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MEASURING WELLBORE HEAT LOSSES IN ACTIVE STEAM INJECTION WELL

FINAL REPORT

By
B. V. Traynor

April 1992

Performed Under Contract No. DE-AC22-89BC14260

Kawasaki Thermal Systems, Inc.
Tacoma, Washington
Bakersfield, California

National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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

Thomas B. Reid, Project Manager
Bartlesville Project Office
P. O. Box 1398
Bartlesville, OK 74005

Prepared by
Kawasaki Thermal Systems, Inc.
Tacoma, Washington
Bakersfield, California

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1.0 EXECUTIVE SUMMARY

Many things can change between the original concept of a program and its ultimate execution. However, in the cae of this "Wellbore Heat Loss" Program the original objective has been constant. This objective was stated in late 1988 as follows:

> "Establish a body of valid heat loss data from an active steam injection well. This data will be used to validate a comprehensive wellbore heat loss software program. The software developed must be user friendly and must accurately estimate wellbore heat losses for a wide range of operational thermal EOR parameters and well completions."

There were delays in project start-up. Contractual authority was effective just prior to the beginning of government fiscal year 1990. There were also major delays in the conduct of the well site test program. Nevertheless, the original objective has been achieved. A large body of test data was obtained from an instrumented test well and the wellbore heat loss software system has been developed, validated and delivered.

A project team was organized to execute this program. The contractor, Kawasaki Thermal Systems (KTS) of Bakersfield, California and Tacoma, Washington, and its subcontractors: Texaco Producing Inc., Bakersfield Producing Division, and Scientific Software-Intercomp (SSI) comprised the project team. KTS managed the program, designed and fabricated and installed all test well instrumentation and data handling systems and reduced test data for use by SSI. Texaxo provided the well site, drilled the test well and completed and operated the steam injection test cases. SSI developed and verified the wellbore heat loss model.

The following approach was established to accomplish the program objectives:

- An instrumented test well was completed in the Kern River Field, Bakersfield, California.

- Six steam injection test cases, utilizing instrumented completions were run in the test well to establish the wellbore heat loss data.

- A wellbore heat loss model was developed. This model was verified and calibrated with the data from the test well. This model constitutes the ultimate program deliverable.

The test well was drilled and instrumented in April 1990. Steam injection testing began in June 1990. There were many delays in the operation of the steam injection test cases. The final test was completed in late January 1991. The downhole instrumentation performed very well throughout the entire series. This is true of the instrumentation installed on the O.D. of the casing string as well as that fixed to the individual steam injection strings. The casing instrumentation provided continuing service over a nine month period.

The test program included tests with six different steam injection string configurations - wellbore data was derived from each test series and this data was formatted for use in validating the wellbore heat loss software system SIMSTEAM.

The end products of the software development task were the user friendly SIMSTEAM system and the SIMSTEAM USER'S GUIDE. This system can be run on any IBM compatible computer. A hard disk is not necessary.

2.0 INTRODUCTION

This report describes the program in terms of the three tasks which were established to organize and direct program effort. KTS, Texaco and SSI responsibilities were defined on a task by task basis.

2.1 TASK 1 - A Survey of experience with the measurement, prediction and analysis of wellbore heat loss was conducted to provide information for both the Test and Measurement and Software Development tasks within the first few weeks of the program. The survey employed contacts throughout the thermal EOR industry and a review of literature, describing both Test and Measurement programs and Wellbore Heat Loss software.

KTS and SSI were the principal pariticipants. The results of this preliminary work were directed to Tasks 2 and 3. The information obtained on heat loss measurement techniques and instrumentation was utilized in the definition of test well instrumentation systems. This part of the survey was conducted by KTS. SSI reviewed existing models and algorithms. The results were utilized to outline the approval to Task 3 software development.

The survey task methodology and results are described in Section III.

2.2 TASK 2 - Test and Measurement was the most visible phase of the program. A multiphase test program was designed with the objective of obtaining valid wellbore heat loss data from a series of injection configurations. This data was utilized to aid in the development and verification of the software program. The requirement that data produced in this task be optimized for use in software program validation was of paramount importance and was the central controlling issue guiding test planning and instrumentation design.

The centerpiece of this task was the instrumented test well, instrumented injection strings and the attendant data collection capability.

The test well was located in Texaco's Cordes Lease at Kern River Field in Bakersfield, California. This well was very thoroughly instrumented.

- Thermocouples were installed on the casing O.D. at 100' intervals.

- Three, ten-foot long, casing instrumentation subs were fabricated and run into the well as a part of the casing string at 250' intervals. These subs utilized heat flux sensors to measure directly the heat transferred from the well to the earth.

- A 1.99" sidestring was run in the well on the O.D. of the casing to permit temperature surveys during each test case.

- Each steam injection string was instrumented with thermocouples at 100' intervals and included one or more heat flux sensors.

In addition to the data obtained from this downhole instrumentation, temperature and pressure logs were run. Steam temperature, pressure, flow and quality were measured and controlled at the wellhead. All downhole and surface data was recorded.

This instrumented test well was operated over an eight month period - June 1990 through January 1991. The instrumentation proved to be very effective and durable. The instrumentation system was effective in that large volumes of accurate downhole temperature and heat flux information were obtained. This information was useful and interesting in and of itself, as a means of comparing performance of the several steam injector configurations. In addition, it did serve the basic program objective of validating the Task 3 well bore heat loss software system.

KTS designed, fabricated and installed the instrumentation and the data retrieval and handling systems. KTS also formatted all data for use in Task 3. Texaco provided the well site and all surface facilities

and drilled the test well. Texaco also completed the well with the several steam injector configurations and operated the steam injection tests.

The Test and Measurement Task is discussed in detail in Section III.

2.3 TASK 3 – Software Development was the primary end product of this DOE project. There were two objectives upon which this software program development was based. These objectives were satisfied.

1) The program provides accurate, verified predictions of the wellbore energy loss to be expected in a steam injection well over a wide range of possible combinations of completions and operational conditions.

2) The program is user friendly and capable of running on widely available IBM compatible computers.

SSI produced the SIMSTEAM software system. The system was verified utilizing test data developed on Task 2.

The software system development is described in Section III.

In addition to a description of the work accomplished, conclusions as to the impact of program accomplishment and recommendations as to future work are provided. Finally, the summarized test data developed in Task 2 and the Task 3 tables of calculations are provided in separate volumes as Appendices to this report.

3.0 DESCRIPTION OF EFFORT

The work accomplished on each task is described in terms of plans, work conduct and results achieved. A task-by-task discussion follows.

3.1 TASK 1 SURVEY AND PROBLEM ASSESSMENT

3.1.1 Summary

The objective of this Survey and Problem Assessment Task was to establish through literature searches and direct contacts the extent to which existing knowledge and experience could be applied to requirements of the Well Bore Heat Loss Measurement Program. This survey activity was directed to two discrete areas.

- Instrumentation for the determination of well bore heat losses.
- Modeling of wellbore heat losses.

Information was developed from within the Kawasaki Thermal Systems, Texaco, Scientific Software team; from industrial sources and from government and academic sources.

The purpose of the survey investigations was to establish a baseline of outside and previous experience to maximize the potential for avoiding previously identified pitfalls and to insure as far as possible that the lessons learned by previous investigators were incorporated in the approaches taken under this contract in Task 2, Test & Measurement and Task 3, Software Development.

The survey was conducted in two parts. Kawasaki Thermal Systems surveyed the results of previous programs designed to instrument and obtain data from steam injection wells. Scientific Software screened public literature to identify the approaches taken by previous investigators in the development of well bore heat loss models.

In the survey of well bore heat loss measurement techniques and instrumentation, contacts were made with industrial, government and academic sources having a background in enhanced oil recovery. As the result of these contacts, a number of specific recommendations relative to instrumentation, attachment techniques, and instrumentation deployment techniques, were obtained. These recommendations were highlighted for consideration in the definition of the Task 2 instrumentation.

A 5700' instrumented well was completed by Vertec, in Longmont, Colorado, for their patented Vertical Tube Reactor (VTR) process. Although this was not a steam injection process, 670°F fluid was injected downhole and casing temperatures were monitored. The results of this work have not been reported, due to the private nature of the processes. However, telephone interviews were conducted on Vertec's experiences and processes.

The review, conducted by SSI, of literature published on the development of modeling applicable to wellbore heat loss and steam injection wells also involved a range of industrial and government sources. As a result of this survey, a series of specific recommendations were established to help define the software development to be carried out under Task 3.

3.1.2 Test Well Design and Instrumentation

3.1.2.1 Discussion

Contact was made with the major sources of technical information in the EOR industry, including major operator research laboratories, universities and government agencies. Five areas of interest were discussed with each contact:

- The instrument utilized in downhole applications, particularly temperature measuring devices, heat flow sensors and steam quality measurement instruments were discussed.

- Attachment techniques utilized to assure the integrity and reliability of both casing and tubing instrumentation was reviewed.

- Logistics involved with well completion and run-in techniques were reviewed to assure that instrumentation was installed in a manner to insure long term integrity.

- Test results were discussed to determine the success and significance of the program. The availability of formal or informal reports of the results of the test and evaluation programs was established.

3.1.2.2 Results

Results of the survey may be categorized in several areas.

Instrumentation

Concerns about types of thermocouples wire, gage, and coverings were expressed by several respondents. Long operational life of Thermocouples and heat flow sensors in a hot, wet environment, requires careful selection and installation. Certain thermocouple manufacturers were identified as preferred because of their work with downhole thermocouple applications. Notably, Gordon Company's product was recommended, with Kapton insulation, type J wire. Another recommended source was Omega Company's product which incorporates stainless steel sheathing on the type K thermocouple.

New fast acting heat flow sensors were identified. They provide rapid response and include an improved design thermopile capable of temperatures up to 1000°C. These devices are based on the computer microchip technology. Detailed information on heat flux sensors' accuracy and capabiltiy is provided in Appendix 1.

Attachment Techniques

Respondents advised that temperature sensors must be attached and protected from undue stretching forces and from damage by the sides

of the hole/casing. The attachments must also be made so as not to abnormally affect heat flow in the attachment areas.

Details on attachment techniques used by Aschilman and other investigators are described in the Appendix 1 and AOSTRA papers Appendix 1#. Also, considerable unpublished knowledge and information was available from Vertec.

Well Completion and Run-in Techniques

Several issues surfaced as a result of inquiries on this topic. They revolved around:

a. Design of completions to accommodate the instrumentation.

b. Protection of instrumented string and casing during run-in.

c. Logisitics of run-in techniques.

Vertec reviewed the instrumentation of its 5,700' well and agreed to share the procedures and logistics of running in long lengths of sheathed thermocouple wire. Pictures were available for review. Most other details were considered proprietary to the Vertec processes.

The survey resulted in the development of a considerable amount of information regarding instrumentation, instrumentation attachment techniques, well completions, run-in techniques, testing/results and software development. Where applicable, this information was integrated into the Task 2 test program.

Contacts made during this part of the survey are presented in Appendix 1.

3.1.3 Wellbore Heat Loss Modelings

3.1.3.1 Discussion

Scientific Software - Intercomp (SSI) conducted the survey to identify techniques, algorithms and public domain software which could be integrated into the new state-of-the-art heat transfer model to be developed under Task 3 of the program. In conducting this survey, SSI examined published literature on steam injection to identify the critical technology for application in the Task 3 model. In addition, several organizations with existing public domain software were contacted to determine the applicability of such software to the Task 3 software development effort. As the result of these surveys, SSI developed a preliminary concept of the hardware platform to be utilized in the software development effort.

The published literature on the steam injection wells have been screened to identify the critical technology which should be included in the wellbore heat loss model, the final objective of this task. The literature on steam injection to recover oil first started appearing in the late fifties and with the availability of computers, it reached a reasonable maturity in the seventies. Since then, the published papers are more scientific in nature and the engineering solution of the problem has not advanced as in the seventies.

For the purpose of identifying the critical technology, the subject can be divided into four sub-sections in the chronological order of study, these topics are:

- Wellbore (tubing and annulus)
- Formation (surrounding rock)
- Fluids (steam and water)
- Multiphase Flow (gas and liquid)

Even though the topics are presented separately, it is clear that all four relate to each other very closely. The authors of the papers reviewed in

this study usually deal with all the topics mentioned above.

Papers and publications in each of these areas were reviewed. These references are included in Appendix 1 to this Final Report.

As a part of its focused literature search, SSI canvassed several organizations who might be in possession of software that could have application to Task 3. Of the firms canvassed, only Sandia indicated that they were in possession of any public domain software that might be of use in Task 3. In addition, Scientific Software - Intercomp offered the code of its proprietary software, VSTEAM, as a basis for development of the Task 3 heat-loss model. The two Sandia Models BORE and GEOTEMP 2, which were developed under DOE contract in the early eighties were reviewed in detail.

The advantages of VSTEAM over and above these Sandia packages are outlined below.

- VSTEAM was designed specifically for the modeling of production and injection of steam/water mixtures.

- Several two-phase empirical relationships are available within the program. Besides the Orkiszewski work mentioned previously, the following correlations are incorporated and can be selected.

  - Hagedorn and Brown

  - Azia and Govier

  - Beggs and Brill

  - Mukherjee and Brill

- The concepts of two-phase slip and liquid hold-up are fully supported.

3.1.3.2 Results

The survey effort results in the definition of a series of concepts for the Task 3 Software Development effort.

1. Use Willhite's method to calculate overall heat transfer coefficient, and flexibility to overwrite individual coefficients.

2. Add built in heat transfer coefficients for materials.

3. Add the capbility to model multiple casings down to different depths.

4. Use the two-dimensional (R-Z) finit differenced representation of the soil such that, layering and known aquifers can be accommodated.

5. Define the capability to account for all qualities of fluids, and their variation with respect to pressure and temperature.

