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EVALUATION OF THE J. FRIEMEL #1 VERTICAL WELL TESTS, DEAF SMITH COUNTY, PALO DURO BASIN, TEXAS PANHANDLE

by

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This report describes the vertical well test in the Wolfcamp interval of the J. Friemel #1 hydrologic test well. Included are (1) purpose of the test, (2) test approach, (3) "what went right with the test," (4) "what went wrong with the test," and (5) what should be done differently next time.

Purpose of the Test

The overall purpose of performing the vertical well test was to begin to estimate the importance of fracture permeability in the regional flow system. This aspect of the regional flow system has not been tested in either field tests or modeling exercises. It is probable that there is vertical fluid movement through the various hydrologic units of the Palo Duro Basin. Within each of the hydrologic units as well as across formation boundaries vertical flow may be through fractures. The purpose of this test was to assess the importance of fracture permeability between two porous Wolfcamp carbonate intervals.

Test Approach

The test approach was to measure the leakage between two zones in the Wolfcamp formation. This was to be accomplished by injecting fluid into the upper of the two perforated intervals and monitoring the pressure rise in that interval and in the lower perforated interval.

It was also necessary to document that there was no leakage between the two zones in the well bore. The two zones were isolated by complex packer system which allowed the packer seal to be tested.

What Went Right With The Test

The surface tool equipment and downhole test tool design and construction are the most significant things that went right with the vertical well test.

The tool was designed to document that there was no leakage in the wellbore past the packers by testing the packers before and after the vertical well test under similar pressure differences to those expected during the test. By testing the packers prior to and after the test, the expense and complexity of having a third transducer in the well during the test was eliminated.

Figure 1 shows the final test tool as it was installed in the well. There were two packers permanently installed in the well between the two perforated intervals. Seal assemblies were spaced in the tubing string such that they would seat into the two packers simultaneously. A perforated length of tubing was positioned between the two seal assemblies and thus between the two packers. A seat nipple was positioned below the lowermost seal assembly, so that a plug set into the nipple would isolate the tubing from the lowermost perforated zone. With the plug in place the tubing is in communication with the interval between the packers through the perforated length of tubing, but is isolated from both perforated casing zones. The tubing can then be pressured up to a pressure high enough to document that the packers are not leaking. After the packers are successfully tested, then the plug can be removed, restoring commmunication from the tubing to the lowermost perforated zone.

There were two transducers mounted on the tubing string, one ported to the tubing to monitor the lower perforated zone (monitor zone) and one ported to the annulus to monitor pressure in the upper perforated zone (injection zone).

A standing valve was located in the tubing string above the transducer carrier to allow the monitor zone to be shut in. A pump seat nipple was located above the standing valve to allow a sucker rod pump to be used to pump from the monitor zone.

The test plan was to inject into the upper zone, monitoring the injection pressure with the annulus transducer, and monitoring the monitor zone pressure with the tubing transducer.

This tool design allows the test to be conducted without having to install a transducer between the two packers, yet have documentation that the packers have held. This simplification eliminates the problem of having a transducer cable or port passing through a packer, yet retains the capability of testing the packers.

The surface equipment design is illustrated in figure 2. Four tanks holding a total of 425 barrels of brine were each connected to the injection pump by 2-inch PVC pipe. Each tank was equipped with a valve so that injection could be from any combination of the tanks. The small 50-barrel tank was fitted with a manometer-type sight gauge for measuring fluid level in the tank. The injection pump is an 8-horsepower gasoline engine pump. Pressure in the injection line is regulated by two return lines from the injection line to the 50-barrel tank. On the primary return line, a 1-1/2-inch ball valve can be partially opened to adjust the amount of flow bypassing the injection line and returning to the 50-barrel tank. The secondary return line is equipped with a pressure relief valve which can be adjusted to open at a specified pressure. The system was designed to allow the pressure to be adjusted by the primary return line valve and regulated by the secondary return line pressure relief valve.

