PRODUCTION OPTIMIZATION OF SALDANADI GAS FIELD BY NODAL ANALYSIS METHOD

M. B. Haq, E. Gomes and M. Tamim
Department of Petroleum and Mineral Resources Engineering
Bangladesh University of Engineering and Technology

Abstract
Overall performance of a production system is determined by the flow rate. This rate is sustainable for the conditions established by the system components (tubing, pipelines, chokes, etc), reservoir pressure, and separator pressure. Nodal analysis technique identifies each resistance in the system starting from sand face to the outlet of the separator. It allows sensitivity study of each component and optimizes the overall performance of the production system. Production capacity of all the wells of the Saldanadi Gas Field has been optimized using nodal analysis method. The results are based on production data up to August 31, 2002. At the same time different sensitivity studies have been performed to determine the effect of the system components. This study finds that the production rates of all the wells in this field have not been maintained at the optimum production capacity in the past.

Introduction

Bangladesh Petroleum Exploration and Production Company Ltd (BAPEX) with the drilling of the Saldanadi well # 1 in 1986 discovered Saldanadi Gas Field. It is located approximately 40 km north of *Comilla*.

Three distinct commercial hydrocarbon accumulations *are encountered by the two wells in this field.* The upper, middle and lower gas zones are found at a depth of approximately 7130 ft true vertical depth (TVD), 7103 ft (TVD), and 7890 ft (TVD) respectively.

Saldanadi Well # 1 was completed as a dual producer (short and long strings). *It started production on March* 28, 1998 from upper and lower zones. Saldanadi well # 2 was directionally drilled in 1999. Production began from middle zone on May 3, 2001.

Initial production rates[1] of the Saldanadi well # 1 for short and long strings were about 5.34 mmscfd and 11.44 mmscfd, respectively. Short and long strings wellhead pressures were 1980 psia and 2120 psia, respectively. Cumulative productions of the Saldanadi well # 1 (short and long strings) from March 28, 1998 to August 31, 2002 are about 3324 mmscf and 14521 mmscf, respectively. Production rates (August 31, 2002) of the two strings (short and long) were 1.16 mmscfd and 5.99 mmscfd and the flowing wellhead pressures (FWHP) were 1264 psia and 2244 psia respectively. The initial reservoir pressure and FWHP of the well # 2 [2] were 3244 psia and 2299 psia, respectively. The initial production rate was about 15 mmscfd. On August 31, 2002, the production rate and FWHP of the well # 2 were about 10.30 mmscfd and 2099 psia respectively. Cumulative production of the Saldanadi well # 2 from May 3, 2001 to August 31, 2002 is about 6663 mmscf.

The objectives of the study are to perform production system analysis of the Saldanadi Gas Field as of August 2002 to understand the production behavior, to recommend optimum production approach and future adjustments for the wells and to find out optimum production rates under different operational conditions. Using the nodal analysis method and the PIPESIM software, the individual well performances have been conducted for sensitivity studies of the important well variables.

Nodal Analysis

Nodal Analysis[3] is the method for analyzing any well, *which will allow determination of the producing* capacity for any combination of components. This method may be used to determine locations of excessive flow resistance or pressure drop in any part of the system. The success of Nodal Analysis method, however, depends on the use of appropriate correlation and equations while analyzing inflow performance relationship (IPR) and outflow performance relationship (OPR).

The nodal analysis method can be summarized in five steps:

1st: Solution node is selected. This node usually corresponds to a component or point in the system. It is the most convenient for specific sensitivity calculations.
2nd: Appropriate correlation and equations are assigned to each component for analyzing IPR and OPR.
3rd: Pressures are calculated at the selected node for each part of the system (one part always starts from the reservoir pressure and the other part from the separator pressure) for several flow rates.
4th: Calculated results (pressures and rates) are used to generate a plot of node pressure vs flow rate.

5th: A plot of node pressure versus flow rate will produce two curves of Inflow and Outflow. The overall production performance of the system is determined from the intercept of the inflow and outflow performance curves. The procedure is illustrated graphically in Figure 1.

The effect of a change in any of the components can be analyzed by recalculating the node pressure versus flow rate using the new characteristics of the component that was changed. If a change was made in an upstream component, the outflow curve will remain unchanged. However, if either curve is changed, the intersection will be shifted, and a new flow capacity and node pressure will be established. The curves will also be shifted if either of the fixed pressures is changed, which may occur with depletion or a change in separation conditions.

Pressure Losses in Producing Wells

A series of pressure drops occur when reservoir fluid moves from the reservoir to surface through wellbore, tubing string and process facilities[4] The system has been divided into five major components for better understanding of the pressure losses. Figure 2 shows the pressure losses in a producing well[5]. These are summarized as follows:

1. the pressure loss in the producing formation required to get the fluid into the wellbore;
2. the pressure loss in the tubing string from the bottom of the tubing to the surface which includes all downhole chokes, restrictions, etc. within the tubing string and the wellhead;
3. the surface choke;
4. the surface flow lines from the choke to the separator; and
5. the separator (or separators).

Adding up all five pressure losses give the total pressure loss that occurs between the reservoir and the stock tank or sales line. The design pressure drop can be determined when any four of the pressure drops are known. In our country, the separator pressure is fixed depending upon the flow rate. Therefore, any trial and error solution of any of the other losses will require beginning the calculation either in the reservoir, or at the separator, or both.

Phase Envelope

The PIPESIM[6] software using the composition given in Table 1 has drawn three phase envelopes for three zones of upper, lower and middle respectively. Phase envelopes for three zones are shown in Figures 3, 4 and 5. In Figure 3 (Upper Zone, Well # 1), line AB is the bubble point curve and line BE is the dew point curve. The critical point B, is the intersecting point of the two curves. Point C is the criocondenbar, which is the maximum pressure at which liquid and vapor may subsist in equilibrium. Point D is the cricondentherm, the maximum temperature at which liquid and vapor may co-exist in equilibrium. The same parameters are determined for lower and middle zones from Figures 4 and 5 respectively.

Systems Analysis as Applied to Producing Wells

The effect of various changes in one component of the system has an overall effect on the entire system. Typical wells are selected in order to show the effect of various changes, such as: separator pressure, surface choke size, tubing size and average reservoir pressure. The effect on production rate of various restrictions, such as surface chokes, downhole chokes, safety valves, and completion restrictions, can all be properly accounted for. The analysis will show whether or not the particular well is limited in its production rate by the reservoir's ability to give up fluids or by the producing system.

(1)Effect of Separator Pressure:

The selection of some parameters, such as separator pressure is related to economics. For example, the selection of the separator pressure in a gas-lift system is extremely important in determining compressor horsepower (HP). Separator pressures between 500 and 1100 psi may have very little effect on the flow rate from a low productivity well, but may have a very decisive effect on the flow rate of high productivity wells. A complete systems analysis will show the effect of varying the separator pressure on compressor HP and, hence, the economic feasibility of buying more or less HP. The various profit indicators such as payout, rate of return, net present value etc can be used to make the decision.

