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Strategic Petroleum Reserve (SPR) Oil Storage Cavern Sulphur Mines 2-4-5 Certification Tests and Analysis

Part 1 1981 Testing
Part 2 1982 Testing

Richard R. Beasley

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STRATEGIC PETROLEUM RESERVE (SPR) OIL STORAGE CAVERN SULPHUR MINES 2-4-5 CERTIFICATION TESTS AND ANALYSIS

PART I 1981 TESTING
PART II 1982 TESTING

Richard R. Beasley
SPR Geotechnical Division 9773
Sandia National Laboratories
Albuquerque, NM 87185

ABSTRACT

Well leak tests and a cavern pressure test were conducted in June through December 1981, and are described in PART I. The tests did not indicate conclusively that there was no leakage from the cavern, but the data indicate that cavern structural failure during oil storage is unlikely. The test results indicated that retesting and well workover were desirable prior to making a decision on the cavern use. Well leak tests were conducted in March through May 1982, and are described in PART II. The tests indicated that there was no significant leakage from wells 2 and 4 but that the leakage from wells 2A and 5 exceeded the DOE criterion. Because of the proximity of cavern 2-4-5 to the edge of the salt, this cavern should be considered for only one fill/withdrawal cycle prior to extensive reevaluation.

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INTRODUCTION

Cavern 2-4-5 at the Sulphur Mines, Louisiana SPR Oil storage site was certified for oil storage on November 2, 1977 (Ref. 1). The Dowell Sonar caliper survey taken November 29, 1977, and included in Ref. 1, indicated a total composite cavern volume of 12.34 x 10^6 bbls.

The surveys taken in May 1979 (included in the W-F&S well histories) indicated a total cavern volume of 13.57 x 10^6 bbls. The surveys in well 2A and well 4 as taken in 1981 (Ref 2 & 3) do not include a composite cavern volume because no survey was run in well 5. There was surely a volume increase in cavern 5 as a result of continued brining, prior to June 10, 1981, to get brine enrichment for PPG.

Testing described in Part I of this report was started in July 1981 using test procedures (Ref. 4) which were developed in conjunction with the procedures and testing of West Hackberry cavern 6 (Ref. 5 and 6). This testing continued through December 1981 and verified gas entry into the cavern and indicated some abnormal pressure behavior. We recommended to DOE that testing to locate the gas entry/exit location be conducted and that access through well 5 be provided and that well 5 be tested prior to oil storage.

Testing described in Part II of this report was started in March 1982 and included wells 2, 2A, 4, and 5. Preliminary data indicated a combined leak rate at storage conditions of the order of two thousand barrels per year from well 2A and from well 5. This information was discussed with DOE, and the test effort was stopped in May 1982.

HISTORY

Well 2 was originally completed in 1946, well 4 in 1949, and well 5 in 1953 as brine producing wells. A sonar caliper survey conducted in 1973 for Allied Chemical Company indicated a composite cavern volume of approximately 15 x 10^6 bbls (Ref. 1). The cavern survey conducted in 1977 for Gulf Interstate indicated a composite cavern volume of 12.34 x 10^6 bbls (Ref. 1).

The site has a commercial history which dates back to 1868 when the Louisiana Petroleum and Coal Oil Company drilled the first oil exploration well. Subsequent exploration efforts discovered large deposits of high quality sulphur in the caprock. After several attempts to mine the sulphur conventionally, Herman Frasch invented a method to recover the sulphur using pressurized hot water. Approximately 9,400,000 tons of sulphur were removed from the caprock using the Frasch process. The removal of this vast amount of sulphur caused the overlying caprock to collapse causing subsidence at the surface. In addition to the sulphur industry, oil and gas have been produced by Union Texas Petroleum Company from the flanks of the dome. Pittsburgh Plate Glass and Allied Chemical still have active brining operations in the dome. PPG produces brine from BSW 14 and BSW 15. Allied Chemical stores ethylene in BW 1 and BW 3 (Ref. 7).

In 1977 the DOE acquired approximately 640 acres for the SPR facilities at Sulphur Mines from Allied Chemical Corporation. During 1977, Gulf Interstate Engineering Company undertook certification studies for each of the acquired caverns. These were the 2-4-5 gallery and caverns 6 and 7. All were determined to be suitable for oil storage for five storage cycles (Ref. 1). Later, DOE determined that Sulphur Mines would only be utilized for one storage cycle. The storage potential in 1977 was approximately 24 million barrels (Ref. 7). The cavern locations are illustrated in Figure 1.

A workover of well 2 in May and June 1979 included installation of the 8 5/8 inch-32 lb/ft-K55-flush joint casing to a casing seat depth of 1821 ft (Ref. 8). A hanging string of 5 1/2 inch-14 lb/ft-K55 casing was set to 3057 ft, but this casing was removed by TBC prior to the initiation of testing in 1981.

Reentry well 2A was drilled in July and August 1979 (Ref. 9). The final cemented string was 10 3/4 inch-45.5 lb/ft-K55 casing to a casing seat depth of 1815 ft below bradenhead. A hanging string of 7-inch 23 lb/ft-K55 casing was set to 2748 ft, but this string was removed and reinstalled by TBC prior to the initiation of testing in 1981 (Ref. 10).

A workover of well 4 in May and June 1979 (Ref. 11) included installation of the 8 5/8 inch-32 lb/ft-K55 flush joint casing to a casing seat depth of 1788 ft below

bradenhead. A hanging string of 5 1/2 inch-14 lb/ft-K55 casing was set to 3070 ft, but this string was removed and reinstalled by TBC prior to the initiation of testing in 1981 (Ref. 12).

Free gas was observed in wells 2 and 2A in early 1980 by TBC. The quantities of gas were not determined, and since cavern leaching continued until February 1981, there is no verification from the pressure records.

A workover of well 5 in 1957 included installation of 4.1 inch inside diameter pipe to a depth of 1690 ft below bradenhead. A workover of well 5 by W-F&S in May through July 1979 included a sonar log of cavern 5 and installation of a cement plug from 1570 ft to 1850 ft (Ref. 13). A workover of well 5 by TBC, in 1981, included drilling the cement plug, gas bleed-off, attempts at logging, and reestablishing a cement plug from 1550 ft to 1860 ft (Ref. 14). The well configurations are shown in Figures 2, 3, 4, and 5.

Certification testing was started with the low pressure cavern test on July 13, 1981, and was continued through December 9, 1981. There were interruptions in the testing for well workovers along with other delays. During interruptions and delays and after December 9, 1981, the O&M contractor continued to collect pressure data from wellhead gages. Results of this test indicate significant gas entry at low pressures and a zero cavern pressure increase with the cavern pressurized to a gradient at 0.77 psi/ft at the shallowest casing seat. These results led us to recommend that oil not be stored until additional cavern evaluation and workover can be completed. This recommendation was presented to DOE in briefings on December 9, 1981, and on January 14, 1982.

Gas entry and well leak testing was restarted on March 17, 1982, and was continued through May 31, 1982. Results of this test indicate significant gas entry at low pressures and significant leakage from wells 2A and 5. This information led DOE to stop the testing prior to installation of any new piping in well 5.

DIAGNOSTIC ACTIVITIES

All the cavern analyses use salt properties as derived from West Hackberry salt as published in Ref. 15 because there is no salt core and no side-wall-sample material available from Sulphur Mines site.

Table 1 contains a listing of all available logs for the four wells. The interface logs were run to locate the nitrogen/brine interface during well leak tests. The temperature logs in well 2 (Figure 6) indicate nearly negligible temperature increase over a period of about 6 months. The average temperature from 0 to 2000 feet was 126°F with a maximum temperature of about 160°F. These high temperatures in the area of 600 feet are the result of residual heat from the sulphur mining operations. The brine samples were analyzed and show about 99% saturation. The analysis of these samples is included in Table 4.

Cavern sonar surveys were made and indicate the following volumes:

Date	Well	Composite Volume, bbls
1977 (Ref. 1)	2, 4, 5	12.34×10^6
1979 (Ref. 8, 11, 13)	2, 4, 5	13.57×10^6
1981 (Ref. 2&3)	2A, 4	No composite

The latest sonar survey indicates a composite cavern shape as shown in Figure 7.

To determine the best estimate of the distance from cavern 4 to the edge of the salt, a study was done to review all of the available data from wells outside and inside of the salt dome, in the area of cavern 4. The cavern sonar data from Ref. 3, the well 4 directional log data from Ref. 10, data collected during preparation of Ref. 7, and the results of a 1981 well location survey by Todd Engineering were combined to arrive at an edge distance of 140 ft. ± 100 ft. The tolerance on this estimate is composed of (1) ± 25 ft. for downhole wellbore locations for off dome wells, (2) ± 55 ft. for location of the salt edge based on contours through the salt picks from well logs and drilling records, (3) ± 13 ft. for location of the cavern wing using 5 percent error on 250 ft. radius, and (4) ± 7 ft. for the location of well 4 at the cavern roof. The cavern and salt edge are shown in Figure 7.

PART I

LOW PRESSURE TEST
WELL LEAK TEST AND CAVERN PRESSURE TEST
IN JULY - DECEMBER 1981

Following a partial completion of the well workover activities by TBC (Ref. 10, 12, 14) testing was started on July 13, 1981, at 1130 hours using the procedures in Ref. 4. On some occasions it was necessary to achieve compatibility with equipment availability, schedules and other site activities.

The test sequence was: 1) a low pressure test at a .47 psi/ft gradient; 2) cavern pressure tests at a 0.80 psi/ft gradient followed by 0.65 psi/ft gradient; 3) the well leak tests and 4) pressure tests at 0.75, 0.70, 0.65, 0.60, and 0.55 psi/ft gradient summarized in Figure 8 and in Table 5. The test pressure records are shown in Figures 9 through 35.

Low Pressure Test

The low pressure test was conducted from July 13, 1981, through July 27, 1981, as defined in Ref. 4. The pressure criteria for the low pressure test was 0.47 psi/ft at the casing seat (1700 ft x 0.47 = 799 psia). This test was conducted at 0.05 psi/ft less than the 0.52 psi/ft brinehead to verify that there would not be a loss of cavern structural integrity, particularly of the salt web between the cavern and the edge of dome, at minimum storage pressures.

Brine was extracted from the cavern using an airlift in well 2A and a downhole transducer at a depth of 1700 ft. in well 2 served as the control. After the desired pressure level was reached, the airlift was run intermittently to maintain the pressure at 1700 ft near 799 psia. The cavern average closure rate to maintain this 799 psia pressure was difficult to determine because of the oil extraction from well 4 and the workover on well 5, but the pressure was increasing at about 8 psi/day. The pressure vs time plots are shown in Figures 9 and 10.

Cavern Shut in at Maximum Allowable Pressure

Cavern pressurization was started on August 27 using the site pumps and taking brine from the site pond. There was no test activity from July 27 to August 27, but the data start time of July 13 at 1130 hours was retained. The cavern was pressurized through well 2 over a period of 2 days to a well 2A pressure of 515 psia which is 0.80 psi/ft at a depth of 1788 ft. Pressure change was from 140 psi to 515 psi and 36167 bbls

were pumped. This test was run with Lynes instruments until September 3 when the Lynes instruments were removed for economic reasons. From September 3 through September 22, the pressure was monitored using site gages. From September 23 through September 25, the pressure was monitored using Sandia gages. From September 25 through October 2, the pressure was monitored using site gages. The slope of the pressure curve from September 23 through October 2 was 0.0 psi/day and the final brine pressure was 428 psia (0.76 psi/ft at 1690 ft).

On October 2, TBC bled the cavern through well 2A annulus to a pressure of 250 psig and DUCI continued to monitor the pressures. Small quantities of gas and oil were occasionally bled from the three wells, but it is likely that this was trapped roof oil released due to the pressure decrease. This test was continued through October 20, and the final slope of the pressure curves was about plus 1.5 psi/day. The pressure curves for this test are shown in Figures 11 through 13, and the data from the Sandia transducers is shown in Figure 14.

Well Leak Test

Testing with Lynes instrumentation resumed on October 15, 1981. The brine pressure had increased to about 300 psi so no pressurization was required. The data start time for the remainder of the 1981 tests is October 21, 1981 (Day 294) at 2000 hours. The cavern pressure vs time plots from this time are shown in summary in Figures 15 through 17. The data from the interface logs, the cavern pressures, and the calculated leak rates are shown in Table 6. Details of the leak rate calculational procedures are identical to those used in Ref. 16 and 17. The pressure vs. time plots are shown in Figures 18 through 20. The pressure curve near the end of this test was increasing at about 0.7 psi/day.

The leak rate calculation requires knowledge of pressures, temperatures, interface depths, and borehole volumes in the zone of the nitrogen-brine interface. The interface depths are measured, the pressures are measured, and the nitrogen temperature is assumed to be a constant. The borehole volumes are obtained from a combination of drilling history, caliper logs if available, and weights of nitrogen put into the well. The nitrogen weights are obtained by using a load cell to weigh the Waukesha-Pierce Ind. liquid nitrogen tank during injection and using a density log to spot the interface as it passes a given depth. The borehole volume data are probably the most inaccurate of the inputs required for leak rate calculation.

Leak rates are a function of several variables including pressures, fluid type, flow path, flow type, and others. The pressures during the tests and during oil storage are described in Table 7, and it is apparent that the average oil pressure at the casing seat will be less than the nitrogen test pressure at the casing seat. This reduced pressure will result in a reduced leak rate. A review of the pressure drop equations (Ref. 18)) indicates that for turbulent flow through rough wall passages, volumetric loss rates of crude oil could be as high as about one-third the volumetric loss rates of nitrogen at 100 atmospheres and 100°F. From this maximum, the volumetric loss rate of crude oil decreases about two orders of magnitude for laminar flow (Ref. 6). At the maximum ratio of one-third oil to nitrogen volumetric loss rate and the probable reduced casing seat pressure, the indicated oil leak rate from the wells is less than the DOE criterion of 100 bbls/yr for a cavern.

Cavern Shut In at Maximum Operating and Lower Pressures

After completion of the well leak tests and the removal of N_2 from the wells, the series of cavern brine tests at 5 pressures was started. Cavern pressurization on October 30 was through the annulus of well 2A, used the site pumps at a pump pressure of 725 psi, and raised the cavern pressure from 305 psi to 405 psi in about 2.5 hours. The pressures were monitored and well 4 annulus slope went positive at about 300 hours while the other slopes are negative. This was an indication of a low density material (gas or oil) entering well 4. On November 6, 95 ft^3 of gas at STP (3.7 ft^3 at well pressures) and 0.37 bbl of gas cut oil were bled from well 4 annulus. It was concluded that this was oil off the cavern roof that released gas as it migrated up the well bore. Except for well 4 annulus, the final slope of the pressure curves at 385 psi (0.75 psi/ft) was 0.0 psi/day. The pressure behavior for eleven days can be seen in Figures 21 through 23. This behavior was unexpected because other caverns showed positive slopes at the maximum operating pressure of 0.75 psi/ft.

After the eleven-day test at maximum operating pressure, the pressure was about 385 psia (0.74 psi/ft) and a sequence of tests were started at incrementally lower pressures to determine at what pressures gas started to enter the cavern. Brine was bled through the 2A annulus to reduce the pressure to about 320 psia (0.70 psi/ft). The test at this level was run for only three days, and the pressure curves are shown in Figures 24 through 26. There were no indications of gas entry.

Brine was bled off to reduce the pressure from about 340 psia to about 235 psia (0.65 psi/ft). This test was run for 10 days, and the pressure curves reached a final slope of plus 1.9 psi/day. The pressure curves are shown in Figures 27 through 29. There were no indications of gas entry.

Brine was bled off to reduce the pressure from about 280 psia to about 150 psia (0.60 psi/ft). This test was run for eight days, and the pressure curves reached a final slope of plus 3.0 psi/day. The pressure curves are shown in Figures 30 through 32. The step in the pressure curve of Figure 32A was a bleed of gas and oil from well 4, but it is probable that the gas was released from the oil as it migrated up the well. There was no other indication of gas entry.

Brine was bled off on December 1 to reduce the pressure from about 200 psia to about 65 psia (0.55 psi/ft). During the bleeddown, it was noted that well 2 started making gas. Immediately after we stopped bleeding brine through 2A annulus, it became obvious that well 2A was also making gas. Gas and oil were periodically bled from the three wells and the resulting changes in pressure can be seen in the pressure curves shown in Figures 33 through 35. Oil and gas quantities that were bled from the wells are summarized in Table 8, and a summary of the gas analyses is presented in Table 9. The gas and oil bled prior to December 1 could logically have come from out gassing of oil and brine and from oil migrating from the cavern roof. The large quantities found on December 1 indicate that another gas source was tapped. The Lynes pressure instruments were removed on December 9, but DUCI continued to read the well pressure gauges. The cavern was kept shut in and no gas or oil was bled off between December 7 and February 10, 1982. The pressure curve from well 4 annulus, Figure 35A, shows a change in slope near hour 1717 which was January 1, 1982. This change indicates the beginning of a free gas cap formation in the well. The slope of the pressure curves appear to have reached a constant value of plus 1.0 psi/day in late January 1982 (60 days at this pressure). Activities after January 1, 1982, are discussed in PART II of this report.

Pressurization and Bleeddown

The cavern depressurization to 0.47 psi/ft on July 14 and July 15 used an airlift system. The brine pumped was 5800 bbl to reduce the downhole pressure from 900 psia to 810 psia in a period of 18 hours. This is 73 bbl/psi, .08 psi/min, and 322 bbl/hr. The value of elasticity, 73 bbl/psi, is taken from the straight line portion of the curve in Figure 36 prior to the disturbance of a gas release from well 5. The recovery rate at 800 psia after about 300 hours at low pressure was 8 psi/day. The average recovery rate from 800 psi to 900 psi was not determined due to well workover activity on well 5.

Cavern pressurization on August 27-29 went from approximately 140 psi to 515 psia with several shutdown perious. This pressurization gave a high elasticity value of 96 bbl/psi due to several shutdowns and several plumbing leaks. Therefore, this value will not be used in any calculations. There were no volume measurements made during the subsequent bleeddown and pressurization cycles.

The system elasticity at a pressure change rate of about 0.1 psi/min is 73 bbl/psi This system elasticity is compared to the value of brine elasticity, using the values from Ref. 19 at 90°F, of:

2.1×10^{-6} bbl/bbl/psi x 13.57×10^{6} bbl = 28.5 bbl/psi which leaves 73 - 28.5 = 44.5 bbl/psi for a cavern (salt) elasticity. This 44.5 bbl/psi for cavern 2-4-5 is high compared to 9.7 bbl/psi for cavern 6 (Ref. 16) and 7.1 bbl/psi for cavern 7 (Ref 17).

Summary of Pressure Change Rate Results

The measured rates of cavern 2-4-5 wellhead brine pressure change at different cavern pressures are summarized as follows:

Wellhead Pressure (psia)	Pressure Change Rate (psi/day)
-100	+ 8
428	0
300	+1.5
310	+0.7
385	0
280	+1.9
200	+3.0 (+1.0 in Jan. '82)

The parameters of brine temperature and brine salinity must be considered with the pressure change rate. As previously stated, the temperature change rate was negligible, and the brine salinity was near saturation. Therefore, it is expected that both affects are very small and being of opposite sign, essentially are canceling effects.

The decreasing pressure at the maximum allowable pressure, constant pressure at maximum operating pressure, and the trend of increasing pressure change with decreasing pressure must be due to a combination of salt creep and cavern leakage.

Salt creep, the time dependent flow of salt under stressed conditions, will cause volume changes of underground salt storage caverns. Changing volumes correspond to changing pressures, therefore, evaluation of salt creep is essential to the analysis of leak rate in terms of cavern pressure. Salt creep is a very complex and incompletely understood phenomenon. Finite element methods, as

currently used for salt creep analyses of underground salt storage caverns, are generally considered to provide comparative relative results, but only order of magnitude results in an absolute sense for short times (< 300 days). Factors affecting the accuracy of such analyses include; typical relatively large variations in measured values of salt properties which must be used in the analyses; differences between the behavior of laboratory specimens and the insitu salt; the dependence of creep on salt temperature to about the ninth power; and the time dependent and stress history dependent nature of creep. Unfortunately, order of magnitude creep analyses are inadequate for analysis of cavern pressures in terms of leak rate. It is thus generally concluded that complete analysis of pressure test results for SPR storage caverns, in terms of leak rates, are not possible with presently available methods of salt creep analysis. It appears possible that in-situ measurements underway in caverns may in the future provide data to improve the accuracy of creep calculations, possibly to the point where they would be useful to calculate actual leak rates from pressure tests. (Ref. 6).

The unknowns associated with creep and the data scatter of the data points make detailed quantitative intepretation questionable. Some general conclusions are possible:

1. Cavern closure rate and leak rate are indistinguishable at this time. Therefore, pressure change rates are cavern closure rate minus leak rate. However, for this cavern gallery at maximum operating pressures, the pressure was constant indicating creep closure equaled any pressure loss due to a leak. All other caverns tested had a pressure increase at this pressure condition.
2. Pressure change rate is higher with lower cavern pressure.
3. The pressure change rates of Sulphur Mines 2-4-5 (Table 10) are lower than Sulphur Mines 6 and 7 which are similar to those of West Hackberry 6 (Ref. 6).

PART I DISCUSSION

Generally speaking, the most probable location of leakage from a cavern is from the wells, where the competent salt has been breached. However, there is a possibility of leakage from the cavern proper. If such leakage does exist, the probability is high that it will be to a nearby cavern or a nearby edge of dome. In the case of salt domes where extensive gas is present, a possible leakage path would be to caprock through a zone of gas bearing impurities in the salt.

Cavern 2-4-5 is about 140 ft. from the dome edge as shown in Figure 7 and well 5 casing is 130 ft into salt as shown in Figure 5. The pressure data at maximum operating pressure shows a slope of 0.0 psi/day which indicates that cavern leakage is equal to cavern creep. The well test data excluding well 5, which could not be tested because it was plugged, indicated leaks in the well casing seat area are less than the DOE criterion of 100 bbls/yr.

In addition to concerns regarding cavern leakage, another concern is the structural integrity of the cavern. Sonar surveys indicate that the cavern has salt ledges and consists of three coalesced caverns. The sonar caliper has a definite beam width and, therefore, cannot "see" brine paths smaller than this beam width. For example, the leached lense in cavern 4 at 2930 ft. shows a dimension of 340 ft. to the east as illustrated in Figure 7, but in fact this lense may be significantly larger than indicated. Based on analysis of ledges in SM #6, a ledge fall during oil fill/storage is possible but unlikely and would not cause a cavern structural integrity problem.

PART I CONCLUSIONS AND RECOMMENDATIONS

Although all questions cannot be conclusively eliminated, cavern 2-4-5 in its condition at the end of 1981 does not appear to be suitable for long term oil storage at normal pressure.

1. In general, the most probable location of a cavern leak is from the wells. Well 2, 2A, and 4 leaks measured during the 1981 test indicate oil leaks from the wells during storage at near brine head pressures were within the DOE leak rate criterion of 100 bbls/yr per cavern.

2. It was not possible on the basis of the pressure tests to determine conclusively that there was no cavern leakage, in addition to that measured from the wells, due to the indeterminate effect of creep closure. However, this cavern did not exhibit the same pressure/time behavior as other caverns that have been tested. This leads us to a concern that the cavern is leaking.

3. The cavern is separated from the edge of the dome by about 140 ± 100 feet in cavern 4 and 130 feet ± 20 feet in well 5, which is less than the 300 feet minimum required in new design. With good salt properties under normal conditions the 100 feet is structurally adequate but the quality of salt is unknown.

4. Analyses indicate the cavern, assuming 100 feet of competent salt to the dome edge, is structurally adequate except for unlikely ledge falls during or after oil fill.

5. The cavern produces gas at brine pressures less than 200 psi.

6. It is recommended that the cavern be evaluated to determine the source of gas and the potential for oil escape along the gas entry path.

7. It is recommended that access to the cavern be provided through well 5 and that this well be tested prior to oil storage (Ref. 20).

8. It is recommended that prior to oil storage a program be initiated to monitor the activities and the production of all Union Texas Petroleum and PPG wells and caverns in the vicinity of cavern 2-4-5 (Ref. 21 and 22).

PART II

Well Leak Tests in March-May 1982

Following the stop of testing and removal of the Lynes pressure instruments on December 9, 1981, the site personnel continued to take gauge pressure readings with the cavern shut in. The shut in pressure on December 1, 1981, was about 65 psia, and this pressure continued to increase to 275 psia on March 17, 1982. The slope of the pressure curve in early February was plus 1.2 psi/day.

On February 10, 1982, wells 2, 2A, and 4 were bled to remove all gas and oil to verify what each well was producing. The results of this bleed were:

Well #	Start Pressure psig	Finish Pressure psig	Gas Vol. At STP ft^3	Oil Vol. bbl
2	235	235	0	0
2A	350	210	28000	<1
4	335	220	18000	<1

This data verified that wells 2A and 4 were both producing gas at pressures between 65 and 220 psig.

The configurations of wells 2A and 5 as of May 1982 are shown in Figures 37 and 38. A summary of the borehole logs is shown in Tables 11 and 12. A summary of the 1982 testing is shown in Table 13 and Figure 39.

Well Leak Tests with N_2 (Brine Pressure = 275)

These well leak tests started March 17 and continued through April 2. The data time was started with hour zero at 0000 hours March 17. The brine pressure had increased to about 271 psia and the desired N_2-brine interface depth was 2325 ft. This resulted in pressure gradients at the casing seats in 2, 2A, and 4 of less than 0.81 psi/ft, and this gradient was considered acceptable to POSSI and to SNL. The cavern pressure vs. time plots are shown in Figures 40 through 43. The data from the interface logs, the cavern pressures, and the calculated leak rates are shown in Table 14. Details of the leak rate calculational procedures are identical to those used in References 16 and 17. The hole volume used is that determined from N_2 injection and not that calculated from the caliper logs. The technique of weighing the nitrogen injected will in general give calculated hole sizes that are reasonable when compared to the caliper logs.

The oil leak rates in wells 2 and 4 corresponding to the measured nitrogen leak rate were considered acceptable, but based on the measured nitrogen leak rate the oil leak rate in well 2A was expected to exceed the DOE criterion of 100 bbl/yr.

Low Pressure Tests (Brine Pressure = 25)

This evaluation was run during the workover to drill through the plug in well 5. The cavern was depressurized on April 2 and repressurized on April 14. The details of the drilling can be obtained from the drillers record from Welsh Drilling. The penetration rates indicated primarily poor quality cement and unconsolidated salt. There was such a small quantity of core recovered that analysis was not attempted, but some of the core showed high angle joints between two kinds of cement. The primary data obtained during this time were cavern bleeddown volumes which are summarized in Table 15 and gas analyses which are summarized in Table 16. The cavern pressure vs. time plots are shown in Figures 44 through 47.

Well Leak Tests with N_2 and Oil (Brine Pressure = 200)

These well leak tests started April 15 and continued through May 5. The brine pressure increased from the 200 psia set pressure on April 15 to 223 psia on May 5. The cavern brine pressure was increasing at about 1 psi/day at the end of this test. The cavern pressure vs. time plots are shown in Figures 48 through 51, and the leak rates are shown in Table 14. This test involved N_2 tests on wells 2A and 5 and a preliminary oil test of well 2A. One of the problems with the nitrogen test in well 5 was that 5 continued to produce gas at the rate of about 500 ft^3/day at STP. These tests offer an opportunity to compare a N_2 leak rate with an oil leak rate even though the pressures and depths were not identical. This comparison (oil leak rate about half of the N_2 leak rate) is sensitive to leak path and leak path pressures; therefore, this ratio should not be applied to other wells or other test conditions.

The logging of the oil-brine interface was difficult with this hole size and the hanging string. The technique used was to select a possible interface location on the density log then add oil or remove oil and determine if the log character changed. The first run of adding oil on 4/29 created additional difficulty because the oil was not measured and the interface was at the cavern roof before the logging techniques were established. The change in cavern pressure of 9 psi during oil injection, subsequent oil flow measurements, and detailed review of events during oil injection on 4/29 makes us confident that the total oil injected was about 9 psi x 70 bbl/psi = 630 bbl instead of the 268 bbl - 2440 ft x .0476 bbl/ft = 152 bbl required. The oil removed on 5/5 was 221 bbl.

The oil leak rates in wells 2A (measured) and 5 (estimated) were greater than the DOE criterion.

Well Leak Tests with Oil (Brine Pressure = 425)

These well leak tests started May 13 and continued through May 21 when the Lynes pressure instruments were removed (refer to Table 13). The brine pressure was increased to near the maximum allowable casing seat gradient of 0.81 psi/ft with oil in well 2A in an attempt to stop the gas entry into the wells. This brine pressure

of about 425 psia did stop the gas entry in 2, 2A, and 4, but not in well 5. We therefore continued to bleed the gas off of well 5 each day, and the average gas production at this pressure was approximately 200 ft^3/day at STP. The cavern pressure vs. time plots are shown in Figures 52 through 55, and the leak rates are shown in Table 14.

Prior to injection of oil into 2A on 5/13, the 7 inch hanging string was cut off at 1990 ft. The total volume of oil injected to set the interface to 2440 ft was 268 bbl. The total oil volume injected during this test was 374 bbl and the quantity details are shown in Table 15. This test was run by logging the interface and resetting that interface back to 2440 ft each day which gave a total of eight tests. The leak rate decreased with time and with decreasing pressure, but it is not clear what is controlling this relationship. It was decided that because the leak rates were more than an order of magnitude higher than the 100 bbl/year criterion, the test should be stopped.

Well Leak Test with Oil (Extension)

The previous tests were run with a daily interface relocation and with Lynes pressure instrumentation. It was determined that the test could continue for some longer duration with minimum cost after the Lynes instruments were removed by using dial gages to be read by the POSSI operators. This extension of the oil test ran from May 21 through May 31. On May 21, the interface was logged at 2381 ft but was not reset. On May 31, the interface was logged at 2173 ft and then the oil was removed. There were 218 bbl of oil removed compared to a total of 374 bbl injected between May 12 and May 20. The pressure vs. time curves are shown in Figures 56 and 57, and the leak rate is shown in Table 14.

Subsequent oil removed was 55 bbl on 6/10, and 10 bbl on 6/29 with the cavern at low pressure, plus we expect this well will continue to return small quantities of oil as it has since May 1981. This leak rate is lower than the tests of May 13 through May 21, but it compares with the preliminary oil test of April 29 through May 4 and is still over an order of magnitude higher than the 100 bbl/year criterion.

Summary of Pressure Change Results

When the cavern pressure was to be changed, the brine injected or removed was measured with a 6-inch Halliburton turbine flow meter. The summary of this data is shown in Table 17. It appears that the cavern elasticity is about 70 bbl/psi during pressurization and depressurization. As discussed in Part I of this report that leaves a relatively high value of elasticity for the salt cavern. This high cavern elasticity could be due to a combination of cavern shape, cavern proximity to dome edge, liquid or gas entrapments outside the measured volume, flow paths between the cavern and the area sediments, unusual salt properties such as the unconsolodated salt in well 5, and possibly other things.

SUMMARY DISCUSSION

The leak testing described in Part I of this report indicated no significant N_2 leaks from wells 2, 2A, and 4 with the N_2-brine interface at 1930 ft. The leak testing described in Part II of this report indicates, (1) no significant N_2 leaks from wells 2 and 4 with the N_2-brine interface below 2300 ft., (2) significant N_2 and oil leaks from well 2A with the N_2-brine or oil-brine interface below 2300 ft., and (3) significant N_2 leaks from well 5 with the N_2-brine interface below 1890 ft. This and other data indicate that the wellbore leak in well 2A is highest near the cavern roof and approaches zero above approximately 2000 ft. It is possible, but unproven, that the well 5 leak increases with depth similar to well 2A. It is also possible, but unproven, that there may be significant leaks directly from the roof around wells 2A and 5.

It had been suspected that there was a communication path between wells 2A and 5. After well 5 was opened on April 12, we were unable to show any communication between 2A and 5 with N_2 in 5, then with N_2 in 2A and then with oil in 2A. It is possible that there is a long tortuous leak path between 2A to 5, but it is more likely that these two wells have independent leak paths. Prior to injection of N_2 into 2A on 4/26, we attempted to calculate a nitrogen balance to compare the N_2 injected with the N_2 recovered and then to calculate an average leak rate. The total N_2 injected (3/19-3/29) was 232,000 ft^3, and the total bled out (3/31-4/26) was 207,000 ft^3. The loss was 25000 ft^3 from 3/19 to 3/31, and this translates to a leak rate of about 1600 bbl/yr. This calculation involves several approximations but does yield leak rates of the same magnitude as other tests.

Generally speaking, the most probable location of leakage from a cavern is from the wells, where the competent salt has been breached. However, there is a possibility of leakage from the cavern proper. If such leakage does exist, the probability is high that it will be to a nearby edge of dome. In the case where extensive gas is present, a possible leakage path would be to caprock through a zone of gas bearing impurities in the salt. This dome may well have some caprock located on the dome flanks as well as on the top. Therefore, this possible leak path is not necessarily vertical.

Cavern 2-4-5 is about 140 ft. from the dome edge as shown in Figure 7 and well 5 casing is 130 ft. into salt as shown in Figure 5. The pressure data at maximum operating pressure show a final slope of zero, which indicates that cavern leakage is equal to cavern creep. The pressure data at 275 psi shows a final slope of plus 1 psi/day after about 3 months, which indicates that cavern leakage is less than cavern creep plus gas entry.

Efforts including field measurements at oil filled caverns are underway to attempt to validate the creep models such as "SANCHO". This data will allow prediction of cavern creep closure on the basis of theory and experimental data. These and other calculations on Sulphur Mines caverns will be limited due to lack of material properties data on Sulphur Mines salt.

CONCLUSIONS AND RECOMMENDATIONS

Although all questions cannot be conclusively eliminated, cavern 2-4-5 in its present condition does not appear to be suitable for long term oil storage under standard storage conditions.

1. In general, the most probable location of a cavern leak is from the wells. Measured oil leak rates in well 2A (with oil to 2440 feet and cavern roof at 2445) were 4000 and 1370 barrels per year at brine surface pressures of 435 and 200 psi respectively. The measured nitrogen leak rate in well 2A at 200 psi surface brine pressure was 2374 barrels per year. The measured nitrogen leak rate in well 5 with nitrogen to 1900 feet was 1550 barrels per year at a brine surface pressure of 200 psi.

   Based on extrapolation of the above test data to oil storage conditions (brine pressure $\approx$50 psi) the combined leak rate is approximately 2000 barrels per year.

2. At a surface brine pressure of 200 psi, wells 2A and 5 produce gas (predominantly methane) at a rate of 120 and 500 standard cubic feet per day respectively.

3. It was not possible on the basis of the pressure tests to determine conclusively that there was no cavern leakage in addition to that measured from the wells due to the indeterminate effect of creep closure. However, this cavern did not exhibit the same pressure/time behavior as other caverns that have been tested. This may be due to the leaks in wells 2A and 5.

4. The cavern is separated from the edge of the dome by about 140 $\pm$ 100 feet in cavern 4 and from the top of the salt in well 5 by 160 $\pm$ 20 feet, which is less than the 300 feet minimum required in new design. Analyses indicate the cavern, assuming 100 feet of competent salt to the dome edge, is structurally adequate except for unlikely ledge falls during or after oil fill.

5. It is recommended that if there is to be oil storage, a program be initiated to monitor the activities and the production of all Union Texas Petroleum and PPG wells and caverns in the vicinity of cavern 2-4-5 (Reference 21 and 22).

6. It is recommended that oil not be stored such that it is in contact with the borehole of wells 2A and 5.

7. The risk associated with storage of oil in cavern 4 above the connection to caverns 5 and 2 (about 1.5 million bbl) appears to be acceptable.

Sulphur Mines Cavern 6
Test Report References

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4. Letter, J. F. Ney to E. E. Chapple, re: Proposed Test Procedures for Sulphur Mines Caverns, SL-SPR-EE-SM-10A, dtd 5/26/81.

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20 Memo, J. F. Ney to E. E. Chapple, Sulphur Mines Cavern 2-4-5, dtd 2/6/81, SL-SPR-EE-SM-04.

21. Memo, J. F. Ney to E. E. Chapple, Possible Oil Loss at Sulphur Mines, dtd 3/31/81, SL-SPR-EE-SM-09.

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TABLE 1

List of Borehole Logs S. M. Well 2

Date	Type of Log	Log Co.	Log Location
9/2/77	Temperature	McC	Ref 1
9/8/77	Sonar	Dowell	Ref 1
9/9/77	Direction	Sperry-Sun	Ref 1
9/12/77	Casing Insp	Micro	Ref 1
5/6/79	Direction	Sperry-Sun	Ref 8
5/12/79	Sonar	Dowell	Ref 8
5/22/79	Caliper	Sch	Ref 8
6/1/79	CBL	GO	Ref 8
6/6/79	Collar	GO	Ref 8
6/12/79	Formation Tester	Sch	Ref 8
5/29/81	Downhole TV	Sandia	DOESPRPMO
6/4/81	CBL	Micro	TBC
6/5/81	Caliper	Gearhart	TBC
6/9/81	Temperature	Gearhart	TBC
7/20/81	Interface	Micro	TBC
10/23/81	Interface	Micro	TBC
10/26/81	Interface	Micro	TBC
10/29/81	Interface	Micro	TBC
12/18/81	Temperature	Micro	TBC

List of Borehole Logs S. M. Well 2A

7/3/79	Induction	Sch	Ref 10
7/4/79	Caliper	Sch	Ref 10
7/12/79	Density	Dresser	Ref 10
8/2/79	Caliper	Dresser	Ref 10
8/8/79	CBL	Sch	Ref 10
8/9/79	Density	Sch	Ref 10
8/10/79	Caliper	Sch	Ref 10
8/15/79	Sonic	Sch	Ref 10
8/15/79	CBL	Sch	Ref 10
8/20/79	Direction	Unknown	Ref 10

TABLE 1 (CON'T)

List of Borehole Logs S. M. Well 2A (Con't)

Date	Type of Log	Log Co.	Log Location
6/4/81	Downhole TV	Sandia	DOESPRPMO
6/4/81	Caliper	GO	TBC
6/9/81	Sonar	Dowell	TBC
6/11/81	CBL	Micro	TBC
6/11/81	Temperature	Gearhart	TBC
7/20/81	Interface	Micro	TBC
10/22/81	Interface	Micro	TBC
10/26/81	Interface	Micro	TBC
10/29/81	Interface	Micro	TBC

List of Borehole Logs S. M. Well 4

8/13/77	Direction	Sperry-Sun	Ref 1
8/30/77	Sonar	Dowell	Ref 1
8/31/77	CBL	Micro	Ref 1
8/31/77	Casing Insp	Micro	Ref 1
5/15/79	Sonar	Dowell	Ref 11
6/4/79	Caliper	French	Ref 11
6/7/79	Casing Insp	Micro	Ref 11
6/15/79	CBL	Welex	Ref 11
6/19/79	Collar	GO	Ref 11
7/29/81	Temperature	Gearhart	TBC
7/29/81	Caliper	Gearhart	TBC
8/5/81	Sonar	Dowell	TBC
10/22/81	Interface	Micro	TBC
10/26/81	Interface	Micro	TBC
10/29/81	Interface	Micro	TBC

List of Borehole Logs S. M. Well 5

9/1/77	Casing Insp	Micro	Ref 1
9/1/77	Temperature	Micro	Ref 1
9/2/77	Sonar	Dowell	Ref 1
9/2/77	CBL	Micro	Ref 1
9/6/77	Direction	Sperry-Sun	Ref 1
9/6/77	Temperature	McC	Ref 1
5/17/79	Direction	Sperry-Sun	Ref 13
5/18/79	Sonar	Dowell	Ref 13
6/4/79	Caliper	French	Ref 13
6/24/81	Caliper	Gearhart	TBC
6/25/81	Density	Micro	TBC
7/16/81	Temperature	Gearhart	TBC

TABLE 2

Comments on Logs

Well 2	Comments
Sonar 9/8/77	Composite volume of 12.34 x 10^6 bbl, roof at 2446 ft, floor at 3086 ft
Direction 5/6/79	A 44.7 ft deviation in a southerly direction at a depth of 2460 ft
Sonar 5/12/79	Composite volume of 13.57 x 10^6 bbl, roof at 2446 ft, floor at 3082 ft
CBL 6/1/79	A fair to good bond below 1490 ft with poor bond above this level
DHTV 5/29/81	Poor visibility, but could see gas bubbles at 1827 ft
Caliper 6/5/81	Irregular hole from casing seat at 1821 to 2050 ft at about 2 ft diameter, a 4-inch diameter neck at 2050 ft, a relatively smooth hole from 2100 ft to 2350 ft, an aburpt enlargement at 2350 ft.
Temperature 6/9/81 & 12/18/81	Summary sketch on Fig 6. Maximum temperature of 160°F at 600 ft, an average borehole temperature of 126°F, a cavern temperature of 90°F, a probable gas entry point at 1835 ft.
Interface 10/23/81	N_2 interface at 1930 ft
10/26/81	N_2 interface at 1923 ft
10/29/81	N_2 interface at 1913 ft
Well 2A	
Sonic 8/15/79	Small zone of high gamma and low transit time from 2260-2280 ft. but they did not show on repeat log.
CBL 8/15/79	Good to fair bond from Brandenhead to 1815 ft.
Direction 8/20/79	A 18.5 ft deviation in a westerly direction at a depth of 2460 ft

TABLE 2 (Con't)

DHTV 6/4/81	Poor visibility, but could see gas bubbles at 1825 ft
Caliper 6/4/81	Relatively smooth hole from casing seat at 1815 ft cavern roof at 2444 ft
Sonar 6/9/81	Show an individual volume of 9.25×10^6 bbl, roof at 2441 ft, floor at 3054 ft a large wing to the south only at 2441 ft which is probably into cavern 5
Temperature 6/11/81	Well was flowing brine just prior to logging. Maximum temperature of 115°F, at 530 ft, small temperature irregularities at 2065, 2090, and from 2240 to 2380, a cavern temperature of 89°F.
Interface 10/22/81	N_2 interface at 1930 ft
10/29/81	N_2 interface at 1916 ft
10/29/81	N_2 interface at 1915 ft

Well 4	Comments
Direction 8/18/77	A 13.8 ft deviation in a northwesterly direction at a depth of 2650 ft
Sonar 8/30/77	Composite volume of 12.34×10^6 bbl, roof at 2792 ft, floor at 3115 ft
Sonar 5/16/77	Composite volume of 13.57×10^6 bbl, roof at 2646 ft, floor at 3090 ft
CBL 6/15/79	Good bond from 1788 ft to 1645 ft and high gamma ray in the same zone
Temperature 7/29/81	Maximum temperature of 144°F at 980 ft, temperature irregularities at 2360 to 2390 ft, cavern temperature of 88°F

Caliper 7/29/81	Reasonably regular hole at 24 inch to 16 inch from the seat at 1788 ft to 2130 ft, reasonably regular hole at 7 inch to 9 inch from 2130 ft to 2410 ft, expands to about 18 inch then goes off scale at 2550 ft
Sonar 8/5/81	Individual volume of 4.91×10^6 bbl, roof at 2646 ft, floor at 3086 ft
Interface 10/22/81	N_2 interface at 1930 ft
10/26/81	N_2 interface at 1916 ft
10/29/81	N_2 interface at 1916 ft

Well 5

Sonar 9/2/77	Composite volume of 12.34×10^6 bbl, roof at 2447 ft, floor at 3450 ft. with a large chimney above the roof, wings at 2450 ft and at 2900 ft, with a small diameter sump from 3000 ft to 3450 ft.
CBL 9/2/79	No bond 1690 to 1663 ft, good bond 1663 to 1522 ft, no bond or poor bond above 1522 ft.
Direction 5/17/79	A 23.5 ft deviation in a westerly direction at 2570 ft
Sonar 5/18/79	Composite volume of 13.57×10^6 bbl, roof at 2447 ft, floor at 3420 ft, similar sump and chimney as before
Caliper 6/24/81	A casing diameter just over 4 inches, and top of plug at 1585'. Attempts to run caliper logs after drilling through the plug on July 16, 1981, but two caliper tools were lost.
Density 6/25/81	Indicated top of cement outside the 4-inch pipe at about 1030 ft.
Temperature 7/16/81	Maximum temperature of 127°F at 1030 ft. Temperature disturbances at 250 ft, 710 ft 970 ft, 1160 ft, and 1670 ft.

TABLE 3

Abbreviations and Symbols

BSW	Brine Source Well
BW	Brine Well
bbl(s)	barrels (42 US gallons)
BH	Bradenhead Flange
BLI	Bottom of logged interval
CBL	Cement bond log
CDL	Compensated density log
DOE	Department of Energy
DUCI	Dravo Utility Constructors, Inc.
GO	Gearhart (GO Wireline Co.)
GR	Gamma Ray Log
KB	Kelly Bushing on Drill Rig
LSU	Louisiana State University
POSSI	Petroleum Operations and Support Services Inc.
PPG	Pittsburg Plate Glass Co.
PSIA	Pounds per Square Inch Absolute
PSIG	Pounds per Square Inch Gauge
McC	McCullough (Baroid Petroleum Services)
MICRO	Micro Gage, Inc.
N_2	Nitrogen
Sch	Schlumberger Limited
SM	Sulphur Mines
SNL	Sandia National Laboratory
SPR	Strategic Petroleum Reserve
STP	Standard Temperature and Pressure
TBC	Texas Brine Company
W-F&S	Williams Brothers Engineering Co. - Fenix & Scisson, Inc.
WP	Waukesha - Pierce, Ind. Nitrogen Services Div.

TABLE 4

Results of Analysis of Cavern 2-4-5 Brine Samples

Materials Description

Brine at or near saturation

Sample No.	Site-Well-Depth (ft)	Sample Date
SPR 109	SM - 2A - 2450	6/11/81
SPR 110	SM - 2A - 2500	6/11/81
SPR 111	SM - 2A - 2750	6/11/81
SPR 112	SM - 2A - 2965	6/11/81
SPR 130	SM - 4 - 2700	7/29/81
SPR 131	SM - 4 - 2800	7/29/81
SPR 132	SM - 4 - 2900	7/29/81
SPR 133	SM - 4 - 3000	7/29/81

Sample No.	Density at Temp g/mL	at °C	NA** mg/L	NA** mg/g	CL mg/L	CL mg/g	pH
109	1.200	21	124500	-	191550	-	6.94
110	1.201	21	125250	-	191800	-	7.09
111	1.201	21	125250	-	190900	-	6.96
112	1.201	21	124750	-	190950	-	6.99
130	1.195*	39	127000	106	192560	161.1	-
131	1.190	41	126000	106	191990	161.3	-
132	1.196	35	125000	104	191790	160.4	-
133	1.195	39	126000	105	192530	161.1	-
Saturation values at 20°C							
	1.200	20	124000	103	192000	160	
Saturation values at 40°C							
	-	40	126000	104	194000	162	

*Salt crystals remained after heating
**10 milliliter sample taken at temp shown

The saturation value during the test period is taken as between 99% and 100%.

