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ENHANCED OIL RECOVERY UTILIZING HIGH-ANGLE WELLS IN THE FRONTIER FORMATION, BADGER BASIN FIELD, PARK COUNTY, WYOMING

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By
Jerome P. Walker
Richard G. Fortmann

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Edith Allison, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Sierra Energy Company
Reno, Nevada 89511

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ABSTRACT

Badger Basin Field was discovered in 1931. It produces at stripper rates from low-permeability fractured sandstones of the Upper Cretaceous Frontier Formation. Only 15% of the estimated 25 million barrels of oil originally in-place will be produced from the twenty-two attempted vertical completions. This project will increase recoverable reserves through a better understanding of the reservoir and factors which control production.

Characterization of the reservoir has been accomplished through an integrated engineering, geological and geophysical approach. Production data, drilling and completion techniques, and relative location of wells on the anticline were reviewed and related to productivity. Literature was reviewed for interpretations on preferred flow directions on anticlinal structures. A structure map of the producing Frontier reservoir was constructed. Porosity development and its relationship to fracture networks was examined petrographically. Fractures in core were described and oriented using paleomagnetic techniques. Azimuths of fractures in outcrop were compared to fracture azimuths measured in the core. A 17 square-mile 3D seismic survey was designed, acquired and processed. Interpretation is being performed on a Sun workstation using Landmark Graphics software. Time-structure and amplitude-distribution maps will be constructed on three Frontier horizons. A location for a high-angle well will be chosen. The slant/horizontal test will be drilled and completed to increase recovery of reserves. Transfer of successful technologies will be accomplished by technical publications and presentations, and access to project materials, data, and field facilities.

Five significant accomplishments have been achieved. First, we successfully oriented core from the Frontier using paleomagnetic techniques, thus orienting the coring-induced and natural fractures. We found that the predominant azimuth of the natural fractures in this core is NNW, subparallel to the crest line of the anticline. A second set of natural fractures trends ENE. <u>Two</u> sets of coring-induced fractures were discovered, with azimuths comparable to the natural fractures. Secondly, petrographic study of thin sections through known fracture sets has increased our understanding of the porosity system and its relationship to well productivity. The secondary porosity found in the Frontier sandstones appears to be both better developed and interconnected adjacent to fractures, providing localized volumes in the reservoir with higher recovery factors. Thirdly, using production records, we were able to show a clear relationship between location of a well relative to the anticlinal crest line and the well's productivity. The better wells are located on or adjacent to the primary or secondary crest line. Fourthly, we verified that the highest productivity came from a well in the downthrown block immediately adjacent to the main normal fault. Finally, we were able to acquire high-quality seismic data using the low-cost sign-bit recording system. This economic benefit can only help to increase the use of 3D seismic by independents.

EXECUTIVE SUMMARY

Badger Basin Field, located 28 miles north of Cody, Wyoming, was discovered in 1931. Sixty-three years later, it produces at stripper rates from low-permeability fractured sandstones of the Upper Cretaceous Frontier Formation. Only 15% of the estimated 25 million barrels of oil originally in-place will be produced from this reservoir by the 22 attempted vertical completions, leaving over 21 million barrels of oil in the ground. The purpose of this project to increase the recoverable reserves from the Frontier Formation through a better understanding of the reservoir and factors which control production. Characterization and analysis of the reservoir will be accomplished through an integrated geological, geophysical and engineering approach. The investigation into the depositional, diagenetic, and fracture heterogeneities of the reservoir has been followed by a 3D seismic survey to gain a more accurate picture of the structural configuration of the producing anticline. A slant/horizontal test will be drilled and completed in an attempt to overcome reservoir conditions associated with low recovery of hydrocarbons, resulting in increased productivity and recovery of additional reserves. Transfer of successful technologies tested in this demonstration to other interested parties will be accomplished by technical publications and presentations, and access to project materials, data, and field facilities.

The Frontier reservoir has been characterized using engineering, core and outcrop data, and through the analysis of the producing structure's geometry. A structure map of the producing reservoir was constructed from subsurface well control and two 2D seismic lines. Individual well production data, completion techniques and relative location of wells on the anticline were reviewed to determine any relationship between these factors and level of productivity. Though the better producers are predominately located along the crest line of the structure, this alone does not guarantee an economic level of production. Core from a well located on the gentler dipping southwest flank was described macroscopically and petrographically, and its fractures oriented using paleomagnetic techniques. Numerous mineralized fractures are present in vertical to subvertical and diagonal shear orientations, as well as coring-induced petal and centerline fractures. Predominant azimuth trend, based on paleomagnetic orientation, of the natural fractures is NNW, subparallel to the crest line of the anticline. A second set of natural fractures trends ENE. Surprisingly, two sets of coring-induced fractures were found. Sixty-two percent of the induced fractures trend NNW, while 38% trend ENE. Measurement of fracture direction in outcrop coincided with the two sets of fracture azimuth recorded in the core. Published work analyzing pressure-interference tests at six fields in the Bighorn Basin indicates preferred flow direction is northeast, perpendicular to the axial trace. Petrographic analysis of thin sections suggests that the distribution of the secondary porosity network in the Frontier sandstones may be the result of the fractures and localized stress field controlling the flow paths of corrosive organic acids formed in and expelled from the source rocks just prior to the generation and migration of hydrocarbons.

A design was developed for a 17 square-mile 3D seismic survey, based on the areal extent, desired bin size, fold and offset distribution. A routine processing flow was chosen with the addition of 3D refraction statics and one-pass finite difference migration. Interpretation of the data would include mapping of three horizons to determine the faulting pattern on the anticline, and analysis of various seismic attributes, such as amplitude or

frequency distribution, as a tool to map fracturing. Bids to acquire the field data were solicited from eight contractors. Geophysical Systems Corporation's bid of $202,664 was selected from four bids ranging from $202,664 to $446,693. Acquisition of the 3D seismic required 25 shooting days during the Spring of 1993. The crew averaged 46 vibrating points per day. Vector Seismic Data Processing, Inc.'s processing bid for $37,560 was chosen from a total of four bids received ranging from $37,560 to $57,556. The 3D survey was processed during the summer of 1993. The processing flow occurred as planned, substituting a 2-pass finite difference migration for the planned 1-pass. Interpretation is being performed on a Sun Sparcstation10 workstation (UNIX based) using Landmark Graphics latest version of Seisworks 3D software. Time-structure and amplitude-distribution maps will be constructed on the three Frontier horizons.

INTRODUCTION

Location and History

Badger Basin Field (T57N, R101W), in Park County, Wyoming, is located in the northwest part of the Bighorn Basin (Figure 1), 28 miles north of Cody, Wyoming and 5 miles south of the Wyoming-Montana border. The field is bisected by State Route 120, an all-weather, paved two-lane highway. It is just 6 miles east of the synclinal axis of this asymmetrical Laramide-age basin, and 10 miles from the east flank of the Beartooth Mountains where the Frontier Formation (the field's main productive formation) outcrops. The field is 12 miles southwest of the giant Elk Basin Field.

Badger Basin is a shallow, topographic depression surrounded by low ridges. Laterally discontinuous, cross-bedded sandstones of the Tertiary Fort Union Formation form these ridges, and dip away from the center of the basin, providing surface evidence of an anticlinal feature. Early exploration for oil in the Bighorn Basin had been very successful following the simple expedient of drilling surface anticlines. After the discovery of Elk Basin in 1915, explorationists began their evaluation of the oil potential at Badger Basin. Leases were taken and reconnaissance and field mapping was done during the late 1910's and early 1920's. However, surface dips of only 1 to 5 degrees, which indicated moderate folding, and the prohibitive (for that time) estimated depth of between 5,000' and 7,000' to the Frontier sandstone, the highest productive interval at Elk Basin, impeded exploratory drilling at Badger Basin until June 3, 1928 when Resolute Oil Corporation spudded its initial test.

The discovery well, the Resolute Oil Corporation No. 1 (also called the Northern Pacific No.1, and currently designated the #11 BBFU, Table 1), is located in the NE/4 of Section 17, T57N, R101W (Figure 2). Drilling was done with cable tools. The Frontier sands were expected between 5,100 and 5,500'. However, sands of the 1st Frontier weren't reached until November 1930, 2½ years after spudding, at the depth of 8,215'. Oil and gas shows began at 8,250', and shortly thereafter the cable tools were blown up the hole. A second oil sand was encountered at 8,350'. Finally, on April 19, 1931 a third sand was drilled into, and the well began to flow by heads, discharging about 20 barrels of oil every 14 hours. The drillers reached total depth at 8,723' on July 15, 1931, just over three years from the start of drilling. After a period of swabbing and testing, the well was completed in August 1931 capable of flowing 40 barrels of oil per day up the casing on a 10/64" choke with surface pressure of 600 psi. Production was from the openhole interval 8,226' to 8,723' in the 1st, 2nd and 3rd Frontier sands.

Four additional wells (Table 2) were drilled and deepened southeast of the discovery well between 1933 and 1939. Based on surface mapping (Figure 3), the second well (now designated the #9 BBFU) drilled by Resolute Oil was located updip, at the culmination of the surface structure, and southeast of the discovery. Drilling began July 29, 1933. The well reached what was thought to be the deepest productive sand (i.e., the 3rd Frontier) in late 1933, and drilling was stopped at a total depth of 8,458'. However, the sand at T.D. was the shallower 2nd Frontier. After shooting the well with 110 quarts of nitrogelatin on December 21st the well began to flow at the rate of 192 barrels of oil per day from openhole interval of the 1st and 2nd Frontier. The miscorrelation of sands between the first two wells suggested that the surface and subsurface structures did not conform, and strengthened the operator's theory that the anticline possessed greater structural relief in the subsurface than indicated by surface mapping. This interpretation, in combination with an almost five-fold improvement in the flow rate of the second well over the first, enabled the operators to easily raise money for another test. The 3rd well (now called the #17 BBFU) was spudded south-southwest of the #9 BBFU in April 1937. Total depth was reached at 8,585' in the 2nd Frontier. Again, the operator believed that they had drilled to the 3rd Frontier, as they had done in the discovery well. However, the openhole interval of the 1st and 2nd Frontier did not produce more than a show of oil or gas. The well was deepened into the 3rd Frontier in April 1939 to 8,709'. The well flowed 219 barrels of oil during its first 24 hours of production. Though all three sands of the Frontier were open, this production was only from the 3rd.

The experiences garnered by Resolute Oil during the drilling and completion of their first five wells indicated that all three Frontier sandstone benches were capable of production. However, the chief producing sand was believed to be the 3rd. Two of the wells were producing solely from the 3rd, while one well flowed chiefly from the 2nd sand. The discovery well probably produced from all three benches, though the 3rd sand was thought to be the primary contributor of oil. The fifth well drilled, the #10 BBFU, located amidst three of the wells, did not produce more than a show of oil or gas from any of the three sands. By 1939, the confounding variability of the reservoir had been ascertained.

The sixth well was drilled northwest of the discovery in 1943, and demonstrated that the structural axis continued in that direction. Nine more wells, located primarily in the northwest portion of the structure were completed by 1947. During this period, the first well on the upthrown block of the Frontier was drilled, and the Cloverly Formation and Madison Limestone were tested. Only four wells were sunk in the twenty years of the 1960's and 1970's. One well was drilled as a Cloverly test in 1980. The final four wells on the structure were drilled in 1987 after the formation of the Badger Basin (Frontier) Unit ("BBFU").

Badger Basin Field has undergone numerous changes in ownership since Resolute Oil Corporation discovered the field. Previous operators include Williston Oil & Gas Company, Midwest Oil Company, Badger Oil Company, Petro Lewis, Cerelli Petroleum, Inc., and Fernstrum Energy Corporation. The field is currently operated by Sierra Energy Company. Oil is trucked and sold to Enron Oil Trading and Transportation Company; natural gas liquids are trucked and sold to Interline Energy. Natural gas is sold to InterEnergy Corporation, a broker, for usage primarily in the local market area.

Producibility Problem

Badger Basin Field produces principally from the fractured, low matrix-permeable sandstones of the Upper Cretaceous Frontier Formation that are situated on a cross-faulted, doubly-plunging anticlinal structure. (See Figure 4 for a stratigraphic column, and Figure 5 for the type log over the Frontier interval.) This combination of low matrix-permeability and compartmentalization of the reservoir by faulting and fracturing has created the producibility problems associated with the poor recovery of hydrocarbons by the 22 attempted vertical completions. Only an estimated 11.4% of the original oil in place is expected to be produced (Table 3).

Evidence for a fractured reservoir comes from the wide range of cumulative production for individual wells, reported blowouts and lost-circulation zones during drilling, presence of dry holes surrounded by producers, presence of fractures in vertical core, and pressure build-up rates during drillstem tests. Cumulative production for individual wells (Figure 6 and Table 4) ranges from a low of 3,656 barrels to 1.4 million barrels of oil. The best well accounts for 50% of the field's Frontier production, while the top seven producers (i.e., 32%) of the twenty-two completion attempts in the Frontier account for 91% of the production. Blowouts have been reported while drilling in the 1st Frontier (e.g., in the discovery well, the #11 BBFU, while drilling with cable tools; and, in the #3 BBFU). According to the Oil and Gas Journal (June 1946), the #3 BBFU "broke loose while circulating", flowing 950 barrels of oil in 11 hours. (This equates to 2,073 barrels of oil per day, the highest flow rate reported in this field.) Lost circulation commonly occurs in the 3rd Frontier (e.g., the #3, #9 [questionable, as the lost circulation may have gone into the 2nd Frontier], #13, #20, and #22 BBFU wells). Production can be sporadic within the productive area. The 5th well drilled (the #10 BBFU) has produced only a show of oil and gas, though it is surrounded by the 2nd, 3rd and 4th wells drilled, all of which were commercial producers. This example is not the only one of a dry hole within the productive area. Both the #8 and #15 BBFU wells were drilled for deeper objectives. However, subsequent completion attempts in the Frontier sandstones were unsuccessful. The #4 and #13 BBFU wells, drilled as Frontier tests, have also failed to produce in any economic fashion. Numerous fractures have been reported in vertical Frontier cores (e.g., the #6 and #19 BBFU wells). A drillstem test of the 2nd Frontier in the #2 BBFU well showed rapid, nearly instantaneous pressure build-ups when the tool was shut in. The measured shut-in pressures virtually equaled the extrapolated static pressures.

An incomplete understanding of the distribution of the complex dual fracture-matrix porosity system on the productive structure and its control over permeability has contributed to the low recovery from the Frontier Formation. Furthermore, the relationship between normal faulting and porosity/permeability is comprehended only at a basic level. Predictions of the movement of subsurface fluids will be greatly improved, therefore, if we can increase our understanding of this association of porosity and permeability with normal faulting and fracturing, more precisely map the location of normal faults (particularly those faults with smaller displacements), and orient the fracture systems and local stress field(s) at the productive horizons.

Depositional variability within the 2nd and 3rd Frontier benches is relatively minor at the scale of the field, and apparently has a significantly lower order of control on production than fracturing. However, the laterally variability in the delta-plain and mixed delta-marine sediments of the 1st Frontier has undoubtedly influenced the poor recovery from this interval, despite the highest reported flow rate in the field. The better quality reservoir-rock of the 1st Frontier, expected to be found in the fluvial-deltaic channel lithofacies, probably possesses the same porosity and low permeability values as the sandstones in the 2nd and 3rd Frontier, due to the loss of primary porosity principally through mechanical compaction. However, one may speculate that the channel lenses, limited in lateral extent, may be more highly fractured than the sandstones with greater laterally continuity present in the other Frontier benches. The differential stress available for fracturing may be amplified within the channel sandstones as a result of their geometry and enclosure in muddier lithofacies with different rock properties (e.g., ductility). This situation would be ideal for creating pockets of overpressuring, prone to causing blowouts when wells drill into them.

Aspects of geophysics, geology, and engineering are being used to overcome problems associated with production of hydrocarbons from the Frontier reservoir. Analysis of depositional, diagenetic and fracture heterogeneity in the Frontier has led to a 3D seismic survey over the producing structure. Based on the results of the 3D seismic, a slant/horizontal test will be drilled and completed in an attempt to overcome the factors which limit productivity and provide access to undrained or poorly drained volumes of the reservoir. Thus, the goal of this project is to attain higher recovery-efficiency through better characterization of fracture and fault control on the porosity system. Increasing our understanding of this aspect of the reservoir will enable optimum placement of additional wells and result in increased productivity. Experiences and lessons acquired during the work will be transmitted throughout the industry to aid in recovery of reserves in similar petroleum traps.

DISCUSSION

Engineering Characterization of the Frontier Reservoir

High-gravity oil (49° API, Figure 7) and rich gas (1,300 BTU per cubic foot, Figure 8) is produced from the Frontier sandstones at Badger Basin Field through solution-gas drive. Original reservoir pressure, based on extrapolated pressures from a drillstem test of the 3rd Frontier in the #2 BBFU well, is estimated to have been 3,057 psi at an elevation of -4,049' (8,261'). Thus, the pressure gradient for the Frontier originally equaled 0.37 psi per foot, typical of underpressured Rocky Mountain reservoirs. Limited pressure data (Figure 9) of varying reliability suggests that little communication has occurred among the productive wells, despite field reports of changes in performance of wells when the #3 BBFU was brought onstream.

The main productive sandstones, the 2nd and 3rd Frontier sands, are distributed fully across the anticlinal structure. However, drilling results have ranged from dry holes to a producer with a maximum stabilized initial potential (I.P.) of 1,159 barrels of oil per day (Table 4). Median I.P. for a Frontier well is 58 barrels of oil per day. Decline rates (Table 5 and Appendix C) range from 1% to 56% per year. The #11 BBFU, the discovery well, declined at the rate of 3% per year over its first nine years of production. Such a low rate for an extended time implies a large but poorly connected reservoir. Cumulative production for individual wells ranges from 3,656 barrels to 1,416,776 barrels of oil and an unaccounted amount of natural gas. Median cumulative production is 57,465 barrels of oil per well.

The #11 BBFU well, the discovery for the field, was drilled with cable tools. All subsequent wells have been drilled with mud and rotary tools. Lost-circulation zones and blowouts have been reported. Cable tools were blown up the hole and became stuck during drilling of the 1st Frontier sand in the #11 BBFU well. The #3 BBFU also reportedly blew out while drilling in the 1st Frontier, flowing at the rate of 2,073 barrels of oil per day. Wells drilled prior to 1953 were all openhole completions. Stimulation initially consisted of blasting the Frontier openhole with quarts of nitrogelatin. Subsequent analysis concluded that this technique was primarily successful in producing downhole rubble with little beneficial results on the productive rates. With the advent in 1954 of cemented casing or liner and production through perforations, hydraulic fracturing (i.e., "fracs") with oil were initiated. Two state-of-the-art CO_2 foam fracs were applied to the #19 BBFU well in 1987, using about 70,000 gallons of gelled KCl water to make a 70Q foam and 100,000 pounds of 20/40 sand. Despite the efforts to enhance production through stimulation techniques as well as attempts to reduce possible formation damage during cementing, Badger Basin wells have not responded in a positive manner. Wells with good shows during drilling or shortly after swabbing began have turned out to be better producers. Poor wells have successfully resisted all attempts to enhance their yield. Location along the crest line appears to be a better guarantee of productivity than any stimulation technique.

These results suggest that the hydraulically-induced fractures are not connecting additional fracture systems to the wellbore. Instead, the local stress field which controls the permeability of the fractures in the subsurface (i.e., those fractures paralleling σ_1 are thought to be more permeable) also controls the orientation of the hydraulically-created fracture. Thus, the natural and man-made fractures parallel each other. These circumstances inhibit the opportunity of the hydraulic fracture to increase productivity.

#19 BBFU Frontier Core: Parameters, and Petrographic and Fracture Description

The Frontier sands are low in matrix permeability. Geometric average permeability for the 2nd and 3rd Frontier sands from the #19 BBFU well is only 0.074 millidarcies (to nitrogen), with a range from 0.005 to 1.094 millidarcies (Figure 10). Average core porosity is 9.162%, and ranges from 5.012% to 12.407%. Density-log porosity (Figure 11) recorded values between 12-1/2% to 16-1/2% (for matrix density equal to 2.65 gm/cc). (Higher density-log porosity values in the 3rd Frontier may be invalid due to poor pad contact with the wellbore, possibly caused by a rough hole due to fracturing. The significant corrections in $\Delta\rho$ (i.e., DRHO) suggest this may be the case.) Initial petrographic work by TerraTek on one thin section from the 3rd Frontier indicated that pores types are mostly micropores (pore throats less than 5 microns) with some small mesopores (pore throats 5 to 15 microns) created by dissolution of unstable grains and calcite cement. Mechanical compaction of labile grains, primarily sedimentary lithic rock fragments of illitic and chloritic shales and minor micas, produced a pseudomatrix which has significantly reduced the matrix permeability.

Subsequent petrographic analysis has been done for Sierra Energy Company by Eby Petrography & Consulting Inc. Five oriented thin sections across known fractures in the 2nd Frontier sandstone and one unoriented thin section from the 3rd Frontier sandstone were made from the #19 BBFU core. The purpose of this study was to determine the mineralogy and extent of fracture-fill within different fracture sets, as well as to compare and contrast diagenetic history and types of porosity found in matrix both adjacent to and distant from the fractures.

The examined sandstones were feldspathic litharenites (Figure 12) to lithic arkoses. The pseudomatrix produced by the compacted lithic rock fragments gives the appearance of textural immaturity, though the samples lack notable mud matrix and are moderately well sorted. A significant observation was the fresh, relatively unaltered state of the chemically unstable feldspar and lithic grains (e.g., plagioclase and chert). Apparently, burial occurred rapidly, protecting these easily altered grains. Destruction of primary porosity is due primarily to mechanical compaction preceded by minor silica cementation, which, in combination, produced a tight, interlocking fabric (Figure 13). Present porosity is solely secondary in natural. It consists of dissolution of grains and silica cement, and is best developed adjacent to the fractures. The secondary porosity appears to form a crude grid-like network surrounded by tightly cemented, fresh sand (Figure 14). Certain fractures, possibly controlled by orientation to the stress field, have open porosity along their traces (Figure 15). Some fractures show dissolution of calcite fill and adjacent grains. (TerraTek also noticed that calcite-filled fractures experienced a later stage of fracture development and minor dissolution along these second-generation fractures.) Other fractures are partially to completely filled with calcite (Figure 16) and possibly silica. A possible explanation for this porosity style is that the open fracture network controlled the movement of corrosive organic acids in the Frontier sands just prior to the generation and migration of hydrocarbons. Thus, dissolution of grains and cement occurred preferentially along and adjacent to permeable fracture pathways, leaving many areas of the rock unaltered and tight. This type of porosity network may not develop as high a storage volume as those rocks altered throughout their volume. But, the fracture-controlled porosity may be better connected, providing higher permeability and greater drainage in the portions of the rock where it is developed.

However, based on core work, it is open to question if fractures will provide vertical permeability over significant intervals (i.e., ± 10 feet), penetrating variable lithologies and diagenetic boundaries. For example, a potential barrier to vertical fluid flow is the development of horizontal stylolites caused by pressure solution. Examples were seen where subvertical fractures terminated at horizontal stylolites.

Fractures in the 2nd Frontier core (Figures 17 through 25) have been described by John Lorenz, of Sandia National Laboratories. He made the following observations about the fractures. There are four fracture sets in the core. Set 1 consists of petal and centerline fractures induced during coring with an assumed constant orientation controlled by the present-day stress field. Set 2 consists of vertical, mineralized and unmineralized fractures, oriented 90 degrees to the coring-induced fractures of set 1. Set 3 consists of vertical, mineralized fractures approximately 45 degrees to set 1. Finally, set 4 is a set of diagonal-shear fractures, with both normal and reverse dip-slip offset and mineralized and unmineralized surfaces, which strike parallel to the coring-induced fractures.

It is believed that the orientation of the fracture sets relative to the present-day stress field has an important effect on the reservoir permeability, which directly controls the producibility of the reservoir. The fracture set which is most closely oriented to the present maximum horizontal stress is the most likely set to be open in the reservoir, providing the greatest permeability. Thus, fracture set 4 which strikes parallel to the coring-induced fractures, that is, parallel to the present maximum horizontal stress, would be the primary target for any drilling on this structure. Fracture set 3, which strikes 45 degrees to fracture set 1, may also provide significant permeability in the subsurface.

However, 2nd and 3rd Frontier core from the #19 BBFU well (Figure 26) was unoriented. Orientation techniques have been devised using paleomagnetic capabilities. Because of the importance of knowing fracture azimuths, Sierra Energy used Applied Paleomagnetics, Inc. of Redmond, Washington to orient this core. Orientation of fitted core segments and fractures contained within these segments was successfully accomplished in January 1992. Surprisingly, both coring-induced and natural fractures showed a dominant NNW trend (Figure 27). The petal/centerline coring-induced fractures (Figure 28) formed a bimodal pattern, with 62% striking NNW and 38% striking ENE. Further, 100% of the natural subvertical fractures (Figure 29) and 80% of the non-vertical shear fractures (Figure 30) were consistently oriented NNW, subparallel to the axial trace of the anticline.

One can infer from the dominant NNW trend of the fractures that the local stress field is oriented such that the maximum principal stress, σ_1, parallels the axial crest of the structure. However, the present-day maximum stress on the overall anticline may still be oriented

ENE/WSW, parallel to 38% of the coring-induced fractures and 20% of the shear fractures. The predominance of coring-induced fractures oriented NNW may be due to a preexisting rock fabric caused by fracturing that formed in response to the local stress field found along the crest of the structure, with σ_1 (maximum principal stress) oriented parallel to the axial trace and σ_3 (minimum principal stress) perpendicular to it, both in the plane of bedding.

An important point to regard concerning the NNW orientation of the fracture trends in the 2nd Frontier core from the #19 BBFU well is that the productivity from this interval has been poor. Stabilized initial potential (I.P.) from the hydraulically-fractured (i.e., "frac'd") 2nd Frontier perforations was only 16 barrels of oil and 42 thousand cubic feet of gas per day. Production declined at the rate of 54% per year during the first year. Cumulative production after 5 years onstream is a meager 9,662 barrels of oil and 35,444 thousand cubic feet of gas. Current production is only averaging 2 barrels of oil and 9 thousand cubic feet of gas per day from the 2nd Frontier. The predominant fracture orientation would be detrimental to fluid flow if its azimuth is aligned perpendicular to the maximum horizontal stress. If the poor production is due to the NNW-trending fractures in the subsurface being closed, then this implies the orientation of the maximum horizontal stress is northeast-southwest. An alternate explanation of the 2nd Frontier sand's poor permeability would be that the well penetrated a fracture system that does not possess sufficient fracture density and lateral extent.

This later interpretation is supported by production testing of the 3rd Frontier in the #19 BBFU well, which indicated this sand possessed an economic level of permeability. A two-hour swab test after hydraulic fracturing recovered load fluid cut by 1% oil at the rate of 26 barrels of water per hour, an extrapolated rate of 624 barrels of fluid per day. Although the 3rd Frontier core was highly fractured to a greater degree than the 2nd Frontier core, most of the fractures were unmineralized. These nonmineralized fractures were primarily vertically oriented, and were either coring-induced centerline or natural fractures. The few examples of shear fractures seen were poorly developed compared to the shear fractures in the 2nd Frontier. The absence of identifiable coring-induced <u>petal</u> fractures precluded the ability to distinguish between the natural or coring-induced origin of these vertical fractures, as was done in the 2nd Frontier core because of the perpendicular relationship of the petal/centerline and unmineralized fractures. The decision was made not to paleomagnetically orient the 3rd Frontier core because of the difficulty in piecing together sufficiently long continuous intervals. (Only a 17" interval at the top of the core could be fitted together.) One can only speculate whether the fractures in the 3rd sand are principally oriented in an ENE direction, parallel to the assumed regional bearing of the maximum horizontal stress field, or NNW, as seen in the 2nd Frontier.

Additional Information on Preferred Flow Direction

Outcrop measurements of fracture orientations (Figures 31 through 33) at Badger Basin Field corroborate the paleomagnetic measurements in the Frontier core. Two directions of fractures dominate. These trends (Figure 34) range from NW to NNW, that is, subparallel to the axial trace, to NNE to ENE, which approaches perpendicular. The predominance of the fracture sets varied in the three measured outcrop areas. These results are supported by geologic studies of the Sheep Mountain anticline (Harris, Taylor and Walper, 1960; and, Johnson, Garside and Warner, 1965), located in the northeast part of the Bighorn Basin. Two main fractures sets are developed at Sheep Mountain, trending parallel and perpendicular to the axis of the anticline. Thus, surface information can only limit preferential flow to two directions.

