SPE 36655

Society of Petroleum Engineers

Permeability Reduction by Pyrobitumen, Mineralization, and Stress Along Large Natural Fractures in Sandstones at 18,300 ft. Depth: Destruction of a Reservoir

John C. Lorenz, SPE, Sandia National Laboratories, Randal L. Billingsley, and Lesley W. Evans, Amoco Production Company

This paper was prepared for presentation at the 1996 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, U.S.A., 6–9 October 1996.

Abstract

Production of gas from the Frontier Formation at 18,300 ft depth in the Frewen #4 Deep well, eastern Green River basin (Wyoming), was uneconomic despite the presence of numerous open natural fractures. Initial production tested at 500 MCFD, but dropped from 360 MCFD to 140 MCFD during a 10-day production test, and the well was abandoned. Examination of the fractures in the core suggests several probable reasons for this poor production. One factor is the presence of a hydrocarbon residue (carbon) which filled much of the porosity left in the smaller fractures after mineralization. An equally important factor is probably the reorientation of the in situ horizontal compressive stress to a trend normal to the main fractures, and which now acts to close fracture apertures rapidly during reservoir drawdown. This data set has unpleasant implications for the search for similar, deep fractured reservoirs.

Introduction

The Frewen #4 Deep well is located in Sweetwater county, southwestern Wyoming (section 13 of Township 19 North, Range 95 West). The target of the well was natural gas from sandstones of the Frontier Formation (Fig. 1), at a depth of approximately 18,300 ft. The Frontier Formation consists of Cretaceous age sandstones and shales. The main reservoir sandstone is about 40 ft thick at this location, with thick over- and underlying shales.

The Frewen Deep Unit was formed in 1988 by Amoco Production Company to evaluate the hydrocarbon potential of the Cretaceous sedimentary section in a sixteen square mile area on the south flank of the Wamsutter Arch. The Wamsutter Arch is a WNW-ESE trending arch in southwestern Wyoming along which the eastern Green River Basin proper can be divided into two sub-basins, the Red Desert to the north and the Washakie to the south (Fig. 2).

The Cretaceous sedimentary section is commonly productive in stratigraphic traps along the crestal portion of the Wamsutter Arch in the Echo Springs-Standard Draw and Wamsutter Fields. The Frewen Deep Unit was formed to explore for deeper production in the Lakota Formation and younger strata. The initial unit well, the Frewen Deep #1, was drilled to a total depth of 19,299 ft on a southward plunging, fault-related anticline, and completed in the Lakota. Extended production tests indicated non-commercial rates. Shows had been observed in the Frontier Formation while drilling through it to the Lakota, but the wellbore became mechanically unusable during the course of moving uphole to test the Frontier. Mechanical problems associated with great depth, completion fluids, and problems with casing integrity in the Frewen Deep #1 were grounds for the decision to evaluate the formation in a completely new wellbore. The Frewen #4 Deep well was drilled as a replacement, offset 600 ft from the #1 well.

Much of the Frontier Formation in the #4 well was cored with good recovery, and the core contained numerous partially mineralized natural fractures of a unique type. The fractures had obvious open porosity (Fig. 3), and therefore, presumably, permeability. Four fracture sets were identified

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

in the core. These included three sets of irregular but numerous natural fractures, designated F1, F2, and F3 in order of their formation, and a fourth set of fractures consisting of coring-induced petal fractures. Gas in the drilling mud and the presence of open fractures seemed to promise significant gas production, but the initial production rate was not high, and declined precipitously to an uneconomic level. The natural and coring-induced fractures in the Frewen core were analyzed during this study, in order to assess the possible reasons for the low and declining production despite the apparent support from natural fractures. This paper documents the conclusions from the core study, and also offers an interpretation for the origin of these unique fractures.

Well history and Reservoir Properties

The Frewen #4 Deep well was spudded on 10/18/90 and reached a total depth of 18,600 ft on 3/3/91. Three separate conventional cores (totaling 87 ft recovered) were taken through the Frontier Formation. Horizontal Dean Stark air permeabilities were measured at each foot in the sandstone core; 61 measurements yielded an average permeability of 0.007 md (range 0 to 1.23 md), an average porosity of 3.7% (range 0.8 to 7.1%), and a flow capacity of 1.7 md-ft. Geophysical logs were collected over the objective interval, including induction and neutron/density suites.

Mud weight at total depth was 15.0+ ppg, indicating a pressure of approximately 14,489 psi (minimum) at the reservoir level. Shows of gas requiring the use of a gas buster to de-gas the mud began at 18,225 ft and continued during coring operations. Shows periodically supported 10-20 ft (estimated) flares. Below 18,380 ft the mud did not require de-gassing to remain manageable and control the well.

Multiple sets of casing were set in anticipation of high pressures: 13 3/8" surface casing was set at 2358 ft, 9 5/8" intermediate casing was set at 10,835 ft, and 5 1/2" casing was set at 18,114 ft prior to initiating coring operations. A 5" liner set from 18,114-18,593 ft completed the casing of the well. Each of the casing and liner strings was cemented in place and an acceptable bond was achieved.

Completion operations began on 4/23/91 when the well was perforated from 18,316-18,344 ft with 6 shots per foot, 6000 psi underbalanced. The well did not flow. Swabbing was required in order to achieve a 15-20 MCFD flow rate for 7 days. Subsequently, a CO_2 breakdown was performed, with 110 tons CO_2 pumped at 8.5 BPM into 14,400 psi tubing pressure. The well flowed back CO_2 and gas at a rate of 500 MCFD (>25% CO_2) and was shut in preparatory to flow testing and BHPBU.