TABLE 5

Cavern 2-4-5 Test Chronology

Date and Day of year	Activity/Comment
7/13/81, 194	Data start at 1130 hrs for a low pressure test. Workover crew was fishing for Dyna-drill in well 5.
7/14/81, 195	Began brine removal from well 2A at 1415 hours using N_2. Starting pressure at 1700 ft in well 2 was 900 psia. DUCI started oil removal from well 4 with trucks.
7/15/81, 196	Finished brine removal from well 2 at 0900 at a pressure of 810 psia at 1700 ft. Workover crew on well 5 got to 1650' and had a gas release at about 0830.
7/16/81, 197	DUCI began releasing oil out of 4 into a FRAC tank, this increased rate made it unnecessary to remove brine from well 2. Drilled thru plug in well 5 and got the tool stuck trying to caliper. Plug in well fell away at 1750 ft.
7/17/81, 198	DUCI still removing oil from well 4 and pressure in well 2 went down to 793 psia.
7/18/81, 199	Temporarily stopped oil removal from well 4. Corrected instrument malfunction on probe in well 2. Got significant gas pressure in 2 and 2A.
7/19/81, 200	Continued monitoring
7/20/81, 201	Ran interface logs on 2, 2A, and 4. Took gas samples from 2 and 2A. Took oil sample from 4, oil gravity was 29°.
7/21/81, 202	Removed brine from well 2A to reduce pressure from 820 to 810 psia.
7/22/81, 203	Removed 809 bbls.brine from well 2A to reduce pressure from 820 to 810 psi. Underream well 5. Pumped oil from well 4.
7/23/81, 204	Pumped oil from well 4

7/24/81, 205	Removed brine from well 2A but they were pumping brine into well 5 faster than we could remove it.
7/25/81, 206	Removed 987 bbl brine from well 2A and there was no other cavern activity, 78 bbl/psi.
7/26/81, 207	Removed 537 bbl brine from well 2A
7/27/81, 208	Removed 574 bbl brine from well 2A to pressure of 811 psia. Removed downhole pressure transducer from 2 and ended the low pressure test.
7/28/81, 209	Automatic data recorders failed and were replaced
7/29/81, 210	Tried to run temperature tool in well 4 and had hangup problems at 2167 ft and 2311 ft.
7/30/81, 211	Ran drill string into 5 and hit metal obstruction at about 916 ft.
8/1/81, 212	Well 2 is producing 75 ft^3/day (at STP) gas with well pressure about 30 psia. Well 2A is producing 315 ft^3/day (at LSTP) gas with well pressure about 100 psia.
8/2/81, 213	Sandia left the site. TBC was to periodically bleed gas from 2 and 2A and complete the workover on well 5.
8/3/81, 214	Through 8/26/81, 238 no activity
8/27/81, 239	Started pumping brine into well 2 to increase pressure for a brine test.
8/28/81, 240	Continued pumping brine into well 2. Well 2A pressure was 280 psig.
8/29/81, 241	Put Lynes instruments on to monitor cavern pressure. Pumped until 1810 hours when pressure reached 515 psia 36167 bbl.
8/30/81, 242	Monitor pressures
8/31/81, 243	Bled 3.4 bbl oil from 4 brine side. Bled 8.8 bbl oil from 4 oil side. Pumped additional brine into well 2 to empty tank, total volume in was 36502 bbl. Injected 1200 ft^3 (at STP N_2 into well 4 annulus to check for hanger leak.
9/1/81, 244	Checked wells and found no gas on 2, 2A annulus, 4 pipe. Bled N_2 out of 4 annulus.

9/2/81, 245	Monitor pressures.
9/3/81, 246	Removed Lynes instruments and installed gages on wells. Cavern will hold at this condition until funding becomes available.
9/4/81, 247	Through 9/21/81, 264 no activity
9/22/81, 265	Through 9/24/81, 267 Monitored well 2A pressure with Sandia transducers. Showed zero slope on pressure curve.
9/25/81, 268	Removed transducers and reinstalled gages.
9/26/81, 269	Through 10/1/81, 274 no activity
10/2/81, 275	TBC bled cavern to 250 psig
10/3/81, 276	Through 10/20/81, 293 TBC checked wells periodically and got gas from 2A and 4 and got oil from 2 and 4.
10/21/81, 294	Installed Lynes instruments on 2, 2A, and 4. Data start time is 2000 hours
10/22/81, 295	Bled 3.6 bbl oil from 4 and little gas. Bled 2 gal oil from 2 and no gas. Bled 0 gal oil from 2A and little gas. Injected N_2 into well 4 to 1930 ft. Injected N_2 into well 2A to 1930 ft.
10/23/81, 296	Injected N_2 into well 2 to 1930 ft. but W-P scales were nonfunctional.
10/24/81, 297	And 10/25/81, 298 Located wellhead leaks on all three wells. Monitored pressures.
10/26/81, 299	Had roustabout crew tignten bolts to stop wellhead leaks. Logged interfaces: well 4 at 1916 ft, well 2A at 1916 ft, well 2 at 1923 ft.
10/27/81, 300	Monitor pressures
10/28/81, 301	Tom Magorian on site to work with JDE and Todd Eng. to get survey data for well locations.
10/29/81, 302	Logged interfaces well 4 at 1916 ft, well 2A at 1915 ft, well 2 at 1913 ft. Removed N_2 from all three wells. Tom Magorian met with UTP (Mr.Oblah) and PPG (Mr. Oliff) to discuss site history.

10/30/81, 303	Injected brine thru 2A to 405 psia, 0.75 psi/ft.
10/31/81, 304	Through 11/5/81, 309 Monitor pressures and work on site survey and well locations.
11/6/81, 310	Bled 95 Ft^3 (at STP) gas and 0.37 bbl oil from well 4.
11/7/81, 311	Through 11/9/81, 313 Monitor pressures
11/10/81, 314	Bled 43 ft^3 (STP) gas and 2 gas oil from 4, 20 ft^3 (STP) gas and 0 gal oil from 2A, 0 ft^3 gas and 8 gal oil from 2. Bled brine from 2A annulus to go from 384 psia to 320 psia which is 0.7 psi/ft.
11/11/81, 315	The automatic data recording system malfunctioned and was sent to Albuquerque.
11/12/81, 316	Monitor pressures
11/13/81, 317	TBC bled cavern to 0.65 psi/ft
11/14/81, 318	Thru 11/22/81, 326 Monitor pressures
11/23/81, 327	TBC Bled cavern to 151 psi (0.60 psi/ft)
11/24/81, 328	Thru 11/29/81, 333 Monitor pressures
11/30/81, 334	Bled 140 ft^3 (STP) gas and 7 gal oil from 4, 14 ft^3 (STP) gas and 10 gal oil from 2A, 0 ft^3 gas and 20 gal oil from 2.
12/1/81, 335	Bled 14 ft^3 (STP) gas from 2A and from 4. Then bled cavern pressure from 210 psia to 55 psia by removing brine from 2A annulus. Began to get lots of gas in 2 and in 2A. UTP started a workover on sell 929.
12/2/81, 336	Bled 290 ft^3 (STP) gas from well 2, and 1150 ft^3 (STP) gas from well 2A. This is a rate of about 100 ft^3 (STP)/hr from the cavern.
12/3/81, 337	Monitor pressures
12/4/81, 338	Bled 145 ft^3 (STP) gas from well 2, 1275 ft^3 (STP) gas from well 2A, and 39 ft^3 (STP) gas from well 4.
12/5/82, 339	Thru 12/8/81, 342 Monitor pressures

12/9/81, 343	Had a meeting in New Orleans and agreed that the test should stop. Lynes instruments removed.
12/10/81, 344	Thru 12/20/81, 354 DUCI monitor pressures
12/21/81, 355	Ran temperature log in well 2, and log had an indication of gas entry at 1835 ft.
12/22/81, 356	Thru 12/31/81, 365 DUCI monitor pressures. This activity is to continue until retesting is initiated early in 1982.

TABLE 6

Tabluated Results of Well Leak Test 10/22/81 Through 10/29/81

Well	Date	I'face Depth	Brine Press.(1)	N_2 Press.	Bore Volume Est. Cal.	Bore Volume Ft^3/ft N_2	Bore Volume Avg.	Test Hour	Calc Leak Rate bbl/yr (2)
2	10/23	1930	304.7	1224.3	3.14	4.12	3.62	42	
	10/26	1923	306.7	1222.2	3.14	4.12	3.62	112	
	10/29	1913	309.3	1219.5	3.14	4.12	3.62	184	157
2A	10/22	1930	308.5	1220 -	.74	.47	.60	24	
	10/26	1916	308.9	1220.9	.74	.47	.60	110	
	10/29	1915	310.2	1221.1	.74	.47	.60	182	0
4	10/22	1930	304.5	1221.7	1.40	1.14	1.27	18	
	10/26	1916	312.2	1220.4	1.40	1.14	1.27	108	
	10/29	1916	314.1	1223.2	1.40	1.14	1.27	180	0

(1) Well 2 brine pressure assumed to be equal to 2A brine pressure

(2) Note that a decrease in pressure would cause the interface to move down. Calculations are included in Appendix I

TABLE 7

Comparison Pressures at 1690 Ft. Depth

Condition	Casing Seat Fluid	Psia
Nitrogen test @ 0.70 psi/ft.	N_2	1183
Brine test @ 0.75 psi/ft.	Brine	1267
Brine test @ 0.80 psi/ft.	Brine	1352
Zero brinehead with 0.52 psi/ft. brine	Brine	879
Oil fill at maximum operating gradient of 0.75 psi/ft.	Oil	1267
Oil drawdown with 150 psi on the oil at the wellhead and 150 psi oil flow pressure drop in well with 0.37 psi/ft. oil	Oil	625
Zero brinehead with .37 psi/ft oil and the oil/brine interface at 2768 ft.	Oil	1040

TABLE 8

Gas and Oil Bled from SM Wells During the 1981 Cavern Tests

Date	Well 2 Gas	Well 2 Oil	Well 2A Gas	Well 2A Oil	Well 4 Gas	Well 4 Oil	Approx. Brine Pressure
7/14-23 (1)	---	---	---	---	---	13,000 bbl	---
8/1/81	75 ft^3/d	---	315 ft^3/d	---	---	---	-80
8/31	---	---	---	---	---	---	485
10/4-7	---	(3)	(3)	---	(3)	---	260
10/22	0	2 gal	(3)	0	0	3.6 bbl	305
11/6	---	---	---	---	95 ft^3	16 gal	380
11/10	0	8 gal	20 ft^3	0	43 ft^3	2 gal	384
11/13	0	1 gal	0	0	38 ft^3	2 gal	390
11/23	---	5 gal	(3)	0	190 ft^3	7 gal	151
11/30	0	20 gal	14 ft^3	10 gal	140 ft^3	7 gal	195
12/1	0	1 gal	14 ft^3	0	14 ft^3	0	201
12/1	210 ft^3	16 gal	bleed brine		---	---	55
12/2	290 ft^3	---	1150 ft^3	---	---	---	60
12/4	75 ft^3/d	---	640 ft^3/d	---	15 ft^3/d	---	110
12/7	72 ft^3	(3)	1000 ft^3	(3)	39 ft^3	(3)	120
2/10/82	0	0	1460 ft^3	1 bbl	950 ft^3	1 bbl	210

(1) Unmeasured gas released estimated at 1000 psi for 5 minutes through a 2 inch line 7/15 well 5.
(2) Also bled 3.4 bbl oil out of brine line that had been caught during string installation.
(3) Unmeasured small quantity.
(4) Gas volumes are at well pressures.

TABLE 9

Analysis of Gas Samples from S. M. 2-4-5 (Mol %)

Component	Well 2 Pipe 2/81	Well 2 Annul. 2/81	Well 2 3/81	Well 2A 3/81	Well 2 7/20/81	Well 2 7/20/81
Carbon Dioxide	0.08	7.7	0.06	10.9	1.69	1.80
Nitrogen	9.3	0.11	2.4	0.07	0.81	0.60
Methane	89.2	90.4	93.3	85.5	89.96	81.37
Ethane	0.64	0.33	0.98	0.39	1.98	2.00
Propane	0.11	0.48	1.03	0.20	2.41	2.43
i-Butane	0.02	0.12	—	—	1.17	1.19
N-Butane	0.02	0.36	—	—	3.55	3.60
i-Pentane	0	0.12	—	—	1.73	1.75
N-Pentane	0	0.14	—	—	2.01	2.02
Hexane +	0.62	0.24	—	—	3.69	3.24
BTU/ft^3 Dry	—	—	—	—	1445	1430

TABLE 9 (Con't)

Analysis of Gas Samples from S. M. 2-4-5

Well 2A 7/20/81	Well 2A 7/20/81	Well 2 12/4/81	Well 2A 12/4/81	Well 4 12/4/81	Well 2 12/7/81	Well 2A 12/7/81	Well 4 12/7/81
5.60	5.55	0	0.07	0	0.02	1.63	0.06
0.09	0.09	1.74	0.33	0.61	2.08	0.36	0.73
92.71	92.78	94.49	96.89	97.27	94.18	96.13	96.80
0.41	0.41	0.83	0.53	0.99	0.68	0.46	1.01
0.22	0.22	0.73	0.19	0.31	0.59	0.09	0.28
0.09	0.09	0.26	0.12	0.13	0.22	0.06	0.11
0.30	0.30	0.75	0.43	0.30	0.69	0.25	0.27
0.12	0.12	0.32	0.25	0.13	0.30	0.18	0.13
0.15	0.15	0.34	0.34	0.14	0.36	0.23	0.15
0.31	0.29	0.54	0.85	0.12	0.88	0.61	0.46
1013	1012	1101	1104	1064	1107	1065	1076

TABLE 9 (Con't)
Gas Analysis from Sulphur Mines Brine Samples Taken 1/6/82
(Data in Mole Percent)

Component	Well 2					Well 2A
	1800 Ft	1950 Ft	2100 Ft	2460 Ft	3040 Ft	OFT
Carbon Dioxide	0.50	2.05	10.91	0.35	0.35	4.8
Nitrogen	10.05	14.91	8.55	39.76	9.81	4.41
Methane	89.28	82.91	80.38	59.42	89.24	89.78
Ethane	0.15	0.12	0.13	0.40	0.53	0.38
Propane	0.02	0.01	0.02	0.06	0.06	0.01
Ft^3 Gas bbl Brine	0.451	0.797	2.35	0.742	0.742	NA
Degassed Brine G/ML	1.2012	1.2007	1.1983	1.2009	1.2004	NA

TABLE 10

Comparison of Pressure Curve Slopes

Cavern	Final Press. psia	Test Duration Day	Slope psi/day	Salt Stress (1)	Gradient(2) psi/ft
WH 6	195	4	+6.2	1447	.595
(REF 6)	480	5	+2.2	1162	.704
	495 (3)	6	+1.1	1132	--
	660	5	+0.2	982	.774
	740	8	-2.0	887	.804
SM 6	474 (3)	13	+1.1	1153	—
(REF 16)	608	9	+1.0	1037	.763
	695	9	-1.0	947	.798
SM 7	-110	2	+21	1656	.473
(REF 17)	-58	2	+10	1604	.495
	390 (3)	7	0	1141	--
	553	5	+0.7	993	.756
	570	8	-1.2	976	.763
SM 2-4-5	-80	9	+8.3	1578	.473
	128	8	+3.8	1355	.596
	200	8	+3.0	1298	.638
	250	60	+1.0	1248	.668
	280	10	+1.9	1218	.686
	300	18	+1.8	1198	.698
	312 (3)	8	+0.7	1171	--
	385	11	0	1113	.748
	428	32	0	1070	.773

(1) Lithostatic pressure (1.0 psi/ft) minus brine pressure at the cavern floor (WH 6 = 3390, SM 6 = 3390, SM 7 = 3190, SM 2-4-5 = 3090 Ft).
(2) Equivalent pressure gradient at the critical casing seat depth.
(3) Nitrogen tests.

Table 11

List of Borehole Logs S. M. Wells

(Well 2)

Date	Type of Log
3/18/82	N_2 interface @ 2310
3/30/82	N_2 interface @ 2274

(Well 2A)

3/19/82	N_2 interface @ 2325
3/20	N_2 interface @ 2179
3/22	N_2 interface @ 2146-2372-2292
3/29	N_2 interface @ 2140-2370-2310
4/26	N_2 interface @ 2380-2306-2380-2324
4/29	N_2 interface @ 2203
4/29	oil interface @ 2440
5/3	oil interface @ 2378
5/12	oil interface @ 2174
5/13	oil interface @ 2440
5/14	oil interface @ 2318-2440
5/15	oil interface @ 2341-2440
5/16	oil interface @ 2353-2440
5/17	oil interface @ 2338-2440
5/18	oil interface @ 2384-2440
5/19	oil interface @ 2385-2440
5/20	oil interface @ 2363-2440
5/21	oil interface @ 2381
5/31/82	oil interface @ 2173

(Well 4)

3/17/82	N_2 interface @ 2321
3/23/82	N_2 interface @ 2292

(Well 5)

4/13/82	Caliper
4/15/82	N_2 interface @ 1898
4/19/82	N_2 interface @ 1894
4/21/82	N_2 interface @ 1893-1812
4/24/82	N_2 interface @ 1824

Note: All logs run by microgage for POSSI

Table 12

Comments on Logs 1982

Well 2A

Interface logs that show multiple interface locations were multiple logs to observe interface movement and/or to observe interface reset.

The injection of oil into well 2A allows the calculation of borehole volume and equivalent diameter. The data indicates a typical diameter of 12.5 inches above 2350 ft, expanding to 14.5 inches at 2410 ft, to 17.5 inches at 2440 ft.

Well 5

The caliper logs show casing at 1725 ft and bottom of the plug at 1840 with washout at 1775. Density log on 4/15 verifies the casing seat at 1725, the plug bottom at 1840 and the washout at 1775.

Table 13

Chronology of 1982 Tests

Date and Day of Year	Activity/Comment
1/26/82, 026	DOE accepted test plan for 2-4-5 including well 5 reentry.
2/9/82, 040	Met with POSSI in New Orleans to present our plan for testing.
2/10/82, 041	Bled gas and oil off 2, 2A, 4.
3/16/82, 075	Install Lynes instruments.
3/17/82, 076	Test start time is 03/17/82 00:00:00. Bled well 4 gas. Put N_2 into #4 to 2325 ft. Filled well 5 with water.
3/18/82, 077	Put N_2 into #2 to 2310 ft.
3/19/82, 078	Put N_2 into #2A to 2325 ft. Filled #5 annulus with 500 gal of water. Pressured #5 pipe to 526 psia, it is dropping 1 psi/min.
3/20/82, 079	Log #2A I'face @ 2179 ft. Repressure #5 to 515 psia.
3/21/82, 080	#5 annulus pulled vacumn, pressured to 50 psi and pressure dropping 10 psi/hr.
3/22/82, 081	#2A N_2 interface at 2146, reset to 2380 ft.
3/23/82, 082	#4 N_2 interface at 2292 ft. could not log #2 because Cameron valve would not seal.
3/26/82, 085	Had planning meseting with POSSI
3/29/82, 088	They started putting boards on pad 5. Reset N_2 interface in #2A from 2140 to 2380 ft.
3/30/82, 089	Log well 2 interface at 2274 ft.
3/31/82, 090	Bled N_2 off #2A.
4/1/82, 091	Bled N_2 off #2 and #4.

Table 13 Cont'd

4/2/82, 092	Depressured cavern, 75 bbl/psi
4/6/82, 096	Started drilling plug in well 5 with 3 7/8 inch bit.
4/7/82, 097	Drilling #5 with 4000 lb on bit, making 5 ft/min thru mushy cement. Gas kick at 1648, 260 psig.
4/8/82, 098	Removed core 1710 to 1731 ft, recovered 6.5 ft. Gas kicks at 1743 ft, 1758 ft, 1763 ft. Removed core 1731 to 1763 ft., recovered 1 ft.
4/9/82, 099	Removed core 1763 to 1808 ft, recovered less than 1 ft. Soft cement 1767 to 1782 ft. Gas kick 1808 ft. Decided to quit coring and drill with 3 7/8 inch bit since core recovery was so poor. Started getting salt cuttings at 1830 ft and stopped drilling.
4/10/82, 100	Restarted drilling with drill collars to straighten the hole.
4/12/82, 102	Drilled through the plug, got 860 psig gas kick.
4/13/82, 103	Run dummy sonar and caliper log in #5, and remove drill rig.
4/14/82, 104	Install Lynes probe on #5. Pressure cavern to 200 psia, 73 bbl/psi.
4/15/82, 105	Pressure cavern from 188 to 200 psia. Ran density log in #5 and hit a tight spot at 1750-1760 ft. Put N^2 into #5 to 1898 ft. This was 10408 lb and one pump truck load.
4/17/82, 107	Lynes DSR on #2 malfunction. POSSI repaired small leak on #5.
4/19/82, 109	Logged N_2 in #5 at 1894 ft.
4/21/82, 111	Logged N_2 in #5 at 1893 ft. Then bled N_2 to get I'face at 1812 ft.
4/23/82, 113	Logged N_2 in #5 at 1824 ft., but losses would make this at 1836 ft. Bled N_2 off #5.

Table 13 Cont'd

4/24/82, 114	Started regular bleed of #5 each day.
4/26/82, 116	Injected N_2 into #2A to 2380 ft.
4/29/82, 119	Logged N_2 in #2A at 2203 ft. Bled off N_2 and injected oil. Had trouble locating oil-brine I'face, and we put in excess oil prior to locating I'face. Oil volume was about 650 bbl injected.
5/3/82, 123	Log oil in #2A at 2378 ft.
5/4/82, 124	On site meeting with DOE, POSSI, SNL. Started oil removal from #2A.
5/5/82, 125	Completed oil removal from #2A, got 178 bbl. Injected brine to raise pressure to 330 psia, 75 bbl/psi.
5/7/82, 127	Well 5 still making about 100 psi/day of gas (500 STD ft^3/day). Injected brine to raise pressure to 440 psia, 71 bbl/psi. Bled all wells to brine.
5/11/82, 131	French cut the hanging string in #2A at 1990 ft.
5/12/82, 132	Injected brine to raise pressure to 445 psi. Injected 122 bbl of oil into #2A. Bled unsaturated brine out of #4 pipe.
5/13/82, 133	Injected oil into #2A to set interface at 2440 ft. Took a total of 268 bbl at 77° F.
5/14/82, 134	Set up plan to log oil interface in #2A each day and reset the interface to 2440 ft. See table 14 for quantities.
5/16/82, 136	POSSI poured concrete to improve the site
5/17/82, 137	The pop-off valve blew on the pump and we had an oil spill of less than 1 bbl.
5/19/82, 139	Injected brine to raise cavern pressure to 438 psia.

Table 13 Cont'd

5/21/82, 141	Logged the I'face in #2A at 2381 ft but did not reset. Got word from DOE that we should stop testing, they had decided to only put oil in well 4 above the connection to #5. Removed Lynes instruments and removed Sandia recorders.
5/31/82, 151	Logged I'face in #2A at 2173 ft and removed 218 bbl of oil.
6/1/82, 152	Bled brine to depressure the cavern to zero brine pressure.
6/11/82, 162	Bled additional 55 bbl of oil out of #2A.
6/29/82, 180	Bled additional 10 bbl or oil out of #2A, 5 bbl out of #2, and 1/2 bbl out of #2.

Table 14

Tabulation of Well Leak Tests

Well No.	Mat'l	Dates	Gradient at Casing Seat psi/ft	I'face Depths ft	Typical Brine Press psia	Leak Rate bbl/yr
2	N_2	3/18-4/1	.80	2310-2274	275	150
4	N_2	3/17-4/1	.81	2321-2292	275	50
2A	N_2	3/19-3/22	.79	2325-2146	275	2400
2A	N_2	3/22-3/26	.79	2380-2237	275	1000
2A	N_2	3/29-3/31	.79	2380-2275	275	2000
2A	N_2	4/26-4/29	.75	2380-2202	200	2400
5	N_2	4/15-4/23	.65	1898-1893	200	1500
2A	oil	4/29-5/4	.69	2440-2378	200	1400
2A	oil	5/13-5/19	.80	2440-2318	425	8000 to 4000
2A	oil	5/19-5/21	.81	2440-2360	425	5000 to 4000
2A	oil	5/20-5/31	.80	2440-2173	425	1600

Table 15

Gas and Oil Bled or (injected)[A]

Date	Well 2 Gas (C)	Well 2 Oil bbl	Well 2A Gas (C)	Well 2A Oil bbl	Well 4 Gas (C)	Well 4 Oil bbl	Well 5 Gas (C)	Well 5 Oil bbl
2/10/82	0	0	140[B]	<1	115[B]	<1	--	--
3/17/82	--	--	--	--	200	<1	--	--
3/18/82	0	0	--	--	--	--	Small	0
3/22/82	--	--	--	--	--	--	Small	0
3/26/82	--	--	Small[D]	0	Small[D]	0	--	--
3/29/82	--	--	Small	0	--	--	--	--
4/2/82	--	--	--	--	Small[D]	0	--	--
4/5/82	All wells bled to brine.							
4/7/82	6000	--	37000 120[D]	--	600	0	Kick	--
4/8/82	--	--	--	--	--	--	Kicks	--
4/9/82	1000	--	7000	--	300	--	Kicks	--
4/12/82	--	--	--	--	--	--	Vent	--
4/14/82	3000	1	13000	1	800	<1	--	--
4/15/82	Small	0	Small	0	Small	0	500	0
4/17/82	0	9	0	0	Small	0	--	--
4/24/82	--	--	--	--	--	--	2000	--
4/26/82	?	Small	?	0	?	Small	Did a gas	
4/29/82	--	--	--	(630)	--	--	bleed each	
5/5/82	--	--	--	221	--	--	day thru	
5/7/82	0	0	?	<1	?	<1	5/21. Got	
5/8/82	Did a gas bleed each day thru 5/12/82 small quantities of gas and oil.						zero oil. Gas was about	
5/12/82	2, 2A, 4 appear to make no gas or oil at pressures above 440 psia on the brine.						500 ft^3/day at 200 psi brine.	
5/12/82	--	--	--	(122)	--	--	--	--
5/13/82	--	--	--	(146)	--	--	--	--
5/14/82	--	--	--	(21)	--	--	--	--
5/15/82	--	--	--	(17)	--	--	--	--
5/16/82	--	--	--	(15)	--	--	--	--
5/17/82	--	--	--	(17)	--	--	--	--
5/18/82	--	--	--	(11)	--	--	--	--
5/19/82	--	--	--	(11)	--	--	--	--
5/20/82	--	--	--	(14)	--	--	--	--
5/31/82	--	--	--	218	--	--	--	--
6/10/82	--	--	--	55	--	--	--	--
6/29/82	?	5	?	10	--	--	?	<1

Notes for Table 15

A. Does not include N_2 or Brine.
B. Pressure drop due to gas bleed psi.
C. Cubic ft of gas at STP.
D. Bled from pipe indicating a hanging string leak.

Table 16

Gas Sample Analyses

Constituent	Well Date	2 4/7	2 4/14	2 4/26	2A 4/7	2A 4/14	2A 4/19	2A 4/26
CO_2			1	1	1	11	15	15
N_2		35	22	26	64	74	17	22
CH_4		61	74	71	32	14	67	62

	4 4/2	4 4/7	4 4/14	4 4/19	4 4/26	5 4/7	5 4/8	5 4/8	5 4/8
CO_2	--	--	1	1	1	--	--	--	--
N_2	97	90	1	--	--	--	--	--	--
CH_4	3	8	98	98	97	98	100	100	99

	5 4/8	5 4/9	5 4/12	5 4/21	5 4/23	5 4/26	5 4/27	5 4/28	5 4/29
CO_2	--	--	--	--	--	3	9	9	6
N_2	--	2	2	100	100	3	3	3	3
CH_4	99	97	97	--	--	92	87	88	91

	5 4/30	5 5/1	5 5/2	5 5/3	5 5/13
CO_2	7	6	6	8	8
N_2	2	2	1	1	1
CH_4	90	92	93	90	91

Note: Samples contained small quantities of ---anes. Valves all rounded to nearest whole number.

Table 17

Brine Removed from Cavern 4/2 - 4/12

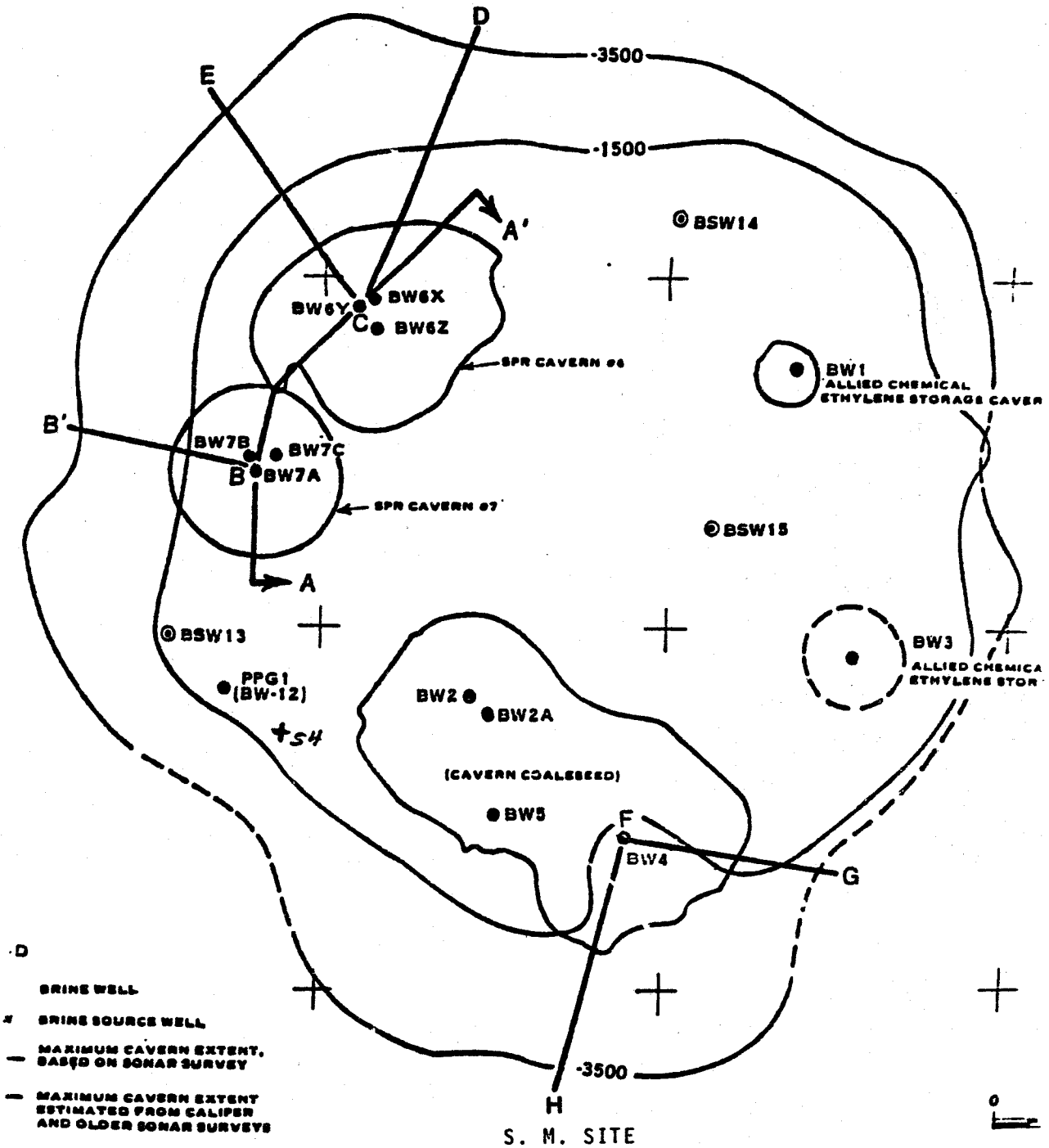
Date	Time	bbl	Test Hour
4/2	1500	1412	
	1600	2614	400
	1700	3372	
	1800	4387	
	1900	--	
	2000	6224	404
	2100	7190	
	2200	8033	
	2300	8900	
4/3	0000	9752	
	0100	10301	
	0200	10955	
	0300	11951	
	0400	12630	
	0500	13288	
	0600	13857	
	0700	14596	
	0800	15177	416
	0900	15777	
	1100	16631	
4/4	1300	16747	
	1600	18563	448
	1800	19380	
	2000	20065	
	2200	20733	
4/5	0000	21464	
	0200	21834	
	1600	22036	472
4/6	0000	22270	
	0200	22321	
	0400	22400	
	1600	22481	496
	1800	22957	
	2000	23636	
	2200	23872	
4/7	0000	24387	
	0200	24735	
	0900	24922	513
4/8	1500	25834	
4/9	1400	26463	Drilled Thru #5 Plug
4/12	1400	28726	

Table 17 (cont'd)

Brine Injected into Cavern 4/14

Time	bbl	psi	Test Hour
1425	0	15	
1500	975	22	
1530	1882	36	
1600	2761	50	688
1630	3636	63	
1700	4495	75.8	
1730	5331	88.8	
1800	6180	100.7	
1830	7028	112.7	
1900	7884	126.8	
1930	8696	139.6	
2000	9594	152.4	692
2030	10422	165.1	
2100	11305	177.4	
2130	12126	189.5	
2200	12988	200.2	

This plots as a straight line
12126 - 975/189.5 - 22 = 11151/167.5 = 67 bbl/psi



S. M. SITE
FIGURE 1.

ARED BY_____ DATE_____ KED BY_____ DATE_____ 3ED BY_____ DATE_____ OVED BY_____ DATE_____	STRATEGIC PETROLEUM RESERVE PROGRAM GEOTECHNICAL CHARACTERIZATION SULPHUR MINES SALT DOME 57 LAW ENGINEERING TESTING COMPANY MARIETTA, GEORGIA	SITE CROSS-SEC

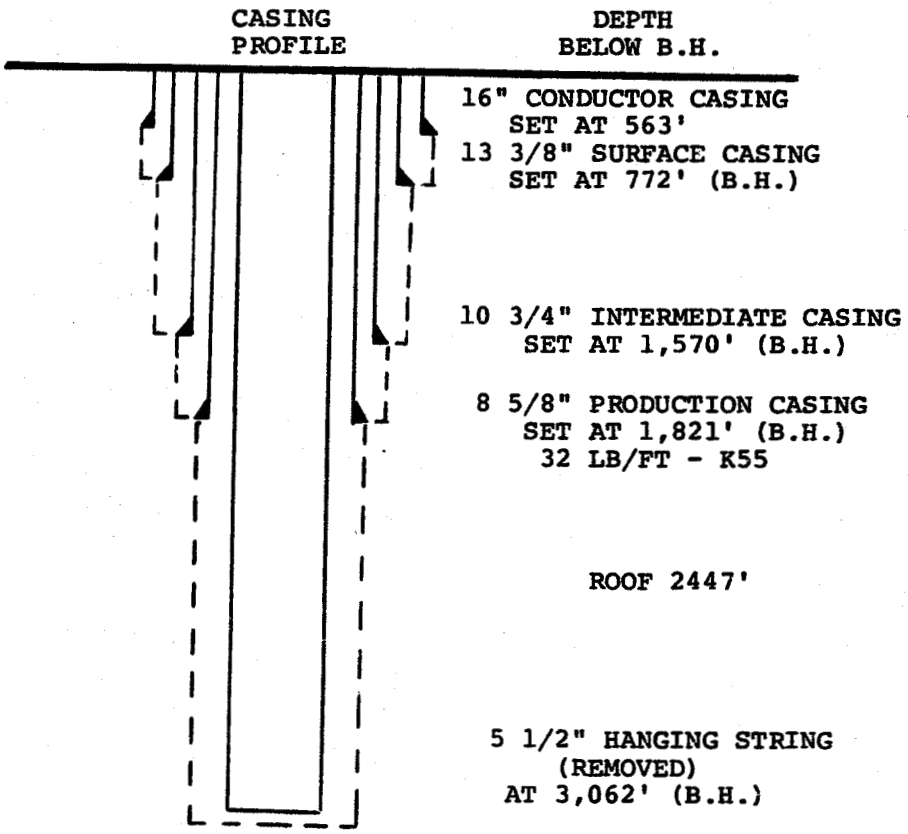


FIGURE 2. AS-BUILT CASING DIAGRAM

SPR 2(WO) SULPHUR MINES

FROM REF 8

K.B. AT 34.5' MSL = 20'
B.H. AT 14.8" MSL

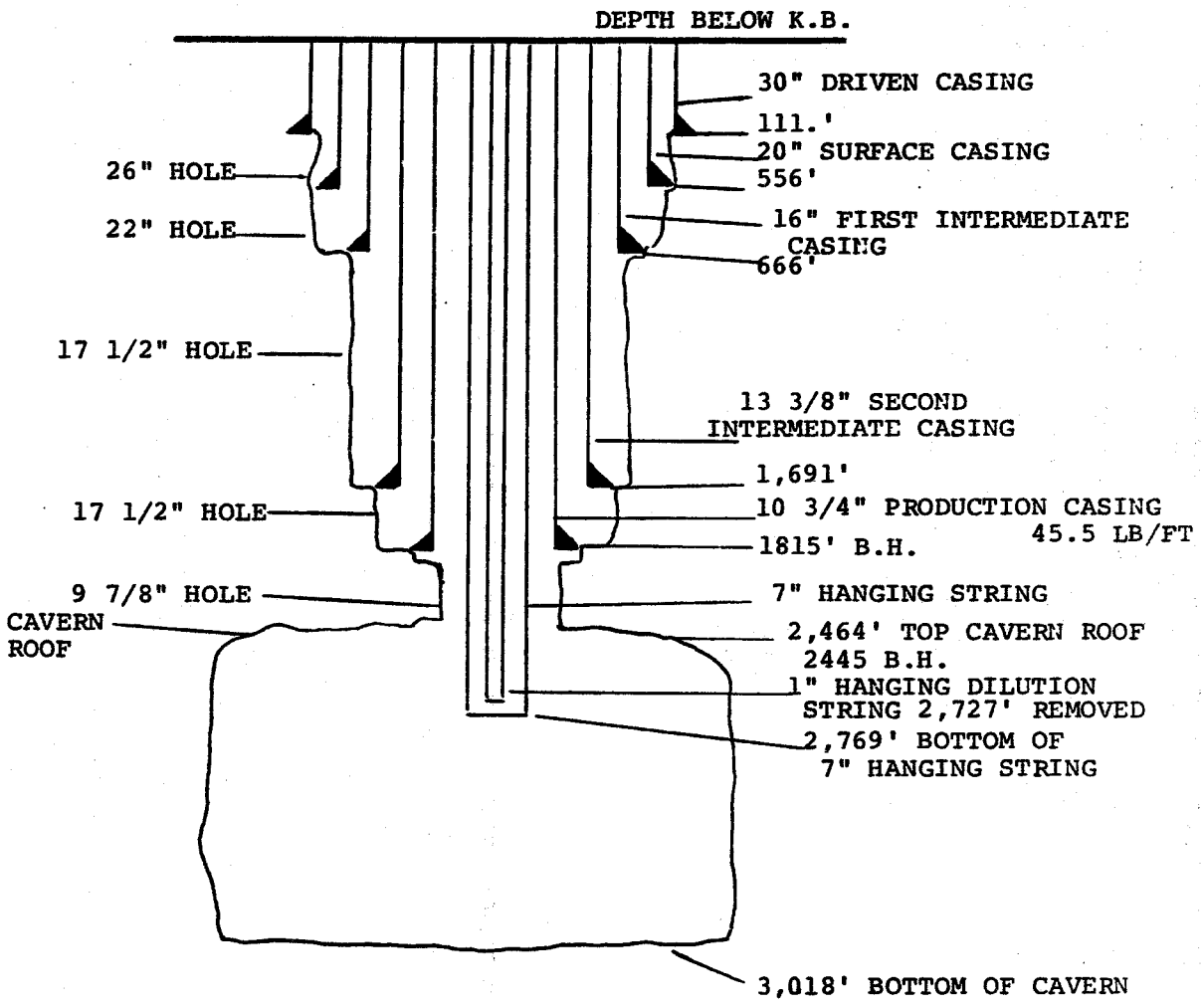


FIGURE 3. AS-BUILT CASING DIAGRAM
SPR RE 2A SULPHUR MINES

FROM REF 9

*BY OTHER THAN WILLIAMS-FENIX & SCISSON
COMPLETE INFORMATION NOT AVAILABLE.

