PRODUCTION SYSTEM ANALYSIS OF THE TITAS GAS FIELD

A Thesis
Submitted to the Department of Chemical Engineering
In partial fulfillment of the requirements for the Degree of Master of Science in Engineering (Chemical)

By

SAQUIB EJAZ

DEPARTMENT OF CHEMICAL ENGINEERING
BANGLADESH UNIVERSITY OF ENGINEERING AND TECHNOLOGY, DHAKA
BANGLADESH

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BANGLADESH UNIVERSITY OF ENGINEERING AND TECHNOLOGY

DEPARTMENT OF CHEMICAL ENGINEERING

CERTIFICATION OF THESIS WORK

We the undersigned certify that **SAQUIB EJAZ**, a candidate for the degree of **Master of Science in Engineering (Chemical),** has presented his thesis entitled "**Production System Analysis of the Titas Gas Field**". The thesis is acceptable in form and content, and the candidate has demonstrated to have acquired satisfactory knowledge in the field covered by this thesis in the oral examination held on the 7th December 1999.

Chairman (Supervisor): ....

Dr. A.K.M.A. Quader
Professor and Head
Department of Chemical Engineering
BUET, Dhaka

Member (Co-Supervisor): ....

Dr. Edmond Gomes
Associate Professor and Head
Department of Petroleum & Mineral Resources Eng.
BUET, Dhaka

Member: ....

Dr. M. Sabder Ali
Professor
Department of Chemical Engineering
BUET, Dhaka

Member: ....

Dr. N. M. Anisur Rahman
Assistant Professor
Department of Petroleum & Mineral Resources Eng.
BUET, Dhaka

Member (External): ....

Dr. M. Waliuzzaman
Former Chairman
BCSIR, Dhaka

ABSTRACT

The overall performance of any well depends on well inflow performance, downhole-conduit flow performance and surface-flow performance. The changes made in one component of the system have an overall effect on the entire system.

The objective of the study is to analyze the performance of 11 gas wells in Titas Gas Field of Bangladesh Gas Field Company Limited (BGFCL), a subsidiary company of Bangladesh Oil, Gas and Mineral Corporation (Petrobangla).

The effects of various parameters on overall well performance have been studied. The parameters considered are:

Separator pressure, flowline size, surface choke size, tubing size, average reservoir pressure and different reservoir parameters.

The sensitivity of each parameter has been observed to identify any bottle necking or over sizing of equipment. In this study, up to date data have been used whereever available, otherwise values have been reasonably assumed. Then the individual wells have been tied in the same way as in the field and the effect of a parameter on the whole system has been observed. Nodal analysis approach has been followed in conducting the system analysis starting from the outer boundary of the reservoir to the sand face, across the perforations and completion section to the tubing intake, up the tubing string including any restrictions and downhole safety valves, the surface choke, the flowline and the separator. For this study, the software- PIPESIM for Windows was used which uses the principle of nodal analysis method.

In the study, wells TT-1 through TT-10 are observed to produce at optimum rate but the flowline and tubing are generally oversized. Tubing of TT-11 is found to be restricted; using optimum size of tubing in the well significantly increases the production rate. Then, in the integrated models, it is found that change in the choke size of any well does not affect the performance of other wells. This is quite expected as all the wells are producing in the critical range of the choke.

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CHAPTER 1

INTRODUCTION

Titas Gas Field is located approximately 50 miles east of Dhaka in east central Bangladesh. Natural gas reserves were discovered in the field by Pakistan Shell Oil Company (PSOC) from the drilling of the well, TT-1 in 1962. After its discovery, Titas Field was given great importance as a potential source of energy due to its proximity to the city of Dhaka. Plans were made to develop this field for commercial production and on April 28, 1968, after prolonged delays in the pipeline construction, gas from Titas Field started flowing to Siddhirganj Power Station.

To date, eleven wells have been drilled. The hydrocarbon accumulations of Titas Gas Field are contained in 13 distinct reservoir sands which have been grouped by depth into the three categories, namely: A Sand Group, B Sand Group and C Sand Group.

PSOC drilled three wells between 1962 and 1969. These wells (TT-2 through TT-4) represent a single wellbore entity and completed in four sands of the A Sand Group. Petrobangla completed the development of the A Sand Group between 1981 and 1985 by drilling wells TT- 5, TT-6 and TT-7.

Wells TT-8, TT-9 and TT-10 were drilled by the operator of the Titas Gas Field, the Bangladesh Gas Field Company Ltd. (BGFCL). A total of seven independent sands are produced through wellbore commingling at TT-8. The well represents the most prolific producer from the B and C Sand Groups in the Titas Gas Field. Wells TT-9 and TT-10 were drilled from the TT-6 surface location in 1987 and 1989. Both wells are completed in the B and C Sand Groups. These two wells along with TT-5, TT-7 and TT-8 are directionally drilled.

Well TT-11 was drilled as part of the Gas Field Appraisal Project in 1990. T-11 is the last of the eight wells completed in the A Sand group.

Following the start of commercial production in 1968, TT-2 through TT-4 went into production by 1969. Maximum gas production from these four wells approached 110

MMSCFD by mid-1981, when TT-5 was brought on stream. Wells TT-6 and TT-7 were added in early-1984 and mid-1985, respectively. An additional 30 MMSCFD of commingled production from the B and C Sand Groups commenced in February 1986 when TT-8 began production. Wells TT-9 and TT-10 were added in early-1989 and late-1990, respectively, bringing production from the B and C Sand Groups to almost 70 MMSCFD.

With a current production rate of 295 to 300 MMSCFD, it is the biggest gas field in Bangladesh. Two new wells (TT-12 and TT-13) have been recently drilled, one more (TT-14) will be drilled and soon gas from these wells will feed the national grid. Gas from the Titas Field is mainly Methane, having traces of sulfur and does not need any special processing apart from water removing. Along with the gas, condensate is also produced which is refined into Motor Spirit and High Speed Diesel. The gas and condensate processing facilities are all within the Titas Gas Field. With an initial gas in place of 4.132 TCF, recoverable reserve of 2.10 TCF and remaining recoverable reserve of 0.533 TCF (Quader, 1999), it is one of the most important fields in Bangladesh.

Condensate recovery from the Titas Gas Field is on average about 1.3 to 1.4 bbl/MMSCF. Therefore, the field can be considered as a dry gas reservoir. Specific gravity of the dry gas is 0.584 while that of the condensate is 0.827. The gas is supplied to the national grid at a pressure of 1000 psia.

The relative location of Titas wells and their extent of deviation while producing from different sands are shown in Figures 1.1 and 1.2.

The Sand Group, consisting of A, B and C sands are further divided into various sands, as shown in Figure 1.2. The A Sand Group, extending from a depth of 8500 feet to 9300 feet vertical, is the biggest producer in the Titas Gas Field. Wells TT-1 through TT-7 and TT-11 are completed in this sand group. The B Sand Group extends from a depth of 9400 feet to 9800 feet while the C Sand Group extends from 9000 feet to 12000 feet, all depth verticals. Wells TT-8, TT-9 and TT-10 are completed in these sands.

Figure 1.1: Relative Locations of Titas Wells

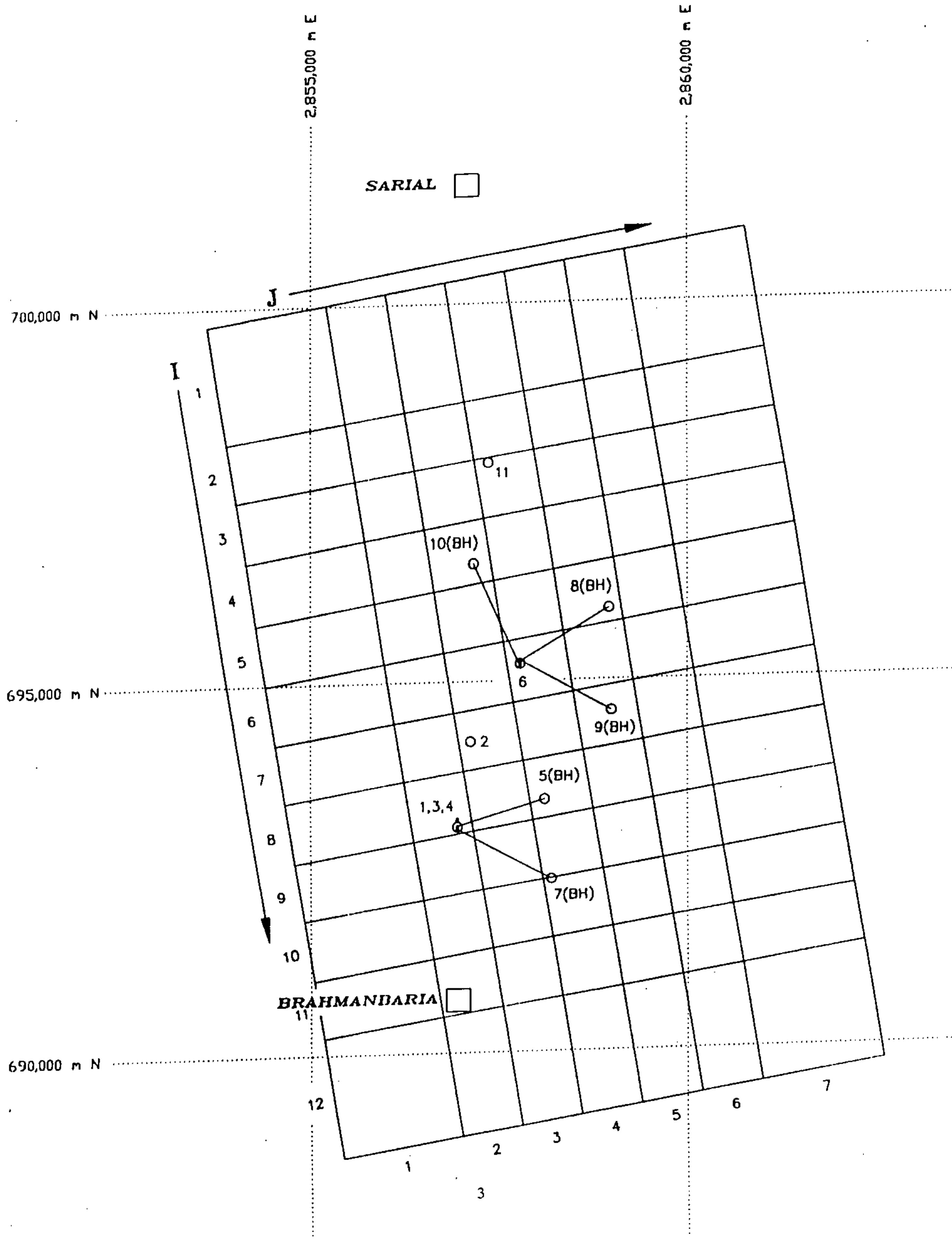
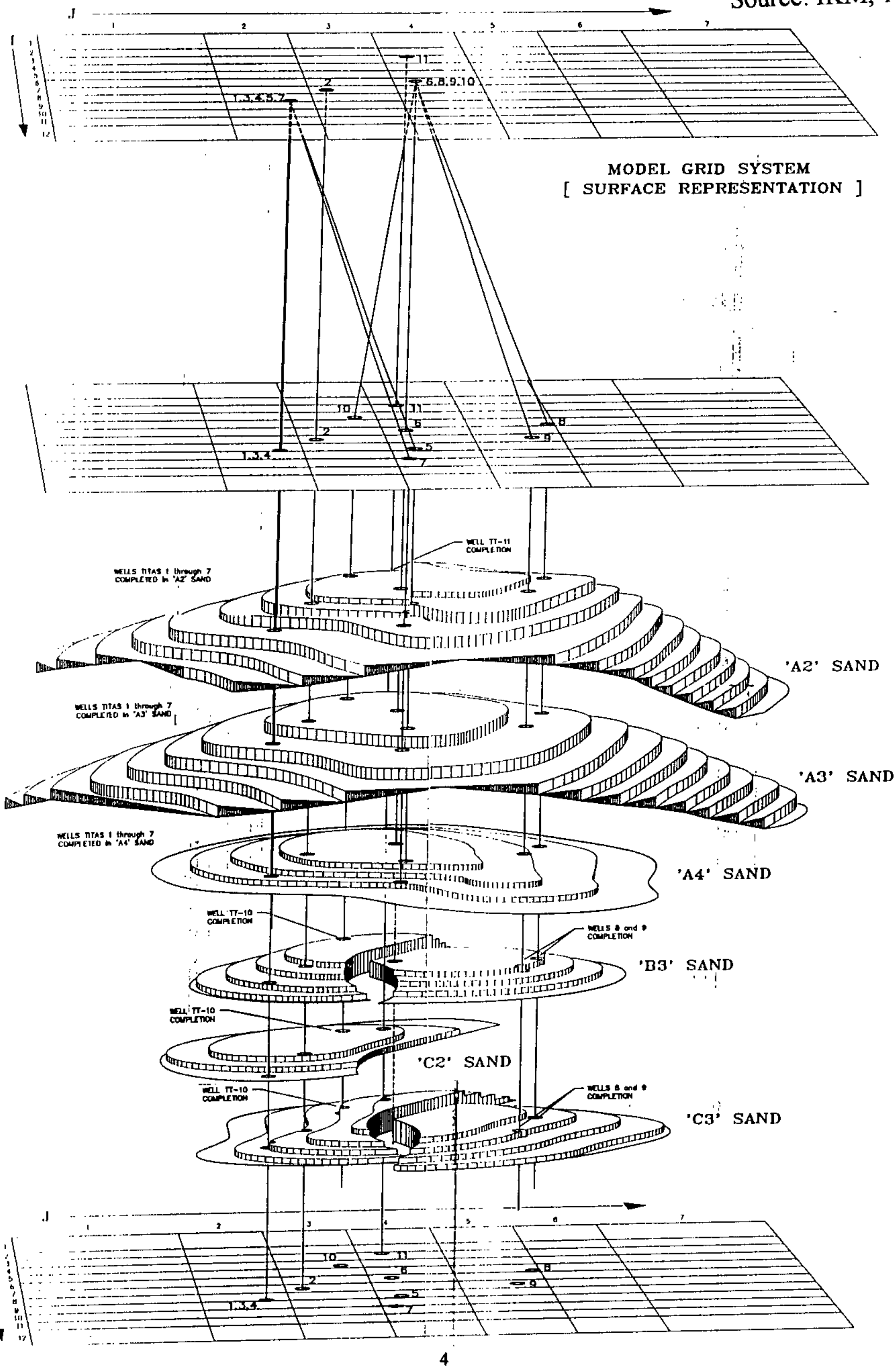


Figure 1.2: SPATIAL ORIENTATION of MAJOR PRODUCTIVE SANDS and MODEL GRID SYSTEM – TITAS RESERVOIR

[Z DIRECTION SEPARATION of SANDS REQUIRED for DELINEATION]

Source: IKM, 1991



CHAPTER 2

LITERATURE REVIEW

2.1 INTRODUCTION

The natural gas has established itself as a major indigenous hydrocarbon resource in Bangladesh. It is the chief source of fuel for industrial, commercial and household operations as well as for power generation. The daily consumption of gas during peak demand lies between 915 and 930 MMSCFD with more than 887000 customers through a network of about 12000-km pipelines.

The exploration activities for gas and oil in Bangladesh started with the exploration at Sitakunda in 1910 and were followed by three more exploratory wells by 1914. Since 1910, 61 wells have been drilled resulting in the discovery of 21 gas fields and 1 oil field. Table 2.1 lists the gas fields so far discovered with their reserve.

National Energy Policy (NEP), promulgated in 1995, indicated an energy-growth rate of 8.77% by year 2000 equivalent to 12 million tons of oil and 19 million tons of oil equivalent, representing energy growth rate of 8.86%. The major part of the future energy demand would be met from natural gas and it is estimated that gas demand would reach about 1450 MMSCD (average) and 1700 MMSCFD (maximum) by 2005 and 1900 MMSCFD (avg.) and 2250 MMSCFD by 2010 (max.) (Khan and Imaduddin, 1999).

Over the past decades demand for gas has increased manifolds. Total gas consumption was 63 billion cubic feet (BCF) for the period 1950 to 1970. This increased to 280 BCF for the 70's, 1068 BCF in the 80's and about 2000 BCF in the 90's. At present 12 gas fields under public and private sectors have a production capacity of 1025 MMSCFD from 44 wells. Sector-wise consumption pattern is 405 MMSCFD by power, 256 MMSCFD by fertilizer and 254 MMSCFD by non-bulk.

At present 20 gas fields have Gas initially in Place (GIIP) of about 25 trillion cubic feet (TCF). Bibiana is still under appraisal. Of these Kailashtila, Rashidpur, Habiganj and Titas contributes 55% of the total GIIP. The remaining reserve of the country is about 9 TCF. Demand for gas as a source of energy is projected to grow at fast pace and current reserve would fail to meet demand. Effort is needed to discover and prove new reserve of gas (Khan and Imaduddin, 1999).

Table 2.1: Gas Fields of Bangladesh

Source: Quader, 1999

Field	Year	Gas in place TCF	Recoverable Reserve, TCF	Remaining Recoverable Reserve, TCF
Sylhet	1955	0.444	0.266	0.104
Chhatak	1950	1.900	1.140	1.114
Rashidpur	1960	2.242	1.309	1.170
Kailashtila	1962	3.657	2.529	2.360
Titas	1962	4.138	2.100	0.533
Habigonj	1963	3.669	1.895	1.208
Bakhrabad	1969	1.432	0.867	0.307
Semutang	1969	0.164	0.098	0.098
Kutubdia	1977	0.780	0.468	0.468
Begumgonj	1977	0.025	0.015	0.015
Feni	1981	0.132	0.080	0.041
Beanibazar	1981	0.243	0.167	0.167
Kamta	1981	0.325	0.195	0.174
Fenchugonj	1988	0.350	0.210	0.210
Jalalabad	1989	1.500	0.900	0.900
Meghna	1990	0.159	0.104	0.094
Narshingdi	1990	0.194	0.126	0.091
Shahbazpur	1995	0.514	0.333	0.333
Saldanadi	1996	0.200	0.140	0.136
Sangu	1996	1.031	0.848	0.836
Bibiyana	1999	Under appraisal		

These gas fields as shown in Table 2.1 are under the jurisdiction of different gas companies, both government owned and multinationals. Table 2.2 shows a list these companies and their production capacities.

Table 2.2: Production Capacities of Various Gas Fields

Source: Monthly Production Report, August 1999, Petrobangla

Company	Gas Field	Total Wells	Producing Wells	Product	Daily Capacity	Production Goal 1999-2000	Production July 1999
Bangladesh Gas Fields Company	Titas	11	11	Gas	8.495	2649.770	223.144
				MS	9.924	3095.460	236.175
				HSD	39.695	12381.850	1418.836
				Condnst	49.619	15477.310	1384.383
	Habi-ganj	7	7	Gas	5.521	2301.150	160.332
				Condnst	1.342	559.180	46.620
	Bakh-Rabad	8	5	Gas	1.134	416.310	29.166
				MS	5.395	1969.310	75.767
				HSD	1.350	492.330	-
				Condnst	6.745	2461.640	187.604
	Salda	1	1	Gas	0.425	155.050	13.169
				Condnst	1.802	657.260	61.533
				MS	1.441	525.810	-
				HSD	0.361	131.450	-
	Norshi-ngdi	1	1	Gas	0.605	206.030	15.037
				Condnst	6.501	2214.000	179.122
				MS	1.300	442.800	-
				HSD	5.201	1771.200	
	Meghna	1	1	Gas	0.552	201.030	16.621
				Condnst	4.814	1753.180	159.040
Sylhet Gas Fields Company Limited	Sylhet	3	1	Gas	0.156	37.620	4.744
				MS	3.000	690.000	86.137
				Kerosin	200.000	30.000	5.146
	Kailash-tilla	4	4	Gas	3.000	1011.000	56.910
				MS	18.000	5700.000	484.456
				HSD	18.500	6388.000	497.369
				Condnst	196.502	64588.000	3448.594
	Rashid-pur	4	4	Gas	2.775	594.060	65.111
				Condnst	24.834	5511.000	548.328
	Biani-bazar	2	1	Gas	0.991	296.000	15.688
				Condnst	83.992	25042.000	1263.778
Ms. Cairn Energy PLC		6	4	Gas	4.531	1653.700	55.120
				Condnst	-	-	161.820
Occidental Bangladesh Limited		4	4	Gas	2.832	1033.560	38.990
				Condnst	-	-	3346.495

Note: Gas: MMSCMD (million standard cubic meter per day), Petroleum Products: Thousand Liters

2.2 TITAS GAS FIELD STUDIES

Since going into production in 1968, no production system analysis has been conducted on the Titas Gas Field. Monitoring and evaluation of the performance of its production systems and its producing sand groups should be considered as a matter of prime importance for proper management of this major source of gas supply of Bangladesh.

The first fieldwide annual pressure survey in this field was conducted by Project Implementation Unit (PIU) of Petrobangla in 1989 for the reservoir engineering studies program. The most significant conclusion of that study was that the main sand group of the field was producing under water drive, which will manifest itself in an early water production and a low ultimate recovery.

Based on this survey and other data Intercomp-Kanata Management Limited (IKM) forecasted on four different production scenario (IKM, 1992). In Case no. 1, 11 wells produce at a rate of 275 MMSCFD for six years and 250 MMSCFD for next two and then declines rapidly as most A Sand group wells are shut-in due to water encroachment. Case no. 2 predicts a production of 300 MMSCFD for three and a half years and 250 MMSCFD for next three years by the 11 wells. The production again declines rapidly due to water encroachment. Case no. 3 predicts 300 MMSCFD production for four and a half years and 285 MMSCFD production for next two years by 12 wells, followed by a rapid decline in production due to water encroachment. Case no. 4 predicts a production of 240 MMSCFD for eight and a half years by 12 wells followed by a rapid decline in production due to water encroachment

The second annual pressure survey was conducted during February through March, 1992, by PIU in coordination with BGFCL. These were all simple static pressure surveys. Three A-Sands wells (TT-4, TT-6 and TT-7) and two B and C sands commingled producers (TT-8 and TT-9) were covered during this program.

The third annual pressure survey at Titas conducted during September through October 1993 consisted of static pressure surveys in wells TT-4 and TT-7 and build-up tests.

These surveys were only aimed at updating information about reservoir pressure of the producing zones and had little to do with determining other characteristics of wellbore and reservoirs. These pressure survey operations, however, revealed valuable information about the mechanical condition of a number of wellheads, subsurface safety valves and detected restrictions in two wellbores (TT-8 and TT-7) probably due to scaling.

Pressure build-up test of 1993 found the presence of aquifer support for A-Sand near TT-11, the distance from the wellbore to the constant pressure boundary being 262 feet. Interpretation of tests conducted IKM in 1991 indicated the distance to be 1311 feet. This implied that the aquifer influx was approaching the wellbore quite fast. Presence of constant pressure boundary was also observed near TT-6.

The results of 1992 and 1993 pressure surveys and available pressure and production history were used to update the understanding about reservoir performance of the producing groups and their reserves based on P/Z material balance. Material balance analysis on A-Sands group indicated a reservoir performance characteristic of volumetric depletion and provides an initial gas in place reserve of 9.21 TCF. This was four times as much the latest volumetric estimate available. This large deviation was due to presence of water aquifer as well larger spatial extents of the A-Sands than that been mapped from available well-controls and seismic for volumetric reserve estimations. Anyway, interpretation of pressure transient tests and static pressure surveys in the producing sand groups showed that the pressure decline in A-Sands was not very significant considering the volume of gas withdrawn.

However, there was some uncertainty about the quality of data available and the mathematical solutions employed. The reservoir performance forecast of Titas Gas Field carries some uncertainty and constant effort should be made to update the forecast with the acquisition of more test data and better characterization of the reservoirs.

CHAPTER 3

TITAS WELLS-AN OVERVIEW

3.1 INTRODUCTION

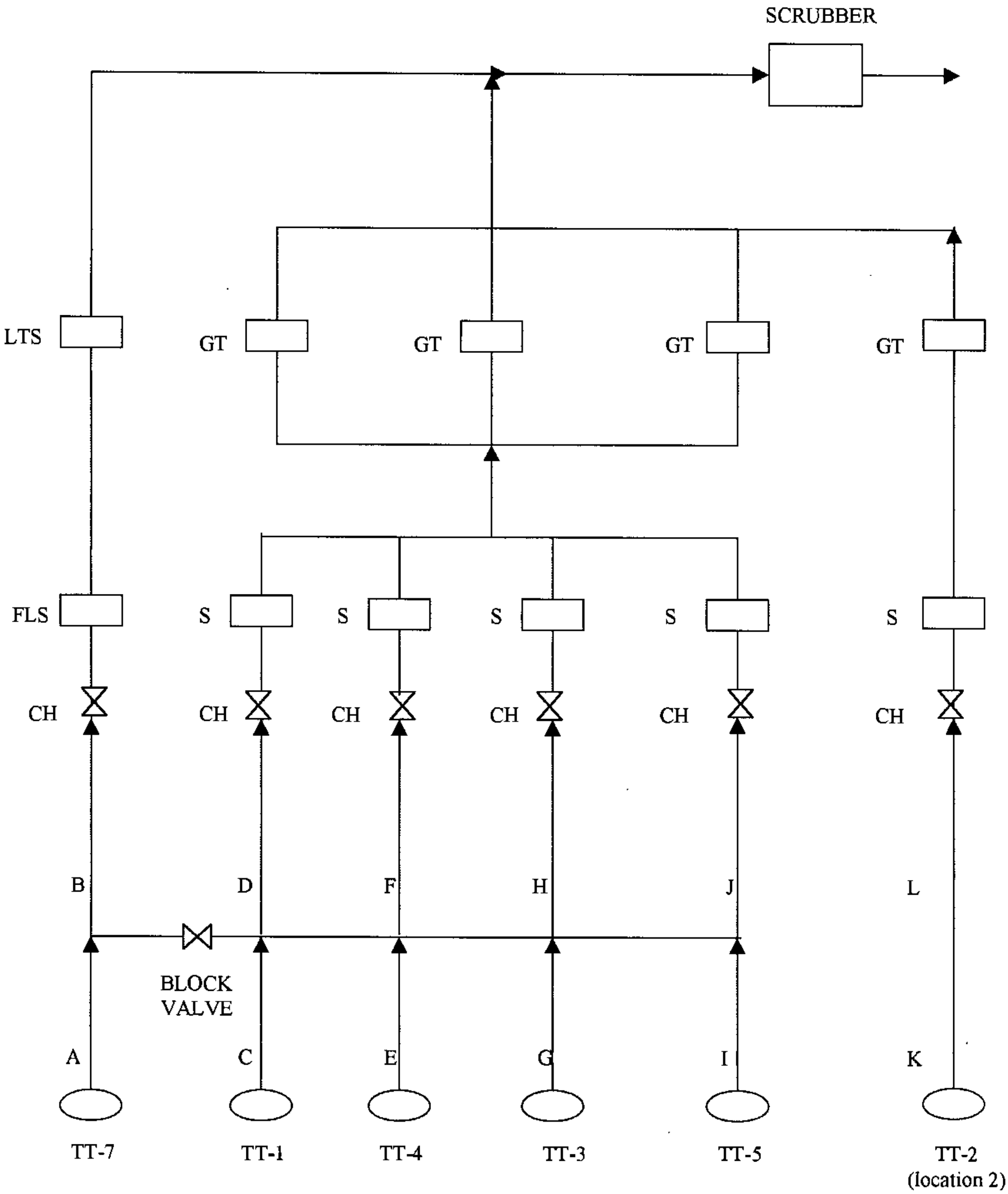
The eleven wells of Titas Gas Field are scattered in four locations. Location 1 consists of TT-1, TT-3, TT-4, TT-5 and TT-7. Location 2 hosts TT-2 only. Wet gas produced by all these wells are processed in location 1 and then they join the national grid through sales line 1. Gas from TT-1, TT-3, TT-4 and TT-5 are combined to be processed in three Glycol dehydration towers where as gas from TT-2 is individually processed in a Glycol tower. Gas from TT-7 is processed in a low temperature separator with Glycol injection.

Wells TT-6, TT-8, TT-9 and TT-10 are situated in location 3 while TT-11 is situated in location 4. Gas produced by these wells is processed in location 3. TT-6 and TT-11 share the same Glycol dehydration unit, whereas TT-8 uses low temperature separation method (LTS) with Glycol injection and TT-9 and TT-10 use LTS without Glycol injection. The processed gas from these two locations enters the national grid through sales line 3. Condensate produced by all these 11 wells are processed in a common unit in location 1.

The schematics of all the wells in the four locations are shown in Figures 3.1 and 3.2. In these figures, the segments AB, CD, EF, GH, IJ and KL (in Figure 3.1) and the segments AB, CD, EF, GH and IJ (in Figure) are the lengths of the flowlines that have been optimized in this study.

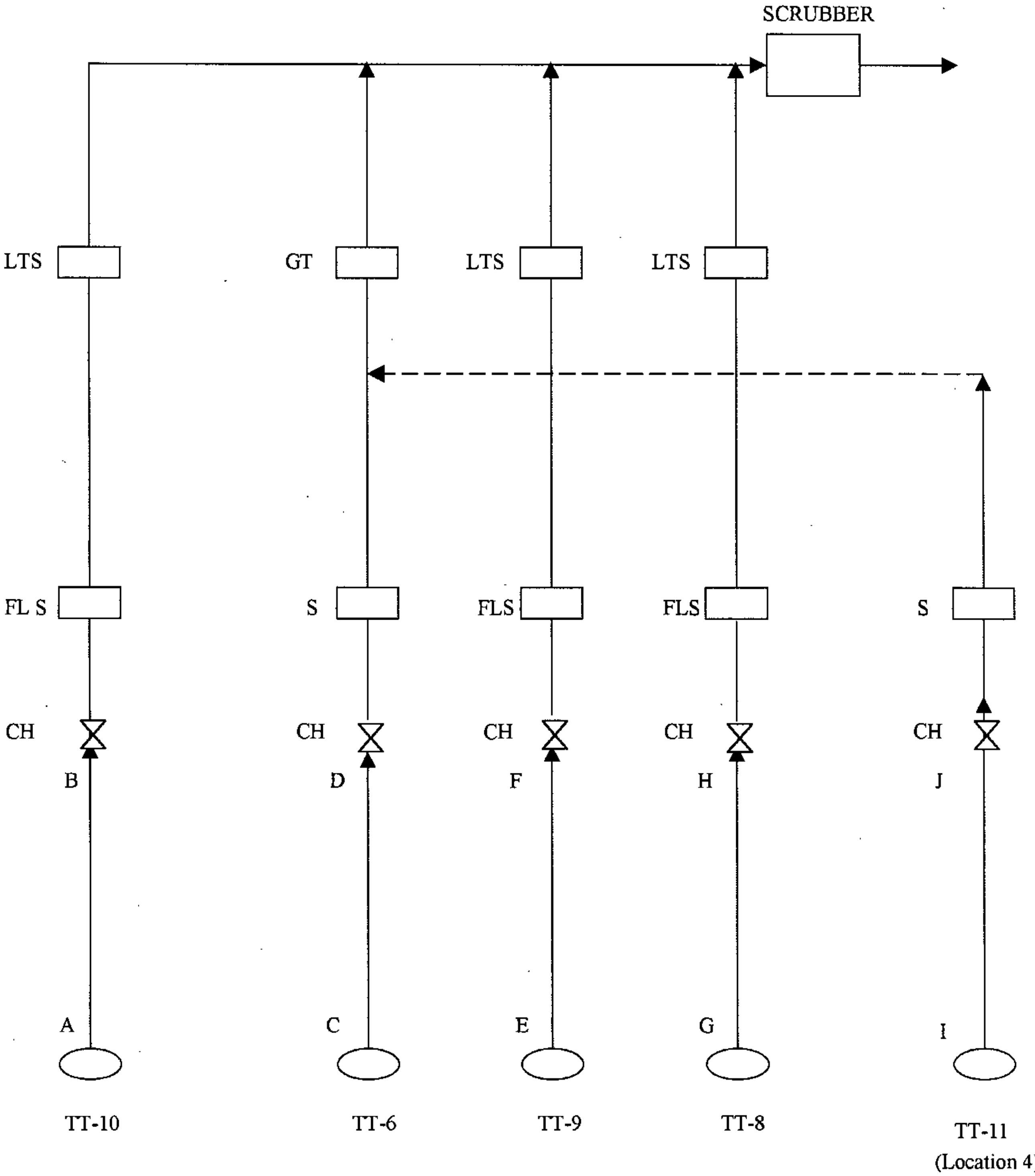
In Figure 3.1, segment AB of TT-7 has a length of 608 feet, nominal diameter of 4 inches and a schedule number of 160. Segment CD of TT-1 has a length of 525 feet, nominal diameter of 6 inches and a schedule number of 160. Segment EF of TT-4 has a length of 605 feet, nominal diameter of 4 inches and a schedule number of 160. Segment GH of TT-3 has a length of 360 feet, nominal diameter of 6 inches and a schedule number of 160. Segment IJ of TT-5 has a length of 790 feet, nominal

FIGURE 3.1: SCHEMATIC DIAGRAM OF LOCATION 1 AND 2 OF TITAS GAS FIELD



CH: Choke Valve
LTS: Low Temperature Separator
S: Separator
FLS: Free Liquid Separator
GT: Glycol Tower

FIGURE 3.2: SCHEMATIC DIAGRAM OF LOCATION 3 AND 4 OF TITAS GAS FIELD



CH: Choke Valve
S: Separator
FLS: Free Liquid Separator
LTS: Low Temperature Separator
GT: Glycol Tower

diameter of 4 inches and a schedule number of 160. Segment KL of TT-2 has a length of 400 feet, nominal diameter of 6 inches and a schedule number of 160.

In Figure 3.2, segment AB of TT-10 has a length of 530 feet, nominal diameter of 4 inches and a schedule number of 160. Segment CD of TT-6 has a length of 360 feet, nominal diameter of 4 inches and a schedule number of 160. Segment EF of TT-9 has a length of 300 feet, nominal diameter of 4 inches and a schedule number of 160. Segment GH of TT-8 has a length of 418 feet, nominal diameter of 4 inches and a schedule number of 160. Segment IJ of TT-11 has a length of 12600 feet, nominal diameter of 8 inches and a schedule number of 160. The flowlines are coated with powdered epoxy resins to increase the resistance to chemicals, stress and corrosion causing action of the soil.

3.1.1 Well TT-1

Well TT-1 was completed in November 1962 and started commercial production in April 1968. It is a vertical well, producing from A sands and up to 12325 feet deep. The well is perforated from 8586 feet to 9085 feet with an effective perforation length of 228 feet. Shot density is 2 and 4 shots per feet (SPF) with the length of 2 SPF perforation is 218 feet. It uses a 4.5 inches and a 3.5 inches tubing (inner diameter of 3.958 inches and 3.068 inches respectively) within a 9 5/8 inches casing. The length of the 4.5-inches tubing is 8456 feet and that of the 3.5 inches tubing is 65 feet. It is connected to the sales line through a 6 inches piping of 525 feet long (inner diameter of 5.187 inches) and a 4 inches piping of 48 feet long (inner diameter of 3.438 inches).

The depth of the sub-surface safety valve is 202.17 feet. It is designed to ensure two specific objects:

1. To provide maximum protection against any damage to surface equipment.
2. To protect the sub-surface installations from corrosion and erosion in order to permit the production of lightly corrosive gas at high rates and high pressures.

TT-1 and other wells are fitted with packers, whose function is to protect the permanent casing from corrosive gas.

3.1.2 Well TT-2

Well TT-2 was completed in February 1963 and started commercial production in March 1968. It is a vertical well, producing from A sands and up to 10574 feet deep. The depth of perforation is from 8615 feet to 9030 feet with an effective perforation length of 270 feet. Shot density is 2 and 4 SPF with the length of 2 SPF perforation is 230 feet. It uses a 4.5-inches tubing (inner diameter of 3.958 inches) within 13 3/8-inches casing. The length of the tubing is 8579 feet. It is connected to the sales line through a 6 inches piping of 400 feet long (inner diameter of 5.187 inches) and 4 inches piping of 13 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 8578 feet

3.1.3 Well TT-3

Well TT-3 was completed in September 1969 and started commercial production in the same month. It is a vertical well, producing from A sands and up to 9315 feet deep. The depth of perforation is from 8589 feet to 9134 feet with an effective perforation length of 240 feet. Shot density is 4 SPF. It uses a 4.5 inches and a 5 inches tubing (inner diameter of 3.958 inches and 4.408 inches respectively) within a 13 3/8 inches casing. The length of the 5-inches tubing is 8406 feet and that of the 4.5 inches tubing is 98 feet. It is connected to the sales line through a 6 inches piping of 360 feet long (inner diameter of 5.187 inches) and a 4 inches piping of 358 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 8502 feet

3.1.4 Well TT-4

Well TT-4 was completed in October 1969 and started commercial production in the same month. It is a vertical well, producing from A sands and up to 9350 feet deep. The depth of perforation is from 8634 feet to 9188 feet with an effective perforation length of 212 feet. It uses a 4.5 inches and a 5 inches tubing (inner diameter of 3.958 inches and 4.408 inches respectively) within a 13 3/8 inches casing. The length of the

5-inches tubing is 8456 feet and that of the 4.5 inches tubing is 96 feet. It is connected to the sales line through a 4 inches piping of 605 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 8470 feet

3.1.5 Well TT-5

Well TT-5 was completed in January 1981 and started commercial production in June 1981. It is a deviated well, producing from A sands and has a drilled depth of 10805 feet. The vertical depth of perforation is from 8639 feet to 9038 feet with an effective perforation length of 165 feet It uses a 4.5 inches and a 3.5 inches tubing (inner diameter of 3.958 inches and 3.068 inches respectively) within a 9 5/8 inches casing. The vertical depth of the 4.5-inches tubing is 8471 feet while that of the 3.5-inches tubing is 19 feet. It is connected to the sales line through a 4 inches piping of 790 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 278 feet

3.1.6 Well TT-6

Well TT-6 was completed in October 1983 and started commercial production in February 1984. It is a vertical well, producing from A sands and up to 10072 feet deep. The depth of perforation is from 8648 feet to 8976 feet with an effective perforation length of 191 feet. It uses a 4.5 inches and a 3.5 inches tubing (inner diameter of 3.958 inches and 3.068 inches respectively) within a 9 5/8 inches casing. The length of the 4.5-inches tubing is 8465 feet while that of 3.5-inches tubing is 54 feet. It is connected to the sales line through a 4 inches piping of 360 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 170 feet

3.1.7 Well TT-7

Well TT-7 was completed in March 1985 and started commercial production in July 1985. It is a deviated well, producing from A sands and has a drilled depth of 11006 feet. The vertical depth of perforation is from 8569 feet to 9160 feet with effective perforation length of 221 feet. It uses a 4.5-inches tubing (inner diameter of 3.958 inches) within 9 5/8-inches casing. The length of the tubing is 8485 feet. It is connected to the sales line through a 4 inches piping of 608 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 157 feet

3.1.8 Well TT-8

Well TT-8 was completed in September 1985 and started commercial production in February 1986. It is a deviated well, producing from B and C sands and has a drilled depth of 11760 feet. The vertical depth of perforation is from 9412 feet to 10257.5 feet with an effective perforation length of 234 feet. It uses a 4.5-inches tubing (inner diameter of 3.958 inches) within 9 5/8-inches casing. The length of the tubing is 9280 feet. It is connected to the sales line through a 4 inches piping of 418 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 159 feet

3.1.9 Well TT-9

Well TT-9 was completed in January 1988 and started commercial production in March 1989. It is a deviated well, producing from B and C sands and has a drilled depth of 11893 feet. The vertical depth of perforation is from 9408 feet to 10261 feet with an effective perforation length of 362 feet. It uses a 4.5-inches tubing (inner diameter of 3.958 inches) within 9 5/8-inches casing. The length of the tubing is 9320 feet. It is connected to the sales line through a 4 inches piping of 300 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 214 feet

3.1.10 Well TT-10

Well TT-10 was completed in May 1988 and started commercial production in September 1990. It is a deviated well, producing from B and C sands and has a drilled depth of 12319 feet. The vertical depth of perforation is from 9526.6 feet to 10205.6 feet with an effective perforation length of 393 feet. It uses a 4.5-inches tubing (inner diameter of 3.958 inches) within 9 5/8-inches casing. The length of the tubing is 9425 feet. It is connected to the sales line through a 4 inches piping of 530 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve is 245 feet.