Following the installation of a polished bore receptacle, seal assembly, and tubing, a leak was discovered in the bottomhole assembly as evidenced by the observation of 7900 psi pressure on the annulus versus 11,200 psi surface pressure on the tubing.

A 10-day flow test was then conducted: the initial rate was 360 MCFD at 220 psi, but it declined to 140 MCFD at 185 psi at the end of the test (Fig. 4). The average flow rate was 196 MCFD at 196 psi for the test period.

Gauges were run with a bottomhole shut-off plug and the well was shut in for 16 days. The gauges failed during the test and yielded no usable pressure build-up data. After evaluating the economic potential of performing a hydraulic fracture stimulation, the well was plugged and abandoned as a dry hole at a cumulative cost of approximately $4.3MM.

Bitumen and F1 Fractures

A material, consisting almost entirely of carbon when analyzed in the Scanning Electron Microscope (J. Krumhansl; personal communication, 6/93), is present along and within the earliest set of natural fractures (F1) in the Frewen core. This material is interpreted to be a residual pyrobitumen. The bitumen occurs primarily within the remnant fracture porosity left after mineralization, but is also present locally in the matrix pores adjacent to fractures and "underneath" the mineralization along the fracture walls. Study of the rock in thin section suggests that fracturing was coincident with bitumen emplacement (although the bitumen was probably originally in the more mobile form of oil), and mineralization is inferred to have occurred after fracturing, after oil emplacement, and possibly also after the conversion of the oil to bitumen.

The bitumen locally conforms to crystal faces of the mineralization that lines the fractures, suggesting emplacement after mineralization. However, the thin sections show that the bitumen is commonly disaggregated and particulate in nature, and occurs under the mineralization as well as over it **(Fig. 5)**, showing that calcite and quartz mineralization grew into the fractures, displacing and breaking up a pre-existing bitumen layer. It is probable that the mineralization grew over/around the bitumen, as opposed to the bitumen having been injected between the mineralization and the wall. (Although it is commonly assumed that the presence of oil in a formation will arrest mineral precipitation, Saigal et al. (1992)[1] have shown that oil in the pores of a formation may retard but does not necessarily stop the precipitation of quartz.) Additionally, bitumen occurs within strands of fractures that were never mineralized, indicating that fracturing and bitumen emplacement were related, but that mineralization was a later process.

Bitumen also accentuates wispy, multi-stranded "mare's-tail" tips of many fractures **(Fig 6)**, most of which are otherwise unmineralized. The mare's tails may represent fossil fracture-tip process zones. Where gas or water is the pressure agent in a formation, process zones in front of an advancing fracture close up and leave little trace. However, where oil is the formation pressuring agent as in this case, remnant bitumen would/could have been emplaced and preserved within the process zone, highlighting the small fracture planes.

The bitumen that is present within the matrix pores adjacent to some of the fractures may also be important. A percentage of the log-derived matrix porosity may in fact be occupied by bitumen, giving an erroneously high porosity reading on the downhole logs in the manner documented by Lomando (1992)[2]. This would result in an overestimation of the volume of gas in place, and may have led to unrealistic production expectations from the well.

Finally, much of the quartz that precipitated into the fractures contains fluid inclusions of oil, strongly suggesting that crystal growth and mineralization occurred in the presence of oil.

The smallest fractures created during the F1 phase of fracturing contain only quartz and/or bitumen. However, formation fluids subsequently precipitated calcite on top of the quartz in the larger F1 fractures.

F2 Fractures

Calcite precipitation in the larger F1 fractures seems to have coincided with a second, F2 fracturing event. Fractures produced during this event are marked by initial calcite mineralization (rather than early quartz as in the F1 fractures), and locally by a second, later quartz mineralization overlying the calcite crystals. (A few of the larger F1 fractures contain all three mineralization stages.)

The morphology of F2 fractures is distinctive. Large remnant apertures are common **(Fig. 3)**, but these wide fractures may change abruptly into local zones of thin, multiple, calcite-filled fractures **(Fig. 7)**. Thin sections of these multi-stranded zones **(Fig. 8)** show a boggling array of closely spaced, calcite-filled, irregular, anastamosed fracture strands. Individual strands locally cut across the grains, indicating that the rocks were lithified at the time of fracturing.

This second phase of fracturing has an orientation that is about 30 degrees oblique to the strike of the F1 fractures. An episode of vertical stylolite formation also apparently separated the two fracture events, with F1 fractures but not the adjacent F2 fractures being offset along the stylolites **(Fig. 9)**.

Present-Day Stress, F3 Fractures

Paleomagnetic orientation of the core indicates that the F1 and F2 fractures strike approximately east-west (85-115 degrees). In contrast, 30 consistently-oriented petal fractures were measured to strike approximately north-south (160-180 degrees) **(Fig. 10)**. Petal fractures typically strike parallel to the maximum horizontal compressive stress[3], and thus the petal fractures in this core indicate that the present-day maximum horizontal compressive stress has a significantly different orientation from that which dominated during the F1 and F2 fracture events.

A third population of infrequent, mineralized natural fractures (F3) strikes parallel to the petal fractures, suggesting that they formed last, under the influence of the present stress field.

Reservoir Character and Production

The Frewen #4 Deep well had a relatively high initial production rate because gas at the depth of 18,300 ft, especially in this overpressured province, is under significant pressure. Unfortunately, the gas volume accessible to the vertical hole from the matrix was insignificant, explaining, in part, the observed rapid decline in production.