6. Ensure that the capability to change injection rate, steam quality, wellhead temperature, wellhead pressure with time for the unsteady state solution of the heat transfer problem.

7. Add the capability to assign tubing temperature profiles, and to vary it by time to represent production during the cyclic injection process.

8. SSI's proprietary heat transfer model, VSTEAM, should be used as the basis for future development work.

9. The final deliverable code should be capable of running on an AT compatible PC with 640 KB of RAM.

10. A graphics oriented pre- and post-processor should be included in the delivered product.

The references developed in the Wellbore Heat Loss Modeling Survey are listed in Appendix 1.

3.2 TASK 2 TEST AND MEASUREMENT

3.2.1 Summary

Under Task 2, an instrumented steam injection well was drilled in Kern River Field in Bakersfield, California. The well casing was highly instrumented and the well incorporated a 1.9" logging side string so that the data obtained from the permanent casing instrumentation could be augmented with temperature logs.

Six instrumented steam injection completions were operated in the test well. Heat flux and temperature signals from the downhole casing and steam injection string instrumentation, transmitted to the surface on hard lines and recorded for analysis through a data logger/PC system.

The well and steam injection string instrumentation were unique in design and performed very well over a nine month period. The downhole instrumentation survived the very difficult high temperature environment of a steam injection well and continued to provide valid heat flux and temperature data for all six of the Test Case injector configurations.

In this section of the repot the test program is outlined. The test well, injection strings and attendant downhole instrumentation are described. Each of the test cases are discussed. The data obtained from each test case are presented in Appendix 2.

During the Task 2 Test and Measurement phase of the program, there were equipment problems and delays. Nevertheless, the instrumented well and injectors proved to be an estremely effective test bed and in fact constituted an absolutely unique test capability. The bottom line objective of Task 2, obtain a valid body of test data to use in the validation of the Task 3 software system, was achieved.

3.2.2 Description of Test Program

The centerpiece of the Task 2 Test and Measurement Program was the instrumented test well. This well and the instrumented injection strings produced a unique capability for the definition of the heat transfer characteristics of a series of steam injector configurations. The following test configurations were defined for the program.

- Test Case A - An insulated steam injection string and thermal packer.
- Test Case A-1 - The Test Case A insulated steam injector, decentralized for a portion of the string length, with a thermal packer.
- Test Case B - An uninsulated steam injector and thermal packer.
- Test Case B-1 - The Test Case B uninsulated injector decentralized for a portion of its length, with a thermal packer.
- Test Case C - An uninsulated steam injector, with no packer, but with inert gas pressure in the injector/casing annulus to balance steam pressure; i.e. a gas pack.
- Test Case D - An uninsulated steam injector with no packer.

These test configurations were sequenced for "A" through "D" so that the tests which will input the most energy to the earth were conducted last.

Task 2 goals may be summarized as follows:

- Obtain measurements of heat flux from the well to the earth, for each test case at depths of 250', 500' and 750'.

- Obtain data suitable to verify the algorithms for convection across the annulus, heat conduction to the earth, and vertical two-phase pressure drop for the flow tubing.

In order to achieve the program goals it was necessary to carefully define the data needs and develop sensing instrumentation capable of surviving the installation and operating environments while providing data with the necessary precision. These goals were fully achieved. The instrumented test well remained fully functional throughout testing of six injector completions. At the end of the program, the downhole heat flux sensors were still functional after a nine month operating period.

3.2.2.1 Instrumentation and Test Well Design

The test well and instrumentation were designed to provide reliable and accurate measurements of downhole temperature and heat flux. Reliability was provided through protection against the environmental stresses during running and cementing and through duplication and redundancy in the sensing elements and cabling and through provision of an external sidestring which could be logged to provide a fallback temperature measurement capability. The sidestring also provided the possibility for interpolation between temperature sensor locations. Accuracy was provided through the use of designs which provided acceptable compromise between mechanical protection and local thermal degradation.

Well Design

Figure B-1 is a schematic diagram showing the layout of tubulars and instrumentation on the instrumented well (casing). Surface casing was run in the upper 200 ft. where the well crosses a fault which was considered to present a hazard to running the 9-5/8" casing. The casing was instrumented with heat flux sensors at 250, 500 and 750 ft. and with thermocouples at nominally 100 ft. intervals over the interval from the bottom of the surface casing to the packer setting depth of 800 ft. The instrumented casing was centralized and run alongside a logging sidestring which terminated at 800 ft.

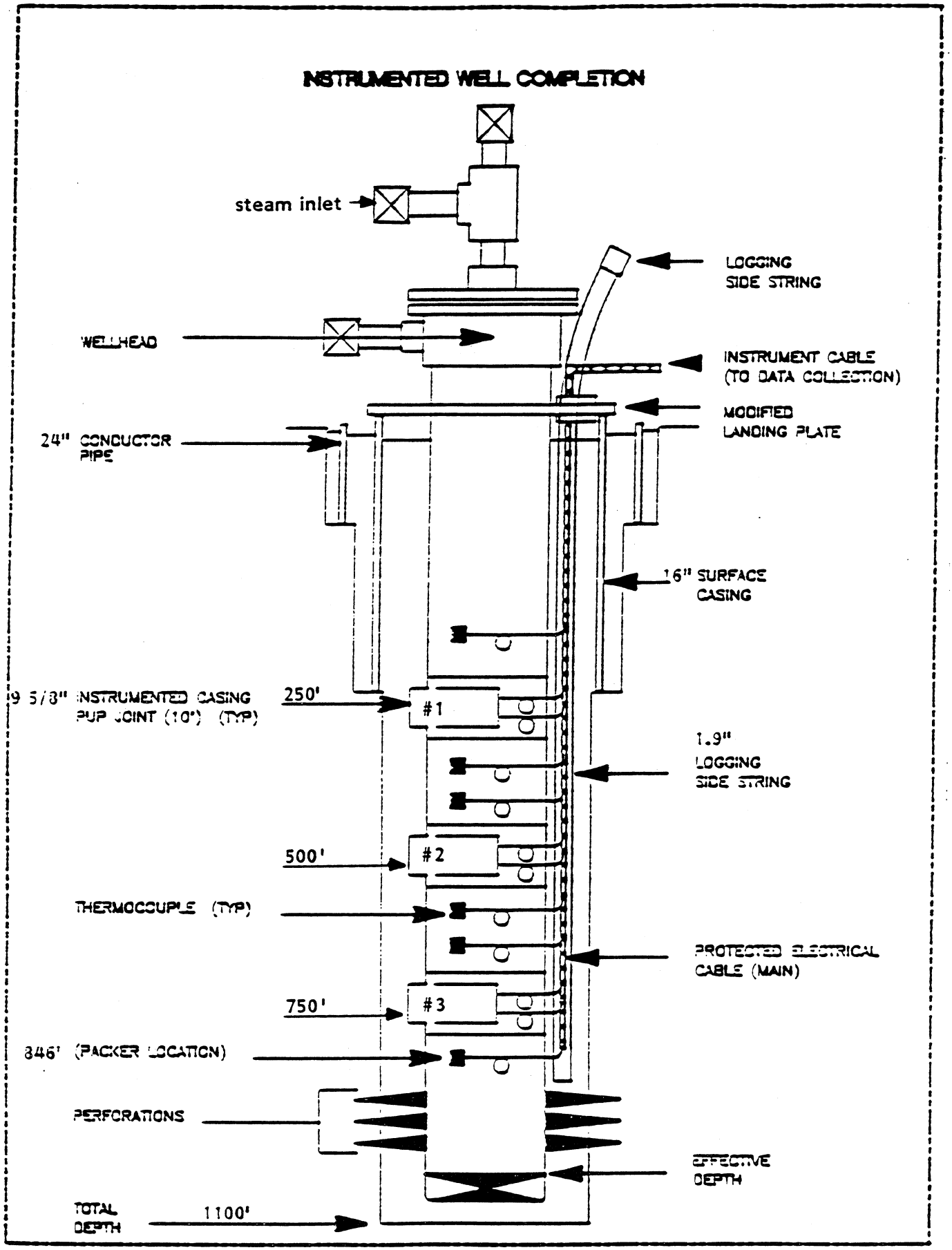


FIGURE B-1
TEST WELL LAYOUT

Figure B-2 shows the centralizer and sidestring clamp which were installed at each casing collar. The bowspring centralizer was a standard 14-1/2 in 8 blade device with one blade removed (to provide space for the sidestring). The centralizer was installed conentionally, astride a casing collar. The sidestring clamp was butted against the bottom of the centralizer and both were tack welded to the casing to prevent relative rotation during installation. the sidestring was also tack welded to the clamp which, in addition, provided a mechanical anchor for each instrument cable, in the protected regions close by (and on each side of) the sidestring.

Downhole instrumentation

As indicated previously, the casing was instrumented with thermocouples at nominally 100 ft. intervals over the interval from the bottom of the surface casing to the packer setting depth of 800 ft. and with heat flux sensors at 250, 500 and 750 ft.

Figure B-3 shows the arrangement of the casing thermocouples. Each of the mineral insulated thermocouples was manufactured in a single continuous piece and protected from the downhole environment by a seamless corrosion resistant sheath. The tip of each thermocouple was coated with high conductivity grease and inserted into a thermowell. The thermowell was maintained in good thermal contact with the casing wall by full length fillet welds. Thermowells and thermocouples were installed at each elevation, on opposite sides of the casing designated A and B. After exiting the thermowell, the thermocouple wire was run diagonally under a metal shield to join the bundles of instrument wires, on each side of the sidestring.

Figure B-4 shows the arrangement of each instrumented casing pup and its integral sensor. The three pups were run as, previously indicated, at depths of 250, 500 and 750 ft. Each pup incorporated a matched pair of sensing elements, connected in parallel, together with a thermocouple. The sensor packaging was carefully designed to minimize the introduction of inaccuracies which could have invalidated the manufacturers calibration. The sensors were attached to the pipe