3.1.11 Well TT-11

Well TT-11 was completed in April 1990 and started commercial production in June 1991. It is a vertical well, producing from A sands and up to 10462 feet deep. The depth of perforation is from 8700 feet to 8902 feet with an effective perforation length of 40 feet. It uses a 2 7/8 inches and a 3.5 inches tubing (inner diameter of 2.658 inches and 3.068 inches respectively) within a 9 5/8 inches casing. The length of the 3.5-inches tubing is 8592 feet while that of 2 7/8-inches tubing is 50 feet. It is connected to the sales line through an 8 inches piping of 12600 feet long (inner diameter of 7.625 inches). The depth of the sub-surface safety valve is 180 feet

3.2 SAND GROUP

The Sand Group consists of A, B and C Sand Groups. A Sand Group consists of A1, A2, A3 and A4 sands. Extending from a depth of 8500-ft sub-surface (SS) to 9300 ft SS, the four reservoirs represent the highest quality formations encountered by the existing wells and account for approximately 80 percent of the total field reserves.

Four distinct and separate reservoirs are identified in the B Sand Group, which extends from a sub-sea depth of 9400 feet to 9800 feet. It consists of BOE, B1, B2 and B3 sands. Generally, the reservoir quality of the sands in this group is noticeably lower than that of the A sands.

The C Sand Group consists of COE, C1, C2, C3 and C4E sands. The sands are found to extend from an SS depth of 9000 to 12000 feet and reservoir quality is lower than that of the B sands.

Of the sands, only major producing sands A2, A3, A4, B3 and C3 are shown in Figure 1.2.

3.3 GAS COMPOSITION

Due to slight variations in different gas samples, an average gas composition has been used for all the 11 wells. The composition is shown in Table-3.1. The composition is based on IKM report, 1991.

Table 3.1: Titas Gas Composition

Component	Mole frac. X	M.W.	X*M.W.	Pc psia	X*Pc	Tc Deg. R	X*Tc
H_2	0.0340	28.014	0.1	493.1	1.7	227.3	0.8
H_2S	0.0000	34.080	0.0	1306.0	0.0	672.5	0.0
CO_2	0.0072	44.011	0.3	1070.6	7.7	547.6	3.9
C1	0.9648	16.043	15.5	667.8	644.3	343.1	331.0
C2	0.0160	30.070	0.5	707.8	11.3	549.8	8.8
C3	0.0035	44.097	0.2	616.3	2.2	665.7	2.3
iC4	0.0010	58.124	0.1	529.1	0.5	734.7	0.7
nC4	0.0008	58.124	0.0	550.7	0.4	765.3	0.6
iC5	0.0005	72.151	0.0	490.4	0.2	828.8	0.4
nC5	0.0004	72.151	0.0	488.6	0.2	845.5	0.3
C6	0.0005	86.178	0.0	445.7	0.2	888.5	0.4
C7+	0.0019	100.205	0.2	410.0	0.8	958.3	1.8

Note: Pc=Critical pressure; Tc=Critical Temperature

Critical pressure of Titas gas=669.6^0 psia

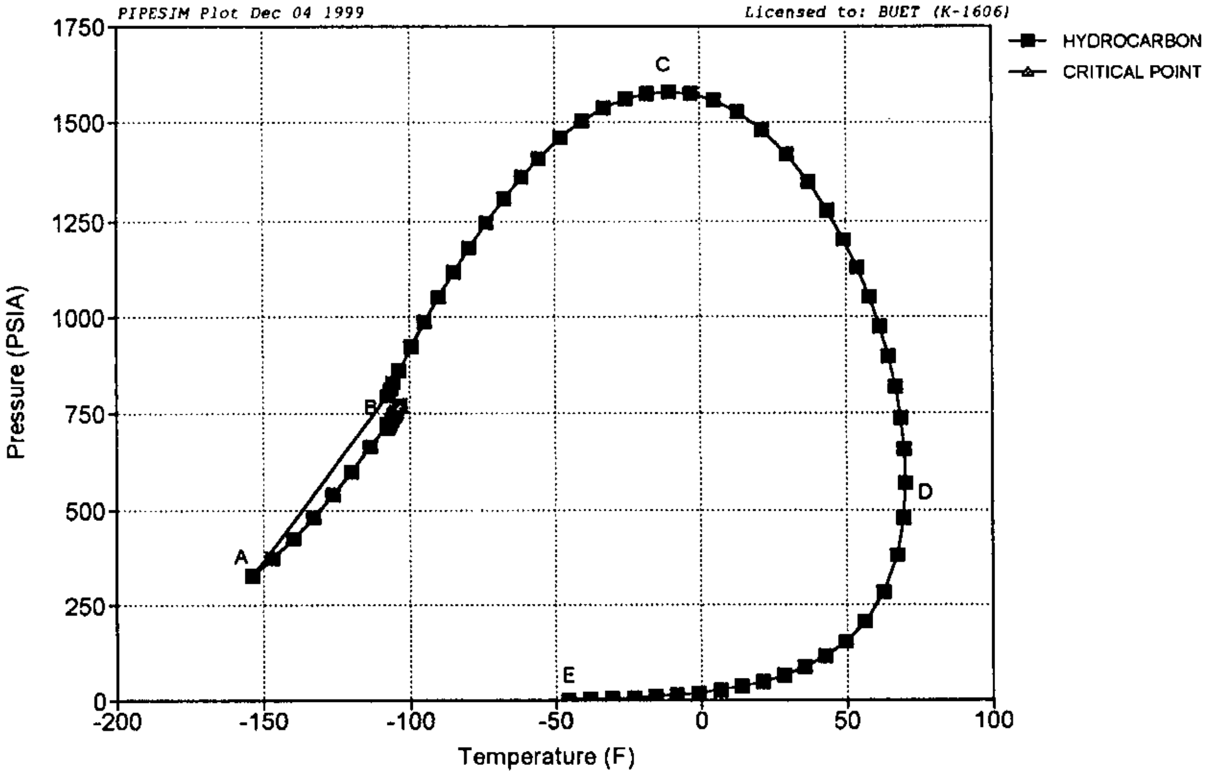
Critical temperature of Titas gas=351.2^0 R

Specific gravity=0.584

3.4 PHASE ENVELOPE

Based on the composition, a phase envelope has been drawn and shown in Figure 3.3. Line AB is bubble point curve and line BE is dew point curve. The critical point, B, is the intersecting point of these two curves. This is located at 700 psia and at -110^0 F. Point C is the criocondenbar, which represent the maximum pressure at which liquid and vapor may exist in equilibrium. Point D is the cricondentherm, the maximum temperature at which liquid and vapor may exist in equilibrium. The cricondenbar is found to be 1588 psia and criocondentherm is found to be 71^0 F. The retrograde region is found within BCD region.

Figure 3.3: Phase Envelope Plot of Titas Gas



PIPESIM for Windows © Baker Jardine & Associates, London

This phase envelop indicates that condensate should be produced only below 70^0 F whereas in the field condensate is being produced at about 100^0 F. Therefore, the gas composition, measured in 1991 and used to generate this envelop, does not truly represent the current composition. The fraction of heavier components has certainly increased since 1991.

3.5 SURFACE FACILITIES

Existing surface facilities of the Titas Gas Field are spread over at four locations adjacent to the surface locations of the associated wells. The gas processing facilities at location 1 consist of four 60 MMSCFD glycol dehydration trains for wells TT-1, TT-3, TT-4 and TT-5 and a 60 MMSCFD low temperature separation (LTS) train for well TT-7. Process diagrams of a Glycol Dehydration Plant and an LTS process with Glycol injection are shown in Figures 3.4 (a) and 3.4 (b) respectively. The LTS train includes a well stream cooler on the inlet and glycol injection for hydrate prevention. Location 1 also hosts common facilities for all sales gas measurement and transmission, and condensate product storage and transport facilities. The capacity of the common facility is 250 MMSCFD of dry gas and 200 bbl/d of liquid condensate.

Location 2 is comprised of the surface location of well TT-2 and, prior to 1991; a 40 MMSCFD LTS train based on LTX process, which makes use of hydrate formation in the recovery of liquid hydrocarbons. In 1991, the LTX process train at location 2 was decommissioned and moved to the Feni Gas Field. The gas stream from well TT-2 is currently connected by flowline to location 1, where it shares the glycol dehydration process trains of wells TT-1, TT-3, TT-4 and TT-5.

At location 3, the gas processing facilities for well TT-6 are based on the glycol dehydration process, while the gas streams from wells TT-8, TT-9 and TT-10 go through LTS process trains which include well stream coolers on the inlet. The facilities for the well TT-8 also incorporate a glycol injection unit for hydrate

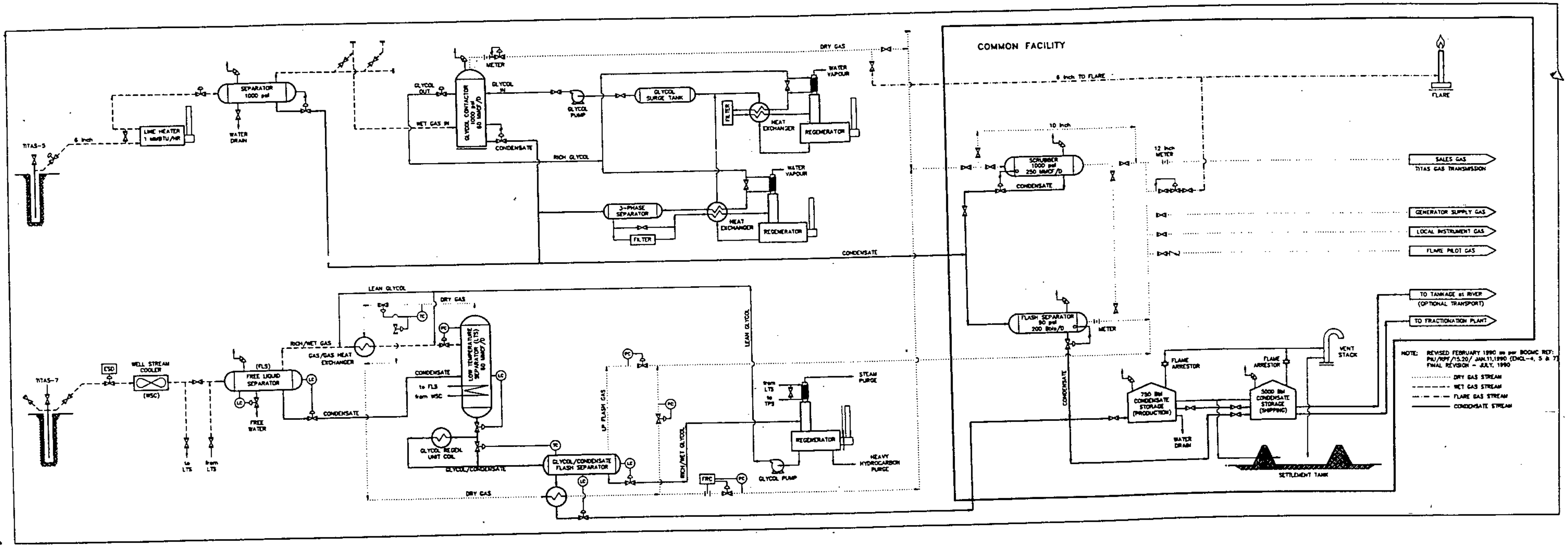


Figure 3.4 (a) Glycol Dehydration Process (b) LTS process with Glycol Injection

prevention. Design capacity of the gas processing trains of the wells TT-6, TT-8, TT-9 and TT-10 is 60 MMSCFD each.

Location 4 consists of TT-11 only. Due to smaller production tubing, the predicted wellhead pressure at TT-11 is significantly less than those experienced by other wells. Since an LTS process requires a significant pressure drop for optimum operation, processing the gas stream from TT-11 through an LTS would not be efficient. Accordingly, the gas stream from TT-11 has been tied-in to the Glycol dehydration process train for TT-6.

It is important to note that the currently installed gas trains at Titas Gas Field have combined design capacity of 540 MMSCFD (location 1-300 MMSCFD, location 2-0 MMSCFD, location 3-240 MMSCFD). This processing capacity is almost double the field maximum capacity. It is also important to note that the existing facilities at Titas Gas Field do not have adequate provision for handling significant volumes for free water production.

3.5.1 PROCESS EVALUATION

Different gas processing schemes have been implemented among the eleven gas production streams at Titas Gas Field. Tri-Ethylene Glycol (TEG) absorption, LTS separation without hydrate formation and LTS with hydrate formation, under the appropriate operating conditions, are effective processes for hydrocarbon and water dew point control, with some potential for recovery of condensable hydrocarbons. Hydrate is a low molecular, solid product of natural gas with connate water.

3.5.1.1 GLYCOL DEHYDRATION PROCESS

Tri-Ethylene Glycol (TEG) has the following properties, which makes it ideal for being used as an absorbent in the dehydration of natural gas:

1. High affinity for water due to hydrogen-oxygen bonds which are set up between atoms of the hydroxy groups and those of water
2. Low cost
3. Non-corrosiveness

4. Stability towards gas components
5. Stability during regeneration
6. Ease of regeneration
7. Low or moderate viscosity
8. Low vapor pressure at contact temperature
9. Low solubility for natural gases and hydrocarbon liquids
10. Low foaming or emulsifying tendencies

Some of the physical properties of TEG are shown in Table A.1 of Appendix A.

In the TEG process, wet gas at wellhead temperature of 150^0 F is passed through a choke where temperature is reduced to 105^0 F and 1010 psia. Then it is sent to a separator where condensate, water as well as mud and debris are removed, otherwise they might lead to foaming, flooding and higher glycol loss. Then this gas comes in contact with concentrated TEG in a counter-current Glycol Contactor or absorber and the dry gas leaves at about 100^0 F. This gas is dried in the scrubber and send to sales line at 1000 psia.

The wet glycol is sent through a high pressure-filter to remove any solids that may have been acquired by from the gas stream. A three-phase separator is used to remove liquid hydrocarbon absorbed from the gas stream in the contactor. Then the glycol is sent to stripper, mounted on a reboiler, where the glycol is regenerated.

Process flow diagram is shown in Figure 3.4 (a).

The glycol plant is mainly consisted of two units:

I. Absorber

The upper limit of the temperature of absorption is governed by the vaporization losses to TEG. A practical upper limit temperature is about 100^0 F. The actual temperature of the absorption is determined by the temperature to which the regenerated glycol can be cooled, the inlet gas temperature, the heat of absorption of the absorbed water and the gas-liquid ratio. A minimum temperature of 50^0 F is generally observed.

Equipment-construction rather than phase equilibrium relationships place limitations on the pressure at which glycol-absorption units may be operated. TEG plant with working pressure up to 20000 psia have been reported although at high pressure the viscosity of TEG is substantially higher than at atmospheric pressure.

The cross-sectional area of the absorber is governed primarily by its gas-handling capacity, since the liquid rate required to dehydrate the gas is low. Still, stagewise efficiencies of the order of 70 per cent can be obtained.

Dew point depression of the gas leaving the absorber can be as high as 60^0 to 75^0 F corresponding to inlet glycol concentration of 98 to 99 wt % glycol. This corresponds to a maximum regeneration temperature of 350^0 F.

II. Stripper

The temperature on the glycol side of the regenerator is an important variable because its determines the concentration of the regenerated glycol-water solution and because an excessive temperature will cause the thermal decomposition of the glycol. Gas-liquid contact in the stripper occurs in a packed section. The glycol flows downwards through packing into the reboiler. Water vapor liberated from the glycol in the boiler passes upwards through the packing, providing heat and picking up some water from the wet glycol flowing downwards. The water vapor leaves the unit from the top of the still column. A reflux is provided at the top of the column. A significant excess of packed height is usually provided.

Heat for regeneration is provided by direct combustion of natural gas in tubes in the reboiler. A preheater is used before the reboiler to reduce the residence time at elavated temperature to as short time a period as possible in order to minimize glycol breakdown and subsequent corrosion. A three-phase separator is also provided before the stripper in order to release the gas absorbed by glycol in the absorber. Otherwise, the gas released in the stripping column would create turbulence and induce erosion.

Pollitzner et al. (1951) reported TEG losses attributable to vaporization of 0.012 gal/MMSCF, which agree with total losses of 0.025 gal/MMSCF reported in field practice by Campbell and Laurence (1952). Some TEG is also lost due to due to entrainment, leakage, solubility, etc.

3.5.1.2 LOW TEMPERATURE SEPARATION PROCESS

The saturated-water content of natural gas decreases with decreased temperature. Thus, hot gases saturated with vapor are partially dehydrated by direct cooling. Unless the cooling process reduces the temperature to the lowest value that the gas will encounter at the prevailing pressure, cooling does not prevent further condensation of water.

In the LTS process, as shown in Figure 3.4 (b), wet gas is first cooled in the well stream cooler and LTS separator from well head temperature of 150^0 F to 135^0 F. It is further cooled by 5^0 F in the free liquid separator. The overhead gas from this separator is cooled to 90^0 F in the gas/gas heat exchanger by the cold dry gas from the LTS separator. The wet gas is injected with TEG to prevent hydrate formation and then further to cooled to 50^0 F by through a J-T valve at the inlet of the separator. TEG and condensate are separated in the flash separator and then TEG is regenerated to be used again. A heater may be required in conjunction with the separator as the liquid mixture tends to form emulsions, which are quite stable at low temperatures but separate more rapidly as the temperature is increased.

A theoretical liquid recovery in the range of 2.0 to 2.5 bbl/MMSCF might be expected for these processes. The TEG processes on wells TT-1, TT-3, TT-4, TT-5 and TT-6 have performed consistently near the average of 1.3 bbl/MMSCF. The LTS process on wells TT-7, TT-8, TT-9 and TT-10 has proven only slightly more efficient, 1.39 bbl/MMSCF. At 2.10 bbl/MMSCF, the LTX process on well TT-2 has demonstrated significantly higher performance before being moved to the Feni Gas Field. It is not possible for the glycol dehydration or low temperature separation process to effectively recover more than 75% of the C_5 + components and, possibly some small quantity of the C_3 and C_4 components. Lack of vapor recovery system, elevated inlet gas stream temperatures and different gas stream compositions are likely reasons which explain why liquid recovery in the theoretical range 2.0-2.5 bbl/MMSCF range has not been achieved.

CHAPTER 4

SCOPE OF THE STUDY

4.1 OBJECIVE OF THE STUDY

The objective of the study is to perform production system analysis of the Titas Gas Field to understand the production behavior, to find out whether there is any over sizing or bottlenecking of piping or tubing and predict its future performance utilizing the available information. To achieve this objective, this study has been subdivided as follows:

1. To analyze the performance of individual wells and suggest optimum sizes of piping and tubing.

2. To integrate the wells into network and simulate the models to see whether they match with the field values.

4.2 METHODOLOGY

To achieve the above objectives the following methods were used

1. Collect all the necessary production data and field data.

2. Due to lack of up to date data, for all wells except T-6 and T-10, average reservoir pressure, reservoir temperature and exponent of back-pressure equation are reasonably assumed. Then with the help PIPSIM software, choke diameter and back-pressure equation coefficients are determined.

3. Using the nodal analysis approach and using the PIPESIM software analyze the individual well performance by conducting selectivity studies of the important well variables.

4. Then analyze the performance of the network of wells by simulating the system using PIPESIM-Net software.

CHAPTER 5

PRODUCTION SYSTEM ANALYSIS

Any production well is drilled and completed to move the gas or oil from its original location in the reservoir to the stock tank or sales line. Movement or transport of these fluids requires energy to overcome friction losses in the system and to lift the products to the surface. This loss is the sum of the pressure drops occurring in all of the components of the system as illustrated by the Figure 5.1.

The system consists of three major parts:

1. flow through porous medium
2. flow through vertical conduit
3. flow through horizontal pipe

The pressure drop through any of these components varies with the production rate, so the producing rate will be controlled by the components selected. The selection and sizing of the individual components is very important, but because of the interaction among the components, a change in the pressure drop in one may change the pressure drop behavior in all the components. This occurs because the flowing fluid is compressible, and, therefore, the pressure drop in a particular component depends not only on the flow rate through the component, but also on the average pressure and temperature that exist in the component.

The final design of a production system cannot be separated into reservoir performance and piping system performance and be handled independently. The amount of gas flowing into the well from the reservoir depends on the pressure drop in the piping system, and the pressure drop in the piping system depends on the amount of fluid flowing through it. Therefore, the entire production system must be analyzed as a unit.

The production rate or deliverability of a well can often be severely restricted by the performance of only one component in the system. If too much pressure drop occurs in one component or module, there may be insufficient pressure drop remaining for efficient performance of the other modules. For example, even if a reservoir is capable of producing a large amount of gas, resulting in too much pressure drop in the tubing, well performance suffers. On the other hand, when there is an excessive pressure drop caused by formation damage or inadequate perforations, improving the performance of piping and tubing will be fruitless. If the effect of each component on the total system performance can be isolated, the system performance can be optimized in the most economical way.

Nodal Analysis is the method for analyzing any well, which will allow determination of the producing capacity for any combination of components (Beggs, 1991). This method may be used to determine locations of excessive flow resistance or pressure drop in any part of the system.

The nodal analysis method was first introduced by Glibert (1954) but only recently it has found wide application in USA. Advancement in measurement methods, computer applications and increase in allowable production in government regulations has increased awareness about identifying wells producing less than their capacity and has enabled engineers to optimize the production to the desired level, using this technique.

The method consists of selecting a division point or node in the well and dividing the system at this point. All of the components upstream of the node comprise the inflow section, while the outflow section consists of all the components downstream of the node. A relationship between flow rate and pressure drop must be available for each component in the system. The flow rate through the system can be determined once the following requirements are satisfied:

1. flow into the node equals flow out of the node;
2. Only one pressure can exist at a node.

At a particular time in the life of a well, there are always two pressures that remain fixed and are not function of flow rate. One of these pressures is the average pressure $P_{R,}$ and the other is the system outlet pressure, usually the separator pressure.

Once the node is selected, the node pressure is calculated from both directions starting at the fixed pressures.

Inflow to the node:
P_R - ΔP (upstream components) = P_{node}

Outflow of the node:
$P_{sep} + \Delta P$ (down stream components) $= P_{node}$

The pressure drop, ΔP, in any component varies with flow rate, q. Therefore, a plot of node pressure versus flow rate will produce two curves of inflow and outflow, the intersection of which will give the conditions satisfying requirements 1 and 2. The procedure is illustrated graphically in Figure 5.2.

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 flow capacity and node pressure will exist. 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.

Nodal analysis method has a wide variety of applications. The general objectives of the method are:

1. To determine the flow rate at which an existing gas well will produce by considering wellbore size and production limitations.
2. To determine under what flow conditions a well will load with fluid and estimate the time to clean up the fluid.
3. To select the most economical time for the installation of gas lift.
4. To optimize the system to produce a desired flow rate most economically.
5. To design well stimulation size and stimulation methods to maximize the production rates.
6. To permit quick recognition by the operator and Technical people of ways to increase the production rates.

The success of nodal analysis method, however, depends on the use of appropriate correlation and equations while analyzing IPR and OPR.

Figure 5.1: Different Pressure Losses in a Complete System

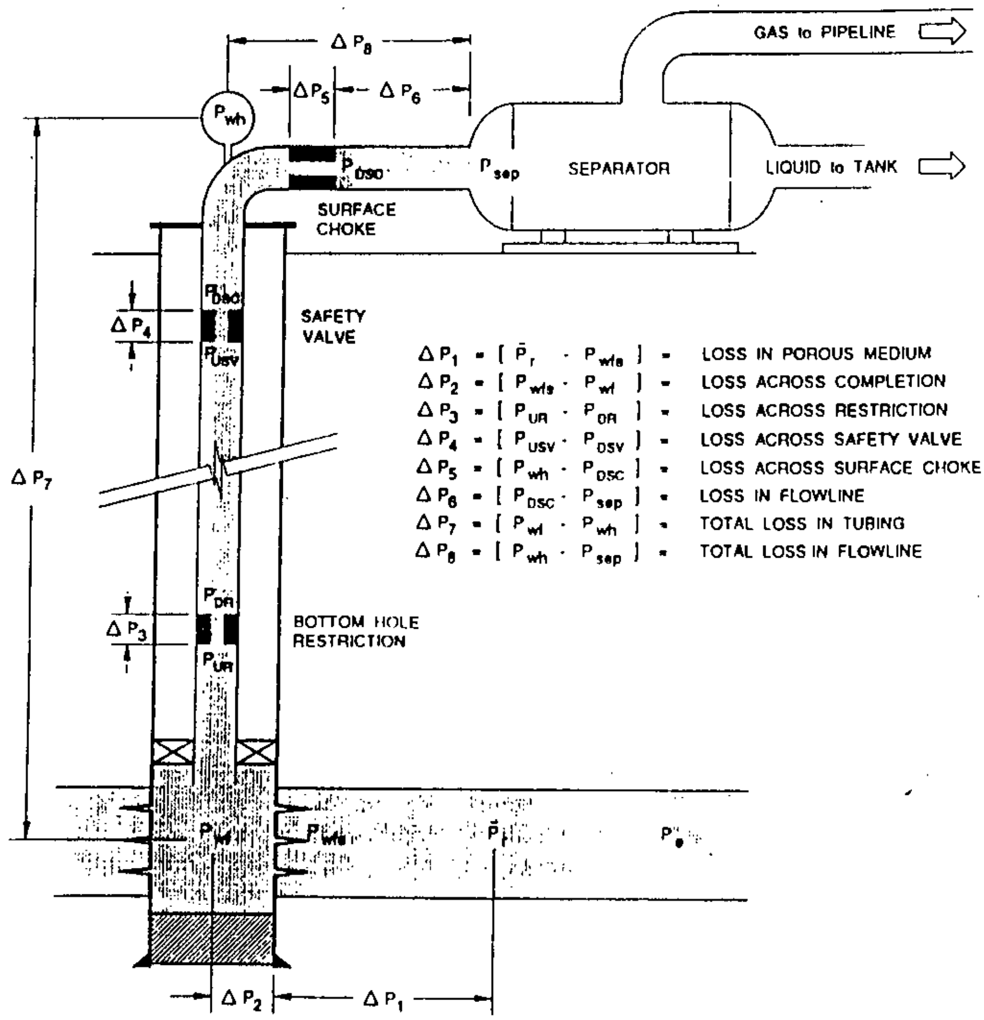
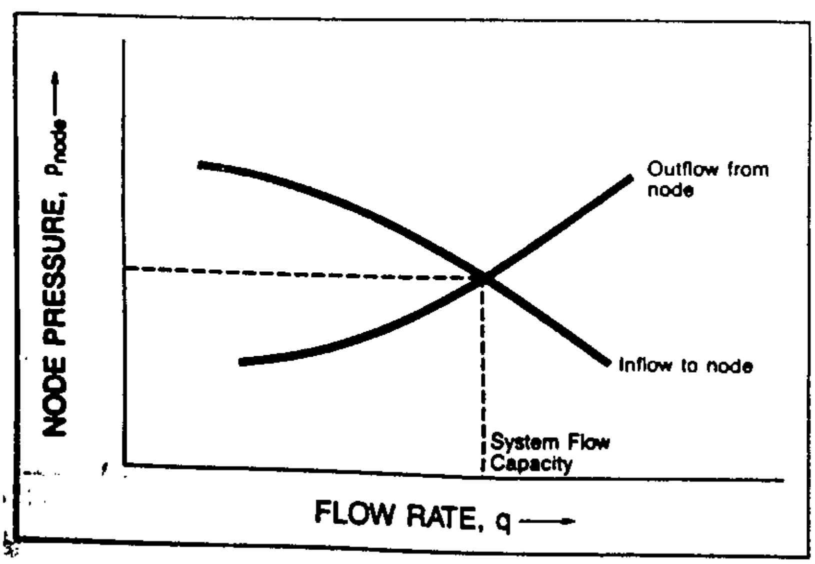


Figure 5.2: Determination of Flow Capacity



Source: Beggs (1991)

CHAPTER 6

CALCULATION BASIS

6.1 CALCULATING BOTTOM HOLE PRESSURE FROM WELL HEAD PRESSURE FOR FLOWING CONDITION

Sometimes it is necessary find out the flowing bottom hole pressure for flow calculations. But due to absence of recording gauge at the bottom hole, using vertical flow correlation becomes the only alternative.

General equation for vertical flow calculations (Lee and Wattenbarger, 1996) can be written as follows, neglecting changes in kinetic energy:

$$(53.34TZ*dP/\Upsilon g*P) + g*dz/g_c + (2.667*10^{-9}fT^2Z^2/d^5P^2)*\ Q^2dL=0; \qquad (6.1)$$

Where, the units are: P = pressure, psia; Q = flow rate, MSCF/D; T= temperature, ^{0}R; L = measured depth, feet; d = inner diameter, inch; z = vertical depth, feet;

The equation can not be easily integrated as compressibility factor Z is a complex function of P and T, and the temperature variation with depth is not easily defined. Various simplifying assumptions made in the evaluation of this integral form the basis for the different methods that give results of varying degrees of accuracy.

One method is the average temperature and Z-factor method. The method assumes that Z factor and the temperature can be represented with an average value calculated at the average or surface temperature and bottom hole temperature and surface pressure and bottom hole pressure. With this assumption, the equation becomes, after integration:

$$P^2_{wf} = P^2_{wh}e^s + [6.67*10^{-4}Q^2\, fT^2_{avg}Z^2_{avg}(e^s-1)/d^5\cos\theta]; \qquad (6.2)$$

Where,

$s = 0.0375\Upsilon gL\cos\theta/Z_{avg}T_{avg}$;

P_{wf} = flowing bottom hole pressure, psia;

P_{wh} = flowing well head pressure, psia;

f = Moody friction factor;

The friction factor f can be calculated from the following equation (Lee and Wattenbarger, 1996):

$$f = 4[2.28-4\log(0.0023/d + 21.25/N^{0.9})]^{-2} \tag{6.3}$$

Where,

Reynolds number $N = 20\gamma_g Q/\mu_g d$

γ_g = gas specific gravity

μ_g = gas viscosity

The calculation procedure involves use of multi step calculation with intermediate pressures at several points in the production string. The average Z factor is obtained by iteration at each step. A good initial guess of P_{wf} be calculated from the equation (Lee and Wattenbarger, 1996):

$$P_{wf} = P_{wh} + 0.25 P_{wh} L\cos\theta/10^4 \tag{6.4}$$

The C++ program for this method is shown in Appendix-B.

6.2 PIPELINE FLOW CALCULATIONS

Transportation of natural gas by pipeline requires knowledge of flow formulas for calculating capacity and pressure requirements. The initial assumptions made in the derivation of any specific flow equation are as follows (Katz et al., 1959):

1. Kinetic energy change is negligible;
2. The flow is steady state and isothermal;
3. The flow is horizontal;
4. There is no work done by the gas in flow;

General equation for horizontal flow can be written as:

$$\int V\, dP + \int fV^2\, dL/2gcd = 0; \tag{6.5}$$

Where,

V = The specific volume of flowing fluid, ft^3/lb mass;

P = pressure, psia;

f = Darcy friction factor;

By making various additional assumptions, the equation can be made the starting point for the derivation of specific flow equations for the transmission for natural gas.

One of the earliest of such equations was the Weymouth equation (Katz et al., 1959):

$$Q = (18.062\ T_o/P_0)[(P_1^2-P_2^2)d^{16/3}/\gamma_g TLZ_a]^{0.5}; \tag{6.6}$$

Where,

Q = gas flow measured at T_0 and P_0, std ft^3/hr;

L = length of line, miles;

d = internal diameter, inch;

P = pressure, psia;

γ_g = gas gravity (air = 1);

T = average line temperature, ^0R;

Z_a = average compressiblity factor;

f = friction factor;

This equation is suitable for pipelines with inner diameter less than 15 inches. For larger pipelines, Panhandle or Modified Panhandle equation (Kumar, 1987) provide better results.

6.3 GAS VISCOSITY

Gas viscosity calculation is required for pressure calculation. Lee et al method (1996) method can be used to determine gas viscosity for sweet natural gas as well as for sour gas. If the gas density or the Z factor is corrected for contaminants, this viscosity correlation accurately estimates gas viscosity.

The Lee et al method for estimating gas viscosity is:

$$\mu_g = 10^{-4}K \exp(X\rho^Y) \tag{6.7}$$

Where,

$$\rho = 1.4935*10^{-3}(pM/ZT) \tag{6.8}$$

$$K = (9.379 + 0.01607M)T^{1.5}/(209.2 + 19.26\ M + T) \tag{6.9}$$

$$X = 3.448 + 986.4/T + 0.01009M \tag{6.10}$$

$$Y = 2.447 - 0.2224X \tag{6.11}$$

These correlations are used in the C++ program in the appendix B for determining flowing bottom hole pressure from flowing wellhead pressure.

6.4 CHOKE CORRELATION

The flow rate from a well is controlled with a well head choke, a device that places a restriction in the flow line. A variety of factors may make it desirable to restrict the production rate from a flowing well, including the prevention of coning or sand production, satisfying production rate limits set by regulatory authorities, and meeting limitations of rate or pressure imposed by surface equipment.

When gas flows through a choke, the fluid may be accelerated sufficiently to reach sonic velocity in the throat of choke. When this condition occurs, the flow is called "critical" and changes in the pressure downstream of the choke do not affect the flow rate, because pressure disturbances cannot travel upstream faster than the sonic velocity.

For isentropic flow of an ideal gas through a choke, the rate is related to the pressure ratio P_2/P_1 (Economides, 1994).

$$Q = \pi d^2 P_1 T_{SC}\, \alpha/4P_{SC} \sqrt{[(2g_c R/28.97\gamma_g T_1)(\gamma/(\gamma-1))\,[(P_2/P_1)^{2/\gamma} - (P_2/P_1)^{(\gamma+1)/\gamma}]} \quad (6.12)$$

Where,

Q = gas flow rate, MSCF/D;

d = choke diameter, inch;

T_1 = temperature upstream of the choke, ^0R;

P_1 and P_2 = upstream and downstream pressure;

γ = heat capacity ratio, C_p/C_V;

α = flow coefficient of the choke;

γ_g = gas gravity;

T_{sc} = standard temperature, ^0R;

P_{sc} = standard pressure, psia;

6.5 BACK-PRESSURE EQUATION

Darcy's equation for radial gas flow may be expressed as follows: (Beggs, H.D., 1991)

$$Q_{Sc} = [703*10^{-6}K_g h(P^2_R - P^2_{wf})]/\mu_g ZT[\ln(0.472r_e/r_{w)} + S'] \tag{6.13}$$

Where,

h = pay zone thickness;

K_g = relative permeability to gas;

P_R = average reservoir pressure;

P_{wf} = flowing wellbore pressure;

S' = skin factor which includes both turbulence and actual formation damage;

Solving for $P^2_R - P^2_{wf}$ and collecting terms yields:

$$P^2_R - P^2_{wf} = AQ_{SC} + BQ^2_{SC} \tag{6.14}$$

Where,

$A = 1422\ \mu_g ZT[\ln(0.472r_e/r_{w)} + S']/ K_g h$

$B = 1422\mu_g ZTD/ K_g h$

Where D = turbulence coefficient

The effects of turbulence can be accounted for by including an exponent in the pressure term of equation 6.14. This results in the back-pressure form of the equation:

$$Q_{SC} = C(P^2_R - P^2_{wf)})^n \tag{6.15}$$

Where,

C = flow coefficient

n = exponent depending on flow characteristics and wellbore damage or skin

For negligible turbulence ($B = 0$), the value of n is 1.0. When the flow is turbulent, the value of n is 0.5. The actual value of n usually ranges between 0.5 and 1.0 for gas wells. Elenbass and Katz (1948) have shown that back-pressure curve can have curvature resulting from the onset of turbulence.

For high-permeability reservoirs the performance of a well over the life of the field can be predicted from a single back-pressure curve. The value of n and C can be evaluated from pressure test data. Generally, C is assumed to be constant with time for a high permeability reservoir.

6.6 SEPARATOR CALCULATION

For gas-liquid separation, horizontal separators are used. The act on the principle of gravity settling and impingement. The effectiveness of separators can be calculated from Souders- Brown equation (Kumar, 1987):

$$Q = (\pi hL/4)[4gd_p(\rho_l - \rho_g)]^{0.5}/(3C_d\rho_g)^{0.5} \tag{6.16}$$

Where,

Q = gas flow rate

h = height of the separator

L = length of the separator

ρ_l, ρ_g = liquid and gas density, respectively

d_p = smallest particle size that can be separated.

C_d = drag coefficient

CHAPTER 7

DATA ANALYSIS

7.1 INTRODUCTION

Detailed pressure survey has been conducted in only wells TT-6 and TT-10 recently. So, up to date parameters like average reservoir pressure and temperature, back-pressure equation parameters C and n are available for only those two wells. Shut in wellbore or average reservoir pressure and temperature are also available for TT-1. For other cases, average reservoir pressure and temperature and n have been reasonably assumed. C and choke diameter have been calculated, based on the assumed values. It should be mentioned that in the field, it is not possible to read the actual choke size as choke is applied through an adjustable valve.

In the analysis, bottom hole point has been taken as the nodal analysis point.

7.2 SOLUTION ALGORITHM

Procedure for iterating on pressure increment for determining outflow performance relationship (OPR):

1. Starting with the known pressure P_1 at location l_1, length increment dl is selected.

2. For a certain flow rate, a pressure increment dP is estimated corresponding to length increment dl.

3. Average pressure and for non-isothermal cases, the average temperature in the increment is calculated.

4. From laboratory data or empirical correlation's, the fluid and PVT properties at conditions of average temperature and pressure are determined.

5. Using the appropriate pressure gradient correlation's, the pressure gradient dP/dl is calculated in the increment of average conditions of pressure and temperature and pipe inclination.

6. The pressure increment corresponding to the selected length increment is calculated; $dP = dl*(dP/dl)$.

7. The estimated and calculated values of dP, obtained in steps 2 and 6 are compared. If they are not sufficiently close, a new pressure increment is estimated and steps 3 through 7 are repeated until the estimated and calculated values are sufficiently close.

8. Set $l = l_1+dl_1+dl_2+\ldots\ldots\ldots\ldots+dl_n$

   $P= P_1+dP_1+dP_2+\ldots\ldots\ldots\ldots +dP_n$

9. If l is less than the total conduit length, step 2 through 8 is repeated.

7.3 PIPESIM for Windows Family

The pipesim for windows family of multiphase software products consists of:

PIPESIM for Windows-Single Branch

A comprehensive multiphase flow model with system analysis capabilities. Typical applications of the model include:

- Multiphase flow in wells, flow lines and pipelines
- Point by point generation of pressure and temperature profiles
- Calculation of heat transfer coefficients
- Well and flowline performance modelling
- Well inflow performance modeling
- Gas lift performance modeling
- ESP (electrical submersible pump) performance modeling
- Horizontal well modeling
- Injection wells
- Annular and tubing flow

- Matching of observed data with different correlation's
- Calibration of gas viscosity and compressibility, oil formation volume factor, oil density and live oil viscosity above and below bubble point.

PIPESIM-Net

A network analysis model extension to PIPESIM for WINDOWS-Single Branch. Features of the network model include:

- Unique network solution algorithm to model wells in large networks
- Rigorous thermal modeling of all network components
- Multiple looped pipeline/flowline capability
- Well inflow performance modeling capabilities
- Rigorous modeling of gas lifted wells in complex networks
- Comprehensive pipeline equipment models
- Gathering and distributing networks

PIPESIM-GOAL

The model allows field wide optimization of gas lifted or ESP lifted production systems to be performed on a day to day basis.

HoSIM

Hosim is designed to model horizontal and multilateral wells in details.

PIPESIM-FPT

This field-planning tool allows PIPESIM-Net models to be linked to a reservoir model to model reservoir behavior over time. In addition conditional logic decision can be taken into account.

WINGLUE

Allows detailed gas lift design and surveillance.

PIPESIM-online

Allows PIPESIM-Net and PIPESIM-GOAL to be linked to a SCADA system. Online then takes production data from the field and distributes this to GOAL for gas lift optimization. The results from GOAL are then passed back to the field via online.

PIPESIM-Connect

Allows PIPESIM to connect directly with a database to update well test data automatically.

In this study PIPESIM for Windows-Single Branch and PIPESIM-Net software were used for system analysis and simulation.

7.4 PROBLEMS ENCOUNTERED IN USING PIPESIM

Due to presence of bugs, the following problems were encountered:

- Mixed units for tubing/completion temperature caused the incorrect temperature to be set for the completion. If the temperature unit in the completion dialog was different from the temperature unit specified globally then the completion temperature was changed when the detailed tubing profile was entered.

- Using customized long length km units when the basis units were in engineering resulted in the PIPESIM file being corrupted. The resulting file could not be read into PIPESIM.

- The models sometimes collapsed without any apparent reason.

