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THE TECHNOLOGY AND ECONOMICS OF GAS RECOVERY FROM TIGHT SANDS

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ABSTRACT

Tight gas sands for this analysis have less than .1 millidarcy (100 microdarcies) insitu gas permeability ranging down to .001 md. (1 microdarcy). Eliminating speculative basins and portions of basins where production is proven, a tight gas resource of 409 T C F has been identified.

Estimated recoverable reserves vary between 149 and 182 T C F at \$1.75 and \$3.00 / MCF (1977 dollars) with anticipated technology improvements in five years. Annual production rates, affected by technologic advances and price growth could be around 2 T C F per year in 1985 increasing to 7--7½ T C F per year for the last decade of this century. This compares with total US production in 1977 of 19 ½ T C F.

Most of the technology advancements anticipated relate to better methods for resource characterization, lateral and vertical control of massive hydraulic fractures (MHF) extension by design, and the ability to design fracture programs to expose lenticular pays existing within a thousand or more feet from the well bore but not penetrated by the well programmed to drain the area. Parallel with these major objectives are improvements in fracture fluid design, proppants, and post fracture production performance analysis.

INTRODUCTION

Lewin Associates, Inc. were commissioned by E R D A (now D O E) in 1977 to study the technology and economics of gas recovery from four identified types of unconventional gas, i.e. Tight gas, Devonian Shale, Geopressured water (gas disolved) and Methane from coal. Two reports on this study have recently been published by D O E and a third report detailing methodology will soon be issued. This paper deals only with the tight gas resource as studied by Lewin and Associates. The author of this paper has been heavily involved in this study. While this paper incorporates the relevant findings of the D O E study it enlarges and expands on the evolving MHF technology and how it has brought this type of resource into play.

Prior to this study the Federal Power Commission included in its National Gas Survey a study on Natural Gas Technology. This was initiated in 1971 and was published in 1973. It was during this study that deeply penetrating fractures became recognized as having potential for exploiting tight gas sands in three major western basins--particularly the Mesa Verde Section. At that time the term "Massive Hydraulic Fracturing" was coined admitedly, for lack of a better alternative. With growing application the abbreviation M H F has become an accepted term. However, there is no real definition as to when a big fracture treatment enters the M H F category.

Most treatments in tight gas formations defined herein are categorized as M H F . It is technology related to M H F that is highlighted in this paper.

Exploitation of several tight gas formations is also accellerating with production in 1977 amounting to about .9 T C F. The advanced technologies required are primarily aimed at reducing the risk and maximizing economic recovery efficiency of the resource.

THE TIGHT GAS RESOURCE--a definition

Most Tight Gas Formations in this study are classified as those having insitu permeability to gas of less than .1 millidarcy (100 microdarcies) and ranging down to 1 microdarcy. See Figure 1. Some shallow low pressure formations may fall into the near tight category. Most of these formations have 40 to 60 percent connate water saturation and porosities generally in the 8 to 12 percent range.

Single phase bench top permeabilities often must be reduced by a factor of 10 or 20 to approximate insitu gas permeability. The reduction is necessary to account for relative permeability to gas at 40 to 60 percent water saturation and compaction due to overburden net confining pressure.

When production is initiated after M H F the pressure in the matrix rock porosity (progressively foot by foot away from the fracture face) is substantially reduced. Thus the net confining pressure is increased and permeability to gas reduced below that at initial reservoir conditions.

In some massive formations some portions of the sections may be very tight and "wet" (75% to 100% water saturation). M H F may expose large areas of this type of formation. Where exposed to a propped open fracture both water and gas are produced. Water as seepage and gas at much lower rates than from the "non-wet" pay (40 to 60% water saturation). Bear this in mind: 10% immobile gas saturation at 4000 psi reservoir pressure expands to 40% at 1000 psi next to the fracture--thus creating its own permeability. This expansive energy expels both gas and water out of this "wet pay".

SIZE AND LOCATION OF THE RESOURCE

Twenty major tight gas basins were identified in this study. See Figure 2. Seven lacked adequate information to characterize the potential producing formations and thus were judged to be too speculative.

In the other thirteen basins portions of potentially producing areas were also deemed too speculative to include in the resource inventory as shown in Table 1 below:

TABLE 1

TIGHT GAS RESOURCE

	Gas in place T C F	Technically Recoverable T C F	Technical Recovery Eff. %
Western Tight Lenticular	176	66	37
Other Tight Lenticular	51	24	47
Sub Total	227	90	40
Tight Blanket	94	67	71
Shallow Gas	74	35	47
Other low Permeability	14	10	71
Total	409	202	49

The five types of Tight Gas Resource group the formations into categories requiring differing types of development programs. The technically recoverable gas will be discussed later.

The non-speculative portions of the thirteen basins analyzed were divided into 622 blocks (arealy and vertically). Each block was assigned formation qualities necessary to estimate gas in place quantities. These formation properties had been placed into a fairly extensive data base assembled by several teams of geologists and engineers knowledgable of the basins studied.