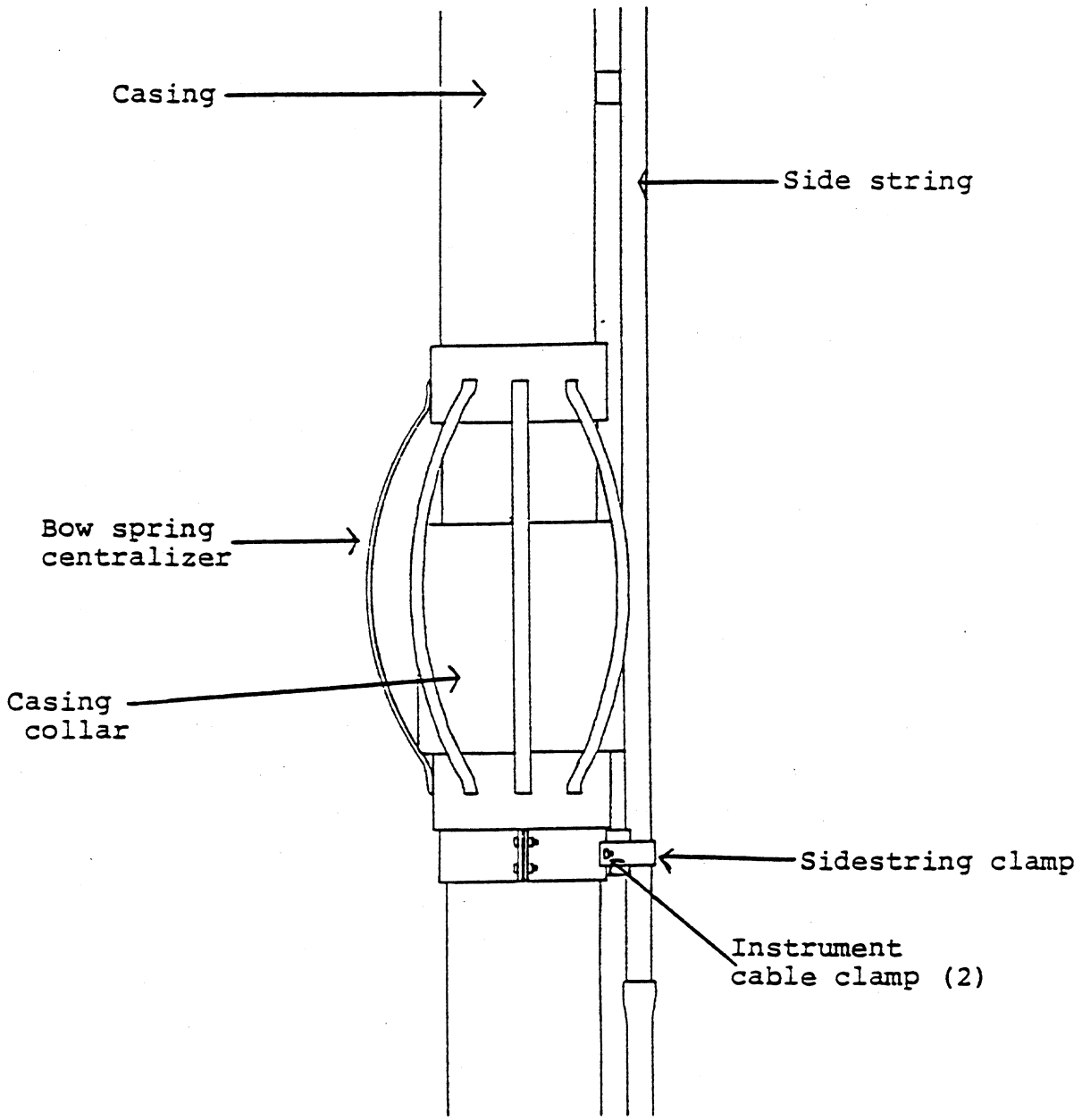


FIGURE B-2: SIDE STRING CLAMP AND CENTRALIZER ARRANGEMENT

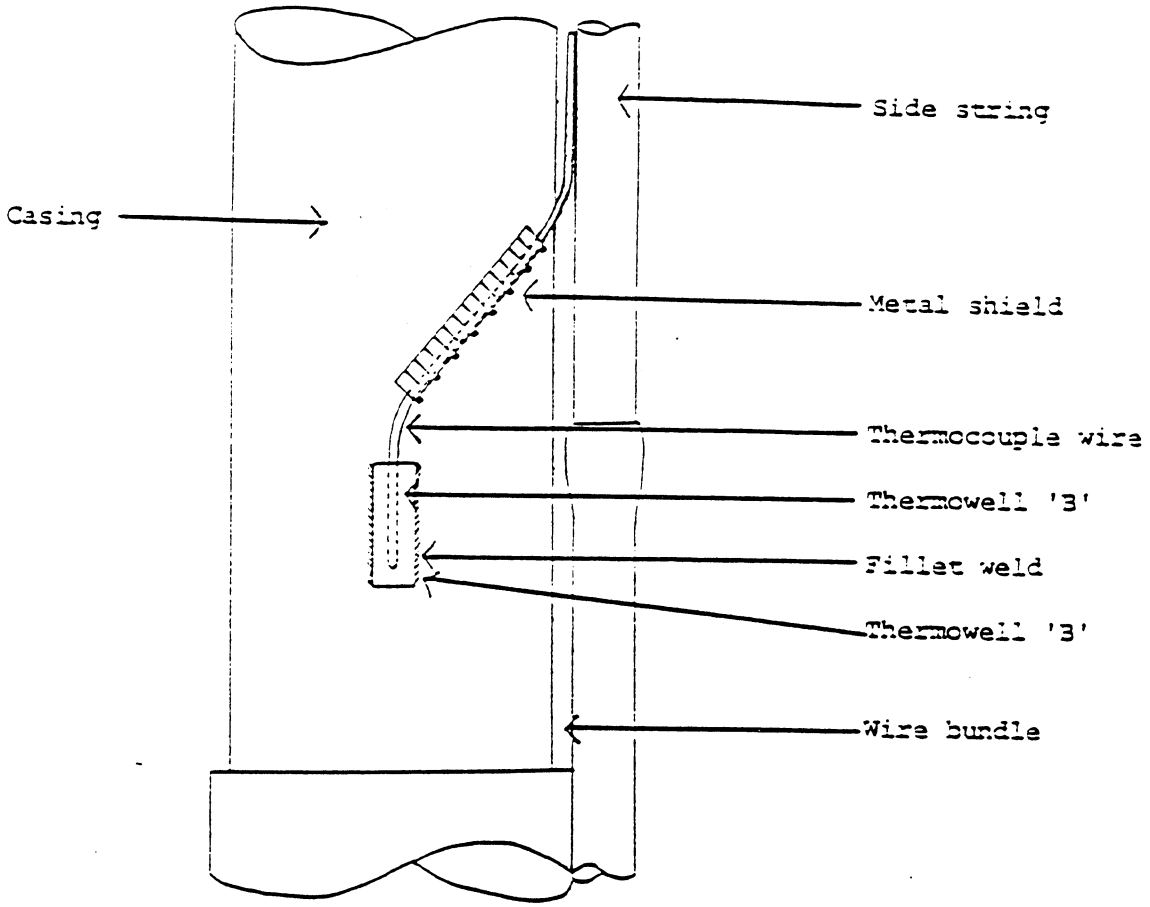


FIGURE B-3: THERMOCOUPLE ARRANGEMENT

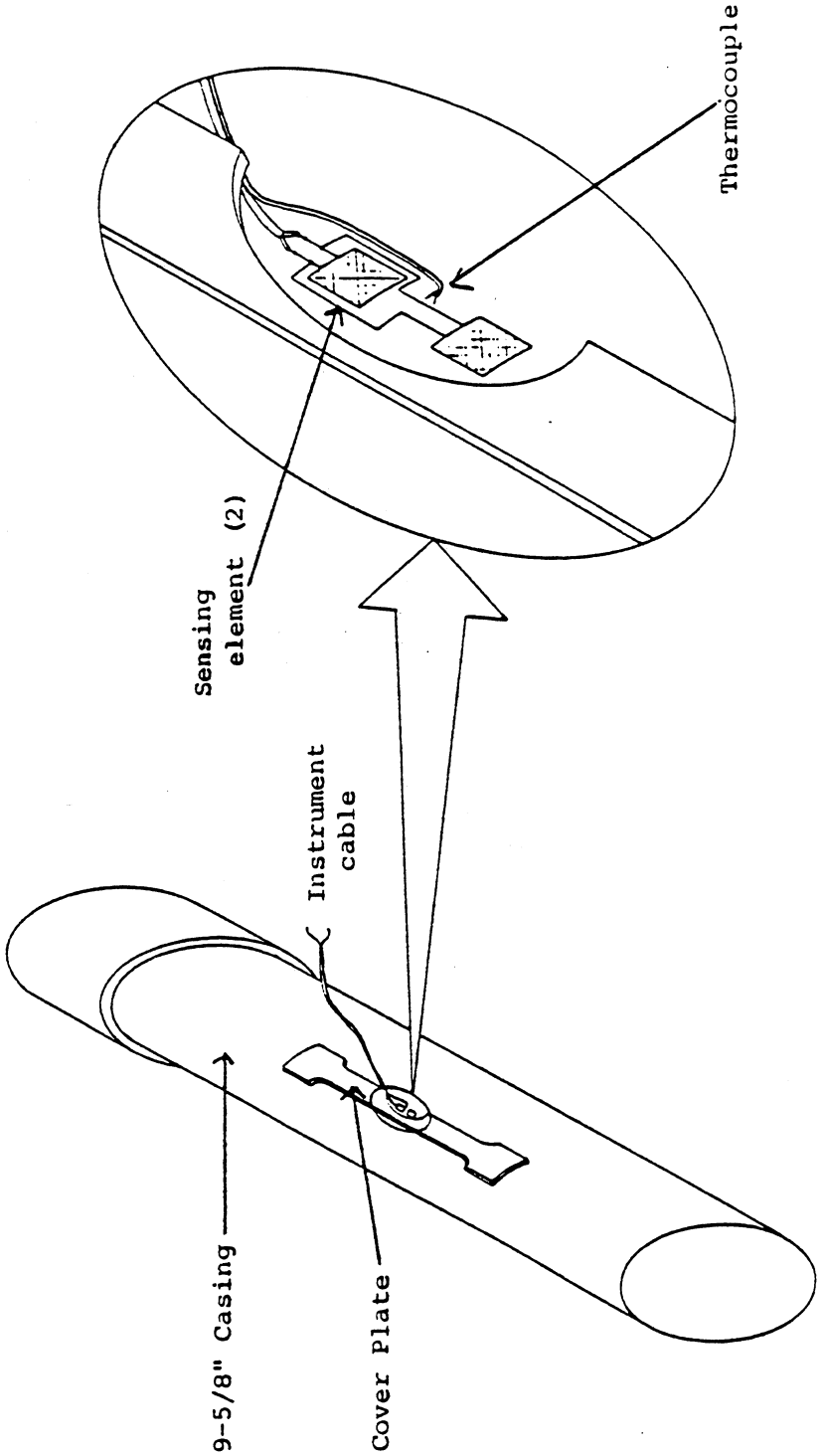


FIGURE B-4: CASING PUP WITH INTEGRAL HEAT FLUX SENSOR

wall and encapsulated in silicone rubber and covered by a steel cover. The thicknesses of the rubber and steel layers were matched to the thermal conductivity of the oilwell cement, and the dimensions of the cover were chosen to maintain the parasitic heat conducted through the cover mounting at less than .5% of the measured heat flux. The design was validated prior to fabrication by subjecting a finite element model to the anticipated well conditions and comparing the sensor heat flux to the parasitic flux conducted around the element by the package cover.

Wellhead Steam Supply Facilities

Figure B-5 shows the flow schematic for the steam suply and monitoring facilities. Steam and water were delivered to the test site from the field distribution system. The steam and water flowrates were measured and each was controlled by hand operated valves. After mixing the wet steam was passed throgh a cyclone separator. Steam passed from the top of the separator through a vortex meter and was transmitted to the wellhead. The liquid phase passed from the separator under level control, and was also measured by a vortes meter before being recombined with the steam. Flow computers calculated the mass flow of each phase and transmitted this information, together with the steam temperature to the data collection sub-system.

Data Collection Sub-system

The data collection sub-system received analog signals from the downhole and steam supply instrumentation and provided analog to digital conversion and temporary data storage. Data were transmitted to KTS facility at Tacoma, Washington for reducton and analysis on a daily basis.

3.2.2.2 Installation

The field test well was located in Kern River Field, Bakersfield, California, on Texaco Producing Inc. Cordes lease, well #513. Prior

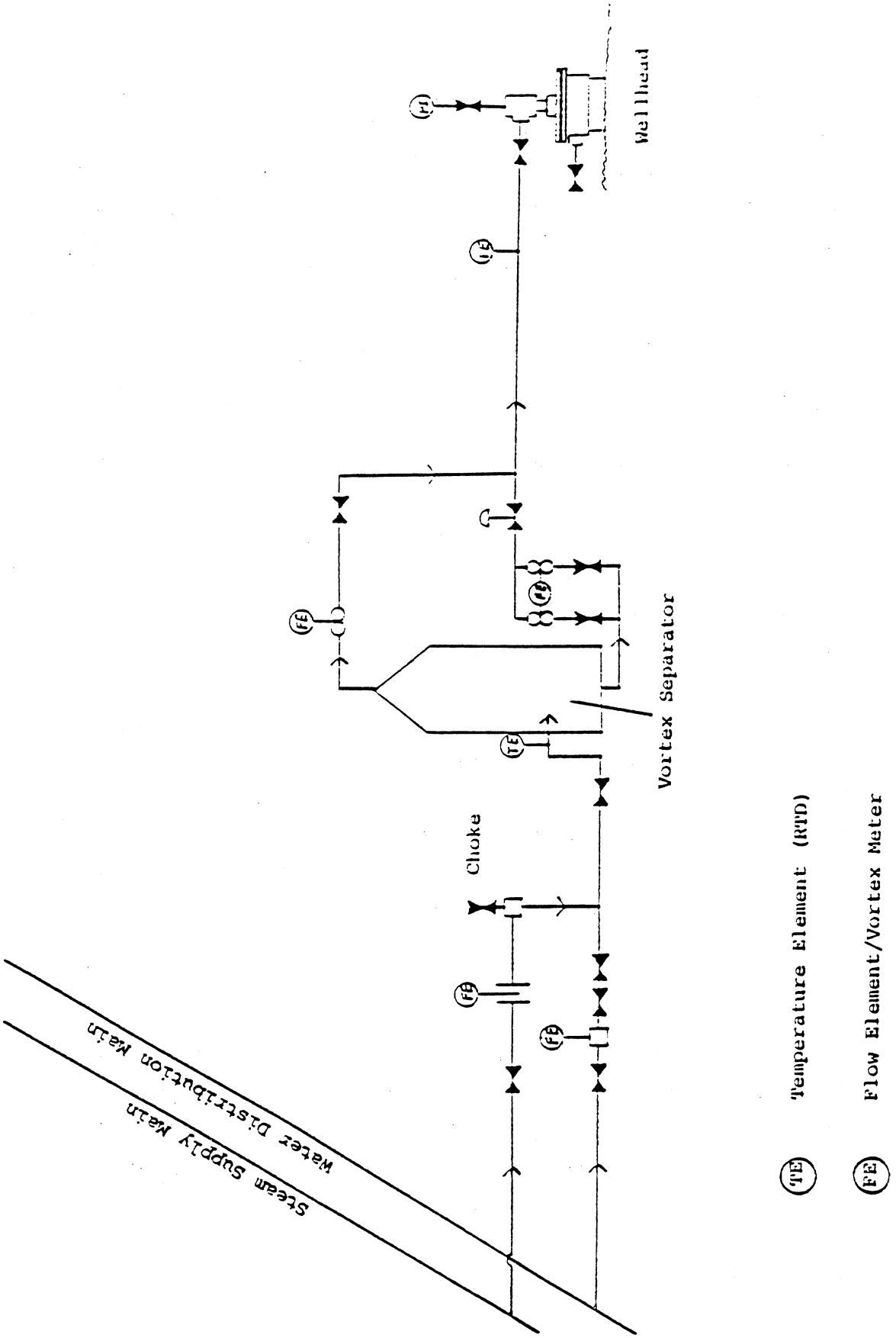


FIGURE B-5: STEAM SUPPLY SYSTEM SCHEMATIC

to drilling the site required grading, installation of fresh water and electrical supplies, and installation of 24" 100# conductor pipe to a depth of 40 ft.

The well was spudded in with a 20" bit and drilled from surface to 200'. The hole was wiped and circulated clean. The 16" surface casing was run to 200' depth and cemented with 106 sacks of class G cement mixed with silic flour (40%), perlite (1:1), $CaCl_2$ (2%) and gel (2%).

A dry run was conducted on 5/20/90 to test the installation procedures and to set up the instrument cable handling equipment. The casing was carefully tallied and numbered. Adjustments were made to the planned thermocouple locations to eliminate undesirable conflicts with casing collars and the revised thermocouple locations were marked on the casing.

The well was drilled to 1100 ft. with a 14-3/4 inch bit. the well was then swabbed and circulated clean and open hole logs were run. After logging the hole was again swabbed and circulated clean and the lower 300 ft of casing run. The sidestring shoe was welded to the outside of the casing and two links were removed from the slips to permit passage of the sidestring. The 1.9" flush joint sidestring was run into the hole strapped to the casing, taking care to ensure that the sidestring was always vertical and that the casing did not rotate while being lowered into the hole. As installation of casing joints proceeded, additional joints of sidestring were connected and tightened by hand, centralizers and sidestring clamps were installed at each coupling, and metal spacers were installed at intervals to maintain a uniform spacing between the sidestring and the casing. Thermowells, thermocouples and casing pups were attached to the casing at the appropriate locations and their associated cable were added to the bundled instrument cable. Cable reels were added one at a time to a cable reel support frame which provided frictional drag to each individual cable.