In analyzing these wells, it is important to see the effect of different separator pressures while maintaining everything else constant. Input data of this case study is presented in Table 3. Absence of measured average reservoir pressure has forced the use of calculated reservoir pressure from IPR curves. These values could not be verified. Salda Well # 1 (Short String) did not have production test data. Results from DST were used. Several computer runs were made varying the separator pressure from 500 to 1000 psia. The delivery pressure out of gas processing plants in Bangladesh is 1000 psia. From Bakhrabad gas field, gas is being supplied around 600 psia. The separator pressure range was selected on the basis of prevailing operating conditions in most of the Bangladeshi fields. At the same time average reservoir pressure were also varied from 1500 psia to initial reservoir pressure. The results of this case study are in Figures 6 to 8. The change in separator pressure has a significant effect on the flow rate.

Figure 6 shows the variation of average reservoir pressure with outlet pressure of Salda well # 1 (short string). Optimum gas flow rate can be calculated at average reservoir pressure ranging between 1500 psia and 3358 psia and outlet pressure between 500 psia and 1000 psia. At initial reservoir pressure of 3358 psia and outlet pressure of 1000 psia, the optimum gas rate is 2.80 mmscfd. Actual gas rate on August 31, 2002 and flowing wellhead pressure are 1.1628 mmscfd and 1264.7 psia respectively. The optimum production rate of the Salda well # 1 (short string) is 1.20 mmscfd. Similarly, from Figures 7 and 8 optimum gas rates are determined for well # 1 (long string) and well # 2. Actual gas rates on August 31, 2002, and optimum gas rates are shown in Table 4.

A case study[7] was also made when there is no Surface Critical Sub-surface Safety Valve (SCSSV) present at the tubing. It indicates that there was a pressure loss across the SCSSV. SCSSV has an effect on gas rate in the well # 2. Removing SCSSV will cause a flow increase by about 1.09 %. But no pressure loss was found in the well # 1.

(2)Effect of Surface Wellhead Choke:

The production rate largely depends on the surface chokes. The easiest way of increasing the flow rate is to increase the opening of the choke. The input data of this case study is presented in Table 5. Several computer runs were made varying the average reservoir pressure from 1500 psia to initial reservoir pressure and choke size 0.10 inch to 1 inch keeping all other parameters constant. Results of this study are shown in Figures 9 to 11.

The variation of average reservoir pressure with choke size of Salda well # 1(short string) is shown in Figure 9. The present bean size of Salda well # 1 (short string) is 0.2366 inch. It has been calculated from upstream and downstream pressure. On August 31, 2002 actual production rate is 1.1628 mmscfd and optimum gas rate has been found from Figure 9 as 1.20 mmscfd. Similarly, optimum rates for well # 1 (long string) and well # 2 have been determined from Figures 10 and 11. On August 31, 2002 average reservoir pressures were 1900 psia, 3600 psia and 2900 psia for the Well # 1 (Short and Long Strings) and Well # 2 respectively. Optimum gas rates at different bean sizes on those reservoir pressures can be calculated from Figures 10 and 11 and the values are presented in Table 6.

Optimum gas rate from this study is same as the previous results, because all parameters remain same. Changing separator pressure or bean size can change optimum rate. The purpose of the optimization process is finding out the most cost-effective way to increase the optimum rate. In this case it is easier and economically feasible to change optimum rate by changing bean size.
A case study [7] was made in absence of the SCSSV at the tubing. Pressure loss across the valve was found and affected the gas rate in the well # 2 but no effect was found in the well # 1. If the valve is removed then the gas flow will increase by 1.09%(approximate).

Conclusions

1. In the well # 1 (short string), separator pressure may affect the optimum gas rate within the range of 0 to 2 mmscfd. Separator pressure was varied from 500 psia to 1000 psia. For well # 1 (long string), the maximum optimum rate of 5.00 mmscfd was achieved by lowering the separator pressure to 500 psia. For the same limiting separator pressure of 500 psia, a maximum optimum rate of 7.00 mmscfd was found for well # 2.
2. The increase of bean size can considerably affect the production rate of the well # 1 (short string and long string) and well # 2. Significant additional production rate may be achieved in these wells after the bean size increase (Table 6).
3. The optimum production rates under the present operating condition as of August 31, 2002 are:
4.

Well	Optimum Gas Rate (mmscfd)
Well no 1 (Short String)	1.20
Well no 1 (Long String)	6.10
Well no 2	8.30

Recommendations

1. Pressure survey should be conducted on a regular basis in each well to know the present reservoir pressure.
2. Bean size of the surface wellhead chokes of the well # 1 (short string and long string) should be exactly measured to find out the up to date values of the optimum rate.
3. A good reservoir simulation model should be developed for future optimization of the field.

References

1. Production Test Report (1996): Saldanadi Well No. 1, Bangladesh Petroleum Exploration and Production Company Ltd. (BAPEX), (November).

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3. Brown, K.E., Lea, J.F. (1985): "Nodal Analysis of Oil and Gas Wells," SPE paper 15292.
4. Mogensen, A. C., (1999): "Gas Field Production Optimization", ACM Consulting Ltd. BUET U of A Institutional Linkage Project, Report, (February)
5. Beggs, H. D.(1991): "Production Optimization Using Nodal^{TM} Analysis," OGCI Publications, Oil and Gas Consultants International Inc, Tulsa.
6. PIPESIM User Guide, Copy right 1989-1998 Baker Jardine & Associates Limited. London, England.
7. Haq, M. B., Gomes, E., and Tamim, M.,(2003): "Production Optimization Study of Saldanadi Gas Field." Report, (March), Dept. of PMRE, BUET.