Results of pressure-interference testing at six Bighorn Basin anticlinal fields has been published by Haws and Hurley (1992). Their interpretation of the data shows that the preferential direction of fluid flow in these fields is northeast-southwest, that is, perpendicular to the axes of the anticlines. They also presented an interpretation of fractures detected by the Formation MicroScanner log and borehole breakout data that supports preferential flow across the axes of the anticlinal traps. The anticlinal axis at Badger Basin Field as well as those at the fields studied by Haws and Hurley (Byron, Garland, Grass Creek, Little Sand Draw, and Oregon Basin fields) are all oriented northwest-southeast. Thus, the interpretation presented in this paper strongly suggests that fractures oriented in a northeasterly direction at Badger Basin Field will exert a preferred flow direction along their trend.

Pre 3D-Seismic Analysis of Badger Basin Structure

The pre 3D-seismic structure (Figure 34) at Badger Basin Field was interpreted using surface geology maps created from aerial photography, subsurface well-control, and two modern seismic lines oriented in a dip (BB-90-1) and strike (BB-90-2) position. The field produces from a doubly-plunging anticline, with an axial trace extending approximately 4-1/2 miles in a northwest-southeast direction. It is asymmetrical, with a steeper northeast flank dipping 15 degrees at the Frontier level, and the gentler southwest flank dipping 6 degrees. The northeast flank is controlled by a high-angle southwest-dipping reverse fault, which may cut beds as young as the Upper Cretaceous (Turonian to Coniacian Stage) Cody Shale. The Badger Basin anticline is cross-cut by normal faults that trend northeast in the Upper Cretaceous Mesaverde, Meeteetse and Lance Formations and the Paleocene Fort Union Formation. At the resolution of the present seismic data, most of these normal faults die out above the Cody Shale. However, one significant normal fault zone may have offset beds at least as deep as the Jurassic Sundance Formation. Missing section in the #4 and #6 BBFU wells shows that this fault has caused approximately 320' of vertical separation (approximately equal to the throw) at the Lance Formation, and 160' of vertical separation (approximately equal to the throw) at the deeper Cody marker.

The original structural interpretation of the 2nd Frontier sand, dated April 23, 1991 (Figure 34), had one normal fault cross cutting the doubly plunging asymmetric anticline just southeast of the #4 BBFU well. This interpretation was based on earlier synthetic seismograms that have been revised through the use of a more sophisticated software program. The new synthetics make it apparent that the original reflector tied to the Frontier interval is actually the Cody marker. The new tie shows that the normal fault at the Frontier level has actually broken into two en echelon dipping segments. Thus, the April 23, 1991 map has been revised (Figure 35) to include the proper positioning of the normal fault based on the two 2D seismic lines, BB-90-1 and BB-90-2. A NW-SE structural cross-section (Figure 36) drawn along BB-90-2 (Figure 37), which parallels the axis, ties together the seismic and subsurface control for the structural interpretation which existed prior to acquisition of the 3D seismic survey.

Productivity of the wells, based on cumulative production, was noted on the structural interpretation (Figure 38). The greatest production, both in terms of flow rates and cumulative yield, came from the #3 BBFU well, which is located on the downthrown (hanging wall) block immediately southeast of the normal fault zone and along the crest line. The #3 well reached total depth in the 3rd Frontier sand, or possibly into the uppermost few feet of the Mowry Shale. Excellent marker beds permit precise correlation of the Cody and Frontier formations in this well to nearby wells. There is no indication of missing section within these intervals. Thus, the normal fault zone must pass below the total depth of this well. However, if a vertical wellbore is assumed for the #3, then its bottomhole location, based on seismic line BB-90-2, would be in the faulted-out zone for the 3rd Frontier. This apparent contradiction between no missing section on the well log versus the apparent fault cut on the seismic can be remedied by assuming that the #3 wellbore deviated to the southeast, moving updip towards the rollover into the normal fault, and remaining in the downthrown block.

Six additional wells have produced over 115,000 barrels of oil each at Badger Basin. The best five wells (#2, #7, #9, #11, and #12 BBFU) are all located along the crestal trace of the anticline. One well is in the upthrown block (#2 BBFU), while the remainder are all within the downthrown block. The field's second best producer, the #7 BBFU, is located just east of the #3. It is barely northeast of the crest line, and is probably still close enough to benefit from fracture porosity and permeability associated with the normal fault Only one well, the #17 BBFU, is removed any significant distance from the anticlinal crest. It is located at the junction of the more gently dipping southwest flank and the southeast plunge of the structure. Although anomalous, its position may be on a secondary anticlinal nose that plunges due south off the main feature. Based on well control, the Badger Basin anticline possesses a broad or blunt southeast-plunging end, which could easily break into ancillary crest lines.

One further well of interest is the #16 BBFU. It is found on the gentle southwest flank of the structure, farther off the crest line than any other well. Yet, it is by far the best producer of any of these wells in terms of rates and yield. It has produced over 57,000 barrels of oil from the Frontier. The next best well on the southwest flank has only made 9,662 barrels of oil. The #16 is too far away from the normal fault adjacent to the #3 well to account for its better production. A possible explanation for these observations may be the presence of a smaller displacement fault just to the northwest of the #16. Just such a fault can be seen on seismic line BB-90-2 southeast of the main normal fault. However, the fault can only be resolved down to the Eagle Sandstone. It may continue into the Frontier, but be below the minimum vertical offset needed to be seen on the seismic.

3D Seismic Survey

Though core analysis provides important information about fractures, it is unable to indicate the areal distribution of the fracture systems in the reservoir. These data are critical in determining areas of potentially undrained reservoir. A 3D seismic survey can help determine fracture distribution. It provides a detailed, higher-resolution picture of the normal faults, which may be genetically related to fractures. 3D seismic also allows analysis of amplitude response along individual reflections. Low amplitude may be an indication of fracturing. Thus, low amplitude trends can be mapped to emulate fracture trends. Combining the position of the normal faults with areas of low amplitude may provide the best picture of fracturing within the reservoir.

Requests for bids for acquisition of an approximately 17 square-mile 3D seismic survey were sent out to eight companies. Bids from four contractors were received, ranging from $202,664 to $496,693 for comparable programs. Geophysical Systems Corporation's bid of $202,664, accepted September 15, 1992, was 32% less than the second lowest bid of $297,000. The use by Geophysical Systems of sign-bit recording contributes significantly to their lower acquisition costs. At Badger Basin, the sign-bit recording system provided data equal in quality to that achieved with conventional recording systems (e.g., used in recording lines BB-90-1 and BB-90-2) at a notably lower cost. Thus, where good quality data can be achieved with sign-bit, its economy can positively impact the use of 3D seismic by independents.

Production shooting by Geophysical Systems began April 10, and was completed May 18, 1993. Acquisition required 25 shooting days, averaging 46 vibrating points (VP's) per day. The following list summarizes general parameters of the seismic program.

SURVEY SIZE: 17.0625 sq. mi. (17,160' x 27,720')
CONTRACTOR: Geophysical Systems Corporation (Pasadena, CA)
RECORDING INSTRUMENT: 2,048-channel GEOCOR IV Model 2 (sign-bit recorder)
ENERGY SOURCE: Vibroseis
VIBRATORS: 4 Litton Model 311 in box pattern, unless prohibited by topography; remained stationary at VP during sweeps
NUMBER OF SWEEPS: 8 per VP
SWEEP FREQUENCIES: 12-26-100-132 hertz Varisweep™ composite (Varisweep™ is a Geophysical Systems' proprietary technique for clarifying the correlation wavelet by using different parameters for each sweep at a single source point
SWEEP LENGTH: 12 seconds
RECORD LENGTH: 4 seconds
SAMPLE INTERVAL: 2 milliseconds
CORRELATED RECORD: 4 seconds
GEOPHONES: 6 per channel
RECEIVER GROUP (GEOPHONE) ARRAY: potted in a 1- to 2-foot diameter circle
RECEIVER GROUP INTERVAL: 165'
RECEIVER LINE SPACING: 660'
ACTIVE CHANNELS PER LINE: 104
ACTIVE LINES: 10
TOTAL ACTIVE CHANNELS PER RECORD: 1,040
SOURCE INTERVAL: 330'

SOURCE LINE SPACING: 1,320'
TOTAL RECEIVER POINTS: 4,472 planned, 4,464 actual
TOTAL VIBRATING POINTS: 1,183 planned, 1,148 actual
BIN SIZE: 82.5' by 82.5' (with offset chatter), 82.5'$_{\text{Receiver}}$ by 165'$_{\text{Source}}$ (without offset chatter)
NOMINAL FOLD: 16 to 20 in main survey area

Four bids were received for processing, ranging from $37,560 to $57,556. Vector Seismic Data Processing, Inc.'s bid of $37,560 was selected, and processing began in May 1993. Completion occurred September 8, 1993 with the delivery of migrated tapes. Processing consisted of demultiplex/reformat, 3D geometry assignment, preliminary data analyses, gain recovery, brute stacks, deconvolution, spectral balancing, 3D velocity analysis, surface-consistent 3D autostatics via Ronen-Claerbout method, preliminary stacks, final data analyses, NMO and trace mute applications, CDP correlation autostatics, final stacks, bandpass filter, trace balancing, 3D refraction statics and 2-pass finite difference migration.

Interpretation of the 3D seismic survey has begun on a Sun Sparcstation10 workstation (UNIX based), using Landmark Graphics latest version of Seisworks 3D software. The first step was to tie the key formations to the seismic reflectors by using synthetic seismograms. Then, normal and reverse faults were picked to constrain the productive structure. Six reflectors were picked on a 10 by 10 (inline by crossline) grid. An autopicking routine will be used to fill in the picks throughout the remainder of the survey for the three Frontier reflectors. Each crossline (NW-SE orientation, which is the preferred direction to identify the NE-SW trending normal faults) within the productive area of the field will then be checked for quality of the auto picks, and edited if necessary. Time-structure maps and amplitude maps will be constructed for the three Frontier reflectors. A conversion from time-structure to depth will be made. Using the structure maps, the location and wellbore paths for the slant and horizontal wellbores will be chosen.

REFERENCES

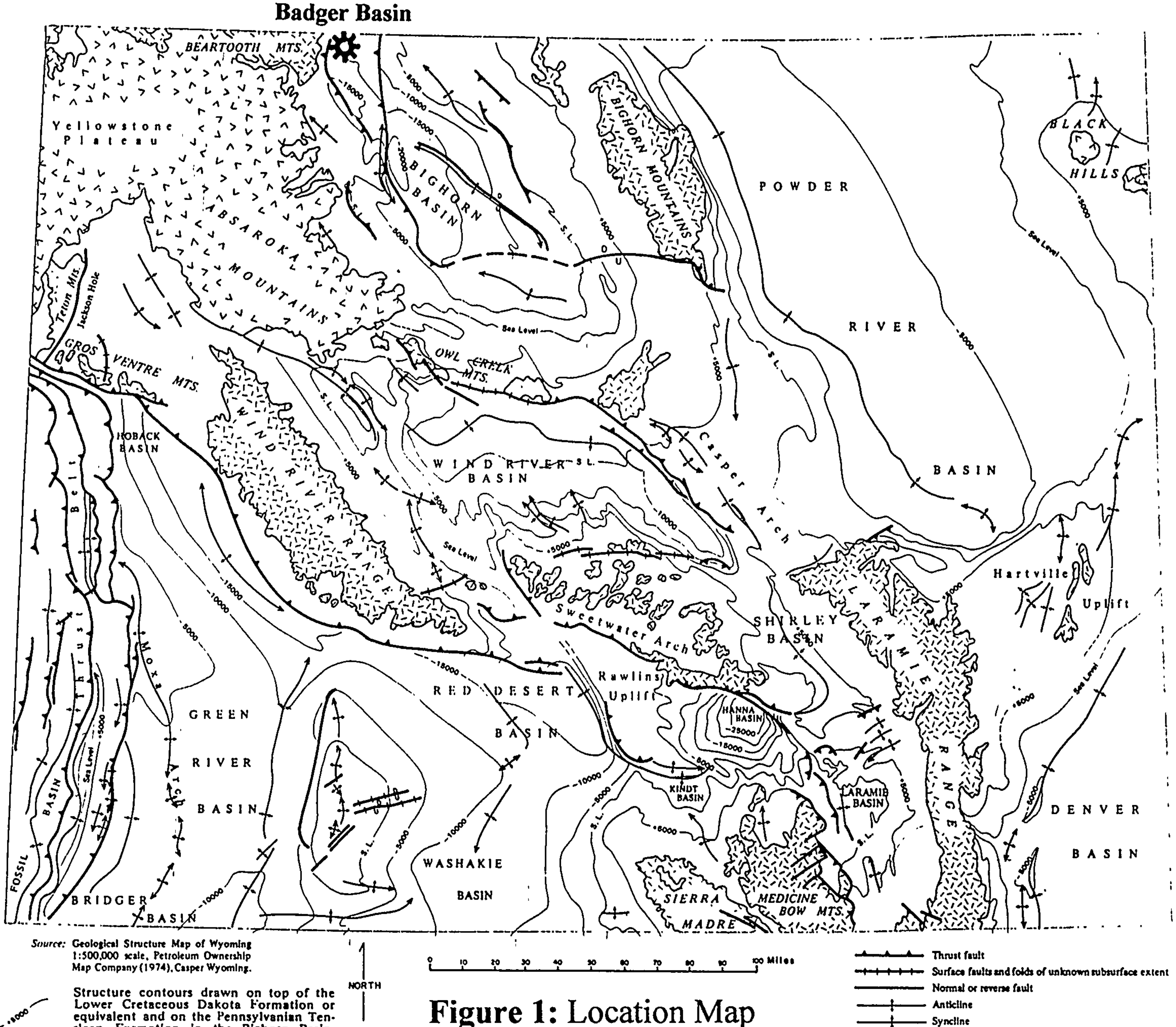
Harris, J.F., G.L. Taylor and J.L. Walper, 1960, Relation of deformational fractures in sedimentary rocks to regional and local structure: AAPG Bulletin, v. 44, p. 1853-1873.

Haws, G.W. and N.F. Hurley, 1992, Applications of pressure-interference data in reservoir characterization studies, Big Horn Basin, Wyoming: SPE Paper 24668, 67th Annual Technology Conference and Exhibition, SPE, Oct. 4-7, 1993, Washington, D.C.

Johnson, G.D., L.J. Garside and A.J. Warner, 1965, A study of the structure and associated features of Sheep Mountain Anticline, Big Horn County, Wyoming: Proceedings Iowa Academy of Sciences, v. 72, p. 332-342.

Appendix A - Figures

STRUCTURAL INDEX MAP



Source: Geological Structure Map of Wyoming 1:500,000 scale, Petroleum Ownership Map Company (1974), Casper Wyoming.

Structure contours drawn on top of the Lower Cretaceous Dakota Formation or equivalent and on the Pennsylvanian Tensleep Formation in the Bighorn Basin. (Contour interval = 5000 feet)

Figure 1: Location Map

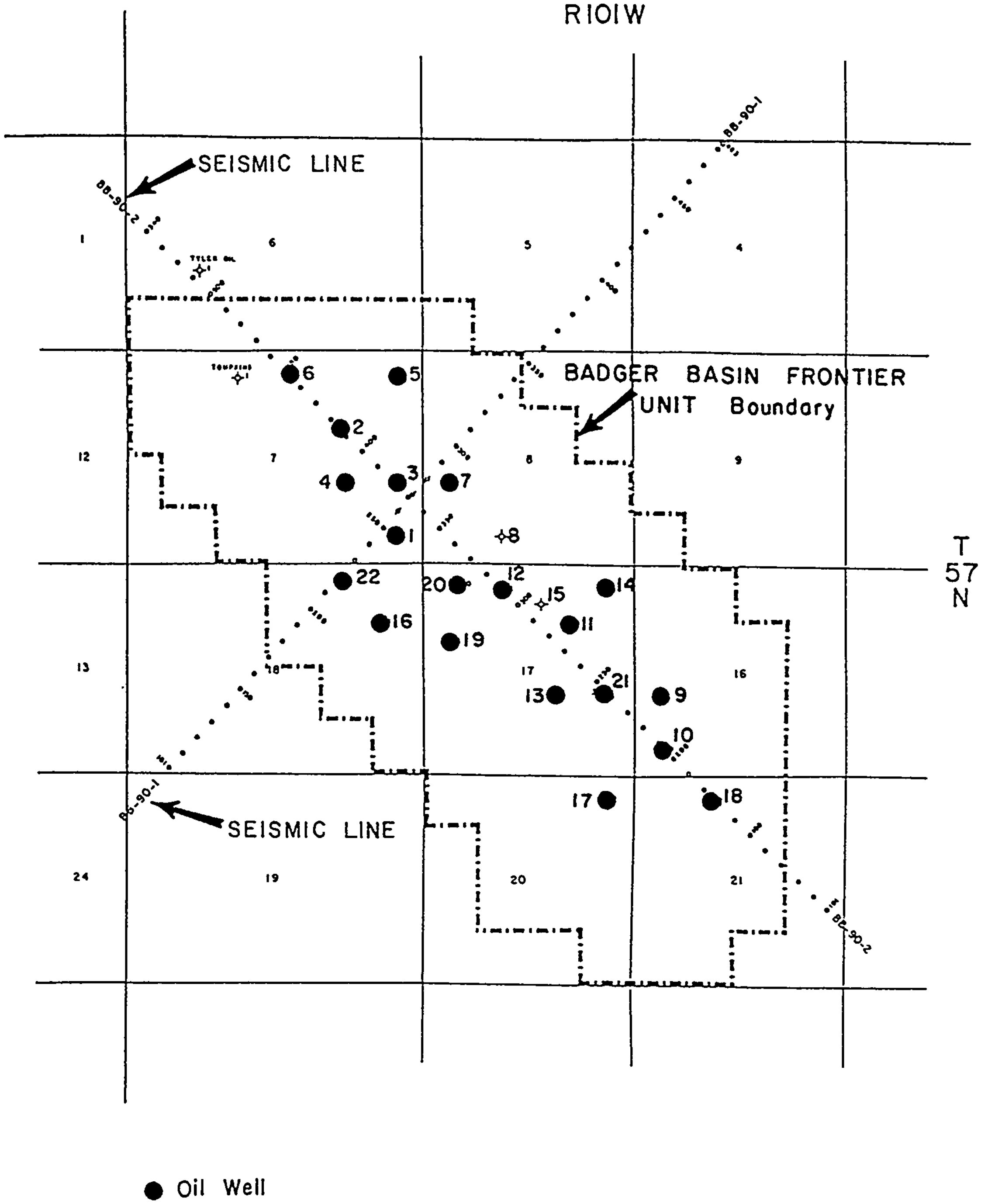


Figure 2: Base Map
Badger Basin Field
Park County, Wyoming
Scale: 1 inch = 4,000 feet

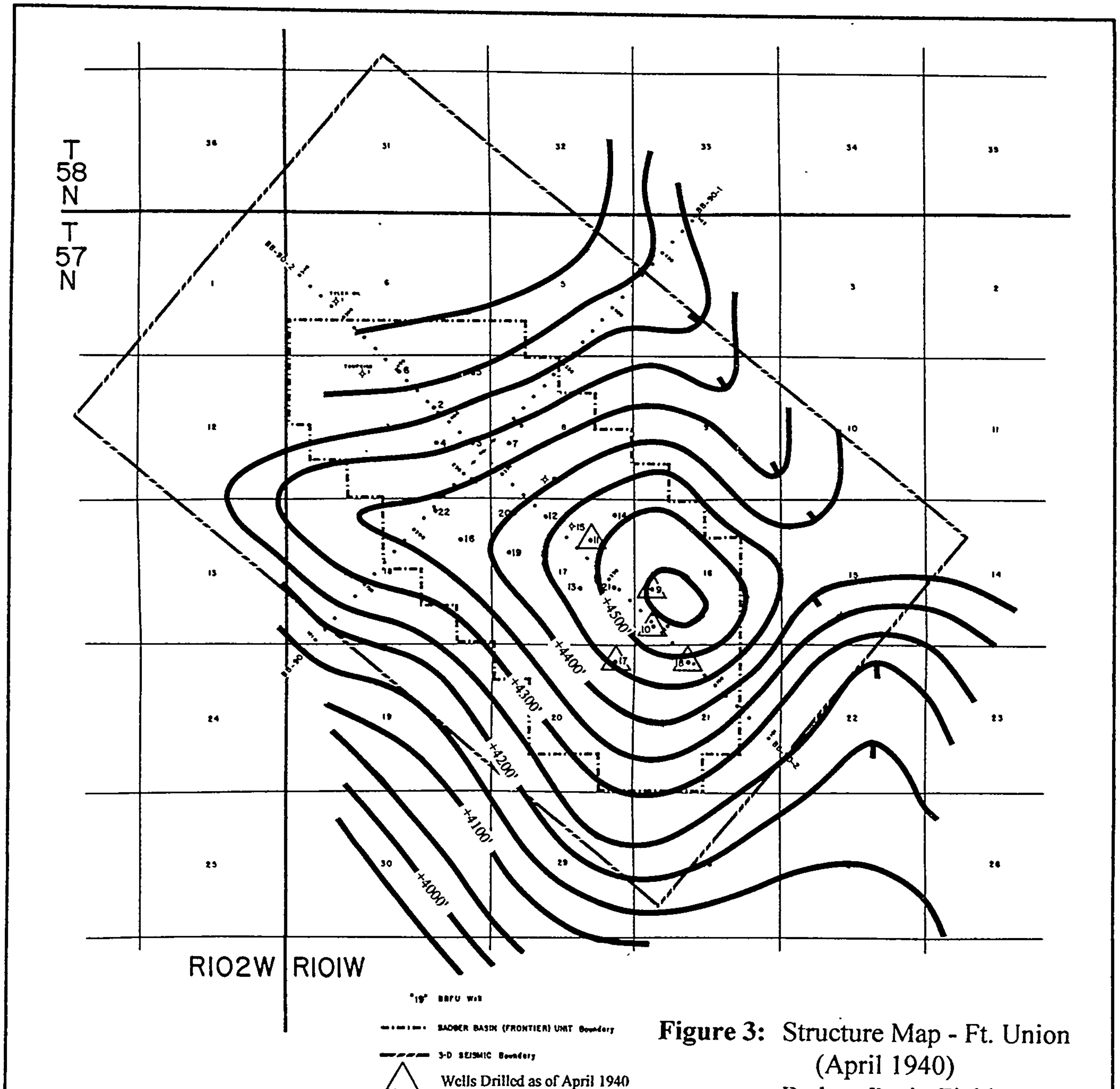


Figure 3: Structure Map - Ft. Union
(April 1940)
Badger Basin Field
Park County, Wyoming

C.I. = 50 feet
Scale: 1 inch = 5,300 feet

Mapped compiled from "Structure Map of Badger Basin Field" by Karl A.E. Berg, assisted by L.T. Christian and L.V. Mullen, for the Northern Pacific Railway Company, 1931 and 1935, corrected to April 1940.

As noted by Karl A.E. Berg, "Structure contours are drawn on sandy beds in Fort Union formation below lowest red shale exposed on Lot 3, Sec.18, T57N, R101W. These were carried around structure chiefly on structural rather than stratigraphic data and any faulting there may be could not be mapped with any assurance of reasonable accuracy."

STRATIGRAPHIC COLUMN
BADGER BASIN FIELD
Sections 7, 8, 16, 17, 18, 20 & 21, T57N, R101W
PARK COUNTY, WYOMING

	Age (Ma)	
QUATERNARY		
PLIOCENE	1.65	
MIOCENE	5	
OLIGOCENE	24	
EOCENE	38	
PALEOCENE	55	Ft. Union Fm.
UPPER CRETACEOUS	66	Lance Fm. Fox Hills Ss. Meeteetse Fm. Upper Mesaverde Fm. Lower Mesaverde Fm. Eagle Ss. Cody Sh. Frontier Fm. —1st Kf sd. —2nd Kf sd. —3rd Kf sd. Mowry Sh.
LOWER CRETACEOUS	96	Muddy Ss. Thermopolis Sh. Cloverly Group —Dakota - "rusty beds" —Dakota - "Greybull sd." —Fuson Sh. —Lakota (or Pryor) Cgl.
JURASSIC	138	Morrison Fm. Sundance Fm. Gypsum Spring Fm.
TRIASSIC	205	Chugwater Fm. Dinwoody Fm.
PERMIAN	240	Phosporia Fm.
PENNSYLVANIAN	290	Tensleep Ss. Amsden Fm.
MISSISSIPPIAN	330	Madison Ls.
DEVONIAN	360	Darby Fm. Beartooth Butte Fm.
SILURIAN	410	
ORDOVICIAN	435	Bighorn Dol.
CAMBRIAN	500	Gallatin Ls. Gros Ventre Fm. Flathead Ss.
PRECAMBRIAN	570	(metamorphics and igneous intrusives)

Figure 4

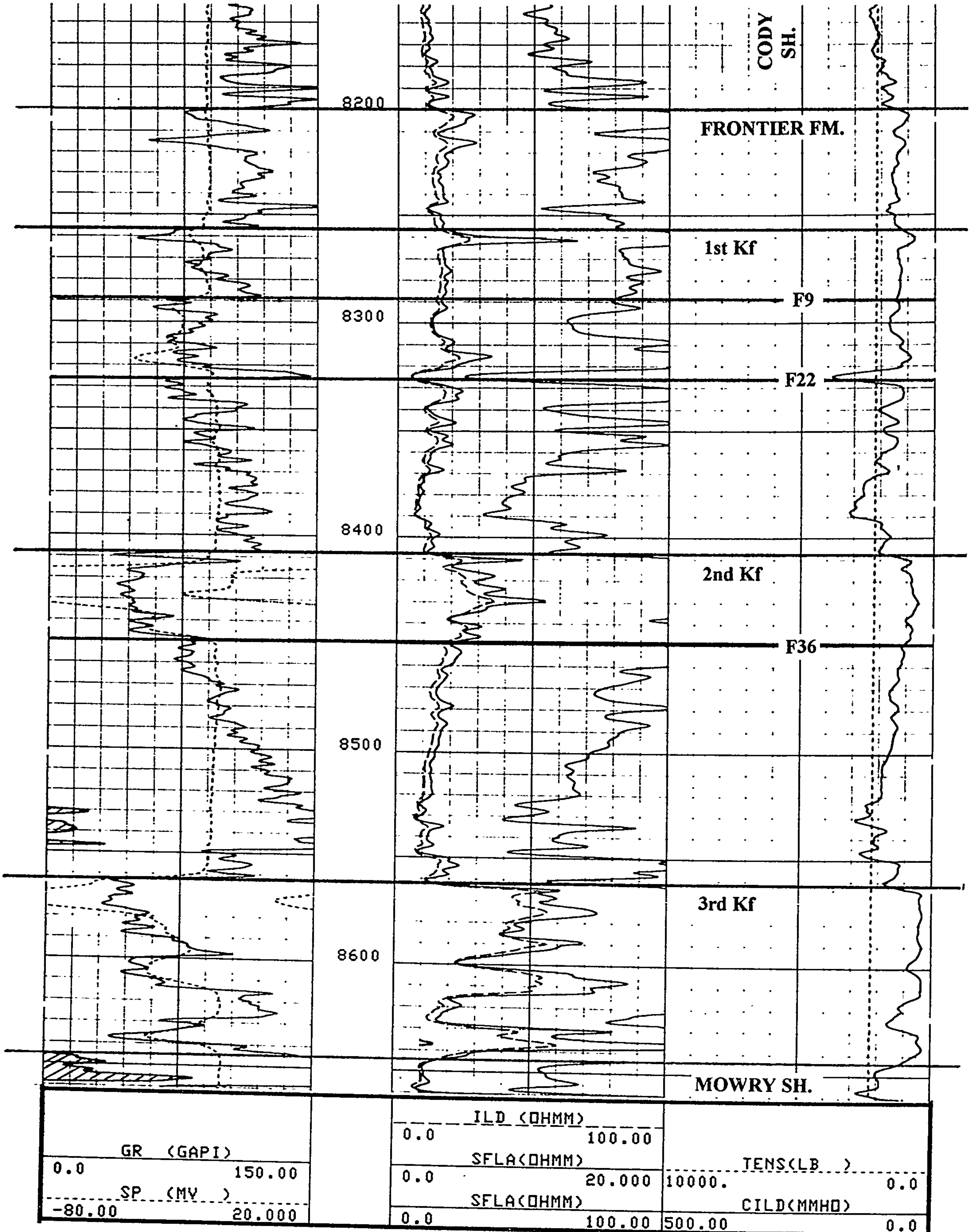


Figure 5: Type Log (DIL-SP-GR) for the Frontier Formation

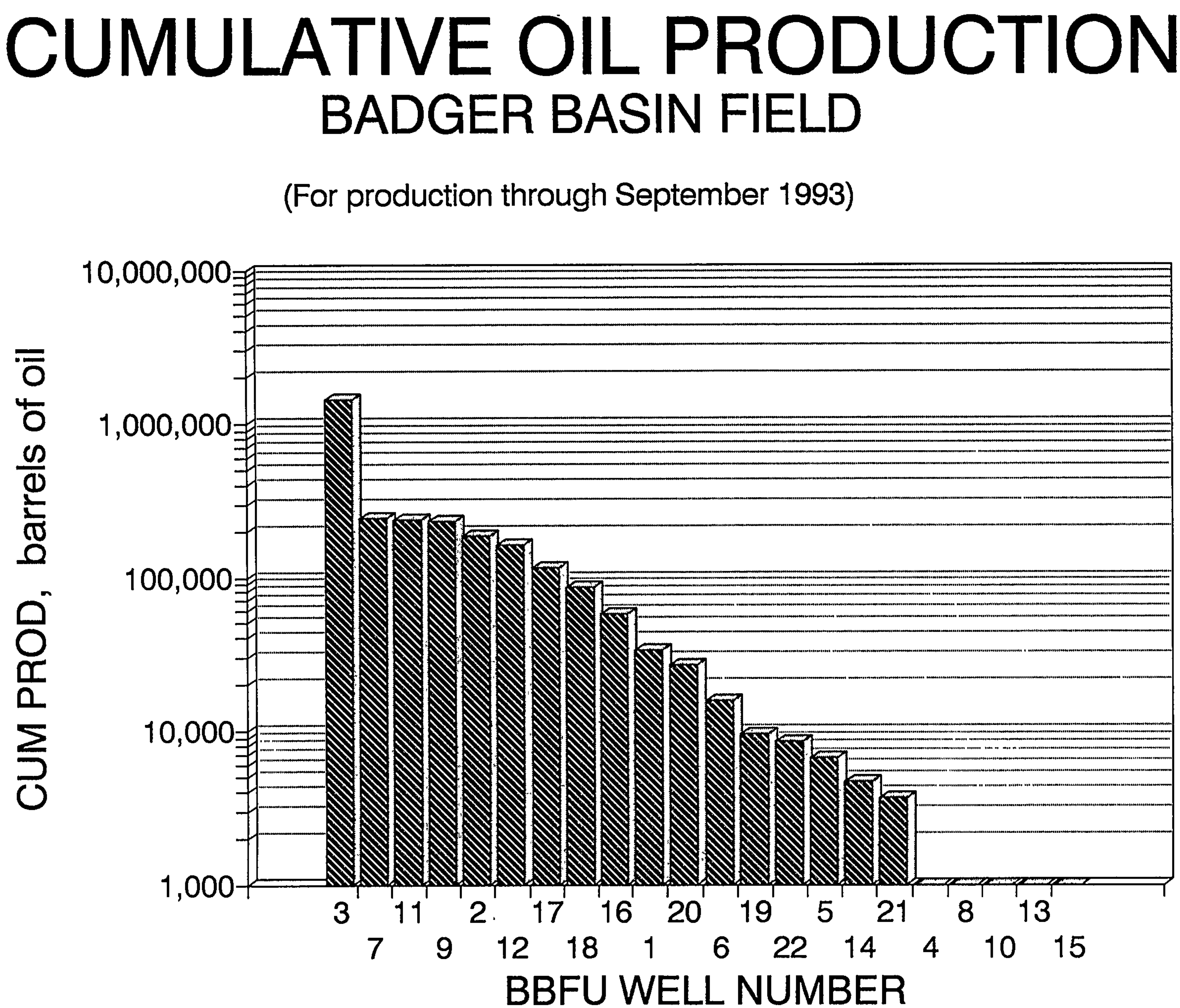

CUMULATIVE OIL PRODUCTION
BADGER BASIN FIELD
(For production through September 1993)
CUM PROD, barrels of oil
10,000,000
1,000,000
100,000
10,000
1,000
3
7
11
9
2
12
17
18
16
1
20
6
19
22
5
14
21
4
8
10
13
15
BBFU WELL NUMBER