When the instrumented casing string was completely assembled, the well was circulated and cemented with 312 sacks of class G cement mixed with silica flour (40%), perlite (1:1), $Cacl_2$ (2%) and gel (2%). The following day the rig was removed, the casing was cut to the correct elevation and the modified wellhead flange was installed. The final stage of installation involved connection of the instrument cabling to the data collection equipment, installation of the wellhead steam supply equipment and installation of the explosively set thermal packer at 846 ft depth. Table B-1 and B-2 show the as-installed locations of the tubulars and downhole sensors.

A temperature log was run in the sidestring on May 29 to establish the initial earth temperature profile. Passage of the tool was blocked at 583 ft. Figure B-6 shows the resulting temperature log.

TABLE B-1: TEST WELL CONFIGURATION (AS INSTALLED)

Drill Diameter (In.)	Tubular		Depth Ft.	Weight Lb/Ft
N/A	Conductor Pipe	24	40	100
24	Surface Casing	16	200	75
14.75	Casing	9.625	1100	40
	Side String	1.9	850	2.76

TABLE B-2: CASING INSTRUMENTATION (AS INSTALLED)

Depth	Instrument
0 Ft.	Wellhead (Datum)
188.5	200 Ft. Thermocouples A & B
235.2	250 Ft. Heat Flux Sensors A & B and TC A
312.4	300 Ft. Thermocouples A & B
394.2	400 Ft. Thermocouples A & B
483.2	500 Ft. Heat Flux Sensors A & B and TC A
594.2	600 Ft. Thermocouples A & B
686.4	700 Ft. Thermocouples A & B
734.9	750 Ft. Heat Flux Sensors A & B
794.2	800 Ft. Thermocouples A & B

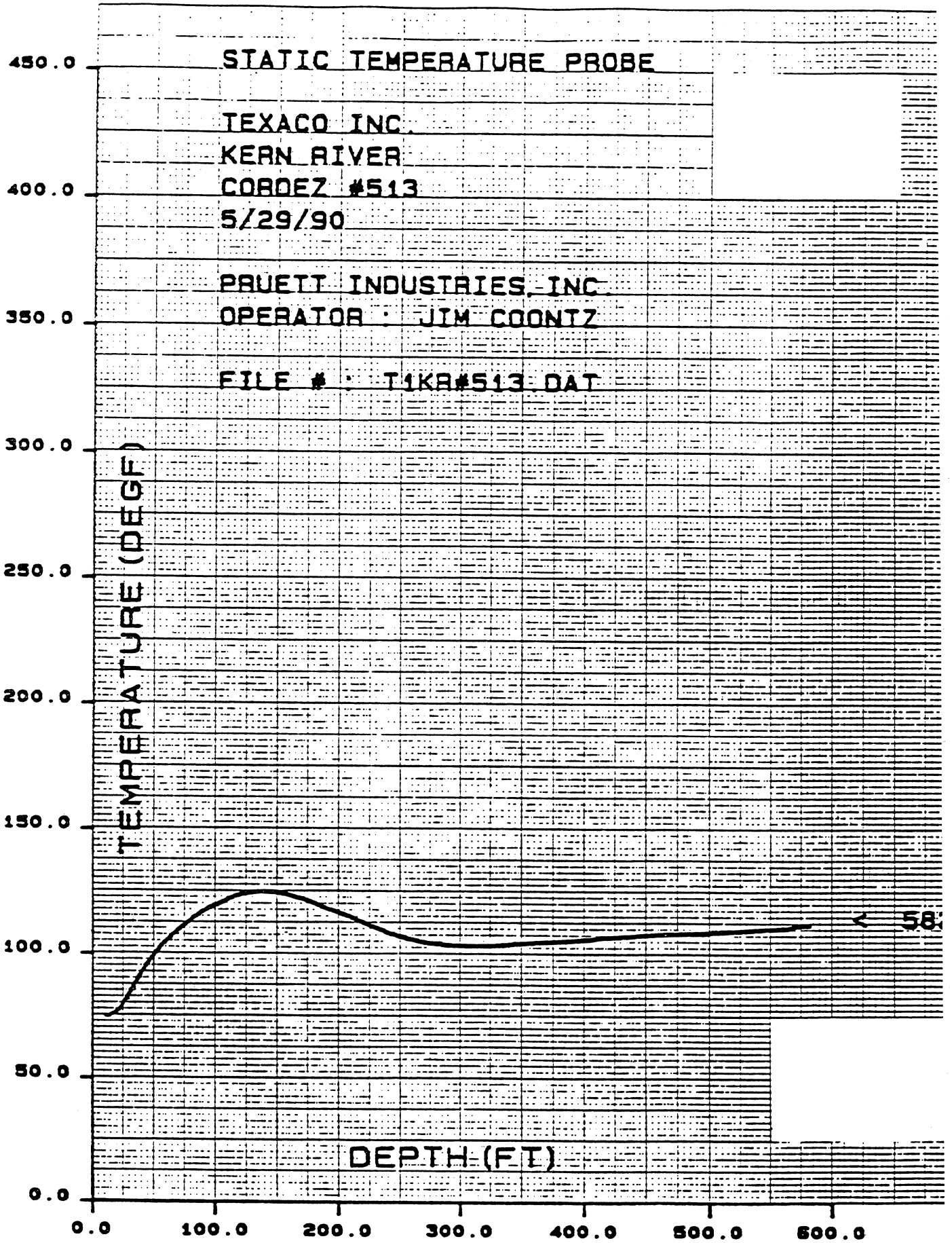


FIGURE B-6: INITIAL (WELL) VERTICAL TEMPERATURE PROFILE

3.2.2.3 Test Conduct

The test program was planned to provide heat loss measurement from six steam injection configurations. The test sequence was planned so that the test cases with the highest anticipated casing temperatures were conducted last. Table B-3 shows the matrix of steam conditions planned for each test case.

TABLE B-3: TEST MATRIX

	STEAM CONDITIONS		
	#1	#2	#3
QUALITY PRESSURE TEMPERATURE	5% 120 psi 350 °F	90% 230 psi 400 °F	80% 335 psi 430 °F
A CONCENTRIC THERMAL INSULATED TUBING VENTED ANNULUS	2 DAYS *	2 DAYS *	3 DAYS *
A-1 ECCENTRIC	------	2 DAYS * LOG SIDESTRING	3 DAYS * LOG SIDESTRING
B CONCENTRIC THERMAL PACKERS BARE TUBING VENTED ANNULUS	------	2 DAYS *	3 DAYS *
B-1 ECCENTRIC	------	2 DAYS *	3 DAYS *
C NO PACKER BARE TUBING GAS PACK	------	2 DAYS * LOG SIDESTRING	3 DAYS * LOG SIDESTRING
D NO PACKER BARE TUBING SEALED ANNULUS	------	2 DAYS * LOG SIDESTRING	3 DAYS * LOG SIDESTRING

* OR UNTIL STABLE

Test of Centralized Insulated Tubing With Thermal Packer

Test Case A incorporated an insulated tubing which was centralized and equipped with a thermal packer and sliding mandrel. The tubing string incorporated 19 joints of standard 3 1/2" x 2 3/8" Thermocase 750® insulated tubing, one specially instrumented joint, and, initially, an 08' steam separator. The annular space between the outside of the insulated tubing and the inside of the well casing contained air initially, and was initially vented at the surface; however, after recurring steam leaks at the packer the annulus was sealed at the surface and pressurized with nitrogen.

Figure B-7 shows a cross section through the vacuum insulated tubulars at the end connection. The vacuum insulated pipe body incorporates inner and outer tubings with a gettered vacuum and multi-layered insulation in the annulus. A Product Specification is presented in Table B-4.

Steam injection started on June 8 with a wellhead pressure of 120 psi (steam condition 1). Figure B-8 shows the steam temperature with mass flows of water and steam, and the calculated steam quality. Testing proceeded and data was collected until June 12 when the wellhead pressure was increased to 230 psi. Testing proceeded and data was collected for steam condition 2 until June 15.

After the pressure was increased to 335 psi, for test condition 3, extreme fluctuations in wellhead pressure were observed and the packer failed on June 21 forcing the well to be shut in and the insulated tubing pulled. The entire tubing string was re-instrumented and the thermal packer was rebuilt and tested at 400 psi and found to be operational. The tubing was pulled, run back into the hole with the instrumented joint. Steam injection resumed on July 10. Recorded data indicated the presence of refluxing in the annulus, however, data collection proceeded because the refluxing phenomena appeared to be confined below the 300 ft level.

Kawasaki Thermal Systems

THERM KTS CASE® 750 INSULATED TUBULARS

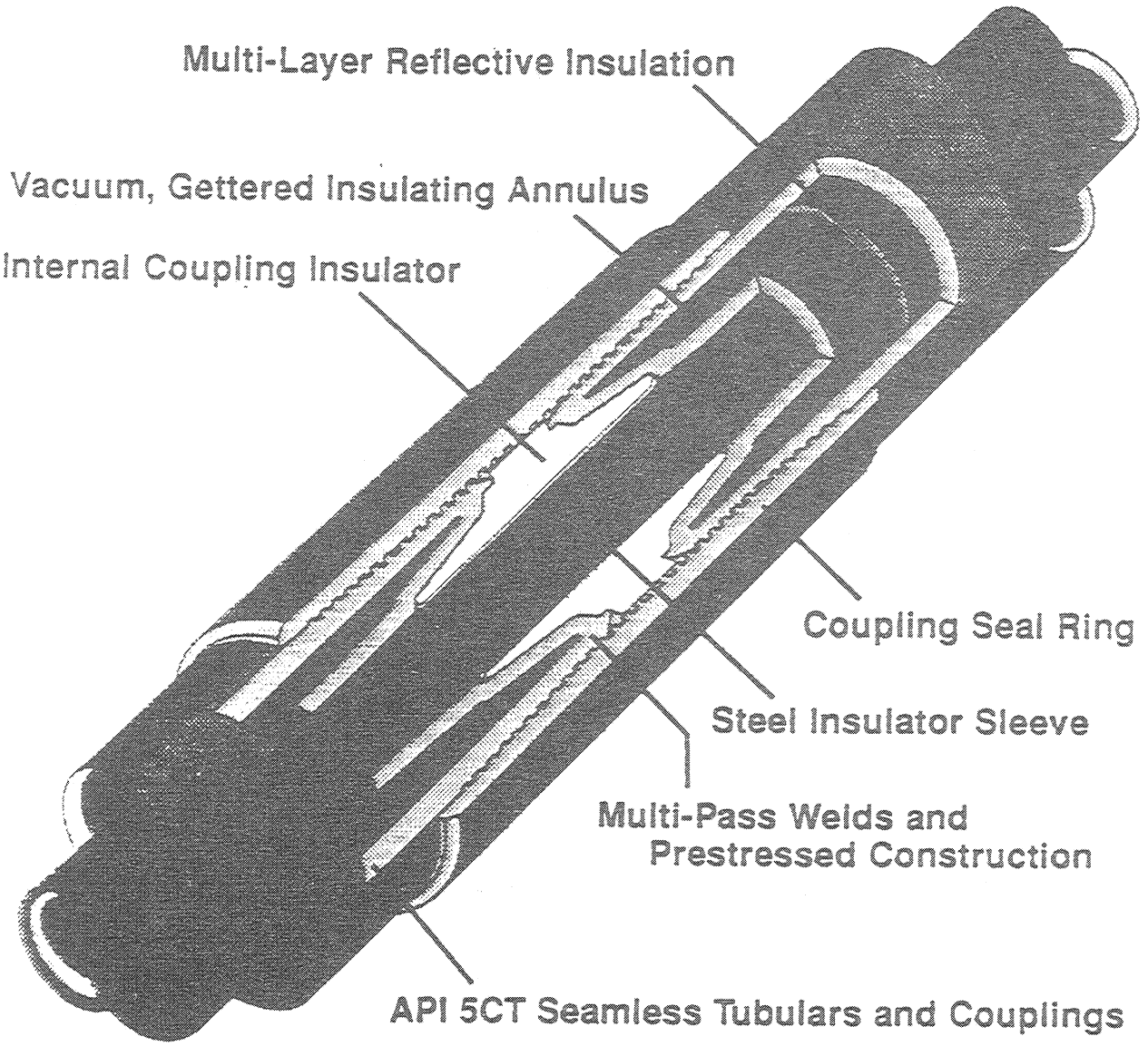


FIGURE B-7

TABLE B-4

THERMOCASE 750

VACUUM INSULATED STEAM INJECTION TUBULARS

PRODUCT SPECIFICATION

PHYSICAL

Size	3 1/2" X 2 3/8"
Total Weight (#/Ft)	13.8
Length	Range 3

OUTER TUBE (Threaded and Coupled)

Grade	API 5CT, K-55 Seamless
O.D. (In.)	3.5
I.D. (In.)	2.992
Wall (in.)	0.254
Weight (#/Ft)	9.2
Threads	USS Buttress

INNER TUBE

Grade	API 5CT, L-80 Seamless
O.D. (In.)	2.375
I.D. (In.)	1.995
Wall (in.)	0.190
Weight (#/Ft)	4.43

COUPLING

Grade	API 5CT, K-55
O.D. (In.)	4.250
Threads	USS Buttress w/Seal Rings Manganese Phosphate Coated