7.5 TITAS WELLS

7.5.1 Well TT-1

TT-1 has an average reservoir pressure of 3242.35 psia and an average reservoir temperature of 195.0^{0}F. The value of the back-pressure equation coefficient C is 0.00026 and Back-pressure equation exponent n is 0.80

Figure 5.1 shows a typical well. The well, TT-1, is perforated from 8586 feet to 9085 feet with an effective perforation length of 228 feet. It uses a 4.5 inches and a 3.5 inches tubing (inner diameter of 3.958 inches and 3.068 inches respectively) within a 9 5/8 inches casing. The length of the 4.5 inches tubing is 8456 feet and that of the 3.5 inches tubing is 65 feet. It is connected to the sales line through a 6 inches piping of 525 feet long (inner diameter of 5.187 inches) and a 4 inches piping of 48 feet long (inner diameter of 3.438 inches). The depth of the sub-surface safety valve, designed to prevent any blowout, is 202.17 feet.

Figure 7.1 shows the variation of flow rate with average pressure. At the initial reservoir pressure of 3999 psia, recorded in July 1968, the flow rate was 29.3 MMSCFD at a wellbore pressure of 3735 psia. For the current reservoir pressure of 3242 psia, the flow rate is 23.5 MMSCFD at and wellbore pressure of 2990 psia. The well is expected to produce 15 MMSCFD when the average reservoir pressure goes down to 2200 psia in future. It is assumed that all other parameters will remain the same. The decrease in average reservoir pressure causes a corresponding decrease in flow rate.

Figure 7.2 shows the effect of well stimulation on production rate. Well stimulation increases the value of C. For a low C value of 0.0001, production rate is only 20 MMSCFD. At present, a C value of 0.00026 produce 23.5 MMSCFD. Well stimulation to higher C value of 0.0006, will increase the flow rate to 24.8 MMSCFD but beyond that any improvement will not be much productive. Figure 7.2 also shows that the effect of well stimulation will not increase the flow rate very significantly. This is probably due to the fact that the well is not significantly damaged very close to the wellbore.

Figure 7.1: Effect of Average Reservoir Pressure on the Performance of Well TT-1

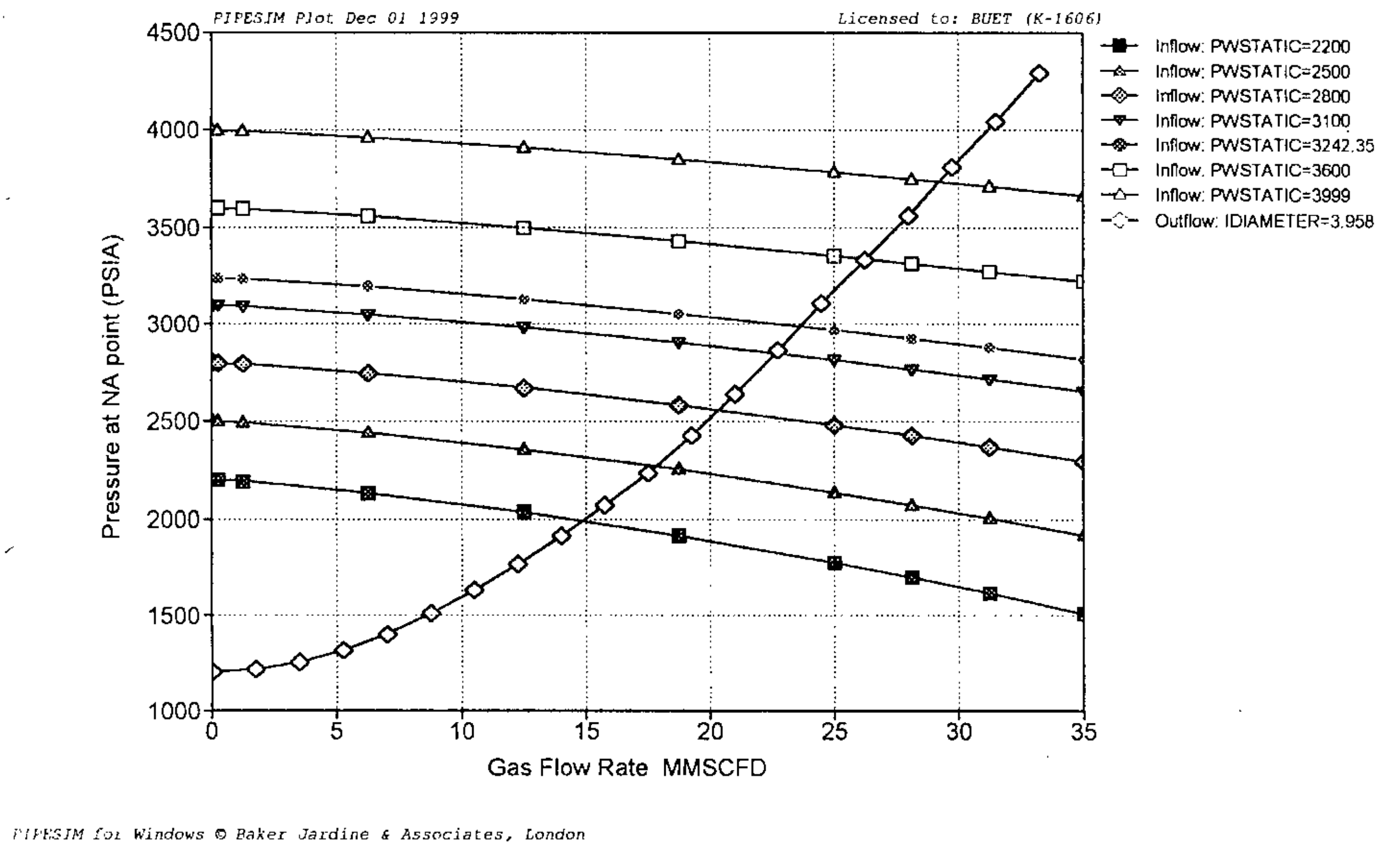
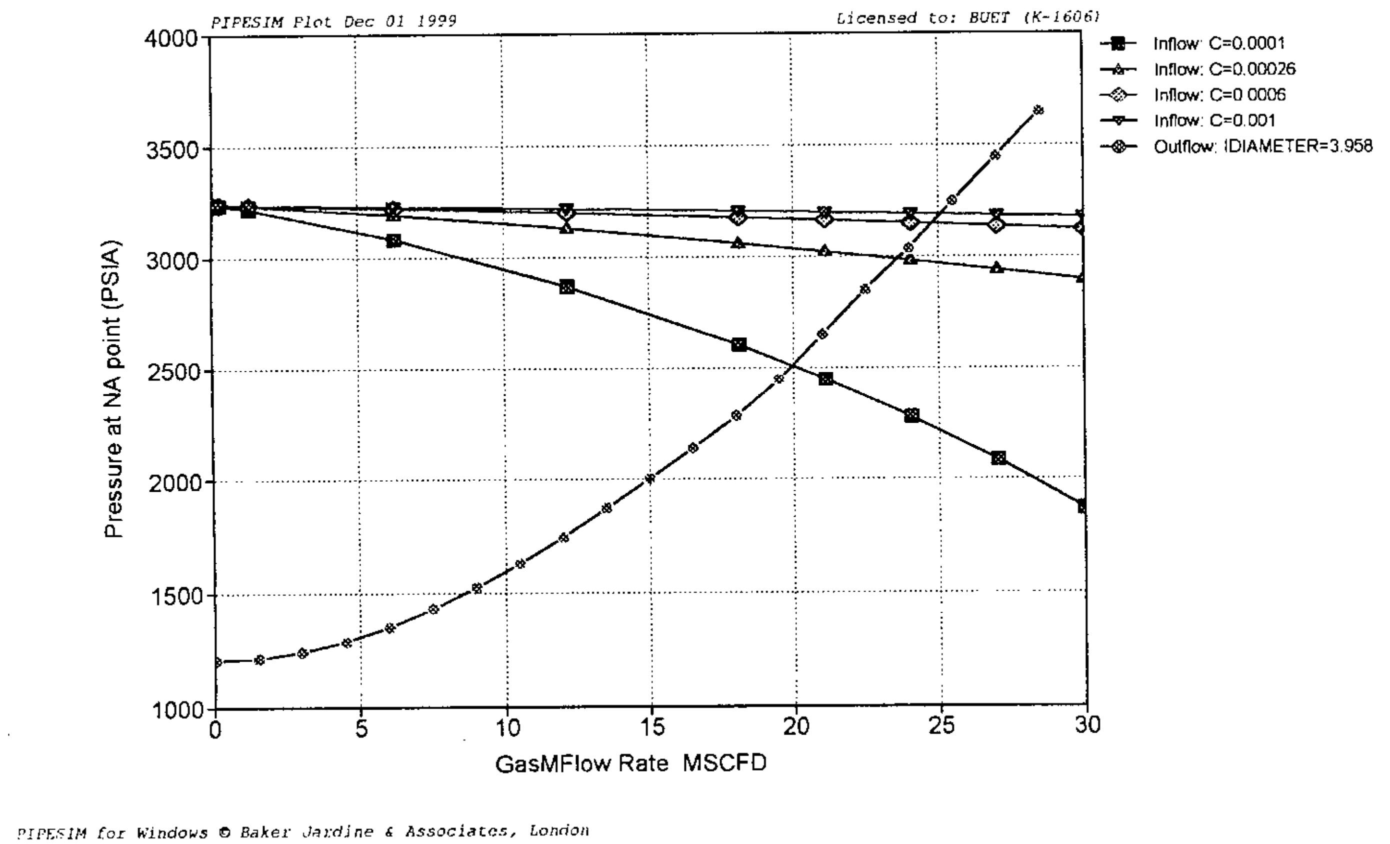


Figure 7.2: Effect of Back Pressure Coefficient on the Performance of Well TT-1



Well stimulation also increases the value of n, the exponent of the back-pressure equation. As shown in Figure 7.3, when n is 0.6, the flow is highly turbulent, a very large pressure drop occurs along the reservoir and a very low flow rate of only 4 MMSCFD is obtainable. With an increase in n, flow rate increases drastically. This is more so between the range 0.6 and 0.7, and increase in flow rate from 4 MMSCFD to 15 MMSCFD occurs. But the increase in less steep between n = 0.7 and n = 0.8. Beyond the value of n = 0.8, an increase in n is not productive. Therefore to get the optimum flow turbulence in the reservoir should be avoided and the value of the exponent should be kept around 0.8.

The easiest way of increasing the flow rate is to increase the opening of the choke. Figure 7.4 shows the effect of changing the bean diameter. Flow rate increases from 17.5 MMSCFD to 33.5 MMSCFD as bean size is increased from 0.60 inch to 0.90 inch. The well now produces 23.5 MMSCFD at a bean size of 0.72 inch.

Figure 7.5 shows the variation of flow rate with different size of tubing. For a tubing inner diameter of 2 inches a flow rate of only 12.8 MMSCFD is possible and the outflow performance relationship curve is very steep, indicating a large pressure drop. But for an increase of only 0.5-inch, the flow rate increases to almost 18.3 MMSCFD. For the next increment of 0.5 inch, flow rate further increases by 3.5 MMSCFD. The current tubing with an internal diameter of 3.958 inches sustains a production of 23.5 MMSCFD. Figure 7.5 also suggests that the present level of production can be sustained with a 3.5-inches tubing and any further increase in the tubing diameter will not increase the flow rate.

Figure 7.6 shows the effect of flow line inner diameter. A diameter of 2 inches produces at a rate of 22.3 MMSCFD and a 2.5-inches diameter produces 23.3 MMSCFD, which is very close to the existing flow rate. Analysis of the integrated model of six wells has shown that using 3-inches diameter tubing will increase the production rate to 23.5 MMSCF/D only. So existing flow line diameter of 5.187 inches is very large for the current production requirements, which can be met by much smaller size of 2.5 inches.

Figure 7.3: Effect of Back Pressure Exponent on the Performance of Well TT-1

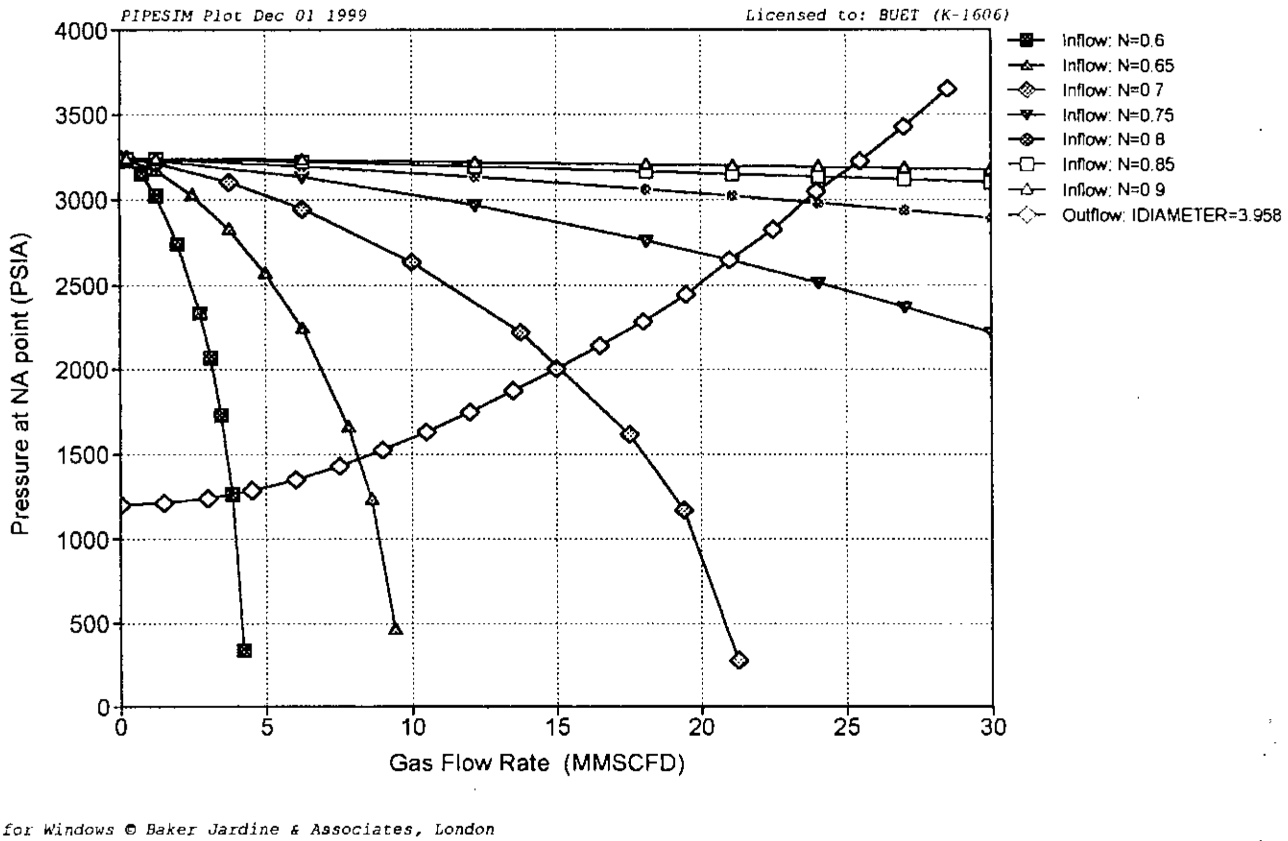


Figure 7.4: Effect of Choke Size on the Performance of Well TT-1

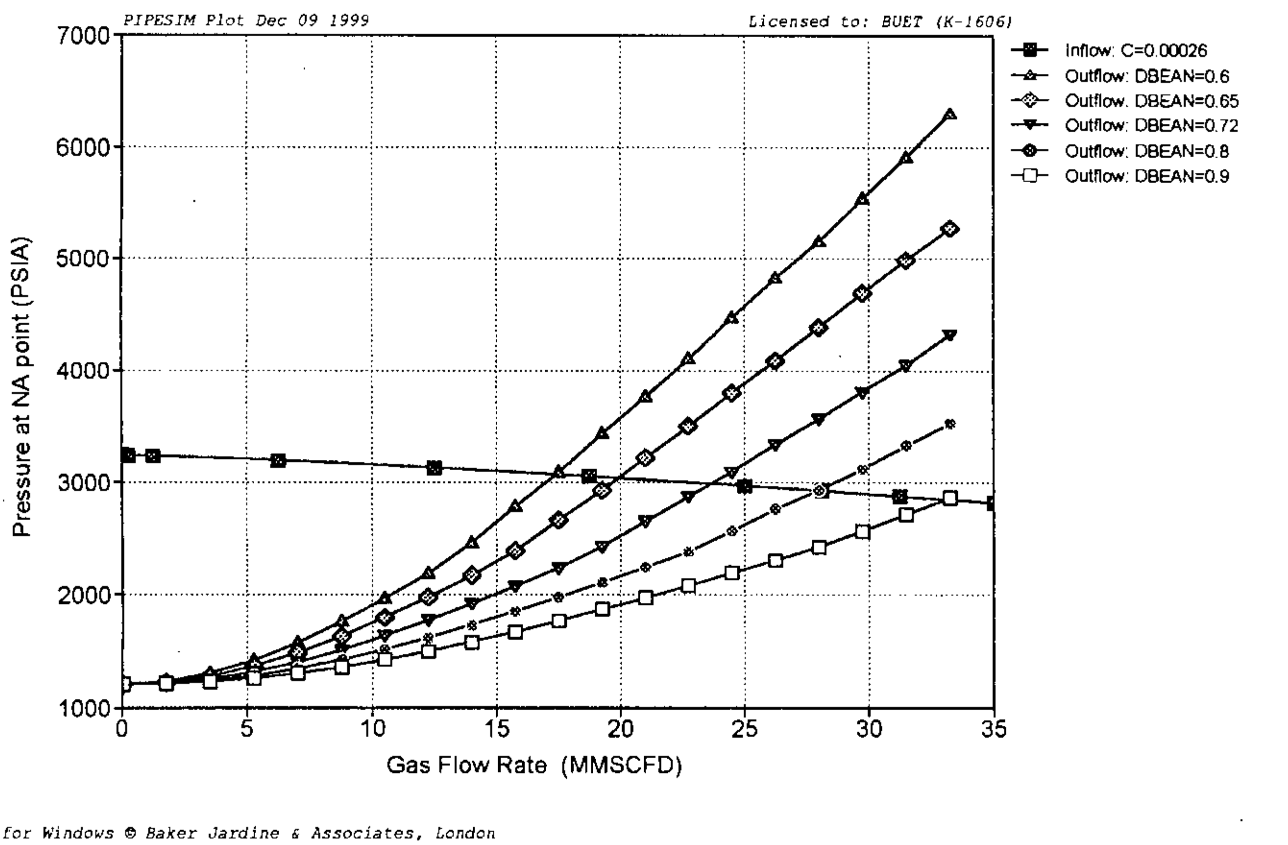


Figure 7.5: Effect of Tubing Inner Diameter on the Performance of Well TT-1

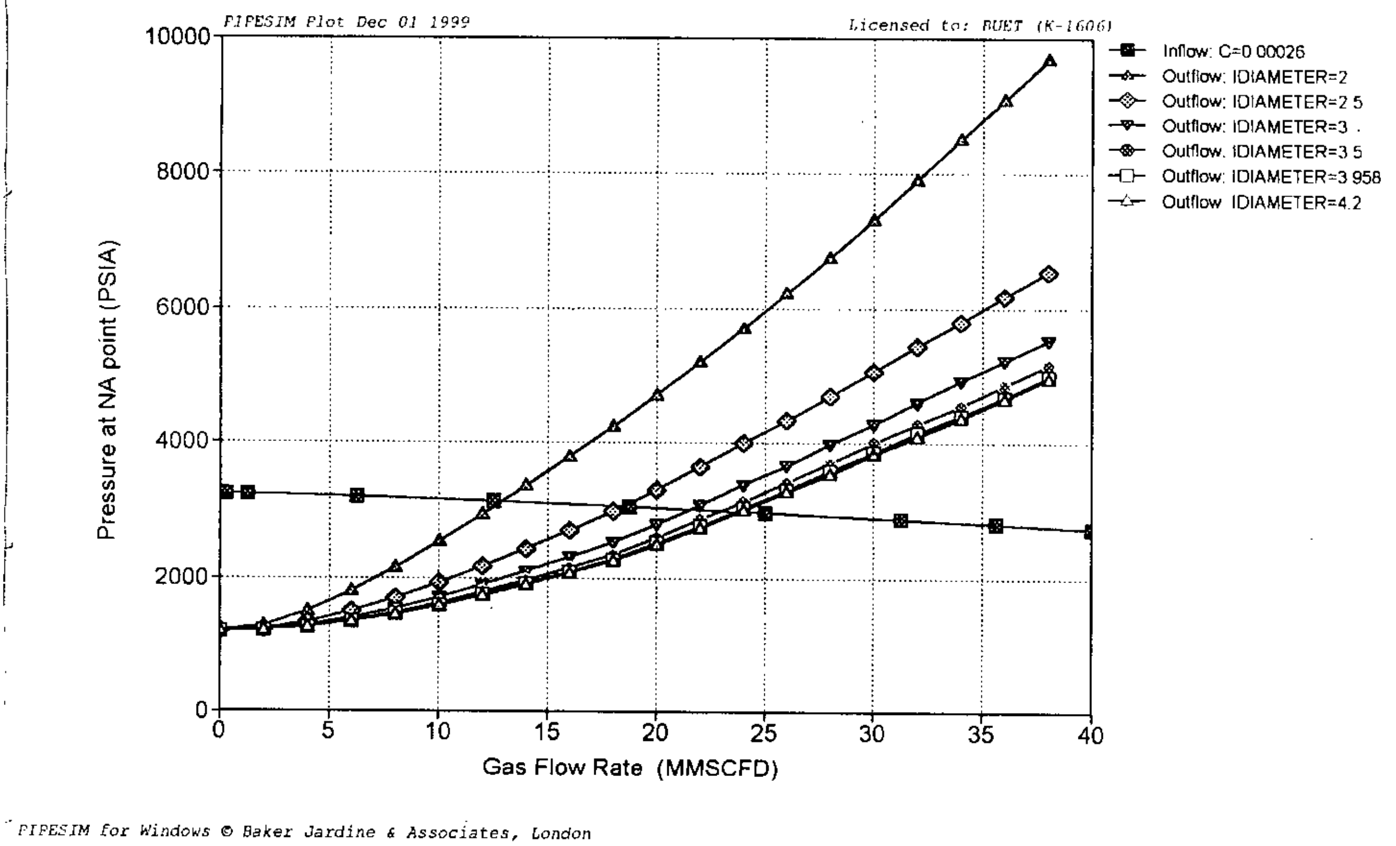
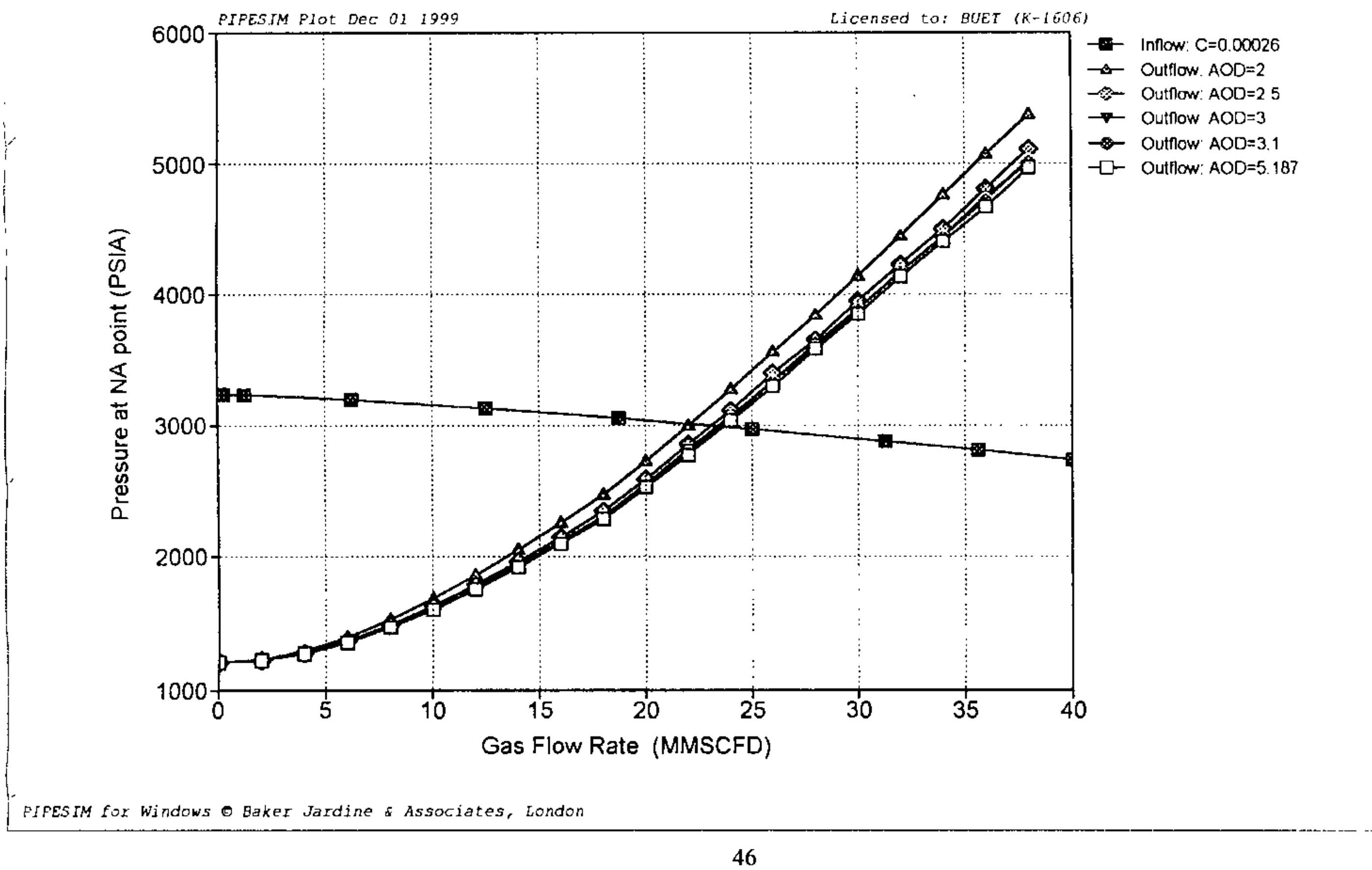


Figure 7.6: Effect of Flow Line Inner Diameter on the Performance of Well TT-1



Another way of controlling the flow rate is to control the separator pressure. Figure 7.7 shows the effect of separator pressure on the flow rate. At high separator pressure of 1800 psia, the flow rate is 20 MMSCFD and at 1300 psia, the flow rate is 23.5 MMSCFD. For a separator pressure of 1300 psia and below, the choke is in critical range. As separator pressure is decreased, gas velocity increases, also increasing the gas friction. As a result, decreasing the separator pressure below 1300 psia has no positive effect on the flow rate. So, it is possible to maintain a maximum pressure of 1300 psia at the downstream side of the choke instead of current pressure of about 1010 psia. High-pressure gas can be transmitted more efficiently. On the other hand, higher pressure would mean more strain on the transmission lines and on the processing plants and less condensate production. High pressure also increases the viscosity of TEG in the gas processing plant. Figure 7.7 also shows that lowering the separator pressure would not increase the flow rate much.

Figures 7.8 to 7.10 show the effect of tubing inner diameter and flowline diameter and separator pressure for a larger choke size of 0.9 inch. As shown in Figure 7.8, existing tubing diameter of 3.958 inches will be able to sustain a production rate of 32.5 while a size of 4.2-inches produces 33.2 MMSCFD. Also, a flow line diameter of 3.2 inches is enough to sustain a flow of 33.5 MMSCFD, as shown in Figure 7.9. Beyond that size, production hardly increases. So, a size of 5.187 inches is still more than adequate. Figure 7.10 suggests that a maximum separator pressure of 1200 psia can be maintained without sacrificing the flow rate. At a bottom hole pressure of 2000 psia, corresponding to lower reservoir pressure, the well is able to produce 8.9 MMSCFD against a separator pressure of 1600 psia and 19 MMSCFD against 1200 psia. These values are 6 MMSCFD and 13.2 MMCFD respectively for current choke size of 0.8 inches.

Figure 7.11 and 7.12 show the pressure and temperature profiles along the vertical tubing for different flow rate, using the existing choke size. It is evident from Figure 7.11 that for flow rate up to 32 MMSCFD, the friction loss per unit length of tubing is same and moderate and well head pressure above 2200 psia is available, but beyond that, losses become significant. At a flow of 50 MMSCFD, wellhead pressure becomes only 1500 psia. Figure 7.12 shows that as flow rate increases, wellhead