Figure 6

P. O. BOX 582

YAPUNCICH-SANDERSON LABORATORIES

BILLINGS, MONTANA

5 & 9½ N. 25TH ST

LABORATORY REPORT

Lab. No. 1522-1

To Williston Oil & Gas Company Date 12-31-53

Address P. O. Box 411, Casper, Wyoming

CRUDE OIL ANALYSIS

Badger Basin, Park, Wyoming
Well No. Gov't 1B
Frontier

No. 7 BBFU
NW/4 SW/4
Section 8, T57N, R101W

GENERAL CHARACTERISTICS

API Gravity @ 60°F 50.3 Specific Gravity @ 60/60°F 0.778

Sulfur -0.1% B.S. & Water None Pour Point below - 75°F

Color Greenish Orange

Viscosity:

@ 60°F Saybolt -32 sec., Absolute 1.30 centipoises

@ 100°F Saybolt -32 sec., Absolute 0.99 centipoises

HEMPEL DISTILLATION

	Percent	Specific Gravity
Gasoline (392°F)	58.2	0.722
Kerosene Distillate (500°F)	12.1	0.826
Reduced Crude	25.6	0.880

Barometric Pressure 26.7 in. Hg

Remarks: Frontier Crude Oil

Figure 7: Oil Analysis

No. 5 BBFU Well

NE/4 NE/4 Section 7, T57N, R101W
Park County, Wyoming

Gas Analysis

	October, 1948		June, 1965		October, 1968	
Constituent	Mol%	G.P.M.	Mol%	G.P.M.	Mol%	G.P.M.
Nitrogen	0		5.14		1.62	
Carbon Dioxide	0		0		0.21	
Hydrogen Sulfide	0		0		0	
Methane	79.86		67.71		76.50	
Ethane	11.24		12.29		11.36	
Propane	5.5	1.506	8.54	2.39	6.25	1.732
Isobutane	0.79	0.257	3.00	0.981	0.83	0.273
N-Butane	1.64	0.516	1.46	0.460	1.74	0.552
Isopentane	0.35	0.128	0.29	0.106	0.59	0.217
N-Pentane	0.33	0.119	0.82	0.296	0.47	0.171
Hexanes Plus	0.29	0.134	0.75	0.323	0.43	0.199
Total	100.00	2.660	100.00	4.515	100.00	3.144
Gross BTU/cu ft @ Standard Conditions		1270		1324		1291
Specific Gravity		0.719		0.823		0.753
Tpc -						405° F
Ppc -						665 psia

G.P.M. = gallons of liquid at standard conditions per 1000 cubic feet of moisture-free gas at standard conditions

Figure 8: Gas Analysis

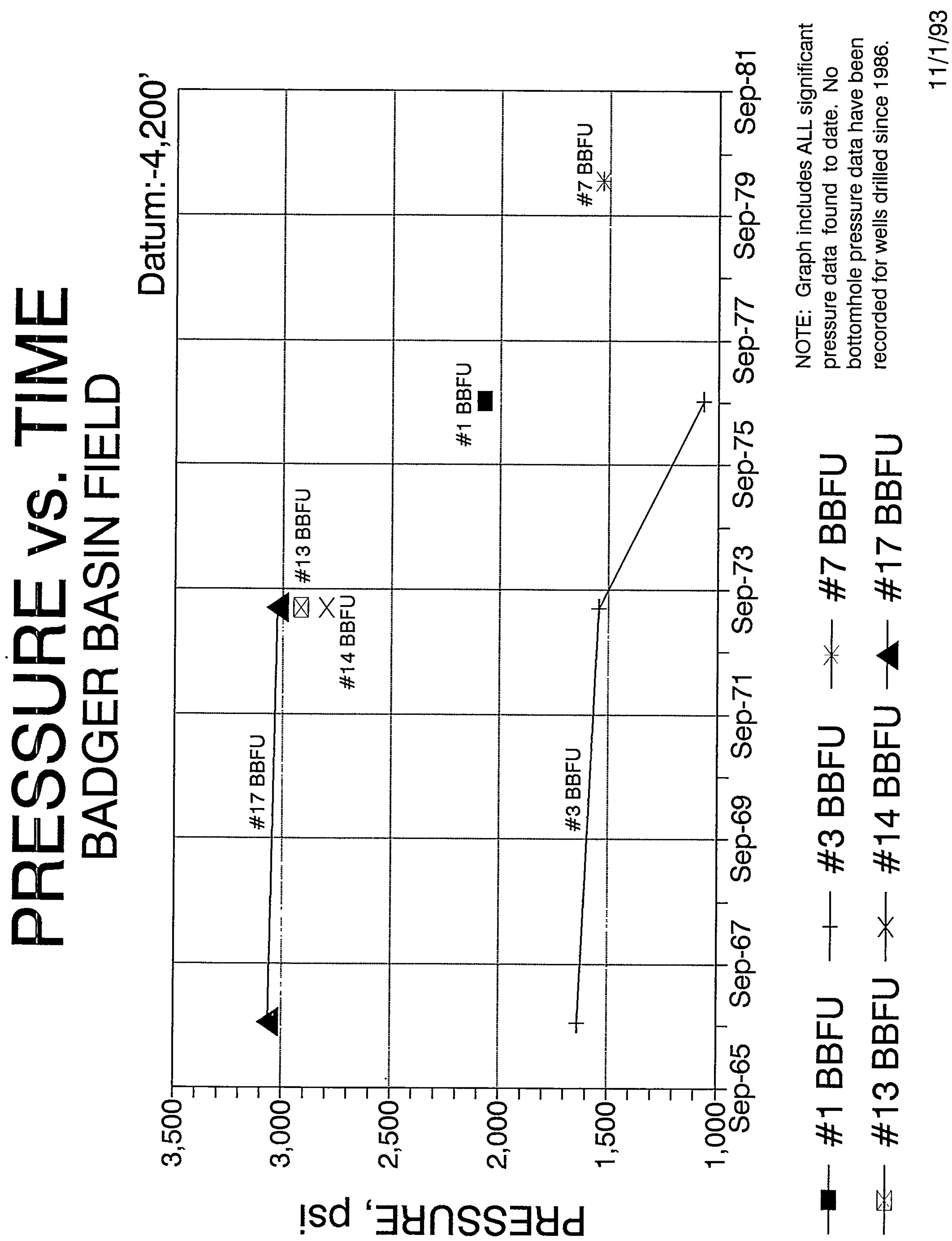

PRESSURE vs. TIME
BADGER BASIN FIELD
Datum:-4,200'
PRESSURE, psi
3,500
3,000
2,500
2,000
1,500
1,000
Sep-65
Sep-67
Sep-69
Sep-71
Sep-73
Sep-75
Sep-77
Sep-79
Sep-81
#17 BBFU
#13 BBFU
#14 BBFU
#3 BBFU
#1 BBFU
#7 BBFU
#1 BBFU
#3 BBFU
#7 BBFU
#13 BBFU
#14 BBFU
#17 BBFU
NOTE: Graph includes ALL significant pressure data found to date. No bottomhole pressure data have been recorded for wells drilled since 1986.
11/1/93

Figure 9

TerraTek Core Services, Inc.®

University Research Park · 360 Wakara Way · Salt Lake City, Utah 84108 · (801) 584-2480 · TWX 910-925-5284

HORIZONTAL PERMEABILITY
VS
POROSITY

SIERRA ENERGY COMPANY No. 19 BBFU
(original operator: FERNSTRUM ENERGY)
Badger Basin Field
Park Co., Wyoming
May 26, 1987

Depth Interval: 8421 to 8597 feet TTCS# 87151		
Porosity (phi),		
Min	Max	Average
5.012	12.407	9.162
Permeability (Kh), mD		
Min	Max	Geo. Ave
0.005	1.094	0.074
Equation of the Line log Kh = α phi + β log Kh = 0.2568 phi −3.4858 Correlation Coefficient : 0.921		
Frontier Formation		

[Porosity was determined by Boyle's law (helium) grain volumes and Archimedes (mercury) bulk volumes. Horizontal permeability to nitrogen was measured in a Hassler sleeve using an orifice-equipped pressure transducer to monitor downstream flow.]

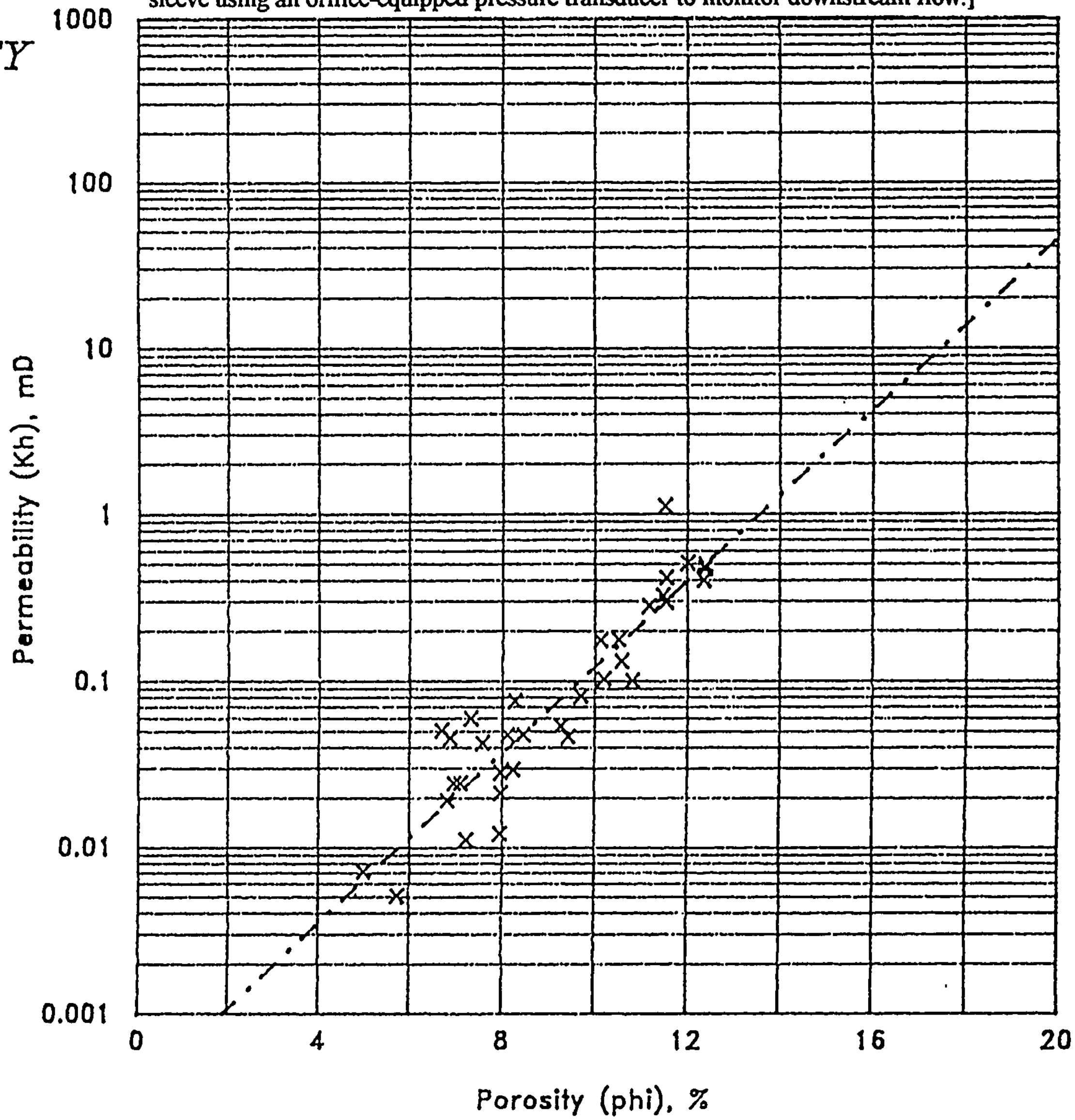
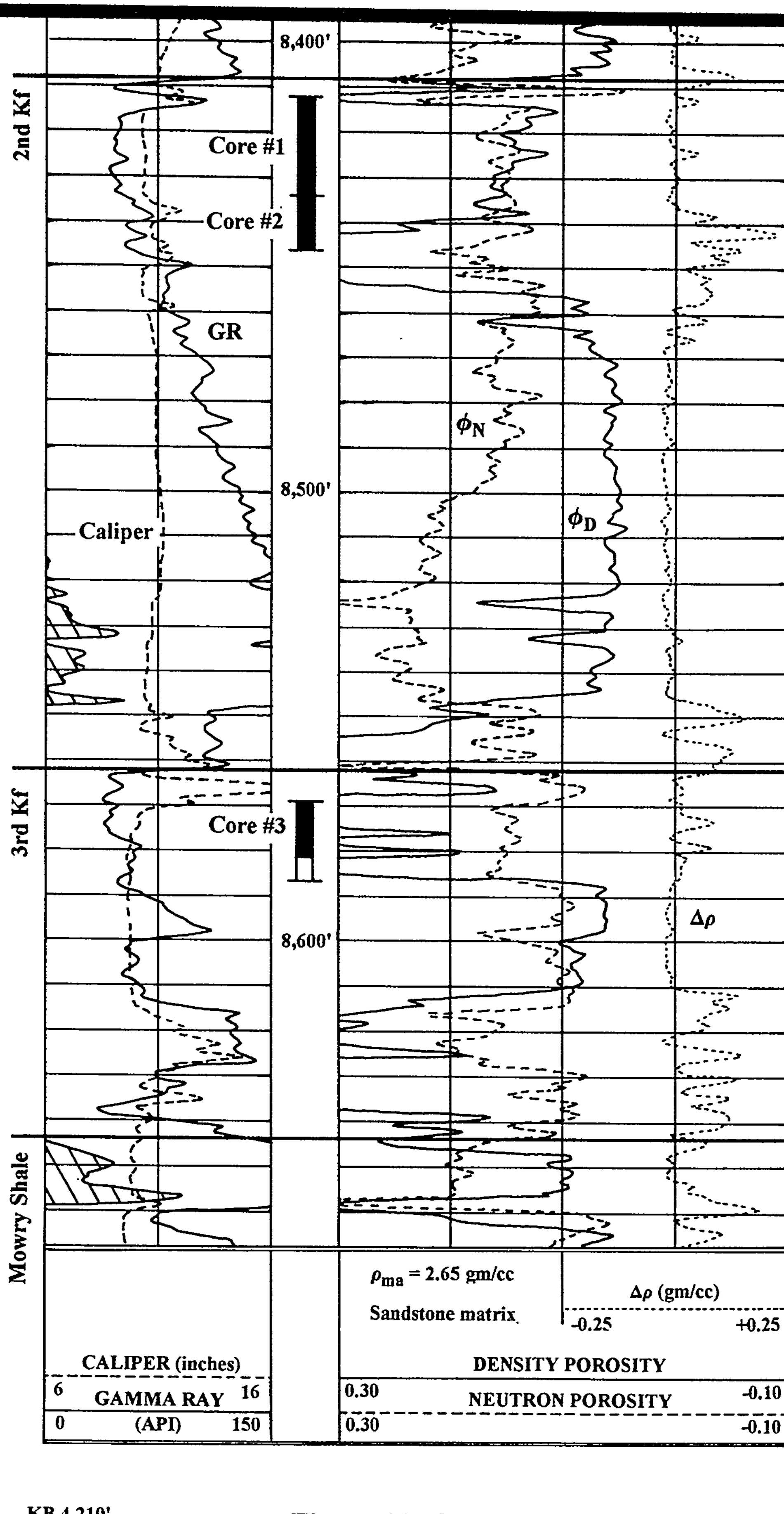


Figure 10



KB 4,210'
C SW/4 NW/4 Section 17
T57N, R101W
Park County, Wyoming

Figure 11: GR-Density-Neutron Log over the 2nd and 3rd Frontier sands, #19 BBFU well

Figure 12: Tight feldspathic litharenite. 8424.8', 2nd Frontier sand, #19 BBFU well. (Plane light) 1.0 mm

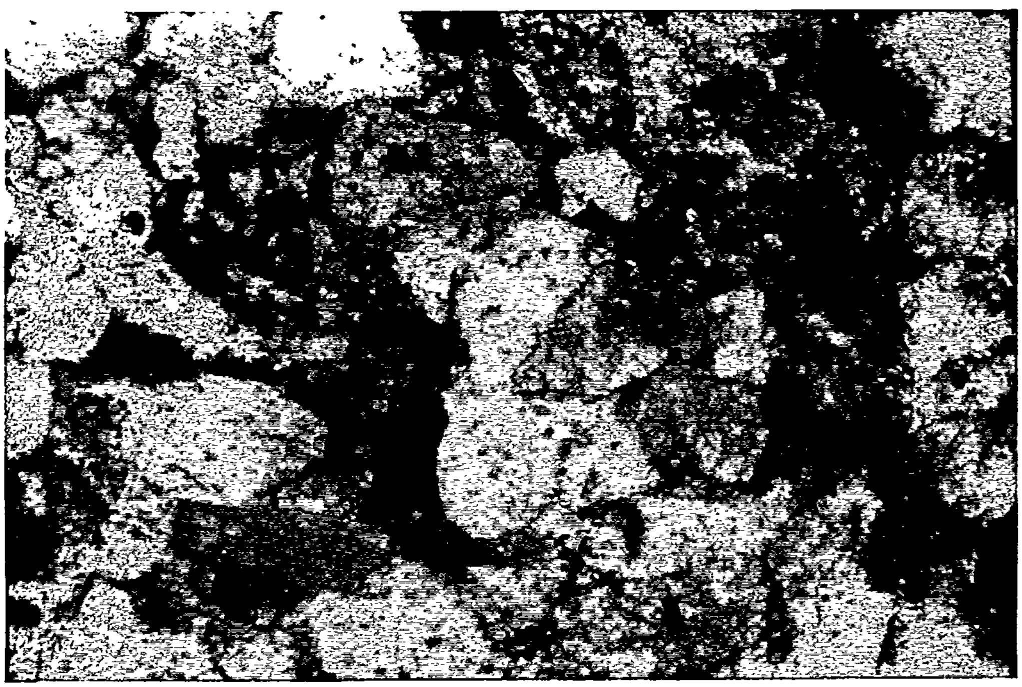


Figure 13: Tight, interlocking fabric of quartz, partially altered feldspars and volcanic-derived(?) grains. 8424.8', 2nd Frontier sand, #19 BBFU well. (Plane light) 0.1 mm

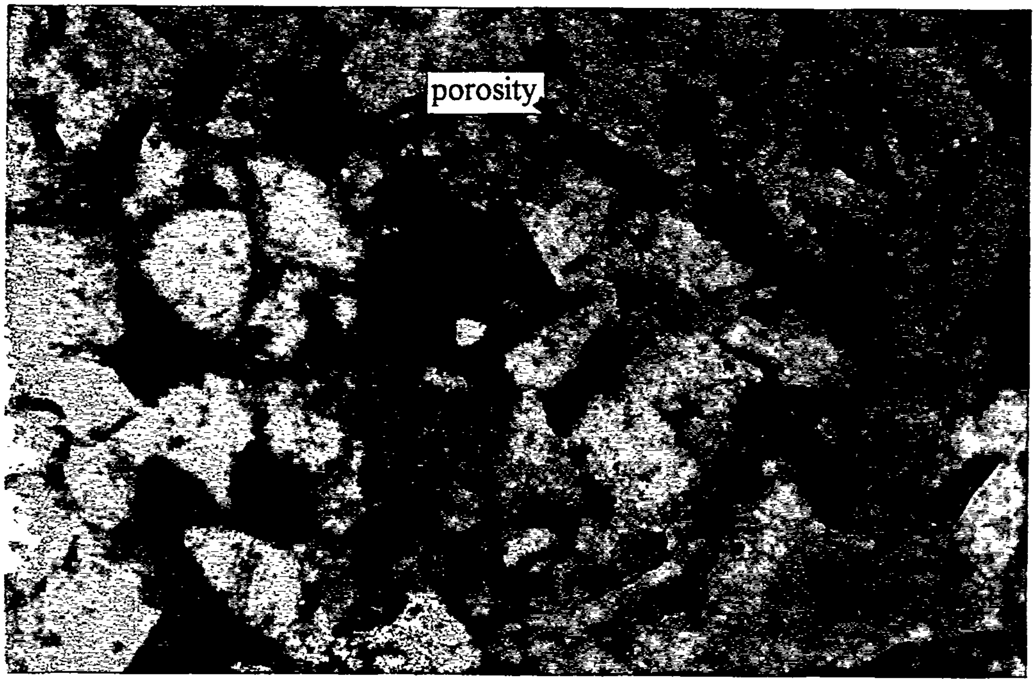


Figure 14: Better developed porosity (outlined) appears to form a gridwork around tightly cemented grains. Secondary porosity resulted from dissolution of grains and silicate cements. 8425', 2nd Frontier sand, #19 BBFU well. (Plane light) 0.1 mm

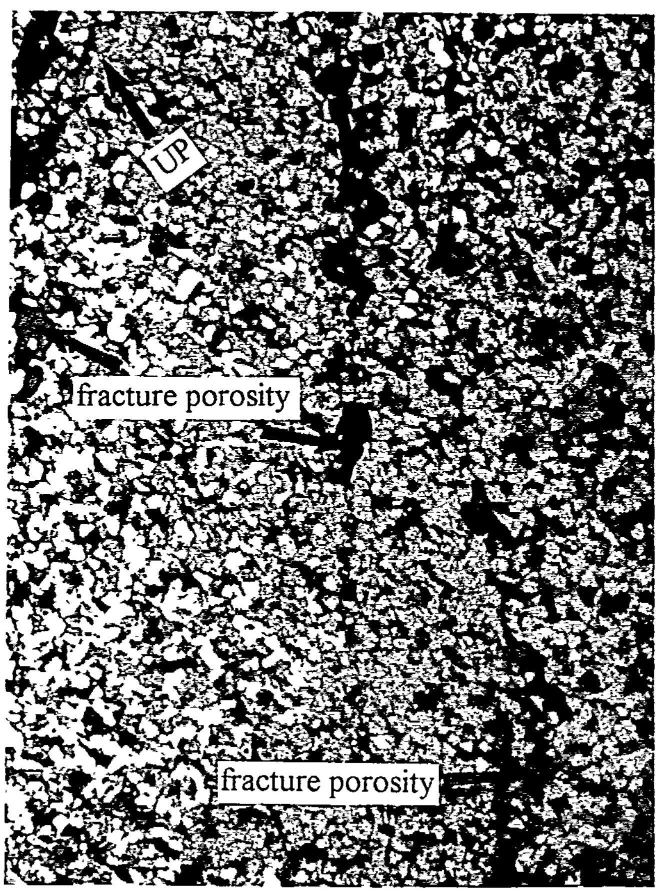


Figure 15: Swarm of subparallel open shear fractures. Arrow points upward. 8438', 2nd Frontier sand, #19 BBFU well. (Crossed nicols) 1.0 mm

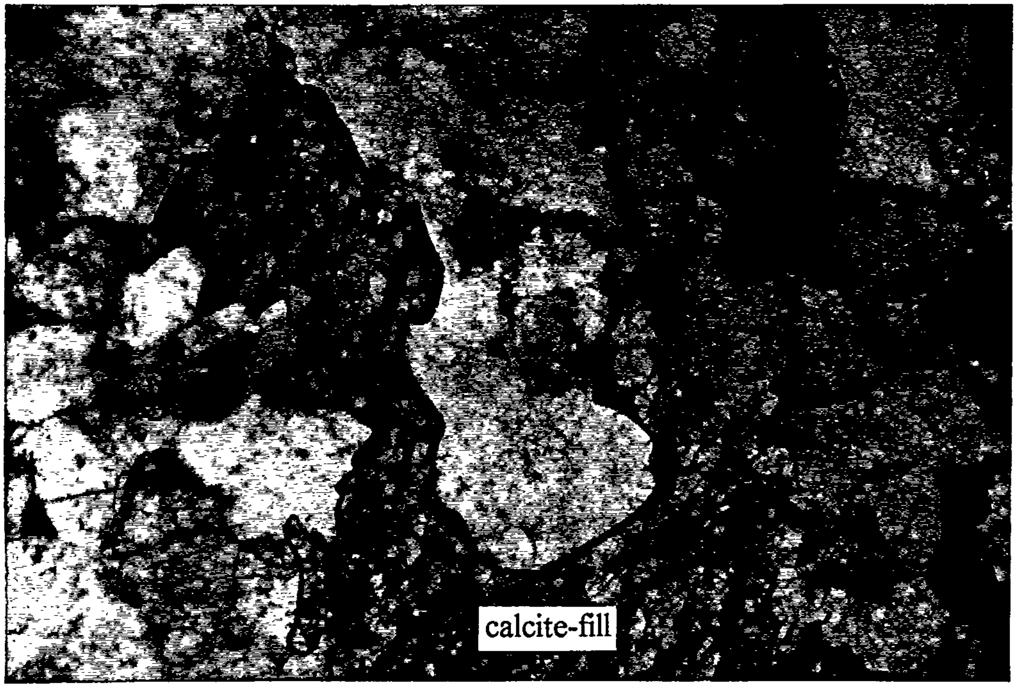


Figure 16: Calcite-filled fracture (outlined). 8425', 2nd Frontier sand, #19 BBFU well.

