10/21/07 NA LR DRC IPI PLR0329538188

BP America Production Company
501 Westlake Park Boulevard
Houston, Texas 77079

David D. Reese
Reservoir Engineer
Phone: 281.366.5834
Fax: 281.366.7836

2 16

IPI

RECEIVED

OCT 21 2003

OIL CONSERVATION DIVISION

October 9, 2003

30-045-27799
1270 FNL
580 FWL
D

New Mexico Oil Conservation Division
1220 South Francis Drive
Sante Fe, NM 87505

Attention: David Catanach

Dear Mr. Catanach:

Re: Request for Revised Maximum Injection Pressure
E.E. Elliott SWD Well No. 1

This letter is to request that the injection pressure limit for the E.E. Elliott SWD Well No. 1 be set at 1790 psig. This request is based on a reevaluation of the step rate test performed on this well May 5, 2000. The original evaluation had identified a parting pressure of 1740 psig, which resulted in the establishment of the current injection pressure limit 1690 psig. A careful review of the test and evaluation, however, shows that the step rate test was valid but that the evaluation was in error because of a time synchronization issue between the rates and pressures. This resulted in the incorrect identification of a parting pressure where none had been encountered. The original evaluation and correspondence is included as Attachment 1.

Bottom hole pressure was recorded using a different clock than the injection rates. The plot that showed the reported times for rates and pressures, as submitted in May, 2000, is included as Figure 1. The clock recording the rate data is about two minutes behind the clock recording the pressure data. This can be observed as the pressure increase associated with each rate increase precedes the rate change based on recorded time. Rates and pressures had been plotted for each rate step as shown on Figure 2. Data was intended to be reflective of pressure at the end of each time step; however, because of the time shift, the pressures were actually taken from early in the subsequent time step. This was consistent for each step except the last step where there was no subsequent step. That step, by default, had a pressure at the end of the time step. This inconsistency resulted in the last point being low compared to the other points and the incorrect identification of a parting pressure. Figure 3 shows step data points for rate and pressure compared to the raw data, where the rate is representative of the end of a step while the pressure (psia) is from the beginning of subsequent step. The step data is plotted on Figure 4, showing the (false) break. Figure 5 shows step data where the rate and pressure data is reflective of the middle of each step, avoiding errors associated with a small time shift. This data is cross plotted on Figure 6 where it can be seen that there is not a break in the data that could be attributed to exceeding a parting pressure.

The step rate test data was also evaluated using pressure transient techniques. A reservoir model was built for the injection well and the step rate test was simulated through a history matching procedure. The result of the simulation is shown on Figure 7. The symbols are bottom hole recorded pressure data points while the continuous line is the simulation pressure data. The match of the data through each of the steps and the subsequent pressure falloff period occurred with a constant reservoir/well condition description.

This shows that the test was valid and the well condition did not change throughout the test i.e., no fracture extension occurred.

The incremental injection pressure of this well is very low compared to the net overburden pressure. During the step rate test the incremental injection pressure compared to reservoir pressure reached a maximum of 85 psi at a rate of 6500 bwipd. Reservoir pressure at a depth of 8300 feet is approximately 5000 psia. Assuming an overburden pressure gradient of 1 psi per foot yields a net overburden of 3300 psi. Incremental injection pressure of 85 psi is less than 3% of the net overburden pressure. This is illustrated on Figure 8 where the bottom hole pressure is plotted compared to reservoir pressure. This plot is scaled to where the maximum point on either scale is equivalent to the overburden pressure. A unit slope is shown for reference. At a bottom hole pressure below the unit slope, the well would be producing. At a pressure above the slope the well would be injecting. The distance between the unit slope and the top of the plot is the net overburden. A typical fracture pressure gradient of 0.7 times the net overburden is shown on the plot for reference

Currently we are injecting about 800 bwpd at a surface pressure of 1630 psig, about 40 psig above the wells shut-in pressure (about 1% of the net overburden pressure). Although we currently have a pressure limit of 1690 psig, we have maintained a conservative margin of 50 psi from the established limit, so that momentary pressure spikes (meter jiggle?) do not approach the pressure limit. Additionally, the field operations have maintained an additional 10 psi margin, periodically shutting in the well, so that the pressure spikes don't exceed the 50 psi margin.

Because we are injecting at a pressure that is marginally (1%) above the reservoir pressure, we are constrained to a rate that is 12.5% of the level that has been demonstrated to be safe. Figure 9 shows the surface injection data recorded during the last step of the step rate test, which was shown to not be above parting pressure (the complete data set is included in the attachment). The median surface pressure during the last step was 1795 psig. We would like the injection pressure limit be set to 1795 psig (surface). As such, we will maintain a 50 psi pressure margin at 1745 psig.

If you have any questions, please contact me at 281-366-5834.