ESTIMATES OF GAS RECOVERY EXPECTED

Each of the 622 blocks mentioned earlier was equated to a well having typical average block properties. This well was completed (on paper) using both base case (present technology) and advanced technology expected. Each well with base case and advanced technology was produced at capacity for 30 years using computer models previously proven reliable by actual well studies. Individual well projections were extended to total block development and then the blocks summed to get both ultimate technical recoverable and economic recoverable reserves for two price and technology levels.

The technically recoverable gas is shown on Table 1 with resulting recovery efficiency factors shown for the different type formations.

The estimated potential gas reserves (ultimate economic recovery) is shown for the two price and technology levels in Table 2.

TABLE 2
PROVED U.S.A. GAS RESERVES
Excluding Alaska
1/1/78

	T C F
Total	177
Less Dissolved	36
Total Free	141
Estimated Gas From Tight Basins	
At $1.75 / M C F	
Base Case	70
Advanced Technology	149
At $3.00 / M C F	
Base Case	100
Advanced Technology	182

The present proved gas reserves is shown to put the tight gas potential in perspective.

A development program was structured to prudently develop the non-speculative portions of the thirteen basins analyzed. The possible range of annual gas production rates is shown on Table 3

TABLE 3

ESTIMATED TIGHT GAS ANNUAL PRODUCTION RATE

AT $3.00 / MCF

T C F per YEAR

	Technology	
	Base	Advanced
1985	1.8	3.8
1990	3.2	7.7
1995	3.9	7.2
2000	4.0	6.8

At $1.75 / MCF

Rates would be lower by about:
25 % for base Technology 15--20 % For Advanced Technology

For perspective the domestic gas production, including dissolved gas, in the U.S. for 1977 was 19.5 T C F. There are sound indications that, under the gas price regulations becoming effective December 1, 1978, gas from both conventional and that from most attractive non-conventional resources might steadily increase domestic supplies for several years to come. This could reduce oil import requirments during the next decade or so while the U.S. gets our other energy options better firmed up for the long term.

THE TECHNOLOGY

WELL STIMULATION -- OVERVIEW

Well stimulation is the key to exploiting tight gas formations. Hydraulic fracturing has proved to be the most promising method.

Nominal size fracturing treatments like 40,000 or 50,000 gallons with about 2 lbs proppant per gallon were first tried in "tight" and "near tight" formations. Results were not seemingly satisfactory in the truly tight (less than .1 md gas permeability) formations. So an operator in Wattenberg, a tight gas field being developed, gradually increased fracture treatment sizes. Typical results are shown on Figure 3 . Pay conditions in this area (C) are not the best or worst in Wattenberg. Permeability to gas is below .05 md. Note fracture treatment size (gal. of frac fluid) has a pronounced affect on cumulative production (at capacity into the pipeline).

The increased production is due to the increased amount of pay exposed to a propped open fracture. With the blanket type sand at Wattenberg, pay exposed is a function of fracture length. The most likely fracture lengths for this group of 8 wells varied from 500 ft. to probably in excess of 3,000 ft. per wing. Tip to tip length would be 1,000 to 6,000 ft.

Due to overlying and underlying shales (encasing the 20 to 40 foot blanket sand) the fracture height probably varied from 150 to 250 feet.

Not easily recognized on Figure 3 is the rapid decline in productivity (about 50%) during the first month of capacity production. This is shown typically on Figure 4 . After 4 to 6 months, the decline rate is much less pronounced. Performance like this is typical of the tight gas sands fractured using M H F technology. Even so productivity data collected during the first two or three months can be used with computor models to project expected production for 20 to 30 years with good accuracy.

Wattenberg served as an excellent control for demonstrating the significance of fracture treatment size (ie. length) on gas productivity from tight blanket sands where fracture height growth was fairly restricted by natural forces coupled with an injection pressure limited by casing strength. Other types of formations will require special treatment design features not yet fully demonstrated.

These typical results gave strong support to the concept that very deeply penetrating vertical fractures exposing acres, rather than square feet, of pay formation to essentially well bore pressure (around 20 % of initial reservoir pressure) provides the key to economic exploitation of tight gas pays.

