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CHEMICAL EXPLOSIVE FRACTURING DEVONIAN SHALE KENTUCKY

First Annual Summary Report, July 1, 1976—June 30, 1977

By
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A. M. Spencer

MASTER

February 1979

Work Performed Under Contract No. EY-76-C-08-0685

Petroleum Technology Corporation
Redmond, Washington

U. S. DEPARTMENT OF ENERGY

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**CHEMICAL EXPLOSIVE FRACTURING
DEVONIAN SHALE KENTUCKY**

FIRST ANNUAL SUMMARY REPORT

For The Period

1 July 1976 through 30 June 1977

**S. J. LaRocca
and
A. M. Spencer**

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February 1979

Prepared for:

**The U. S. Department of Energy
Nevada Operations Office**

Under Contract No. DOE EY-76-C-08-0685

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ABSTRACT

This first annual report of DOE Contract No. EY-76-C-08-0685 presents the beginning efforts of a chemical explosive fracturing program to stimulate Devonian shale gas production in eastern Kentucky. A 12-year old below average production gas well was obtained as the first test well in a three well program. Selection was based on geological, off-set well and surface lineament factors. Prior to stimulation, the well was to be cleaned out and flow tested as a data base for post-shot evaluation. Initial clean out was hampered due to water inflow. It became necessary to cement in a new casing liner to seal the wellbore from the subsurface water which had corroded through the old casing. Clean out to total depth was successfully accomplished with a cable tool rig. The well is now being flow tested in preparation for chemical explosive stimulation. Gamma ray, temperature and caliper logs, and the procedures for clean out and well testing are appendices to the report.

I. INTRODUCTION AND SUMMARY

This report is a summary of the accomplishments during the first year, July 1, 1976 through June 30, 1977, under Contract No. EY-76-C-08-0685. This is a 3-well program designed to evaluate chemical explosive fracturing as a means of stimulating gas production from the Devonian shale in eastern Kentucky. The contract requires one existing well and two newly drilled wells to be stimulated.

During this period, negotiations were completed with Kentucky West Virginia Gas Company for the purchase of their Well No. 6810, referred to as Well No. 685-1, located 15 miles southwest of Hazard in Perry County, Kentucky. This well met the criteria established by Kentucky West Virginia Gas Company and DOE personnel in Morgantown for a candidate well, namely:

- 1) had been previously shot with conventional 80% gel explosive;
- 2) offset by hydraulically fractured wells;
- 3) produces at a rate below the average for the area; and
- 4) have sufficient reservoir potential and/or gas reserves to warrant a restimulation attempt.

Also, the well was located in a region where surface lineaments were present as determined by analysis of ERTS and U-2 photographs.

Prior to actual explosives operations, a broader liability insurance package was required. A search for suitable insurance was successful and Certificates of Compliance were forwarded to DOE and other 3rd party interests.

Actual work to clean out and prepare Well 685-1 for chemical explosive fracturing began in mid-March 1977. Cleanout was accomplished with a cable tool rig. Because of water leaks through the 12-year old casing, it was necessary to cement in a new liner before the cavings could be drilled up and bailed out of the well. Cleanout was completed near the end of June, and the well was ready for the long-term pressure build up and flow tests required for pretreatment evaluation of the formation.

II. MANAGEMENT

During the first 6 months of the contract, efforts were directed primarily to obtaining suitable liability insurance coverage and a satisfactory working situation for field operations involving a Kentucky West Virginia Gas Company well while the company was in the midst of a strike. These problems were satisfactorily resolved. Later a contract was let with the Lauffer Well Service Company to clean out Well 685-1 preliminary to gas flow tests prior to stimulation. The selection of Well 685-1 and its successful cleanout are described in the technical section of this annual report. Initially, there were problems with the landowner allowing the service rig on the well location, but these too were satisfactorily resolved. Details of these management actions follow.

INSURANCE COVERAGE

In late June of 1976, Petroleum Technology Corporation (PTC) initiated discussions with its existing insurance broker regarding liability insurance coverage for field testing its chemical explosive fracturing process. It immediately became apparent that obtaining this insurance was going to be a difficult and expensive endeavor with the liability market strained to its limit. Previous testing of the process had been carried out with the well owner/producer indemnifying PTC for essentially all risks and hazards involved with the actual tests. This arrangement minimized PTC's insurance requirements and allowed testing under the limited insurance coverage provided by the policy of PTC's parent company, ROCKCOR, Inc. Negotiations with ERDA and various producers and well owners revealed the necessity of PTC having broader coverage specifically tailored to its type of operations in the petroleum industry.