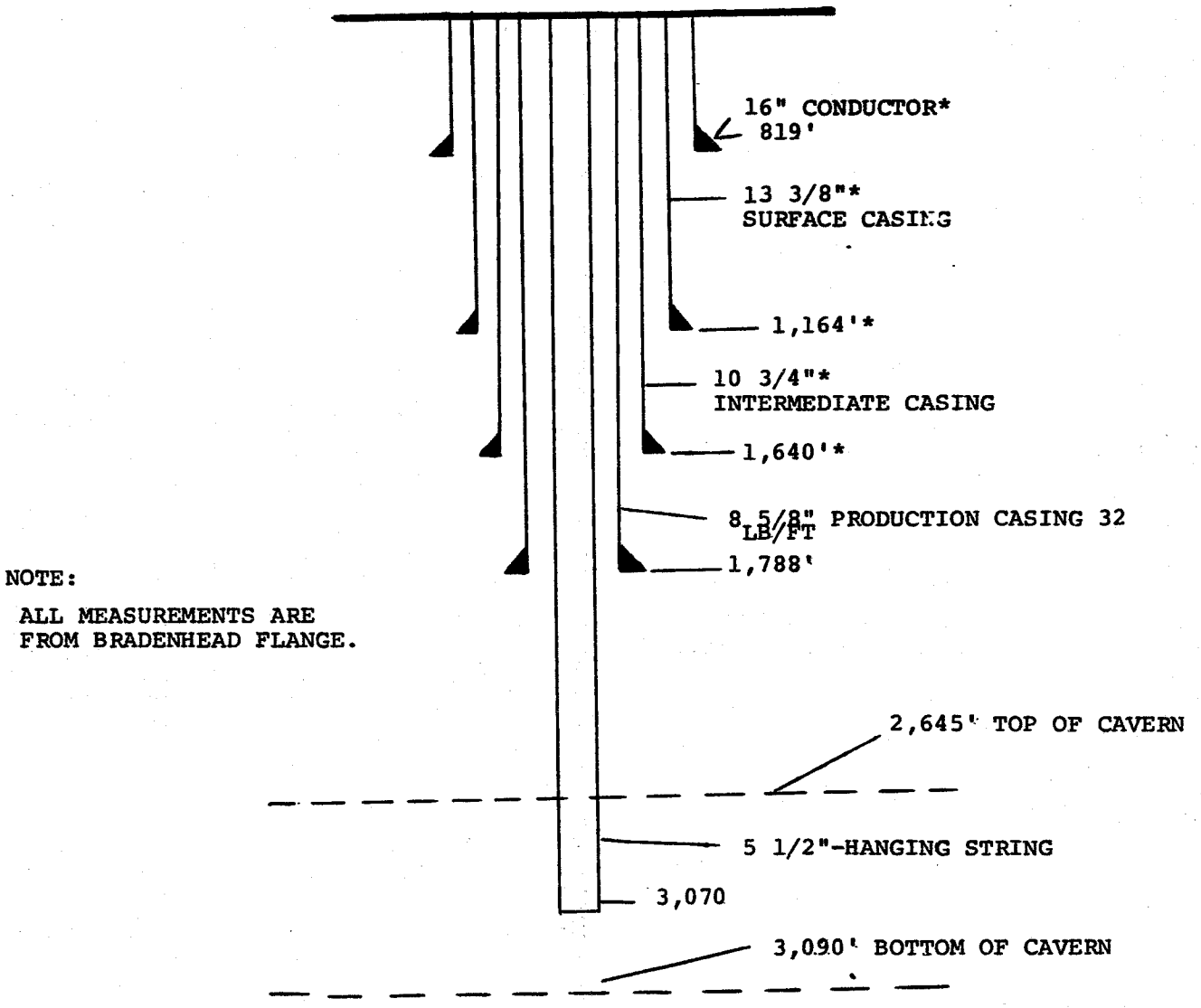
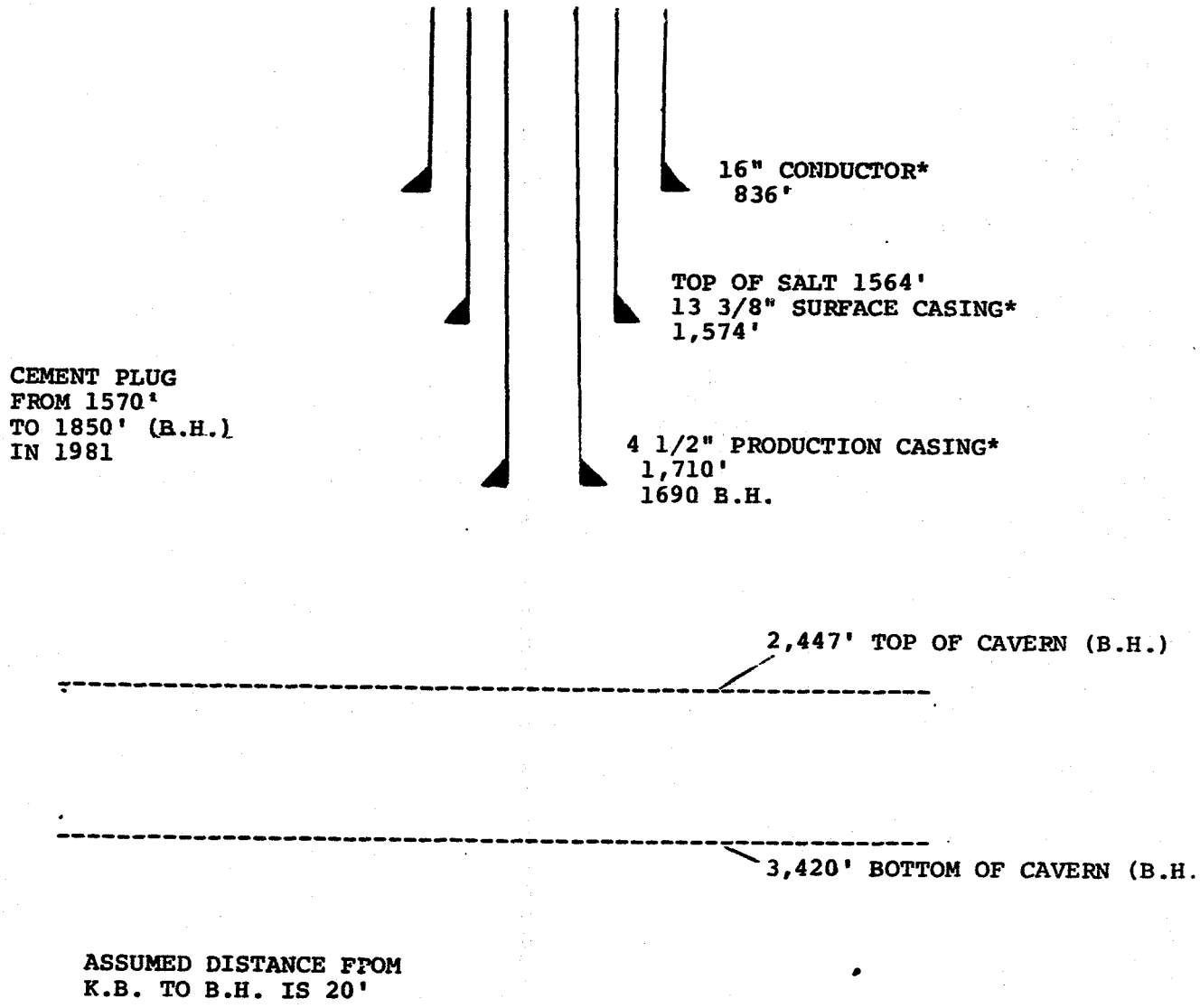


FIGURE 4. AS-BUILT CASING DIAGRAM
SPR 4 (WO) SULPHUR MINES

FROM REF 11

*BY OTHER THAN WILLIAMS-FENIX & SCISSON
COMPLETE INFORMATION NOT AVAILABLE

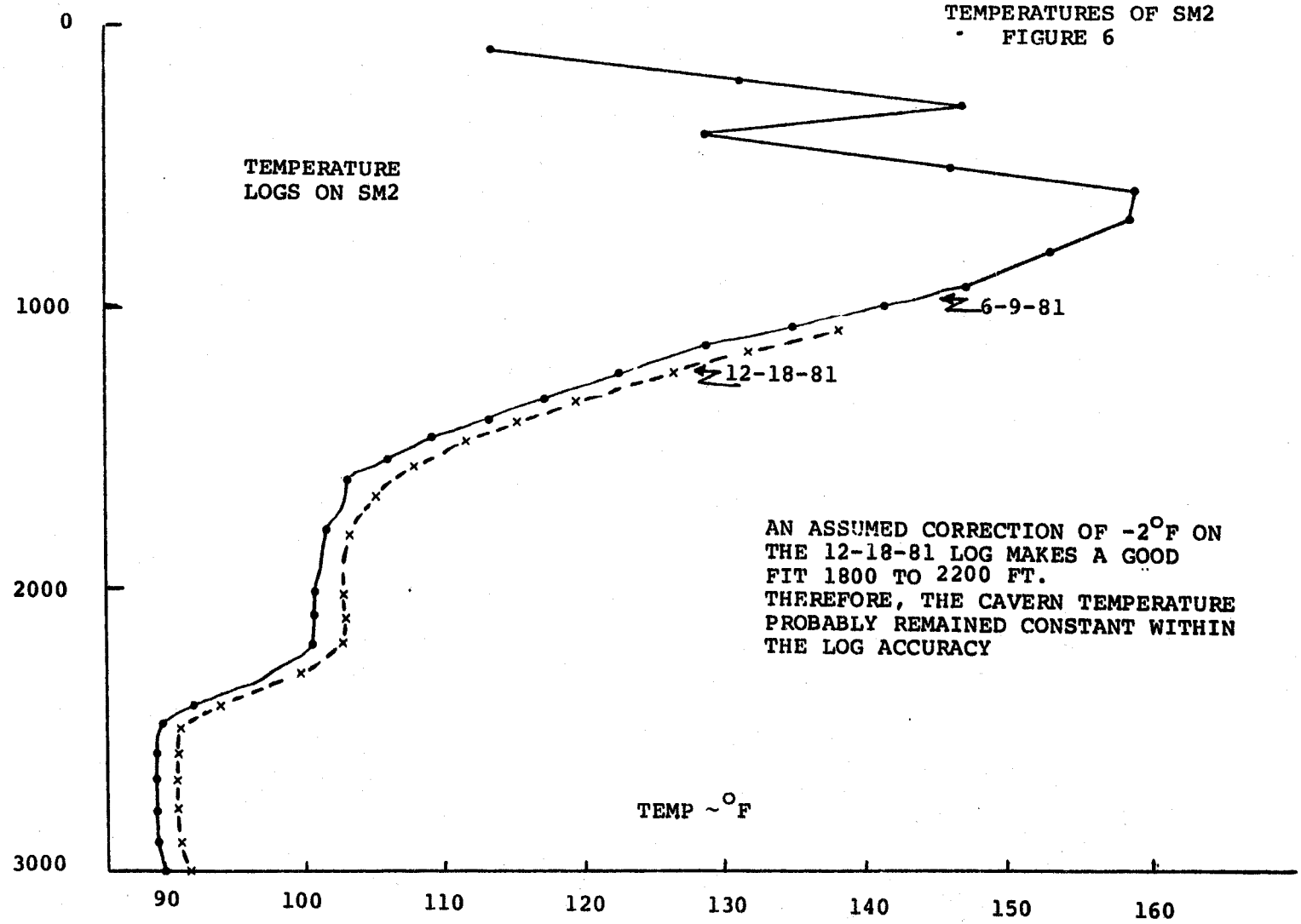


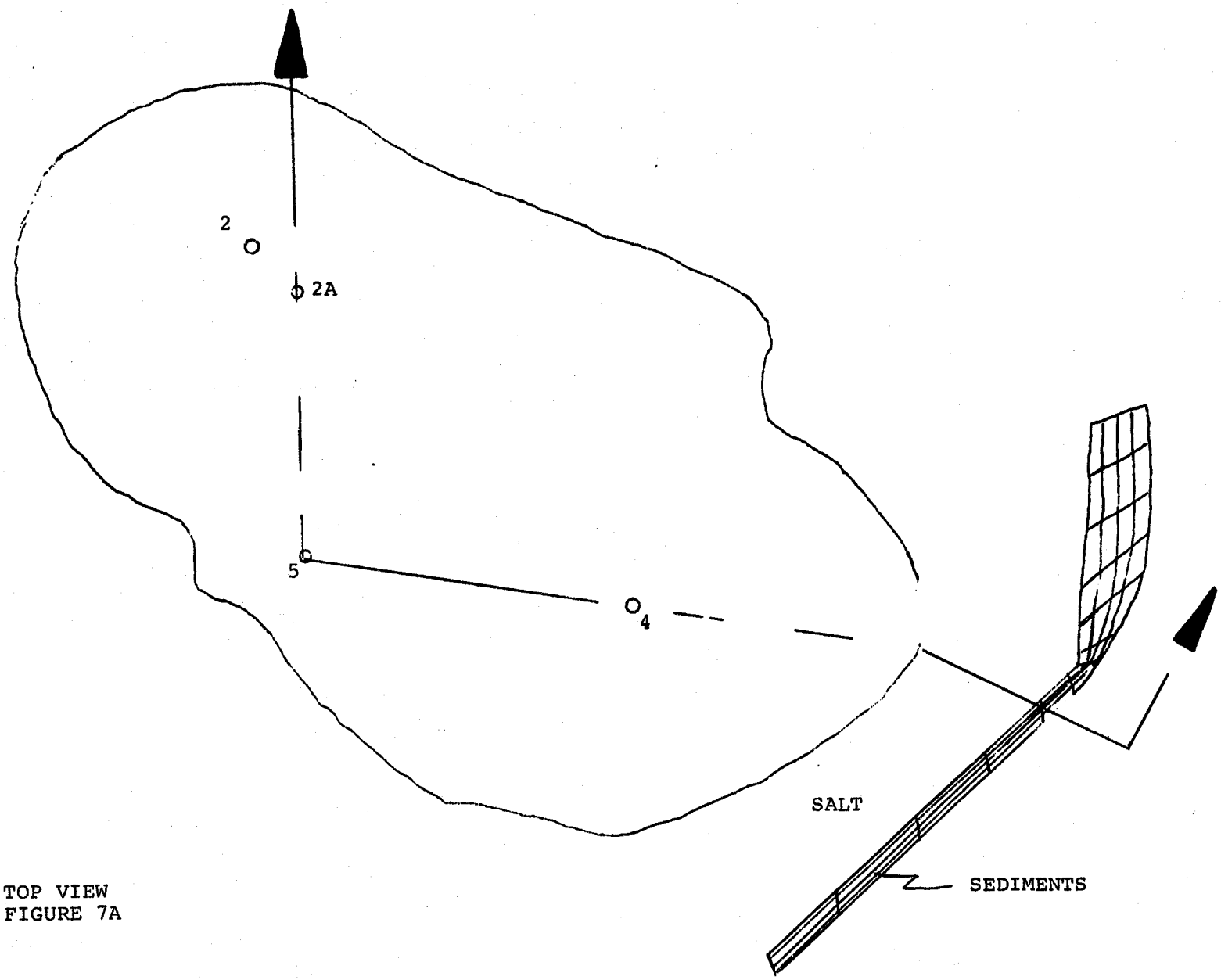
ASSUMED DISTANCE FROM
K.B. TO B.H. IS 20'

FIGURE 5. AS-BUILT CASING DIAGRAM
SPR 5(WO) SULPHUR MINES

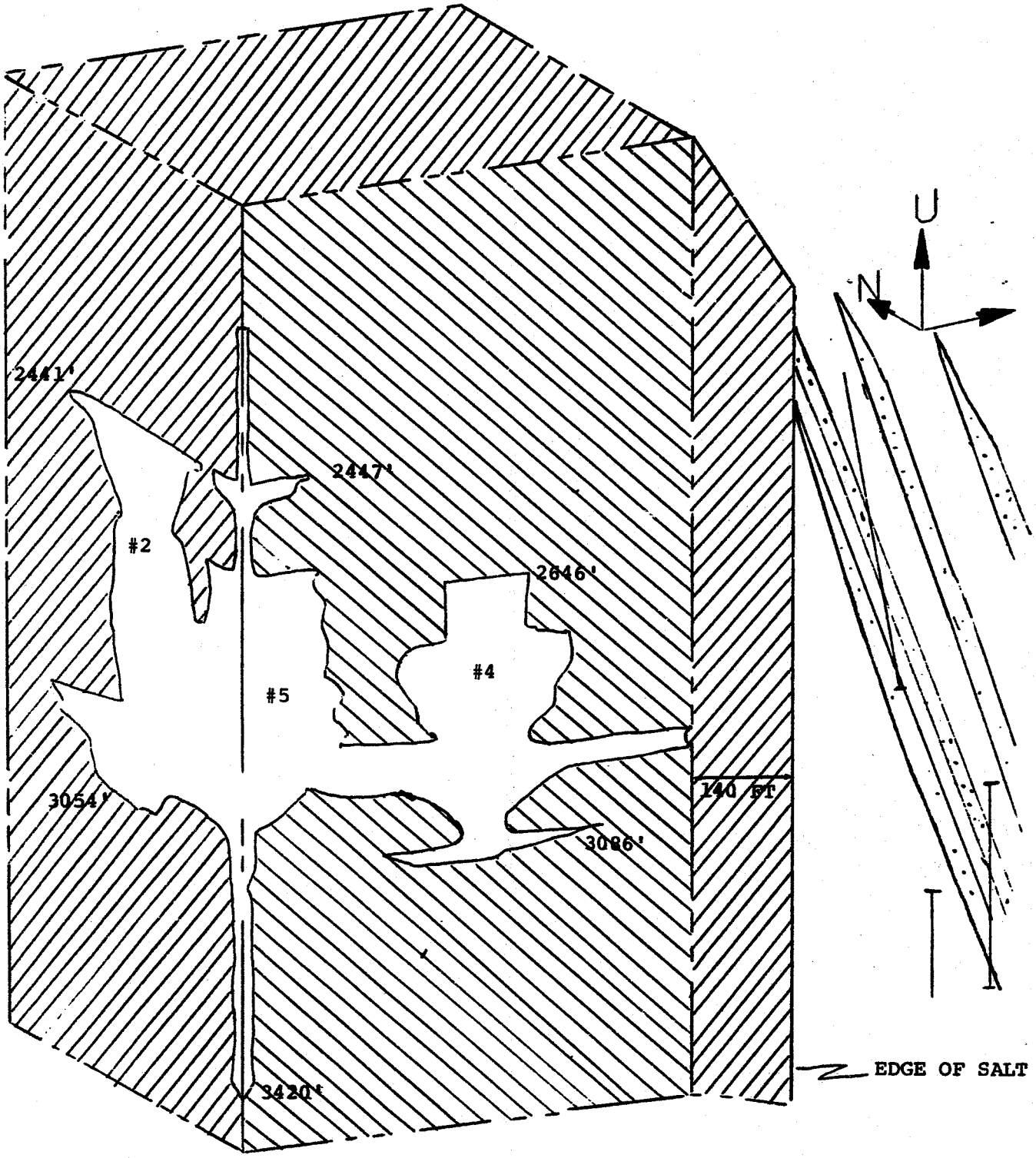
FROM REF 13

TEMPERATURES OF SM2
FIGURE 6



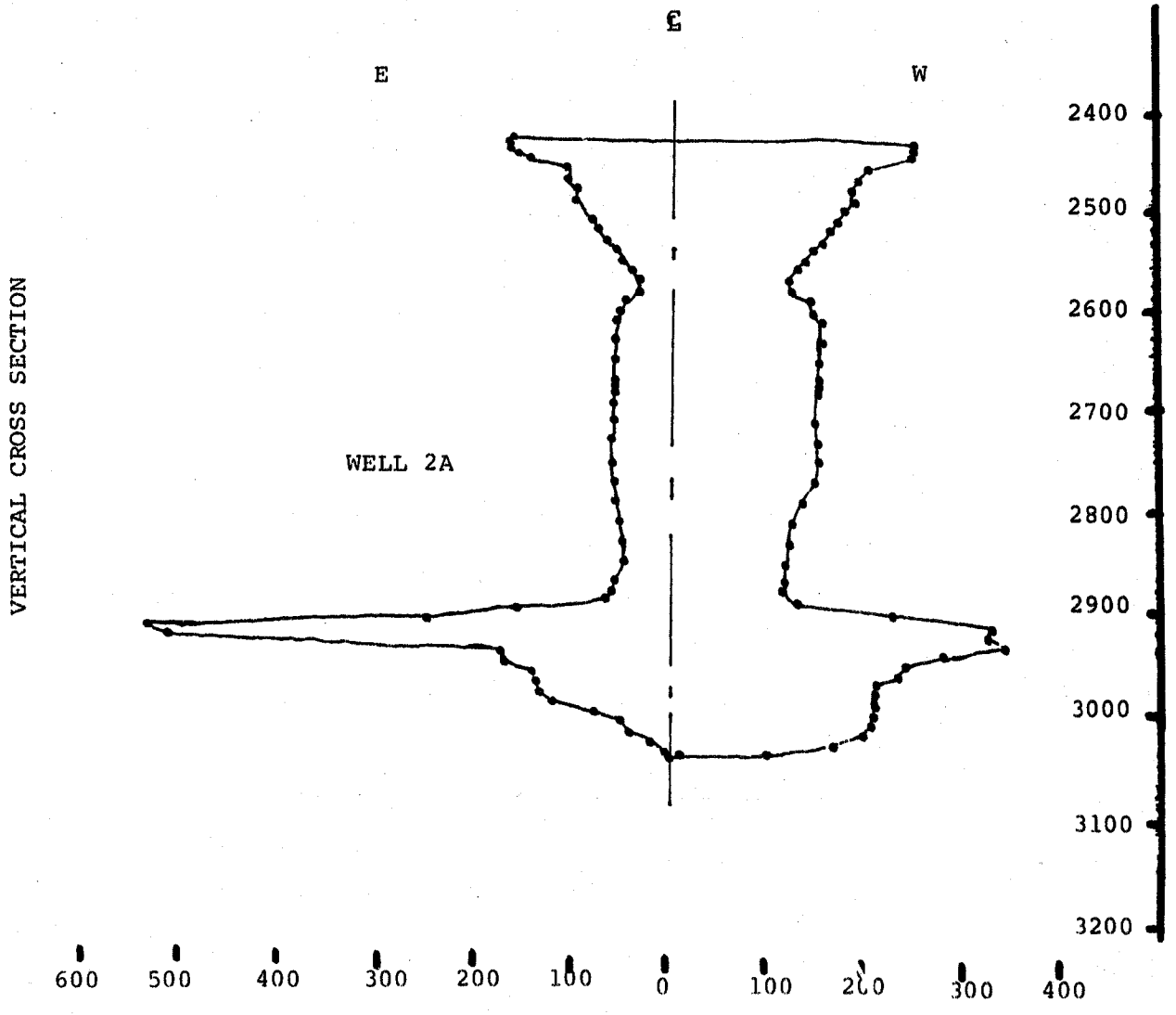


TOP VIEW
FIGURE 7A



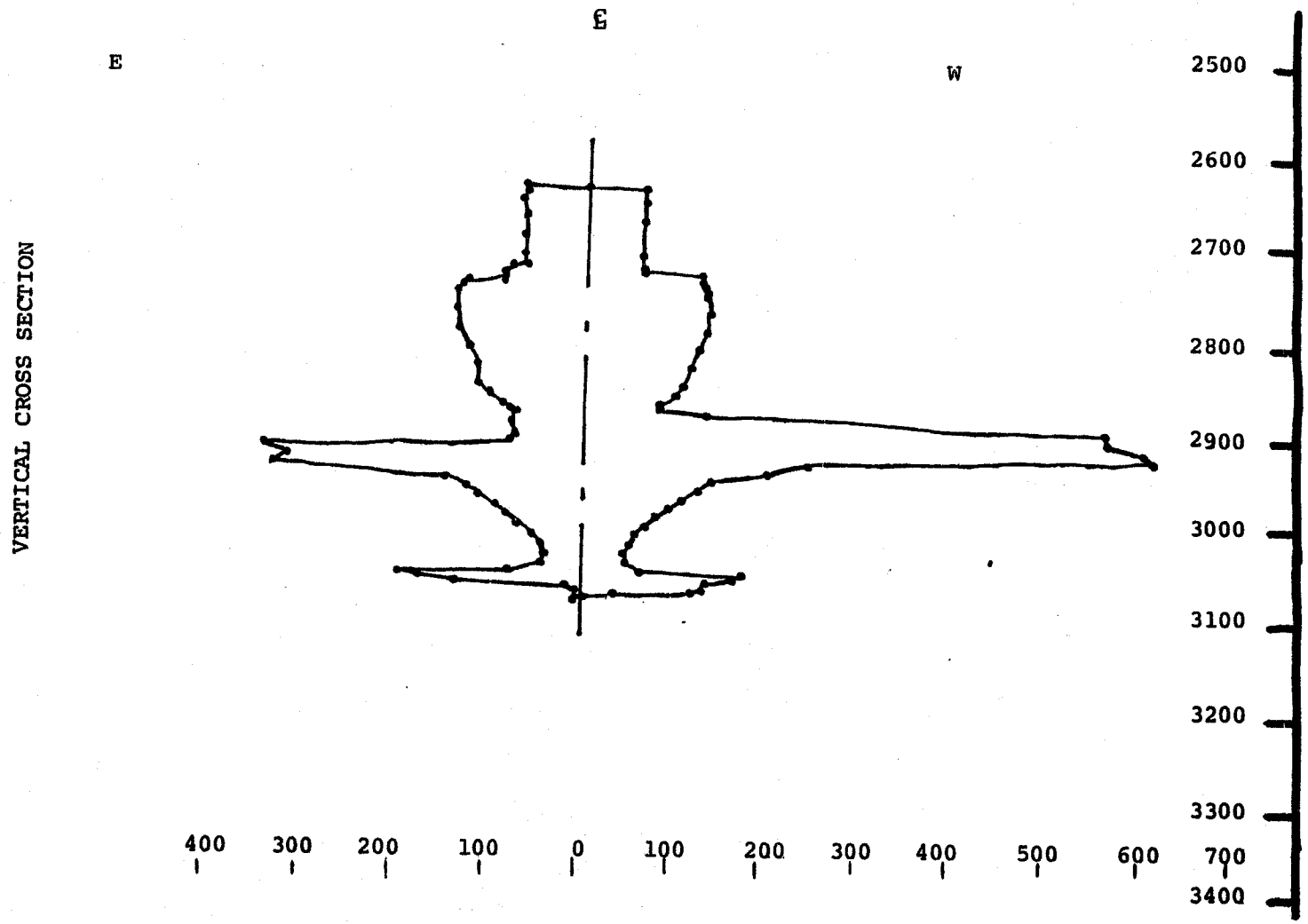
COMPOSITE CAVERN SHAPE
FIGURE 7B

FIGURE 7C. FROM REF. 2



Texas Brine Corporation
Sulphur Mines Site
Well No. 4
August 5, 1981

FIGURE 7D. FROM REF. 3



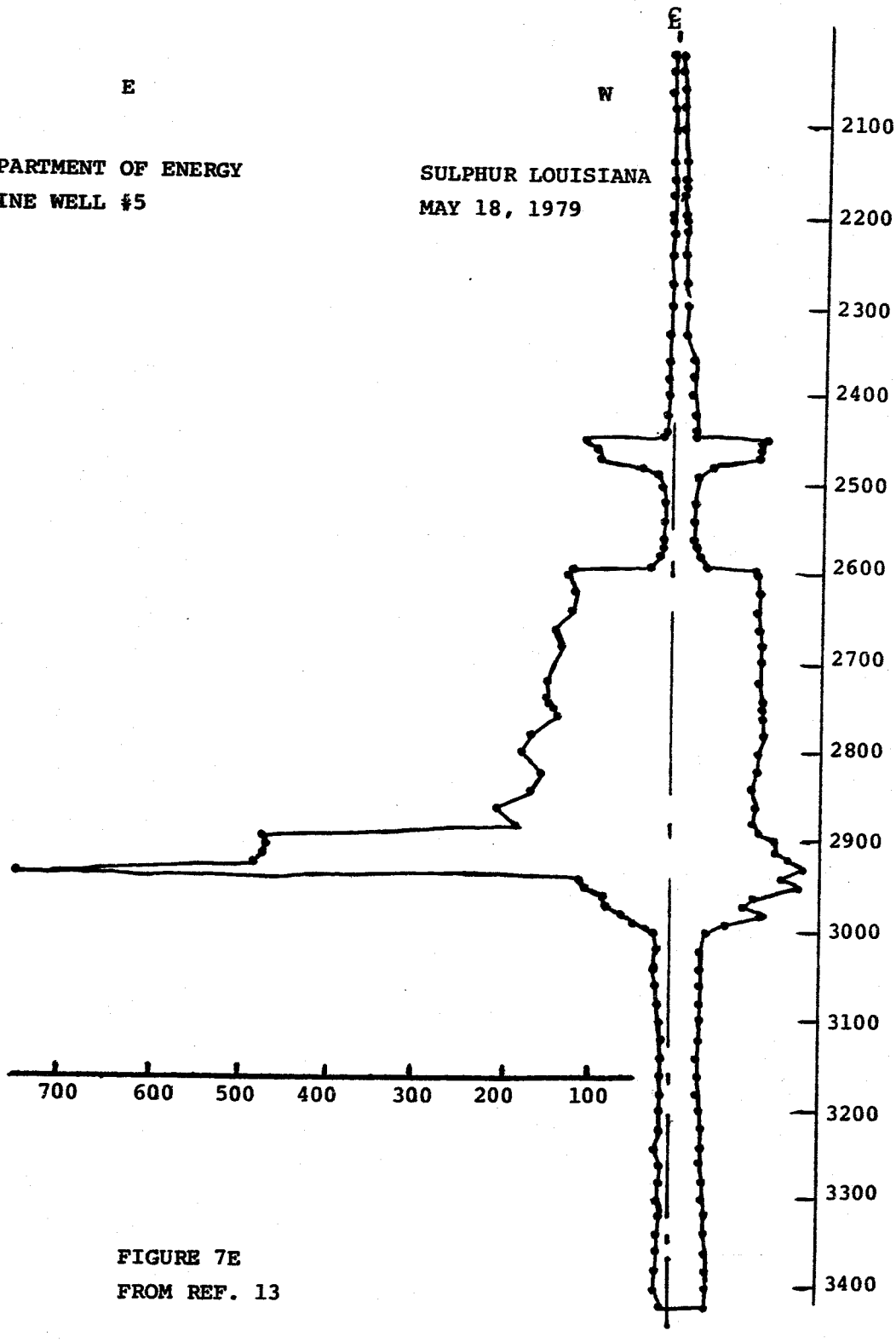
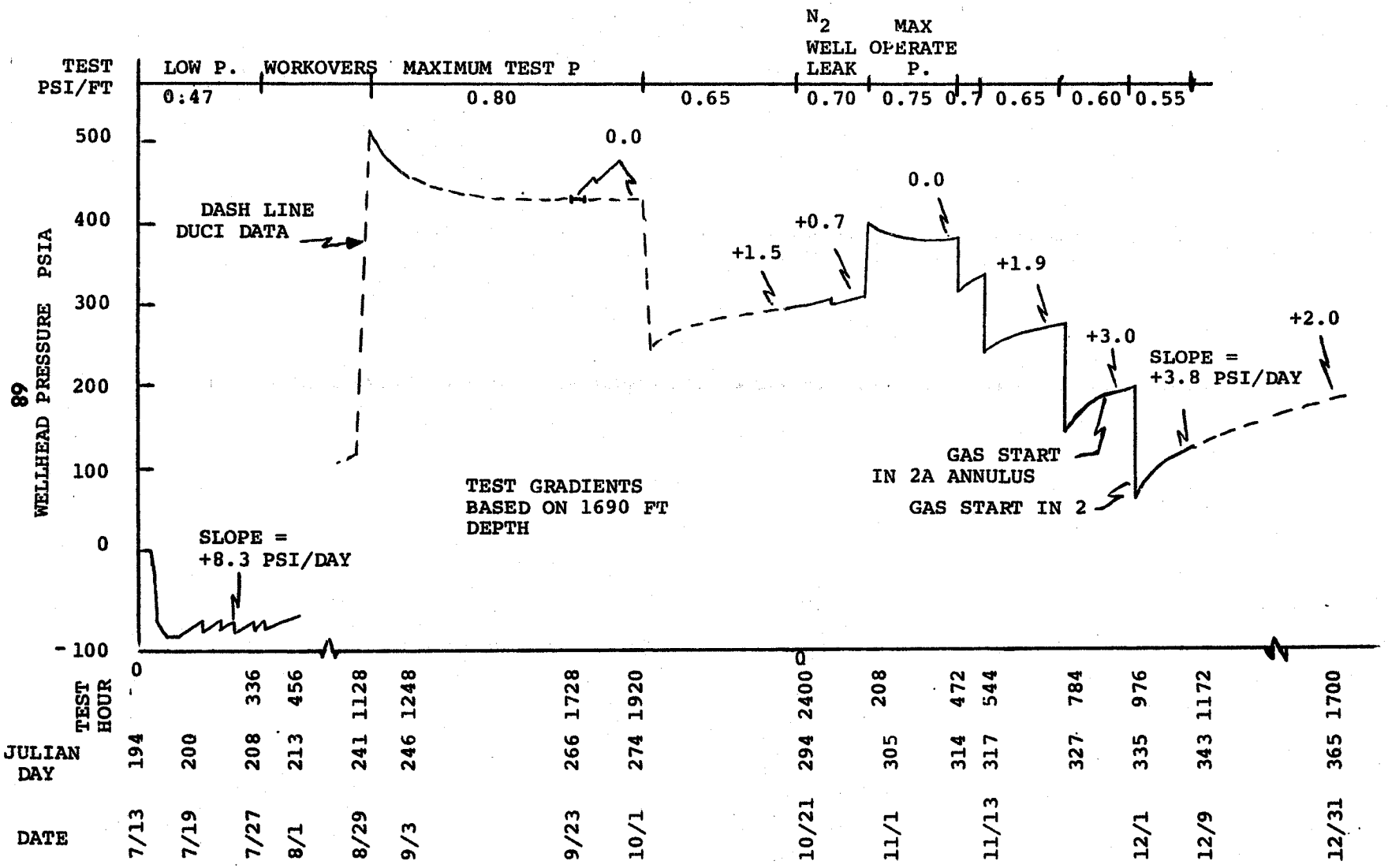