On the wellhead side of the injection pump, the injection line consisted of a primary injection line of 1-1/2-inch galvanized pipe, which could be closed by a ball valve, and a 1/2-inch secondary line containing a Fisher-Porter flow meter. The 1-1/2-inch line was to be used to fill the annulus at a high flow rate. When the annulus was filled, the 1-1/2-inch line was to be closed and the 1/2-inch line opened so that the flow rate could be monitored by the flow meter. The Fisher-Porter flow meter scale was adjusted to read from 0.3 gallons per minute to 10.0 gallons per minute. Pressure, temperature, and flow rate were to be measured in the injection line on the wellhead side of the two injection lines, so that the pressure and temperature of the fluids being injected could be measured, and the actual amount of injection could be measured and recorded.

This tool design is an effective, relatively simple means of conducting a vertical well test. This design should be used for this type of test.

What Went Wrong With The Test

The most important problem with the vertical well test was that the injection zone failed to take any fluid. The second problem was the complete failure of the Baker Production Services downhole pressure gauges.

Fluid Take

Test preparation was completed Saturday, February 25, 1984. The annulus was filled from 4:10 p.m. to 5:30 p.m. At 5:30 p.m. the annulus (injection zone) was pressured up to 40 psi. There was no apparent fluid take after filling the annulus. The fluid to be injected was contained in a stock tank with a manometer-type sight gauge which showed no fluid level drop in the tank. There was a flow meter in line which was calibrated for flow as low as 0.56 gpm, which also did not record fluid take after filling the annulus. At 7:15 p.m. the pump was shut off and valves closed which held the annulus pressure at 40 psi. On February 26, 1984, the valves were opened to allow gravity drain from the stock tank into the injection zone. No fluid take was noted from the tank on February 27, 1984, at 1:00 p.m.

Reasons for no fluid take include low initial formation permeability and plugging of formation permeability by casing scale silt, which was scraped from the casing, January 30, 1984, while preparing for the test. The schedule of events leading to the formation being damaged were:

January 30, 1984	8:30 a.m.	Perforated upper zone	5700-5710
	10:45-12:00 noon	Swabbed upper zone	
	3:15 p.m.	Perforated lower zone	5809-5813
	3:30 p.m.	Began scraping casing	
January 31, 1984	10:00 a.m.	Finished scraping	

At this point, the fluid level in the well is approximately 2,780 feet depth and rising to 2,100 feet depth. The fluid is fouled by the scale scraped from the casing.

From January 31 to February 5, 1984, this water was in contact with the perforated intervals. On February 5, the two packers had been set, and the test tool string was just above the packers ready to be seated into them. Prior to seating into the packers, Wolfcamp fluid tagged with tracer was circulated into the well as a tag for ONWI testing. (ONWI wanted to be able to identify all injected water.) The fluid level in the well was at land surface at the finish of circulating in the tracer water. Fluid level was left at land surface overnight, essentially putting 3,000 psi onto both perforated zones.

On February 6, 1984, Haliburton was called to pressure test the packers.

February 6, 1984	8:30 a.m.	Tubing was seated into packers (it became clear later that the sediment from scraping the casing had actually prevented the tubing from seating into the packers).
	8:30-9:00 a.m.	Baker plugs end of tubing.
	9:00-9:30 a.m.	Haliburton pressures up on tubing to test packer seal. Haliburton was to pressure up to 500 psi at the well head, but, when the pressure reached 400 psi, a surface hose attached to the annulus blew off. Circulation past the packers was evident. The fluid circulated as filled with casing scale.

At this point, the well was actually pressured up to 3,400 psi by the Haliburton truck pushing the casing scale-laden water into the perforations. When the tools were removed to determine why the packer seat failed, the extent of the casing scale buildup was discovered and remedied by bailing.

Prior to pressure testing, these packers with the scale-laden water in the upper injection zone produced approximately 0.35 gpm by swabbing. This is an indication of a low, but measurable, permeability. After pressuring up on these perforations with the scale-laden fluid, there was never a fluid level fall in the well. It is possible, however, that the formation was too tight to allow injection even before the damage.