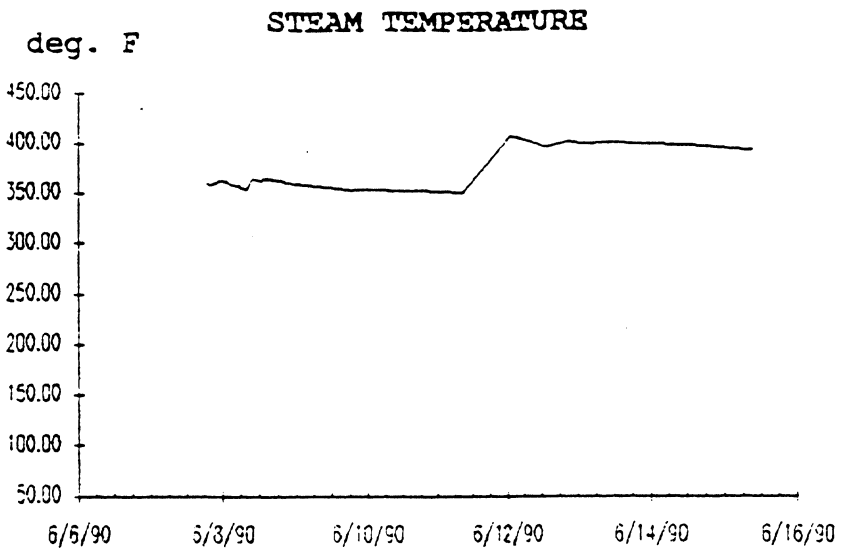
OPERATIONAL

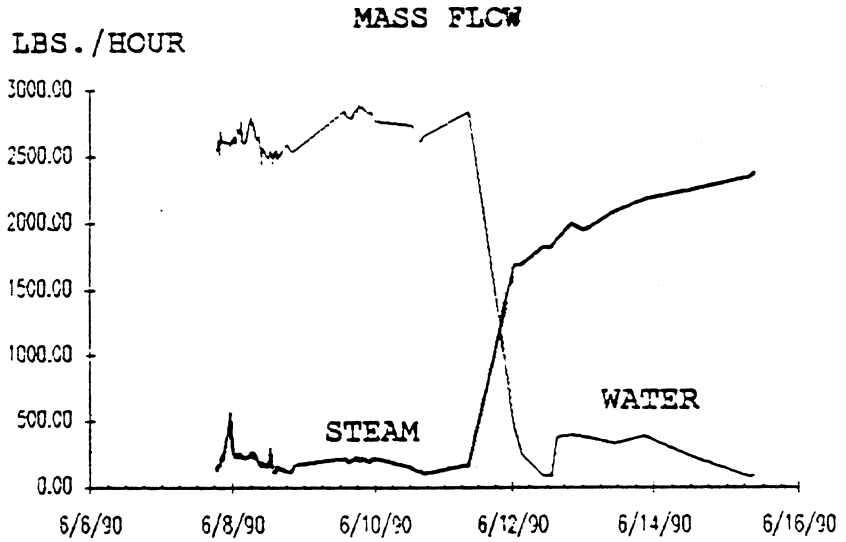
CONDUCTIVITY (BTU/HR·FT·°F) at 670°F

K-Factor:	Body	0.0023
	Coupling	0.15
	Overall	0.010

Gettered for 10-year Life Under Normal Well Conditions

Maximum Start-Up Pressure (psi)	4500 @ 200°F
Maximum Wellhead Operating Pressure	2600 @ 670°F
Maximum Downhole Operating Pressure	3500 @ 670°F





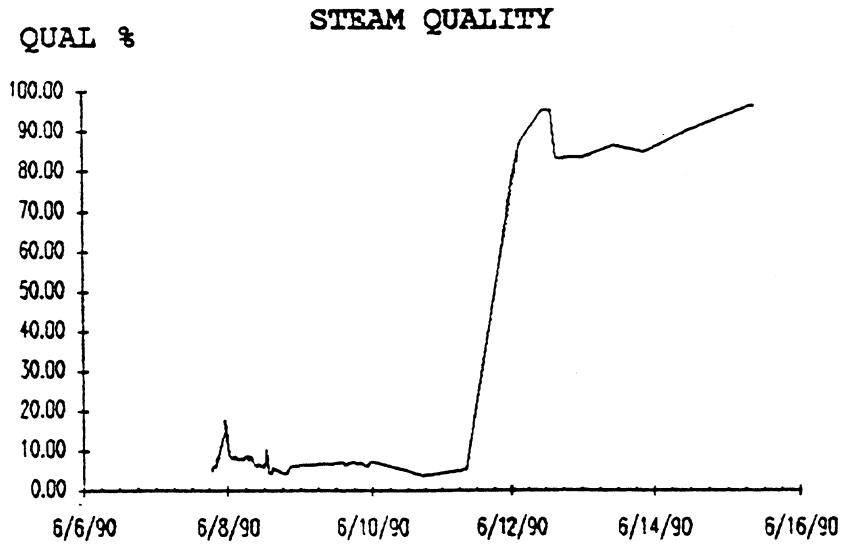


FIGURE B-8 : STEAM CONDITION FOR TEST OF CENTRALIZED INSULATED TUBING WITH THERMAL PACKER (SHEET 1 OF 2)

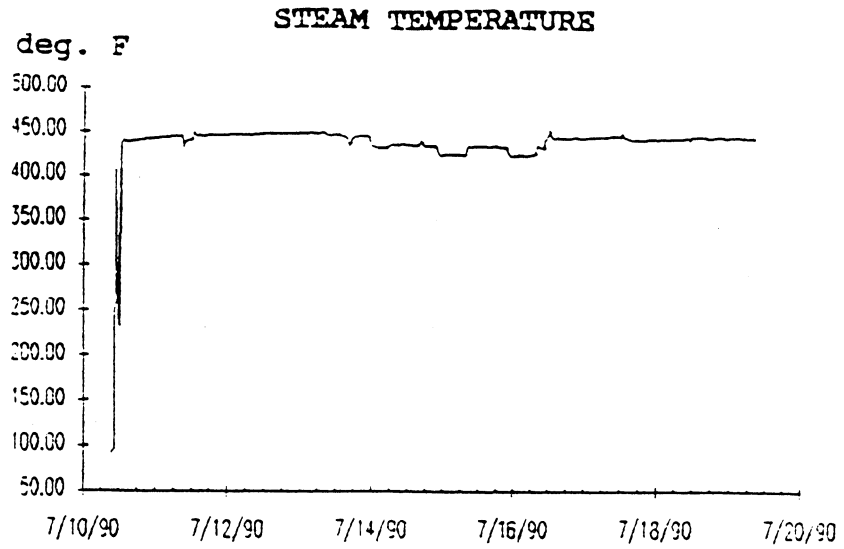
On the afternoon of 18 July, dry nitrogen was introduced into the wellbore annulus bringing annulus pressure to 105 psi at approximately 1630 hours. It was an immediate effect on observed temperatures. The refluxing cell was apparently suppressed below the 300' level and temperatures below 400' increased. Data collection proceeded until July 19 when uniform temperatures of 212°F indicated that the refluxing cell had reached 200 ft. At that time steam injection was terminated and work on Test Case a was completed.

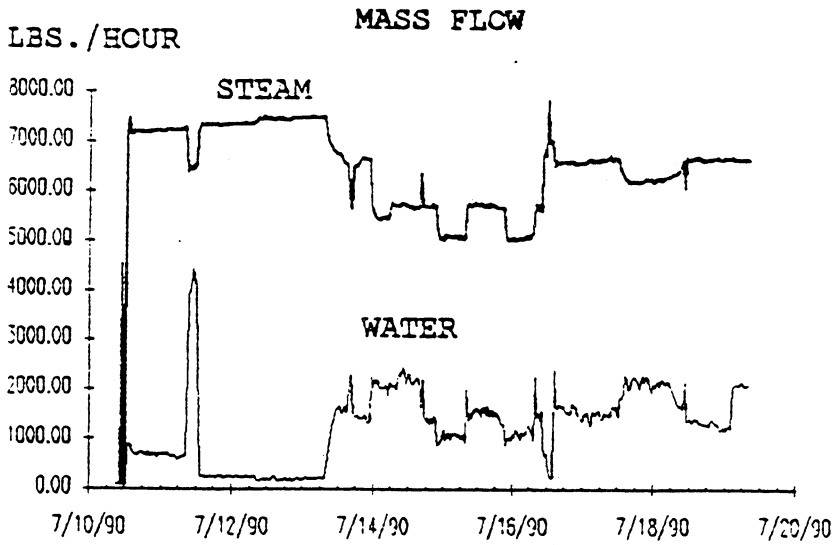
Test of Uncentralized, Insulated Tubing with Thermal Packer

Test Case A-1 of an eccentric (not centralized) insulated tubing string used the same tubing string as case A except that the tubing was forced into contact with the casing wall through the region of the instrumented joint. Further down the well, the tubing was centralized and incorporated an additional heat-flux sensor at 500 ft so that both eccentric and centralized data could be obtained from the same run.

During the months of August and September, several attempts were made to dry the annulus and restart testing. On October 4 the annulus was purged of water using bottled nitrogen and the mandrel was stabbed into the packer body. Overnight the annulus held a small residual pressure of 20 psi and steam injection started the following day with a wellhead pressure of 230 psi (test condition 2) and the nitrogen generator maintaining an 8 scfm feed to the annulus. Figure B-9 shows the steam temperature with mass flows of water and steam, and the calculated steam quality. Testing continued and data was collected without indications of packer leakage with 60 to 80 psi of nitrogen pressure in the annulus. Stable operation continued until October 10 when test condition 2 was completed (shortly after a nitrogen generator failure).

After repairs to the nitrogen generator the annulus was again purged of water using bottled nitrogen and the mandrel was stabbed into the packer body. Steam injection resumed on October 24 with a wellhead





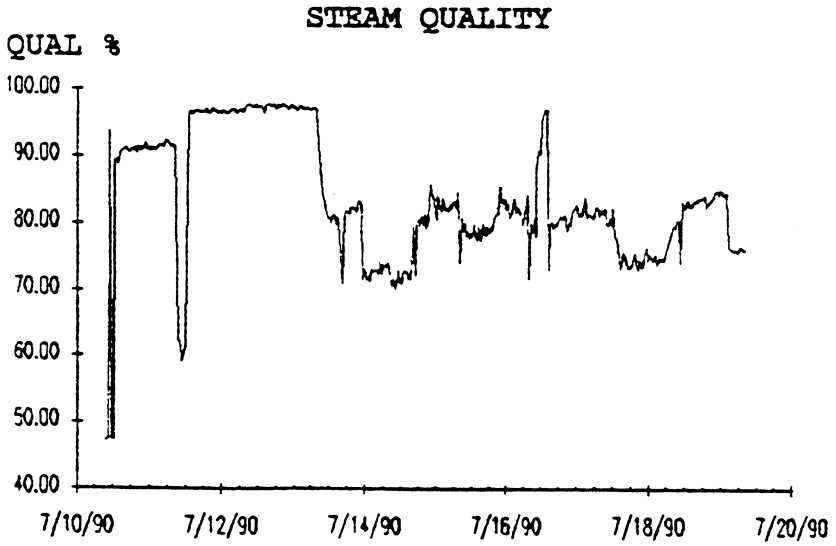


FIGURE B-8: STEAM CONDITION FOR TEST OF CENTRALIZED INSULATED TUBING WITH THERMAL PACKER (SHEET 2 OF 2)

pressure of 300 to 325 psi (condition 3). From October 25 a stable steam pressure of 335 psi, and an annulus pressure of 180 - 200 psi allowed testing and data collection to continue. Another nitrogen generator failure occurred on October 26. However, by that time, sufficient data had been collected to meet the test objectives and test A-1 was completed.

Test of Centralized Bare Tubing With Thermal Packer

On October 29 through 31, the insulated tubing was pulled from the well and replaced with a 2 7/8" bare tubing string.

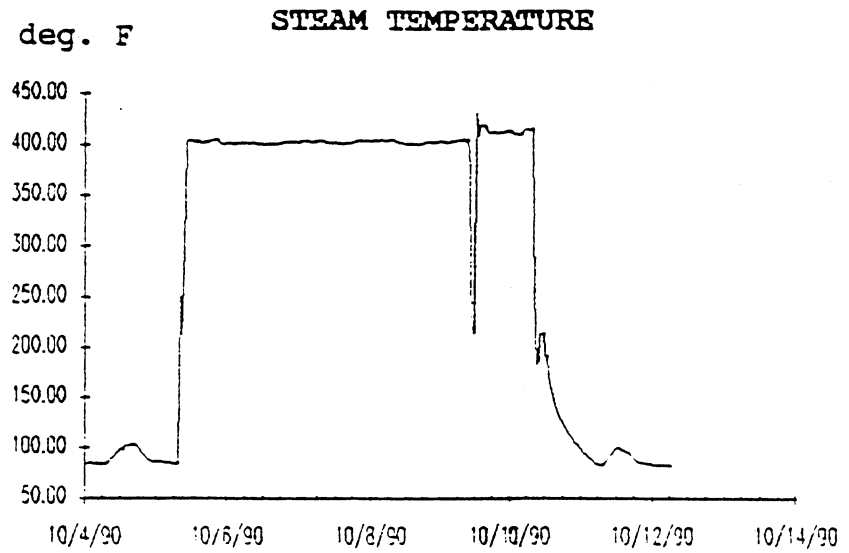
On November 1, steam injection for Test Case B, Condition 3 (335 psi) started at mid-day and continued through November 6. Figure B-10 shows the steam temperature with mass flows of water and steam, and the calculated steam quality. Small packer leaks presented no problem for execution of this test because the increased casing temperatures were not in the range below 212°F where condensation can occur in the vented annulus.