0.1 mm

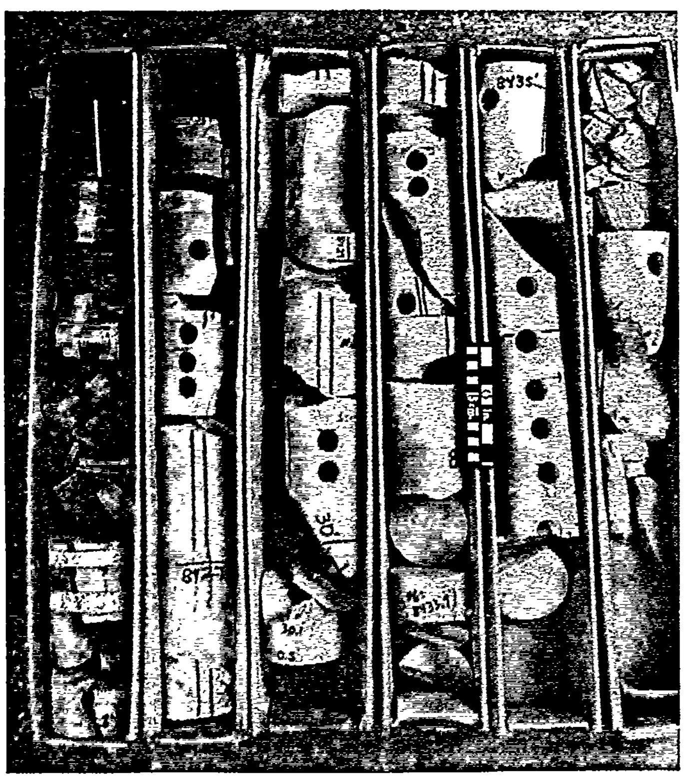


Figure 17: Core #1: 8,421' - 8,440', 2nd Frontier, #19 BBFU well.

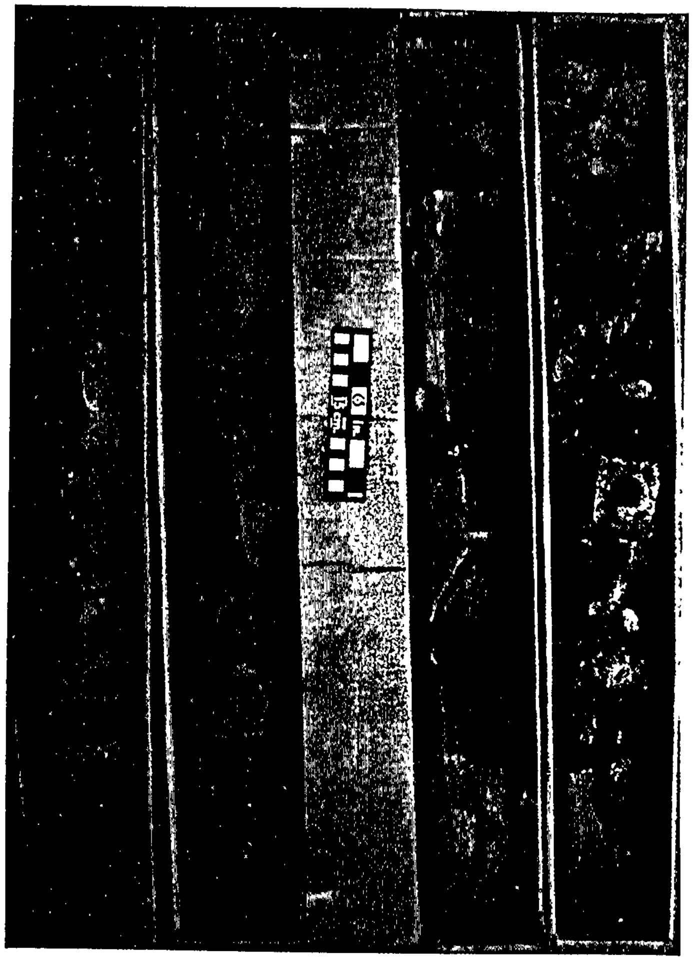


Figure 18: Core #2: 8,440' - 8,453', 2nd Frontier, #19 BBFU well. (Box 3 of 5 is missing.)

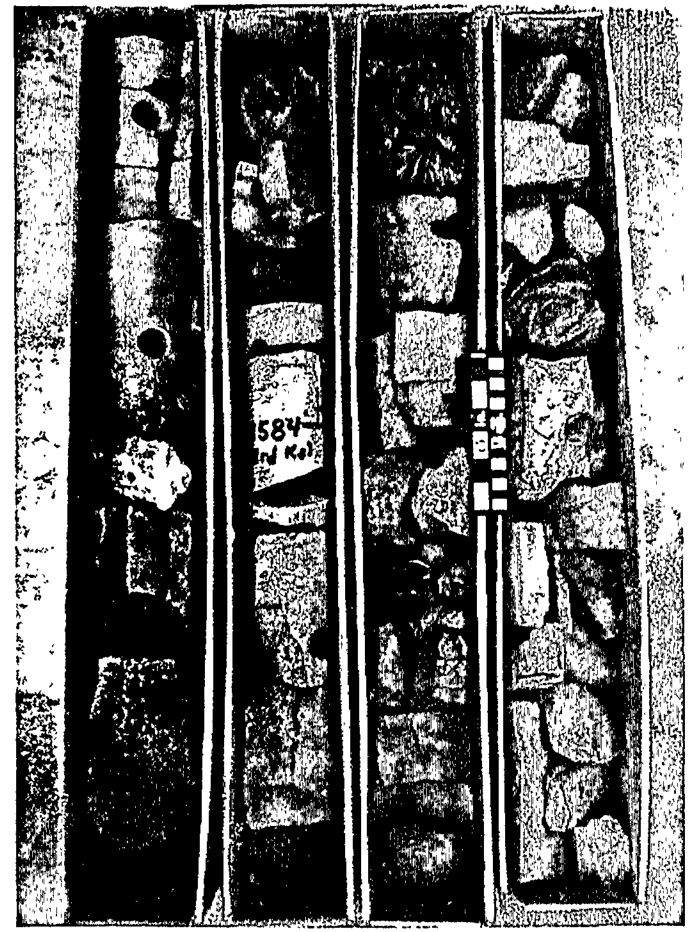


Figure 19: Core #3: 8,578' - 8,588', 3rd Frontier, #19 BBFU well.

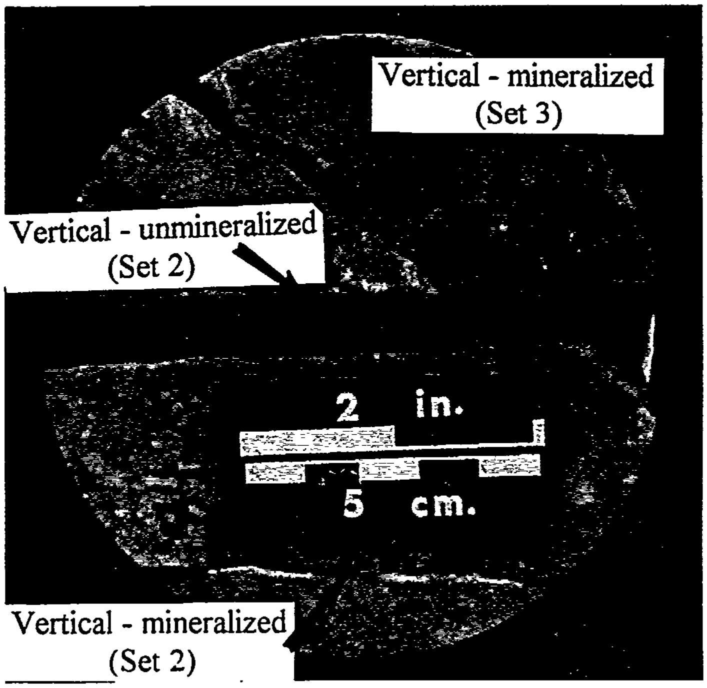


Figure 20: Lorenz' vertical fracture sets 2 and 3, mineralized and unmineralized, intersect at a 38° angle. 8423.5', 2nd Frontier, #19 BBFU well.

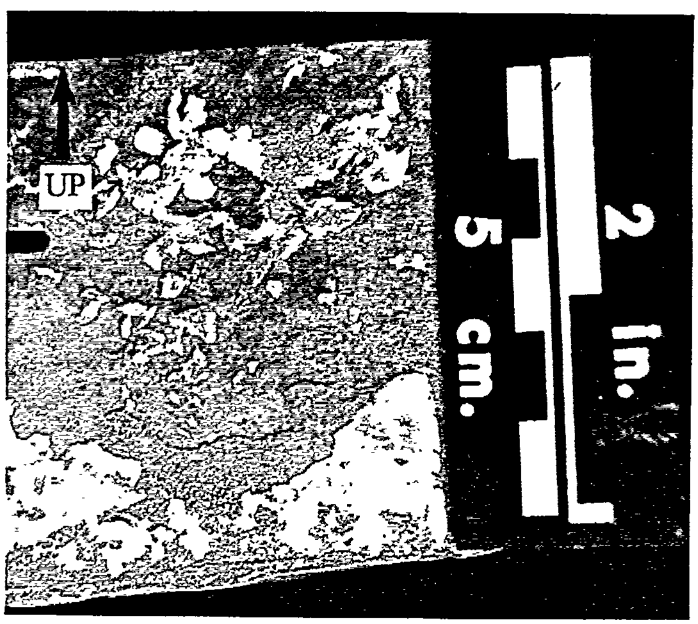


Figure 21: Calcite crystals on fracture face of Lorenz' vertical fracture set 2. Arrow point stratigraphically up. 8424.9', 2nd Frontier, #19 BBFU well.

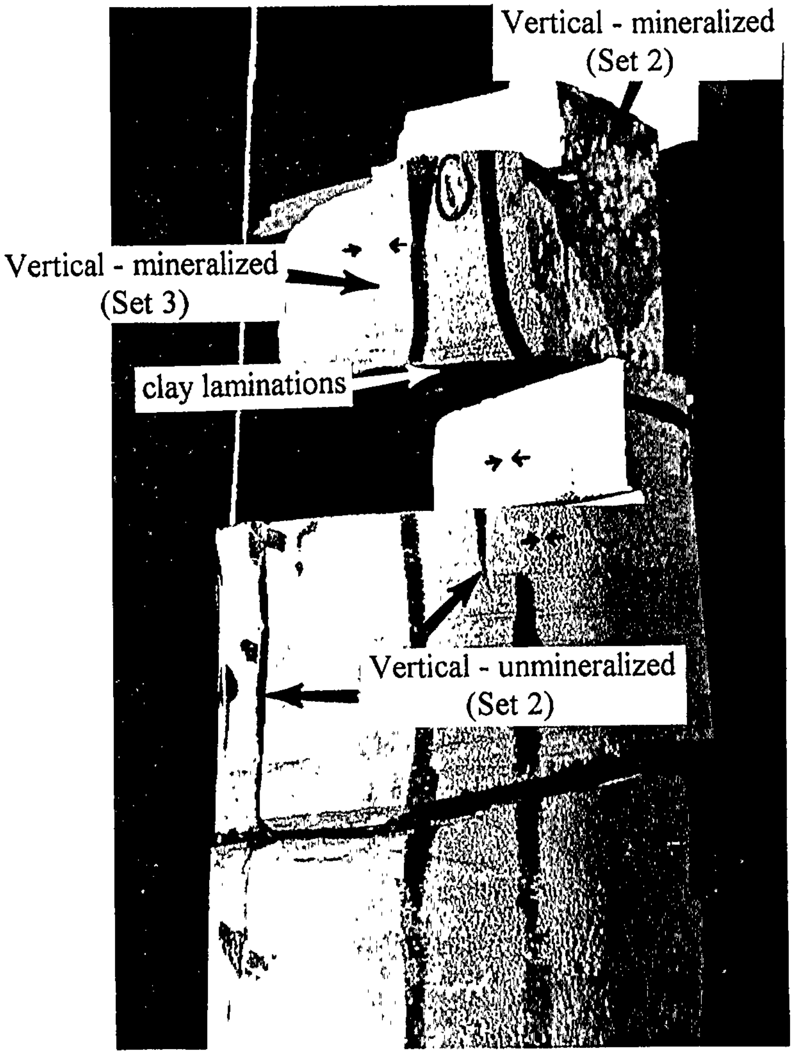


Figure 22: Lorenz' fracture set 2 (mineralized and unmineralized) trends N15°W and set 3 (mineralized, between opposing arrows) N60°W, based on paleomagnetic work. Petal fracture (set 1, on back of core) strikes N75°E. Fractures of sets 2 and 3 terminate against a zone of clay laminations from above and below. 8,425', 2nd Frontier, #19 BBFU well.

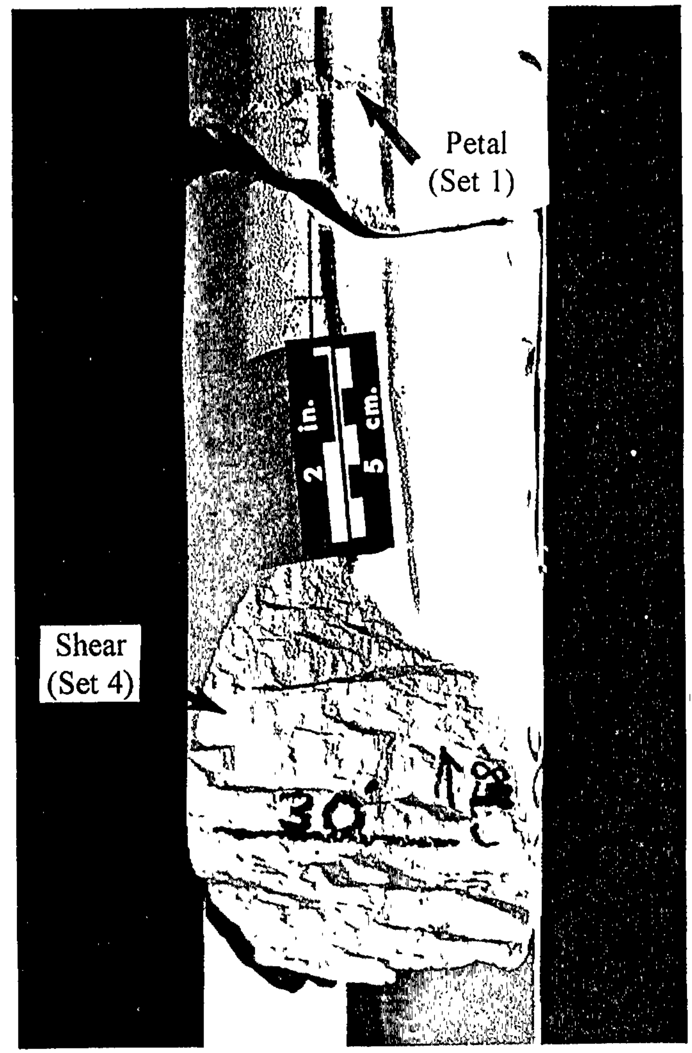


Figure 23: Lorenz' fracture set 1 (coring-induced petal fracture) and set 4 (diagonal shear) with reverse offset at bottom of core both strike N9°W. 8,429.2' - 8,430', 2nd Frontier, #19 BBFU well.

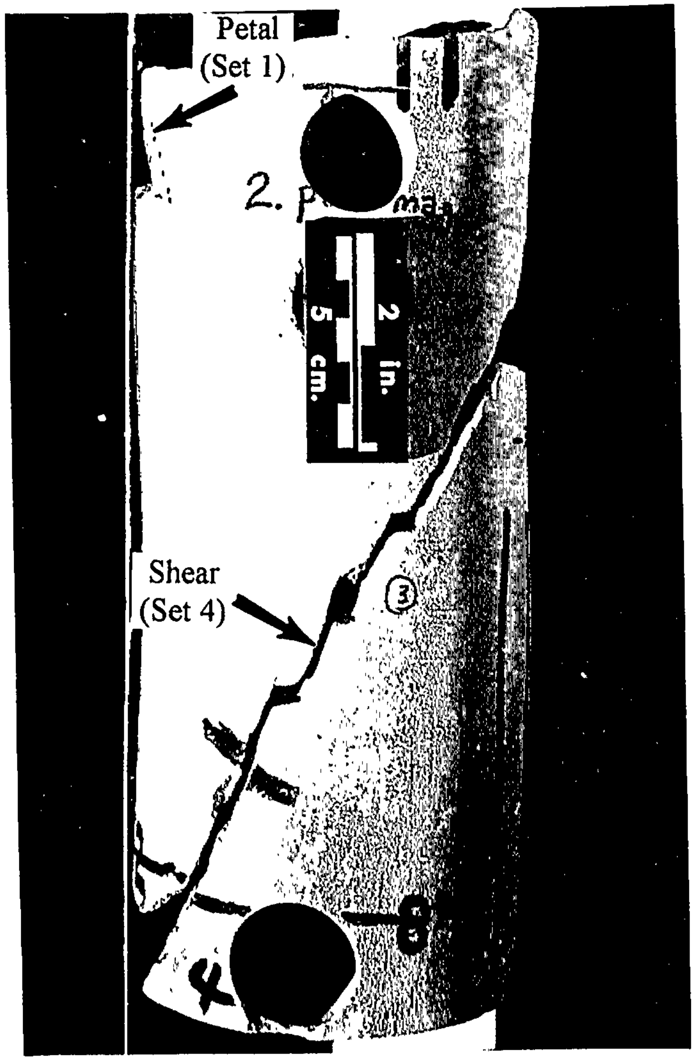


Figure 24: Lorenz' fracture set 1 (petal) and 4 (diagonal shear) with reverse offset. Petal trends N10°E and shear N16°E, based on paleomag work. (Vertical mineralized [set 3] fracture -<u>not</u> seen in photo - strikes N30°E.) Due to small # of paleomag plugs, orientation may be off 25°± (e.g., petal may be trending N15°W.) 8,431.5' - 8,432.1', 2nd Frontier, #19 BBFU well.

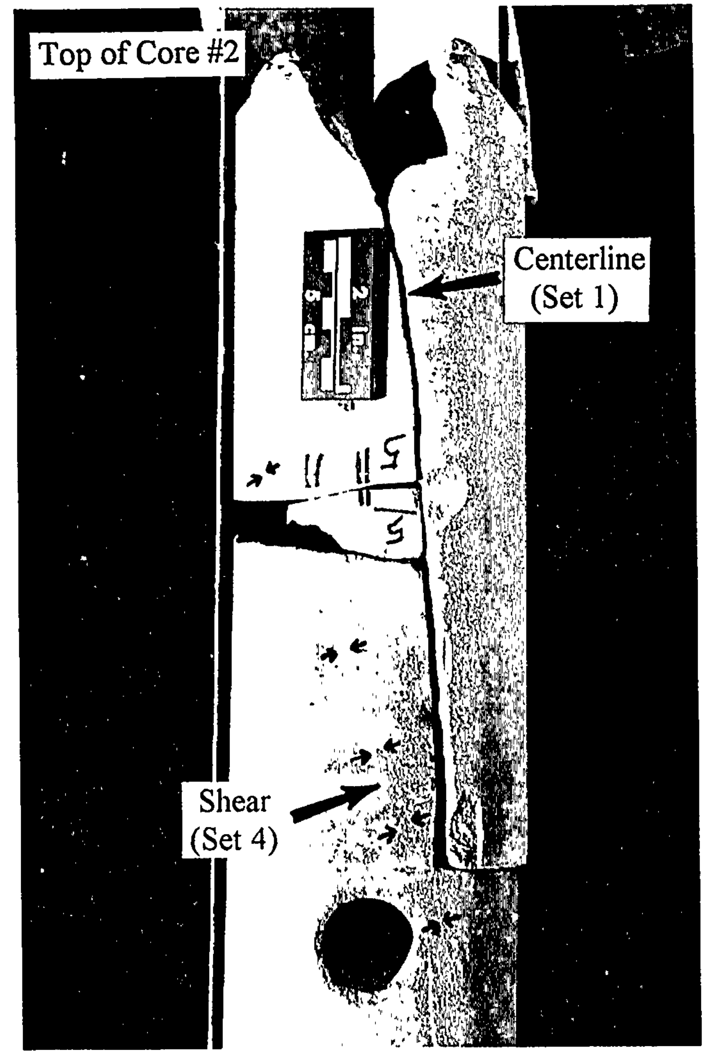


Figure 25: Lorenz' fracture set 1 (coring-induced, petal/centerline) trends N22°W and set 4 (calcite-filled diagonal shear, shown by opposing arrows) N27°W. Shear consists of one or more segments, and shows normal offset. This is top of Core #2. Beveled peak is due to cutting a longer core than length of core barrel. 8,440' - 8,441.8', 2nd Frontier, #19 BBFU well.

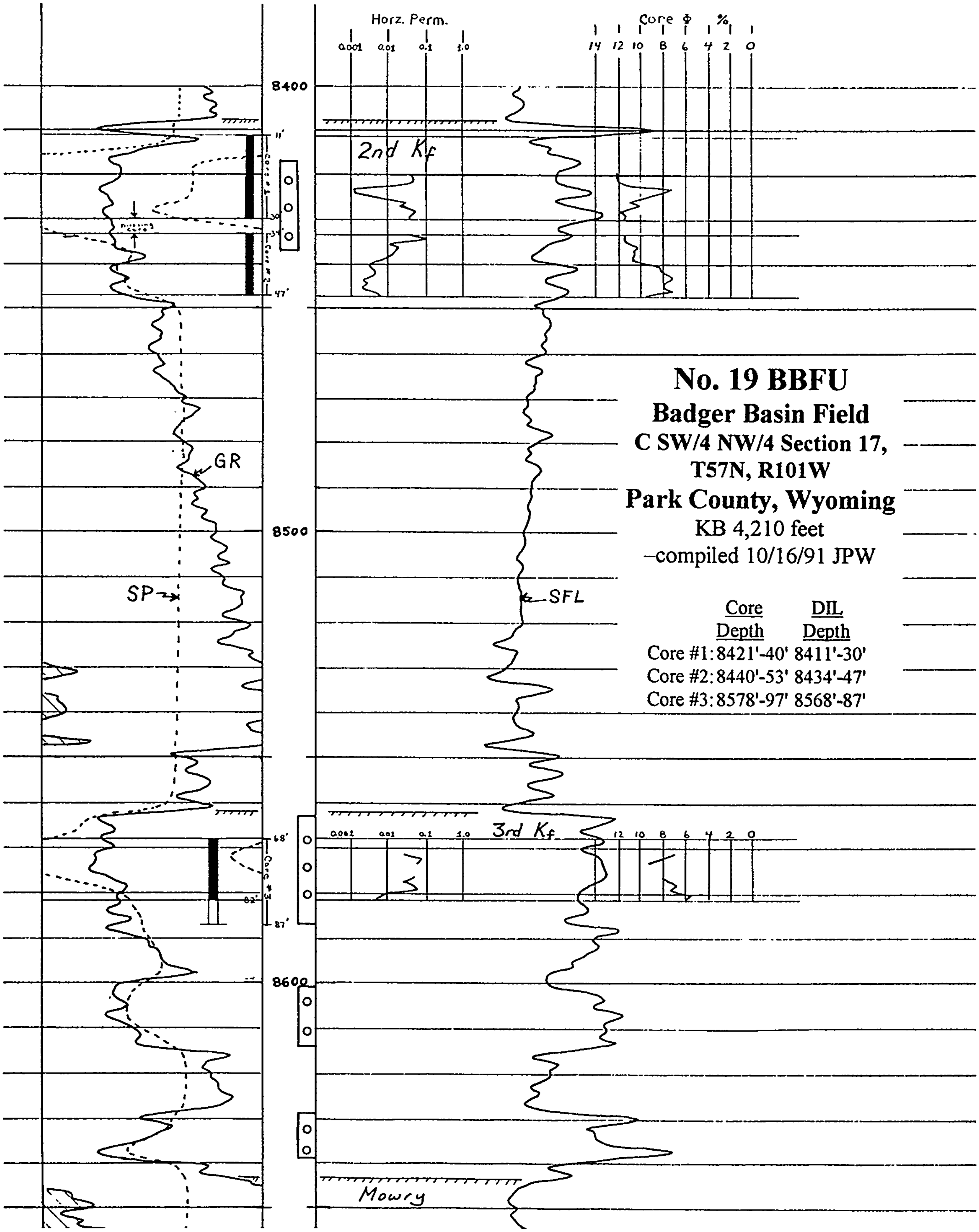


Figure 26: GR/SFL log from #19 BBFU with core intervals and porosity/permeability data

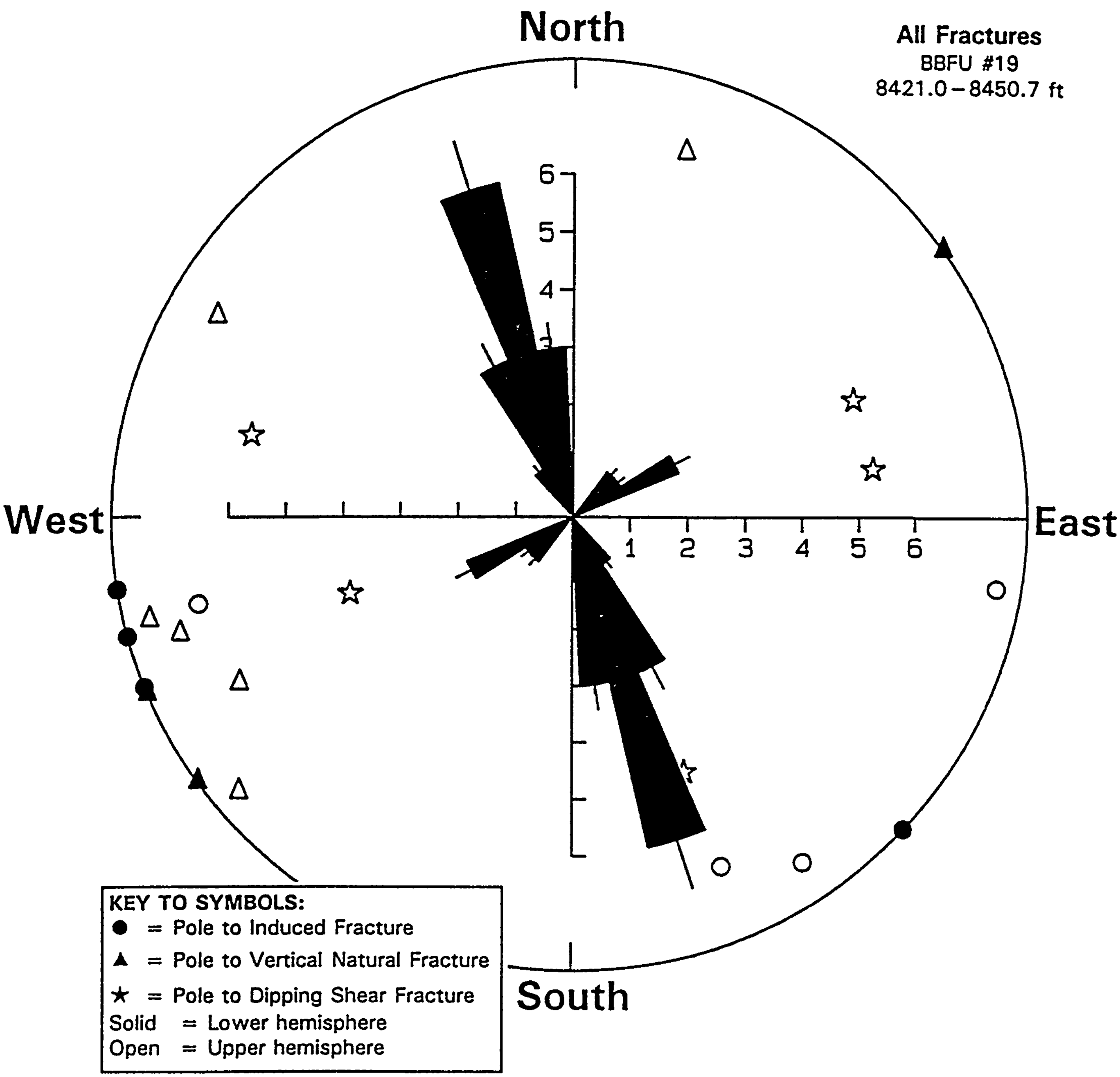


Figure 27 Combined stereographic (fracture poles) and rose diagram (fracture strikes) of all paleomagnetically-oriented fractures (coring-induced and natural) in BBFU #19.