Although the formation is highly fractured, the principle sets of fractures (F1 and F2) are plugged with bitumen residue (and possibly also by the cement used to cement in the casing and liner). The bitumen degrades both porosity and permeability. Moreover, both major fracture sets are oriented nearly normal to the present-day maximum horizontal compressive stress, meaning 1) that the conductivity of this set of fractures is likely limited by a relatively high normal stress, 2) that rapid decreases in the fracture conductivity probably occurred during reservoir draw-down, as fracture apertures were squeezed shut, and 3) that although CO_2 fracture probably cut across the main natural fracture trend (following the in situ stress orientation indicated by the petal fractures), it probably did not permanently access the reservoir fracture permeability because it was unpropped.

Thus, the reservoir volume that was efficiently connected to the wellbore was small, and permanent conductivity within the reservoir probably depends on matrix capability despite a pervasive system of natural fractures.

This interpretation of the low Frewen production rates may have use in ruling out prospects in other areas of the Green River Basin which are likely to have similar characteristics of thermal overmaturation (e.g., avoid bitumen-prone areas). Regions that have potential for tectonically re-oriented horizontal stresses capable of shutting off fracture permeability would also be poor prospects. Unless matrix production can successfully be exploited by horizontal drilling, the best targets for deep-basin gas are areas which have not been as deeply buried nor heated to equivalent temperatures, and/or areas where the geologic and stress histories have not been complicated by local tectonic events.

Fracture Origins

The youngest, F3 fractures are simple extension fractures that probably formed under stress conditions similar to the present-day conditions. The F1 and F2 fractures, however, offer evidence of an unconventional origin.

The association of bitumen, mare's tails, and F1 fractures suggests a system of injected fluids. Crude oils, when confined and heated, are capable of producing extremely high pressures. The pressure magnitude is a function of liquid compressibility and thermal expansion, with a potential pressure rise of approximately 70 psi for each degree Farenheit increase in temperature (T. Hinkebein, personal communication 2/94). At current reservoir temperatures, a potential pressure in excess of 20,000 psi could be generated.

This of course is a gross simplification of the actual conditions during fracturing in that it assumes no leakage of pressure as well as an instantaneous response to pressures and temperatures. However, it highlights the considerable amount of energy potentially available from this source, and the corresponding potential for it to deform or fracture rock.

It is possible that the F1 fractures formed as a type of natural hydraulic fracture, driven by oils expelled from adjacent source-rock shales. Oil leaked off into the process zones at fracture tips once they had exhausted most of the energy associated with expulsion, leaving mare's-tails patterns.

The precise origin of the multi-stranded F2 fractures is not apparent. The mineralization sequence suggests that they formed later than F1 fractures and in a horizontal stress regime that had shifted by about 30 degrees (possibly related to motion of the underlying fault). Differences in rock properties might account for the observed abrupt transitions from wide, single fractures to thin, multi-stranded fractures, although such differences are not apparent in the core.

Summary

Sandstones of the Frontier Formation at 18,300 ft depth in the Frewen #4 Deep well contain numerous natural fractures. Despite fractures and significant pressures, however, the reservoir was incapable of supporting economic production rates. Two major factors are suggested to contribute to this: plugging of fracture permeability by residual pyrobitumen, and reorientation of the in situ compressive stress such that fracture apertures become narrower or even shut during pressure decline. The effective reservoir conductivity, despite numerous natural fractures, is limited by the matrix permeability which is only a few thousandths of a millidarcy.

