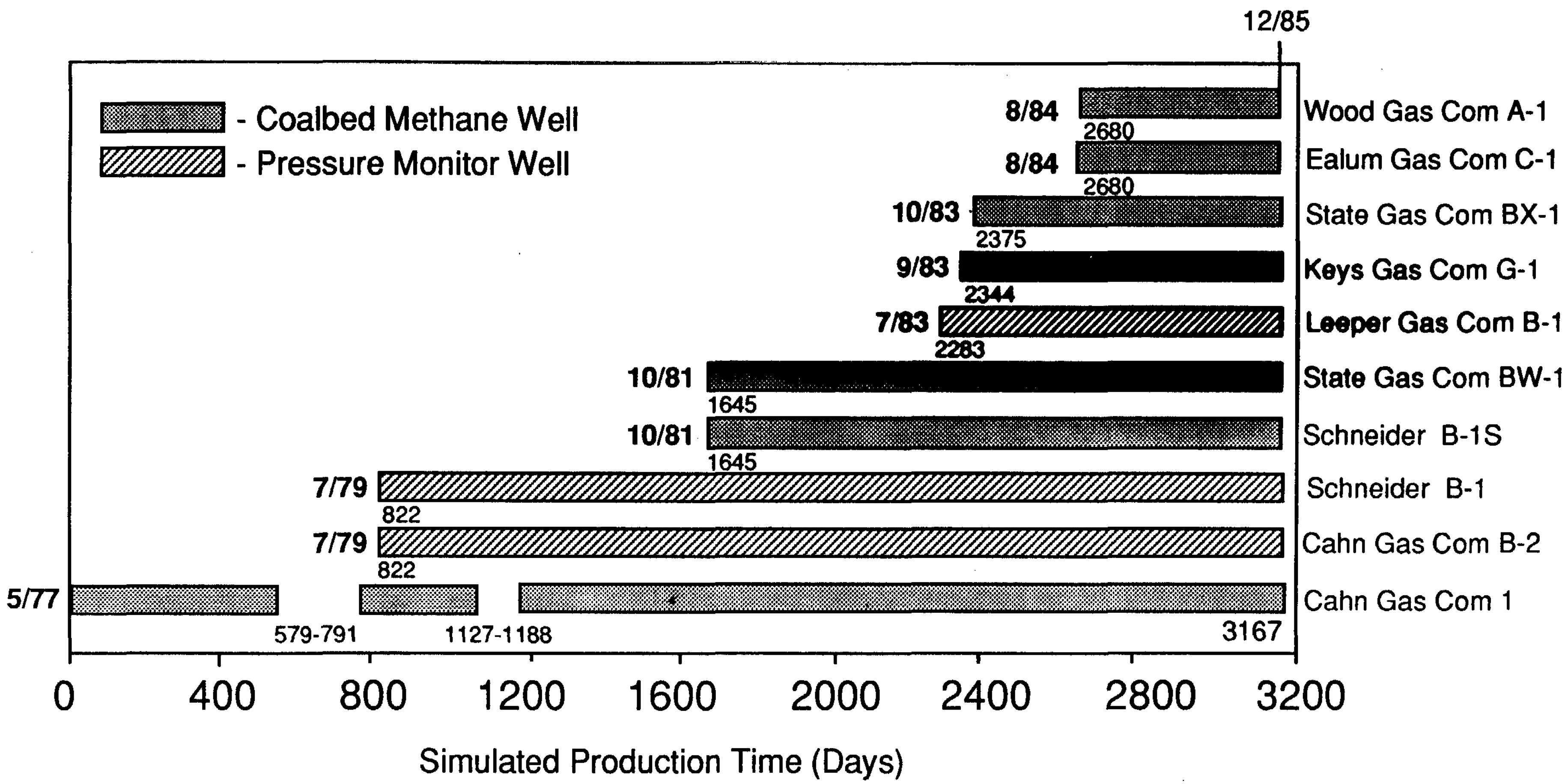
** For Cahn only, 175.13 MBBLS were simulated vs. 160.65 MBBLS observed between August 1980 - December 1985.

| SAN JUAN COALBED METHANE SPACING STUDY<br><br>SUMMARY OF SIMULATED INTERFERENCE EFFECTS IN THE CEDAR HILL FIELD MODEL AREA<br>CUMULATIVE GAS PRODUCTION (BCF) FOR THE PERIOD OF MAY 1977 TO DECEMBER 1985 | | | | | | |
|---|---|---|---|---|---|---|
| WELL NAME | CASE I | CASE II | SUM I + II | CASE III | SUM I + III | HISTORY MATCH |
| Cahn Gas Com 1 | 2.18 | - | 2.18 | - | 2.18 | 2.33 |
| Schneider Gas Com B-1S | - | 0.17 | 0.17 | 0.57 | 0.57 | 0.69 |
| State Gas Com BW-1 | - | 0.39 | 0.39 | 1.22 | 1.22 | 1.35 |
| Keys Gas Com G-1 | - | 0.03 | 0.03 | 0.05 | 0.05 | 0.18 |
| State Gas Com BX-1 | - | 0.10 | 0.10 | 0.17 | 0.17 | 0.45 |
| Ealum Gas Com C-1 | - | 0.21 | 0.21 | 0.27 | 0.27 | 0.36 |
| Wood Gas Com A-1 | - | 0.02 | 0.02 | 0.03 | 0.03 | 0.04 |
| TOTAL MODEL AREA | 2.18 | 0.93 | 3.11 | 2.31 | 4.49 | 5.39 |

CASE I = Cahn 1 is only producing well.
CASE II = All wells are producing except Cahn 1; Schneider and State BW are on rate control.
CASE III = All wells are producing except Cahn 1; Schneider and State BW are on BHP control.

EXHIBIT 21

# San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match
## Well Production Schedule



# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Field Area History Match
# Simulation Grid

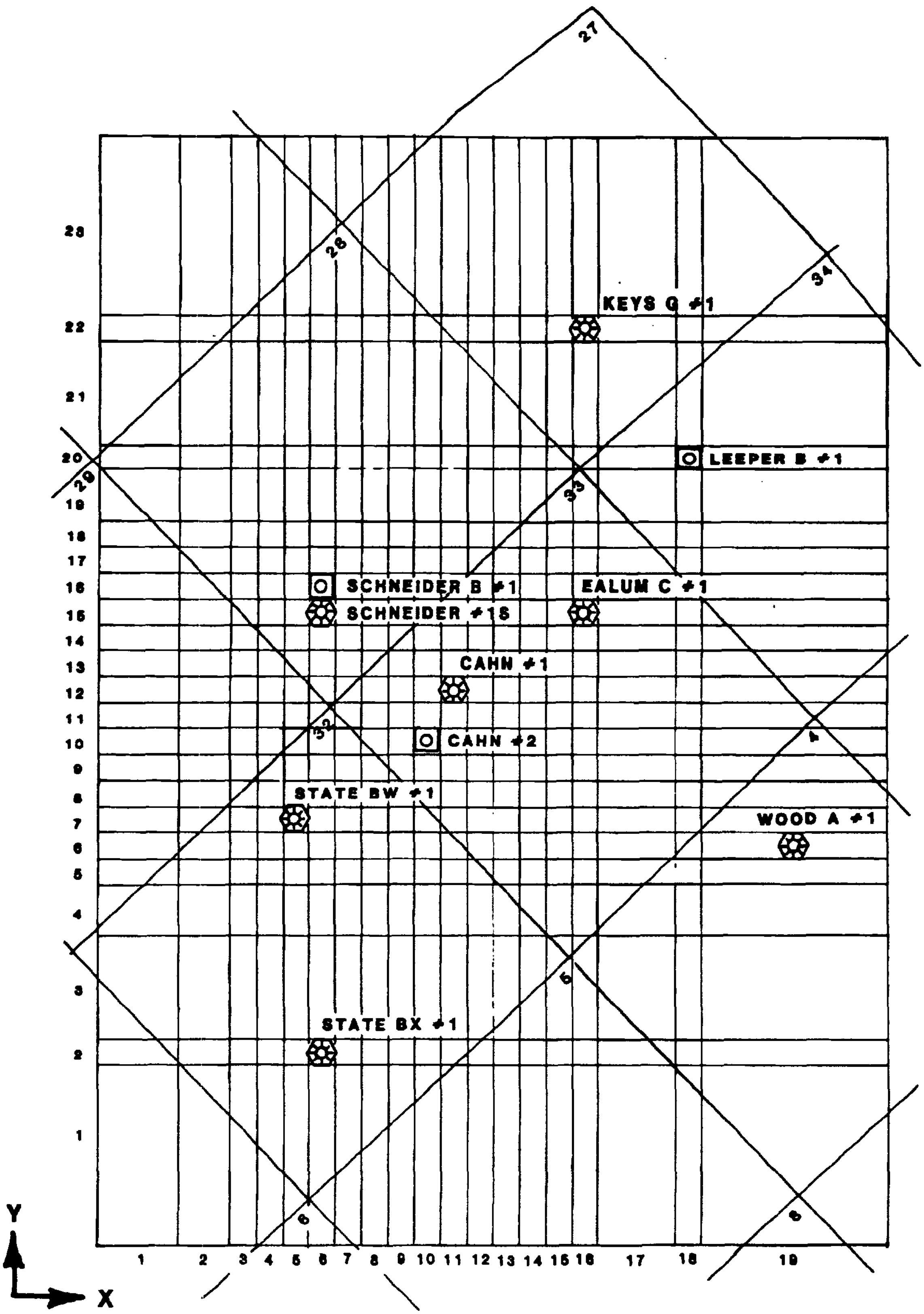


EXHIBIT 23

## San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match
## Sorption Isotherm

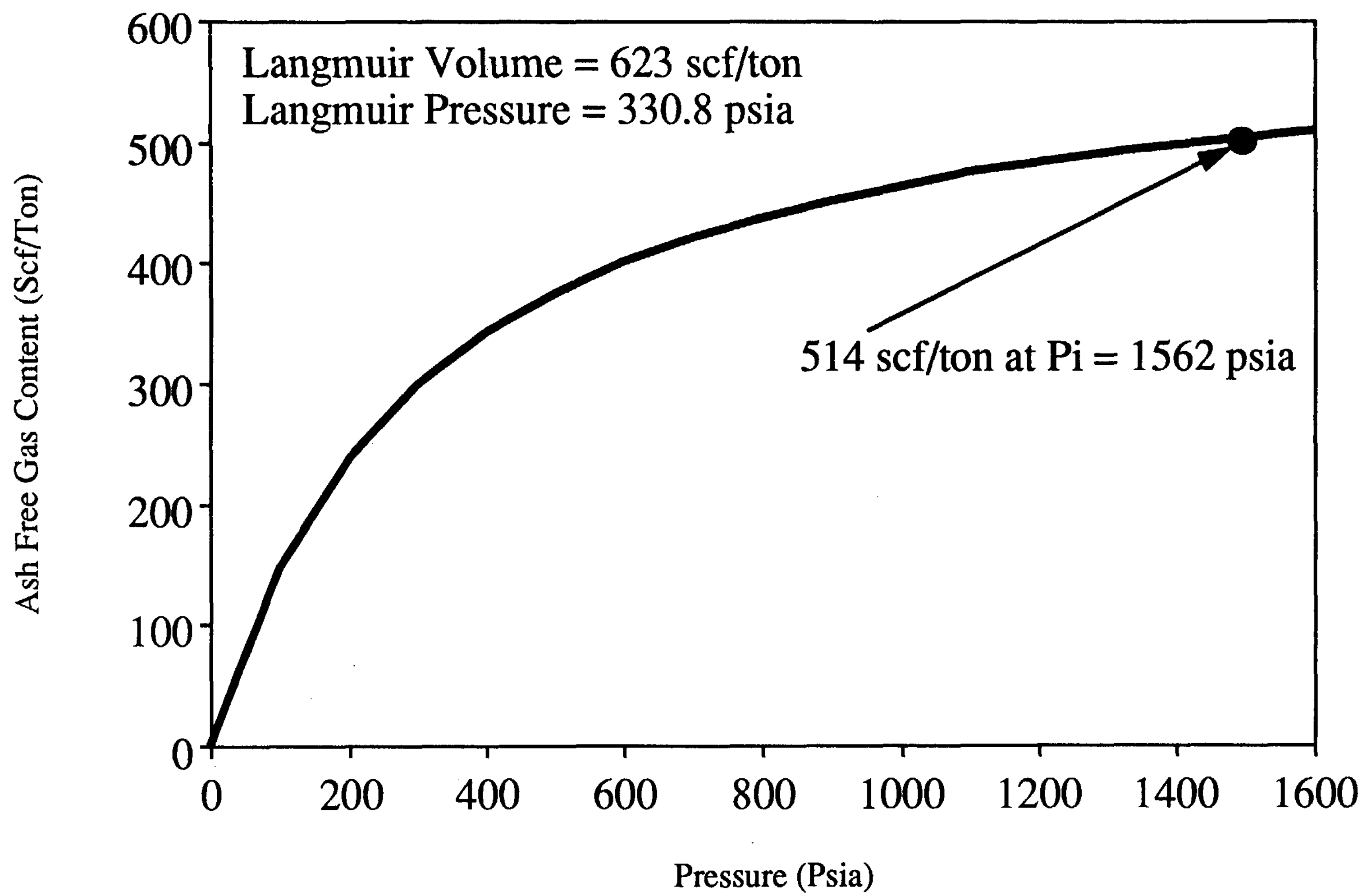
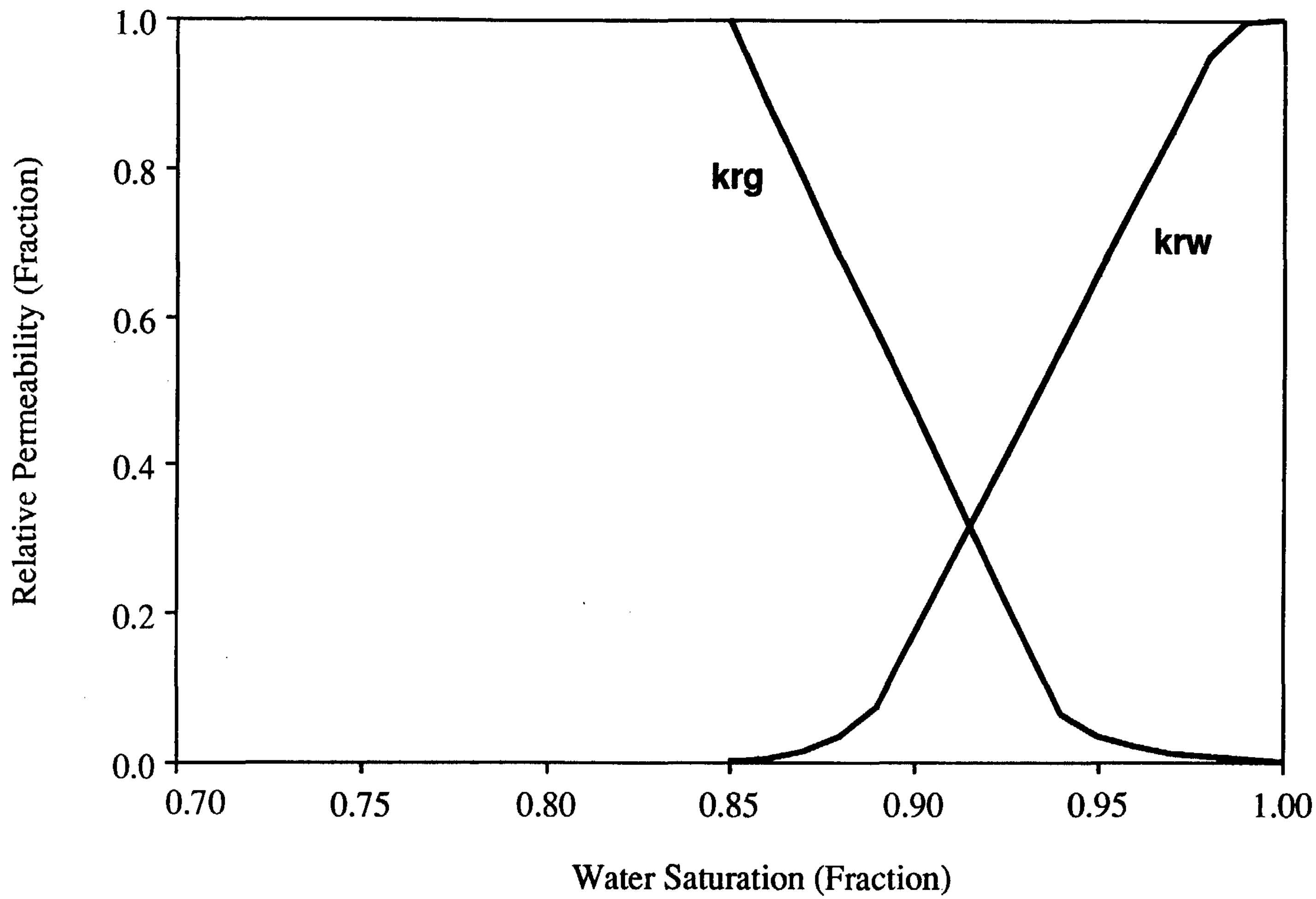


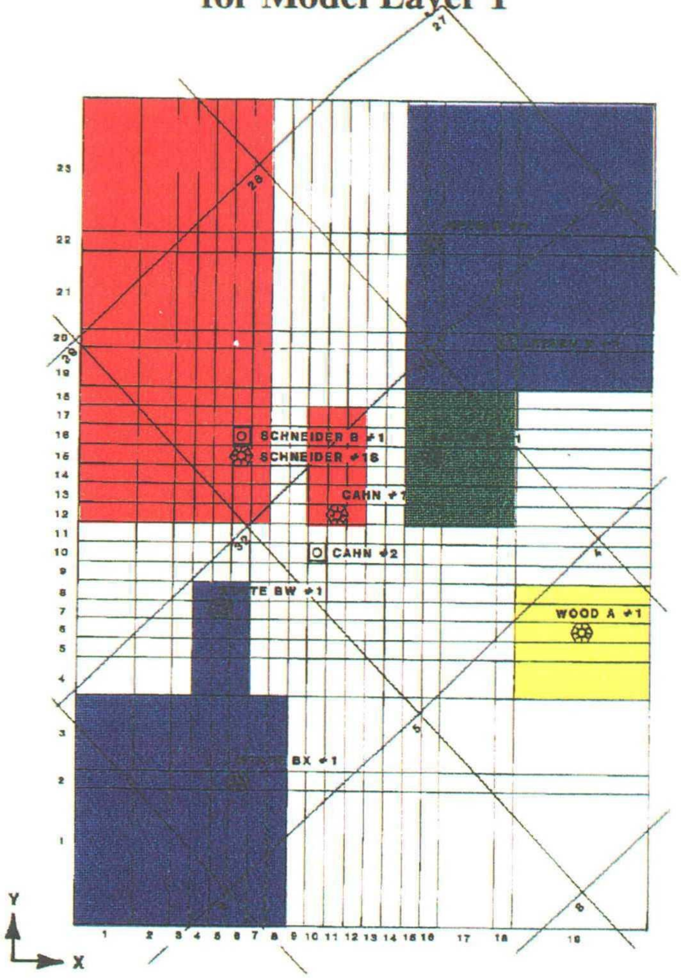
EXHIBIT 24

**San Juan Basin Coalbed Methane Spacing Study**
**Cedar Hill Field Area History Match**
**Relative Permeability Curves**



# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Area History Match

## Distribution in Anisotropic Face and Butt Permeabilities for Model Layer 1




Permeability Legend

$\bar{k}$=10 md ($k_x$ = 5, $k_y$ = 20)

$\bar{k}$=5 md ($k_x$ = 3, $k_y$ = 8)

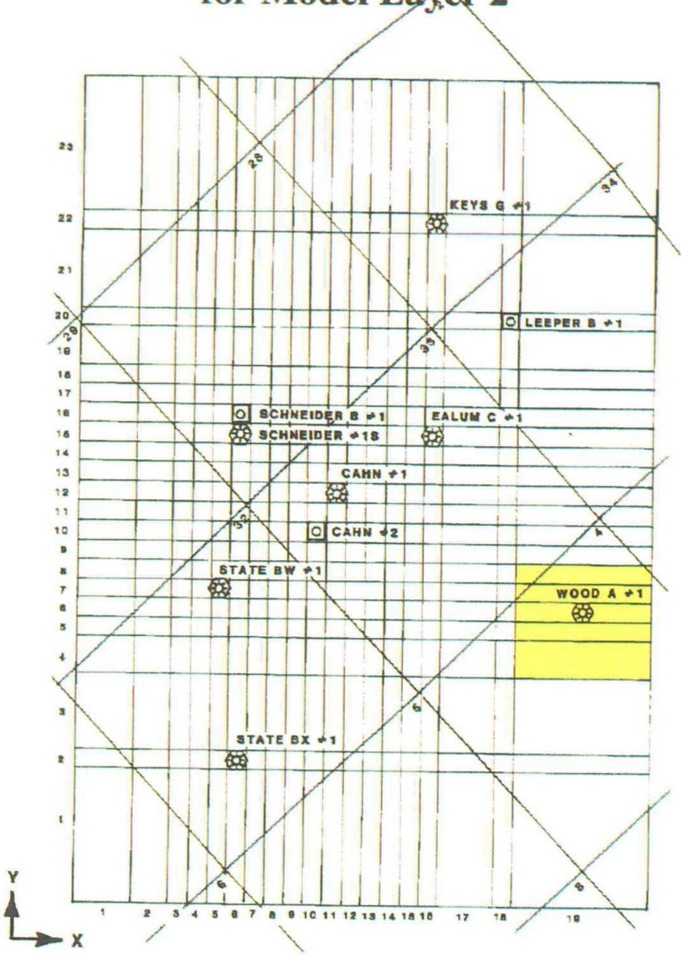
$\bar{k}$=7 md ($k_x$ = 4, $k_y$ =12)

$\bar{k}$=2 md ($k_x$ = 1, $k_y$ = 4)

$\bar{k}$=0.5 md ($k_x$ = 0.5, $k_y$ = 0.5)

# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Area History Match

## Distribution in Anisotropic Face and Butt Permeabilities for Model Layer 2



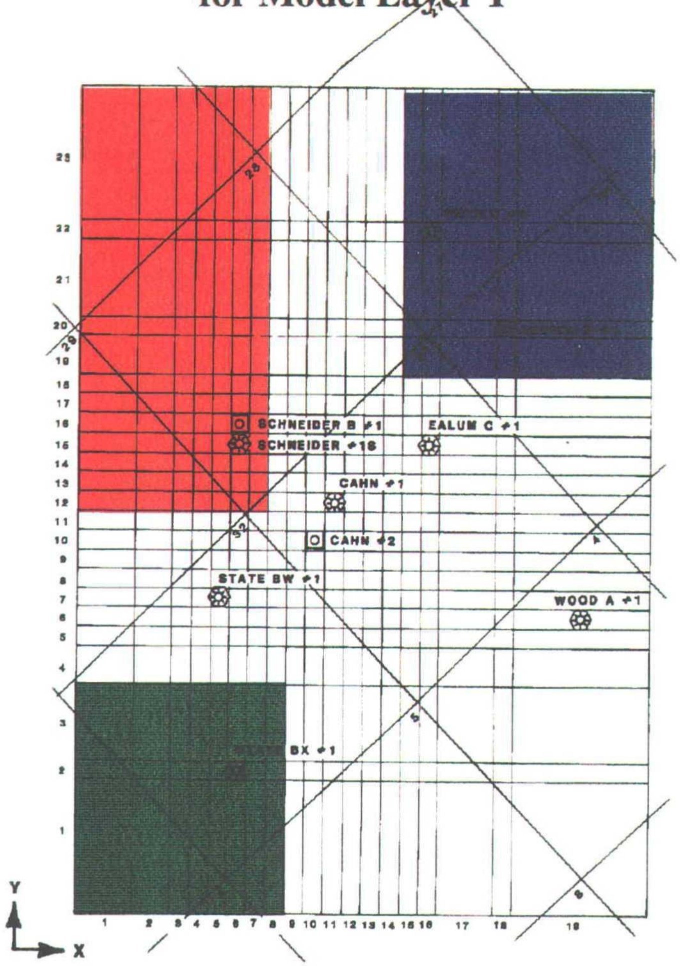

Permeability Legend

$\bar{k}$=10 md ($k_x$=5, $k_y$=20)

$\bar{k}$=1 md ($k_x$=1, $k_y$=1)

# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Area History Match

## Distribution in Cleat Porosities for Model Layer 1




Porosity Legend

| | |
|---|---|
| 0.25% | 0.8% |
| 0.75% | 0.05% |

EXHIBIT 28

# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Field Area History Match

## Water Production Rate vs Time for Cahn Gas Com 1

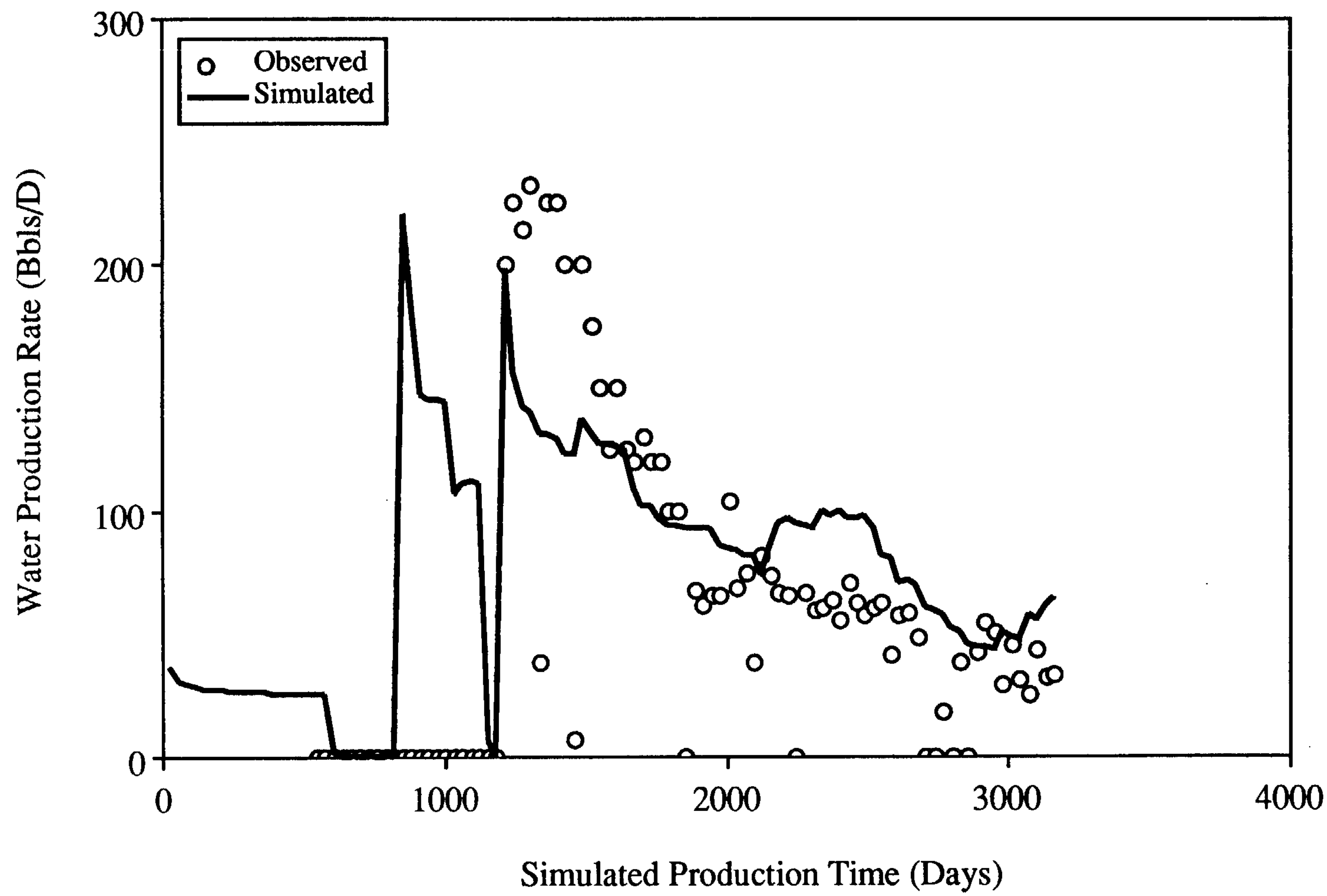


EXHIBIT 29

## San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match

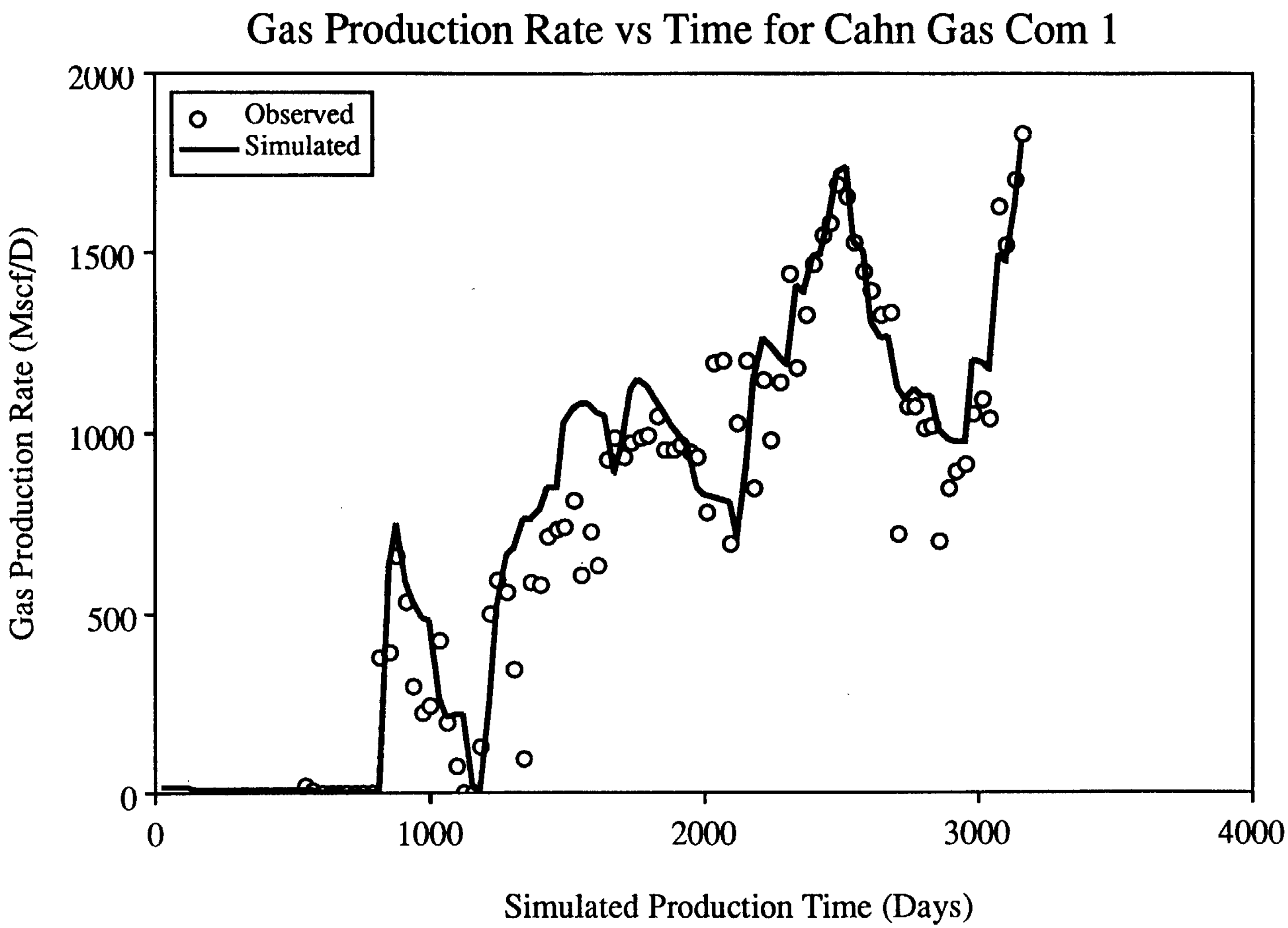


EXHIBIT 30

# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Field Area History Match

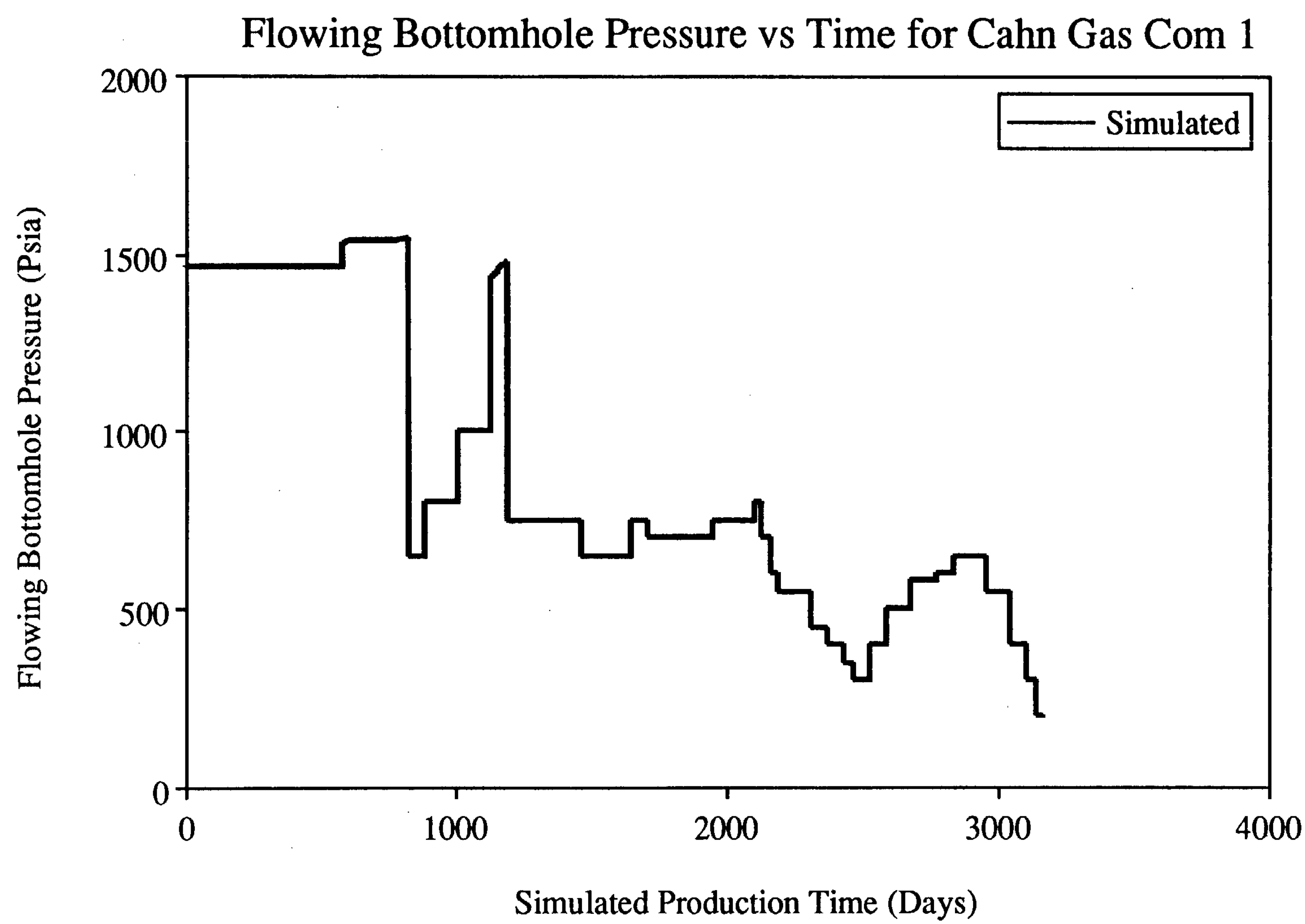


EXHIBIT 31

## San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match

Water Production Rate vs Time for Schneider Gas Com B-1S

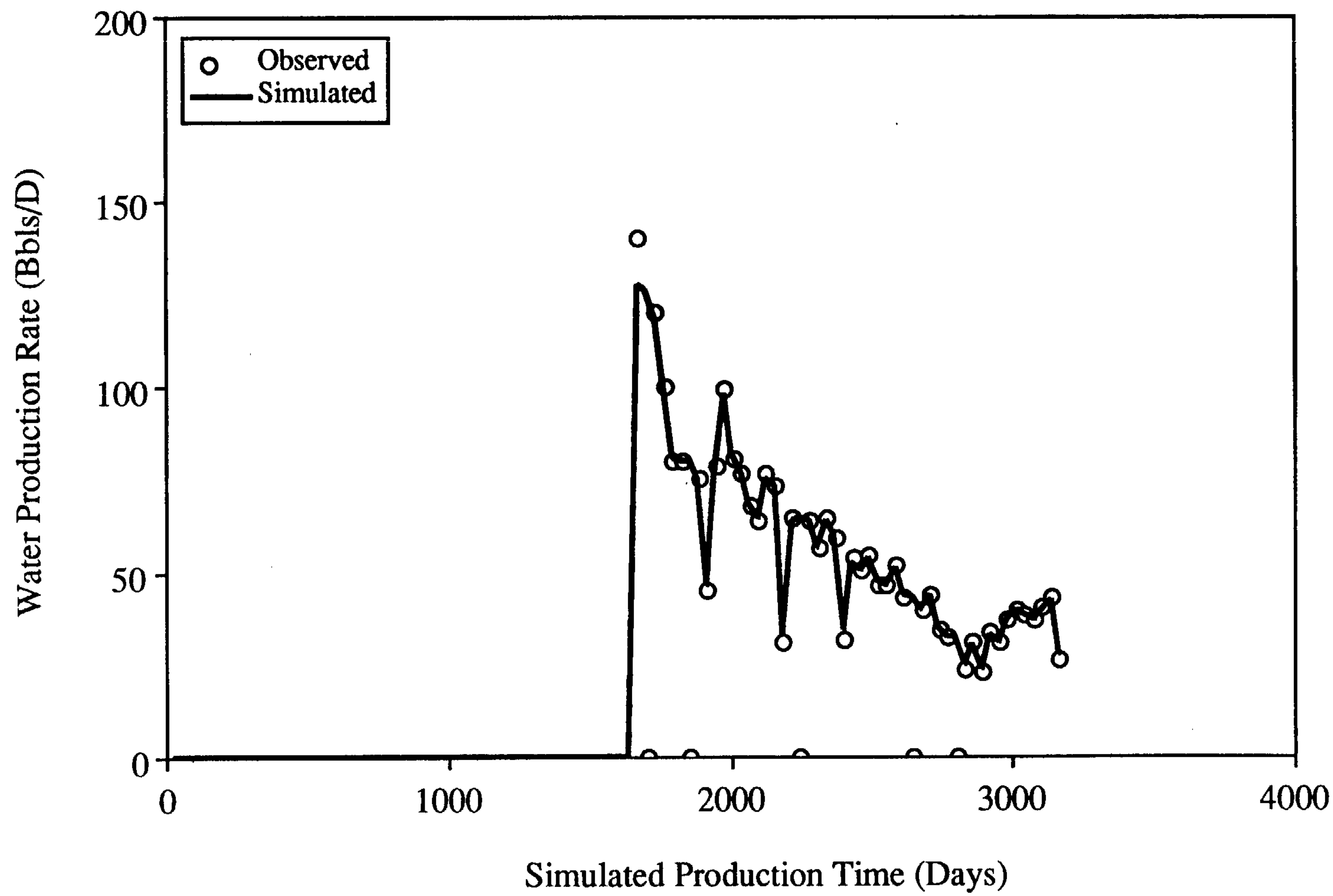


EXHIBIT 32

# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Field Area History Match

Gas Production Rate vs Time for Schneider Gas Com B-1S

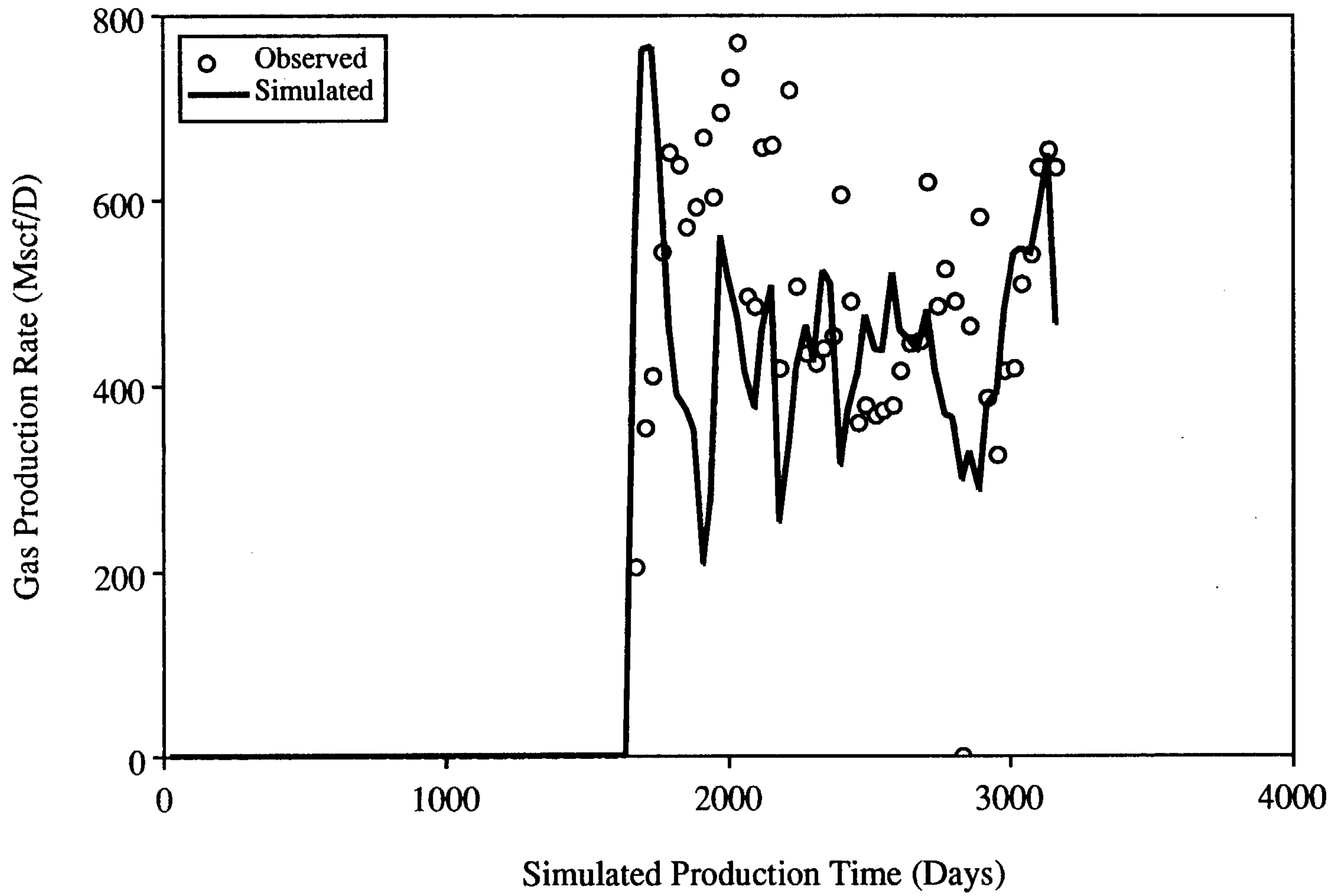


EXHIBIT 33

**San Juan Basin Coalbed Methane Spacing Study**
**Cedar Hill Field Area History Match**

Flowing Bottomhole Pressure vs Time for Schneider Gas Com B-1S

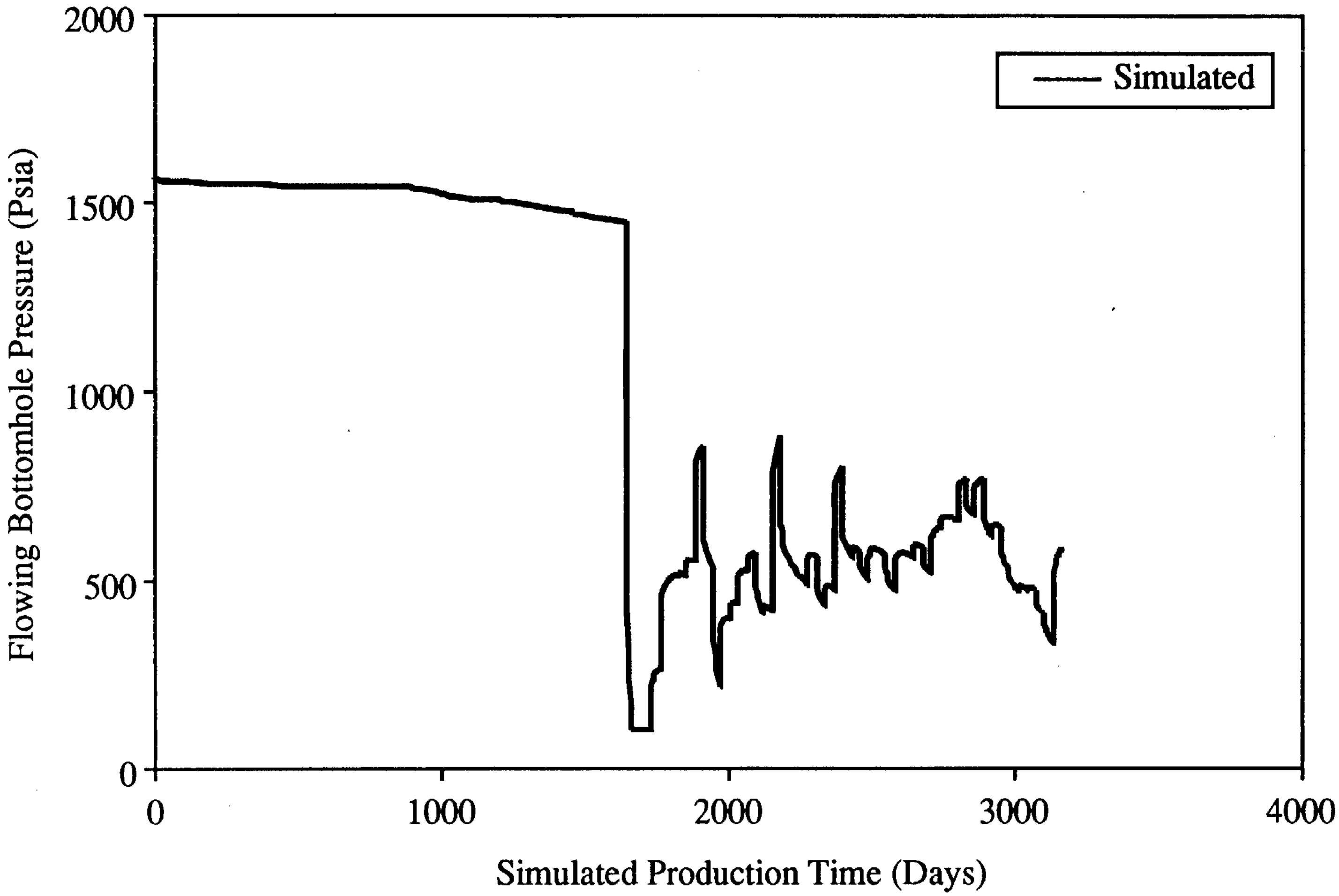


EXHIBIT 34

# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Field Area History Match

Water Production Rate vs Time for State Gas Com BW-1

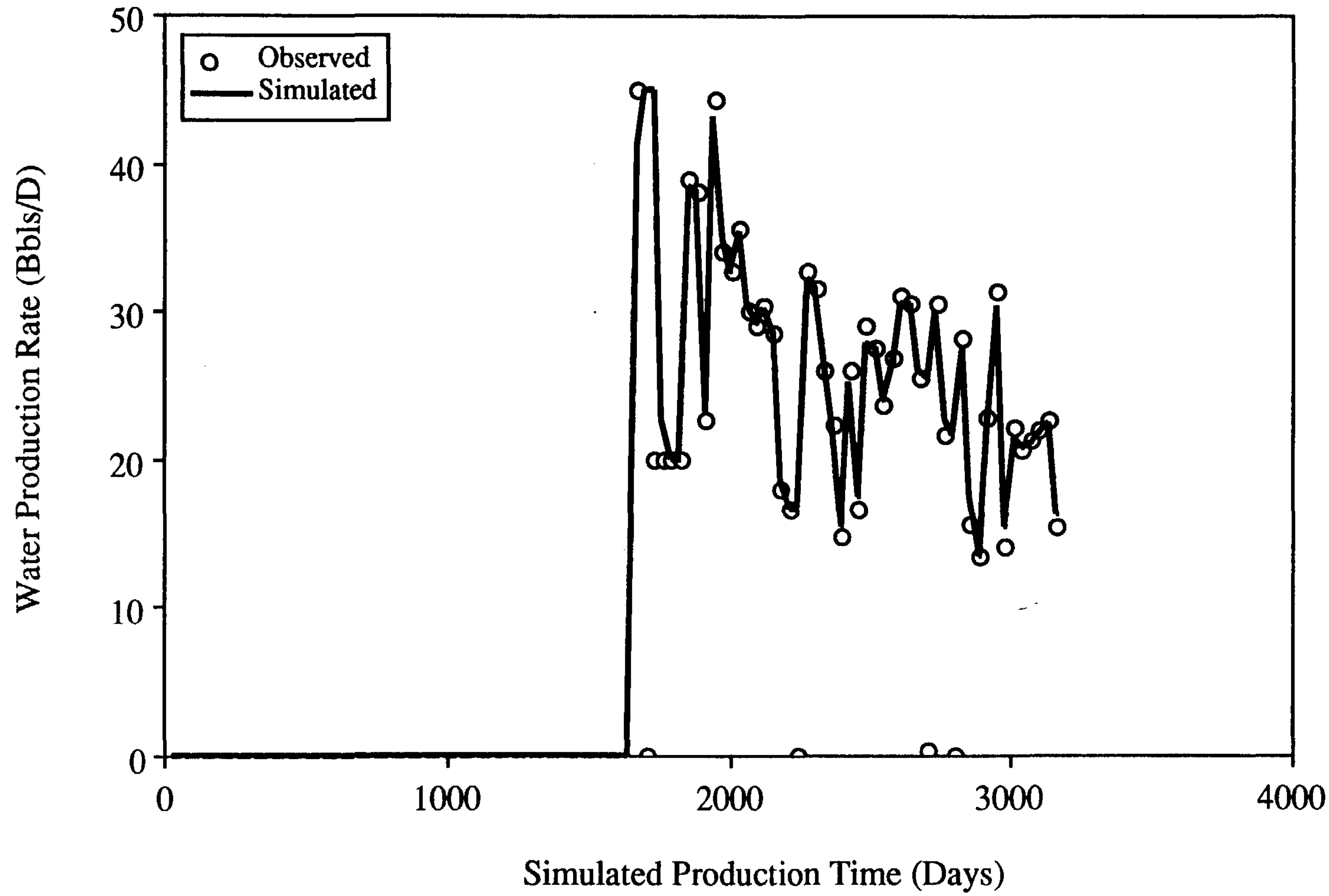


EXHIBIT 35

# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Field Area History Match

## Gas Production Rate vs Time for State Gas Com BW-1

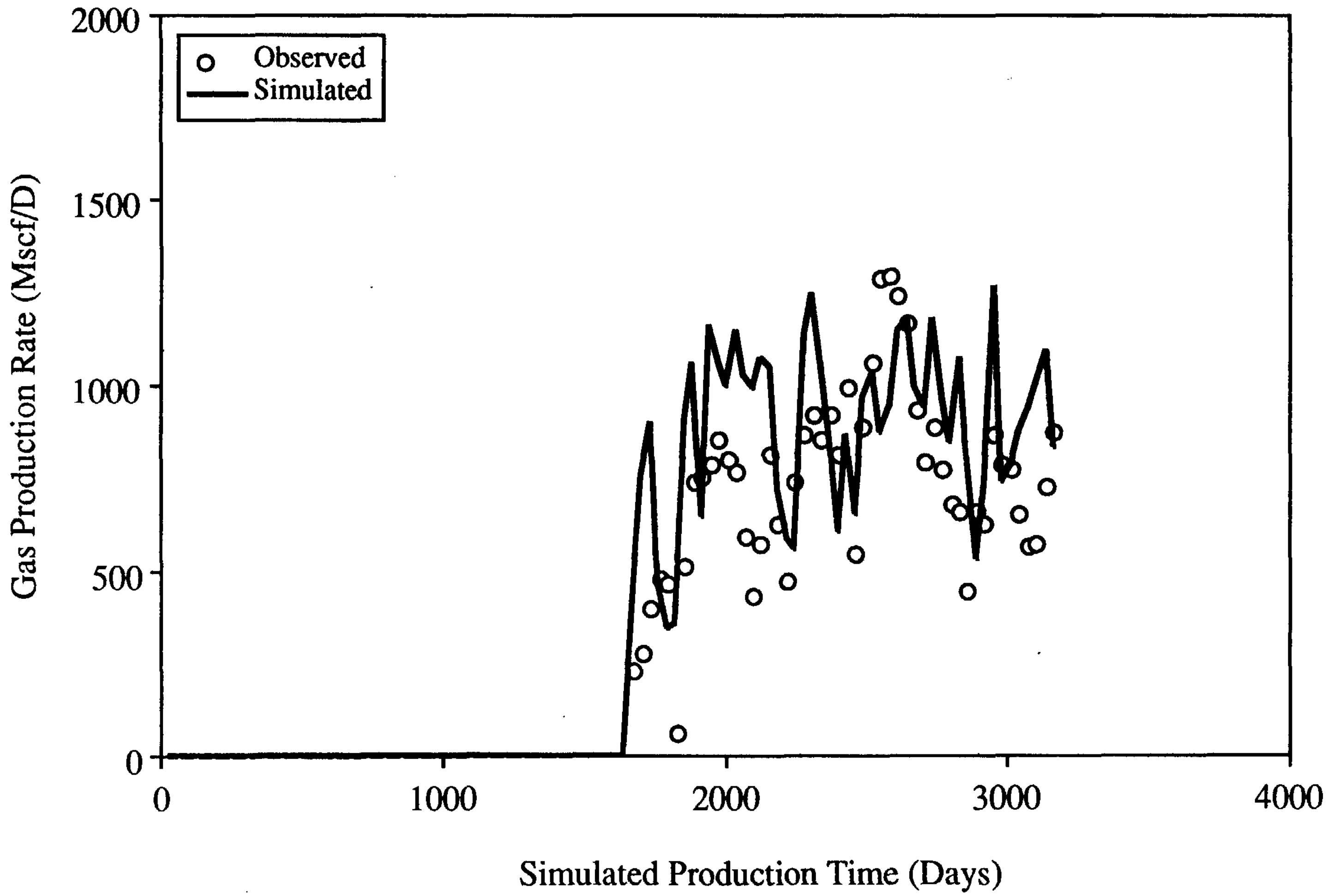


EXHIBIT 36

## San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match

Flowing Bottomhole Pressure vs Time for State Gas Com BW-1

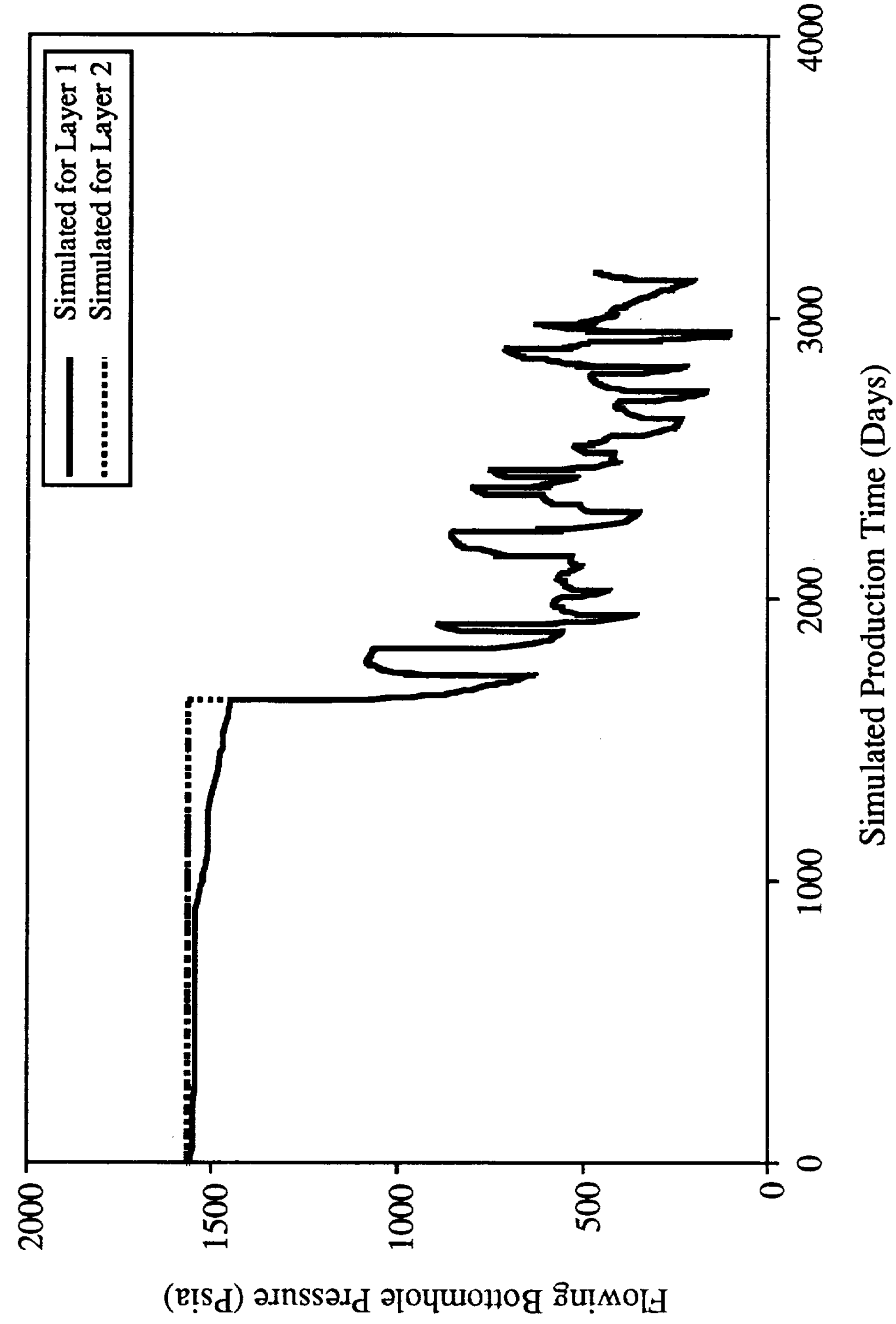


EXHIBIT 37

## San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match

Reservoir Pressure vs Time for Cahn Gas Com 2 Pressure Monitor Well

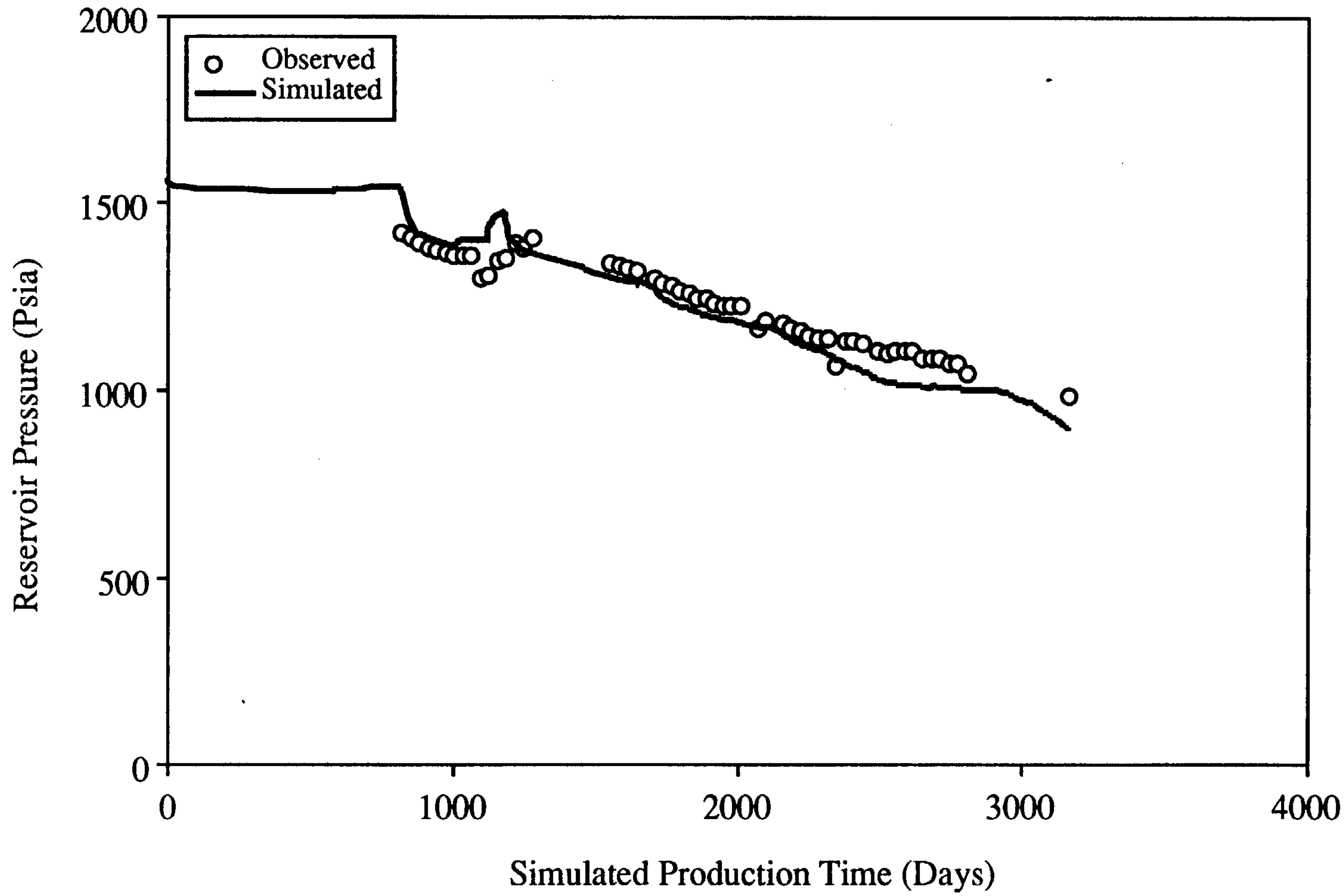


EXHIBIT 38

# San Juan Basin Coalbed Methane Spacing Study
# Cedar Hill Field Area History Match

## Reservoir Pressure vs Time for Schneider Gas Com B-1 Pressure Monitor Well

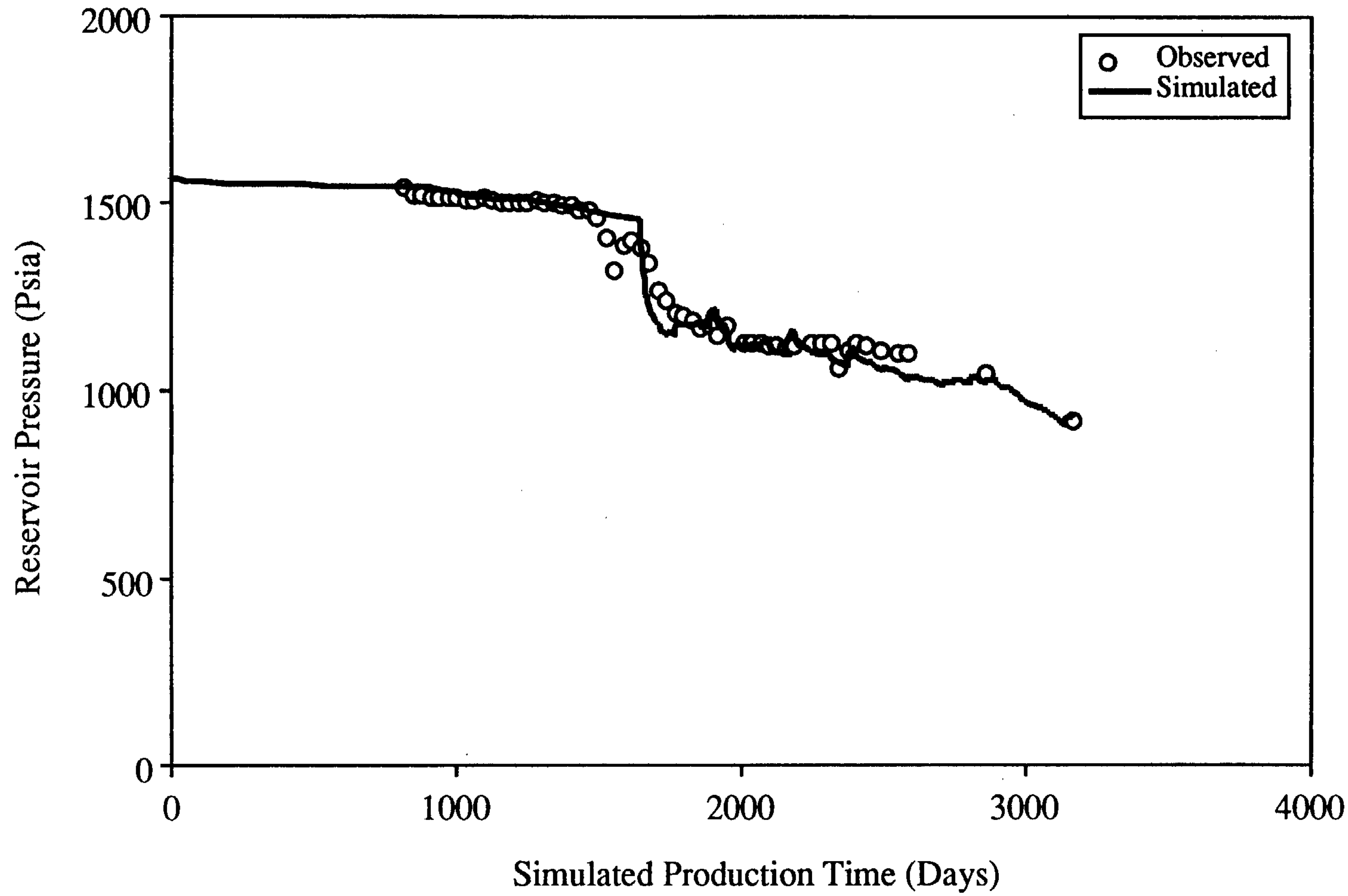


EXHIBIT 39

# San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match

Reservoir Pressure vs Time for Leeper Gas Com B-1 Pressure Monitor Well

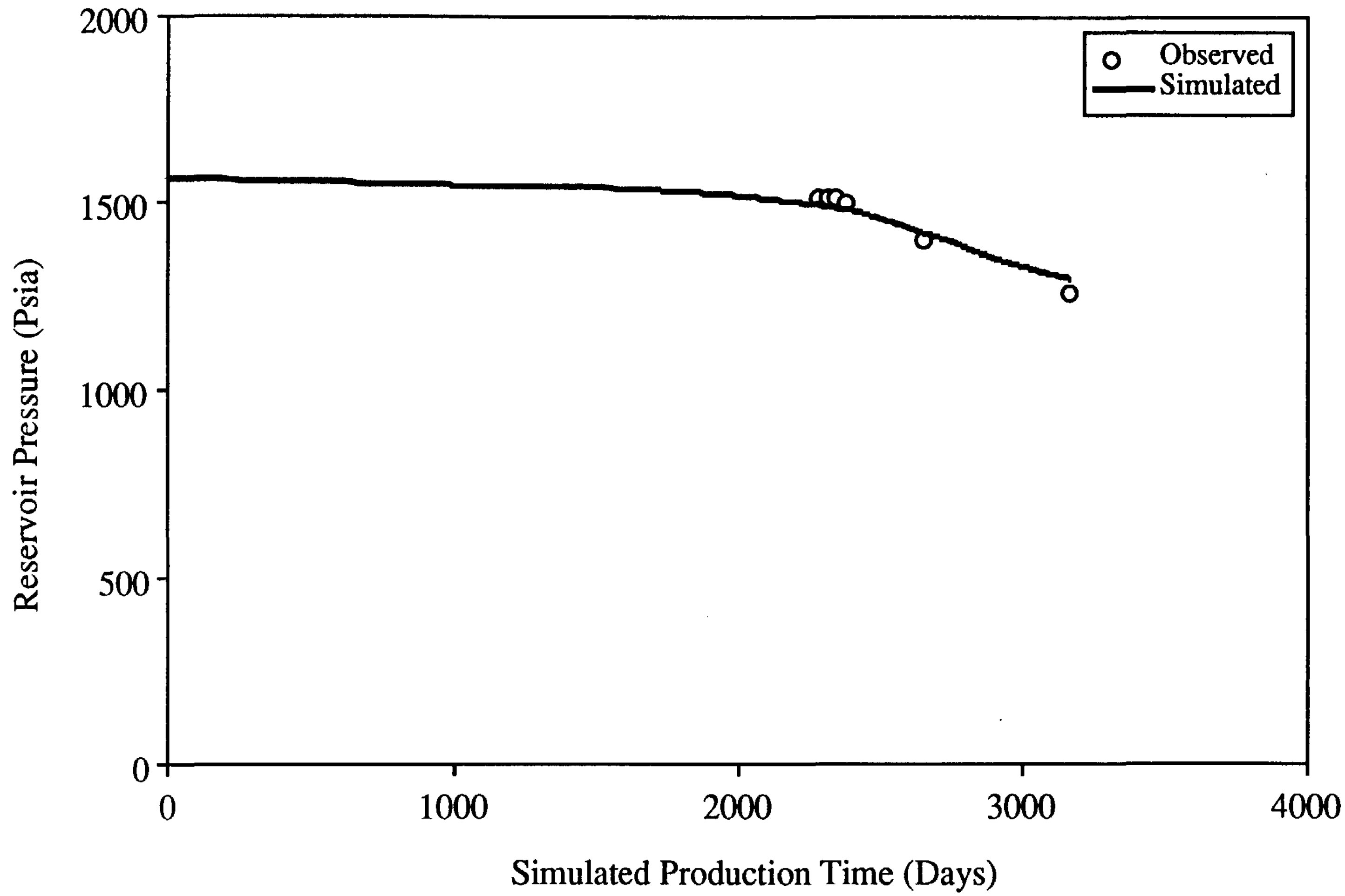
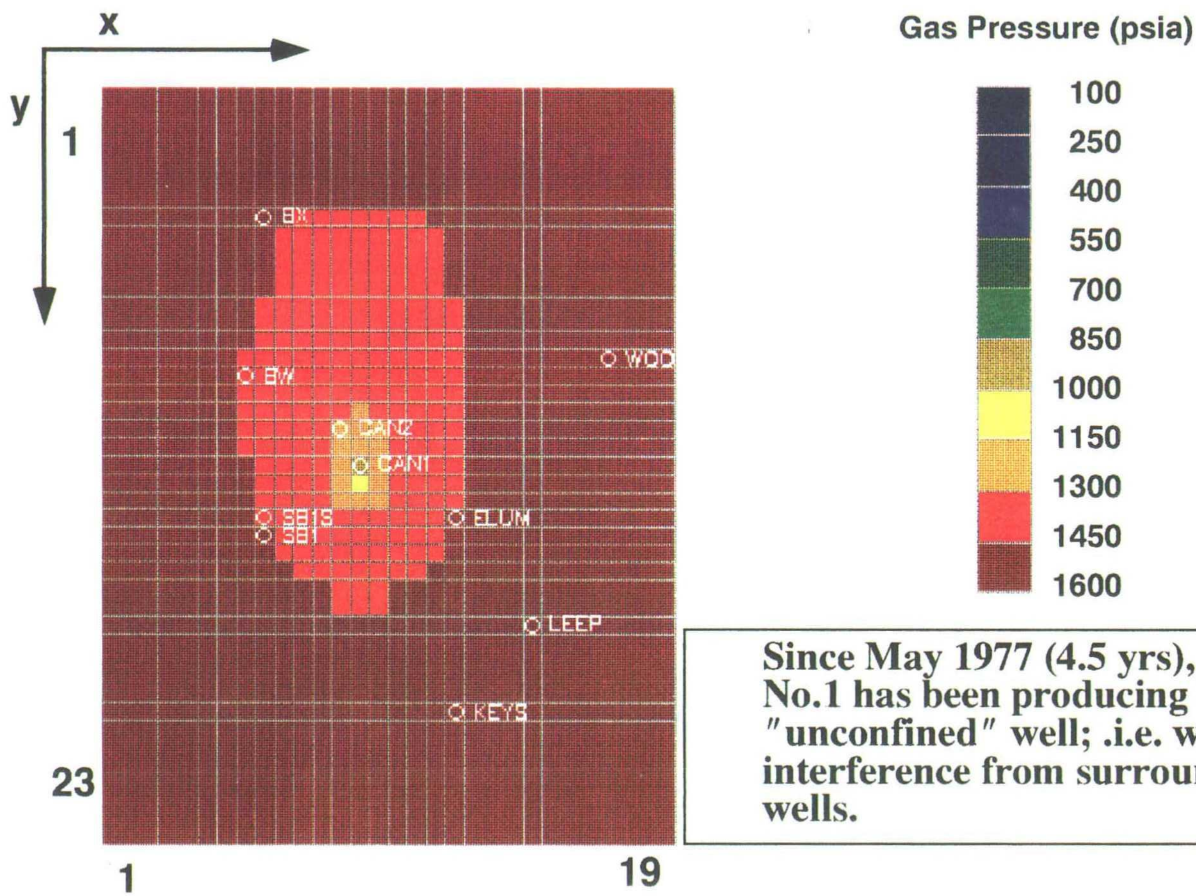