Figure 1 Nodal Analysis Method

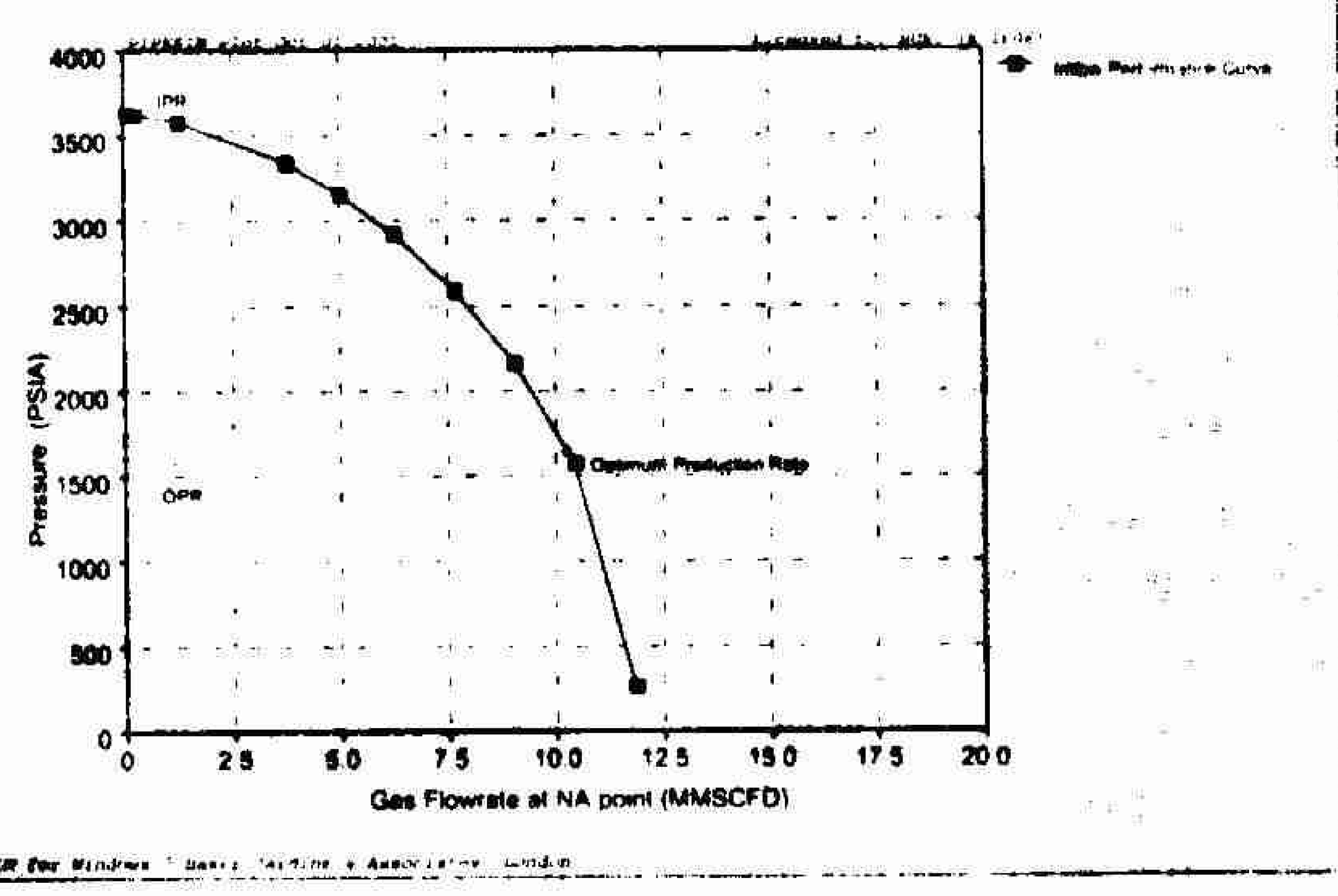

Figure 2 Pressure Losses in a Producing Well

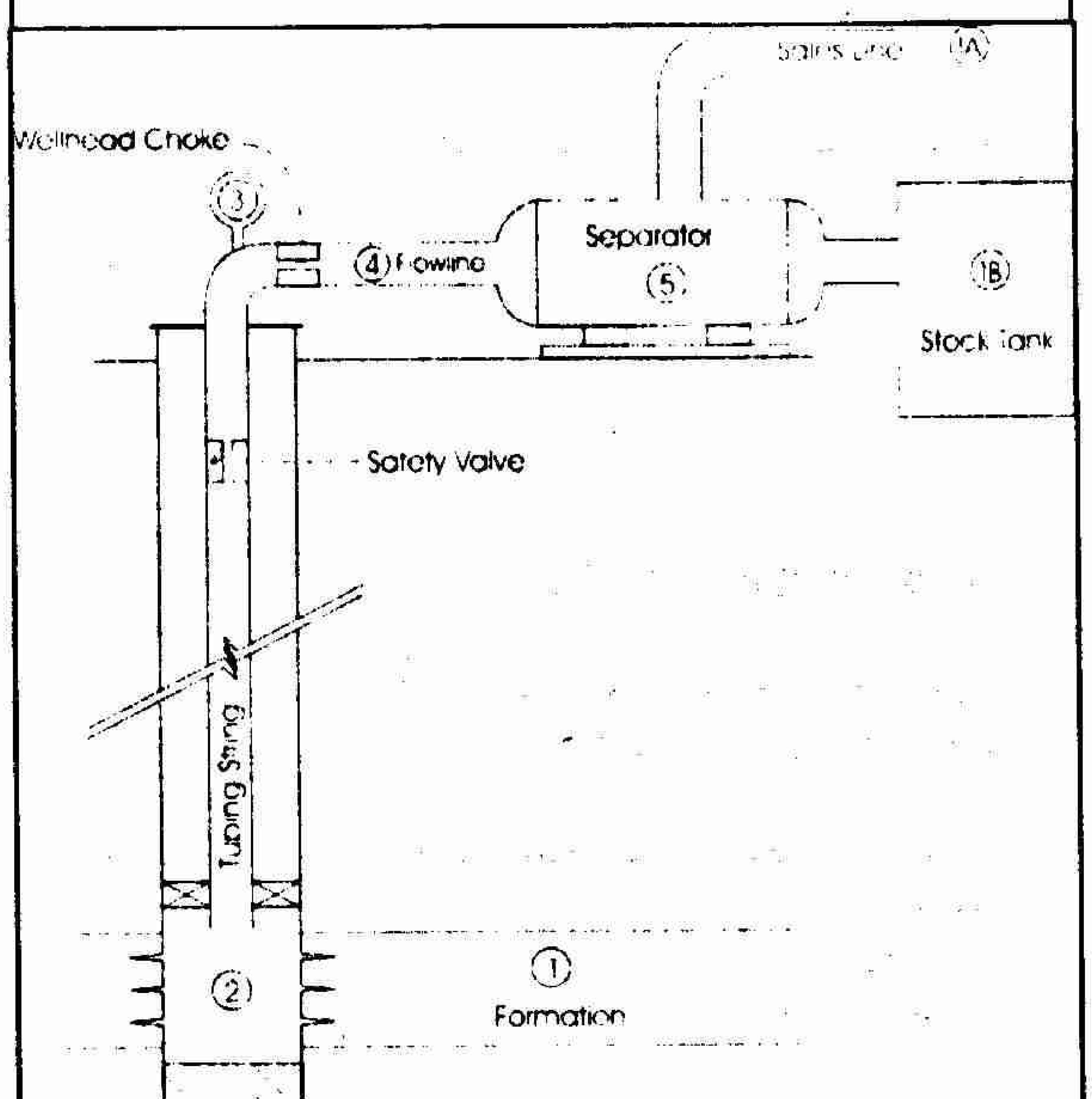

Figure 3 Phase Envelope Plot of Upper Zone