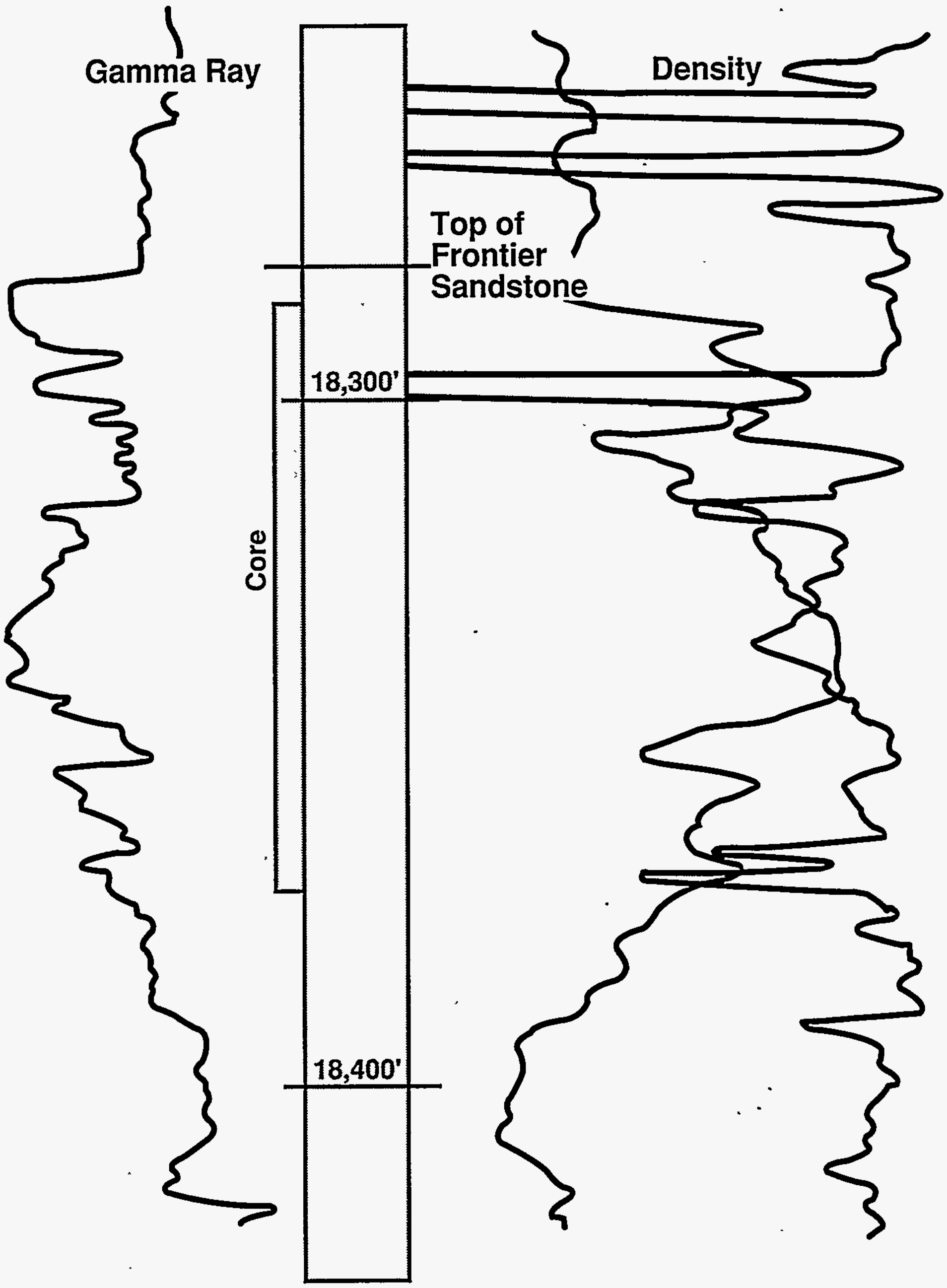
Acknowledgments

We would like to thank Amoco Production Company for permission to publish these data. This work was supported in part by the U.S. Department of Energy (Morgantown Energy Technology Center) under contract number DE-AC04-94AL85000, and in part by the Gas Research Institute under contract no. 5089-211-2059, managed by Steve Wolhart. Steve Clawson provided geophysical support, while Janice Washington and Linda Cleland-Ortiz figured out the intricacies of the SPE computer templates for us.

References

1. Saigal, G.C., Bjorlykke, K., and Larter, S., "The effects of oil emplacement on diagenetic processes: Examples from the Fulmar reservoir sandstones, central North Sea," AAPG Bulletin 76, (1992), 1024-1033.
2. Lomando, A.J. "The influence of solid reservoir bitumen on reservoir quality," AAPG Bulletin 76, (1992), 1137-1152.
3. Lorenz, J.C., Finley, S.J., and Warpinski, N.R., "Significance of Coring-Induced Fractures in Mesaverde Core, Northwestern Colorado", AAPG Bulletin 74, (1990), 1017-1029.