Pressure Gauge Failure

On Saturday, February 25, 1984, the annulus was filled by 5:28 p.m., evidenced by pressure buildup at the well head. At 5:26 p.m. the first questionable annulus measurement, 3,891 psi, was noted. At 5:31 p.m. the first questionable tubing measurement, 1,759 psi, was noted. The annulus gauge went out completely at 5:35 p.m., and both gauges were down by 6:00 p.m. Subsequent troubleshooting by Baker determined that the trouble was downhole, and the tools would have to be removed for repair.

The reason Baker has given for the gauge failure is that there was a leak in the cable at approximately 1,500 feet depth. The cable is run in the annulus from the gauges to the well head. When the annulus was filled to begin pressuring up on the injection zone, the entire length of the cable was wet for the first time. This cable had been in and out of the well nearly ten times and likely had been abraded by rubbing on the casing. The transducers were working well until the annulus was filled and pressured up. The most probable cause of their failure was a short in the cable caused by the injection brine at a weakened spot caused by running the cable in and out of the well several times.

The objectives of the vertical well test could not be met after these developments without (1) removing the test tools for repair, (2) swabbing and acidizing the test zones to remove the wellbore damage, and (3) reinstalling the test tools. Even with this remedial action, it is not likely that the test zone damage will be lessened enough that the interval will take enough fluid for the vertical well test to be successful. The upper interval may have been too tight to allow sufficient injection even without the wellbore damage.

What Should Be Done Differently Next Time

For the next vertical well test, several steps should be taken to prevent a repeat of these circumstances. The most important step to take is to insure that the injection zone is able to take fluid. There are also precautions which Baker could take to lessen the probability of their equipment failing.

Injection Zone Permeability and Damage

In order to insure that the injection zone is able to take fluid, the zone should be sufficiently permeable and should be protected from wellbore damage.

The present zone should have been as permeable as any in this interval, possibly as high as 10 to 20 millidarcys (based on log analysis and a drill-stem test from 5,620 to 5,910 feet depth). When the injection zone was swabbed, it produced 0.5 barrels per hour and would have been too low for a successful vertical well test. For the vertical well test to be successful, the injection zone must take enough fluid so that, if there is interconnection between the injection zone and the monitor zone, the injected fluid will cause a pressure rise in the monitor zone.

The injection zone of the next vertical well test should be better developed by swabbing to stimulate the well. If there is a concern about whether the pressures can build back up to stable before the test starts, then the zone is too tight. During swabbing an Amerada pressure gauge and shut-in tool can be run on a wire line to estimate the formation pressure and horizontal permeability of the injection zone. With the inflow rate data and permeability estimates from serious swabbing of the injection zone, a better decision can be made as to the adequacy of the injection zone permeability.

The most important step to prevent or lessen formation damage during the vertical well test is to clean the casing before any other procedures. The casing should be scraped and then clean water circulated until all the scale is removed. Because the injection fluid is to travel down the annulus, this step is critical.

Only after the casing is clean should the perforating be started. After both zones are perforated, then the upper perforations will have to be scraped to prevent packer damage as the packers pass by the upper perforations. If the casing is cleaned before perforating, then the scale and debris caused by scraping the perforations will be minimized.

A second step to prevent wellbore damage will be to filter the injected water. This will also lessen the amount of debris forced into the injection perforations.

Equipment Failure

Because the annulus in the vertical well test will be filled with brine and pressured up to 50 psi, the downhole pressure transducer cable will be under the highest stress of any of the testing. Steps which Baker could take are either to use a new cable for the vertical well test or develop a wet test of the cable before installing it in the well. More realistically, Baker will probably be aware of the added stress of the brine-filled annulus and will evaluate the age of the cable and the number of trips in the well which it has suffered, and will either use a new cable or will be prepared to repair the cable if it should leak. A second weak spot, which should be carefully inspected, is the o-ring connection between the transducers and the annulus. This connection will also be under a larger strain than in any other testing.

Summary

The test approach and test tool design developed for this test should be capable of giving a successful vertical well test. If the injection and monitoring intervals were chosen carefully and were stimulated by swabbing and were protected from wellbore damage and if the downhole pressure gauges are prepared for the extra stress of the filled annulus, then the chances for a successful test will be very good. The unsuccessful results of this earlier experiment should not preclude a second attempt in another well.