FIGURE 7E
FROM REF. 13

FIGURE 8

SULPHUR MINES CAVERN 2-4-5 TESTS 1981



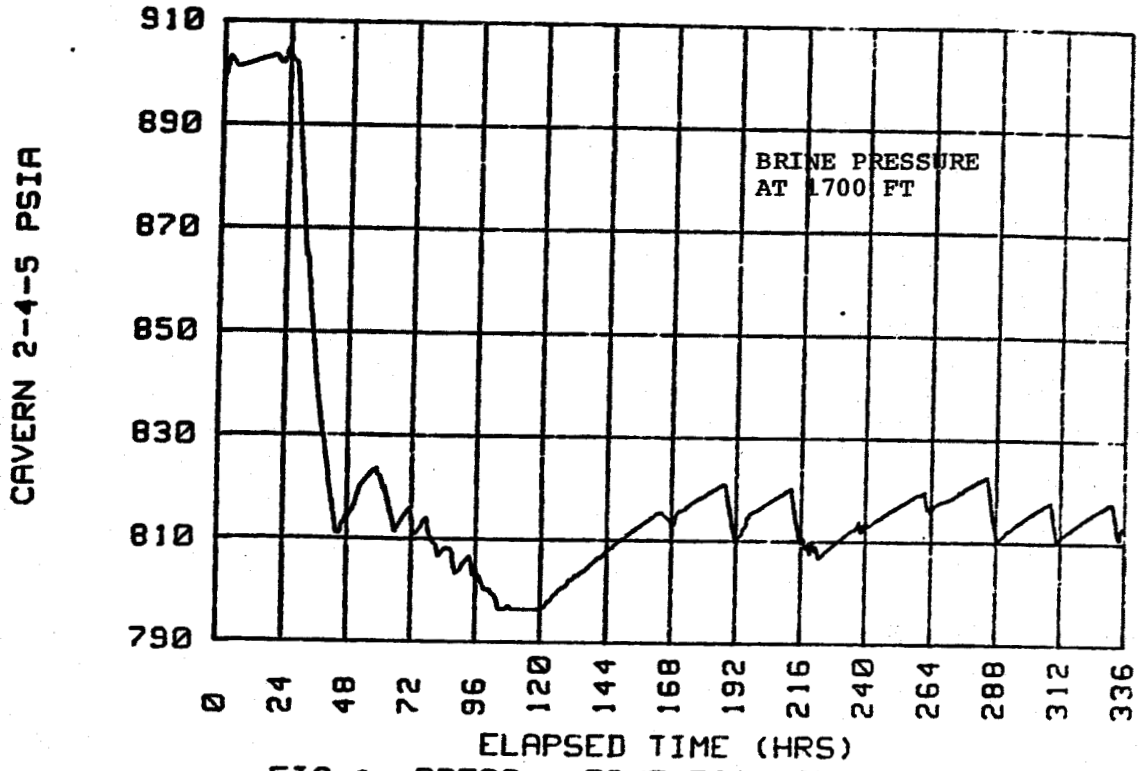


FIG 9 PRESS - TIME FOR LOW PRESS TEST

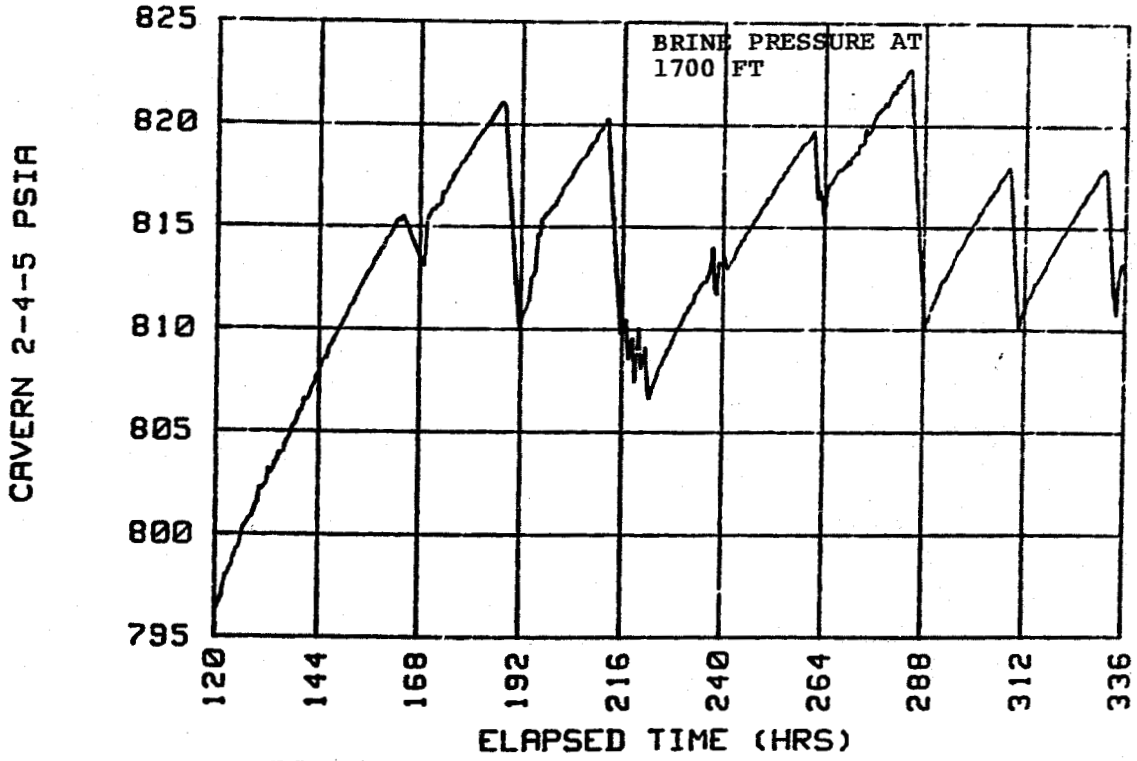


FIG 10 PRESS - TIME FOR LOW PRESS TEST

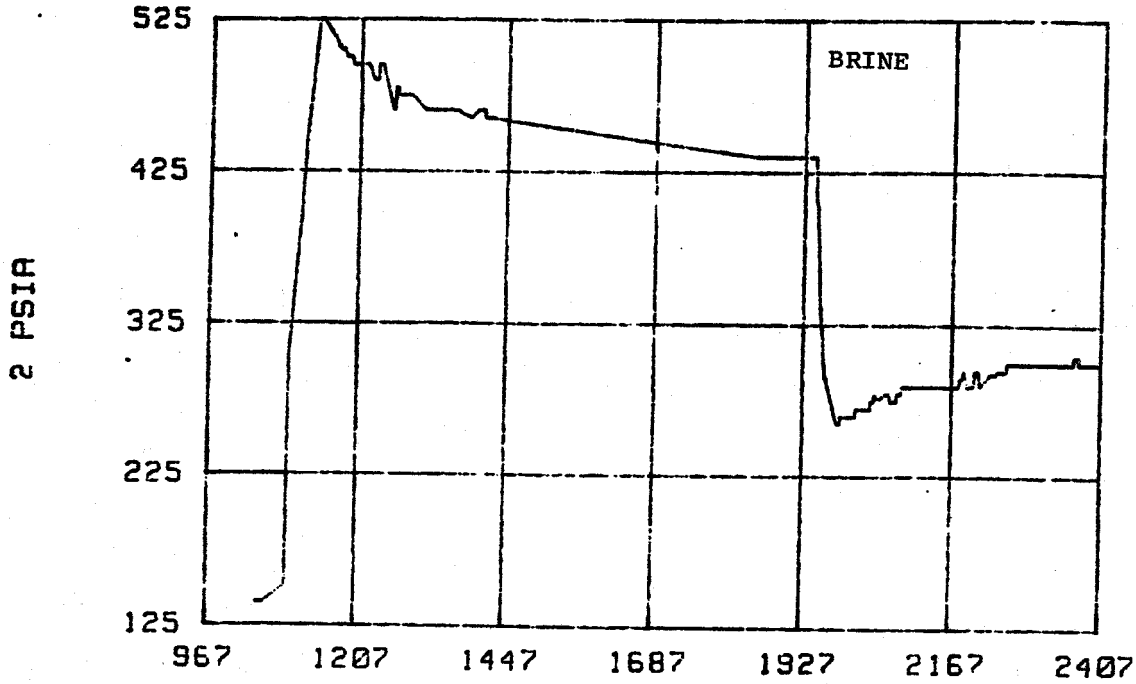


FIG 11 PRESS - TIME .8 & .65 PSI/FT

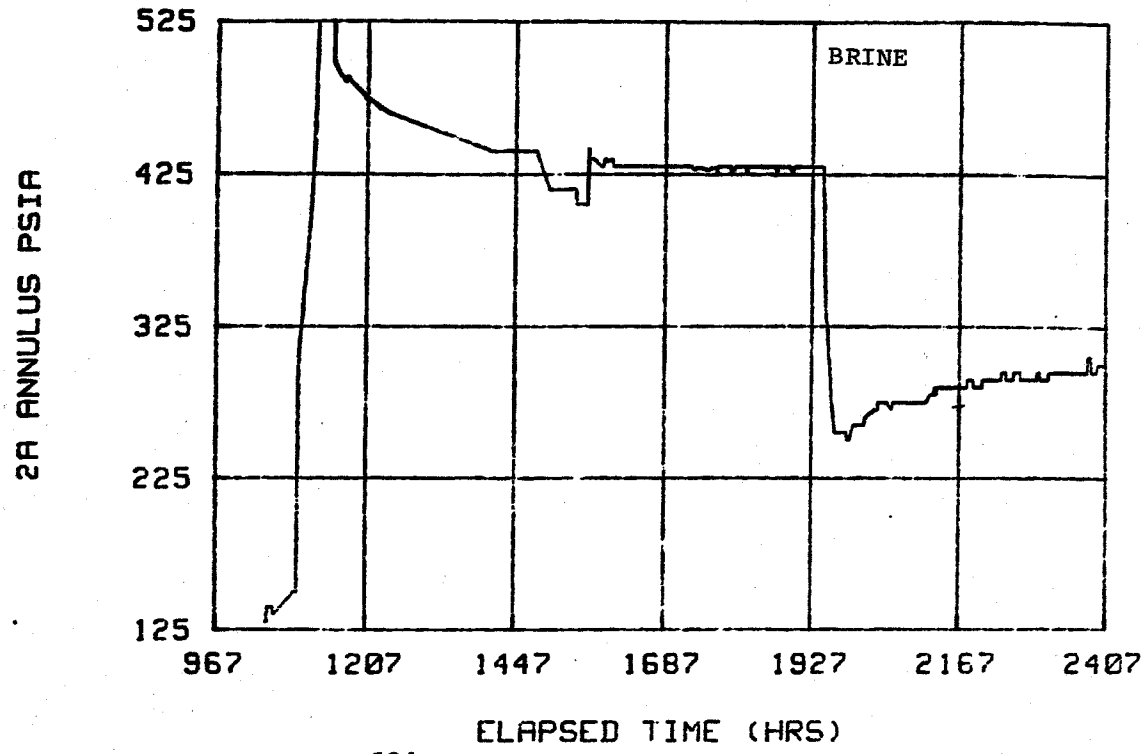


FIG 12A PRESS - TIME .8 & .65 PSI/FT

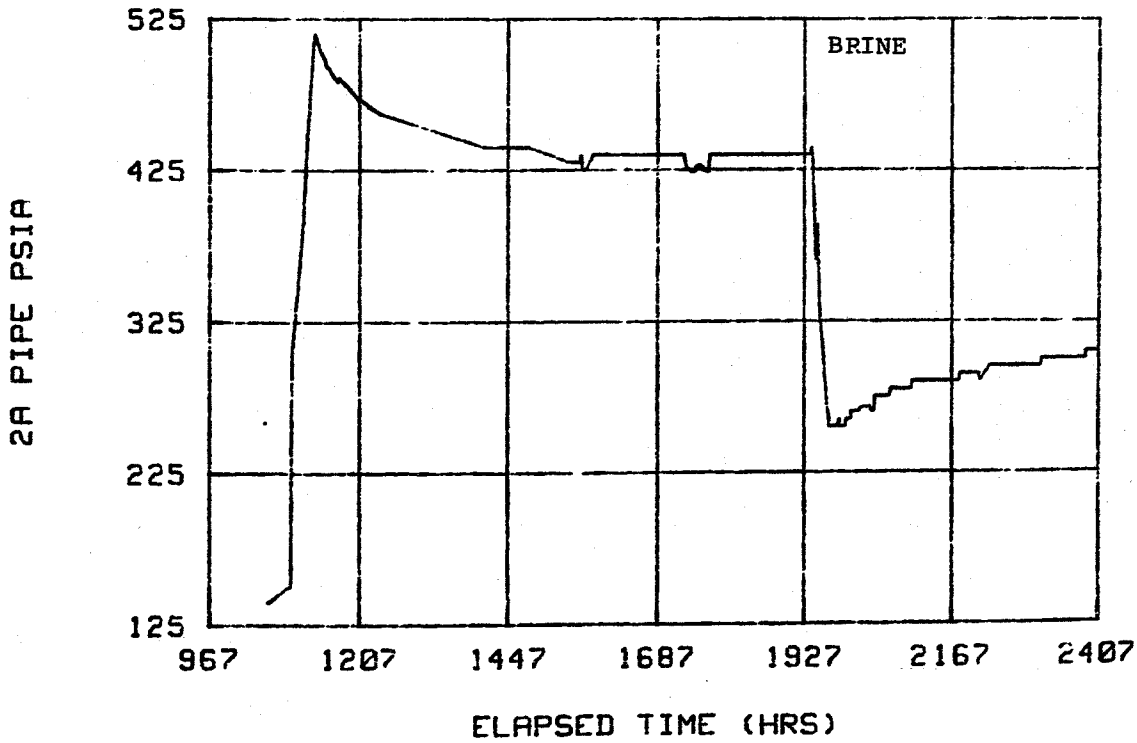


FIG 12B PRESS - TIME .8 & .65 PSI/FT

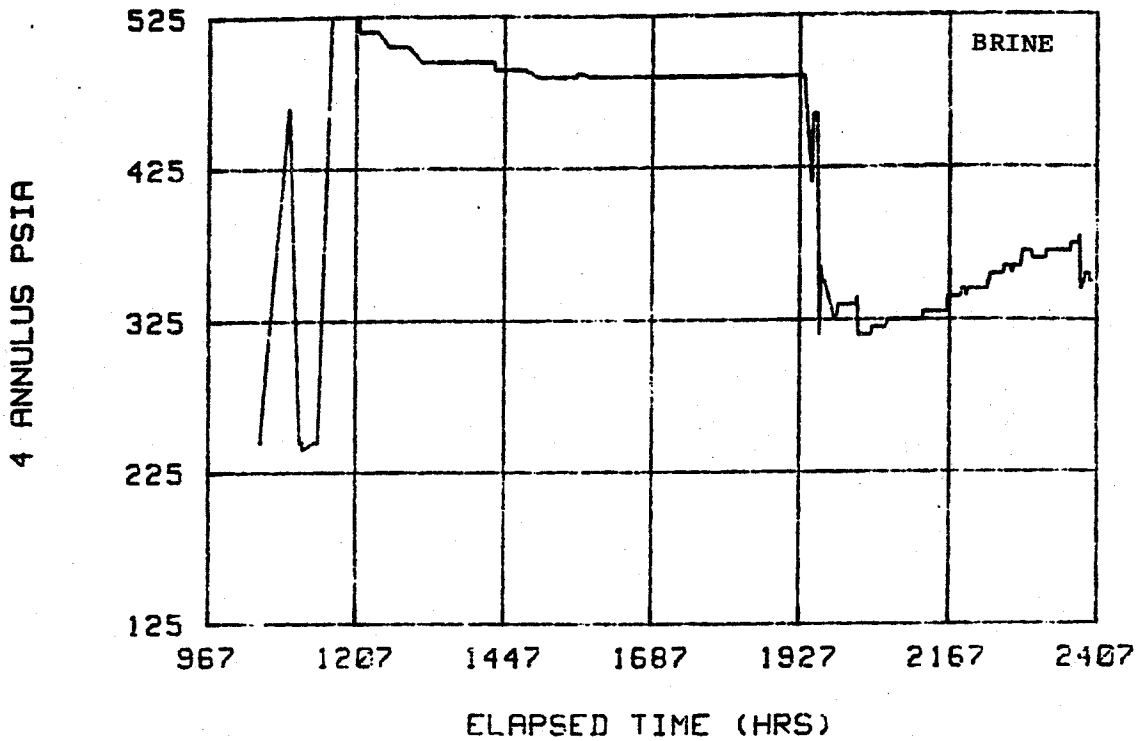


FIG 13A PRESS - TIME .8 & .65 PSI/FT

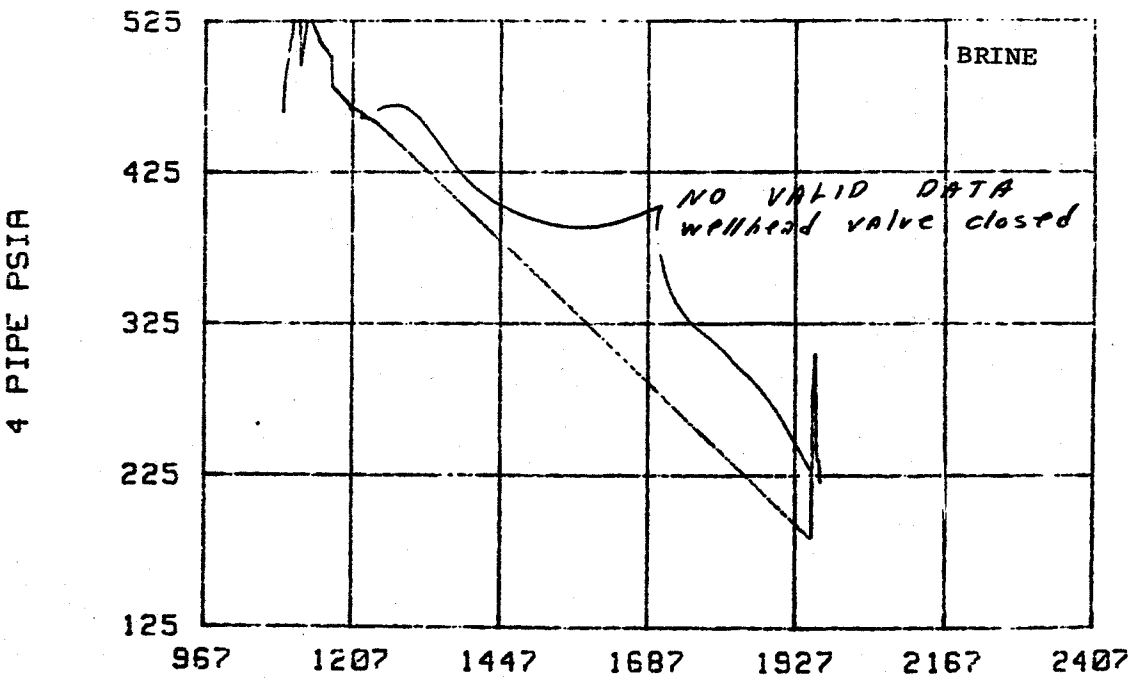


FIG 13B PRESS - TIME .8 & .65 PSI/FT

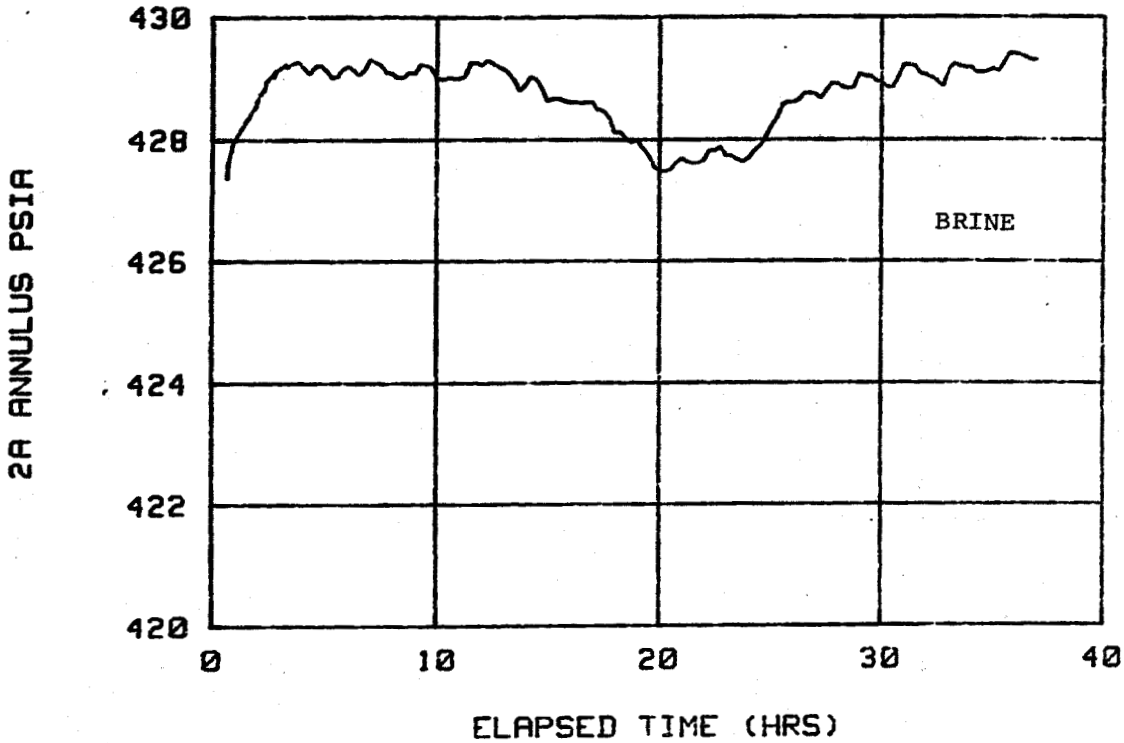


FIG14A PRESS - TIME FOR .8 PSI/FT TEST

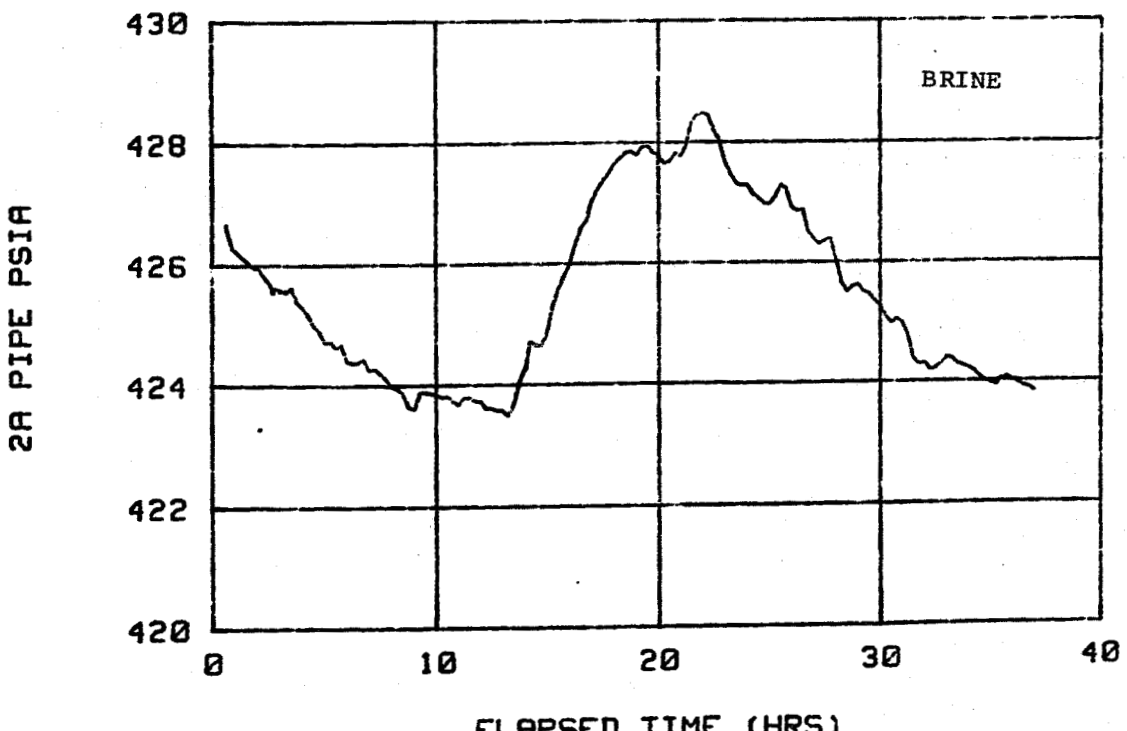


FIG 14B PRESS - TIME FOR .8 PSI/FT TEST

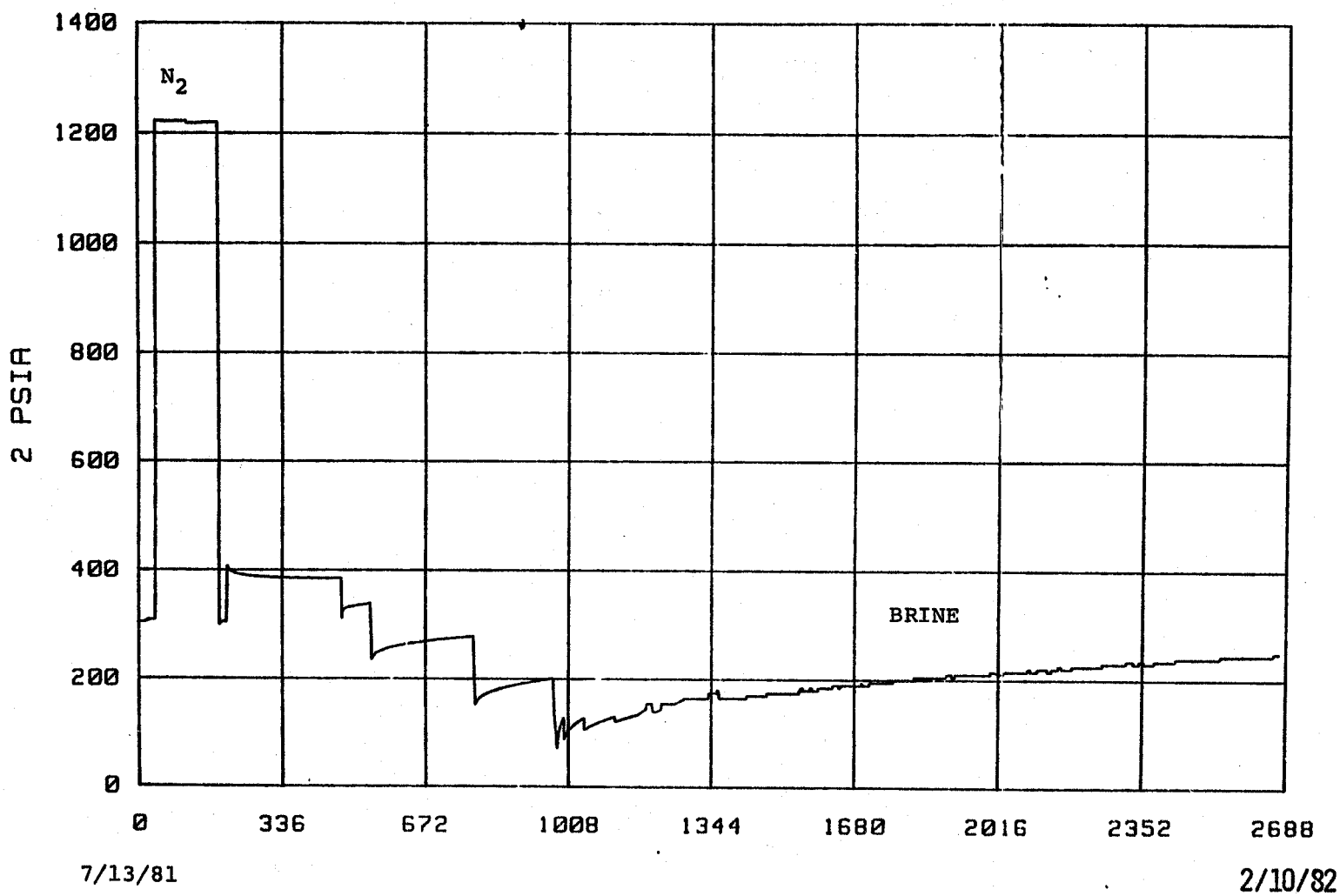


FIG 15 PRESS - TIME FOR CAVERN TEST

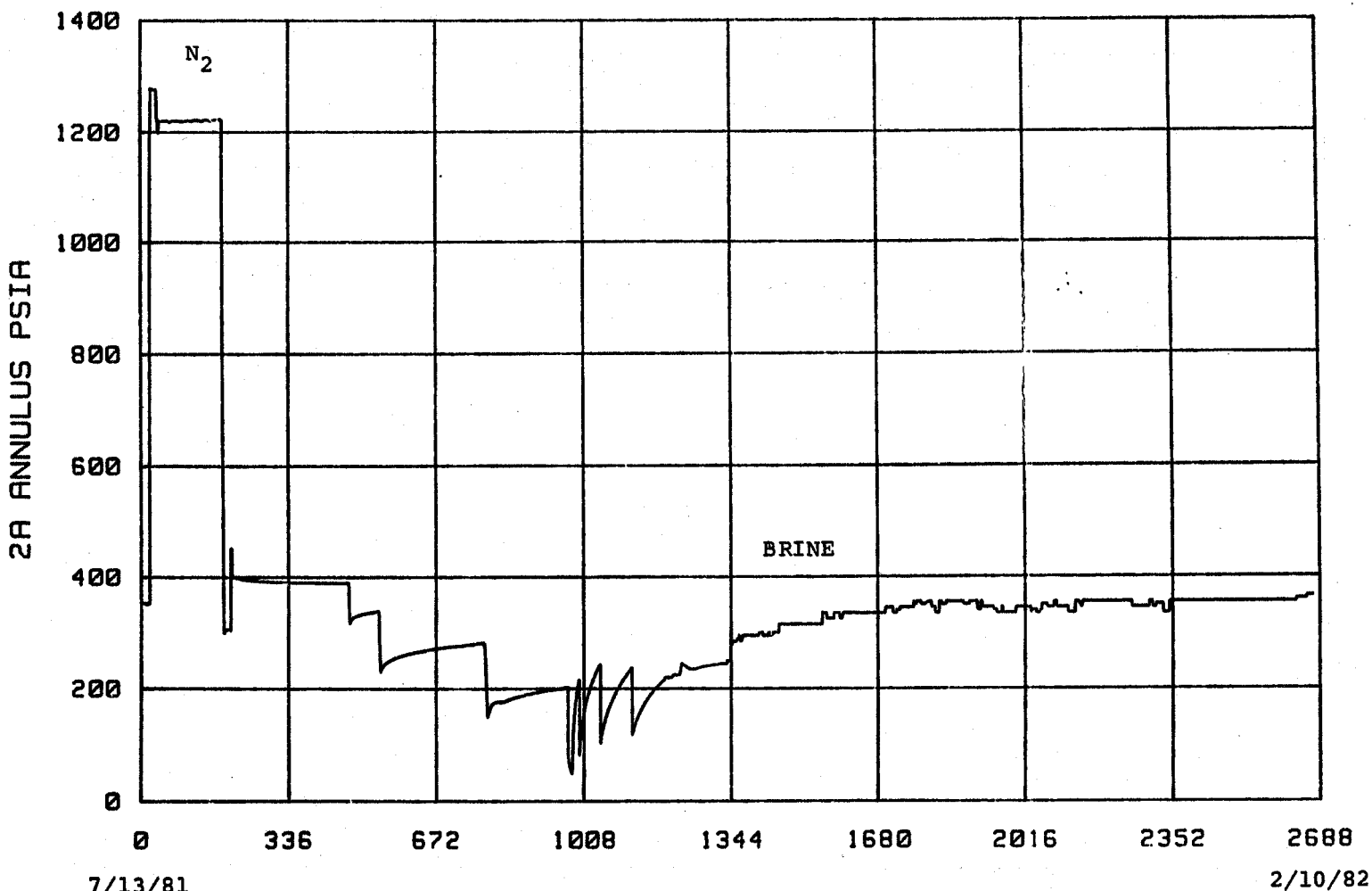


FIG 16A PRESS - TIME FOR CAVERN TEST

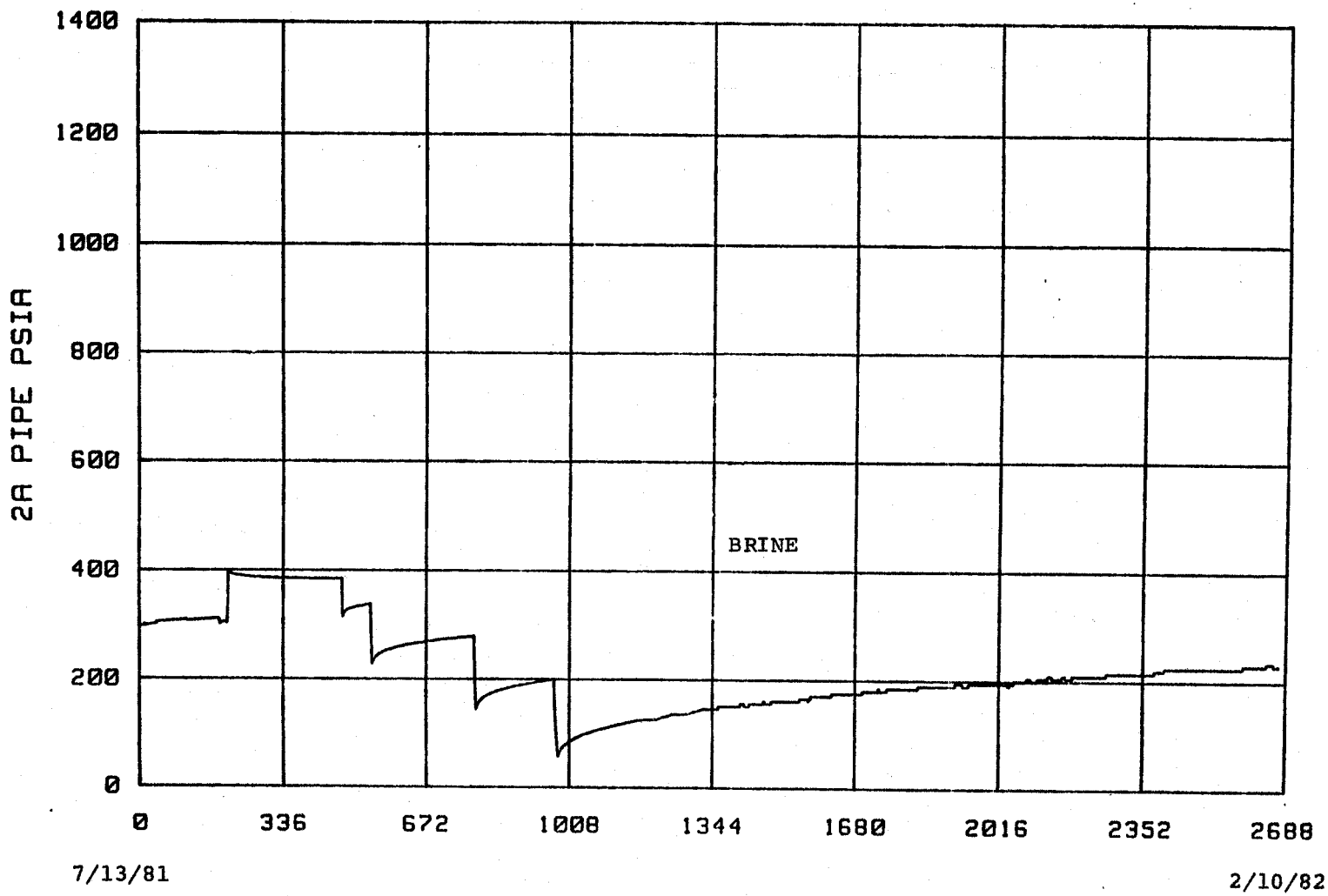


FIG 16B PRESS - TIME FOR CAVERN TEST

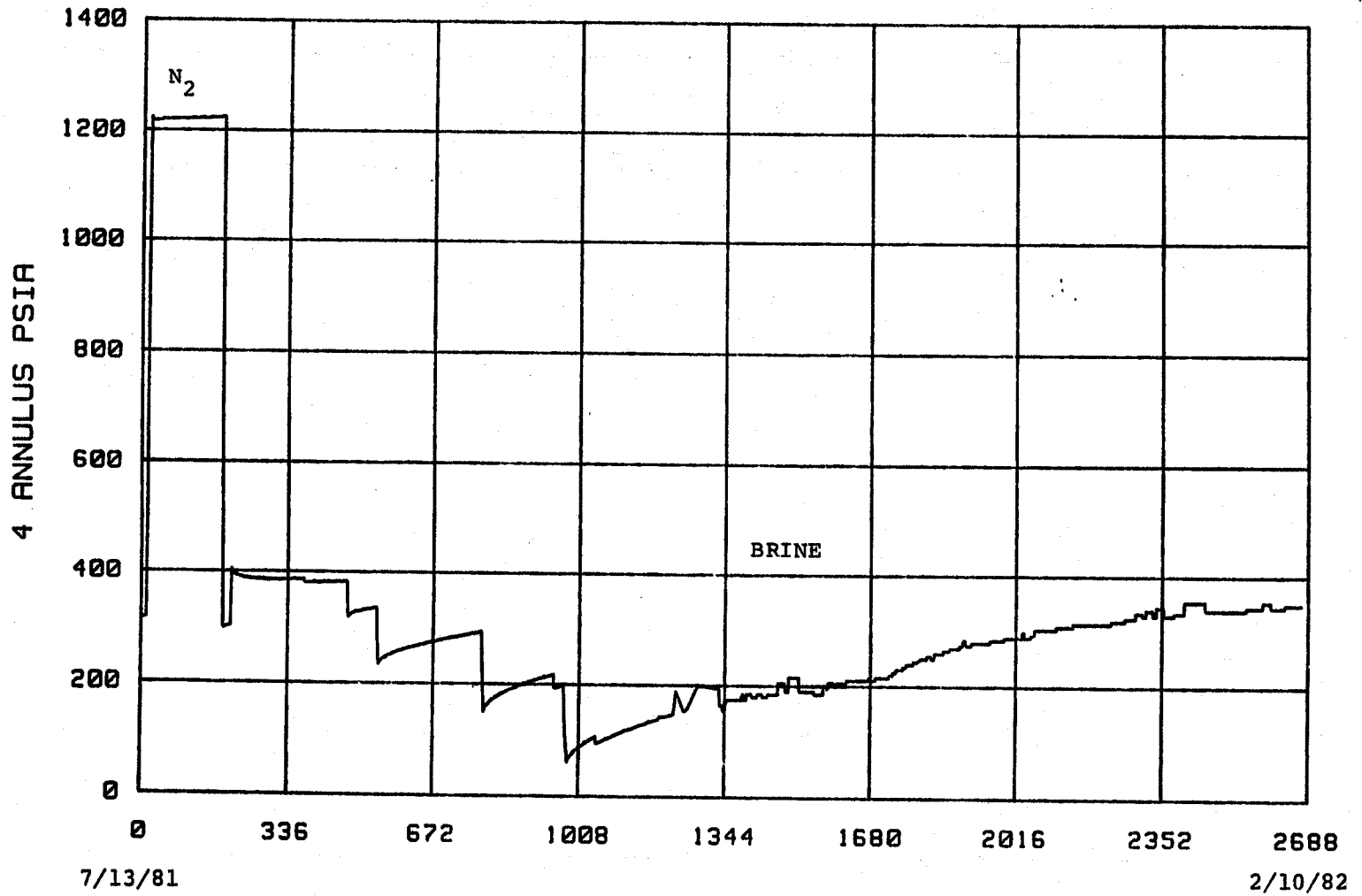


FIG 17A PRESS - TIME FOR CAVERN TEST

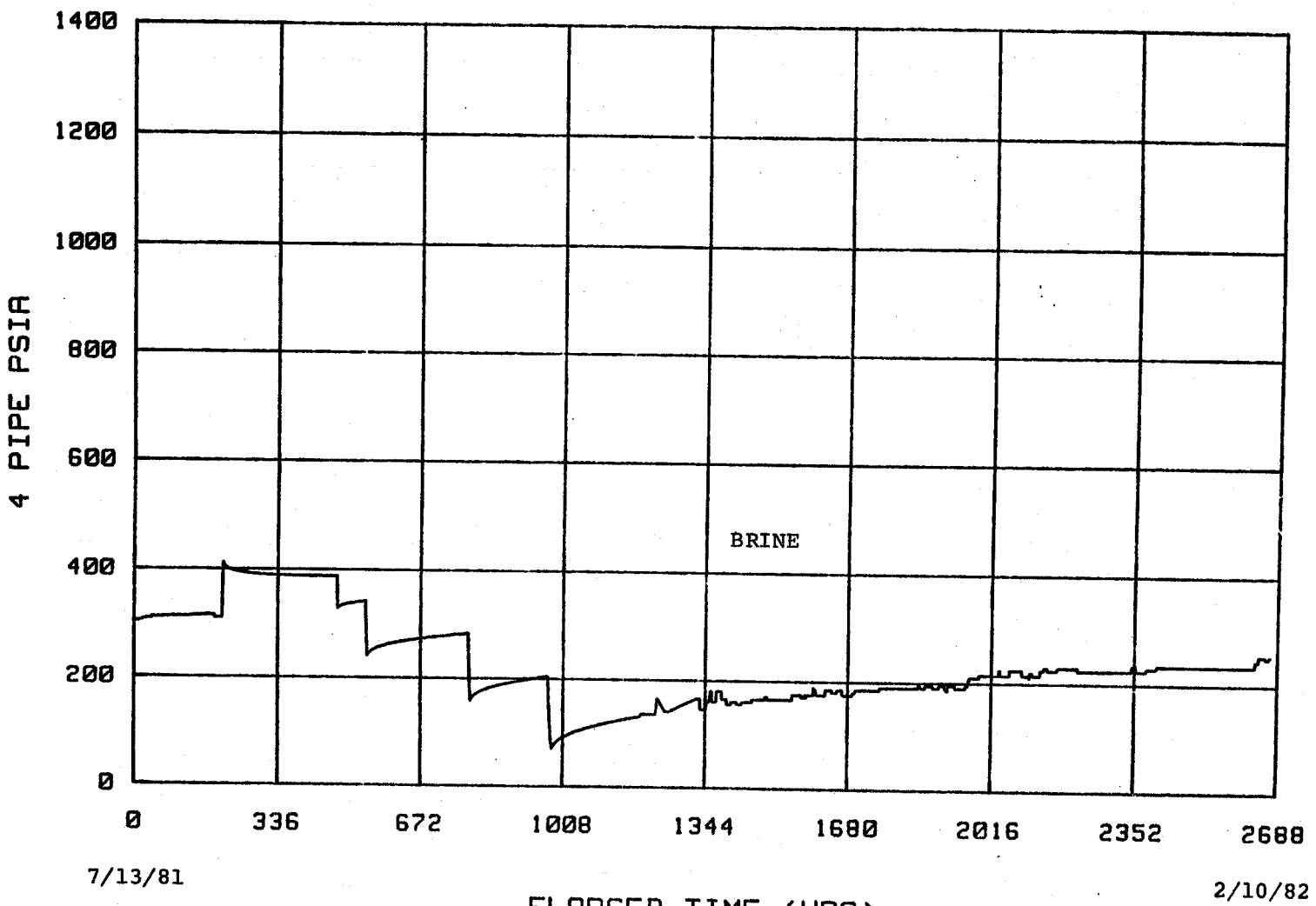


FIG 17B PRESS - TIME FOR CAVERN TEST

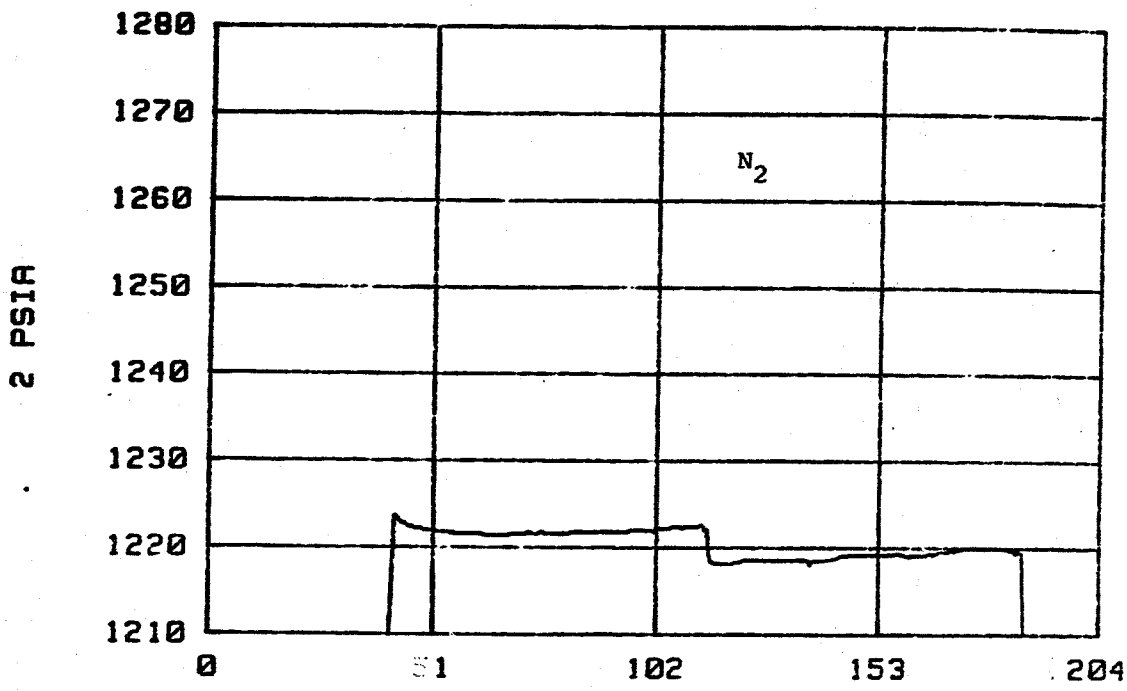


FIG 18 PRESS - TIME FOR WELL LEAK TEST