Fig. 1



T.369.C.CP7609.03

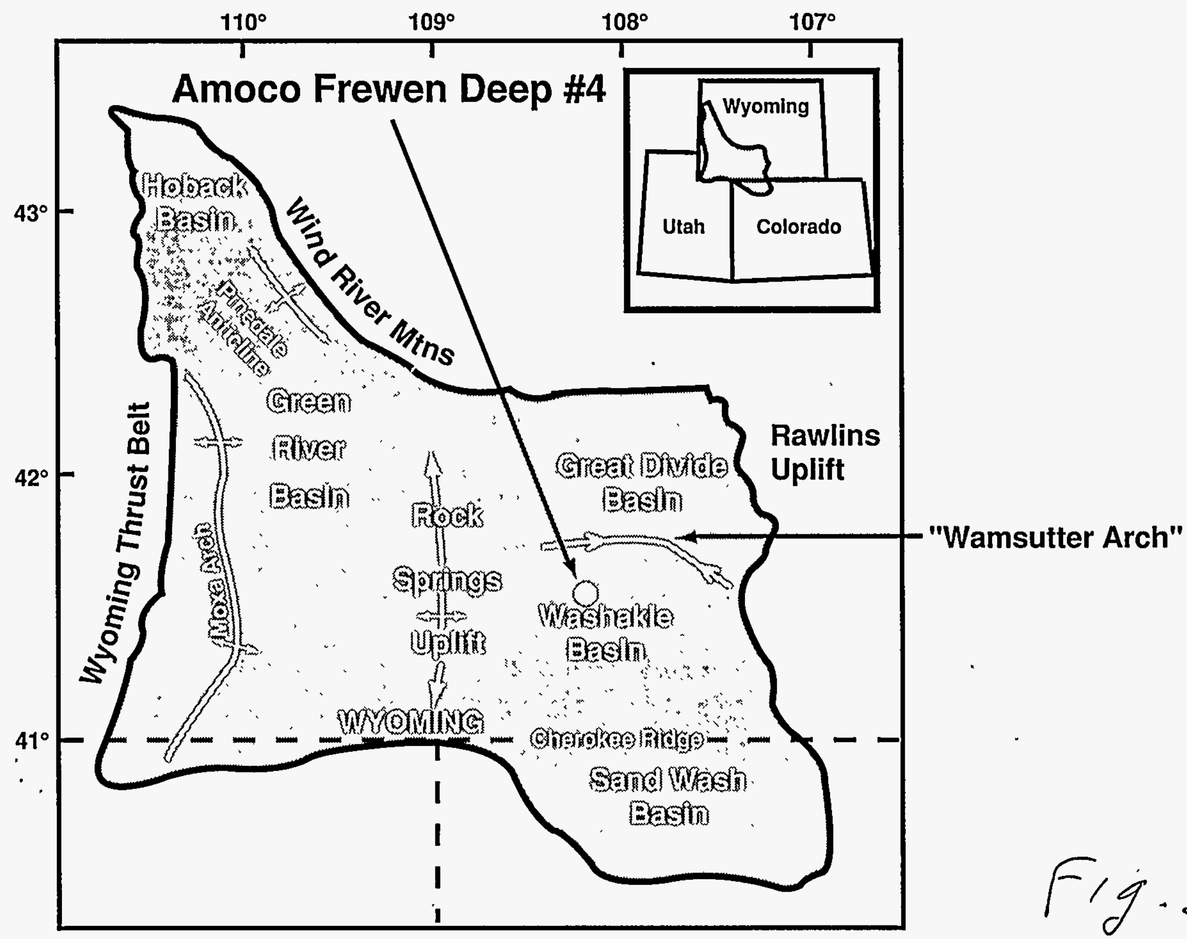


Fig. 2a

T.369.C.CP7609.04

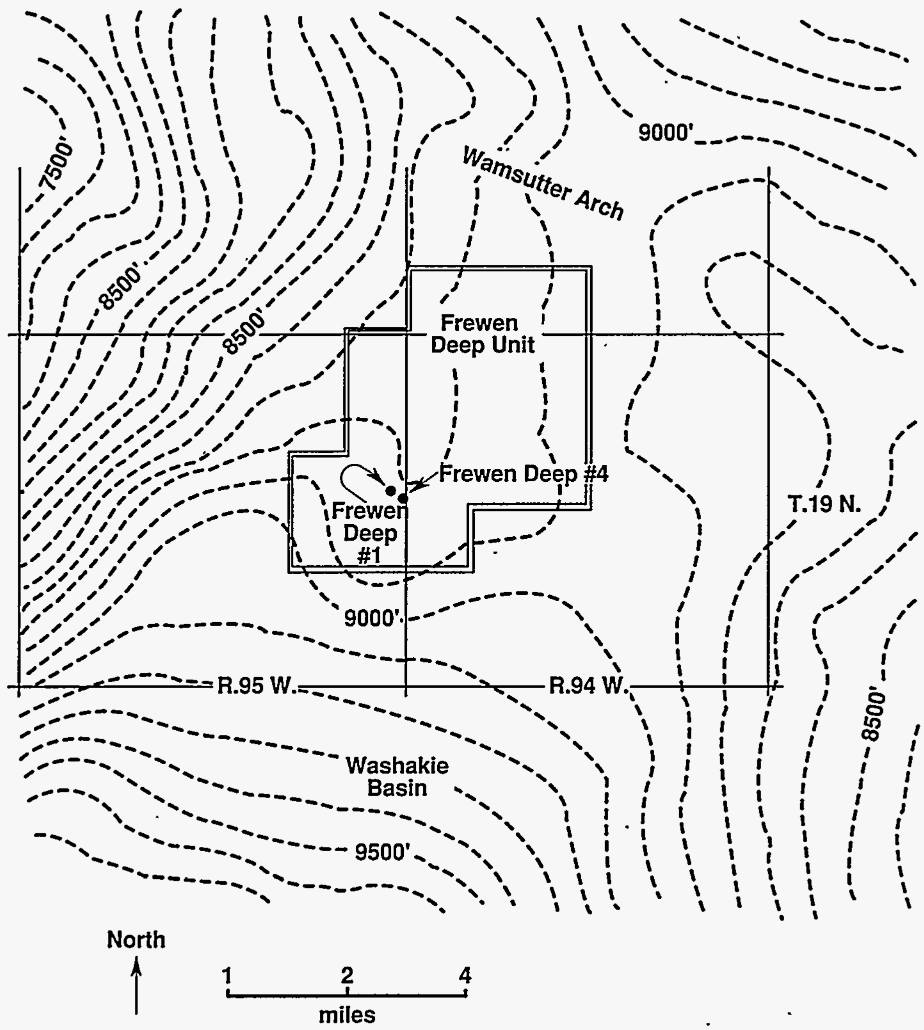