EXHIBIT 40

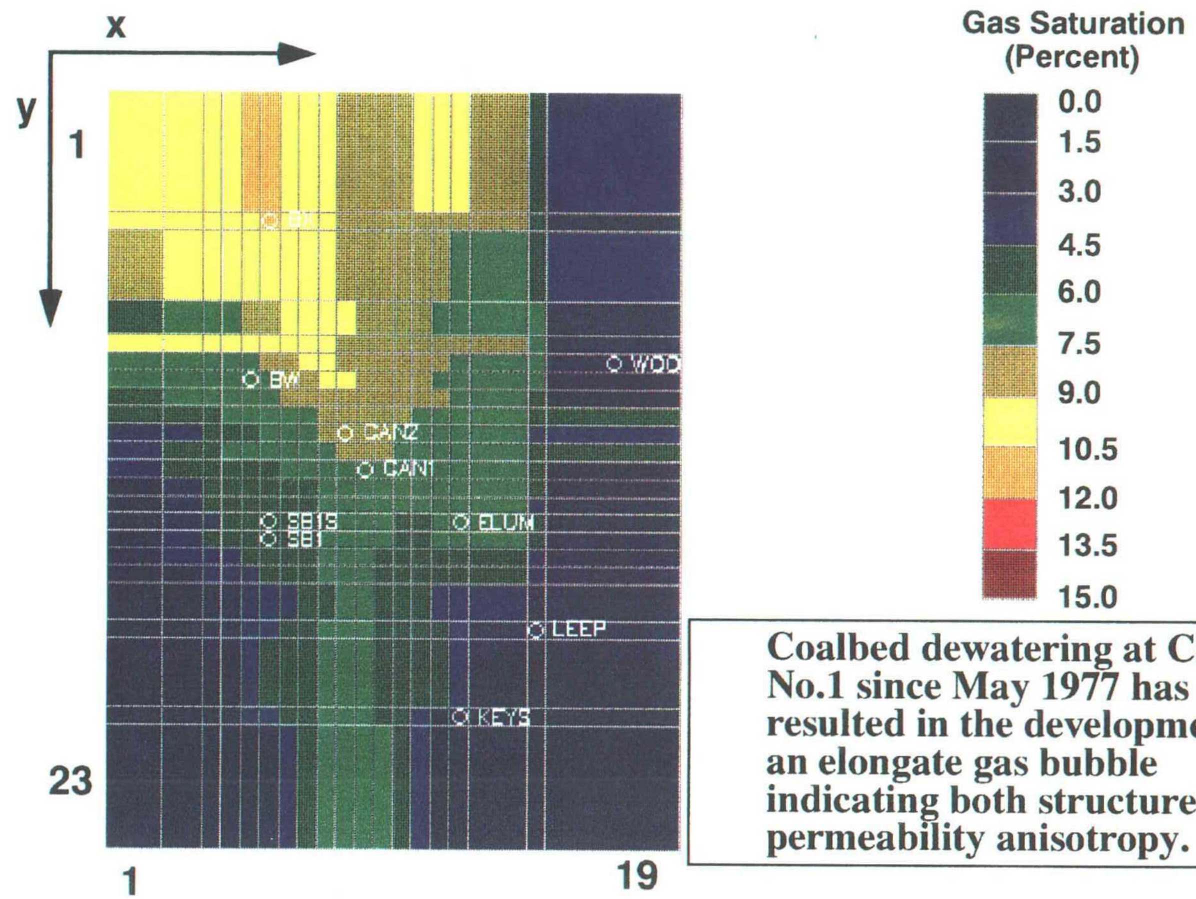
## Cedar Hill Field History Match
## Simulated Gas Pressure for the Upper Basal Fruitland Coal Seam

October 1981 (1645 Simulation Days)



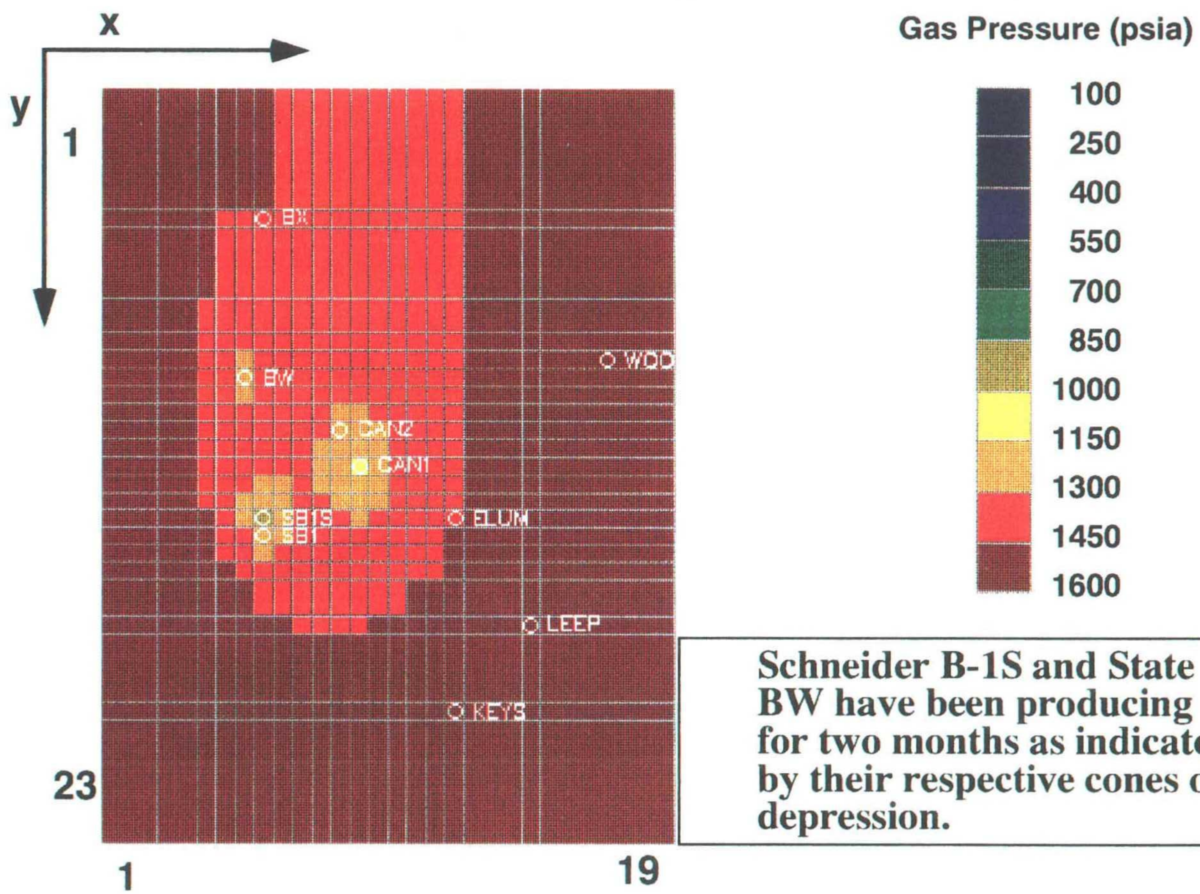

**Since May 1977 (4.5 yrs), Cahn No.1 has been producing as an "unconfined" well; .i.e. without interference from surrounding wells.**

## Cedar Hill Field History Match
## Simulated Gas Saturation for the Upper Basal Fruitland Coal Seam
### October 1981 (1645 Simulation Days)




**Coalbed dewatering at Cahn No.1 since May 1977 has resulted in the development of an elongate gas bubble indicating both structure and permeability anisotropy.**

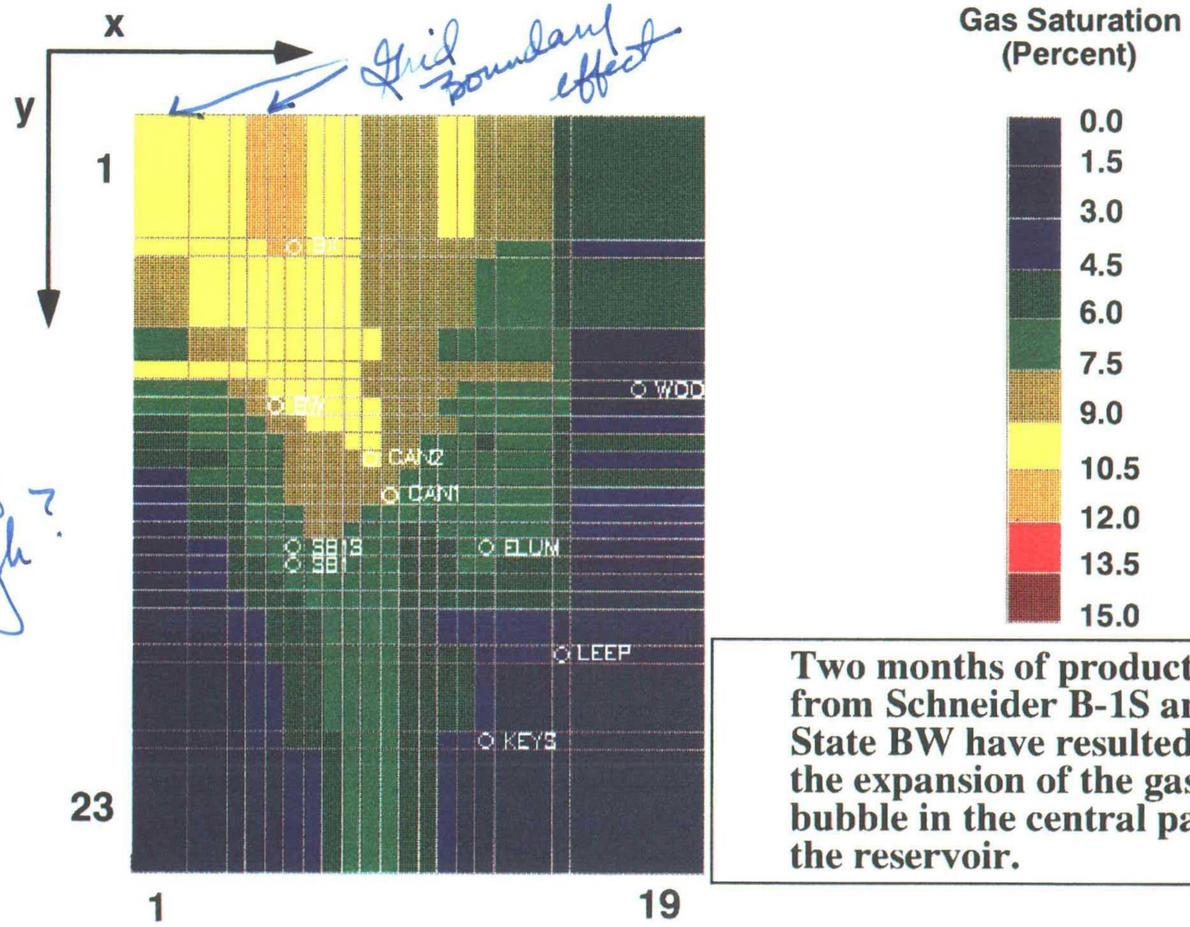
## Cedar Hill Field History Match
## Simulated Gas Pressure for the Upper Basal Fruitland Coal Seam
### December 1981 (1706 Simulation Days)




**Schneider B-1S and State BW have been producing for two months as indicated by their respective cones of depression.**

# Cedar Hill Field History Match
## Simulated Gas Saturation for the Upper Basal Fruitland Coal Seam
December 1981 (1706 Simulation Days)

Grid boundary effect

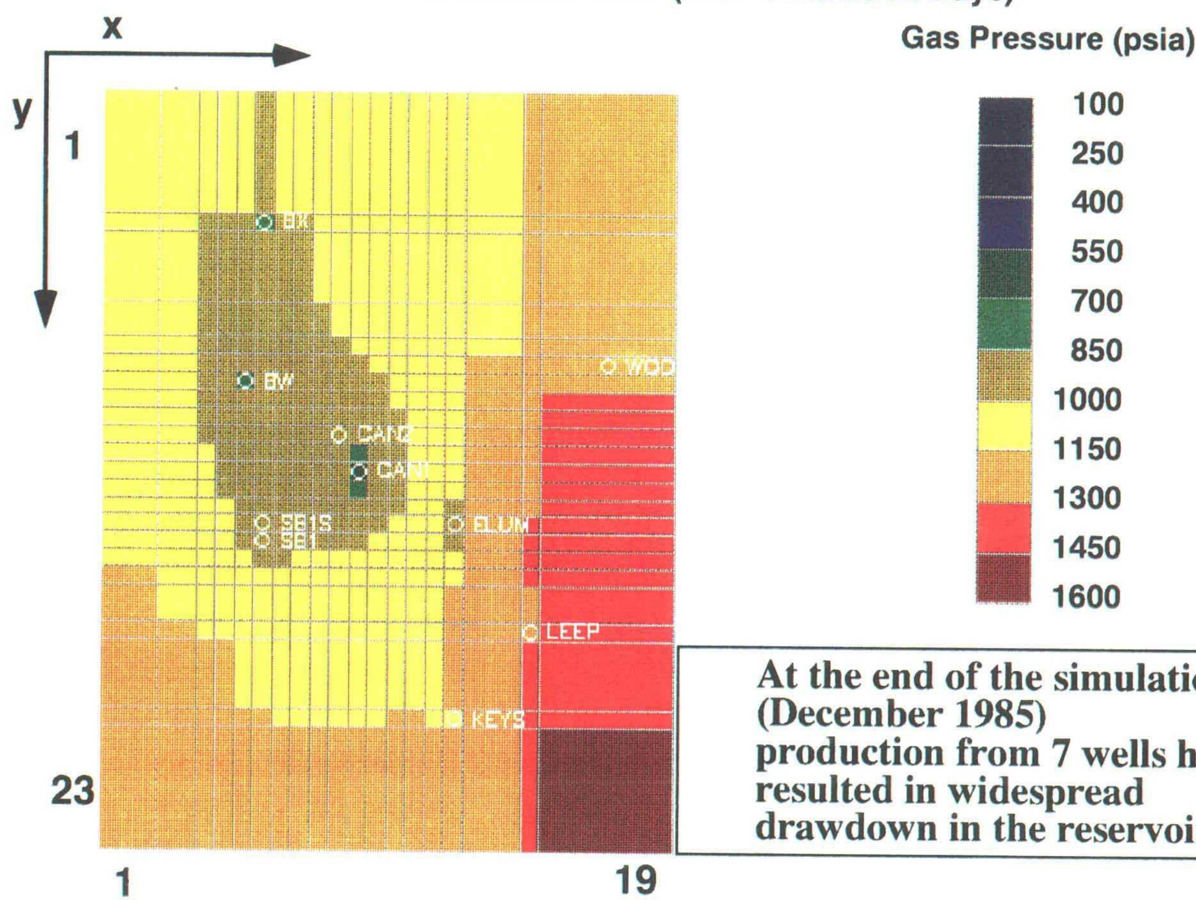



Is modeled area large enough?

**Two months of production from Schneider B-1S and State BW have resulted in the expansion of the gas bubble in the central part of the reservoir.**

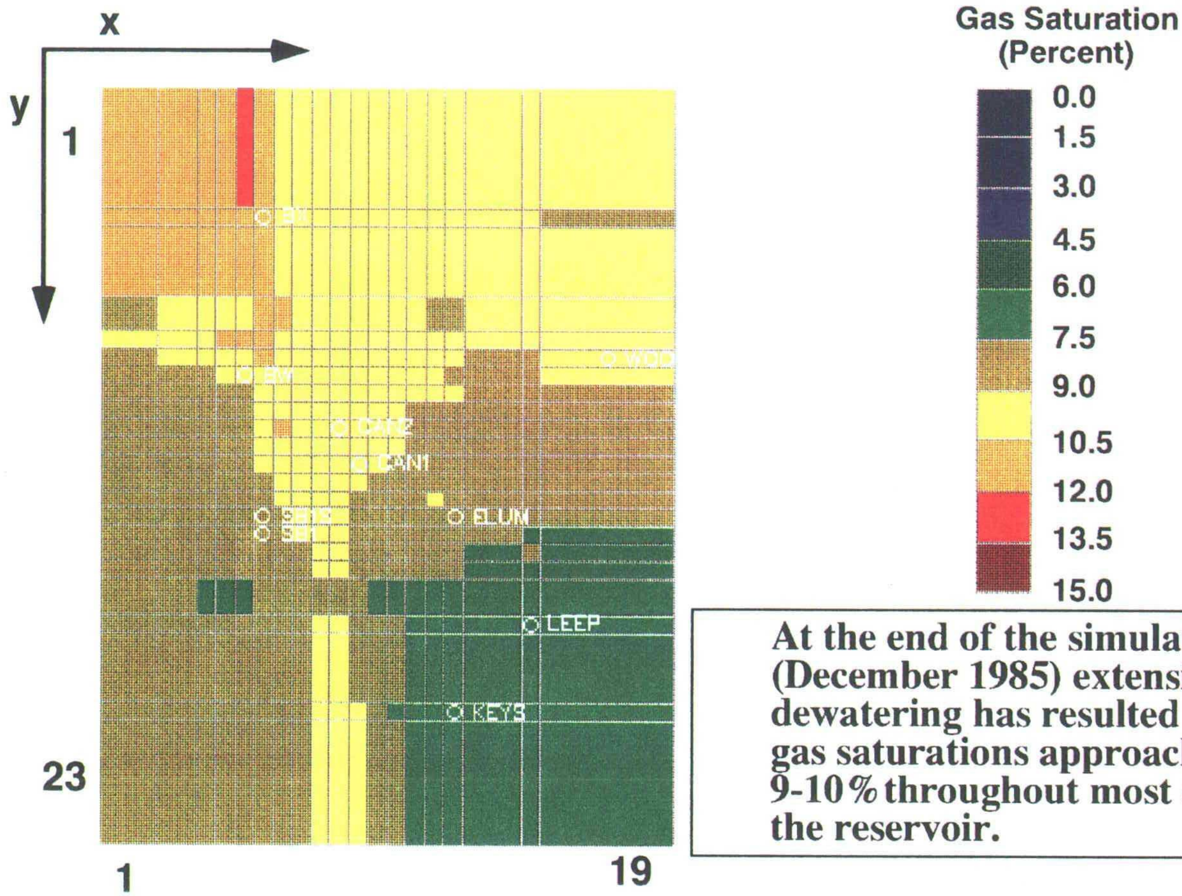
EXHIBIT 43

# Cedar Hill Field History Match
## Simulated Gas Pressure for the Upper Basal Fruitland Coal Seam
### December 1985 (3167 Simulation Days)




**At the end of the simulation (December 1985) production from 7 wells has resulted in widespread drawdown in the reservoir.**

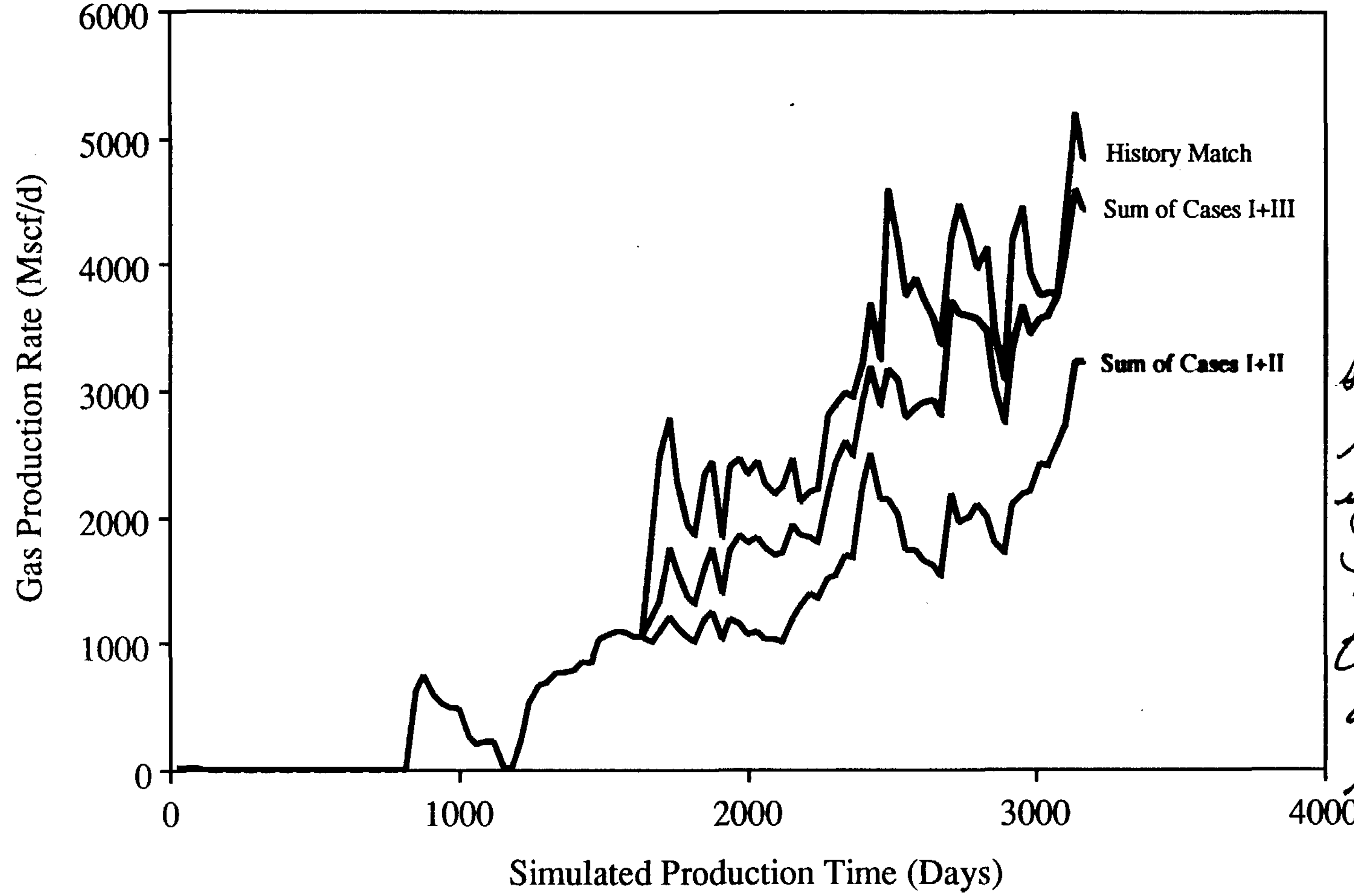
## Cedar Hill Field History Match
## Simulated Gas Saturation for the Upper Basal Fruitland Coal Seam
December 1985 (3167 Simulation Days)




**At the end of the simulation (December 1985) extensive dewatering has resulted in gas saturations approaching 9-10% throughout most of the reservoir.**

## San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match

Gas Production Rate for Simulated Interference Effects

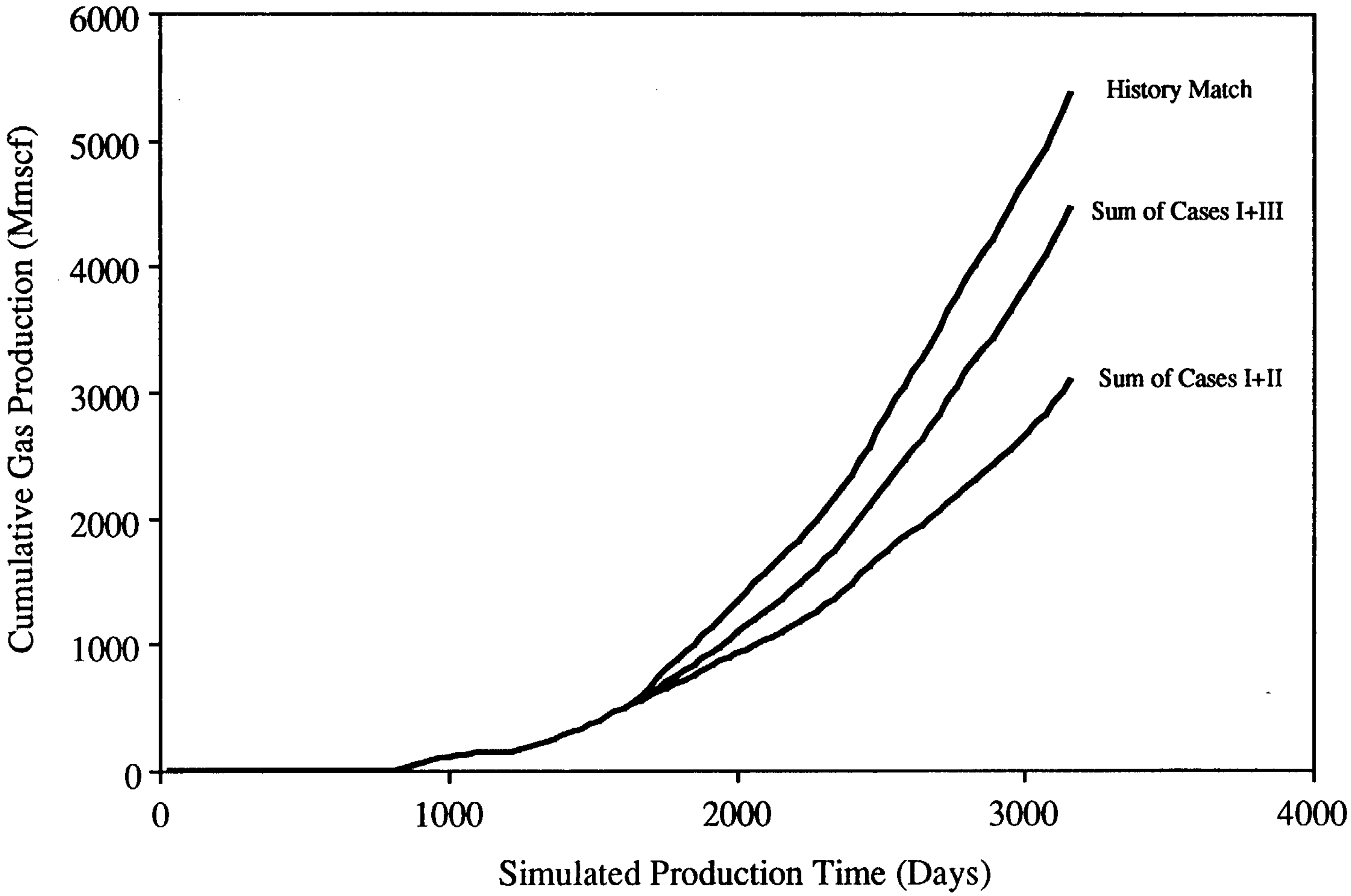



shows some beneficial effect between the Cedar and other wells in area due to well interaction

EXHIBIT 46

EXHIBIT 47

## San Juan Basin Coalbed Methane Spacing Study
## Cedar Hill Field Area History Match
### Cumulative Gas Production for Simulated Interference Effects



## SAN JUAN BASIN COALBED METHANE SPACING STUDY

### TIFFANY FIELD AREA HISTORY MATCH
### SUMMARY OF RESERVOIR PARAMETERS

| FIXED PARAMETERS | VALUE | SOURCE |
|---|---|---|
| Coal Depth | Plate 10 | Density logs |
| Net Pay | Plate 11 | Density logs |
| Initial Pressure (p*) | 1,610 psi @ +3,530' msl | Amoco's PTA |
| Langmuir Volume | 822.6 scf/ton | Amoco Measured |
| Langmuir Pressure | 707.4 psia | Amoco Measured |
| Desorption Pressure | $P_i$ | Estimated[1] |
| Initial Gas Content | 571.5 scf/ton | Calculated |
| Temperature | 120°F | Amoco Measured |
| Pore Volume Compressibility | $200 \times 10^{-6}$ $psi^{-1}$ | Estimated |
| Initial Water Saturation | 100% | Estimated[1] |
| Cleat Spacing | 0.25 inches | Measured[4] |
| Sorption Time | 10 days | Estimated[13] |
| Gas Gravity | 0.6123 | Amoco Measured |
| Water FVF | 1.006 RB/STB | Estimated[4] |
| Water Viscosity | 0.565 cp | Estimated[4] |
| | | |
| **HISTORY MATCH PARAMETERS** | | |
| Porosity | 0.50 - 1.00% | Exhibits 56 and 63 |
| Permeability | 1.0 - 2.2 md | Exhibits 56 and 62 |
| Relative Permeability Curves | | Exhibit 61 |

| SAN JUAN BASIN COALBED METHANE SPACING STUDY<br><br>TIFFANY FIELD AREA HISTORY MATCH<br>SUMMARY OF WELL PRODUCTION CONTROLS | | | |
|---|---|---|---|
| **Well Name** | **Simulation Time (Days)** | **Calendar Date** | **Well Control** |
| Hott 20-2 Unit 1 | 0 | 10/01/83 | Gas Rate |
| Hott 20-4 | 0 | 10/01/83 | Gas Rate |
| Hott 30-2 | 0 | 10/01/83 | Gas Rate |
| Robertson 19-1 | 31 | 11/01/83 | Gas Rate |
| Hott 30-1 | 31 | 11/01/83 | Gas Rate |
| Southern Ute 20-1B | 61 | 12/01/83 | Gas Rate |
| Baird 18-1 | 304 | 08/01/84 | Gas Rate |
| Southern Ute Tribal G-1 | 1,642 | 04/01/88 | Gas Rate |
| Hott 29-2 Unit 2 | 2,037 | 05/01/89 | Gas Rate |
| Hott 30-1 Unit 2 | 2,037 | 05/01/89 | Gas Rate |
| | | | |
| End of Simulation | 2,251 | 11/30/89 | |

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

### TIFFANY FIELD AREA HISTORY MATCH
### SUMMARY OF POROSITY AND PERMEABILITY FOR THE MODEL AREA

| Well Name | Porosity (%) | Permeability (md) | | |
|---|---|---|---|---|
| | | $\bar{k}$ | $k_x$ | $k_y$ |
| Hott 20-2 Unit 1 | 1.00 | 1.1 | 1.2 | 1.0 |
| Hott 20-4 | 0.50 | 2.2 | 4.0 | 1.2 |
| Hott 30-2 | 0.75 | 1.0 | 1.0 | 1.0 |
| Robertson 19-1 | 0.75 | 1.8 | 3.2 | 1.0 |
| Hott 30-1 | 1.00 | 2.0 | 4.0 | 1.0 |
| Southern Ute 20-1B | 0.50 | 1.7 | 2.9 | 1.0 |
| Baird 18-1 | 0.50 | 1.8 | 3.2 | 1.0 |
| Southern Ute Tribal G-1 | 1.00 | 1.2 | 1.4 | 1.0 |
| Hott 29-2 Unit 2 | 1.00 | 1.2 | 1.4 | 1.0 |
| Hott 30-1 Unit 2 | 0.75 | 1.4 | 2.0 | 1.0 |

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

### TIFFANY FIELD AREA HISTORY MATCH
### SIMULATED AND OBSERVED CUMULATIVE VOLUMES
### FOR THE PERIOD OF OCTOBER 1983 TO NOVEMBER 1989

| Well Name | Cumulative Gas Production (MMscf) | | Cumulative Water Production (MBbls) | |
|---|---|---|---|---|
| | Simulated | Observed | Simulated | Observed |
| Hott 20-2 Unit 1 | 130.22 | 135.48 | 42.69 | 37.90 |
| Hott 20-4 | 205.60 | 131.22* | 56.01 | 22.04* |
| Hott 30-2 | 53.64 | 52.30 | 40.41 | 39.42 |
| Robertson 19-1 | 134.78 | 149.52 | 48.64 | 34.71 |
| Hott 30-1 | 263.42 | 286.44 | 92.28 | 72.50 |
| Southern Ute 20-1B | 131.06 | 134.50 | 44.05 | 39.03 |
| Baird 18-1 | 147.20 | 150.18 | 54.62 | 33.01 |
| Southern Ute Tribal G-1 | 36.27 | 38.81 | 22.32 | 16.91 |
| Hott 29-2 Unit 2 | 13.71 | 13.71 | 3.12 | 4.10 |
| Hott 30-1 Unit 2 | 29.81 | 32.32 | 5.82 | 5.18 |
| | | | | |
| Total Model Area | 1145.71 | 1124.48 | 409.96 | 304.80 |

* For Hott 20-4 only, observed cumulative volumes were only available between October 1983 through November 1988. During this period, 130.77 MMscf of gas and 45.73 MBbls of water were simulated.

# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Well Production Schedule

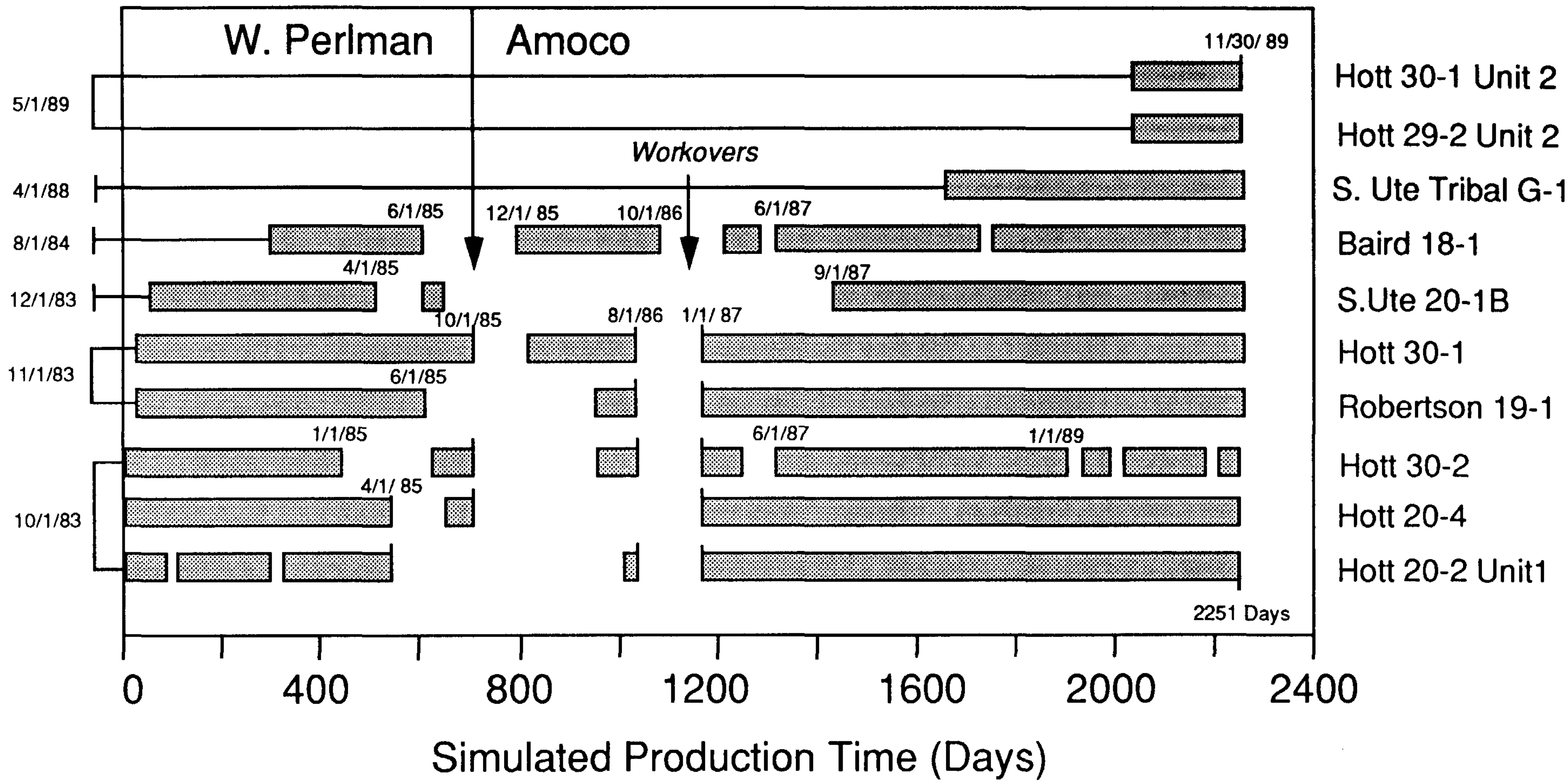


EXHIBIT 59

# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Simulation Grid

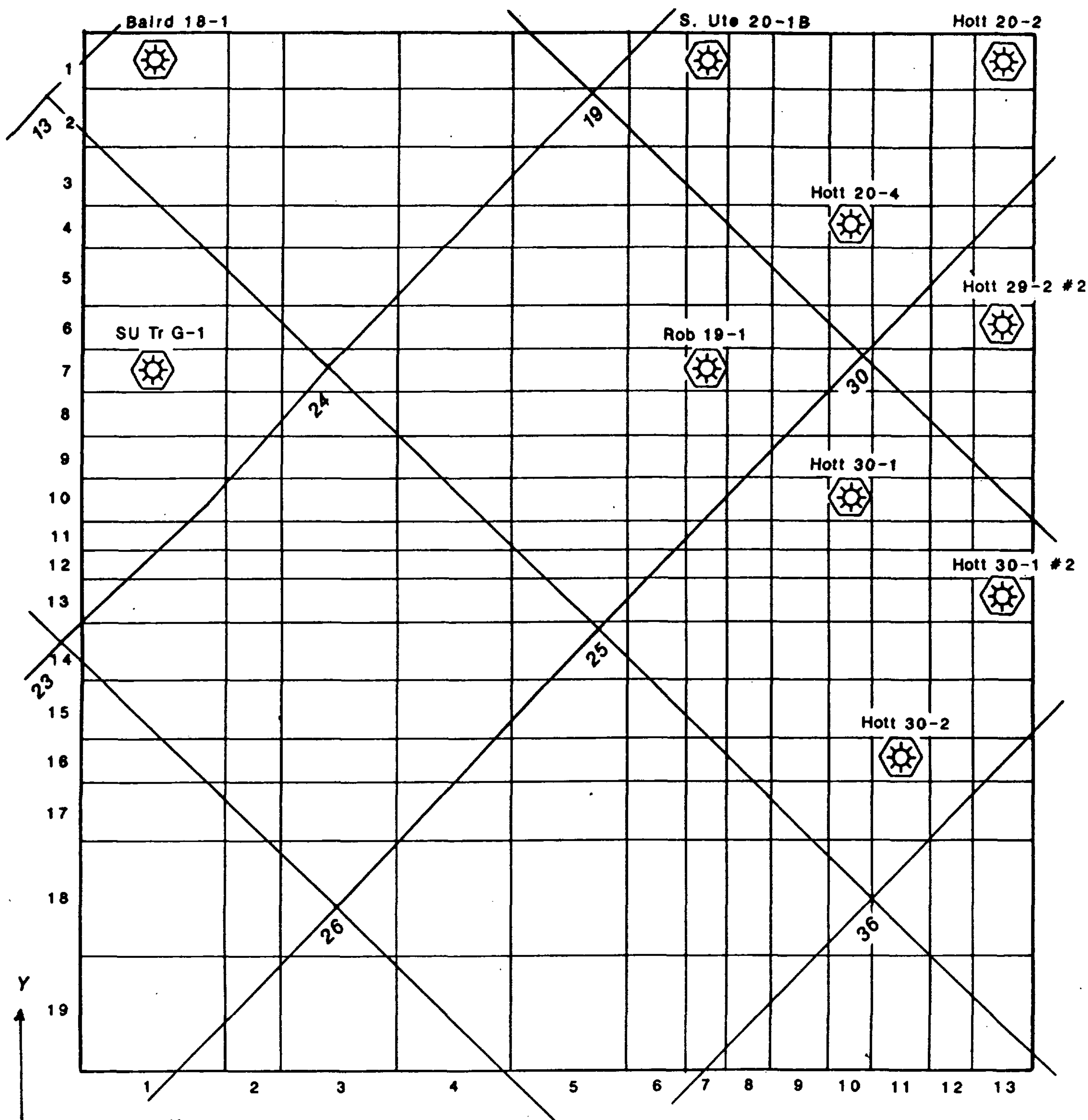


EXHIBIT 60

# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Sorption Isotherm

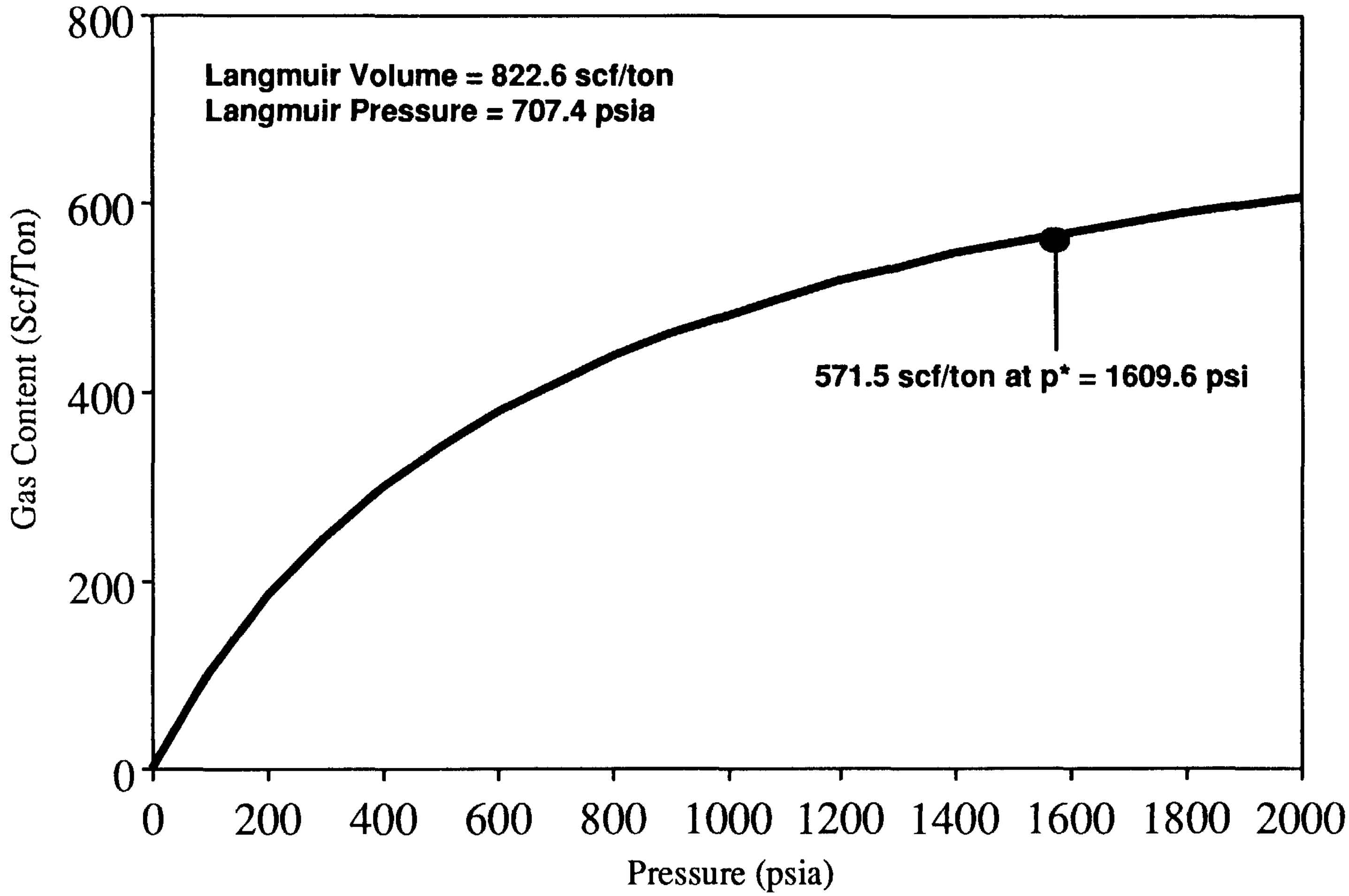
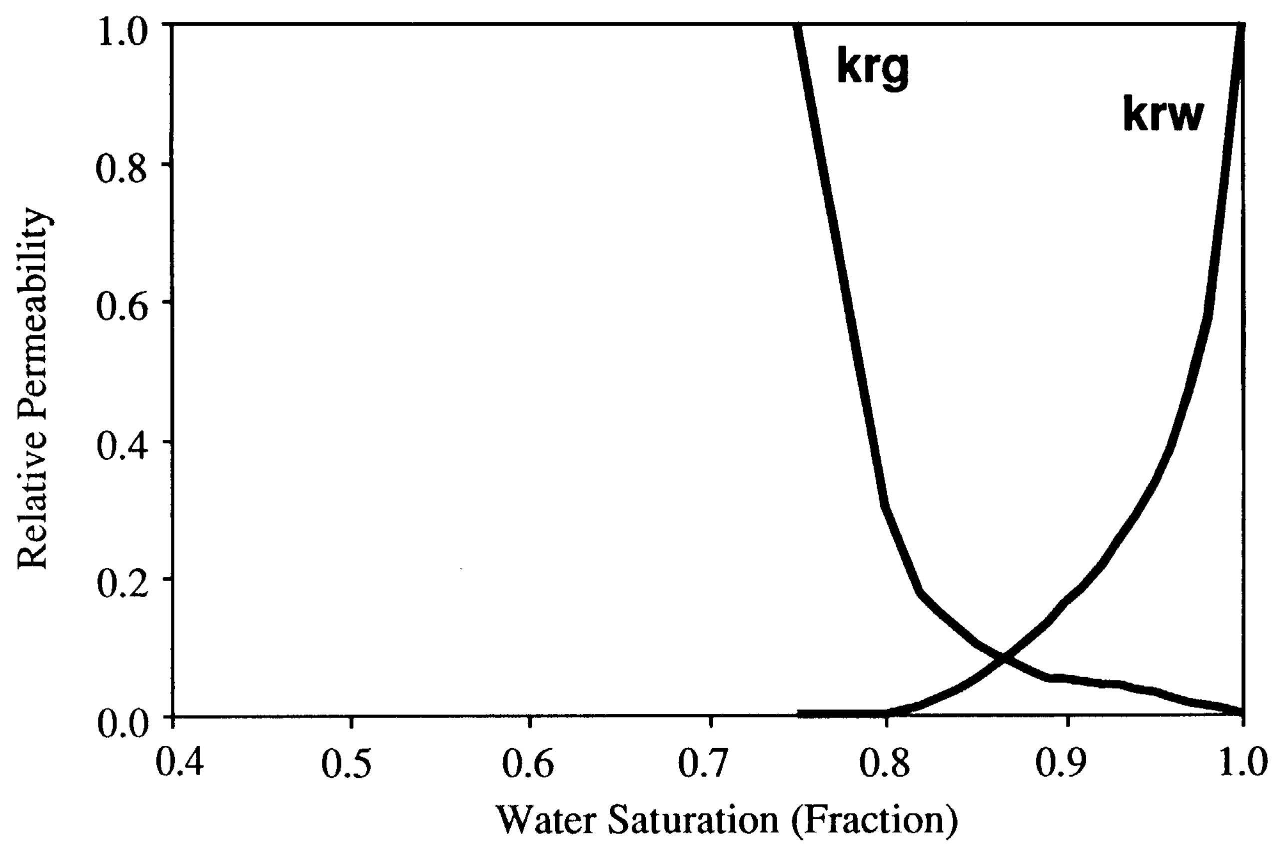


EXHIBIT 61

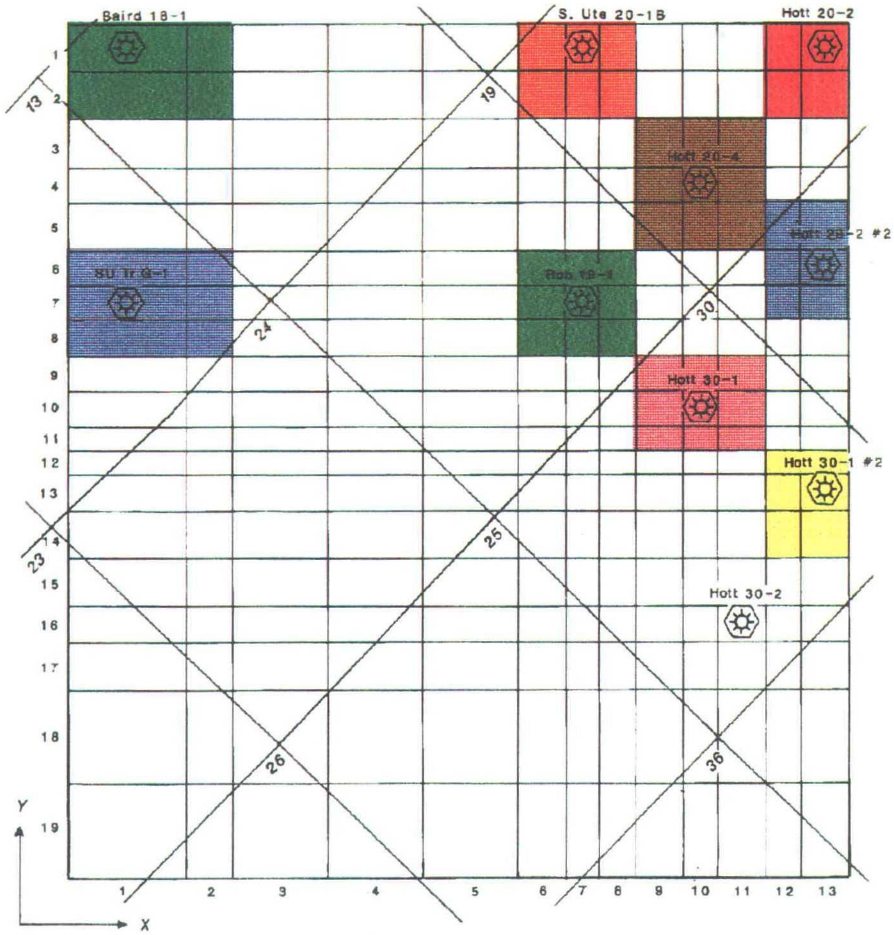
# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Relative Permeability Curves



# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Distribution in Anisotropic Face and Butt Cleat Permeabilities

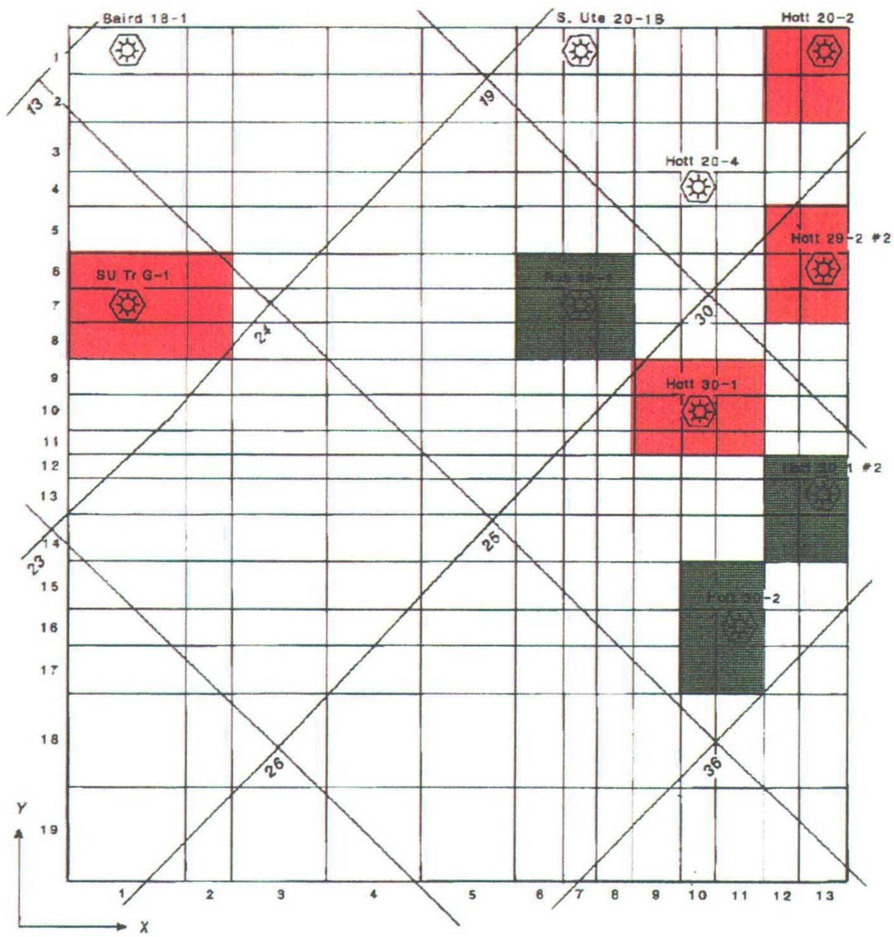



### Permeability Legend

$\bar{k}$ =1.0 md (kx=1.0, ky=1.0)
$\bar{k}$ =1.1 md (kx=1.2, ky=1.0)
$\bar{k}$ =1.2 md (kx=1.4, ky=1.0)
$\bar{k}$ =1.4 md (kx=2.0, ky=1.0)
$\bar{k}$ =1.7 md (kx=2.9, ky=1.0)
$\bar{k}$ =1.8 md (kx=3.2, ky=1.0)
$\bar{k}$ =2.0 md (kx=4.0, ky=1.0)
$\bar{k}$ =2.2 md (kx=4.0, ky=1.2)

# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Distribution in Cleat Porosities




Porosity Legend

1.00% 0.75% 0.50%

EXHIBIT 64

# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Gas Production Rate vs Time for Hott 20-2 Unit 1