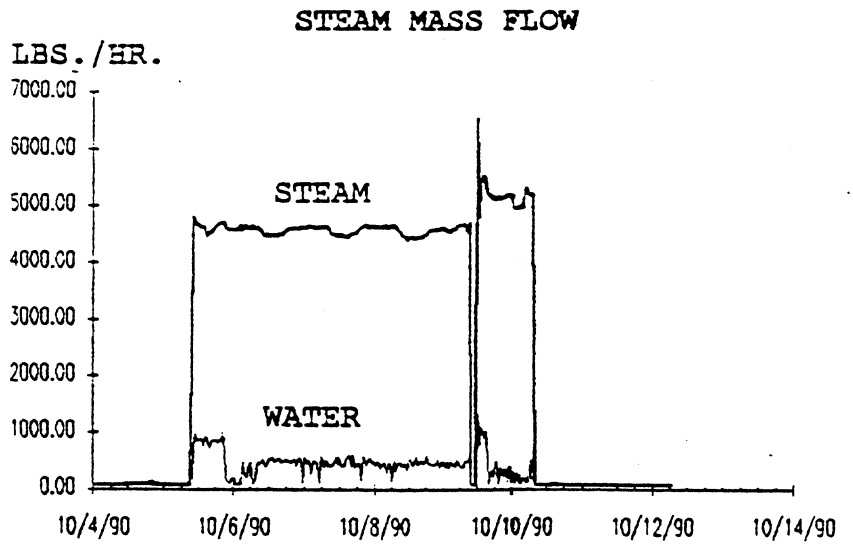
On November 6 steam injection pressure was reduced to 235 psi (condition 2) and operation continued November 14 when the sidestring was logged and case B terminated.

Test of Uncentralized Bare Tubing With Thermal Packer

The test of an uncentralized bare tubing with a thermal packer (Case B-1) utilized the same 2 7/8" bare tubing and explosively set packer as the previous test, with modified centralizers which pushed the tubing over against the casing wall. The tubing was instrumented with 5 thermocouples and one heat flux sensor and run back into the well on November 14. Steam injection started on December 7 at 8 a.m. with a wellhead pressure of 235 psi (condition 2). Figure B-11 shows the steam temperature with mass flows of water and steam and the calculated steam quality.

Refluxing did not occur in the annulus because the high heat loss from the bare tubing raised the casing temperature above the temperature





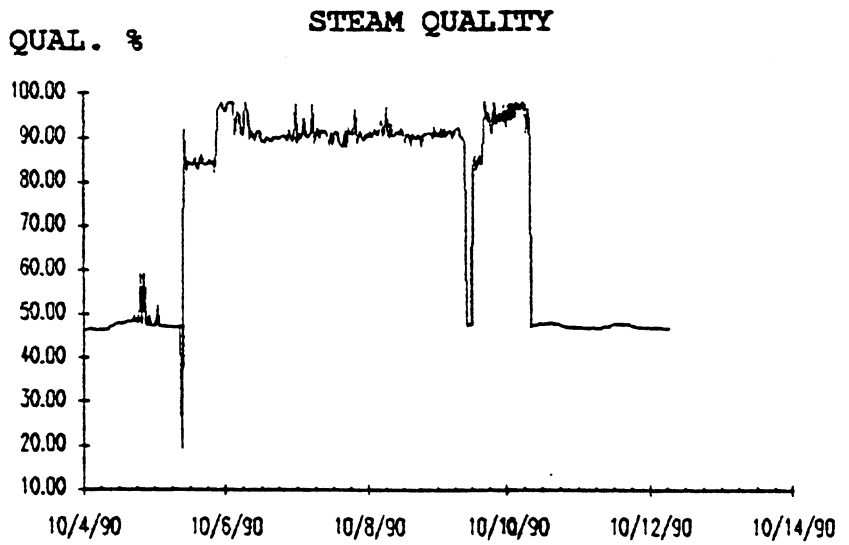
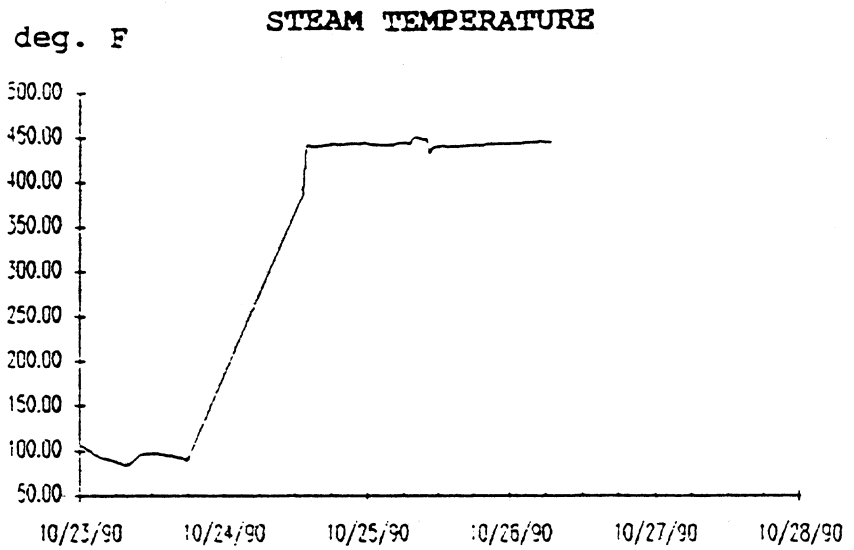
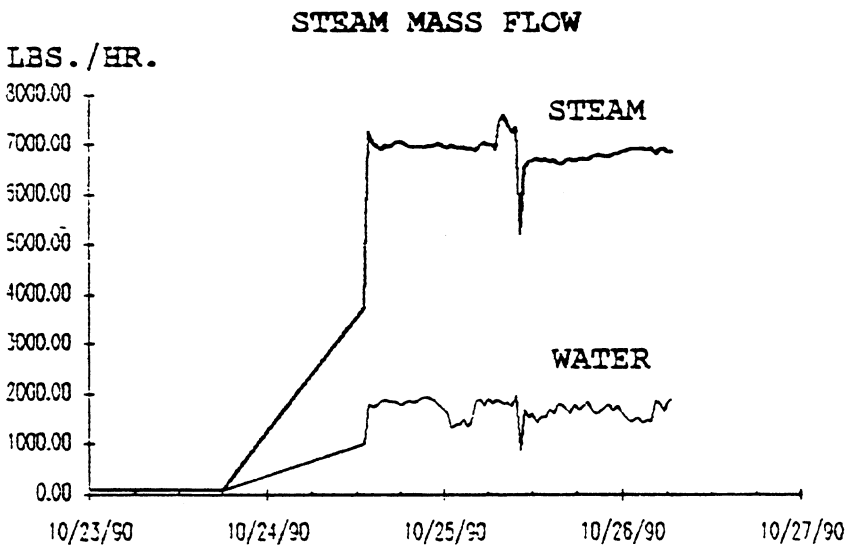


FIGURE B-9: STEAM CONDITION FOR TEST OF UN-CENTRALIZED INSULATED TUBING WITH THERMAL PACKER (SHEET 1 OF 2)





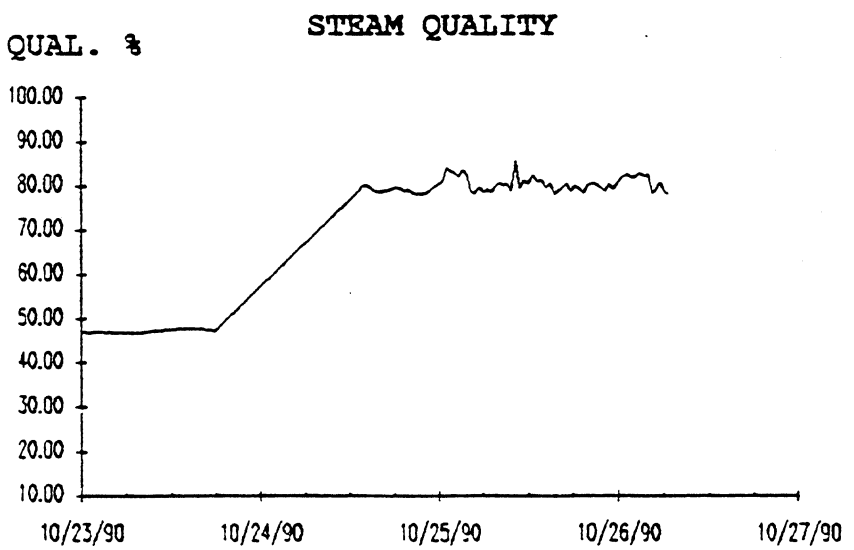
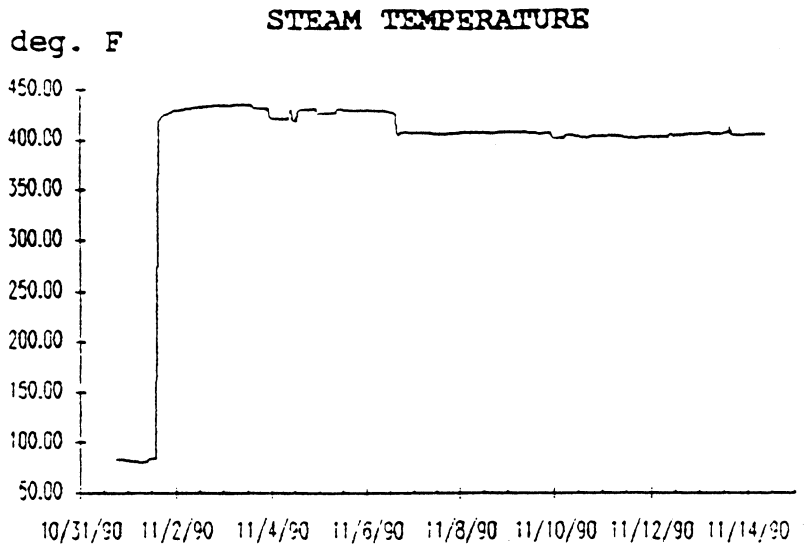
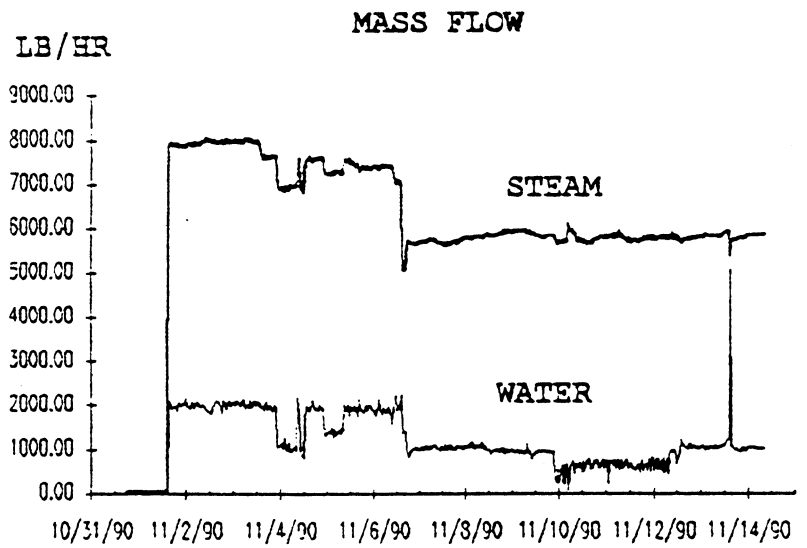


FIGURE B-9: STEAM CONDITION FOR TEST OF UN-CENTRALIZED INSULATED TUBING WITH THERMAL PACKER (SHEET 2 OF 2)