Initial efforts to obtain this more comprehensive coverage through the existing brokerage firm by modification of ROCKCOR's policy failed. ROCKCOR immediately extended the search by offering the bulk of the Corporation's insurance package to the brokerage that successfully came up with suitable insurance for PTC's activities. The search reached a successful conclusion in mid-December 1976. PTC now has insurance coverage consistent with its field activities as well as the requirements of the owner/producers. Certificates of Compliance have been forwarded to ERDA as well as the participating company. The direct cost for the new insurance package will be borne entirely by PTC and ROCKCOR and included in their respective indirect burden centers.

LABOR PROBLEMS

Throughout discussions regarding the test program, Kentucky West Virginia Gas Company (KWV) warned PTC and ERDA that labor contract negotiations scheduled for the last quarter of 1976 may result in a strike. KWV's field personnel actually went on strike the last of October, and this halted PTC's and ERDA's field activities involving the selection of the first test well. As the dispute continued into December with no immediate solution expected, PTC and Kentucky West personnel finalized discussions concerned with PTC buying the well for use in the test program. As the well owner, PTC would not be restricted by the strike, and field work could be resumed aimed at

selecting the first test well. PTC and KVV management reached agreement during December on the transaction and PTC purchased Well No. 6810. This arrangement also freed KVV of any liability associated with the actual chemical explosive fracturing test, which was a major factor also behind the purchase of the well. In the event that this well is not suited for treatment using chemical explosives, a second well will be selected through a similar agreement between KVV and PTC.

WORKOVER RIG CONTRACTOR

While discussions concerning the well were underway, inquiries were made to find a suitable workover rig operator. These were successful, and a satisfactory agreement was reached with Lauffer Well Service Company of Paintsville, Kentucky, to clean out the well. Also, Mr. James B. Lauffer, an independent well operator and oil and gas consultant with over 20 years experience in drilling and production of oil and gas wells in Kentucky, Ohio and West Virginia, was retained as a consultant for this field operation. On March 13, 1977, the Lauffer Well Service Company workover rig (Walker-Neer cable tool spudder) arrived on location to begin the clean out operation.

LANDOWNER RELATIONS

Problems with the landowner delayed the rig moving in on the well. The owner was quite hostile towards PTC personnel and oil and gas people in general. He would not allow a vehicle, much less a workover rig, on his property. The reasons behind his hostility grew out of misunderstandings which had occurred in the past. After a couple of meetings with PTC personnel, he consented to limited use of his land surrounding the well, which is normally planted in corn and/or potatoes, provided he would be reimbursed for the loss of crops and damage to the surface.

It is doubtful if the area surrounding the well will accommodate a rotary rig with associated air compressors, return pits, etc. Furthermore, it is reasonably certain that the noise and dust associated with a 24-hour rotary rig would be objectionable to the landowner whose home is approximately 400 feet away from the well. Therefore, any clean out of rubble necessary after the well is treated with chemical explosives will have to be done using a cable tool rig or "spudder". This should pose no real problem as far as the rubble removal is concerned, since this type of rig was used to clean out the well.

COSTS

Actual costs incurred to the government over this first year (July 1, 1976 through July 1, 1977) were \$200,388. Details were presented in Monthly Financial Management Reports, No. 1 through No. 10. The costs for the clean out operation were higher than forecasted because of the unusual problems associated with shutting off the water leaks through the old casing.

SCHEDULE

The pressure buildup (begun on July 1, 1977) and modified isochronal flow tests are expected to take 4 to 6 weeks. These tests will be followed by a longer term production test. Results from these flow and buildup tests will permit calculations to be made of the well's productivity. Flow testing should be completed by October, after which a workover rig will pull the production tubing and packer, and then run PTC's downhole equipment required to treat the well. Discussions and plans will be made to acquire sites for two new wells to be drilled to the Devonian shale to complete the contract.

III. TECHNICAL PROGRESS

SELECTION OF CANDIDATE WELL

Technical efforts through January 1977 for this contract have been concentrated on the selection of an existing well which is suitable for treatment using PTC's chemical explosive fracturing process. In accordance with criteria established by KWV and ERDA personnel in Morgantown, this well should be a well which: 1) had been previously shot with conventional 80% gel explosive; 2) offset by hydraulically fractured wells; 3) produces at a rate below the average for the area; and 4) have sufficient reservoir potential and/or gas reserves to warrant a restimulation attempt. In addition, the surface area surrounding the well must be large enough to accommodate necessary equipment as well as PTC's three vehicles. Finally, if practical, lineament plats prepared from ERTS and U-2 photographs should be employed to assist in selecting the test well.