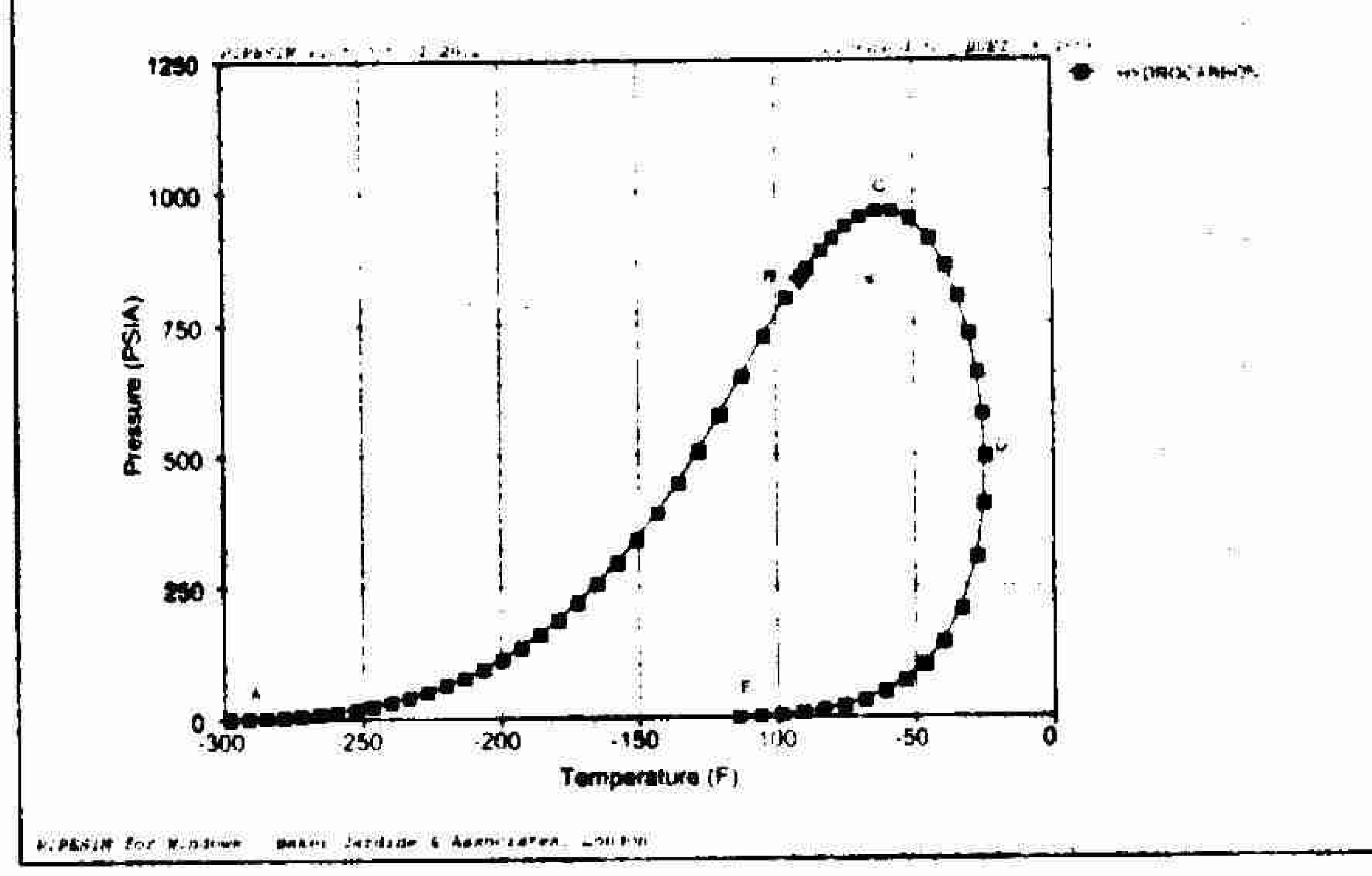

Figure 4 Phase Envelope Plot of Lower Zone

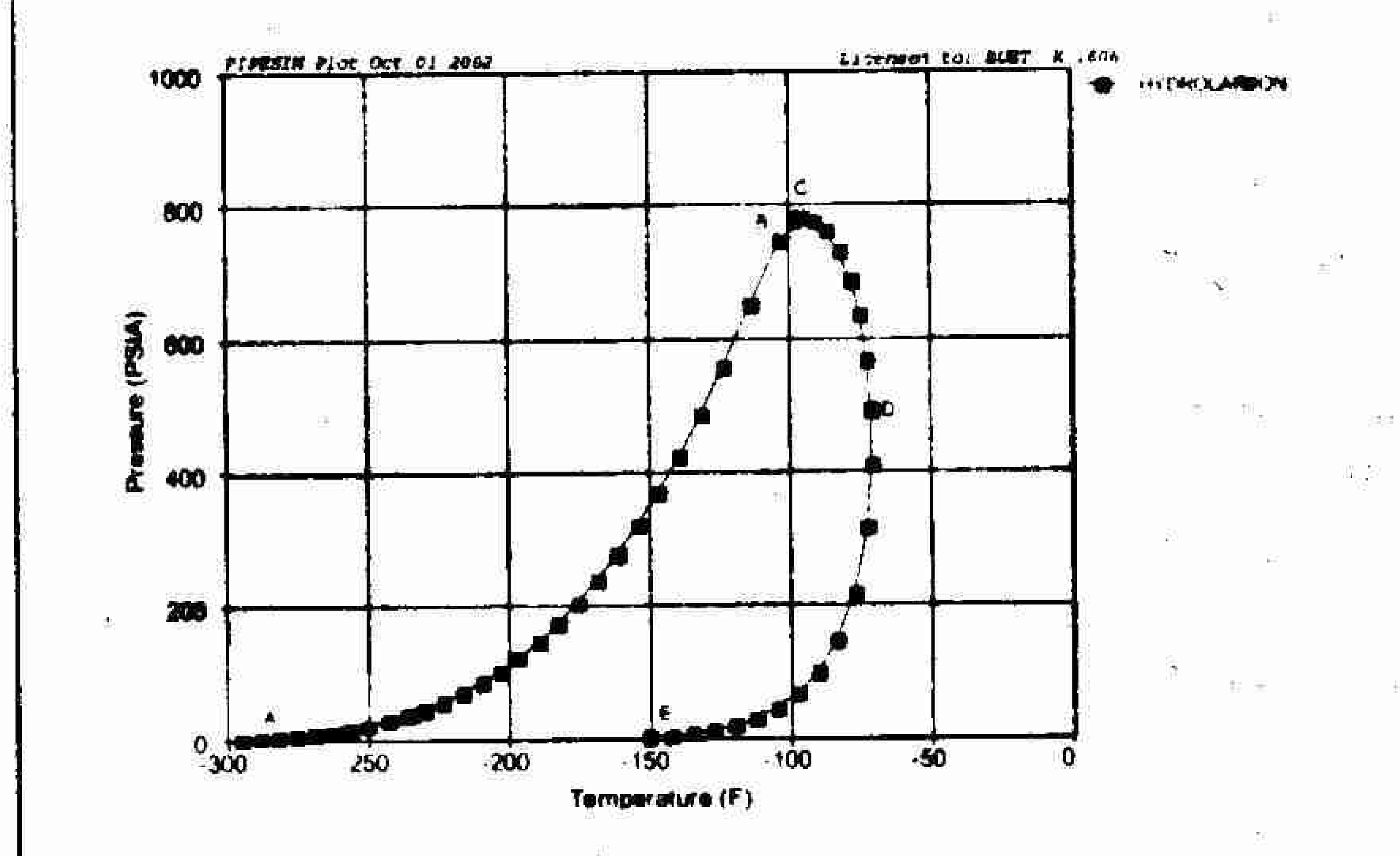

Figure 5 Phase Envelope Plot of Middle Zone