Sincerely,

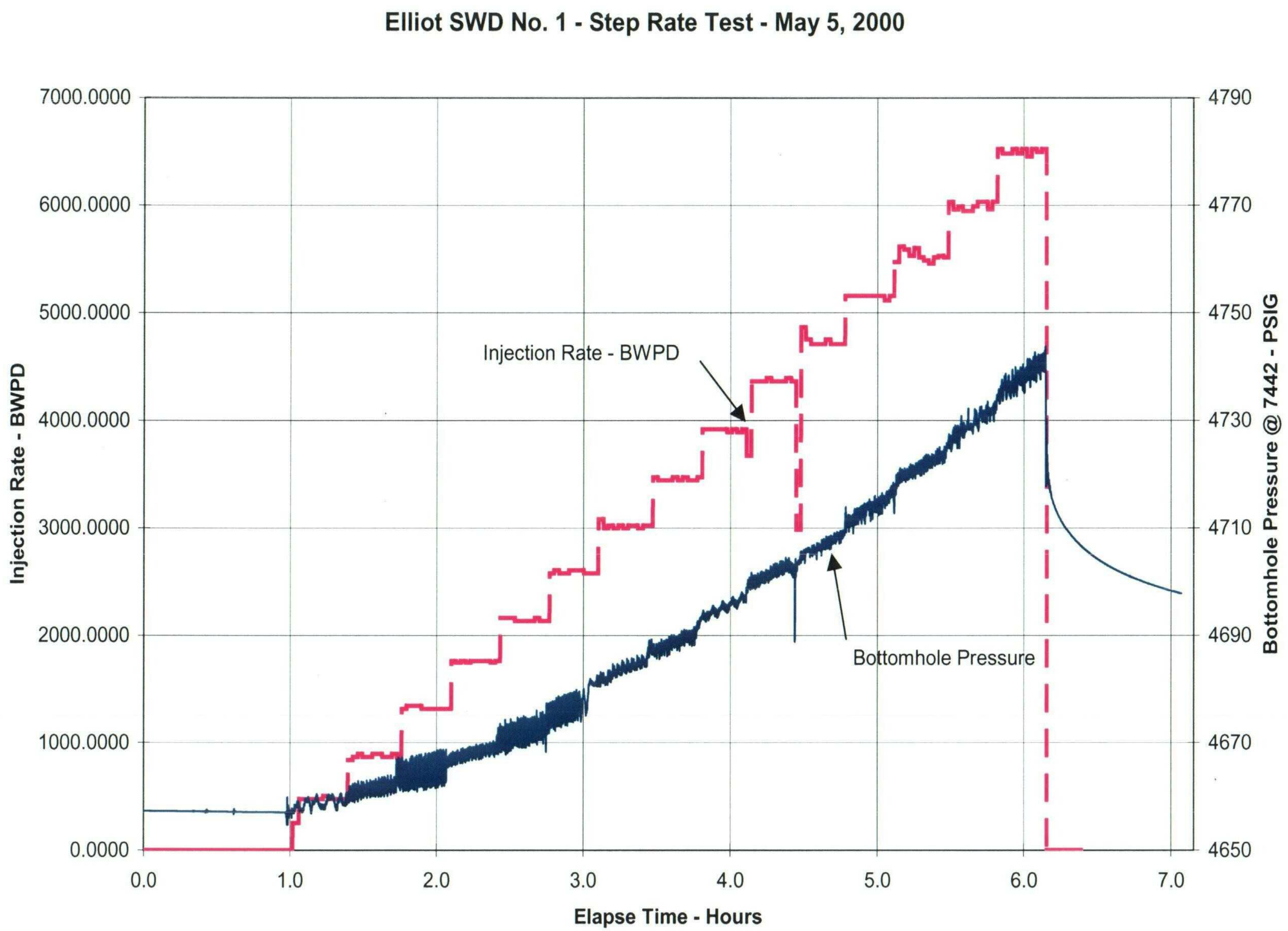
David D Reese

David Reese

Attachments

CC: New Mexico Oil Conservation Division
Attention: Charles Perrin
1000 Rio Brazos Road
Aztec, NM 87410

Brittany Benko – Farmington OC
Gary Munson – Farmington OC



Elliot SWD No. 1 - Step Rate Test - May 5, 2000
Injection Rate - BWPD
Bottomhole Pressure @ 7442 - PSIG
Elapse Time - Hours
Injection Rate - BWPD
Bottomhole Pressure
7000.0000
6000.0000
5000.0000
4000.0000
3000.0000
2000.0000
1000.0000
0.0000
4790
4770
4750
4730
4710
4690
4670
4650
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0