However, there remain several major technological breakthroughs necessary before the several types of massive tight gas sections can be optimally explored and developed. They are listed in the following section of this paper principally to stimulate research and field testing on the part of interested parties. These challenges are categorized as follows:

1. Resource Characterization
2. Fracture Extension -- lateral
3. Fracture Extension -- vertical
4. Maximizing Production from Fraced Pays
5. Post Fracture Technology
6. Water Production

WELL STIMULATION -- SOME CHALLENGES

CATEGORY	EXPLANATORY COMMENTS
RESOURCE CHARACTERIZATION	
Definition of Pay Quality ---Define all levels of gas and water saturation ---Calibrate logs with insitu measurement of gas ---Calibrate core analysis with insitu measurments ---Improve logging systems	In some basins conventional logging systems do not detect the contrast between water and gas saturation. Techniques for measuring insitu gas permeability have not been perfected.
Rock Mechanics ---Measure rock characteristics controlling frac extension ---Core tests ---In place measurment	This is a must in most basins. Variation in rock strength and elastic properties are forces that either help or hinder control of fracture geometry.
Sand Continuity ---Probable geometry of lenses ---Lenticular direction relative to frac azimuth ---How many sands not at well can be contacted by frac?	In sections containing lenticular gas pays this is a tough problem. If frac azimuth parallels the long demension of lenses at the well location the opportunity to expose unseen lenses is limited. Geological studies of specific areas should precede fixing well spacing and planning of drilling and completion programs.
FRACTURE EXTENSION--LATERAL	
Measure azimuth ---Potential field intersected ---Tilt meter ---Question looking at frac in well bore ---Key wells in basins	Azimuth of fractures can be measured while the fracture is being extended. Probably both the tilt meter and systems to measure where an established electrical field is intersected by the growing fracture should be employed simultaneously. This type information will probably only be necessary at key wells located in specific regions in a basin where tectonic activity appears to have been uniform.

Asymmetry

---Not equal length from well

---How to measure

---How to assure symmetry

---Pressure pulsing ?

In analyzing fracture performance, analysts have assumed that both wings of a vertical fracture are symetrical. In a perfectly uniform system this could happen In real life it is very unlikely.

Fracturing techniques may be practiced which minimize assymetry.

Analysts should always recognize the influence of assymetry on performance interpretation and predictions. For example relatively low productivity of well #7 in Figure 3 might be due to assymetry.

FRACTURE EXTENSION --VERTICAL

Control of Vertical Height

---Level of stress concentration in adjacent formations

---Effect of frac pressure gradient

---How discourage vertical growth

---Or accellerate vertical growth

---Effect of thin coal beds

---Effect of rock character vs stress level

---Demonstrate in key wells

Vertical extension may need to be limited (e.g. in blanket sands). See case A in Figure 5. However in multisand and lenticular sections it may be desireable to encourage greater vertical extension if it is possible. See Cases C and D in Figure 5

Usually one does not want downward vertical extension as illustrated in Case B.

Control of vertical height probably offers the greatest technical challenge and perhaps will prove to be the key to optimum development in many situations.

How measure fracture height?

---Temperature logs ?

---Radioactive ?

---Special Production Tests--maybe

---In place after frac some way ?

This has to be done to know if vertical height is to be controlled.

Logging techniques are only valid if the vertical fracture plane parallels the well bore and a good cement job exists. But these tests are helpful

In situations like illustrated in Cases A, B, & C in Figure 5 planned tests during the flow back of fracture fluids displaced out of the fracture by gas can be helpful. Alternating production and shut in cycles for 6 hour intervals (for example) and carefully measuring produced gas-frac fluid ratios may help qualify frac height of the total fracture system.

In high fractures filled with liquid, gas comes in to push liquid out. Gas tends to rise to the top of the fracture and cone down to the perforations at the well. When shut in the gas cone rises and liquid temporarily blocks the perforations to gas production until a cone again forms.

In A the gas-fluid ratio would not be significantly changed after the shut-in cycles. Medium to high recovery of frac fluid would be expected.

In B the gas-fluid ratio would start high and not be affected by the shut in cycles. Low recovery of frac fluid would be expected.

In C, due to gas coning down to the perforations gas production would be low during the first several cycles and after the shut in cycles would be low until the gas cone is reestablished. High frac fluid recovery should be expected.

With increasing experience fracture height should be reasonably approximated on a gross basis.

MAXIMIZING PRODUCTION FROM FRACED PAYS

Prevent damage to exposed sands

---Minimize clay expansion or dislodging
---Minimum fluid loss -- frac fluids

Adequate Fracture Conductivity
---Optimum proppant selection
---size
---strength, need cheaper high strength
---Imbedment factors

Fracture Fluid Design
---Maximize proppant carrying capacity

Most of these concerns are covered by current technology. Even normal fluid loss is not too damaging while fracing formations containing gas under normal or high pressures. It is quickly expelled under high flowing pressure gradients.

However if the well is re-fraced (to extend the first fracture) after several months of gas production it is a different story. Fluid loss invades matrix rock where pressure has been drawn down. Very little energy will be there to expell the liquid for several weeks. Gas production will be from newly fraced high pressure pays after the refrac. Later and gradually the old frac pay will clean up and resume the production rate immediately prior to the refrac.

No comments needed on the other concerns.

POST FRACTURE TECHNOLOGY

Reservoir Fracture Simulators

---Match short time performance

---Estimate frac length
ie. exposed pay

---Estimate frac conductivity

---Predict production vs time

---Approximate shape of drainage area

---Probable contribution from "unseen" lenses

Several computer simulators have been developed and are in use to approximate reservoir and fracture parameters based upon production performance. Use of these to post analyze fracture systems in complex tight formations is really a must.