Well files on several wells which fell into the above categories were reviewed, followed by on-site inspections of the better candidate wells. As a result of these efforts, Well No. 6810 in Perry County near the community of Hazard, Kentucky, emerged as the best candidate for the first test. Aside from being favorably located near access roads, it has a large enough location to accommodate the required equipment and is offset by hydraulically fractured wells. In fact, it is offset approximately 2,200 feet to the northeast by KWV's Well No. 7246, which was recently foam fractured under an ERDA contract. It is reported that, after treatment, Well No. 7246 recorded an open flow of 366 MSCFPD and had a shut-in surface pressure of 540 psig. Gas production from Well No. 6810 was turned into the pipeline in December 1965. Through September 1976, the well produced a total of 32 MMSCF of gas, and was reported to be producing at a rate of 9 MSCFPD when shut in the last of September for bottom hole pressure surveys. Figure 1 is a map of the test area and shows Well No. 6810 (for contract purposes now referred to as Well No. 685-1) and No. 7246 as well as other offset wells and inactive mines in the vicinity. The area map was copied from the central portion of the Vicco Quadrangle topographic map which is in southeastern Kentucky.

Interpretation of ERTS and U-2 photographs over the Vicco Quadrangle indicate the presence of surface lineaments in the vicinity of Wells No. 685-1 and 7246. Further investigation is under way to compare the gas producing characteristics of existing wells in area to an overlay lineament plot. This study should indicate if there is a correlation between the lineaments in the area and well productivity.

SCREENING SURVEY

During a meeting held in late September 1976, representatives of ERDA, PTC, and Kentucky West established guidelines for a screening survey to be conducted on Well No. 685-1. This survey would provide information needed before deciding if Well No. 685-1 would be selected for the first test under this contract. Aside from providing bottom hole pressure data, the survey required that the well be worked over and an inflatable packer run and set in the well in order to isolate the Devonian

SECTION OF TOPOGRAPHIC MAP
SHOWING WELL LOCATION

shale section from other zones in the wellbore. The essential steps of this screening survey are presented in Appendix A, which is the procedure to evaluate and clean out the well, plus wellbore diagrams of the well as it exists now and as it will be after the inflatable packer is in place.

A pressure survey, conducted late last year, indicated Well No. 685-1 had shut-in surface and bottom hole (at 3,200 feet) pressures of 337 psig and 454 psig respectively, after being shut in for about 17 days. A subsequent reading, taken after the well had been shut in for approximately 60 days, shows that the surface pressure had increased to 392.5 psig, which is only about 150 psi lower than its original pressure and the current pressure of offset Well No. 7646. The pressure survey also indicated the presence of about 250 feet of liquid, assumed to be 40° API oil, in the bottom of the well. Since the Devonian shale is not known to produce oil or water, the liquids must have entered the wellbore through the open hole section above the shale. Aside from creating unnecessary backpressure on the shale, the liquid has probably caused reservoir skin damage which could further account for the poor producing performance of this well.

A subsequent bottomhole pressure survey conducted February 16, 1977 while the well was flowing, substantiated the findings of the ERDA survey. Figure 2 is a plot of the pressure data obtained during the February survey, and it shows a gas-oil interface at 2,875 feet. As postulated previously, the oil must have seeped into the wellbore from the open hole section (probably from the base of the Big Lime). Figure 3 illustrates the downhole configuration of the well as originally completed and as it existed at the time of pressure surveys.

CLEANOUT OPERATIONS

A spudder-type workover rig belonging to Lauffer Well Service Company of Paintsville, Kentucky, moved in and rigged up on March 13, 1977. Prior to pulling the production tubing and packer, the well was vented into a stock tank and swabbed to remove the oil which had accumulated in the bottom of the well. According to information received from Kentucky West Virginia Gas Company, the well was flowing into their pipeline at a rate of 9 MCFPD against a line pressure of approximately 140 psig. (The line pressure was approximately 100 psi in February when BHP survey was run.) When routed into a nearby stock tank for 2 hours, the well unloaded one-half barrel of light green oil. The well was shut in overnight and the surface tubing pressure increased to 209 psig in 18 hours. After unloading an additional 1/4 barrel of oil into the tank, the well was tested using a 2-inch pitot tube-manometer gauge. While flowing through the gauge and venting to the atmosphere, the well had a measured flow rate between 60 and 70 MCFPD (0.2 in water). Three swab runs to 3,150 feet recovered an additional barrel of oil; and the third run failed to recover any oil. Gas flow from the well was measured at rates of 84 MCFPD with 2-inch pitot gauge and 125 MCFPD with a 1-inch pitot gauge. The well was shut overnight, and in 15 hours the surface tubing pressure climbed to 210 psig. Resumption of swabbing operations to a depth of 3,200 feet yielded another 1/4 barrel of oil, which was dark green and viscous; thus, about two barrels of oil were recovered from the well during the blowdown and swabbing efforts. Flow tests taken with a critical prover showed the well was making 34.3 MCFPD through a 1/8-inch orifice plate with 69 psig pressure, and 65.1 MCFPD through a 1/4-inch plate with 24 psig pressure. Measurements taken with the 1- and 2-inch pitot tubes showed a maximum flow of 75 MCFPD.