Figure 7.7: Effect of Separtor Pressure on the Performance of Well TT-1

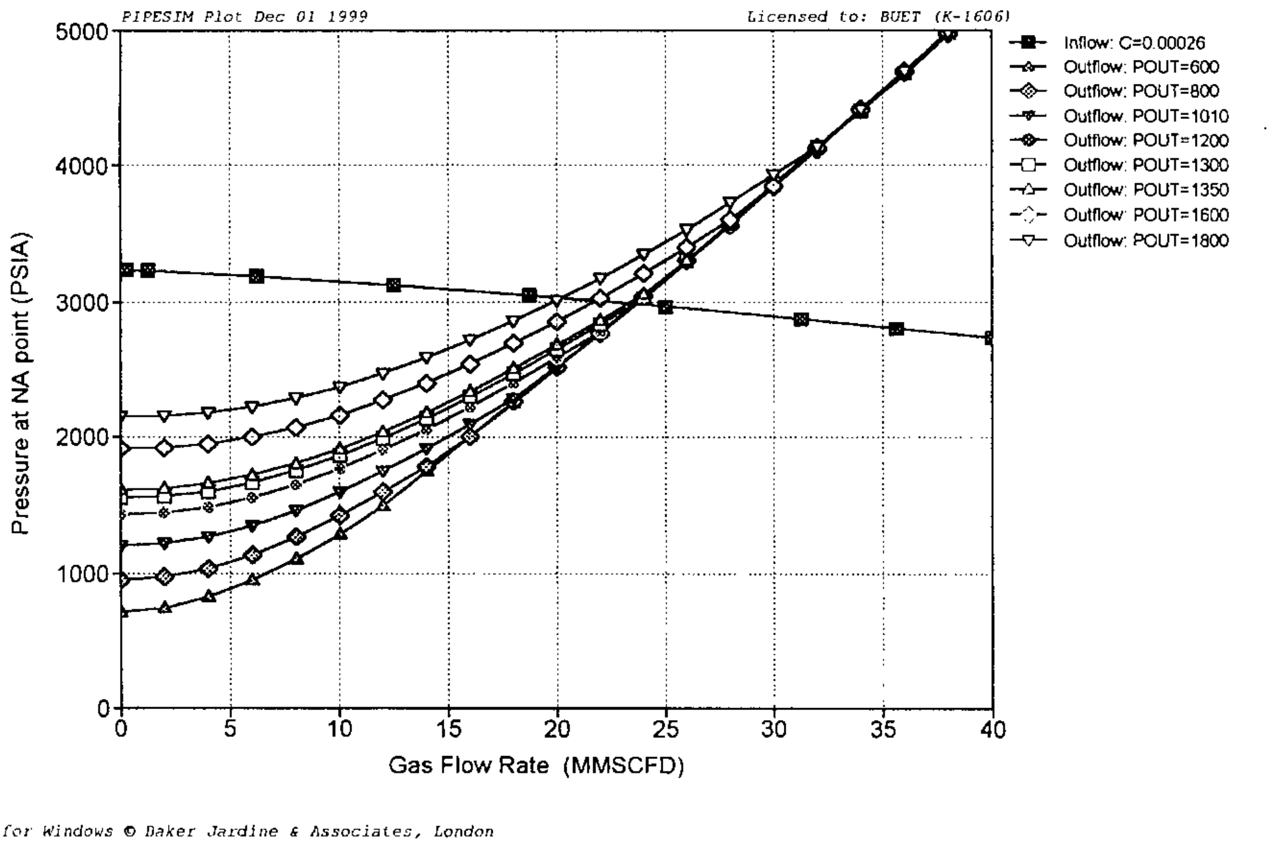


Figure 7.8: Effect of Tubing Inner Diameter on the Performance of Well TT-1

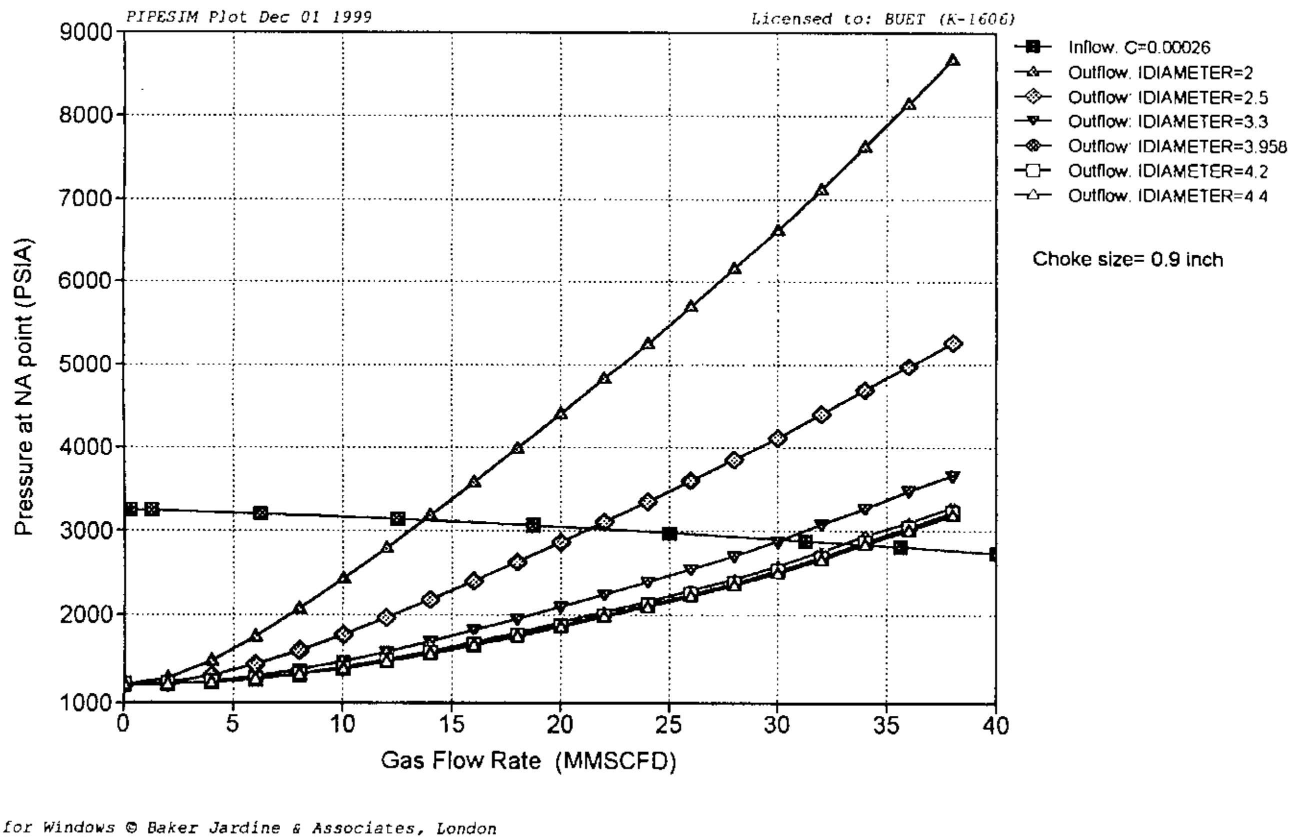


Figure 7.9: Effect of Flow Line Inner Diameter on the Performance of Well TT-1

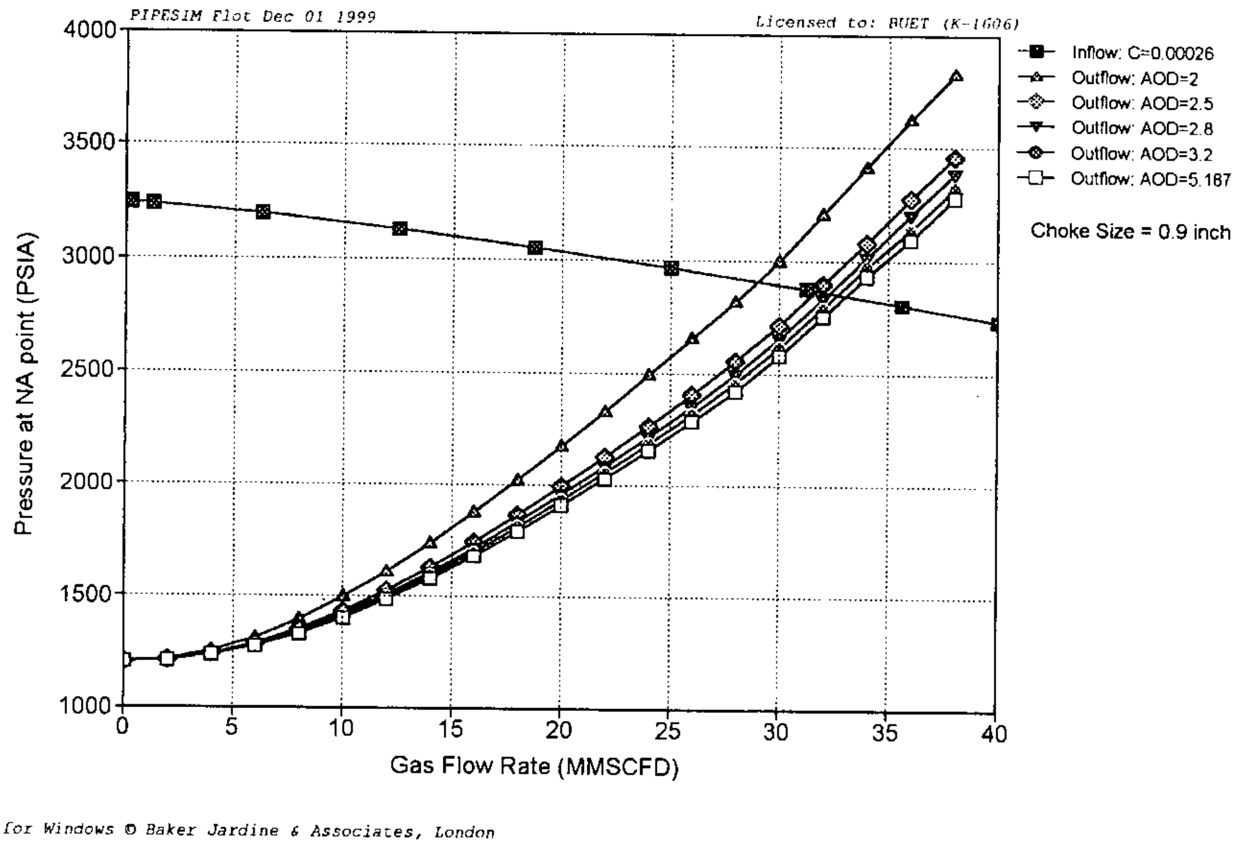


Figure 7.10: Effect of Separator Pressure on the Performance of Well TT-1

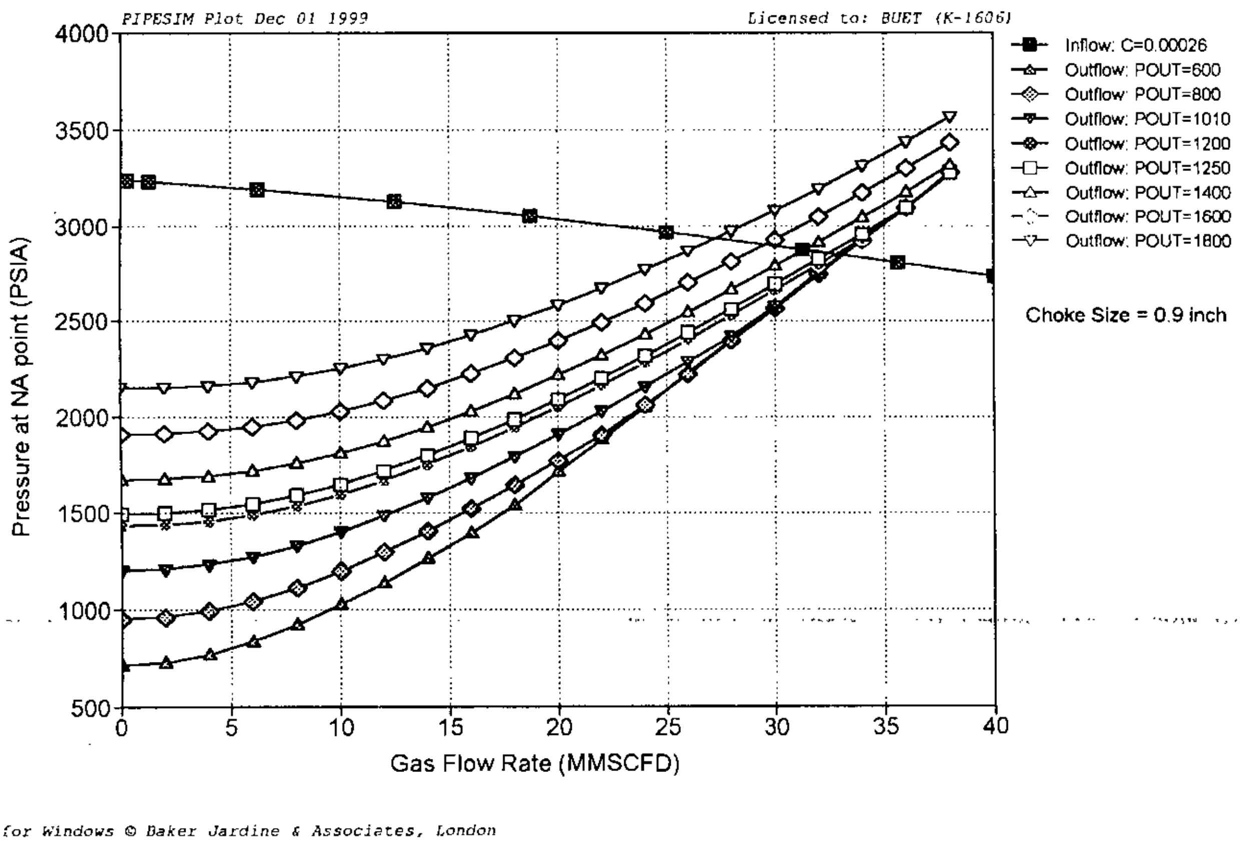


Figure 7.11: Effect of Flow Rate on Pressure Profile in Tubing of Well TT-1

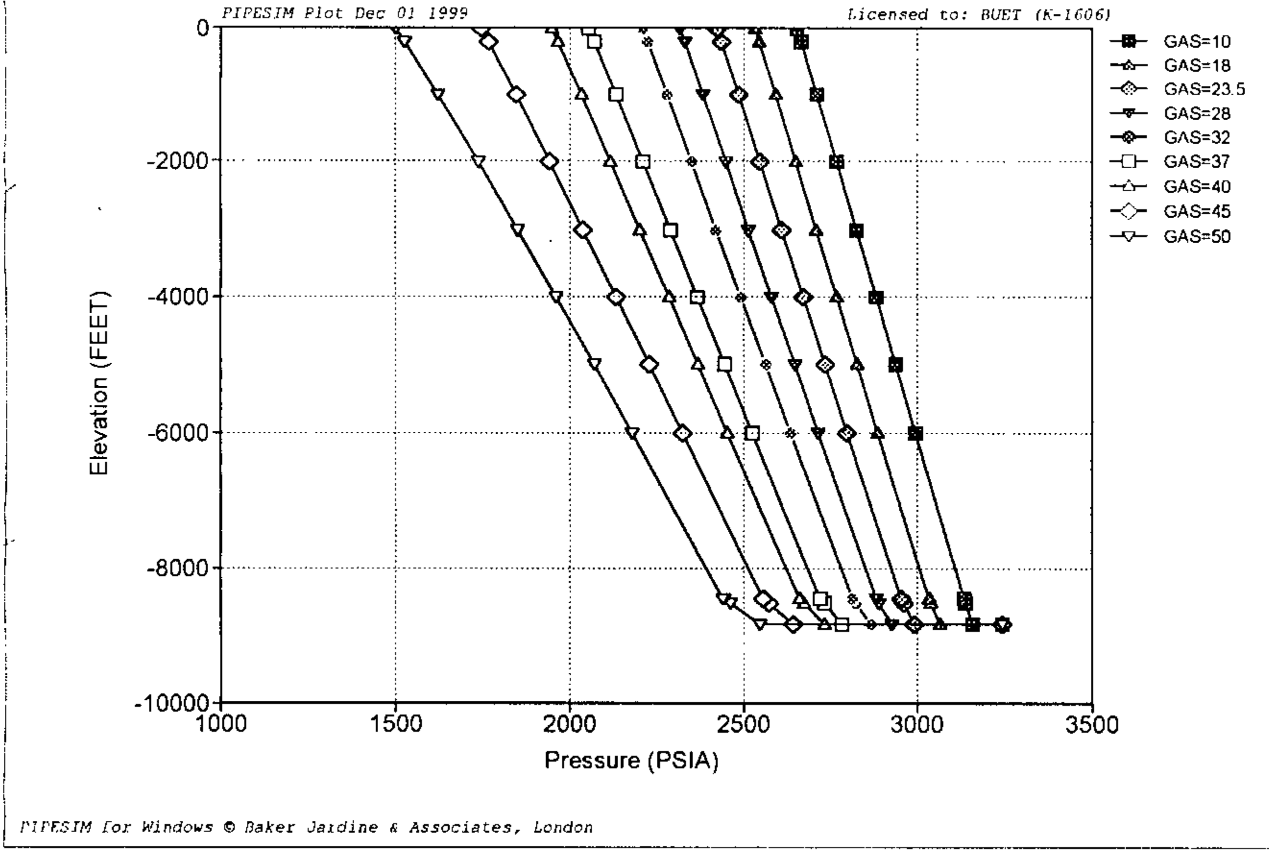
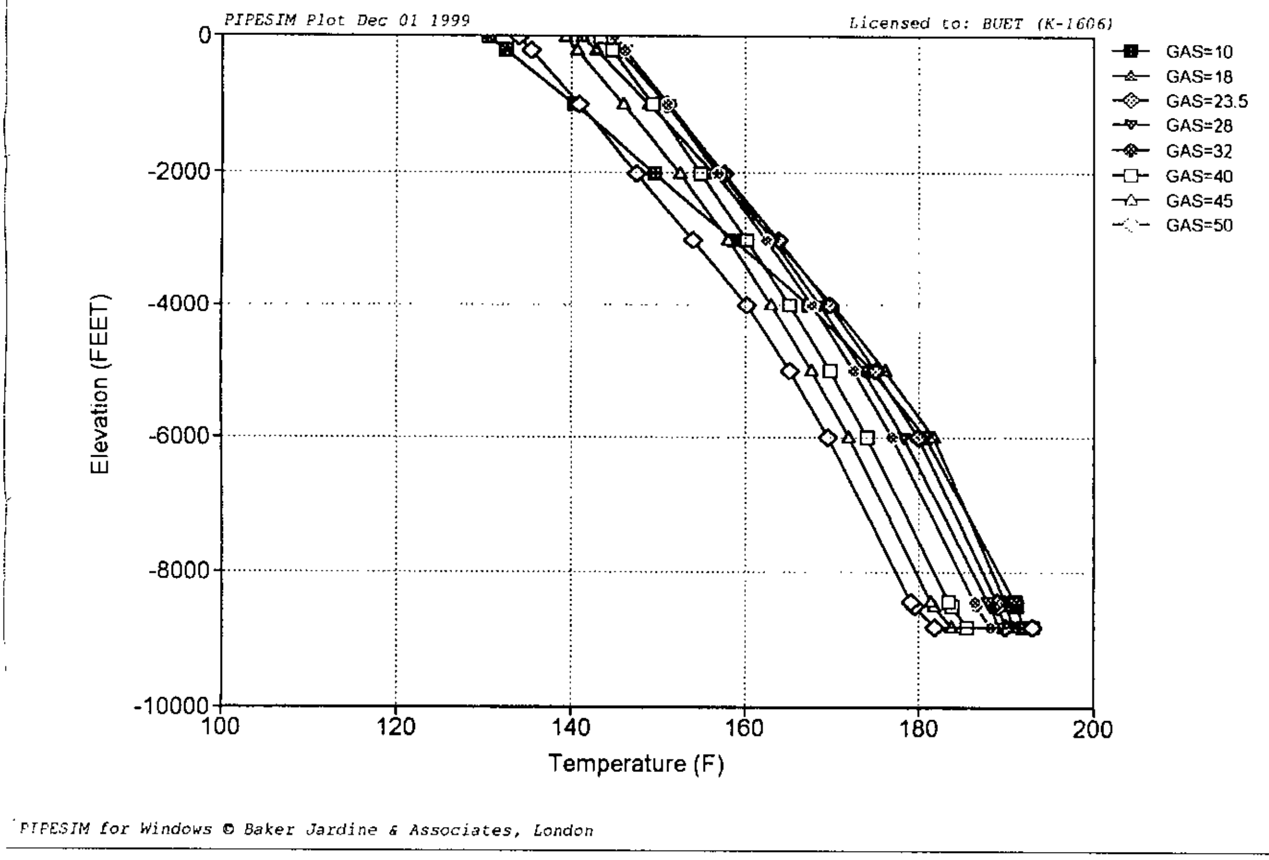


Figure 7.12: Effect of Flow Rate on Temperature Profile in Tubing of Well TT-1



temperature increases due to friction effect. But beyond 30 MMSCFD, temperature begins to decrease due to gas expansion or Joule-Thompson effect. Figure 7.12 shows that the well head temperature for the current flow rate is about 145^0 F, which is very close to the actual value.

There is also a temperature drop at the wellbore. The higher the flow rate, the higher the pressure drop and corresponding temperature drop in the reservoir, this effect is also due to the Joule-Thompson effect.

7.5.2 Well TT-2

Average reservoir pressure: 3350 psia
Average reservoir temperature: 195.0 ^{0}F
Back-pressure equation coefficient C=0.0006
Back-pressure equation exponent n = 0.80

Figure 7.13 shows the variation of flow rate with reservoir pressure for a tubing diameter of 3.958 inches. For an initial reservoir pressure of 3977 psia, recorded in May, 1968, the flow rate was about 33.6 MMSCFD at an wellbore pressure of 3863 psia but now the flow rate is been reduced to 28.3 MMSCFD as the current reservoir pressure is down to 3350 psia. For a low reservoir pressure of 2200 psia, the flow will be as low as 18.0 MMSCFD in the future, assuming all other parameters remain the same. Figure 7.13 verifies past and present well performances, thus it can be concluded that this simulation provides credible results.

From Figure 7.14, it is evident that for C value of 0.0001, the production rate is only 22.5 MMSCFD which increases to 27 MMSCFD when C is 0.0003 and to 28.3 MMSCFD when C is 0.0006. This last value of C is optimum as higher value of C is not further productive.

As found from Figure 7.15, when n is 0.5, a very low flow rate of 2.2 MMSCFD is obtainable. The flow rate increases to 9 MMSCFD, 17 MMSCFD and 23.8 MMSCFD as n is increased to 0.6, 0.65 and 0.7 respectively. Beyond the value of n = 0.85, an increase in n will not have any effect on the flow rate.

Figure 7.13: Effect of Average Reservoir Pressure on the Performance of Well TT-2

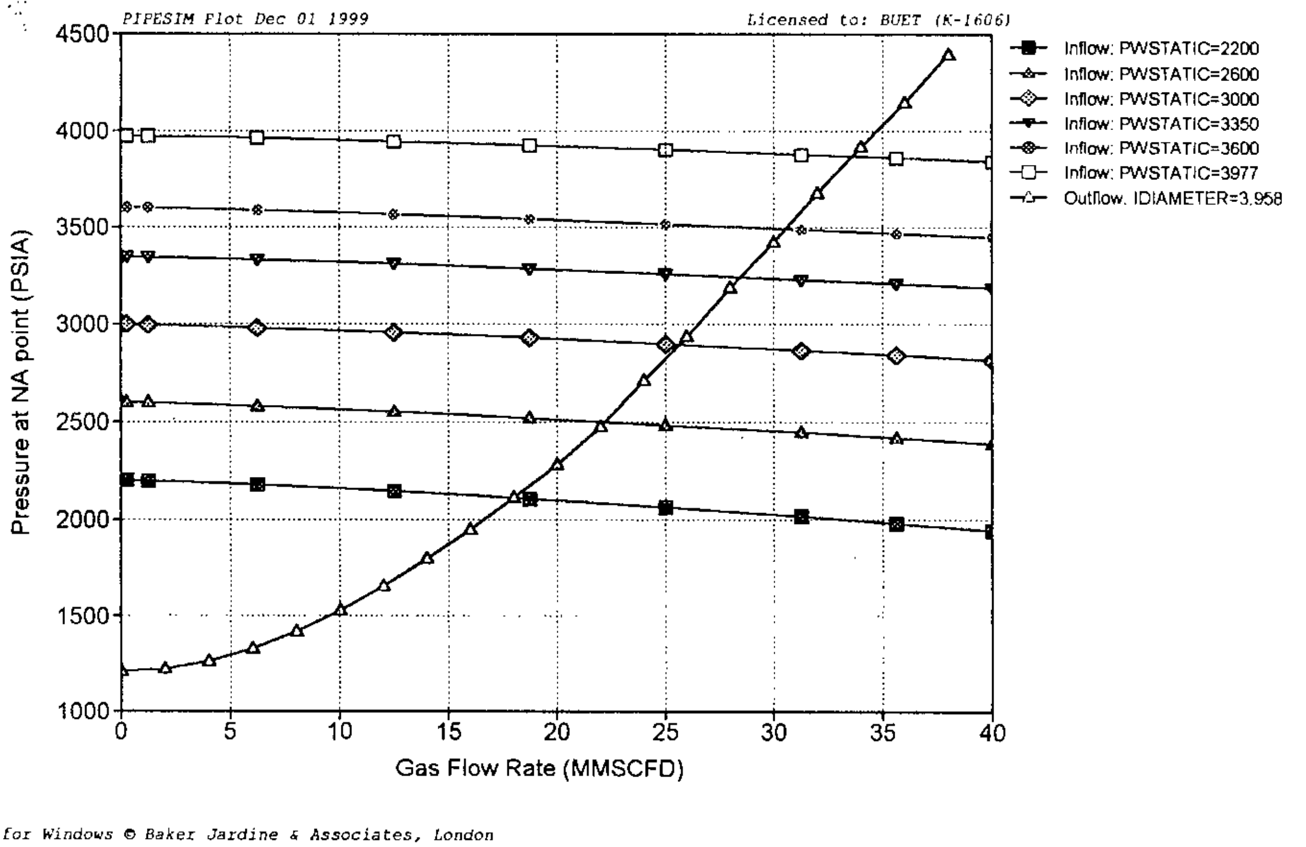


Figure 7.14: Effect of Back Pressure Coefficient on the Performance of Well TT-2

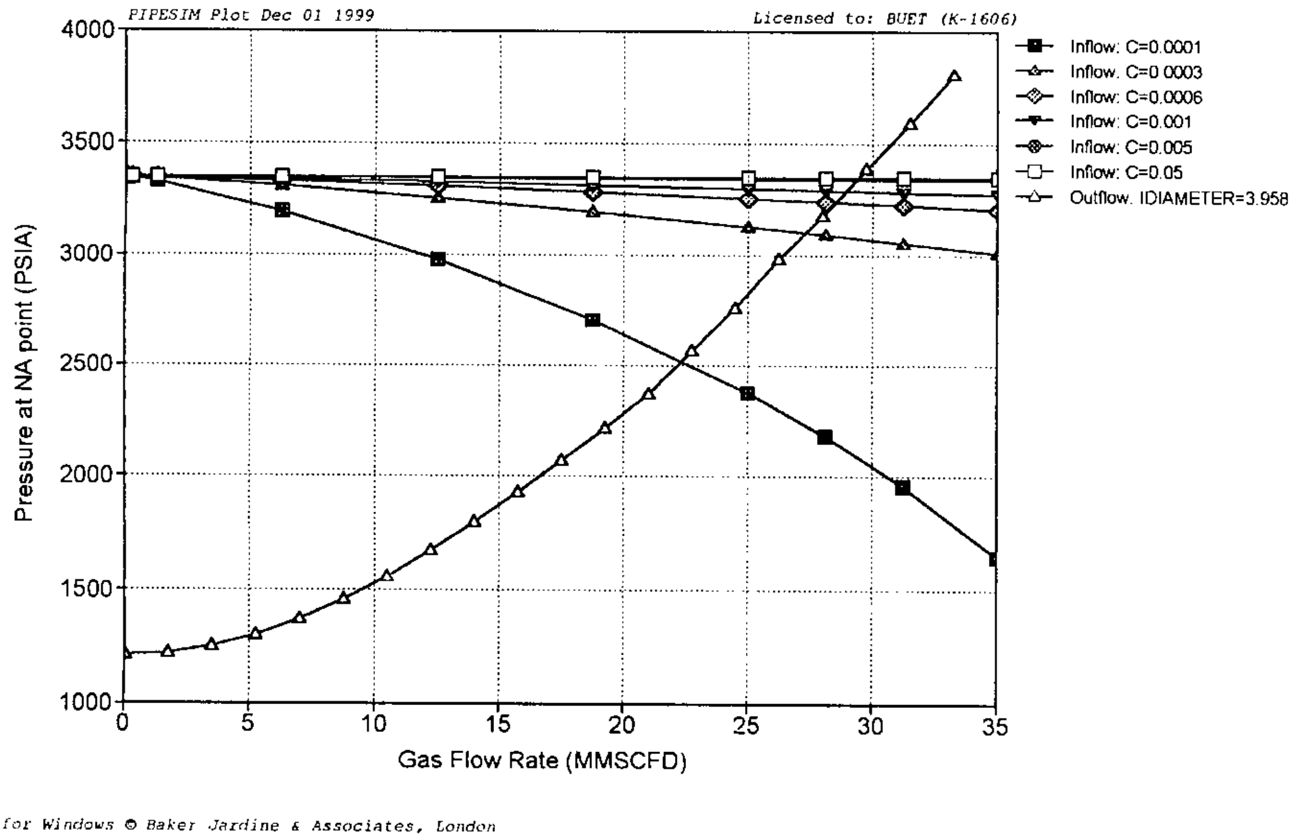


Figure 7.16 shows the effect of the bean diameter. Flow rate increases from 19 MMSCFD to 37.5 MMSCFD as the bean size is increased from 0.60 inch to 0.90 inch. The well presently produces 28.3 MMSCFD at a choke size of 0.765 inch.

Figure 7.17 shows the variation of flow rate with tubing size. From a tubing size of 2.5 inches to 3.0 inches, the flow rate increases from 21 MMSCFD to 25 MMSCFD. Tubing size of 4.5 inches is able to produce at a rate of 28.3 MMSCFD; any further increase will not increase the flow rate.

Figure 7.18 shows the effect of flow line diameter. A diameter of 2 inches produces at a rate of 26 MMSCFD and a 2.5-inches diameter produces at 28.2 MMSCFD, which is the existing flow rate. So existing flow line diameter of 5.187 inches is more than adequate for the current condition.

Figure 7.19 shows the effect of separator pressure. At high separator pressure of 1800 psia, flow rate is 25 MMSCFD and at 1400 psia, the flow rate increases to 28.3 MMSCFD. For a separator pressure of 1400 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1400 psia has no effect on the flow rate. So, it is possible maintain a maximum pressure of 1400 psia at the downstream side of the choke instead of current pressure of about 1010 psia without decreasing the rate.

Figures 7.20 through 7.22 show the effect of tubing inner diameter and flow line size and separator pressure, respectively for a larger choke size of 0.9 inch. Tubing size of 4.3 inches will be able to support the high production rate of 38 MMSCFD; increasing the size will not increase the flow rate further, as shown in Figure 7.20. As evident from Figure 7.21, the smaller flow line diameter of 3.0 inches can support that flow rate. Figure 7.22 suggests that a maximum separator pressure of 1300 psia can be maintained without sacrificing the flow rate. At a bottom hole pressure of 2000 psia, the well will not be able to produce when the separator pressure is 1800 psia but will produce 10 MMSCFD against a separator pressure of 1600 psia and 15.2 MMSCFD against 1400 psia. These values are 6.3 MMSCFD and 12 MMSCFD respectively for current choke size of 0.765 inch.