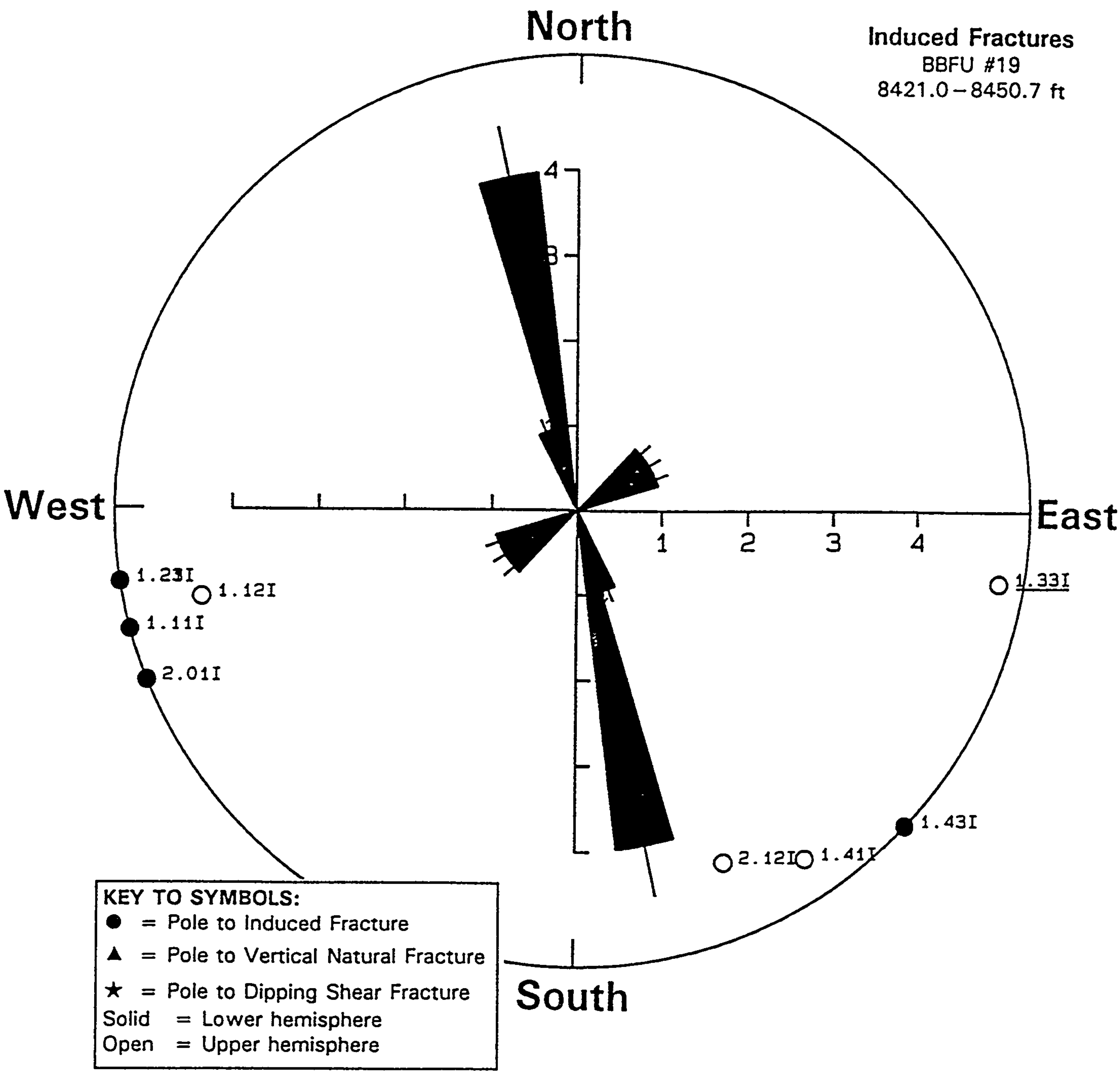


Figure 28 Combined stereographic (fracture poles) and rose diagram (fracture strikes) of paleomagnetically-oriented induced (petal and centerline) fractures in BBFU #19.

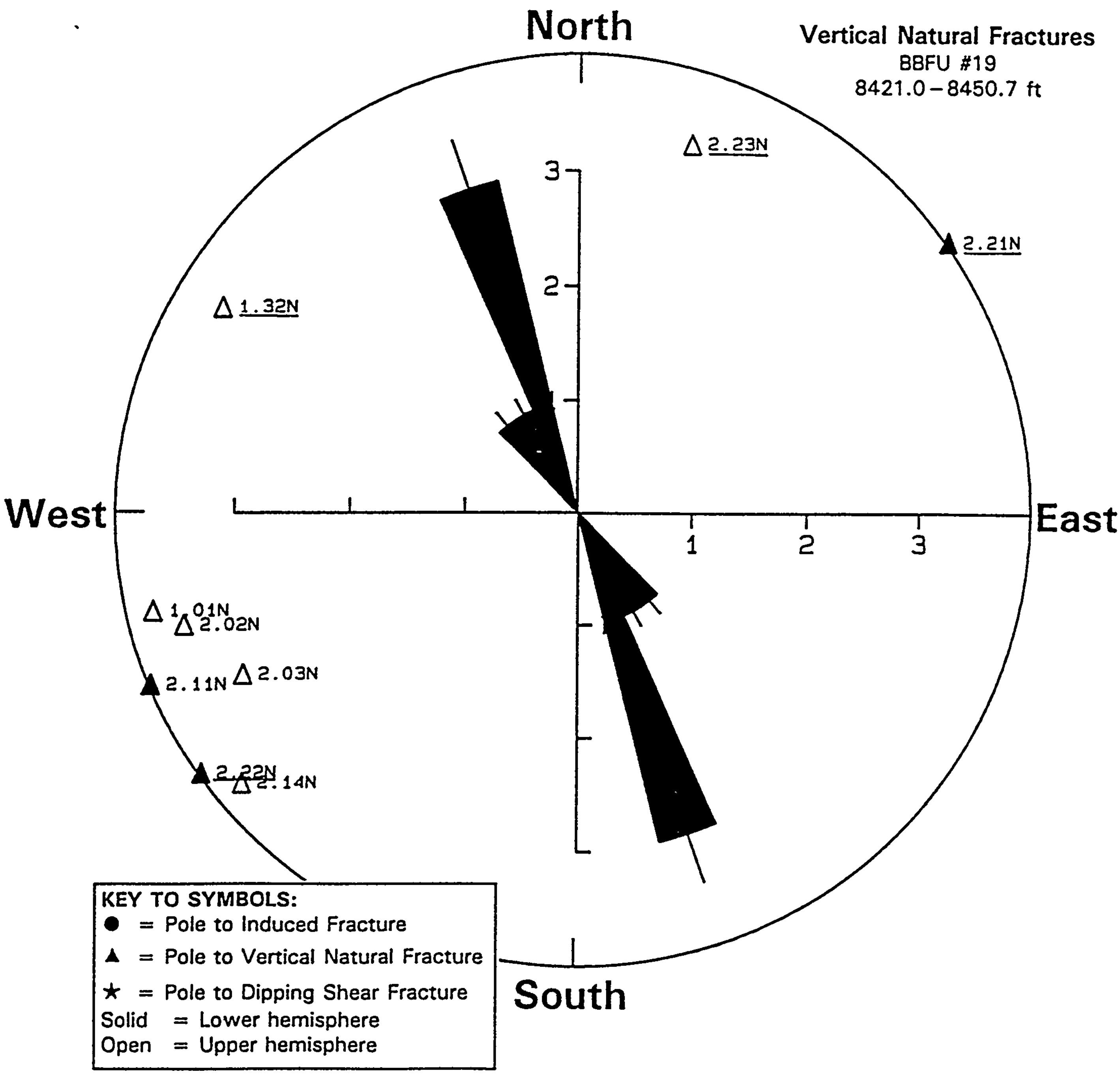


Figure 29 Combined stereographic (fracture poles) and rose diagram (fracture strikes) of paleomagnetically-oriented subvertical natural fractures (mineralized and unmineralized) in BBFU #19.

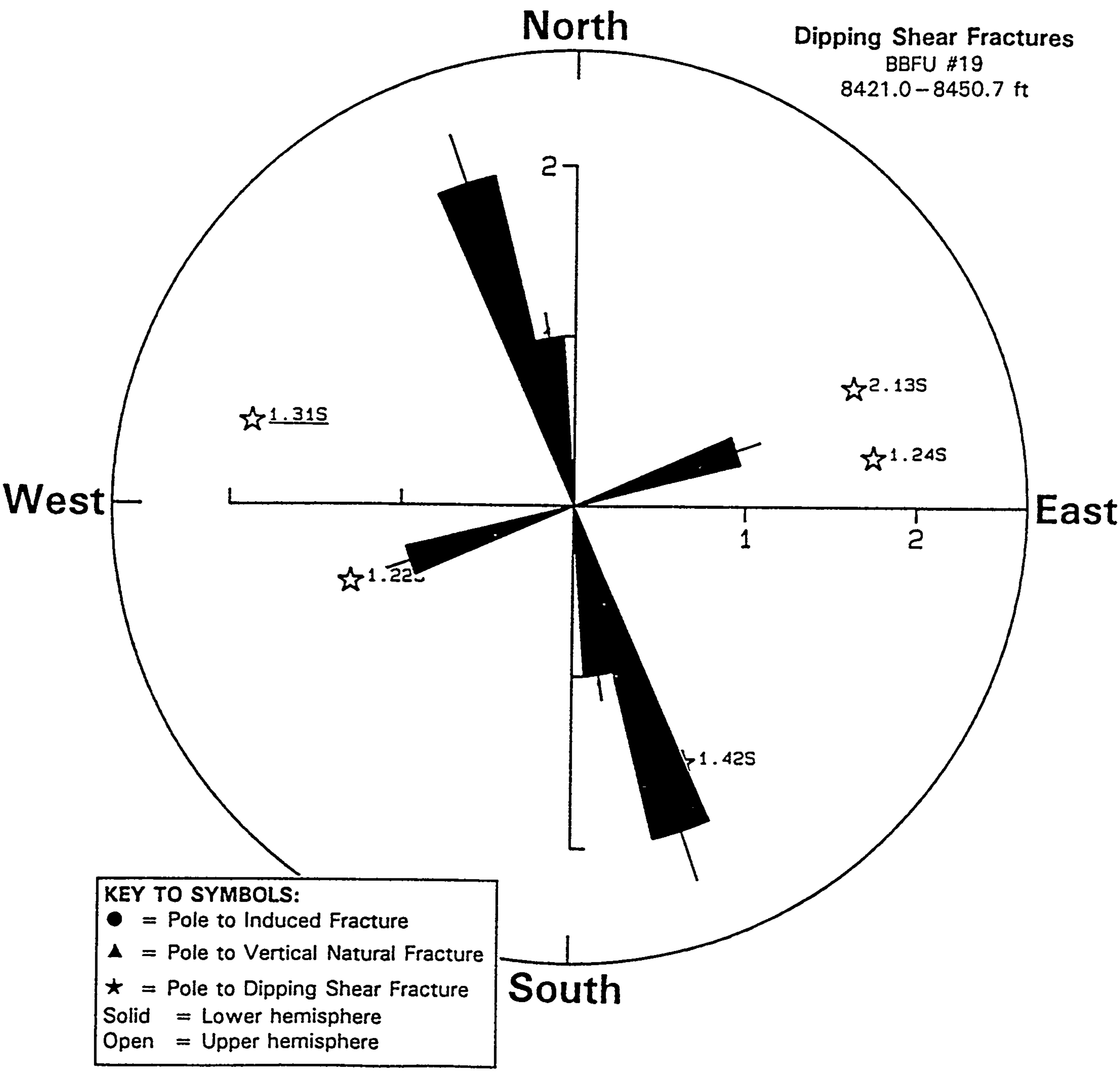
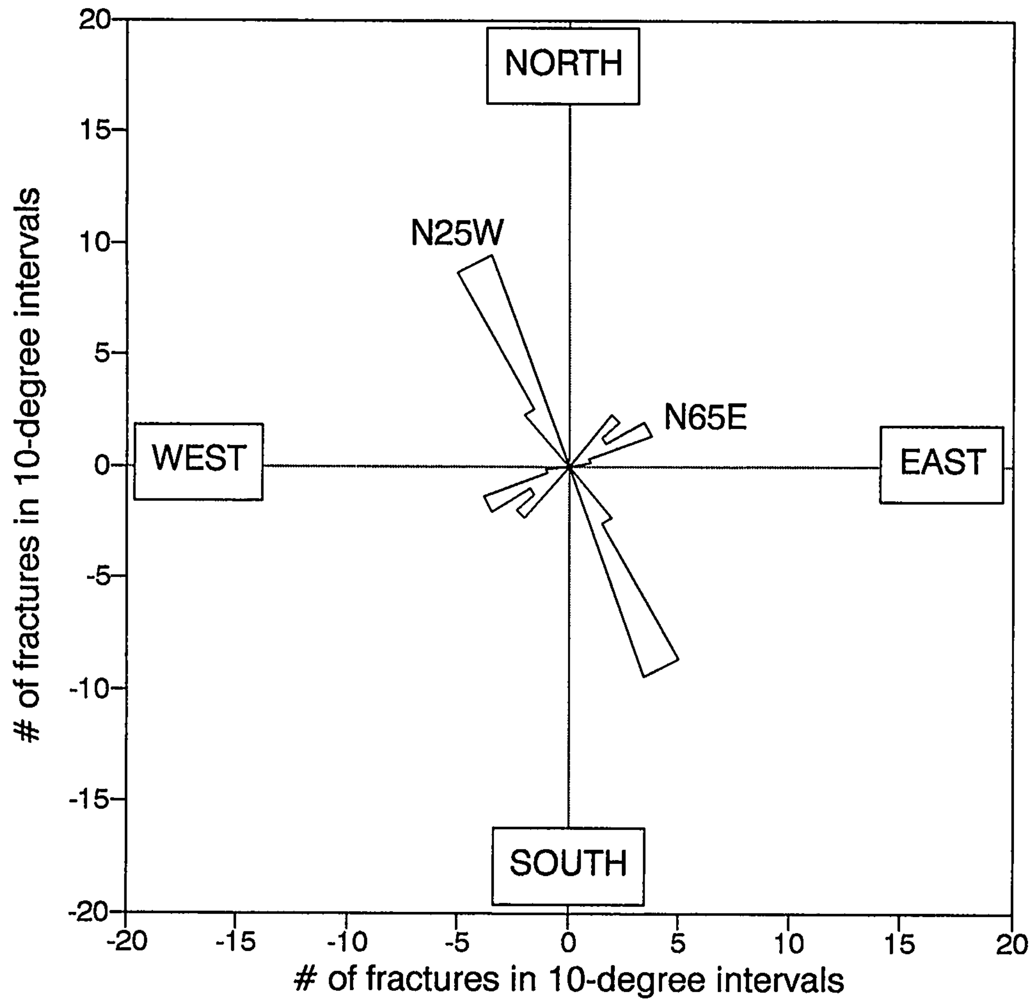


Figure 30 Combined stereographic (fracture poles) and rose diagram (fracture strikes) of paleomagnetically-oriented non-vertical shear fractures in BBFU #19.

ROSE DIAGRAM
SURFACE FRACTURES AT BADGER BASIN

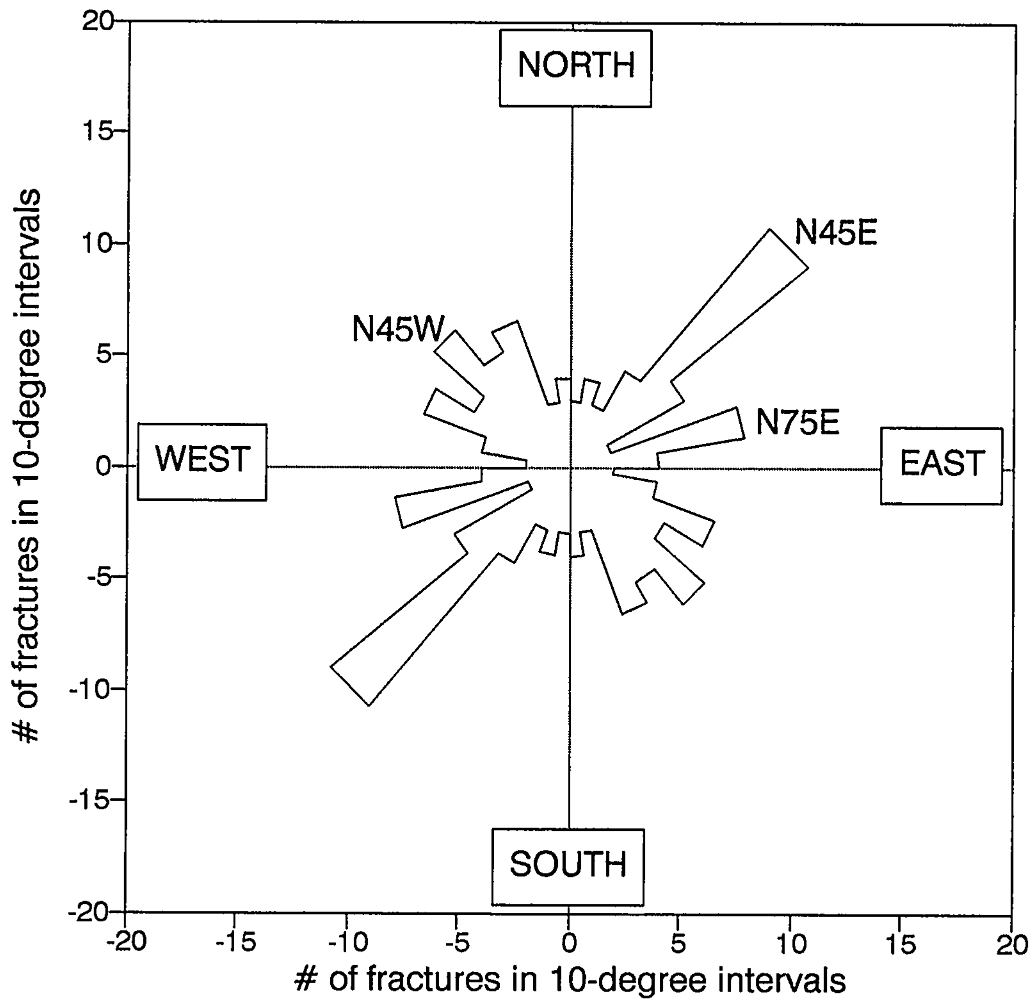


OUTCROP LOCATION #1
Date Measured: 4/11/93
Location: C S/2 S/2 Section 9, T57N, R101W, Park County, Wyoming. (180' South of receiver point 3093 on 3D receiver line 14.)

See Figure 34 for location.

Figure 31

ROSE DIAGRAM
SURFACE FRACTURES AT BADGER BASIN

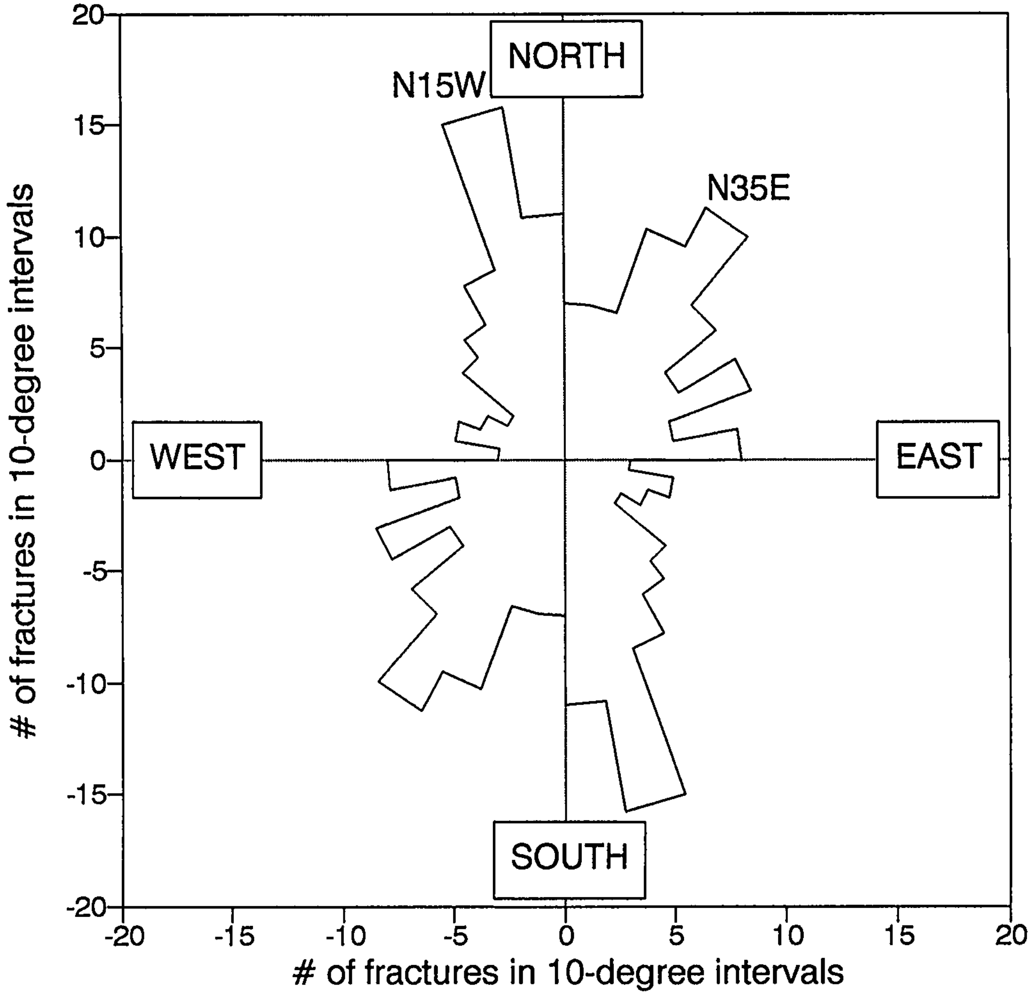


OUTCROP LOCATION #2
Date Measured: 4/11/93
Location: NE/4 NW/4 Section 16, T57N, R101W, Park County, Wyoming. (200' NW of receiver point 3154 on 3D receiver line 13.)

See Figure 34 for location.

Figure 32

ROSE DIAGRAM
SURFACE FRACTURES AT BADGER BASIN



OUTCROP LOCATION #3
Date Measured: 4/9&10/93
Location: NW/4 SW/4 Section 16, T57N, R101W, Park County, Wyoming (East of #9 BBFU, on 3D receiver lines 11 & 12, near receiver points 3275, 3276, and 3380.)

See Figure 34 for location.

Figure 33

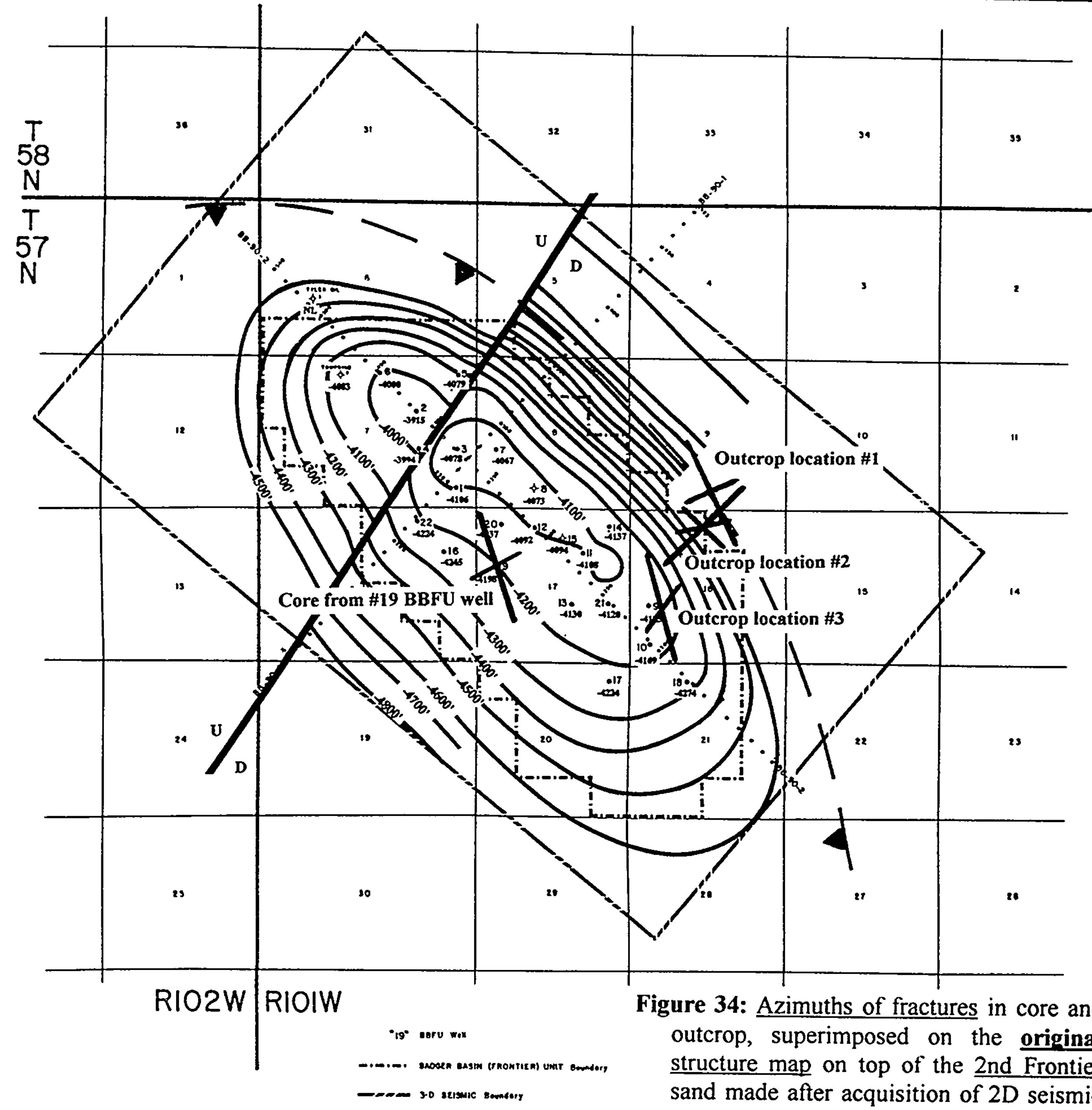


Figure 34: Azimuths of fractures in core and outcrop, superimposed on the **original** structure map on top of the 2nd Frontier sand made after acquisition of 2D seismic lines BB-90-1 and BB-90-2 and before the 3D-seismic program was shot.