To illustrate, pressure build up analysis is complicated by the storage volume of pore space in the fracture. With M H F pressuring up this space (which is not accurately known) buffers the normal use of build up curves. On the other hand production decline rates at constant bottom hole pressures cancel out the fracture pore space factor and serve to measure pay character and exposed fracture length.

WATER PRODUCTION

---Where from

---Very tight
100 % Water Saturation
80 % Water 20 % gas

---Tight
40 -- 60 % water
40 -- 60 % gas

---After few months

---Nuisance

---Handle it

This was first mentioned in the early part of this paper dealing with THE TIGHT GAS RESOURCE. M H F will expose from perhaps 200 to 1,000 ft of vertical section (the 1,000 ft. by design). In most massive tight gas sections seldom is there a permeable member connected to an acquifer capable of sustained high levels of water production. But fracing through a permeable water saturated thin streak will load the fracture system with water for some short period of time before its expansive energy is depleted.

More common will be water coming from the very tight low to zero gas saturated zones adjacent to "normal" gas pays. With 100 % water even if the water saturated section is only 1/10 of the permeability in the gas zone water will "seep" from as many as 50 to 75 acres of exposed drainage face with pressure gradients of several thousand pounds driving that water to the fracture face. First over inches, then

CONCLUSIONS

-1-

Advancing fracturing technology has demonstrated that propped vertical fractures can be extended at least 1,000 feet each way from a well into the hard massive formations in the western basins where the tight gas resource has been identified.

-2-

Current technology applied to the identified most attractive formations now yields about .9 TCF per year. With a combination of achieving recognized technology needs during the next five years and with current well head price trends it is projected that annual rates from tight gas formations can be increased 2 TCF by 1985 and 7 to 7½ TCF for the last decade of the century.

-3-

Estimated ultimate recovery from non-speculative resources is projected to be 149 and 182 TCF respectively for prices of $1.75 and $3.00 / MCF in 1977 dollars. It is quite probable that exploration and development will move progressively into speculative areas and add to this potential.

-4-

Most of the technological improvements anticipated in the production projections should be achieved eventually. However, Federal assisted R & D should encourage private operators to take the extra time and effort in field tests to more rapidly prove up this needed technology.

-5-

A major challenge is to develop the capability of adapting fracture treatment design to rock characteristics in order to control the height of effectively propped fractures extended to at least 1500 feet.

If this can be accomplished there is a good chance that lenticular gas sands in several major basins can be efficiently exploited using M H F technology

-6-

Most other technological needs, as identified in this paper, will come along in the course of meeting the lenticular challenge.

ACKNOWLEDGMENT

The aspects of this paper dealing with the resource, ultimate recovery, and projected producing rates related to price and technology advances are taken directly from a report prepared for the U.S.Department of Energy entitled "The Enhanced Recovery of Unconventional Gas" dated October 1978. The study was made under contract to Lewin and Associates, Incorporated,Washington, D.C. 20024.

The portion of the paper dealing with fracturing technology and its application to the tight gas resource, while incorporated in the study, has been paraphrased, hopefully to catch the attention of those dealing directly with well stimulation problems and the field research needed to achieve the results projected.

Mr. Vello A. Kuuskraa and Dr. J. B. Brashear with Lewin and Assoc. were also principal authors of the Tight Gas sections of the DOE study.