Figure 7.15: Effect of Back Pressure Exponent on the Performance of Well TT-2

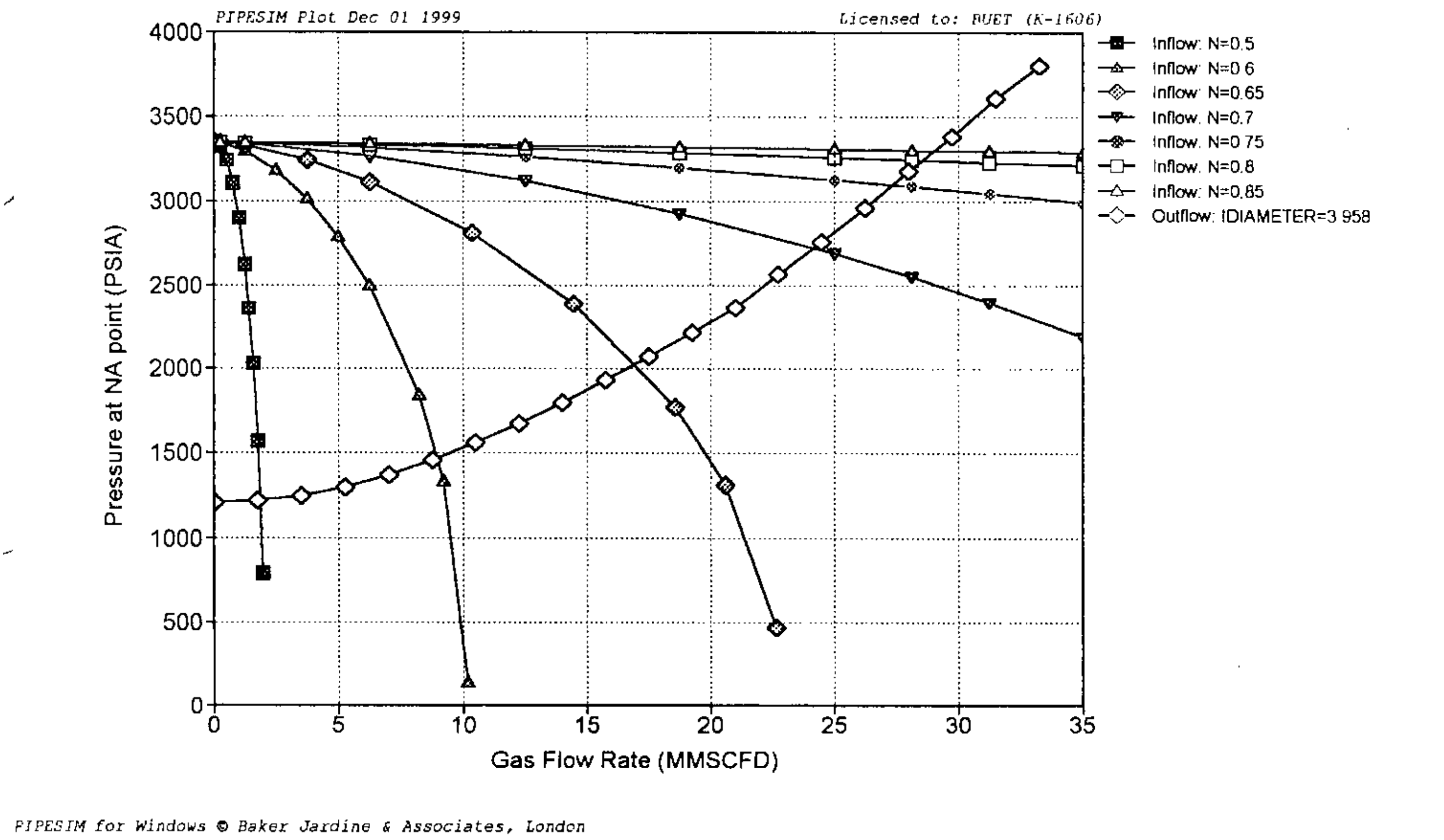


Figure 7.16: Effect of Choke Size on the Performance of Well TT-2

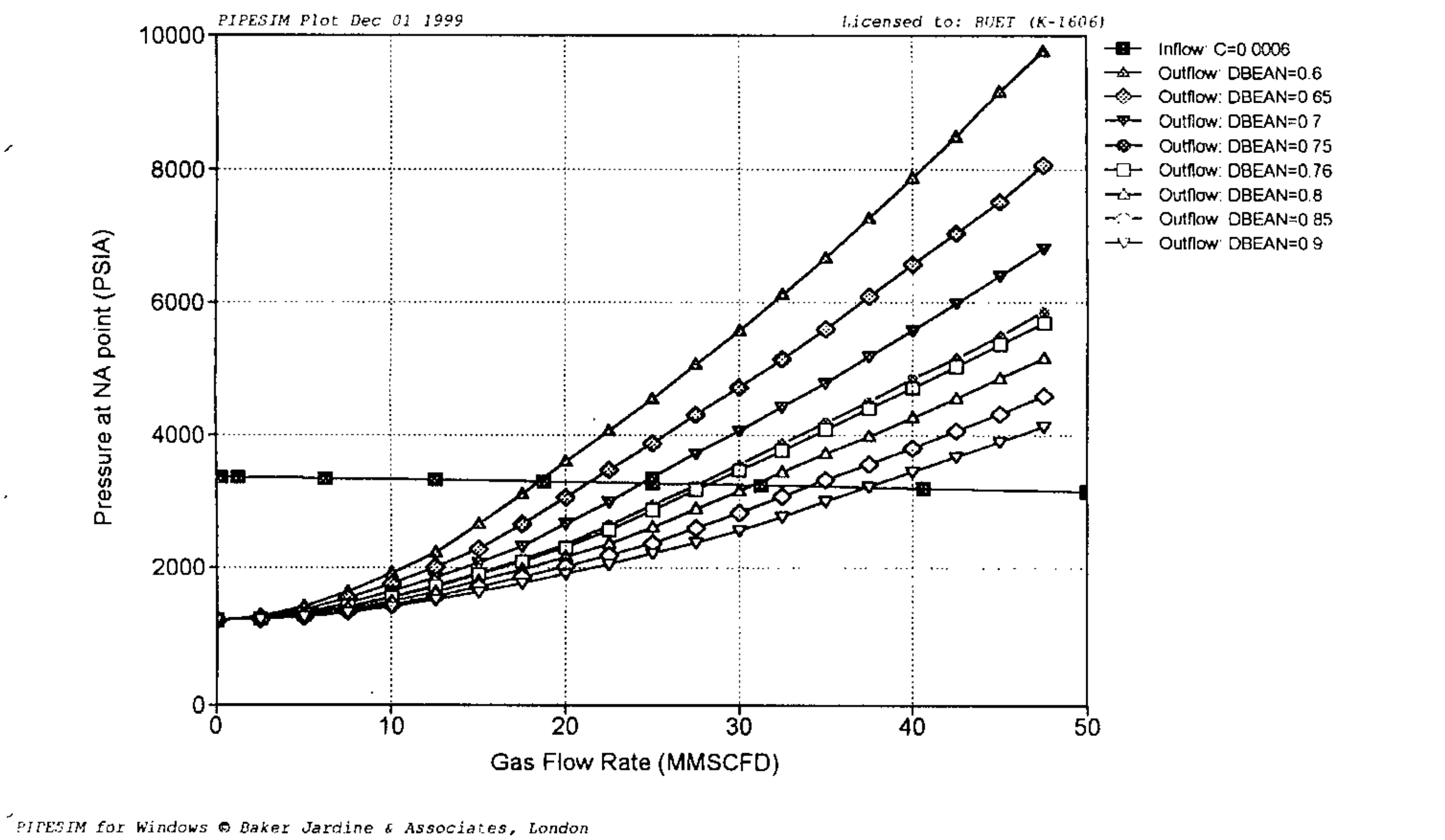


Figure 7.17: Effect of Tubing Inner Diameter on the Performance of Wel TT-2

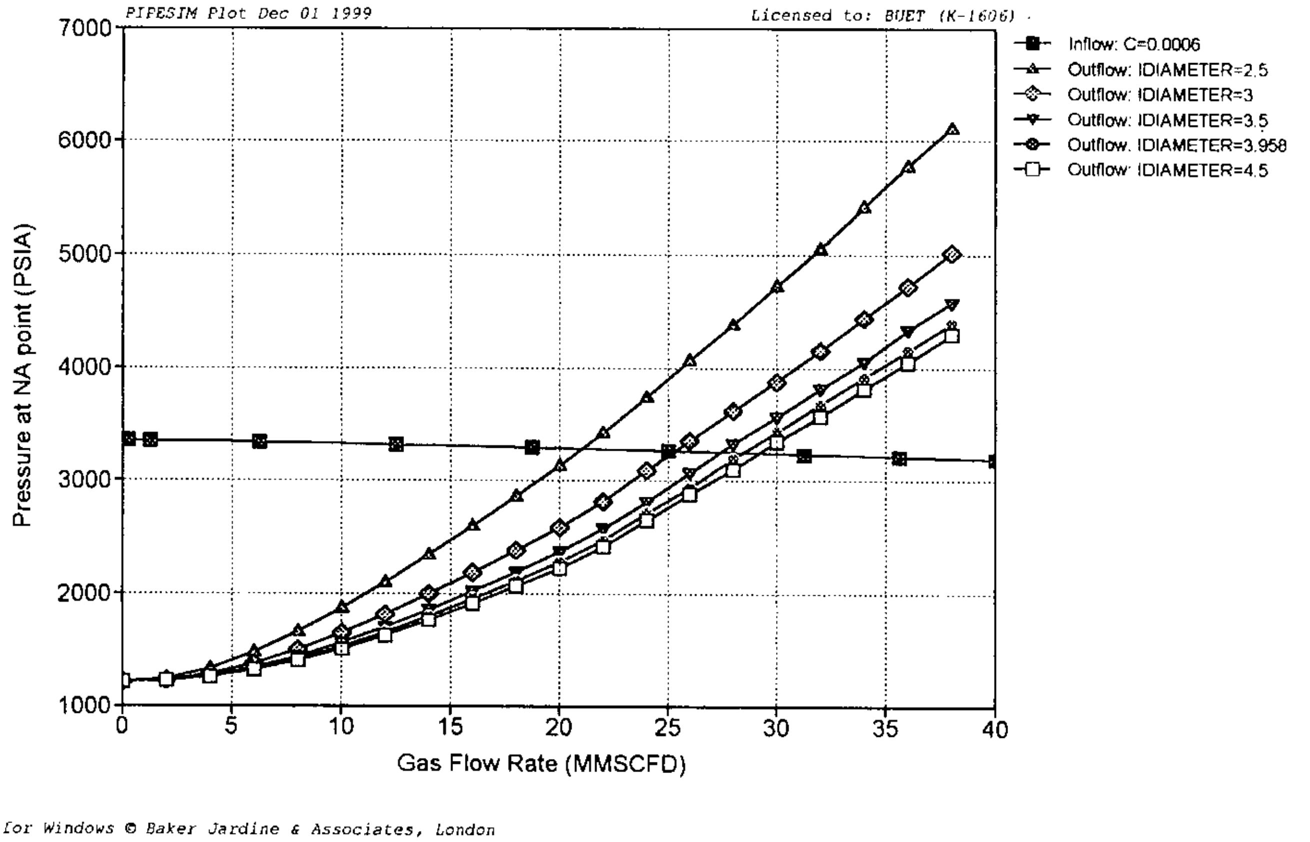


Figure 7.18: Effect of Flow Line Inner Diameter on the Performance of Well TT-2

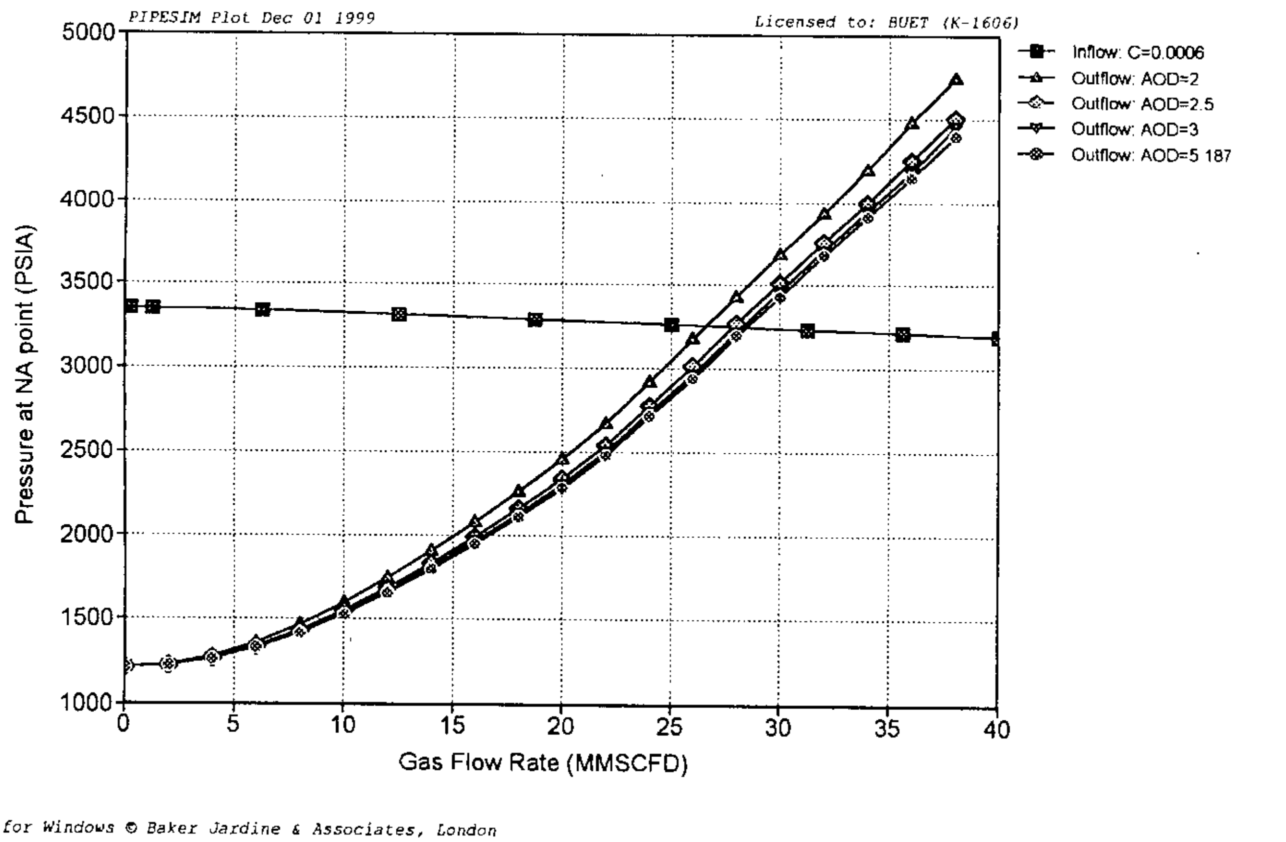


Figure 7.19: Effect of Separator Pressure on the Performance of Well TT-2

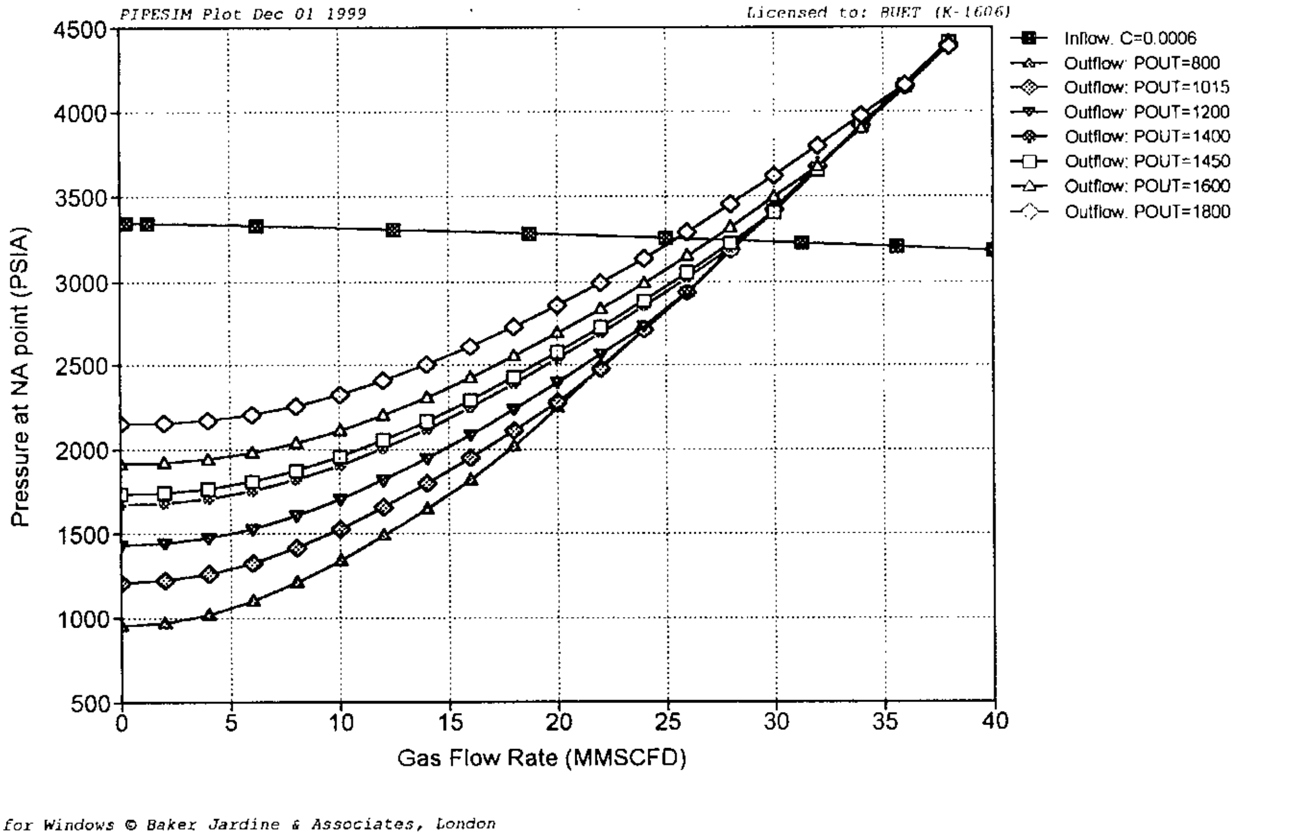


Figure 7.20: Effect of Tubing Inner Diameter on the Performance of Well TT-2

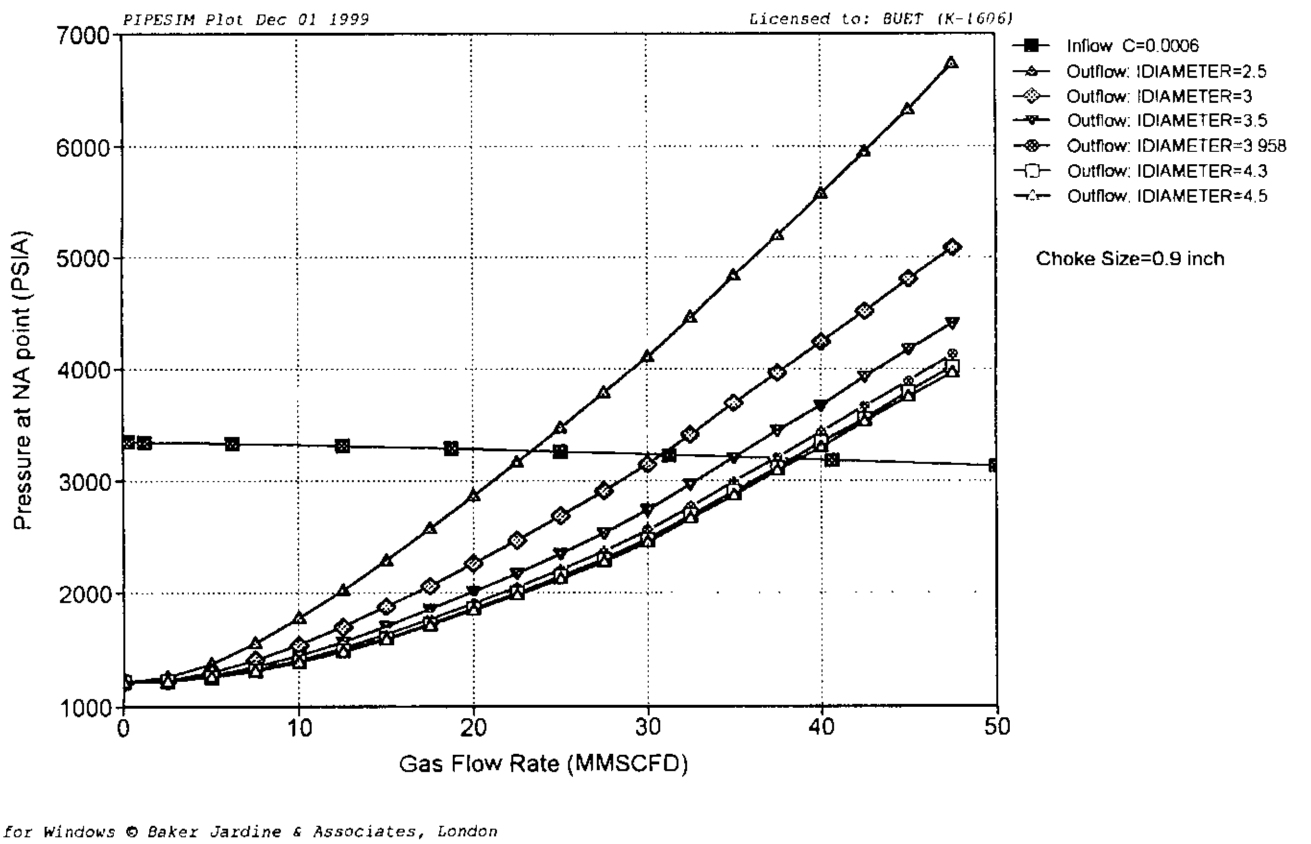


Figure 7.21: Effect of Flow Line Inner Diameter on the Performance of Well TT-2

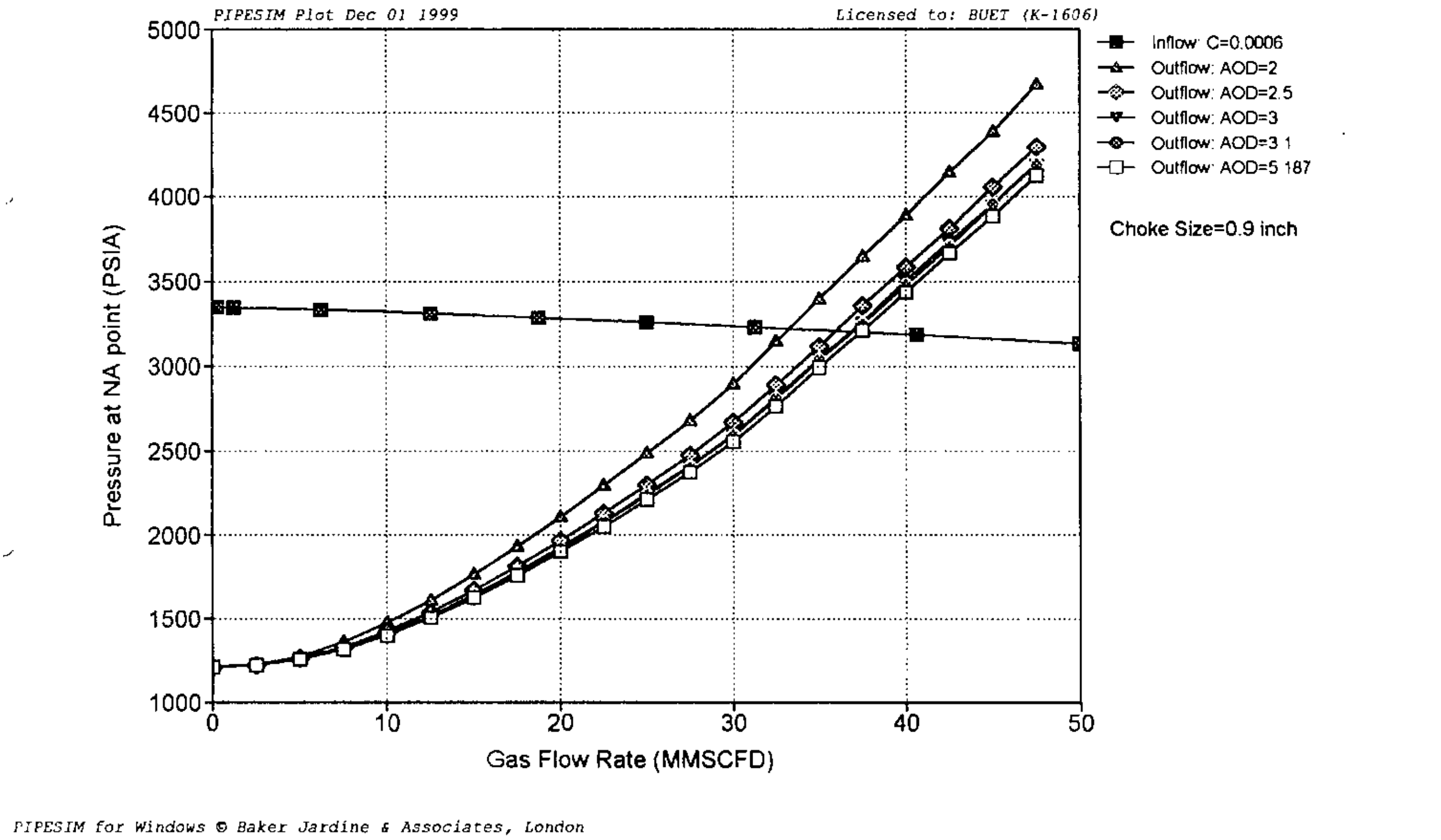
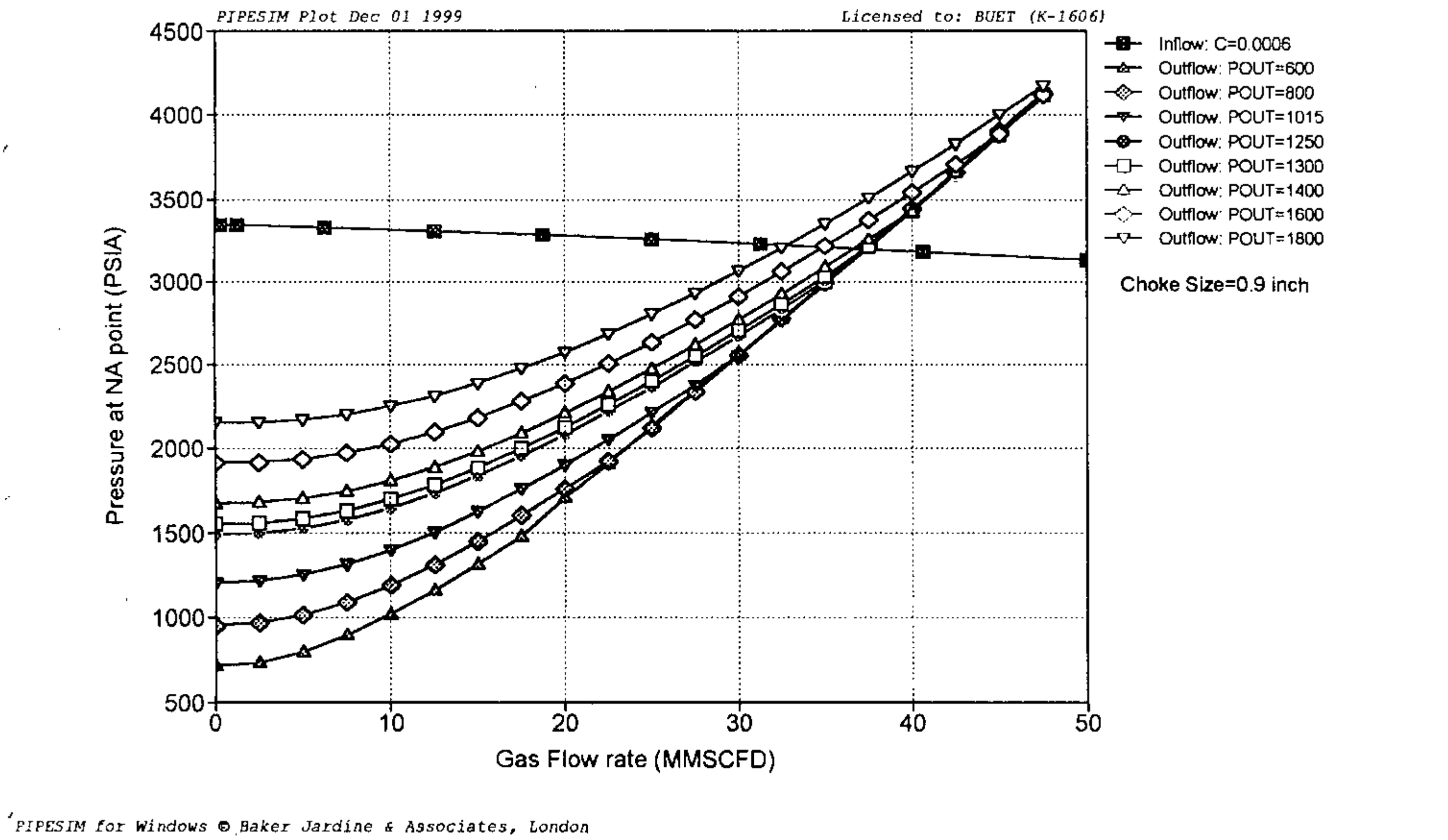


Figure 7.22: Effect of Separator Pressure on the Performance of Well TT-2



Figures 7.23 and 7.24 show the pressure and temperature profiles along the vertical tubing for different flow rate, using existing choke size. It is evident from Figure 7.23 that for flow rate up to 36 MMSCFD, the friction losses per unit length of tubing are very close and moderate and well head pressure above 2500 psia is available. Between 36 and 45 MMSCFD, losses increase and become significant. At a flow rate of 50 MMSCFD, the wellhead pressure becomes only 2200 psia. Figure 7.24 shows that as the flow rate increases, the wellhead temperature is affected by two opposing effect, friction effect and Joule-Thompson affect. The well head temperature for the current flow rate is about 150^0 F, which coincides with the actual value.

7.5.3 Well TT-3

Average reservoir pressure: 3350 psia

Average reservoir temperature: 195.0 ^{0}F

Back-pressure equation coefficient C = 0.00045

Back-pressure equation exponent n = 0.80

Figure 7.25 shows the variation of flow rate with reservoir pressure for a tubing diameter of 4.408 inches. For a reservoir pressure of 3949 psia, recorded in September 1973, the flow rate was about 35.2 MMSCFD at a wellbore pressure of 3775 psia. The well is now producing 30 MMSCFD at the current reservoir pressure of 3350 psia. For a low reservoir pressure of 2200 psia, the flow will be as low as 18.3 MMSCFD in future, assuming all other parameters remain the same.

From Figure 7.26, it is evident that for C value of 0.0002, production rate is only 27.8 MMSCFD which increases to 30 MMSCFD when C is 0.00045, the current value. Increasing the value of C does not increase the production rate further.

Figure 7.27 shows that when n is 0.5; a very low flow rate of 1.5 MMSCFD is obtainable. The flow rate increases to 7.2 MMSCFD, 14 MMSCFD and 23.5 MMSCFD as n is increased to 0.6, 0.65 and 0.7 respectively. Beyond the value of n = 0.80, an increase in n will not be productive as flow rate increases by only 1 MMSCFD.

Figure 7.23: Effect of Flow Rate on Pressure Profile in Tubing of Well TT-2

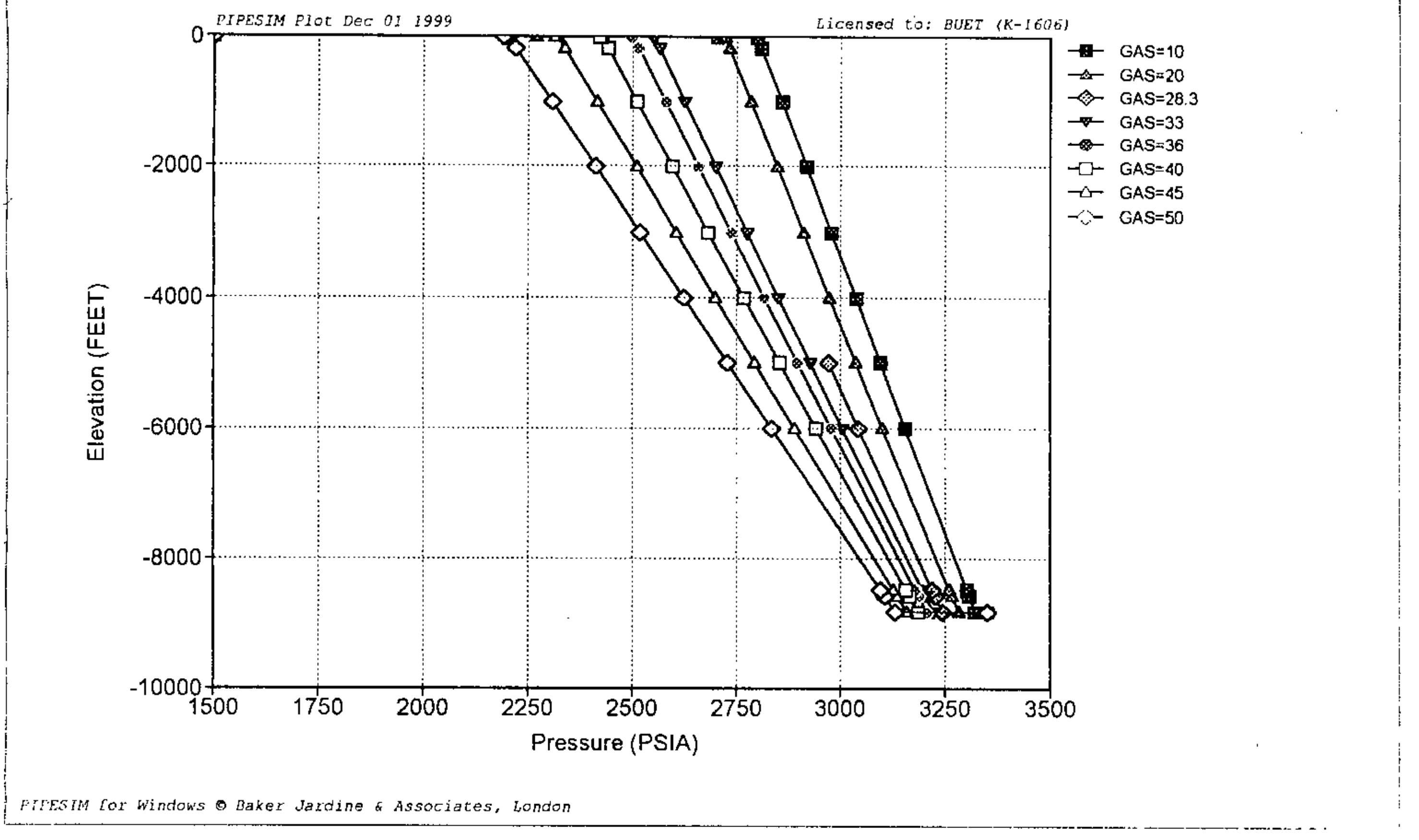


Figure 7.24: Effect of Flow Rate on Temperature Profile in Tubing of Well TT-2

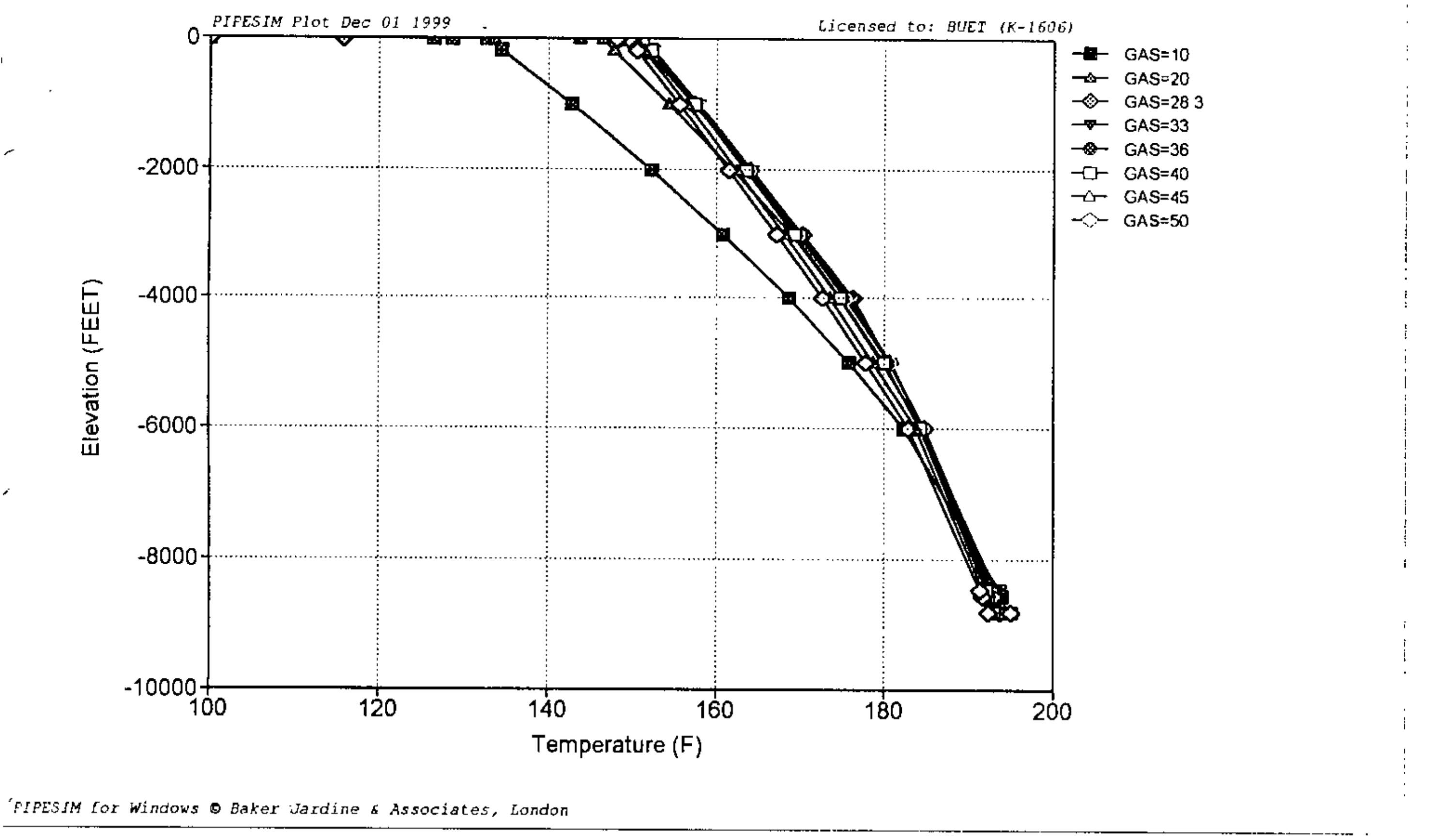


Figure 7.25: Effect of Average Reservoir Pressure on the Performance of Well TT-3

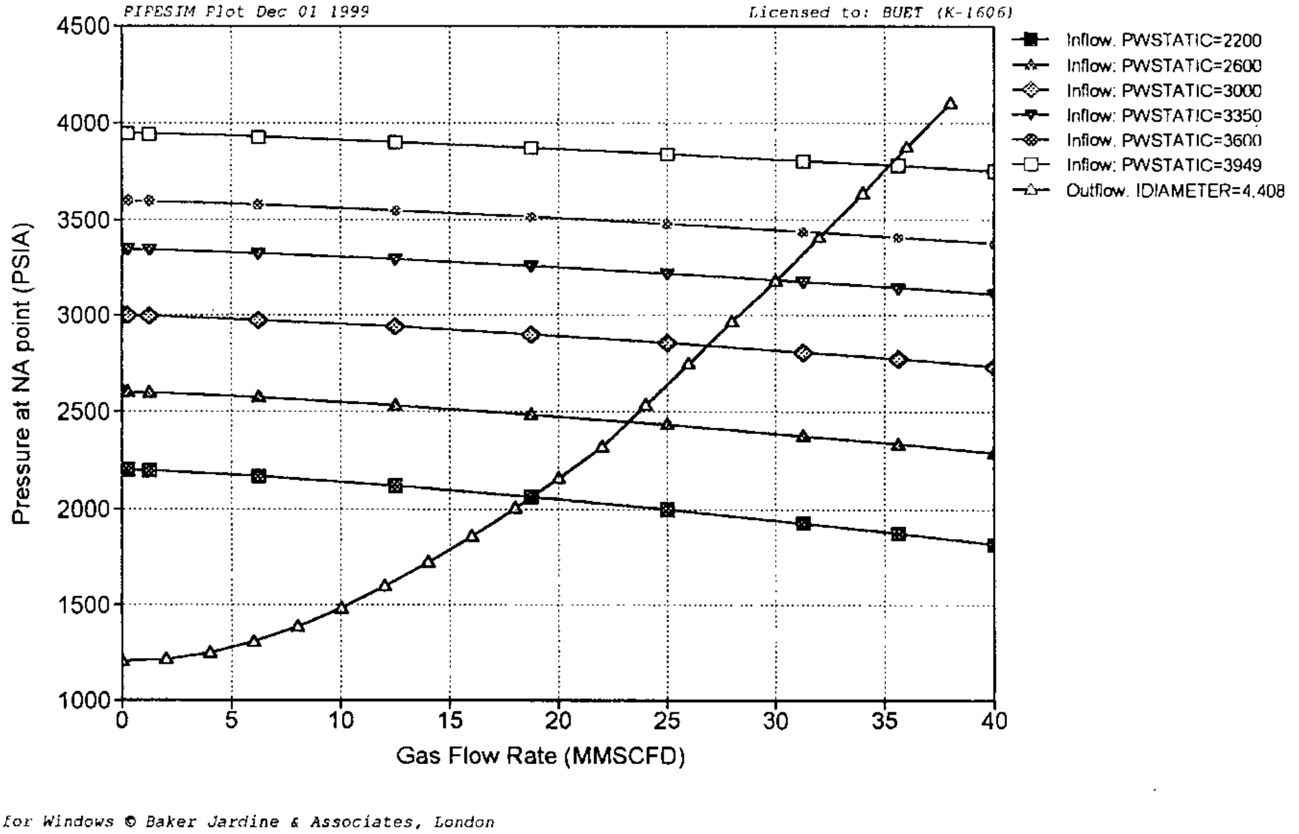


Figure 7.26: Effect of Back Pressure Coefficient on the Performance of Well TT-3

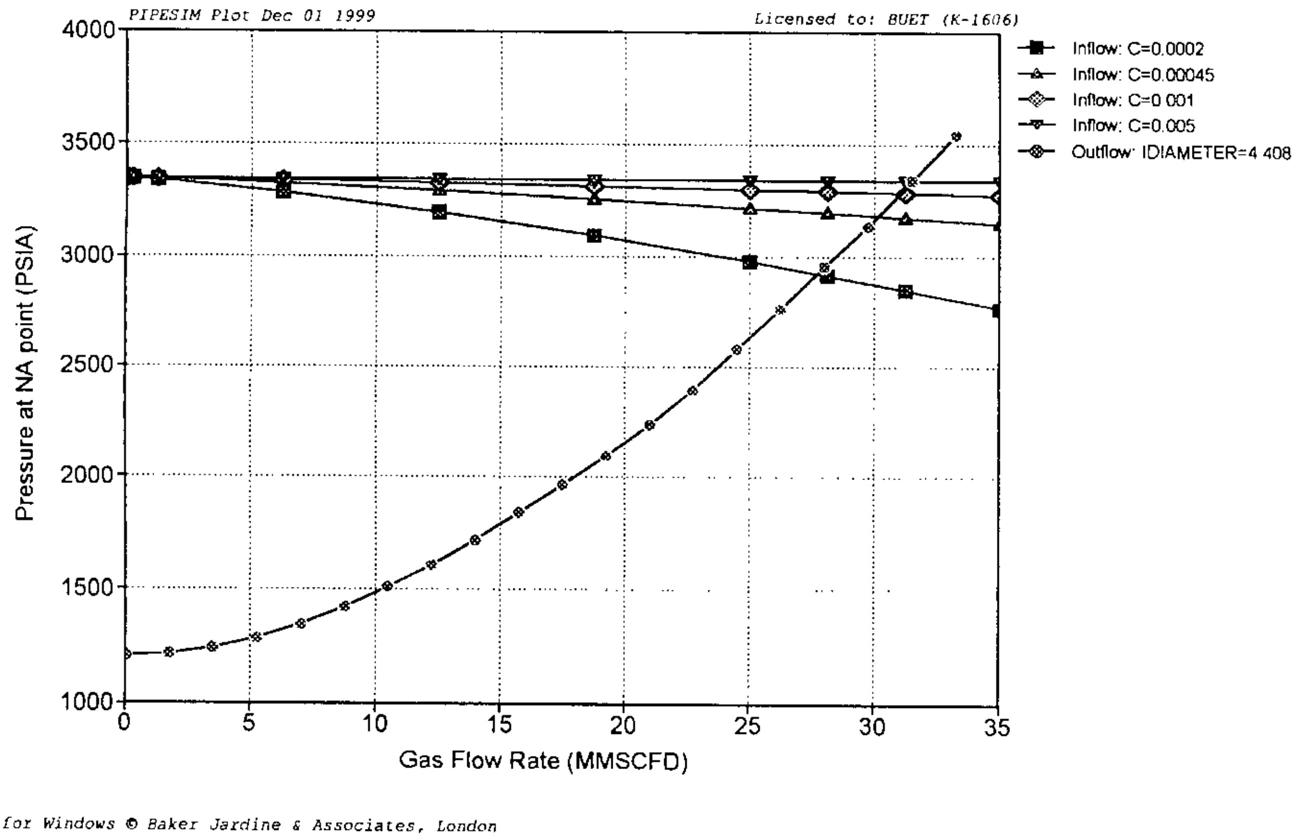


Figure 7.28 shows the effect of the bean diameter on flow rate. Flow rate increases from 15.8 MMSCFD to 37.6 MMSCFD as bean size is increased from 0.55 inch to 0.90 inch. The well is now producing 30 MMSCFD at a choke size of 0.787 inch.

Figure 7.29 shows the variation of flow rate with different size of tubing. For a tubing inner diameter of 2.5 inches a flow rate of only 21.2 MMSCFD is possible. For a tubing size of 3.0 inches and 3.5 inches, the flow rate increases to 25.8 MMSCFD and 28 MMSCFD respectively. An increase in the current tubing size of 4.408 inches will not increase in the flow rate further. So at present, the size of tubing is appropriate for the current production.

Figure 7.30 shows the effect of flow line diameter. An inner diameter of 2 inches produces at a rate of 27.8 MMSCFD and a 3.0-inches diameter produces 30 MMSCFD, which is the existing flow rate. So existing flow line diameter of 5.187 inches is more than adequate for the current condition.

Figure 7.31 shows the effect of separator pressure on well flow rate. At high separator pressure of 1600 psia, flow rate is 28.0 MMSCFD and at 1400 psia the flow rate increases to 30.0 MMSCFD, the current value. For a separator pressure of 1400 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1400 psia has no positive effect on the flow rate. So, it is possible to maintain a maximum pressure of 1400 psia at the downstream side of the choke instead of current pressure of about 1010 psia.

Separator plays an important role as the average reservoir pressure gets lower. At a bottom hole pressure of 2000 psia, the well, at a separator pressure of 1600 psia, produces only 6.8 MMSCFD but at a separator pressure of 1010 psia, produces 17.5 MMSCFD.

Figures 7.32 through 7.34 shows the effect tubing diameter and flow line diameter and separator pressure for a larger choke size of 0.9 inch, other parameters remaining the same. Figure 7.32 shows that the existing tubing size of 4.408 inches is suitable for the higher production scenario. In this case, the smaller flowline diameter of 3.2 inches can sustain a flow of 37.5 MMSCFD, beyond this diameter, the flow rate does not

Figure 7.27: Effect of Back Pressure Exponent on the Performance of Well TT-3

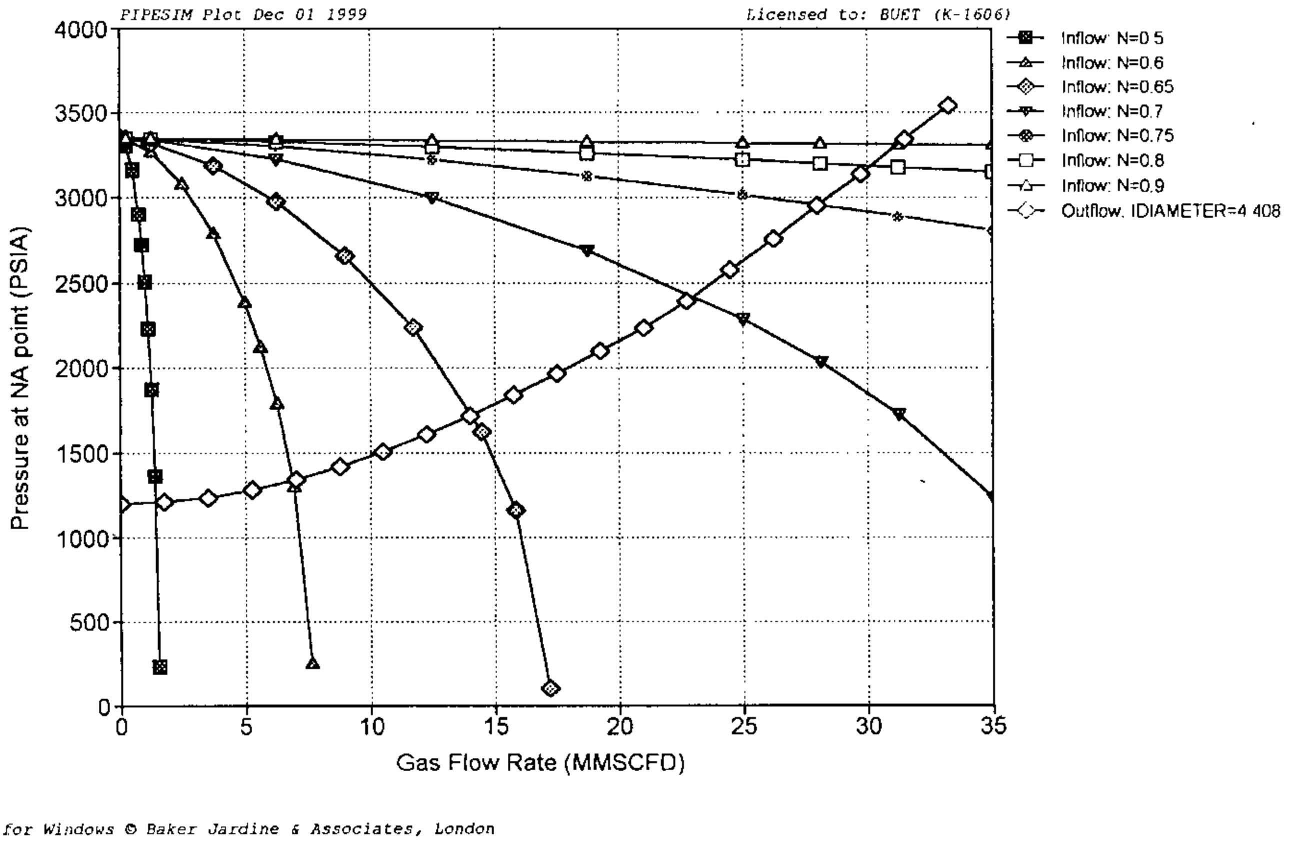


Figure 7.28: Effect of Choke Size on the Performance of Well TT-3

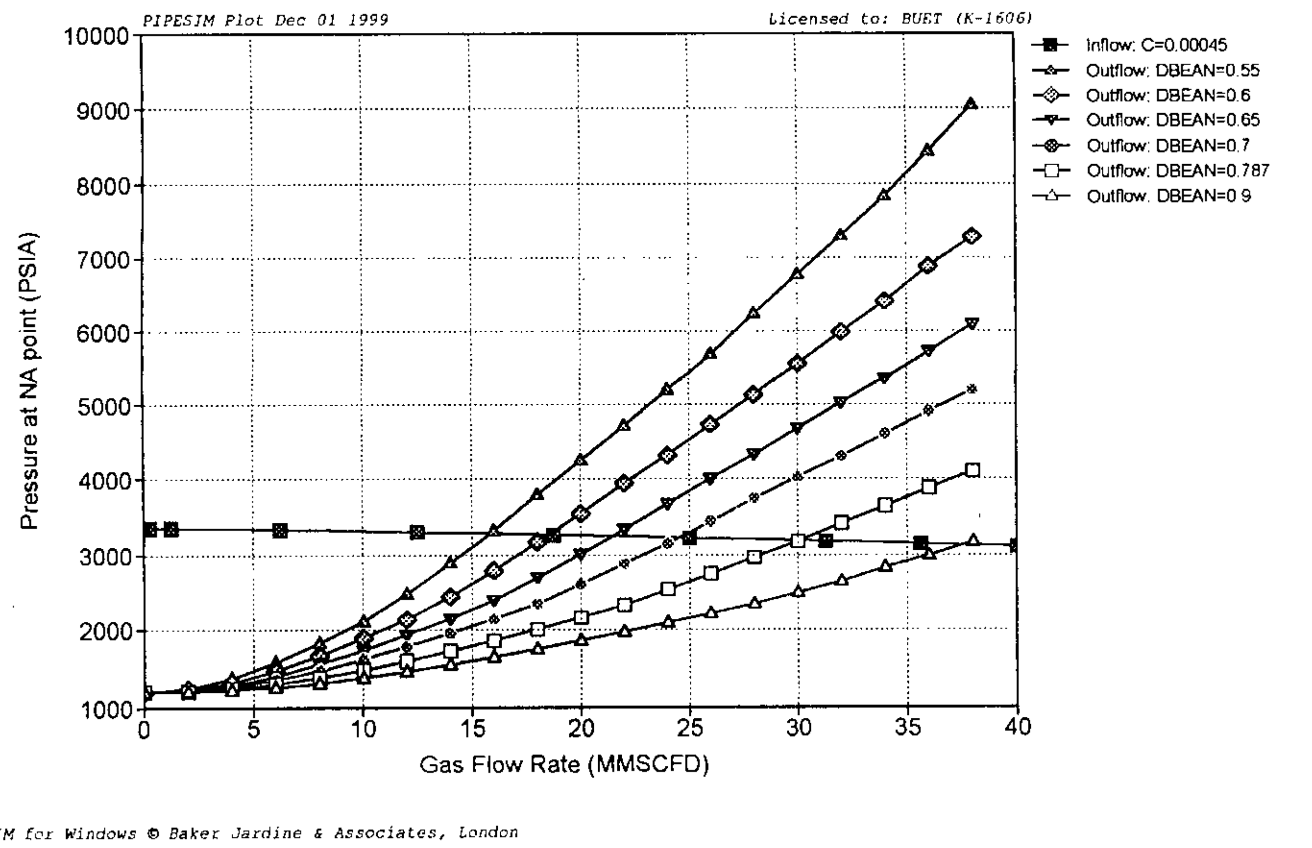


Figure 7.29: Effect of Tubing Inner Diameter on the Performance of Well TT-3

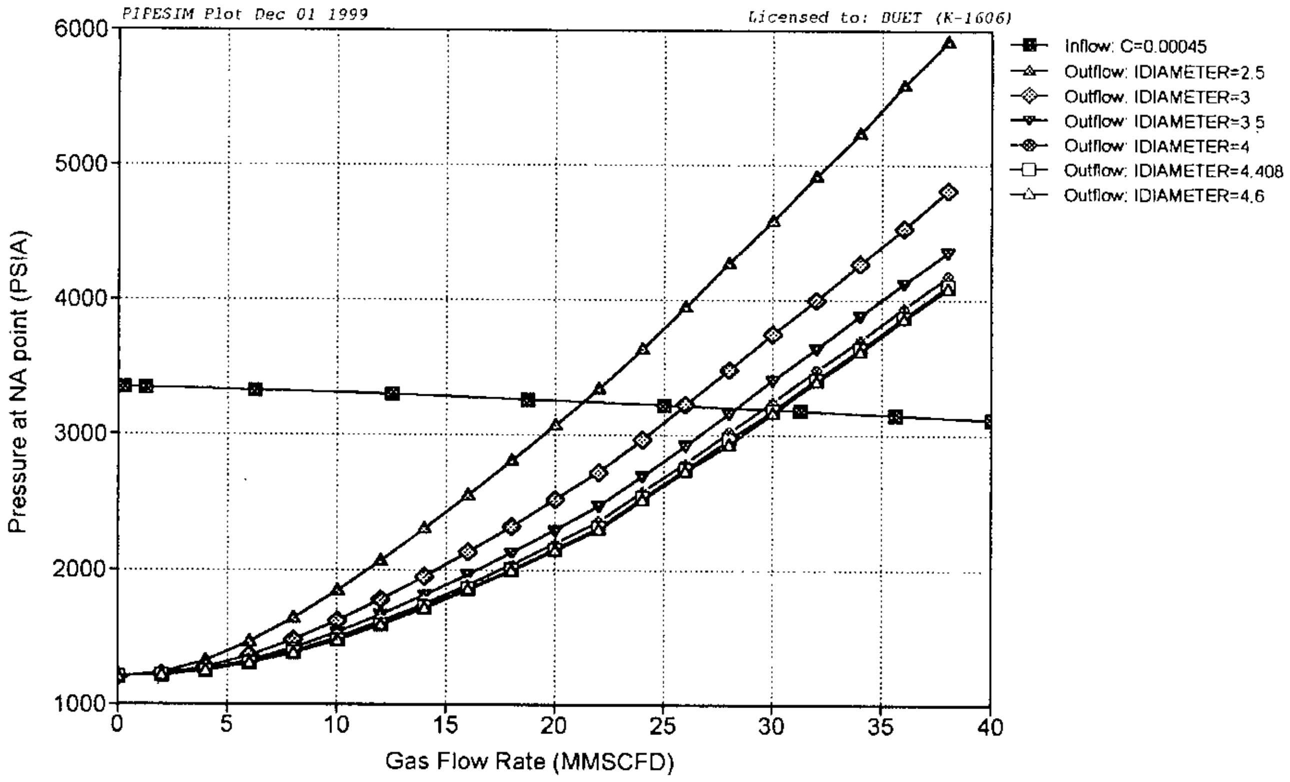


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Figure 7.30: Effect of Flow Line Inner Diameter on the Performance of Well TT-3

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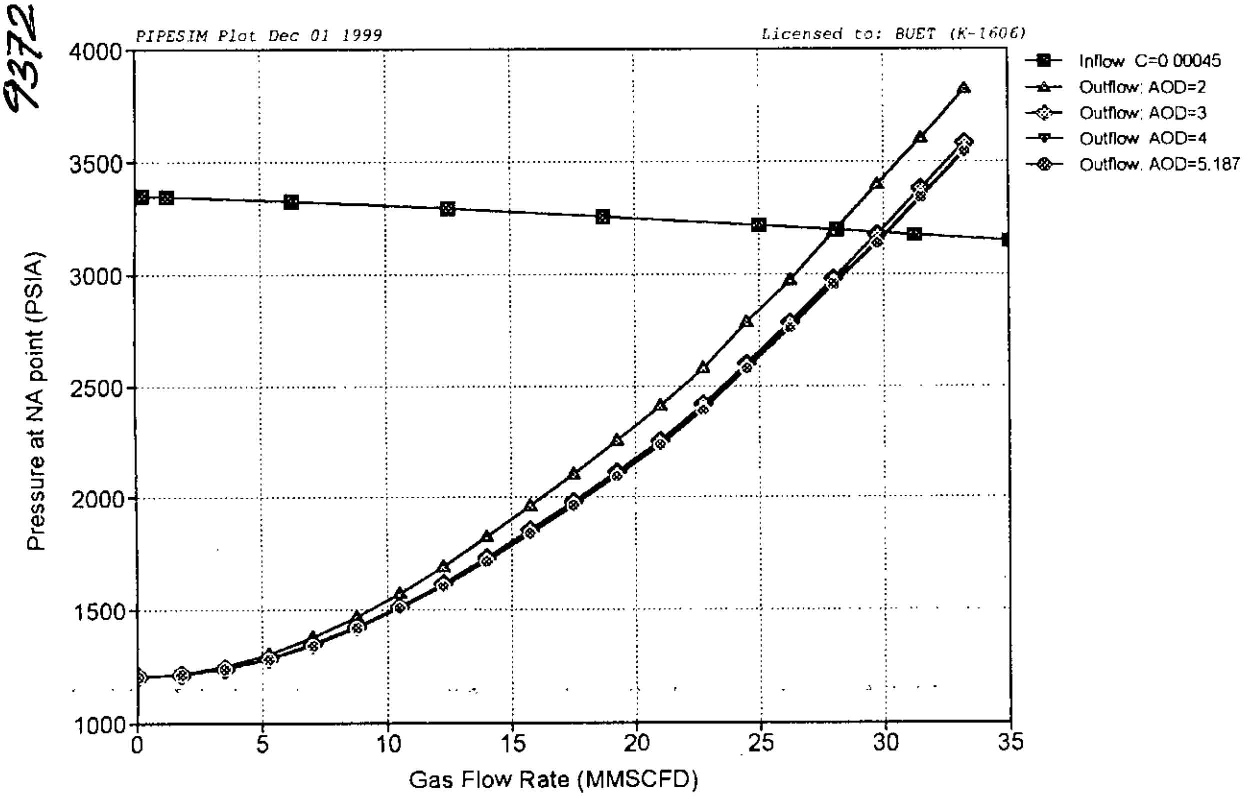

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Figure 7.31: Effect of Separator Pressure on the Performance of Well TT-3