C.I. = 100 feet
Scale: 1 inch = 5,800 feet
(Structural interpretation 4/23/91 by JPW)

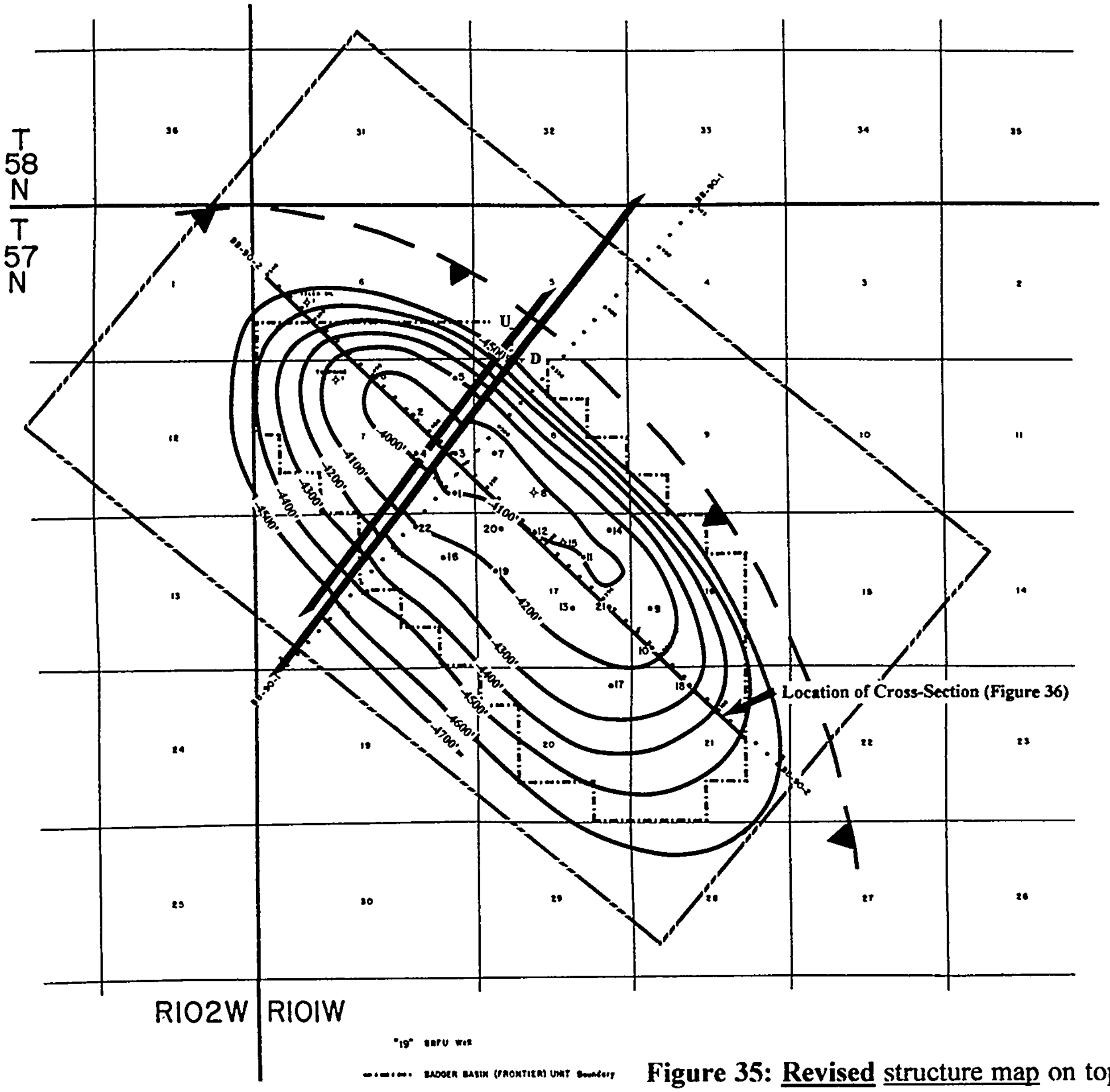


Figure 35: Revised structure map on top of the 2nd Frontier sand (pre 3D-seismic, acquired Spring 1993)

C.I. = 100 feet
Scale: 1 inch = 5,800 feet
JPW 2/23/94

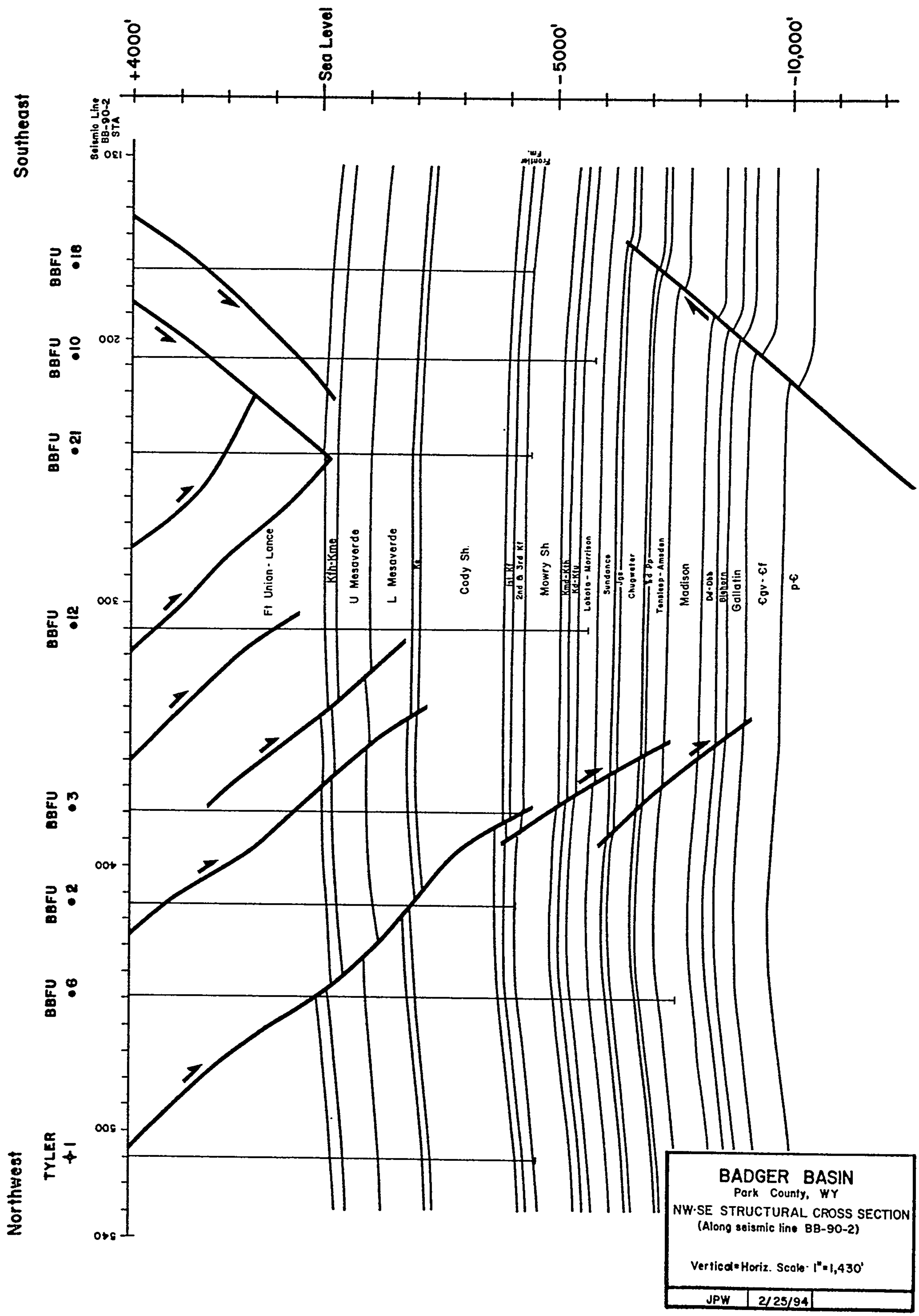

Southeast
Northwest
+4000'
Sea Level
-5000'
-10,000'
Seismic Line BB-90-2 STA
130
200
300
400
500
540
BBFU 18
BBFU 10
BBFU 21
BBFU 12
BBFU 3
BBFU 2
BBFU 6
TYLER 1
Frontier Fm.
Ft Union - Lance
Klh-Kme
U Mesaverde
L Mesaverde
Ke
Cody Sh.
1st Kf
2nd & 3rd Kf
Mowry Sh
Kmd-Kth
Kd-Kfu
Lakota - Morrison
Sundance
Jge
Chugwater
Kd Pp
Tensleep - Amsden
Madison
Dd-Dbb
Bighorn
Gallatin
Ꞓgv - Ꞓf
p-Ꞓ
BADGER BASIN
Park County, WY
NW-SE STRUCTURAL CROSS SECTION
(Along seismic line BB-90-2)
Vertical=Horiz. Scale- 1"=1,430'
JPW
2/25/94

Figure 36

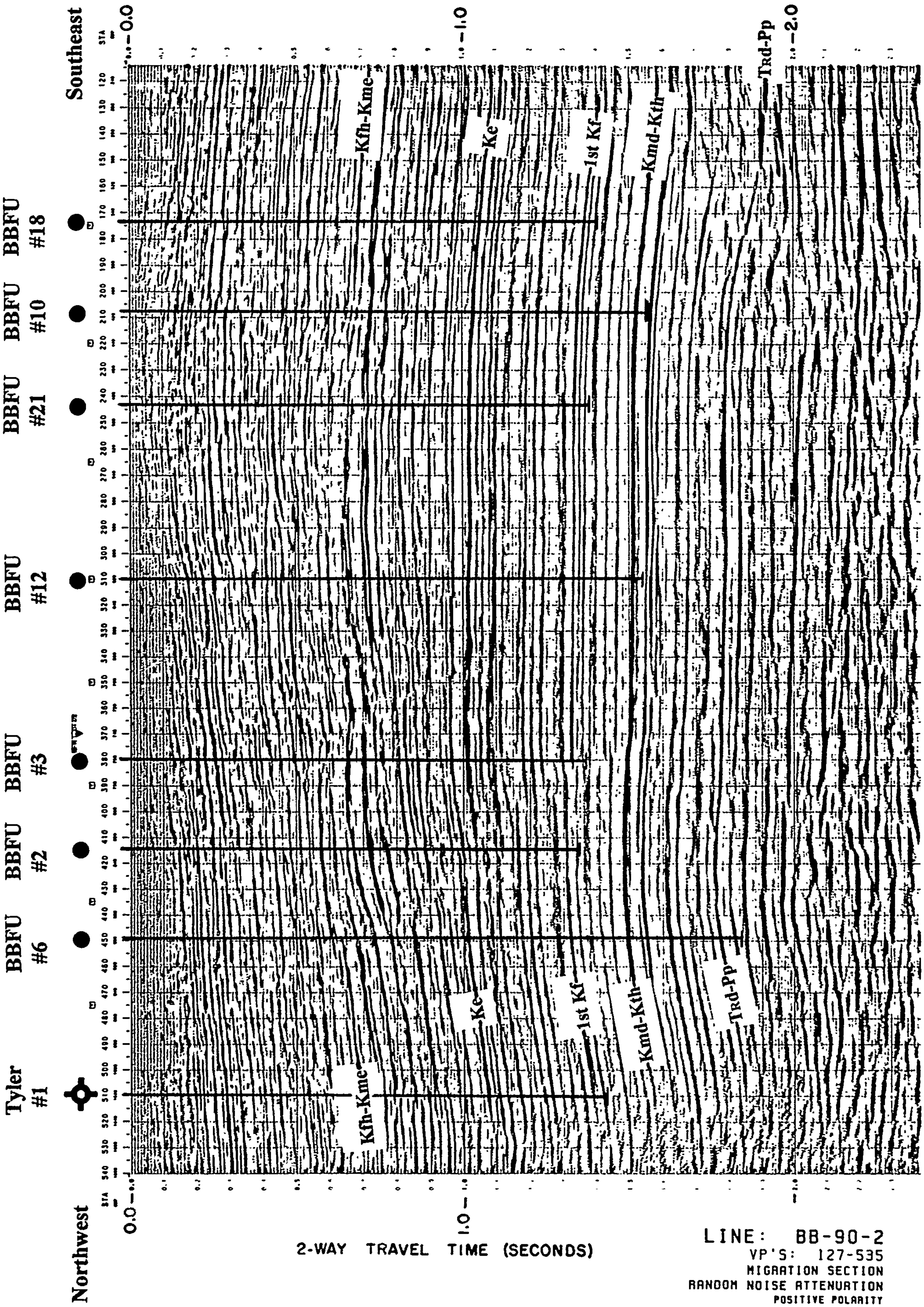

Southeast
Northwest
BBFU #18
BBFU #10
BBFU #21
BBFU #12
BBFU #3
BBFU #2
BBFU #6
Tyler #1
0.0
1.0
2.0
Kfh-Kme
Ke
1st Kf
Kmd-Kth
TRd-Pp
2-WAY TRAVEL TIME (SECONDS)
LINE: BB-90-2
VP'S: 127-535
MIGRATION SECTION
RANDOM NOISE ATTENUATION
POSITIVE POLARITY

Figure 37

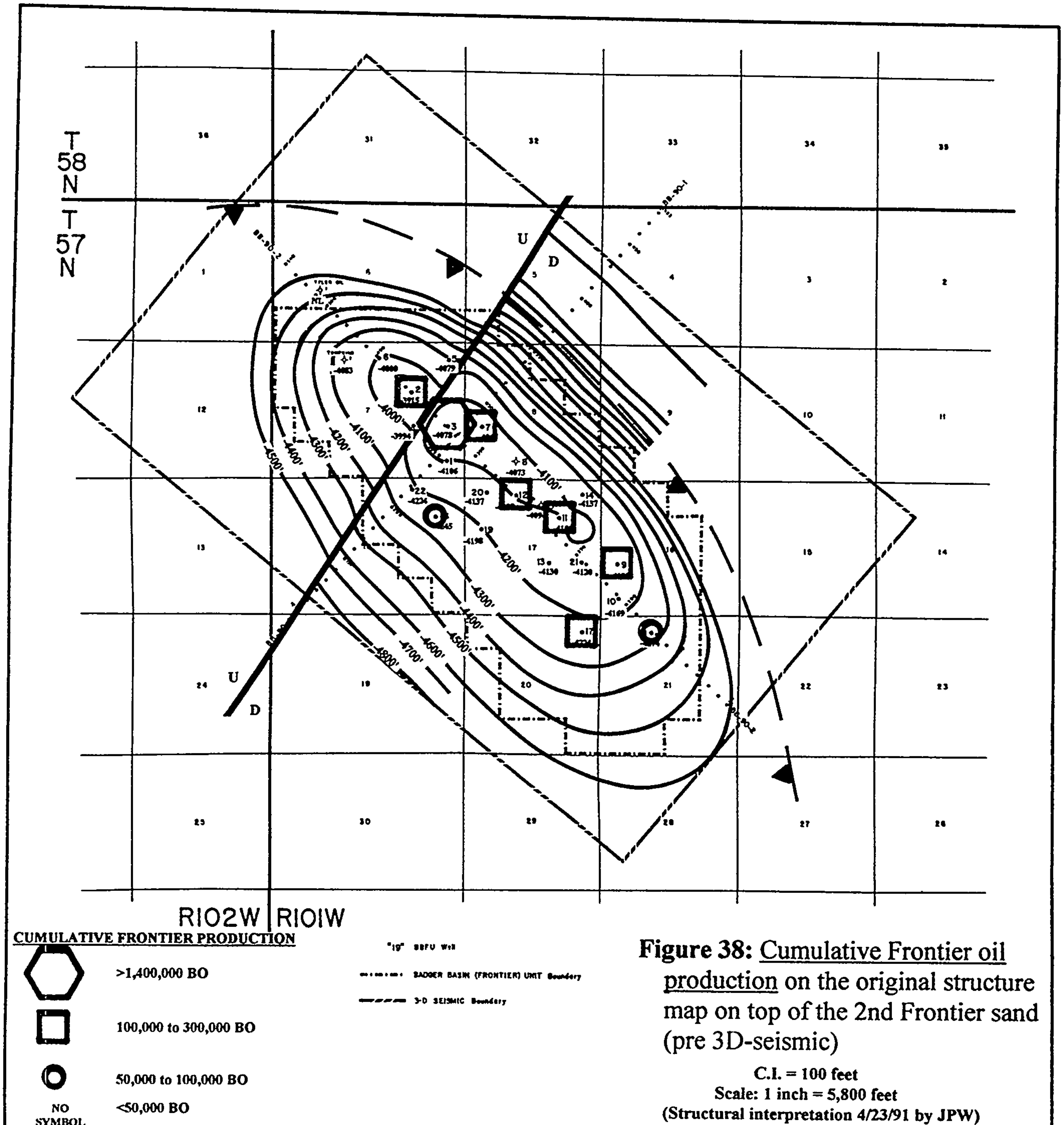


Figure 38: Cumulative Frontier oil production on the original structure map on top of the 2nd Frontier sand (pre 3D-seismic)

C.I. = 100 feet
Scale: 1 inch = 5,800 feet
(Structural interpretation 4/23/91 by JPW)

Appendix B - Tables

CURRENT AND PREVIOUS WELL NAMES
BADGER BASIN FIELD
T57N, R101W
PARK COUNTY, WYOMING

CURRENT WELL NAME	QTR/QTR SECTION	PREVIOUS WELL NAMES
No. 1 BBFU	SE/4SE/4 7	#3-B BN (or NPR), #3-BX BN (or NPR), #11 Resolute
No. 2 BBFU	SW/4NE/4 7	#4-B BN (or NPR)
No. 3 BBFU	NE/4SE/4 7	#1-B BN (or NPR), #8 Resolute
No. 4 BBFU	NW/4SE/4 7	#2-B BN (or NPR), #9 Resolute
No. 5 BBFU	NE/4NE/4 7	#1 Gov't., #10 Resolute
No. 6 BBFU	NE/4NW/4 7	#2 Badura, #1 Fee
No. 7 BBFU	NW/4/SW/4 8	#1-B Gov't., #7 Resolute
No. 8 BBFU	SE/4SW/4 8	#2-8 Federal
No. 9 BBFU	NW/4SW/4 16	#1 State, #2 Resolute
No. 10 BBFU	SW/4SW/4 16	#2 State, #5 Resolute
No. 11 BBFU	SW/4NE/4 17	#1-A BN (or NPR), #1 Resolute
No. 12 BBFU	NE/4NW/4 17	#3-A BN (or NPR), #6 Resolute
No. 13 BBFU	NW/4SE/4 17	#5-A BN (or NPR), #13 Resolute
No. 14 BBFU	NE/4NE/4 17	#4-A BN (or NPR), #12 Resolute
No. 15 BBFU	NW/4NE/4 17	#1-H NP, #1 NP
No. 16 BBFU	SE/4NE/4 18	#18-1 Federal
No. 17 BBFU	NE/4NE/4 20	#1-A Gov't., #3 Resolute
No. 18 BBFU	NE/4NW/4 21	#2-A BN (or NPR), #4 Resolute
No. 19 BBFU	SW/4NW/4 17	
No. 20 BBFU	NW/4NW/4 17	
No. 21 BBFU	NE/4SE/4 17	
No. 22 BBFU	NW/4NE/4 18	
Tompkins No. 1 Badura	Lot 1 (N/2NW/4) 7	
Tyler No. 1 Baker-Badura	Lot 12 (N/2SW/4) 6	

Table 1

DRILLING ORDER (BY SPUD DATE)
BADGER BASIN FIELD
T57N, R101W
PARK COUNTY, WYOMING

	WELL NAME	SPUD DATE	COMPL. DATE	REMARKS
1	#11 BBFU	6/3/28	7/15/31	TD in Mowry
2	#9 BBFU	7/29/33	1/37	TD in 2nd Kf; deepened to 3rd Kf, 3/39; to Fuson, 8/52
3	#17 BBFU	4/29/37	4/1/38	TD in 2nd Kf; deepened to just above 3rd Kf, 3/37; to 3rd Kf, 4/39
4	#18 BBFU	7/9/37	4/17/38	TD in 2nd Kf; deepened to 3rd Kf, 5/39
5	#10 BBFU	5/5/38	2/20/39	TD in Mowry; deepened to Dakota, 6/40; sidetracked for Kf completion, 10/40
6	#12 BBFU	?	12/43	TD in Mowry; deepened to Morrison, 7/52
7	#7 BBFU	9/11/44	4/1/45	TD in Mowry
8	#3 BBFU	1/28/46	6/3/46	TD in 3rd Kf (possibly Mowry)
9	#4 BBFU	6/21/46	10/14/46	TD in 3rd Kf (possibly Mowry)
10	#6 BBFU	1/6/47	10/24/47	TD in Madison
11	#5 BBFU	5/30/47	10/27/47	TD in 3rd Kf
12	#1 BBFU	10/30/47	3/20/48	TD in 3rd Kf; deepened to Fuson, 7/65
13	#14 BBFU	?	3/49	TD in 3rd Kf
14	#13 BBFU	4/11/49	7/30/49	TD in 3rd Kf
15	#15 BBFU	1/26/55	1956	TD in Madison
16	Tyler #1	9/24/63	10/24/63	TD in Mowry
17	#2 BBFU	12/7/64	4/14/65	TD in Mowry
18	Tompkins #1	7/9/65	9/15/65	TD in Lakota
19	#16 BBFU	9/7/78	1/26/79	TD in Fuson
20	#8 BBFU	4/30/80	6/18/80	TD in Morrison
21	#19 BBFU	3/26/87	7/23/87	TD in Lakota
22	#20 BBFU	6/18/87	8/27/87	TD in Mowry
23	#21 BBFU	7/9/87	2/18/88	TD in Mowry
24	#22 BBFU	8/23/87	12/17/87	TD in Lakota

Table 2

	2nd FRONTIER	3rd FRONTIER
A, *acres*	2,500	1,990
h, *feet*	17	8
Φ	11%	11%
Soi	60%	60%
Boi, *RB/STB*	1.2	1.2
OOIP, *barrels of oil*	18,134,325	6,792,905

OOIP (2nd and 3rd Frontier sands) = <u>24,927,230</u> barrels of oil

$$OOIP = \frac{7{,}758\ A\ h\ \Phi\ Soi}{Boi}$$

Where: A = reservoir areal extent, *acres*
h = average pay thickness, *feet*
Φ = average porosity
Soi = initial oil saturation
Boi = initial oil formation volume factor, *RB/STB*

Table 3: CALCULATION OF ORIGINAL OIL-IN-PLACE
2nd and 3rd FRONTIER SANDS
BADGER BASIN FIELD
T57N, R101W
PARK COUNTY, WYOMING

INITIAL POTENTIAL and CUMULATIVE PRODUCTION DATA
BADGER BASIN FIELD
PARK COUNTY, WYOMING

BBFU WELL #	INITIAL POTENTIAL (based on monthly production rates)	CUMULATIVE PRODUCTION (through 9/93)		PRODUCTIVE FORMATION
		BARRELS of OIL	THOUSAND CUBIC FEET of GAS	
1	88 BOPD/unknown	33,608	82,122	FRONTIER
2	35 BOPD/182 MCFD (est)	187,066	2,759,371	FRONTIER
3	1,159 BOPD/unknown	1,416,776	1,592,862	FRONTIER
4	N/A	0	0	FRONTIER
5	12 BOPD/unknown	6,622	97,347	FRONTIER
6	58 BOPD/unknown	15,626	54,100	FRONTIER
7	161 BOPD/1,767 MCFD (est)	242,691	987,840	FRONTIER
8	N/A	0	0	FRONTIER
9	169 BOPD/unknown	230,167	140,617	FRONTIER
10	N/A	0	0	FRONTIER
11	48 BOPD/unknown	235,547	23,749	FRONTIER
12	120 BOPD/unknown 16 BOPD/33 MCFD (est)	160,626 62,490	337,418 159,392	FRONTIER DAKOTA
13	N/A	0	0	FRONTIER
14	3 BOPD/30 MCFD (est)	4,656	34,555	FRONTIER
15	N/A	0	0	FRONTIER
16	214 BOPD/100 MCFD (est) 81 BOPD/unknown	57,465 21,268	313,295 9	FRONTIER DAKOTA
17	142 BOPD/unknown	115,914	27,172	FRONTIER
18	153 BOPD/220 MCFD (est)	86,873	172,781	FRONTIER
19	16 BOPD/42 MCFD	9,662	35,444	FRONTIER
20	42 BOPD/158 MCFD	26,958	112,259	FRONTIER
21	6 BOPD/192 MCFD	3,656	117,169	FRONTIER
22	11 BOPD/115 MCFD	8,539	39,577	FRONTIER

2,842,452	6,927,678	FRONTIER CUM PROD
83,758	159,401	DAKOTA CUM PROD
2,926,210	7,087,079	FIELD CUM PROD

"BOPD" = barrels of oil per day
"MCFD" = thousand of cubic feet of gas per day
"N/A" = not applicable
"est" = estimated

(No commercial production was ever established in the #4, #10, #13, or #15 BBFU wells. Though oil was recovered during a DST of the Frontier in the #8 BBFU well, no production casing was run, nor was a completion attempted.)

Table 4

INITIAL EFFECTIVE DECLINE FACTOR
BADGER BASIN FIELD
PARK COUNTY, WYOMING

WELL	INITIAL EFFECTIVE DECLINE FACTOR
No. 1 BBFU	56% per year
No. 2 BBFU	1% per year
No. 3 BBFU	24% per year
No. 9 BBFU	27% per year
No. 11 BBFU	3% per year (Discovery Well)
No. 12 BBFU	8% per year
No. 16 BBFU	54% per year
No. 17 BBFU	30% per year
No. 18 BBFU	26% per year
No. 19 BBFU	54% per year
No. 20 BBFU	42% per year
No. 21 BBFU	50% per year
No. 22 BBFU	34% per year

Effective Decline Factor, d: $$\mathbf{d} = \frac{q_i - q}{q_i}$$

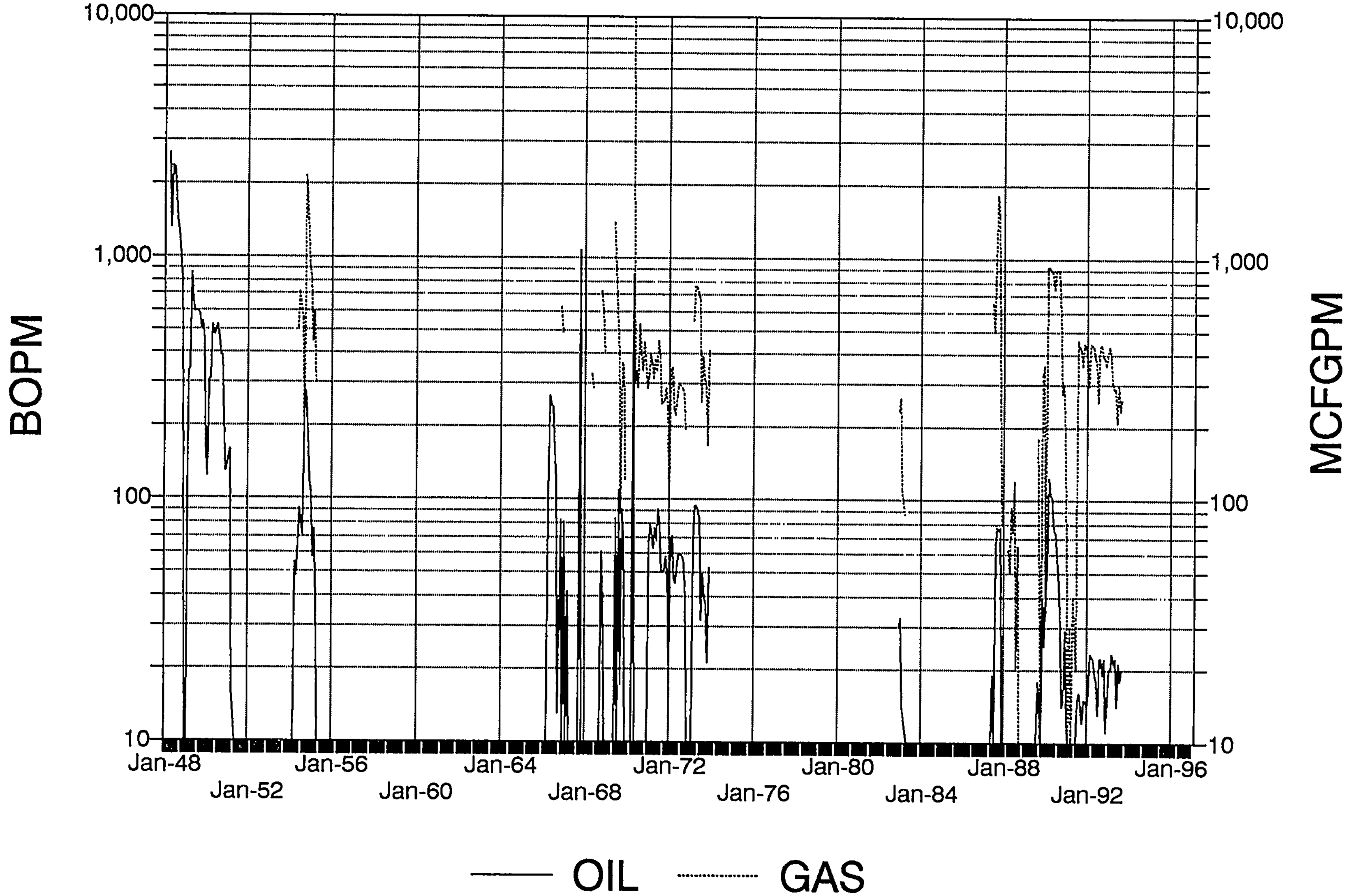
Where: d = effective decline factor, *% per year*
q_i = initial oil production rate at time t, *barrels of oil per month*
q = oil production rate at time t+1 year, *barrels of oil per month*

NOTE: The "effective decline factors" were calculated from the monthly production graphs in Appendix C. Decline curves were fitted to the initial period of stabilized production for production from the Frontier. Straight-line decline curves generally fitted the production data for at least the first two years.