INSITU GAS PERMEABILITY

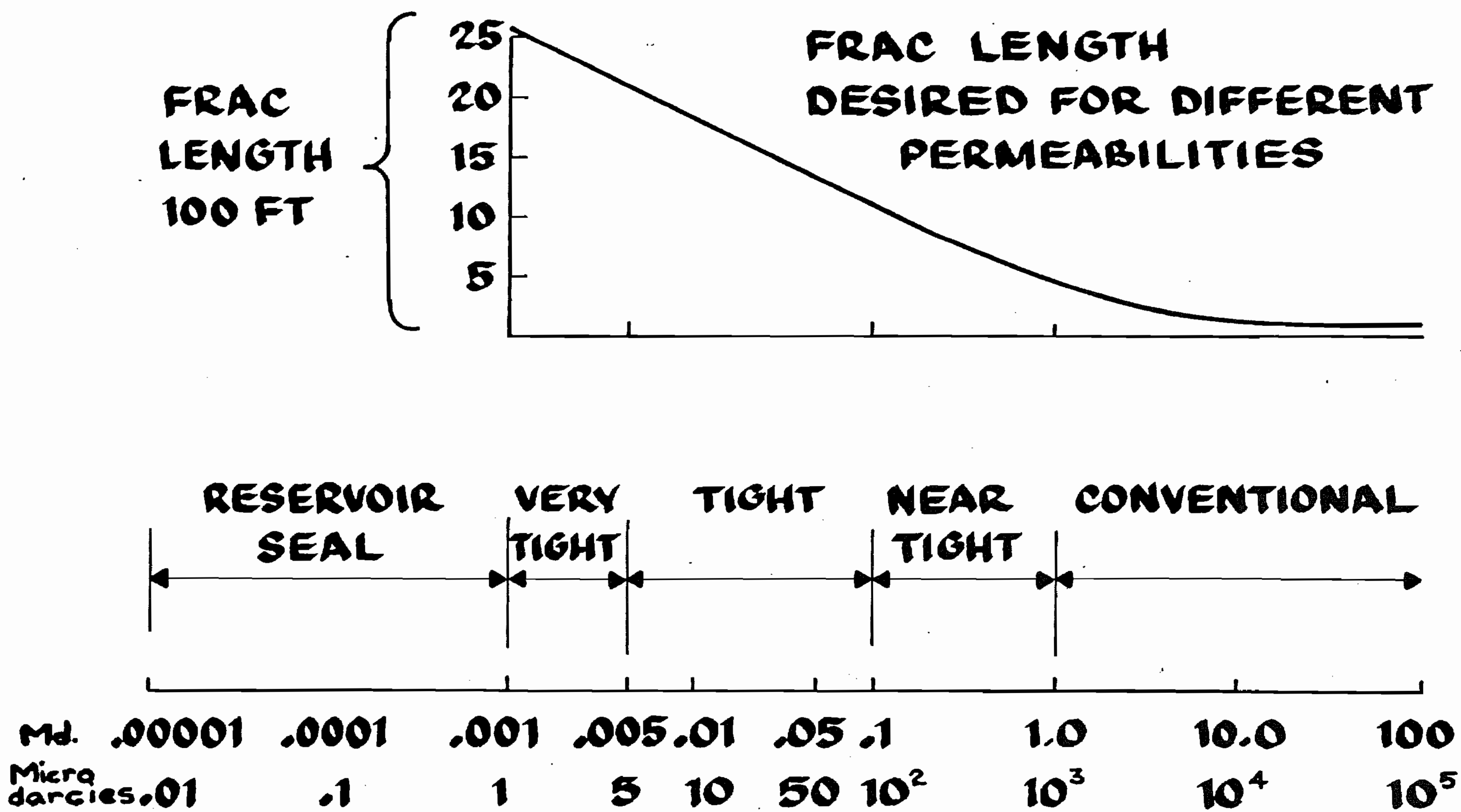
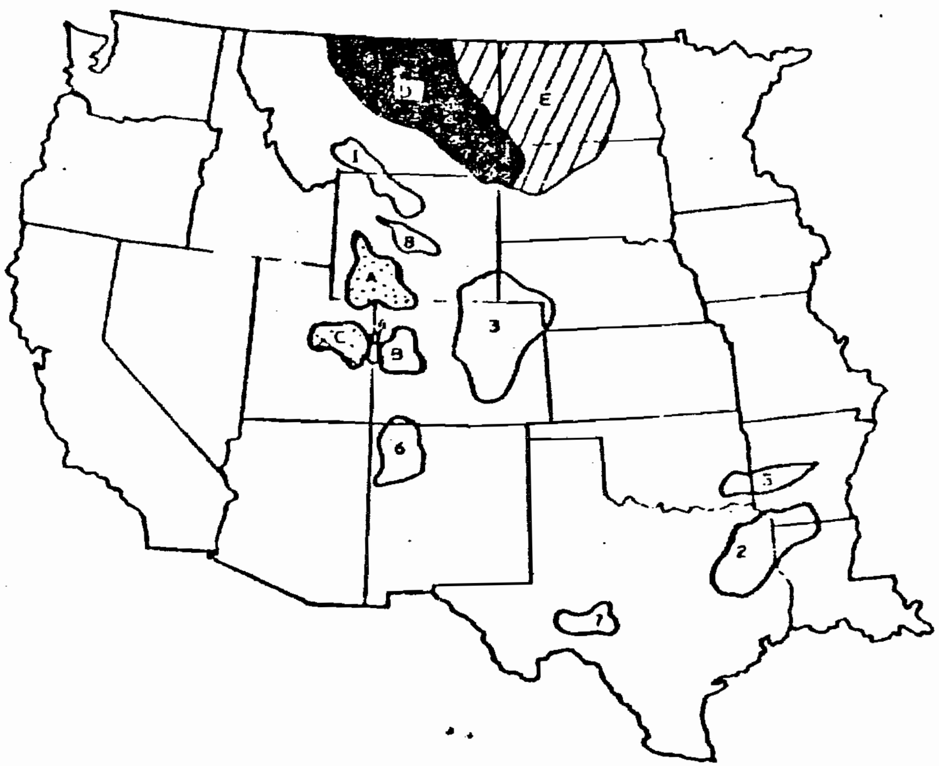