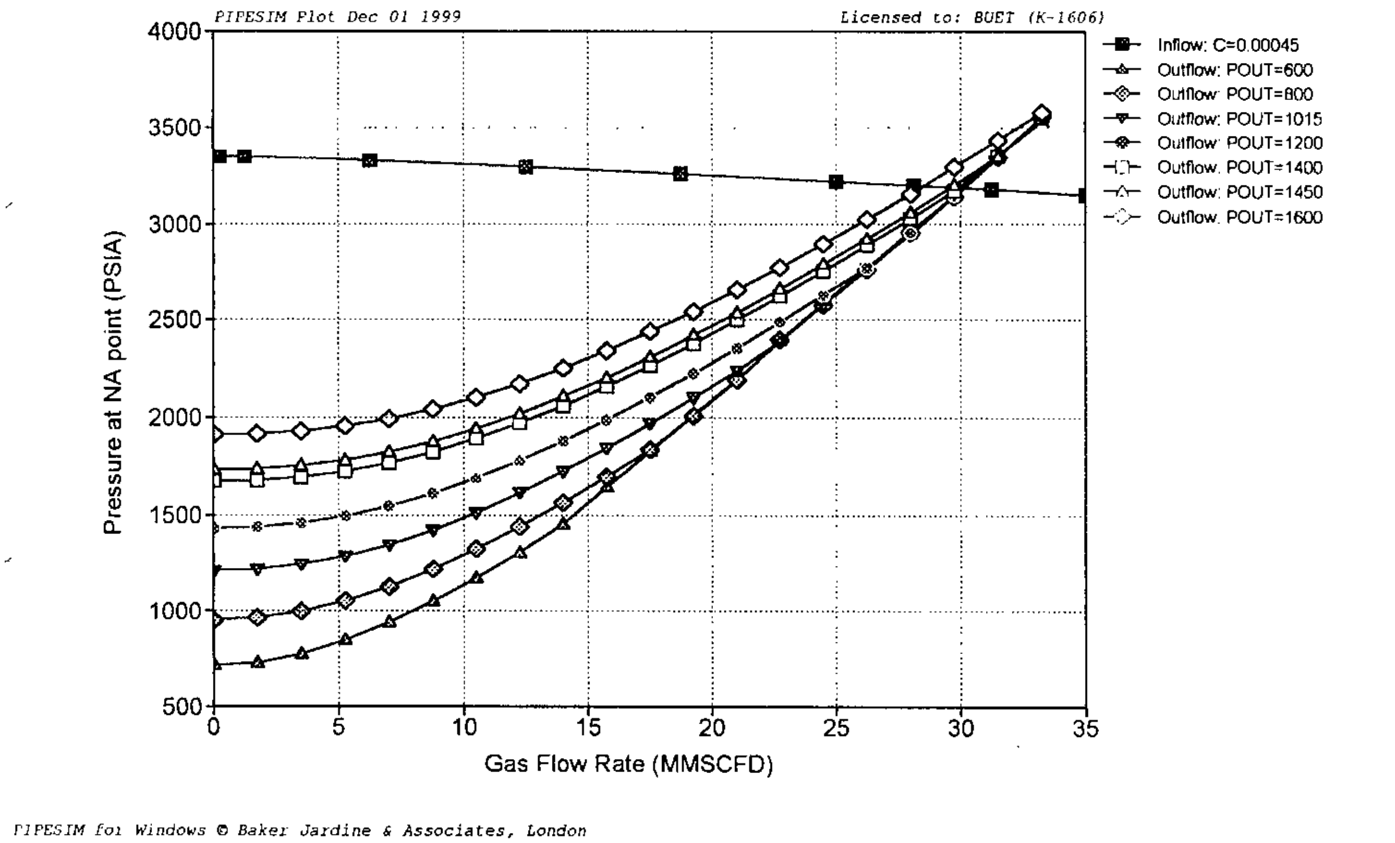
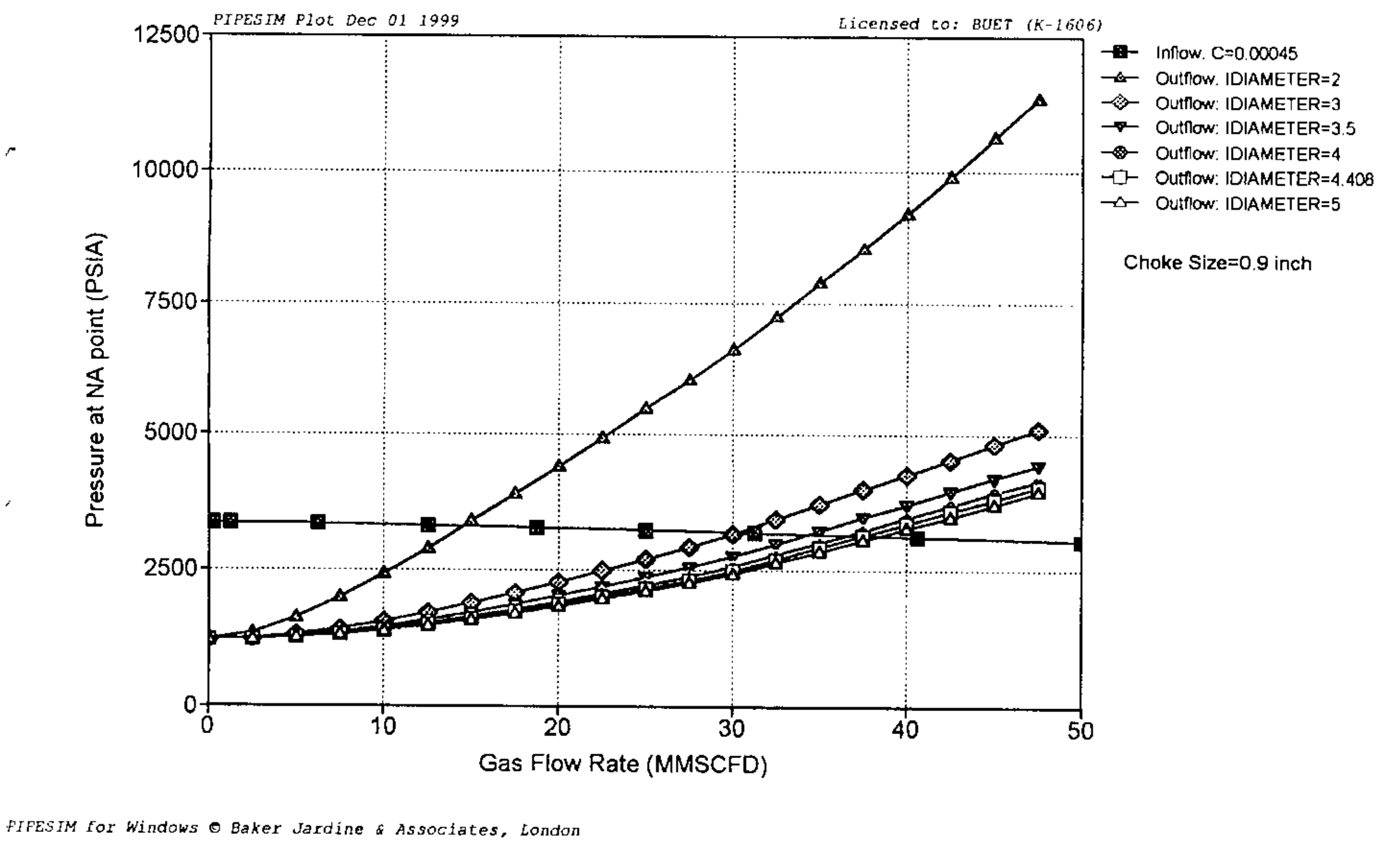


Figure 7.32: Effect of Tubing Inner Diameter on the Performance of Well TT-3



increase with an increase of tubing diameter. Existing flow line size of 5.187 inches is still more than adequate to support this high production rate. Figure 7.34 suggests that at a bottom hole pressure of 2000 psia, the well will produce 10 MMSCFD against a separator pressure of 1600 psia and 22.5 MMSCFD against 1010 psia. These values are 6.8 MMSCFD and 17.5 MMCF/D respectively for current choke size of 0.787 inch.

Figure 7.35 and 7.36 show the pressure and temperature profile along the vertical tubing for different flow rate, using existing choke size. It is evident from Figure 7.35 that for flow rate up to 50 MMSCFD, the friction loss per unit length of tubing is moderate and well head pressure above 2300 psia is available, but beyond this flow rate of 50 MMSCFD, frictional losses become significant. Figure 7.36 shows that well head temperature for the existing flow rate is about 150^0 F, which coincides with the actual value.

7.5.4 Well TT-4

Average reservoir pressure: 3350 psia
Average reservoir temperature: 195.0 ^{0}F
Back-pressure equation coefficient C = 0.0003
Back-pressure equation exponent n = 0.80

Figure 7.37 shows the variation of flow rate with change of reservoir pressure for a tubing diameter of 4.408 inches. For an initial reservoir pressure of 3965 psia, recorded in October 1969, the flow rate was about 33.4 MMSCFD at a wellbore pressure of 3696 psia. The well is now producing at 28 MMSCFD at the current reservoir pressure of 3350 psia. For a lower reservoir pressure of 2200 psia, the flow will decrease to be as low as 17.5 MMSCFD in future, assuming all other parameters remain the same.

From Figure 7.38, it is evident that for a C value of 0.0001, production rate is only 22.8 MMSCFD which increases to 28.0 MMSCFD when C is 0.0003, the current value. Increasing the value of C to 0.0006 will increase the flow to 29.6 MMSCFD.

Figure 7.33: Effect of Flow Line inner Diameter on the Performance of Well TT-3

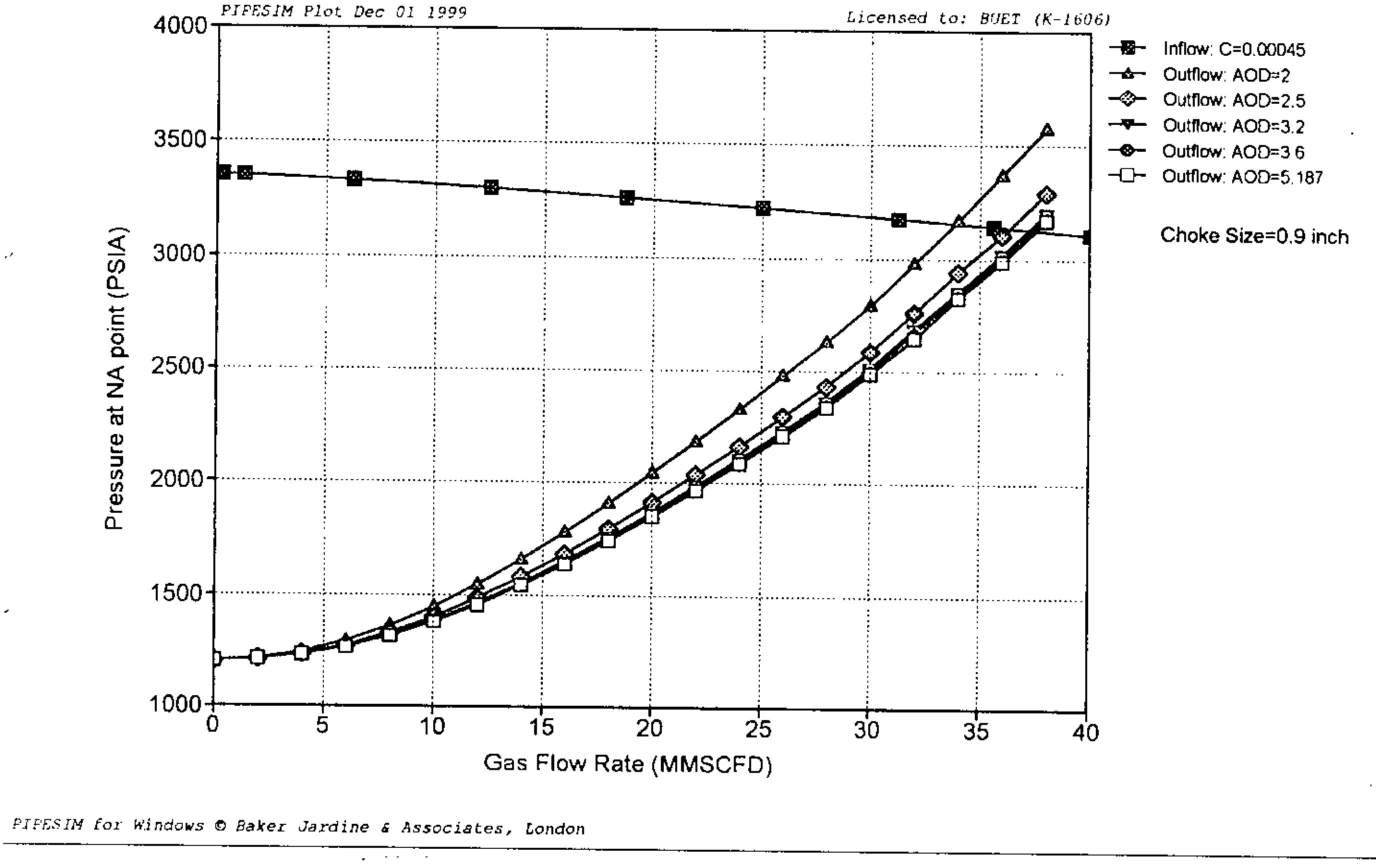


Figure 7.34: Effect of separator Pressure on the Performance of Well TT-3

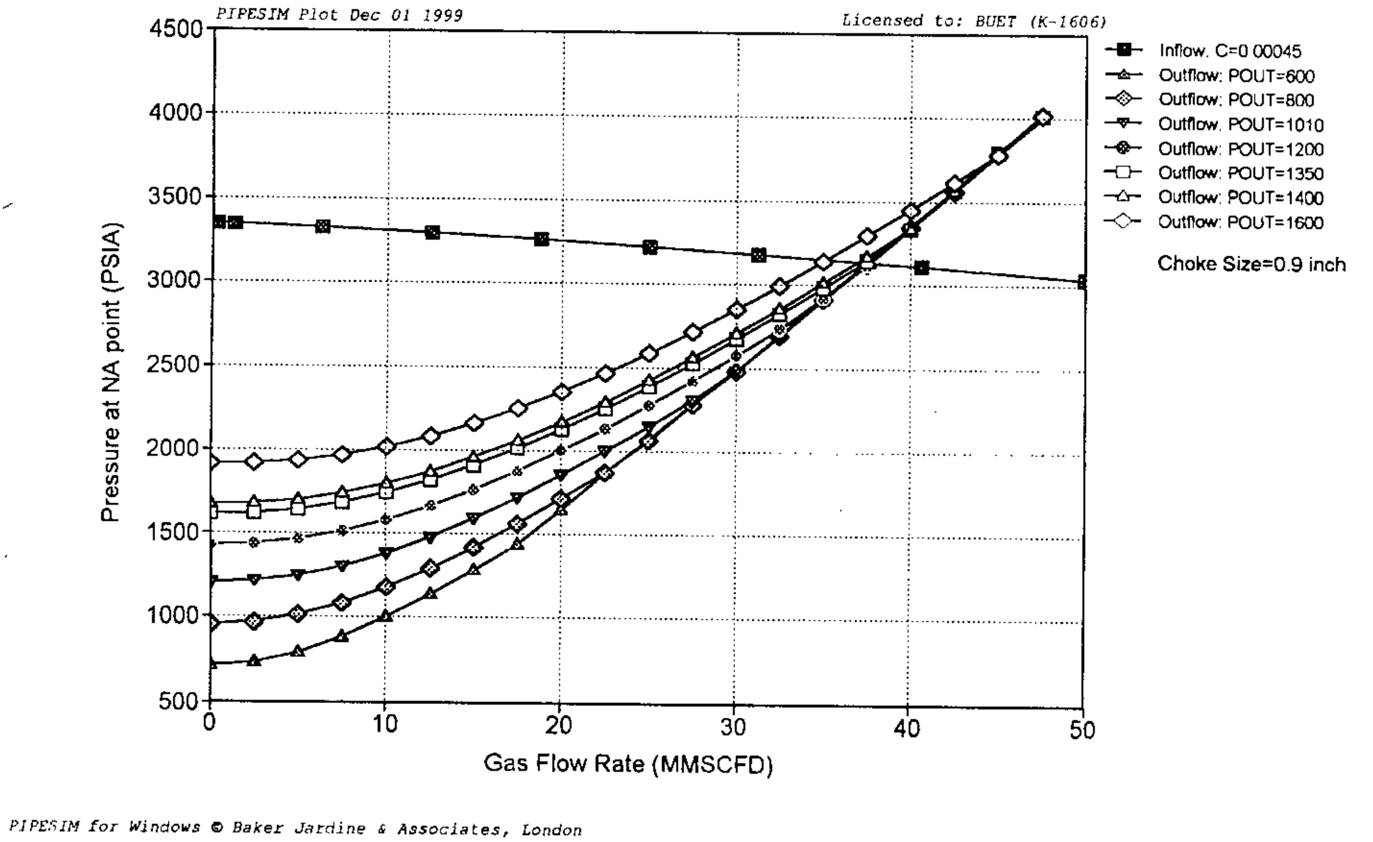


Figure 7.35: Effect of Flow Rate on Pressure Profile in Tubing of Well TT-3

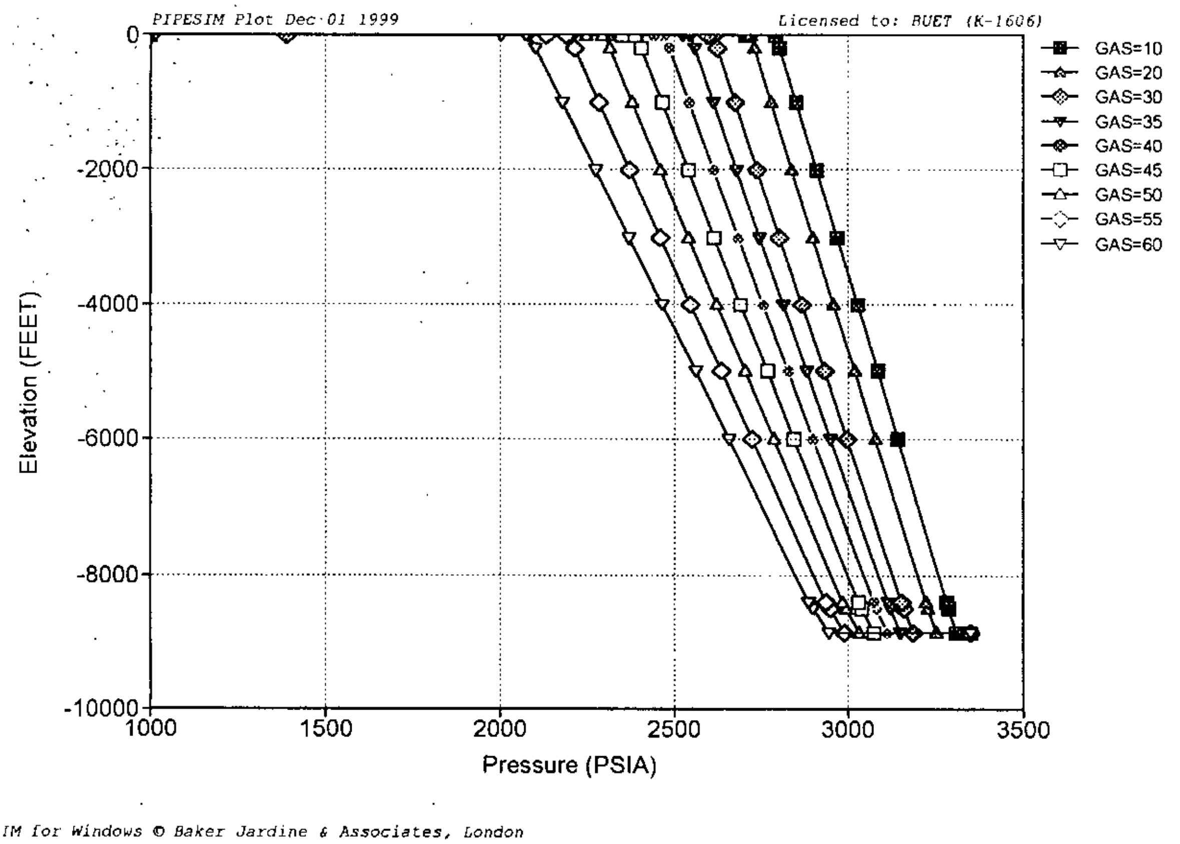


Figure 7.36: Effect of Flow Rate on Temperature Profile in Tubing of Well TT-3

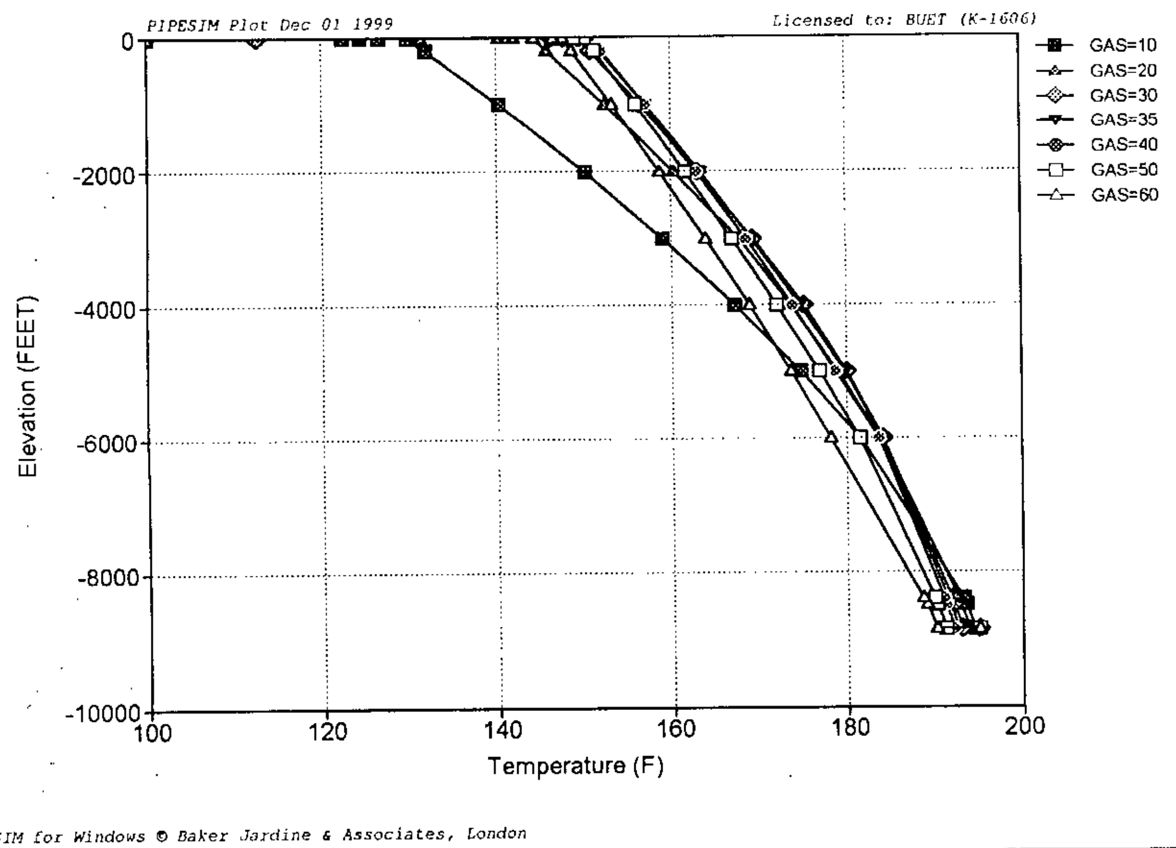


Figure 7.37: Effect of Average Reservoir Pressure on the Performance of Well TT-4

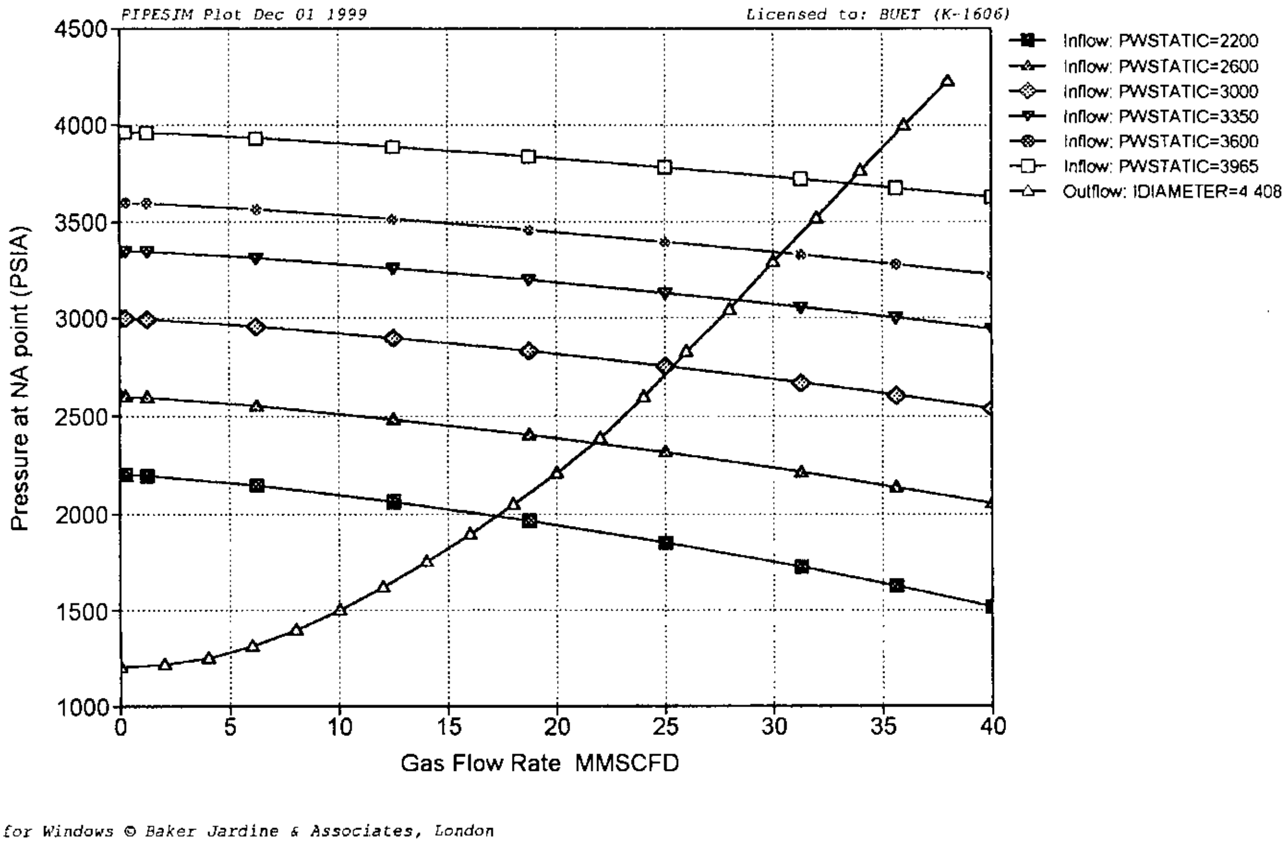
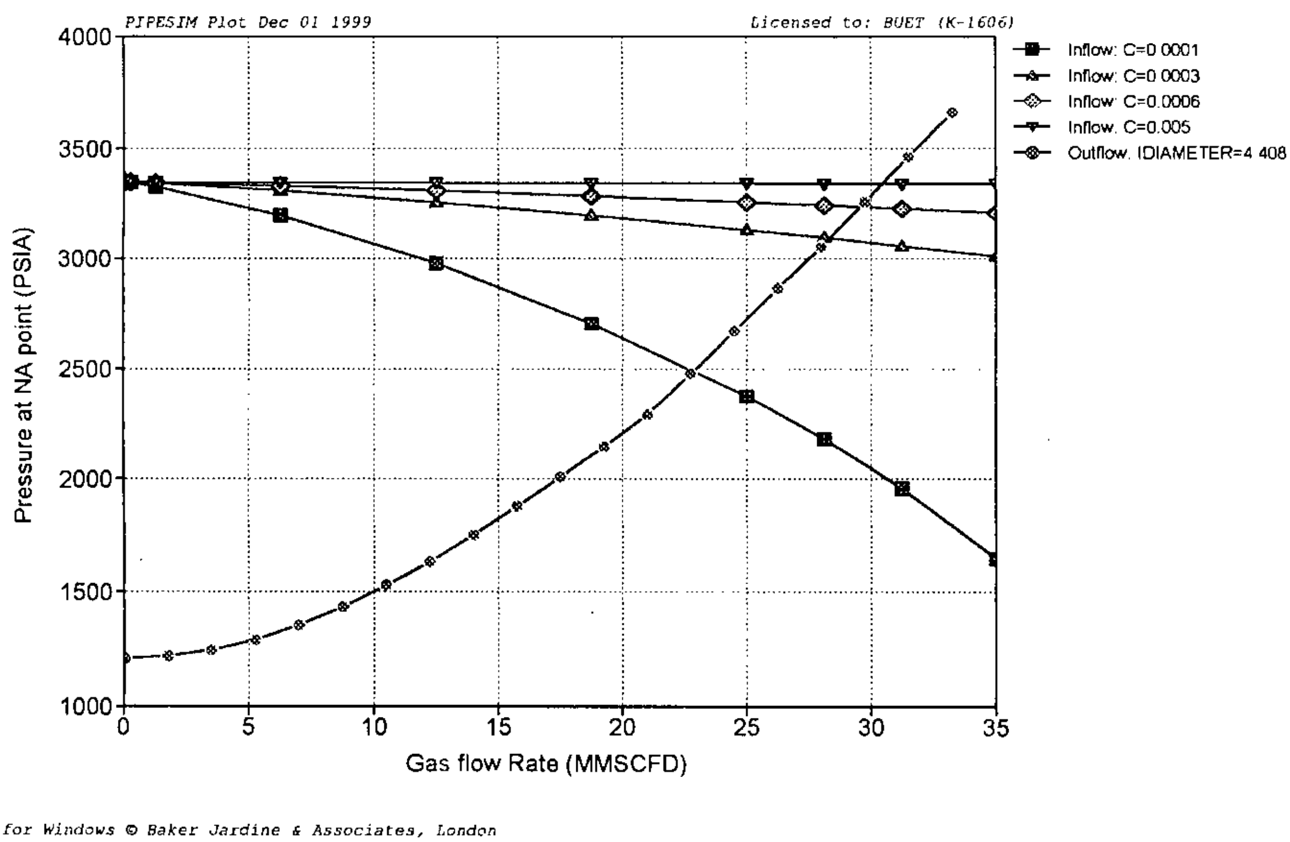


Figure 7.38: Effect of Back Pressure Coefficient on the Performance of Well TT-4



From Figure 7.39, when n is 0.5; a very low flow rate of 1.0 MMSCFD is obtainable. The flow rate increases to 4.5 MMSCFD, 18.0 MMSCFD and 28.0 MMSCFD as n increases to 0.6, 0.70 and 0.80, respectively. Beyond the value of n = 0.80, an increase in n will not be much productive as flow rate increases by only 2 MMSCFD, when n is 0.90.

Figure 7.40 shows the effect of the bean diameter on flow rate. Flow rate increases from 15.3 MMSCFD to 36 MMSCFD as the bean size is increases from 0.55 inch to 0.90 inch. The well is now producing at a rate of 28 MMSCFD at a choke size of 0.775 inch.

Figure 7.41 shows the variation of flow rate with tubing size. For a tubing inner diameter of 2.0 inches a flow rate of only 13.9 MMSCFD is possible. For a tubing size of 2.5 inches and 3.0 inches, the flow rate increases to 20 MMSCFD and 25 MMSCFD, respectively. An increase in the tubing size beyond 4.0 inches will not increase in the flow rate any further.

Figure 7.42 shows the effect of flow line diameter on the flow diameter. A 2.5-inches diameter line produces 27.5 MMSCFD while 3.0-inches diameter line produces 28.0 MMSCFD, which is the existing flow rate. So existing flow line diameter of 3.438 inches is more than adequate for the current condition.

Figure 7.43 shows the effect of separator pressure. At high separator pressure of 1800 psia, flow rate is 25.0 MMSCFD and at 1600 psia and 1350 psia, the flow rate increases to 26.5 MMSCFD and 28 MMSCFD, respectively. For a separator pressure of 1350 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1350 psia has no positive effect on the flow rate. Therefore, it is possible to maintain a maximum pressure of 1350 psia at the downstream side of the choke instead of current pressure of about 1010 psia.

Separator plays an important role as the average reservoir pressure gets lower. At a bottom hole pressure of 2000 psia, a separator pressure of 1800 does not produce any