Table 5

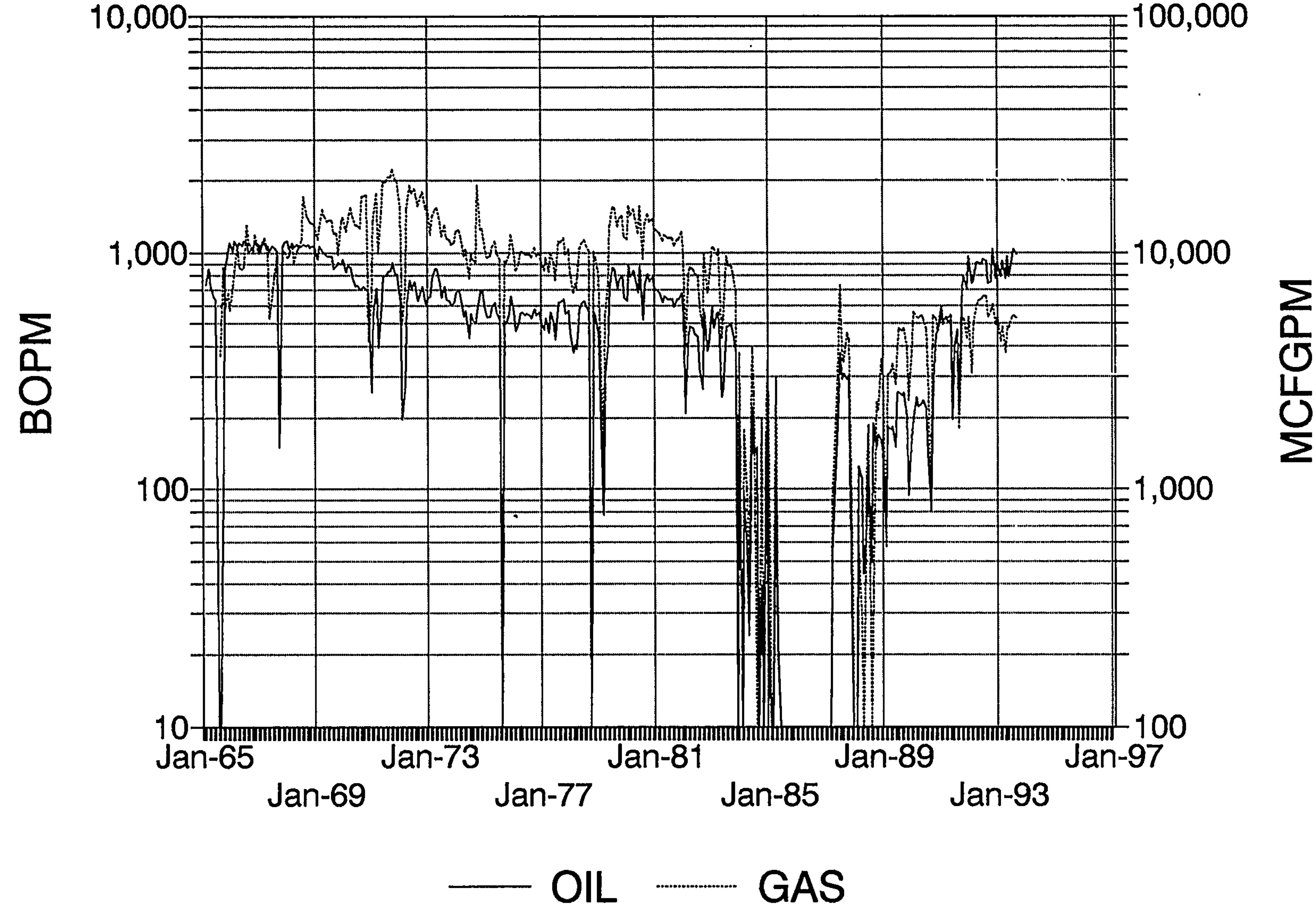
Appendix C - Monthly Production Graphs

SIERRA ENERGY #1 BBFU
MONTHLY PRODUCTION DATA



O&G-ALL 10/29/93 JPW

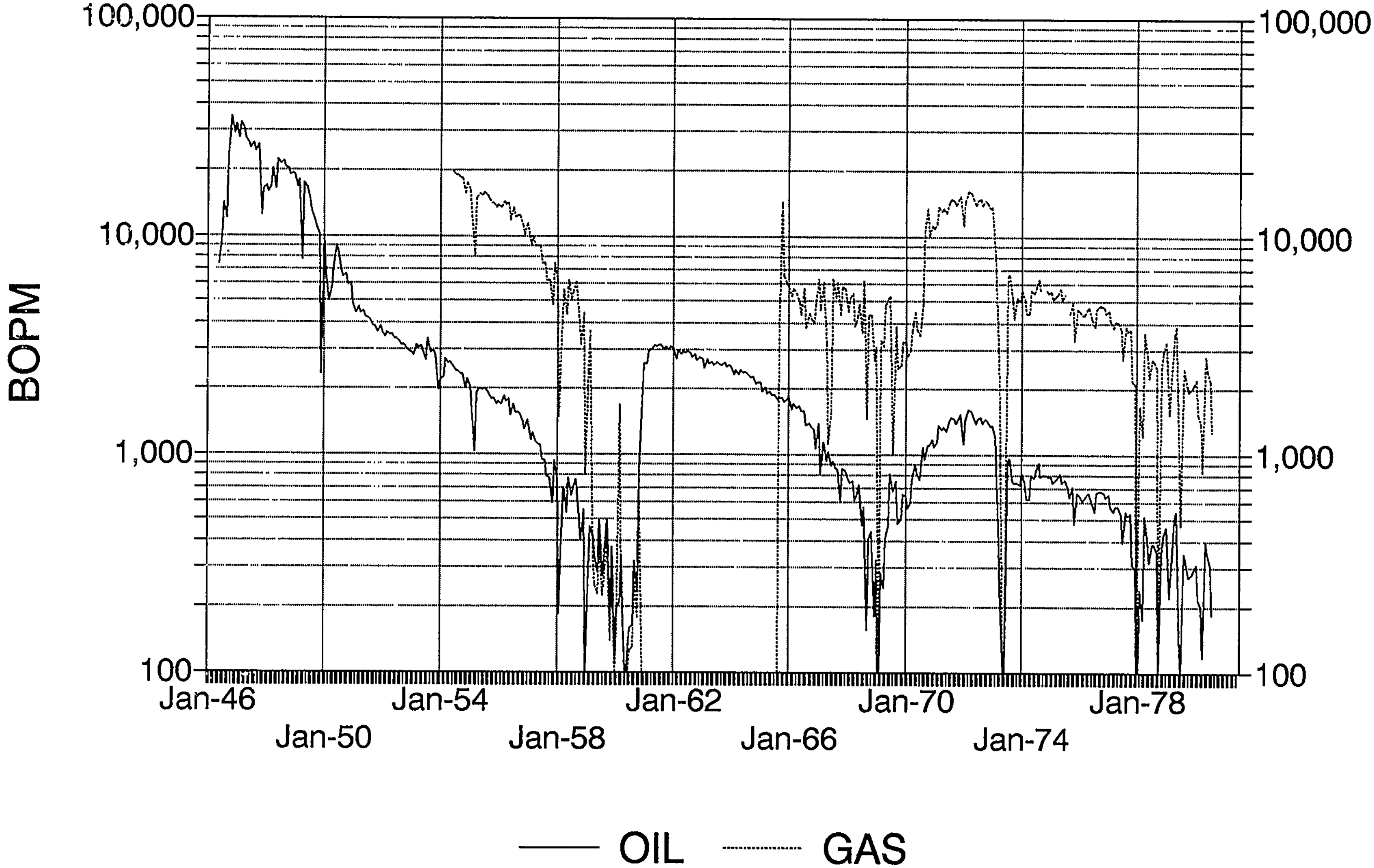
SIERRA ENERGY #2 BBFU
MONTHLY PRODUCTION DATA



O&G 11/1/93 JPW

SIERRA ENERGY #3 BBFU

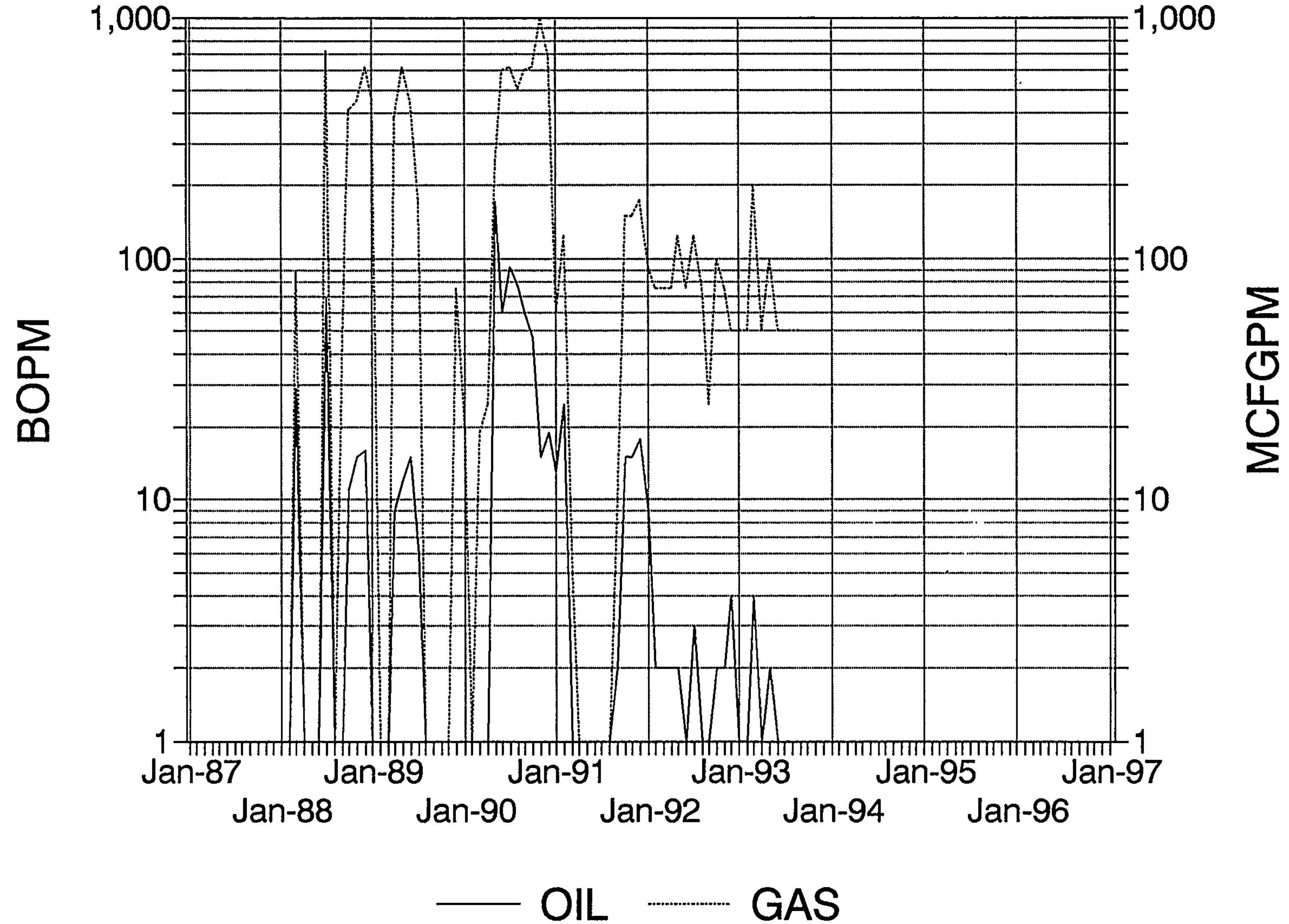
MONTHLY PRODUCTION DATA



O&G-ALL 11/19/93 JPW

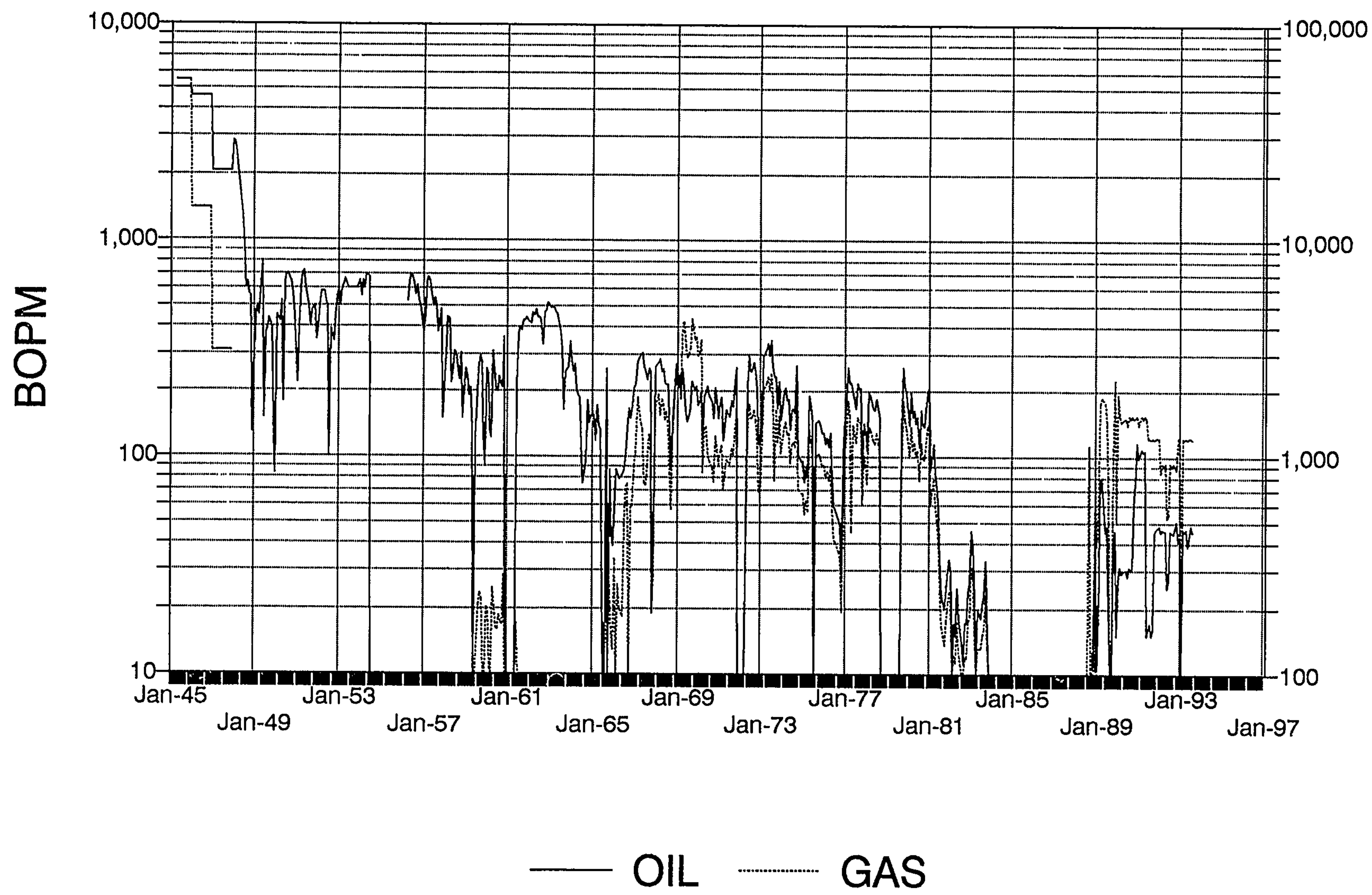
SIERRA ENERGY #6 BBFU

MONTHLY PRODUCTION DATA



O&G 11/1/93 JPW

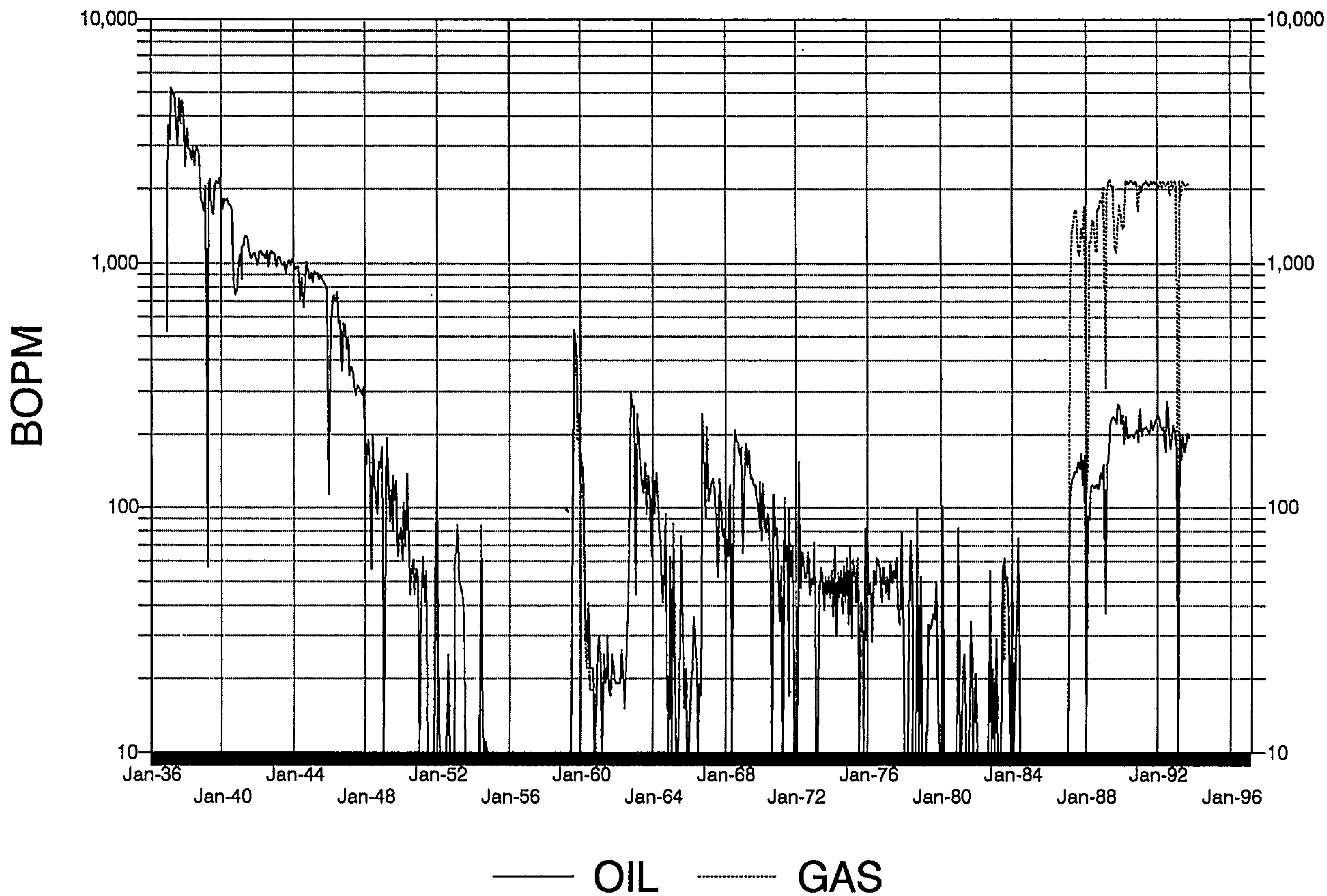
SIERRA ENERGY #7 BBFU
MONTHLY PRODUCTION DATA



O&G-ALL 11/1/93 JPW

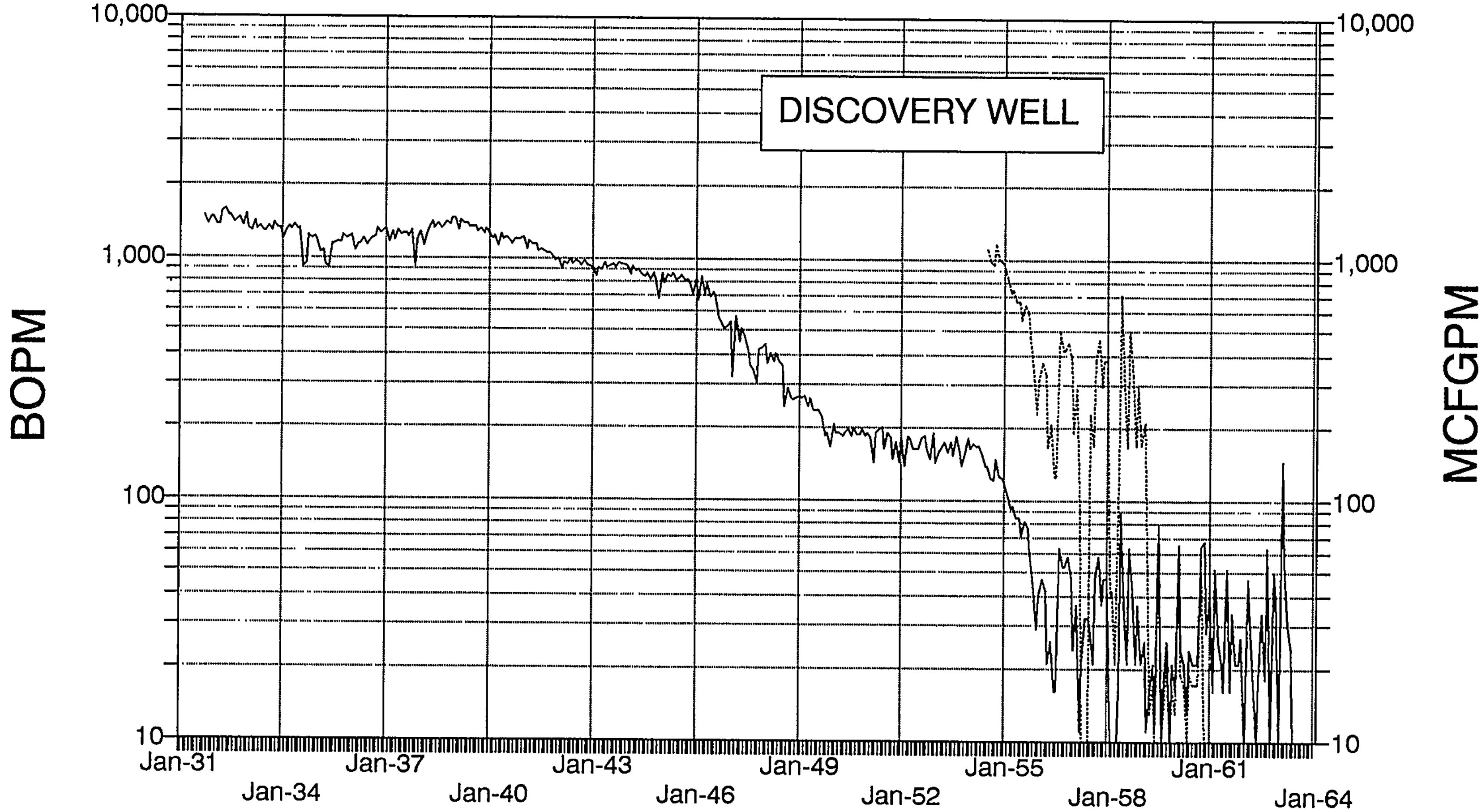
SIERRA ENERGY #9 BBFU

MONTHLY PRODUCTION DATA



O&G-ALL 11/1/93 JPW

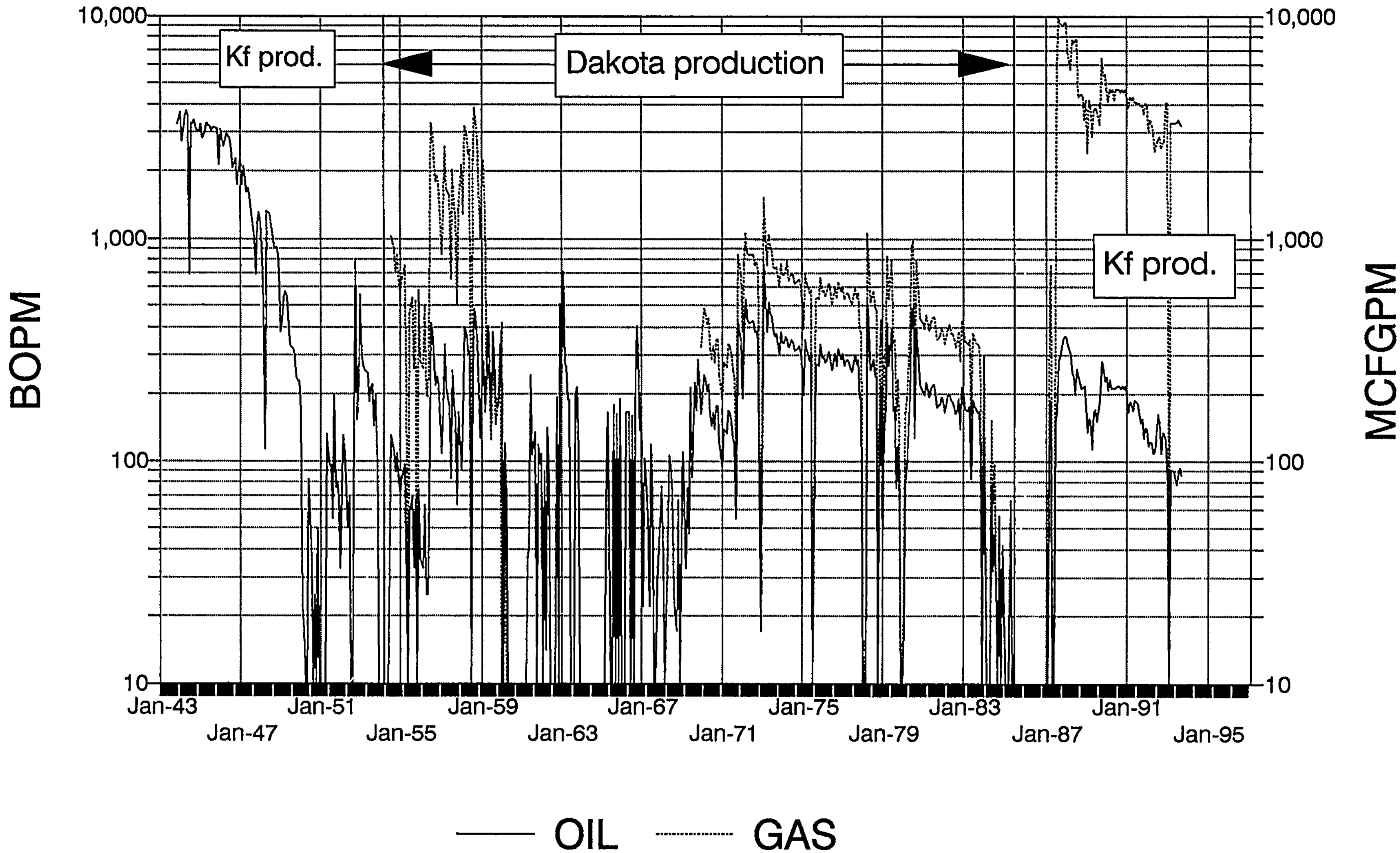
SIERRA ENERGY #11 BBFU
MONTHLY PRODUCTION DATA