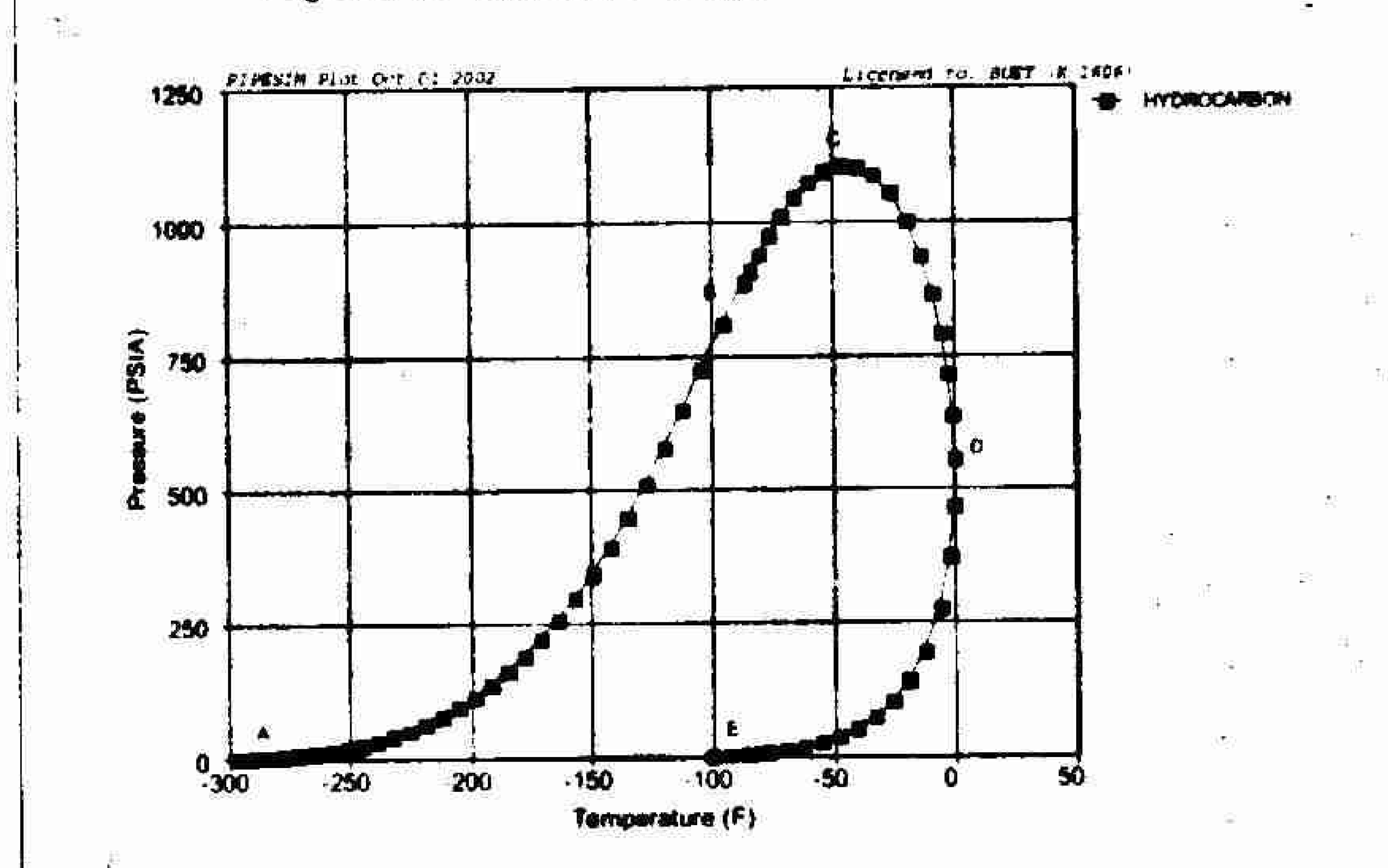

Figure 6 Effect of Seperator Pressure (Short String)

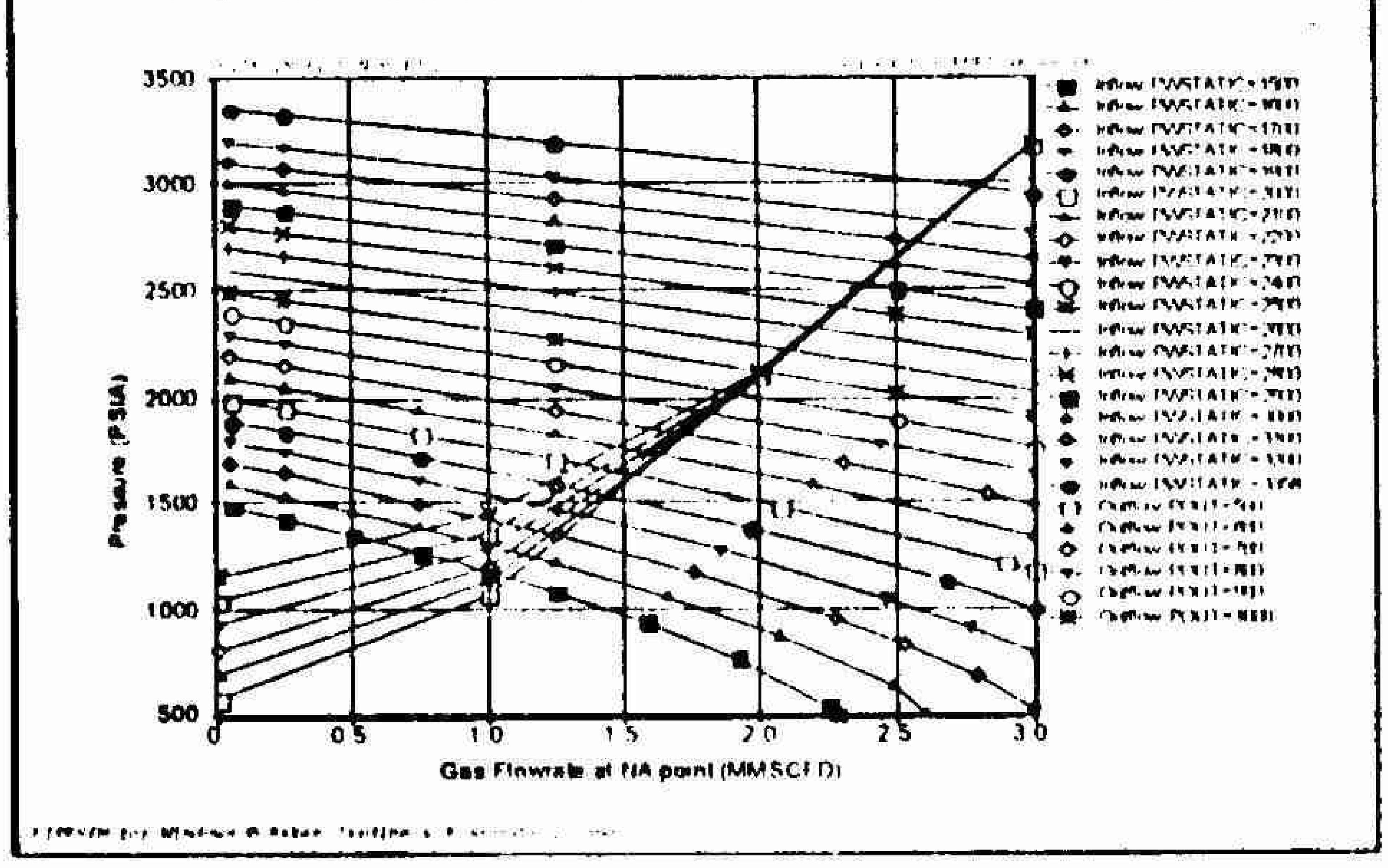

Figure 7 Effect of Seperator Pressure (Long String)