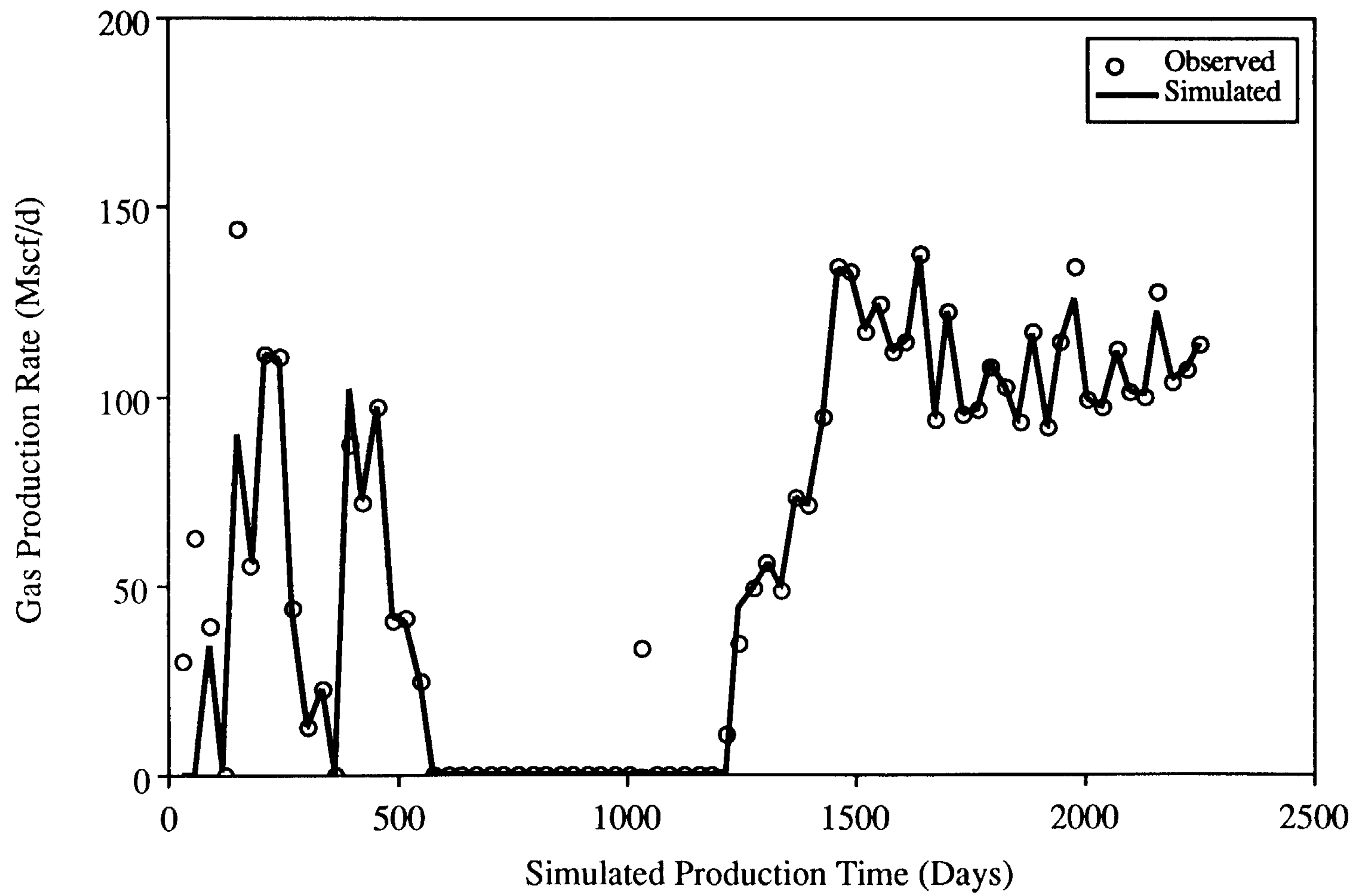


EXHIBIT 65

## San Juan Basin Coalbed Methane Spacing Study
## Tiffany Field Area History Match

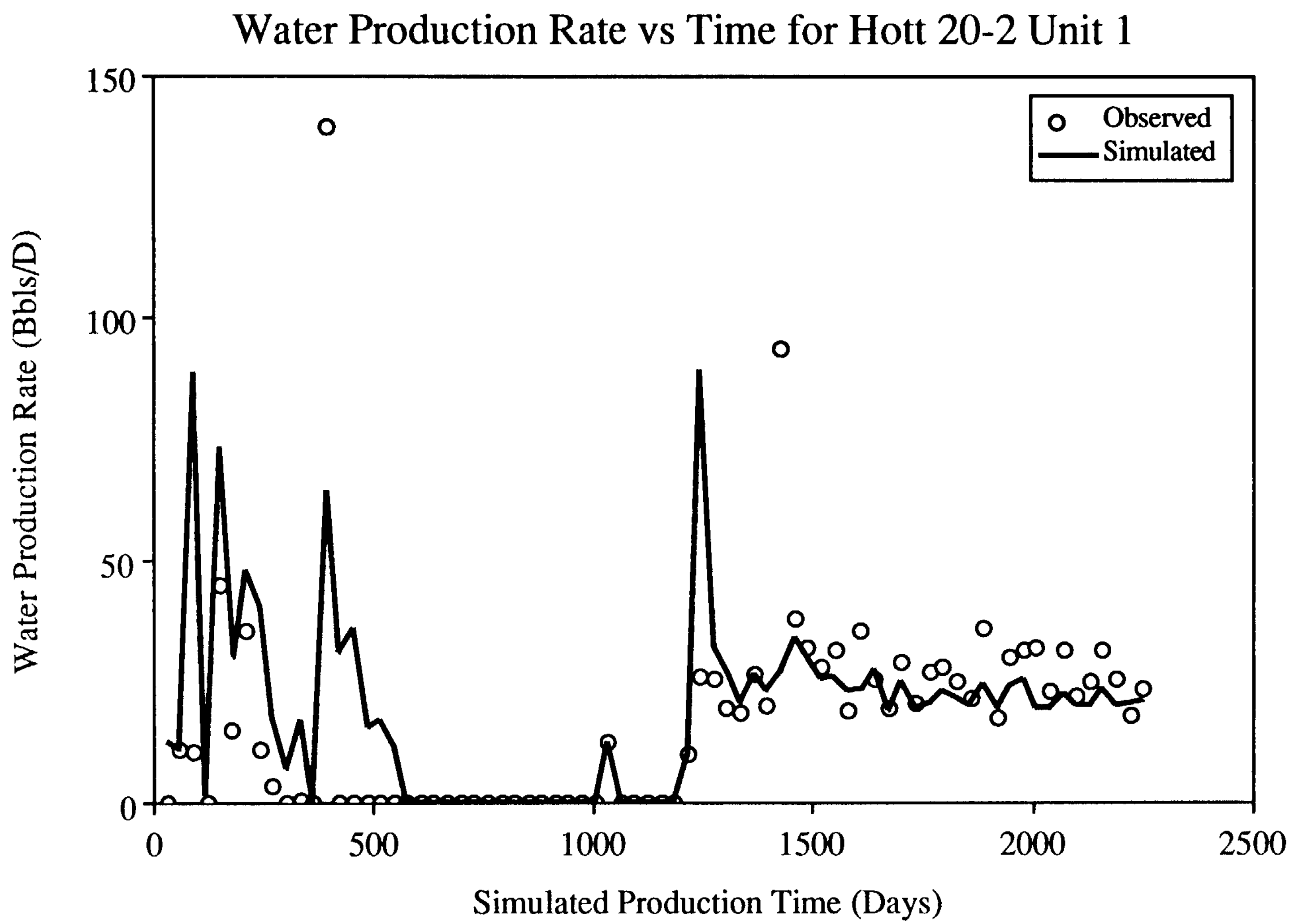


EXHIBIT 66

## San Juan Basin Coalbed Methane Spacing Study
## Tiffany Field Area History Match

Flowing Bottomhole Pressure vs Time for Hott 20-2 Unit 1

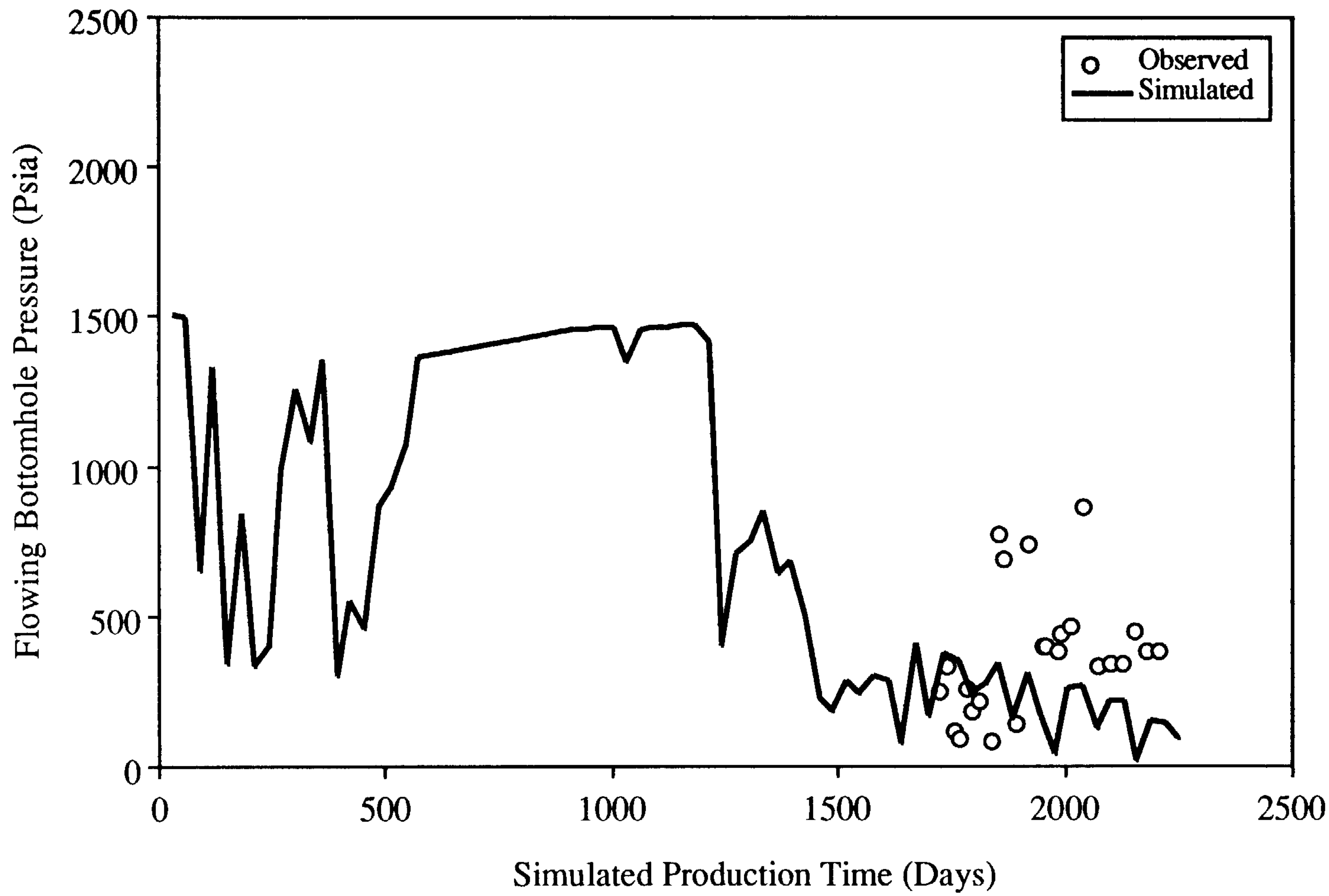
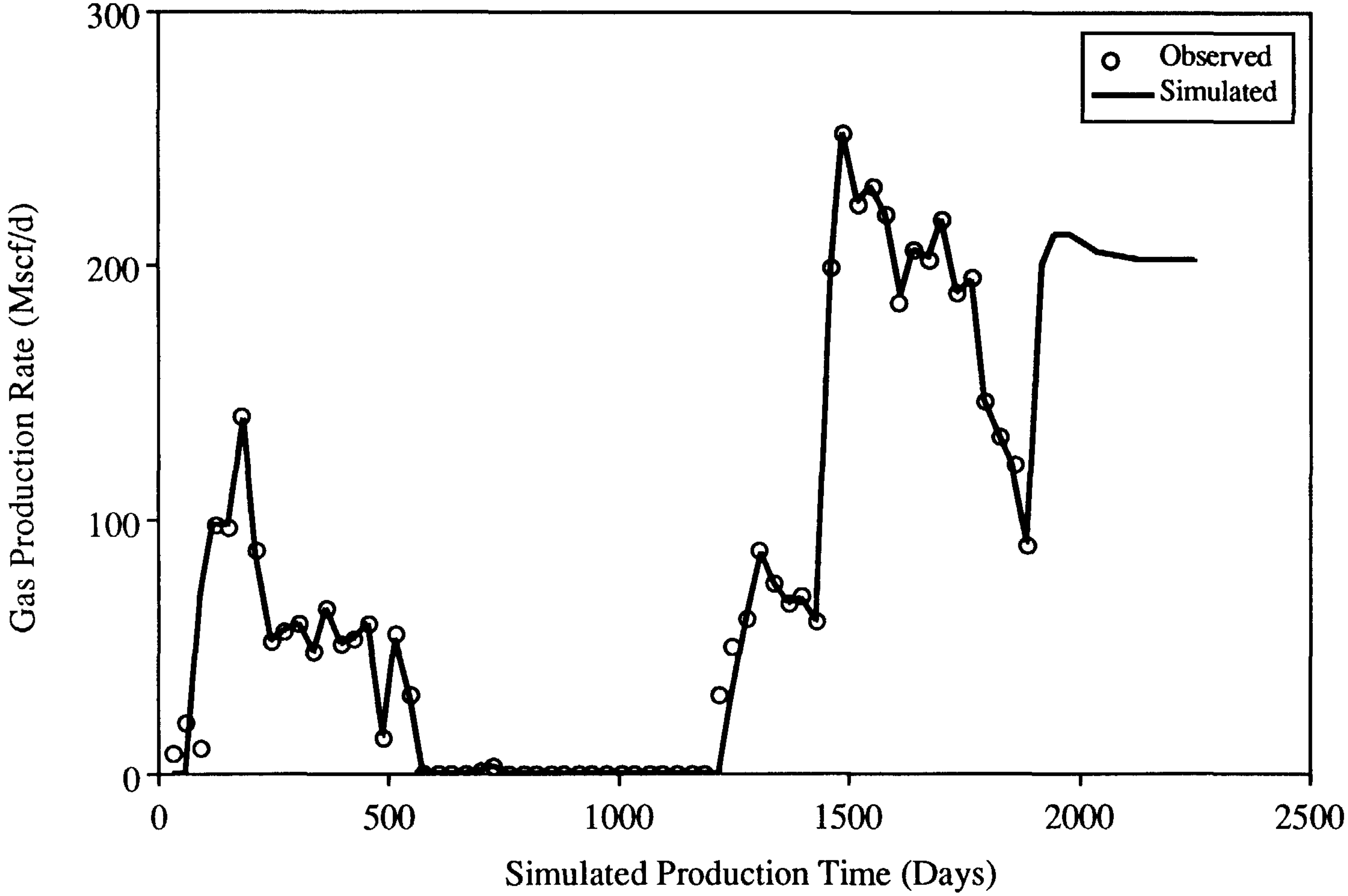


EXHIBIT 67

# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Gas Production Rate vs Time for Hott 20-4



# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

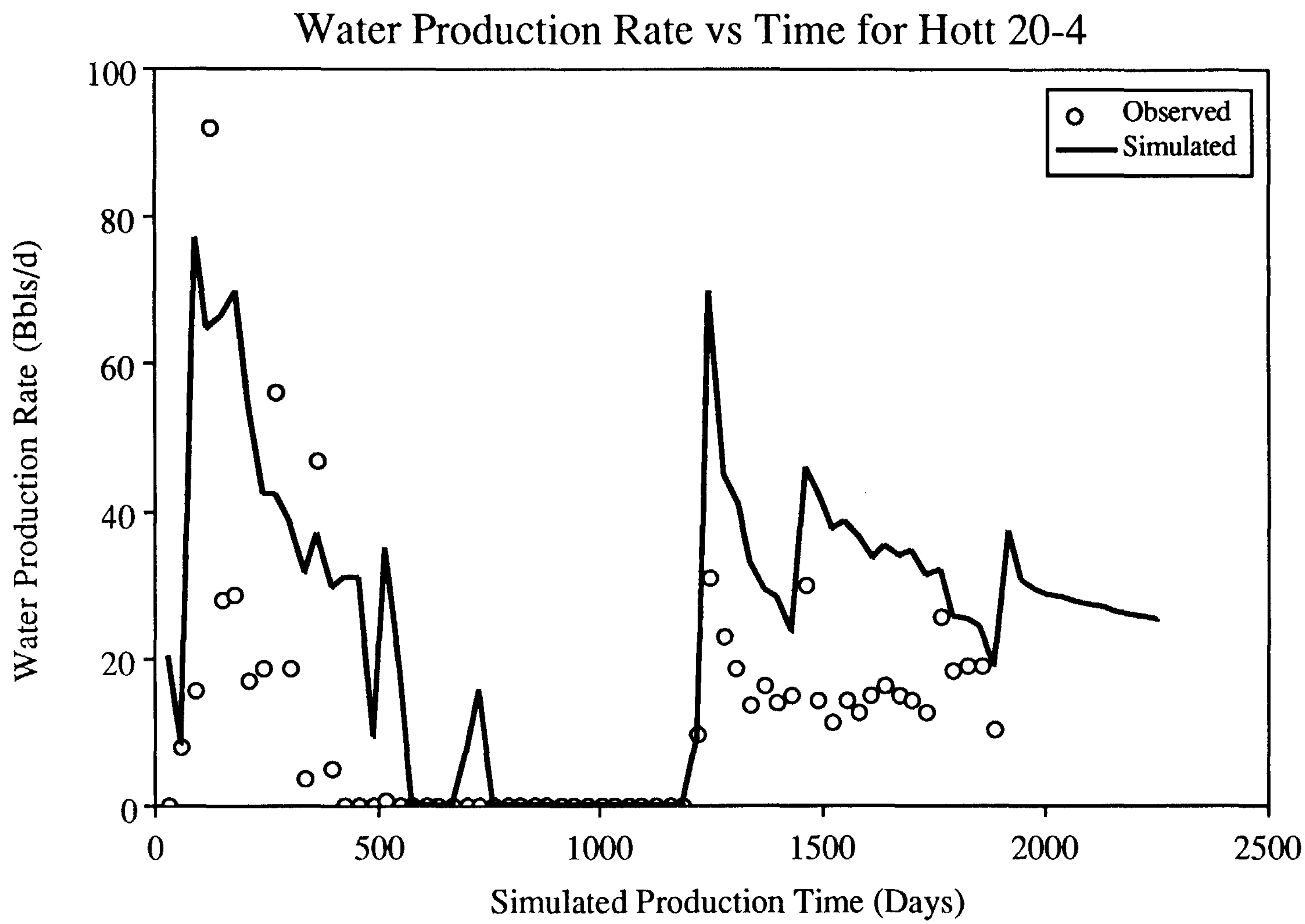



EXHIBIT 68

## San Juan Basin Coalbed Methane Spacing Study
## Tiffany Field Area History Match

Flowing Bottomhole Pressure vs Time for Hott 20-4

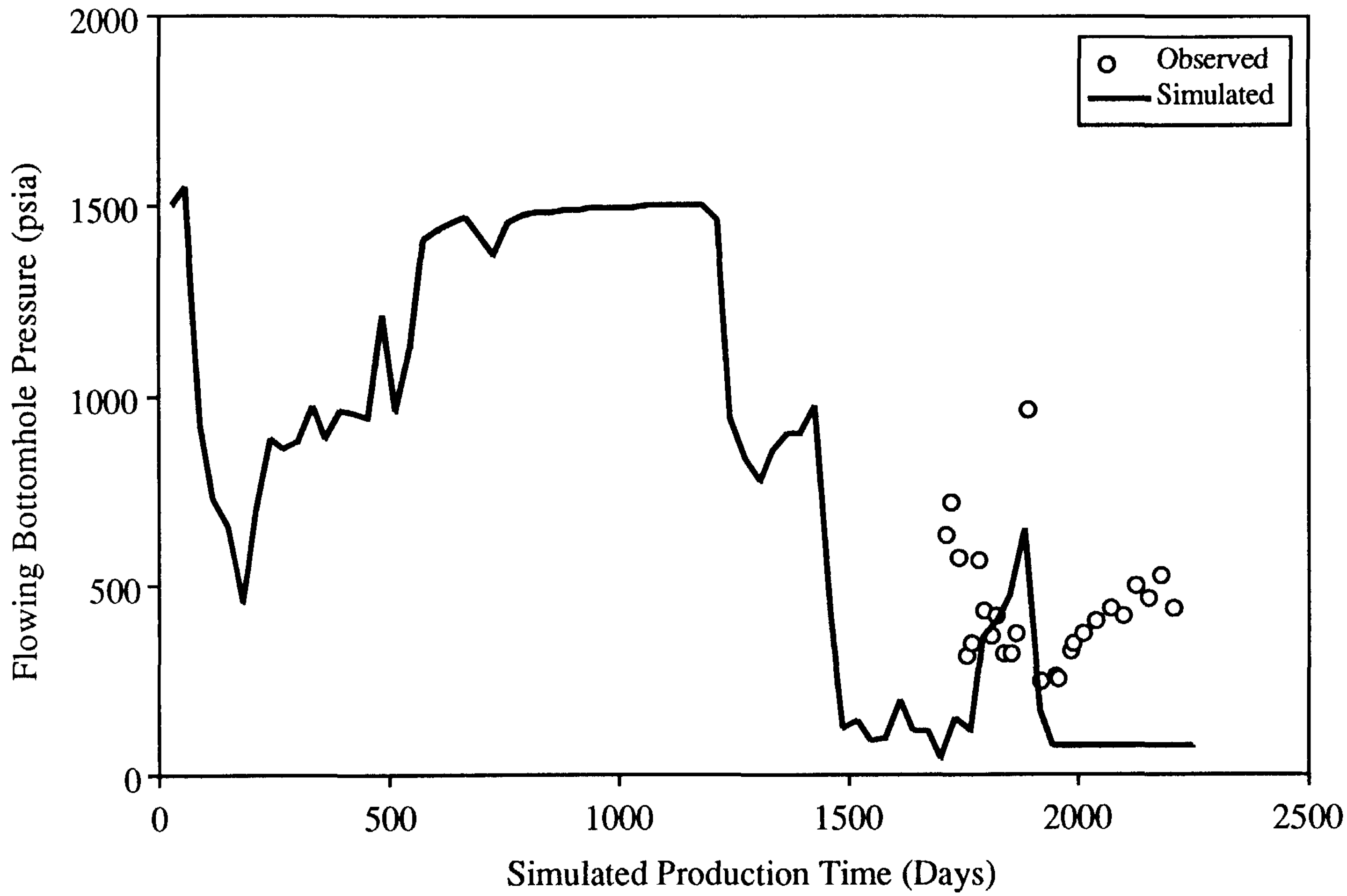
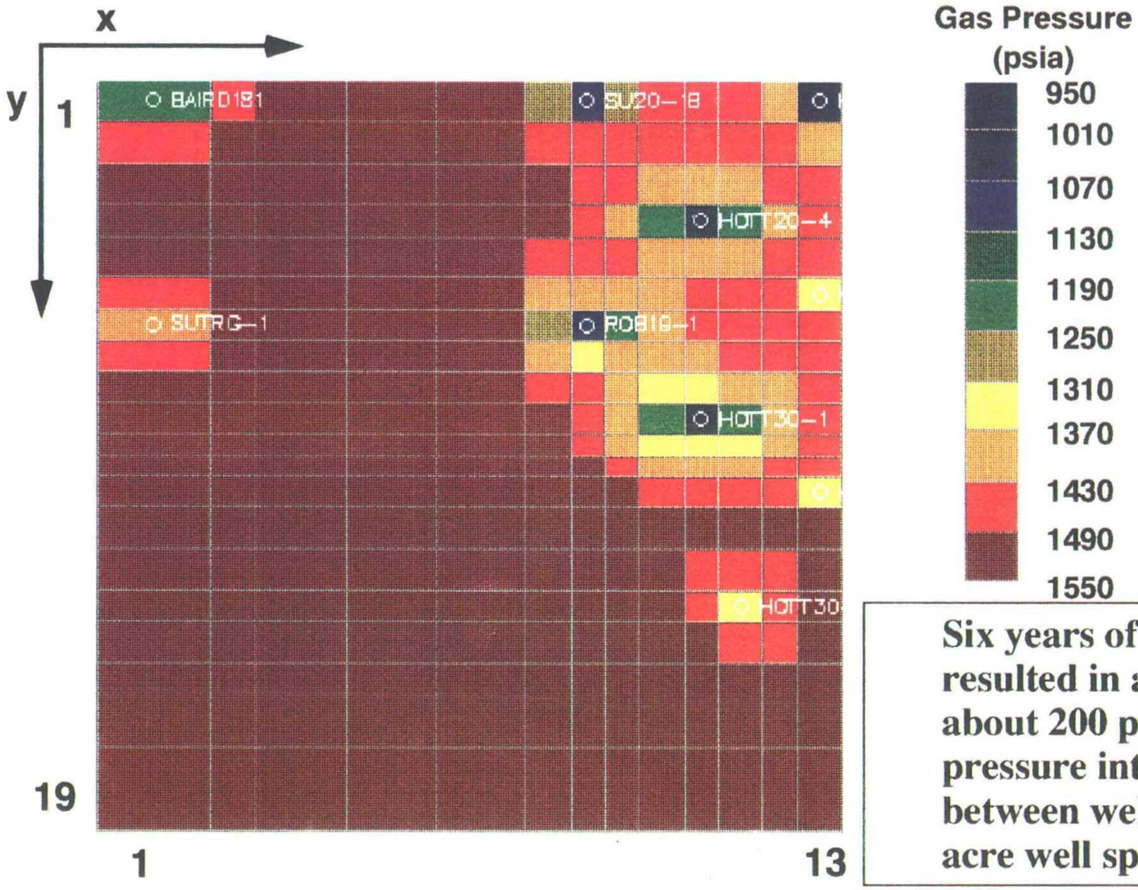



EXHIBIT 69

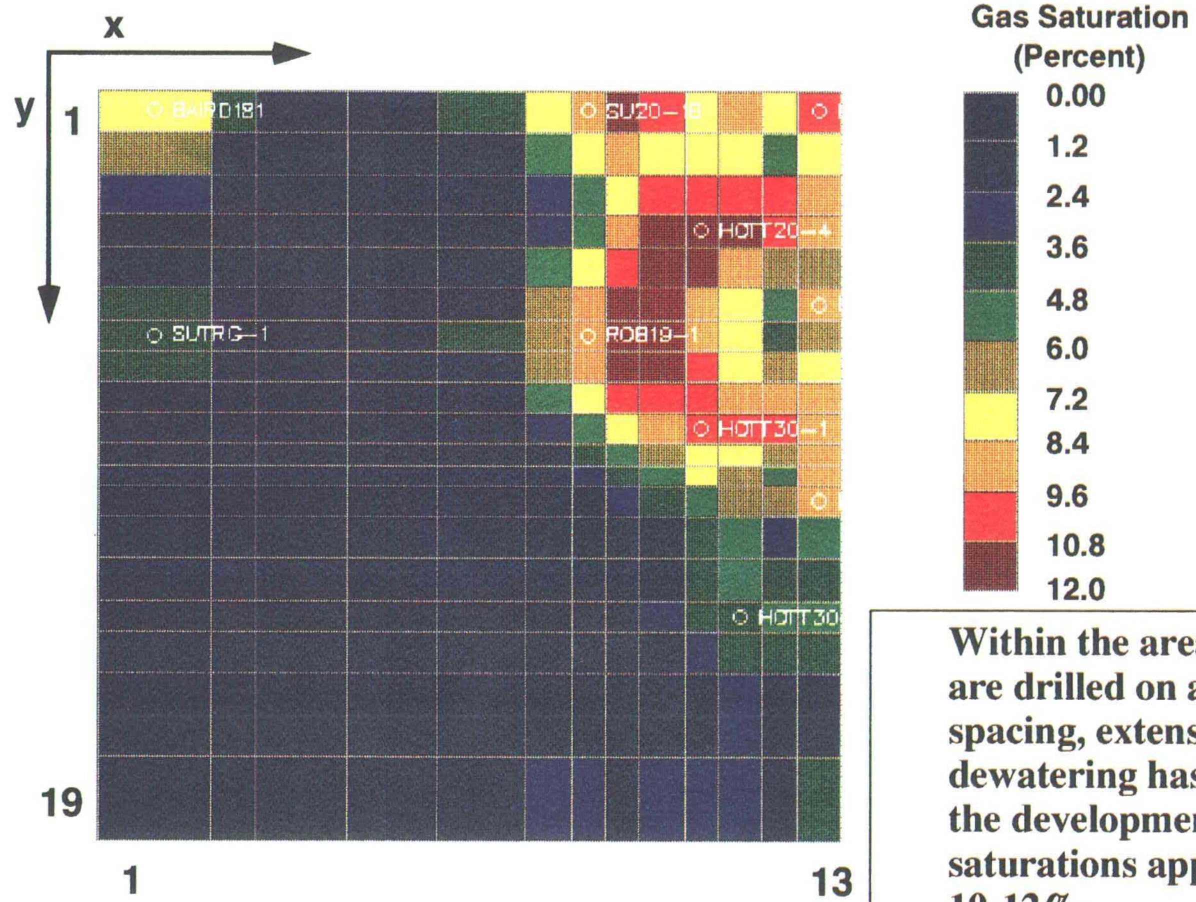
## Tiffany Field History Match
## Simulated Gas Pressure for Basal Fruitland Coal Seam C
November 1989 (2251 Simulation Days)




Six years of production has resulted in a drawdown of about 200 psia with the greatest pressure interference occurring between wells drilled on a 160 acre well spacing (NE of grid)

## Tiffany Field History Match
## Simulated Gas Saturation for Basal Fruitland Coal Seam C

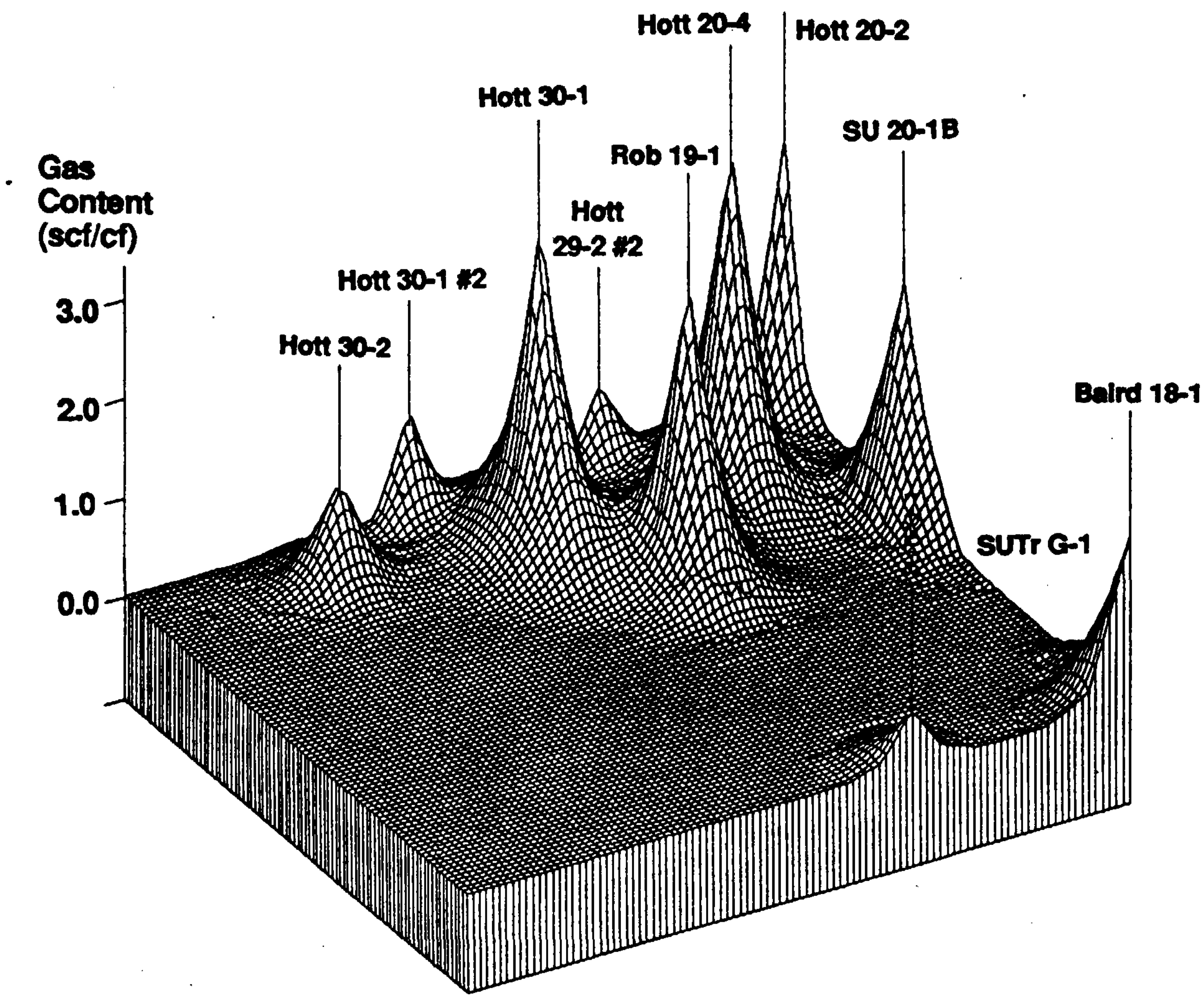
**November 1989 (2251 Simulation Days)**




**Within the area where wells are drilled on a closer spacing, extensive dewatering has resulted in the development of gas saturations approaching 10-12%.**

# San Juan Basin Coalbed Methane Spacing Study
# Tiffany Field Area History Match

## Simulated Difference in Matrix Gas Concentration
## (October 1983 thru November 1989)



| SAN JUAN BASIN COALBED METHANE SPACING STUDY<br><br>AREA 1 SENSITIVITY ANALYSES<br>SUMMARY OF RESERVOIR PARAMETERS | | |
|---|---|---|
| **FIXED PARAMETERS** | **VALUE** | **SOURCE** |
| Coal Depth | 3,000 feet | Logs |
| Coal Thickness | 35 feet | Logs |
| Langmuir Volume (Ash Corrected) | 427 scf/ton | Estimated[13] |
| Langmuir Pressure | 315 psia | Estimated[13] |
| Desorption Pressure | 1,320 psia | Estimated[1] |
| Reservoir Pressure | 1,320 psia | Estimated[1] |
| Gas Content (Ash Corrected) | 345 scf/ton | Calculated |
| Flowing Bottomhole Pressure | 100 psia | Estimated |
| Temperature | 120°F | Logs |
| Pore Volume Compressibility | $200 \times 10^{-6}$ $psi^{-1}$ | Estimated |
| Initial Water Saturation | 100% | Estimated[1] |
| Cleat Spacing | 0.25 inches | Measured[4] |
| Sorption Time | 10 days | Estimated[13] |
| Gas Gravity | 0.60 | Measured[12] |
| Water FVF | 1.006 RB/STB | Estimated[4] |
| Water Viscosity | 0.565 cp | Estimated[4] |
| Relative Permeability Curves | - | Estimated[10] |
| | | |
| **VARIABLE PARAMETERS** | | |
| Cleat Porosity | 0.25, 3% | |
| Cleat Permeability | 1, 5, 10, 50 md | |
| Fracture Half-Length | 100, 300, 500 feet | |
| Well Spacing | 160, 320, 640 acres | |

5% changes here could make a difference

EXHIBIT 79

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

### AREA 1 SENSITIVITY ANALYSES
### INVENTORY OF INITIAL FLUIDS IN PLACE

| | INITIAL CONDITIONS | | | | | |
|---|---|---|---|---|---|---|
| Case Description | Reservoir Pressure (= $P_D$) (psia) | Langmuir Volume (scf/ton) | Langmuir Pressure (psia) | Gas Content (scf/ton) | Gas-In-Place * [(mmscf)/(640 ac-ft coal-scf/ton)] | Water-In-Place * [(mbbls)/(640 ac-ft coal)] |
| WELL SPACING | | | | | | |
| 160 acres | 1,320 | 427 | 315 | 345 | 1.12 | 148.67 |
| 320 acres | 1,320 | 427 | 315 | 345 | 1.12 | 148.67 |
| 640 acres | 1,320 | 427 | 315 | 345 | 1.12 | 148.67 |
| CLEAT POROSITY | | | | | | |
| 0.25% | 1,320 | 427 | 315 | 345 | 1.15 | 12.39 |
| 2.00% | 1,320 | 427 | 315 | 345 | 1.13 | 99.12 |
| 3.00% | 1,320 | 427 | 315 | 345 | 1.12 | 148.67 |
| LANGMUIR VOLUME | | | | | | |
| 350 scf/ton | 1,320 | 350 | 315 | 283 | 1.12 | 148.67 |
| 427 scf/ton | 1,320 | 427 | 315 | 345 | 1.12 | 148.67 |
| 500 scf/ton | 1,320 | 500 | 315 | 404 | 1.12 | 148.67 |
| DESORPTION PRESSURE | | | | | | |
| 932 psia | 932 | 427 | 315 | 319 | 1.12 | 148.67 |
| 1,320 psia | 1,320 | 427 | 315 | 345 | 1.12 | 148.67 |
| 1,960 psia | 1,960 | 427 | 315 | 368 | 1.12 | 148.67 |
| RELATIVE PERMEABILITY | | | | | | |
| Cause 112-73 | 1,320 | 427 | 315 | 345 | 1.12 | 148.67 |
| Kamal & Six | 1,320 | 427 | 315 | 345 | 1.12 | 148.67 |

* Coal thickness was assumed to be 35 feet for all cases simulated in Area 1.

EXHIBIT 80

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

## SIMULATION RESULTS FOR AREA 1 SENSITIVITY ANALYSES

* assume a totally confined well — all offsets have been drilled

| Sensitivity Parameters | | | Cleat Porosity = 3 Percent | | | Cleat Porosity = 0.25 Percent | | |
|---|---|---|---|---|---|---|---|---|
| | | | RATE CUT OFF 50 mscf/d Cutoff | | TIME 25 Year Cutoff | 50 mscf/d Cutoff | | 25 Year Cutoff |
| Permeability (md) | Fracture Half-Length (feet) | Well Spacing (acres) * | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) |
| 1 | 100 | 160 | 0.3 | 0.2 | 8.7 | 34.0 | 35.9 | 30.4 |
| 1 | 100 | 320 | 0.3 | 0.1 | 3.3 | 68.0 | 34.4 | 17.7 |
| 1 | 100 | 640 | 0.3 | 0.0 | 1.3 | 133.0 | 32.0 | 7.9 |
| | | | | | | | | |
| 1 | 300 | 160 | 28.8 | 18.1 | 16.0 | 33.0 | 45.2 | 40.3 |
| 1 | 300 | 320 | 41.8 | 11.1 | 6.4 | 67.0 | 42.4 | 25.2 |
| 1 | 300 | 640 | 2.1 | 0.5 | 2.5 | 134.0 | 39.3 | 12.4 |
| | | | | | | | | |
| 1 | 500 | 160 | 40.1 | 31.4 | 22.1 | 31.0 | 50.0 | 46.5 |
| 1 | 500 | 320 | 68.2 | 23.4 | 9.5 | 64.0 | 47.0 | 30.6 |
| 1 | 500 | 640 | 6.2 | 1.4 | 3.7 | 131.0 | 43.7 | 16.1 |
| | | | | | | | | |
| 5 | 100 | 160 | 40.1 | 46.3 | 35.7 | 26.7 | 57.7 * | 56.8 |
| 5 | 100 | 320 | 80.9 | 44.7 | 19.5 | 53.5 | 56.8 | 44.7 |
| 5 | 100 | 640 | 165.0 | 42.7 | 3.7 | 109.0 | 55.5 | 30.6 |
| | | | | | | | | |
| 5 | 300 | 160 | 34.3 | 54.2 | 47.9 | 22.0 | 61.9 | 63.3 |
| 5 | 300 | 320 | 72.4 | 52.0 | 28.7 | 46.0 | 60.7 | 52.2 |
| 5 | 300 | 640 | 151.0 | 49.4 | 13.6 | 96.0 | 59.2 | 37.7 |
| | | | | | | | | |
| 5 | 500 | 160 | 30.4 | 58.0 | 54.7 | 19.0 | 63.9 | 66.2 |
| 5 | 500 | 320 | 65.3 | 55.8 | 35.8 | 40.5 | 62.6 | 56.7 |
| 5 | 500 | 640 | 140.0 | 53.2 | 17.7 | 87.0 | 61.2 | 42.5 |



→ shows one well per 320 is more economic

* could be w/in accuracy of model.

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

## SIMULATION RESULTS FOR AREA 1 SENSITIVITY ANALYSES

| Sensitivity Parameters | | | Cleat Porosity = 3 Percent | | | Cleat Porosity = 0.25 Percent | | |
|---|---|---|---|---|---|---|---|---|
| | | | 50 mscf/d Cutoff | | 25 Year Cutoff | 50 mscf/d Cutoff | | 25 Year Cutoff |
| Permeability (md) | Fracture Half- Length (feet) | Well Spacing (acres) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) |
| 10 | 100 | 160 | 33.5 | 56.2 | 50.6 | 21.0 | 62.9 | 64.6 |
| 10 | 100 | 320 | 67.7 | 55.0 | 33.6 | 42.5 | 62.3 | 55.5 |
| 10 | 100 | 640 | 140.1 | 53.6 | 17.5 | 87.0 | 61.5 | 42.7 |
| | | | | | | | | |
| 10 | 300 | 160 | 26.9 | 61.2 | 60.2 | 16.7 | 65.6 | 68.2 |
| 10 | 300 | 320 | 56.8 | 59.7 | 44.0 | 34.7 | 64.7 | 61.4 |
| 10 | 300 | 640 | 121.4 | 58.1 | 24.9 | 74.0 | 63.9 | 49.4 |
| | | | | | | | | |
| 10 | 500 | 160 | 22.6 | 63.3 | 64.5 | 14.1 | 66.8 | 69.4 |
| 10 | 500 | 320 | 49.7 | 62.1 | 50.5 | 30.0 | 66.0 | 64.4 |
| 10 | 500 | 640 | 108.4 | 60.5 | 30.7 | 65.0 | 65.1 | 53.6 |
| | | | | | | | | |
| 50 | 100 | 160 | 15.7 | 66.5 | 69.1 | 9.9 | 68.5 | 70.1 |
| 50 | 100 | 320 | 32.5 | 66.4 | 63.7 | 19.6 | 68.3 | 69.3 |
| 50 | 100 | 640 | 67.8 | 66.0 | 50.9 | 40.0 | 68.1 | 64.7 |
| | | | | | | | | |
| 50 | 300 | 160 | 11.8 | 68.0 | 69.9 | 7.4 | 69.2 | 70.2 |
| 50 | 300 | 320 | 24.6 | 67.6 | 67.7 | 15.0 | 69.0 | 70.0 |
| 50 | 300 | 640 | 53.7 | 67.2 | 58.1 | 31.8 | 68.7 | 67.5 |
| | | | | | | | | |
| 50 | 500 | 160 | 9.6 | 68.5 | 70.0 | 6.2 | 69.5 | 70.1 |
| 50 | 500 | 320 | 20.7 | 68.2 | 69.0 | 12.6 | 69.3 | 70.1 |
| 50 | 500 | 640 | 45.6 | 67.8 | 62.0 | 27.0 | 69.0 | 68.8 |

**EXHIBIT 81**

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

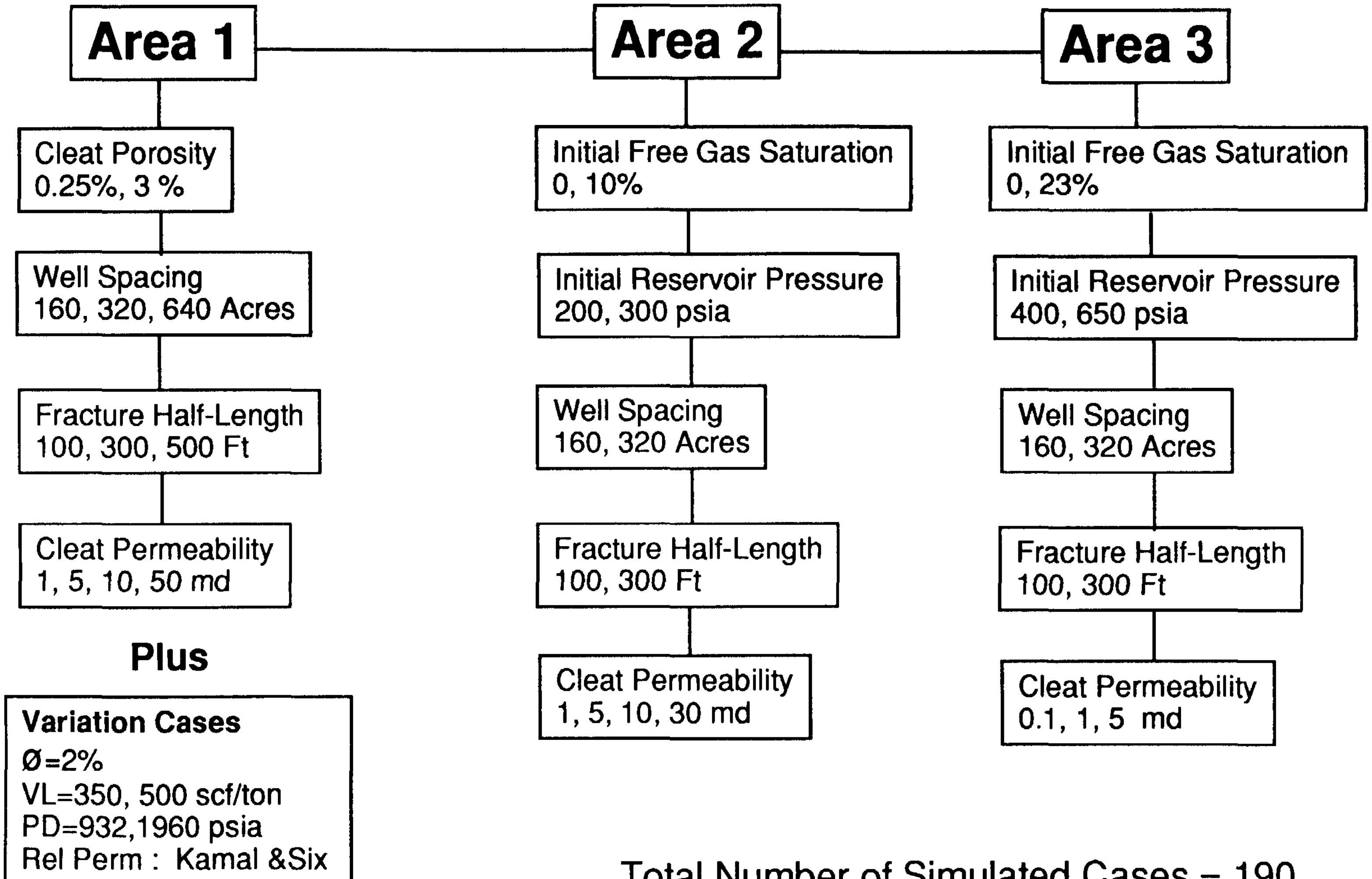
### SIMULATION RESULTS FOR VARIATIONS IN THE AREA 1 SENSITIVITY ANALYSES

| Description of Variations* | Gas Production** | | Water Production** | |
|---|---|---|---|---|
| | Cumulative [(mscf)/(640 ac-ft coal-scf/ton)] | Percent Recovery | Cumulative [(mbbls)/(640 ac-ft coal)] | Percent Recovery |
| CLEAT POROSITY | | | | |
| 0.25% | 705.32 | 61.4 | 5.05 | 40.8 |
| 2.00% | 550.68 | 48.8 | 33.80 | 34.1 |
| 3.00% | 492.06 | 44.0 | 47.65 | 32.0 |
| LANGMUIR VOLUME | | | | |
| 350 scf/ton | 510.36 | 45.7 | 47.69 | 32.1 |
| 427 scf/ton | 492.06 | 44.0 | 47.65 | 32.0 |
| 500 scf/ton | 477.34 | 42.7 | 47.60 | 32.0 |
| DESORPTION PRESSURE (=$P_i$) | | | | |
| 932 psia | 452.56 | 40.5 | 37.75 | 25.4 |
| 1,320 psia | 492.06 | 44.0 | 47.65 | 32.0 |
| 1,960 psia | 523.58 | 46.9 | 64.23 | 43.1 |
| RELATIVE PERMEABILITY | | | | |
| Cause 112-73 | 492.06 | 44.0 | 47.65 | 32.0 |
| Kamal & Six | 502.30 | 45.0 | 57.24 | 38.5 |

* All variation cases assumed 10 md cleat permeability, 300 ft. fracture half-length, and a well spacing of 320 acres.

** All cumulative volumes and recoveries are calculated on the basis of 25 years simulation time.

# San Juan Basin Coalbed Methane Spacing Study
## A Comparison of the Simulated Cases for Areas 1, 2 and 3 Sensitivity Analyses




Total Number of Simulated Cases = 190

EXHIBIT 83

# San Juan Basin Coalbed Methane Spacing Study
## Area 1 Sensitivity Analyses
## 72 Simulation Cases for Gas and Water Production

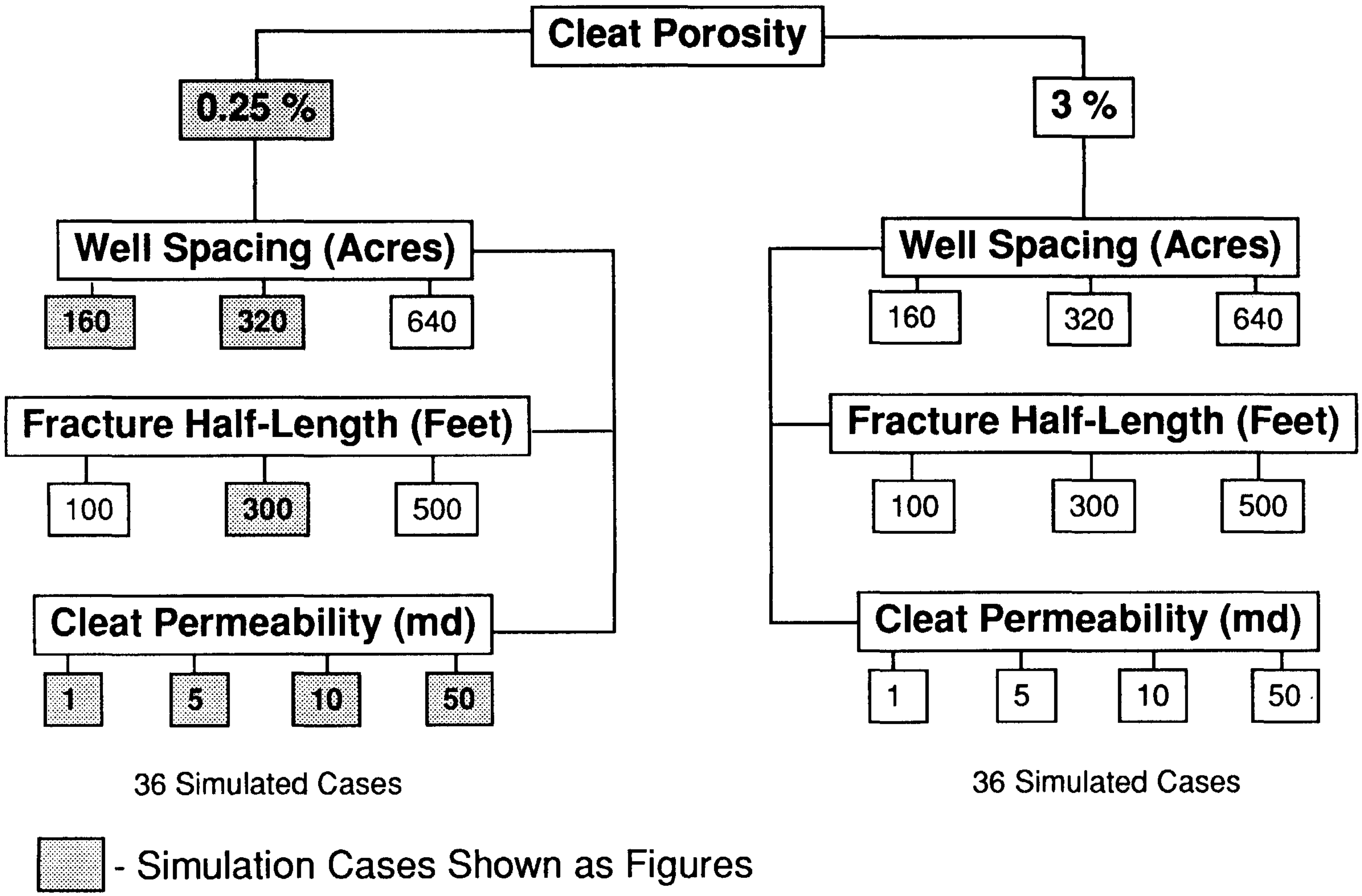
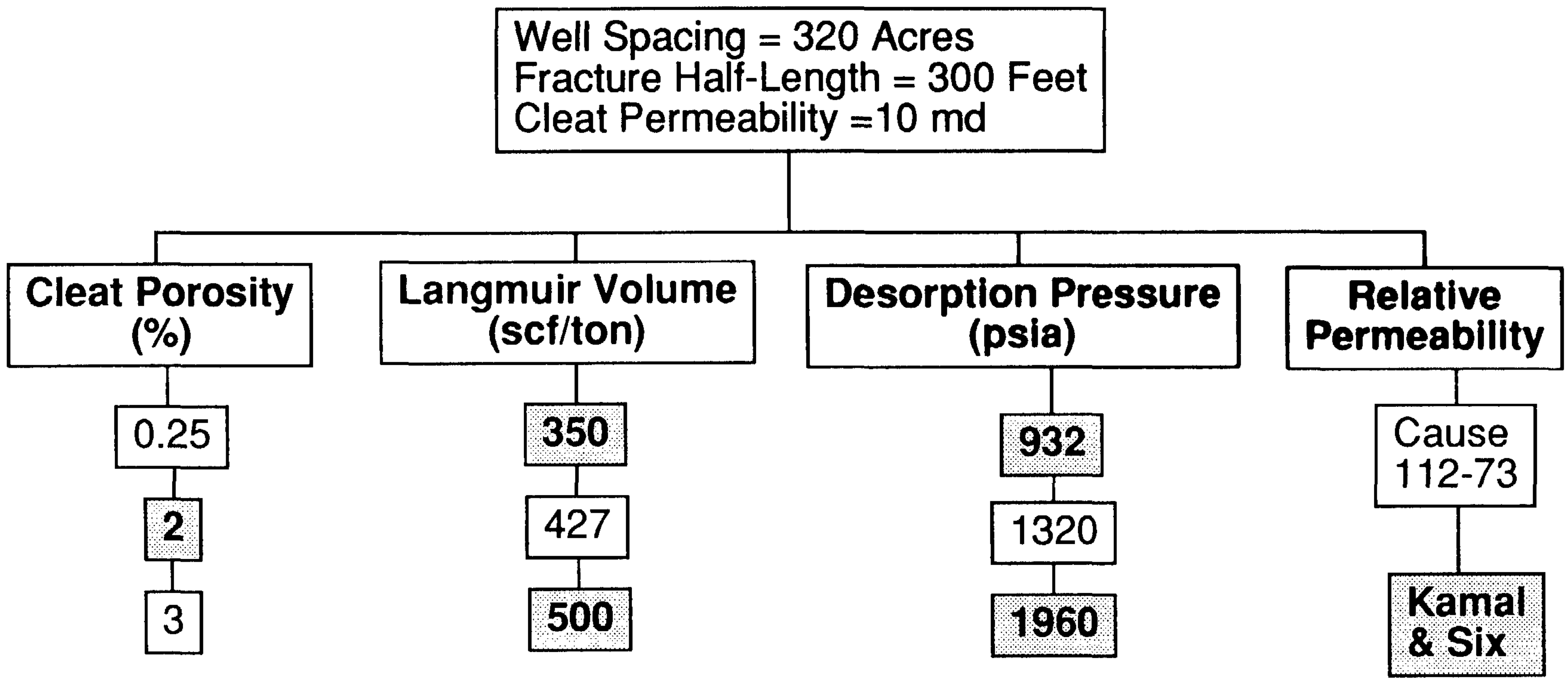


EXHIBIT 84

# San Juan Basin Coalbed Methane Spacing Study
## Area 1 Sensitivity Analyses
## Variation Cases for Simulated Gas and Water Production*



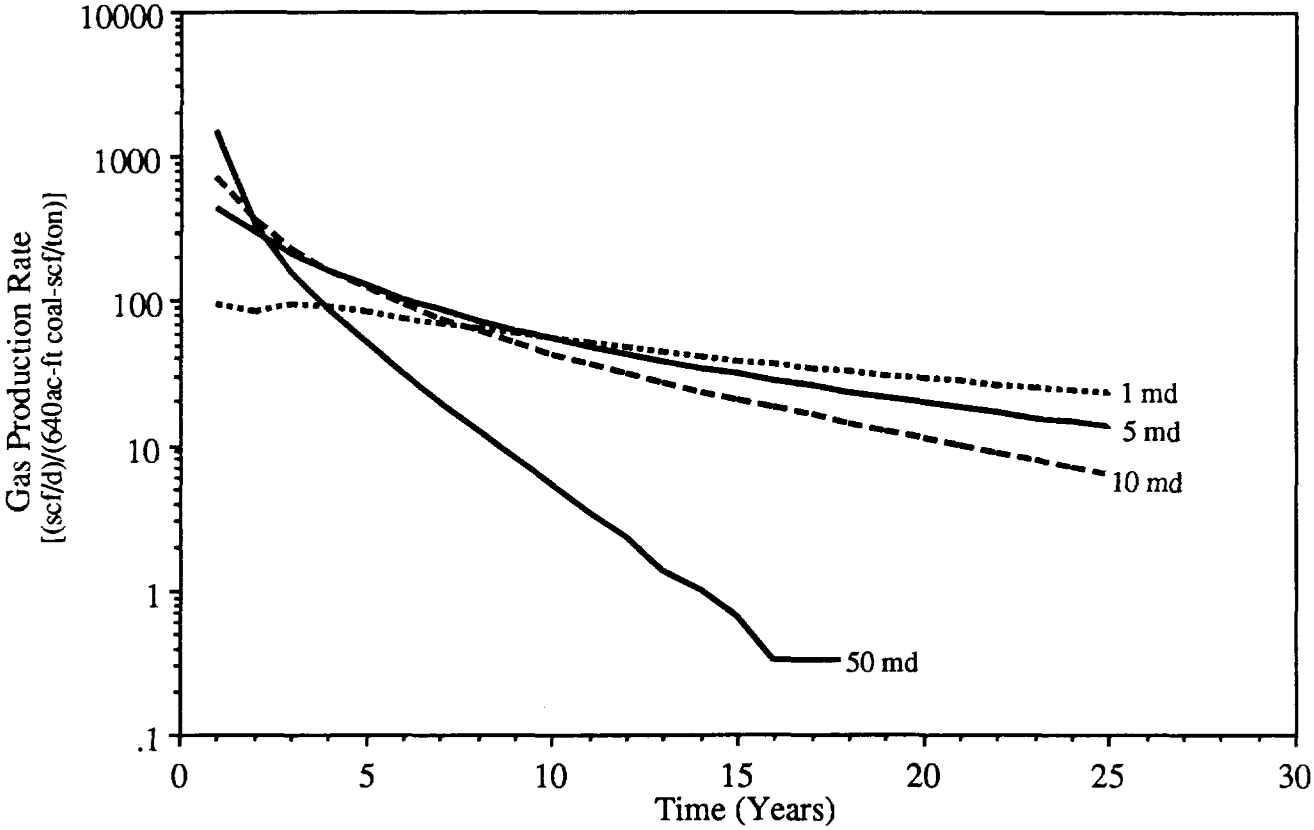

* - All Simulation Cases Shown in Figures.

- Six variation cases run in addition to original Area 1 matrix simulations.

# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Gas Production for a 160 Acre Well Spacing**



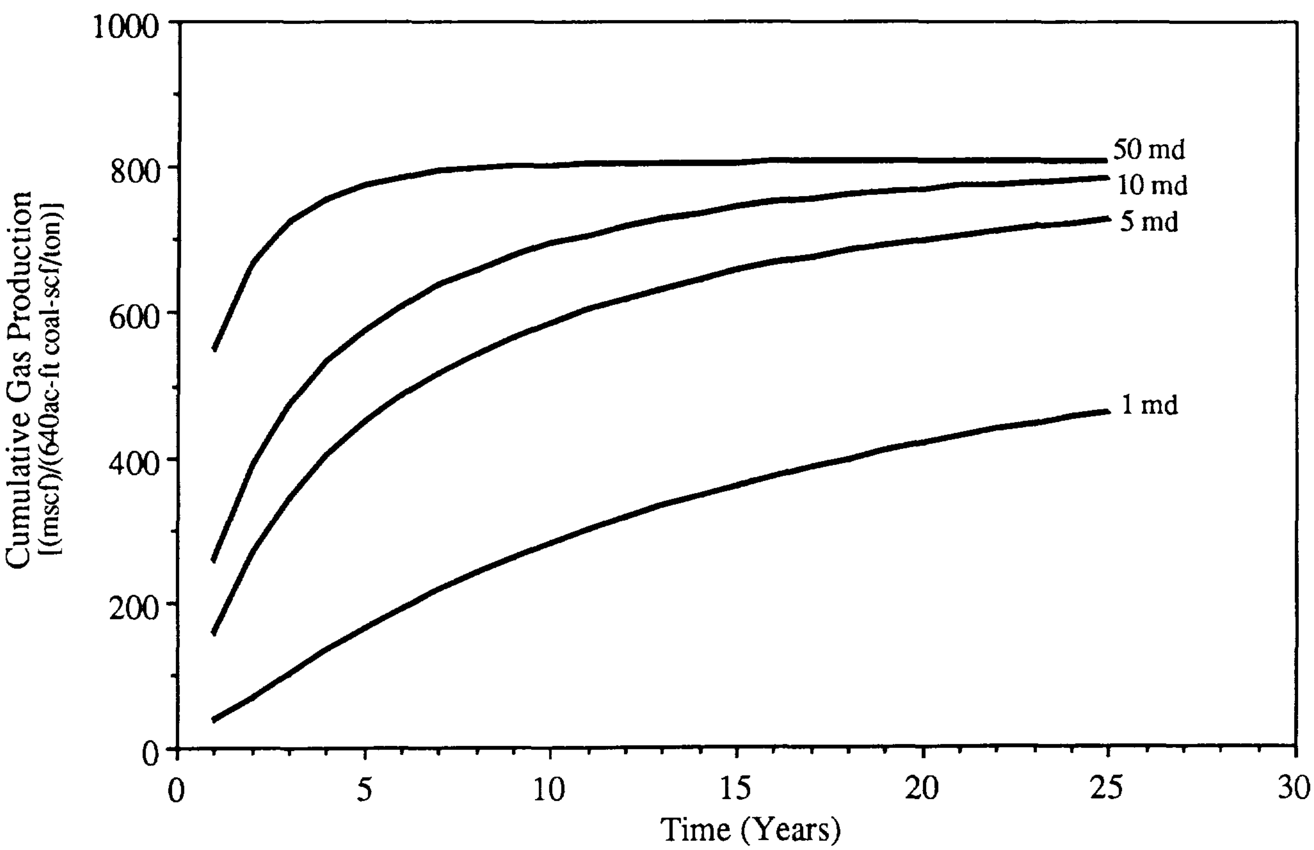
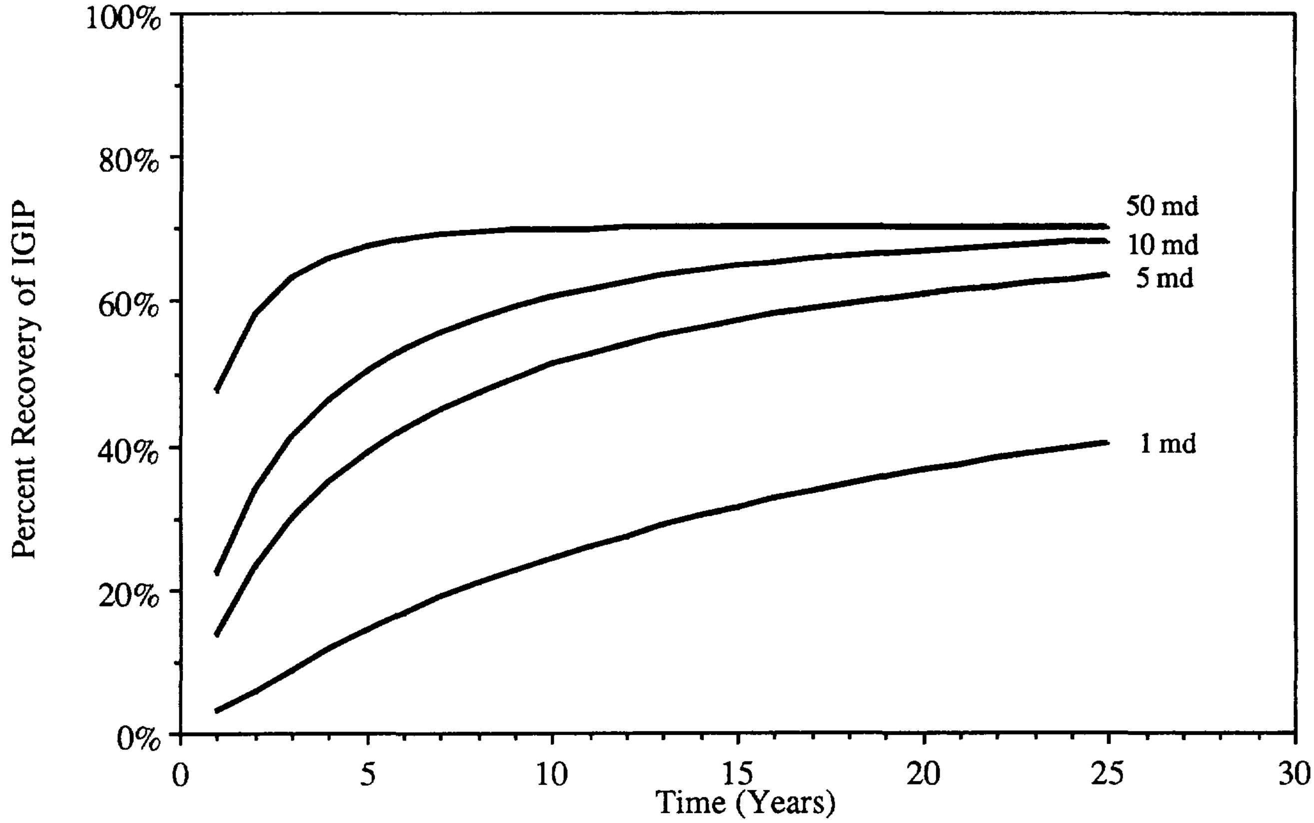



EXHIBIT 86

# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

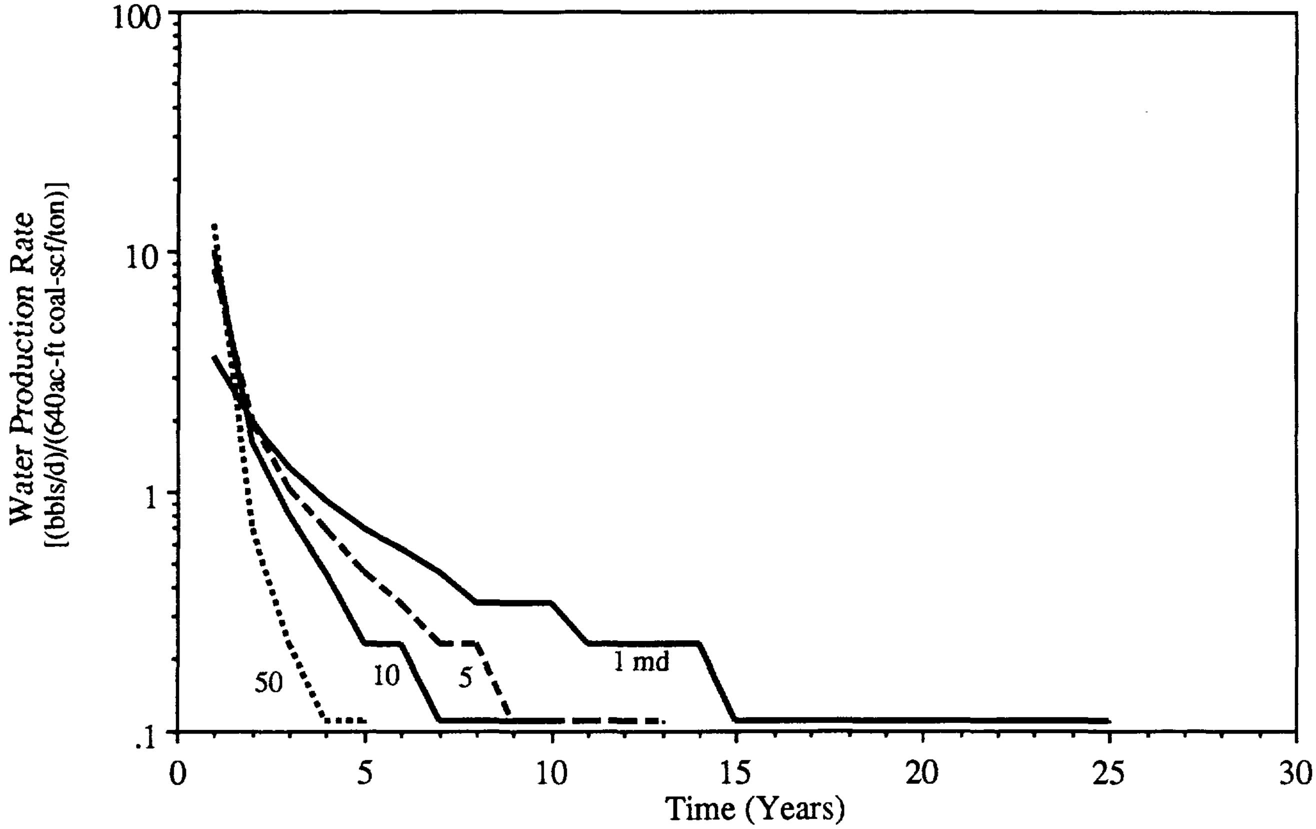
**Gas Recovery for a 160 Acre Well Spacing**

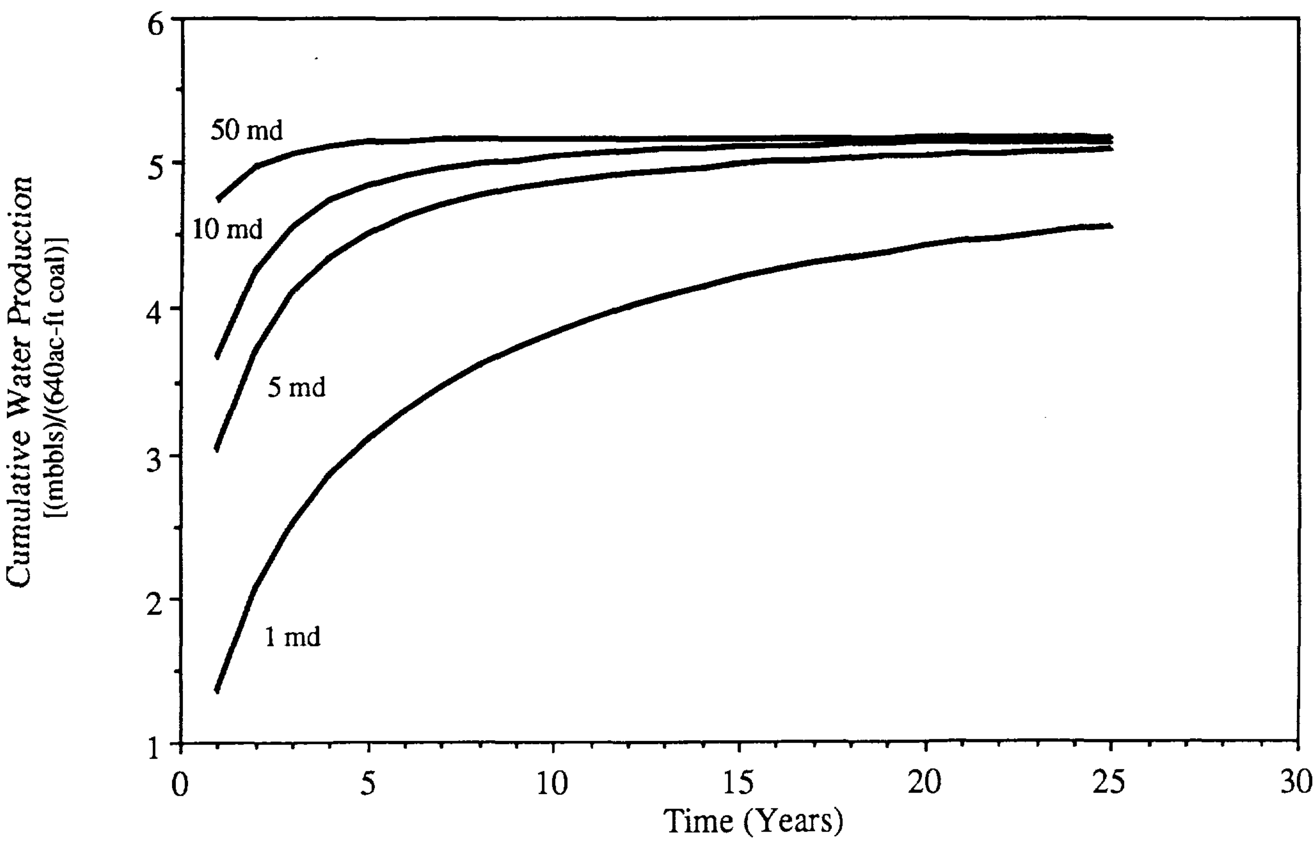


# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

### Water Production for a 160 Acre Well Spacing

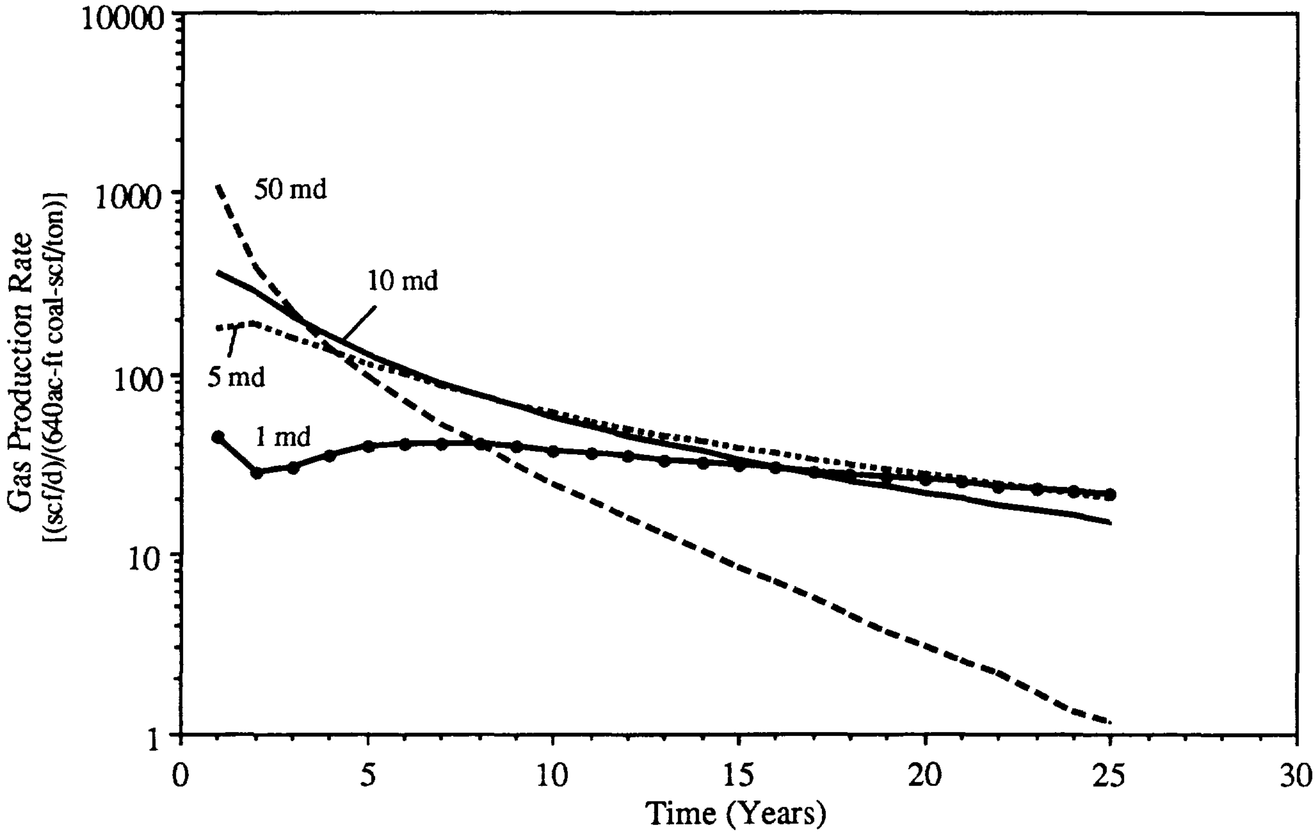


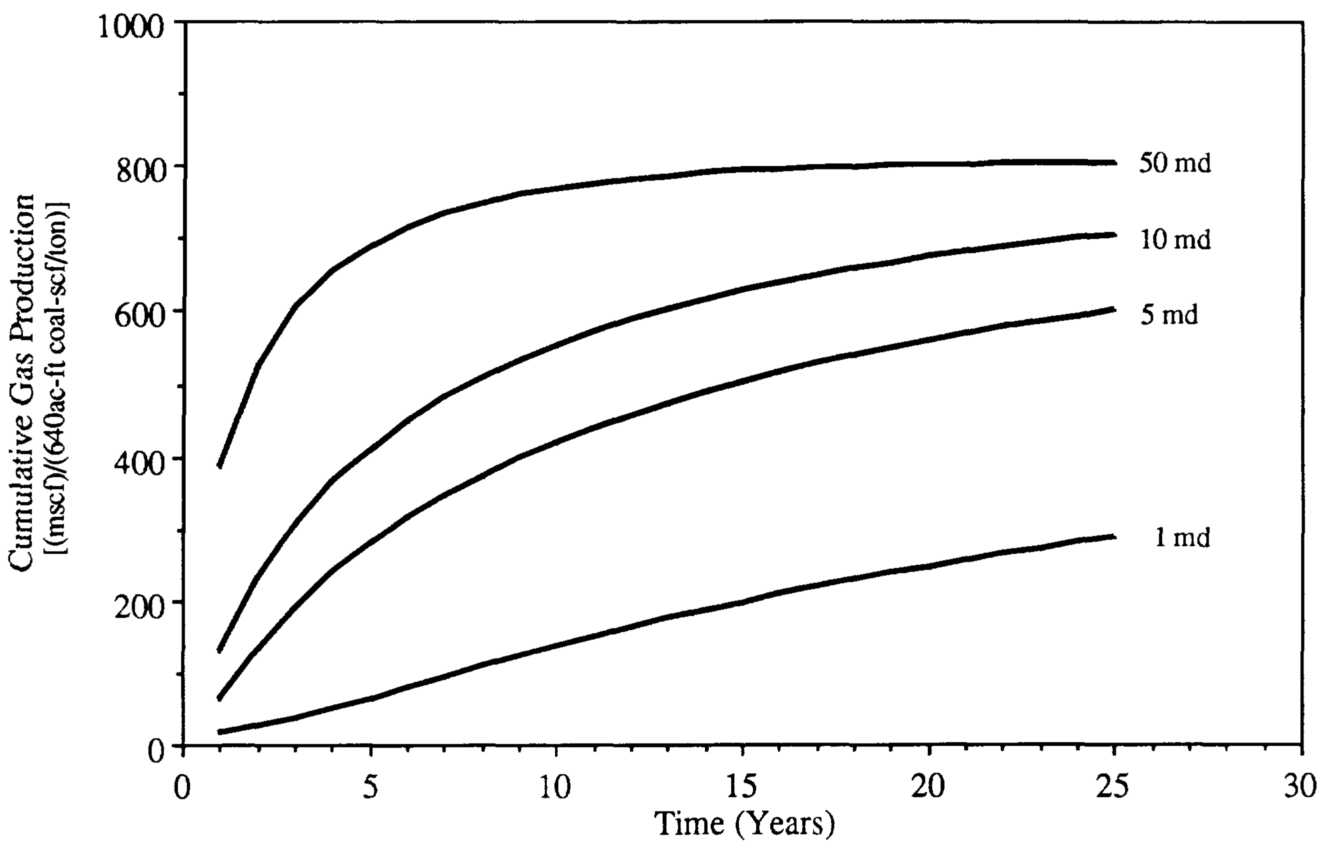



# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Gas Production for a 320 Acre Well Spacing**

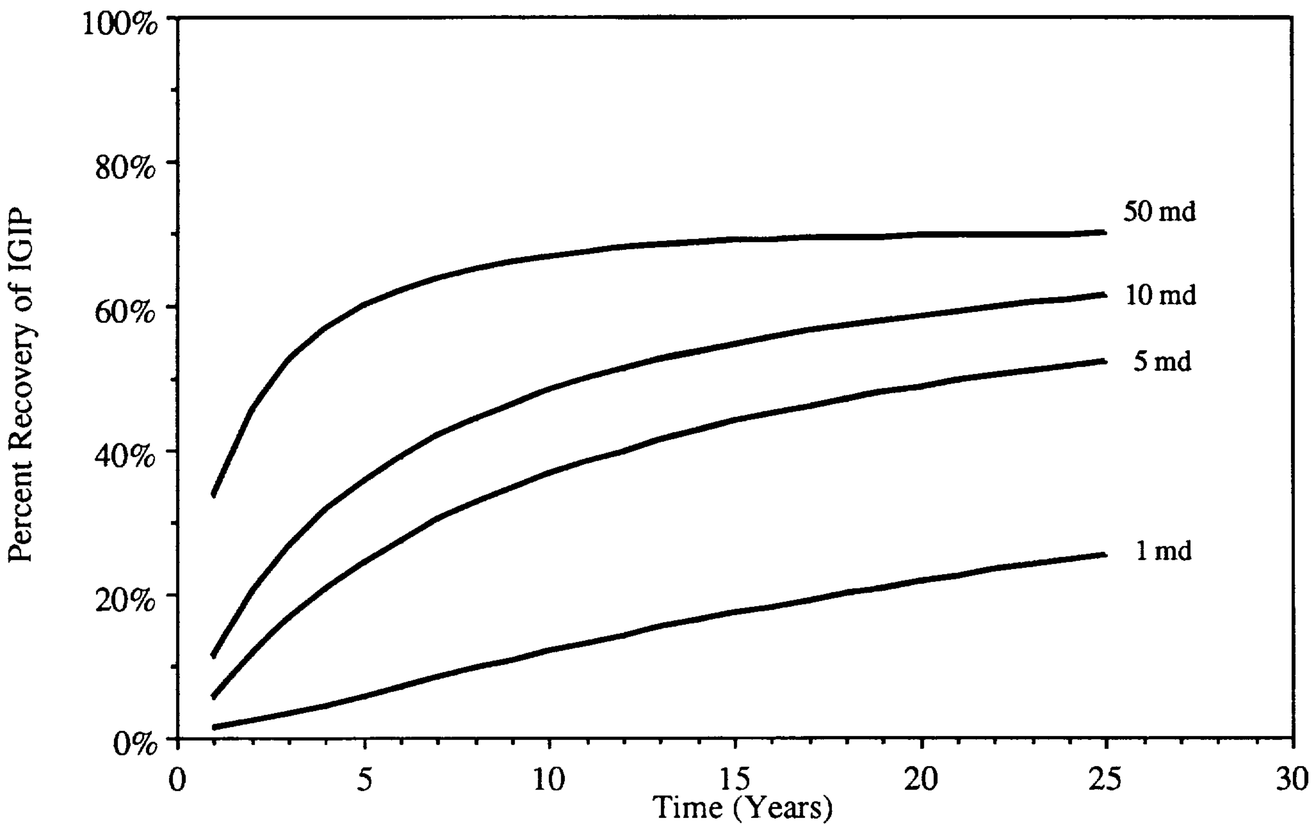


# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

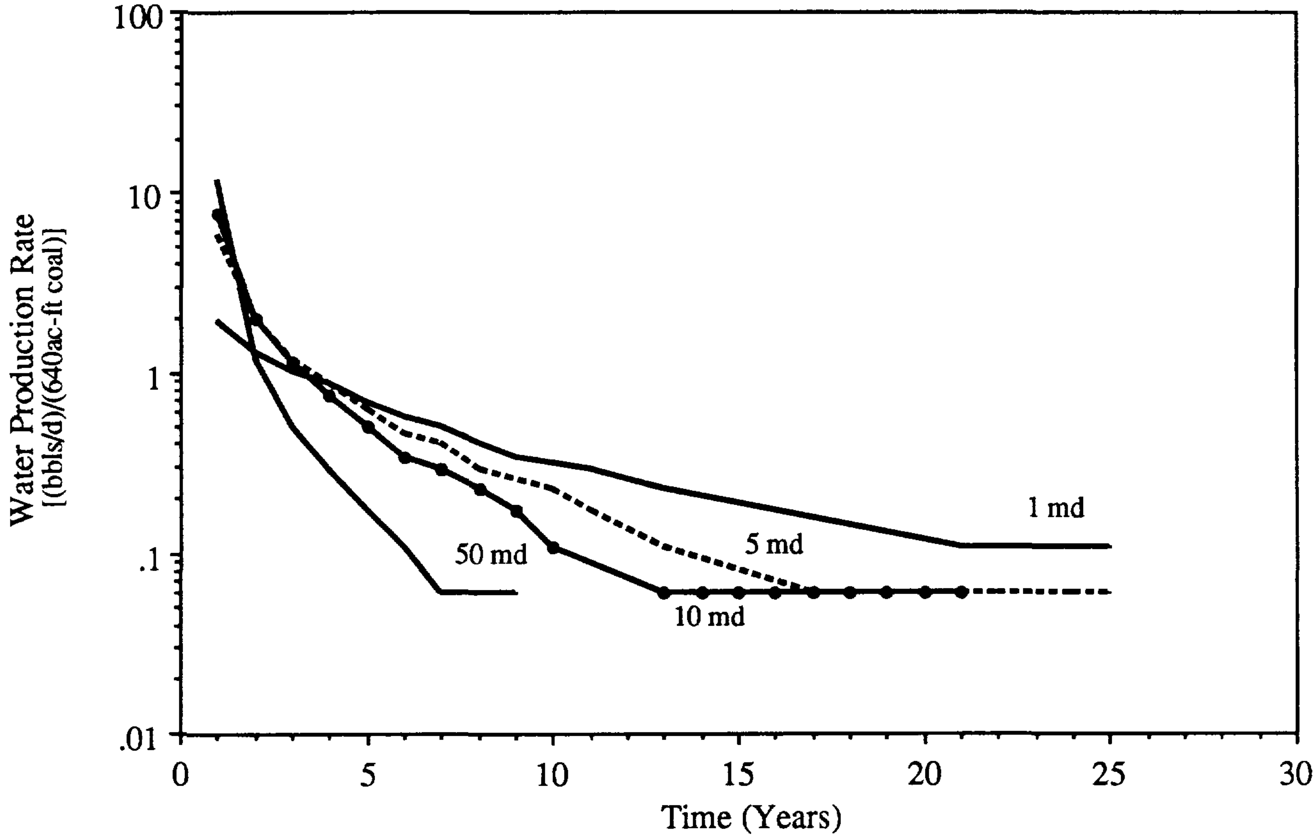
**Gas Recovery for a 320 Acre Well Spacing**

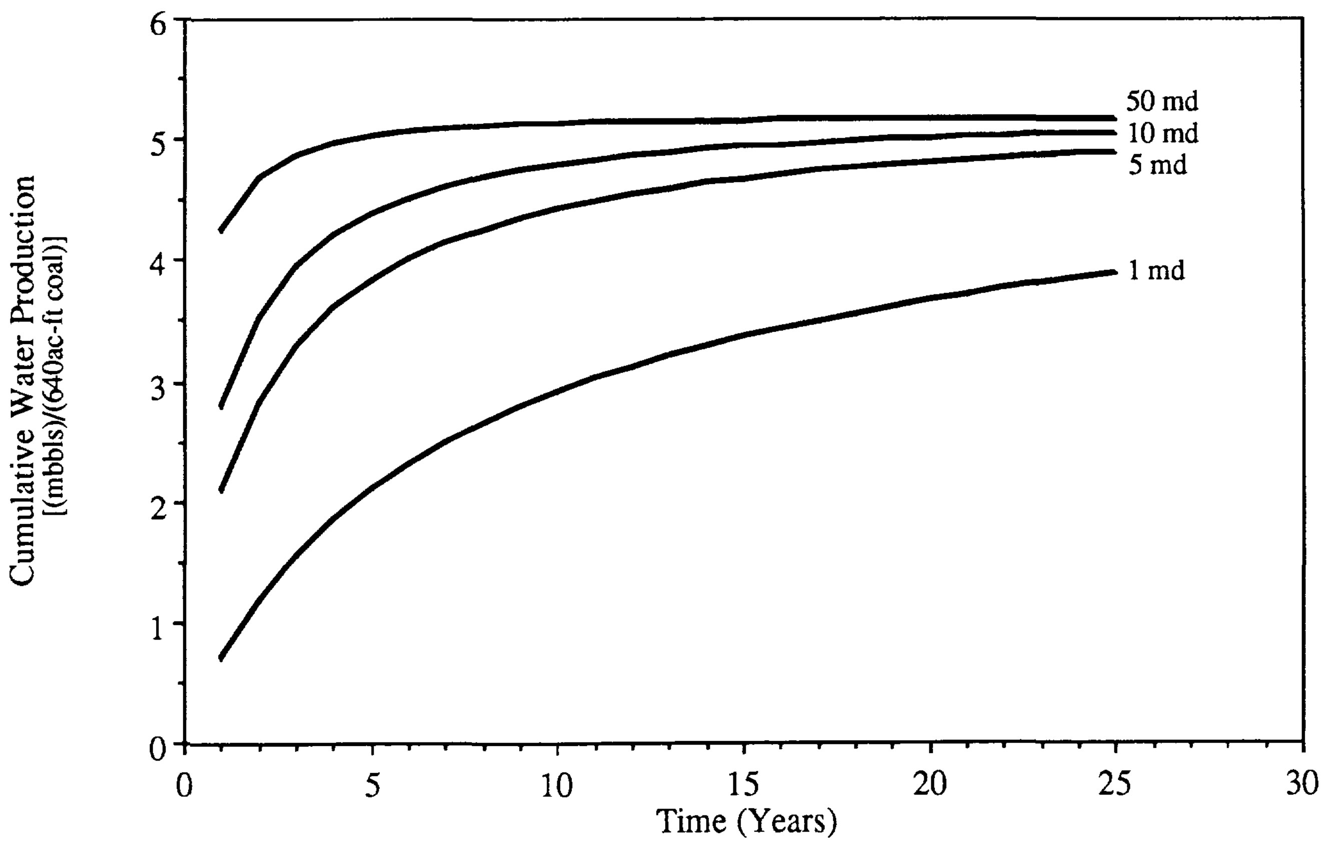


# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Water Production for a 320 Acre Well Spacing**

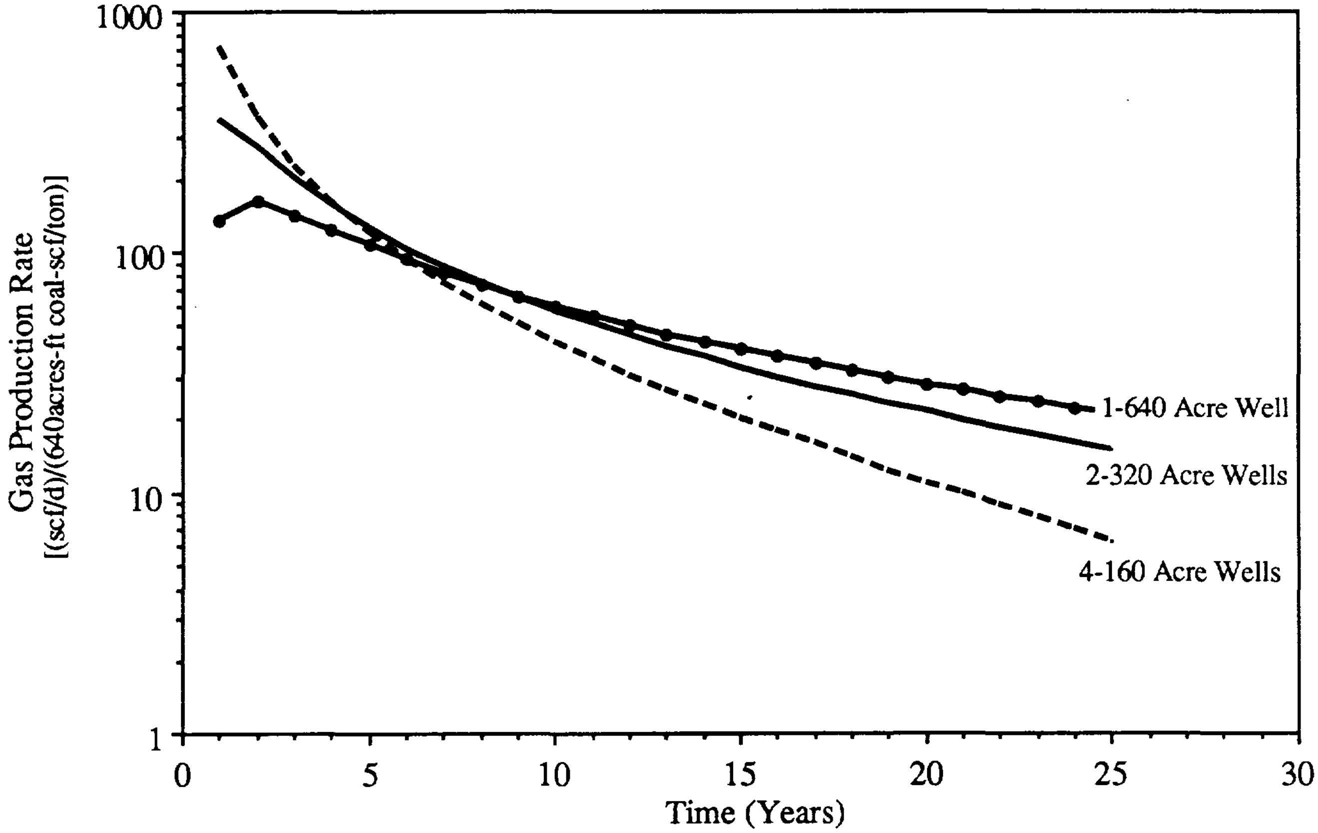


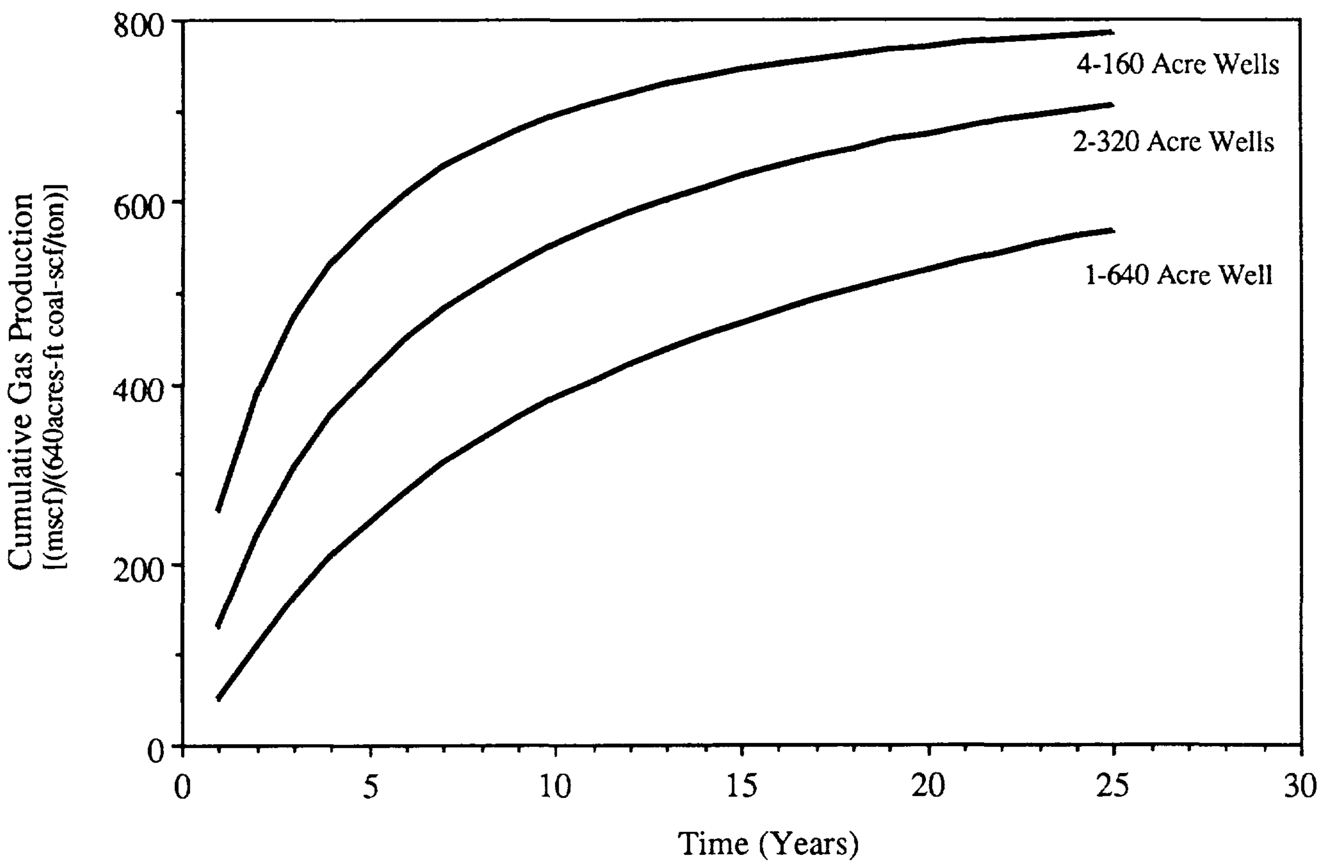



# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

### Gas Production for a Cleat Permeability of 10 md

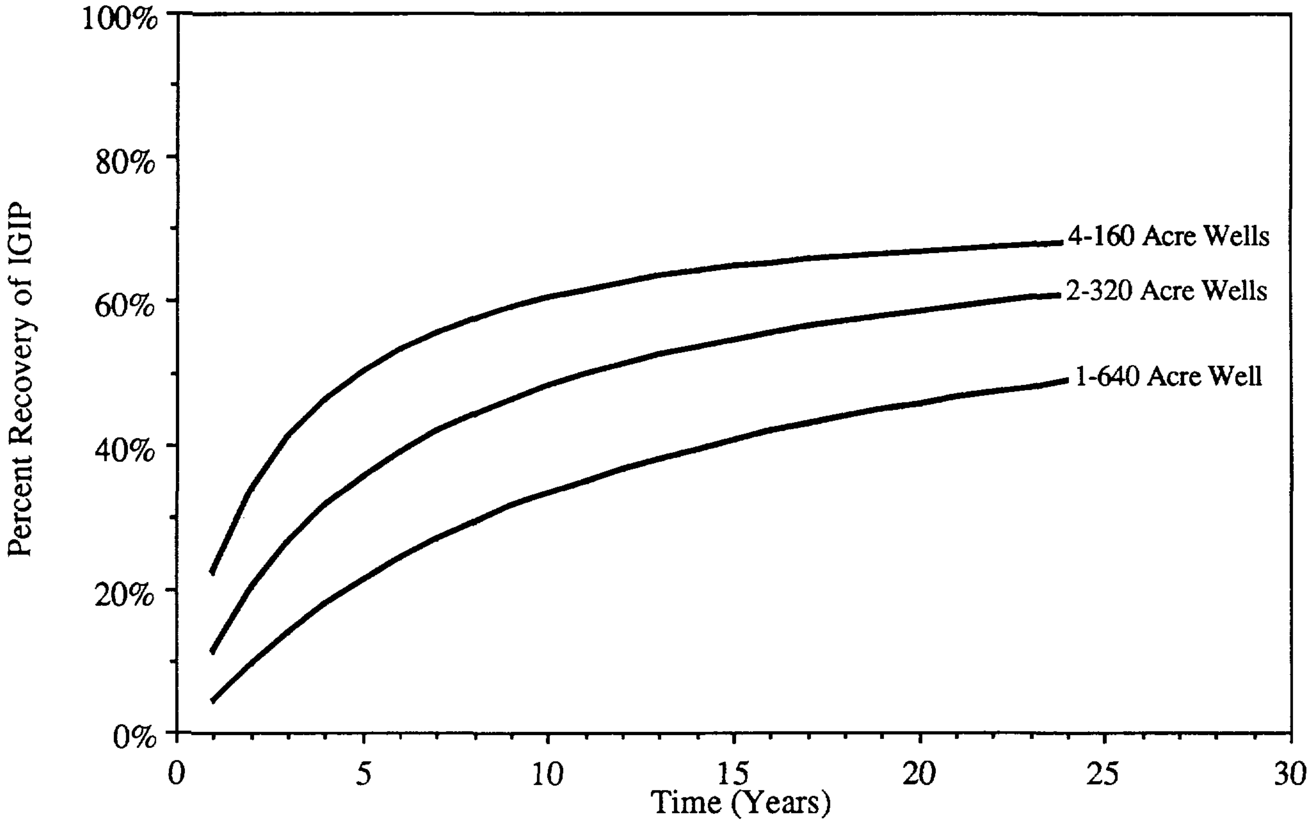


San Juan Basin Coalbed Methane Spacing Study

Area 1 Sensitivity Analyses

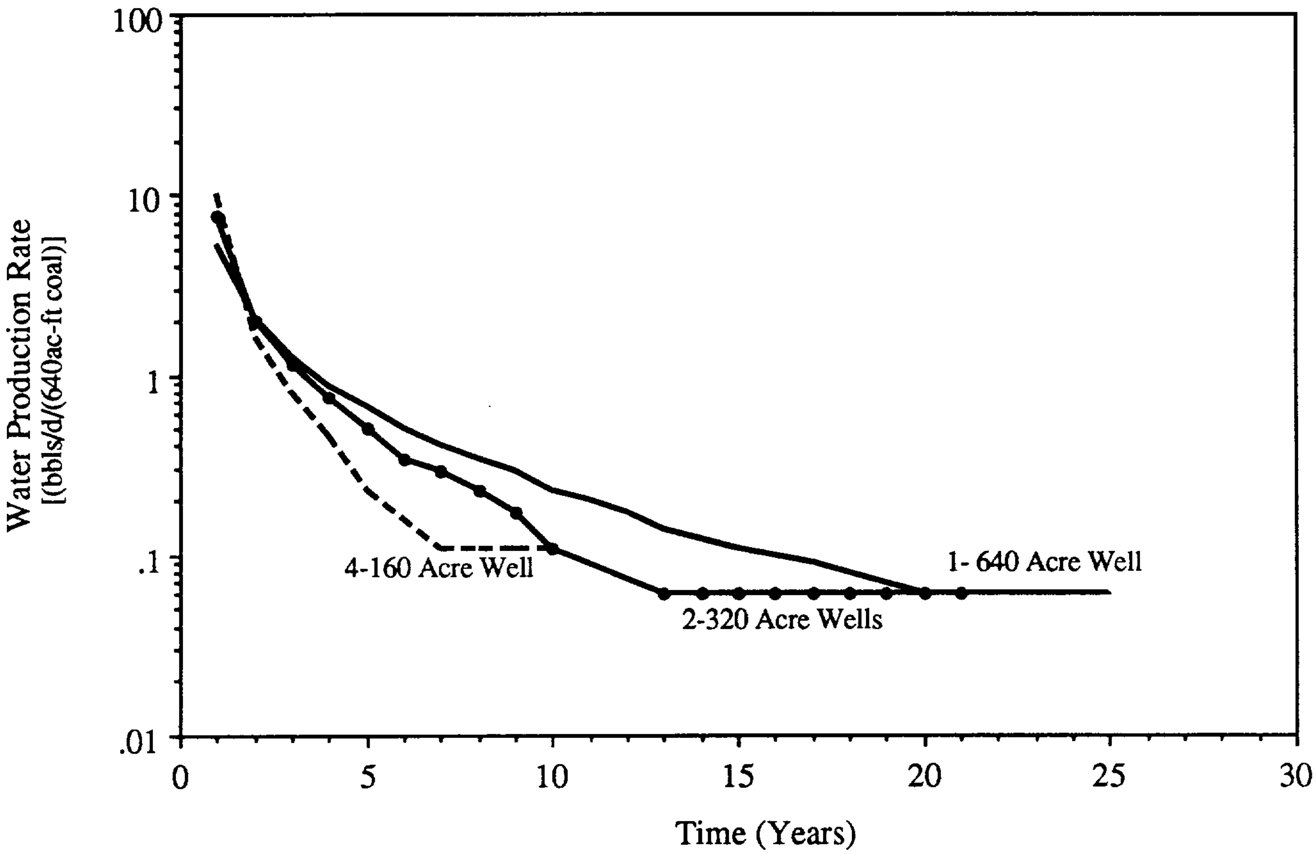
**Gas Recovery for a Cleat Permeability of 10 md**

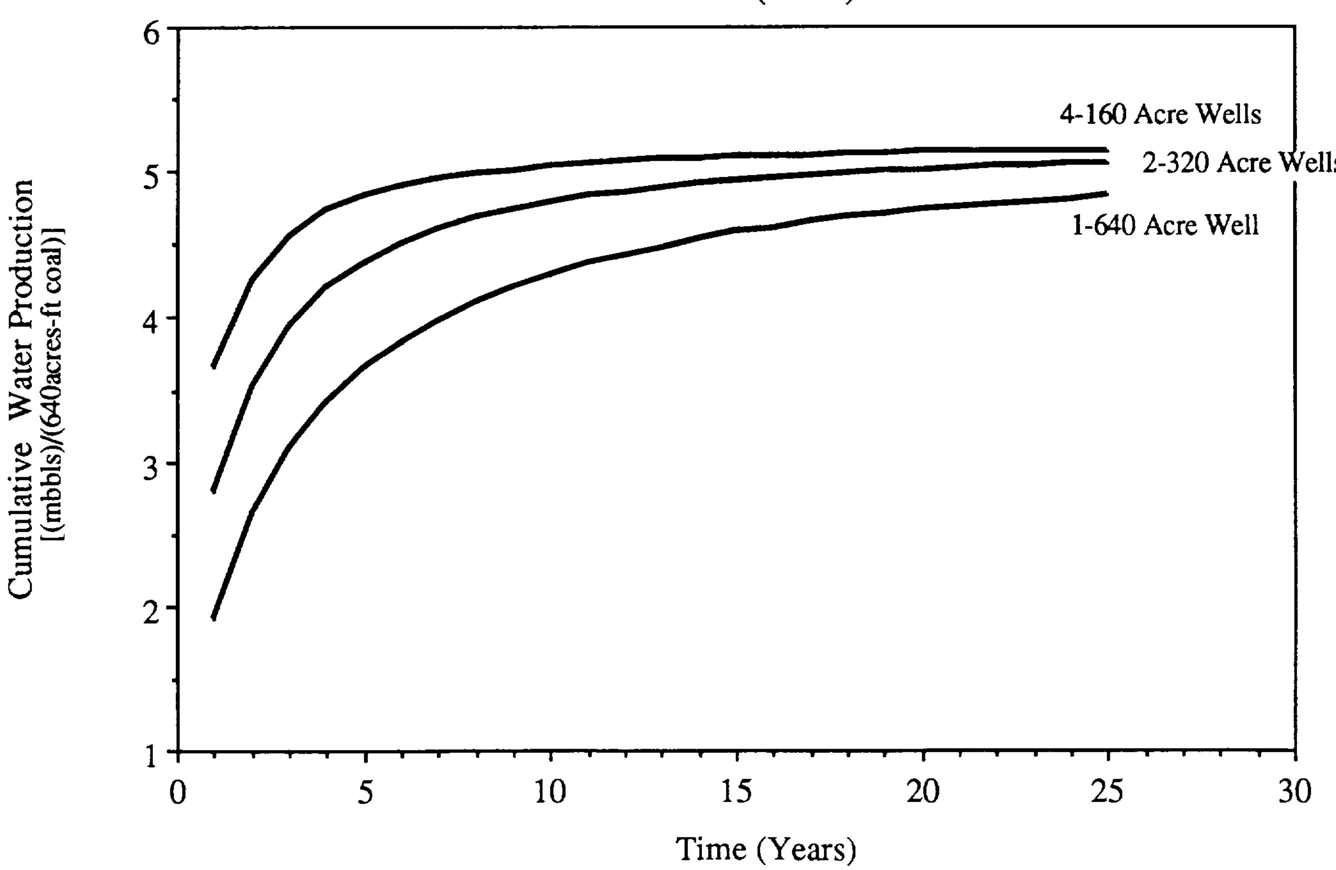


# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Water Production for a Cleat Permeability of 10 md**

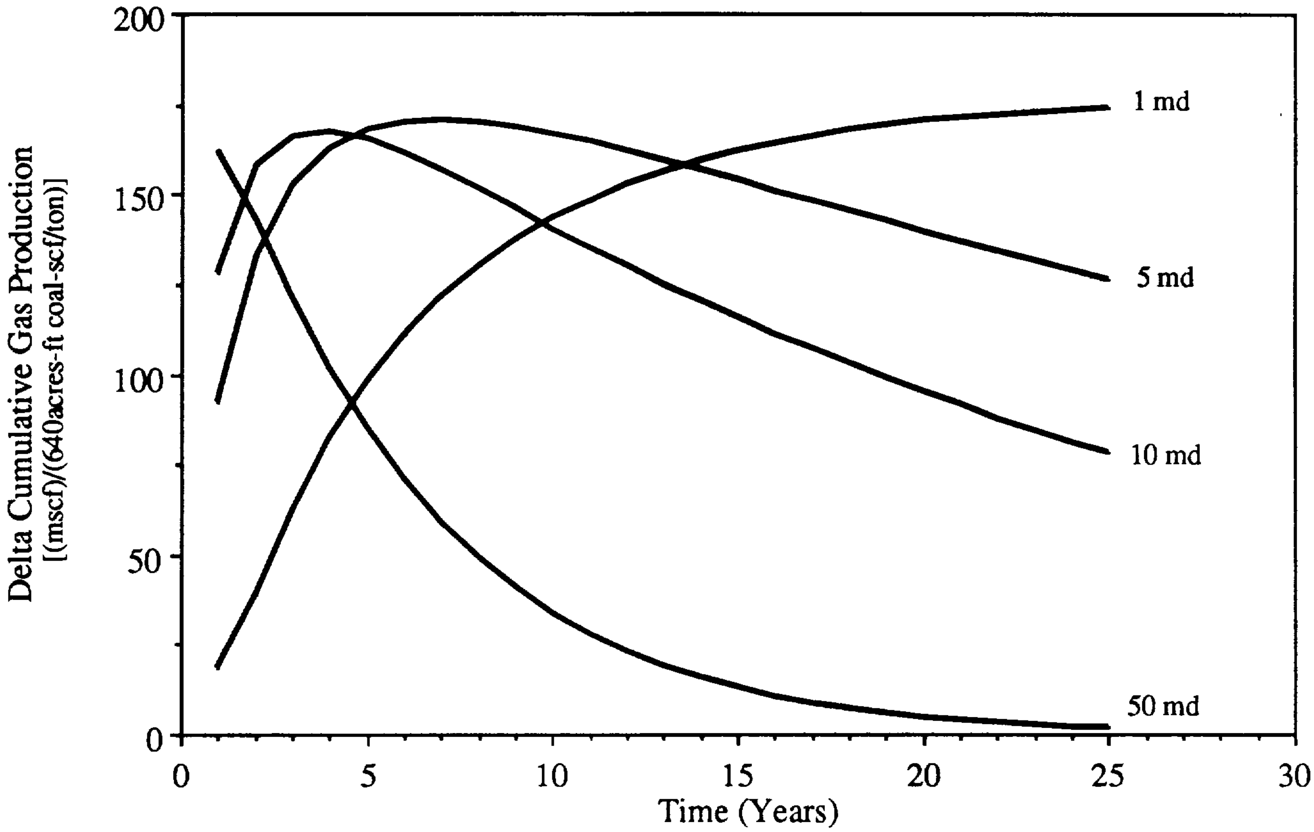


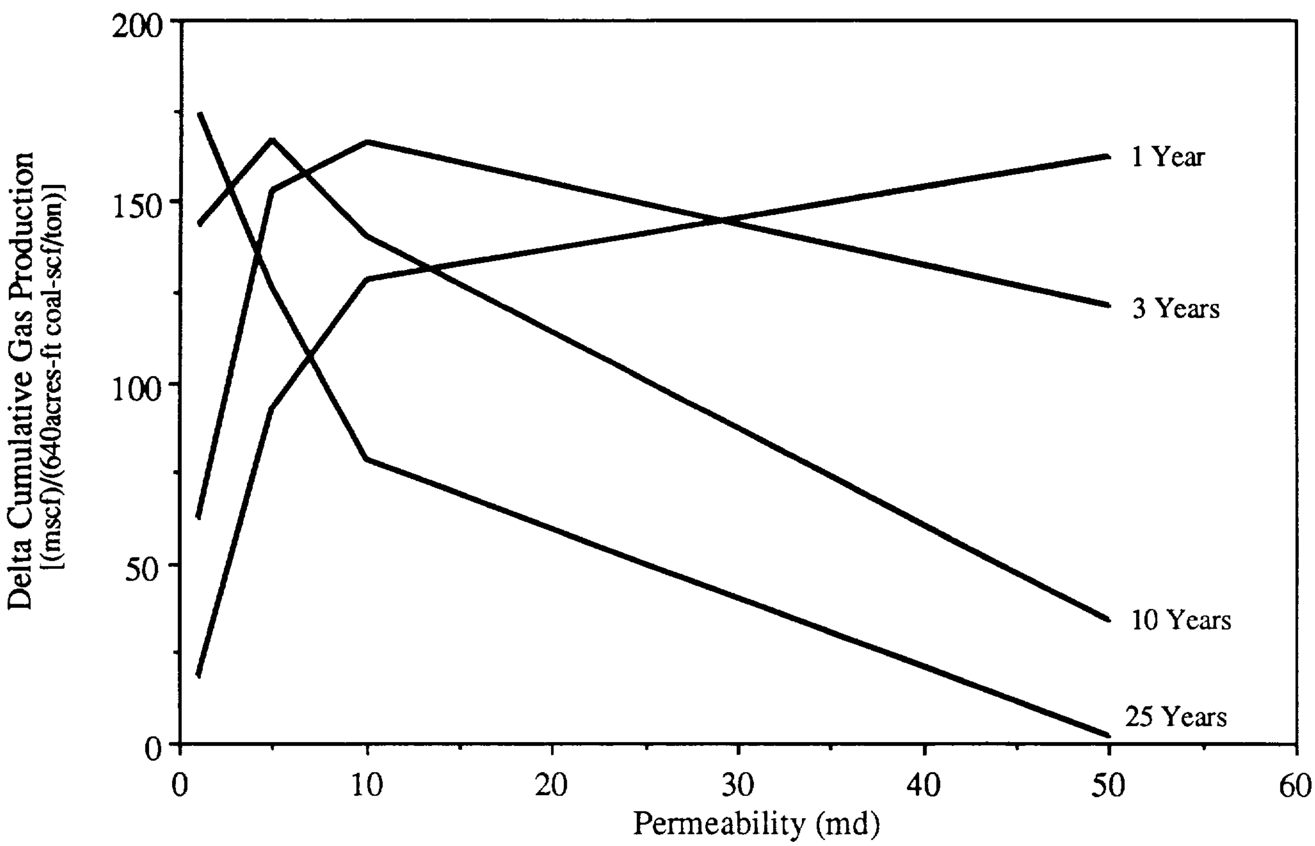



# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Difference in Cumulative Gas Production Between 320 and 160 Acre Well Spacings**

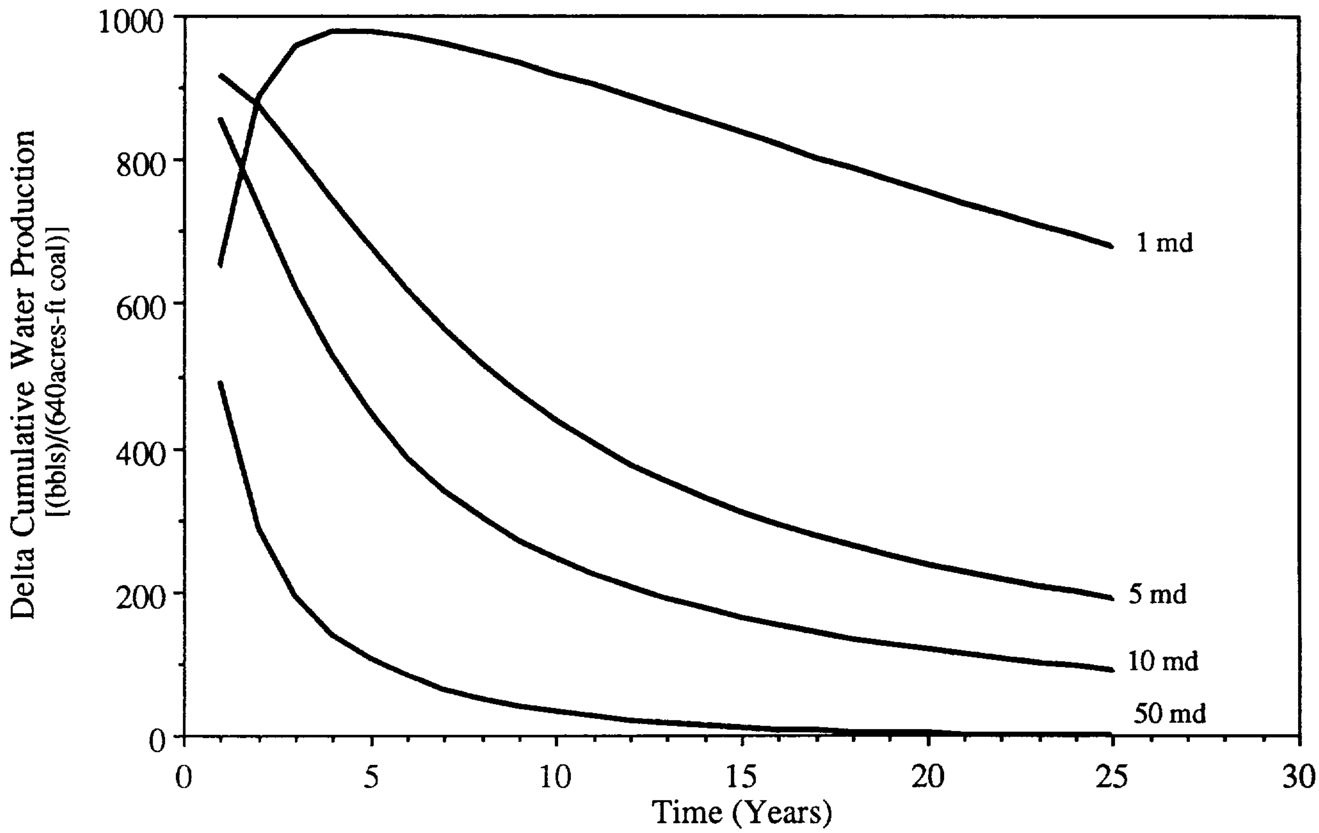


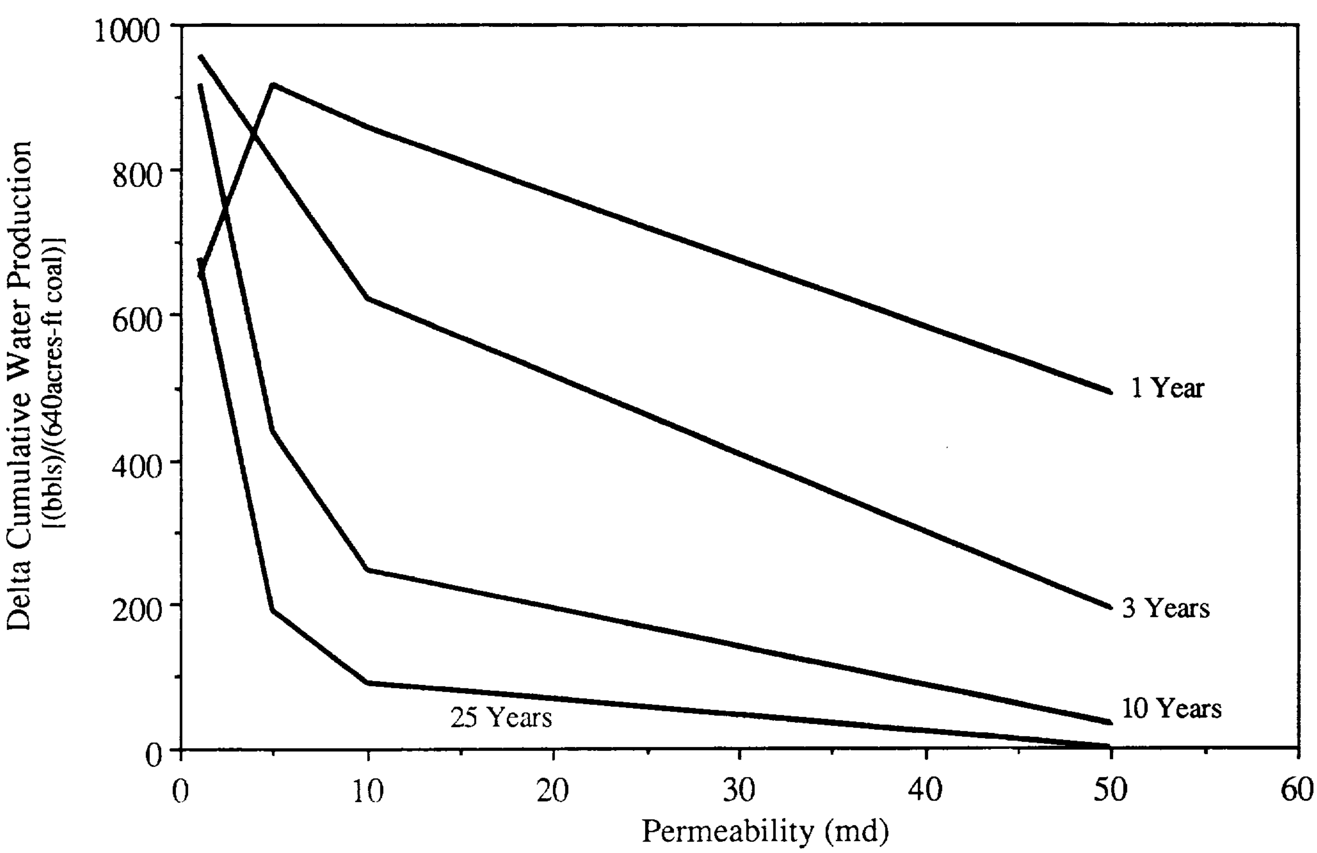



# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Difference in Cumulative Water Production Between 320 and 160 Acre Well Spacings**

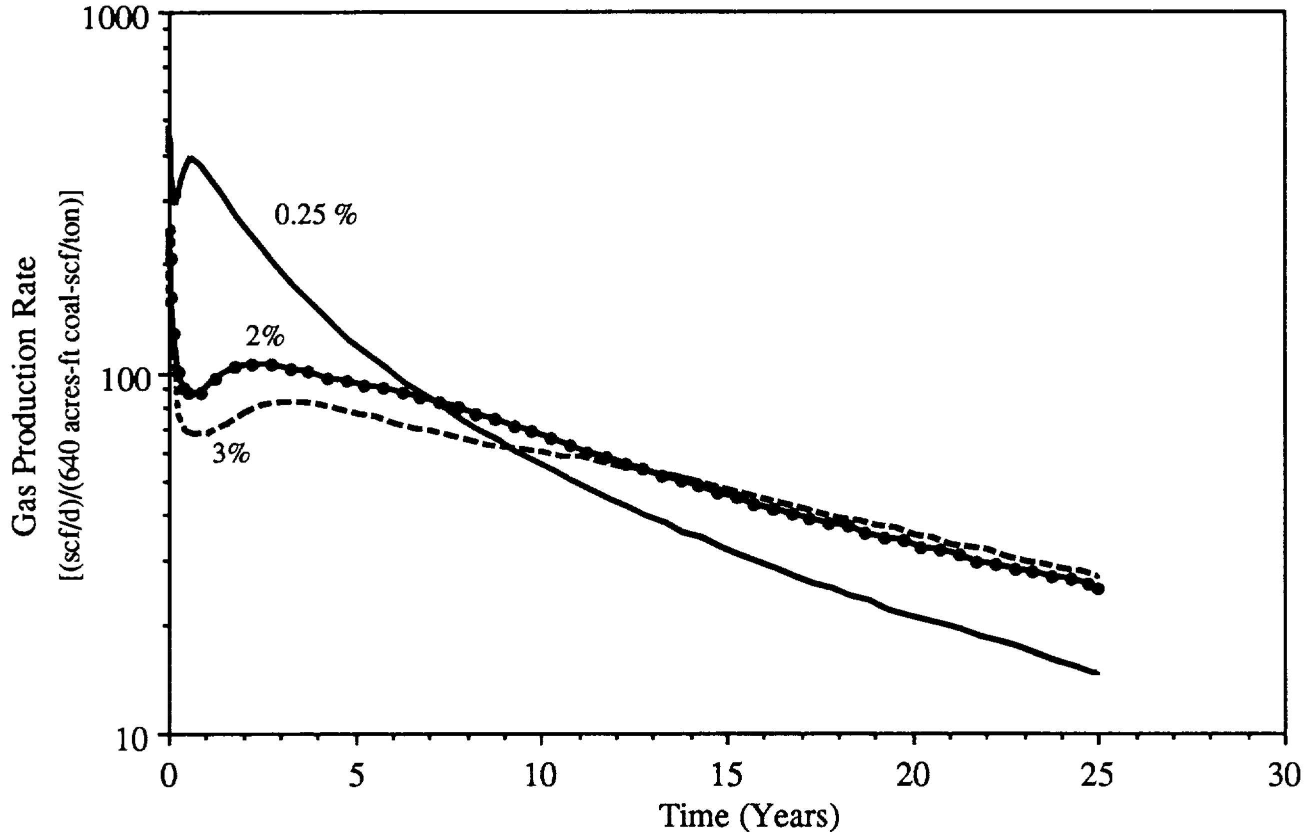


# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Gas Production for Variations in Cleat Porosity**



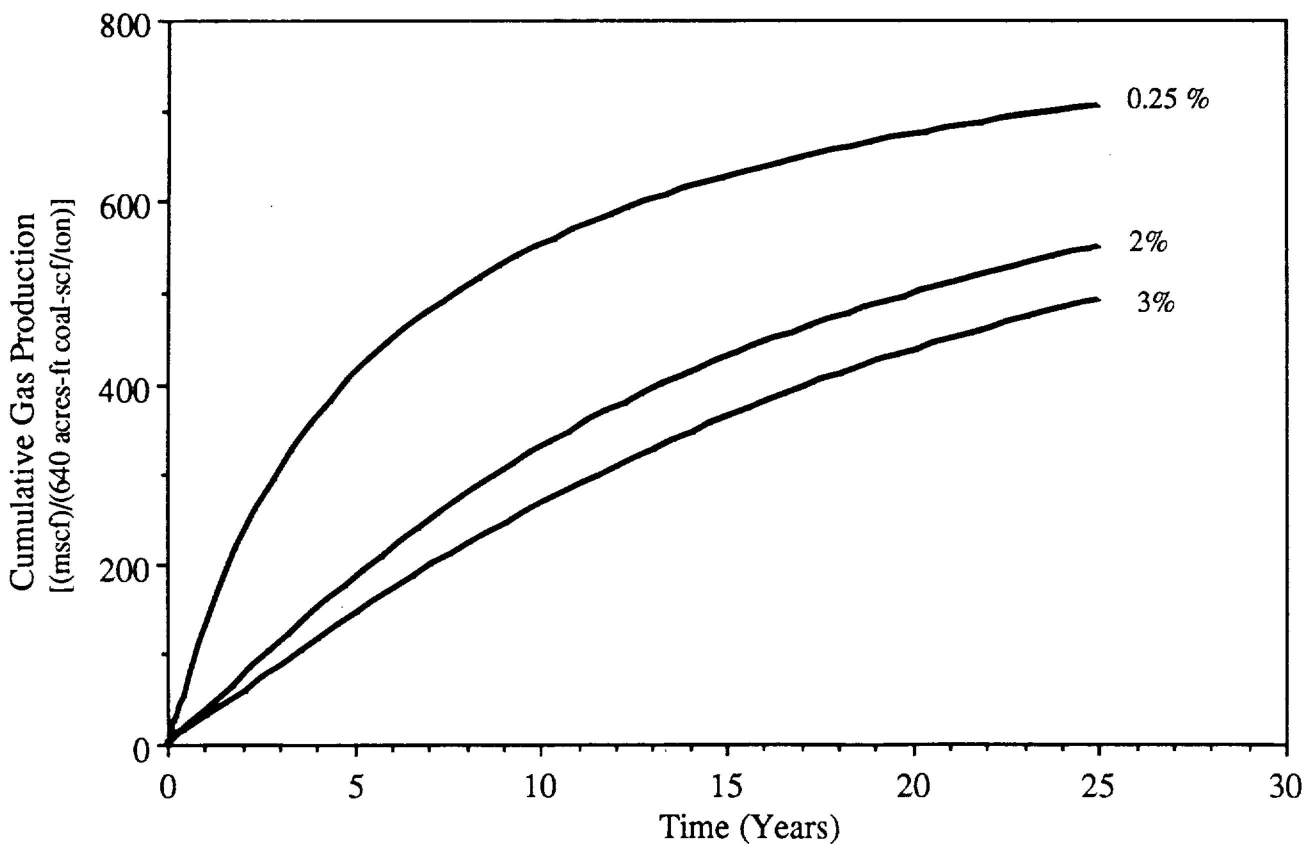
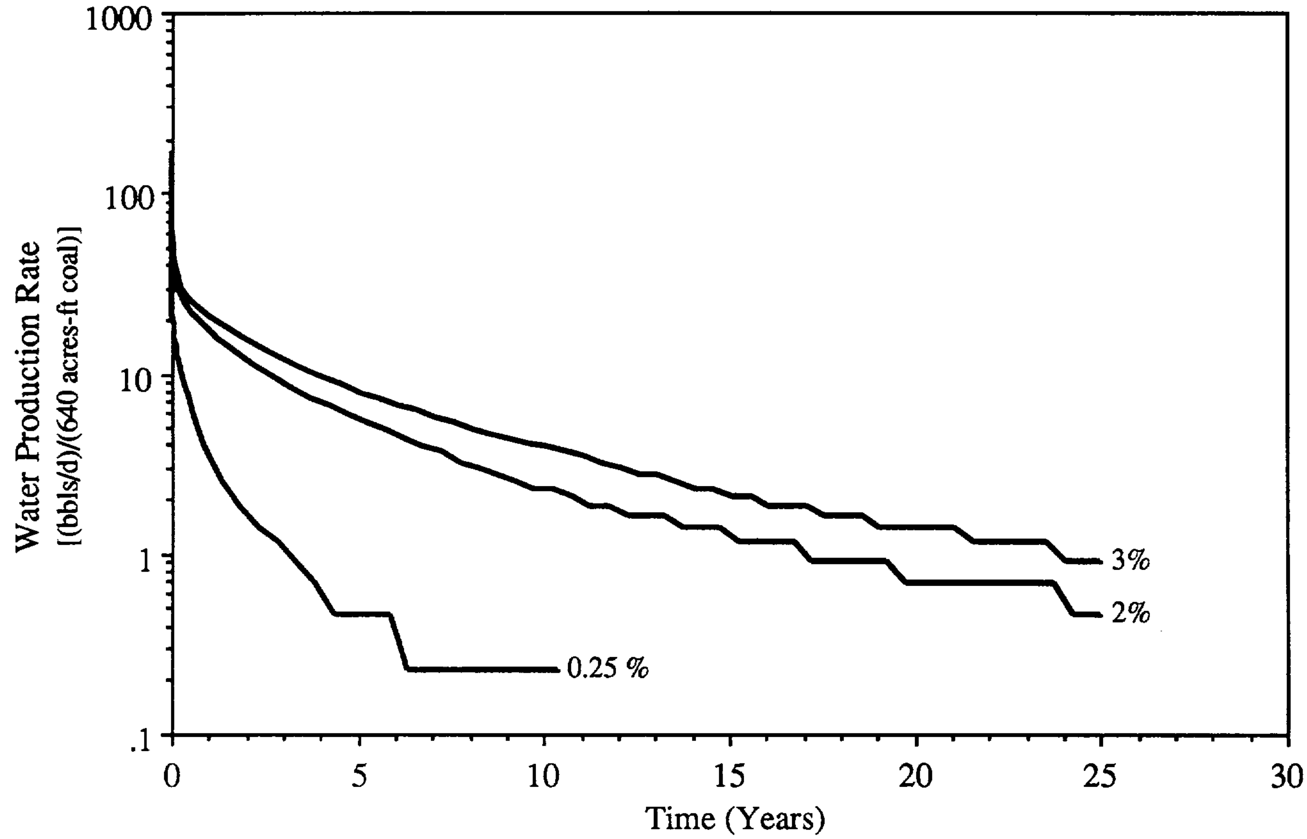