FIGURE 1

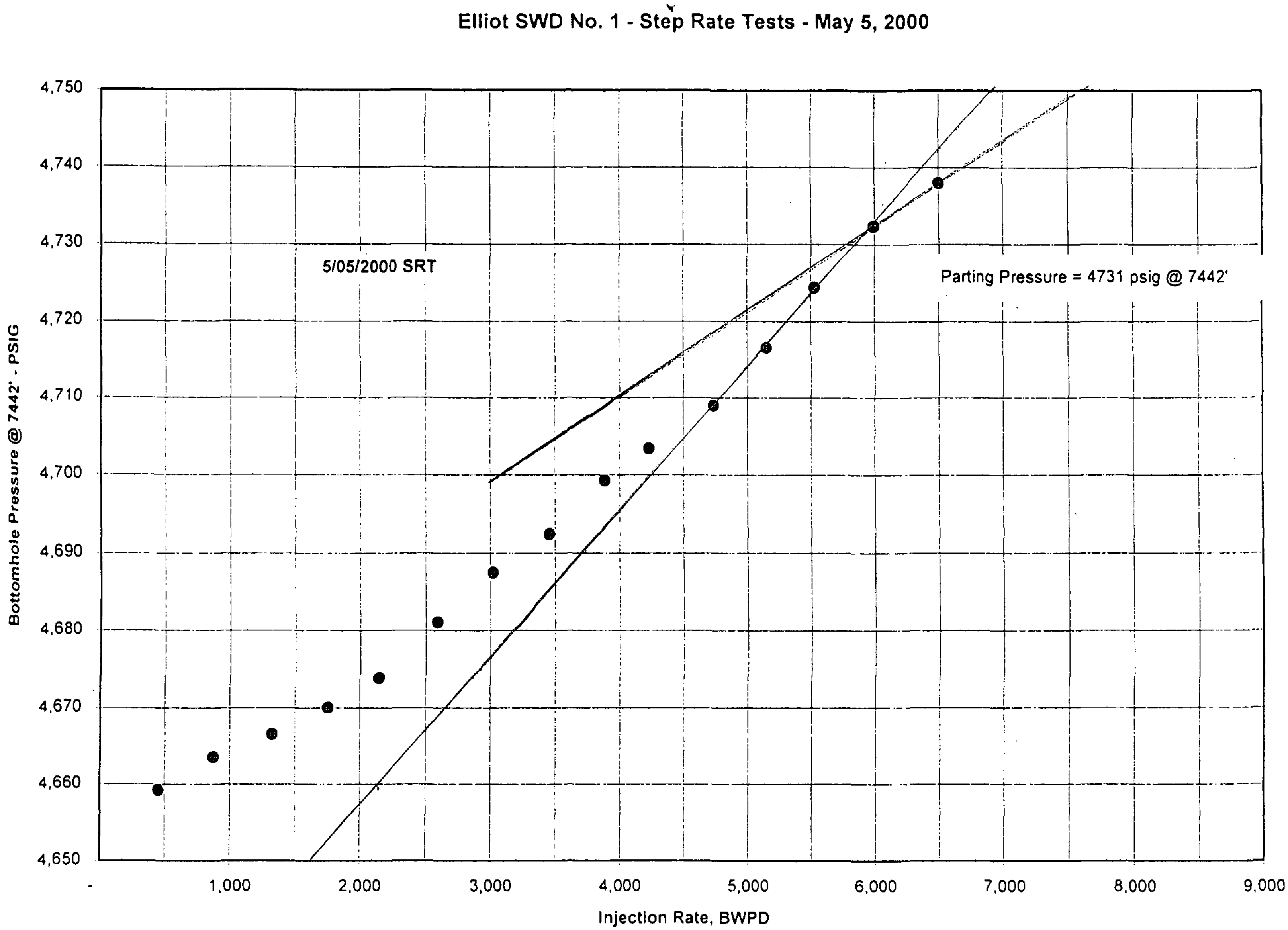

Elliot SWD No. 1 - Step Rate Tests - May 5, 2000
5/05/2000 SRT
Parting Pressure = 4731 psig @ 7442'
Bottomhole Pressure @ 7442' - PSIG
Injection Rate, BWPD
4,750
4,740
4,730
4,720
4,710
4,700
4,690
4,680
4,670
4,660
4,650
-
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000