PRESSURE DEPTH FROM FEBRUARY 1977 SURVEY
(WELL FLOWING)

**PTC WELL NO. 685-1 PERRY COUNTY, KENTUCKY
WELL BORE DIAGRAM PRIOR TO WORKOVER**

It required 2-1/2 days to pull the tubing and compression packer, as the packer would not release. The broken packer and all tubing were brought to the surface on March 19. Gas flowing up the tubing ceased to flow almost immediately when the packer released, and all signs of gas flow had vanished by the time the tubing was pulled. A 6-inch bailer was run into the well and tagged bottom at 3,090 feet; thus, approximately 140 feet of cavings (based on bottom of tubing at 3,222 feet) had fallen in the borehole when the packer and tubing were pulled. In addition, 400 feet of water was found on top of the cavings. Evidently, water had been leaking through the casing for some time and filled the annulus above the packer. Thus, when the packer released the water fell to the bottom and halted all gas flow. The shale continued caving in the hole at such high rates that the hole began to fill up in spite of drilling and bailing efforts. In fact, after 5 days, the hole actually filled up 213 feet to 2,877 feet. Progress improved when the rig went on 24-hour operations. The improvement was short-lived, however, as the water flow increased from 20 to 70 gallons per day and all cleanout progress stopped. At this time the well had been cleaned out to 3,030 feet, still some 230 feet above the original TD.

Efforts to stop or reduce the leaks by squeeze cementing and tightening the 7-inch casing string failed. Two cement squeeze jobs were attempted. In the first attempt, the casing was perforated at 2,295 to 2,300 feet, and circulation established through the perforations and up the 7-inch annulus to the surface with water and gel prior to starting the cement in the well. After displacing 54 sacks of 50/50 Pozmix Class "A" cement through the perforations, an apparent cement bridge outside the casing halted pumping operations. After cleaning out the cement, leak checks were made and water was found to still be leaking into wellbore at the same rate of 70 gallons a day. A cement bond log was run and the top of the cement was determined to be at 1,684 feet. On the assumption that the water could be leaking through a casing collar, the 7-inch casing was "torqued up" approximately 30 turns until it would "spring back". Although this effort tightened and shortened the casing 3 inches on the surface, it failed to alter the rate of water inflow into the well. Perforations were made in the 7-inch casing at 1,668 to 1,673 feet for the second squeeze attempt. After circulating 55 barrels of gel to the surface, 312 sacks of 50/50 Pozmix "A" cement were pumped through the perforations with stringy returns to surface. The casing was cleaned out to 2,238 feet, and leak checks revealed the water influx below 700 feet in the casing ranged from 56 to 240 gallons per day at 2,238 feet. Apparently, corrosion of the uncemented casing over the past 12-1/2 years had been severe and widespread.

At this point, alternate ways of stopping the water influx were considered. Aside from attempting another squeeze job, considerations were given to using casing patches or installing a full liner inside the old 7-inch casing. Since corrosion was so widespread (ranging from 700 to 2,300 feet) and difficult to pinpoint, the use of liner patches was not practical. A 10-foot-long patch costs \$10,000 to install. The most cost effective and positive way to proceed was with the full liner. The liner would have to be a 7-inch by 5-1/2-inch tapered string, since the mixer and dual tubing strings employed in PTC process cannot be run in casing smaller than 7 inches. The use of a tapered string would necessitate cutting and pulling 200 feet of the old uncemented casing. This approach was discussed with MERC and Las Vegas Operations Center and verbal approval was given to proceed with the liner. The details associated with this plan of attack are given in Appendix B, which is a "Revised Procedure to Clean Out and Test Well No. 685-1, dated May 7, 1977.

Pipe was ordered for the new casing, and the cement and bridge plugs from the previous squeeze attempts were drilled out. Correlation logs consisting of the gamma ray, caliper and casing collar locator curves were run to determine where to set the open hole bridge plug and where to cut the existing 7-inch casing. Competent rock for setting the bridge plug was found no lower than 2,609 feet and the plug was set there. The collar log indicated the old casing could be safely cut at 195 feet. A linear shaped charge explosive cutter was lowered to 195 feet and successfully cut the casing. The cut section of casing was pulled, and a 2,570-foot liner was run into the well. The liner consisted of 2,390 feet of 5-1/2 inch, 15-1/2 pound casing, 1 foot long, 7-inch by 5-1/2-inch swage, and 179 feet of 7-inch 20 pound casing. The casing was cemented back to the surface with 220 sacks of Class "A" cement. After the cement cured, the liner was bailed dry and the retainer and cement plug were drilled out. Seven days were required to drill out retainer, 65 feet of cement and the cement plug.