Fig 2b

T.369.C.CP7609.02

Frewen #4
Frontier Flow Test

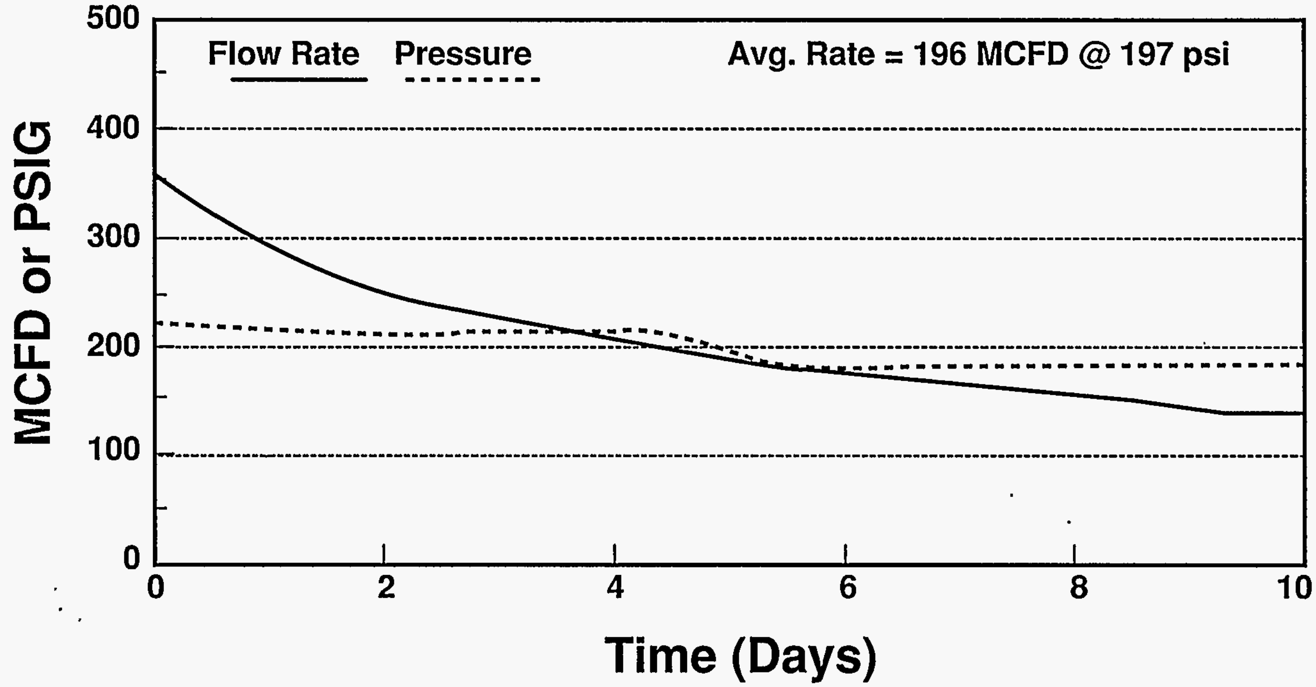


Fig 4