FIGURE 2

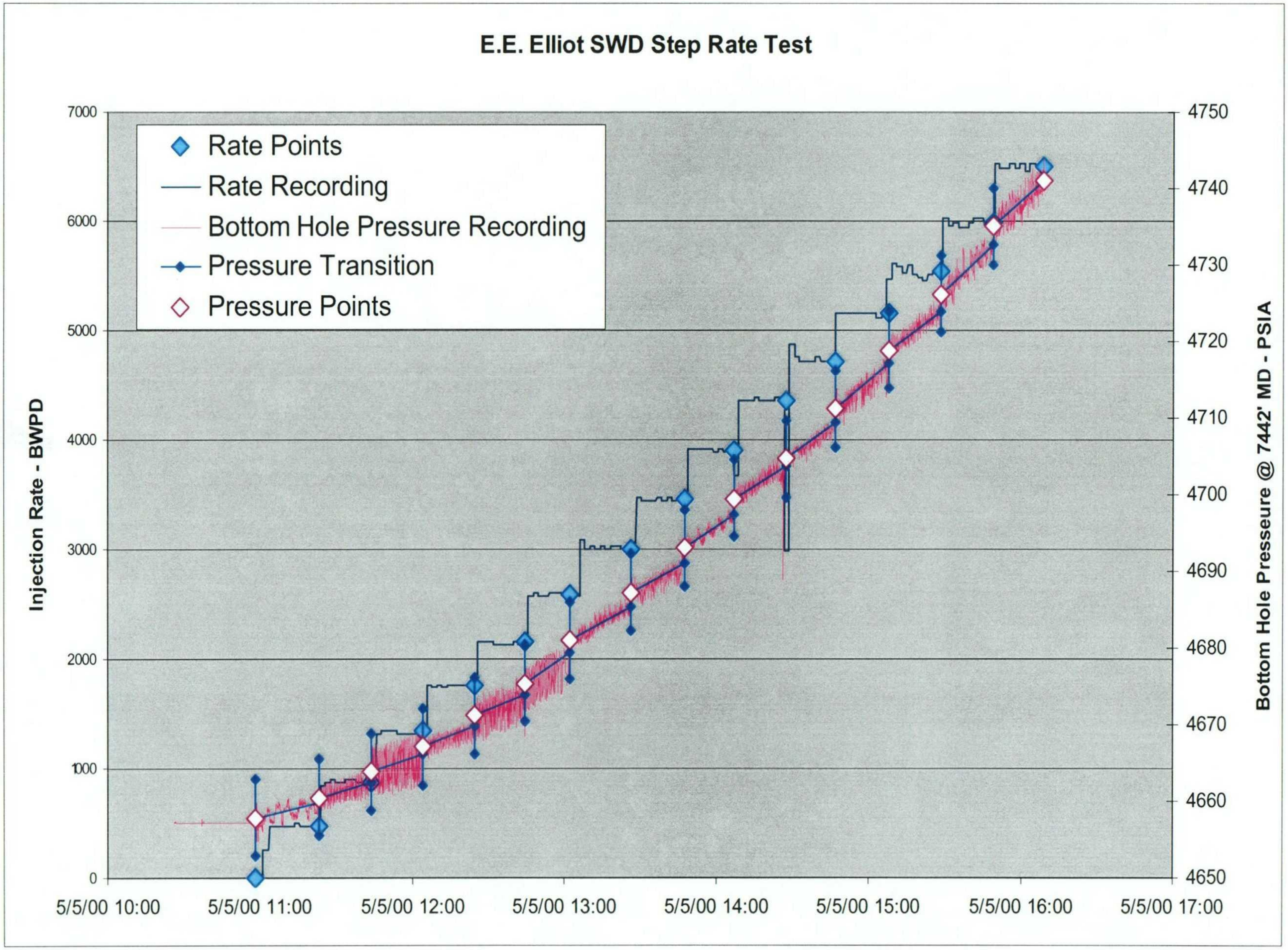
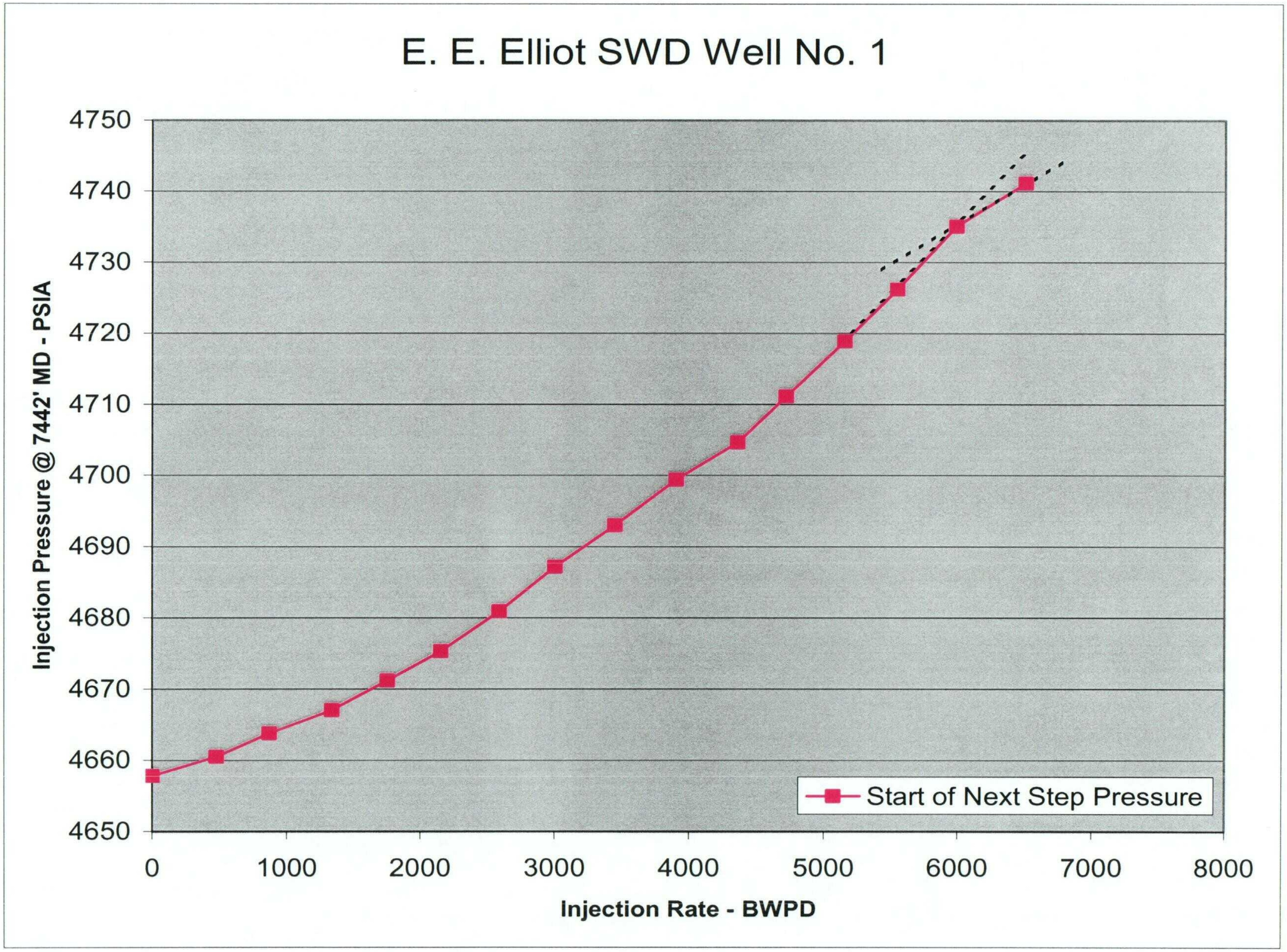