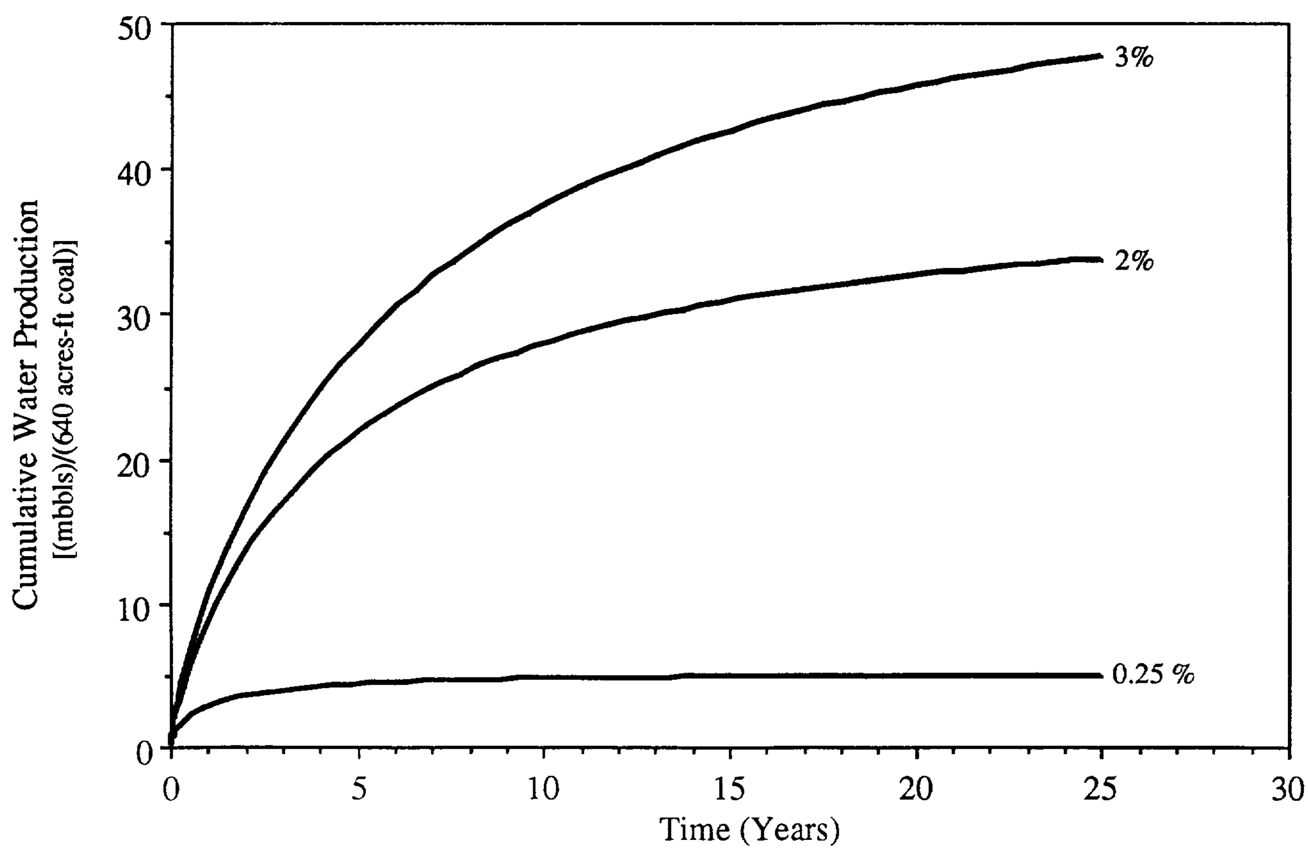
EXHIBIT 97

# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Water Production for Variations in Cleat Porosity**

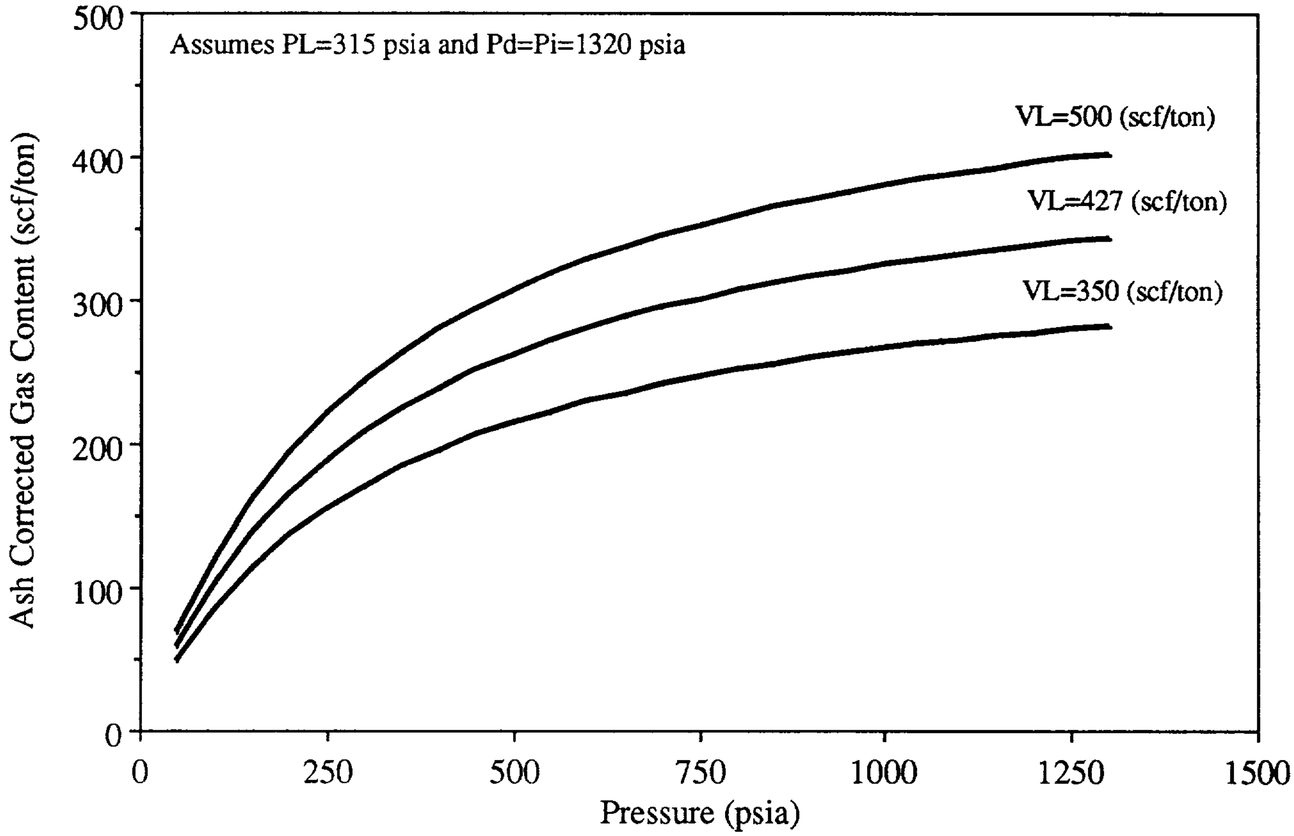


# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

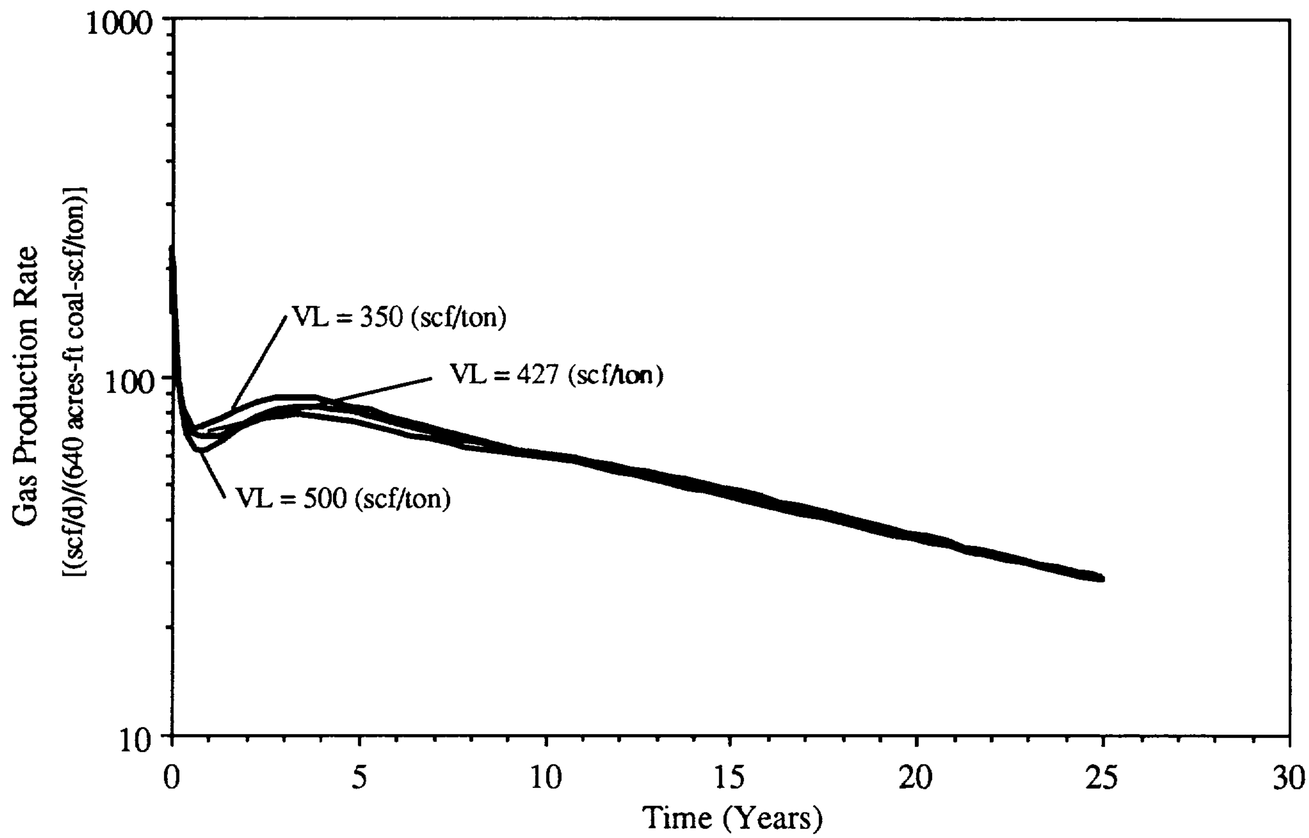
### Variations in the Sorption Isotherm



# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

### Gas Production for Variations in Langmuir Volume



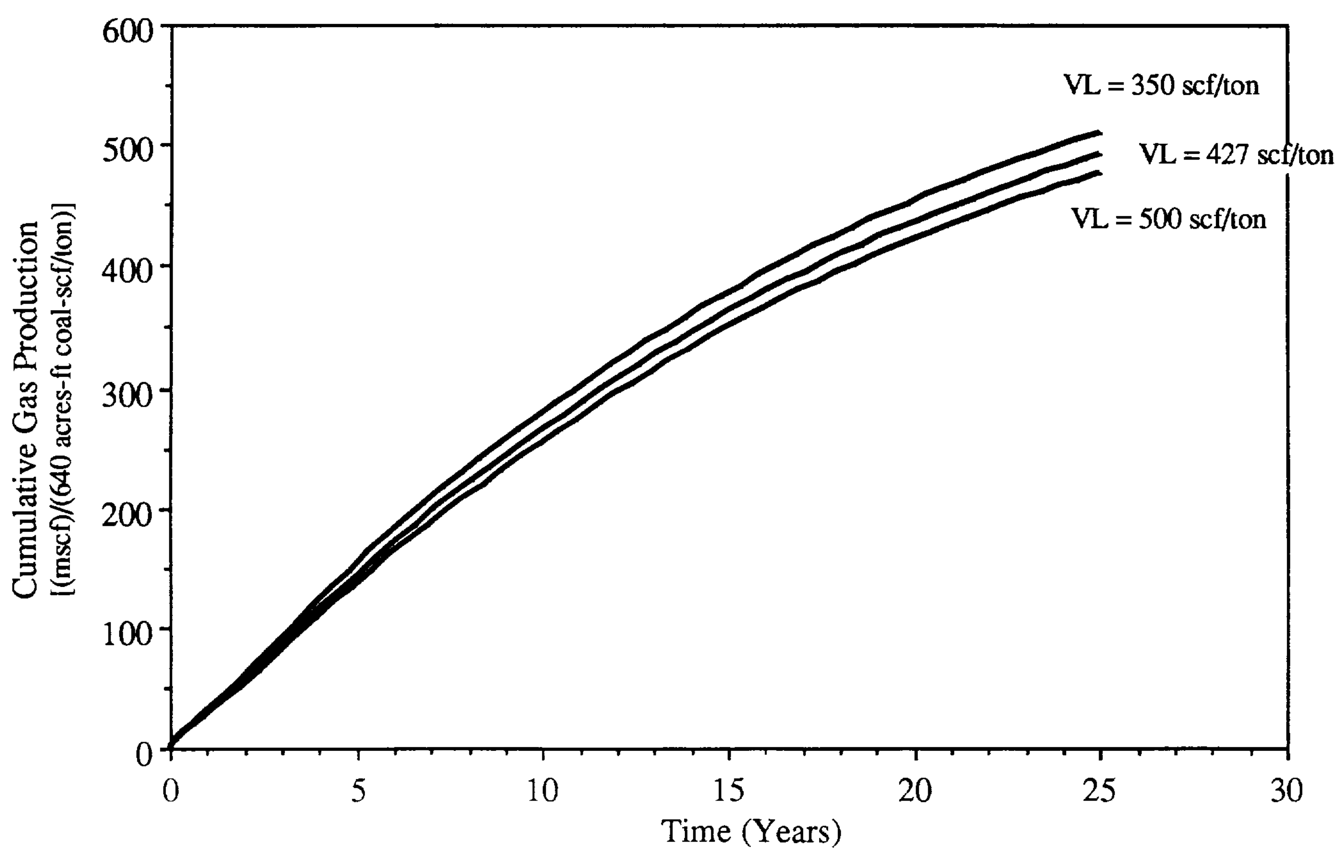
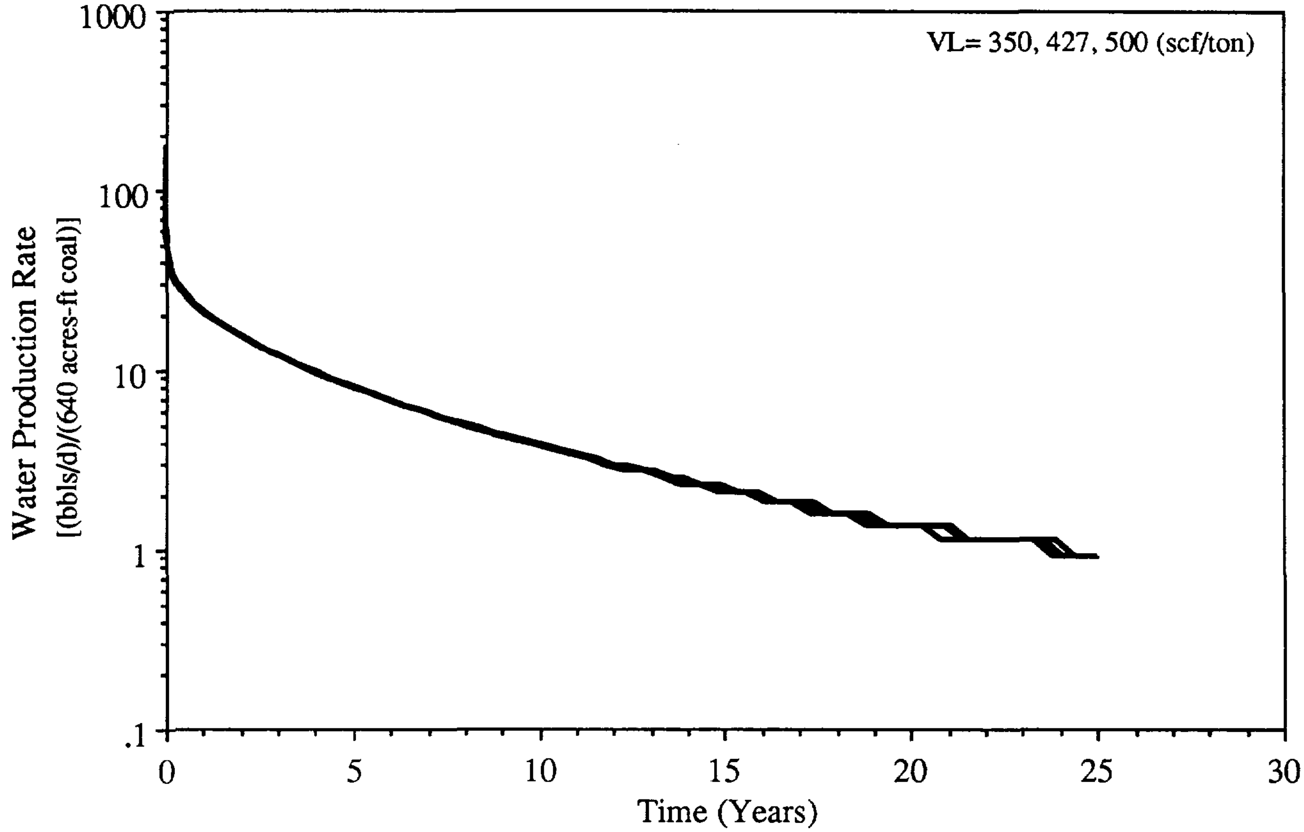



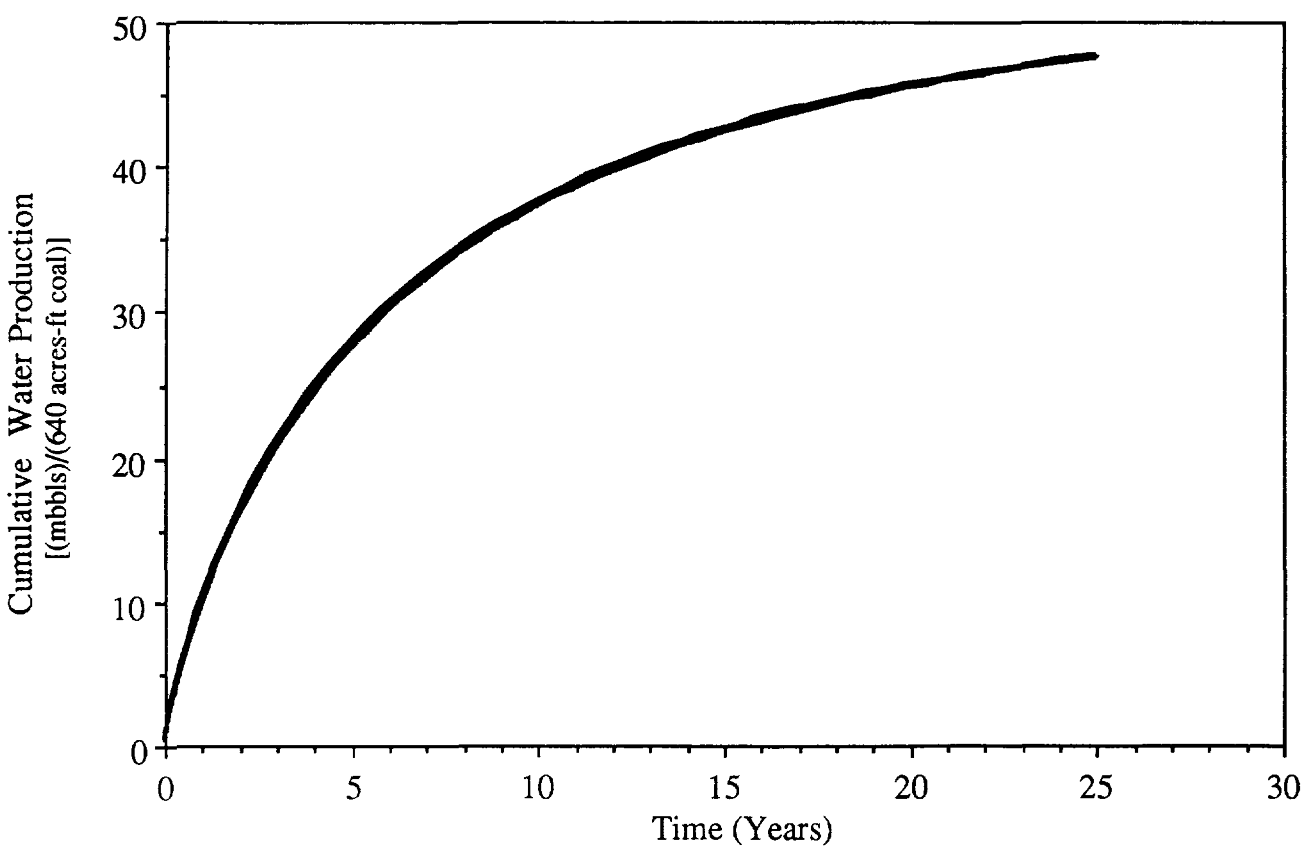
EXHIBIT 100

# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

### Water Production for Variations in Langmuir Volume

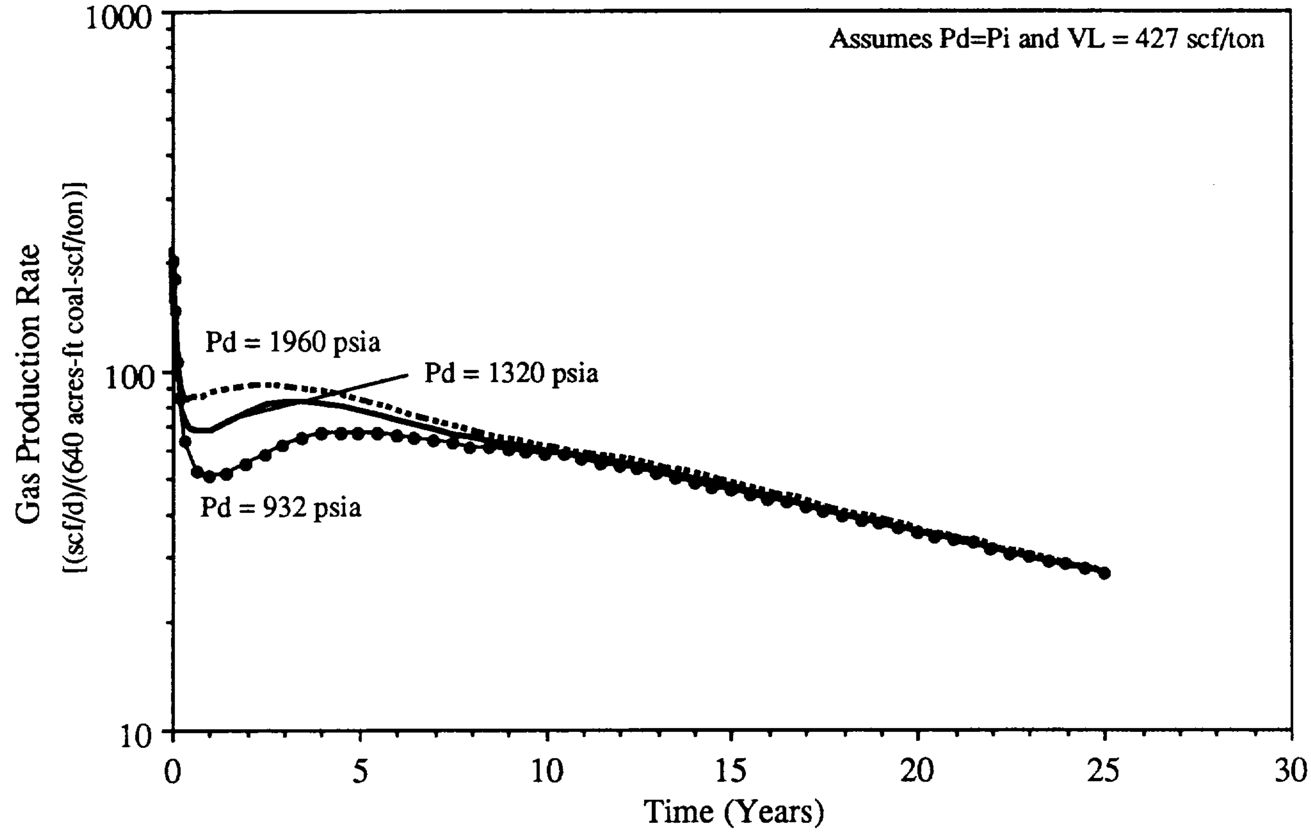


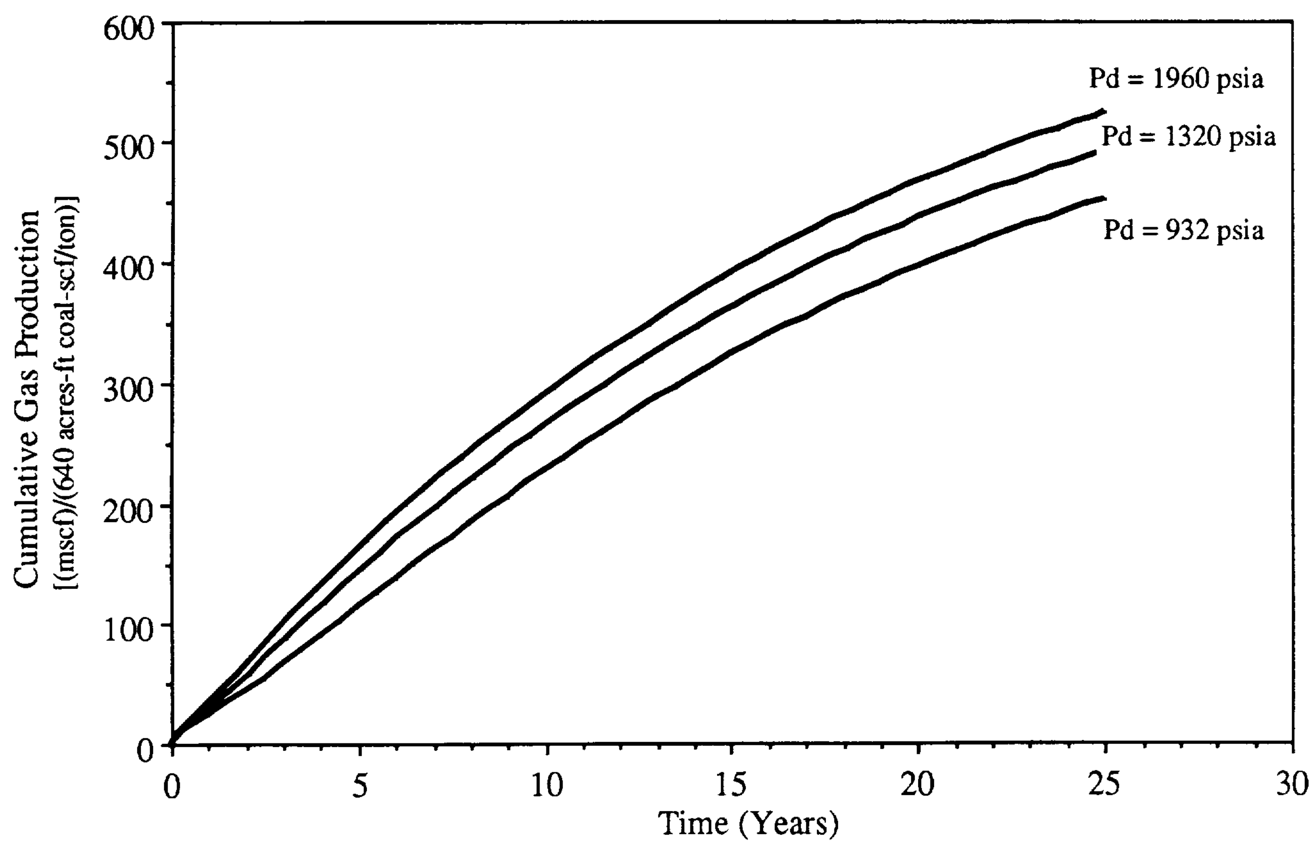



# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

### Gas Production for Variations in the Desorption Pressure

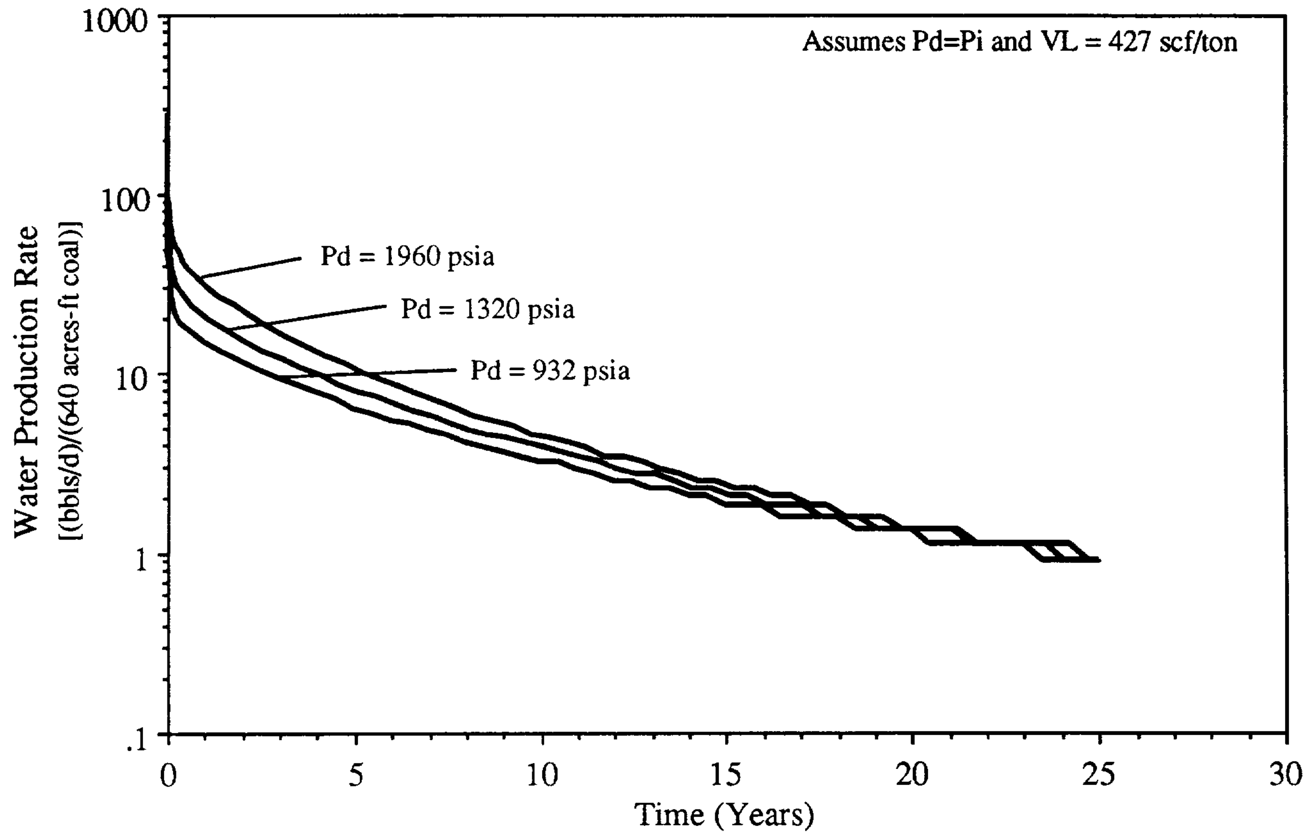


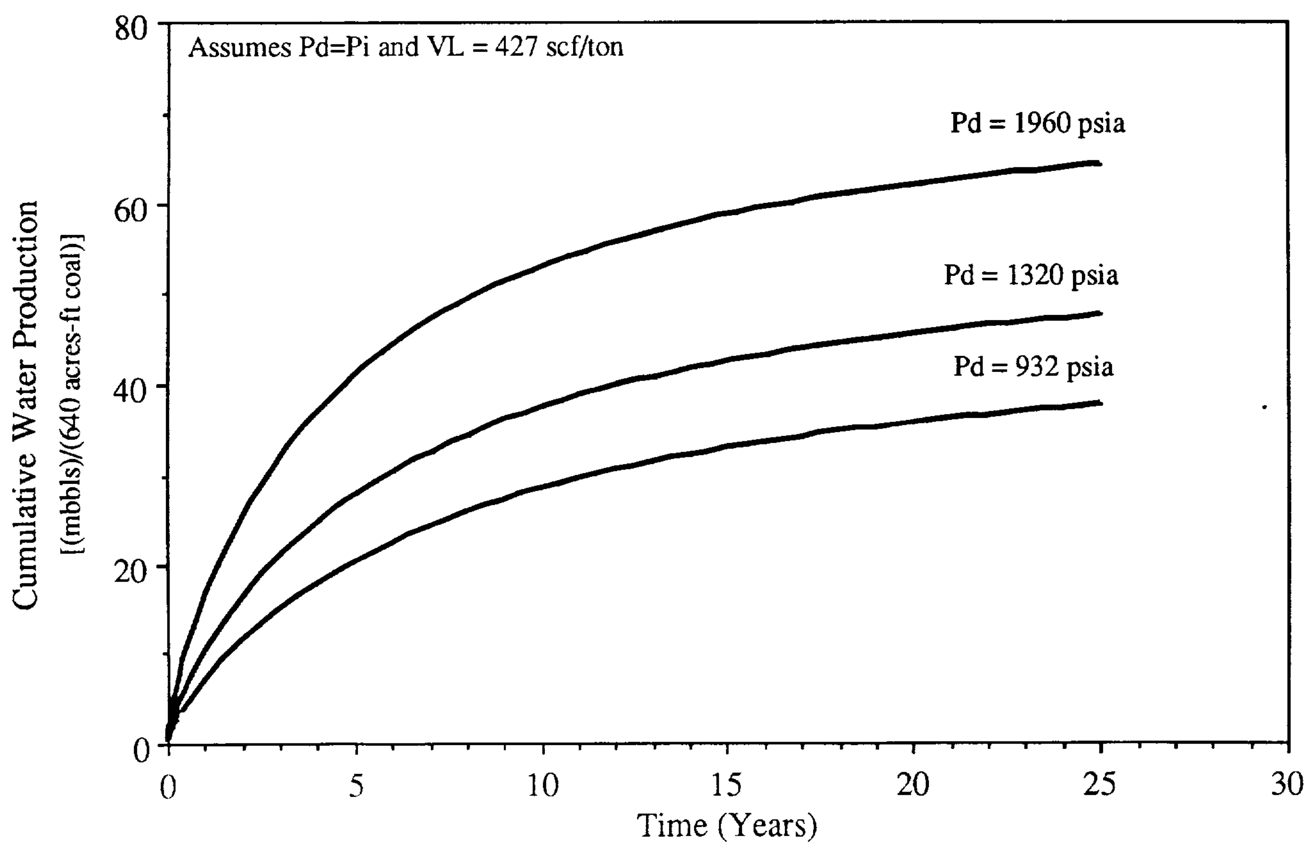



# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

### Water Production for Variations in the Desorption Pressure

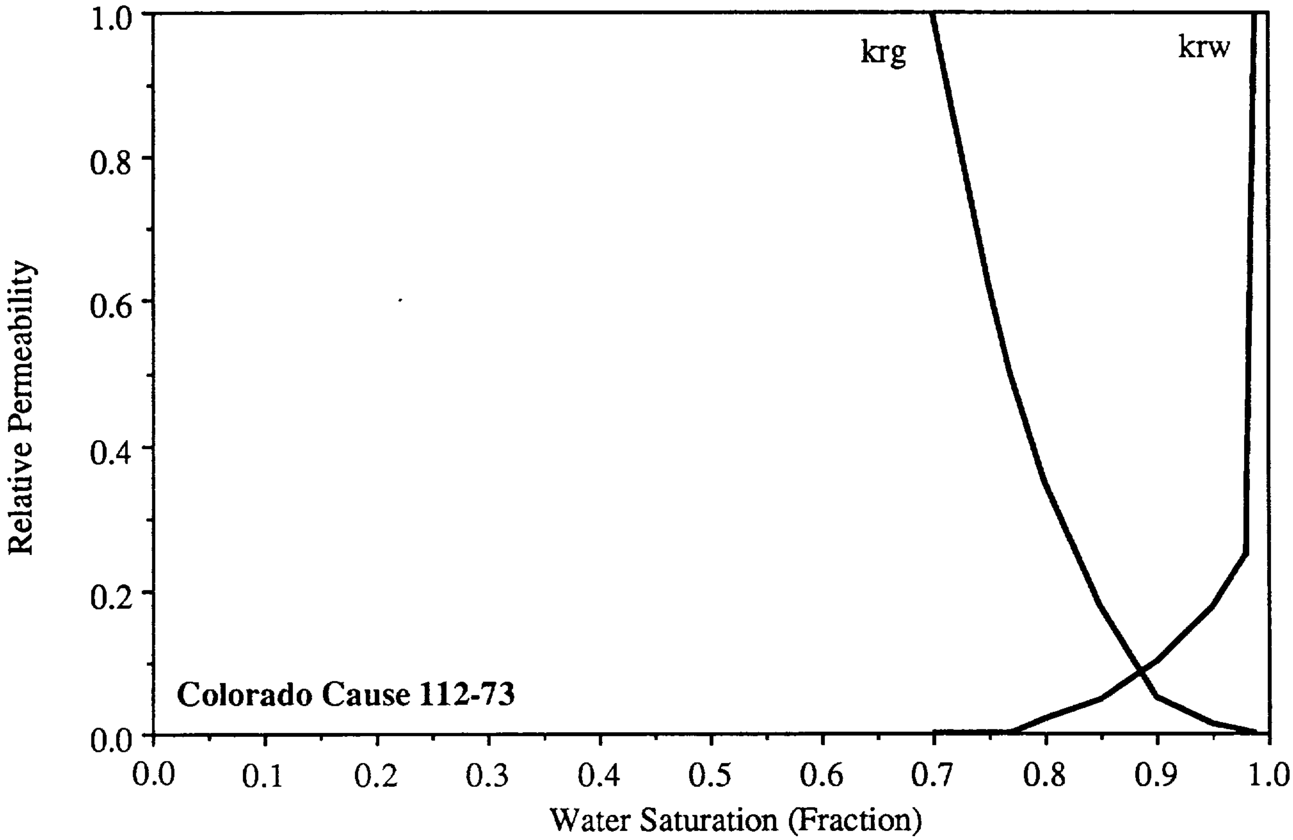


# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Variations in Relative Permeability**



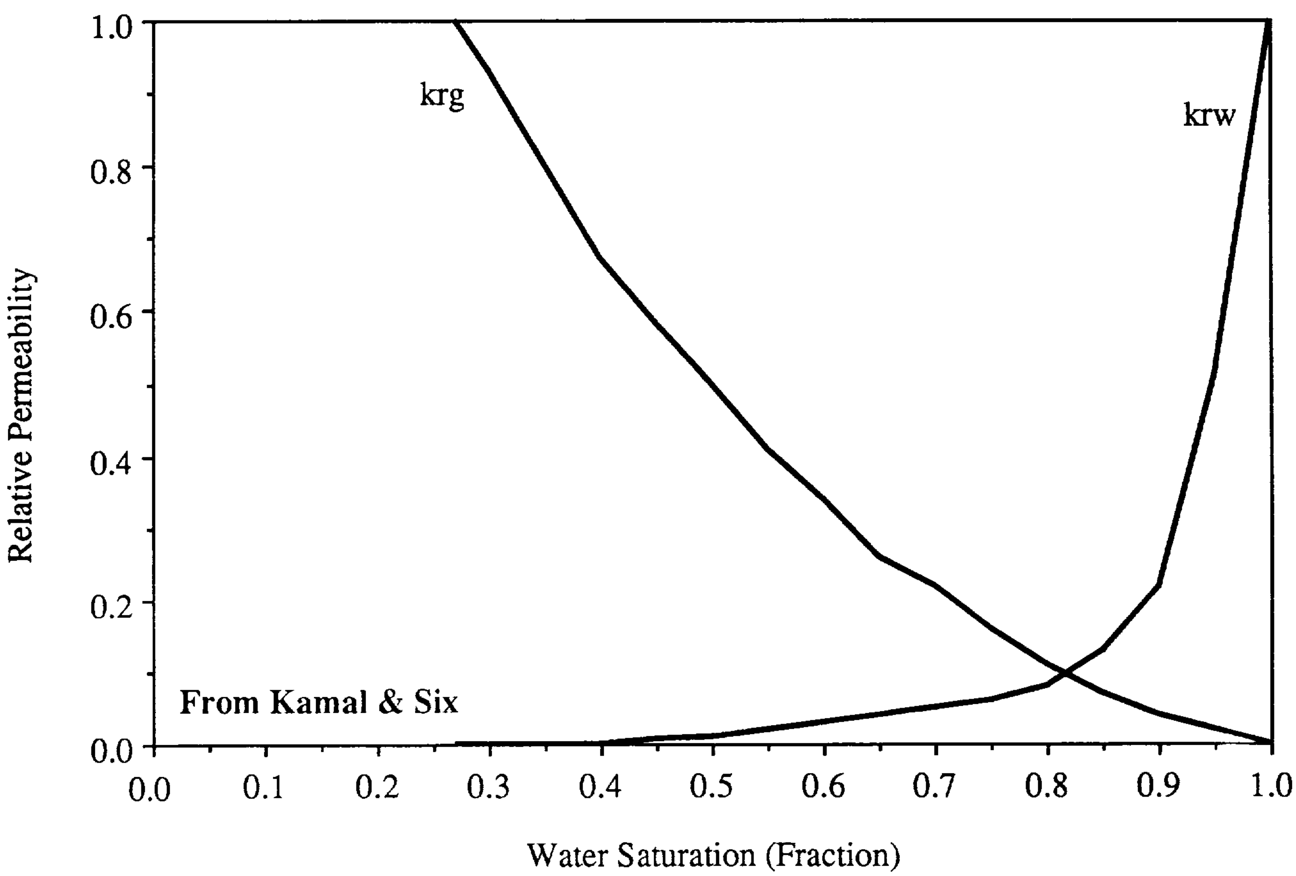



EXHIBIT 104

# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Variations in the krg/krw Ratio**

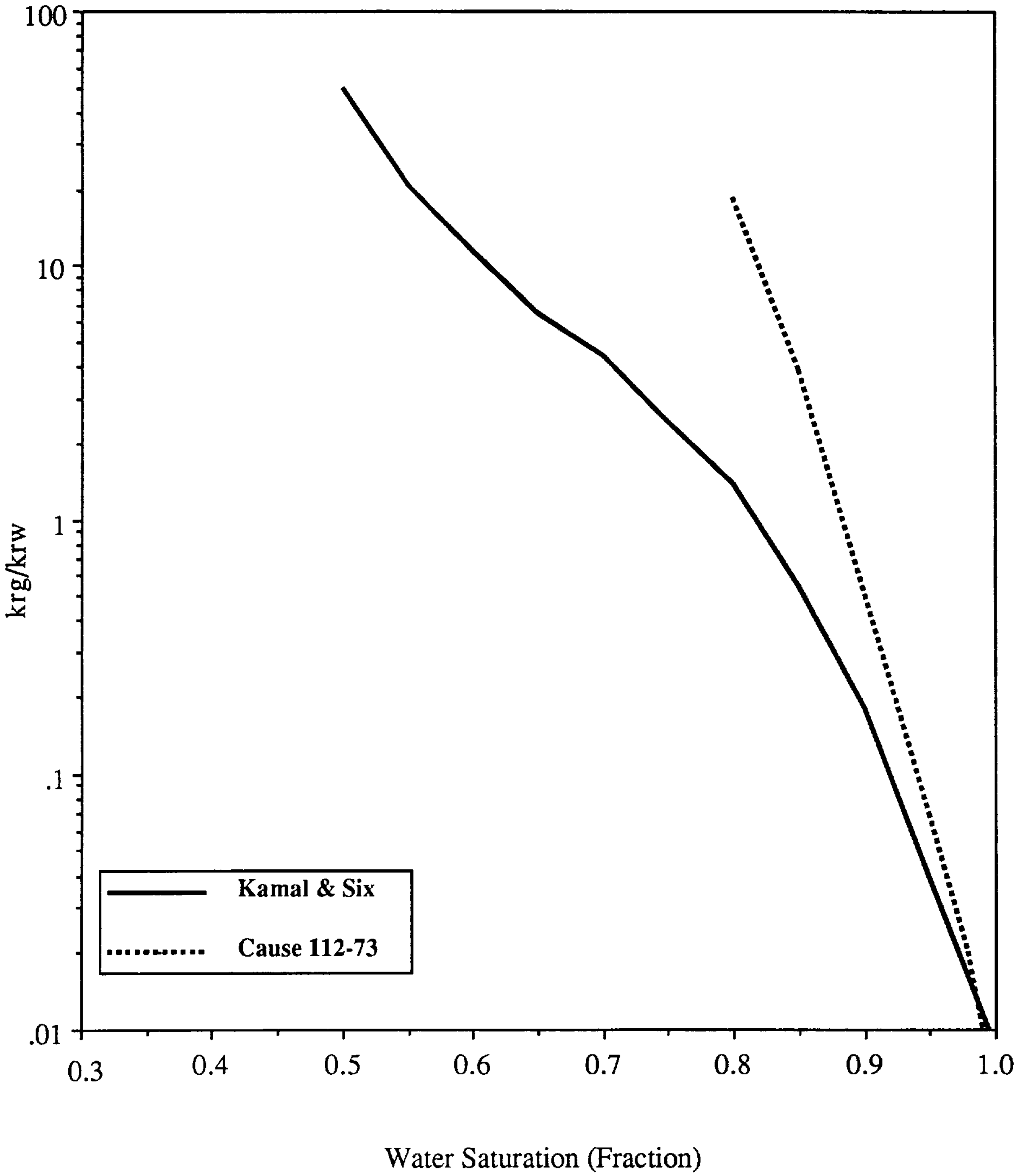
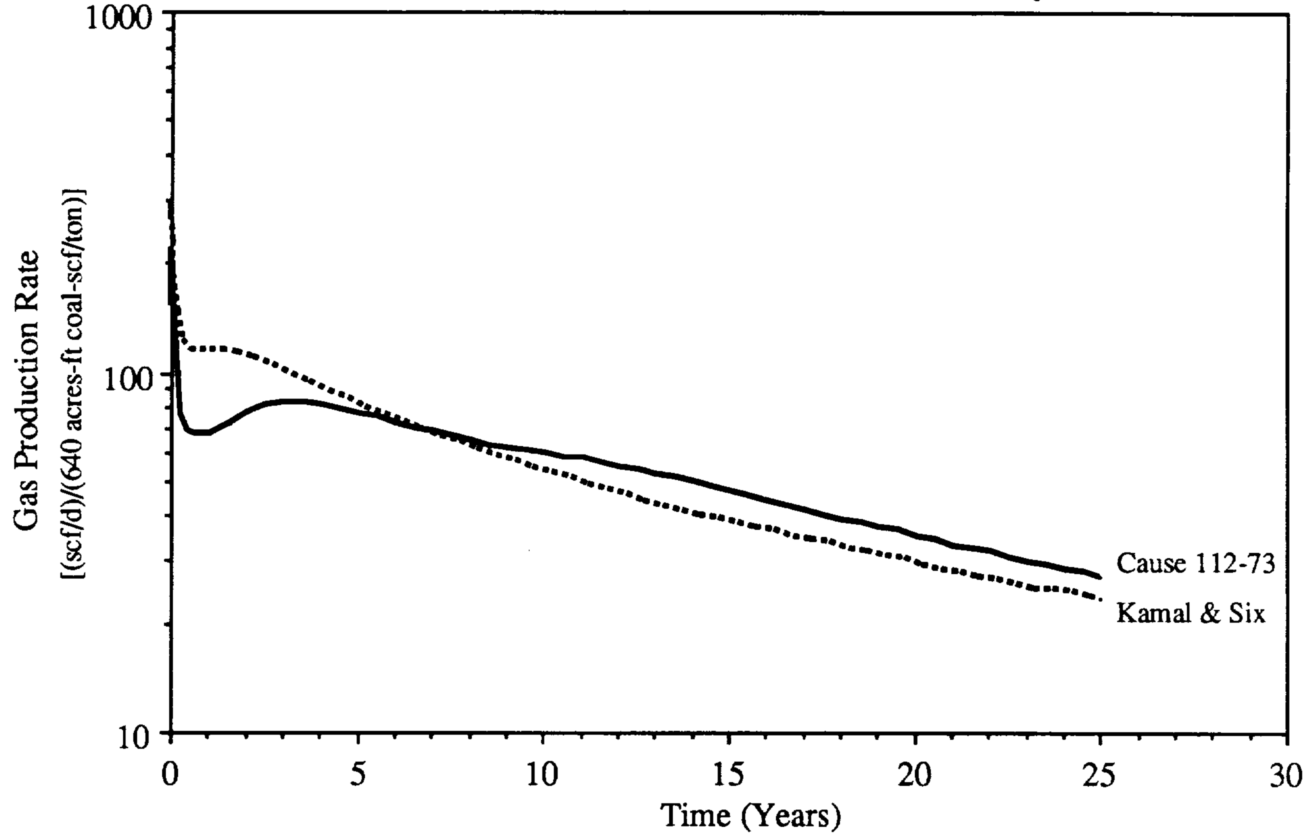


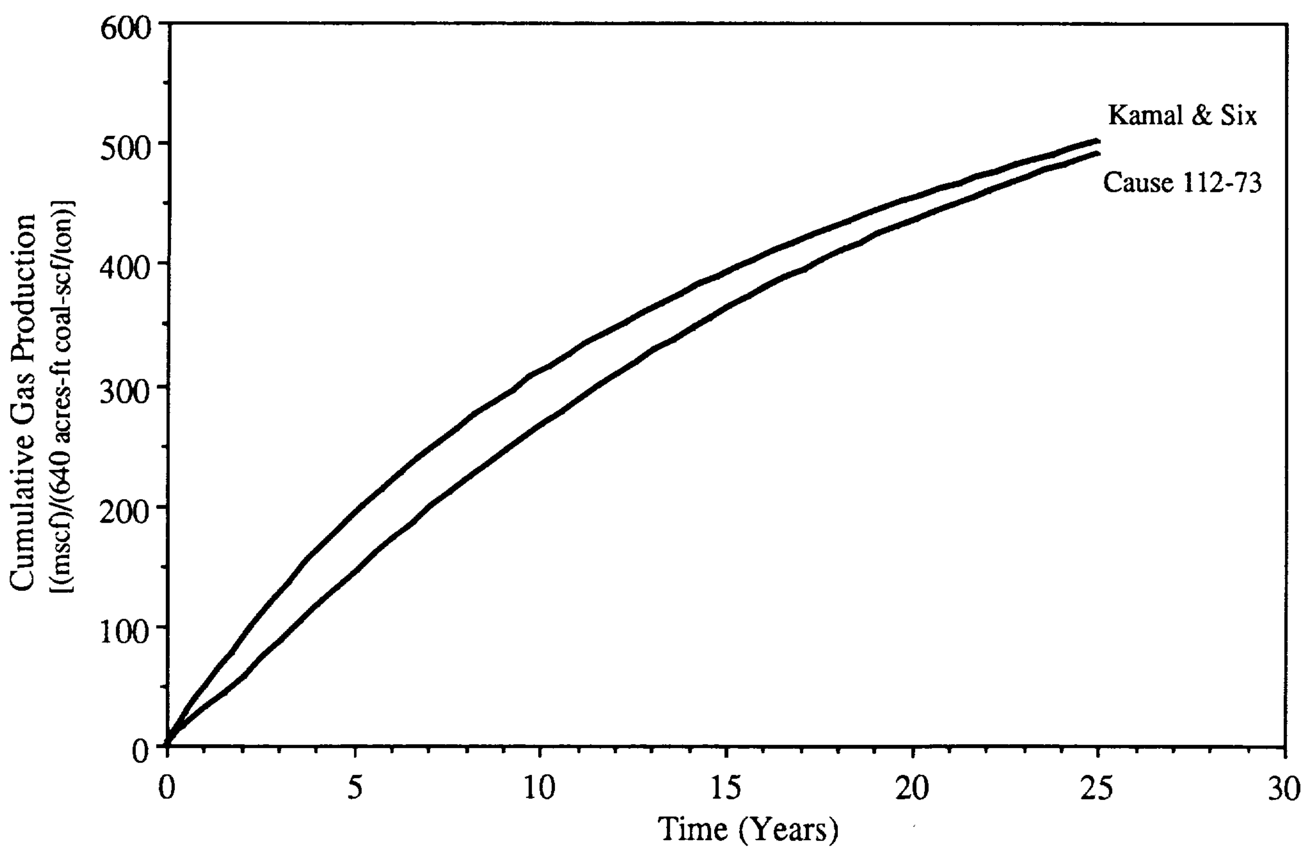
EXHIBIT 105

# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

### Gas Production for Variations in Relative Permeability

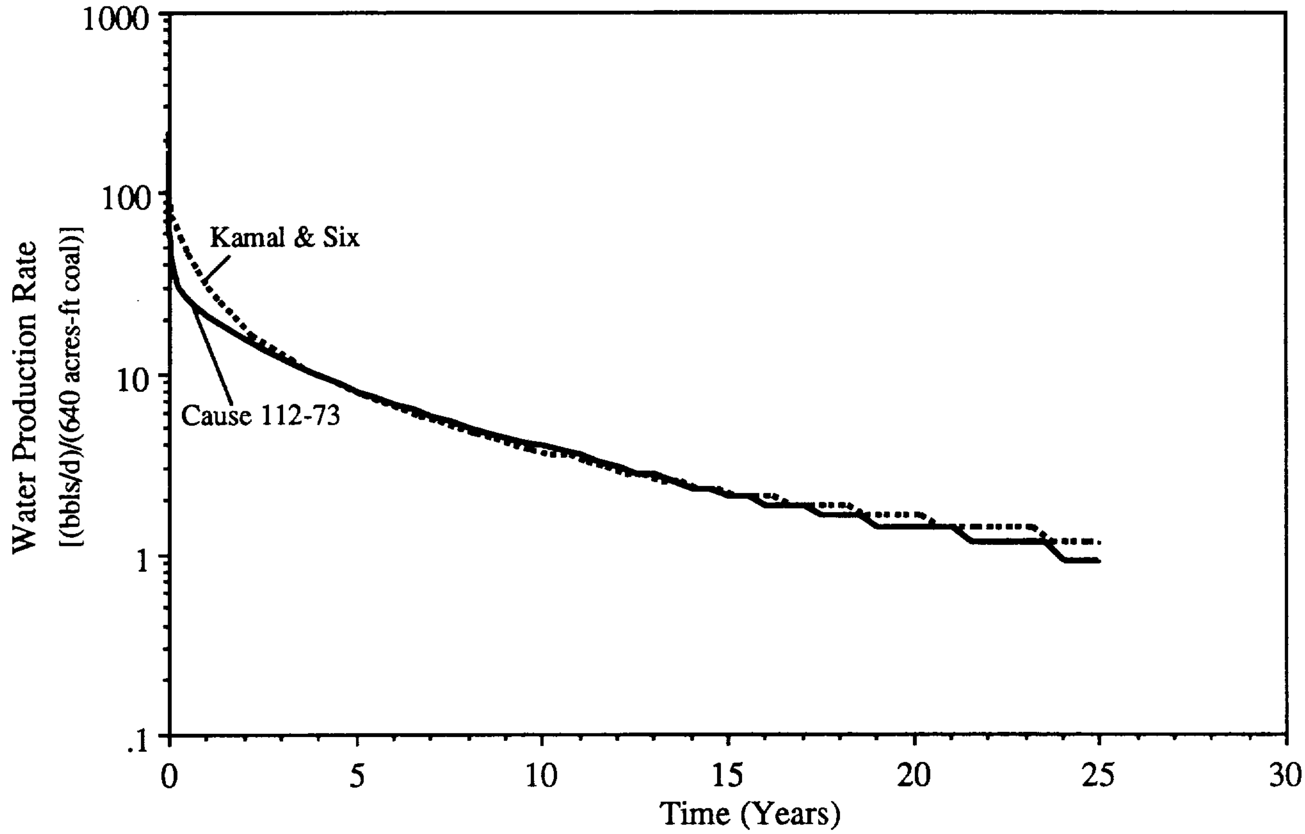


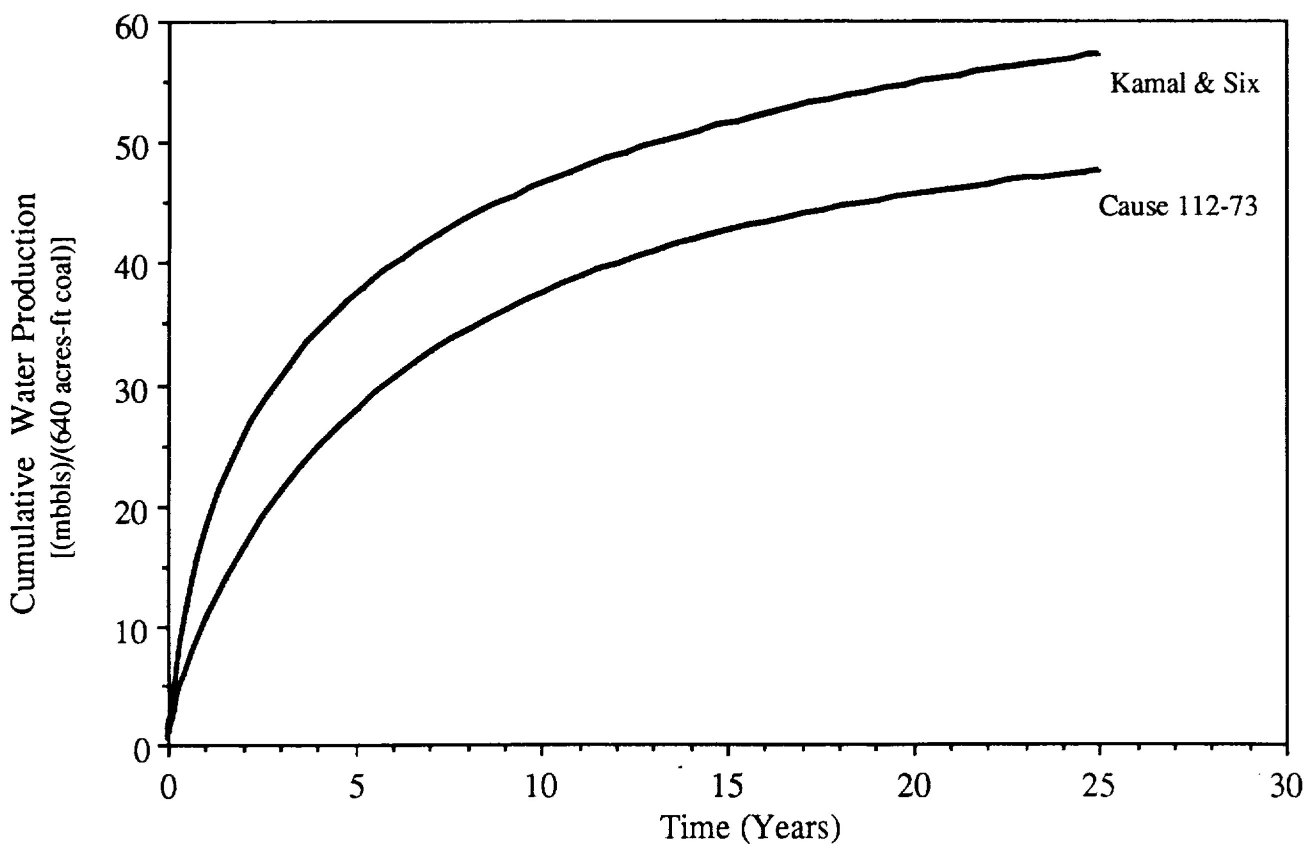



# San Juan Basin Coalbed Methane Spacing Study

## Area 1 Sensitivity Analyses

**Water Production for Variations in Relative Permeability**



## SAN JUAN BASIN COALBED METHANE SPACING STUDY

### AREA 2 SENSITIVITY ANALYSES
### SUMMARY OF RESERVOIR PARAMETERS

| FIXED PARAMETERS | VALUE | SOURCE |
|---|---|---|
| Coal Depth | 1,800 feet | Logs |
| Coal Thickness | 25 feet | Logs |
| Langmuir Volume (Ash Corrected) | 427 scf/ton | Estimated[13] |
| Langmuir Pressure | 315 psia | Estimated[13] |
| Desorption Pressure | $P_i$ | Estimated[1] |
| Flowing Bottomhole Pressure | 100 psia | Estimated |
| Temperature | 93°F | Logs |
| Pore Volume Compressibility | $200 \times 10^{-6}$ $psi^{-1}$ | Estimated |
| Porosity | 0.25% | Estimated |
| Cleat Spacing | 0.25 inches | Measured[4] |
| Sorption Time | 10 days | Estimated[13] |
| Gas Gravity | 0.60 | Measured[12] |
| Water FVF | 1.006 RB/STB | Estimated[4] |
| Water Viscosity | 0.565 cp | Estimated[4] |
| Relative Permeability Curves | - | Estimated[10] |

| VARIABLE PARAMETERS | |
|---|---|
| Initial Free Gas Saturation (Sgi) | 0, 10% |
| Initial Reservoir Pressure (Pi) | 200, 300 psia ($G_c$ = 166, 208 scf/ton) |
| Permeability | 1, 5, 10, 30 md |
| Fracture Half-Length | 100, 300 feet |
| Well Spacing | 160, 320 acres |

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

### AREA 2 SENSITIVITY ANALYSES
### INVENTORY OF INITIAL FLUIDS IN PLACE

| Free Gas Saturation (Sgi) (percent) | Reservoir Pressure (= $P_D$) (psia) | Gas Content* (scf/ton) | Gas-In-Place** [(mscf)/(640 ac-ft coal-scf/ton)] | | | Water-In-Place** [(mbbls)/(640 ac-ft coal)] |
|---|---|---|---|---|---|---|
| | | | Free | Sorbed | Total | |
| 0 | 200 | 166 | 0.00 | 1,148 | 1,148 | 12.4 |
| 0 | 300 | 208 | 0.00 | 1,148 | 1,148 | 12.4 |
| | | | | | | |
| 10* | 200 | 166 | 0.57 | 1,148 | 1,149 | 11.1 |
| 10* | 300 | 208 | 0.69 | 1,148 | 1,149 | 11.1 |

* Assumes a Langmuir volume of 427 scf/ton and a Langmuir pressure of 315 psia.

** Coal thickness was assumed to be 25 feet for all cases simulated in Area 3. All water and free gas volumes were calculated assuming a constant cleat porosity of 0.25%.