FIGURE 1

Location of Major Tight Gas Basins



SOURCE: U.S. ERDA, Western Gas Sands, Project Plan, 8/1/77

FIGURE 2

Low-Permeability Basins

ERDA'S PRIMARY STUDY AREAS	GEOLOGICAL AREA
A. GREATER GREEN RIVER BASIN	TERTIARY AND CRETACEOUS
B. PICEANCE BASIN	TERTIARY AND CRETACEOUS
C. UINTA BASIN	TERTIARY AND CRETACEOUS
D. NORTHERN GREAT PLAINS PROVINCE	CRETACEOUS
E. WILLISTON BASIN	CRETACEOUS
ADDITIONAL LOW-PERMEABILITY AREAS IN THE STUDY	
1. BIG HORN BASIN	TERTIARY AND CRETACEOUS
2. COTTON VALLEY TREND	JURASSIC
3. DENVER BASIN	CRETACEOUS
4. DOUGLAS CREEK ARCH	CRETACEOUS
5. OUACHITA MOUNTAINS PROVINCE	MISSISSIPPIAN
6. SAN JUAN BASIN	CRETACEOUS
7. SONORA BASIN	PENNSYLVANIAN
8. WIND RIVER BASIN	TERTIARY AND CRETACEOUS
OTHER LOW-PERMEABILITY AREAS NOT INCLUDED IN STUDY	
a. ANADARKO BASIN	PENNSYLVANIAN
b. ARKOMA BASIN	PENNSYLVANIAN
c. FORTH WORTH BASIN	PENNSYLVANIAN
d. RATON BASIN	TERTIARY AND CRETACEOUS
e. SNAKE RIVER DOWNWARP	TERTIARY AND CRETACEOUS
f. WASATCH PLATEAU	CRETACEOUS
g. WESTERN GULF BASIN	TERTIARY AND CRETACEOUS