E.E. Elliot SWD Step Rate Test
Rate Points
Rate Recording
Bottom Hole Pressure Recording
Pressure Transition
Pressure Points
Injection Rate - BWPD
Bottom Hole Presseure @ 7442' MD - PSIA
7000
6000
5000
4000
3000
2000
1000
0
4750
4740
4730
4720
4710
4700
4690
4680
4670
4660
4650
5/5/00 10:00
5/5/00 11:00
5/5/00 12:00
5/5/00 13:00
5/5/00 14:00
5/5/00 15:00
5/5/00 16:00
5/5/00 17:00

FIGURE 3



E. E. Elliot SWD Well No. 1
Injection Pressure @ 7442' MD - PSIA
4750
4740
4730
4720
4710
4700
4690
4680
4670
4660
4650
0
1000
2000
3000
4000
5000
6000
7000
8000
Injection Rate - BWPD
Start of Next Step Pressure

FIGURE 4

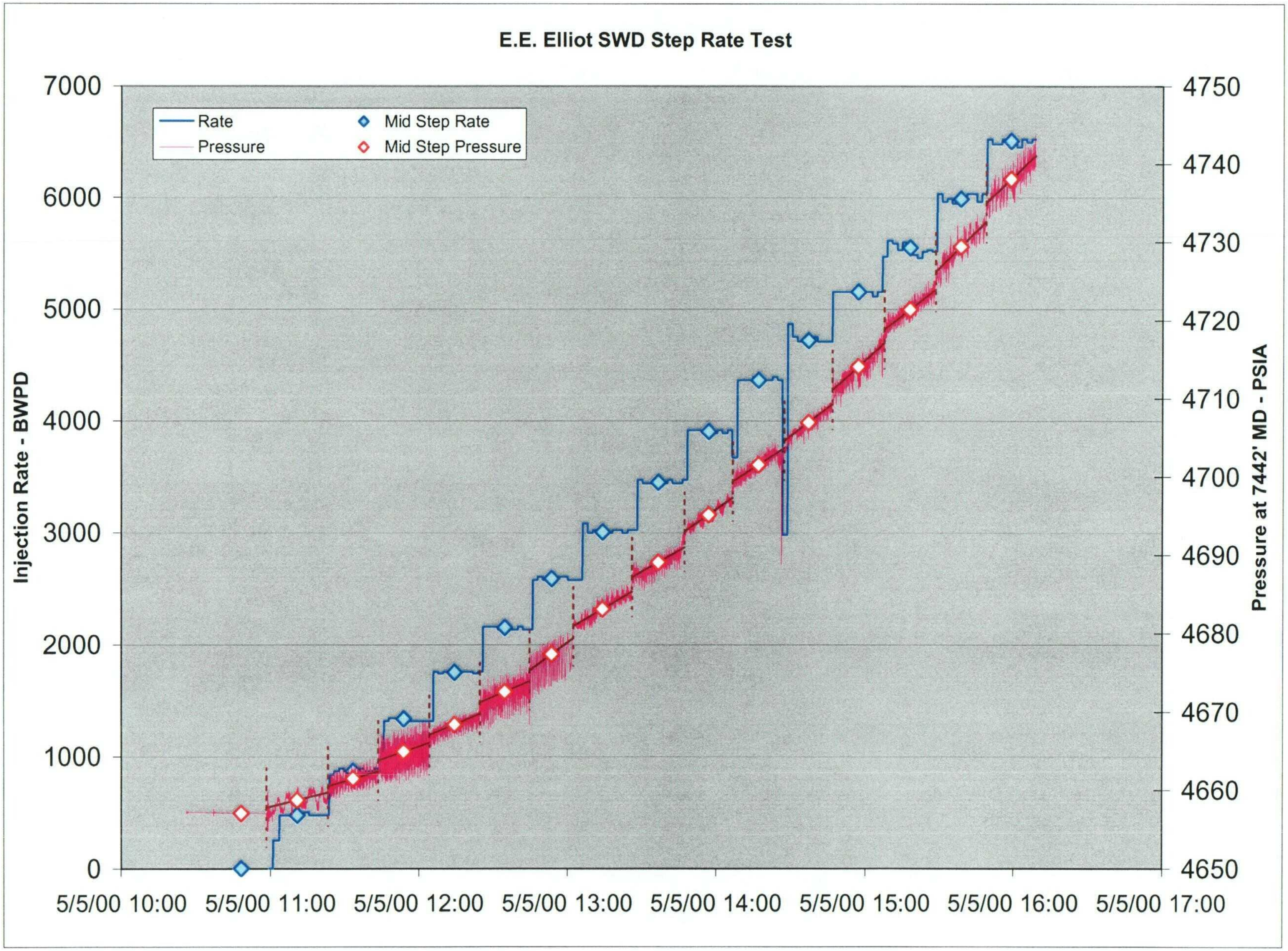

E.E. Elliot SWD Step Rate Test
Rate
Pressure
Mid Step Rate
Mid Step Pressure
Injection Rate - BWPD
Pressure at 7442' MD - PSIA
7000
6000
5000
4000
3000
2000
1000
0
4750
4740
4730
4720
4710
4700
4690
4680
4670
4660
4650
5/5/00 10:00
5/5/00 11:00
5/5/00 12:00
5/5/00 13:00
5/5/00 14:00
5/5/00 15:00
5/5/00 16:00
5/5/00 17:00