EXHIBIT 109

SAN JUAN BASIN COALBED METHANE SPACING STUDY

SIMULATION RESULTS FOR AREA 2 SENSITIVITY ANALYSES

(Assumes NO Initial Free Gas Saturation)

| Sensitivity Parameters | | | Initial Reservoir Pressure = 200 psia | | | Initial Reservoir Pressure = 300 psia | | |
|---|---|---|---|---|---|---|---|---|
| | | | 20 mscf/d Cutoff | | 25 year Cutoff | 20 mscf/d Cutoff | | 25 year Cutoff |
| Permeability (md) | Fracture Half-Length (feet) | Well Spacing (acres) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) |
| 1.0 | 100 | 160 | 0.08 | 0.1 | 2.5 | 0.30 | 0.2 | 5.9 |
| 1.0 | 100 | 320 | 0.08 | 0.0 | 1.2 | 0.30 | 0.1 | 2.4 |
| 1.0 | 300 | 160 | 0.42 | 0.4 | 5.6 | 44.10 | 22.6 | 12.8 |
| 1.0 | 300 | 320 | 0.42 | 0.2 | 2.5 | 83.21 | 17.9 | 4.7 |
| 5.0 | 100 | 160 | 31.70 | 21.7 | 17.5 | 36.64 | 38.7 | 32.0 |
| 5.0 | 100 | 320 | 64.72 | 20.5 | 6.5 | 75.74 | 37.9 | 16.8 |
| 5.0 | 300 | 160 | 27.04 | 27.9 | 26.7 | 28.90 | 43.0 | 41.1 |
| 5.0 | 300 | 320 | 58.45 | 26.5 | 12.3 | 62.60 | 41.9 | 25.7 |
| 10.0 | 100 | 160 | 25.81 | 29.4 | 29.0 | 26.94 | 43.9 | 43.0 |
| 10.0 | 100 | 320 | 53.17 | 28.7 | 15.9 | 56.47 | 43.6 | 30.2 |
| 10.0 | 300 | 160 | 19.73 | 32.6 | 34.9 | 20.50 | 46.6 | 48.1 |
| 10.0 | 300 | 320 | 43.32 | 31.9 | 23.8 | 44.26 | 45.9 | 38.4 |
| 30.0 | 100 | 160 | 10.97 | 35.9 | 37.9 | 10.91 | 48.9 | 50.6 |
| 30.0 | 100 | 320 | 22.41 | 35.8 | 36.4 | 22.97 | 49.0 | 49.4 |
| 30.0 | 300 | 160 | 7.72 | 36.7 | 37.9 | 7.74 | 49.6 | 50.6 |
| 30.0 | 300 | 320 | 16.68 | 36.6 | 37.7 | 16.57 | 49.5 | 50.4 |

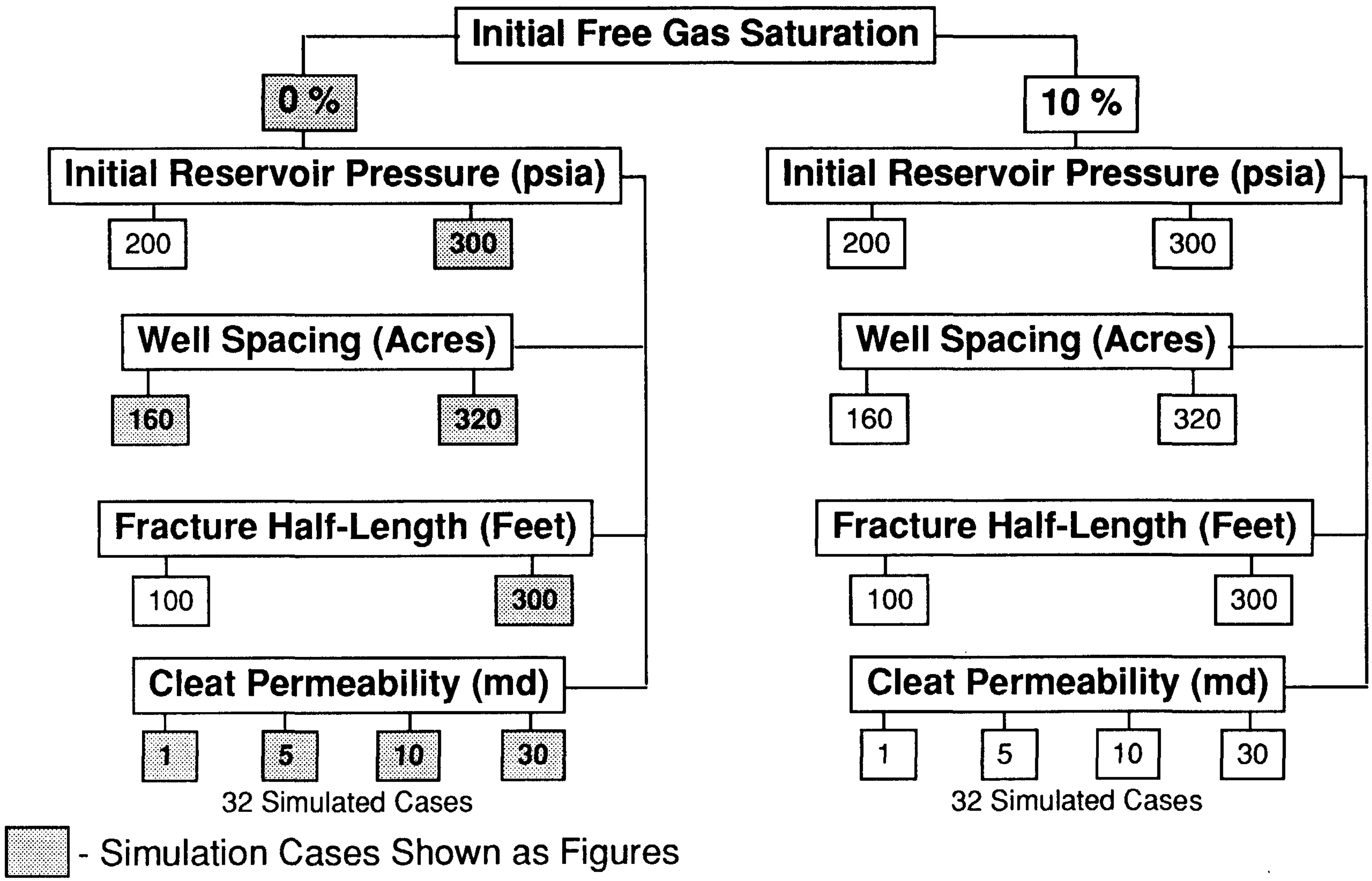
## SAN JUAN BASIN COALBED METHANE SPACING STUDY

## SIMULATION RESULTS FOR AREA 2 SENSITIVITY ANALYSES

**(Assumes 10% Initial Free Gas Saturation)**

| Sensitivity Parameters | | | Initial Reservoir Pressure = 200 psia | | | Initial Reservoir Pressure = 300 psia | | |
|---|---|---|---|---|---|---|---|---|
| | | | 20 mscf/d Cutoff | | 25 year Cutoff | 20 mscf/d Cutoff | | 25 year Cutoff |
| Permeability (md) | Fracture Half-Length (feet) | Well Spacing (acres) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) |
| 1.0 | 100 | 160 | 0.11 | 0.1 | 4.3 | 0.97 | 0.7 | 9.2 |
| 1.0 | 100 | 320 | 0.11 | 0.0 | 2.1 | 0.98 | 0.3 | 4.1 |
| 1.0 | 300 | 160 | 0.87 | 0.9 | 8.3 | 38.37 | 23.0 | 16.4 |
| 1.0 | 300 | 320 | 0.87 | 0.4 | 3.8 | 69.83 | 18.4 | 7.3 |
| 5.0 | 100 | 160 | 28.16 | 22.1 | 20.2 | 34.25 | 38.7 | 33.6 |
| 5.0 | 100 | 320 | 56.19 | 20.7 | 9.9 | 70.78 | 37.9 | 20.0 |
| 5.0 | 300 | 160 | 24.46 | 28.0 | 28.3 | 27.51 | 43.1 | 41.9 |
| 5.0 | 300 | 320 | 51.93 | 26.5 | 15.7 | 59.50 | 42.0 | 28.1 |
| 10.0 | 100 | 160 | 23.79 | 29.5 | 30.1 | 25.85 | 44.0 | 43.6 |
| 10.0 | 100 | 320 | 48.84 | 28.8 | 18.8 | 53.93 | 43.6 | 32.0 |
| 10.0 | 300 | 160 | 18.58 | 32.8 | 35.3 | 19.84 | 46.6 | 48.3 |
| 10.0 | 300 | 320 | 40.13 | 32.0 | 25.8 | 42.65 | 45.9 | 39.4 |
| 30.0 | 100 | 160 | 10.52 | 36.0 | 38.0 | 10.92 | 49.0 | 50.6 |
| 30.0 | 100 | 320 | 21.48 | 35.9 | 36.7 | 22.26 | 49.0 | 49.5 |
| 30.0 | 300 | 160 | 7.57 | 36.8 | 38.0 | 7.54 | 49.6 | 50.6 |
| 30.0 | 300 | 320 | 15.94 | 36.6 | 37.7 | 16.30 | 49.5 | 50.4 |

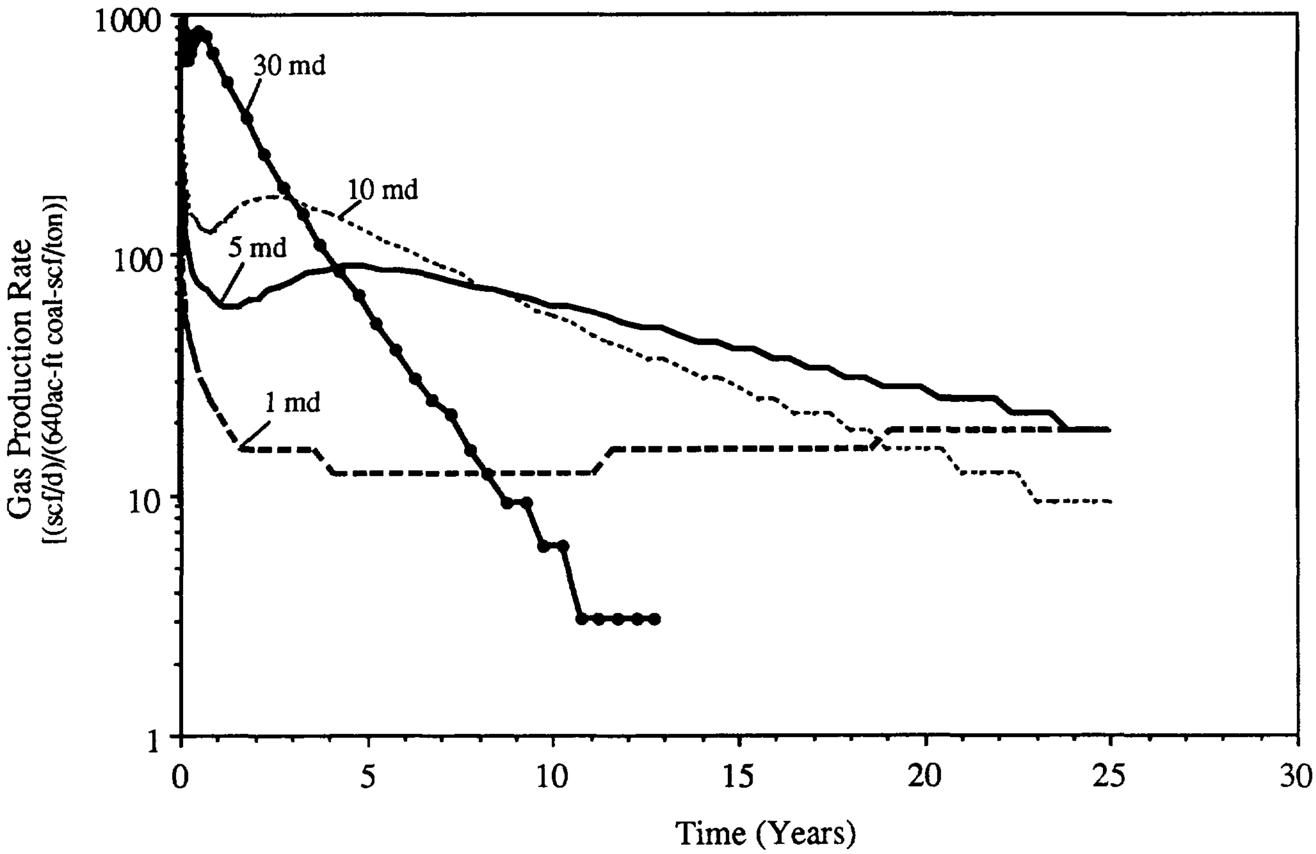
# San Juan Basin Coalbed Methane Spacing Study
## Area 2 Sensitivity Analyses
## 64 Simulation Cases for Gas and Water Production



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

**Gas Production for a 160 Acre Well Spacing**



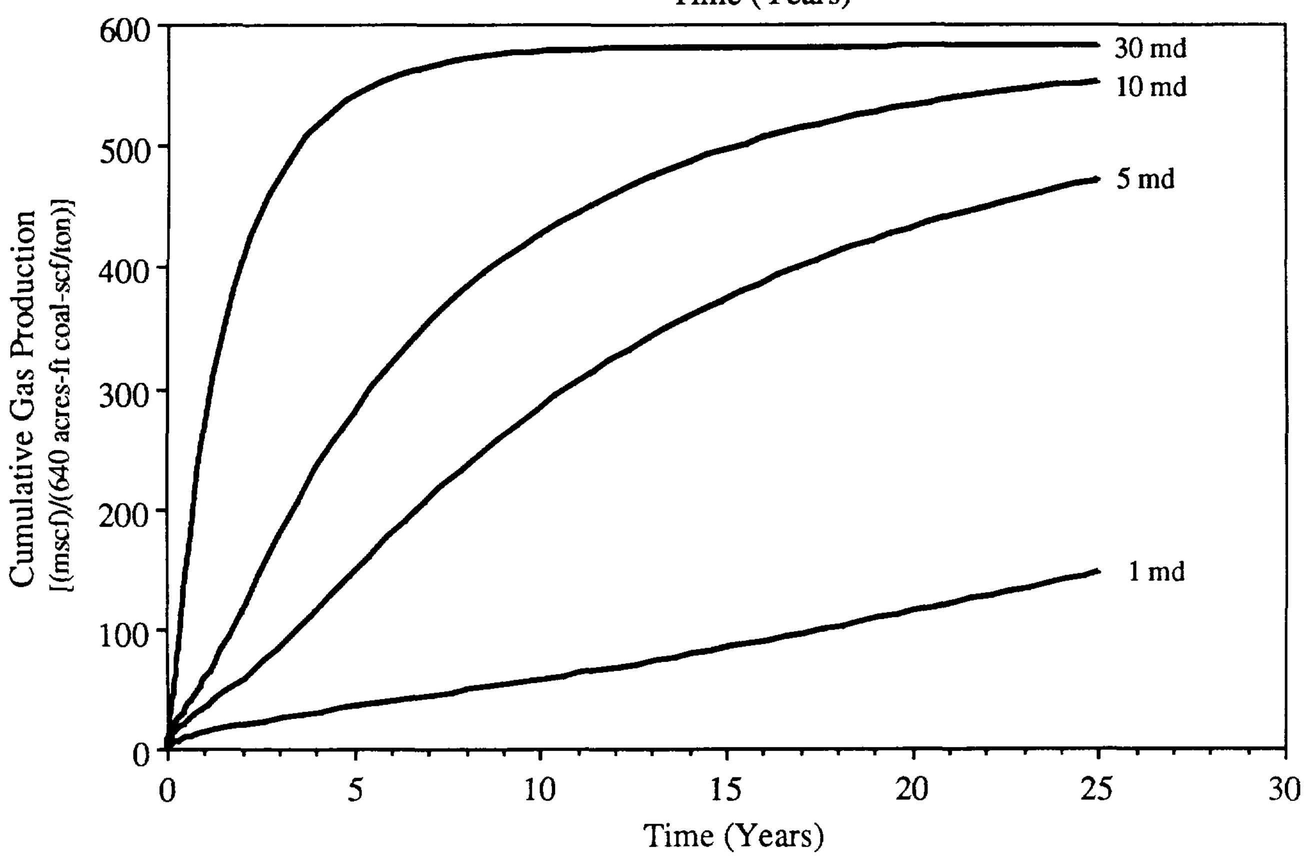
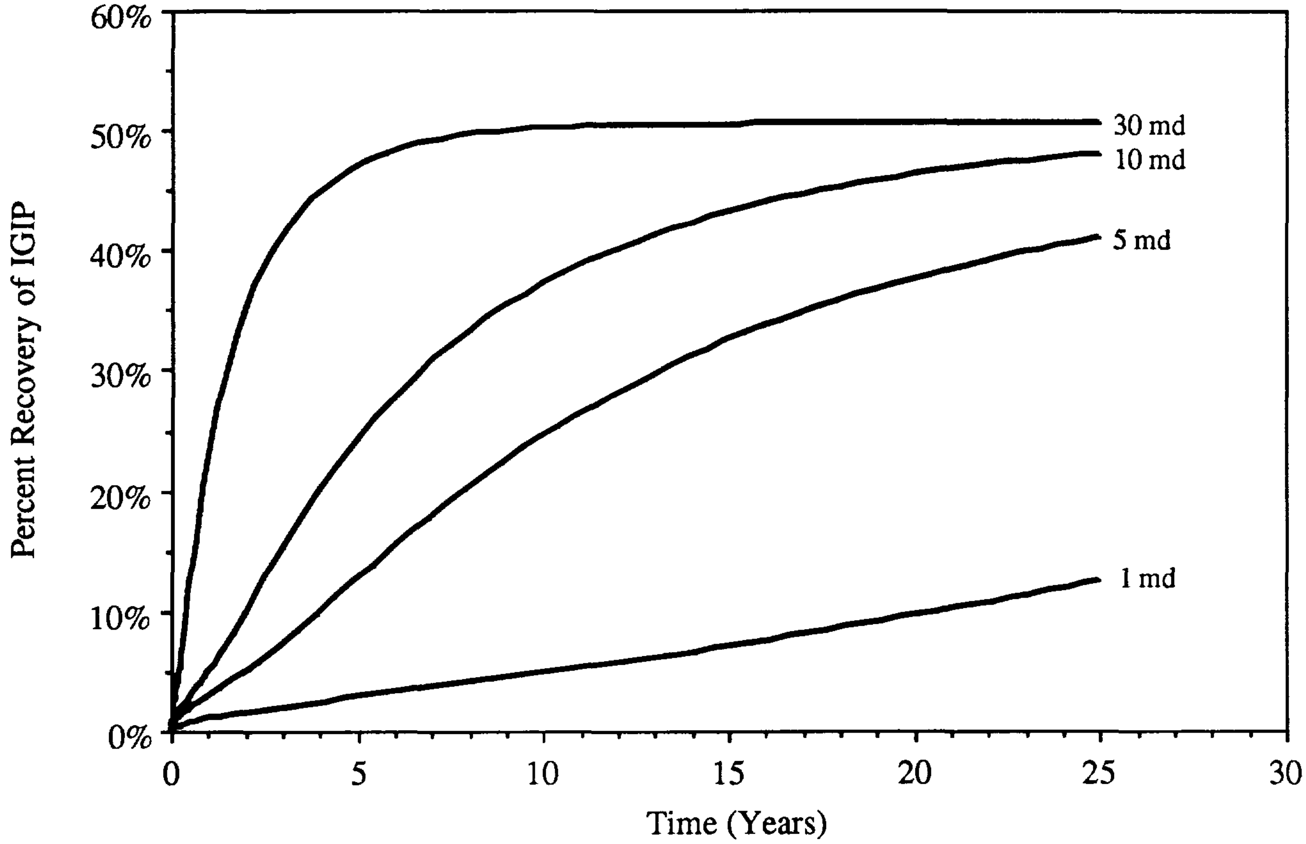



EXHIBIT 113

# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

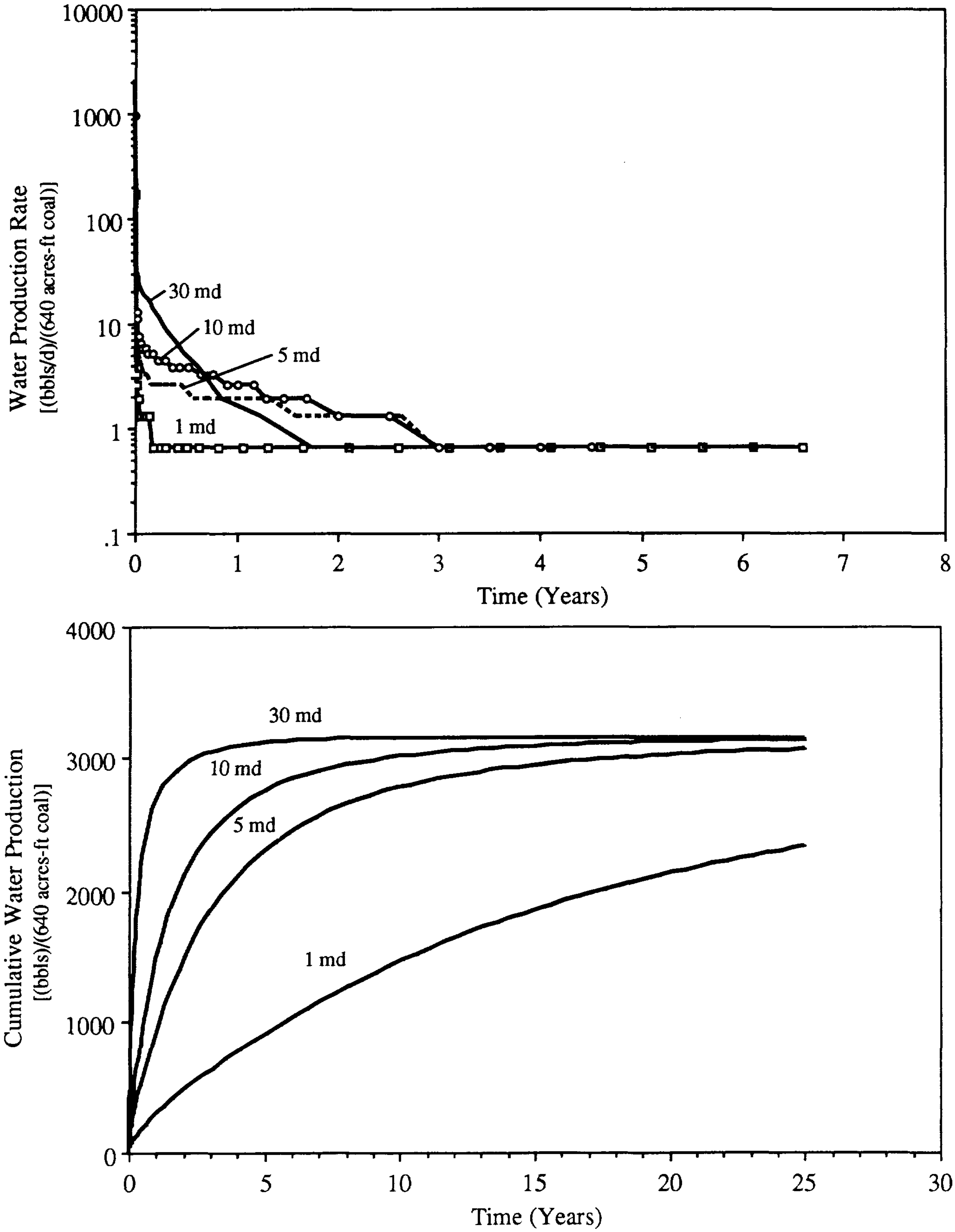
**Gas Recovery for a 160 Acre Well Spacing**



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

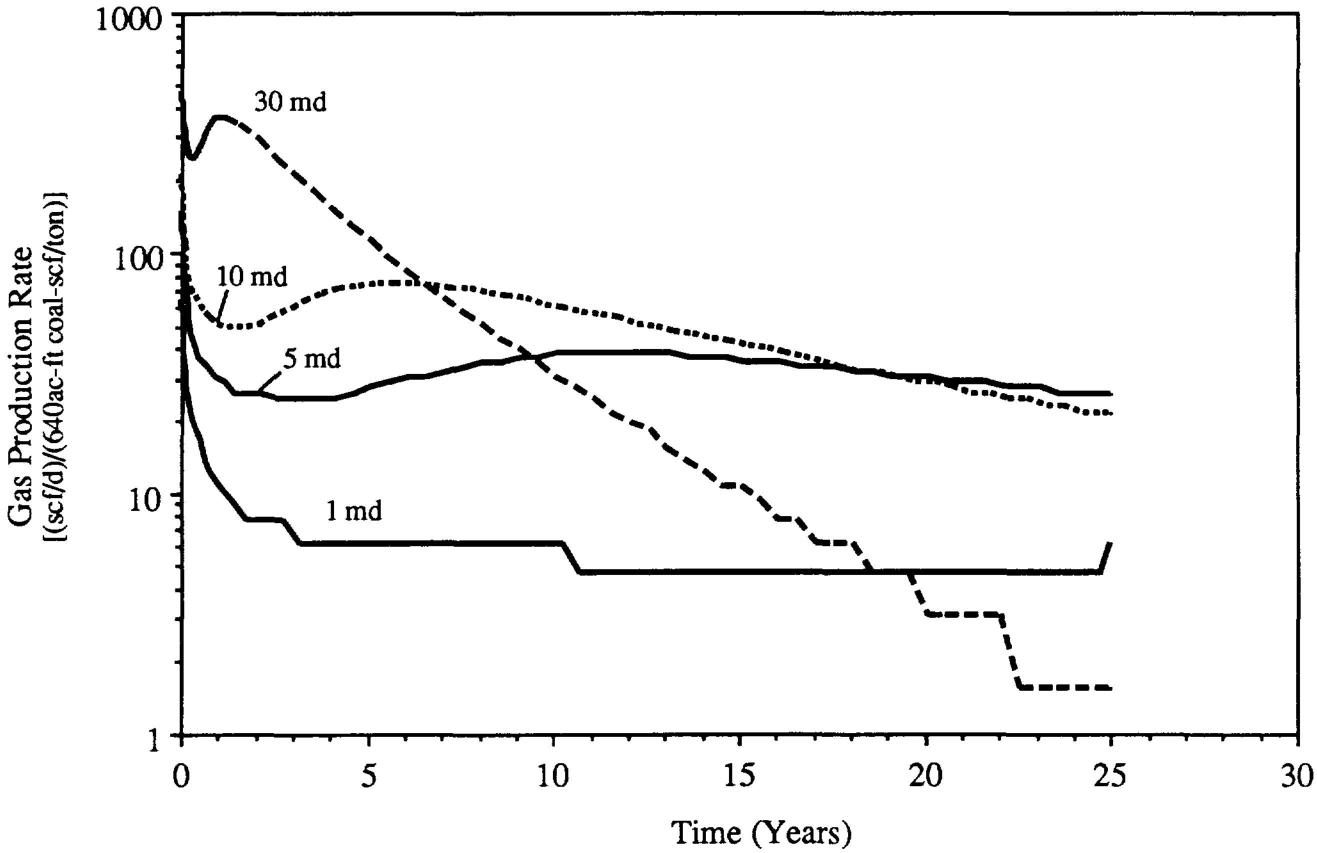
**Water Production for a 160 Acre Well Spacing**

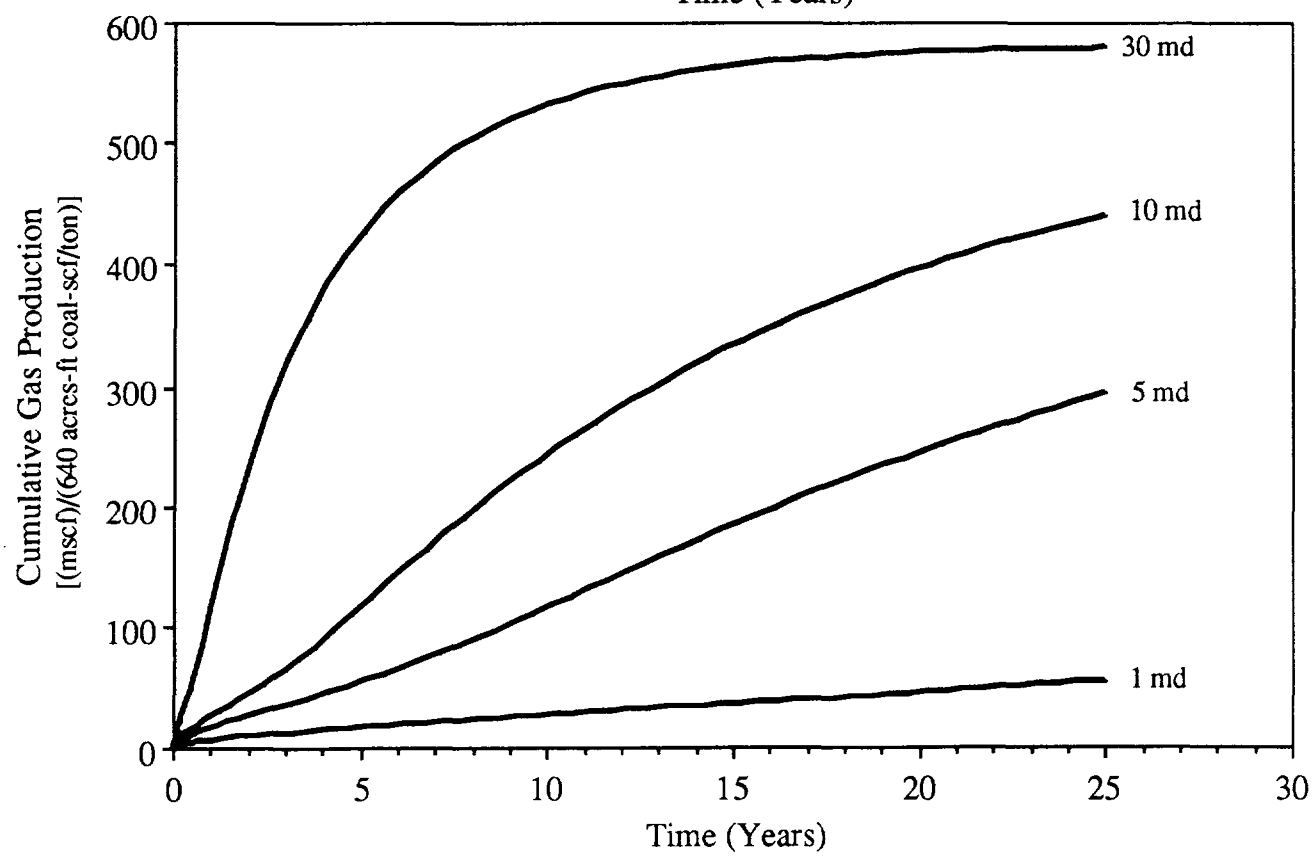


# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

### Gas Production for a 320 Acre Well Spacing

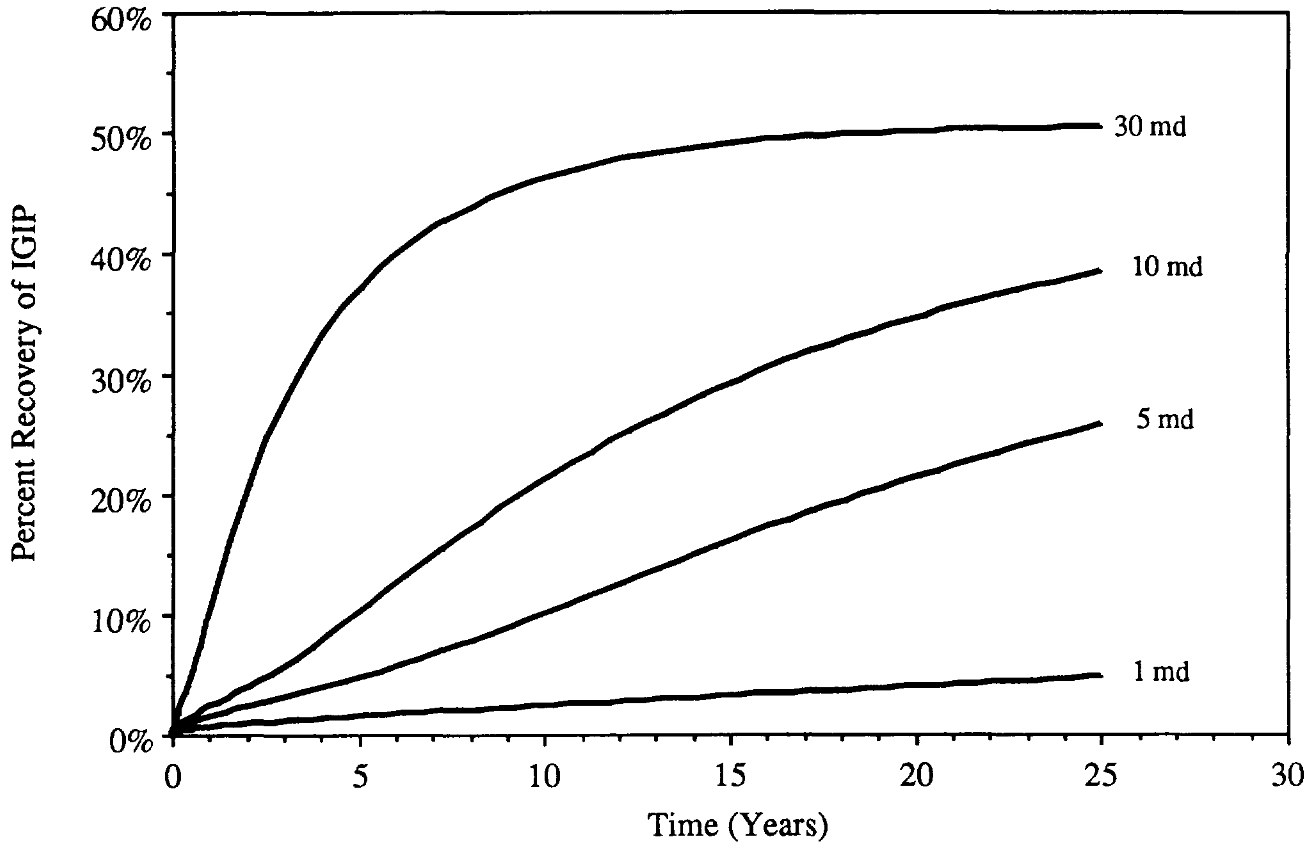


# San Juan Basin Coalbed Methane Spacing Study

Area 2 Sensitivity Analyses

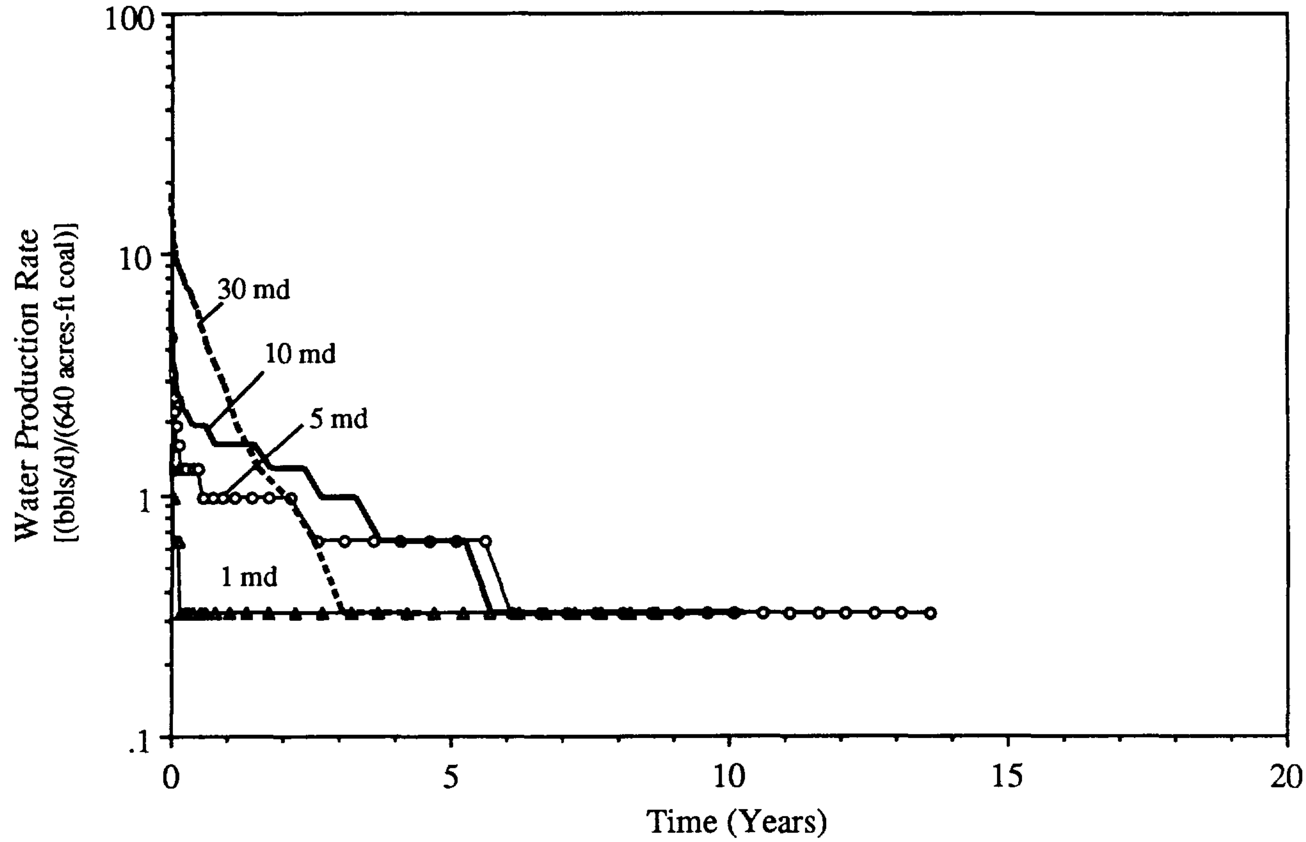
**Gas Recovery for a 320 Acre Well Spacing**

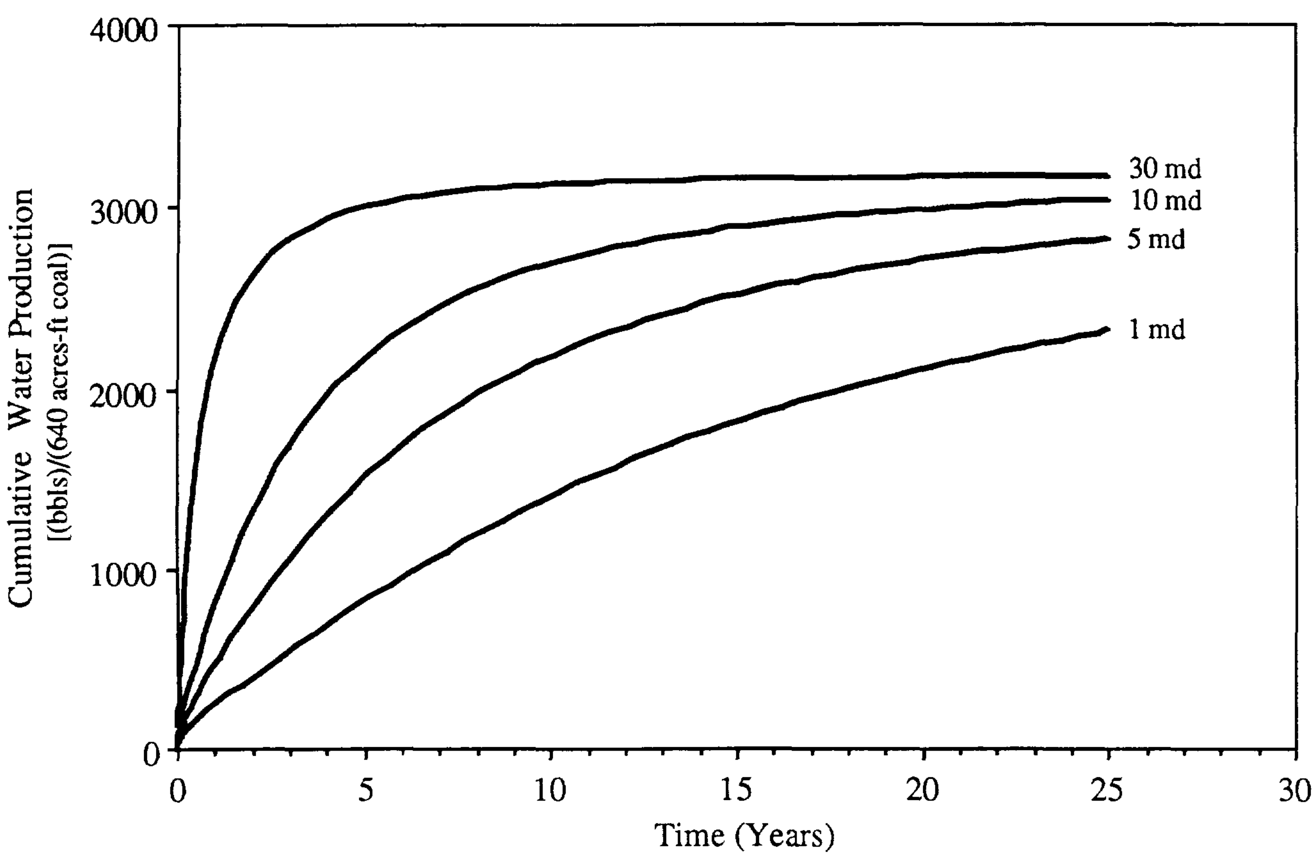


# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

### Water Production for a 320 Acre Well Spacing

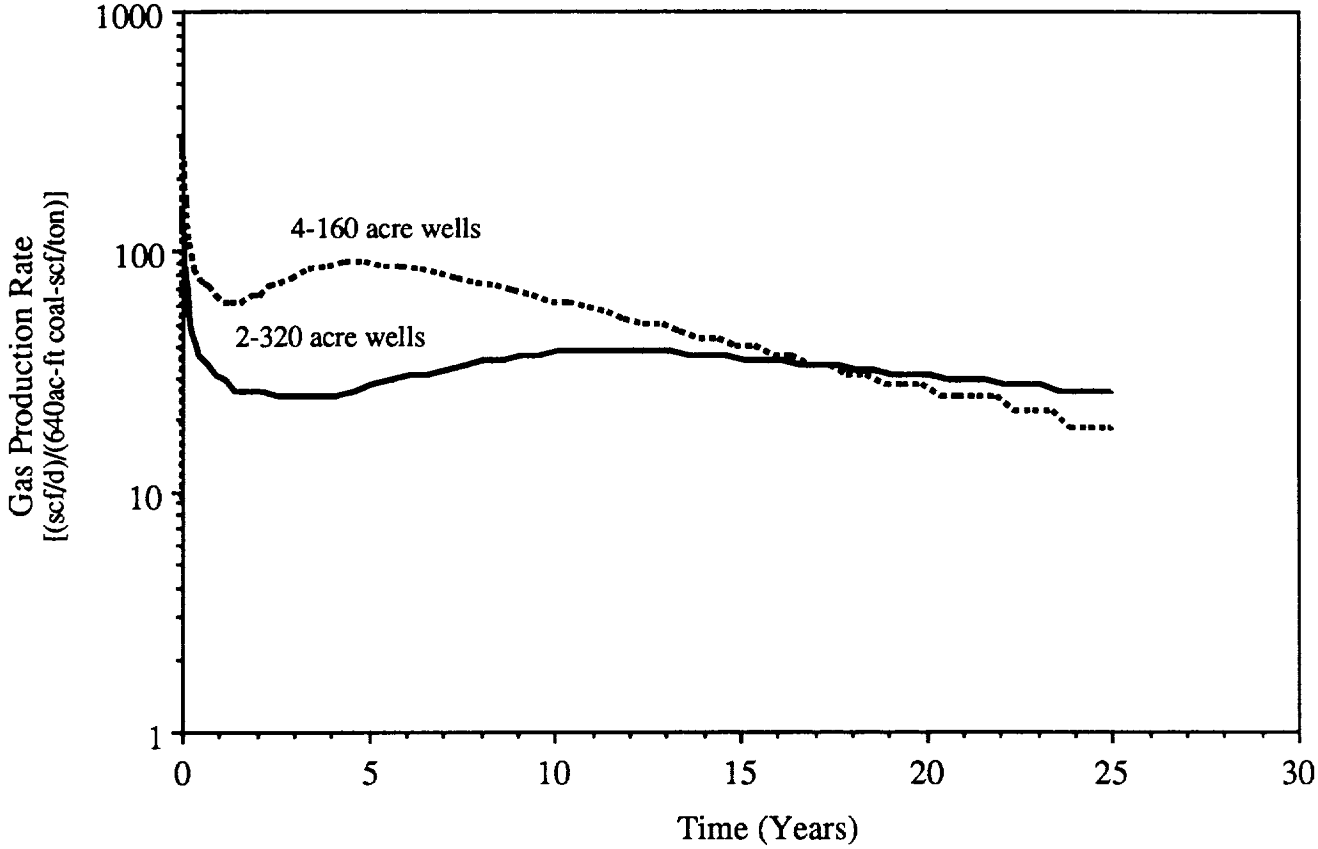


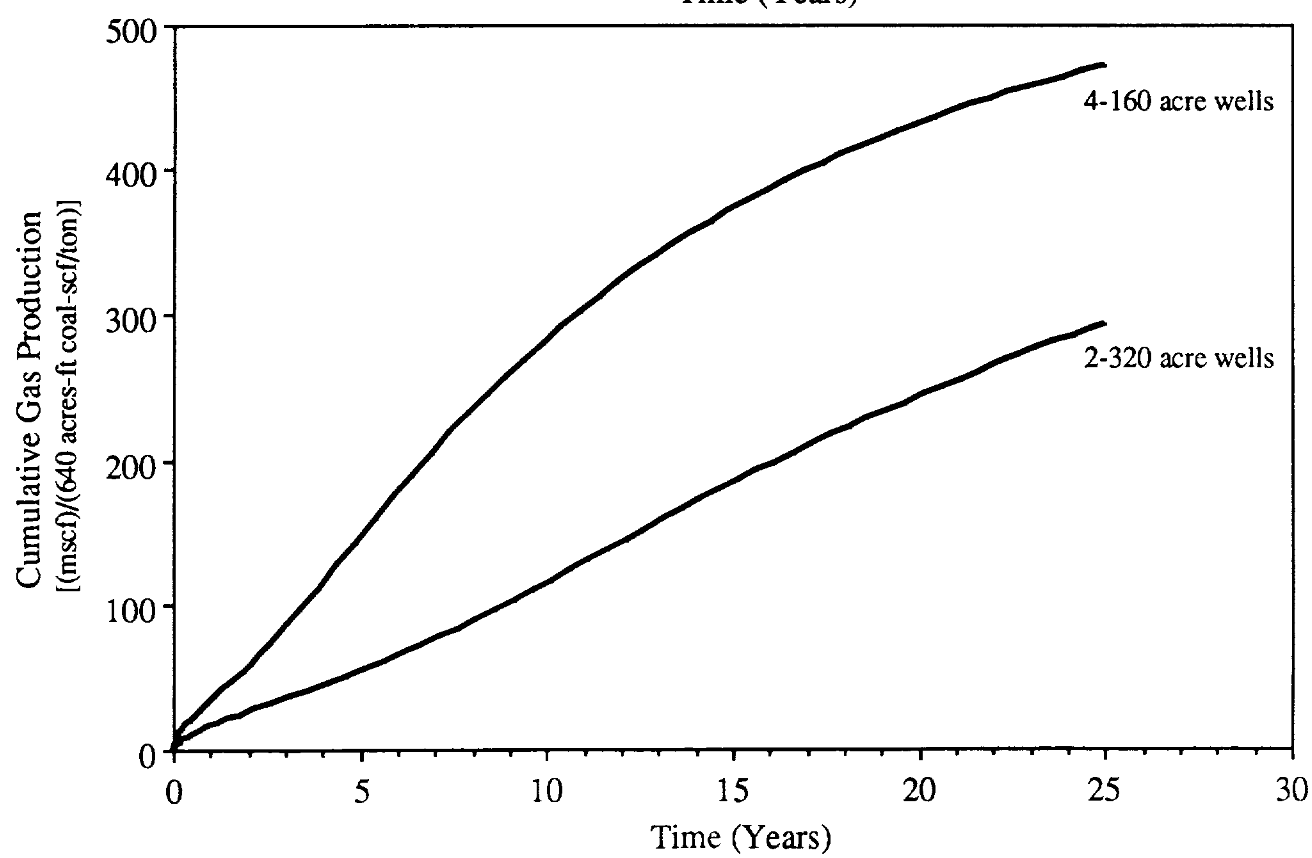



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

### Gas Production for a Cleat Permeability of 5 md

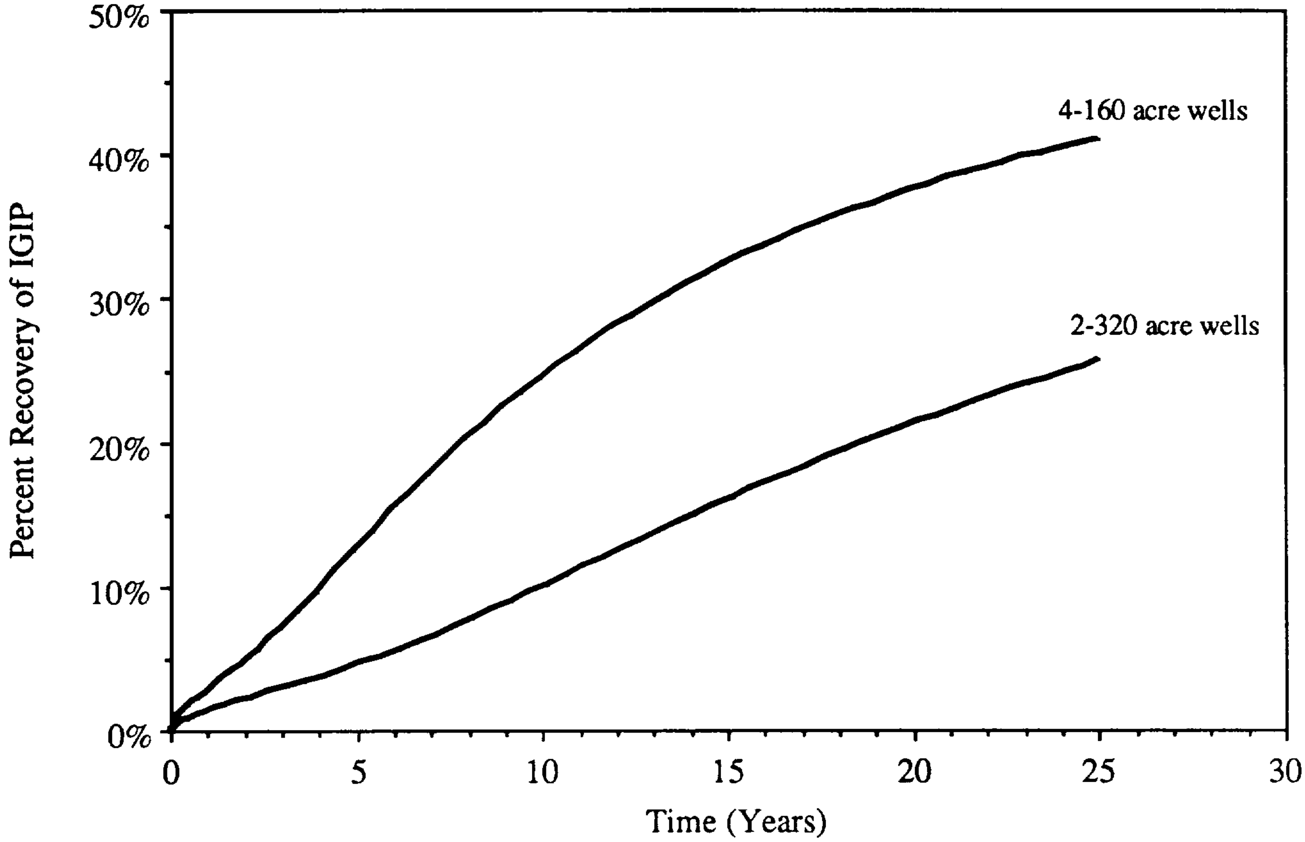


# San Juan Basin Coalbed Methane Spacing Study

Area 2 Sensitivity Analyses

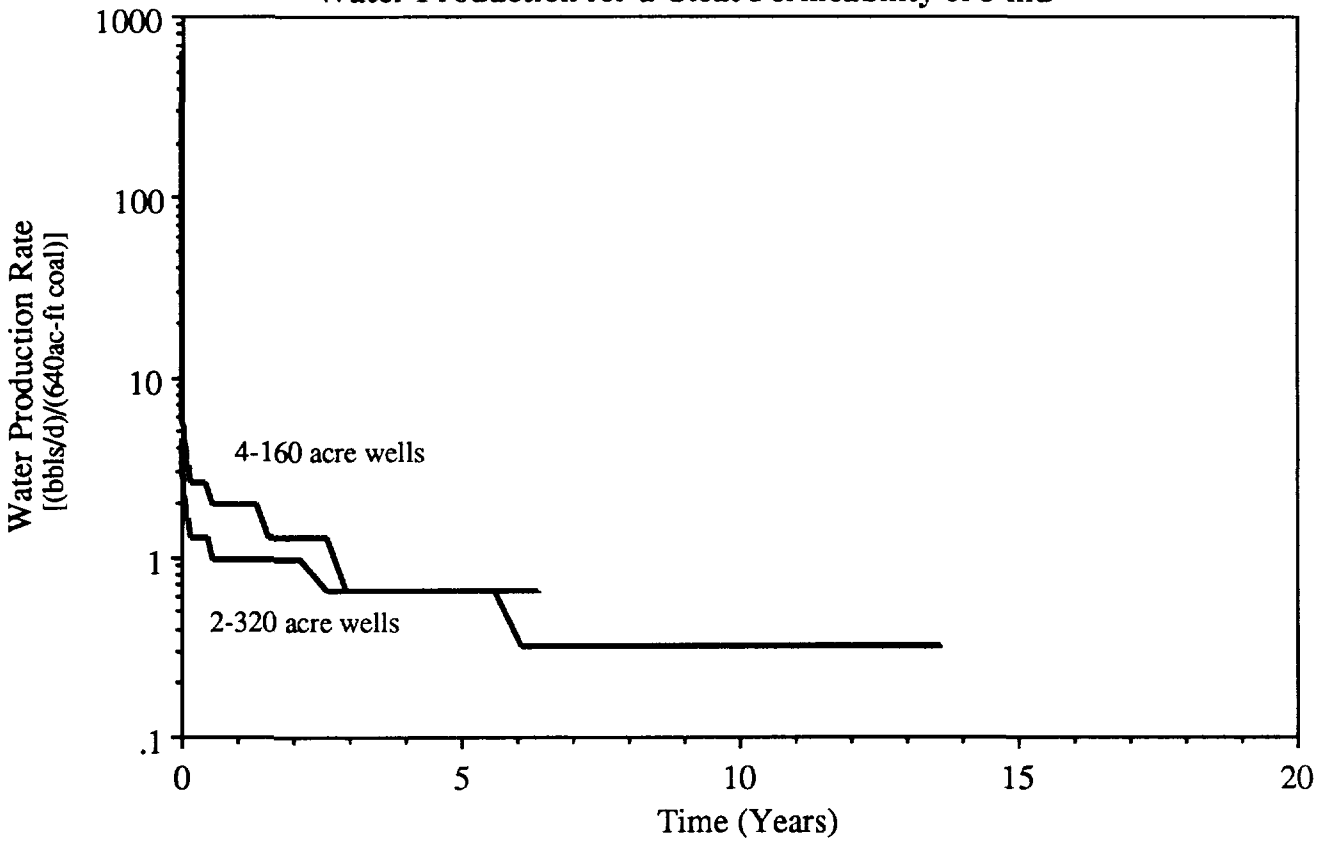
**Gas Recovery for a Cleat Permeability of 5 md**