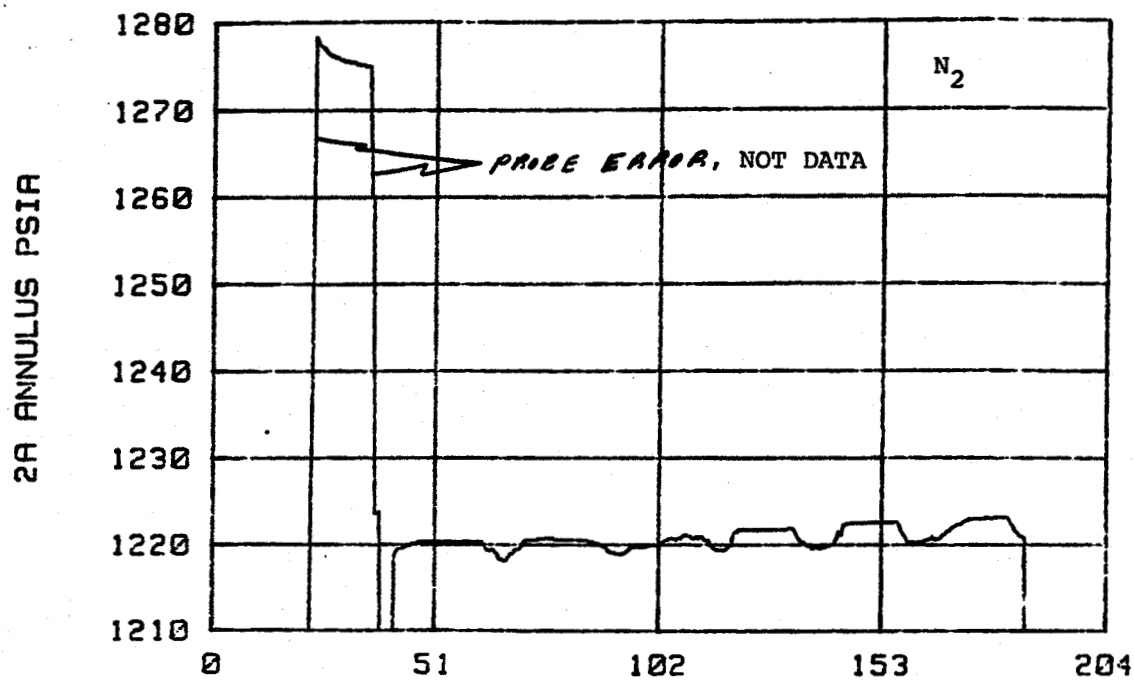


FIG 19A PRESS - TIME FOR WELL LEAK TEST

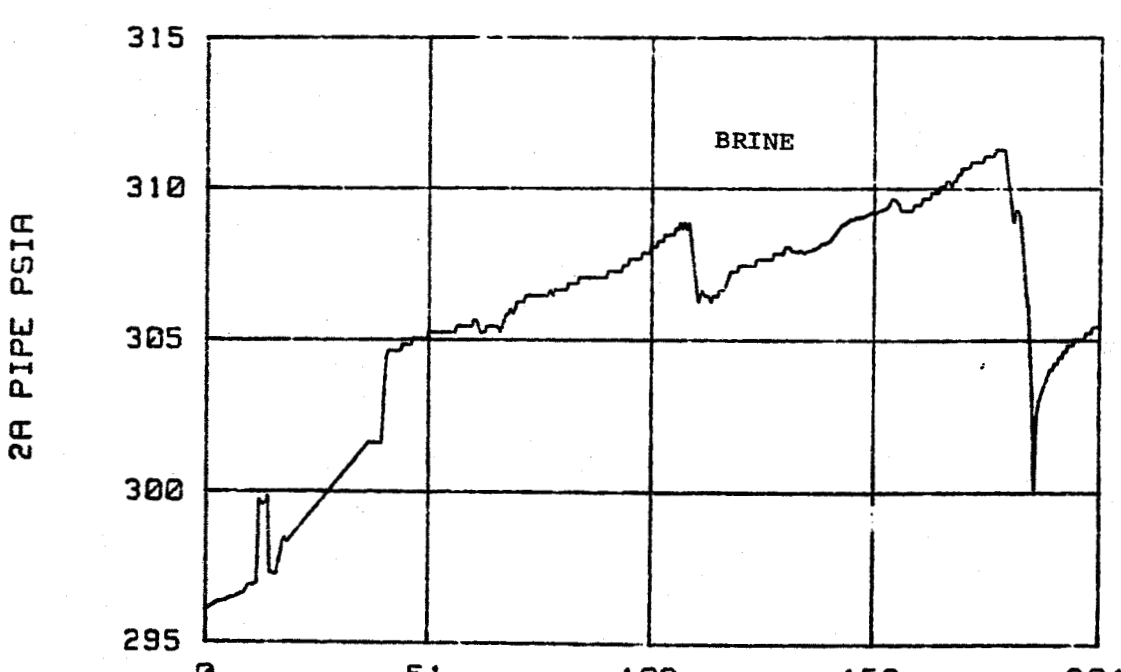


FIG 19B PRESS - TIME FOR WELL LEAK TEST

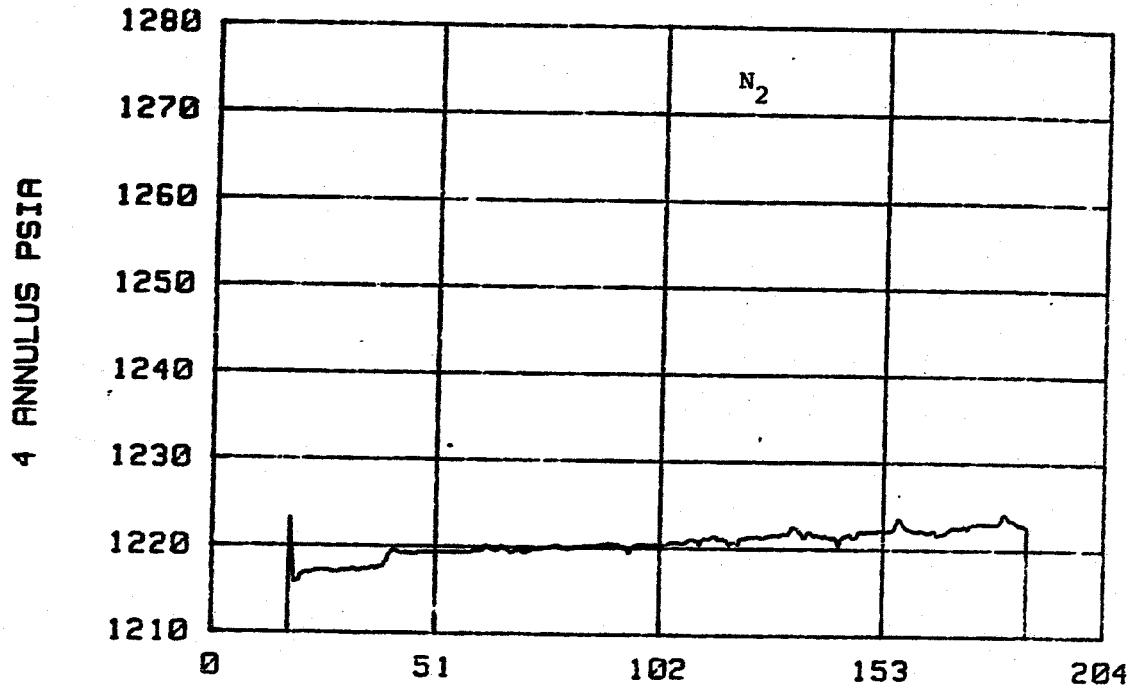


FIG 20A PRESS - TIME FOR WELL LEAK TEST

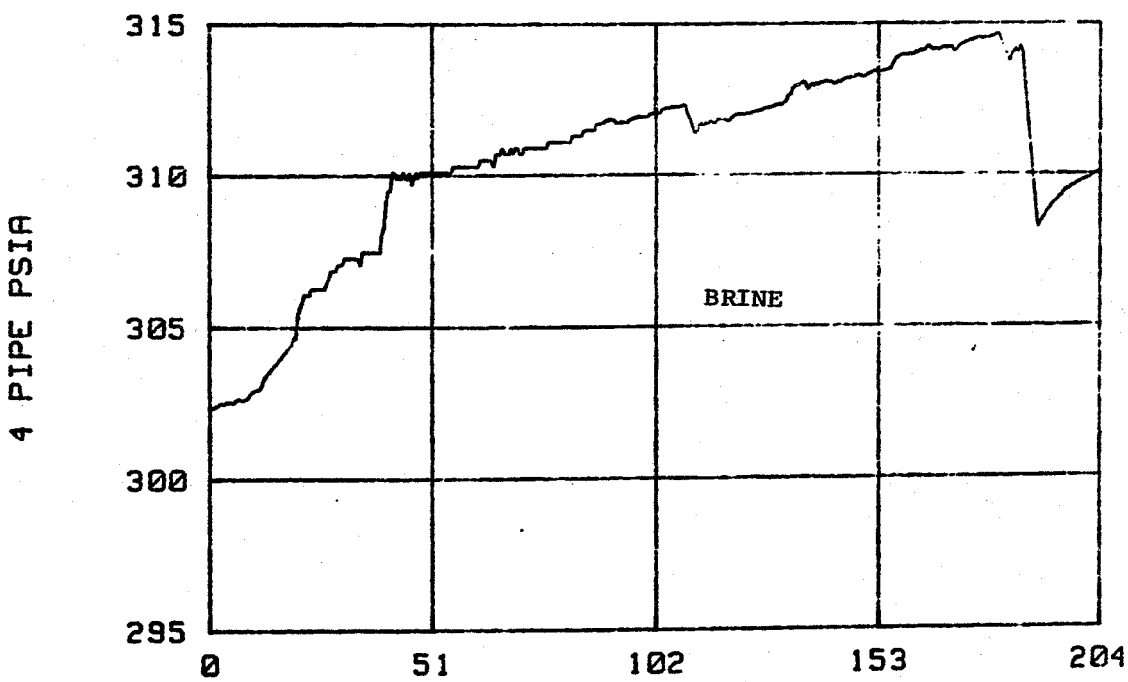


FIG 20B PRESS - TIME FOR WELL LEAK TEST

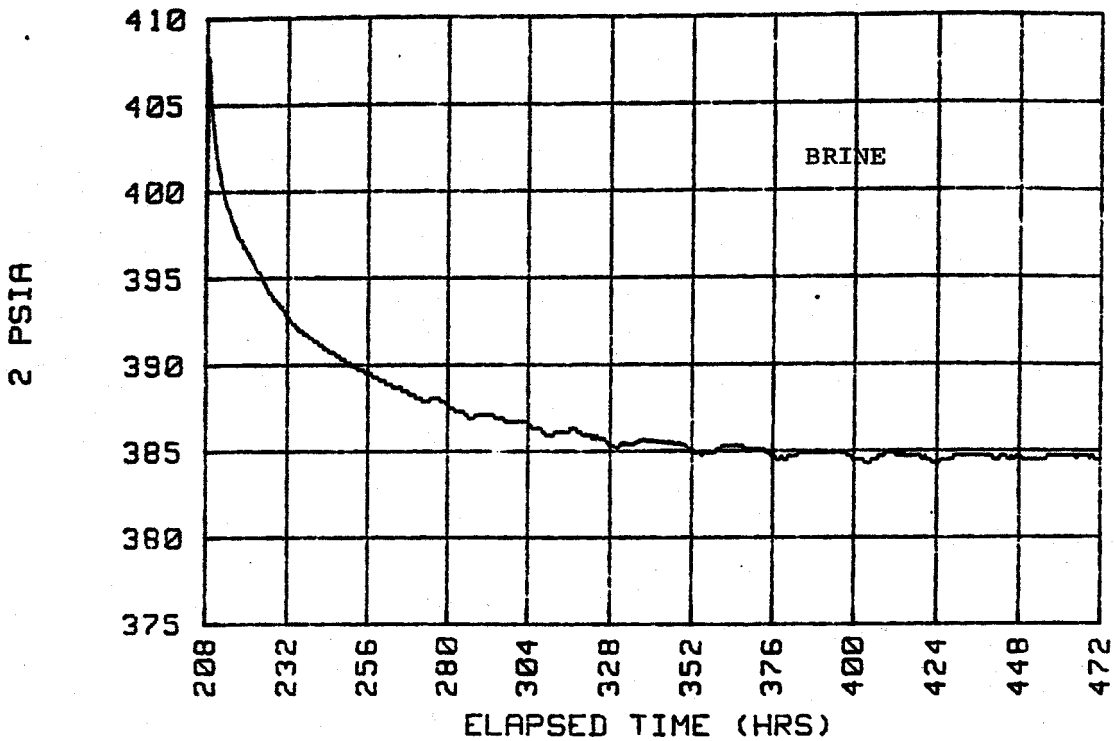


FIG 21 PRESS - TIME FOR MAX OPERATING PRESS

.75

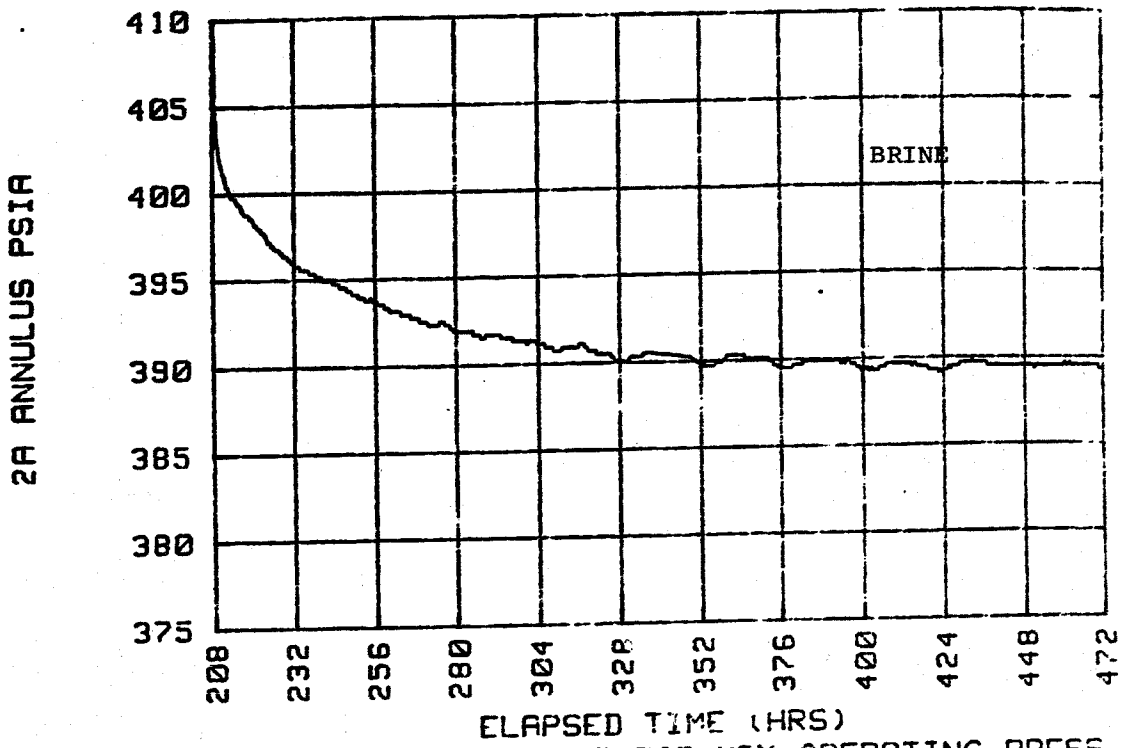


FIG 22A PRESS - TIME FOR MAX OPERATING PRESS

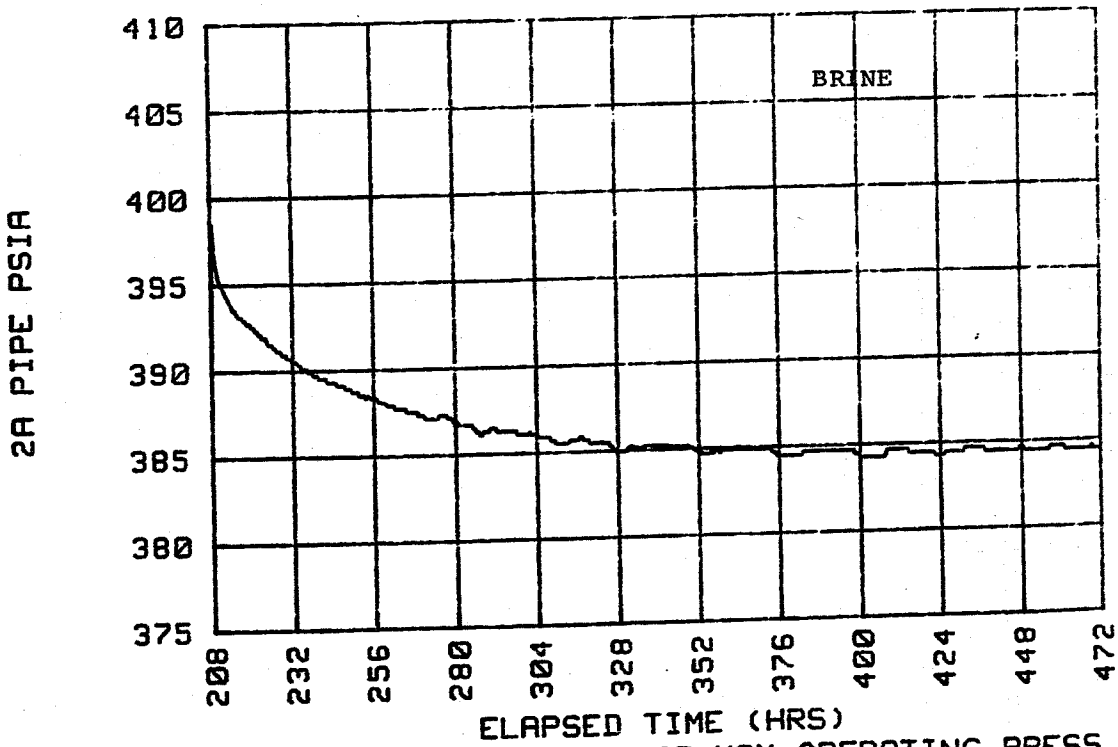


FIG 22B PRESS - TIME FOR MAX OPERATING PRESS

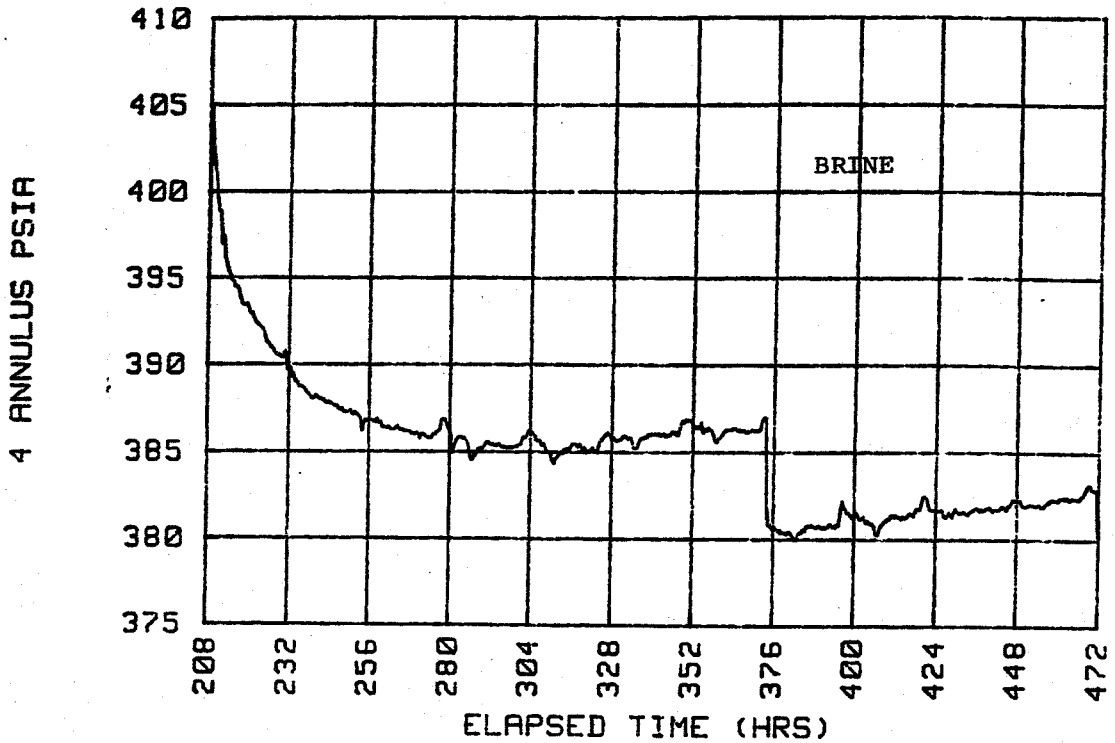


FIG 23A PRESS - TIME FOR MAX OPERATING PRESS

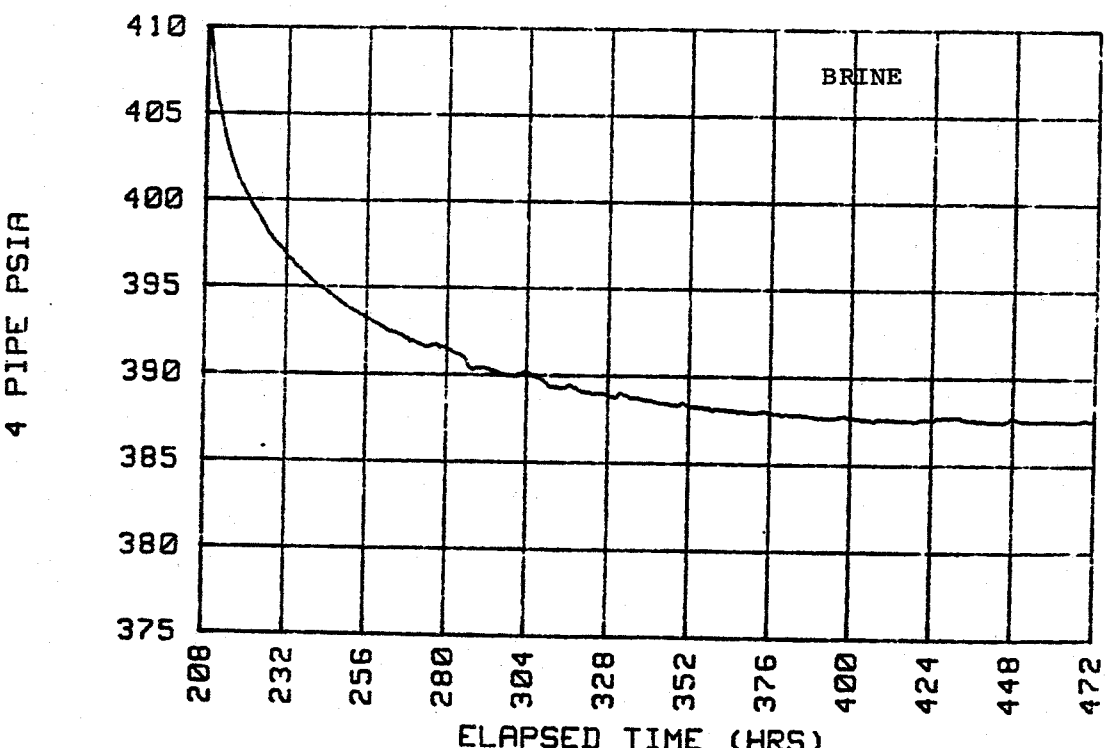


FIG 23B PRESS - TIME FOR MAX OPERATING PRESS

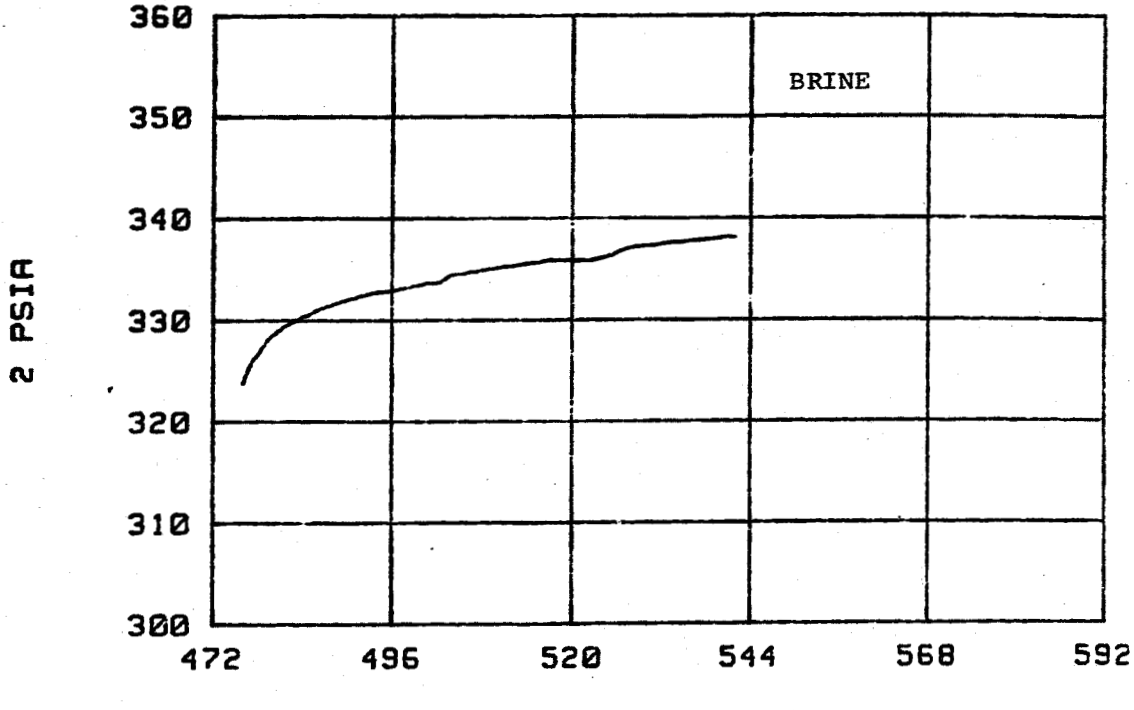


FIG 24 PRESS - TIME START .7 PSI/FT TEST

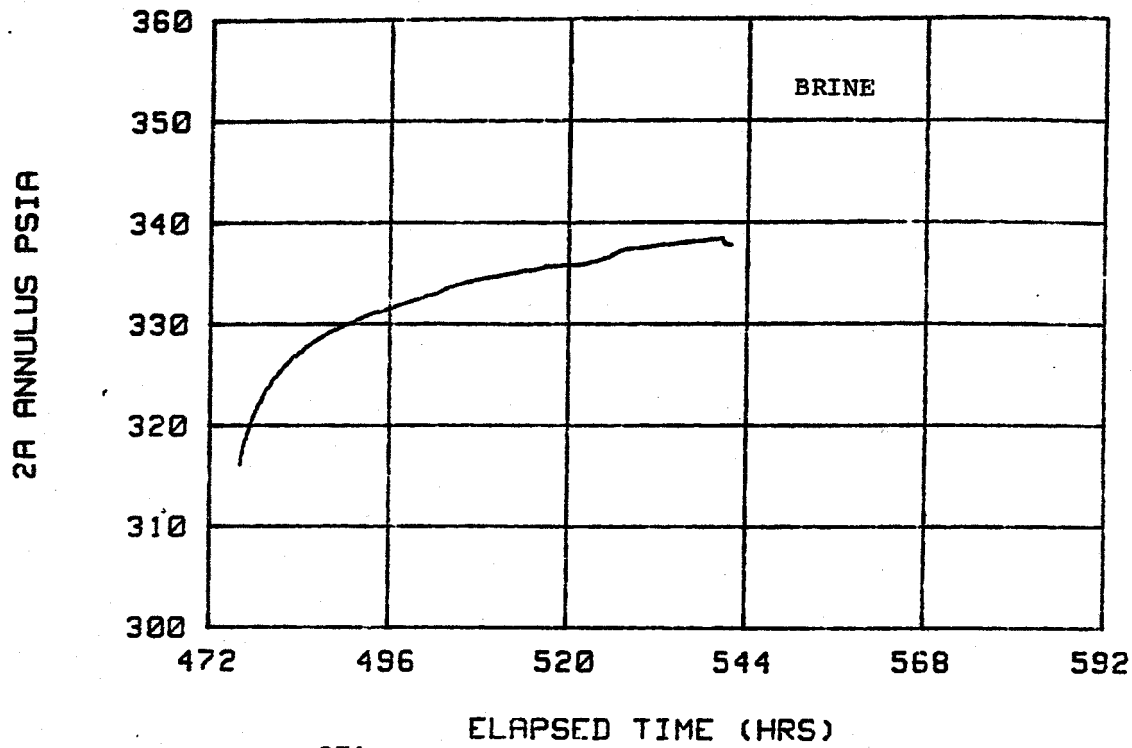


FIG 25A PRESS - TIME START .7 PSI/FT TEST

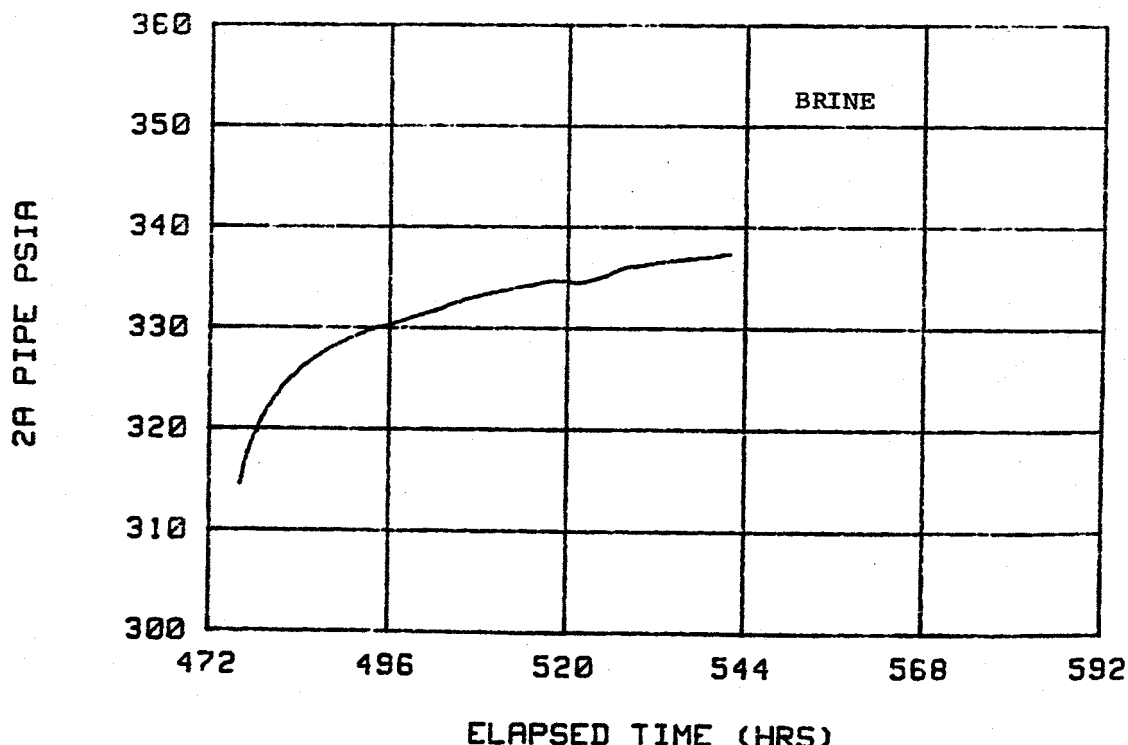


FIG 25B PRESS - TIME START .7 PSI/FT TEST

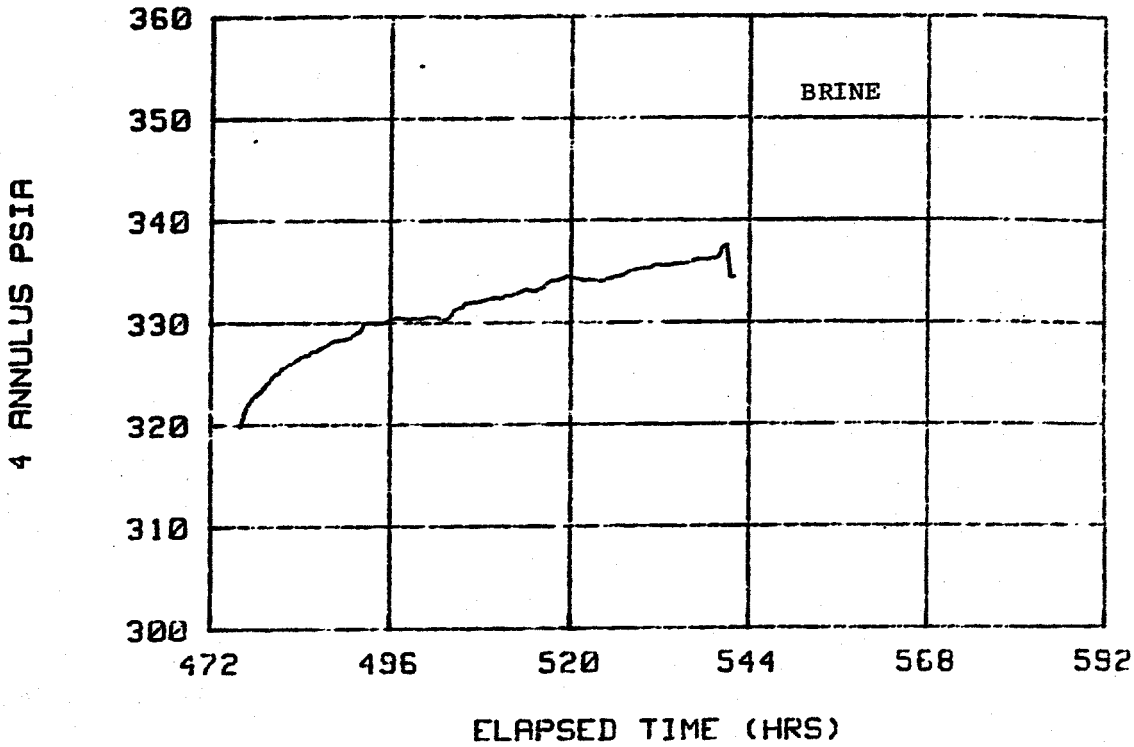


FIG 26A PRESS - TIME START .7 PSI/FT TEST

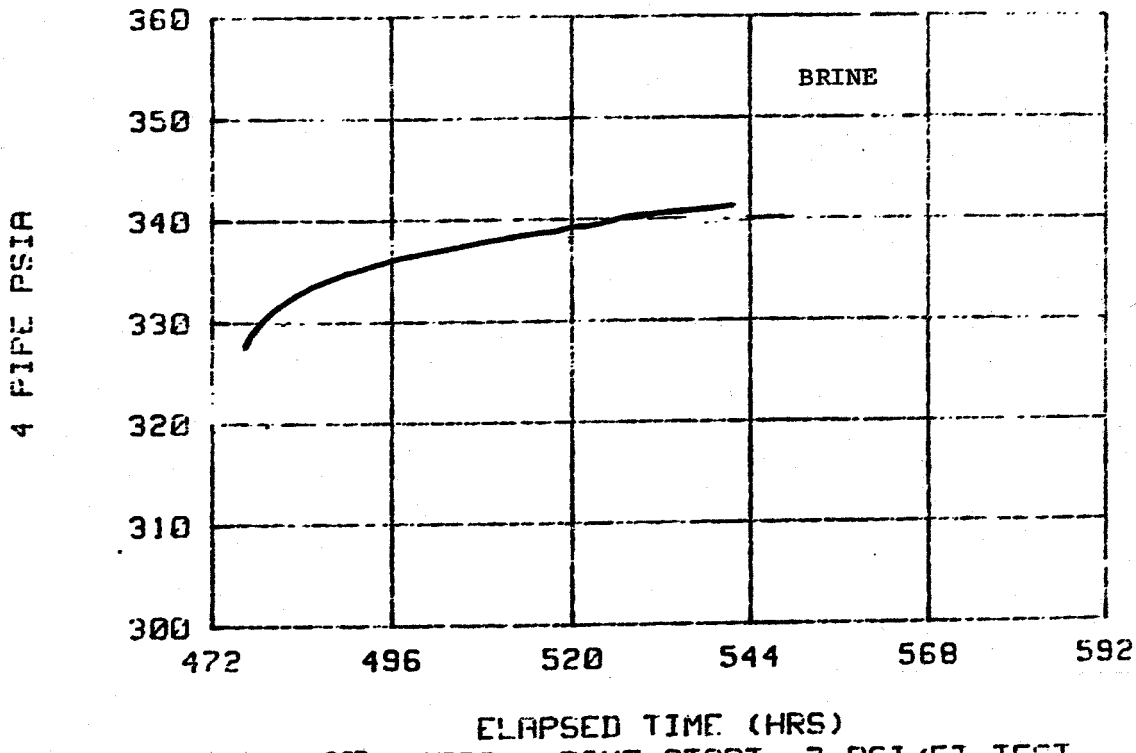


FIG 26B PRESS - TIME START .7 PSI/FT TEST

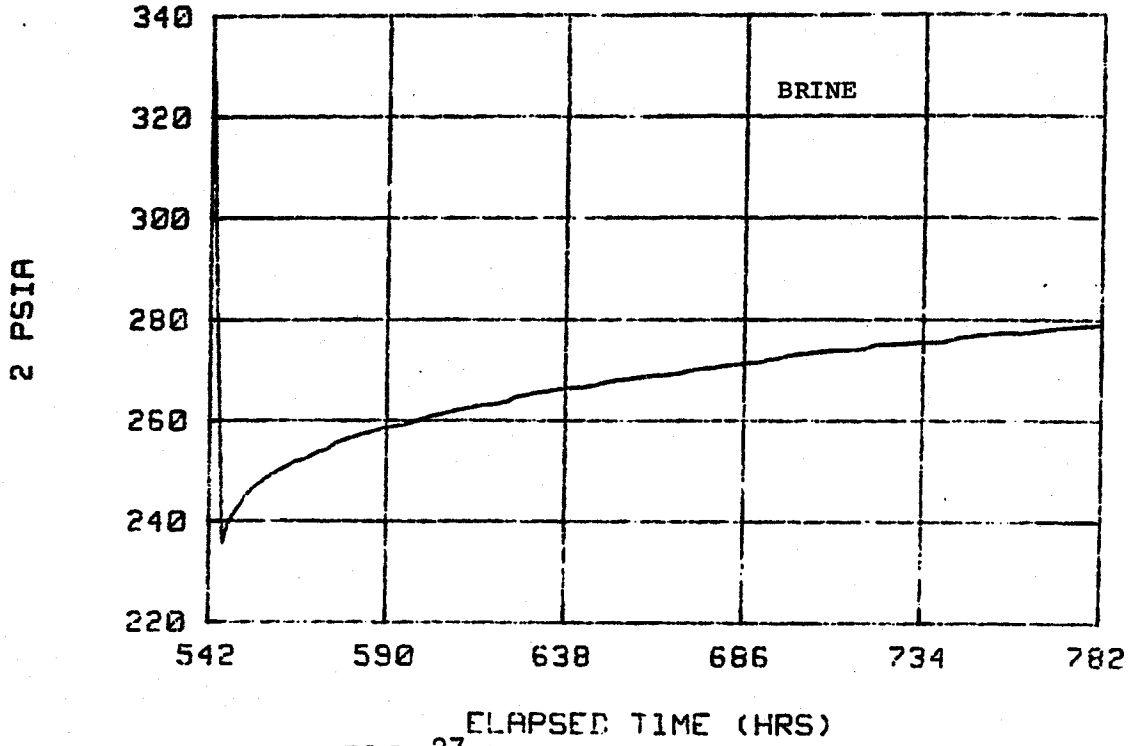
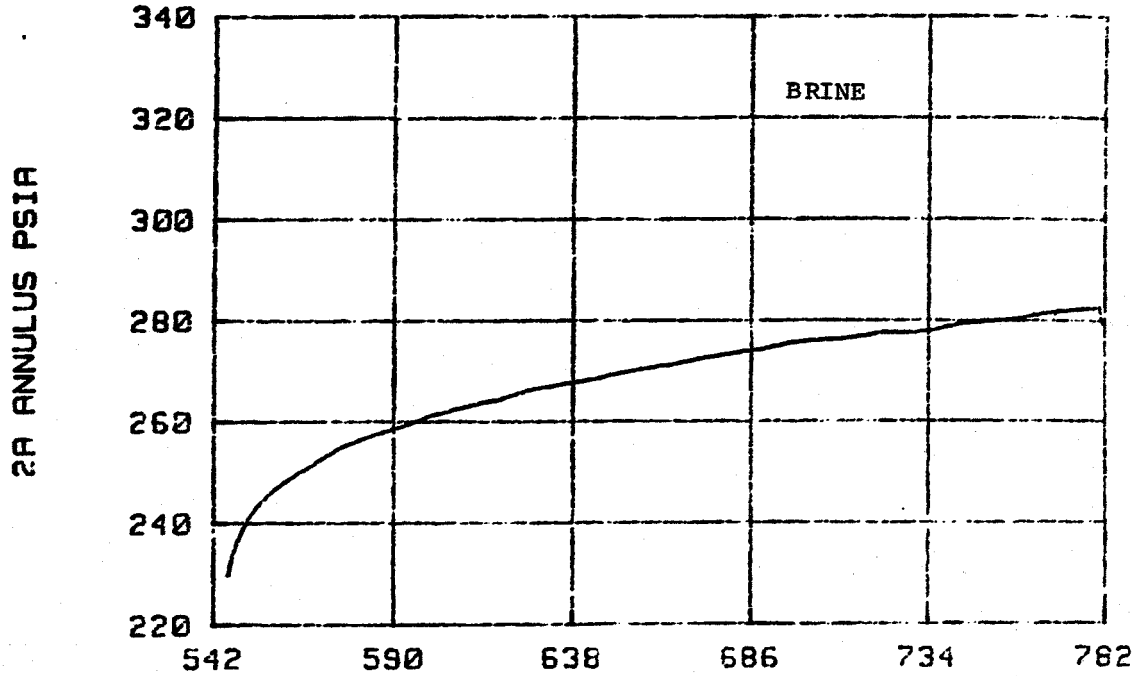
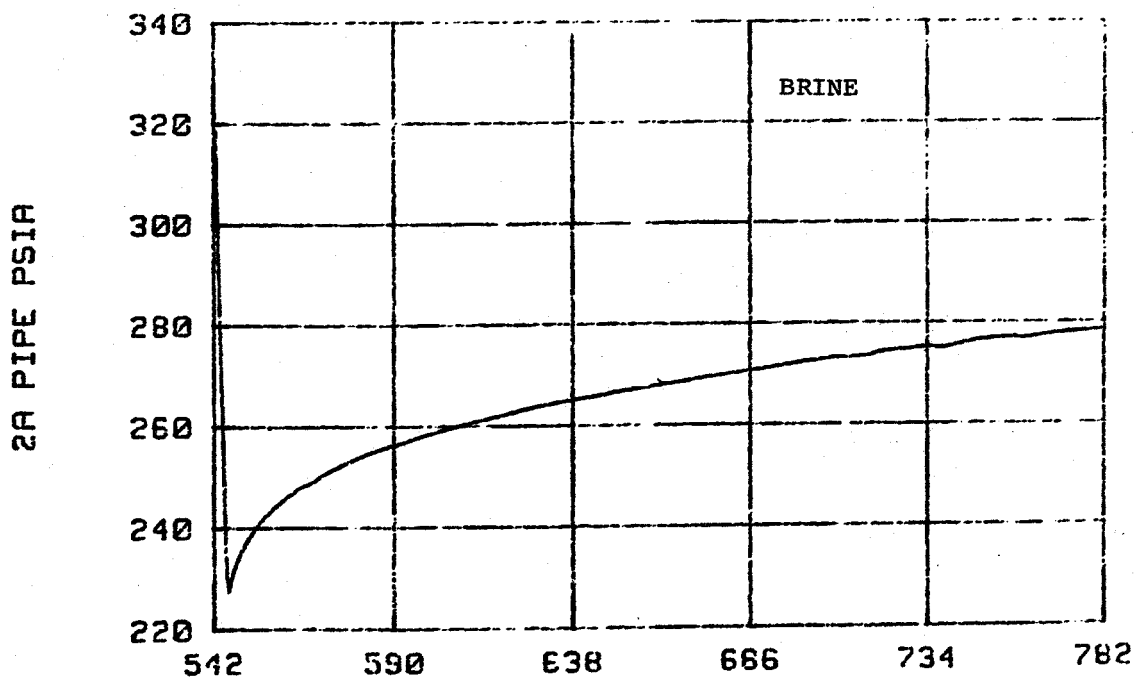