FIGURE 5

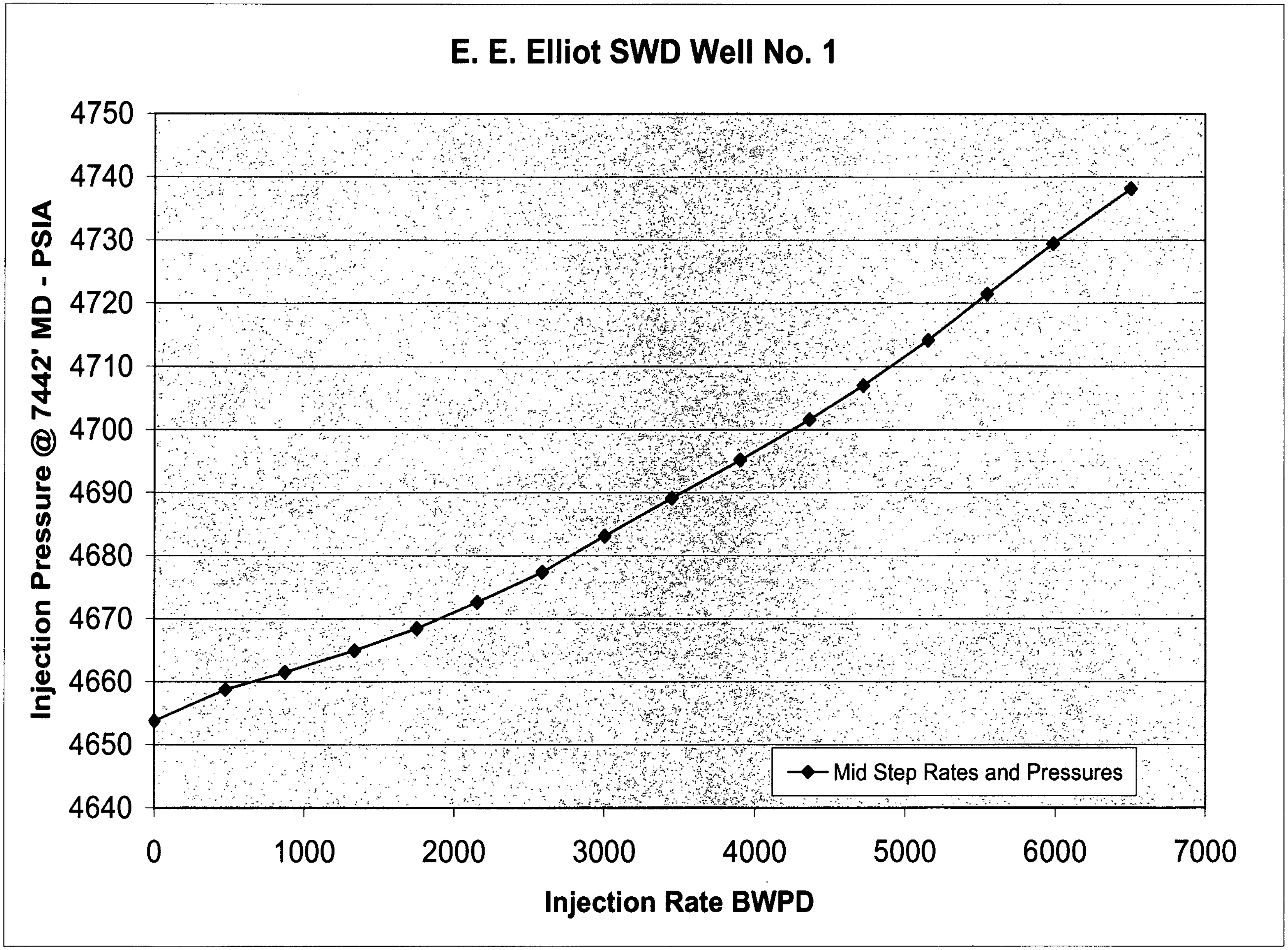
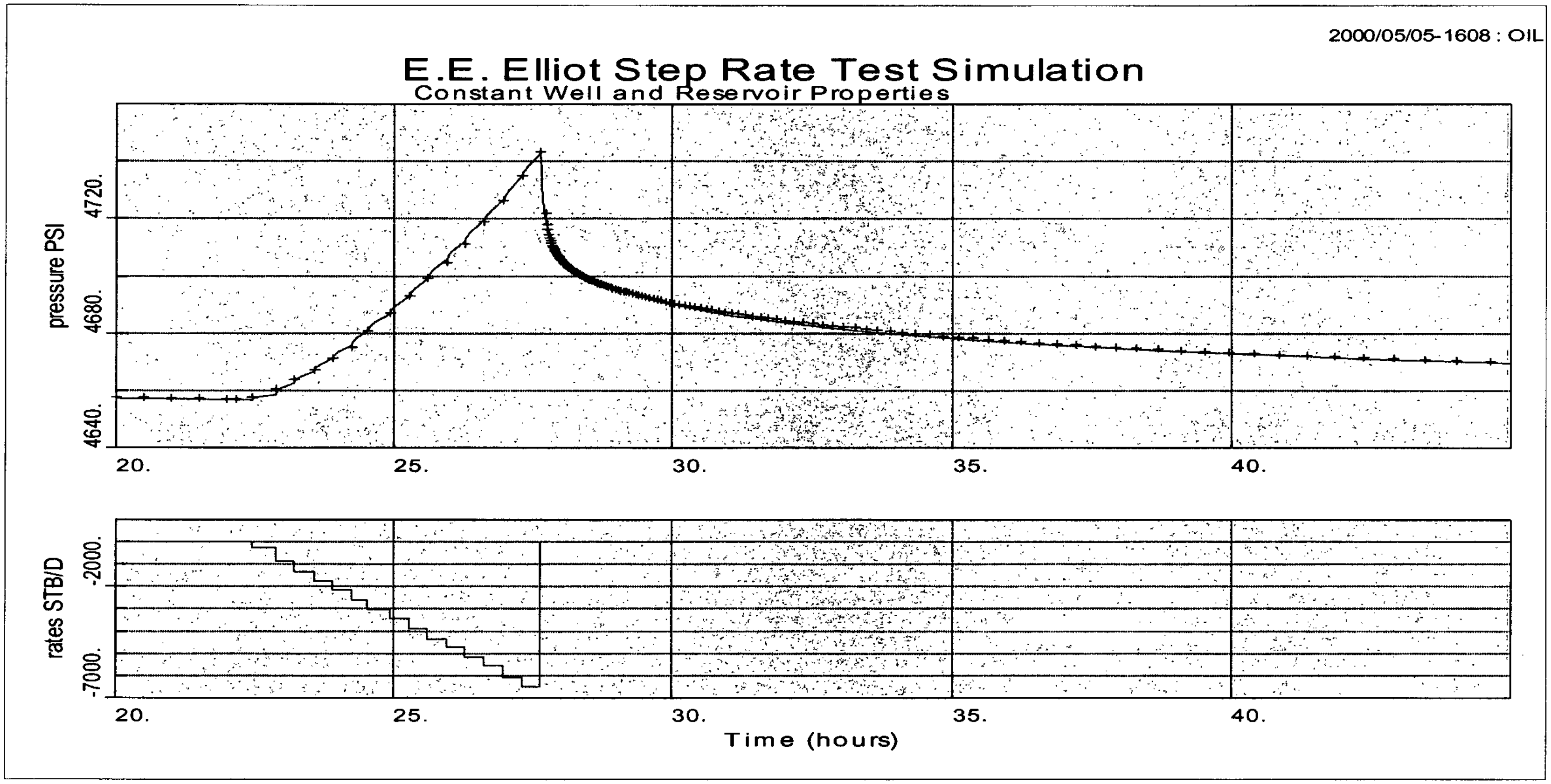