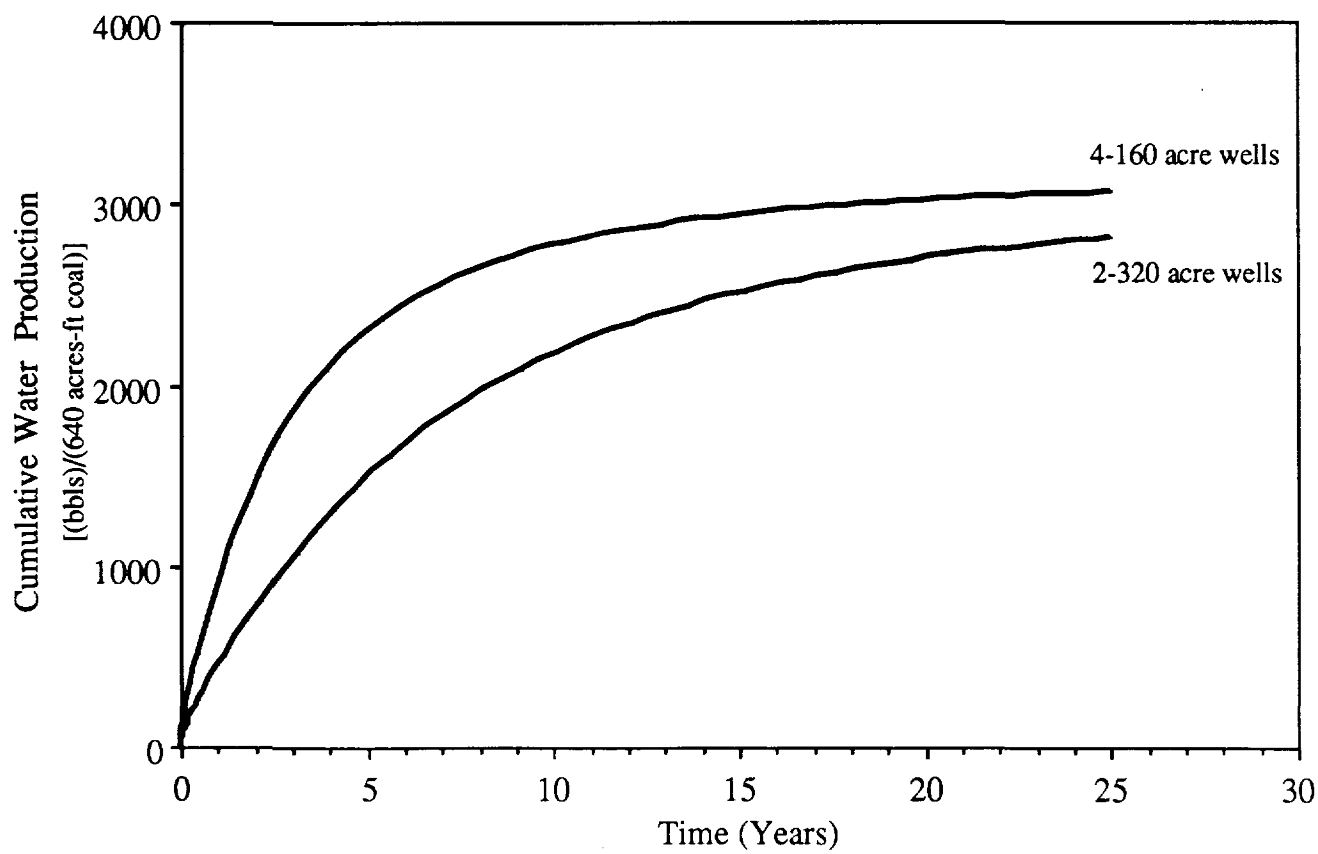


# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

**Water Production for a Cleat Permeability of 5 md**

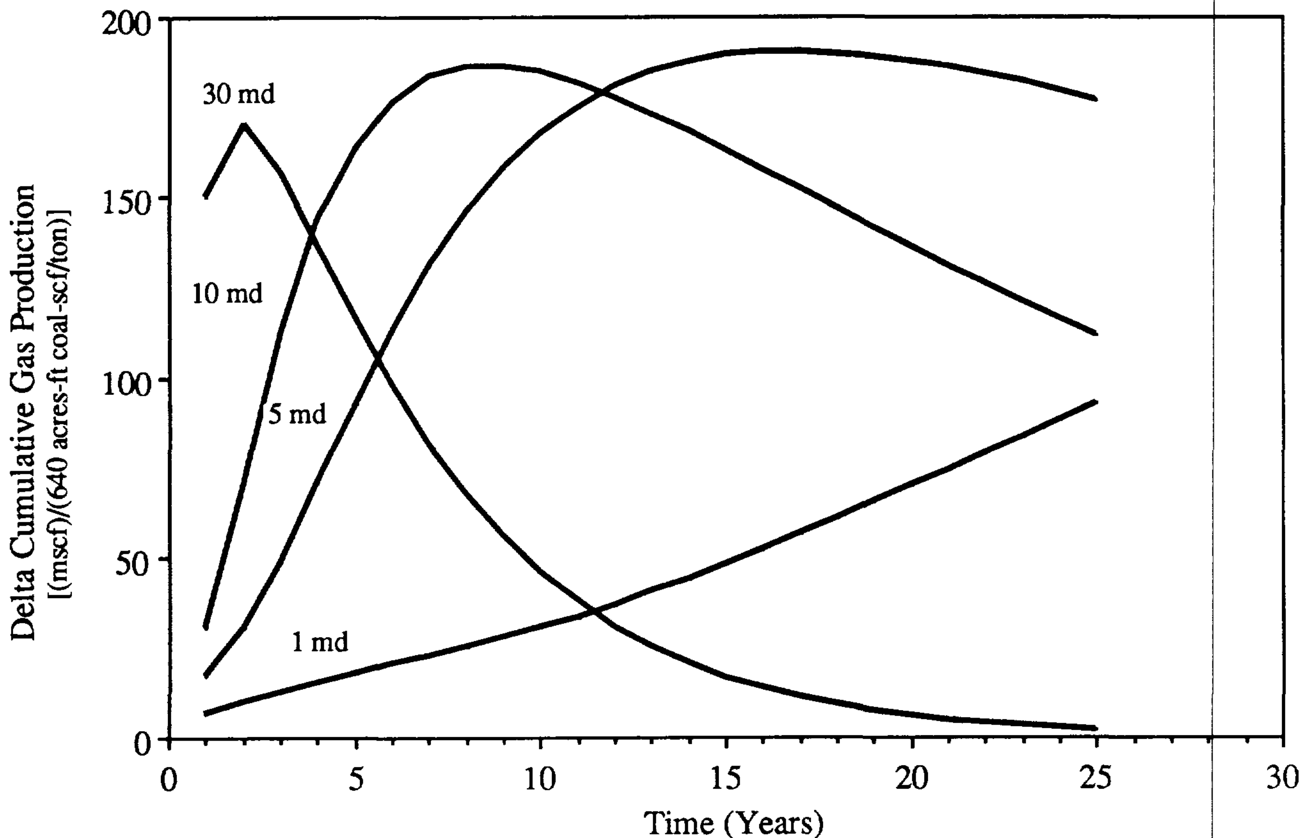


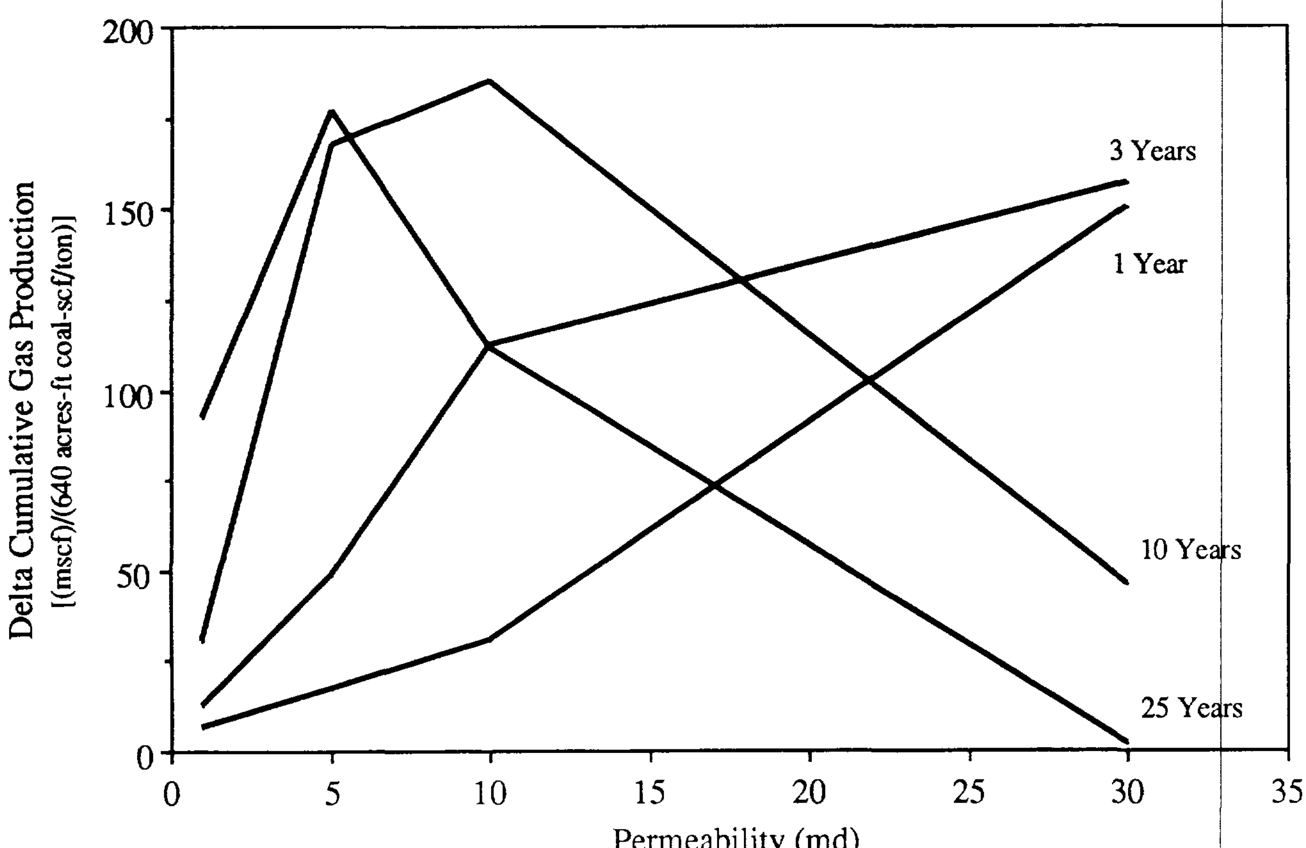



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

**Difference in Cumulative Gas Production Between 320 and 160 Acre Well Spacings**

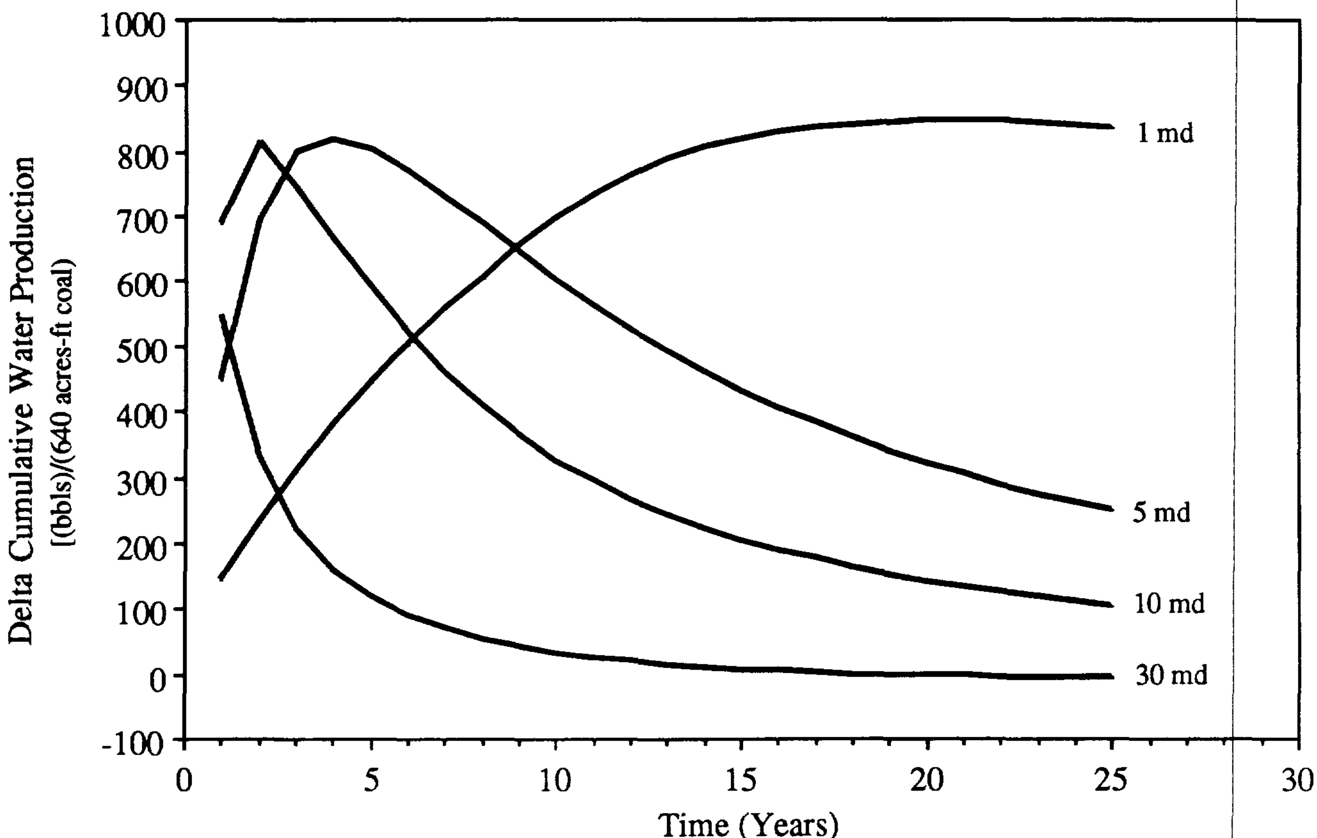


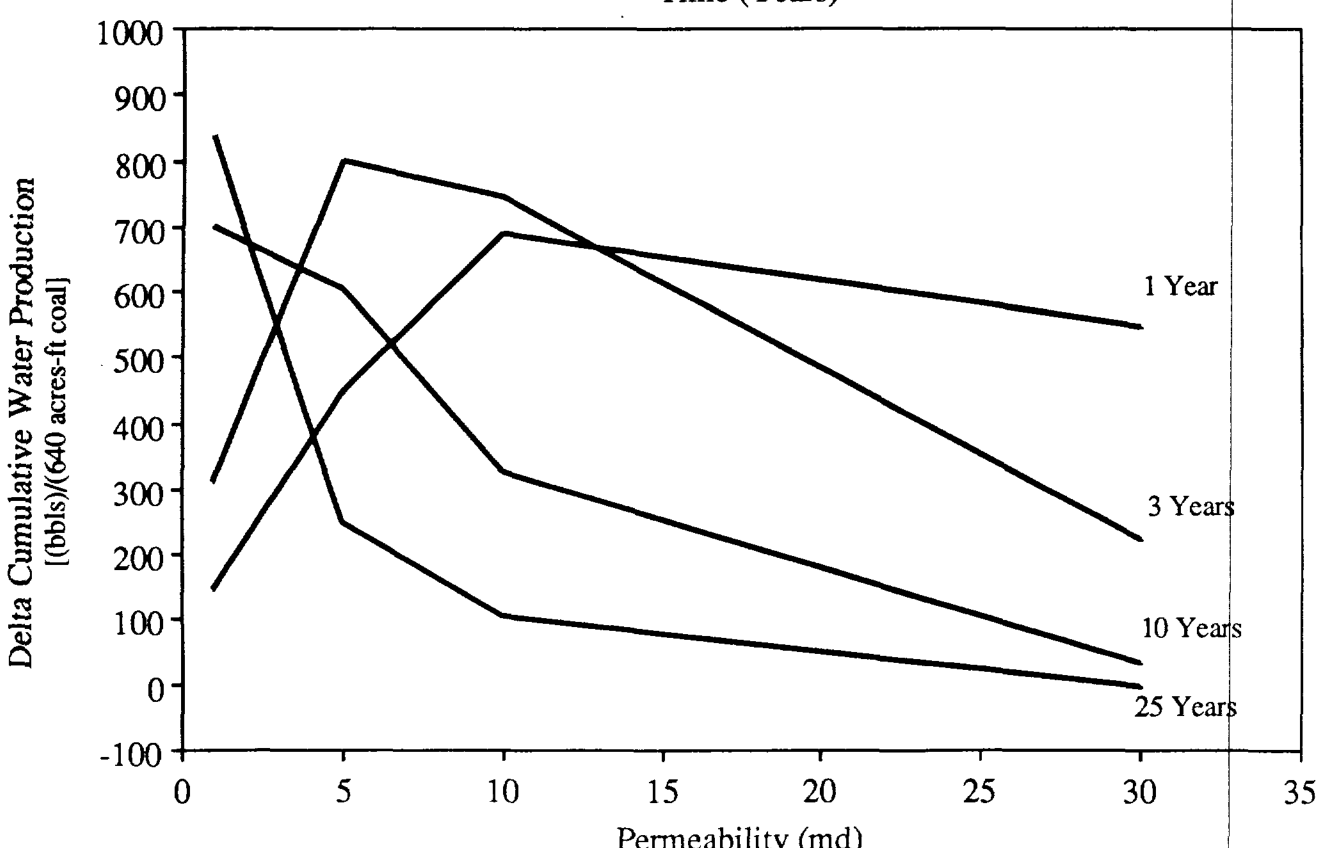



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

**Difference in Cumulative Water Production Between 320 and 160 Acre Well Spacings**

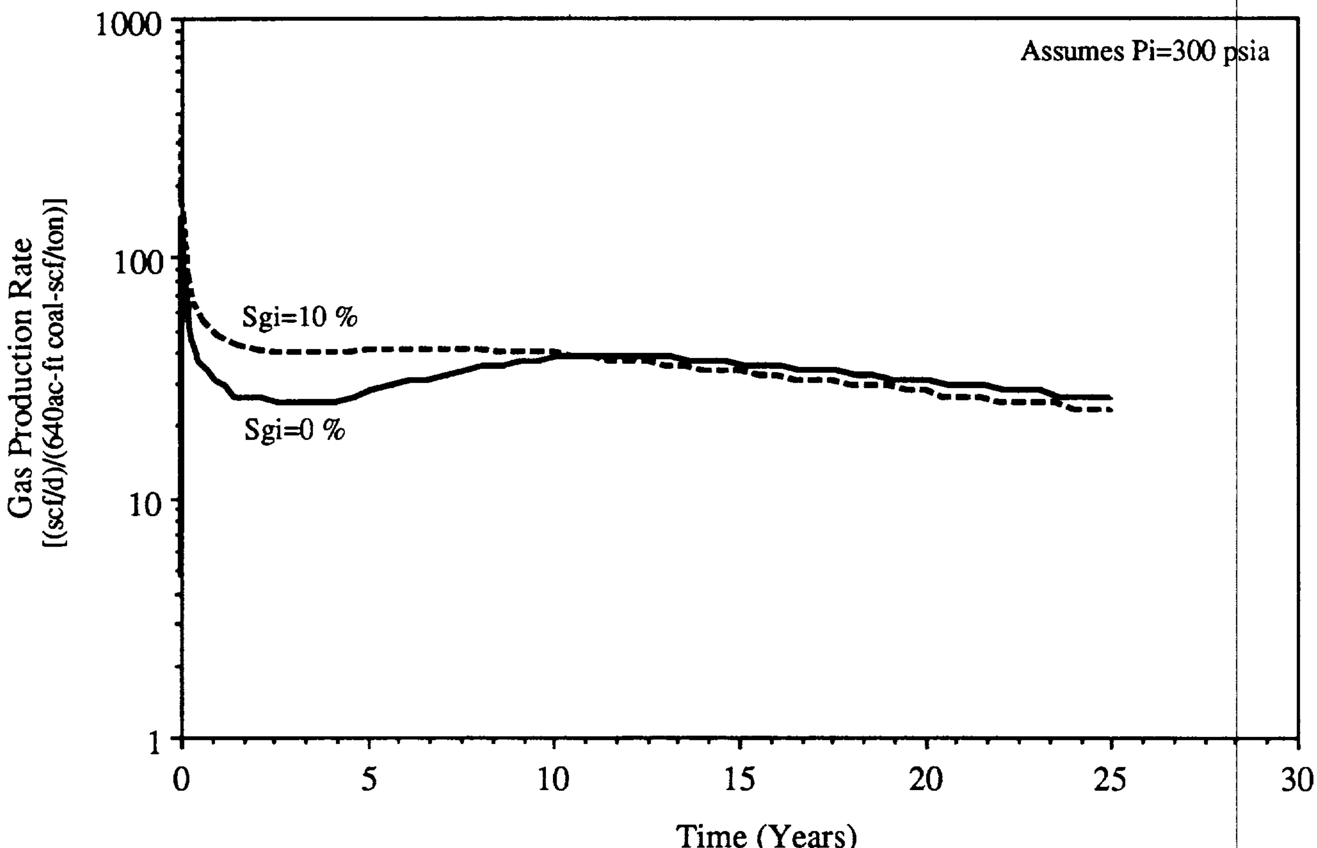


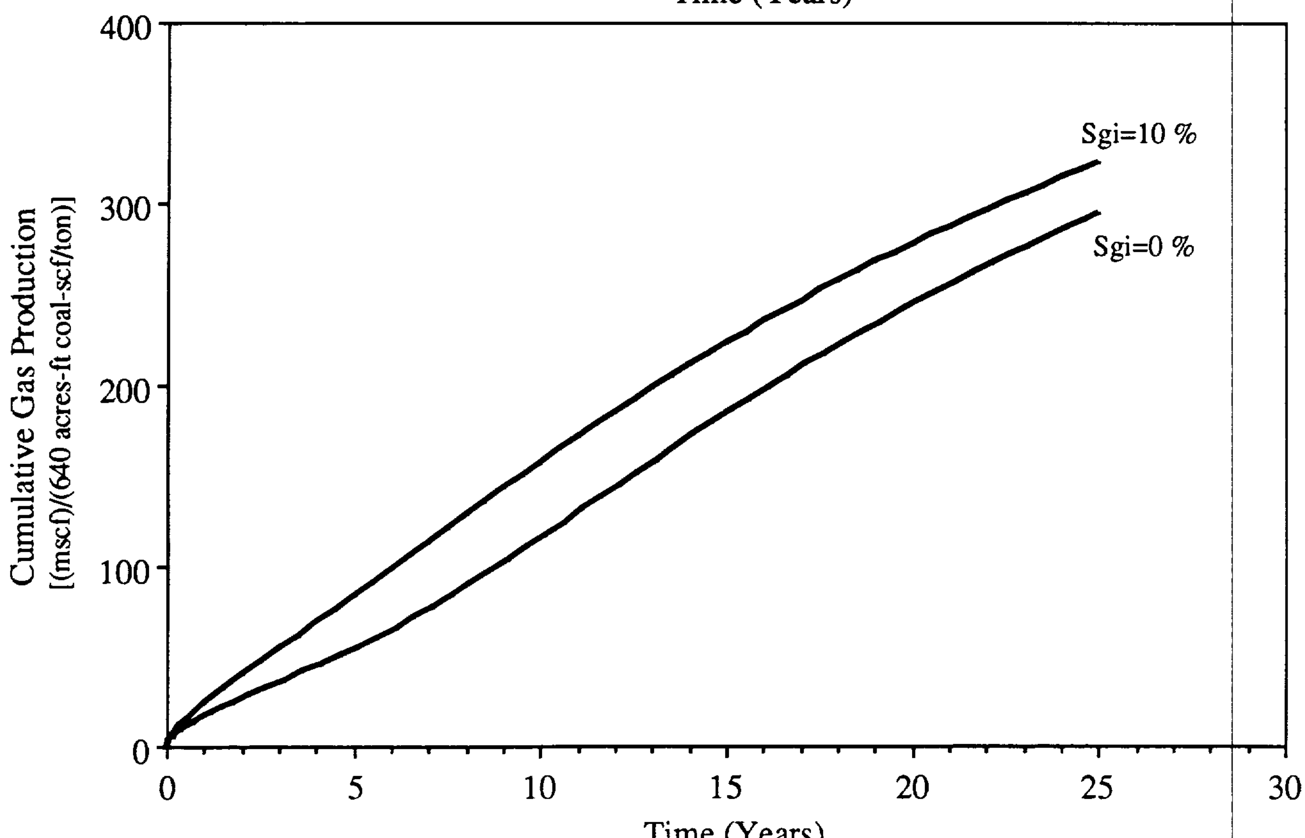



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

**Gas Production for Variations in Initial Free Gas Saturation**

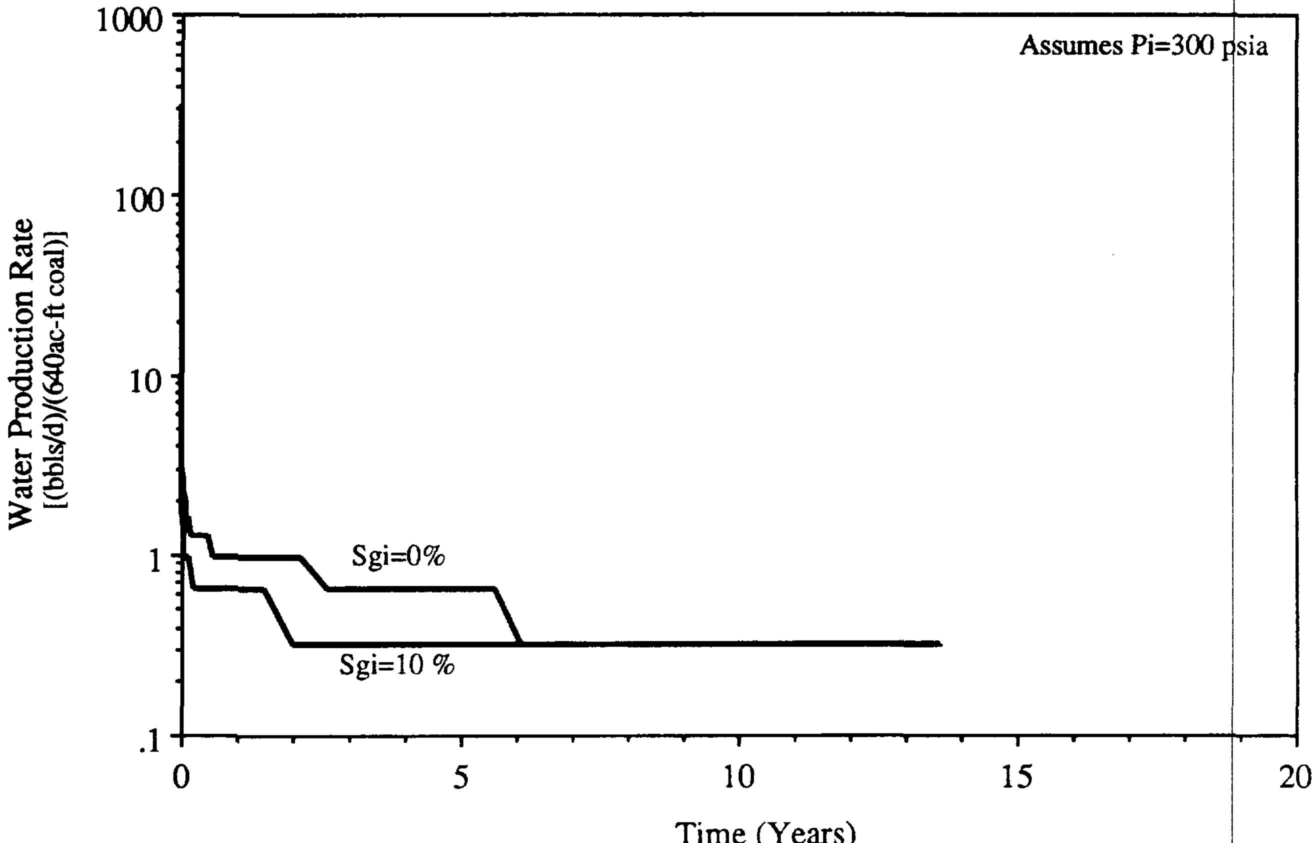


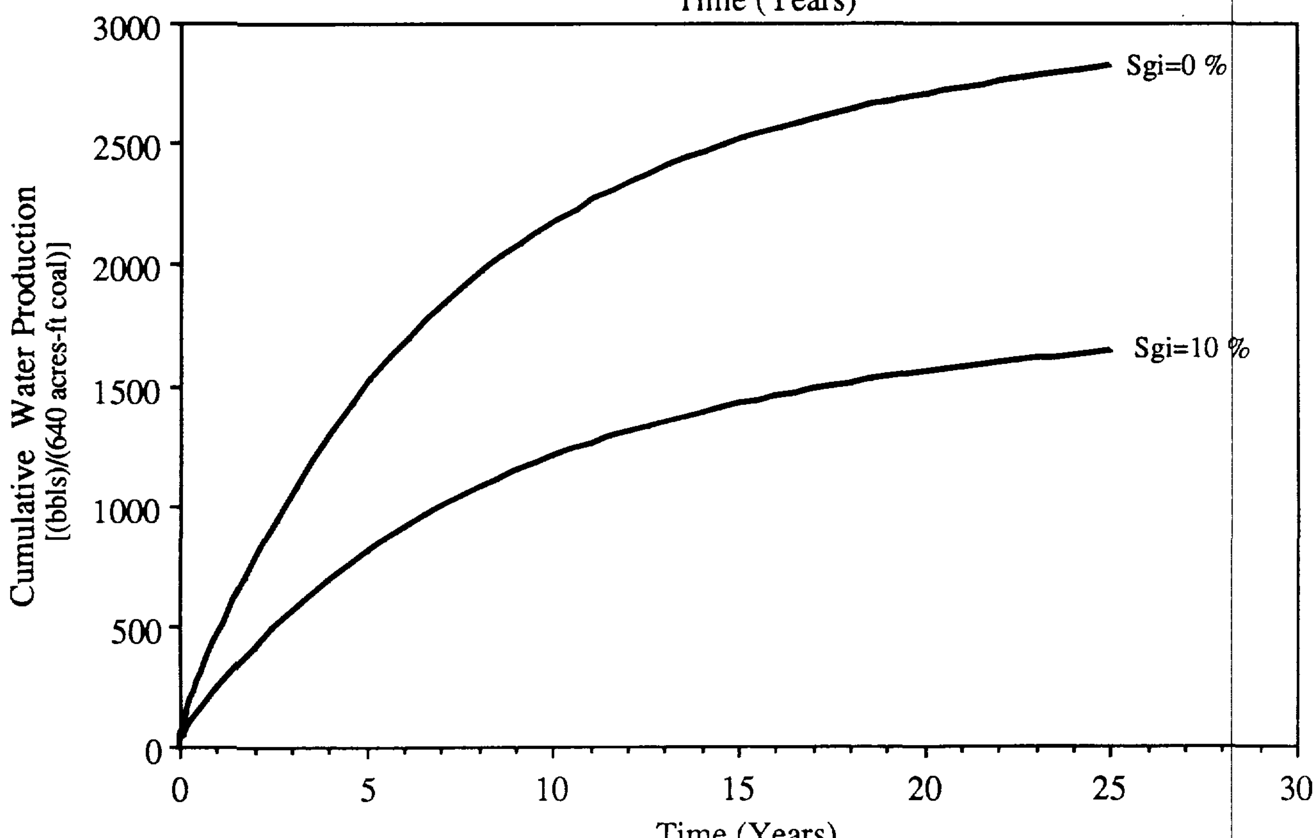



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

**Water Production for Variations in Initial Free Gas Saturation**

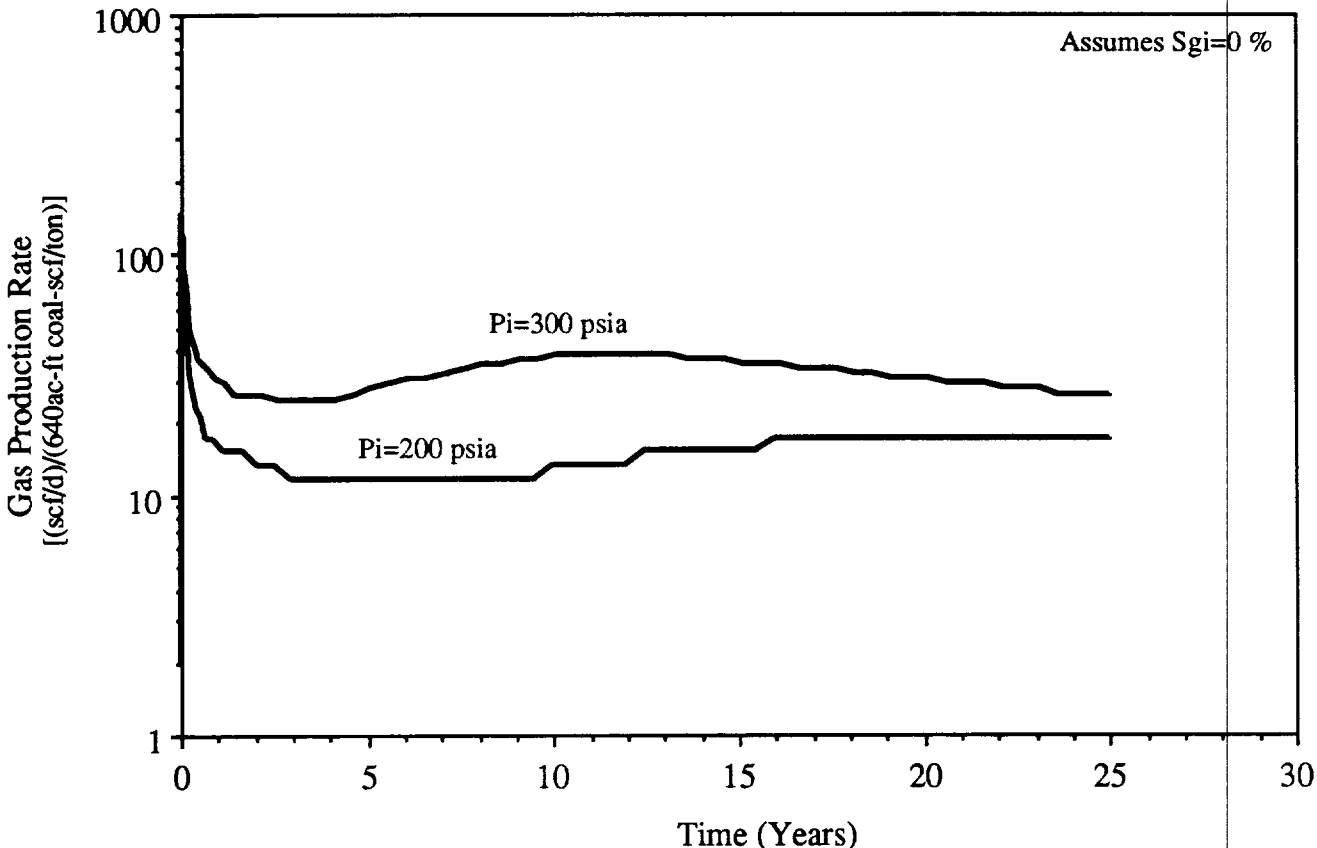


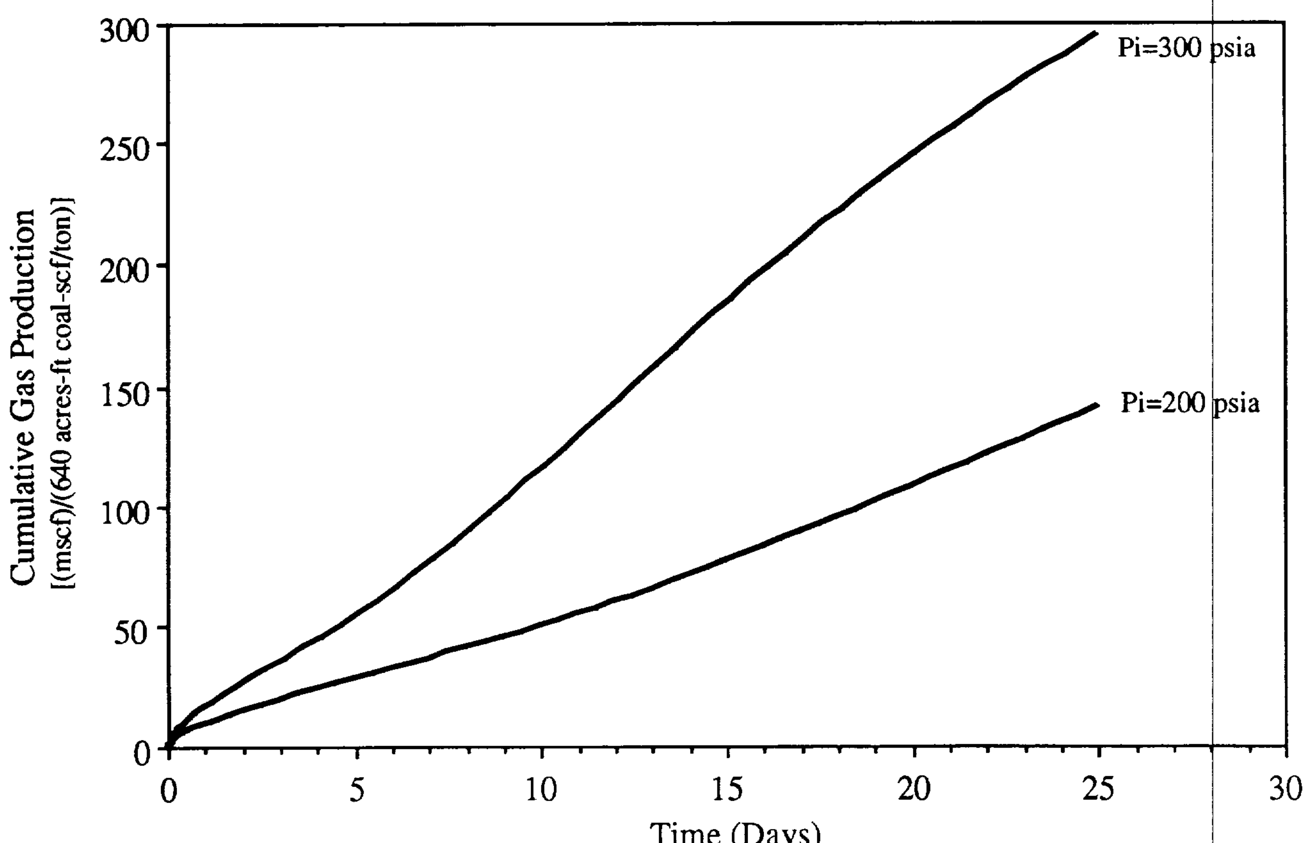



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

### Gas Production for Variations in Initial Reservoir Pressure

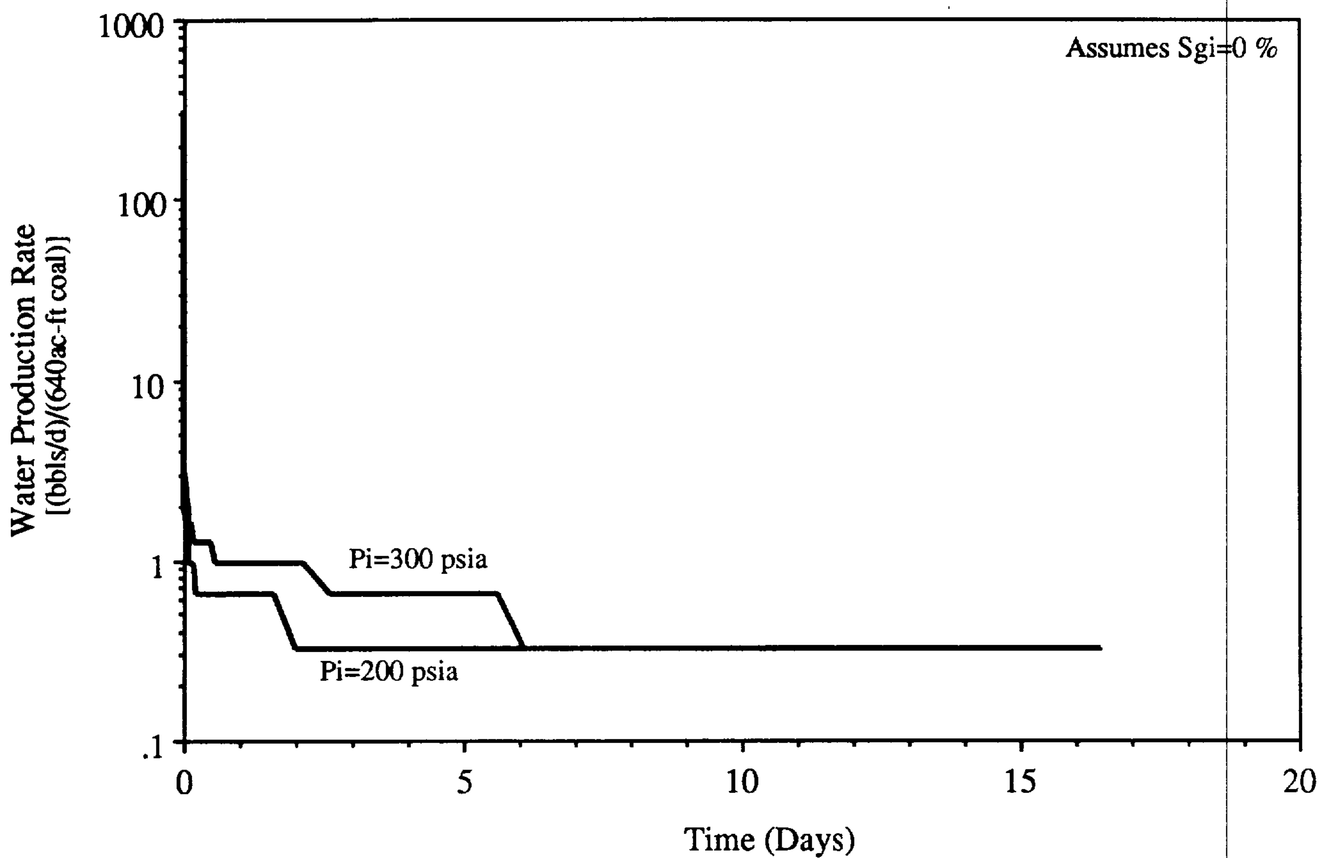


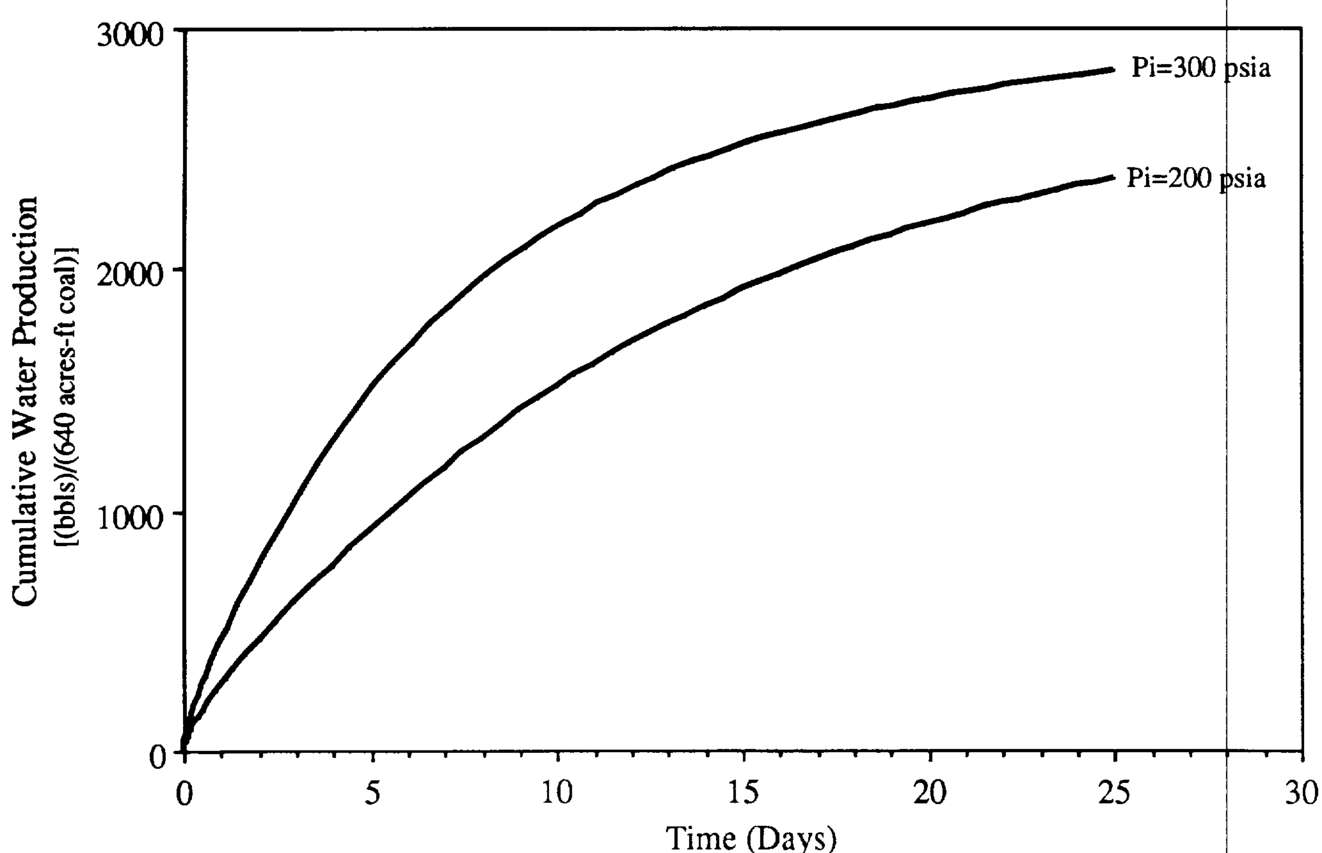



# San Juan Basin Coalbed Methane Spacing Study

## Area 2 Sensitivity Analyses

**Water Production for Variations in Initial Reservoir Pressure**



## SAN JUAN BASIN COALBED METHANE SPACING STUDY

### AREA 3 SENSITIVITY ANALYSES
### SUMMARY OF RESERVOIR PARAMETERS

| FIXED PARAMETERS | VALUE | SOURCE |
|---|---|---|
| Coal Depth | 3,100 feet | Logs |
| Coal Thickness | 40 feet | Logs |
| Langmuir Volume (Ash Corrected) | 427 scf/ton | Estimated[13] |
| Langmuir Pressure | 315 psia | Estimated[13] |
| Desorption Pressure | $P_i$ | Estimated[1] |
| Flowing Bottomhole Pressure | 100 psia | Estimated |
| Temperature | 93°F | Logs |
| Pore Volume Compressibility | $200 \times 10^{-6}$ psi$^{-1}$ | Estimated |
| Porosity | 0.25% | Estimated |
| Cleat Spacing | 0.25 inches | Measured[4] |
| Sorption Time | 10 days | Estimated[13] |
| Gas Gravity | 0.60 | Measured[12] |
| Water FVF | 1.006 RB/STB | Estimated[4] |
| Water Viscosity | 0.565 cp | Estimated[4] |
| Relative Permeability Curves | - | Estimated[10] |
| | | |
| **VARIABLE PARAMETERS** | | |
| Initial Free Gas Saturation (Sgi) | 0, 23% ($=1-S_{wc}$) | |
| Initial Reservoir Pressure (Pi) | 400, 650 psia ($G_c$ = 239, 288 scf/ton) | |
| Permeability | 0.1, 1, 5 md | |
| Fracture Half-Length | 100, 300 feet | |
| Well Spacing | 160, 320 acres | |

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

### AREA 3 SENSITIVITY ANALYSES
### INVENTORY OF INITIAL FLUIDS IN PLACE

| Free Gas Saturation (Sgi) (percent) | Reservoir Pressure (= $P_D$) (psia) | Gas Content* (scf/ton) | Gas-In-Place** [(mscf)/(640 ac-ft coal-scf/ton)] | | | Water-In-Place** [(mbbls)/(640 ac-ft coal)] |
|---|---|---|---|---|---|---|
| | | | Free | Sorbed | Total | |
| 0 | 400 | 239 | 0.00 | 1,148 | 1,148 | 12.4 |
| 0 | 650 | 288 | 0.00 | 1,148 | 1,148 | 12.4 |
| 23*** | 400 | 239 | 1.84 | 1,148 | 1,150 | 9.5 |
| 23*** | 650 | 288 | 2.56 | 1,148 | 1,150 | 9.5 |

* Assumes a Langmuir volume of 427 scf/ton and a Langmuir pressure of 315 psia.

** Coal thickness was assumed to be 40 feet for all cases simulated in Area 3. All water and free gas volumes were calculated assuming a constant cleat porosity of 0.25%.

*** This free gas saturation represents $(1-S_{wc})$.

EXHIBIT 129

## SAN JUAN BASIN COALBED METHANE SPACING STUDY

## SIMULATION RESULTS FOR AREA 3 SENSITIVITY ANALYSES

**(Assumes NO Initial Free Gas Saturation)**

| Sensitivity Parameters | | | Initial Reservoir Pressure = 400 psia | | | Initial Reservoir Pressure = 650 psia | | |
|---|---|---|---|---|---|---|---|---|
| | | | 20 mscf/d Cutoff | | 25 year Cutoff | 20 mscf/d Cutoff | | 25 year Cutoff |
| Permeability (md) | Fracture Half-Length (feet) | Well Spacing (acres) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) |
| 0.1 | 100 | 160 | 0.14 | 0.0 | 1.1 | 0.32 | 0.1 | 1.7 |
| 0.1 | 100 | 320 | 0.14 | 0.0 | 0.6 | 0.32 | 0.1 | 0.8 |
| 0.1 | 300 | 160 | 0.82 | 0.4 | 2.7 | 2.90 | 1.1 | 3.9 |
| 0.1 | 300 | 320 | 0.82 | 0.2 | 1.3 | 2.85 | 0.5 | 1.9 |
| 1.0 | 100 | 160 | 83.20 | 32.7 | 10.6 | 88.43 | 44.5 | 20.7 |
| 1.0 | 100 | 320 | 168.56 | 31.2 | 3.7 | 179.82 | 43.2 | 8.7 |
| 1.0 | 300 | 160 | 73.23 | 40.6 | 19.9 | 75.13 | 50.8 | 31.2 |
| 1.0 | 300 | 320 | 154.37 | 38.4 | 7.4 | 159.17 | 48.9 | 15.4 |
| 5.0 | 100 | 160 | 48.92 | 50.1 | 40.0 | 49.38 | 58.5 | 49.8 |
| 5.0 | 100 | 320 | 101.25 | 49.6 | 24.9 | 102.90 | 58.2 | 36.1 |
| 5.0 | 300 | 160 | 36.96 | 52.7 | 48.4 | 37.37 | 60.7 | 57.0 |
| 5.0 | 300 | 320 | 80.68 | 52.0 | 34.1 | 80.99 | 60.1 | 44.5 |

EXHIBIT 130

**SAN JUAN BASIN COALBED METHANE SPACING STUDY**

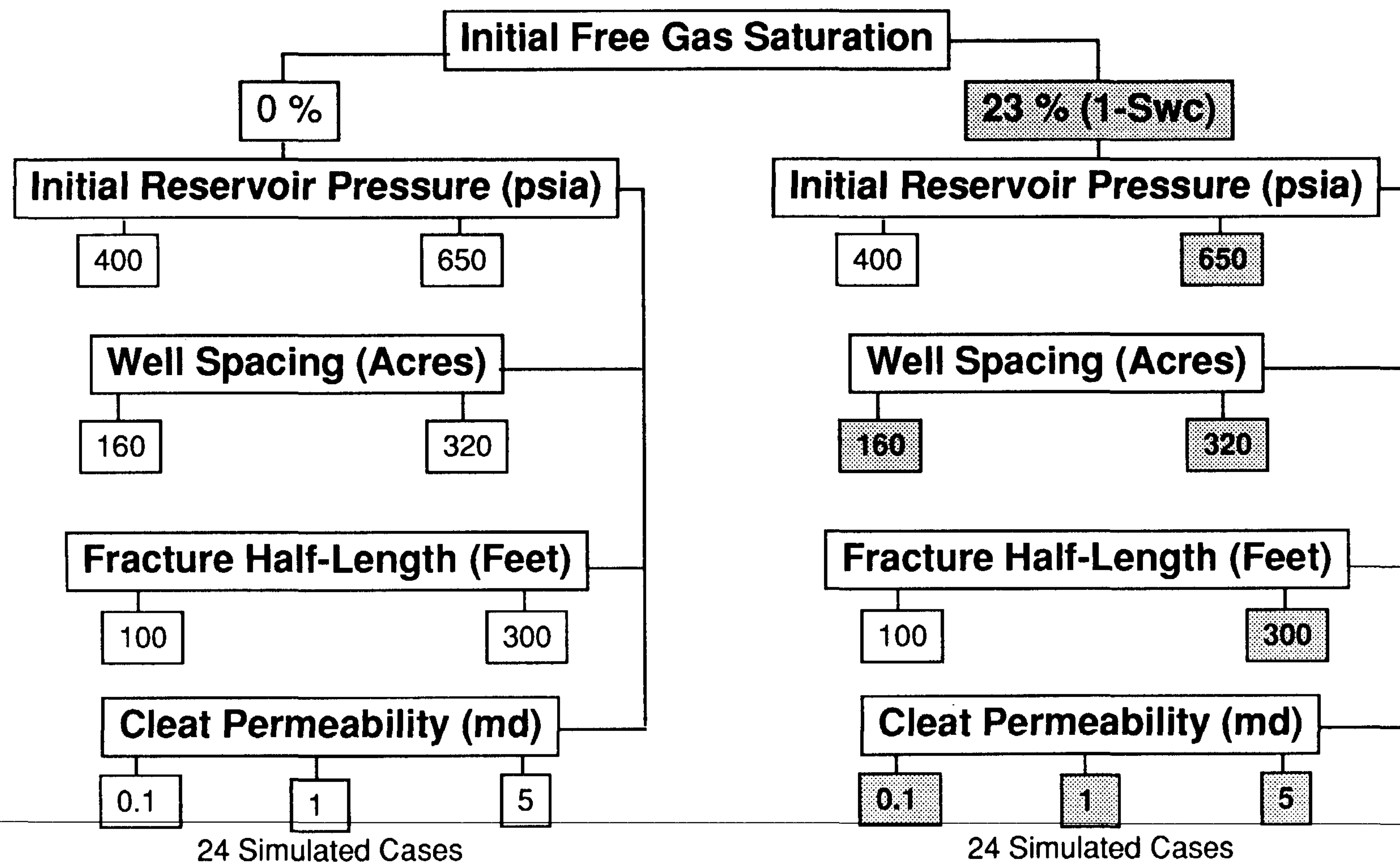
**SIMULATION RESULTS FOR AREA 3 SENSITIVITY ANALYSES**

**(Assumes Assumes 23 % Initial Free Gas Saturation)**

| Sensitivity Parameters | | | Initial Reservoir Pressure = 400 psia | | | Initial Reservoir Pressure = 650 psia | | |
|---|---|---|---|---|---|---|---|---|
| | | | 20 mscf/d Cutoff | | 25 year Cutoff | 20 mscf/d Cutoff | | 25 year Cutoff |
| Permeability (md) | Fracture Half-Length (feet) | Well Spacing (acres) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) | Time (years) | Gas Recovery (% IGIP) | Gas Recovery (% IGIP) |
| 0.1 | 100 | 160 | 1.22 | 0.4 | 4.0 | 30.22 | 8.2 | 7.1 |
| 0.1 | 100 | 320 | 1.22 | 0.2 | 2.0 | 52.72 | 6.8 | 3.8 |
| 0.1 | 300 | 160 | 11.72 | 4.1 | 6.9 | 49.22 | 16.9 | 11.2 |
| 0.1 | 300 | 320 | 11.22 | 2.0 | 3.5 | 87.22 | 13.9 | 5.9 |
| 1.0 | 100 | 160 | 61.08 | 33.6 | 21.3 | 74.00 | 44.7 | 28.8 |
| 1.0 | 100 | 320 | 122.08 | 32.3 | 12.8 | 149.50 | 43.5 | 19.2 |
| 1.0 | 300 | 160 | 58.08 | 41.0 | 29.0 | 66.50 | 51.0 | 37.0 |
| 1.0 | 300 | 320 | 119.58 | 38.9 | 17.8 | 138.50 | 49.2 | 24.9 |
| 5.0 | 100 | 160 | 43.22 | 50.2 | 43.6 | 46.22 | 58.7 | 51.7 |
| 5.0 | 100 | 320 | 89.22 | 49.7 | 32.4 | 95.72 | 58.3 | 40.6 |
| 5.0 | 300 | 160 | 33.22 | 52.7 | 50.1 | 35.22 | 60.8 | 57.9 |
| 5.0 | 300 | 320 | 72.22 | 52.1 | 39.2 | 76.72 | 60.2 | 47.4 |

EXHIBIT 131

# San Juan Basin Coalbed Methane Spacing Study
## Area 3 Sensitivity Analyses
## 48 Simulation Cases for Gas and Water Production

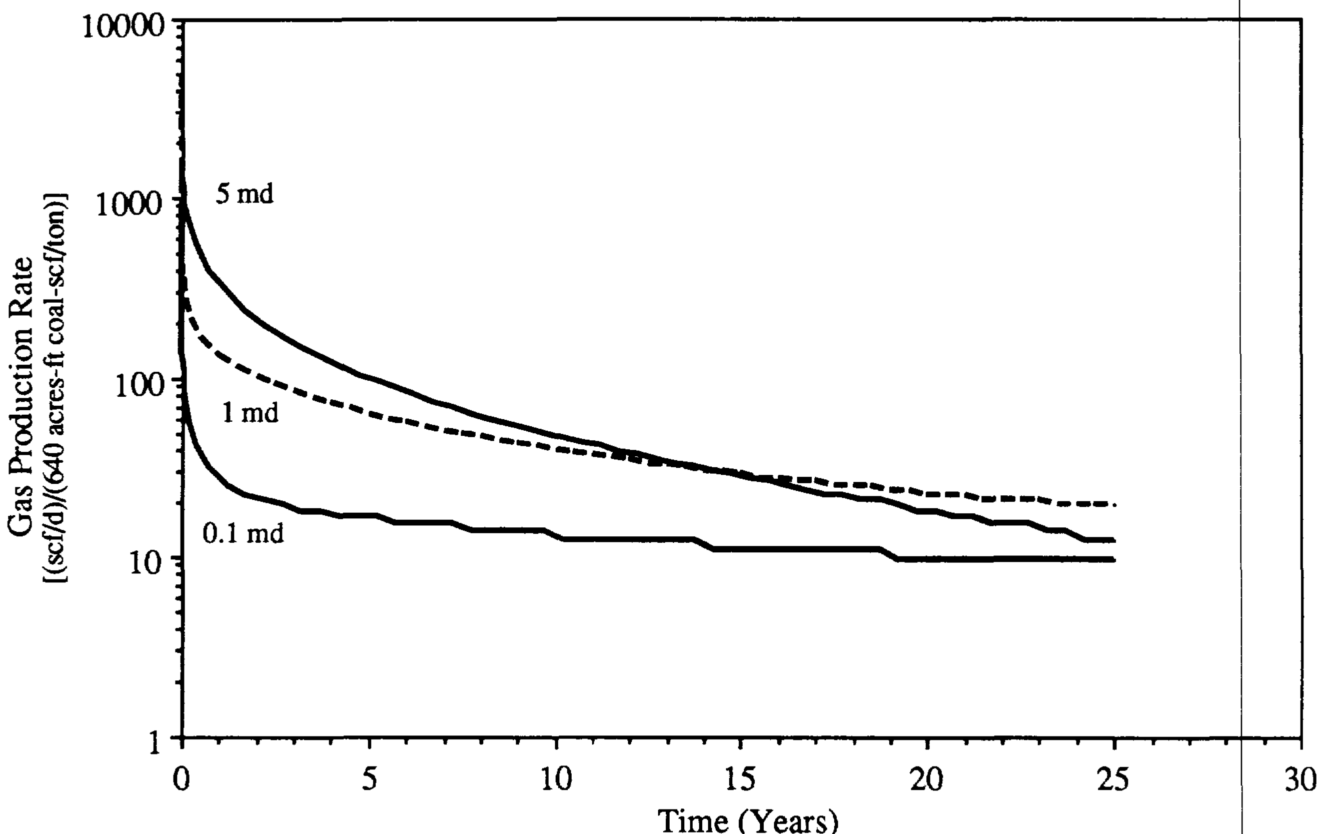



- Simulation Cases Shown as Figures

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Gas Production for a 160 Acre Well Spacing**



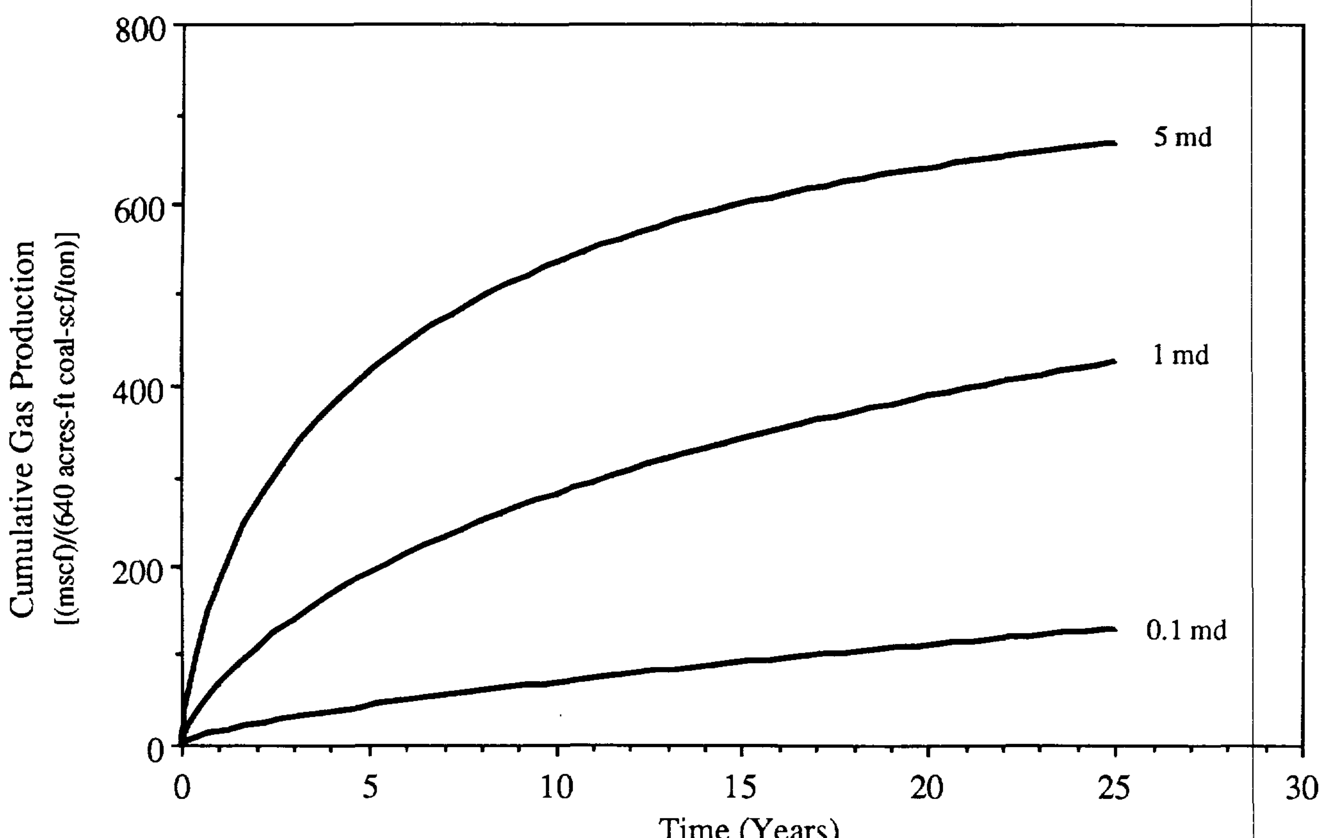



EXHIBIT 133

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Gas Recovery for a 160 Acre Well Spacing**

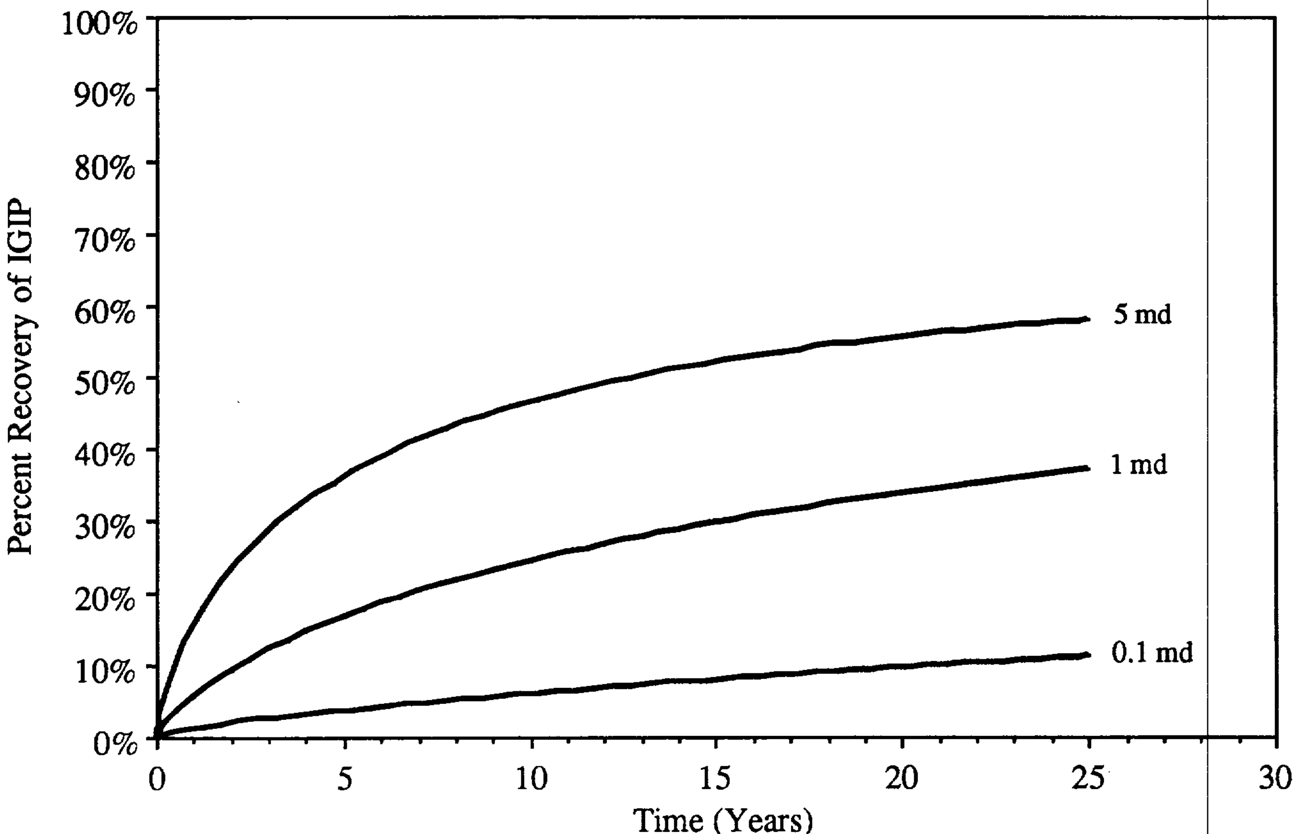
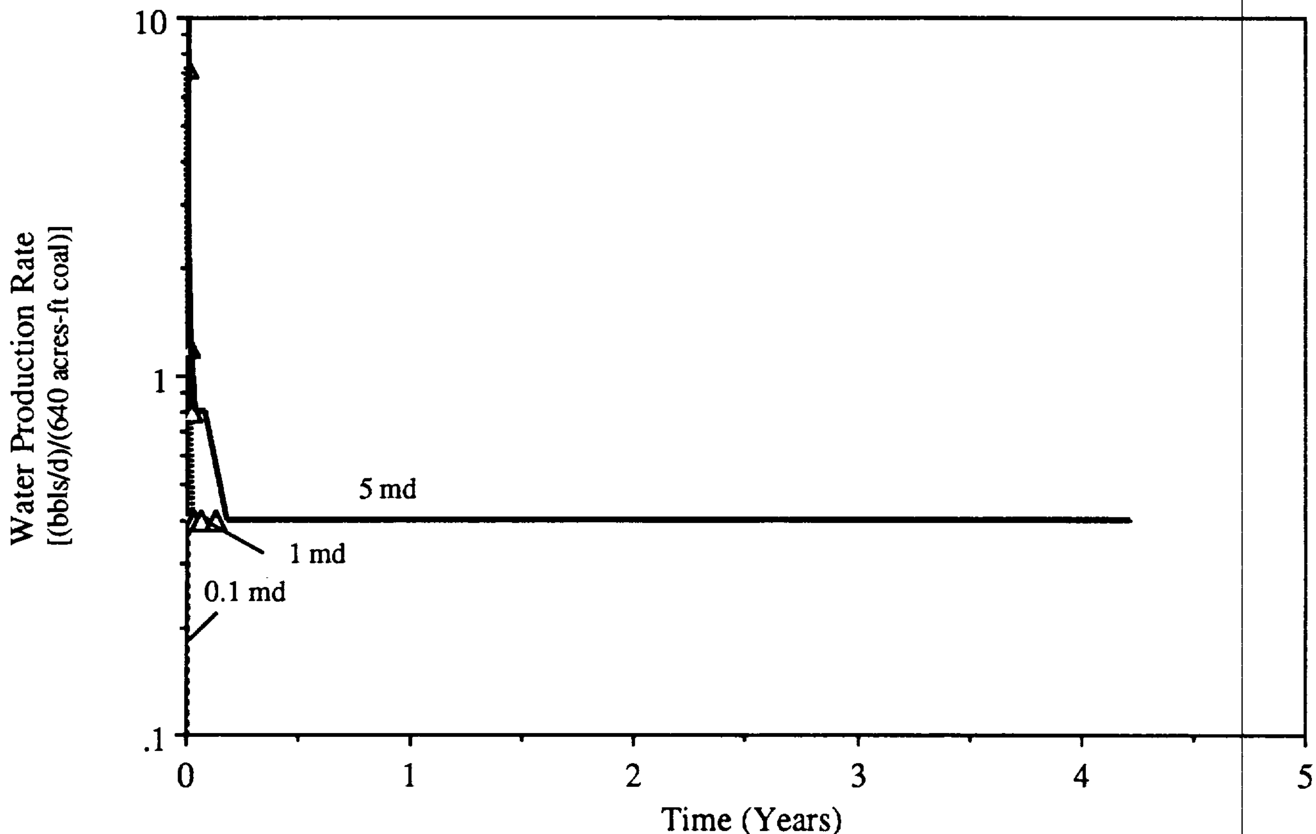


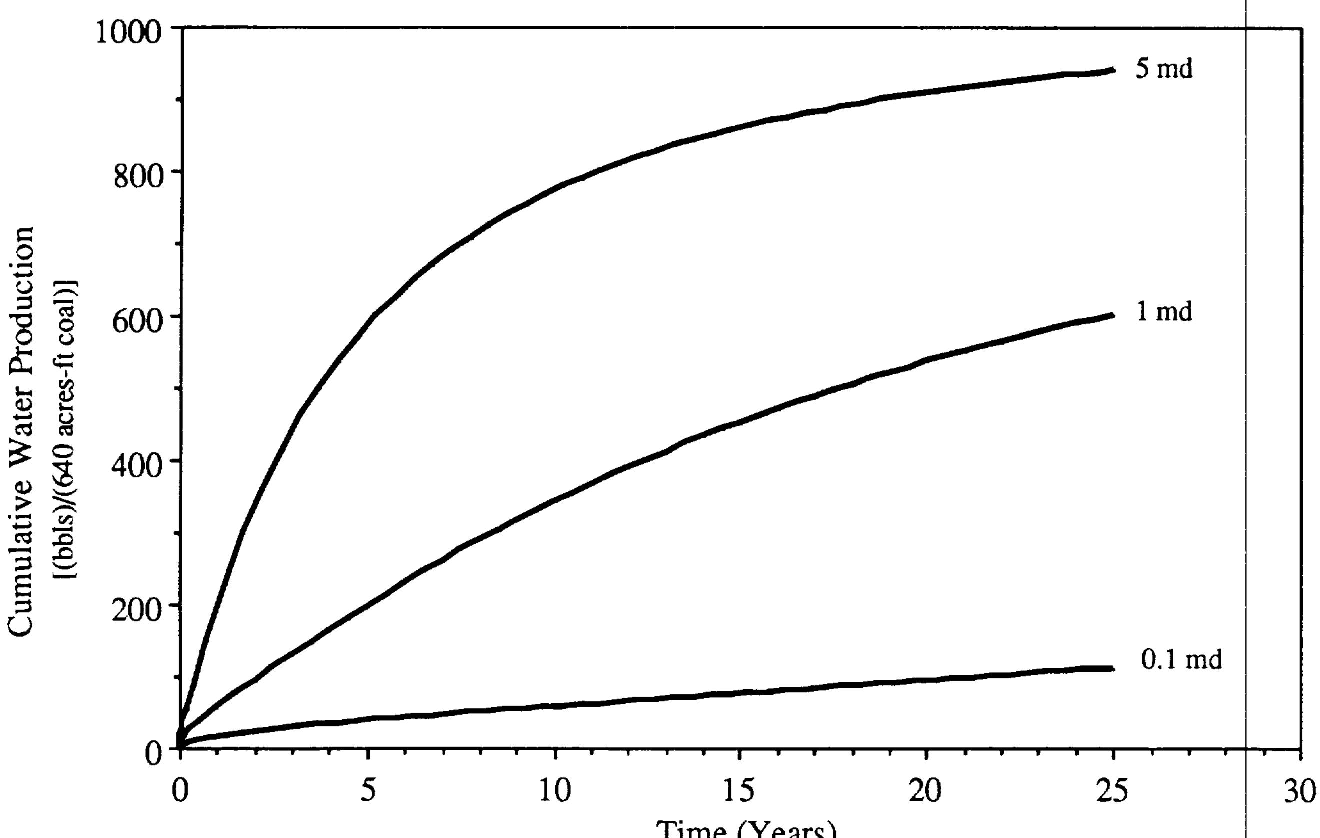
EXHIBIT 134

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Water Production for a 160 Acre Well Spacing**

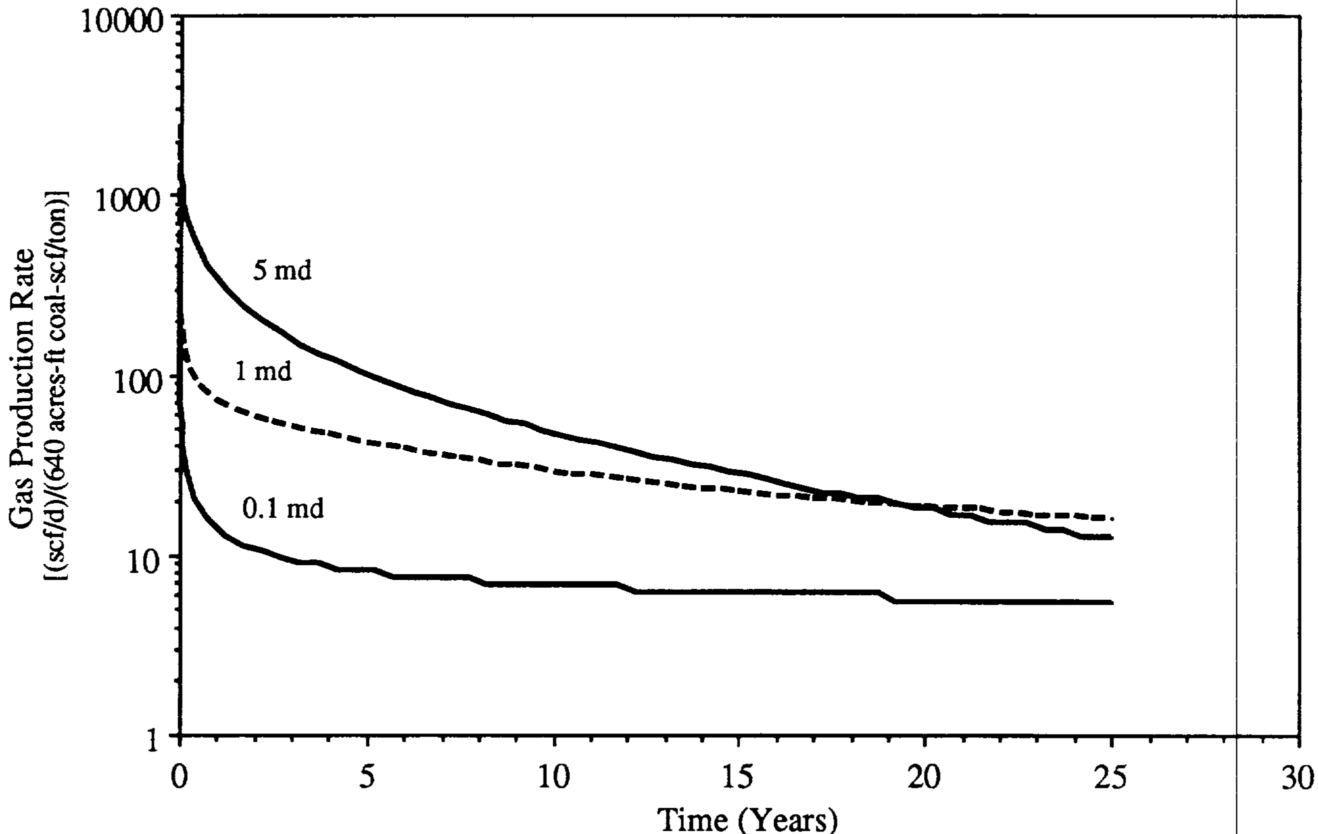


# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Gas Production for a 320 Acre Well Spacing**