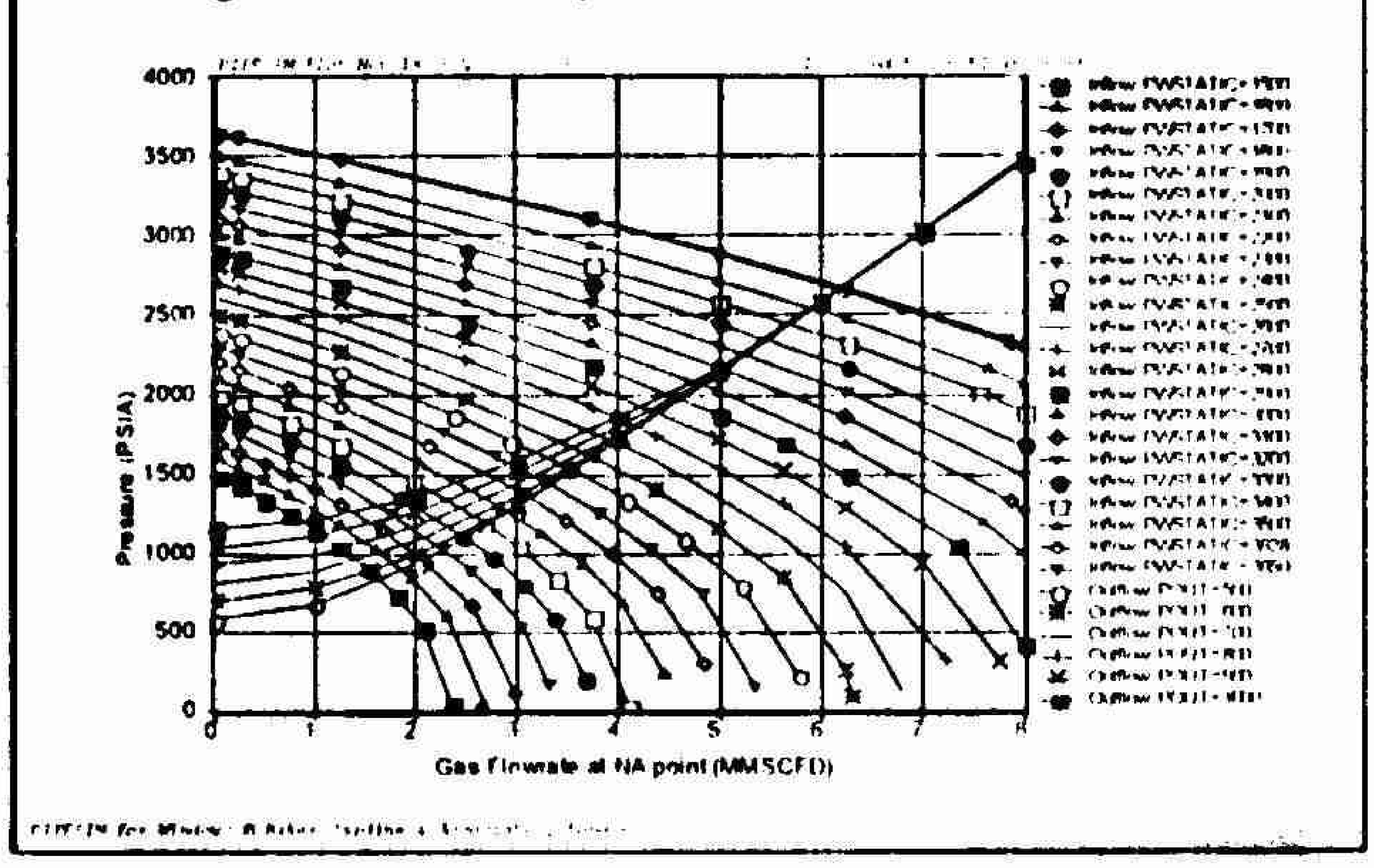

Figure 8 Effect of Separator Pressure (Well # 2)

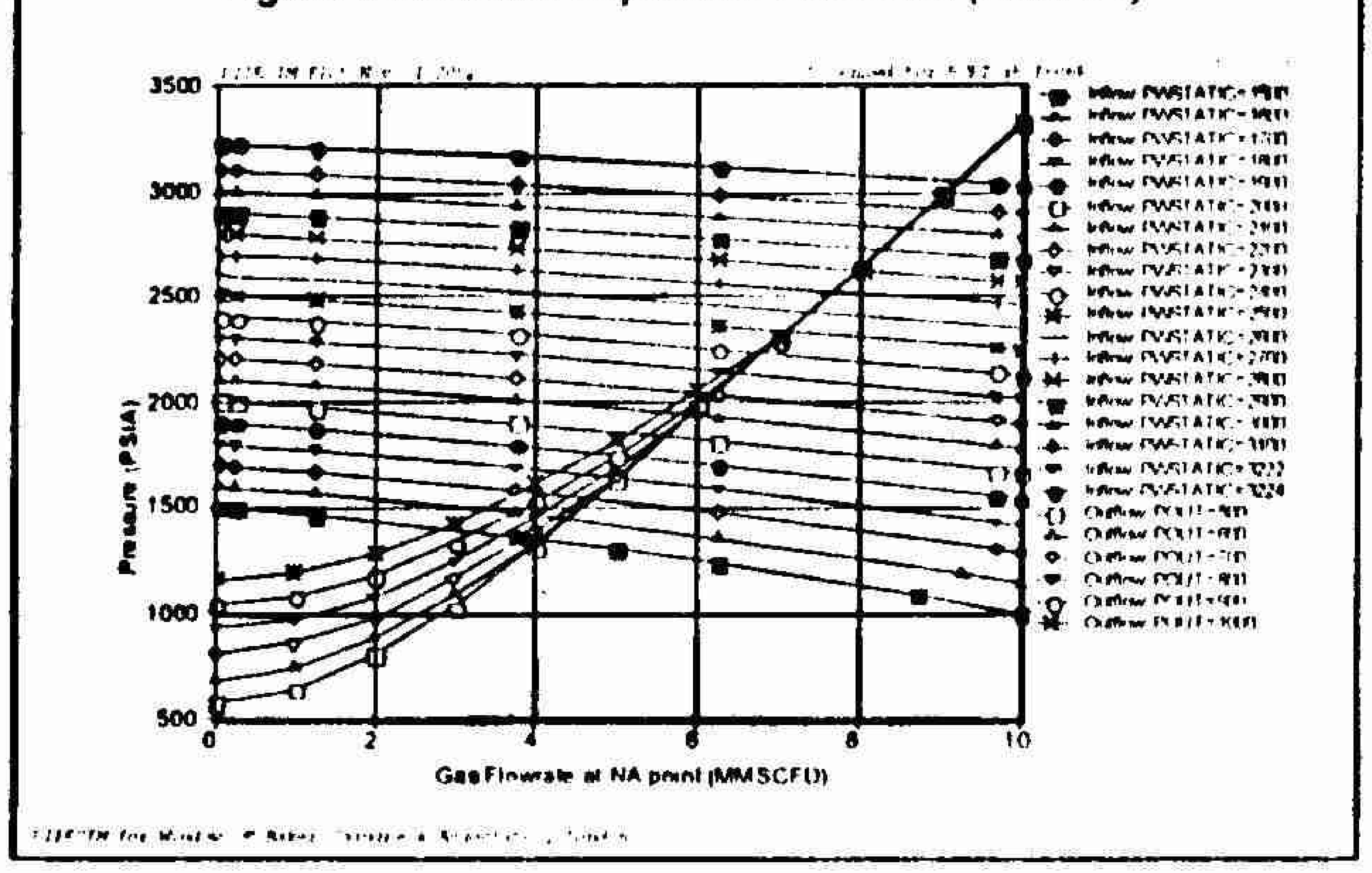

Figure 9 Effect of Surface Wellhead Choke (Short String)