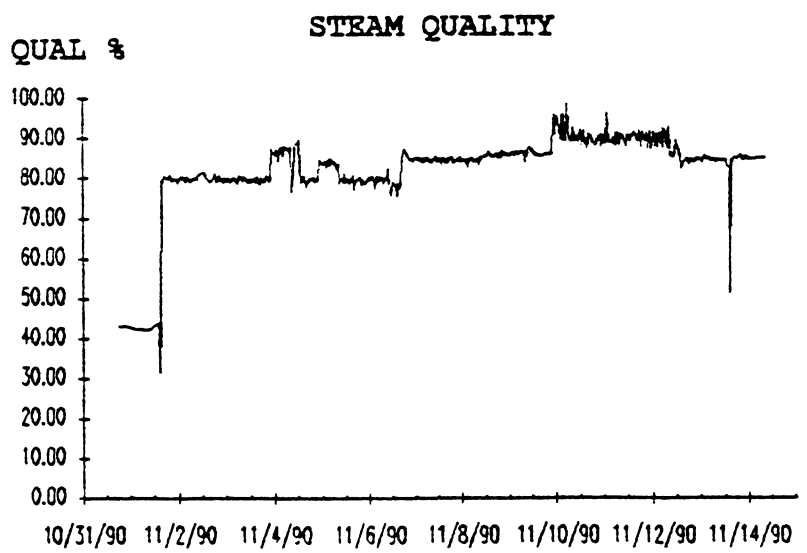


FIGURE B-10: STEAM CONDITION FOR TEST OF CENTRALIZED BARE TUBING WITH THERMAL PACKER

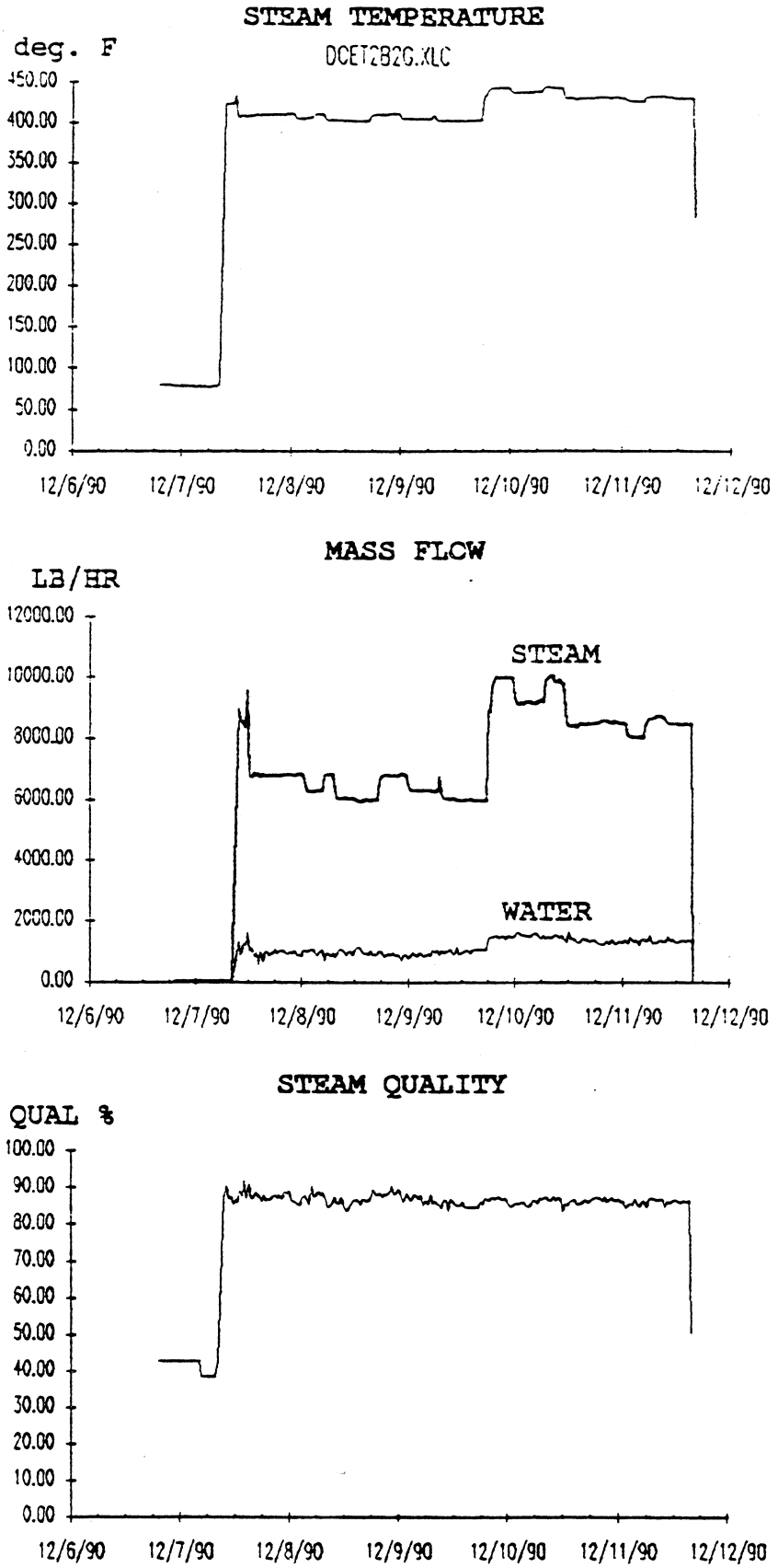


FIGURE B-11: STEAM CONDITION FOR TEST OF UN-CENTRALIZED BARE TUBING WITH THERMAL PACKER

at which condensation could occur. Testing proceeded and stable operating data were collected until December 9 when steam pressure was increased to 335 psi (condition 3). Data collection continued until December 11 when the data objectives for this test case were fully accomplished and the test was terminated.

Test of Centralized Bare Tubing With Gas Packed Annulus

The test of a centralized bare tubing with gas packed annulus (Case C) utilized the same 2 7/8" bare tubing as the previous test but with significant impact on the annulus. Nitrogen gas was continuously fed to the annulus by the generator which had previously been operated and debugged during Test Case A.

Steam injection started on January 11 with a wellhead pressure of 235 psi (condition 2). Figure B-12 shows the steam temperature with mass flows of water and steam and the calculated steam quality. Testing proceeded and stable operating data was collected until January 14 when steam pressure was increased to 335 psi (condition 3). Data collection continued until January 16 when the data objectives for this test case were fully accomplished and the test was terminated.

Test of Centralized Bare Tubing With Sealed Annulus Without Packer

The test of a centralized bare tubing without a packer (Case D) utilized all of the test hardware and instrumentation from the previous test case, except for the nitrogen generator which was no longer required.

Steam injection started on January 22, with a wellhead pressure of 235 psi (condition 2). Figure B-13 shows the steam temperature with mass flows of water and steam and the calculated steam quality. Testing proceeded and stable operating data were collected until January 25 when the steam pressure was increased to 335 psi (condition 3). Data collection continued unti January 28 when the data objectives for this test case were fully accomplished and the test was terminated.

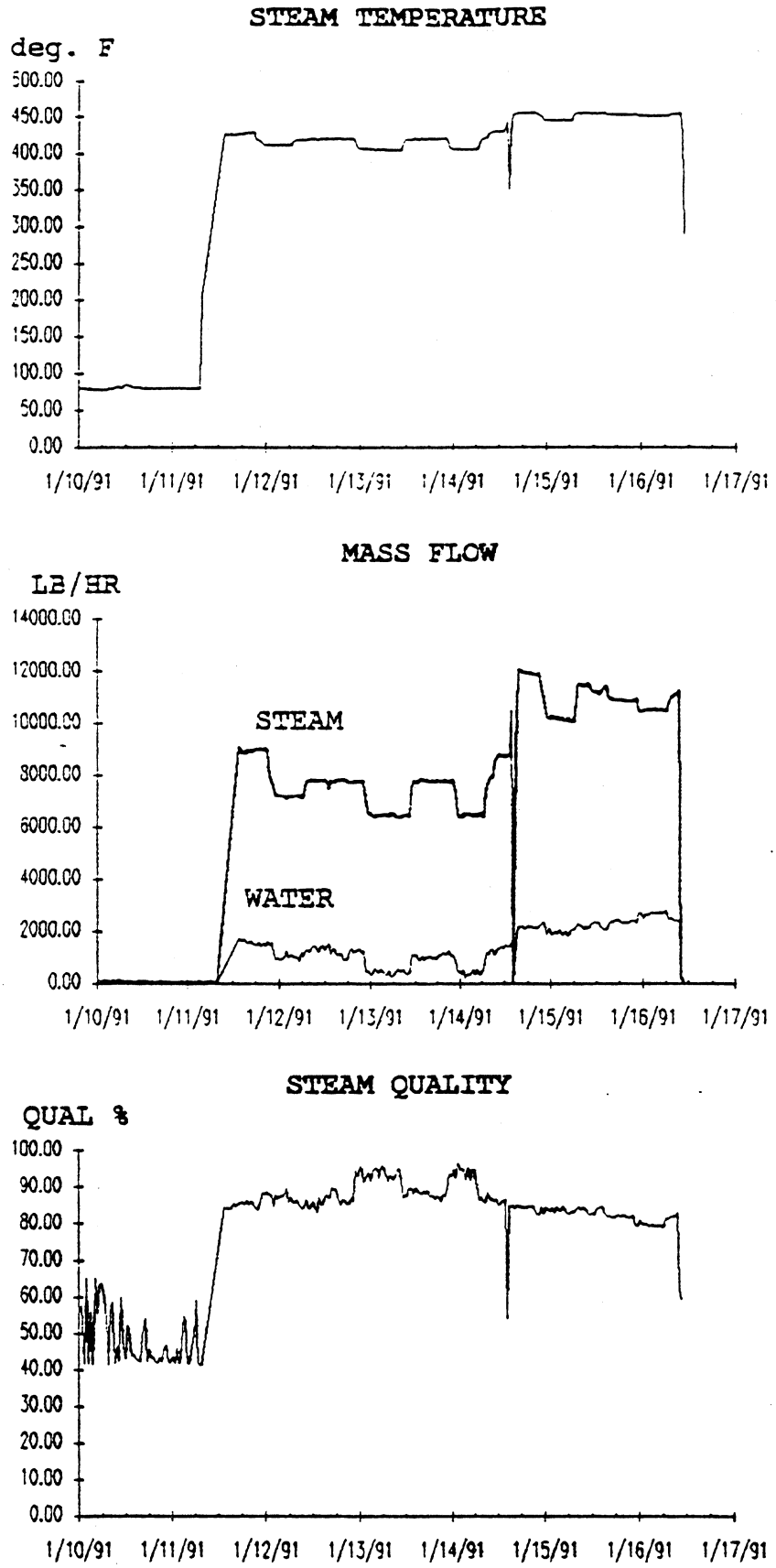
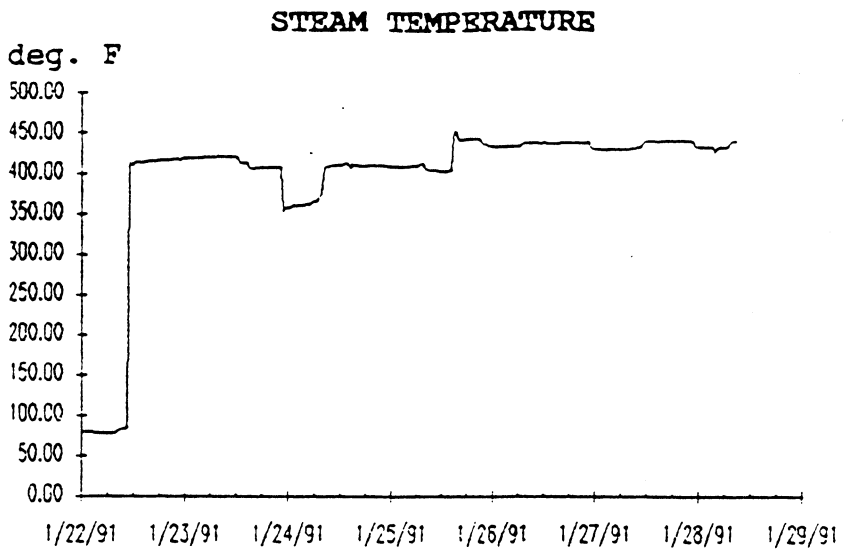
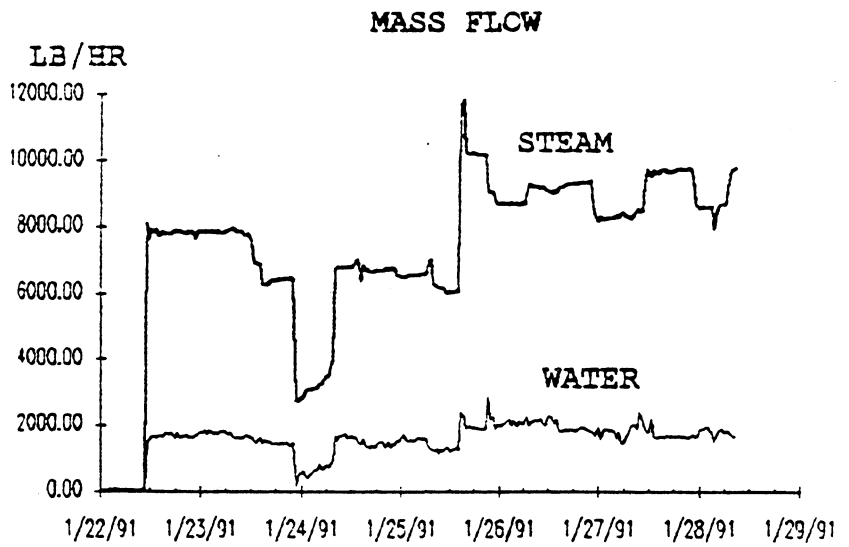


FIGURE B-12: STEAM CONDITION FOR TEST OF CENTRALIZED BARE TUBING WITH GAS PACKED ANNULUS





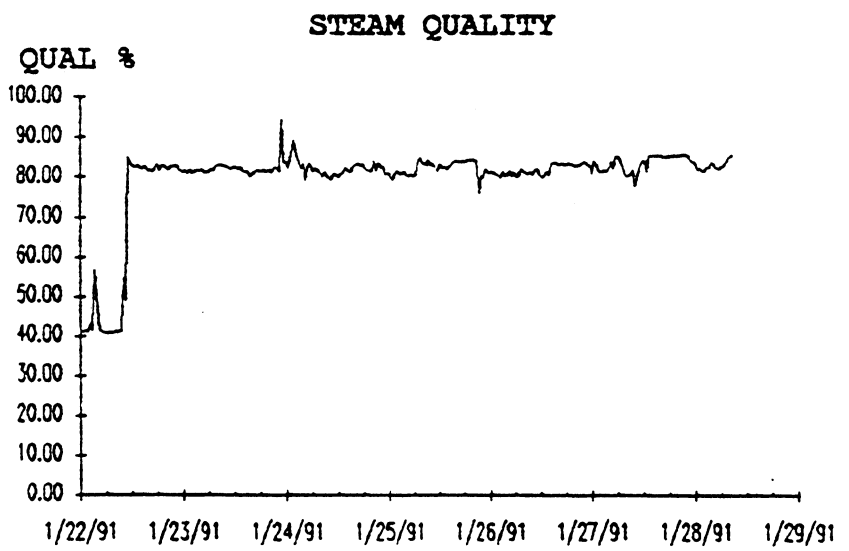


FIGURE B-13: STEAM CONDITION FOR TEST OF CENTRALIZED BARE TUBING WITH SEALED ANNULUS WITHOUT PACKER

3.2.3 Discussion of Results

Table B-5 shows casing temperatures and heat flux rates for each tested completion with the same nominal steam temperature of 430°F.

TABLE B-5: TYPICAL COMPARATIVE CASING TEMPERATURE AND HEAT LOSS DATA (Steam Condition 3: 250 ft depth average data)

Test	Steam Temp (F)	Tubing Temp (F)	Casing Temp (F)	Casing Heat Flux
A	448	155	150	45
A-1	443	143	144	104
B	428	401	262	534
B-A	431	400	276	441
C	452	337	329	685
D	436	369	369	620

As expected, the bare tubing without packer (Cases C & D) shows the highest casing temperatures with heat losses above 500 Btu/Ft/Hr. The insulated tubing showed the lowest casing temperatures, averaging 143°F. Insulated tubing heat losses averaged 48 BTU/Hr/Ft.