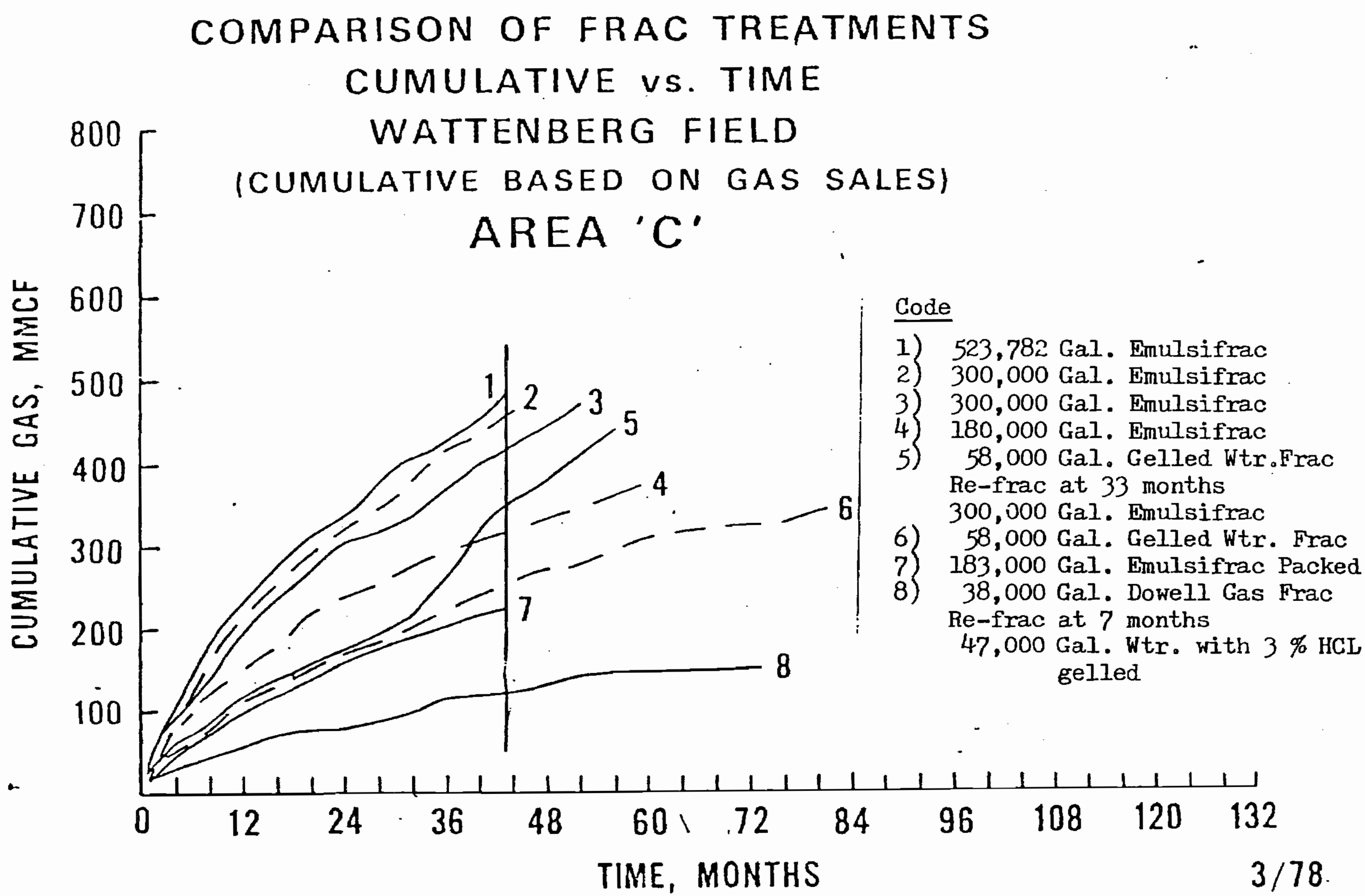

COMPARISON OF FRAC TREATMENTS
CUMULATIVE vs. TIME
WATTENBERG FIELD
(CUMULATIVE BASED ON GAS SALES)
AREA 'C'
CUMULATIVE GAS, MMCF
800
700
600
500
400
300
200
100
0
12
24
36
48
60
72
84
96
108
120
132
TIME, MONTHS
1
2
3
4
5
6
7
8
Code
1) 523,782 Gal. Emulsifrac
2) 300,000 Gal. Emulsifrac
3) 300,000 Gal. Emulsifrac
4) 180,000 Gal. Emulsifrac
5) 58,000 Gal. Gelled Wtr. Frac
Re-frac at 33 months
300,000 Gal. Emulsifrac
6) 58,000 Gal. Gelled Wtr. Frac
7) 183,000 Gal. Emulsifrac Packed
8) 38,000 Gal. Dowell Gas Frac
Re-frac at 7 months
47,000 Gal. Wtr. with 3 % HCL gelled
3/78