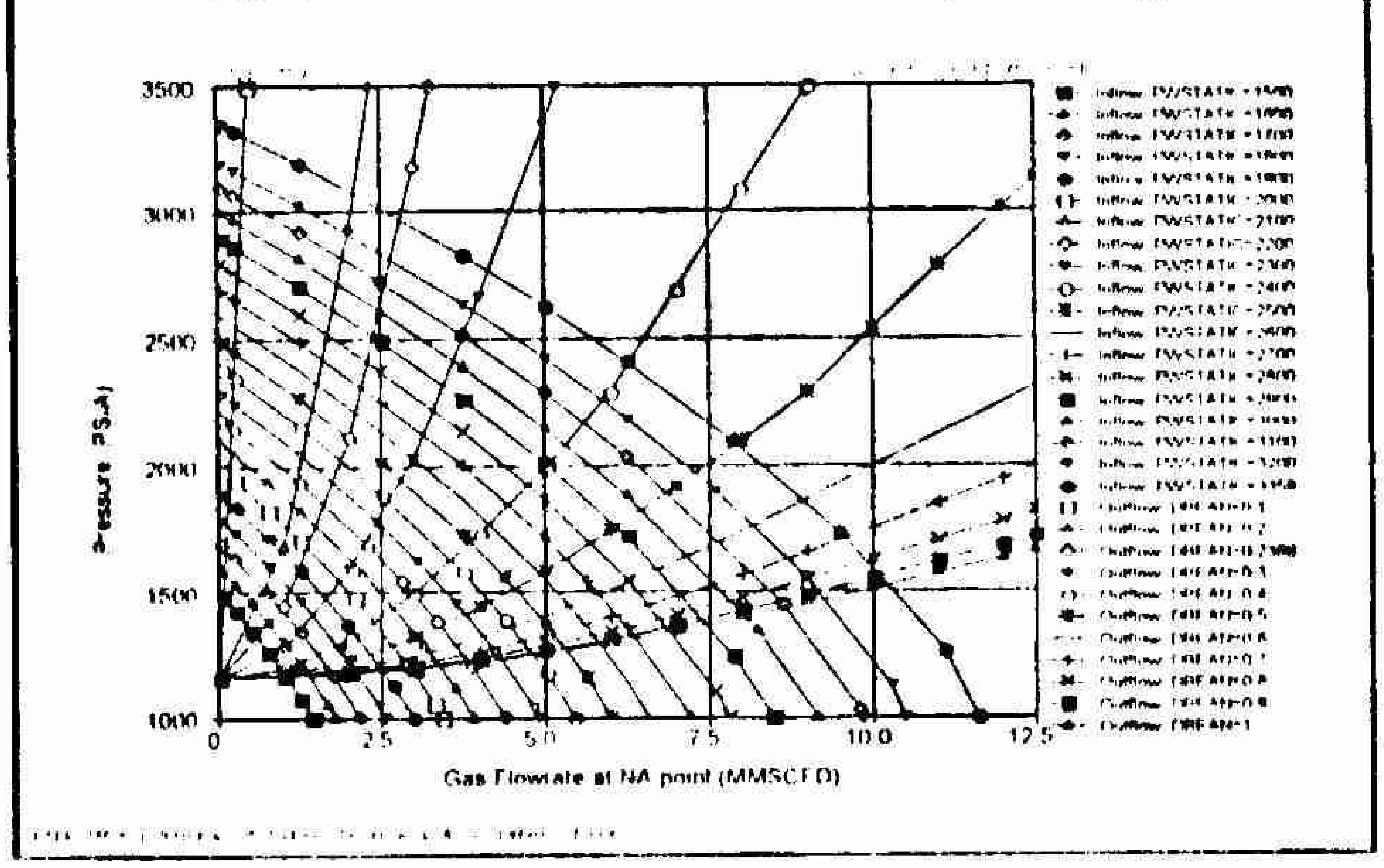

Figure 10 Effect of Surface Wellhead Choke (Long String)

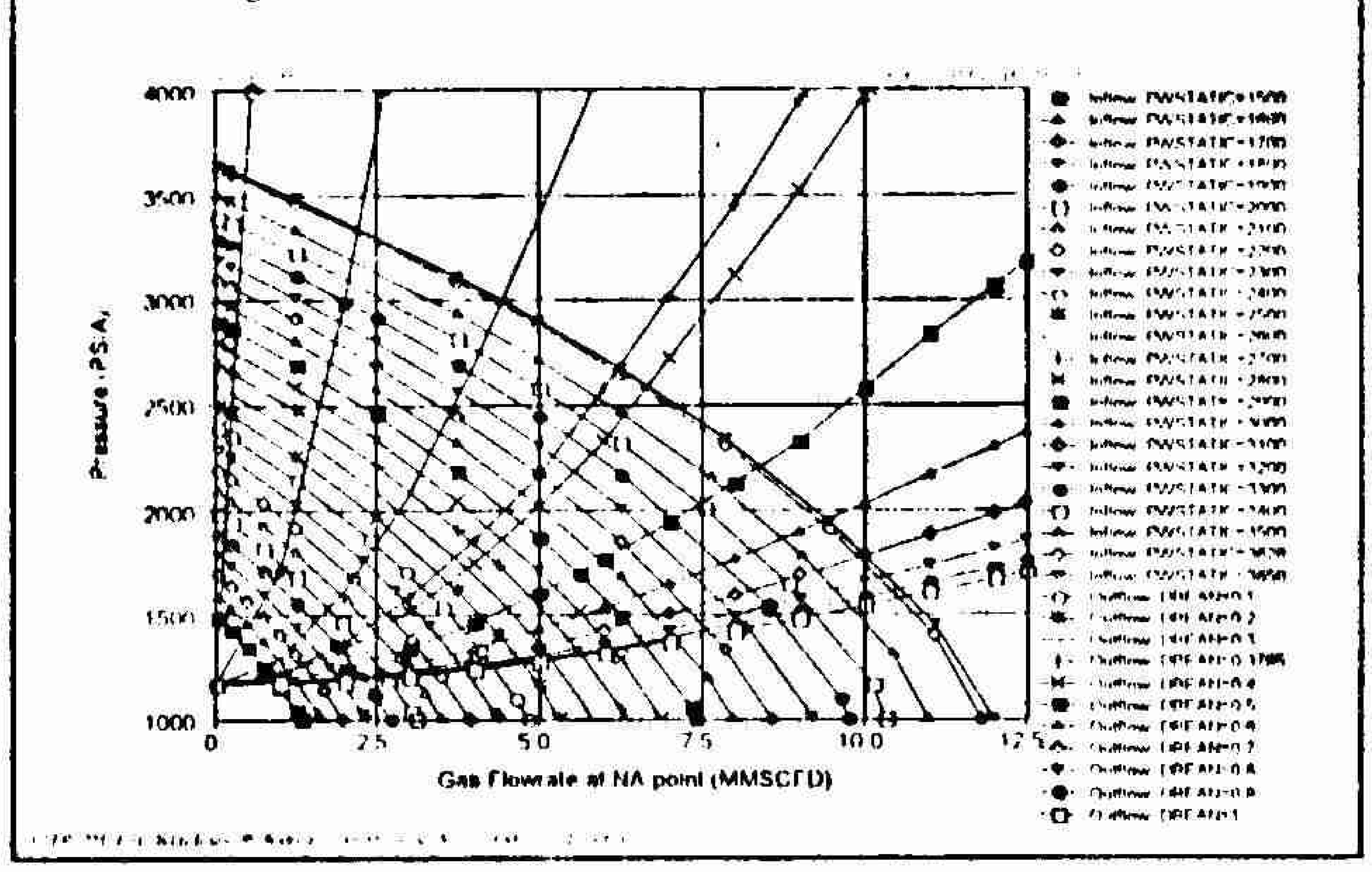

Figure 11 Effect of Surface Wellhead Choke (Well # 2)