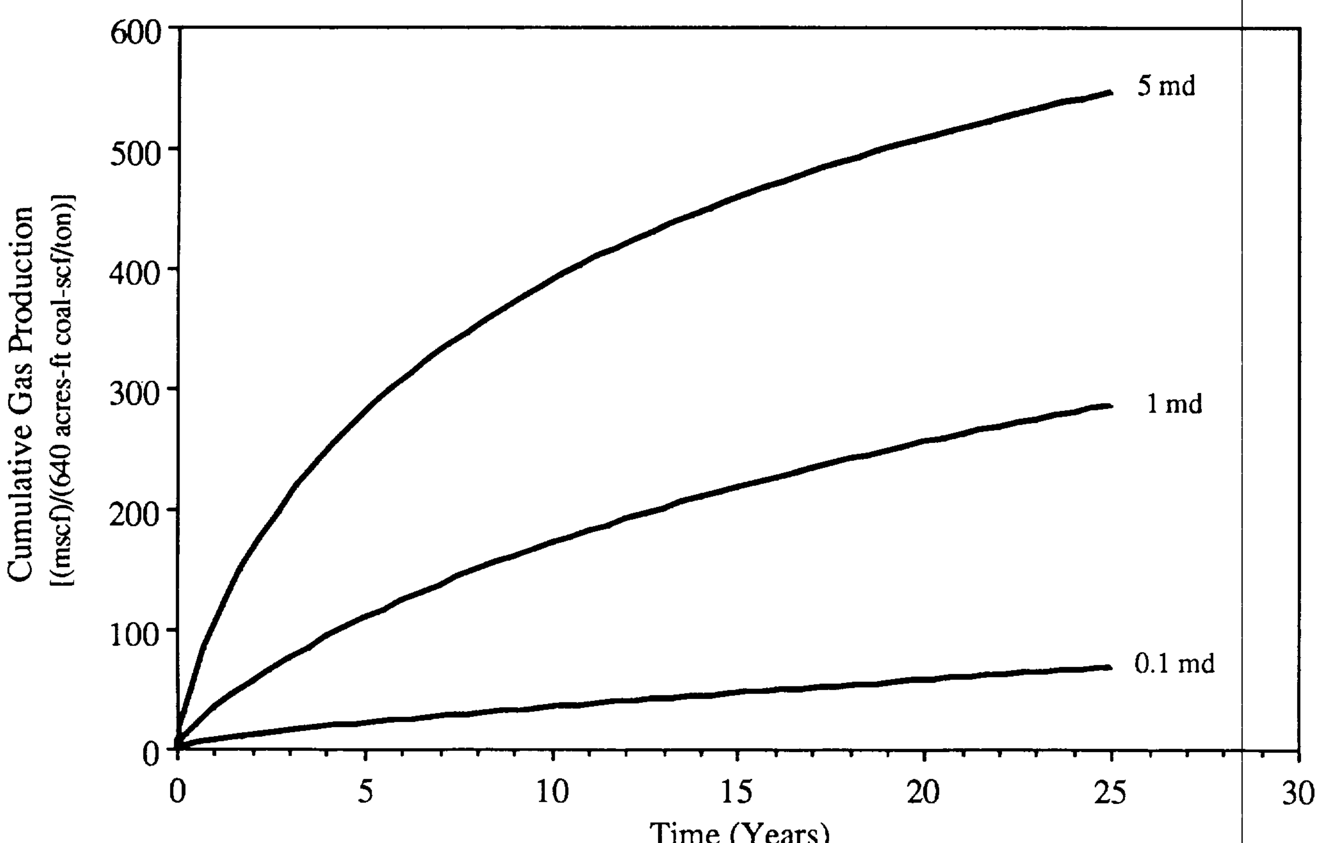



EXHIBIT 136

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Gas Recovery for a 320 Acre Well Spacing**

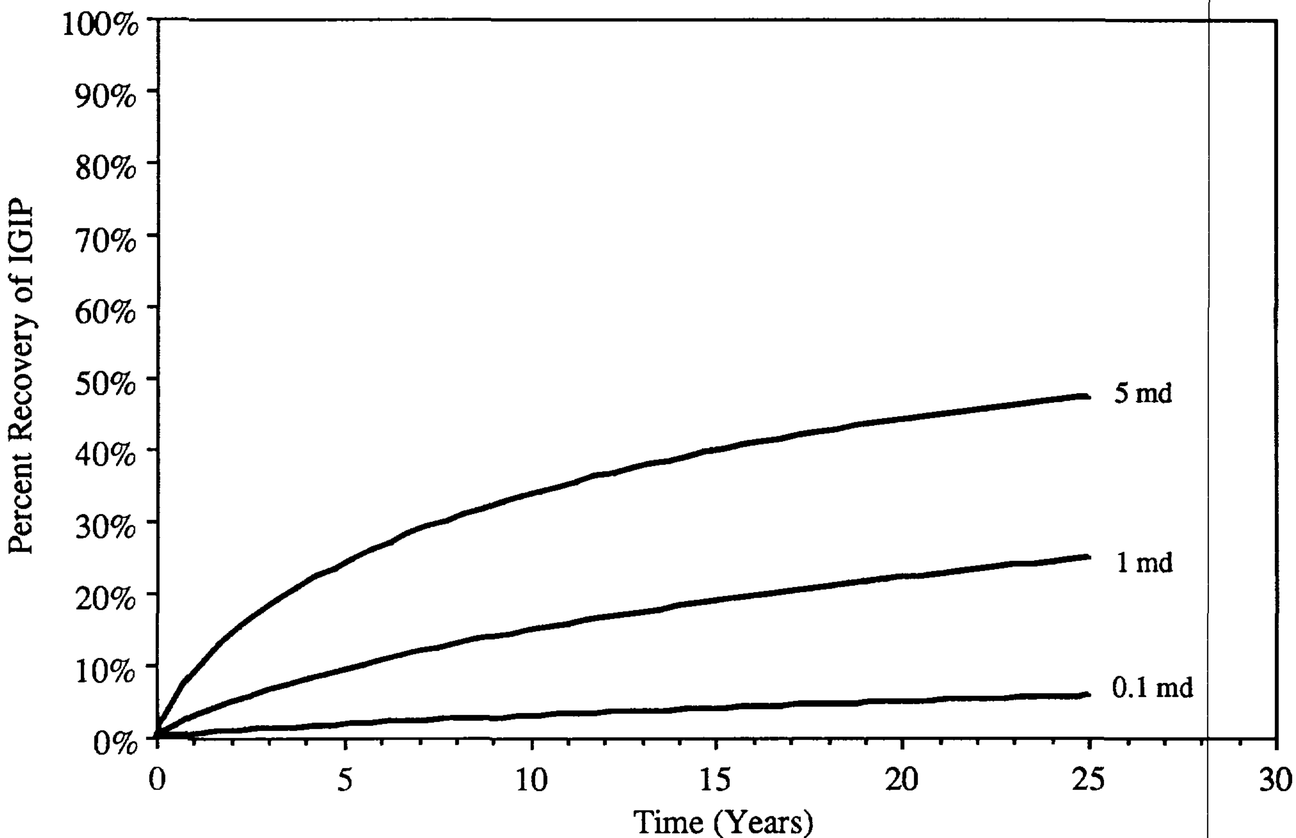
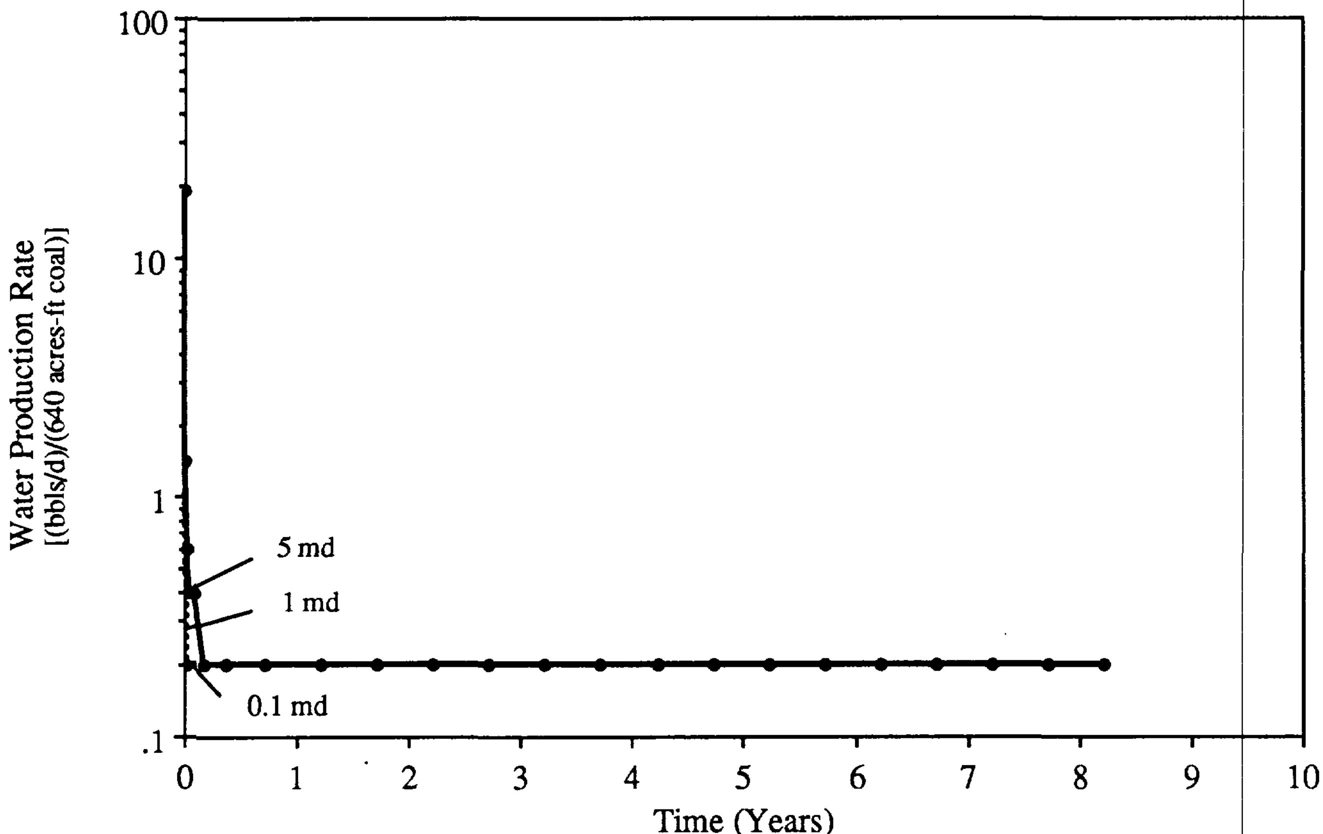


EXHIBIT 137

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Water Production for a 320 Acre Well Spacing**



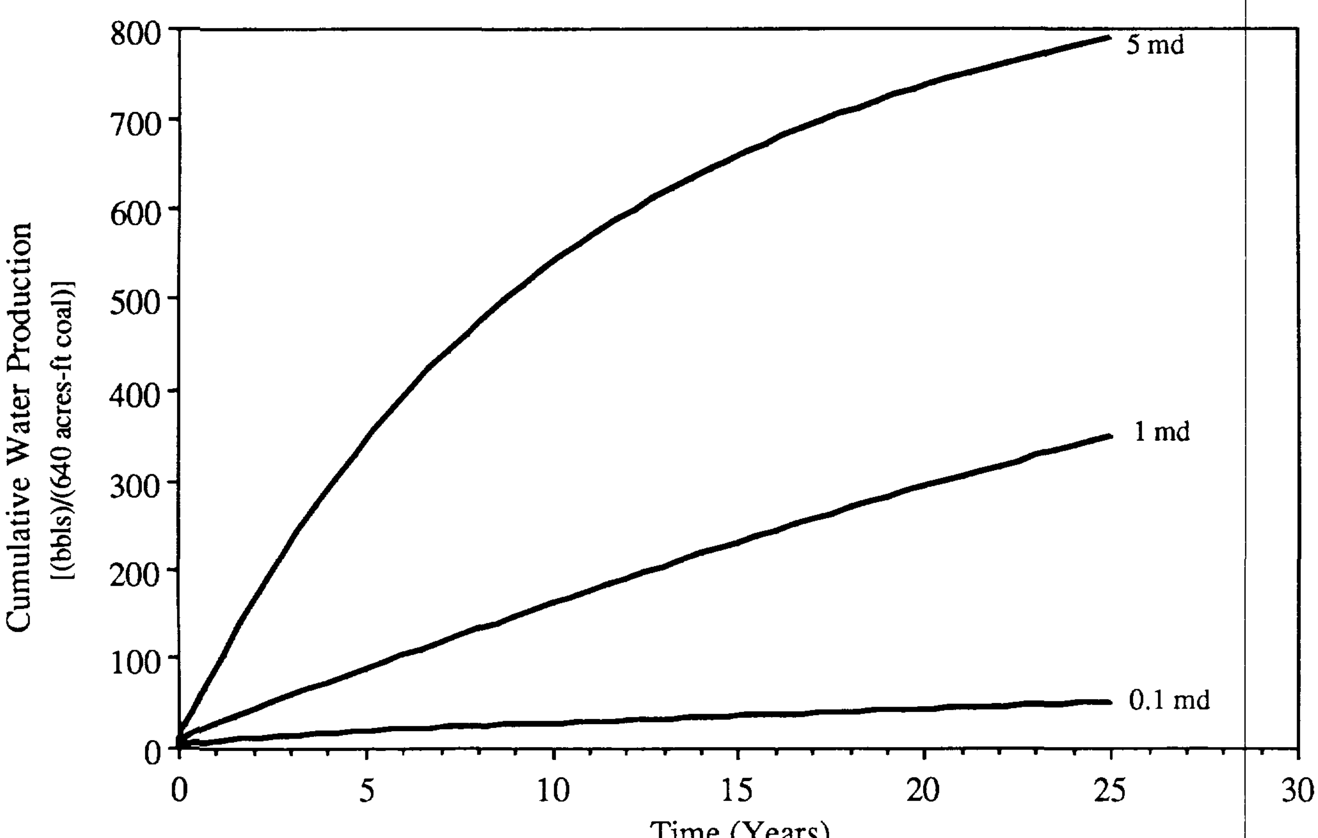
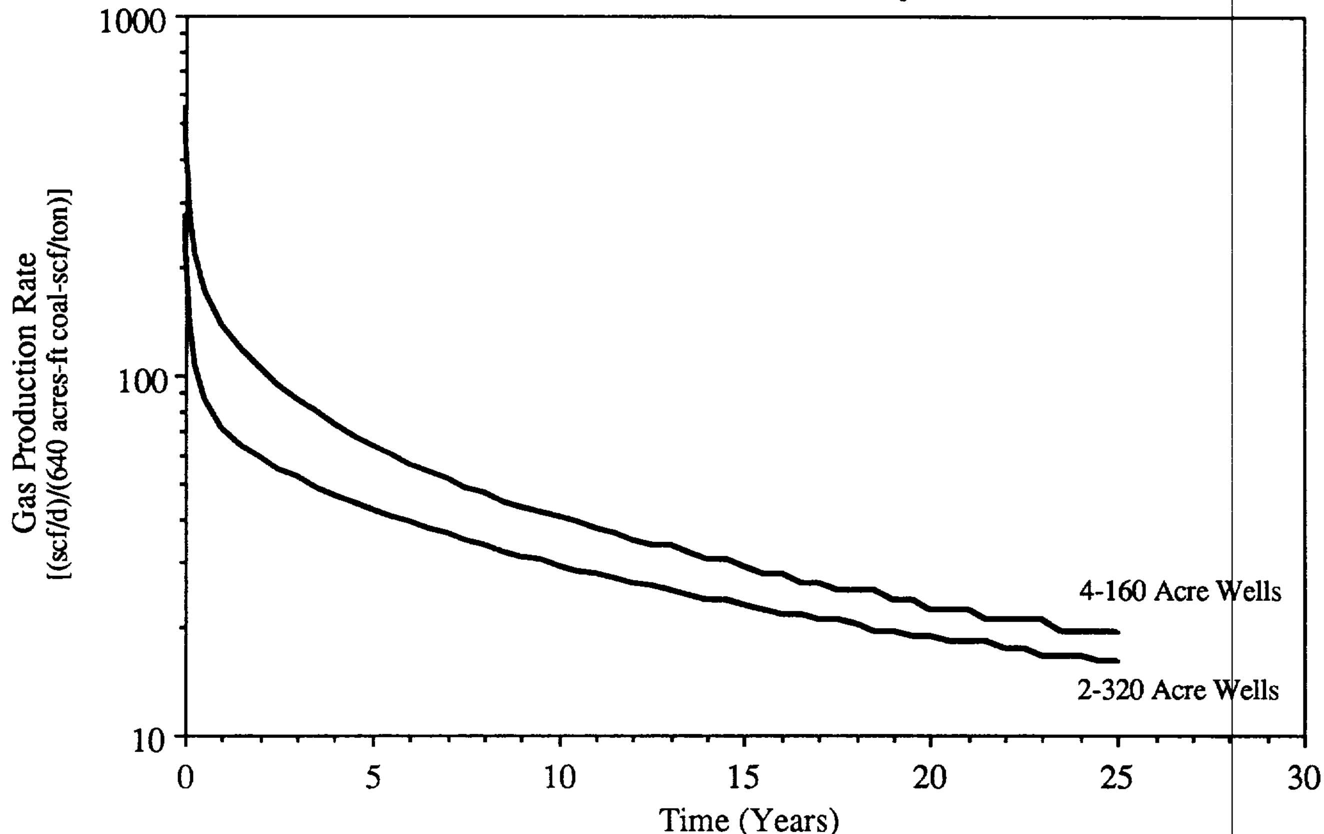



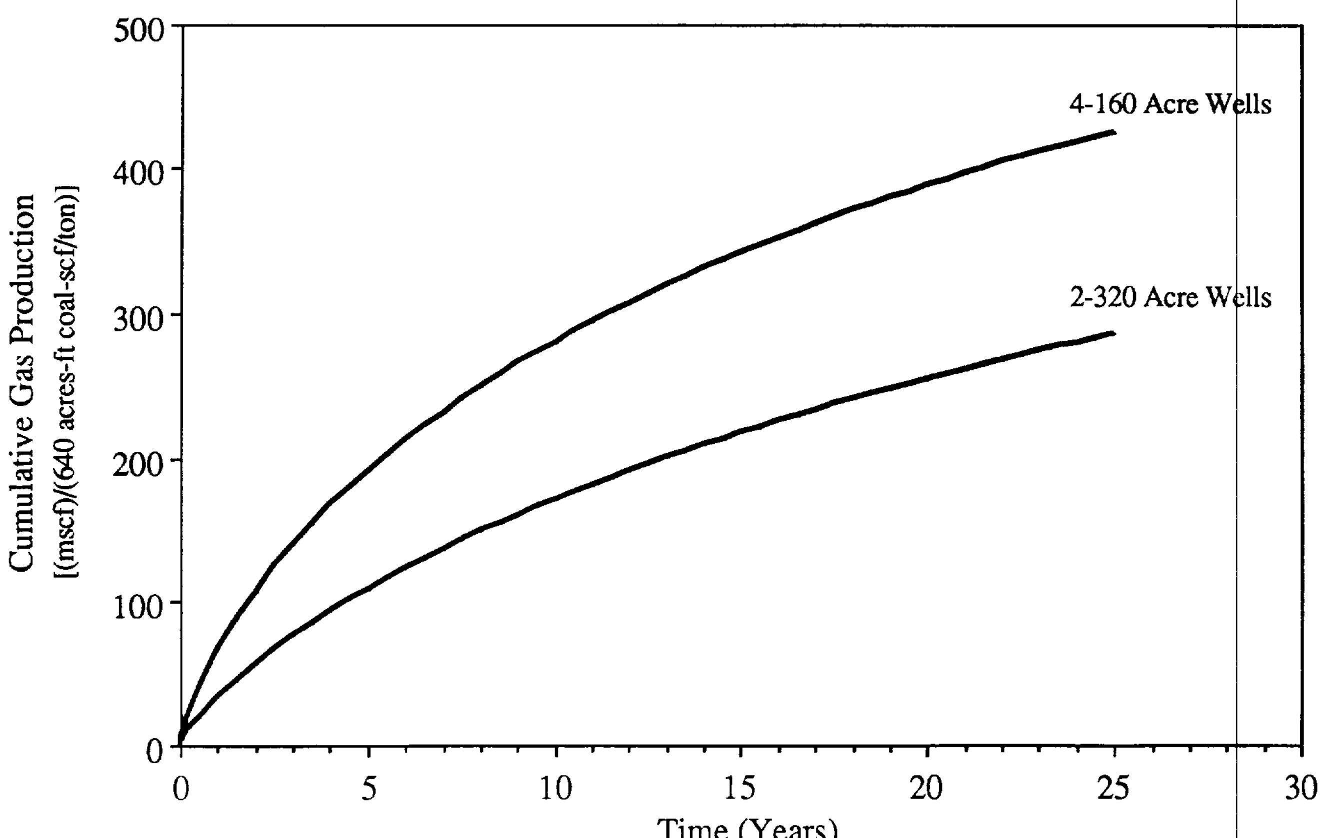
EXHIBIT 138

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Gas Production for a Cleat Permeability of 1md**

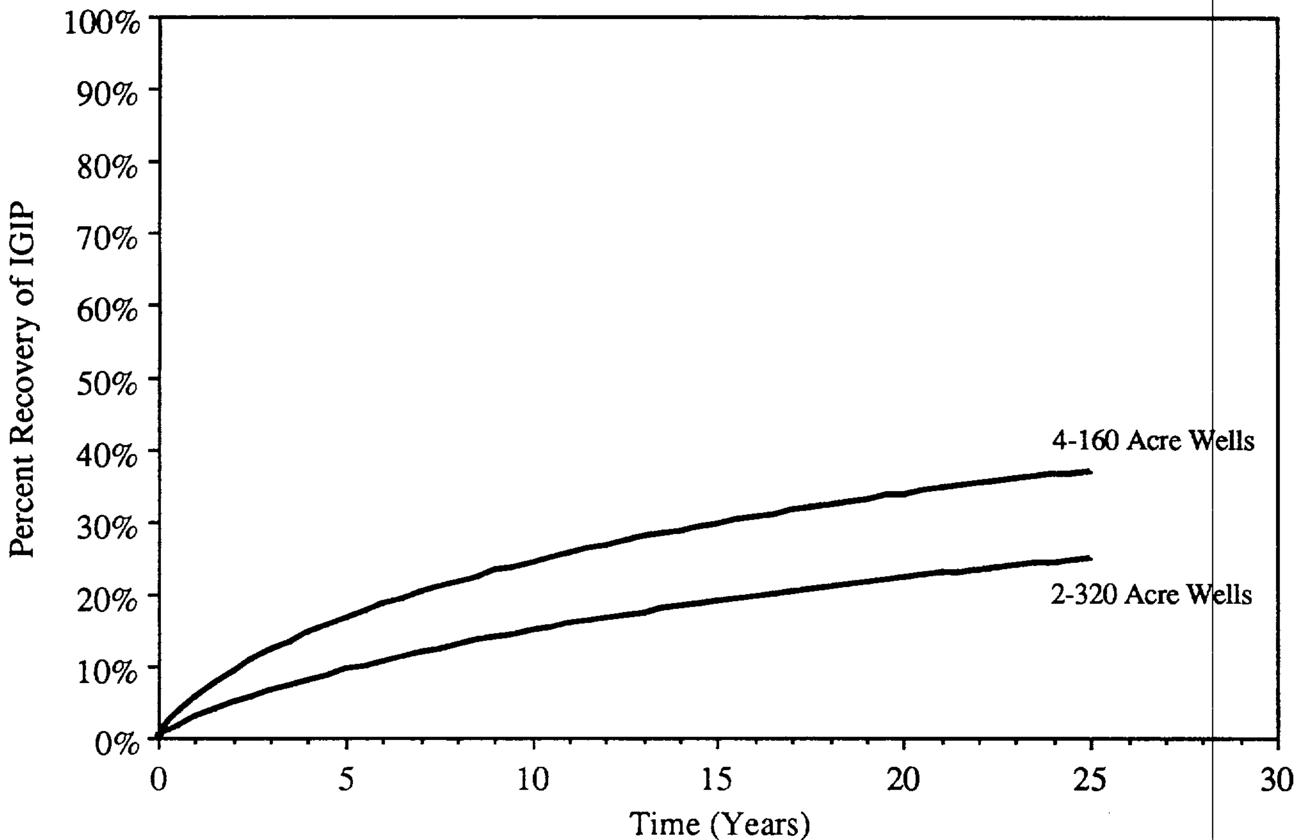


# San Juan Basin Coalbed Methane Spacing Study

Area 3 Sensitivity Analyses

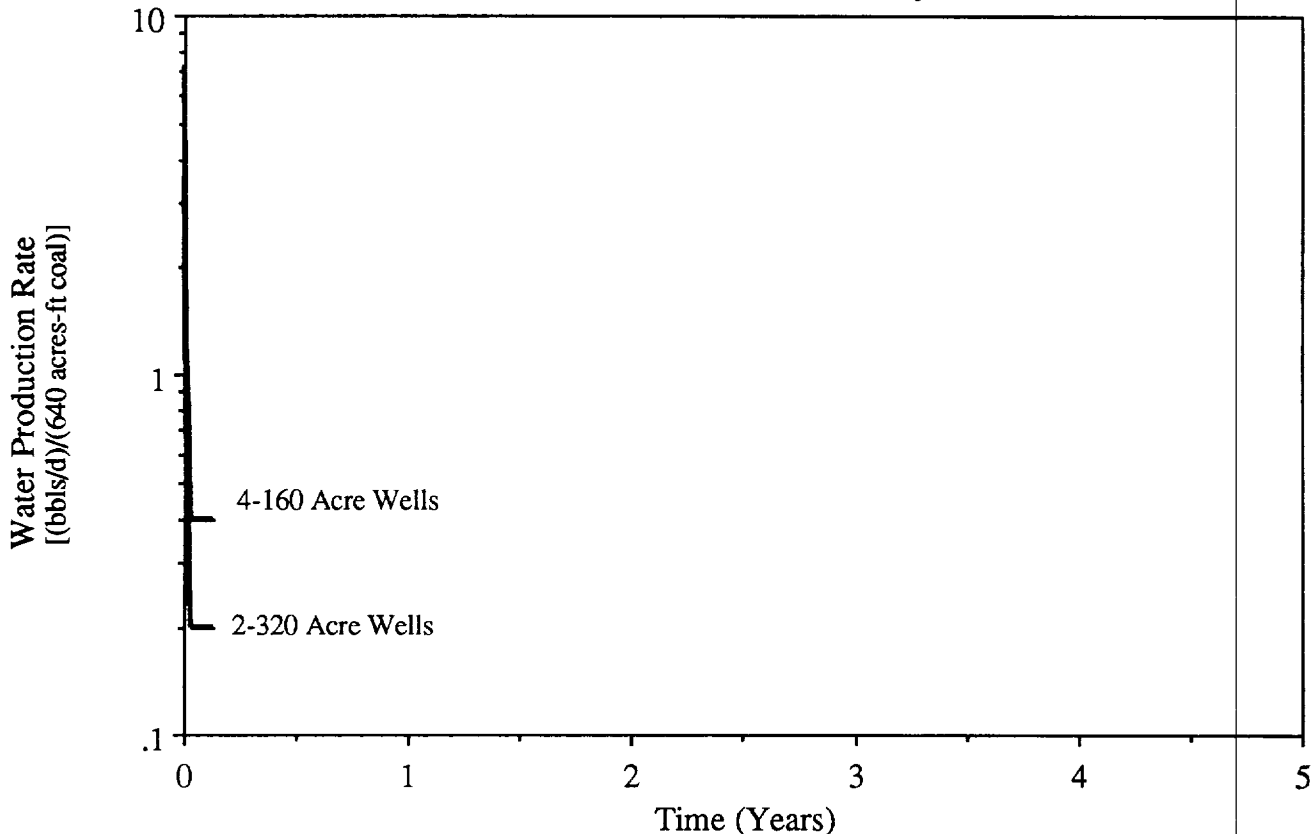
**Gas Recovery for a Cleat Permeability of 1md**



# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Water Production for a Cleat Permeability of 1md**



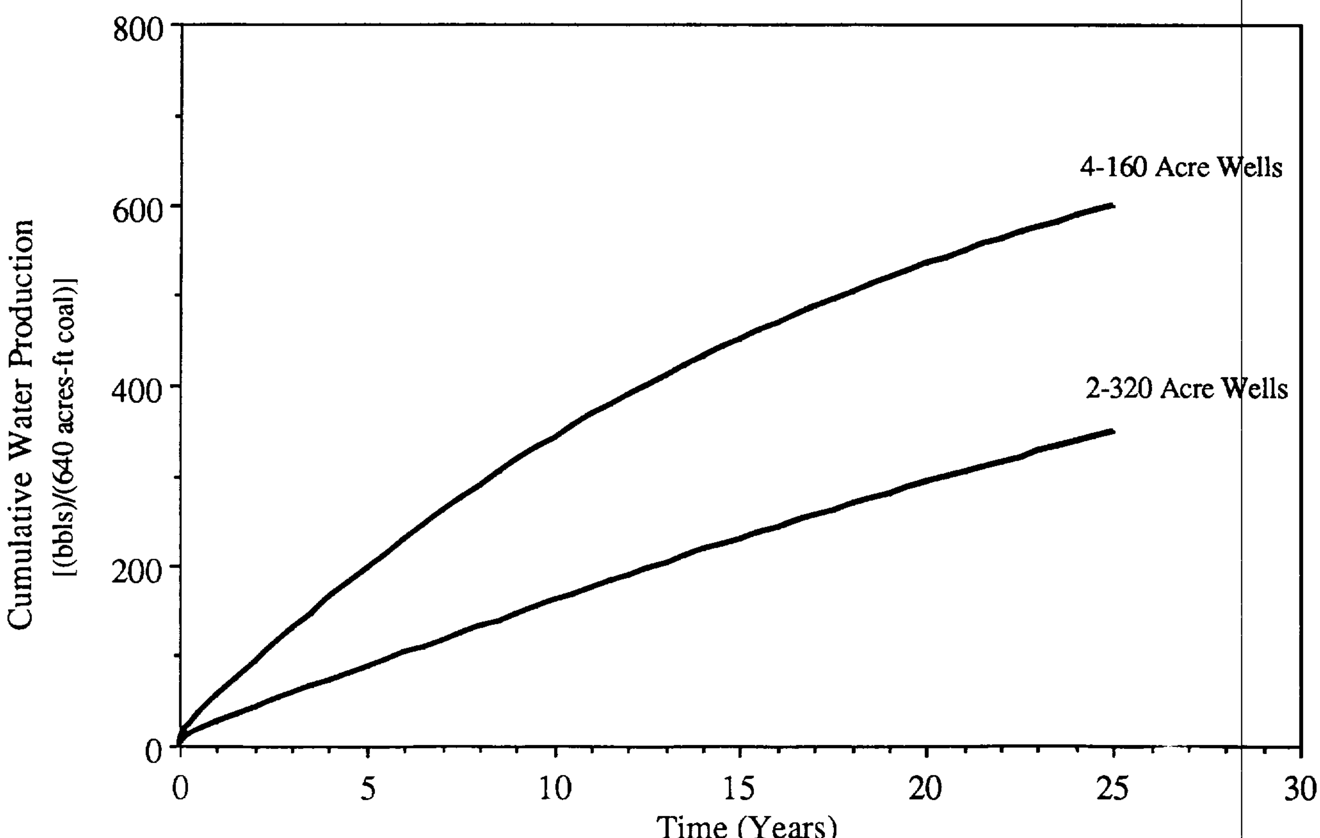
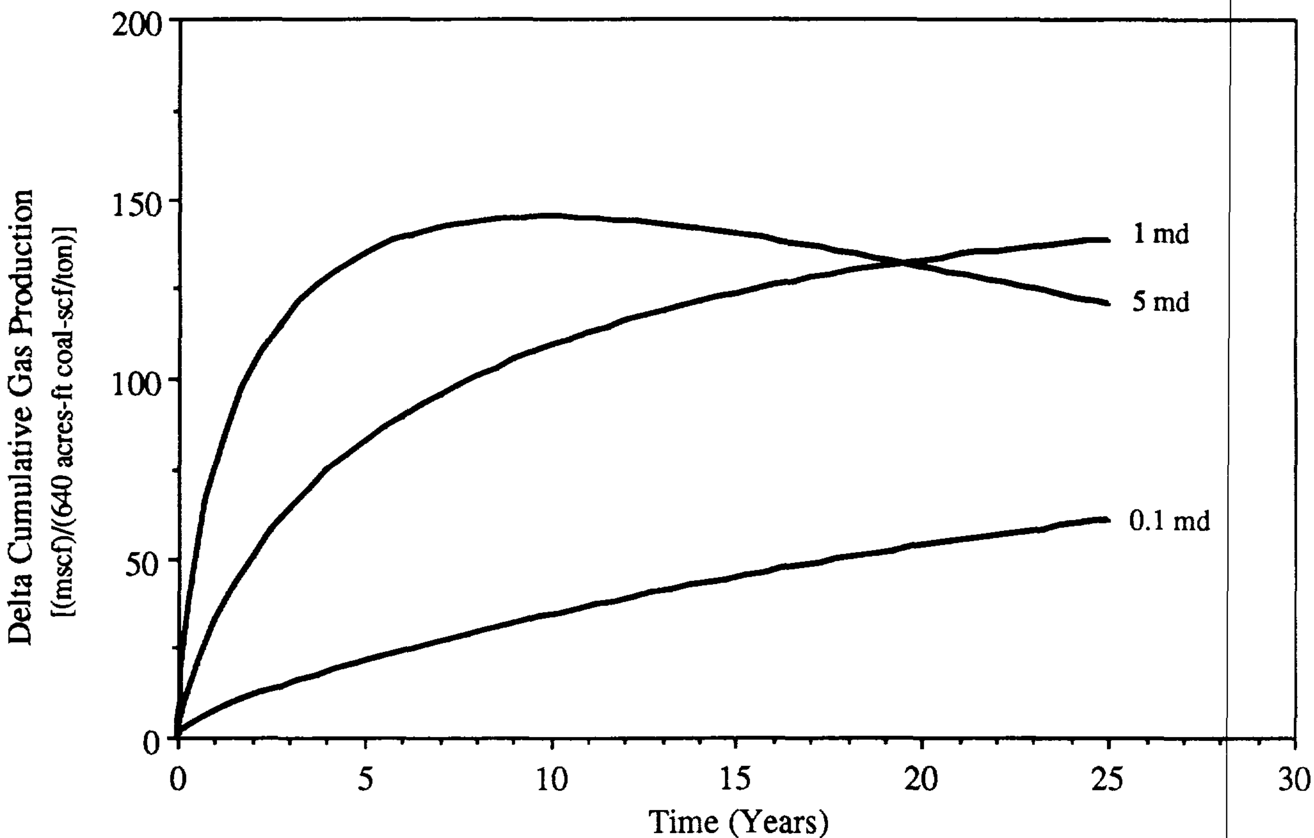



EXHIBIT 141

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Difference in Cumulative Gas Production Between 320 and 160 Acre Well Spacings**



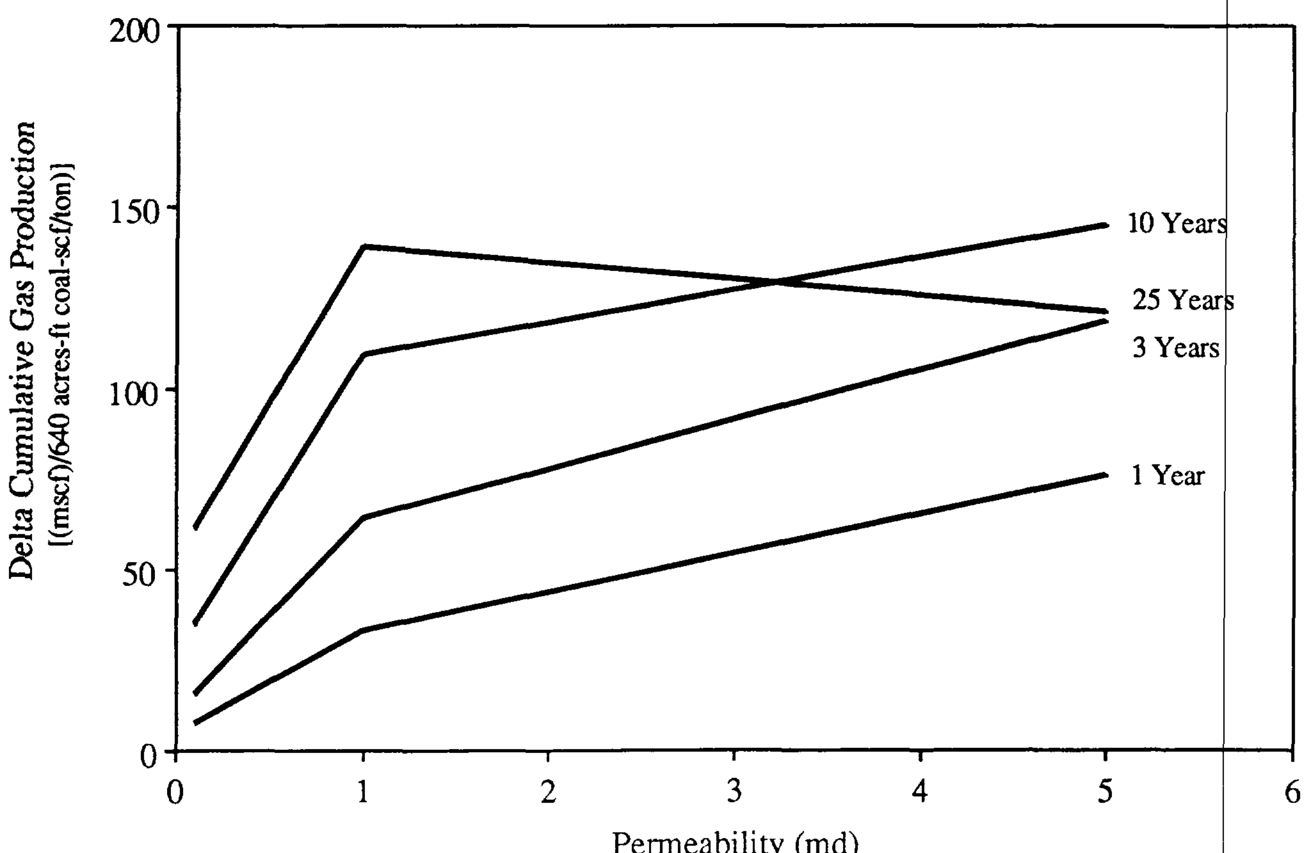
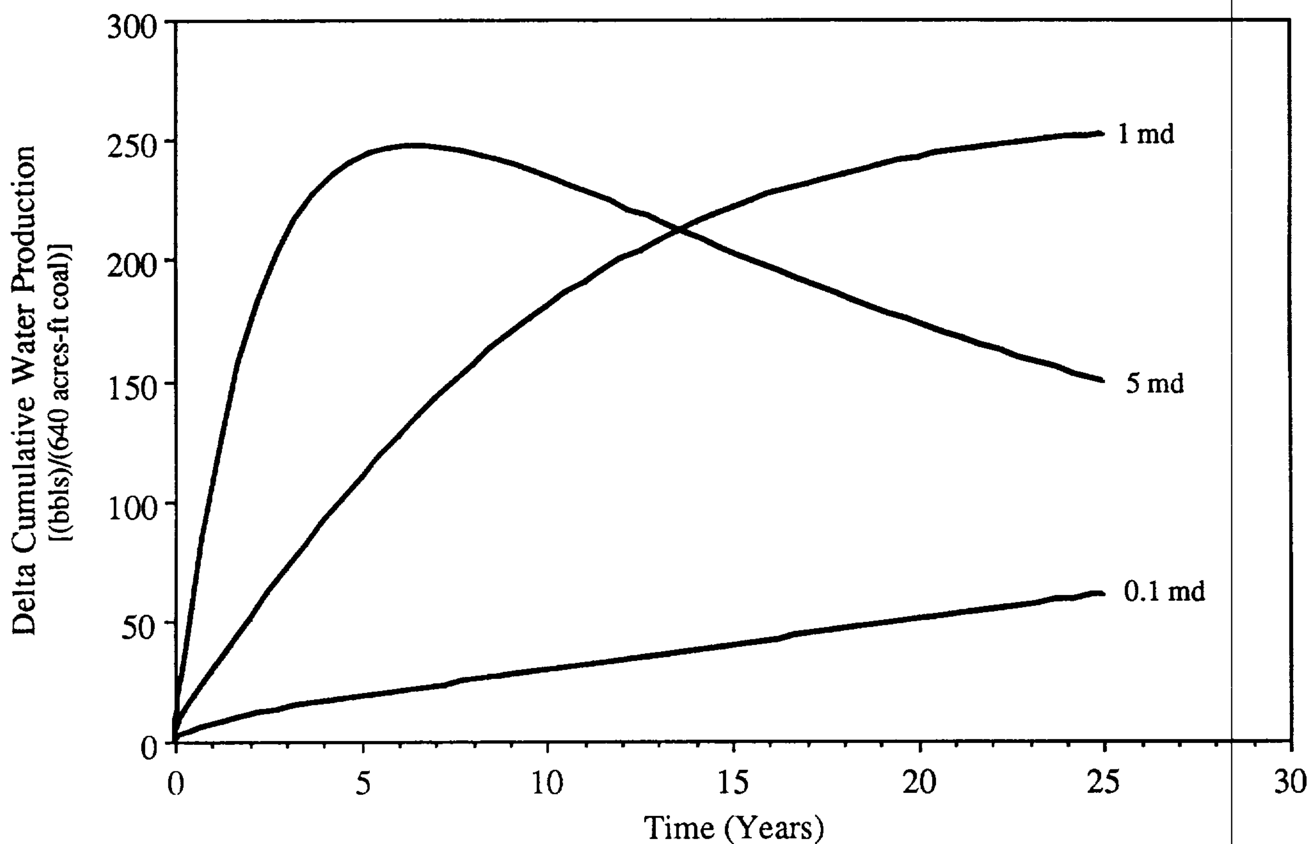



EXHIBIT 142

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Difference in Cumulative Water Production Between 320 Acre and 160 Acre Well Spacings**



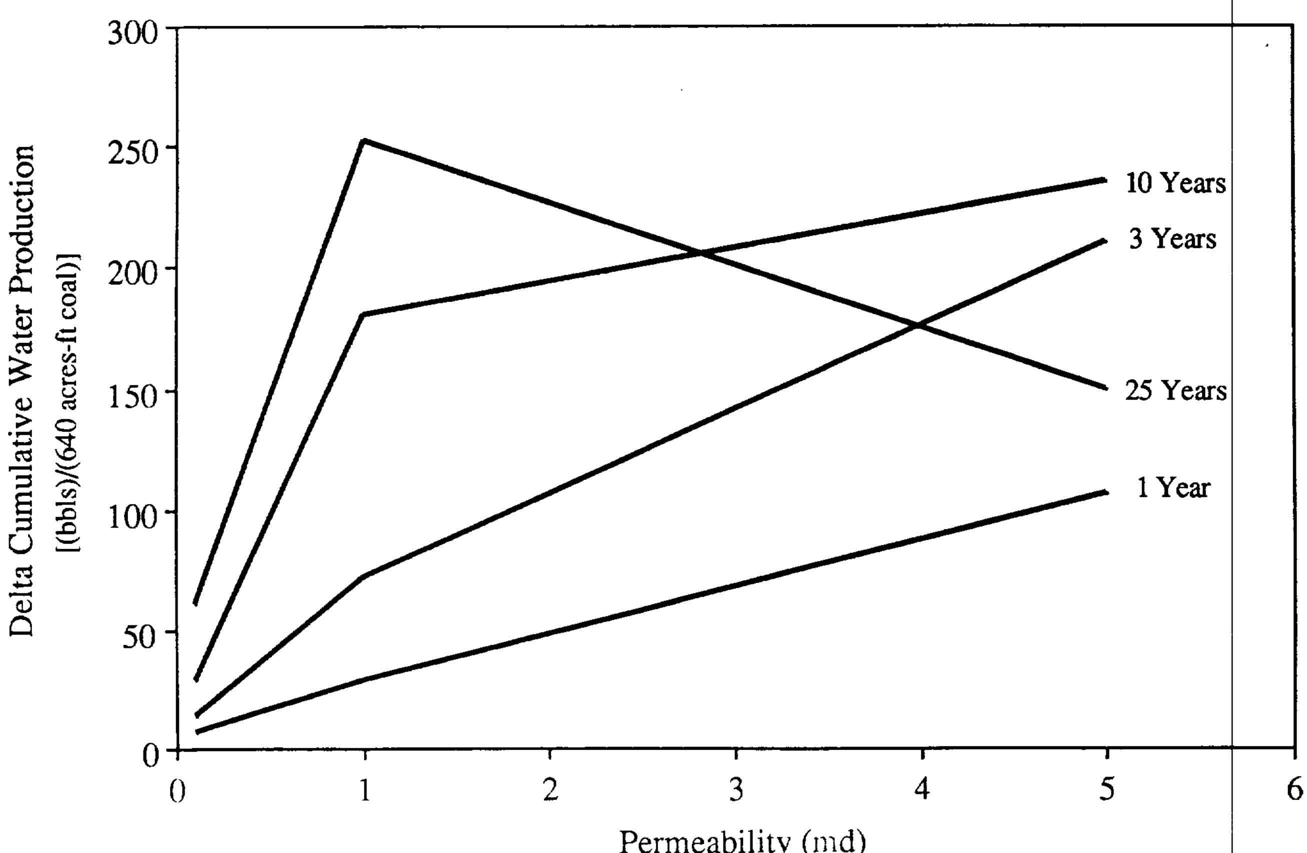
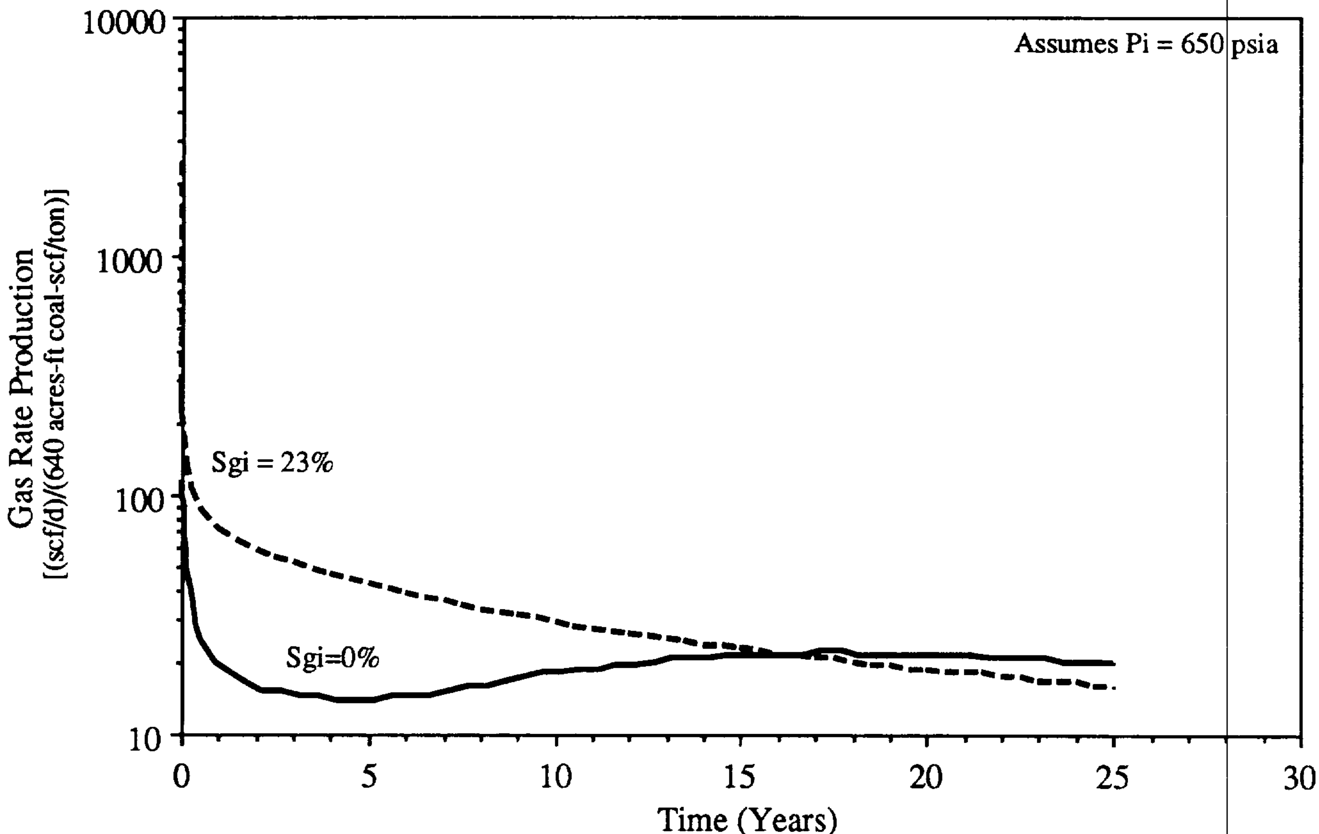



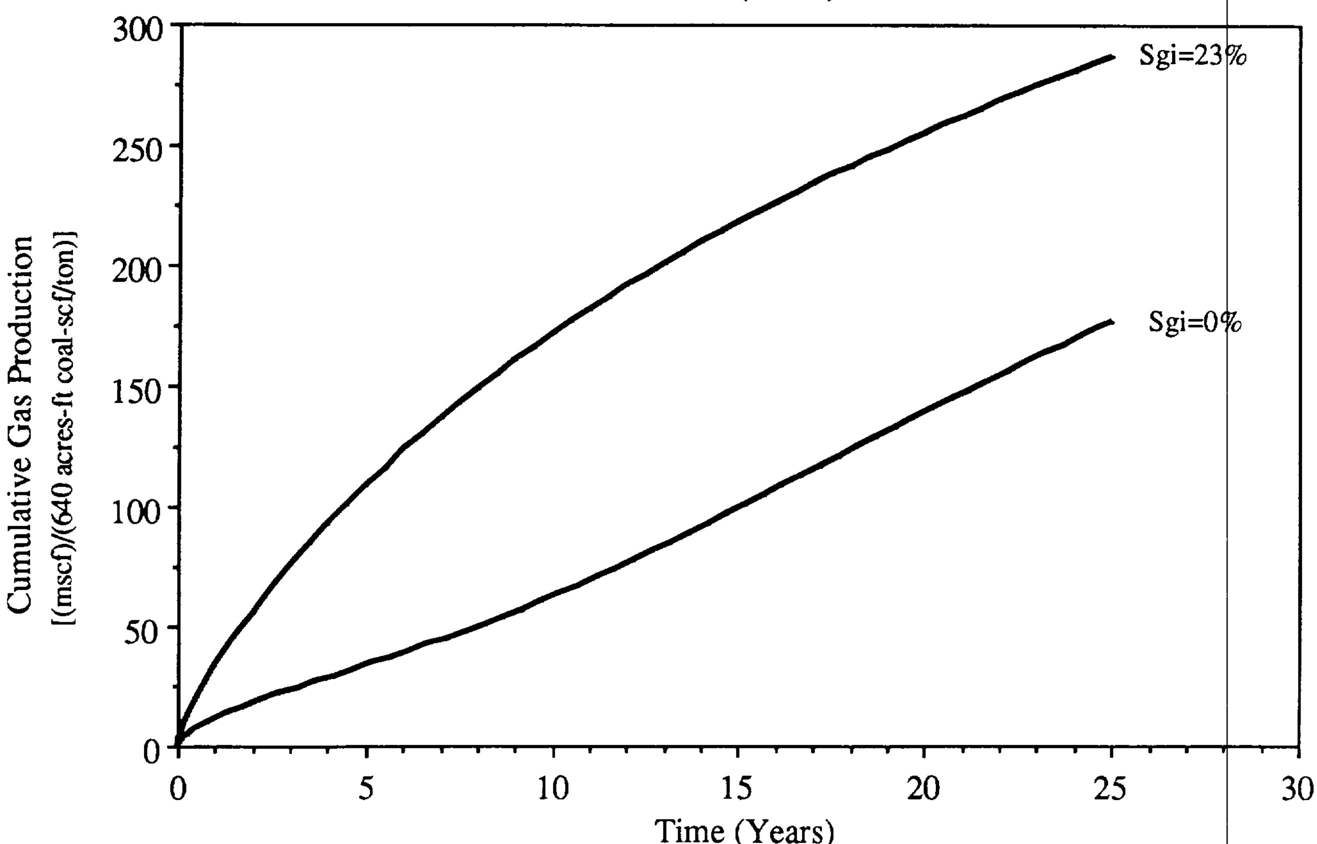
EXHIBIT 143

# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Gas Production for Variations in Initial Free Gas Saturation**

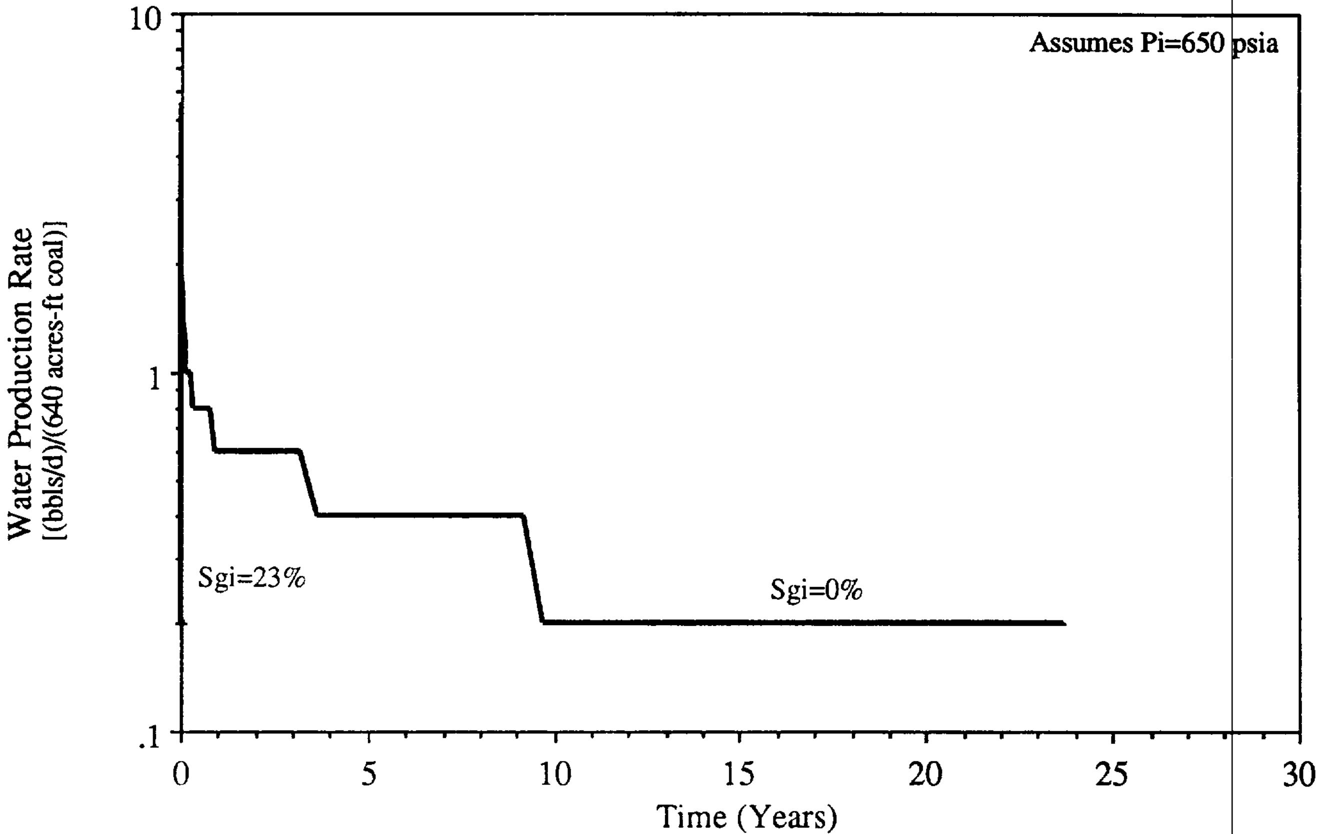


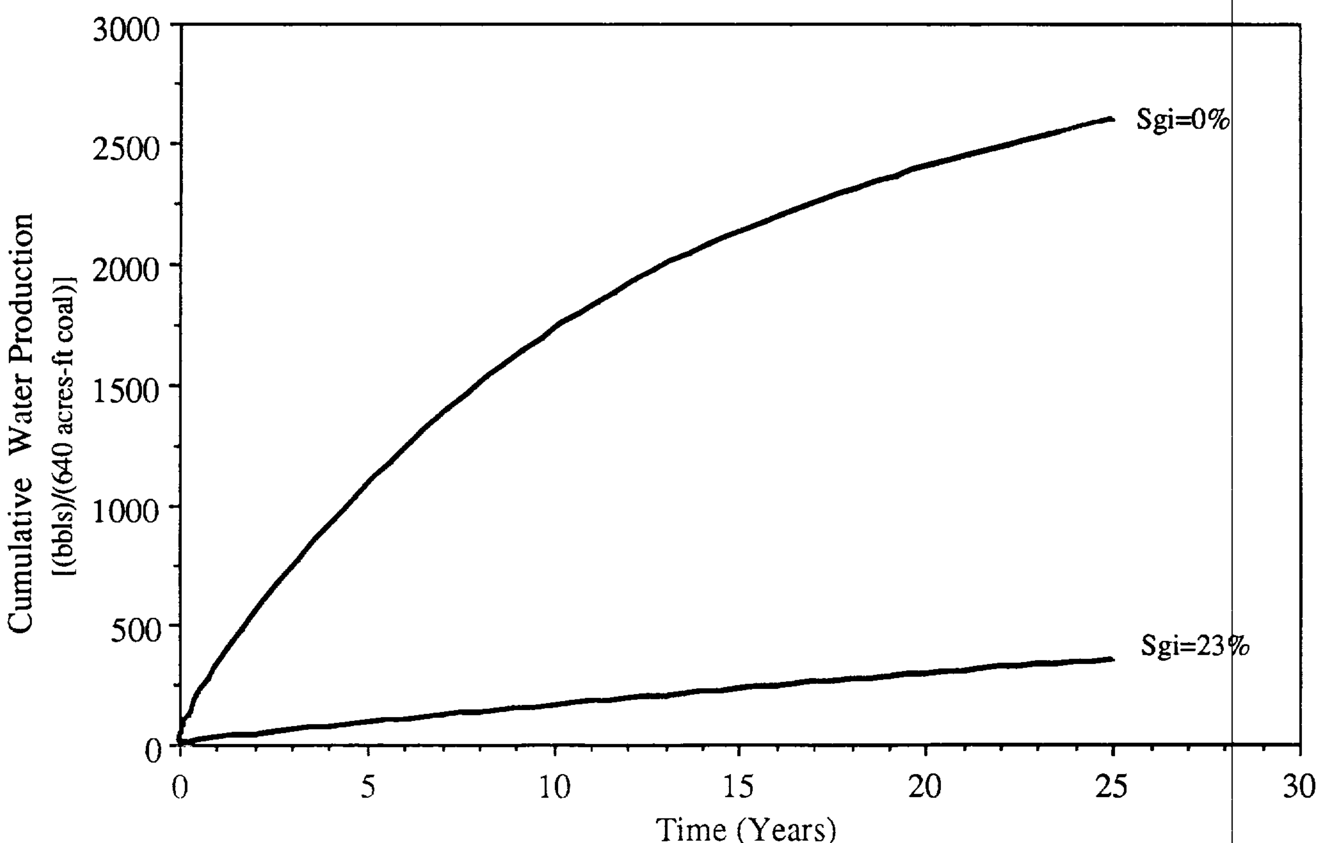



# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Water Production for Variations in Initial Free Gas Saturation**

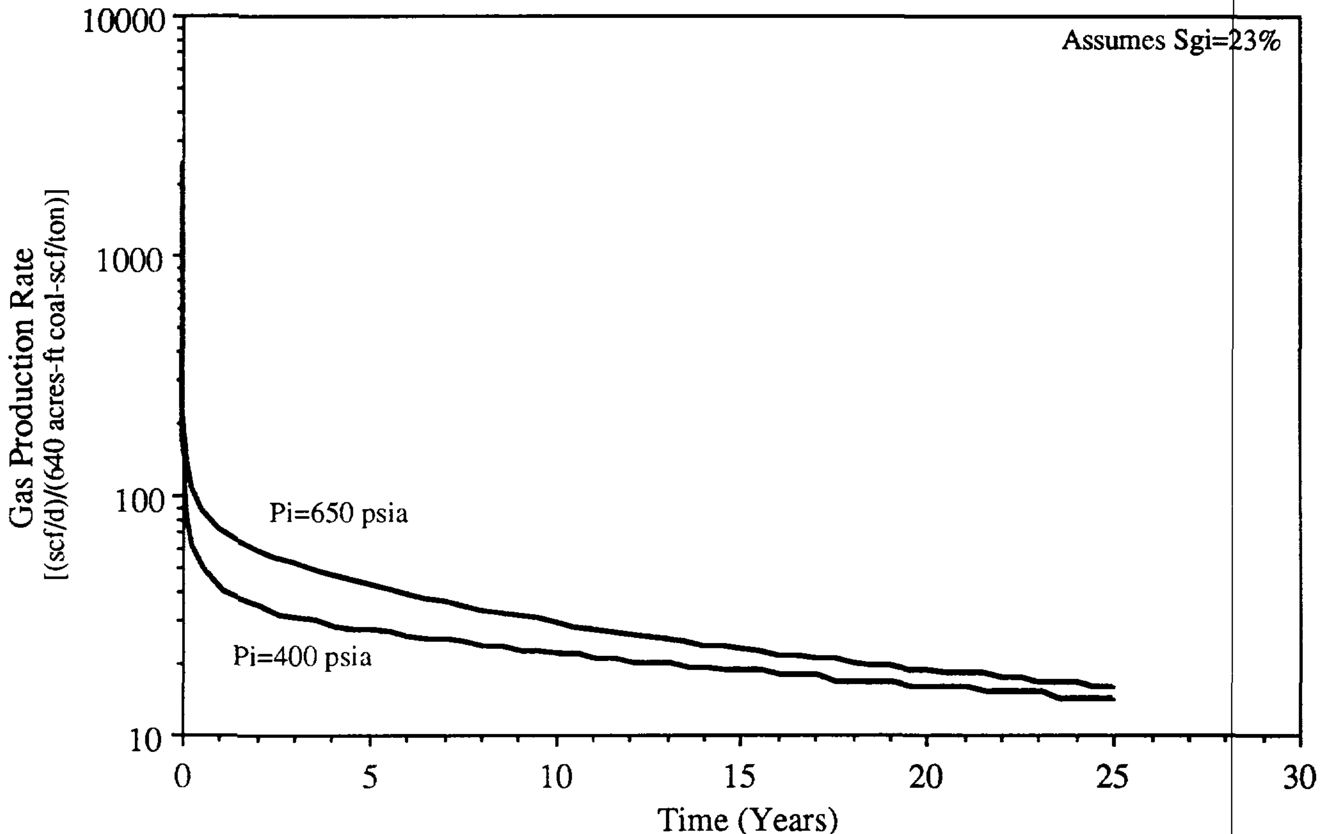


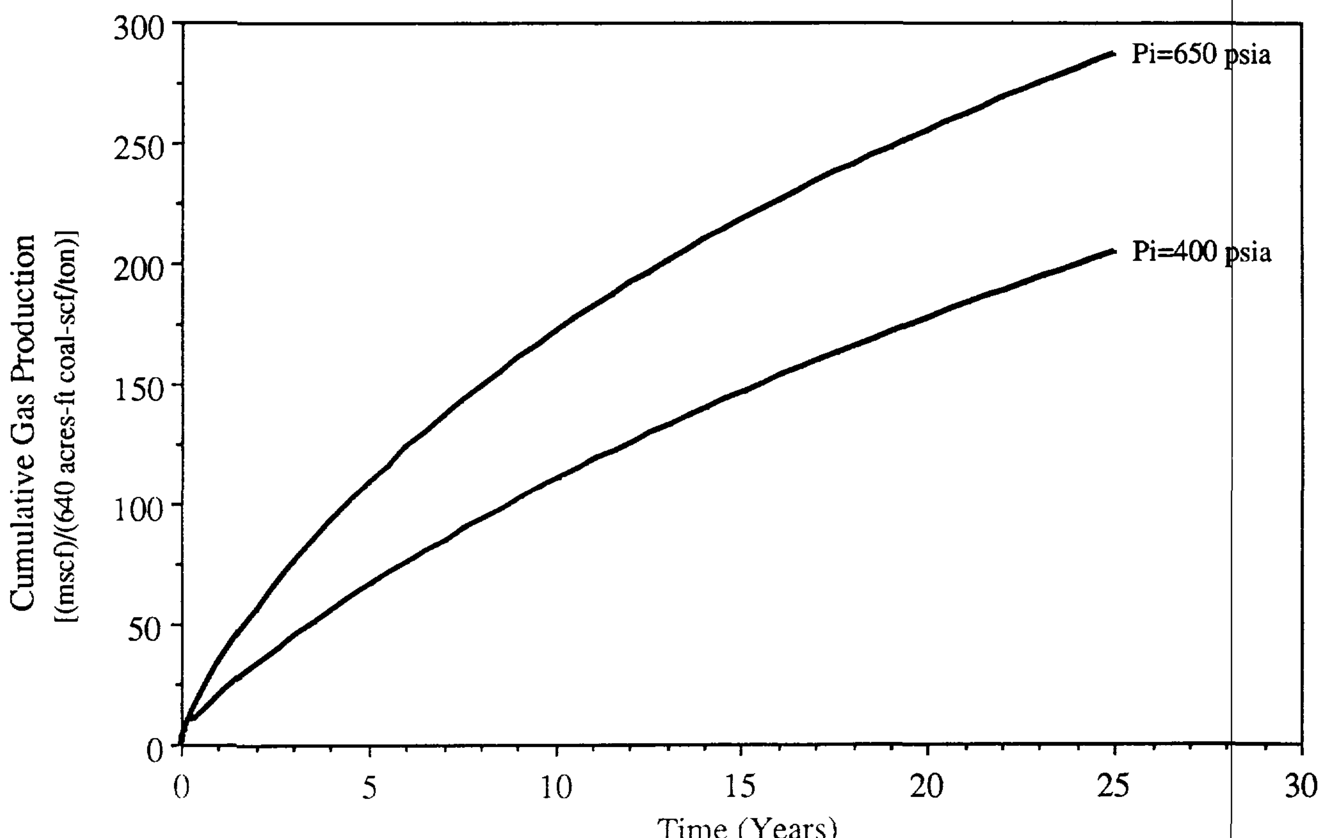



# San Juan Basin Coalbed Methane Spacing Study

## Area 3 Sensitivity Analyses

**Gas Production for Variations in Initial Reservoir Pressure**



# San Juan Basin Coalbed Methane Spacing Study

Area 3 Sensitivity Analyses

**Water Production for Variations in Initial Reservoir Pressure**