During the test of a gas packed completion (Test Case C), 8 scfm of nitrogen was injected into the annulus at the wellhead. This quantity of incondensable gas was expected to significantly reduce the rate of heat transfer due to condensation, and was expected to result in casing temperatures which were lowest near the wellhead but higher near the bottom of the well where the gas pack was diluted by steam. Table B-6 shows vertical profiles of casing temperature and heat flux profiles. The measured heat loss with the gas pack was greater than for the same completion without the gas pack.

TABLE B-6: VERTICAL TEMPERATURE PROFILE FOR GAS PACK (CASE C) (At 02:44 on 1/16/91)

Depth (Ft)	Casing Temperature (°F)	Heat Flux (BTU/FT/HR)
200	319	
250	332	645
300	318	
400	293	
500	302	487
600	284	
700	295	
750		607
800	322	

3.3 TASK 3 SOFTWARE DEVELOPMENT

3.3.1 Summary

Under Task 3, a computer software system has been developed. This system, SIMSTEAM, is a wellbore heat loss model. SIMSTEAM can be used to model the flow of two-phase steam/water applications in a wellbore. Steam injection wells and geothermal production can be modeled using this simulator.

SIMSTEAM has been calibrated with field test data developed under Task 2 of the "Wellbore Heat Loss Program".

The Task 3 Software Development work was carried out under a Kawasaki Thermal Systems subcontract by Scientific Software Intercorp Inc. This development effort included the following subtasks:

- Literature survey and software specifications
- Separation and conversion of Code
- New Module Code
- Software integration
- Matching Field Data
- User's guide

Results of test matches are included as Appendix 3 to this report. A User's Guide has been completed as a separate document. The guide includes the source code listing. Installation floppy disks have also been prepared for delivery. The User's Guide has been published as a separate document. The subtasks are discussed below.

3.3.2 Discussion of Development

3.3.2.1 Literature Survey and Software Specifications

The objective of this effort was to establish through literature searches

and direct contacts the extent to which existing knowledge and experience could be applied to the software development task. A survey was conducted to identify techniques, algorithms, and public domain software which could be integrated into the development of the wellbore heat loss model.

As a result of this subtask, a series of recommendations and guidelines were developed for the actual software development effort.

3.3.2.2 Separation and Conversion of Code to Targeted Hardware

It was determined that VSTEAM, an existing SSI product, would be used as the basis for future development. The source code was ported from a VAX mainframe to the required platform, an IBM compatible PC using the DOS operating system.

3.3.2.3 Software Validation

The initial product, SIMSTEAM, was validated after porting using results reported in various industry standard reports.

3.3.2.4 Modification of Code and Matching of Field Data

Data from several test cases were then delivered by KTS to SSI for verification and matching using, SIMSTEAM. Data files were constructed and various runs performed in an attempt to match the test data. Program modificatons were made to allow:

- Variable thermal properties as a function of depth

- Variable tubing properties as a function of depth

The results of the matches are appended in this report (Appendix 1 through 9). The matches are presented graphically by plotting measured casing temperature versus simulated tubing temperature. Output files are also appended after the primary casing temperature plot for each case matched.

Data from nine actual steam injection tests were matched using SIMSTEAM. Steam injection rate, steam quality, injection temperature, and tubing string configuration were varied for each test. The tests are defined as follows:

Test A-1

Nineteen joints of standard 3 1/2" x 2 3/8" Thermocase 750 were run in the test wells for tests A-1, A-2, A-3. The average test parameters are as follows:

Injection string:	3 1/2" x 2 3/8" Thermocase 750
Steam Separator:	at 365 ft
Injection Rate:	2950 lbm/hr for 36 hours
Steam Quality:	5%
Steam Temperature:	305°F

The measured casing temperatures for Test A-1 were matched by setting the thermal conductivity of the tubing insulation to 0.015 Btu/hr/ft/°F and the thermal conductivity of the annulus fluid to 0.015.

The hot spot created by a non-insulated steam separator was simulated by setting the thermal conductivity of this region to 26 Btu/hr/ft/°F, the published value of steel. In addition, the thermal conductivity of the annulus was increased to 0.10, which may indicate an area of minor refluxing. The hot spot at the bottom of the tubing is caused by the proximity of the non-insulated packer.

Note that this was the only case that fluid injection temperature increased with depth. This is due to the low steam quality and low injection rate.

Test A-2

This case is identical to Case A-1 except the steam temperature

has been increased to 400° and at a steam quality of 90%. Steam injection was maintained at 2950 lbm/hr for 48 hours. The casing temperatures were matched by setting the thermal conductivity of the tubing insulation to 0.02 Btu/hr/ft/°F and the thermal conductivity of the annulus fluid to .015.

Test A-3

The steam injection pressure was increased to 300 psi at an injection temperature of 430°F. The packer failed during this test, therefore, the annulus had no insulating properties as indicated by the data. The test was rerun using a different casing packer. Again, the packer was observed to be leaking.

The steam separator was removed from the string for this test, therefore, this hot spot is not present as in the previous two tests. The thermal conductivity of the tubing was maintained at 0.02 but the thermal conductivity of the annulus fluid was increased to 1.0. By the end of the test all annulus instrumentation recorded 212°F due to the presence of refluxing.

Test B-2

In the remaining steam injection well tests, non-insulated tubing was utilized as the steam injector. The test parameters for these tests were:

Injection String:	2 7/8" centralized tubing with packer
Injection Rate:	5700 lbm/hr
Steam Quality:	90%
Steam Temperature:	400°F

Test B-3

Injection String: 2 7/8" centralized tubing with packer
Injection Rate: 7500 lbm/hr
Steam Quality: 80%
Steam Temperature: 430°F

Tests B-2 and B-3 were matched by setting the thermal conductivity of the tubing to 26.00 and the casing annulus to 0.070.

Test C-2

Injection String: 2 7/8" centralized tubing with gas pack and no packer
Injection Rate: 7000 lbm/hr
Steam Quality: 90%
Steam Temperature: 400°F

Test C-3

Injection String: 2 7/8" centralized tubing with gas pack and no packer
Injection Rate: 10000 lbm/hr
Steam Quality: 80%
Steam Temperature: 430°F

Tests C-2 and C-2 were matched with the same thermal conductivities as tests B-2 and B-3. The thermal conductivity of the casing annulus for Test C-2 was increased to 0.30 near the surface.

Test D-2

Injection String: 2 7/8" centralized tubing without packer
Injection Rate: 8000 lbm/hr
Steam Quality: 90%
Steam Temperature: 400°F

Test D-3

Injection String:	2 7/8" centralized tubing without packer
Injection Rate:	9000 lbm/hr
Steam Quality:	80%
Steam Temperature:	430°F

Tests D-2 and D-3 were performed without a downhole packer, therefore, the thermal conductivity of the casing annulus was set to higher value of 2.0 which matched the measured data.

The eccentric test cases could not be matched as SIMSTEAM cannot simulate this type of configuration.

3.3.3 Discussion of Results

3.3.3.1 SIMSTEAM Description

A wellbore heat loss model SIMSTEAM has been developed. SIMSTEAM provides accurate verified predictions of the wellbore energy loss and steam quality degradation to be expected in a steam injection well. The model is effective over a wide range of combinations of completions and operational conditions.

The program is contained on a single 3 1/2" floppy disk. SIMSTEAM has been compiled and linked to run on any IBM-compatible computer. The program can be entered into a hard drive but a hard disk is not necessary. A minimum of 640K of RAM is required in absence of a hard disk. A numeric co-processor is not required. There would be speed advantages if a co-processor is a part of the system.

The numerical simulator (SIMSTEAM) can be used to model the flow of two-phase steam/water systems in a wellbore. Producing wells for geothermal applications or injection wells for steam flood applications can be modeled using the simulator. The simulator models the following effects:

- Two-phase pressure drop
- Flow regime changes
- Phase changes
- Steady state heat transfer from the wellbore fluid to the formation
- Transient heat flow to the formation

Empirical definitions for the steady-state flow of two-phase fluids in vertical or inclined pipe have been developed based on historical investigations. The empirical pressure drop correlations have been coupled with thermodynamic equations defining heat transfer to simulate geothermal production or steam injection wells. The pressure drop in a wellbore containing steam and water along with phase

behavior can be estimated assuming the mass flow rate, steam quality and pressure are known at some point in the well system. Transient heat loss calculations can also be modeled as a separate option.

The basic equations that make up this numerical model consist of "flow equations" and "heat transfer equations." These equations are coupled numerically through a heat balance. The numerical procedure and associated equations are discussed in detail in the User's Guide.

SIMSTEAM can be used to model both production and injection wells. Heat transfer, though important, is not critical for a geothermal well as these wells normally flow at high rates. The control of heat loss (insulation) is critical for thermal steam injection wells because the oil recovery is dependent on the latent heat and steam quality delivered at the sand face. In addition, mass rates tend to be lower for injection wells. The cost effectiveness of insulated tubing can be evaluated for various conditions using SIMSTEAM.

The simulation of fluids in thermal wells requires the coupling of the pressure drop solution and the heat loss solution using a heat balance. The pressure drop algorithm is composed of various empirical correlations for the head and friction loss terms. Heat loss can be calculated by the following methods:

- Specified Overall Coefficient Ramey
- The Willhite Method
- Two Dimensional Transient Radial Heat Loss

SIMSTEAM is capable of simulating the heat loss behavior in layered intervals with varying heat loss coefficients such that known aquifers and multiple casing strings can be accommodated. The required input data deck can be constructed interactively with recommended default values supplied. The default values can be overriden if desired. Calibration of calculated parameters with measured data can also be accomplished easily and the results saved.

SIMSTEAM can be used to model:

- Steam injection for EOR projects (heat loss and quality)
- Casing and tubing insulation design
- Geothermal producing wells
- Geopressured geothermal wells with solution gas
- Injection/production well deliverability versus bottomhole or wellhead pressure

SIMSTEAM can be used to match transient well test data which is very accurate when properly calibrated. Pressure and/or temperature versus depth at several rates can be established to determine and overall heat transfer coefficient. The temperature profile can be established as a function of rate to determine heat transfer as a function of reservoir rock layer.

3.3.3.2 User's Guide

A complete User's Guide was written for SIMSTEAM. The user guide includes documentation of the technology used for formulating SIMSTEAM in addition to detailed descriptions of data input.

3.3.3.3 Software Deliveries

Installation disks in addition to the source code have been prepared.

4.0 CONCLUSIONS

The ultimate purpose of this program was to provide reliable data from an active steam injection well and use this data to verify the wellbore heat loss model which is defined as the bottom line program deliverable. This objective has been met with the development and delivery of the SIMSTEAM software system. SIMSTEAM is user friendly and can be run on IBM-compatible PC systems of modest capabilities.

In addition, the Task 2 Test and Measurement program has yielded interesting results.

- The downhole casing and injection string instrumentation provided accurate data over an extended period of time.

- Data from the heat flux sensors can be utilized to provide accurate calculations of energy loss.

- The insulated string exhibited thermal conductivity in line with the manufacturers specification (Table B-4). For instance, at steam condition #2, (400°F wellhead steam temperature), the measured string K-factor is 0.0045 Btu/Hr.Ft.°F. "String K-Factor" includes heat losses at the coupling and at internal centralizers.

- There is no appreciable difference in heat flux to the earth from the insulated string where the centralized conductor (Test Case A) is compared to the decentralized condition (Test Case A-1).

- During Test Case A-1, overall heat losses from the insulated injection string at steam condition #3 were in the order of 31000 Btu per hour.

- During Test Case B, steam condition #3, initial heat flux from the uninsulated string during annulus fluid boil off was 1.196 million Btu per hour. Following fluid boil off, heat losses in the centralized string were 0.254 million Btu's per hour.

- The presence of refluxing was clearly demonstrated during Test Cases A & A-1.

- Refluxing was demonstrably suppressed after it occurred by the introduction of annulus pressure. Refluxing was also prevented by forcing reservoir fluids below the packer prior to establishing the packer seal.

- Refluxing did exist in <u>this test well</u> except when the annulus was pressurized.

- It is reasonable to suggest that refluxing will occur if there is fluid above the packer.

5.0 RECOMMENDATIONS FOR FUTURE WORK

Two areas of future work are suggested for consideration. The first will provide a more accurate basis for modeling well bore heat loss. The second will establish a basis for the maintenance of the configuration of the SIMSTEAM software system.

5.1 INVESTIGATION OF REFLUXING HEAT TRANSFER

Annulus convection can be characterized by two types of heat transfer. Vertica semi-infinite annular convection, and evaporation/condensation refluxing. For a well with moisture present in the annulus, evaporation/condensation refluxing provides a large heat transfer coefficient in both the radial and vertical directions. Vertical annular convection coefficients are dependant upon the Grashof number which is length dependent where, for an annular enclosed space, length is not defined.

Basic research is needed to provide heat transfer data which is applicable to the geometry of a well annulus, and covers the cases of dry convection, and the transition from convection to refluxing heat transfer. This data will enable to development and validation of an accurate annulus heat transfer module.

5.2 SIMSTEAM PRODUCT SUPPORT AND MAINTENANCE OF SIMSTEAM CONFIGURATION

As SIMSTEAM is used int he public domain, there are two very predictable requirements which will arise:

- Users will encounter problems and will seek help in applying SIMSTEAM to their specific analysis.

- Users will encounter system related problems. It will be necessary to work out "bugs" which are part of the start-up of any new complex software system if SIMSTEAM is to be truly useful in the field.

It is recommended that consideration be given to establishing a software support and maintenance capability to insure that this system in which there is a considerable investment becomes a useful and used tool.

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