On May 21, drilling and bailing of the open hole below the new liner began. Leak checks with bailer revealed the water influx into the hole had been stopped. The drilling tools would go no lower than 2,924 feet, indicating that a little over 100 feet of fill-up had occurred during the liner job. Gas flow was measured with the 2-inch pitot tube-manometer and found to be 25 MCFPD.

During the early morning hours of May 23, the tools were lost in the well with about 50 feet of drilling line. However, the tools and line were recovered on the second fishing trip, using a two-prong grab, later the same afternoon.

The remainder of the cleanout effort was accomplished using 5-inch tools. After 7 days, only 60 feet of cavings had been cleaned out and the hole was still sluffing, even though the water had been shut off for over 2 weeks. A sodium silicate solution, known by several descriptive names (Linko, No Heave or Cave Stopper), was then spotted and poured in the well at regular intervals. Sluffing stopped and faster cleanout was possible.

By the 23rd of June the well was cleaned out to 3,244 feet, which according to the original drilling records was 14 feet below the base of shale. A drastic reduction in drilling rate occurred at this depth, indicating the slate below the shale had been reached. Cuttings were used to verify the depth and drilling operations were stopped and preparations made to log the well.

LOGGING OPERATIONS

As set out in the May 7 Procedure (Appendix B), it was proposed to run the gamma ray, density, caliper and temperature logs once the hole had been cleaned out. The density log could not be run safely through the 5-1/2-inch casing, since its drift diameter was smaller than the recommended minimum hole size for the logging tool. Furthermore, the "washed out" larger hole diameter expected through the shale section would cause the density to be inaccurate to the point of almost being useless. Consequently, only the GR, caliper, and temperature logs were run in the well. The GR tool picked up two "hot spots" at 3,218 feet to 3,196 feet, and 2,900 feet to 2,892 feet, which tend to be characteristic of the Devonian shale; while the dual pad caliper tool indicated the diameter of the open hole below the 5-1/2-inch liner ranged from just under 7 inches to in excess of

18 inches. The temperature log showed cooling effects at approximately 2,835 feet, 2,985 feet, and 3,070 feet, indicating possible gas entry points into the wellbore. An abrupt shift in the temperature curve at 3,225 feet indicated a gas-liquid interface. The logging tools reached a maximum depth of 3,241 feet or 3 feet shallower than the drilling measurements. The maximum bottom hole temperature recorded was 94°F. From interpretation of the GR and caliper logs, the best possible interval to set the Lynes PI inflatable packer was 2,622 to 2,630 feet. Copies of the 2-inch to 100-foot logs are attached as Appendices C and D.

TEST OPERATIONS

Preparation for the production and reservoir tests followed interpretation of the logs and began by running the production equipment in the well. A Lynes PI inflatable packer was run into the well on 2 3/8-inch steel tubing and set in the open hole at 2,627 feet (tubing measurement). At this setting depth, the packer would isolate the base of the Big Lime from the Devonian shale section. The packer would thus prevent Big Lime oil from dropping on and damaging further the shale, as well as Big Lime gas from commingling with gas from the shale, resulting in erroneous production data.

Figure 4 illustrates the existing downhole configuration of the well as it is prepared for testing.

After the tubing was landed in the wellhead on June 30, the gas flowing through the tubing was measured with a 2-inch pitot gauge at 60 MCFPD. The well was shut in overnight and the surface tubing pressure increased to 150 psig in 13-1/2 hours. The well pressure was bled down and a bottom hole pressure gauge was run into the well and positioned at 3,150 feet. The well was shut in at 1,325 hours on July 1 for an extended pressure buildup test.

Recent discussions with Al Yost and Don Evans of MERC have given rise to changes in the well testing procedure, as presented in steps 19 through 24 contained in the May 7 Procedure, Appendix B. These changes have been incorporated into an updated pretreatment test procedure (Appendix E). The data gained from this test procedure should provide an insight into such reservoir parameters as maximum reservoir pressure, pressure drawdown, gas deliverability, Kh and skin damage effects. These pretreatment parameters would then be compared to similar characteristics obtained after the shale section is subjected to chemical explosive fracturing.

COMPATIBILITY TESTS

Samples of downhole materials were obtained during the cleanout operations for compatibility tests with PTC-4 explosive. These samples were light green oil, dark greenish-black sludge or grease, salt water and shale cuttings. Each material was added to PTC-4 (approximately 10% sample and 90% explosive) and heated to 230 to 240°F for 48 to 96 hours. At the conclusion of each test, no evidence of a reaction was detected (color change, exotherm, pressure rise), and all materials are compatible and stable with the explosive.