T.369.C.CP7609.01

Fig. 5

Fig. 3

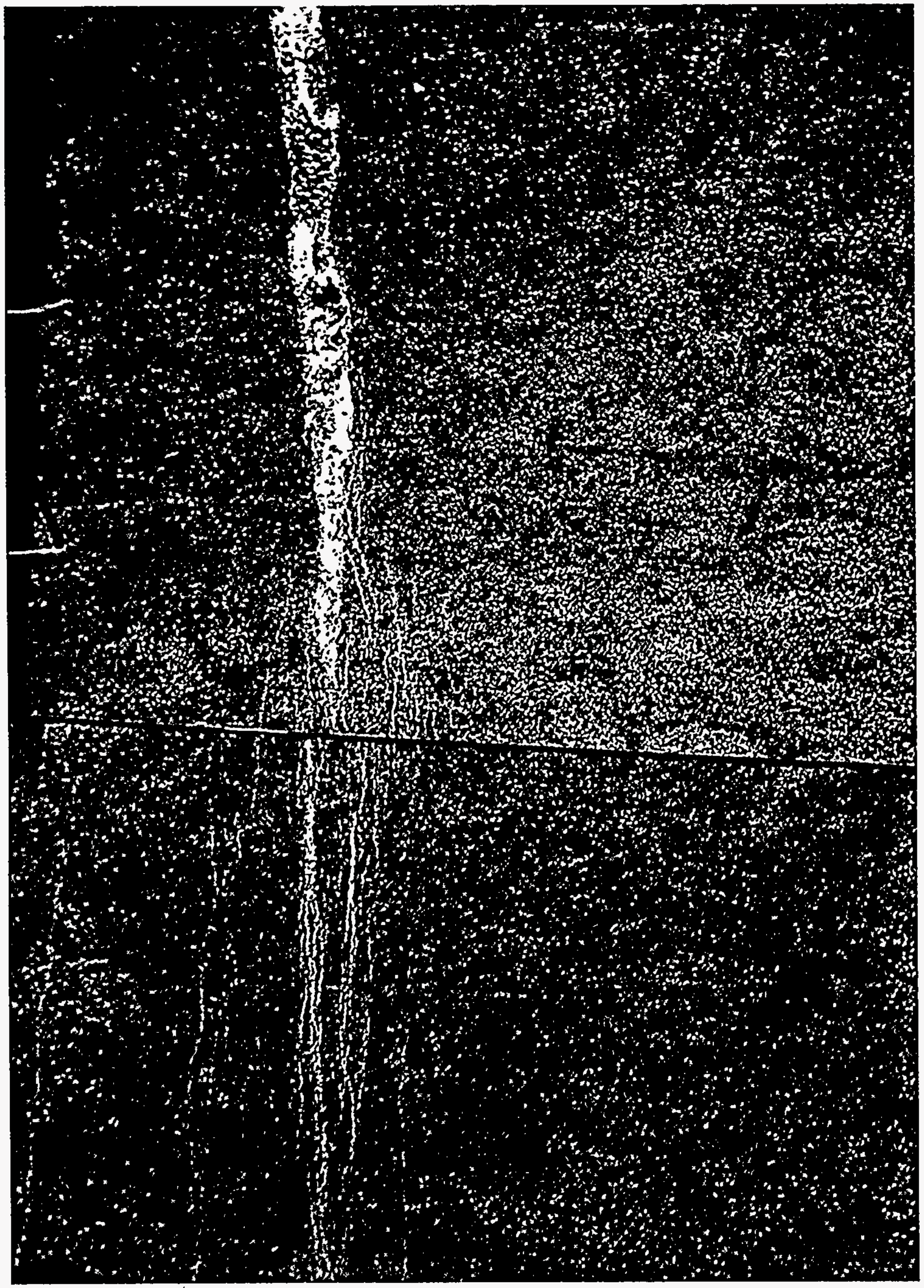


Fig. 7

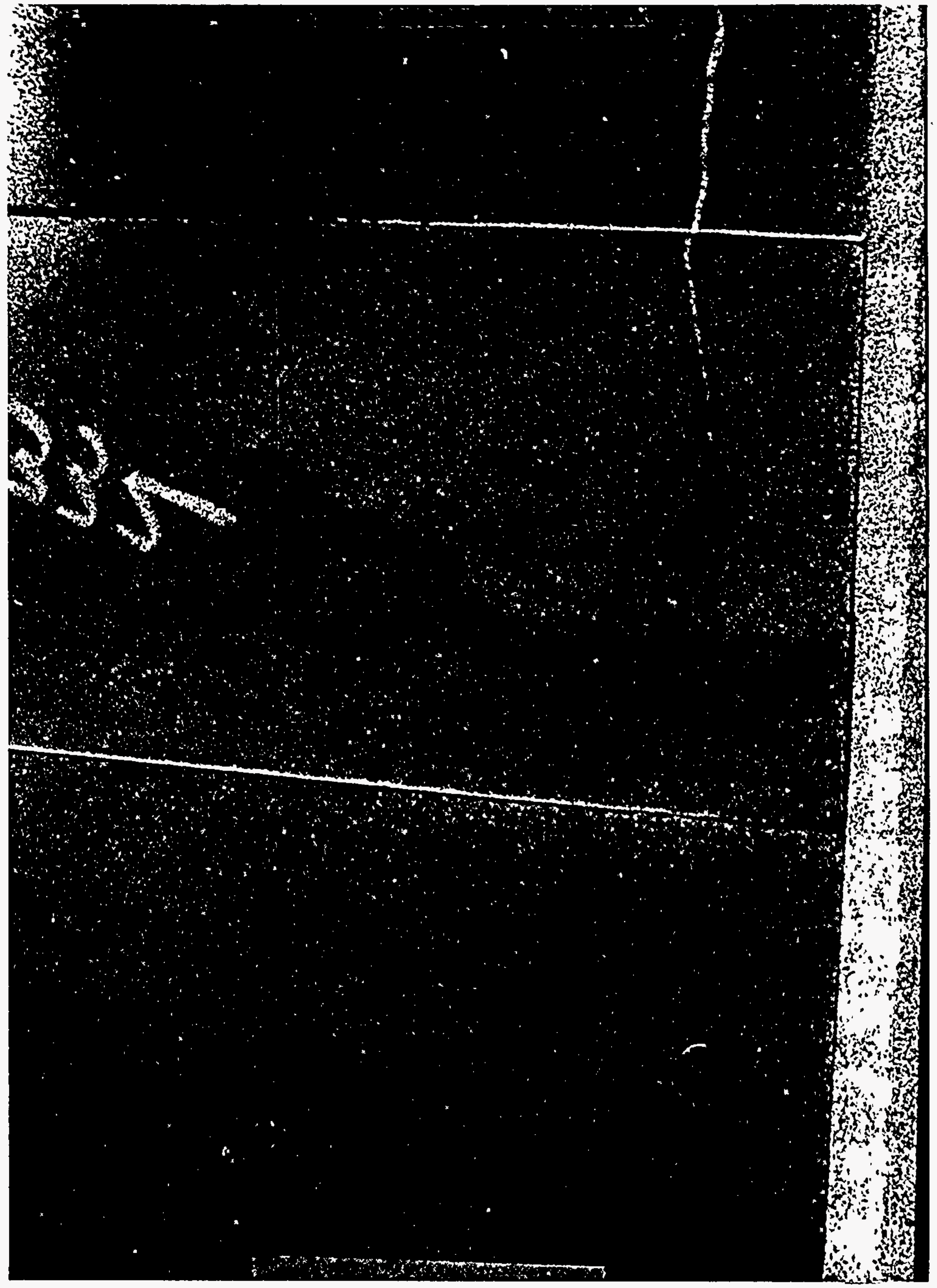