FIG 27 PRESS - TIME .65 PSI/FT



ELAPSED TIME (HRS)
FIG 28A PRESS - TIME .65 PSI/FT



ELAPSED TIME (HRS)
FIG 28B PRESS - TIME .65 PSI/FT

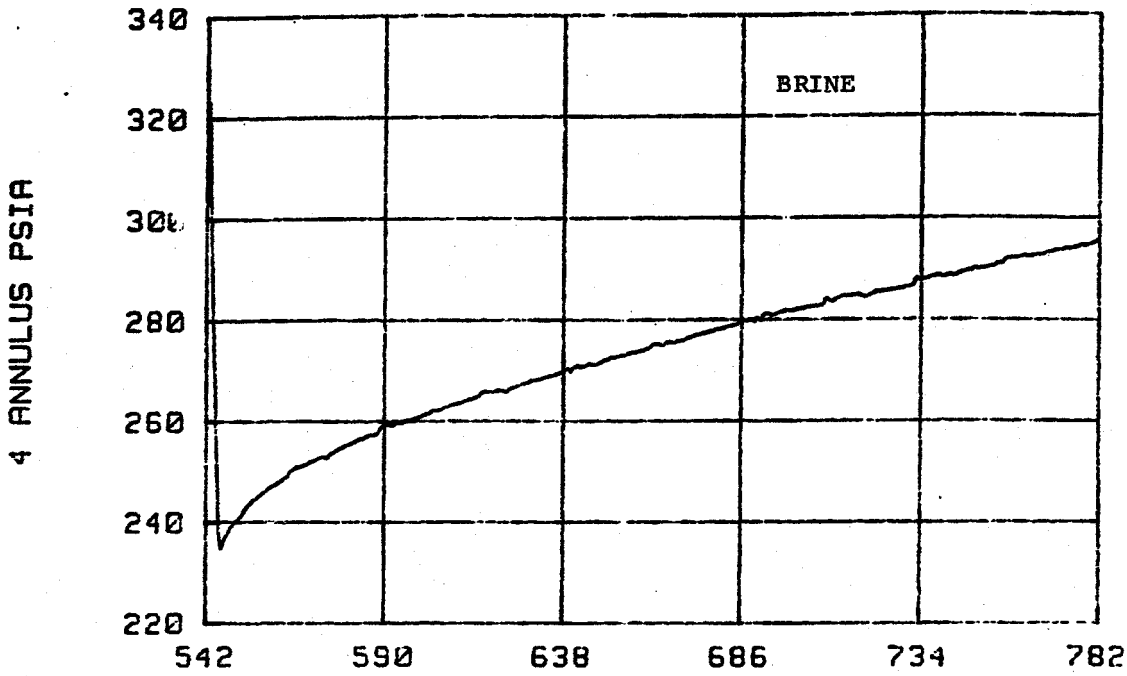


FIG 29A PRESS - TIME .65 PSI/FT

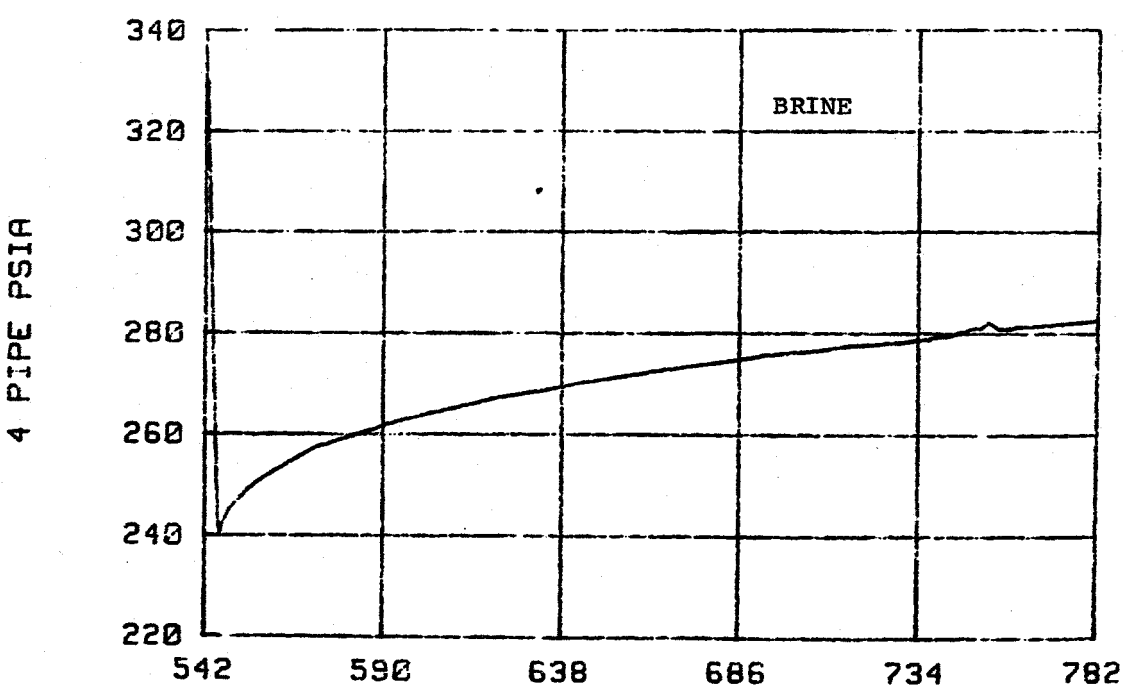


FIG 29B PRESS - TIME .65 PSI/FT

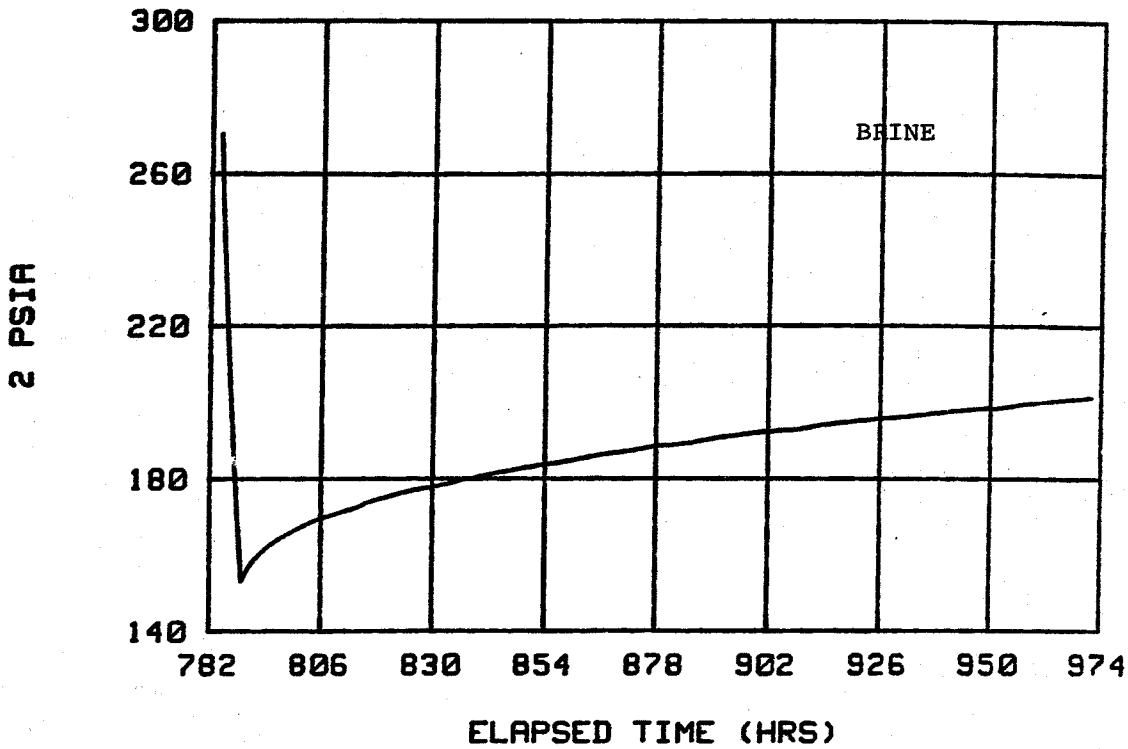


FIG 30 PRESS - TIME .60 PSI/FT

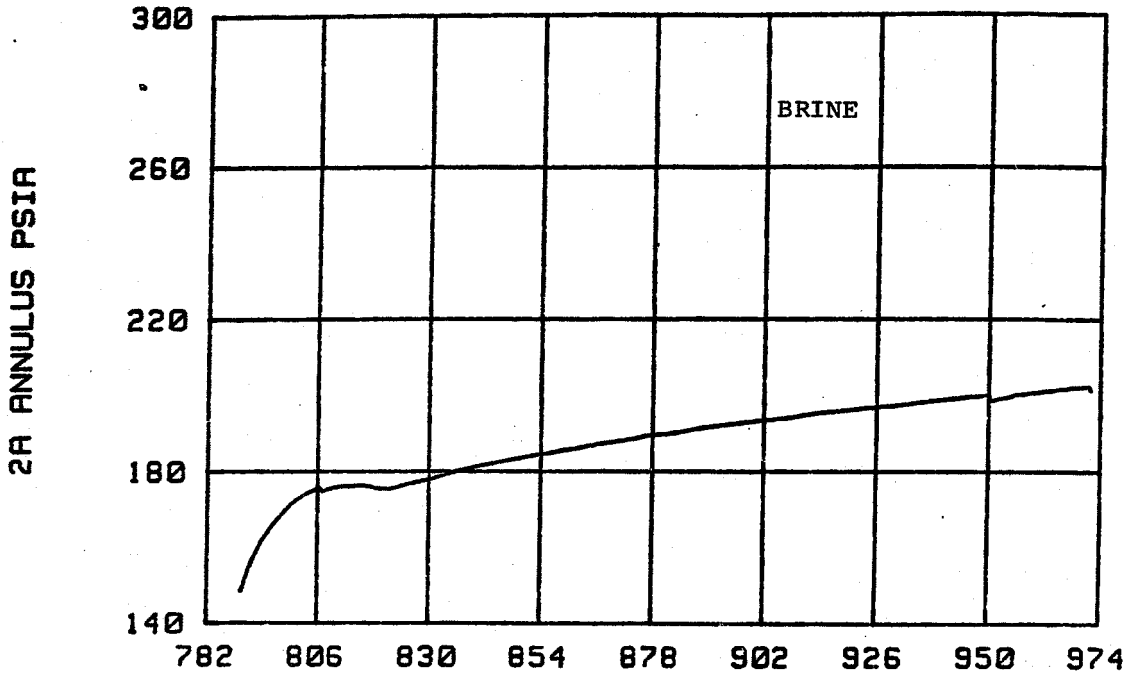


FIG 31A PRESS - TIME .60 PSI/FT

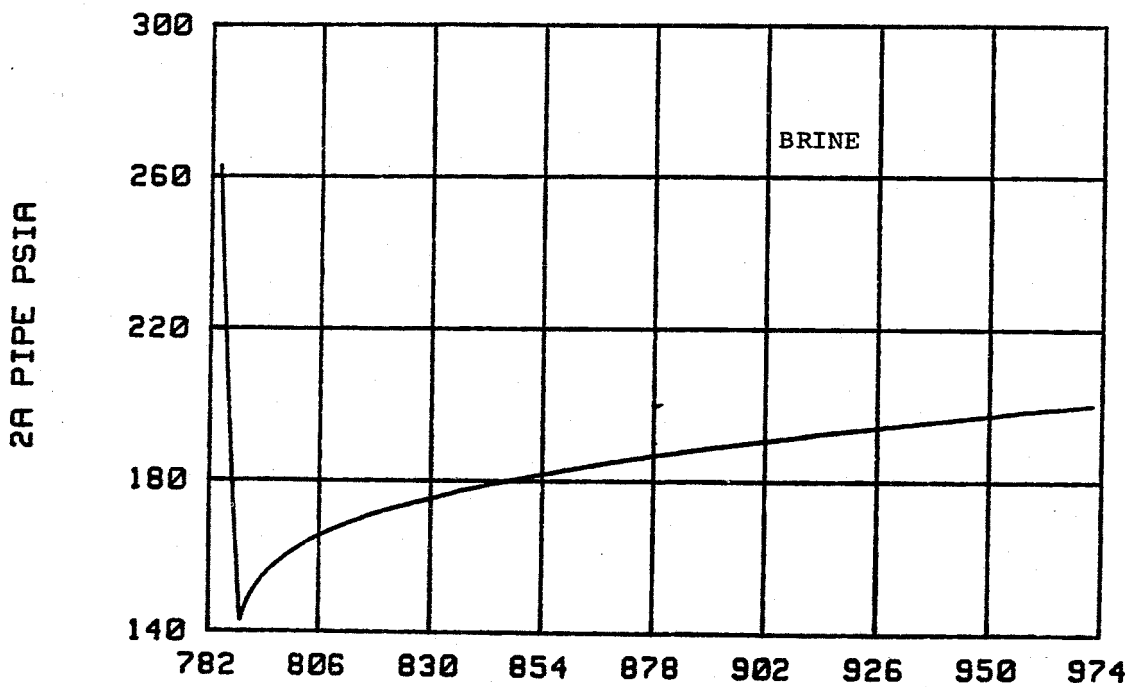


FIG 31B PRESS - TIME .60 PSI/FT

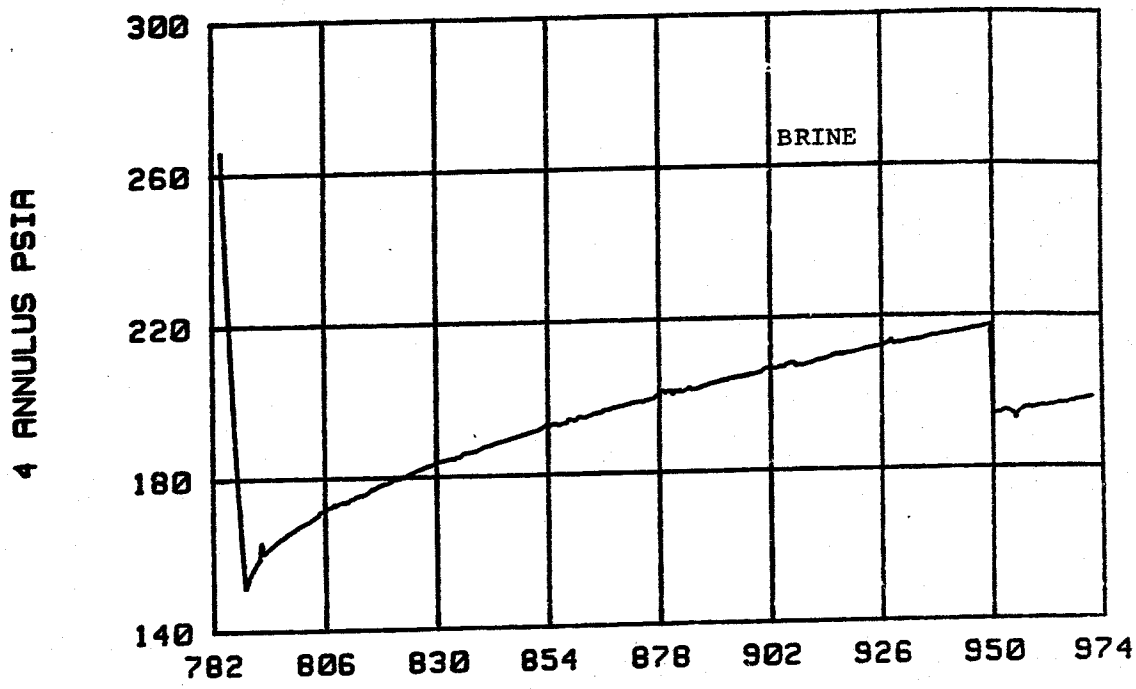


FIG 32A PRESS - TIME .60 PSI/FT

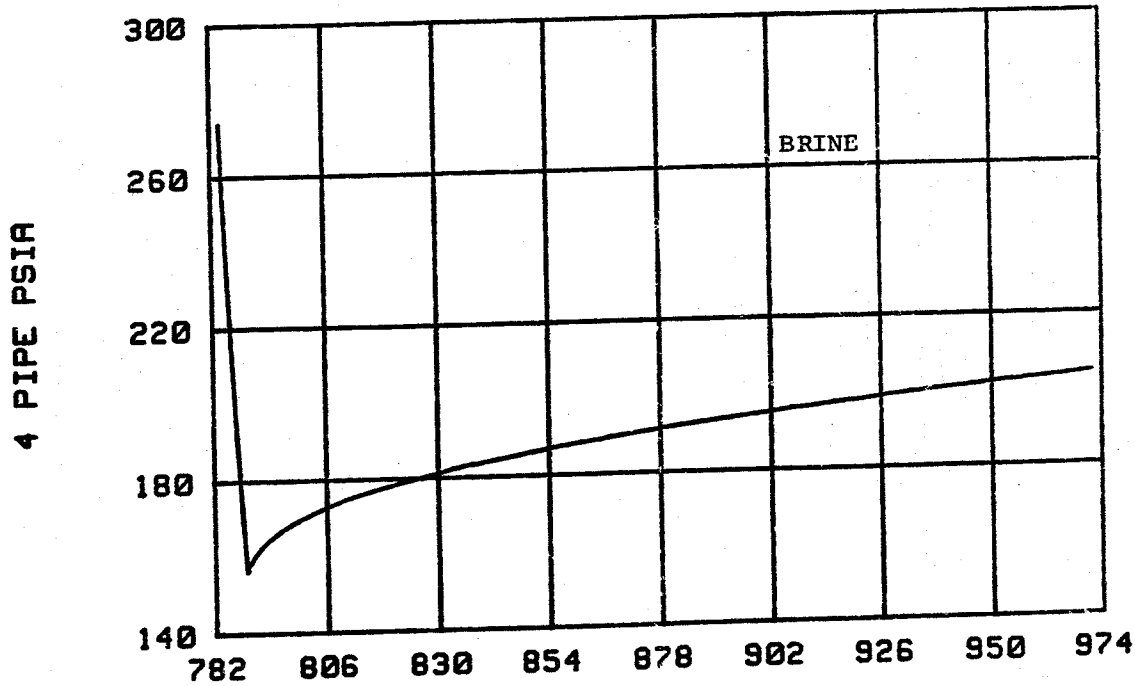


FIG 32B PRESS - TIME .60 PSI/FT

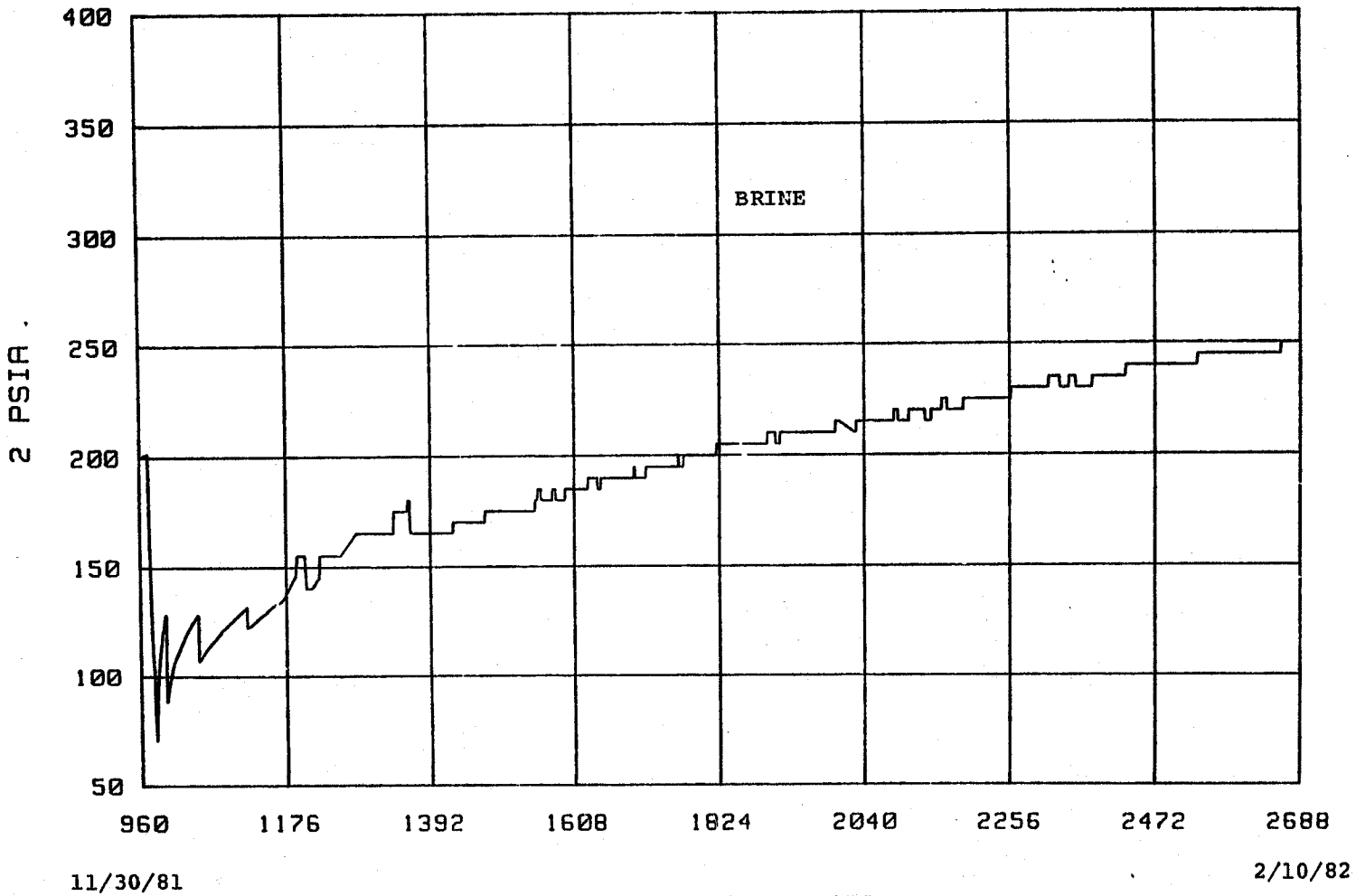


FIG 33 PRESS - TIME FOR CAVERN TEST

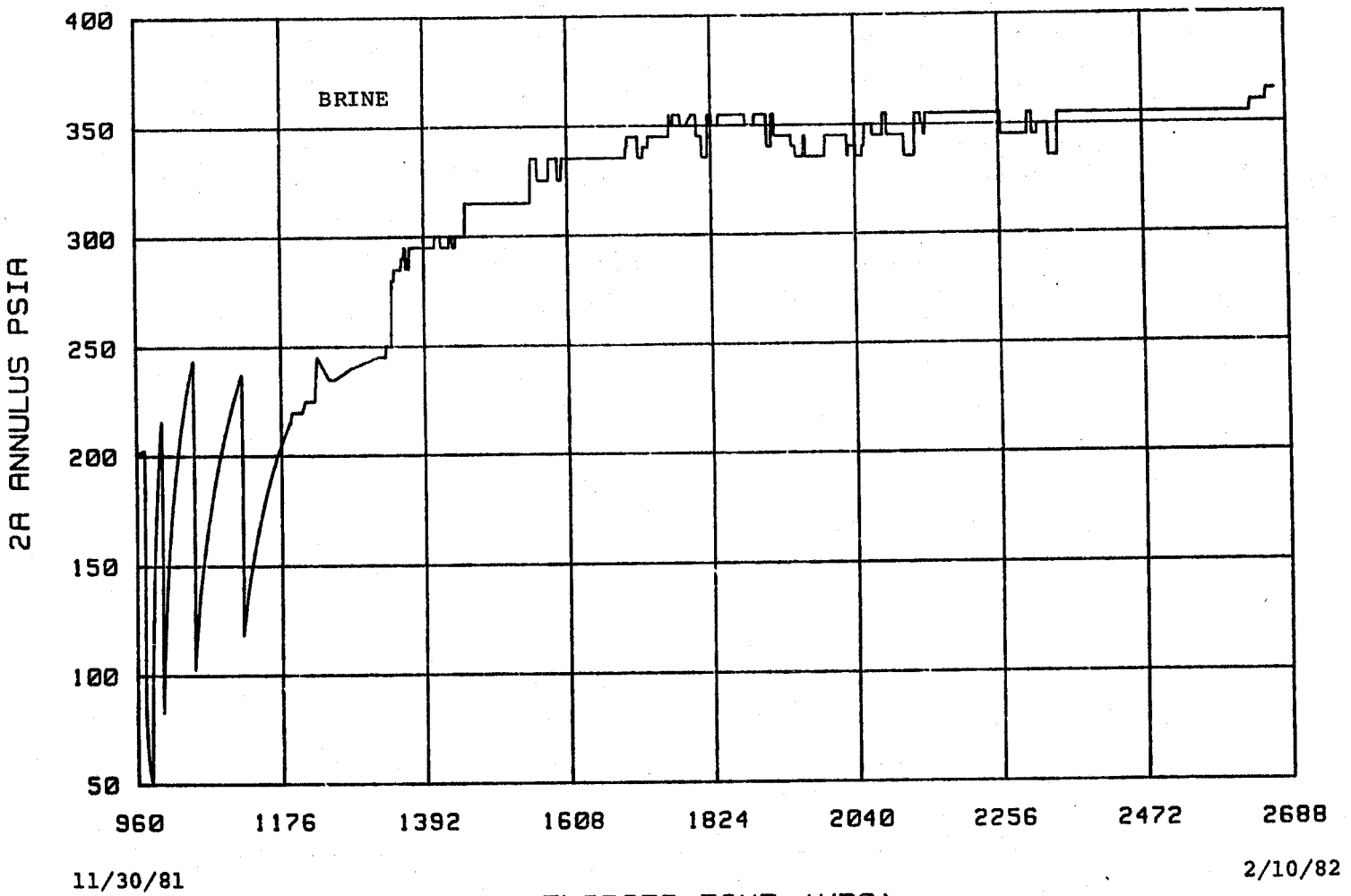


FIG 34A PRESS - TIME FOR CAVERN TEST

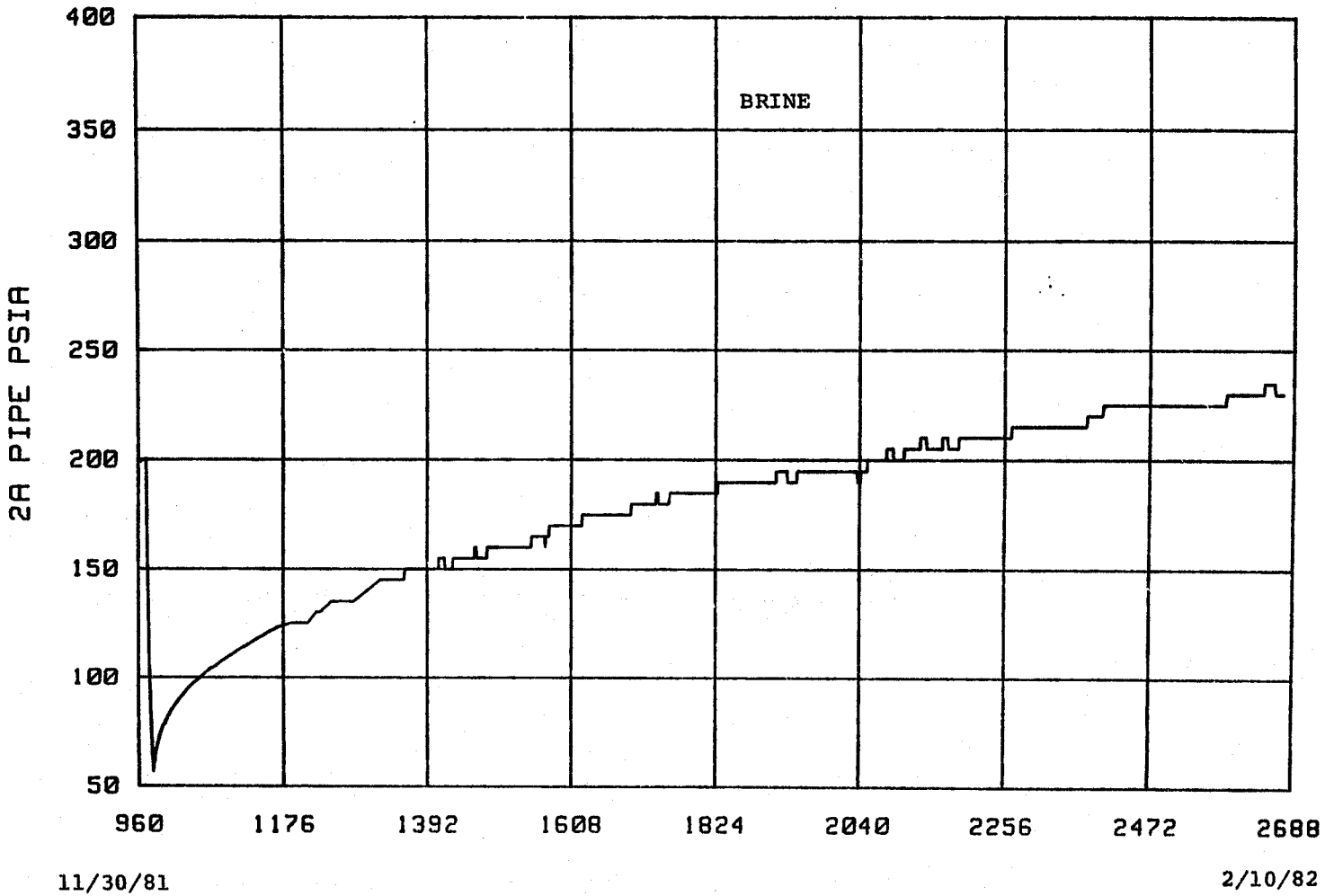


FIG 34B PRESS - TIME FOR CAVERN TEST

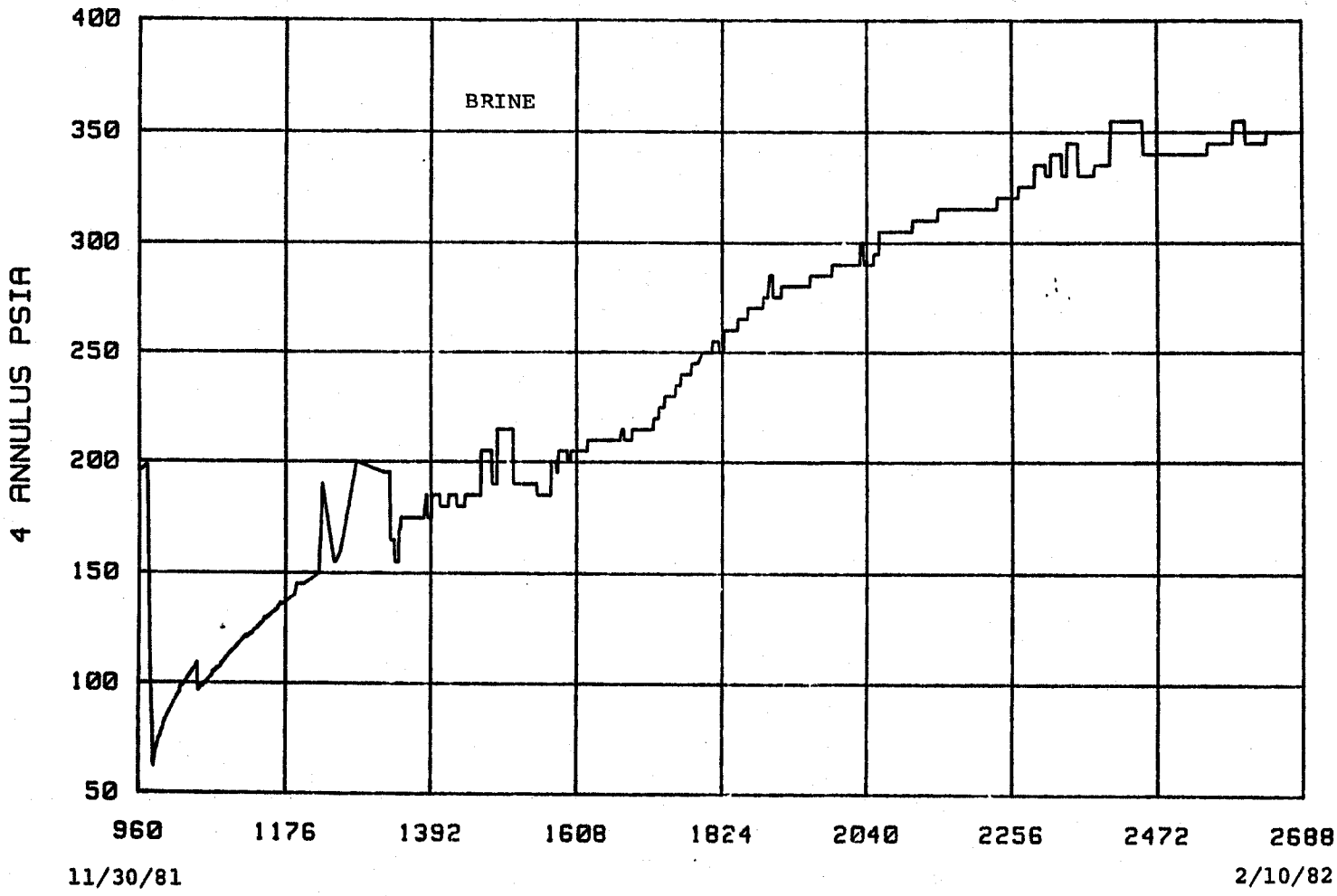


FIG 35A PRESS - TIME FOR CAVERN TEST

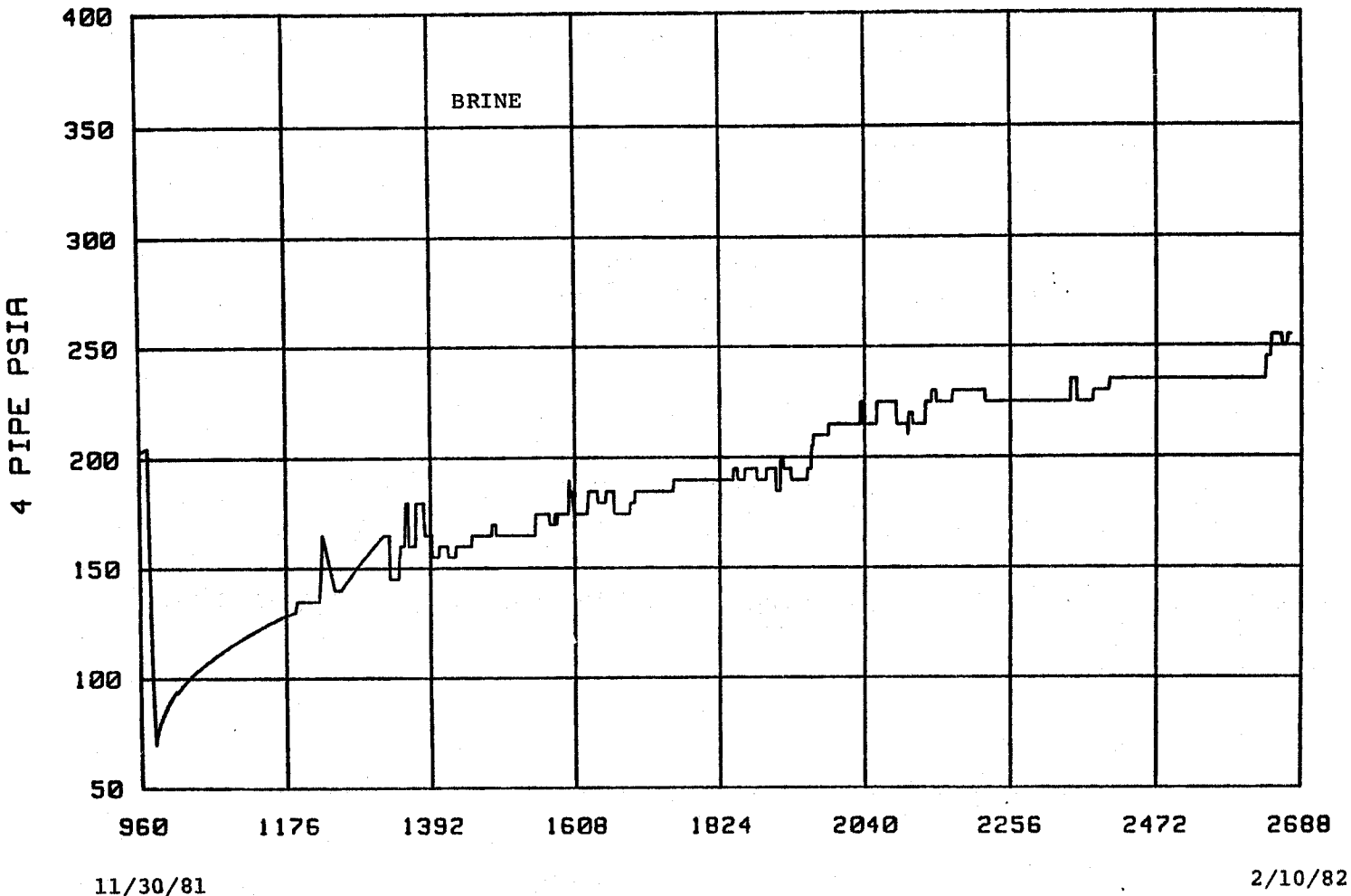
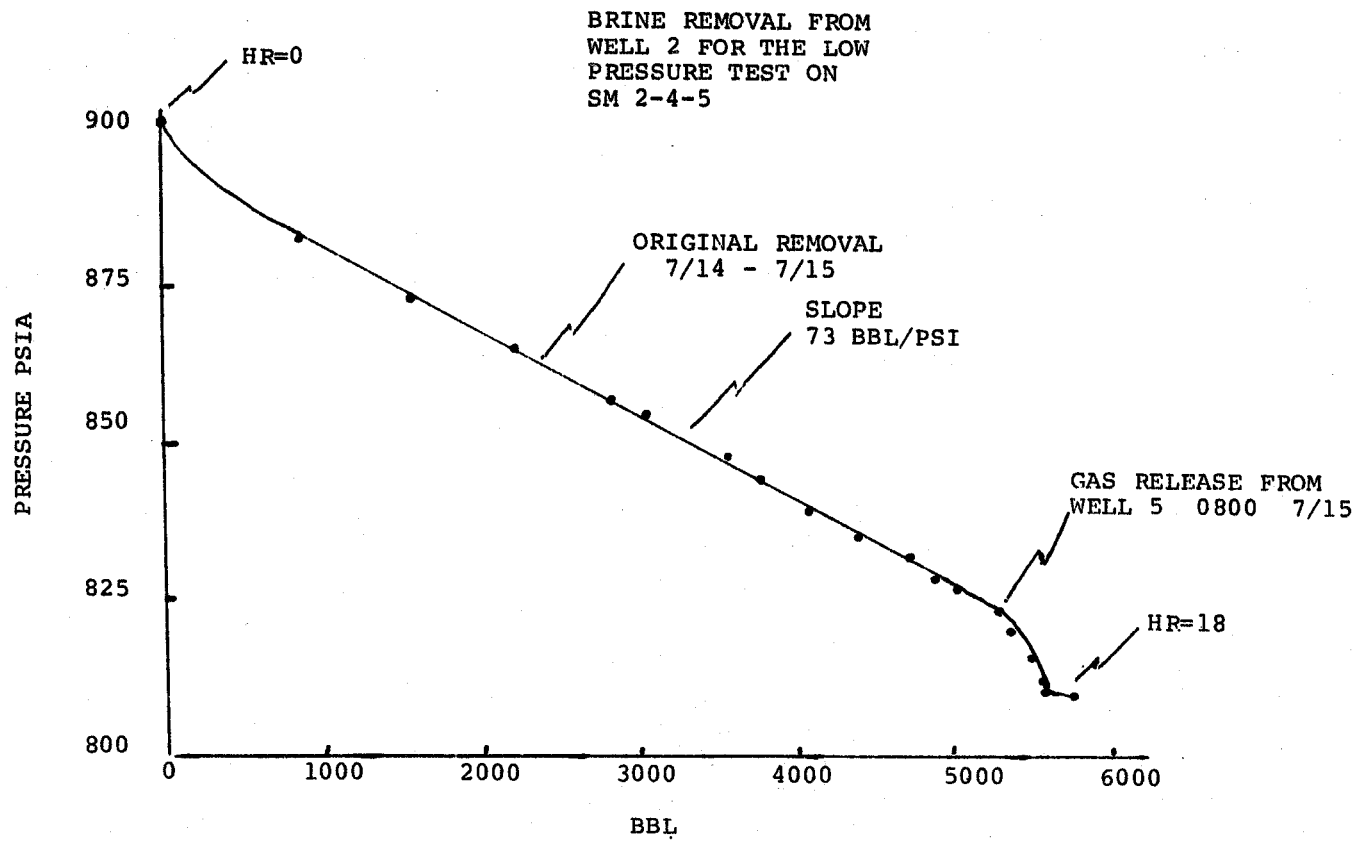


FIG 35B PRESS - TIME FOR CAVERN TEST

FIGURE 36

CAVERN 2-4-5 BLEEDDOWN



K.B. AT 34.5' MSL Δ = 20'
B.H. AT 14.8' MSL

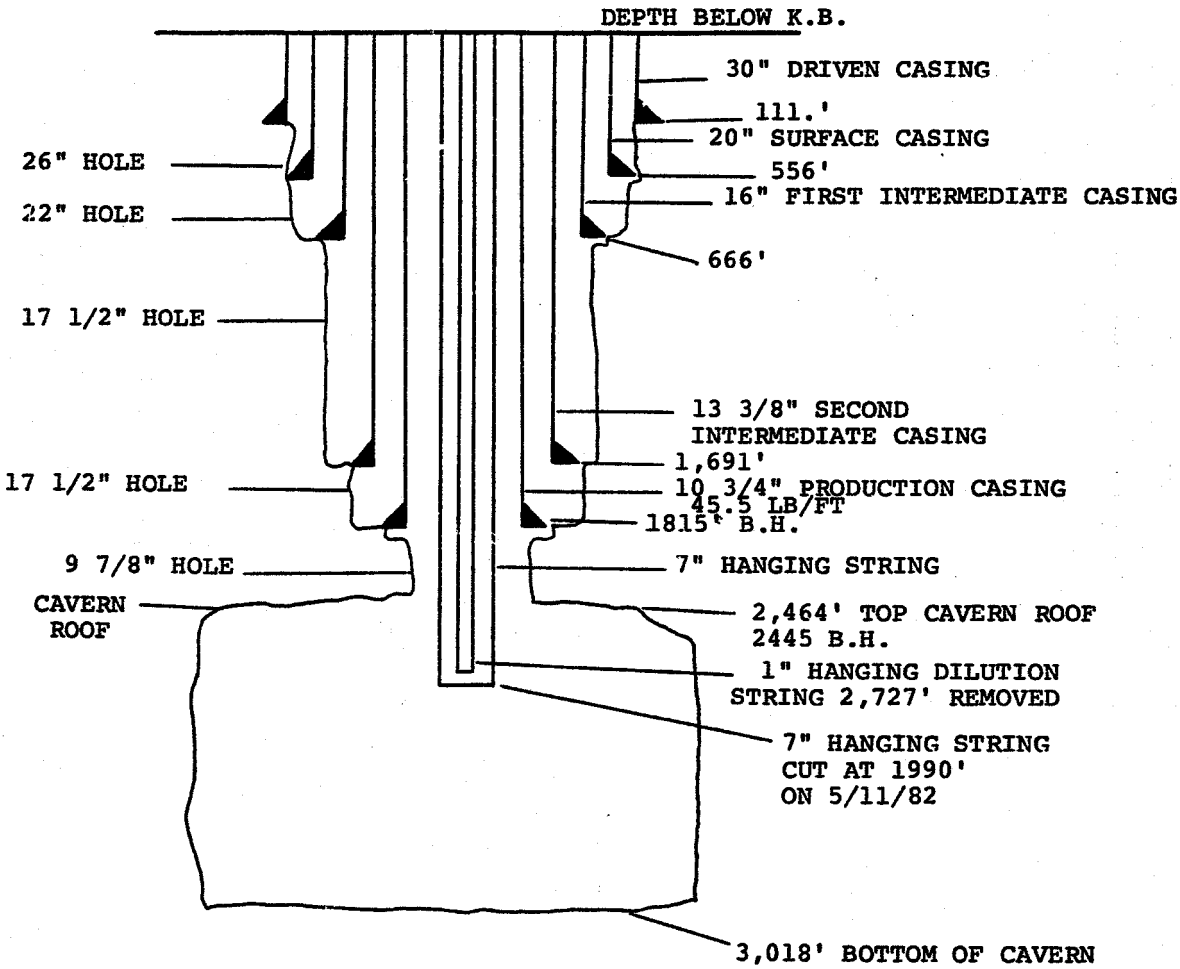
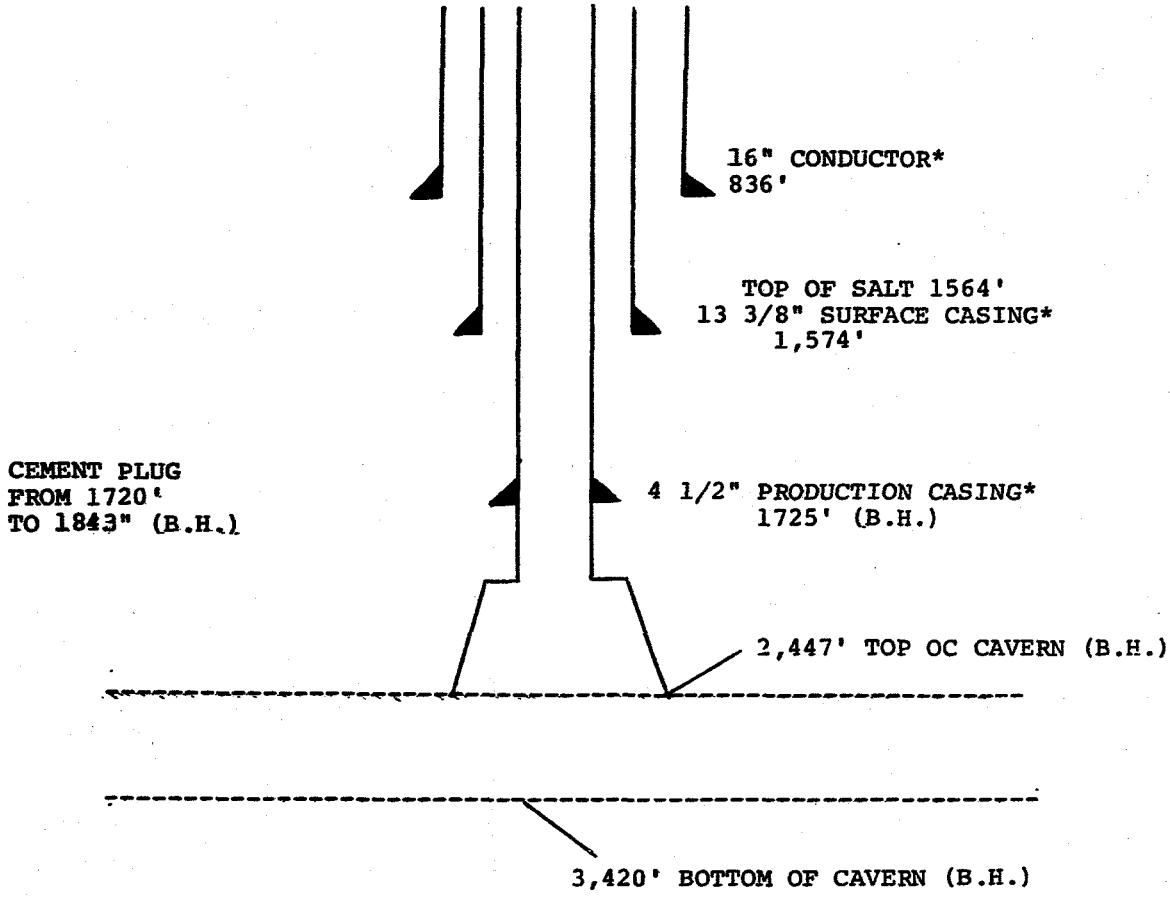


FIGURE 37 AS-BUILT CASING DIAGRAM
SPR RE 2A SULPHUR MINES

FROM REF 9

* BY OTHER THAN WILLIAMS-FENIX & SCISSON
COMPLETE INFORMATION NOT AVAILABLE



ASSUMED DISTANCE FROM
K.B. TO B.H. IS 20'.

FIGURE 38. AS-BUILT CASING
DIAGRAM SPR 5 (WO) SULPHUR
MINES

FROM REF. 13

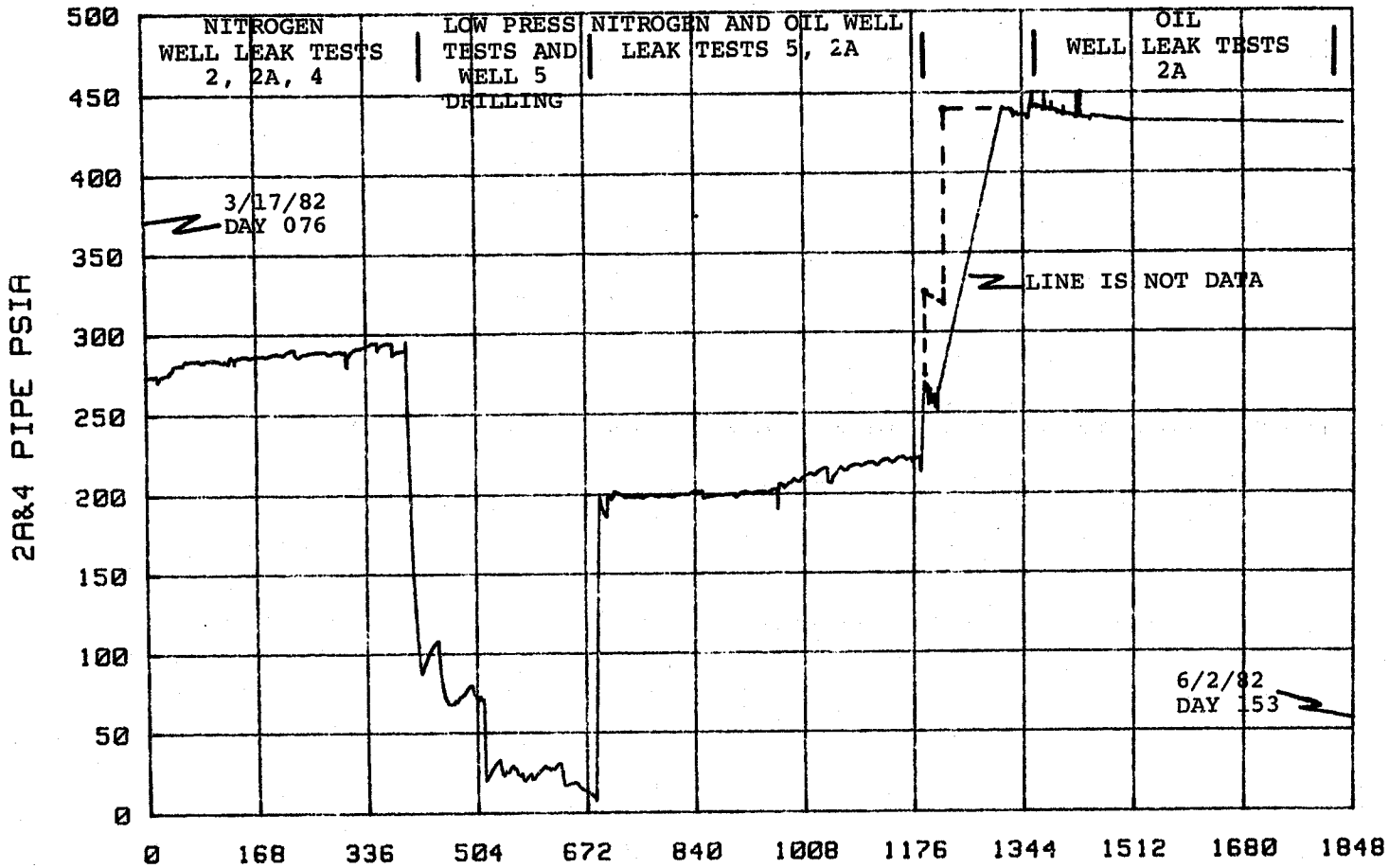
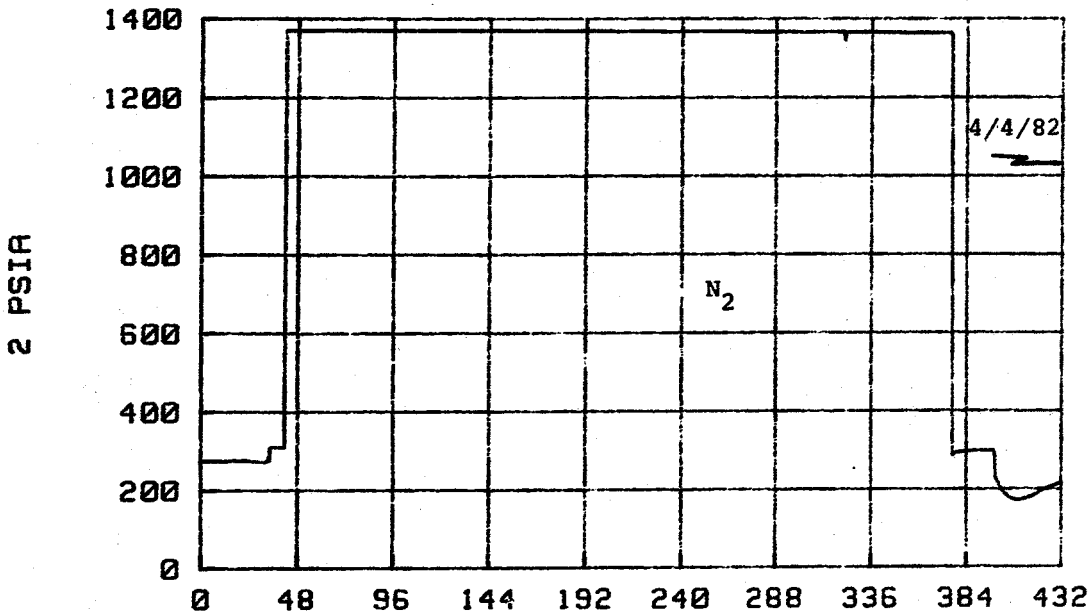
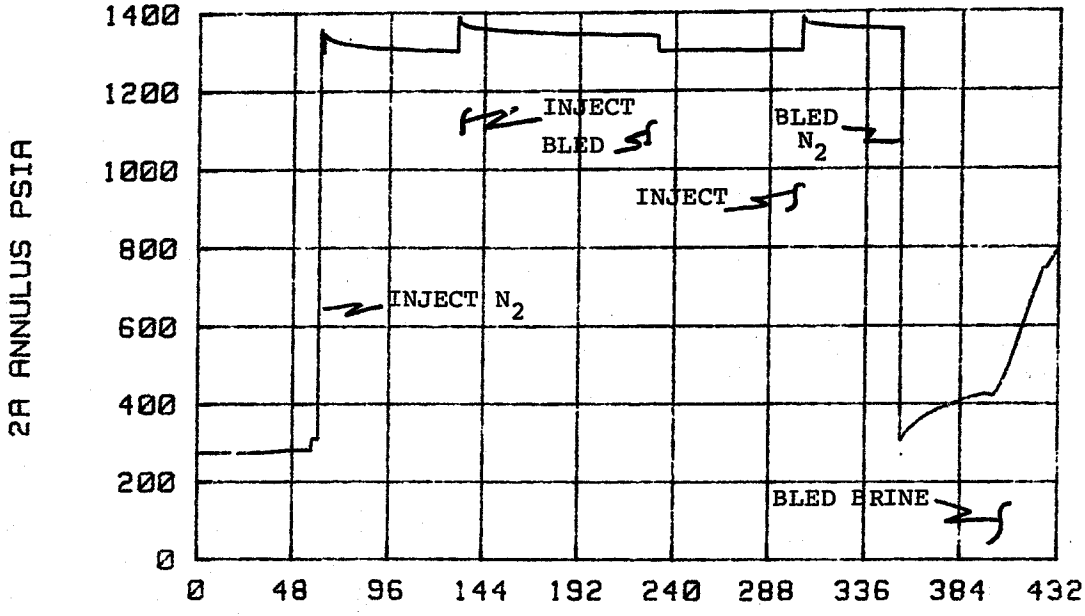


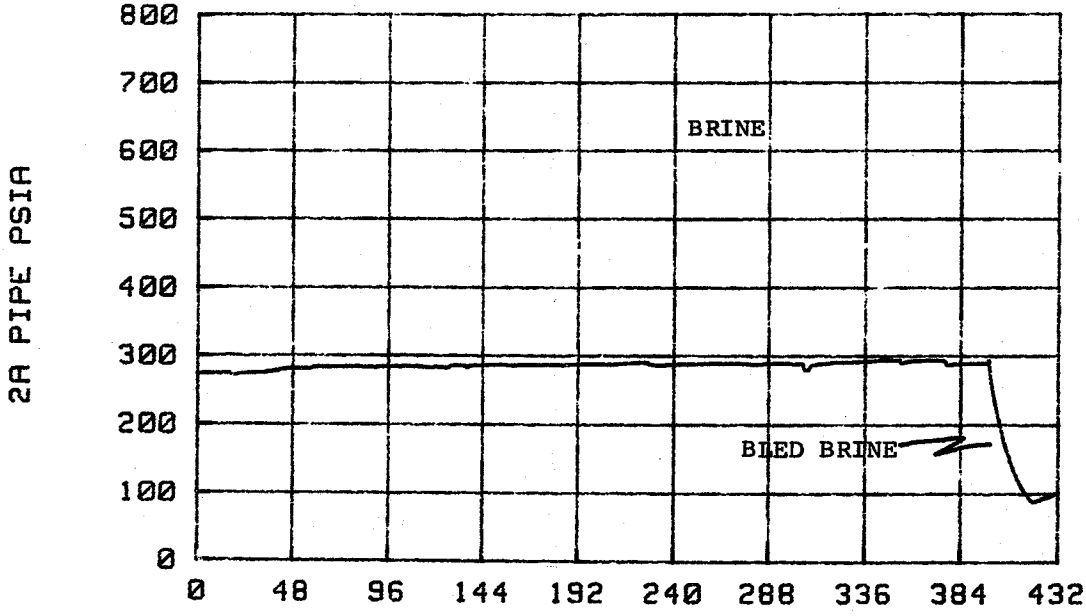
FIG 39 SUMMARY OF CAVERN 2-4-5 TESTS 1982



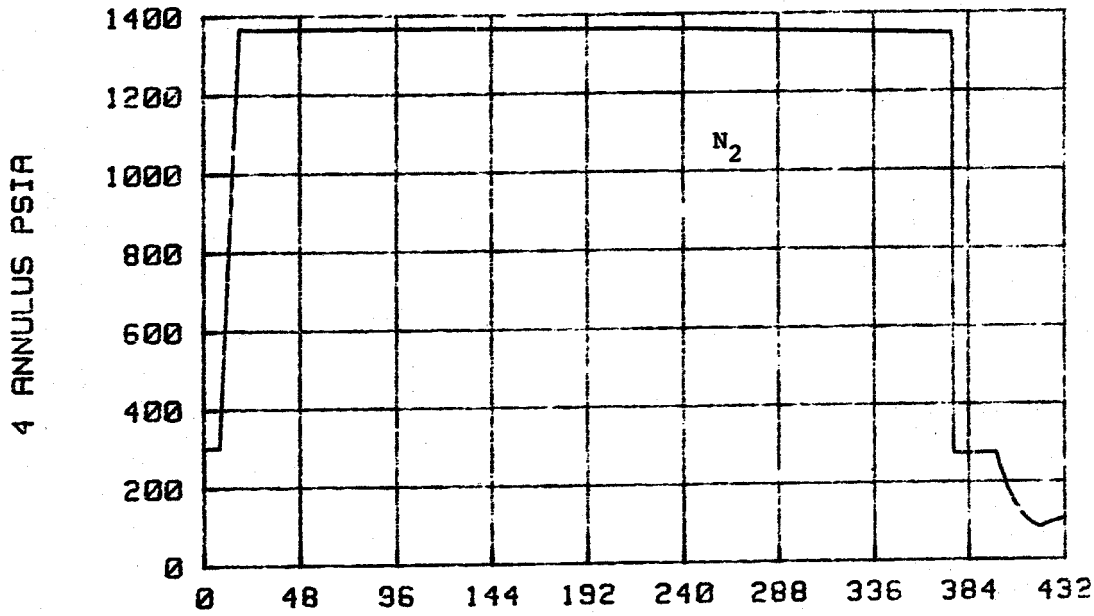
ELAPSED TIME (HRS)
FIG 40 N2 TEST



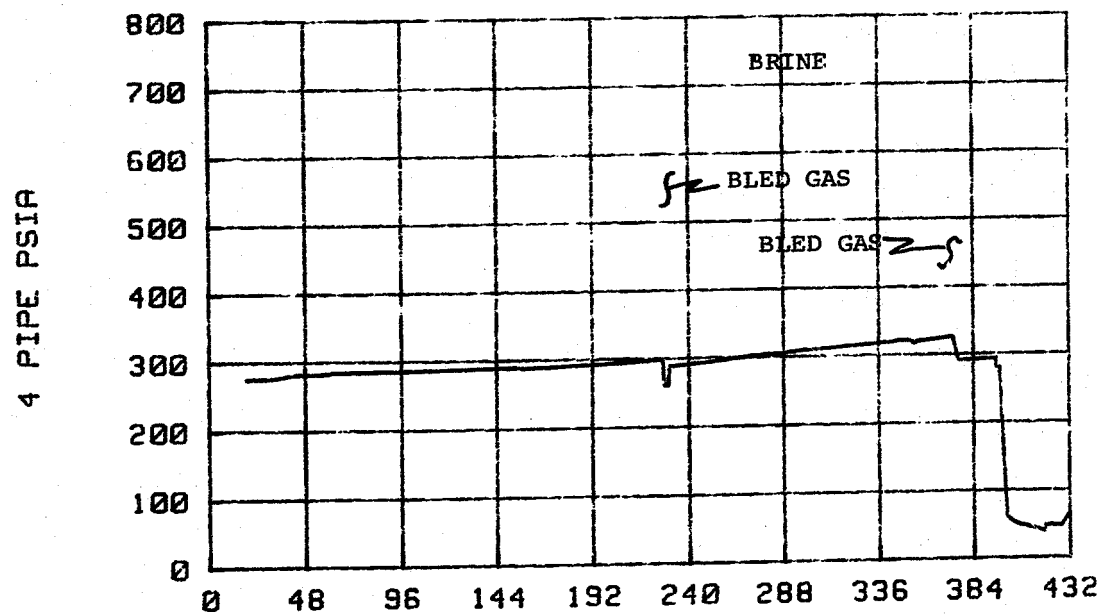
ELAPSED TIME (HRS)
FIG 41A N2 TEST



ELAPSED TIME (HRS)
FIG 41B N2 TEST



ELAPSED TIME (HRS)
FIG 42A N2 TEST



ELAPSED TIME (HRS)
FIG 42B N2 TEST

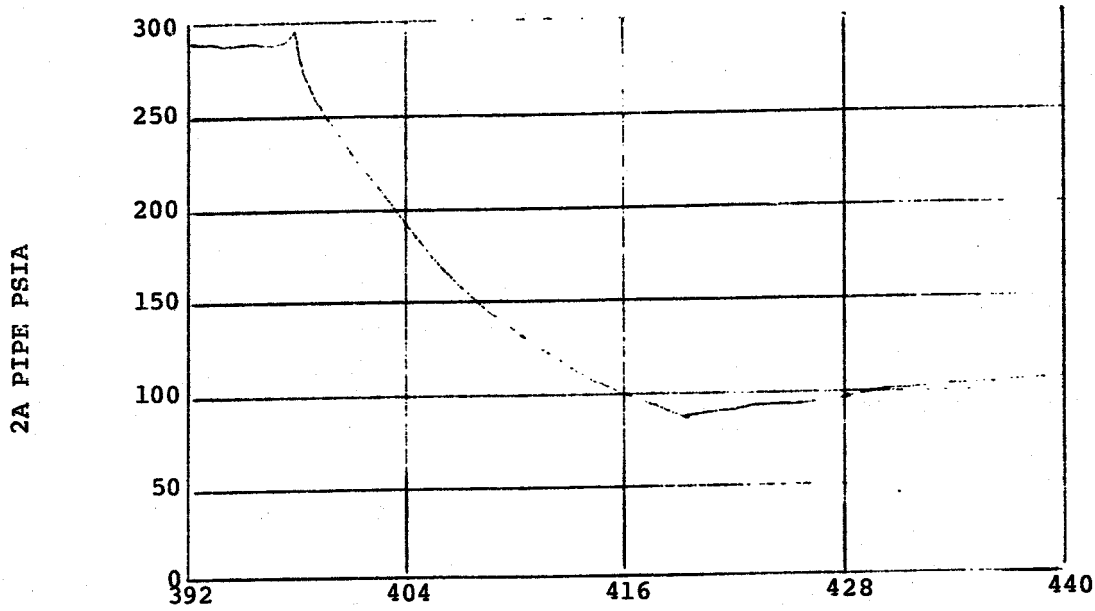


FIGURE 42C. BRINE BLEED

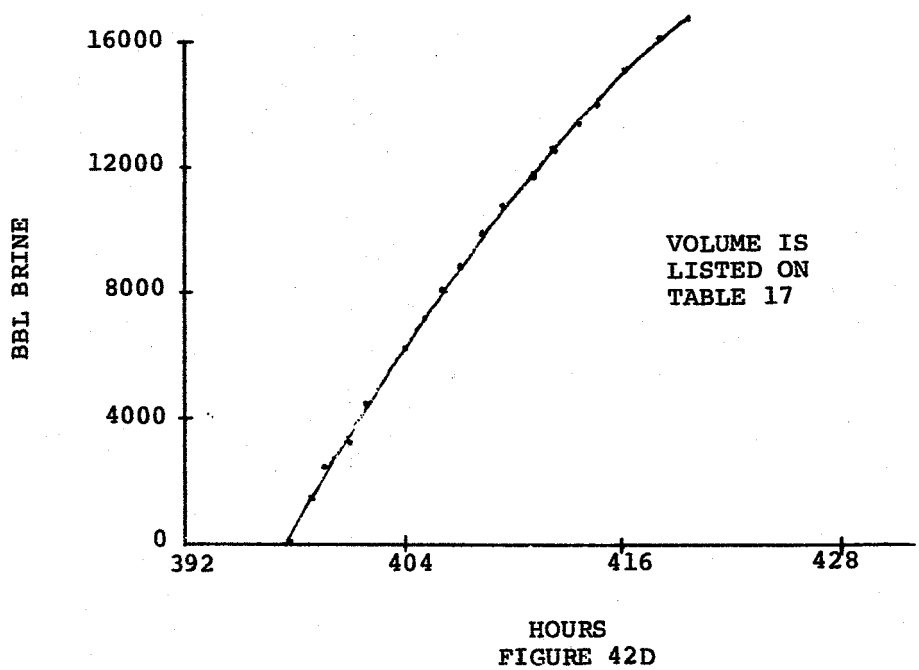
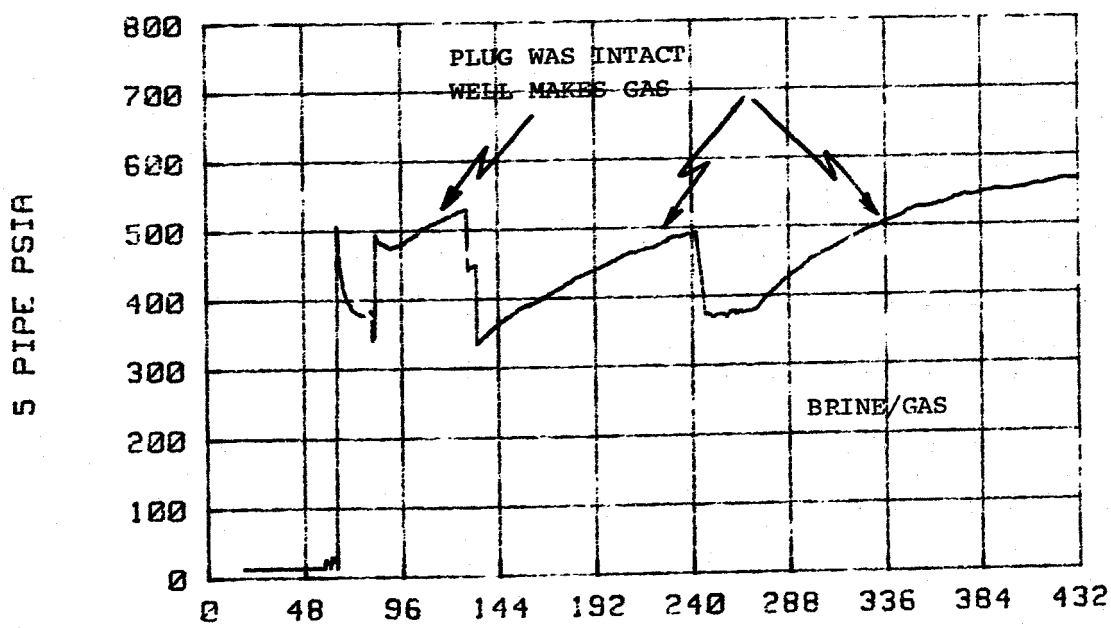
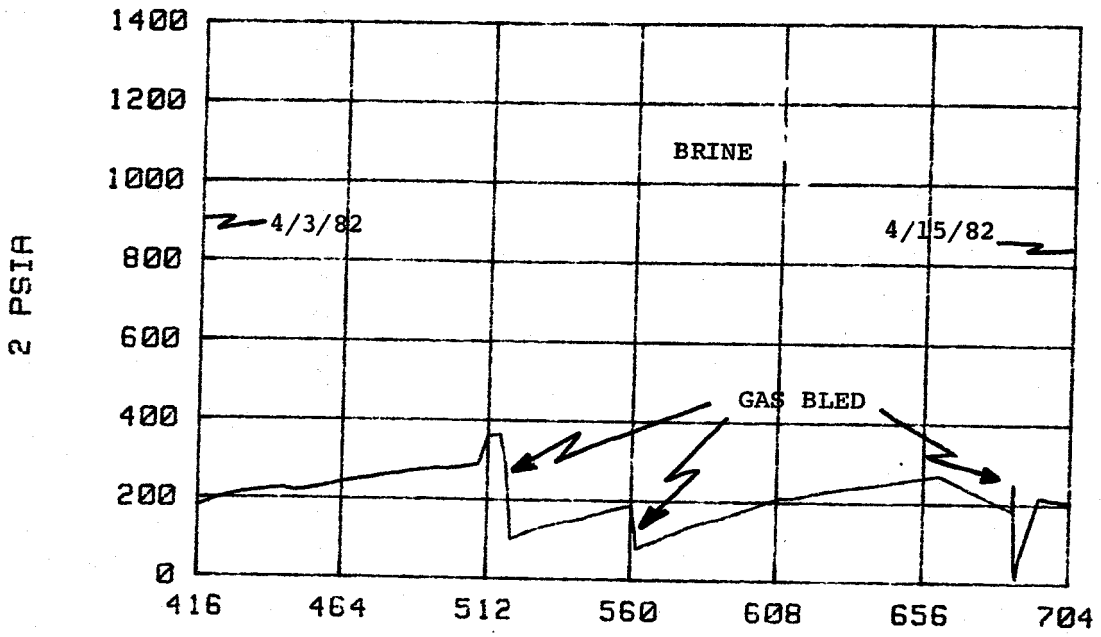