E. E. Elliot SWD Well No. 1
Injection Pressure @ 7442' MD - PSIA
4750
4740
4730
4720
4710
4700
4690
4680
4670
4660
4650
4640
0
1000
2000
3000
4000
5000
6000
7000
Injection Rate BWPD
Mid Step Rates and Pressures

FIGURE 6



Homogeneous Reservoir

** Simulation Data **

well. storage	=	0.00157 BBLS/PSI
skin	=	-5.73
permeability	=	39.2 MD
Perm-Thickness	=	7850. MD-FEET
+x boundary	=	328. FEET (1.00)
-x boundary	=	323. FEET (1.00)
Initial Press.	=	4325.23 PSI

Static-Data and Constants

Volume-Factor	=	1.000 vol/vol
Thickness	=	200.0 FEET
Viscosity	=	0.4000 CP
Total Compress	=	.6000E-05 1/PSI
Rate	=	-6500. STB/D
Storivity	=	0.0001200 FEET/PSI
Diffusivity	=	43100. FEET^2/HR
Gauge Depth	=	7442. FEET
Perf. Depth	=	N/A FEET
Datum Depth	=	8250. FEET
Analysis-Data	ID:	DDR002
Based on Gauge	ID:	GAU001

FIGURE 7

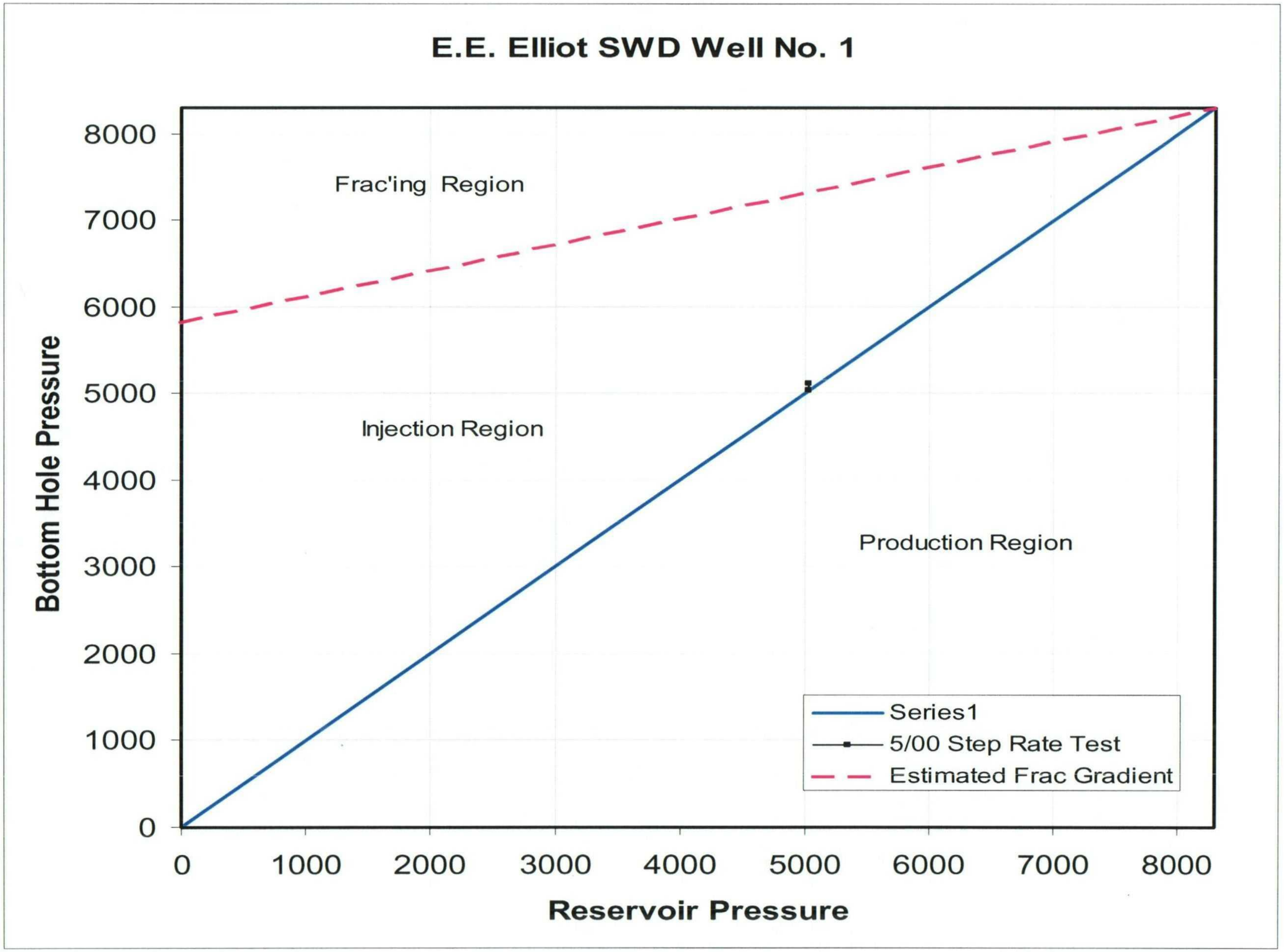

E.E. Elliot SWD Well No. 1
Frac'ing Region
Injection Region
Production Region
Bottom Hole Pressure
Reservoir Pressure
8000
7000
6000
5000
4000
3000
2000
1000
0
0
1000
2000
3000
4000
5000
6000
7000
8000
Series1
5/00 Step Rate Test
Estimated Frac Gradient

FIGURE 8

FIGURE 9

Well	Field	Service Date	Customer	Job Number
E.E. Elliott SWD #1 ##1			1OCO PRODUCTION COMF	20156543

Time 24 hr clock	Annulus Pressure psi	Pressure U1 psi	Total Flowrate bpm	Total Volume bbl					Message
15:37	-36.63	1735	4.13	37.48	0	0	0	0	
15:39	-36.63	1735	4.16	45.88	0	0	0	0	
15:41	-36.63	1735	4.19	54.28	0	0	0	0	
15:43	-36.63	1735	4.19	62.96	0	0	0	0	