VERTICAL WELL TEST DOWNHOLE EQUIPMENT SCHEMATIC

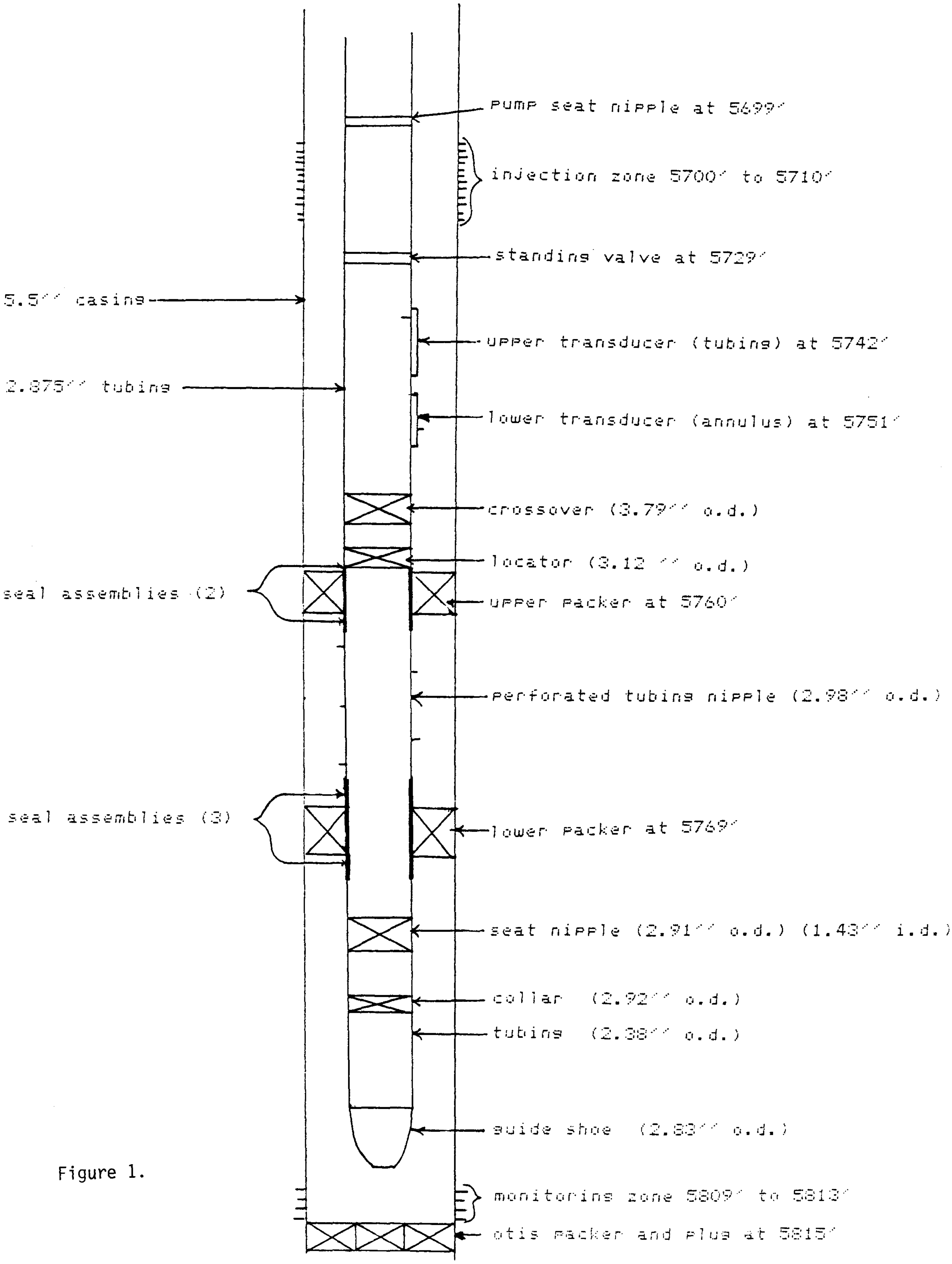
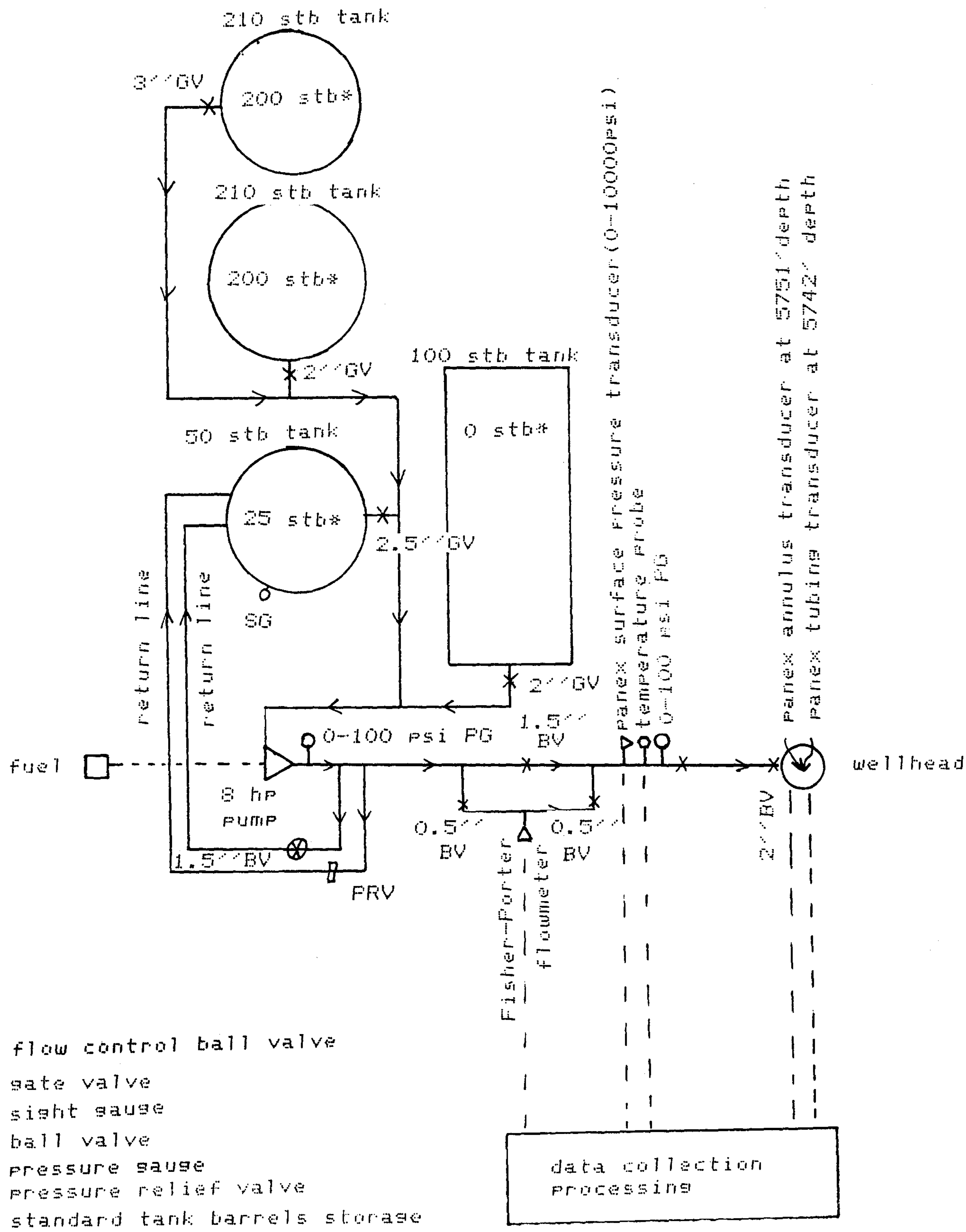


Figure 1.

FIGURE 2 VERTICAL WELL TEST SURFACE SCHEMATIC



⊗ – flow control ball valve

GV – gate valve

SG – sight gauge

BV – ball valve

PG – pressure gauge

prv – pressure relief valve

stb* – standard tank barrels storage

stb – standard tank barrells capacity