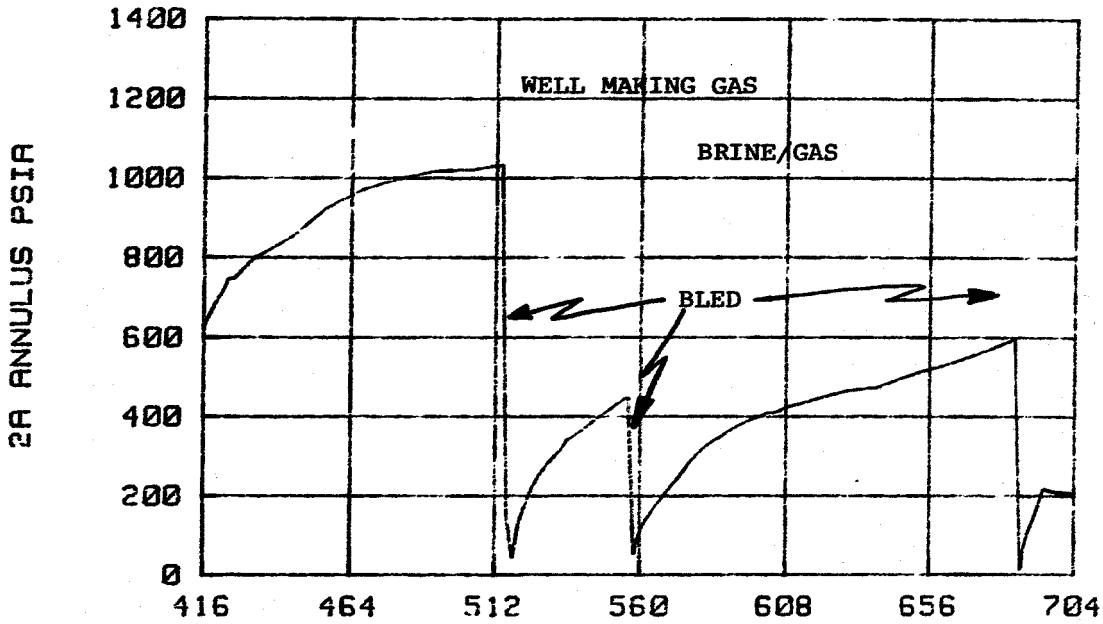
FIGURE 42D



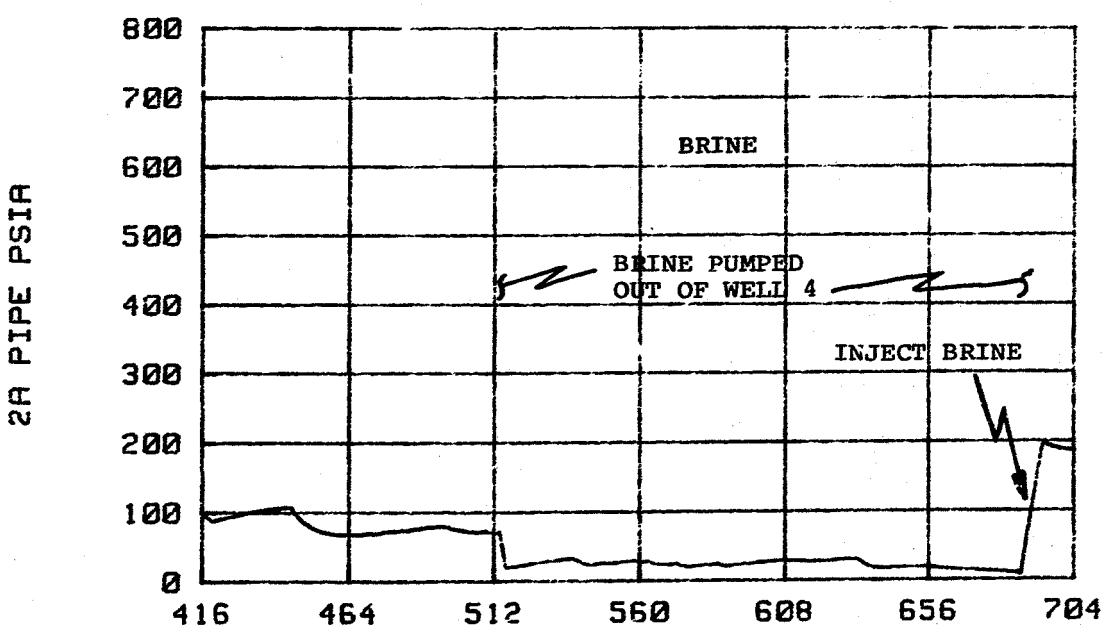
ELAPSED TIME (HRS)
FIG 43 N2 TEST



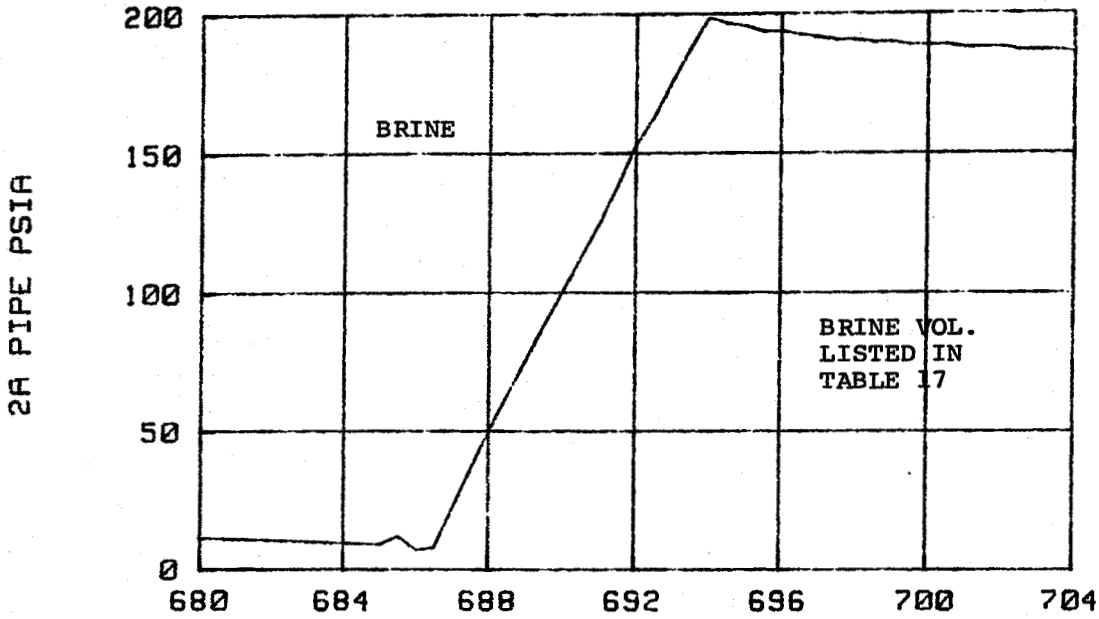
ELAPSED TIME (HRS)
FIG 44 LOW PRESSURE TEST



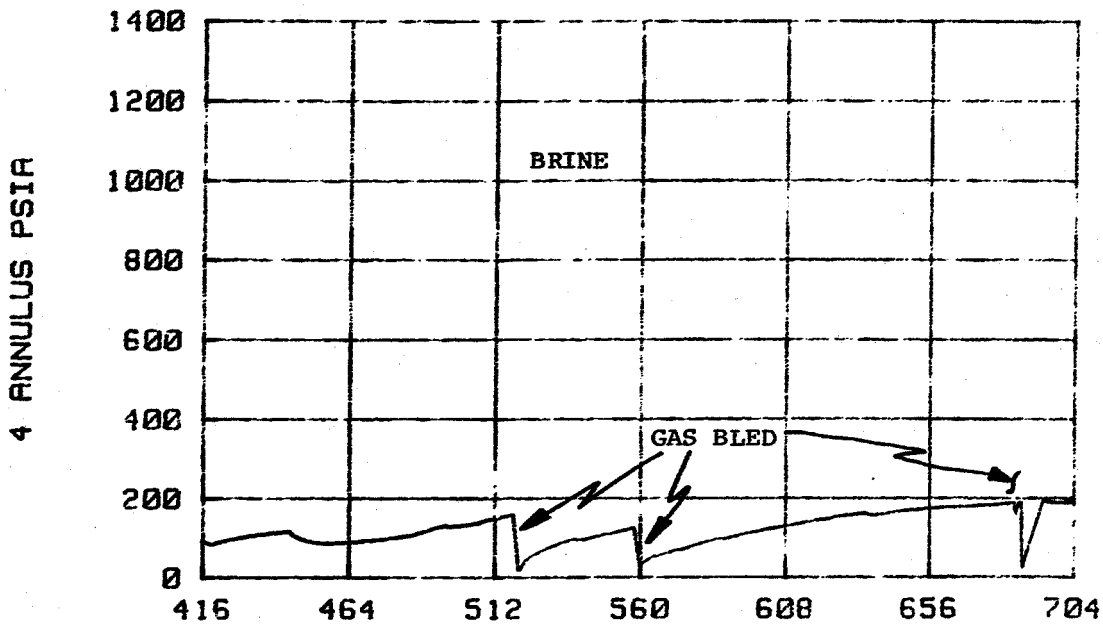
ELAPSED TIME (HRS)
FIG 45A LOW PRESSURE TEST



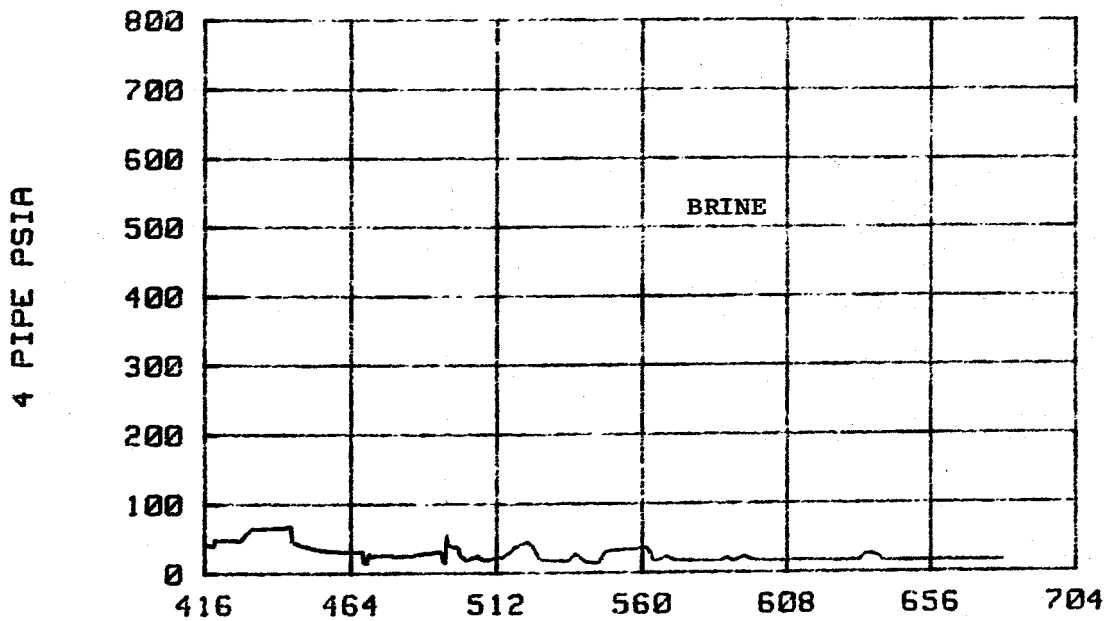
ELAPSED TIME (HRS)
FIG 45B LOW PRESSURE TEST



ELAPSED TIME (HRS)
FIG 45C BRINE INJECT



ELAPSED TIME (HRS)
FIG 46A LOW PRESSURE TEST



ELAPSED TIME (HRS)
FIG 46B LOW PRESSURE TEST

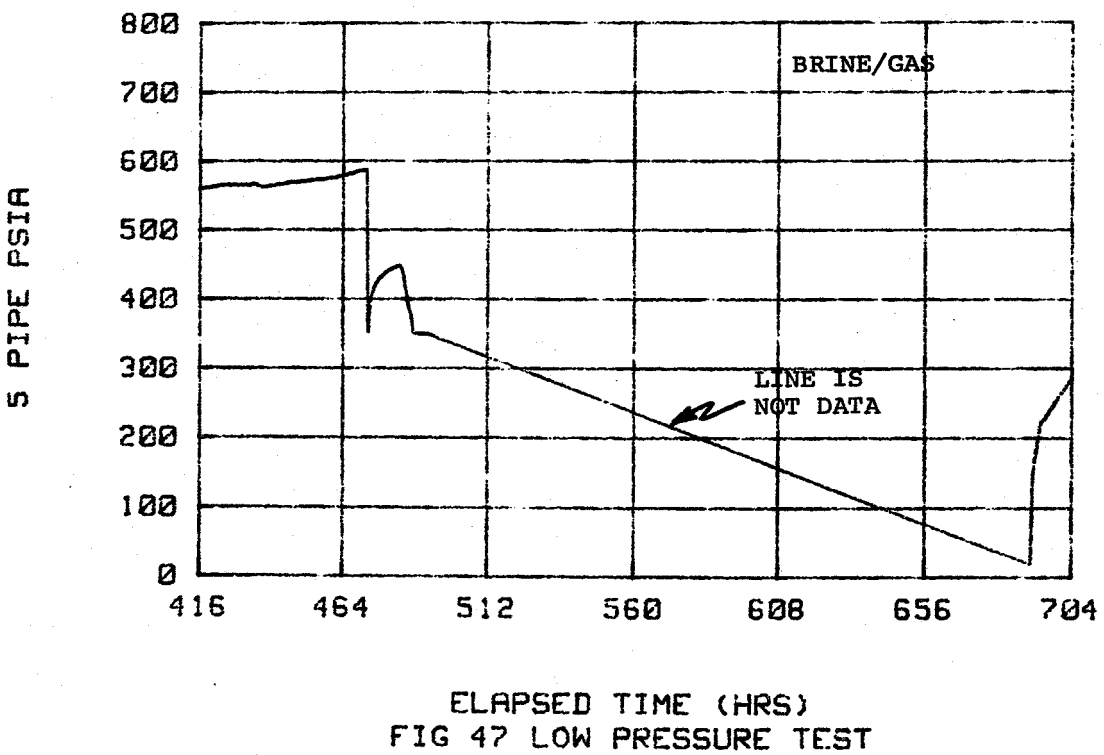


FIG 47 LOW PRESSURE TEST

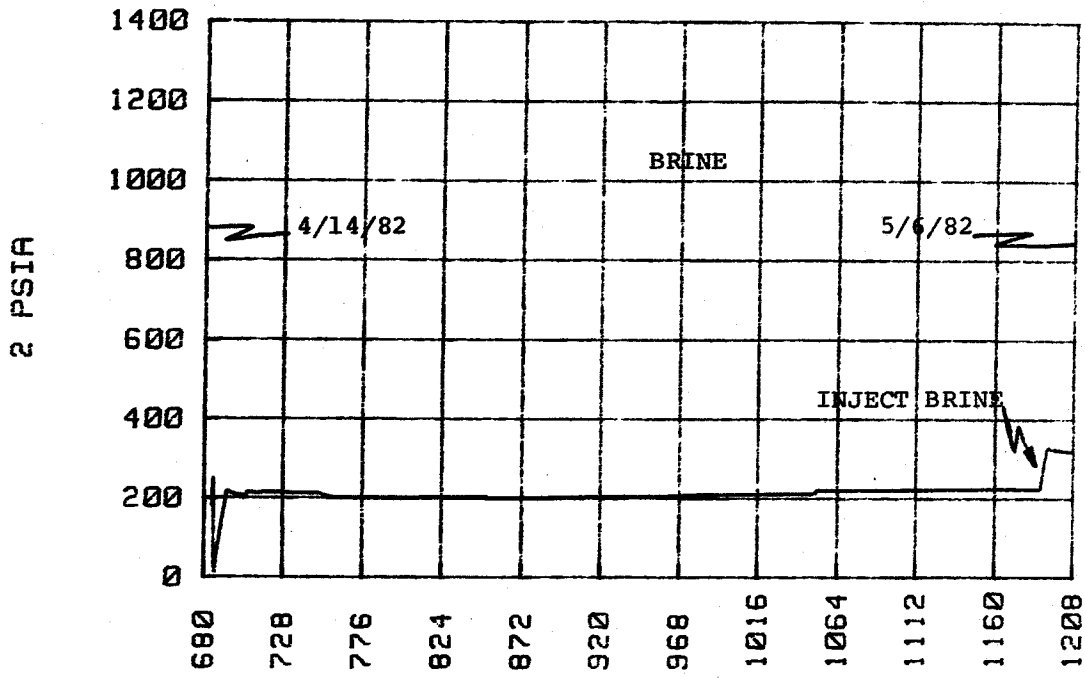


FIG 48 N2/OIL TEST

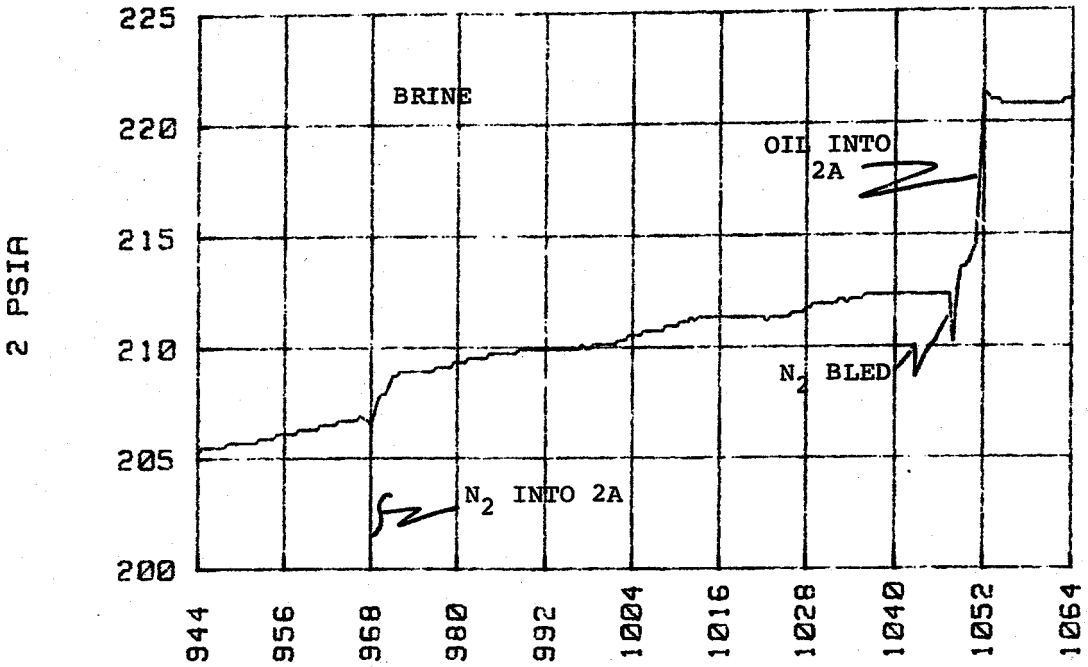


FIG 48A OIL INJECT

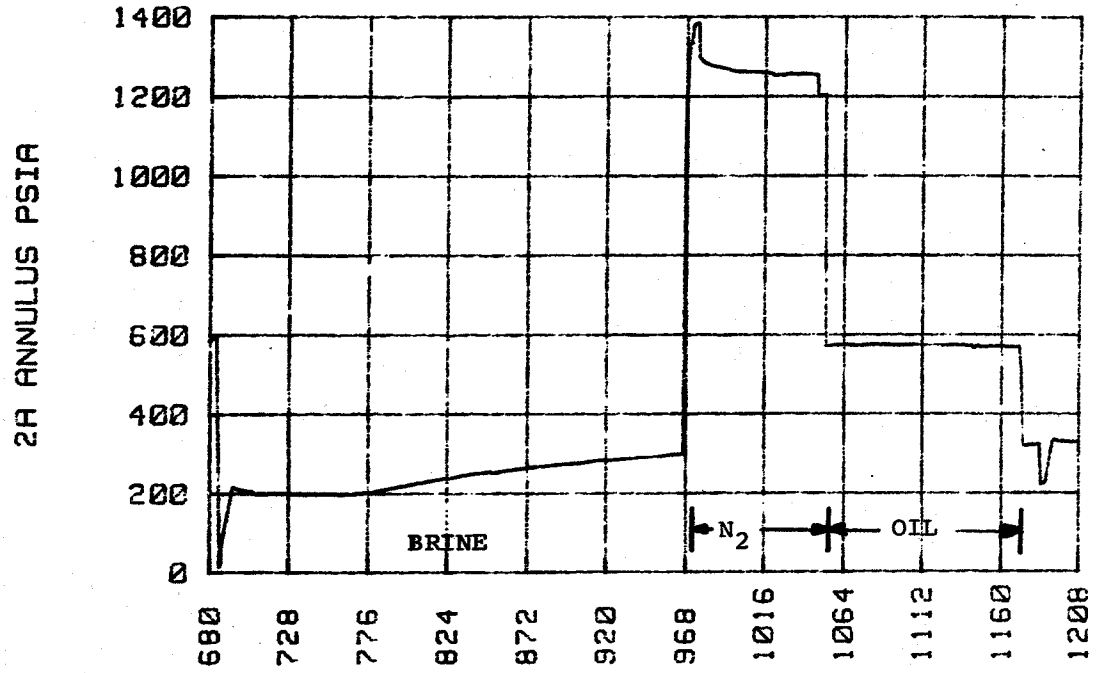


FIG 49A N2/OIL TEST

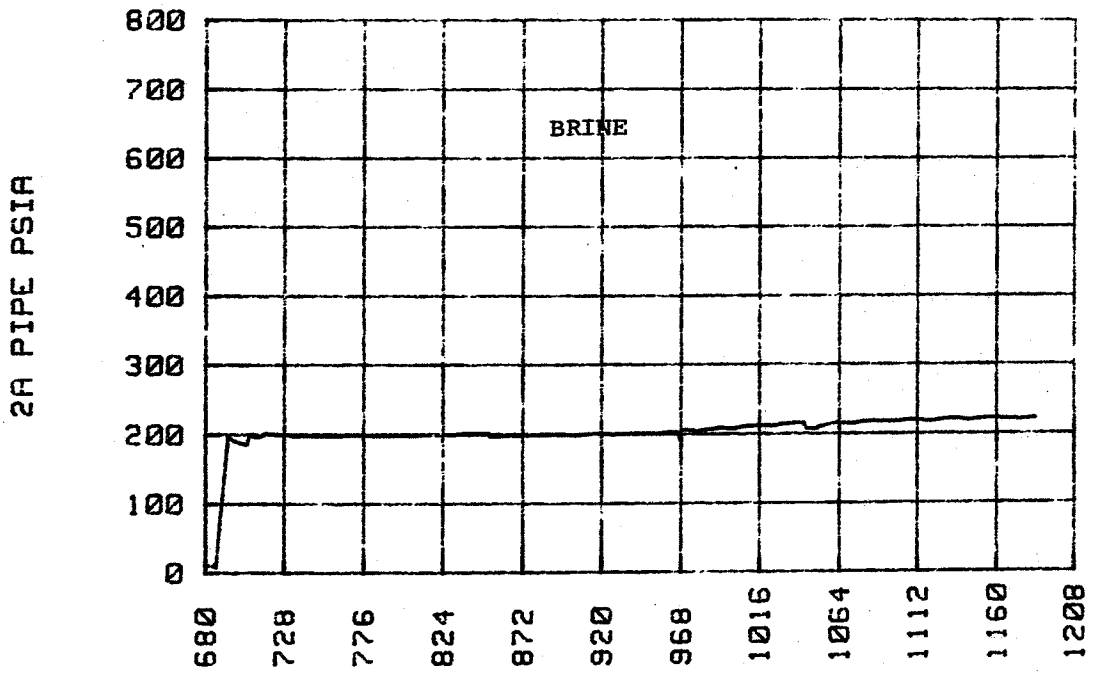


FIG 49B N2/OIL TEST

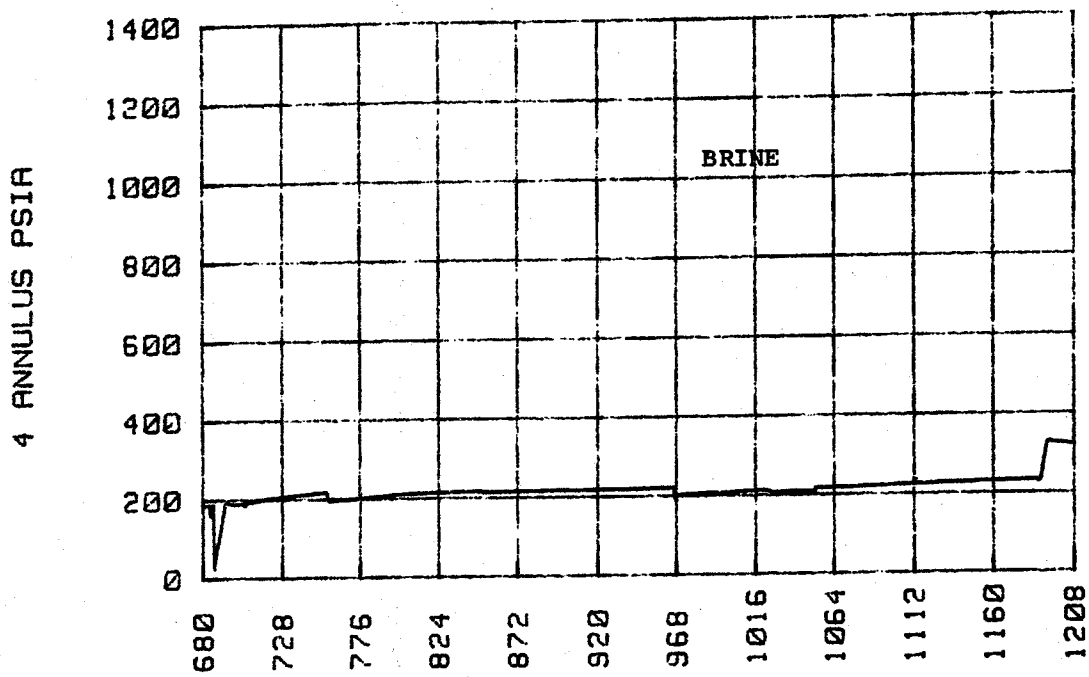


FIG 50 N2/OIL TEST

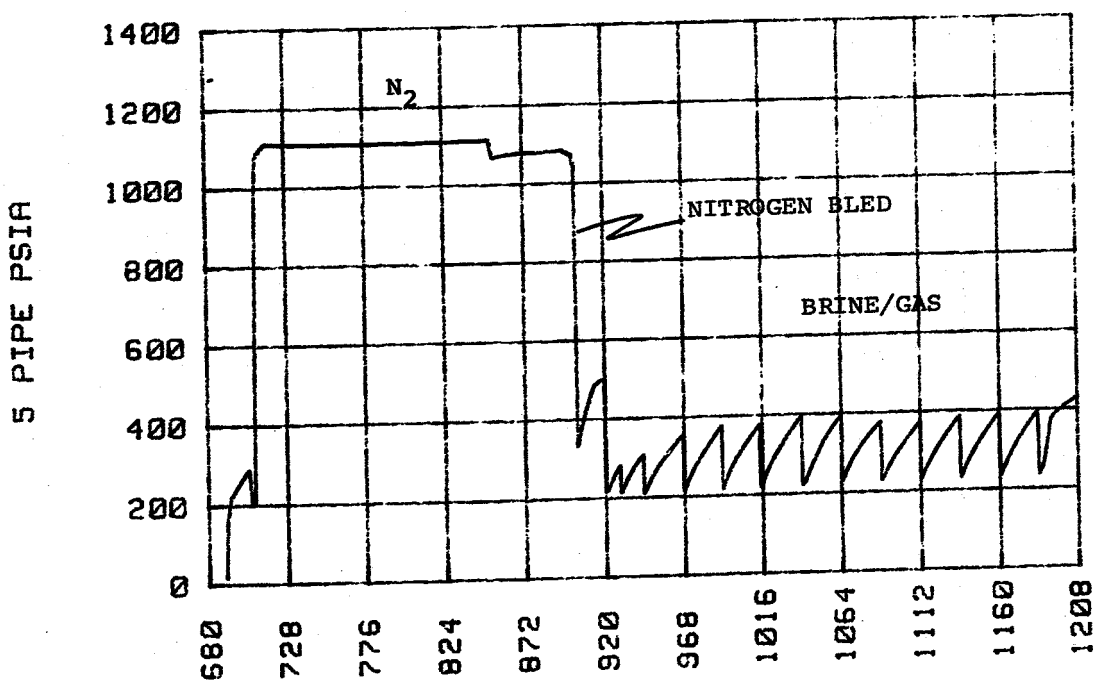


FIG 51 N2/OIL TEST

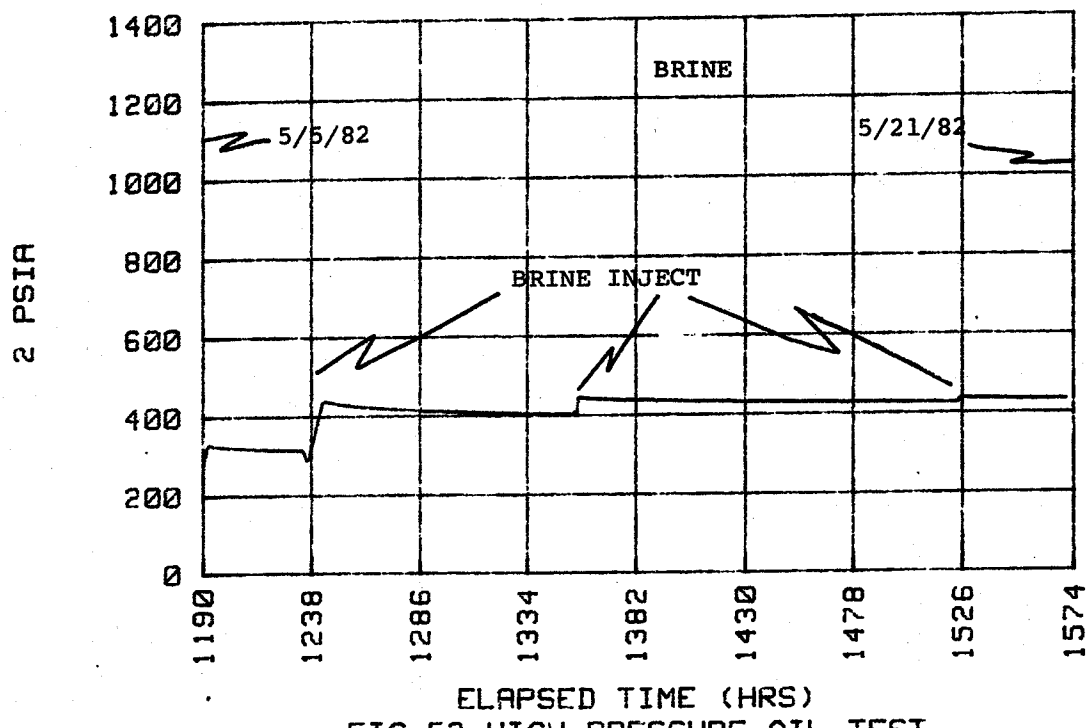


FIG 52 HIGH PRESSURE OIL TEST

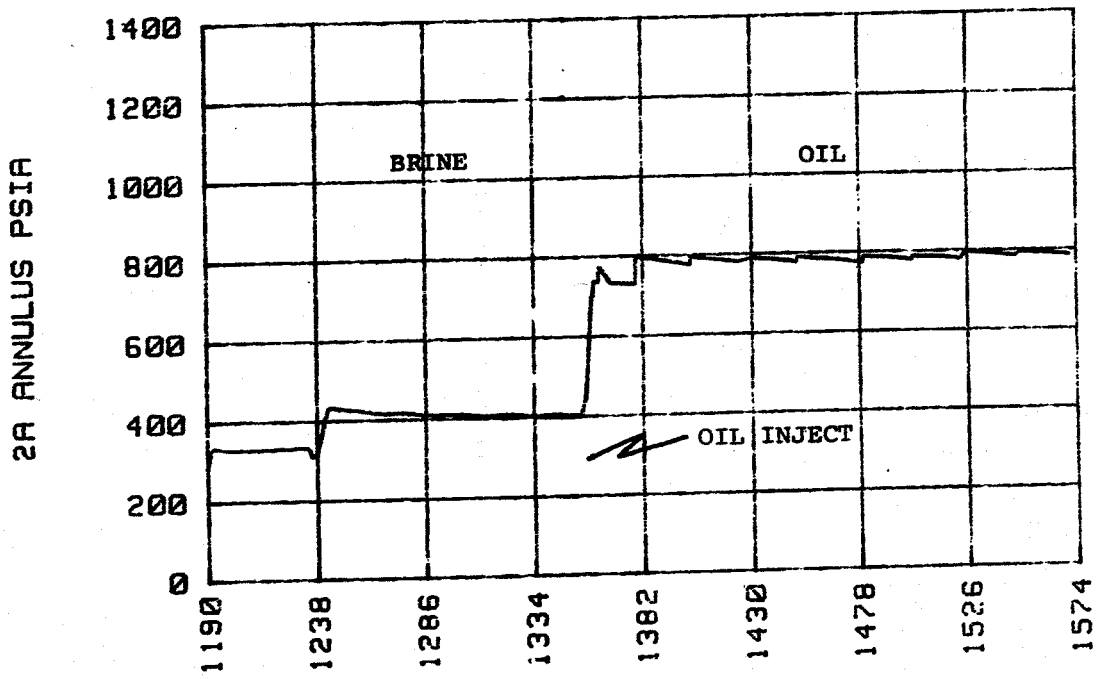


FIG 53 HIGH PRESSURE OIL TEST

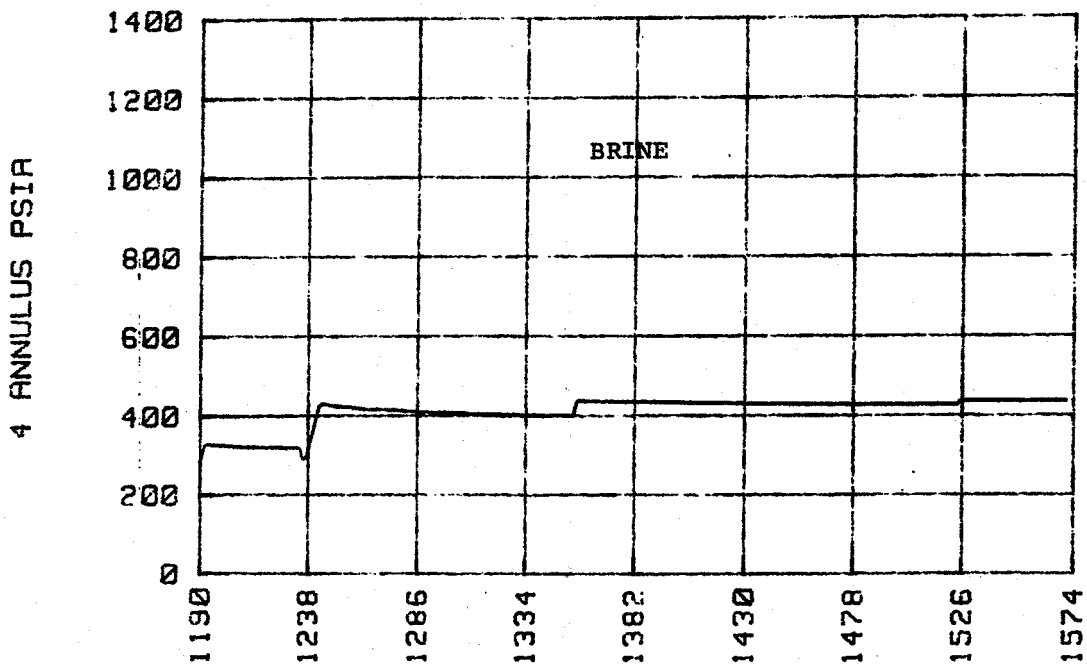


FIG 54A HIGH PRESSURE OIL TEST

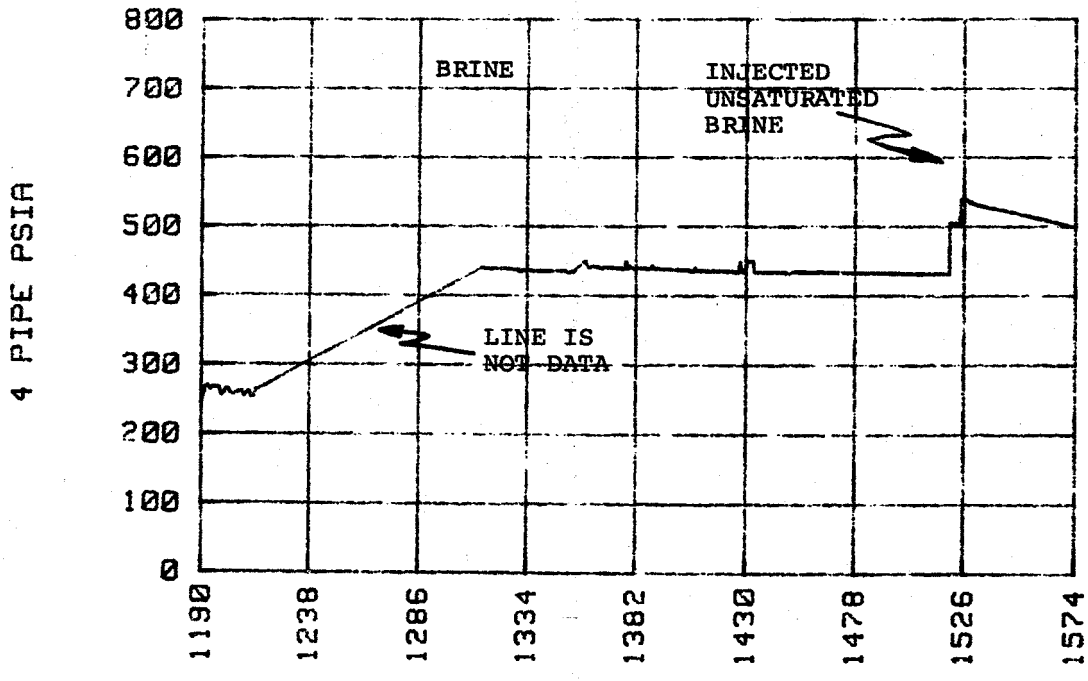


FIG 54B HIGH PRESSURE OIL TEST

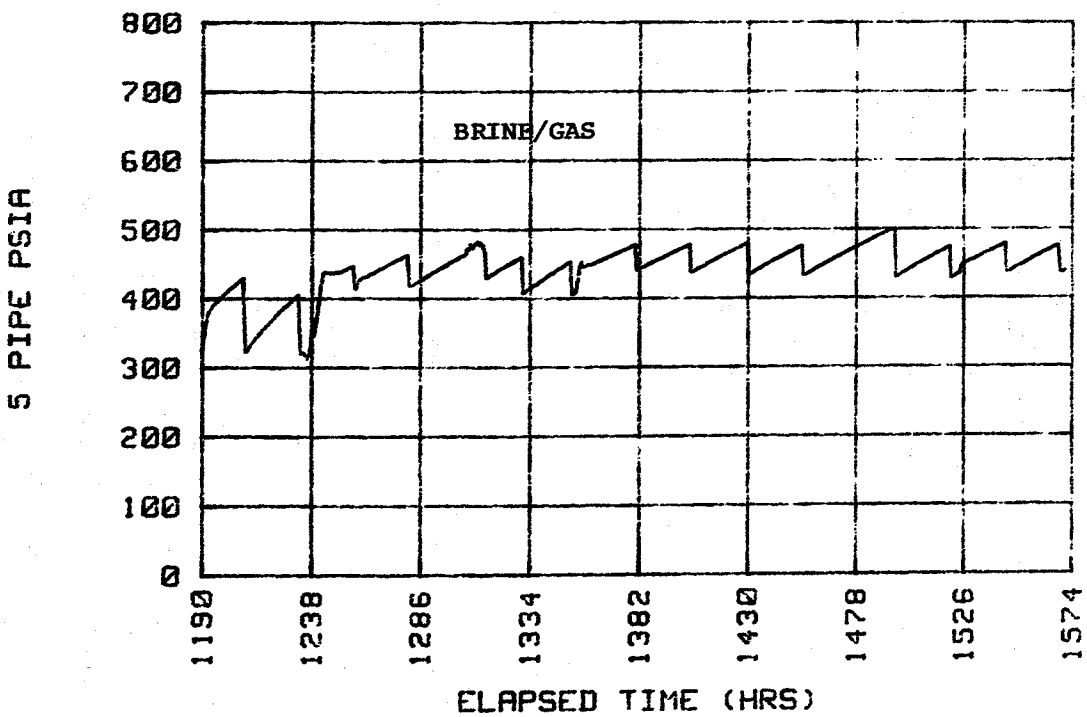


FIG 55 HIGH PRESSURE OIL TEST

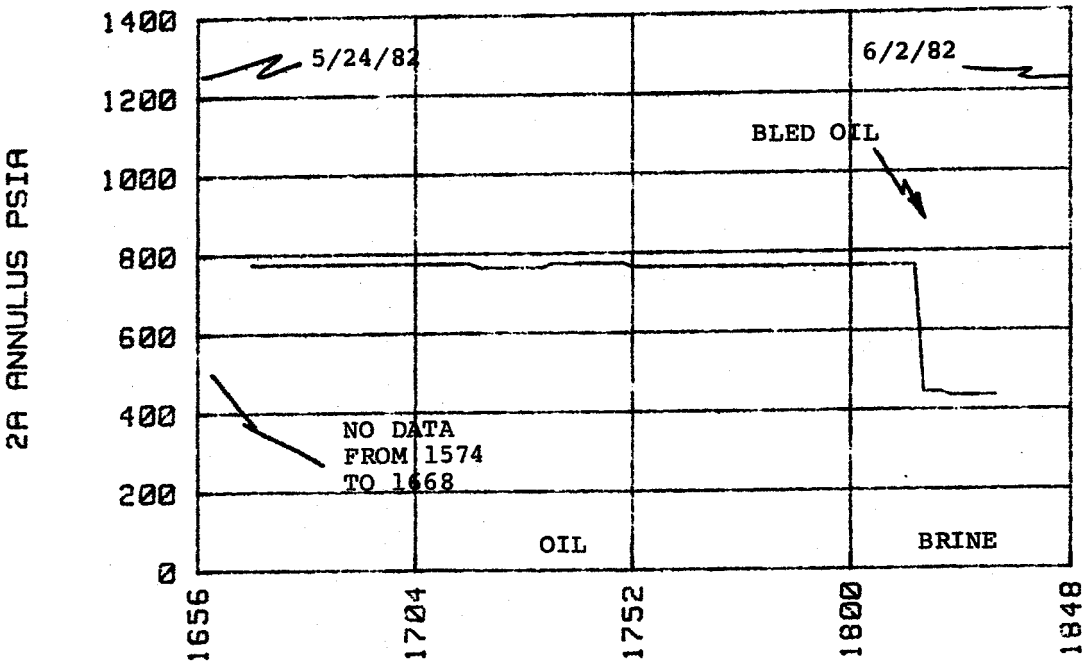


FIG 56 POSSI DATA

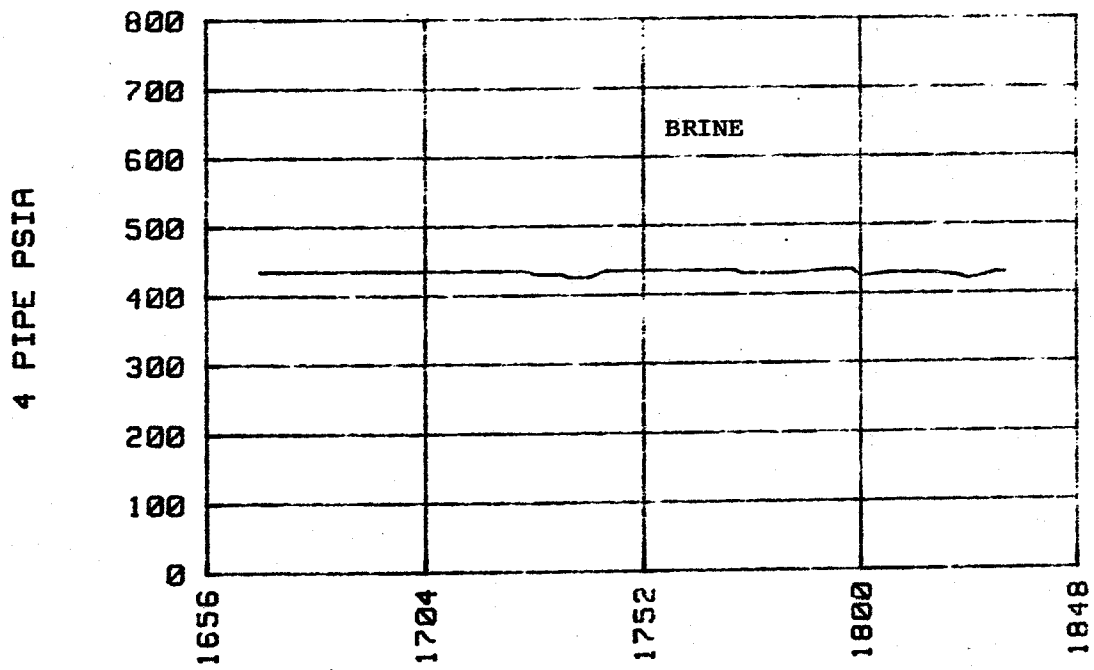


FIG 57 POSSI DATA

APPENDIX I

CALCULATIONS PROCEDURE FOR HOLE

VOLUME AND LEAK RATES FOR PART I

WELL 2

The W-P scales were not functional. The volume from the caliper is 3.1 ft^3/ft using a 24-inch hole. A plot of nitrogen pressure vs time is a straight line from 440 psi to 1184 psi which verifies the desired constant pump rate. The interface movement in the casing was about 12.5 ft/minute and the interface movement in open hole was about 3.6 ft/min. Using the ratio of 12.5/3.6 times the 7.921 diameter of 8 5/8 - 32 lb/ft casing gives a hole diameter of 27.5 inches. The assumed hole diameter will be (24 + 27.5) .50 = 25.75 inches and a specific volume of 0.644 bbl/ft.