OIL GAS

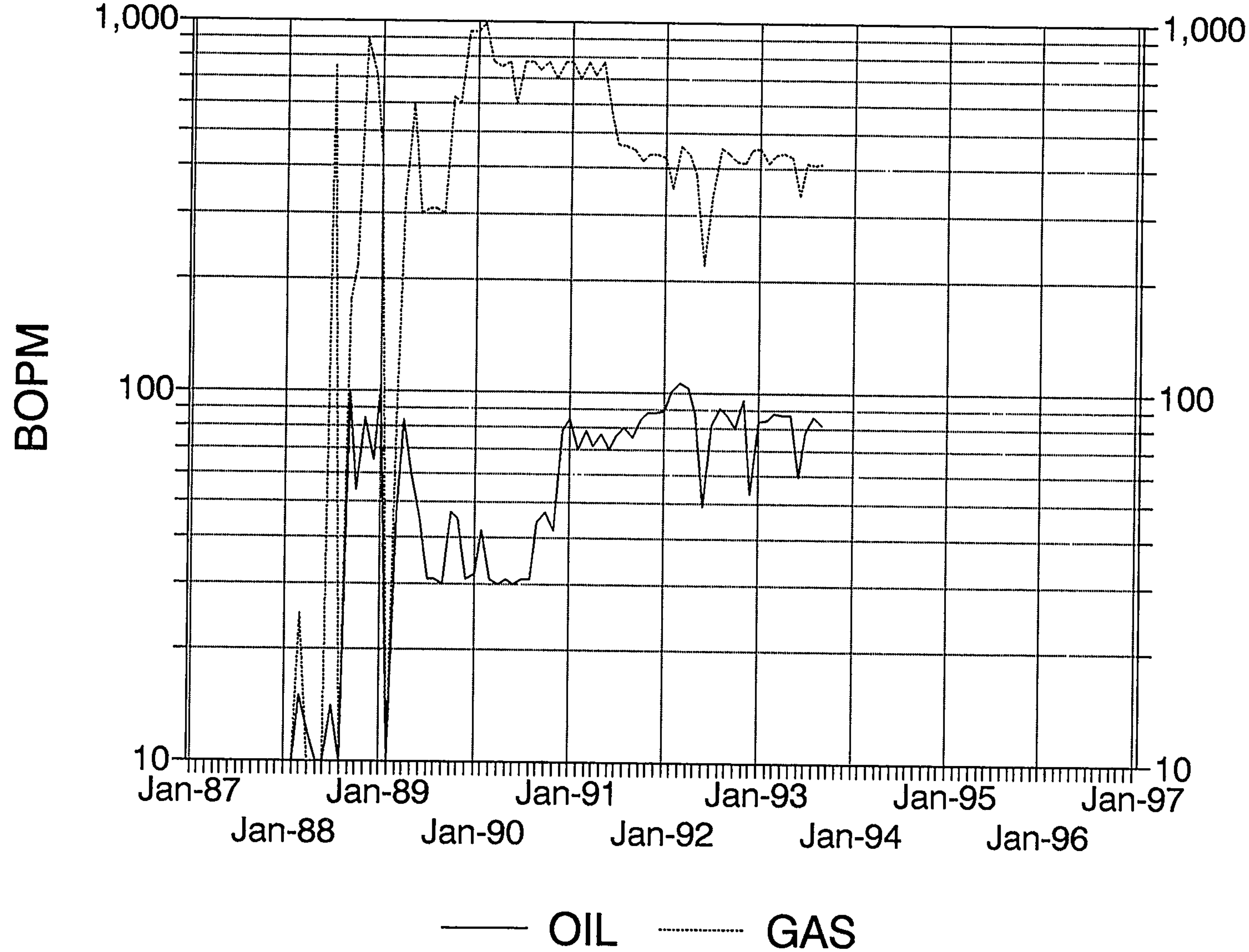
O&G-ALL 11/1/93 JPW

SIERRA ENERGY #12 BBFU
MONTHLY PRODUCTION DATA



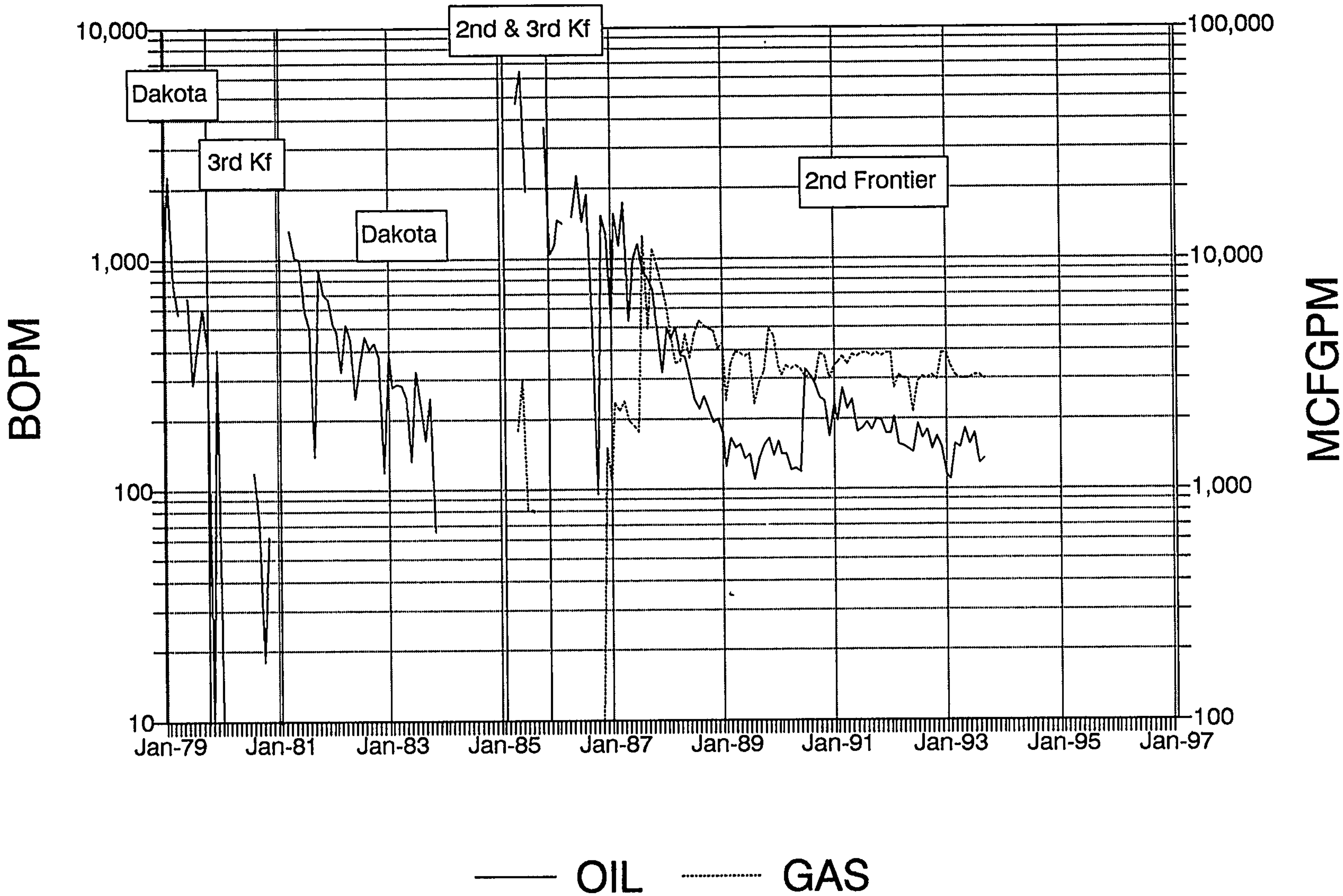
O&G-ALL 11/1/93 JPW

SIERRA ENERGY #14 BBFU
MONTHLY PRODUCTION DATA



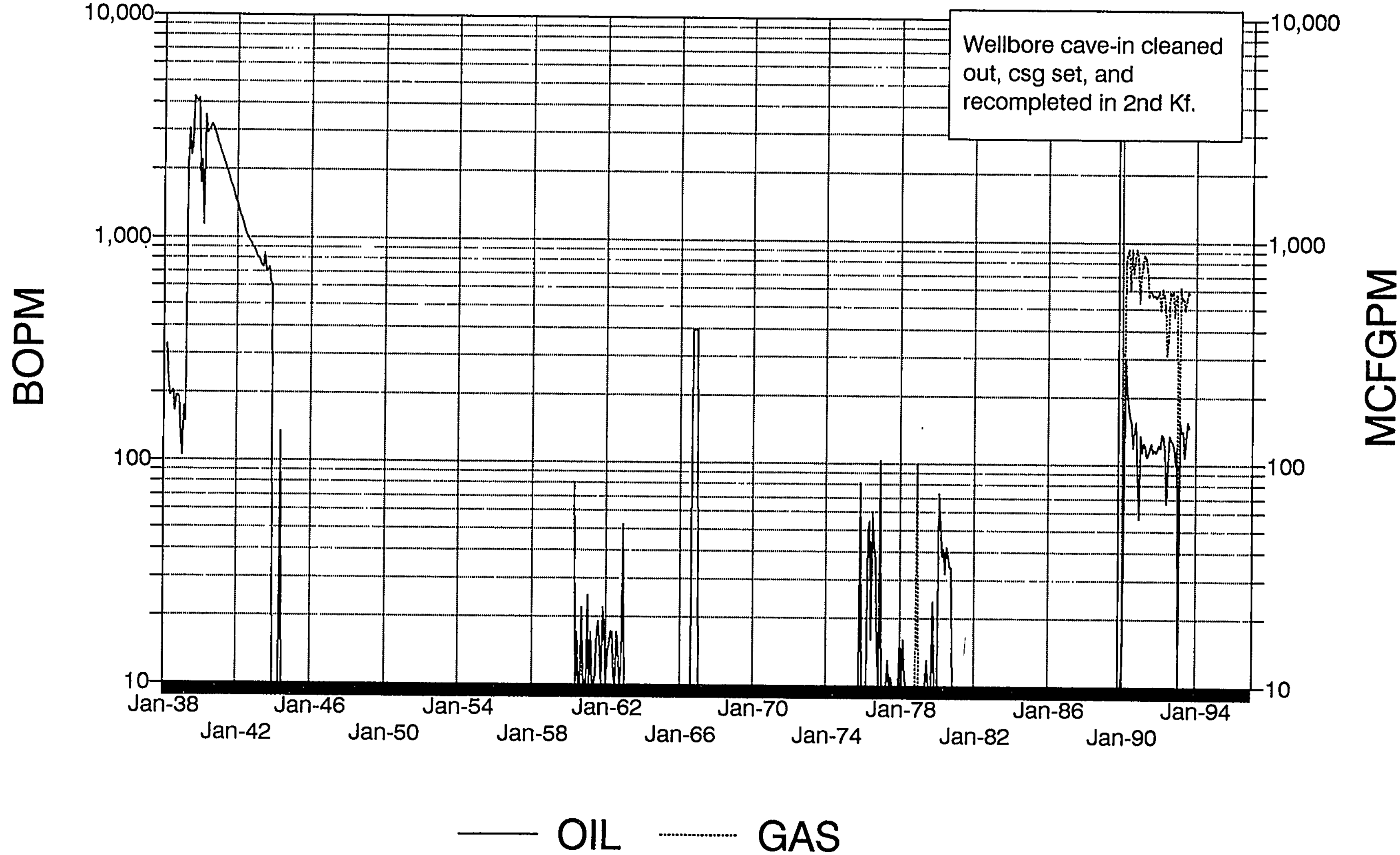
O&G 11/1/93 JPW

SIERRA ENERGY #16 BBFU
MONTHLY PRODUCTION DATA



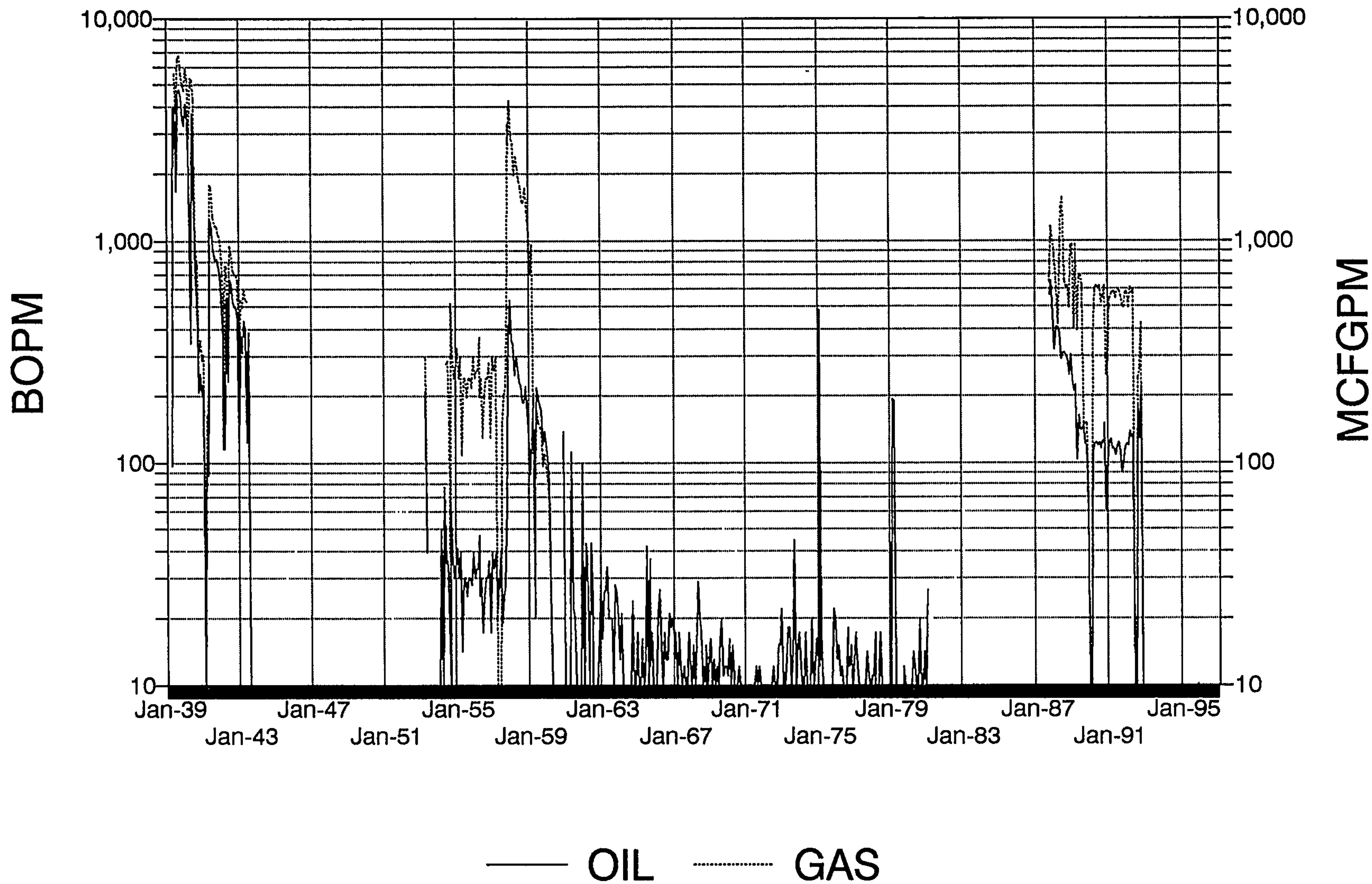
O&G 11/29/93 JPW

SIERRA ENERGY #17 BBFU
MONTHLY PRODUCTION DATA



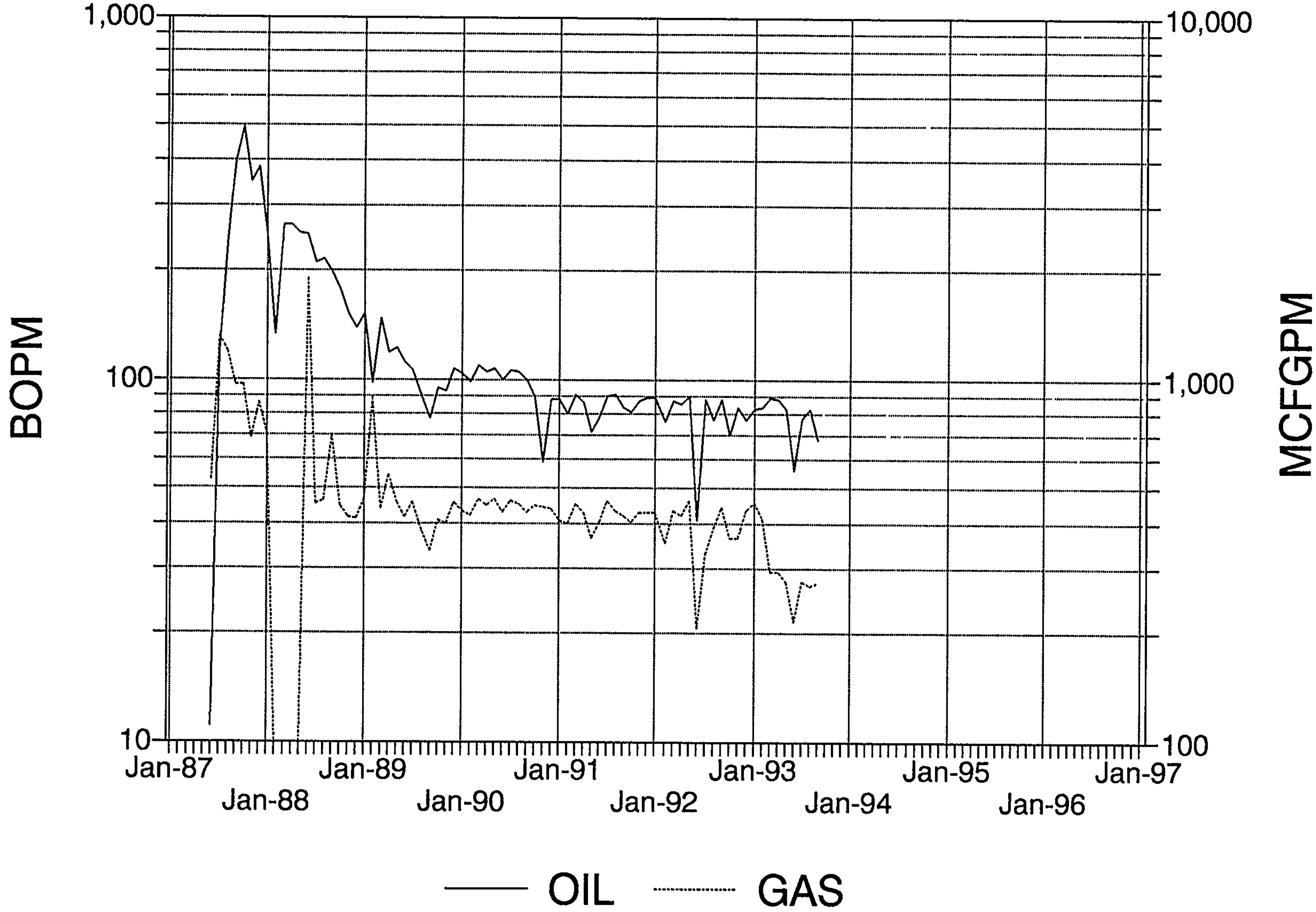
O&G-ALL 11/1/93 JPW

SIERRA ENERGY #18 BBFU
MONTHLY PRODUCTION DATA



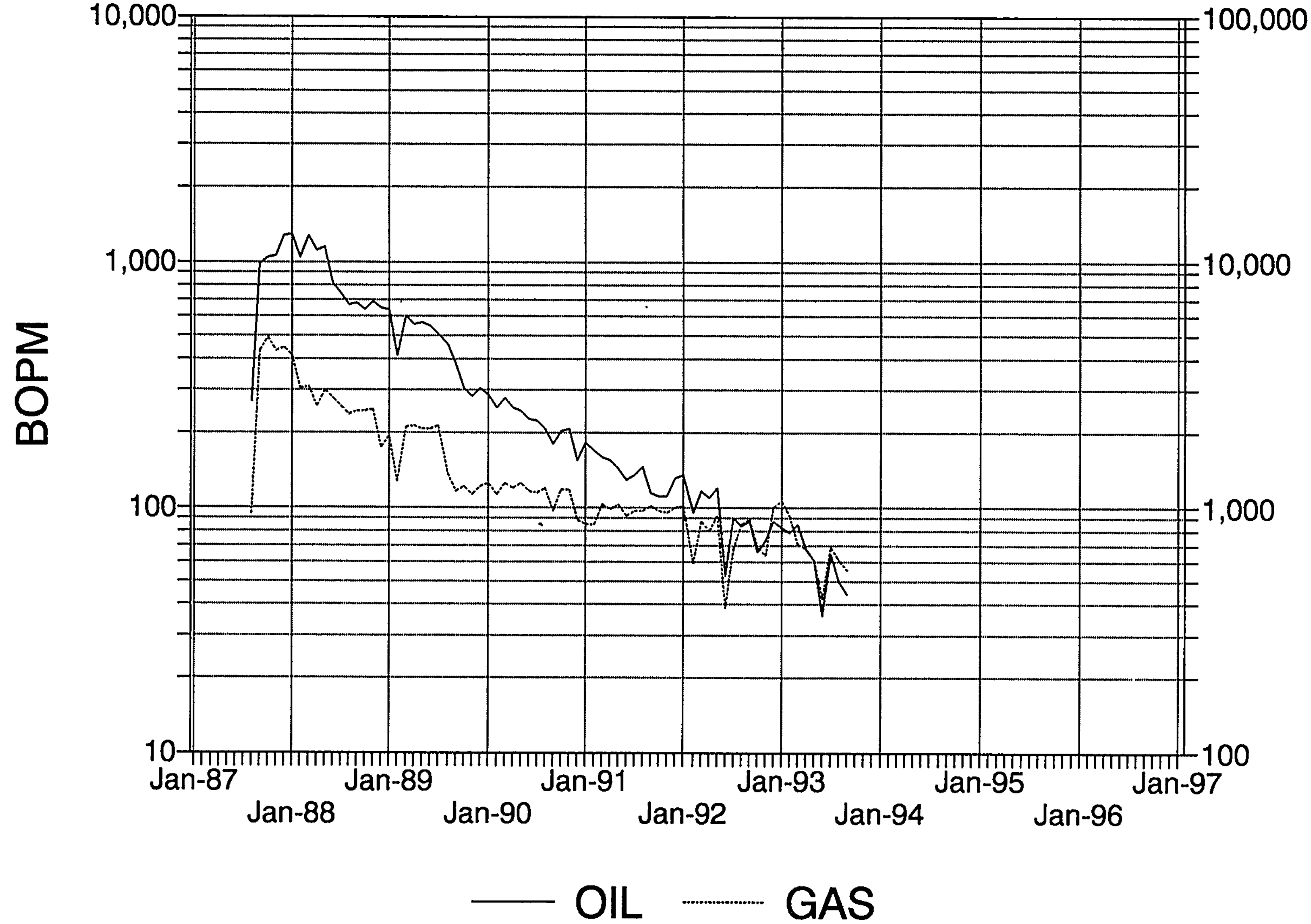
O&G-ALL 11/1/93 JPW

SIERRA ENERGY #19 BBFU
MONTHLY PRODUCTION DATA



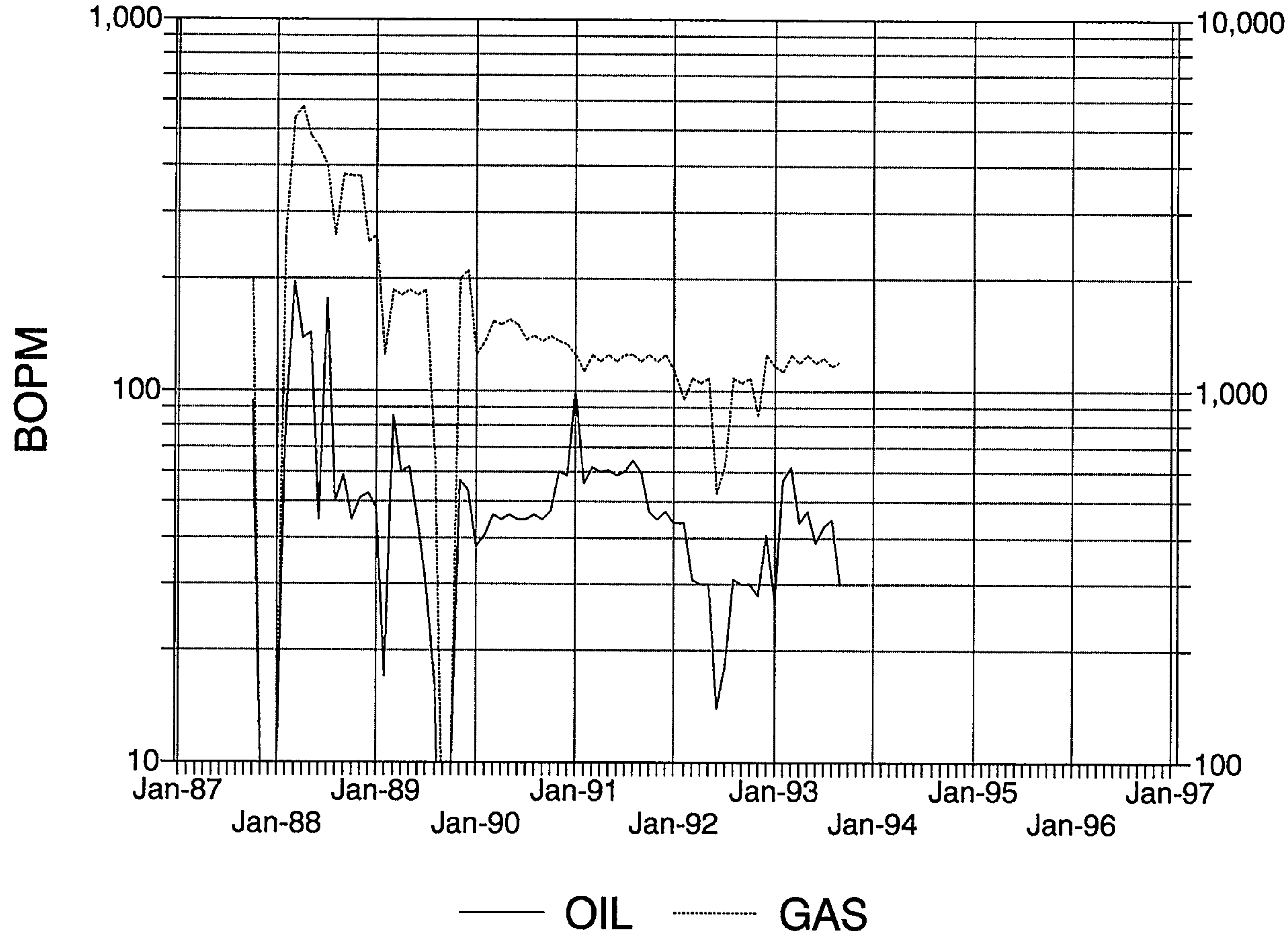
O&G 11/1/93 JPW

SIERRA ENERGY #20 BBFU
MONTHLY PRODUCTION DATA



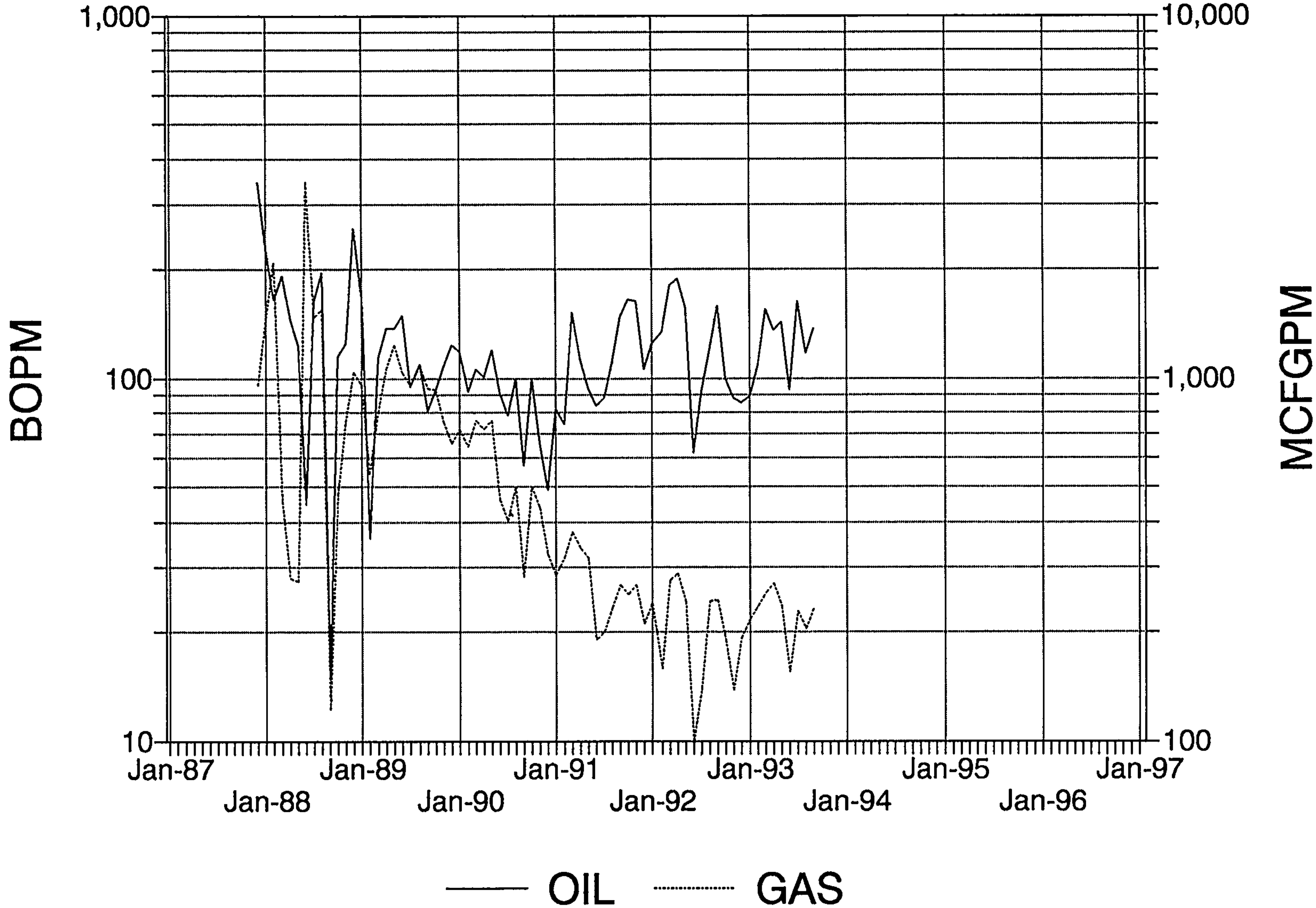
O&G 11/1/93 JPW

SIERRA ENERGY #21 BBFU
MONTHLY PRODUCTION DATA



O&G 11/1/93 JPW

SIERRA ENERGY #22 BBFU
MONTHLY PRODUCTION DATA



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