Fig. 6

Fig 8

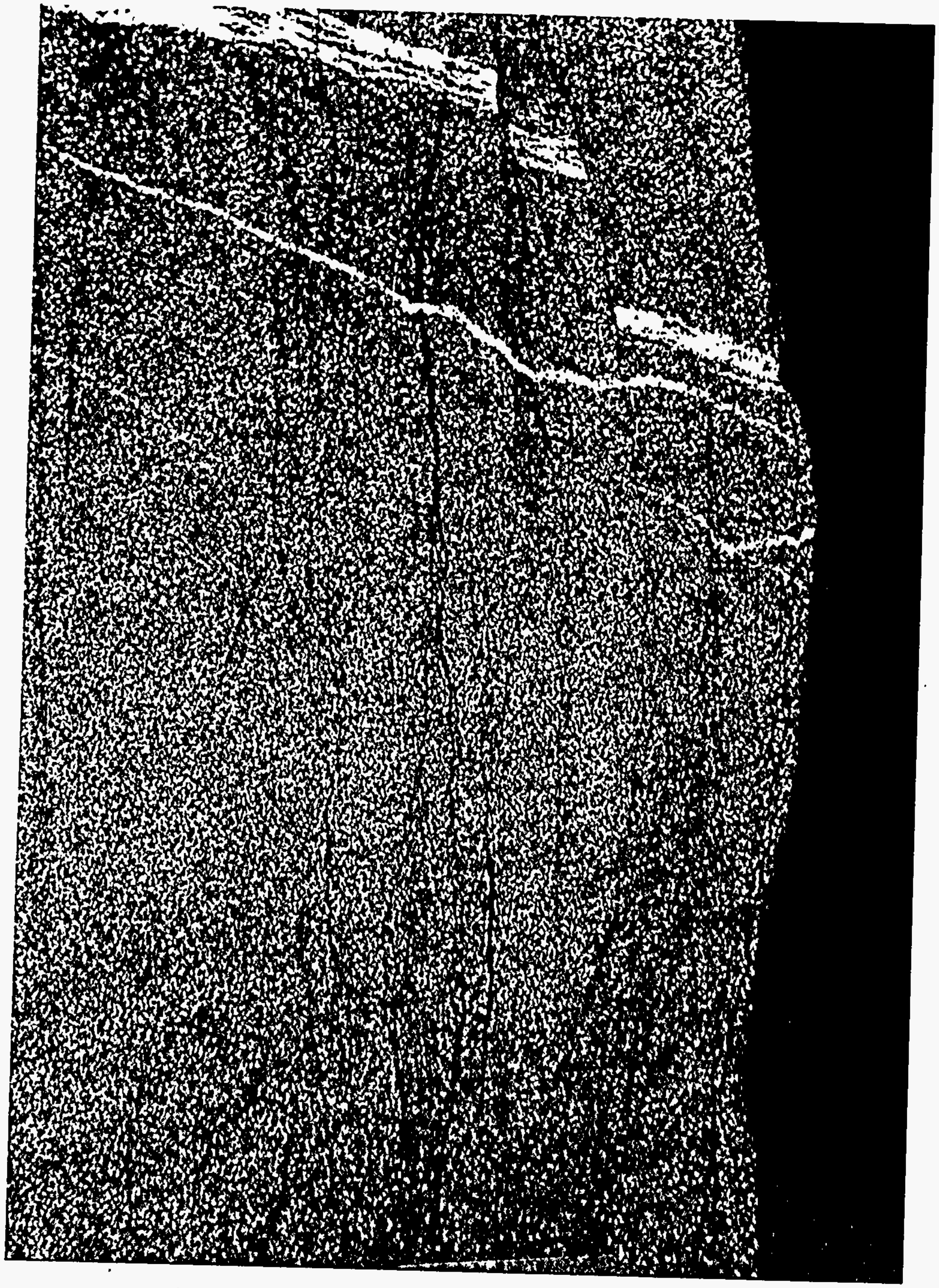


Fig 9

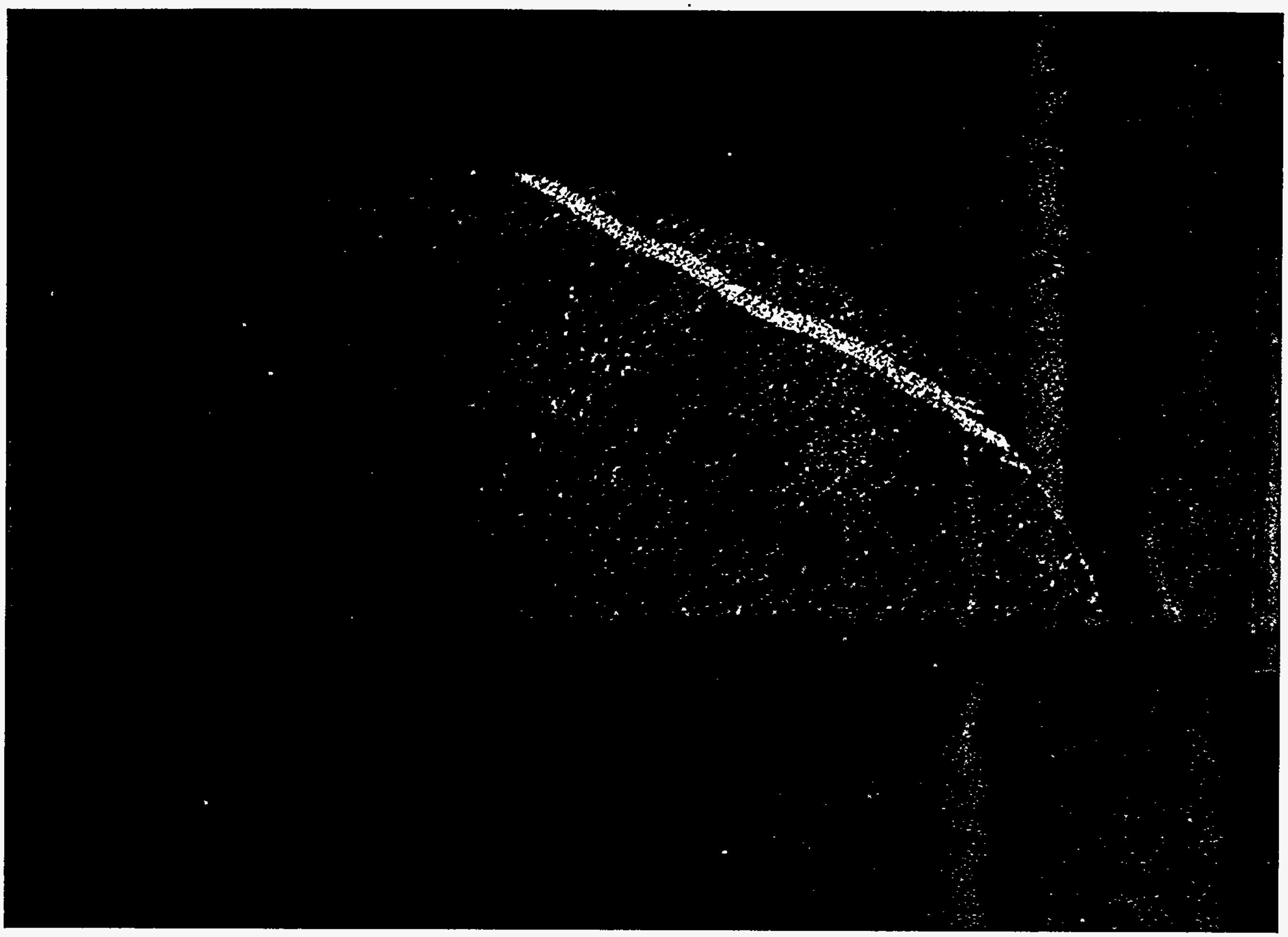


Fig. 10