Well 2A

In Casing:

Depth range selected = 1700 to 1760 ft
N_2 weight = 10020 - 9876 = 144 lb
N_2 vol (STP) = 144 x 13.8 = 1987 ft^3
Average N_2 pressure = Pavg (Ref 16)
Pavg = $1224 + 1224\ (1.00003082)^{1730}\ /2 = 1258$ psi
N_2 Volume in well = 1987 x 14.7/1258 = 23.2 ft^3
N_2 Volume per foot of casing = 23.2/60 = .387 ft^3/ft

The Halliburton book gives .2727 ft^3/ft for this casing, therefore, the N_2 calculation indicates too much N_2 by a factor of .387/.2727 = 1.42. Therefore, to get borehole volume from the N_2 measurements, the value will be divided by 1.42 for this test run.

In open hole:

Depth range selected = 1850 to 1930 ft
N_2 weight = 10186 - 9850 = 336 lb
N_2 Volume (STP) = 336 x 13.8 = 4637 ft^3

Pavg = $1224 + 1224\ (1.00003082)^{1890}\ /2 = 1261$ psi
N_2 Volume in well = 4637 x 14.7/1261 = 54.1 ft^3
Borehole Volume = 54.1/80ft x 1/1.42 = .476 ft^3/ft

This value would result from a hole diameter of about 11.6 inches. The caliper log shows about a 13.6 inch diameter.

APPENDIX I (CON'T)

Well 4

In Casing:

Depth range selected = 1700 to 1780 ft
N_2 weight = 10162 - 10036 = 126 lb
N_2 Volume (STP) = 126 x 13.8 = 1739 ft^3
Pavg = $1222 + 1222\ (1.00003082)^{1740}\ /2 = 1256$ psi
N_2 Volume in well = 1739 x 14.7/1256 = 20.3 ft^3
N_2 Volume per foot of casing = 20.3/80 = .254 ft^3/ft

The Halliburton book gives .1772 ft^3/ft for this casing, therefore, the N_2 calculation indicates too much N_2 by a factor of .254/.1772 = 1.43. Therefore, to get borehole volume from the N_2 measurements, the value will be divided by 1.43 for this test run.

In open hole:

Depth range selected = 1870 - 1930 = 60 ft
N_2 weight = 9222 - 8616 = 606 lb
N_2 Volume = 606 x 13.8 = 8363 ft^3
Pavg = $1222 + 1222\ (1.00003082)^{1900}\ /2 = 1259$ psi
N_2 Volume in well = 8363 x 14.7/1259 = 97.6 ft^3
Borehole Volume = 97.6/60 ft x 1/1.43 = 1.137 ft^3/ft

This value would result from a hole diameter of about 15.5 inches. The caliper log shows about a 17.5 inch diameter.

Leak rate calculations:

Pressure changes will cause the interfaces to move. To eliminate any specific reading error, use the average pressure change:

310.2 - 308.9 = + 1.3	2A Brine
314.1 - 312.2 = + 1.9	4 Brine
1219.5 - 1222.2 = - 2.7	2 N_2
1221.1 - 1220.9 = + 0.2	2A N_2
1223.2 - 1220.4 = + 2.8	4 N_2
delta Pavg = + 0.7	

well 2 1923 x 1222.2/(1222.2 + .7) = 1922 (measured at 1913 ft).

The lubricator fill in the slick hole will move the interface about 1 ft. A faulty valve closure on this well caused a bleed of 4 psi which is equal to 6 ft of interface movement. Therefore, the 1922 should really be 1922-7 = 1915 ft.

well 2A 1916 x 1220.9/(1220.9 + .7) = 1915 measured at 1915 ft

well 4 1916 x 1220.4/(1220.4 + .7) = 1915 measured at 1916 ft

The calculated leak rates are:

well 2 (1915 - 1913) ft x 3.62 ft^3/ft x .178 bbl/ft^3 x 365 days/yr x 1/(184 - 112) hr/24 hr/day = 157 bbl/yr

well 2A 1915 - 1915 = 0 ft = 0 bbl/yr

well 4 1915 - 1916 = -1 ft = 0 bbl/yr

APPENDIX II

HISTORY OF OIL/GAS PRODUCTION (DRAFT)
T. R. MAGORIAN

1. Oil

Approximately 30 million barrels of oil have been produced from the outside of the salt at Sulphur Mines. Possibly twice that much is still present in contact with the edges of the salt.

The oil and gas came through Oligocene sands which produce only on the SW side of the dome. The Anahuac shale forms a seal to hold the oil which is broken by the salt intrusion and its associated active faults. The Miocene sands in contact with the salt at cavern level are filled by vertical migration. They produce all around the dome (Figure 1) but particularly on the southeast flank. The outside surface of the salt probably leaks oil (as well as gas) except where it overhangs the sands. Few shale seals are known within the Miocene.

No bottom-hole pressure data is available from any of the oil-producing holes drilled close to the caverns.

1A Southeast Flank

The salt edge next to the wing of cavern 4 is the best Miocene oil production anywhere around the dome (Figure 1). The oil is trapped by the largest, and possibly deepest overhang (salt reentrant) (Figure 2).

The newest oil well, 947, was completed in January 1980 (Figure 2) in the E sand, a tight, limy zone of the usually mineralized soil at the salt edge. After the gas was blown out and flared, the well finally made a few barrels of oil per day on pump.

Beyond the north end of this overhang, near well 906, oil has not been trapped as well and has migrated upward into the caprock, contaminating the sulphur in well S-1. This black sulphur probably contains 1.0% oil (J. Gabriel, pers. comm.).

The oil in the caprock at sulphur well S-1 thus probably represents the north end of the salt overhang which seals the relatively-large Miocene accumulation in 863 and surrounding wells (Figure 2).

The oil wells closest to the overhang had the following surface pressures in addition to brine heads of 9.6 Lb/gallon in sands at cavern wing level:

Well	Static (Casing) Pressure
882	521 psi
881	590
863	585

The last of these wells, 863, produced over half a million barrels of oil from this sand, the main Miocene D. Well 881 is standing open, still full of oil, bubbling to the surface when its tar seal is broken. Well 882 produced almost no oil.

An oil sand was encountered at the salt/caprock interface when drilling brine well (cavern) 5. Well 798 was completed in this location high on the dome. Well S-2 was also completed in the zone immediately above the salt for 16 barrels per day 20% water.

1B West Side

There is prolific oil production from wells 940, 941, and 942 opposite cavern 7, from both Miocene and deeper Oligocene sands. Since these caverns show nearly normal behavior on pressure test, the detailed data on surrounding sands is not presented here.

1C Rest of Dome

A new well 946 just north of cavern 6 along the west side was completed as a good oil well by directionally drilling down along the edge of the salt. No serious threat of communication to the cavern is found this far north around the dome.

2. Gas

Large quantities of gas have been produced from the outside of the salt at Sulphur Mines. Even larger quantities are still present in contact with the edge of the salt. As hydrocarbons migrate up along the edge of the salt, the gas and oil tend to separate forming gas caps in the upper ends of the sands against the salt. This "attic" gas is difficult to produce and expands as the oil is depleted.

Even where the edge of the salt is tight to oil, gas leakage may be observed. The water wells at Sulphur Mines Dome were first observed to be gassy before oil and sulphur production began.

Large amounts of gas are dissolved in the oil, both inside and outside the salt. Without evidence from successful pressure-maintenance, the salt apparently is not gas-tight, although it traps oil. It may even be weakened by oil production.

The history of gas production in the C and D sands of the Miocene is confused by the absence of data. All of the Union Texas Petroleum wells were completed as oil wells with a small water cut but there are no company records of gas/oil ratio or volume of gas actually produced. Some of the wells are known to have produced gas for use in the plant. Since no pressure maintenance was instituted in the production of the oil field, the lower portions of each sand would be subject to water encroachment, but the upper end of each sand filled with expanded gas. PPG, in their brining operations at this site, has encountered so much gas that they decided some years ago to keep gas pads on all the caverns, since it allows them to gas lift brine, and a gas cap will eventually always form in a leaky cavern: any oil or brine leak to the outside of the dome will equilibrate with an inward counterflow of gas. The extent of the gas cap in most of the Miocene sands is unknown since the gas was blown off and flared to produce oil. Only wells 940 thru 947 have dual-neutron logs which allow differentiation of gas from oil.

2A Southeast Flank Gas

The gas pressure in Miocene sands is probably highest under the salt overhang next to Cavern 4. The wells closest to the salt here produce gas: 881 open and gassy, 882 abandoned as a gas well.

Cavern 5 has made gas since drilling while in cavern 4, gas dissolved in the blanket oil.

In the main sand opposite the cavern wing, well 882 had a final gas-oil ratio of 280 which is relatively low, although virtually no oil was produced. On wells 906 and 767, permits were issued for gas injection with no record of operation.

A gas zone was recognized on the dual neutron log and sidewall core in the top of the new pay in well 947, the mineralized E sand.

2B West Side Gas

Brine well 1A is making gas at same 4 CFD. The gas coming into PPG 15 has been reduced with oil in the annulus into which it is probably dissolving.

Gas production data is limited to:

Well #	Date	Union Texas (Allied) Production Records
944	1979	gas at 2100 psi at 6927 ft depth made about 1/2 MMCFD

(A secondary recovery permit was issued)

935	workover 2/80	gas @ 3670 flowing TP 1200 # made sand (Cut valves)

This recent well, 935 had a blowout in February 1980 which may have fed both flanks of the dome. It blew Frio gas into the Miocene main D sand at high overpressure until it sanded out. The pressure was cemented into the Miocene sand.

Significant quantities of methane CH_4 and carbon dioxide CO_2 have been found in the new brine well drilled for PPG on the west side of the dome beside Allied 1A. Apparently the total amount of gas bled from wells 13/15 is at least a standard MCFD. The nearly-pure CH_4 sampled from these wells on 2/4/81 is typical of gases from South Louisiana domes. Anything else is anomalous. The 16% CO_2 sampled on 7/11/80 and 10% on 3/6/80, are difficult to explain.

The only known sources of CO_2 are in the caprock (again pointing to the leak at the top of cavern 5).

1. Product contamination in Allied caverns 1 and 2. This has been observed in the past. However, it implies communication past caverns 6 and 7 all around or over the dome.

   The second sample taken on 2/4/81 also contained a small propane anomaly, .07% vs only .04% ethane. If the gas came from oil-producing sands against the salt, possibly repressured by well 935, then .04% ethane is normal but no more than .02% propane can occur with it. The excess propane may come from the product known to have been stored in caverns 1 and 2 by Allied. Since the other sample taken at the same time showed no anomalies, replication is needed before drawing any conclusions.

2. Accumulation in the caprock. This implies sulfate-free lime zones in contact with the salt, which are common on North Louisiana domes, but unknown in the South.

The amount of CO_2 is so high that the samples should be replicated before either drastic inference is used as the basis for a decision.

PPG, by filling the annulus with oil, has deferred free gas at the wellhead. It is doubtful that they have stopped it.

2C Rest of Dome

The high-pressure gas released into Miocene sands by well 935 has overpressured wells most of the way around the dome. No data on gas has been compiled away from the cavern edges.

Edge of Dome

Computation of distance from wing of cavern to edge-of-dome based on

1. Pressure test: not readily computable with these tests.

2. Well data: from oil and gas production, computer model in progress 140 $\pm$ 50 ft. Additional dip data and estimates from equation of state being included.

3. Crosshole seismic shooting under consideration (accuracy $\pm$ 10-20 ft), (could be up to 70 ft).

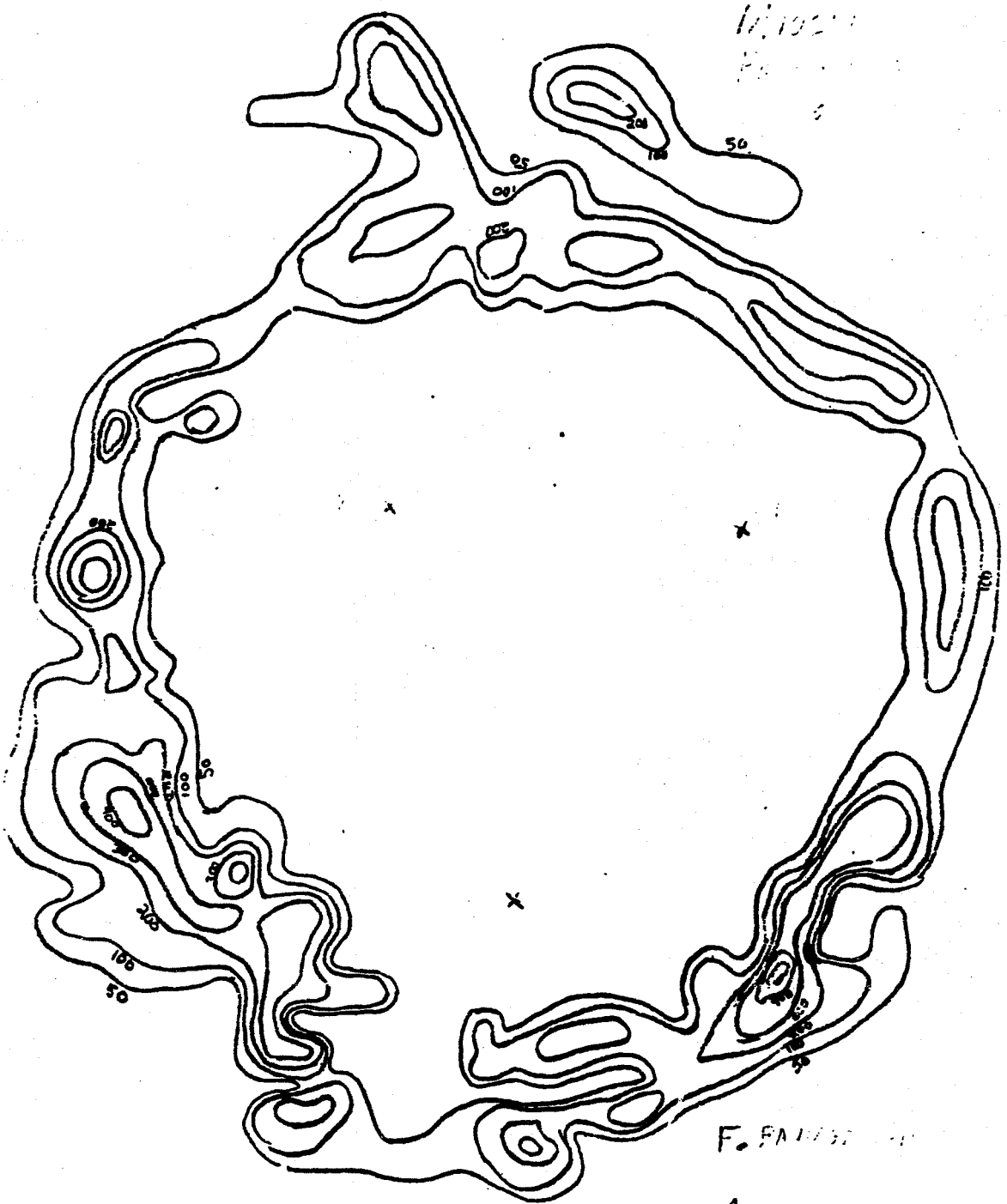
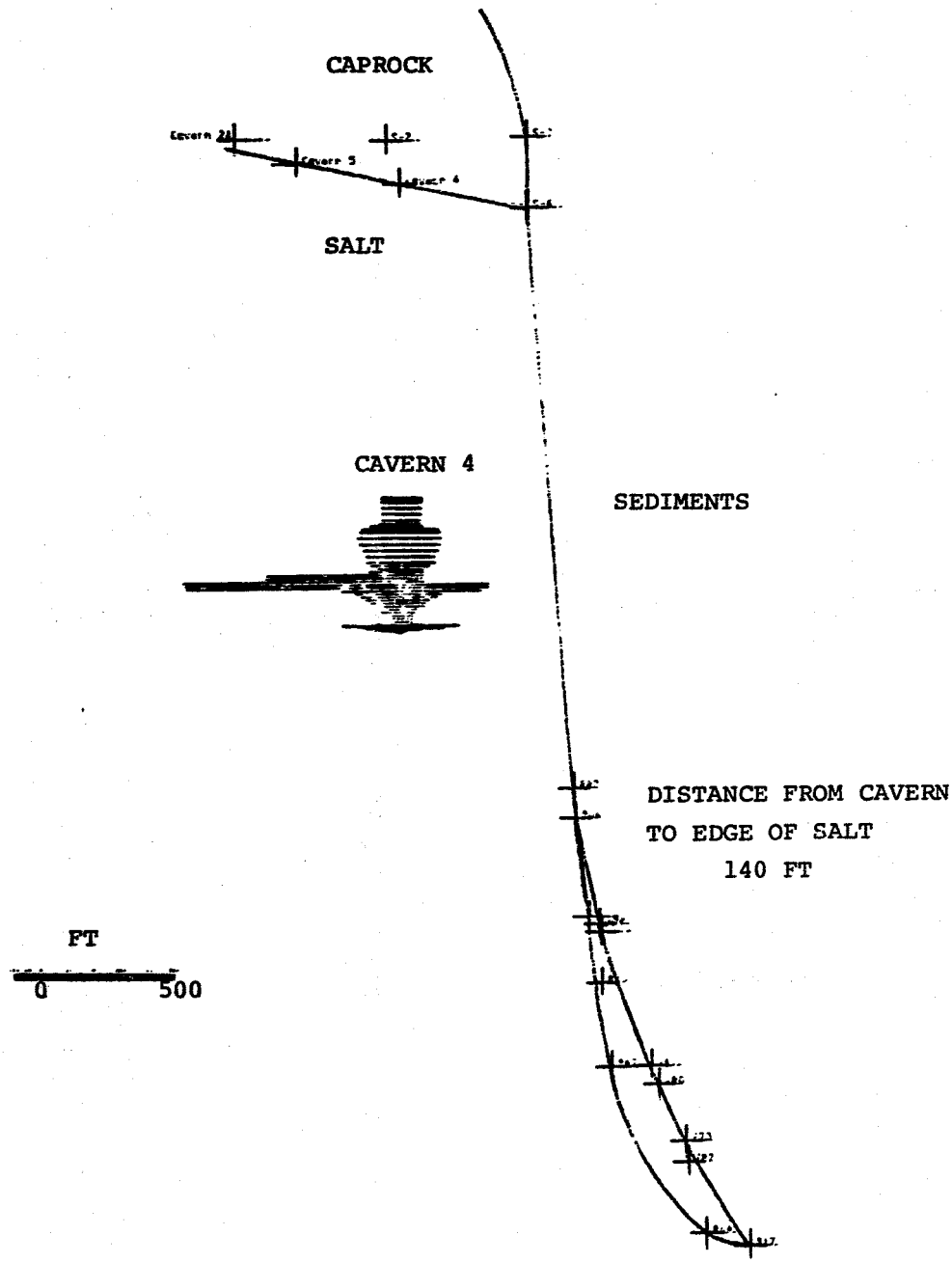
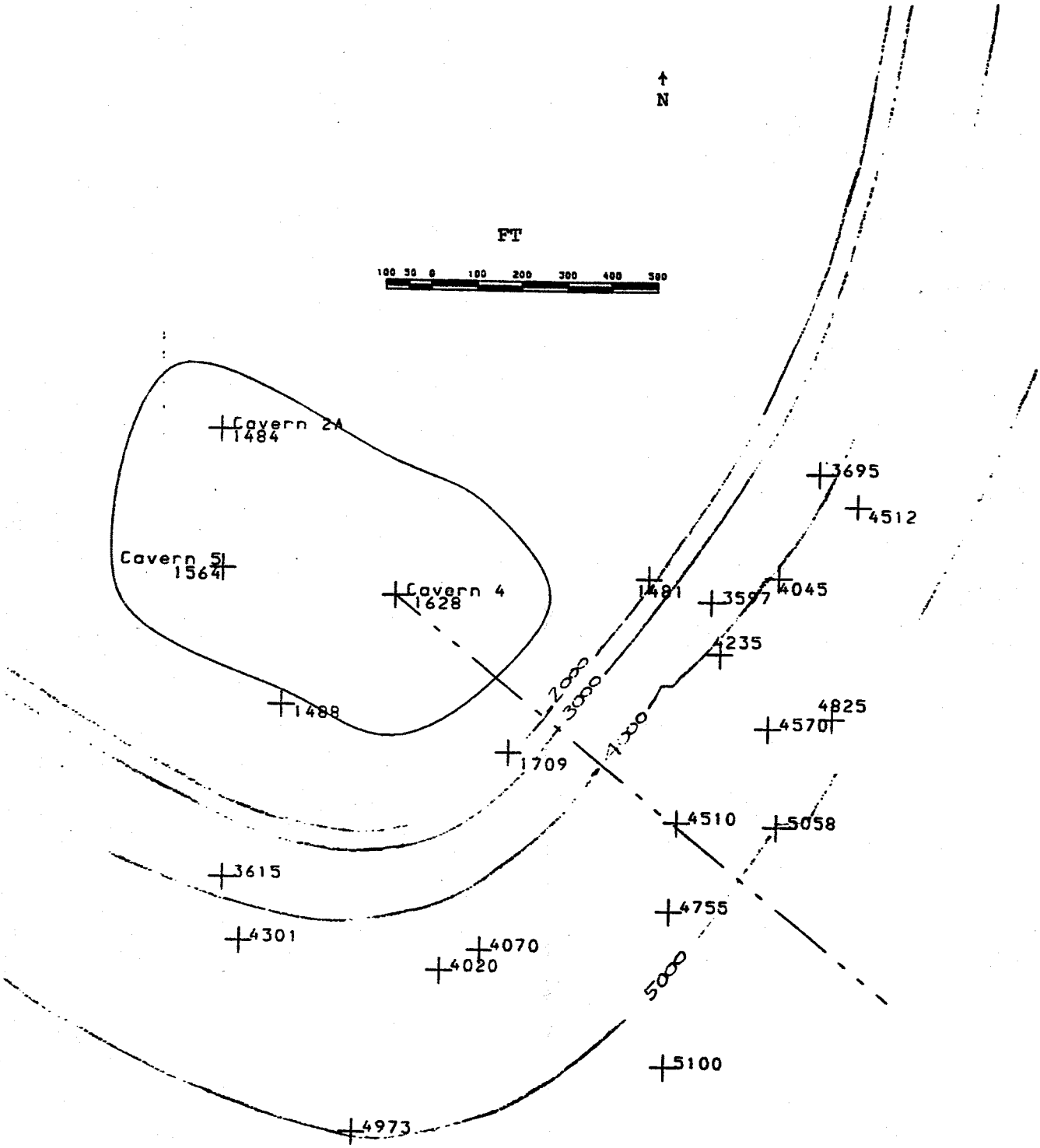


FIG. 1

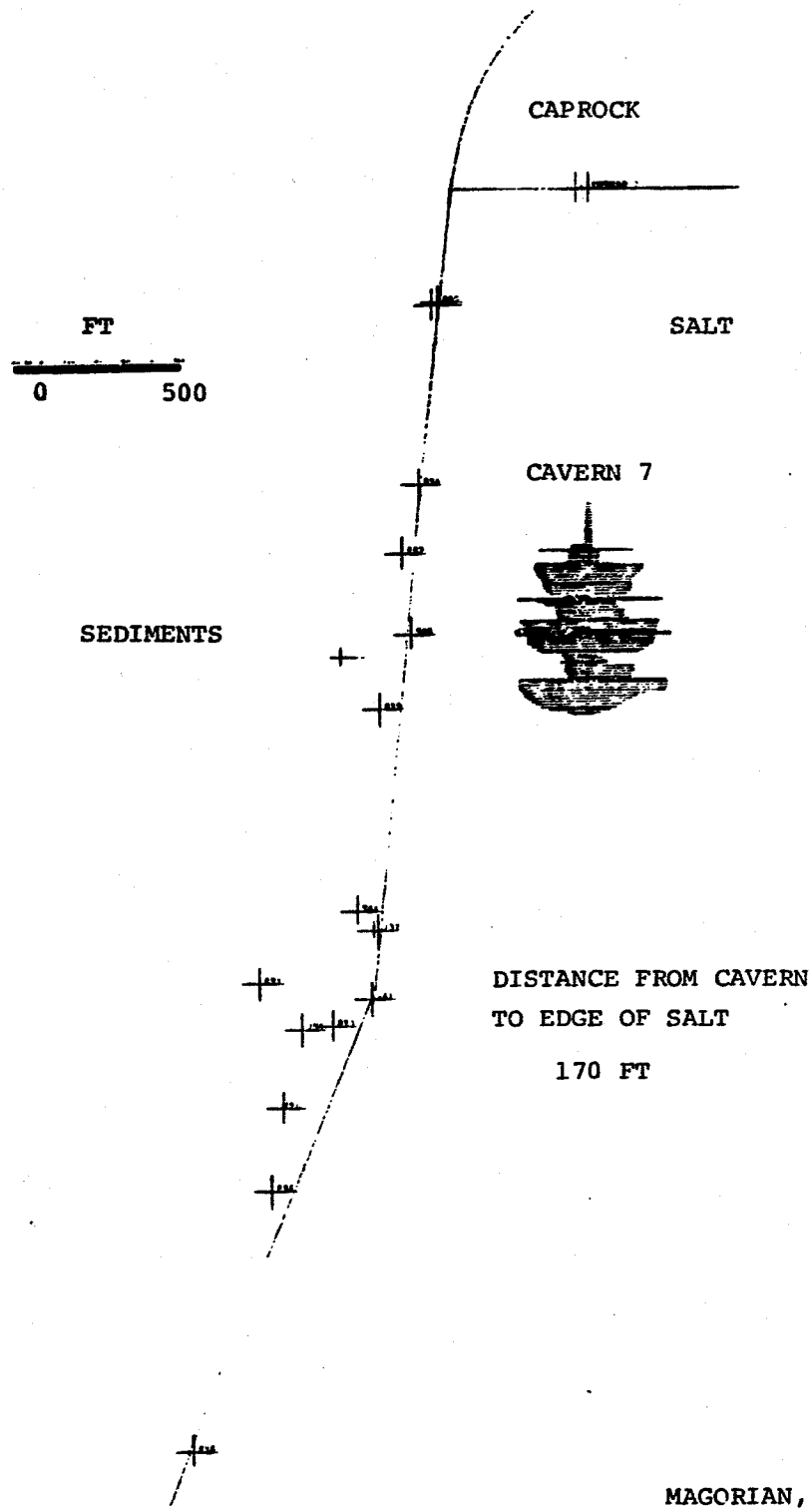


MAGORIAN, 1/82
FIG 2



MAGORIAN, 1/82

Fig 3



MAGORIAN, 1/82
Fig 4

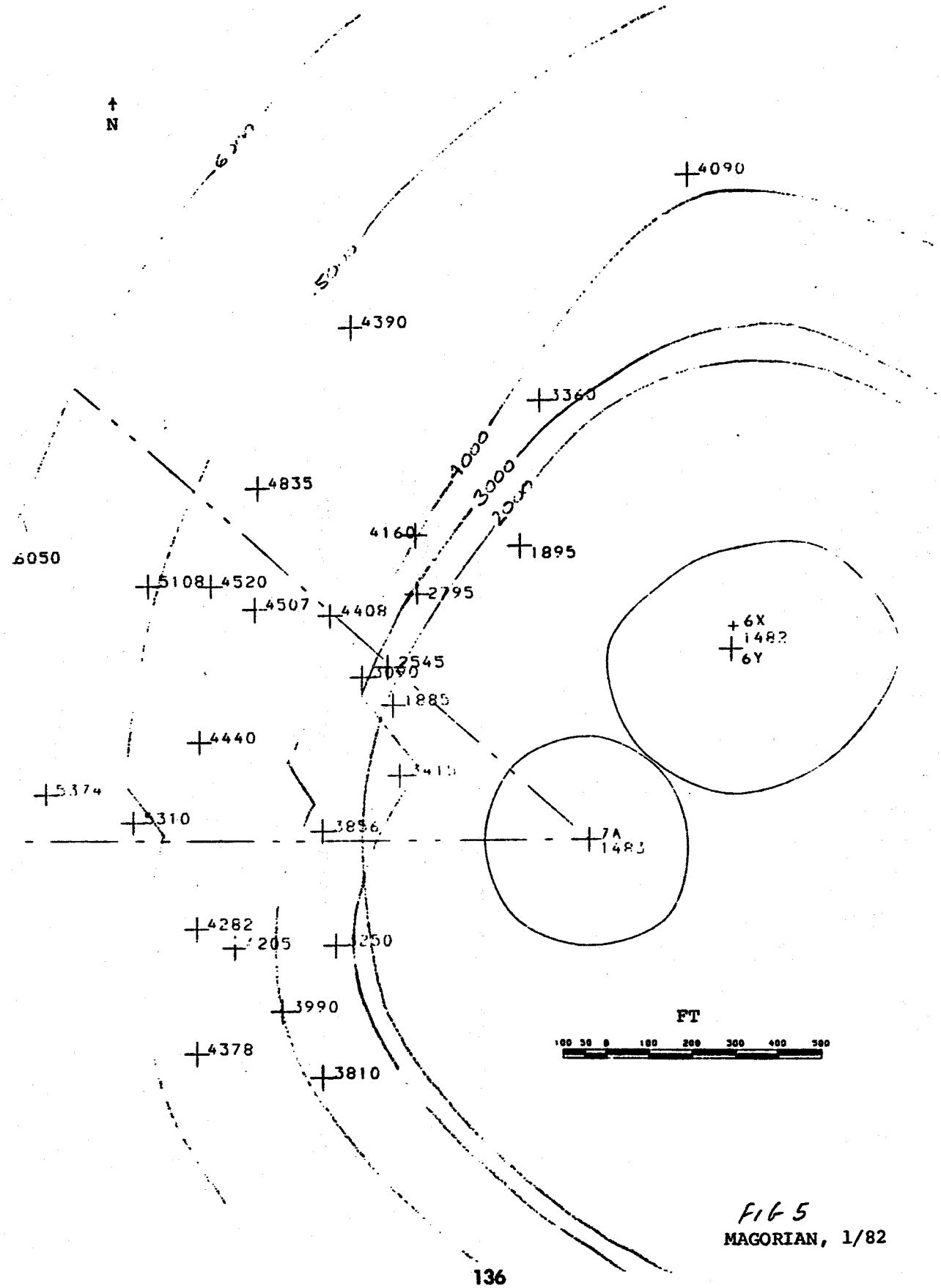


FIG 5
MAGORIAN, 1/82

APPENDIX III

Calculations Procedure for Hole Volume and Leak Rates for Part II

Well 4

In casing:

Depth range selected = 1720 to 1780 ft

N_2 weight = 10844 - 86 lb

N_2 vol (STP) = 86 x 13.8 = 1187 ft^3

Average N_2 pressure = Pavg (Ref. 16)

$$Pavg = 1114 + 1114\ (1.0000307)^{1750}\ /2 = 1145\ psi$$

N_2 volume in well = 1187 x 14.7/1145 = 15.2 ft^3

N_2 volume per ft. of casing = 15.2/60 = .253 ft^3/ft

The Halliburton book gives .1772 ft^3/ft for this casing, therefore, the N_2 calculation indicates too much N_2 by a factor of .253/.1772 = 1.43. Therefore, to get borehole volume from the N_2 measurements, the value will be divided by 1.43 for this test run.

In open hole:

Depth range selected = 2310 - 2210 = 100 ft

N_2 weight = 9502 - 9202 = 300 lb

N_2 volume = 300 x 13.8 = 4140 ft^3

$$Pavg = 1343 + 1343\ (1.0000307)^{2260}\ /2 = 1391\ psi$$

N_2 volume in well = 4140 x 14.7/1391 = 43.8 ft^3

Borehole volume = 43.8/100 x 1/1.43 = .306

This value would result from a hole diameter of about 10 inches. The caliper log shows about an 8 inch diameter.

Leak rate calculation for well 4: Pressure changes will cause the interface to move. To eliminate a specific reading error, use the average pressure change.

289 - 272 = +17	4 pipe
287 - 275 = +12	2A pipe
1366 - 1368 = -2	4 N_2
delta Pavg = +9	

2321 x 1368/(1368 + 9) = 2305 ft

which was measured at 2292 ft

2305 - 2292 = 14 ft

14 ft x .306 ft^3/ft x .178 bbl/ft^3 x 365 day/yr x 1/(155 - 18) hr/24 hr/day = 50 bbl/year

Using the rate of the calculated interface movement just after the log at 2292 on March 23 and the associated pressure change, the interface movement is 2 ft/day for a leak rate of 40 bbl/yr.

Well 2

In casing:

Depth range selected = 1700 to 1800 = 100 ft
N_2 weight = 10500 - 10212 = 288 lb
N_2 volume (STP) = 288 x 13.8 = 3974 ft^3
Average N_2 pressure = Pavg
Pavg = $[1118 + 1118\ (1.0000307)^{1750}]/2$ = 1149 psi
N_2 vol per foot of casing = 50.8/100 = .508 ft^3/ft

The Haliburton book gives .3422 ft^3/ft for this casing, therefore, the N_2 calculation indicates too much N_2 by a factor of .508/.3422 = 1.48. Therefore, to get borehole volume from the N_2 measurements, the value will be divided by 1.42 for this test run.

In open hole:

Depth range selected = 2200 to 2300 = 100 ft
N_2 weight = 10442 - 7264 = 3178 lb
N_2 volume (STP) = 3178 x 13.8 = 4356 ft^3
Average N_2 pressure = Pavg
Pavg = $[1347 + 1347\ (1.0000307)^{2250}]/2$ = 1395 psi
N_2 volume in well = 4386 x 14.7/1395 = 462 ft^3
Borehole volume = 462/100 ft x 1/1.48 = 3.12 ft^3/ft
This value would result from a hole diameter of about 24 inches. The caliper log shows about a 25 inch diameter.

Leak rate calculation:

Using an average brine pressure increase of 15 psi, the interface would have moved from 2310 to:
2310 x 1368/(1368 + 15) = 2285 ft
The leak rate would then be (2285 - 2274) x 3.12 x .178 x .365 x 1/12 days = 186 bbl/yr
Minus the losses due to lubricator filling and valve leakage.

Well 2A

The leak rate calculations for well 2A will be repeated for the several tests that were run in between March 19 and May 31, 1982.

1. Test 3/19 through 3/31 with N_2

In casing:

Depth range selected = 1700 to 1800 = 100 ft
N_2 weight = 12290 - 12054 = 236 lb
N_2 volume (STP) = 236 x 13.8 = 3257 ft^3
Average N_2 pressure = Pavg
Pavg = $[1118 + 1118\ (1.0000307)^{1750}]/2$ = 1149 psi
N_2 volume in well = 3257 x 14.7/1149 = 41.7 ft^3
N_2 volume per foot of casing = 41.7/100 = .417 ft^3/ft

The Halliburton book gives .2727 ft^3/ft for this casing, therefore, the N_2 calculation indicates too much N_2 by a factor of .417/.2727 = 1.53. Therefore, to get borehole volume

from the N_2 measurements, the value will be divided by 1.53 for this test run.

In open hole:

Depth range selected = 2100 to 2300 = 200 ft
N_2 weight = 10700 - 9460 = 1240 lb
N_2 volume (STP) = 1240 x 13.8 = 17112 ft^3
Pavg = $[1325 + 1325\ (1.0000307)^{2200}]/2$ = 1371 psi
N_2 volume in well = 17112 x 14.7/1371 = 183 ft^3
Borehole volume = 183/200 x 1/1.53 = .598 ft^3/ft

This value would result from a hole diameter of about 12.6 inches. The caliper log shows about a 14 inch diameter.

Leak rate calculation:

For 3/19 to 3/22

The brine pressure increased from 284 to 286 which would have moved the interface from 2325 to: 2325 x 1380/(1380 + 2) = 2322 ft. The movement was from 2325 to 2146 = 179 ft from 1300 hrs 3/19 to 0900 hrs 3/22. (179 - 3) ft x .598 ft^3 ft x .178 bbl/ft^3 x 365 day/yr x 1/2.83 day = 2416 bbl/yr.

For 3/22 to 3/26

The brine pressure increased from 286 to 291 which would have moved the interface from 2380 to: 2380 x 1400/(1400 + 5) = 2372 ft. The movement was from 2380 to 2237 = 143 ft from 1000 hrs 3/22 to 1500 hrs 3/26. (143 - 8) x .598 x .178 x 365 x 1/5.2 = 1009 bbl/yr.

For 3/26 to 3/29

The interface moved from 2140 ft to 2157 ft which indicates that gas was entering the well.

For 3/29 to 3/31

The brine pressure increased from 290 to 294 which would have moved the interface from 2380 to: 2380 x 1355/(1355 + 4) = 2373 ft. The movement was from 2380 to 2275 = 110 ft from 1600 hrs 3/29 to 1700 hrs 3/31. (110 - 7) x .598 x .178 x 365 x 1/2.0 = 2000 bbl/yr.

Therefore, for brine pressures of about 290 psi and a N_2 interface about 2350 ft., the leak rate is from 1000 to 2400 bbl/year plus any gas entry volumes.

2. Test 4/26 thru 4/29 with N_2

The brine pressure increased from 205 to 212 which would have moved the interface from 2380 to: 2380 x 1320/(1320 + 7) = 2367 ft. The movement was from 2380 to 2202 = 178 ft, from 1400 hrs 4/26 to 0700 hrs 4/29. (178 - 13) x .598 x .178 x 365 x 1/2.7 day = 2374 bbl/yr. Plus any gas entry volumes.

3. Test 4/29 thru 5/3 with oil
The borehole volume is taken from data from the following test. The interface moved from 2440 ft at 2130 hrs on 4/29 to 2378 ft at about 2100 hrs on 5/3. The change in brine pressure would have made a negligible change. The change in oil temperature from 70°F on 4/29 to near 126°F on 5/3 should have moved the interface downward. The oil expansion would have been: (268 - .0476 x 2440) bbl x 4.5 x 10^{-4}/°F x 56°F = 3.8 bbl. The gas entry into the well at about 200 psi can be estimated from the differences in pressure curve slopes and pressure drops when the gas is bled off. Using 120 ft^3/day at STP and an average well pressure of 1020 psi, the gas entry is approximately 1.7 ft^3/day x 4 days x .178 bbl/ft^3 = 1.2 bbl. Borehole volume from 2440 to 2378 ft is 268-255-.0476 x 62 = 10 bbl. Therefore, the oil leak rate is approximately: (10 + 3.8 + 1.2) x 365/4 = 1370 bbl/yr at brine pressures of about 200 psia.

4. Test 5/13 Thur 5/31 with Oil

5/14	122	21.5	.98	8000	795
5/15	101	17.8	.98	6630	793
5/16	87	15.3	.99	5640	792
5/17	102	18.0	1.21	5430	790
5/18	60	10.6	.88	4400	789
5/19	55	9.7	.92	3850	788
5/20	80	14.1	1.01	5100	796
5/21	59	10.4	.92	4130	—
5/31	267	47.0	11.00	1560	—

(1) This is interface movement times the average volume in the lower portion of the hole of 0.176 bbl/ft.

(2) Volume loss times 365 days/yr divided by elapsed time in days.

(3) Oil pressure after interface reset to 2440 ft.

Therefore, for brine pressures of about 430 psi, the leak rate is about 4000 bbl/year with the oil interface near the cavern roof.

Well 5

In casing:

Depth range selected = 0 to 1820 = 1820 ft.
N_2 weight = 11384 - 10226 = 1158 lb.
N_2 volume (STP) = 1158 x 13.8 = 15980 ft^3.
Average N_2 pressure = Pavg.
Pavg = $[652 + 652\ (1.00003)^{910}]/2$ = 661 psi
N_2 volume in well = 15980 x 14.7/661 = 355 ft^3
N_2 volume per foot of casing = 355/1820 = .195 ft^3/ft.
The volume of a 4 1/8 inch hole is .0928, therefore, the N_2 calculation indicates too much N_2 by a factor of .195/.0928 = 2.1. Therefore, to get borehole volume from the N_2 measurements, the value will be divided by 2.1 for this test run. The probable reason that this value of 2.1 is higher than found for the other wells was the increased pump rate and the associated decreased N_2 temperature.

In open hole:

Depth range selected: 1888 to 1898 = 10 ft
N_2 weight = 10168 - 7812 = 2356 lb
N_2 volume (STP) = 2356 x 13.8 = 32513 ft^3
Average N_2 Pressure = Pavg
Pavg = $[1107 + 1107\ (1.000033)^{1893}]/2$ = 1143 psi
N_2 volume in well = 32513 x 14.7/1143 = 418 ft^3
Borehole volume = 418/10 x 1/2.1 = 19.9 ft^3/ft.
This value would result from a hole diameter of about 60.4 inches. The 1979 sonar gives an average diameter at 1893 ft of 24 inches.

Leak rate calculations for this well must include consideration of pressure changes, N_2 temperature changes, and gas entry. The logged interface was 1898 ft at 2200 hrs on 4/15, 1894 ft at 1100 hrs on 4/19, and 1893 ft at 1000 hrs on 4/21.

The cavern pressure decreased from 4/15 to 4/19 then increased from 4/19 to 4/21 so that the change in brine pressure from 4/15 to 4/21 was only 0.3 psi. This would result in negligible interface movement due to pressure changes. Calculation of the N_2 density from 4/15 to 4/21 shows a temperature increase from 90°F to 125°F.

The total volume of N_2 in the well on 4/15 was:

11384 - 10190 + 10980 - 9950 + 12080 - 8150 + 12046 - 7812 = 1194 + 1030 + 3930 + 4234 = 10388 lb
10388 x 13.8 = 143354 ft^3 STP
Pavg = $[1099 + 1099\ (1.000033)^{1875}]/2$ = 1134 psi
Volume in well = 143354 x 14.7/1134 = 1858 ft^3
Volume should increase due to temperature:
1858 x (460+125)/(460 + 90) x .178 = 352 bbl

The log run on 4/15 found the gas interface at 140 ft after a bleed down 13 hours before. This volume of gas at well pressures is about: .092 x 140/13 = 1 ft^3/hour. For the test duration of 132 hours this is:

132 x .178 = 23 bbl of gas addition.

Leak rate is:

(1898 - 1893) ft x 19.9 ft^3/ft x .178 bbl/ft^3 x 365 day/yr x 1/5.5 days + 352 bbl + 23 bbl = 1175 + 352 + 23 = 1550 bbl/year.

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