Additional compatibility tests will be run on untested materials as required. Preparations are being made to test the sodium silicate-water solution used to stabilize the borehole during cleanout. Similar materials have been compatible and no hazardous reactions are anticipated.

**PTC WELL NO. 685-1 PERRY COUNTY, KENTUCKY
COMPLETED FOR PRODUCTION TESTING**

APPENDIX A
PRELIMINARY WORK SCHEDULE
PTC WELL NO. 685-1
Perry County, Kentucky

1. Move in and rig up wireline unit and lubricator on well. Open master valve and record surface shut-in pressure. Run gauge through 2 3/8-inch tubing, making 10 to 15 minute gradient stops as follows:

2,300 feet
2,500 feet
2,700 feet
2,900 feet
3,100 feet
3,150 feet
3,200 feet (lowest depth to run gauge. BOT @ 3,228 feet)

Note: Liquid level from previous pressure survey is estimated to be at approximately 3,000 feet. Leave gauge at 3,200 feet for 30 minutes to get shut-in bottom hole pressure in well. Refer to Figure A-1 for present well bore data.

2. Improve lease road and location as necessary. Move in workover rig or spudder and necessary tanks. Rig up and swab the well. Gauge the recovered liquid and obtain a sample of well fluid from each swabbing trip (save samples).
3. Pull the tubing and the compression set Butler-Larkin packer.
4. Clean out the well with a bailer or sand pump to original T.D. eg. 3,267 feet.
5. Move in and rig up logging unit and run gamma ray/density, caliper and temperature logs from bottom of the hole to the bottom of the 7-inch casing, approximately 962 feet of open hole.
6. Interpret logs to ascertain fluid entry points and determine where to set a Lynes inflatable packer.
7. Fill approximately 25 feet of rat hole with gravel and then cap with approximately 10 feet of cement to plug back to the bottom of the brown shale at 3,230 feet. (Use logs and correlate to driller measurements.)
8. Rerun tubing with end plugged and perforated joints on bottom. Set Lynes inflatable packer at lowest depth determined by logs. Refer to Figure A-2 for approximate wellbore data. Packer

**PTC WELL NO. 685-1 PERRY COUNTY, KENTUCKY
WELL BORE DIAGRAM PRIOR TO WORKOVER**

**PTC WELL NO. 685-1 PERRY COUNTY, KENTUCKY
WELL BORE DIAGRAM AFTER WORKOVER**

should be set as close to the top of the brown shale as practical to protect the shale from exposure to fluids from higher formation in the wellbore. Make swab run to recheck liquid accumulation in bottom of well.

9. Rig down workover unit and move off location. Shut in well until meter is installed and reservoir testing procedure has been finalized with ERDA personnel.

APPENDIX B
REVISED PROCEDURE
TO CLEAN OUT AND TEST WELL NO. 685-1
Perry County, Kentucky
May 7, 1977

1. Drill out cement inside 7-inch casing to 2,230 feet, top of upper plug (see Figure B-1).
2. Add water if necessary to be 400 feet above plug, then drill out upper cement plug. If gas pressure is relieved, bail casing leaving only sufficient water to drill lower cal seal and lower open hole plug.
3. Dress bit to 6.4 inch and clean sides of 7-inch casing of cement from top to bottom.
4. Resume drilling/bailing of shot hole with 5-inch tools and bailer until logging unit arrives. Prepare well to set plug near base of Big Lime, about 2,595 feet.
5. Run gamma ray and caliper log from 2,200 feet to top of fillup in shot hole. Determine location of Big Lime, Injun and Brown shale. Determine where to set open hole plug near base of Big Lime or in Injun. Measure gas flow rate with pitot tube/manometer, 1-inch swage. May be no gas flow due to water inflow.
6. Set plug at desired depth (about 2,630 feet).
7. Place 25 feet of cal seal on top of plug (40 gal.). Wait 2-1/2 hours to set, then tag bottom with bailer. While waiting, verify that gas flow has been shut off (use pitot tube/manometer, 1-inch swage).
8. Run in hole with 7-inch casing cutter. Cut at 190 ± 5 feet. Pull the 7-inch casing out of well.
9. Run new casing in hole. This string of pipe will consist of a combination guide float shoe on the bottom joint, approximately 2,420 feet of 5 1/2 inch, 15 1/2 lb/ft casing, topped with a 7 x 5-1/2 inch swage plus 180 feet of 7-inch, 20 lb casing. The completed string of casing is to be 5 to 10 feet above the cal seal plug, with the swage 5 to 10 feet above cut of existing 7 inch and the new 7-inch casing to rise 1 to 2 feet above the 10 inches. Centralizers are to be placed on the first 5 1/2-inch joint going into the well, and then the 3rd, 6th, 9th and every 9th joint going up the string. Proper spacing is to be achieved by using short joints of 5-1/2 and 7 inches. The completed casing is shown in Figure B-2.
10. Run tubing in hole with cement retainer on bottom joint. Spot the retainer in the lower 15 feet of the first joint of 5-1/2 inches just above the guide shoe. Re-establish circulation with