Figure 7.39: Effect of Back Pressure Exponent on the Performance of Well TT-4

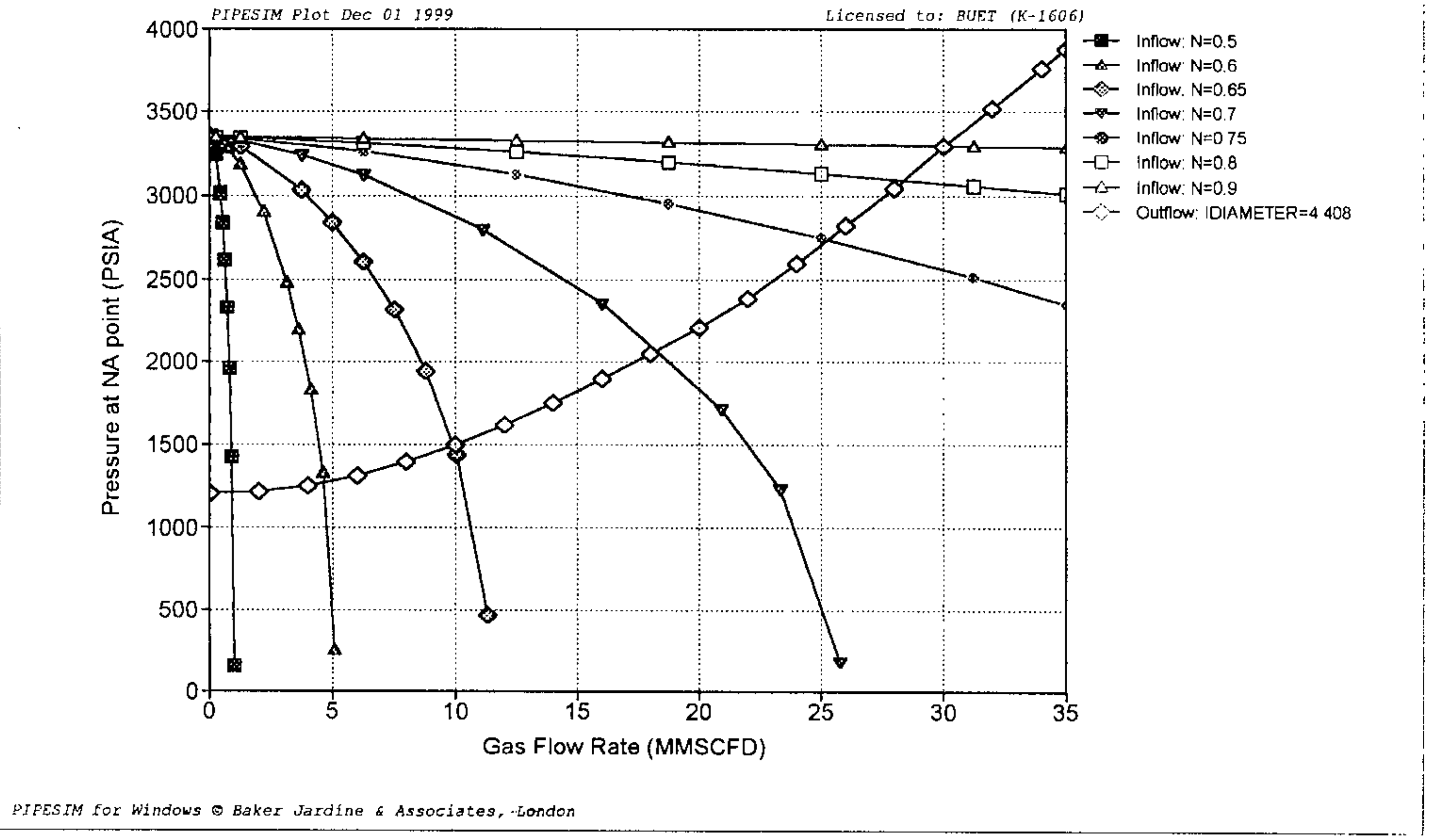


Figure 7.40: Effect of Choke Size on the Performance of Well TT-4

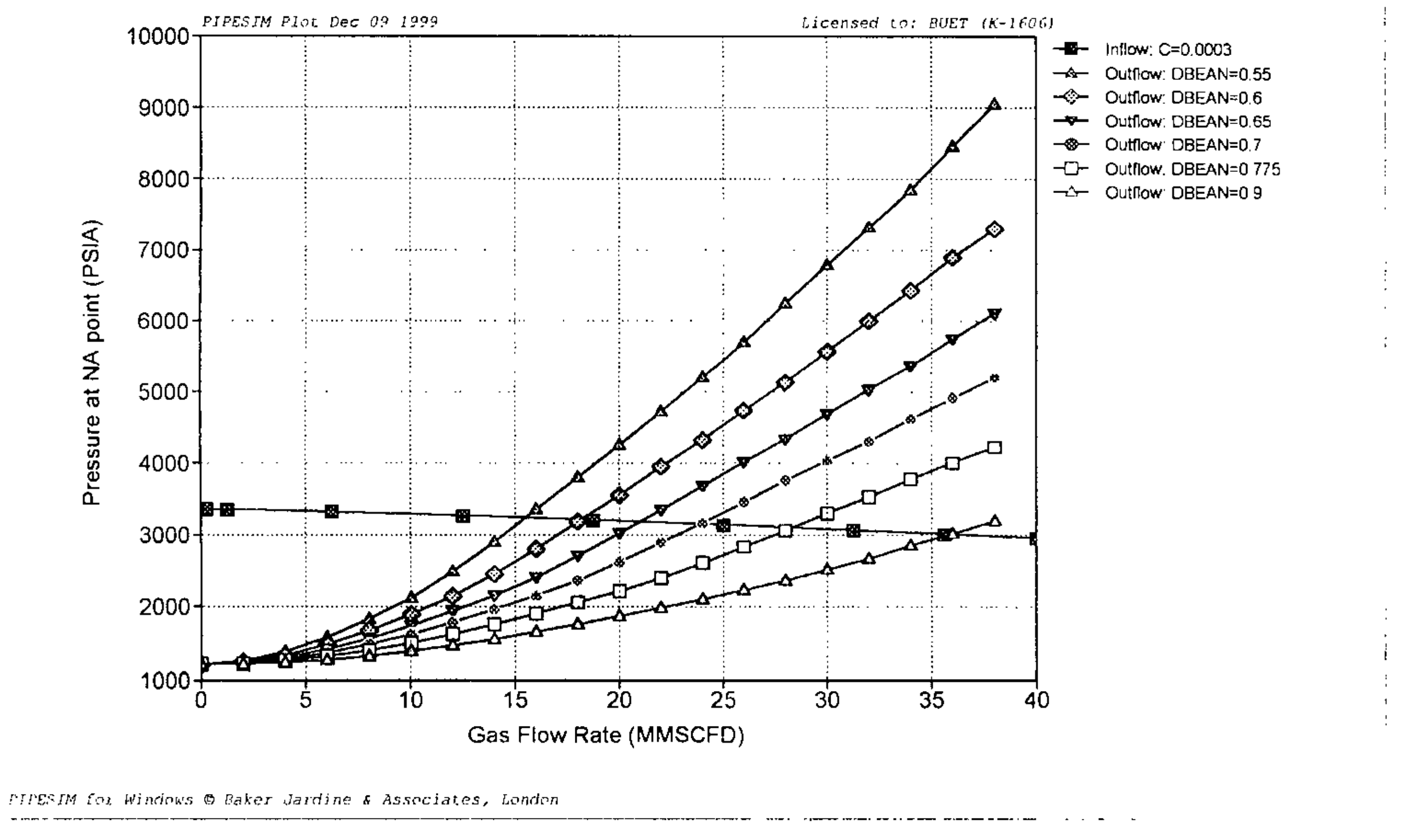


Figure 7.41: Effect of Tubing Inner Diameter on the Performance of Well TT-4

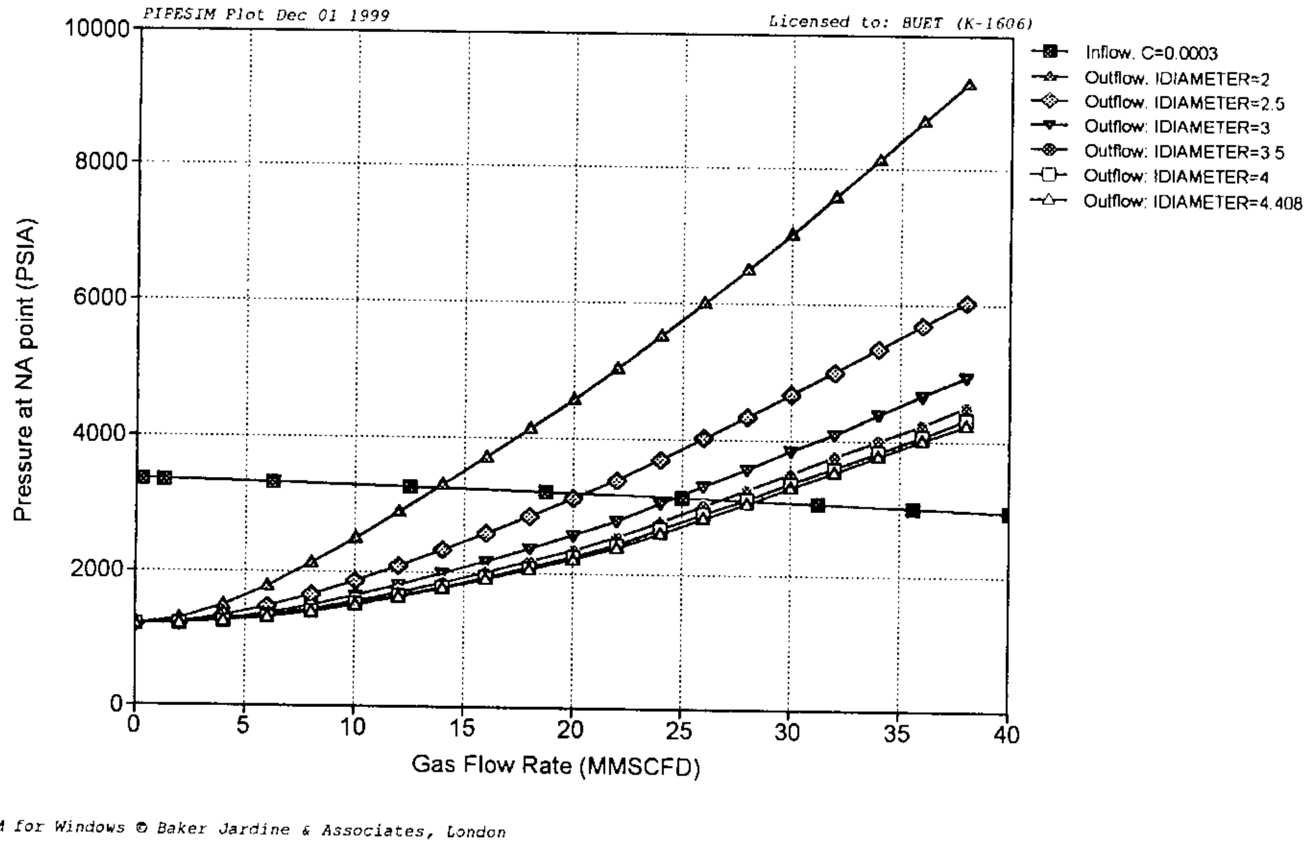
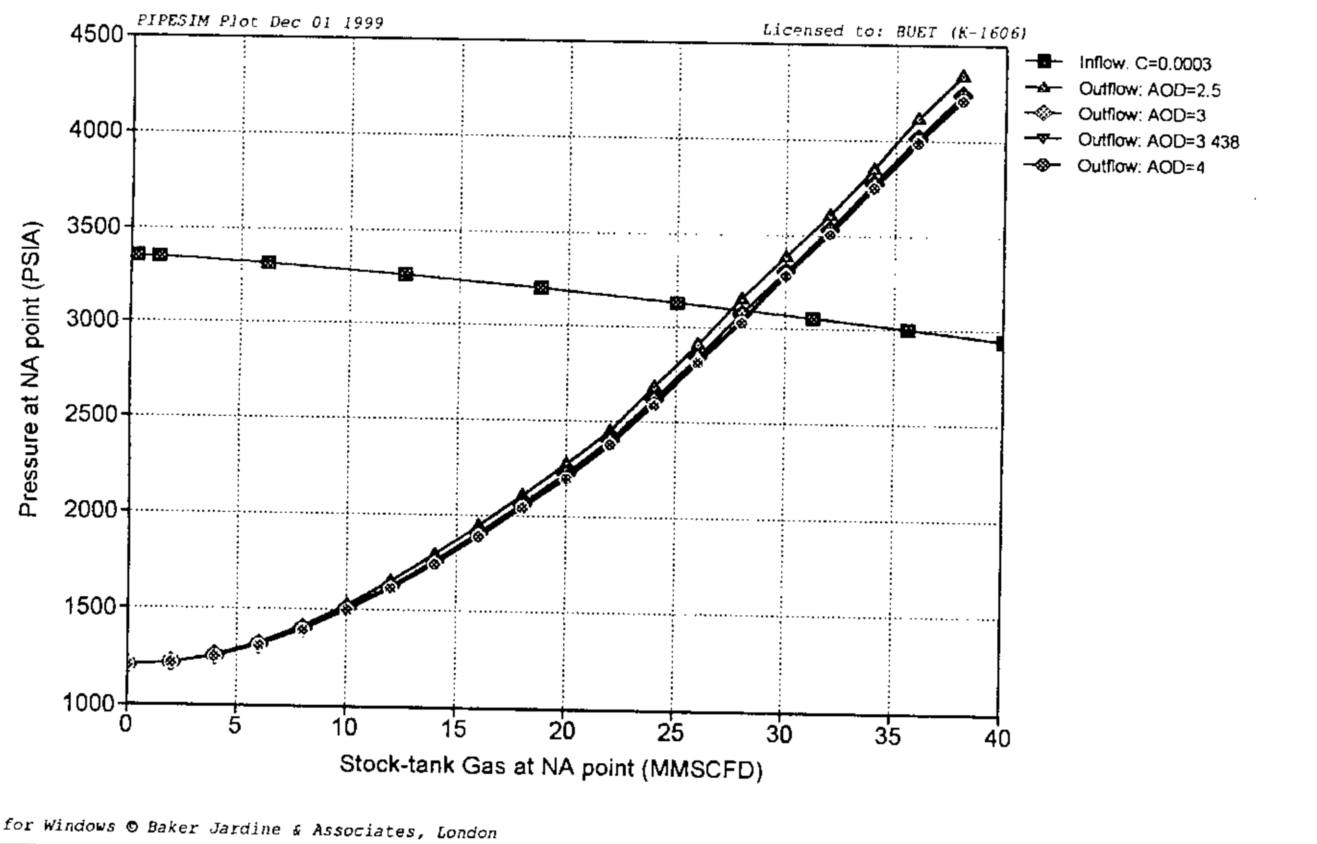


Figure 7.42: Effect of Flow Line Inner Diameter on the Performance of Well TT-4



gas and a pressure of 1600 psia produce only 7 MMSCFD, but a separator pressure of 1010 produces 17.6 MMSCFD.

Figures 7.44 through 7.46 show the effect of tubing diameter and flow line diameter, and separator pressure, respectively for a larger choke size of 0.9 inch. According to Figure 7.44, a 2-inches and a 2.5-inches tubing will produce a flow of 14 MMSCFD and 22.3 MMSCFD, respectively. Existing tubing size of 4.408 inches is suitable for this higher production scenario. In this case, the smaller flow line diameter of 2.0 inches can sustain a flow of 31.2 MMSCFD and 3.438-inches size can produce 36 MMSCFD. Increasing the size will not be productive. Figure 7.46 suggests that at a bottom hole pressure of 2000 psia, the well will produce 9.7 MMSCFD against a separator pressure of 1600 psia and 22.5 MMSCFD against 1010 psia. These values are 7.0 MMSCFD and 17.6 MMCF/D respectively for current choke size of 0.775 inch.

Figure 7.47 and 7.48 show the pressure and temperature profile along the vertical tubing for different flow rate, using existing choke size. It is evident from Figure 7.47 that for flow rate up to 40 MMSCFD, the friction loss per unit length of tubing is moderate and wellhead pressure above 2300 psia is available, but beyond that losses become significant. At a flow of 60 MMSCFD, wellhead pressure becomes only 1780 psia. Figure 7.48 shows that the well head temperature for the existing flow rate is about 150^0 F, which coincides with the actual value.

7.5.5 Well TT-5

Average reservoir pressure: 3350 psia
Average reservoir temperature: 195.0 ^{0}F
Back-pressure equation coefficient C = 0.0006
Back-pressure equation exponent n = 0.80

Figure 7.49 shows the variation of flow rate with a change of reservoir pressure for a tubing diameter of 3.958 inches. For an initial reservoir pressure of 3823 psia, recorded in January 1981, the flow rate was about 34.1 MMSCFD at a wellbore pressure of 3696 psia. The well is now producing 29.7 MMSCFD at the current

Figure 7.43: Effect of Separator Pressure on the Performance of Well TT-4

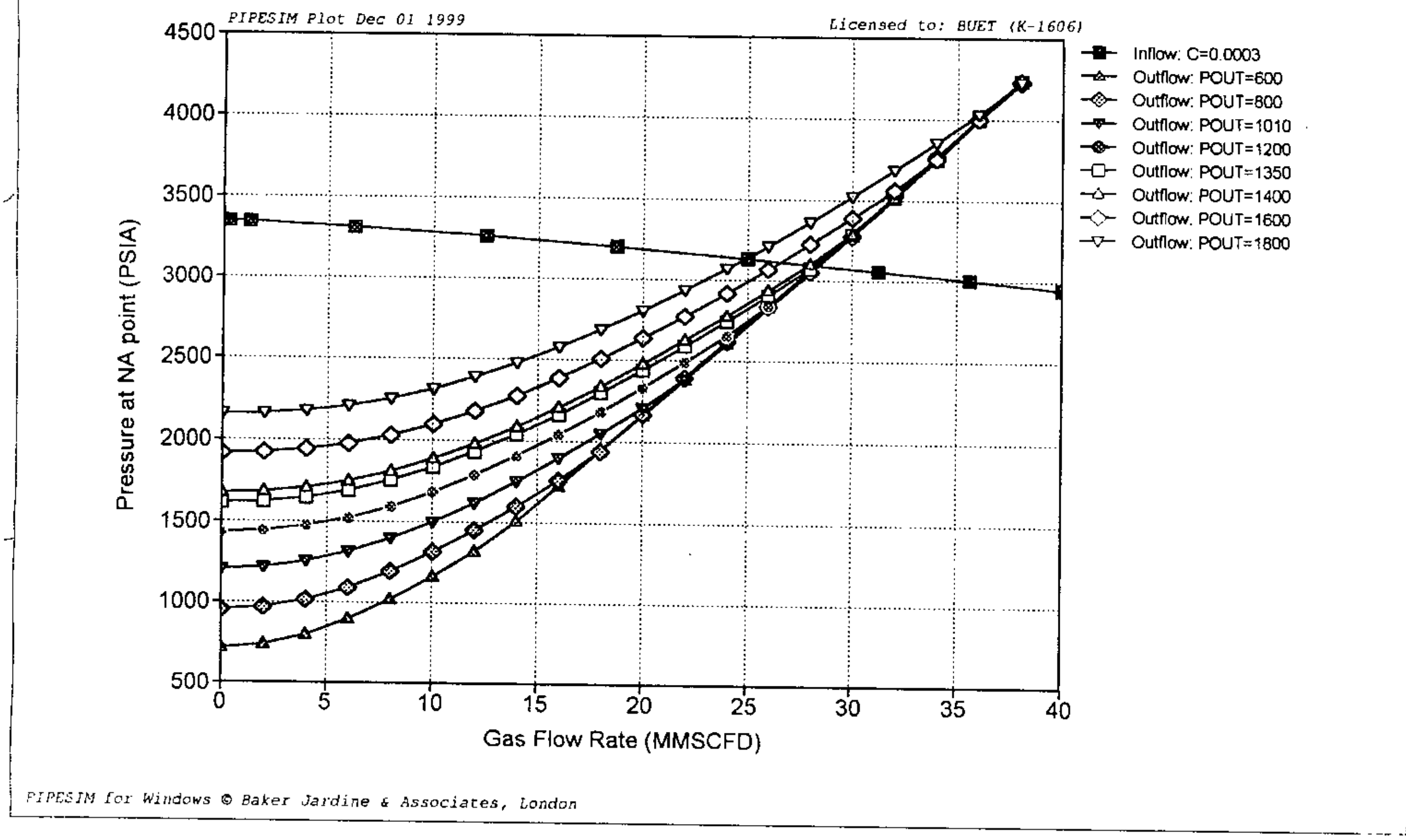


Figure 7.44: Effect of Tubing Inner Diameter on the Performance of Well TT-4

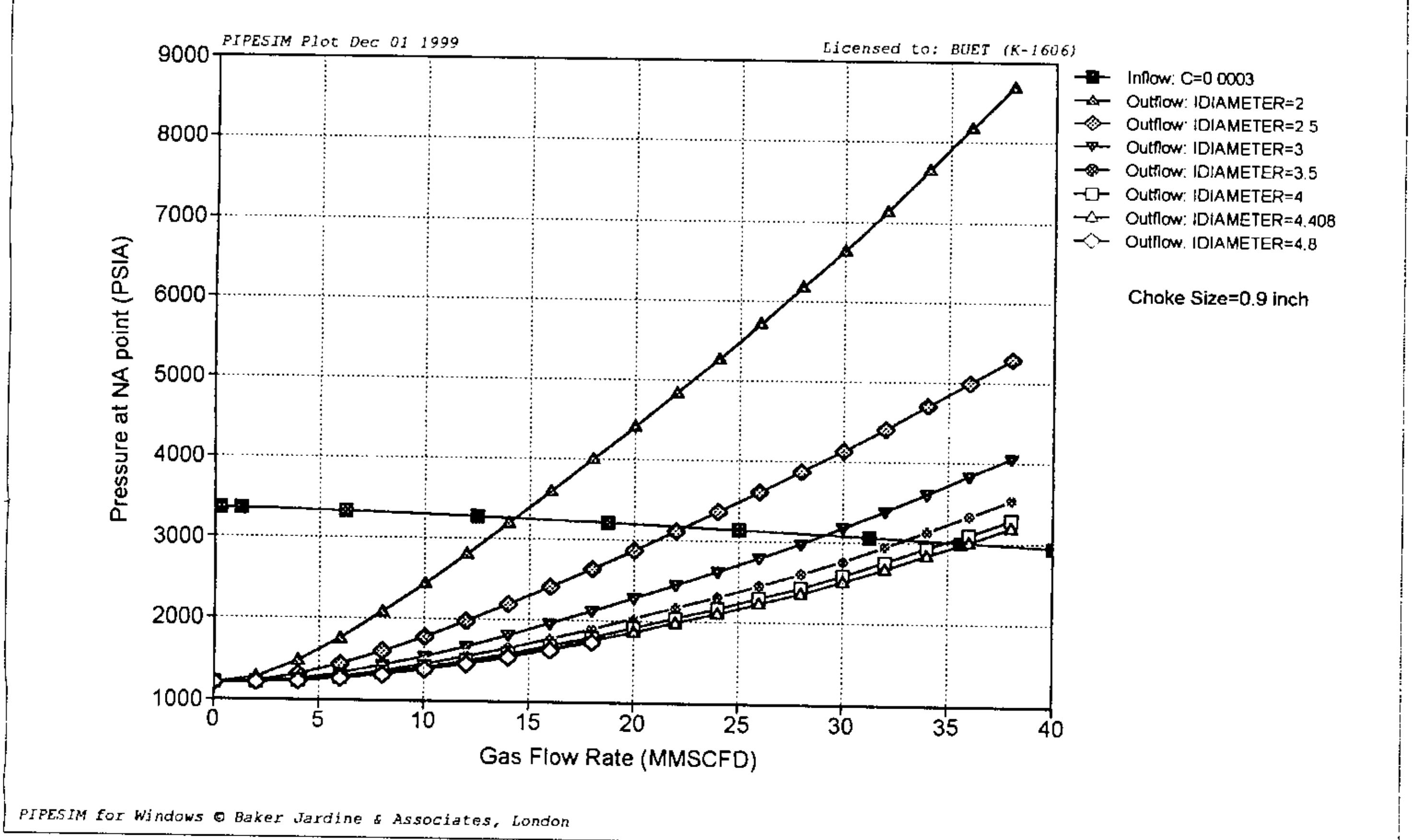


Figure 7.45: Effect of Flow Line Inner Diameter on the Performance of Well TT-4

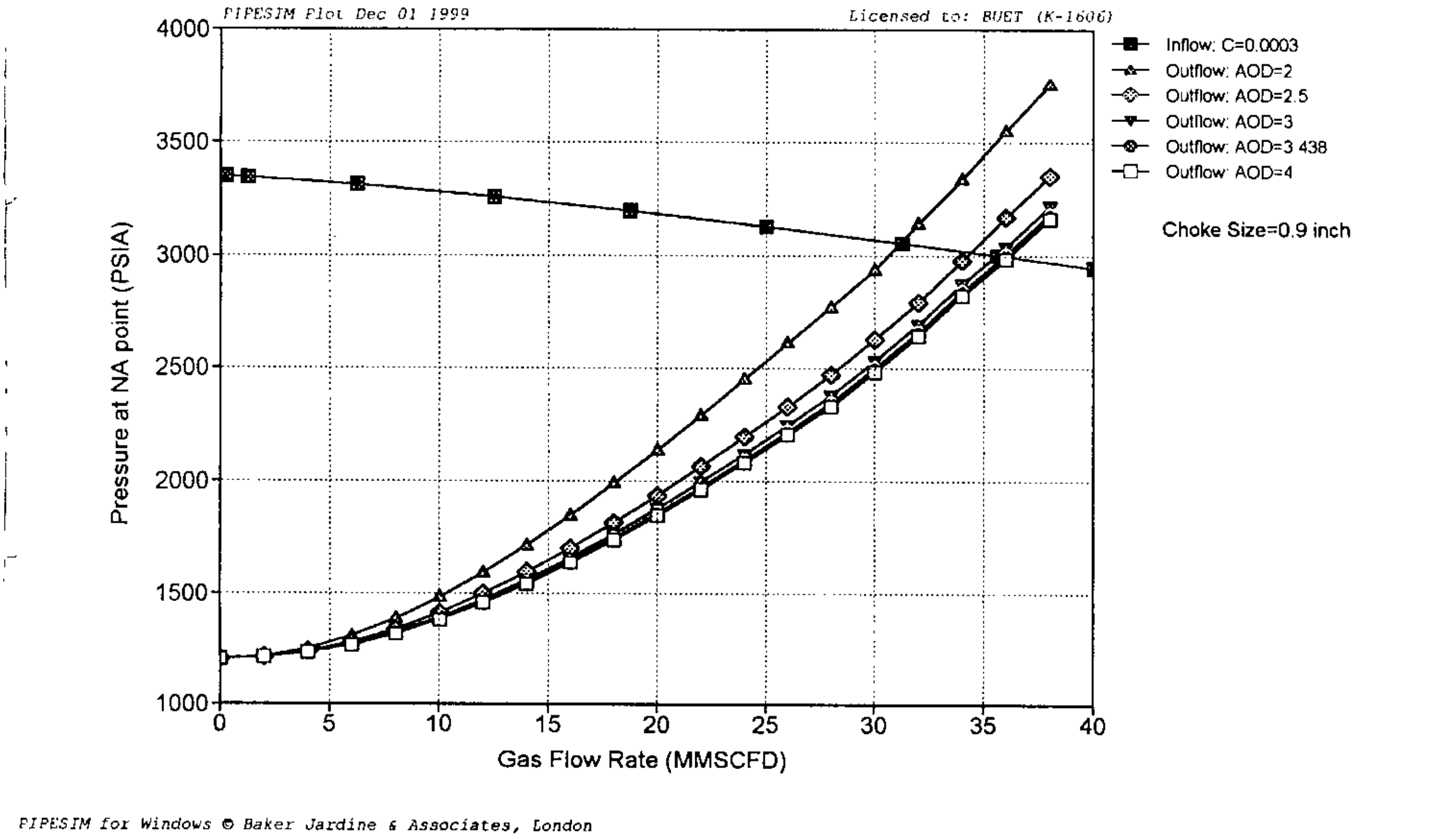


Figure 7.46: Effect of Separator Pressure on the Performance of Well TT-4

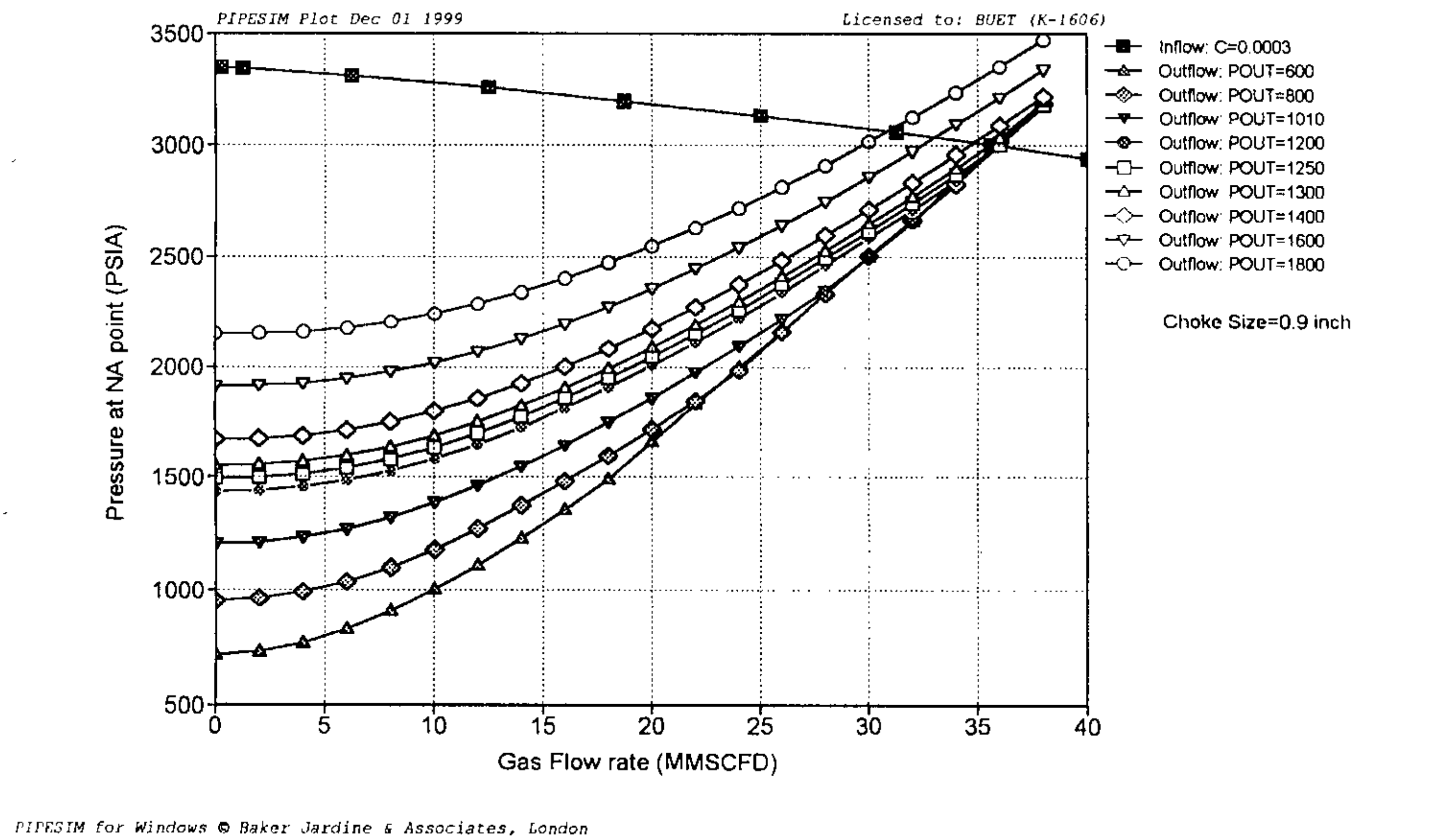


Figure 7.47: Effect of Flow Rate on Pressure Profile inTubing of Well TT-4

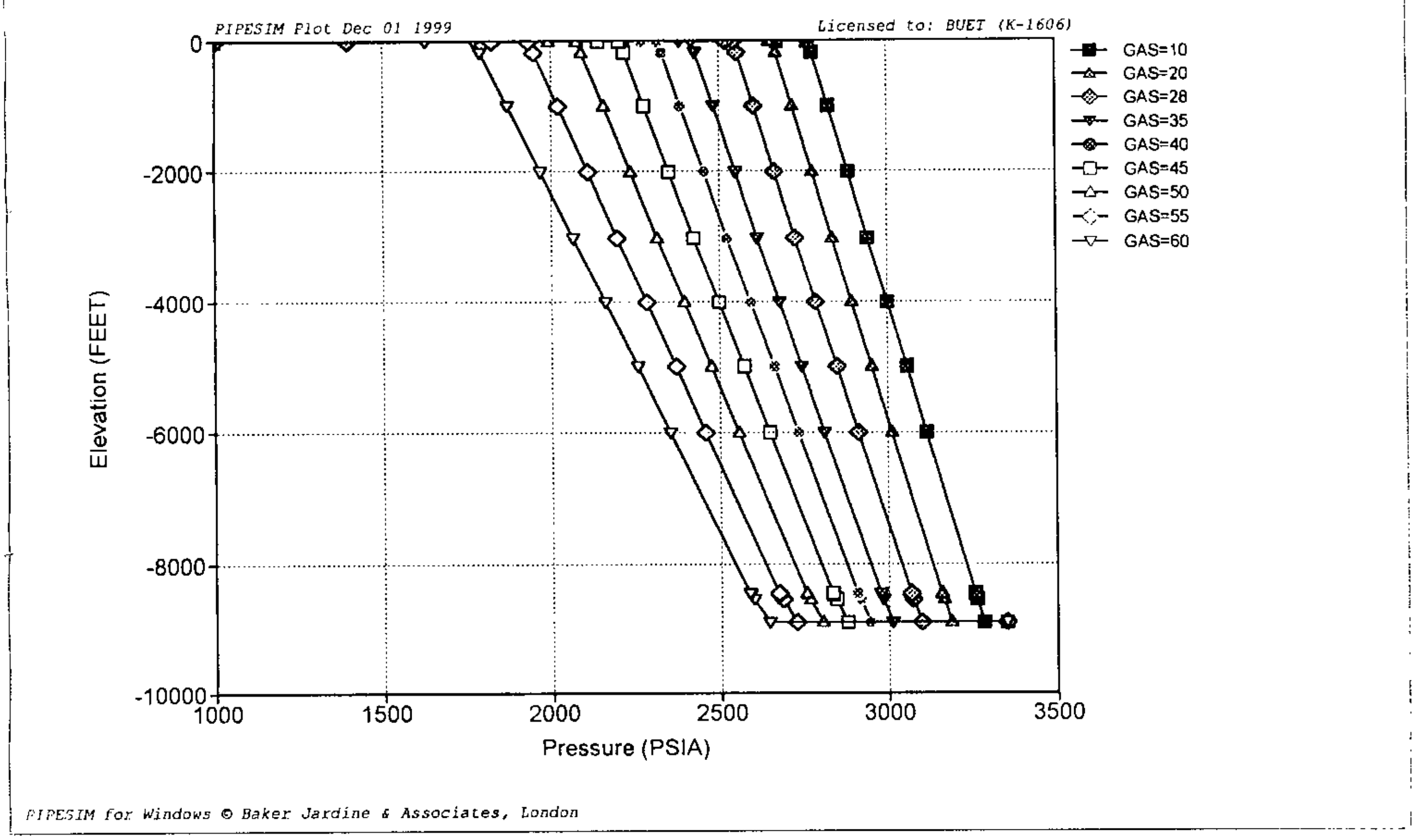
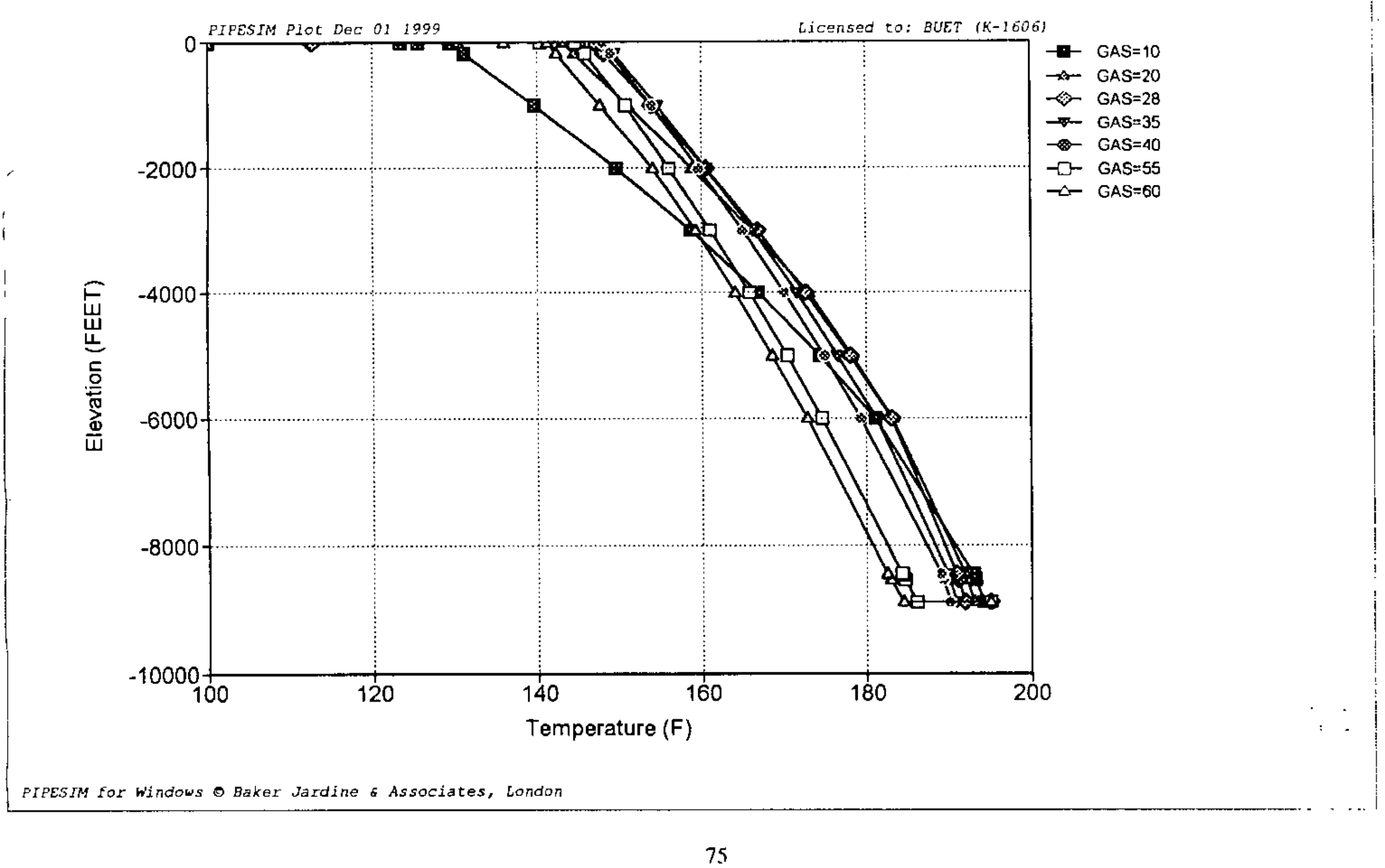


Figure 7.48: Effect of Flow Rate on Temperature Profile in Tubing of Well TT-4



reservoir pressure of 3350 psia. For a low reservoir pressure of 2200 psia, the flow will be as low as 18.8 MMSCFD in the future, assuming all other parameters remain the same

From Figure 7.50, it is evident that for a C value of 0.0003, the production rate is only 28.5 MMSCFD which increases to 29.7 MMSCFD when C is 0.0006, the current value. Increasing the value of C to 0.0009 and beyond will not have effect on the flow rate.

Figure 7.51 shows that when n is 0.5, a very low flow rate of 2.0 MMSCFD is obtainable. The flow rate increases to 8.7 MMSCFD, 25.0 MMSCFD and 29.7 MMSCFD as n is increased to 0.6, 0.70 and 0.80, respectively. Beyond the value of n = 0.80, an increase in n will hardly increase the production rate.

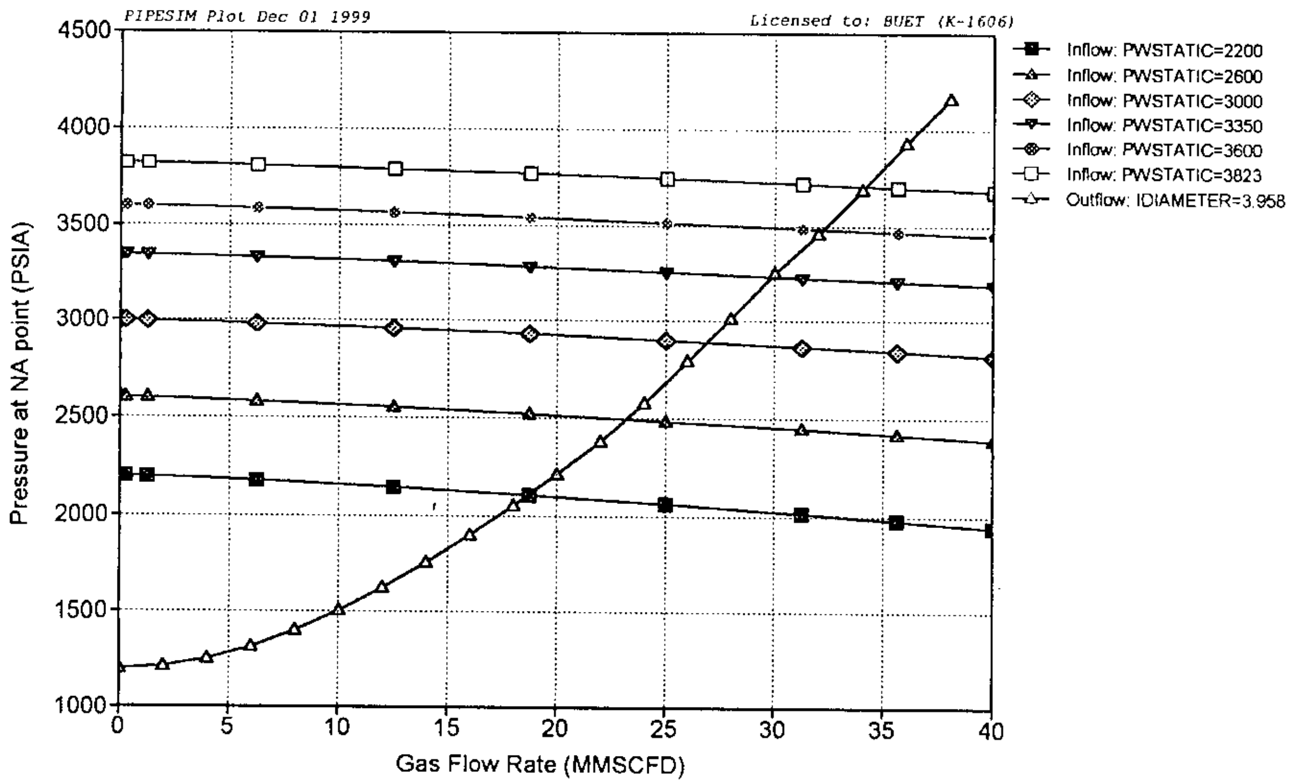
Figure 7.52 shows the effect of the bean diameter on the flow rate. Flow rate increases from 18.2 MMSCFD to 36.5 MMSCFD as bean size is increased from 0.60 inch to 0.90 inch. The well is now producing at a rate of 29.7 MMSCFD at a bean size of 0.795 inch

Figure 7.53 shows the variation of flow rate with tubing size. For a tubing inner diameter of 2.0 inches a flow rate of only 13.5 MMSCFD is possible. For a tubing size of 2.5 inches and 3.0 inches, the flow rate increases to 20.7 MMSCFD and 25.8 MMSCFD, respectively. An increase in the current tubing size of 3.958 inches will hardly increase the flow rate any further. Using a 4.5-inches will only increase the flow rate by 0.1 MMSCF/D.

Figure 7.54 shows the effect of flow line inner diameter on the flow rate. A diameter of 2-inches produces at a rate of 26.0 MMSCFD while 3.0-inches diameter produces 29.7 MMSCFD, which is the existing flow rate. So existing flow line diameter of 3.438 inches is more than adequate for the current condition.