15:45	-36.63	1735	4.14	71.27	0	0	0	0	
15:47	-36.63	1740	4.19	79.66	0	0	0	0	
15:49	-32.05	1786	4.53	88.12	0	0	0	0	
15:49	-32.05	1786	4.53	88.12	0	0	0	0	[Total Volume]=0 bbl
15:51	-32.05	1790	4.5	8.94	0	0	0	0	
15:53	-36.63	1790	4.5	18.03	0	0	0	0	
15:55	-32.05	1790	4.53	27.13	0	0	0	0	
15:57	-36.63	1795	4.5	36.24	0	0	0	0	
15:59	-36.63	1795	4.53	45.33	0	0	0	0	
16:01	-32.05	1795	4.48	54.42	0	0	0	0	
16:03	-36.63	1795	4.53	63.52	0	0	0	0	
16:05	-32.05	1795	4.51	72.62	0	0	0	0	
16:07	-36.63	1799	4.53	81.75	0	0	0	0	
16:09	-36.63	1639	0.	90.37	0	0	0	0	
16:11	-32.05	1451	0.	90.37	0	0	0	0	
16:13	-36.63	1451	0.	90.37	0	0	0	0	
16:14	-36.63	1451	0.	90.37	0	0	0	0	min 5
16:15	-36.63	1451	0.	90.37	0	0	0	0	
16:17	-32.05	1456	0.	93.17	0	0	0	0	
16:19	-32.05	1456	0.	93.17	0	0	0	0	
16:21	-32.05	1451	0.	93.17	0	0	0	0	
16:23	-32.05	1451	0.	93.17	0	0	0	0	
16:24	-32.05	1451	0.	93.17	0	0	0	0	min15

Post Job Summary

Average Injection Rates, bpm				Volume of Fluid Injected, bbl				
Fluid	N2	CO2	Maximum Rate	Clean Fluid	Acid	Oil	CO2	N2 (scf)
3	0	0	4.6	0	0	0	0	0

Treating Pressure Summary, psi						Quantity of & placed, lb	
Breakdown	Maximum	Final	Average	ISIP	15 Min. ISIP	Total Injected	Total Ordered/Designed
0	1808	1808	1500	1680	0	0	0

N2 Percent	CO2 Percent	Designed Fluid Volume	Displacement	Slurry Volume	Pad Volume	Percent Pad
0 %	0 %	0 gal	780 bbl	0 bbl	0 gal	0 %

Customer or Authorized Representative	Dowell Supervisor	Number of Stages	Fracture Gradient	
Daryl Erickson	Larry Jennings	0	0 psi/ft	☐ Job Completed ☐ Screen Out