PRESENT STATUS OF WELL NO. 685-1 PERRY COUNTY, KENTUCKY MAY 7, 1977

WELL NO. 685-1 CEMENTING LINER INPLACE

water, followed by gel and finally cement. Use 235 ft³, this is 15% excess to bring cement to surface. Tail in with water to within 100 feet of retainer (10 bbl). This should bring cement to surface, but if not, do not run in any more water. The cement is shown going down tubing and up the 7 x 5 1/2-inch annulus in Figure B-2.

11. Pull tubing out of retainer, reverse out excess cement and out of hole. Wait 16 hours for cement to set.
12. Bail hole dry of water. Then drill out retainer, cement, cal seal and cement plug. When drilling out cement plug, add 400 feet of water to casing to partially check gas pressure and flow. As soon as gas pressure is relieved, bail remaining water from casing. Then complete drilling out of plug.
13. Clean out shot hole with 5-inch tools to T.D (3,267 feet).
14. Move in logging unit and run gamma ray density caliper and temperature logs from T.D. to bottom of 5 1/2-inch casing, approximately 670 feet of open hole.
15. Interpret logs, ascertain gas entry points and determine where to set Lynes inflatable packer (near top of brown shale, 2,835 feet).
16. Slowly pour gravel down casing to fill rat hole to 3,245 feet and cap off with 15 to 20 feet of cement to base of brown shale (use logs and correlate to drillers measurements).
17. Rerun tubing with end plugged and perforated joints on bottom. Set Lynes inflatable packer at lowest depth from log analysis. Refer to Figure B-3 for approximate wellbore data. Packer should be set as close to top of brown shale as practical to protect shale from exposure to fluids entering wellbore from higher formations. Swab to check liquid accumulation at bottom of well. Measure open flow with pitot tube/manometer using 1- and 2-inch pipe.
18. Rig down workover unit and move off location.
19. Hook up critical flow prover pipes and lubricator to wellhead. Run B.H.P. bomb with 3 or 4 day clock into well with well flowing.
20. Install 1/8-inch orifice in prover. Flow well through prover. Use 24- or 72-hour chart and clock, monitor prover pressure, calibrate while on line using dead weight tester. (Prover pressure must be greater than 20 psig and less than 100 psig. Change orifice plate to stay within these limits.) Pressure should stabilize ± 2 psig in 24 hours. If these conditions, variations in pressure of ± 2 psig over 24 hours, are not met in 3 days, contact ERDA (Al Yost).
21. Data from this 1/8-inch orifice test will be used to establish basis for modified isochronal flow tests. Generally these tests will consist of shutting in well for 24 hours followed by a 24-hour flow test. The orifice plate will be selected so as to provide flow rates which double that of the

WELL NO. 685-1 COMPLETED FOR PRODUCTION TESTING

preceding test, i.e., if first test was 5,000 ft³/day, then the second test would be at 10,000 ft³/day, and the third test at 20,000 ft³/day, etc. The B.H.P. bomb will be run in and out of well at selected intervals to verify operation.

22. Change chart and clock to 7-day version. With well flowing, run in B.H.P. bomb. Shut-in well for 7 days, monitoring surface pressure as well. Calibrate surface pressure recorder with dead weight tester every 2 to 3 days during test. POH with B.H.P. bomb and change charts. Run B.H.P. bomb to bottom of well and continue test for an additional 7 days.
23. After conclusion of pressure build-up test, open well to sales line and install chart on sales meter.
24. Evaluate flow rate and pressure build-up data and schedule explosive stimulation treatment.

APPENDIX C – GAMMA RAY AND CALIPER LOG
WELL NO. 685-1

Schlumberger

TEMPERATURE LOG

COUNTY
FIELD
LOCATION
WELL

COMPANY

COMPANY PETROLEUM TECHNOLOGY CORP.

WELL #6810

FIELD NA

COUNTY PERRY STATE KENTUCKY

LOCATION NA Other Services: GR/CAL

Sec. Twp. Rge.

Permanent Datum: GROUND LEVEL; Elev.: NA

Log Measured From DE 3 Ft. Above Perm. Datum

Drilling Measured From DE

Elev.: K.B.
D.F.
G.L.

Date 25 JUNE 77

Run No. ONE

Depth-Driller 3244

Depth-Logger 3241

Btm. Log Interval 3240

Top Log Interval 2490

Casing-Driller 5 1/2 @ 2595

Casing-Logger NA

Casing Size 1 5 1/2 To 2595 To To

Casing Size 2 7 To 160 To To

Casing Weight 1 NA

Casing Weight 2 NA

Casing Thickness 1 30

Casing Thickness 2

Bit Size 1 5 To 3244 To To

Bit Size 2 To To To

Type Fluid in Hole AIR

Dens. Visc.