FIGURE 3

PRODUCING RATE vs. TIME

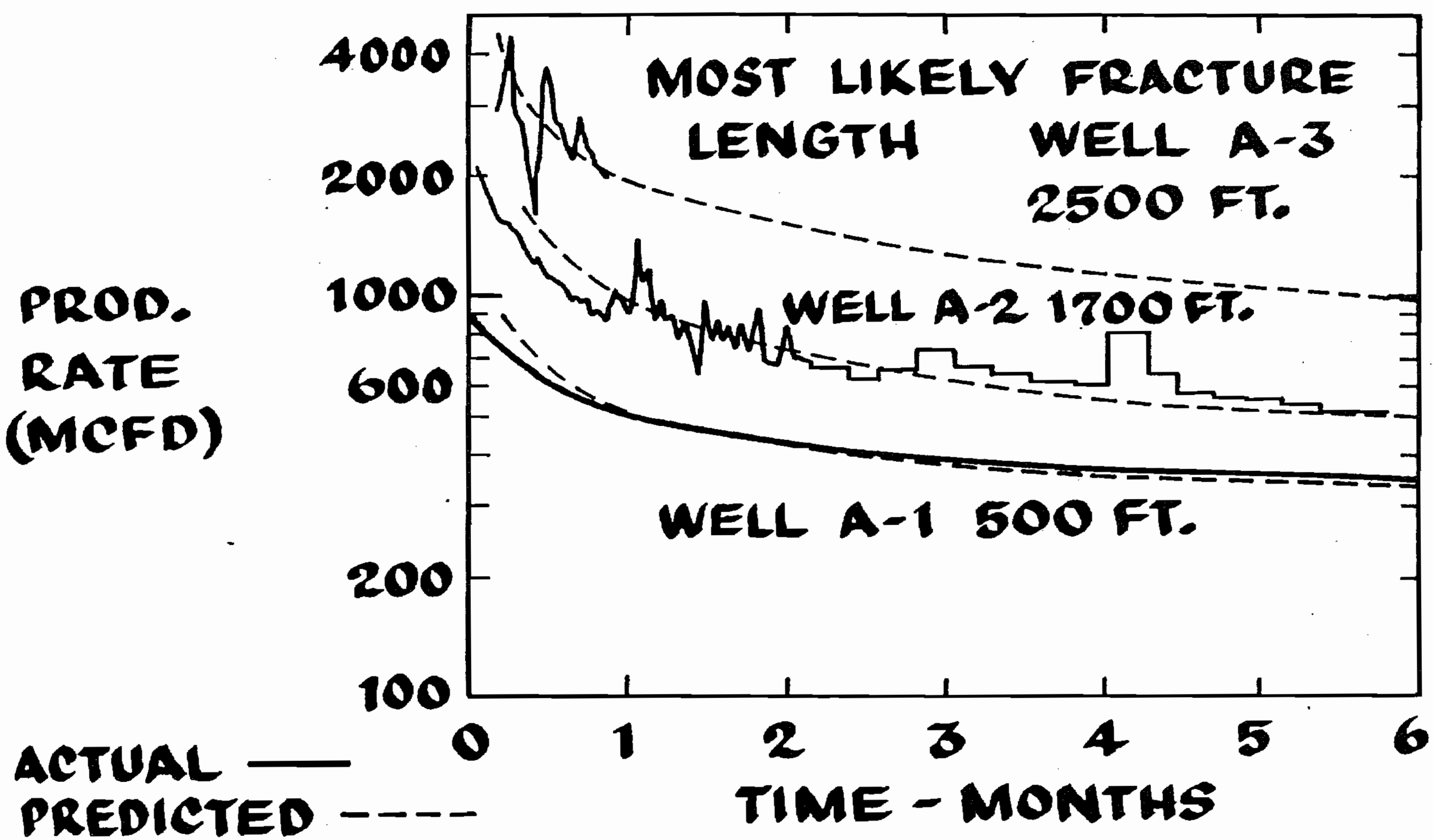
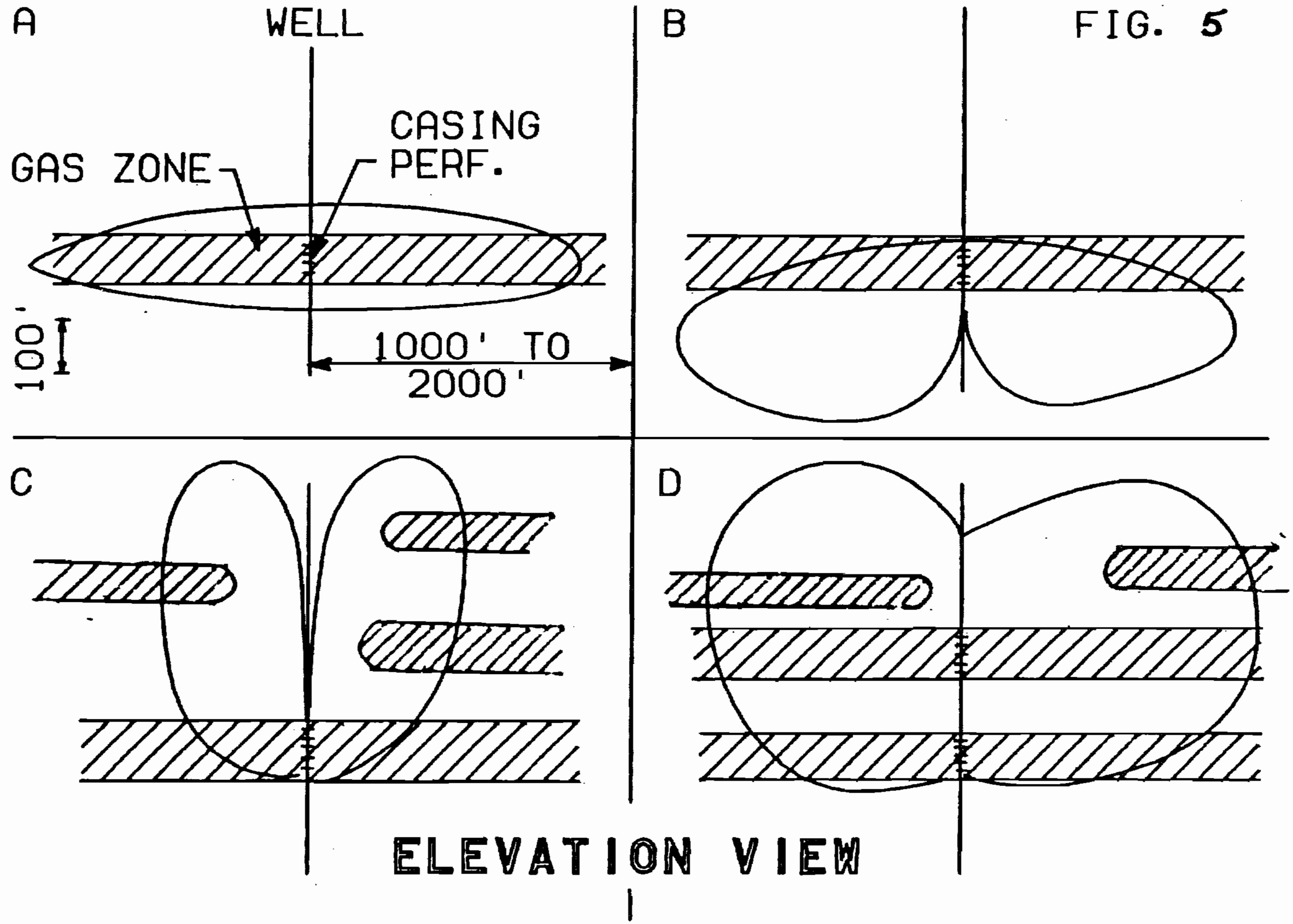


FIGURE 4

SOME POSSIBLE FRACTURE PLANE CONFIGURATIONS

FIG. 5



ELEVATION VIEW