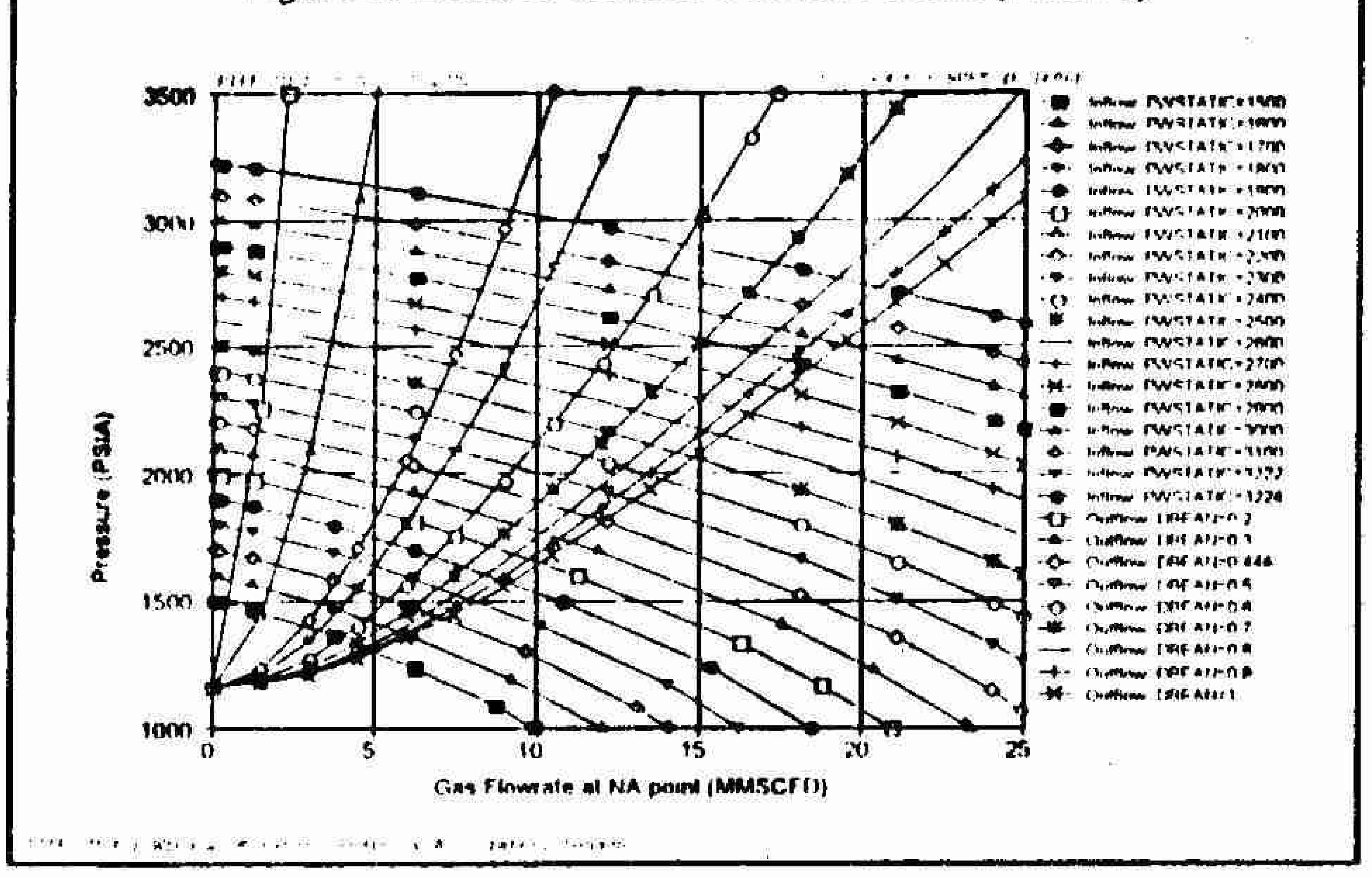

Table 1 Gas Composition of Salda Well # 1 & 2

	Upper	Lower	Middle
Components	**Mole (%)**		
Nitrogen	0.3727	0.26	0.3503
Carbon dioxide	0.6130	0.71	0.5727
Methane	94.8083	96.17	94.5613
Ethane	2.8796	2.18	2.8314
Propane	0.8598	0.45	0.9155
Iso-Butane	0.1630	0.12	0.2355
n-Butane	0.1145	0.06	0.2044
Iso-Pentane	0.0815	0.03	0.1137
n-Pentane	0.0732	0.02	0.1226
Hexane	0.0344		0.0926

Table 2 Critical Point, Tricondenbar And Tricondentherm Values of Upper, Lower and Middle Zones

	Upper	Lower	Middle
Critical Point Temp. (°F)	-94	-101	-92
Critical Point Pres. (psia)	814	757	846
Tricondenbar (psia)	965	787	1108
Tricondentherm (°F)	-25	-71	0

Table 3 Input Data for Separator Pressure

		Salda Well # 1		Salda Well # 2
		Short String	Long String	
Nodal Analysis Point		Bottomhole		
Maximum Gas Rate(mmscfd)		20	20	30
Inflow Sensitivity	Av. Res. Pres (psia)	3358-1500	3650-1500	3244-1500
Outflow Sensitivity	Sep. Outlet Pres. (psia)	1000-500	1000-500	1000-500

Table 4 Results of Separator Pressure

	Salda Well # 1		Salda Well # 2
	Short String	Long String	
Optimum Gas Rate(mmscfd)	1.20	6.10	8.30
Actual Gas Rate(mmscfd) (August 31, 2002)	1.1628	5.9943	10.2979

Table 5 Input Data for Surface Wellhead Choke

		Salda Well # 1		Salda Well # 2
		Short String	Long String	
Nodal Analysis Point		Bottomhole		
Maximum Gas Rate(mmscfd)		20	20	30
System Outlet Pressure (psia)		1000	1000	1000
Inflow Sensitivity	Av. Res. Pres. (psia)	3358 - 1500	3650-1500	3244-1500
Outflow Sensitivity	Bean Size (inch)	0.10-1.00	0.10-1.00	0.10-1.00

Table 6 Results of Surface Wellhead Choke

	Salda Well # 1		Salda Well # 2
	Short String	Long String	
Bean Size (inch)	0.2366	0.3795	0.4440
Actual Gas Rate(mmscfd) (August 31, 2002)	1.1628	5.9943	10.2979
Bean Size (inch)	Optimum Gas Rate (mmscfd)		
	Short String	Long String	Well # 2
0.1000	0.10	0.50	0.40
0.2000	0.90	2.20	1.90
0.2366	**1.20[a]**		
0.3000	1.60	4.40	4.10
0.3795		**6.10[a]**	
0.4000	2.10	6.60	6.90
0.4440			**8.30[a]**
0.5000	2.30	8.20	10.00
0.6000	2.40	9.20	12.90
0.7000	2.48	9.80	15.10
0.8000	2.50	10	16.70
0.9000	2.51	10.2	17.70
1.0000	2.52	10.3	18.40

a. Gas flow rate from the well on August 31, 2002