Time Since Circ. NA

BHT 94°F

Equip. Location 7659 PAINT

Recorded By FURCELL

Witnessed By MR. CONNELLEY E. MALANEE

REMARKS: S.O. # 34174 Expenditure: Casing Drilling / Temperature

The well name, location and borehole reference data were furnished by the customer.

CEMENTATION DATA

Nb of Sacks

Additives

Calculated Top

Depth

Date

APPENDIX D – TEMPERATURE LOG
WELL NO. 685-1

APPENDIX E
PRESSURE BUILDUP AND FLOW TEST PROCEDURE*
FOR WELL NO. 685-1
PRIOR TO EXPLOSIVELY FRACTURING WITH PTC'S PROCESS

1. Hook up critical flow prover with plugged end cap and wireline lubricator to wellhead. Hook up ERDA's 3-pen Foxboro recorder to tubing and casing as shown in Figure E-1. Run Amerada bottom hole pressure bomb into well to 3,150 feet with well flowing. Use 7- or 8-day clocks. Accurately position 7-day chart on Foxboro recorder and note time/date of start of test on chart. Shut in well and observe recorder for proper operation (pressure increasing on tubing pen). Check for gas leaks at all connections and tighten where necessary. (Completed July 1, 1977.)
2. Continue pressure buildup survey until pressure stabilizes, less than 0.1% change in 30 minutes (approximated by less than 5% change in 24 hours). This is estimated to require 3 to 4 weeks. At conclusion of extended pressure buildup survey, POH with B.H.P. bomb and install, if available, a 48-hour clock; if not, use a 72-hour clock. Run B.H.P. bomb back down to 3,150 feet. (In progress as of July 1, 1977.)
3. Each week wind clock and change chart on Foxboro gauge. Pull B.H.P. bomb out of well, remove pressure/time chart and run bomb back down to 3,150 feet.
4. Close wing valve to critical flow prover. Install 0.0625-inch orifice plate. Change chart rotational speed switch to 24-hour position (switch is beneath chart plate) on Foxboro recorder. If surface pressure is less than 500 psig, relocate tubing pressure line to 500 psi element, otherwise continue with 1,000 psi element. Wind clock.
5. Slowly open wing valve to prover. Note exact time test begins. Allow gas to flow for 3 hours. Observe if pressure has dropped about 5%, if it has, then shut in well for 3 hours, using wing valve. If not, then continue flow test for another hour, then shut well in for 4 hours. Record gas temperature throughout test while gas is flowing.
6. While well is shut in change to 0.0937-inch orifice plate. At end of shut-in period, 3 or 4 hours, open valve to prover. Let well flow for same time period as first test. Then shut well in for same time. Verify tubing pressure data with occasional dead weight tester measurements.

*This procedure updates the Revised Procedure, May 7, 1977, and reflects additional insight gained from discussions with Al Yost and Don Evans of MERC and observations made during the modified isochromal testing of KWV Well No. 1627 near Busy, Kentucky. It replaces steps 19 through 24 in the Revised Procedure (Appendix B).

PRESSURE BUILD-UP AND FLOW TEST SET-UP

7. Repeat this constant time interval flow and shut-in test with increasing diameters of orifice plates, 0.125 and then 0.250. At the end of the flow test with the 0.250 orifice plate, the pressure should be 25% less than the maximum surface buildup pressure. If not, run one more test with the 3/8-inch orifice plate.
8. Shut well in. POH with B.H.P. bomb and change to 7- or 8-day clock. Run bomb back down to 3,150 feet. Change Foxboro recorder rotational speed switch back to 7-day operation. Remove critical flow prover and connect well to KVV's gathering system. Verify that all valves are positioned so that gas will flow to stock tank or blow gas from the pipeline through the surface line and back to Well 6810 so that no air is in gathering lines. Place 3/8-inch orifice plate in line and hook up standard 2-pen recorder with 500-psi static 100-inch differential elements to monitor pressures upstream and downstream of orifice plate. If necessary, open valve and blow into stock tank for 5 minutes to clear lines of air, then turn valve so that gas is being delivered to KVV's pipeline.
9. Continue to monitor well B.H.P. bomb for 2 weeks. Verify that pressure has stabilized (less than 0.1% pressure change in 30 minutes). If not, continue test for an additional 7 days.
10. After flow stabilizes, POH with B.H.P. bomb, close swab valve, remove lubricator and release wireline unit.
11. Evaluate flow rate and pressure buildup and schedule explosive stimulation treatment.