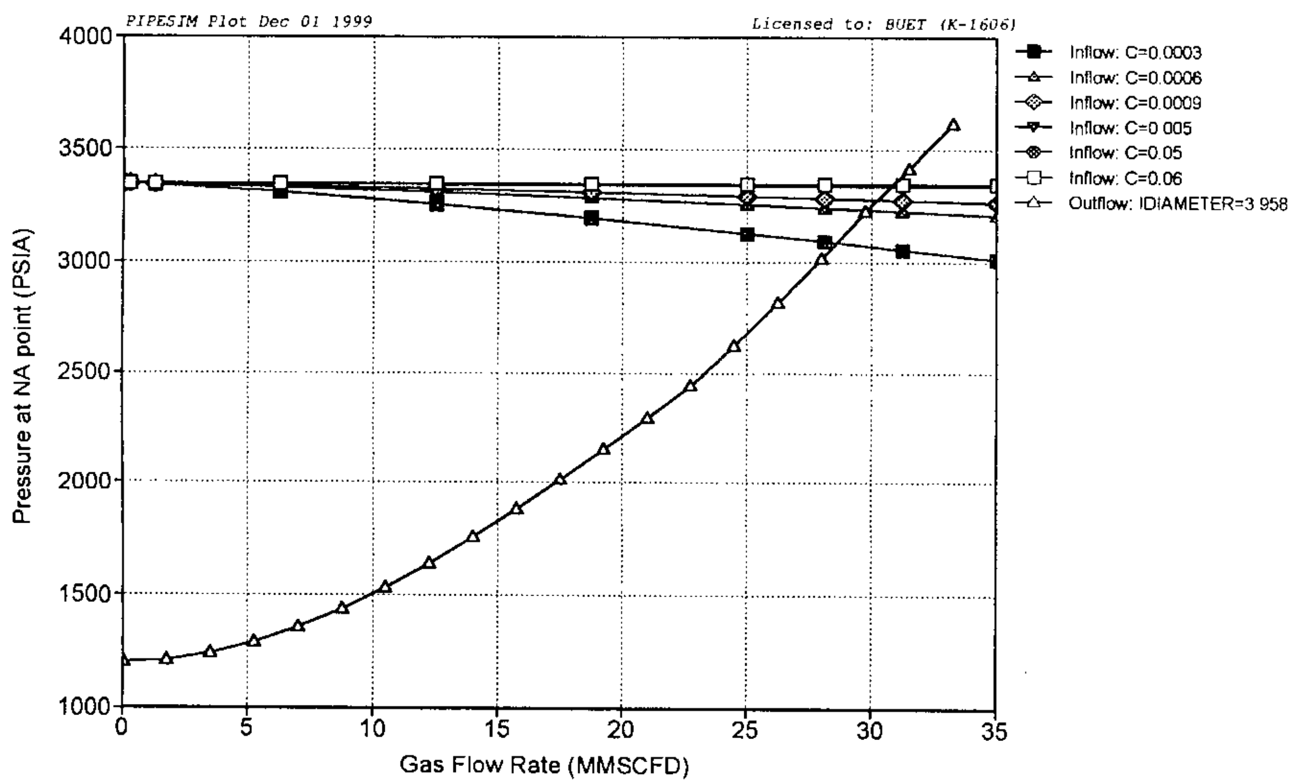
Figure 7.55 shows the effect of separator pressure. At a high separator pressure of 1600 psia, flow rate is 27.8 MMSCFD and at 1400 psia, the flow rate increases to 29.7 MMSCFD, the current value. For a separator pressure of 1400 psia and below, the

Figure 7.49: Effect of Average Reservoir Pressure on the Performance of Well TT-5



PIPESIM for Windows © Baker Jardine & Associates, London

Figure 7.50: Effect of Back Pressure Coefficient on the Performance of Well TT-5



PIPESIM for Windows © Baker Jardine & Associates, London

Figure 7.51: Effect of Back Pressure Exponent on the Performance of Well TT-5

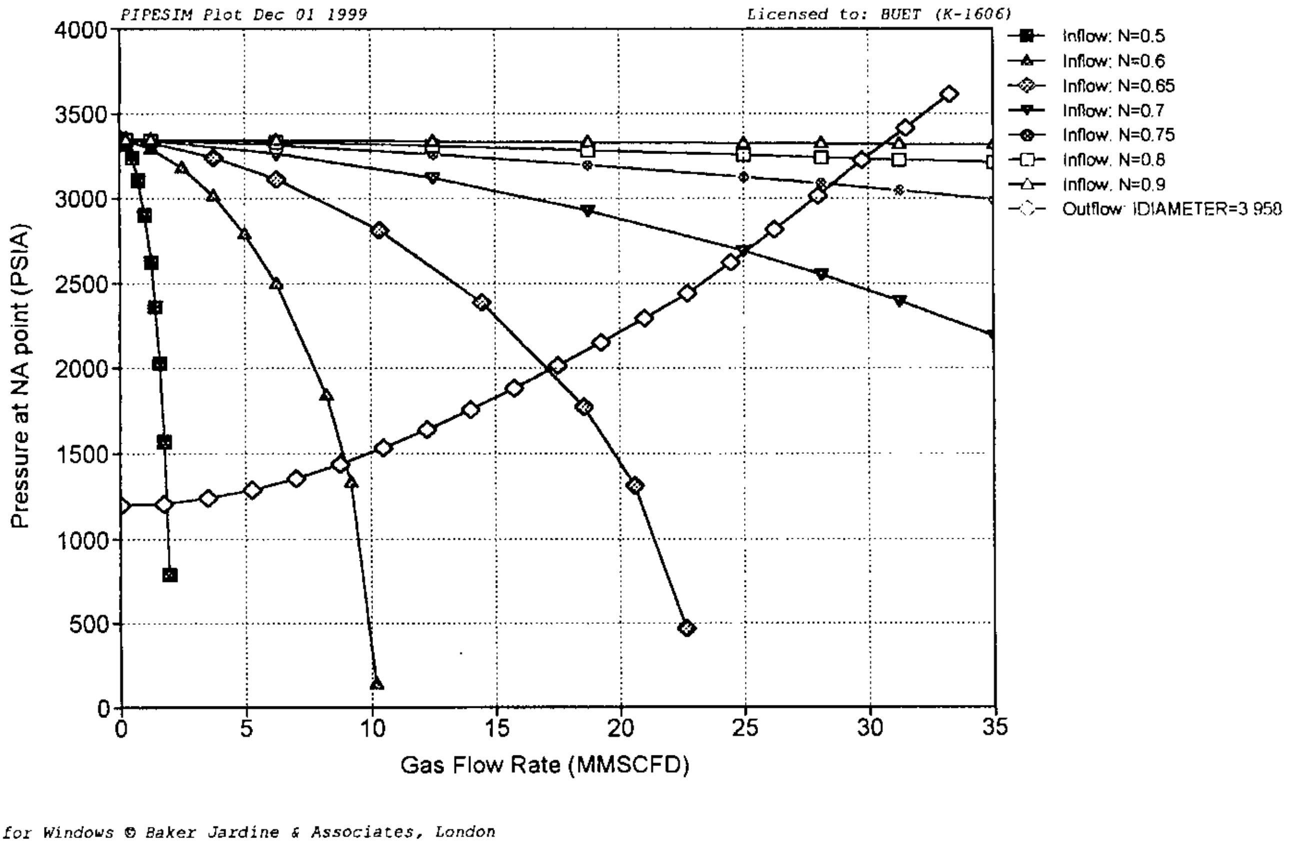


Figure 7.52: Effect of Choke Size on the Performance of Well TT-5

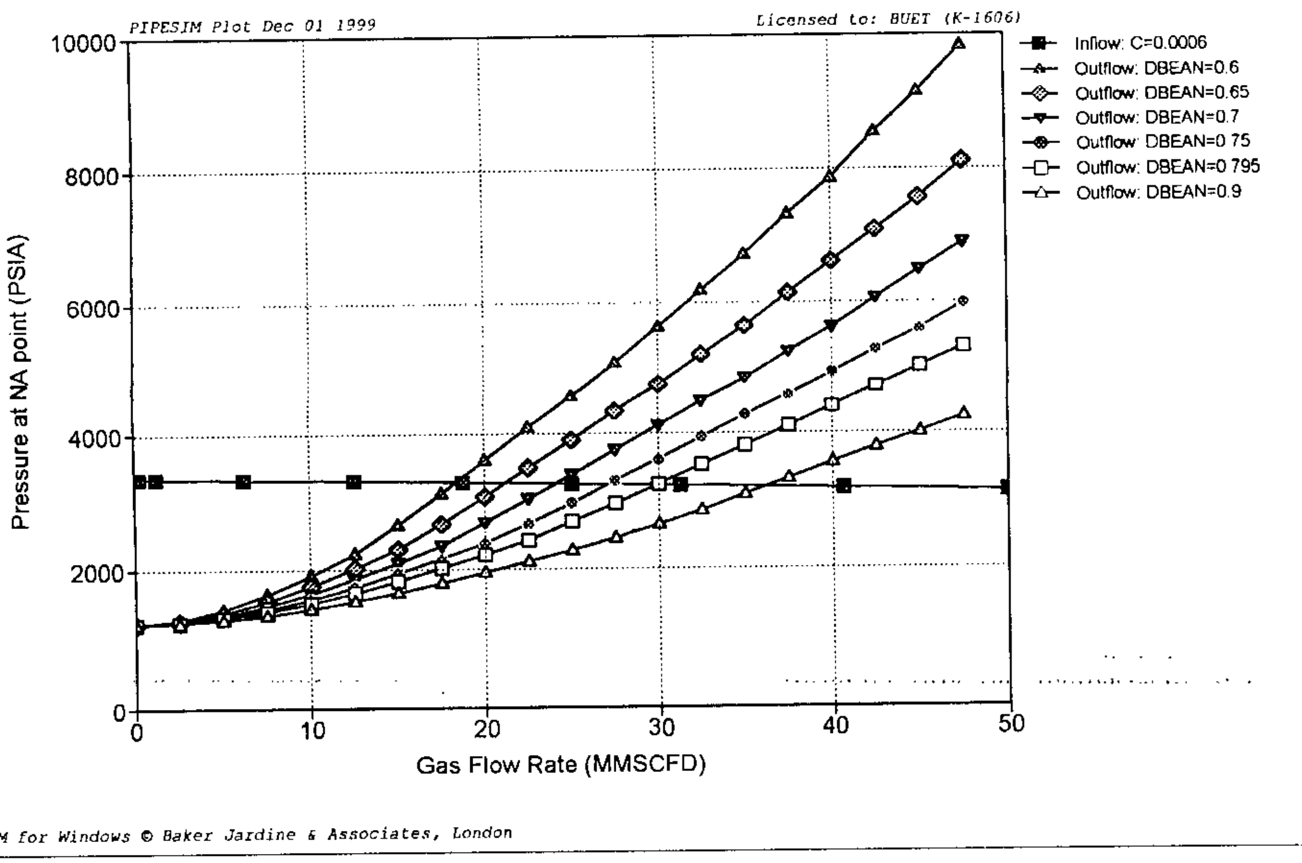


Figure 7.53: Effect of Tubing Inner Diameter on the Performance of Well TT-5

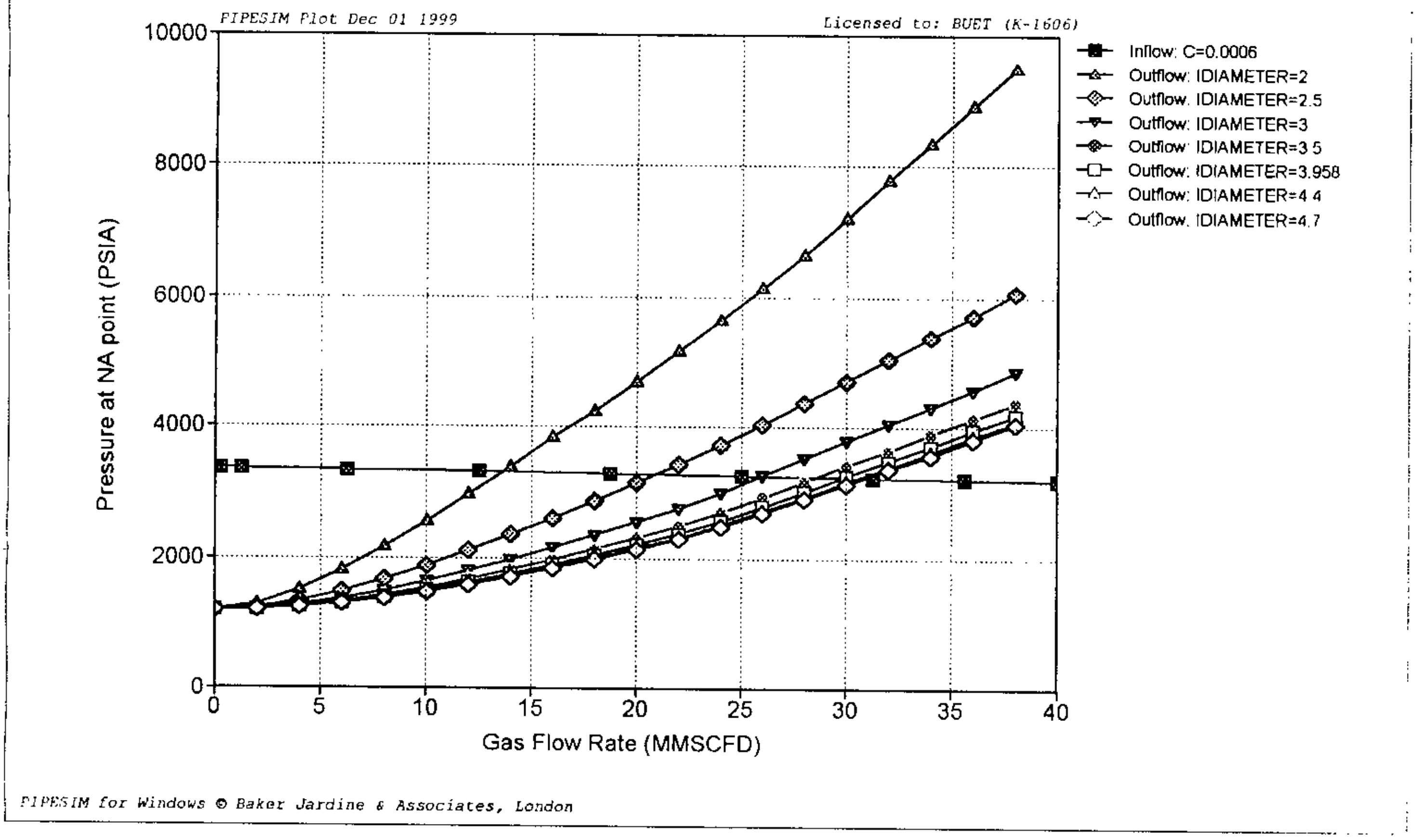
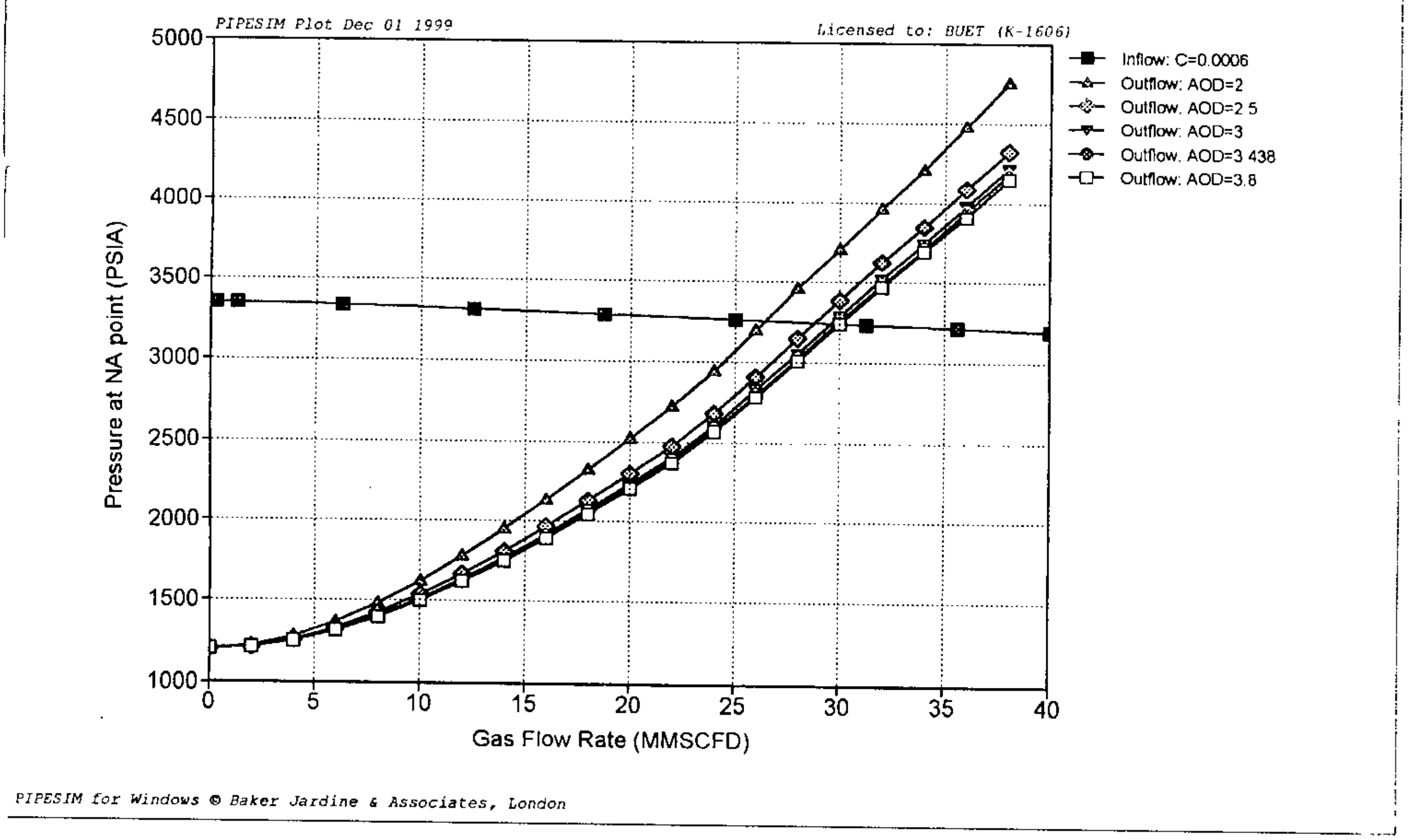


Figure 7.54: Effect of Flow Line Inner Diameter on the Performance of Well TT-5



choke is in critical range. As a result, decreasing the separator pressure below 1400 psia has no positive effect on the flow rate. So, it is possible maintain a maximum pressure of 1400 psia at the downstream side of the choke instead of current pressure of about 1010 psia.

Separator plays an important role as the average reservoir pressure gets lower. At a bottom hole pressure of 2000 psia, a separator pressure of 1600 psia produce only 6.8 MMSCFD but a separator pressure of 1010 produces 17.3 MMSCFD.

Figures 7.56 through 7.58 show the effect of tubing inner diameter and flow line inner diameter, and separator pressure, respectively for a larger choke size of 0.9 inch, other things remaining the same. As shown by Figure 7.56, tubing size of 4.6 inches is suitable for this higher production scenario. In this case, the smaller flow line diameter of 2.0 inches can sustain a flow of 30.1 MMSCFD and a 3.438-inches size can produce 36.0 MMSCFD. Increasing the size beyond existing 3.438-inches will not be productive. Figure 7.58 suggests that decreasing the separator pressure below 1300 psia will not increase the flow rate. At a lower bottom hole pressure of 2000 psia, the well will produce 9.0 MMSCFD against a separator pressure of 1600 psia and at 20.8 MMSCFD against 1010 psia. These values are 6.8 MMSCFD and 17.5 MMCF/D respectively for current choke size of 0.795 inch.

Figures 7.59 and 7.60 show the pressure and temperature profile along the vertical tubing for different flow rate, using existing choke size. It is evident from Figure 7.59 that for flow rate up to 35 MMSCFD, the friction loss per unit length of tubing is moderate and well head pressure above 2450 psia is available But beyond a flow of 35 MMSCFD frictional losses become significant. At a flow of 50 MMSCFD, wellhead pressure becomes only 2100 psia. Figure 7.60 shows that as flow rate increases, wellhead temperature increases due to friction effect. But beyond 35 MMSCFD, temperature begin to decrease due to gas expansion or Joule-Thompson effect. The well head temperature for the current flow rate is about 150^0 F, which coincides with the actual value.

Figure 7.55: Effect of Separator Pressure on the Performance of Well TT-5

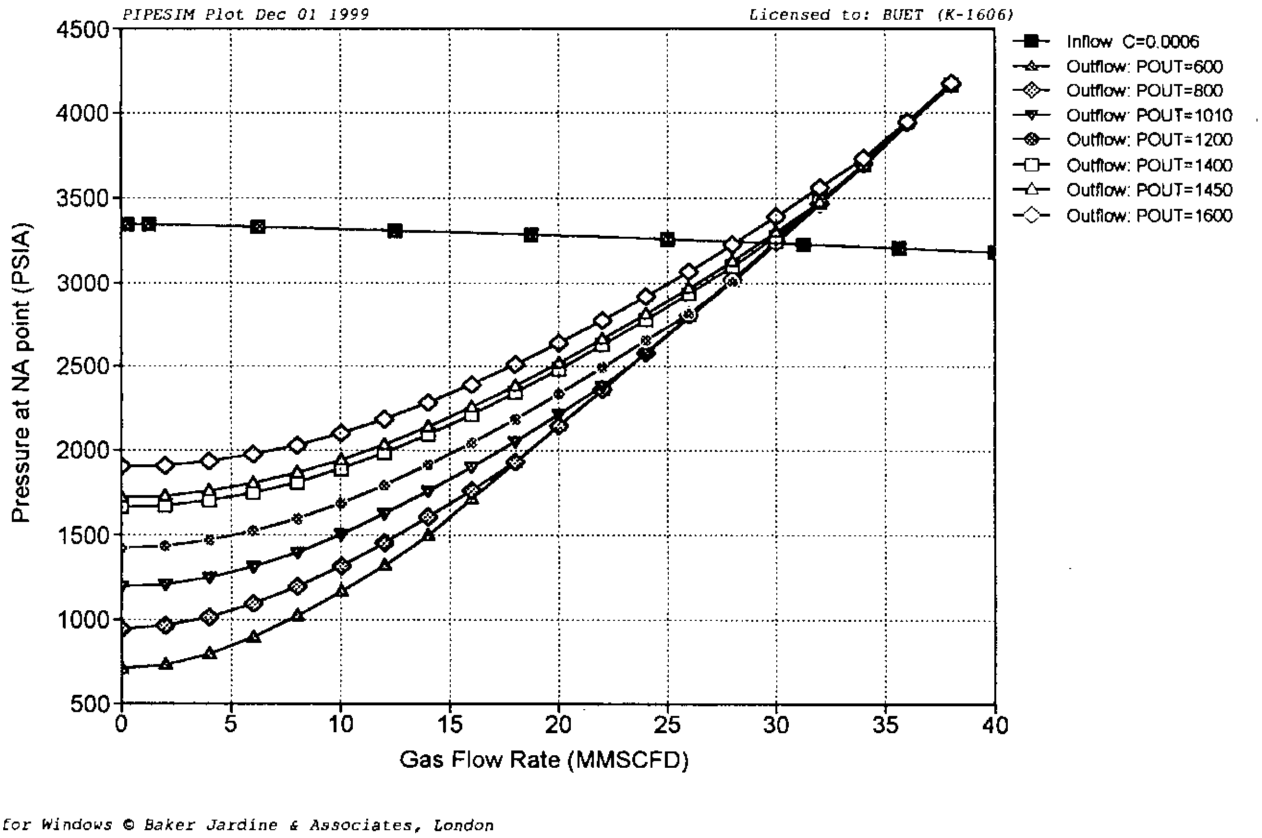


Figure 7.56: Effect of Tubing Inner Diameter on the Performance of Well TT-5

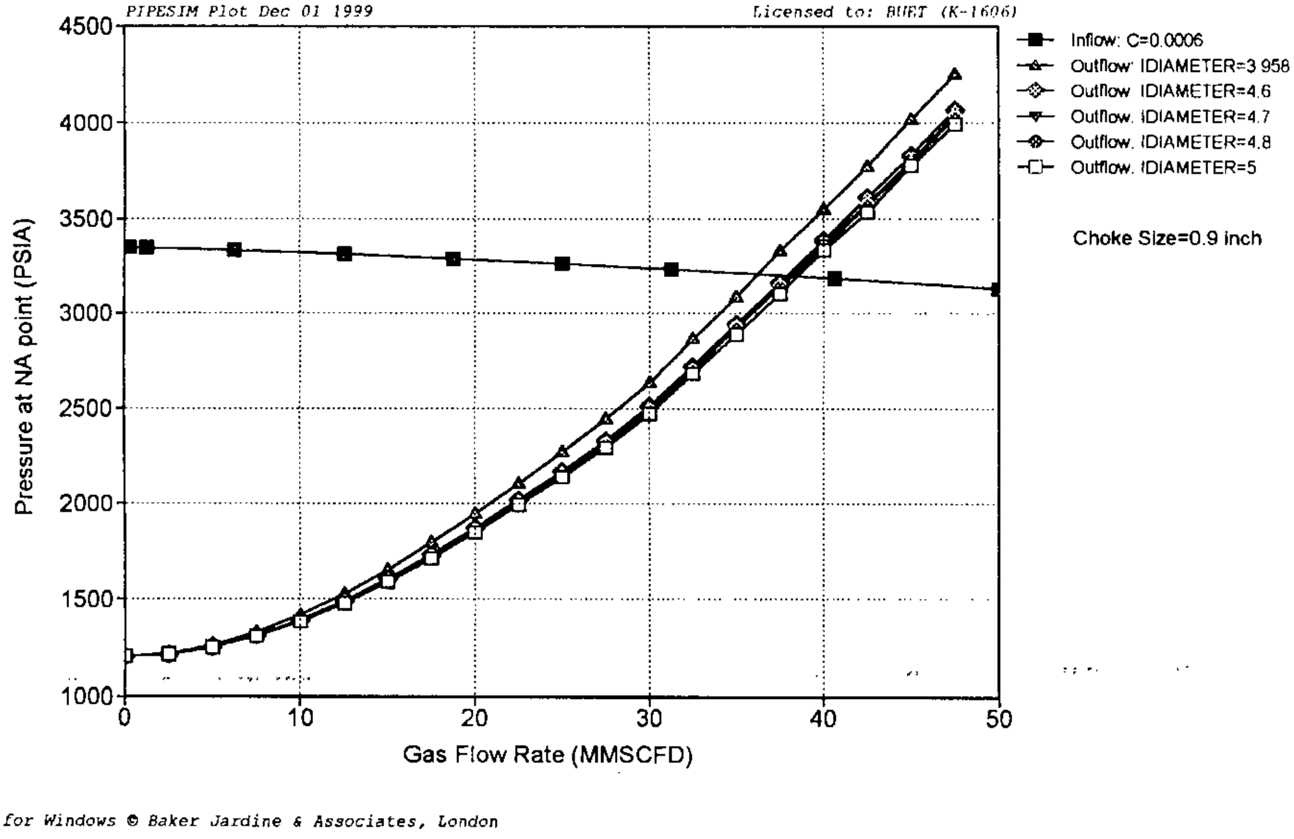


Figure 7.57: Effect of Flow Line Inner Diameter on the Performance of Well TT-5

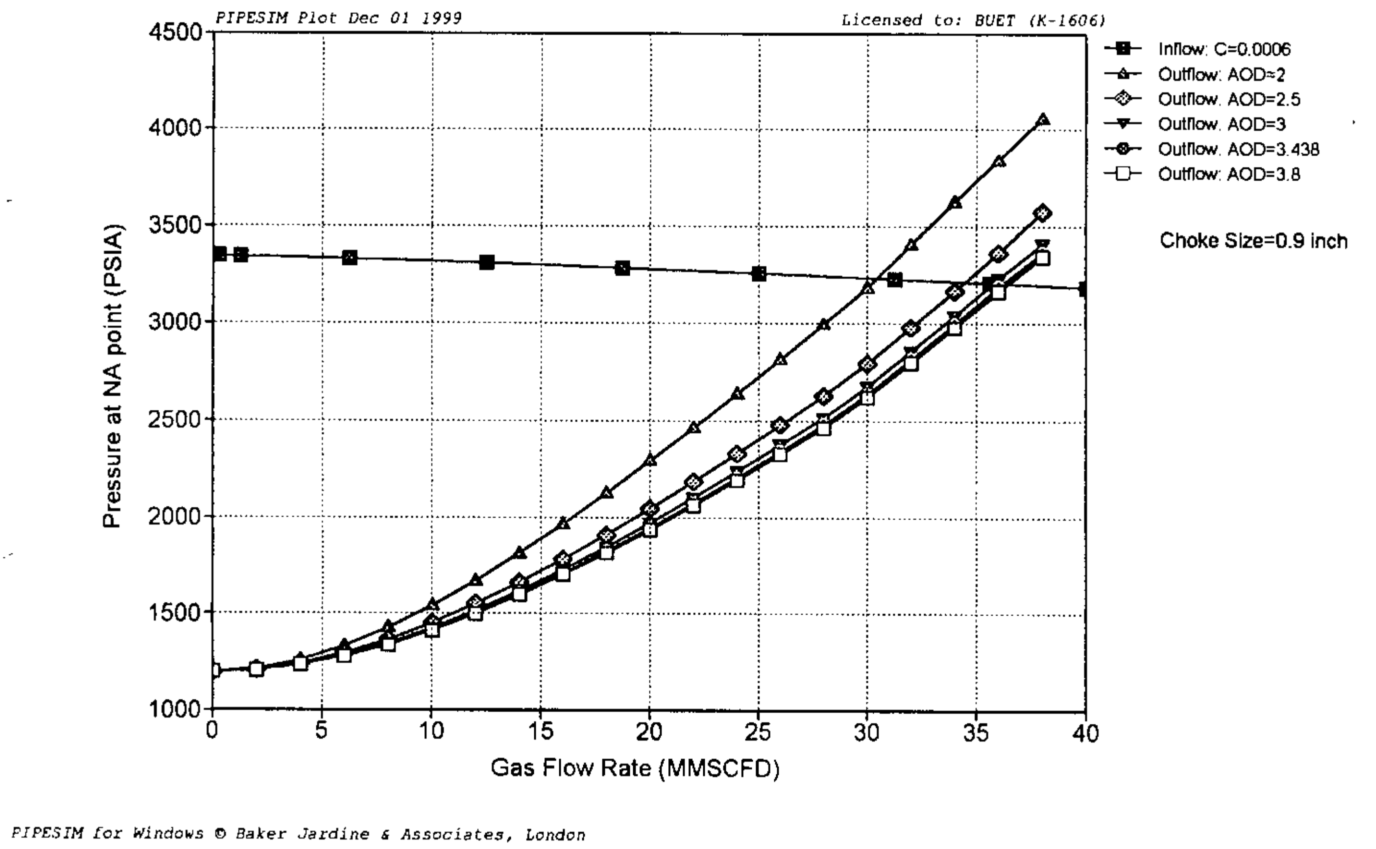


Figure 7.58: Effect of Separator Pressure on the Performance of Well TT-5

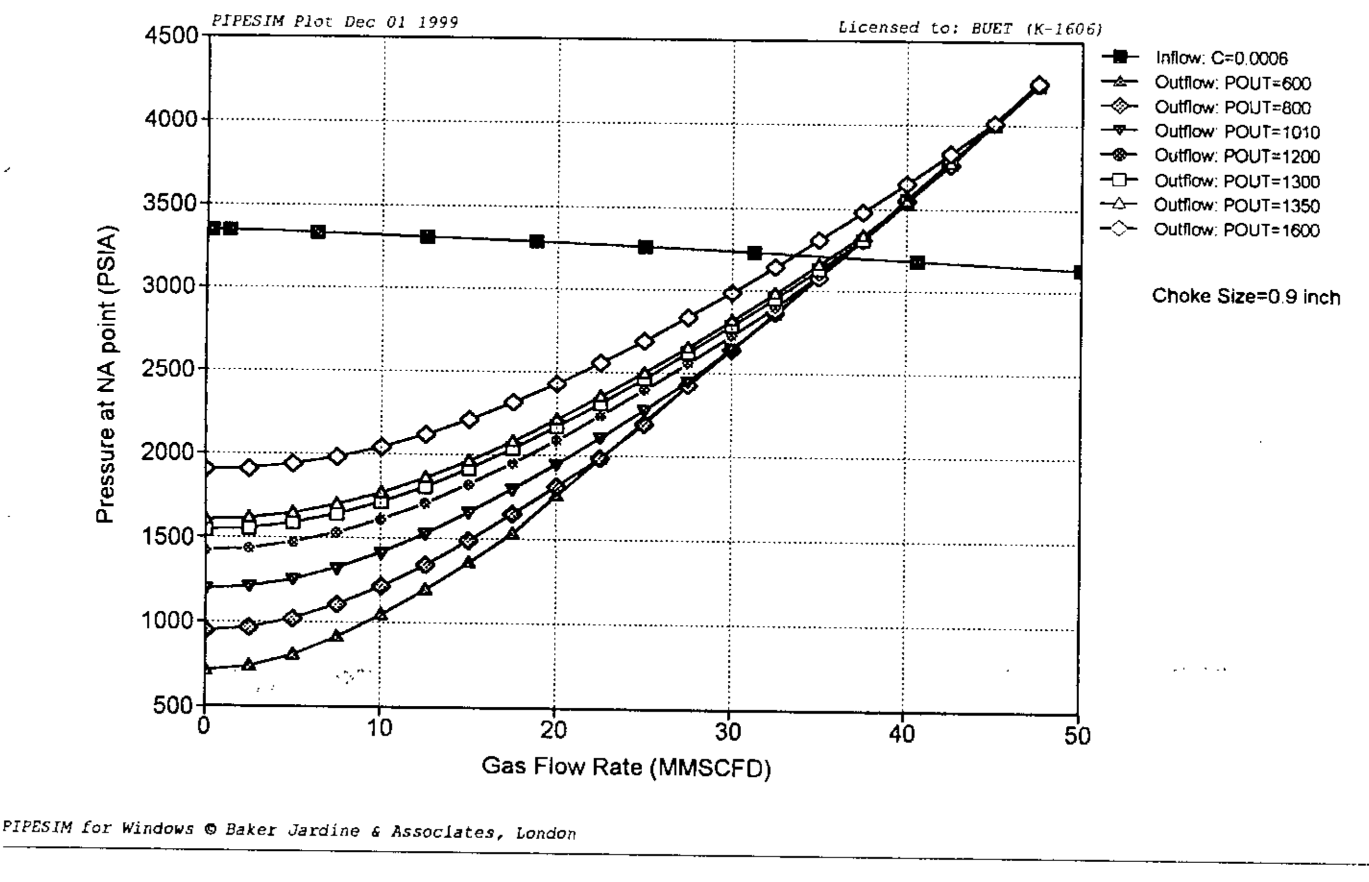


Figure 7.59: Effect of Flow Rate on Pressure Profile in Tubing of Well TT-5

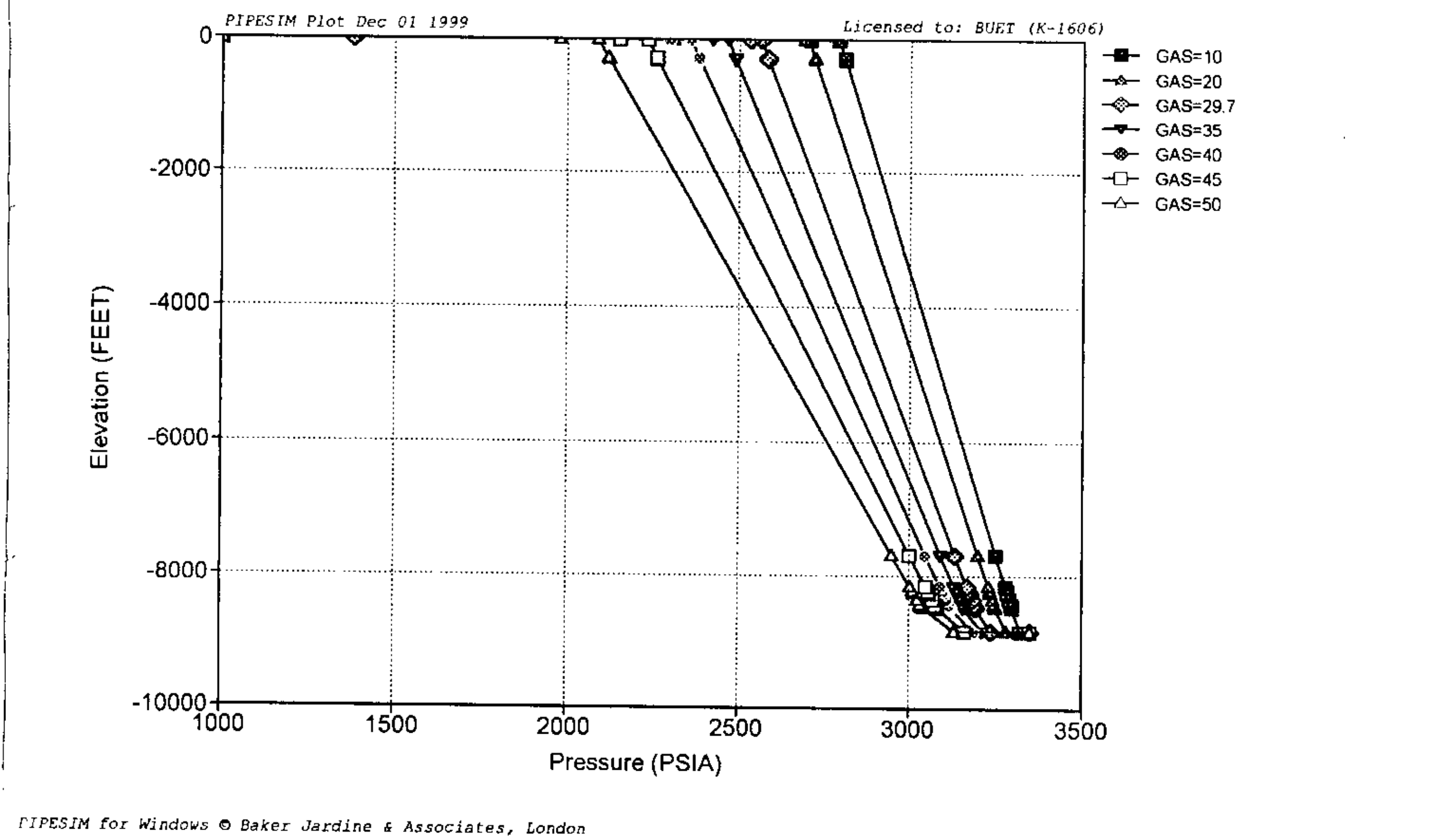
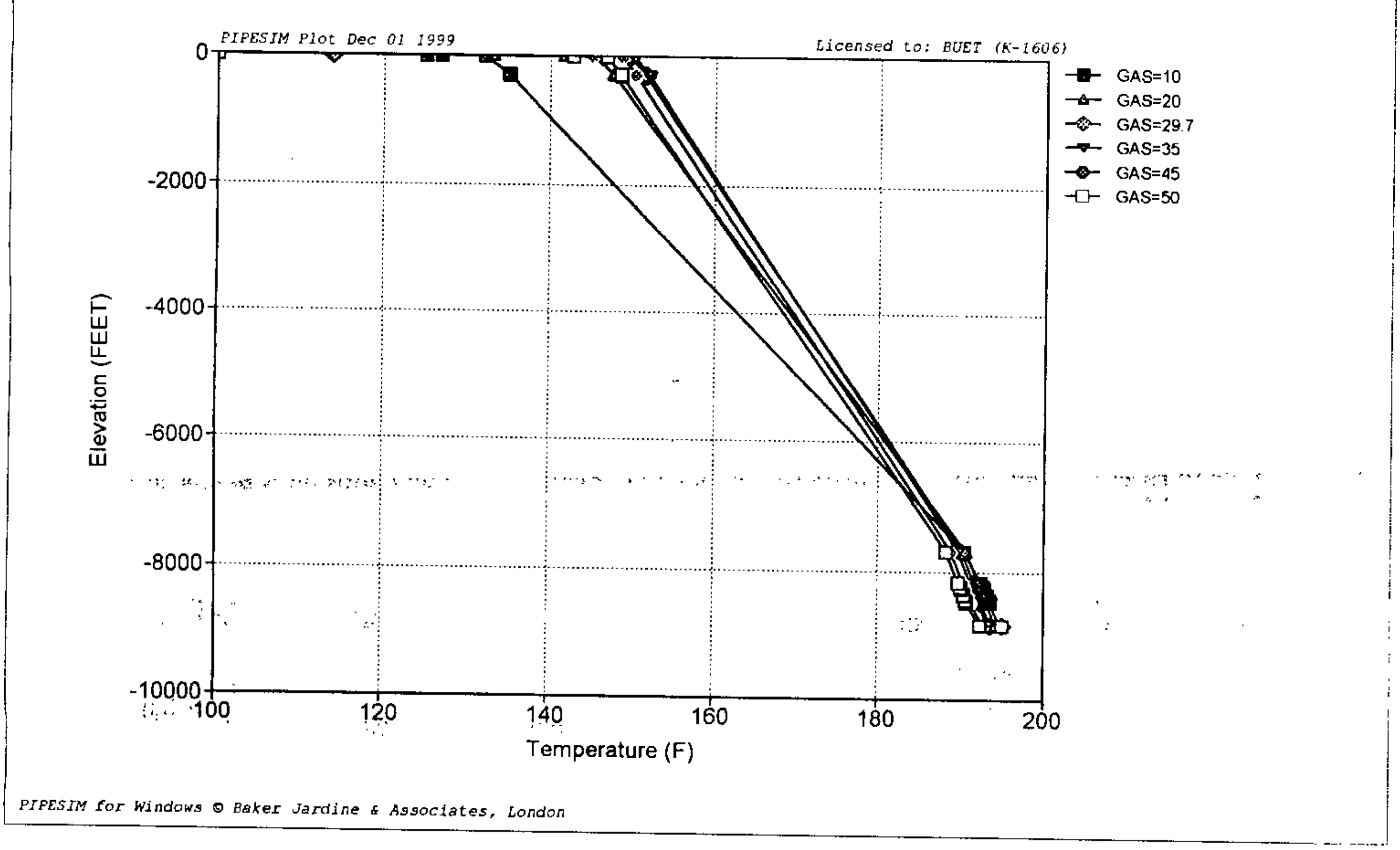


Figure 7.60: Effect of Flow Rate on Temperature Profile in Tubing of Well TT-5



7.5.6 Well TT-6

Comprehensive pressures survey test and flow after test was carried out for TT-6 in 1999. By analyzing the results, the following parameters were obtained:

Average reservoir pressure: 3310.68 psia

Average reservoir temperature: 195.08 ^{0}F

Back-pressure equation coefficient C = 0.0006235

Back-pressure equation exponent n = 0.817595

Figure 7.61 shows the variation of flow rate with change of reservoir pressure for a tubing diameter of 3.958 inches. For an initial reservoir pressure of 3781 psia, recorded in October 1981, the well was producing at 30.7 MMSCF/D at bottom hole pressure of 3700 psia. But currently the flow rate is reduced to 27MMSCFD as the current reservoir pressure is down to 3310 psia. For a low reservoir pressure of 2200 psia, the flow will be as low as 17.5 MMSCFD in future, assuming all other parameters remain the same.

Figure 7.62 shows the effect of well stimulation on production rate. Well stimulation increases the value of C. Well stimulation to increase the C value from 0.0003 to 0.0006235, the current value, will increase the flow rate by 1.5 MMSCFD but beyond that any improvement will not increase the flow rate further.

As shown in Figure 7.63, when n is 0.5, the flow is highly turbulent, a very large pressure drop occurs along the reservoir and a very low flow rate of 2 MMSCFD is obtainable. With an increase in n, flow rate increases drastically. The flow rate increases from 9 MMSCFD to 23.5 MMSCFD as n increases from 0.6 to 0.7. Beyond the current value of 0.817595, an increase in n will not be productive.

Figure 7.64 shows the effect of bean diameter on the flow rate. Flow rate increases from 18 MMSCFD to 36.8 MMSCFD as bean size is increased from 0.60 inch to 0.90 inch. The well is now producing 27 MMSCFD at a bean size of 0.745 inch.

Figure 7.65 shows the variation of flow rate with tubing size. For a tubing size of 2.5 inches a flow rate of only 20 MMSCFD is possible. But for an increase of only

Figure 7.61: Effect of Average Reservoir Pressure on the Performance of Well TT-6

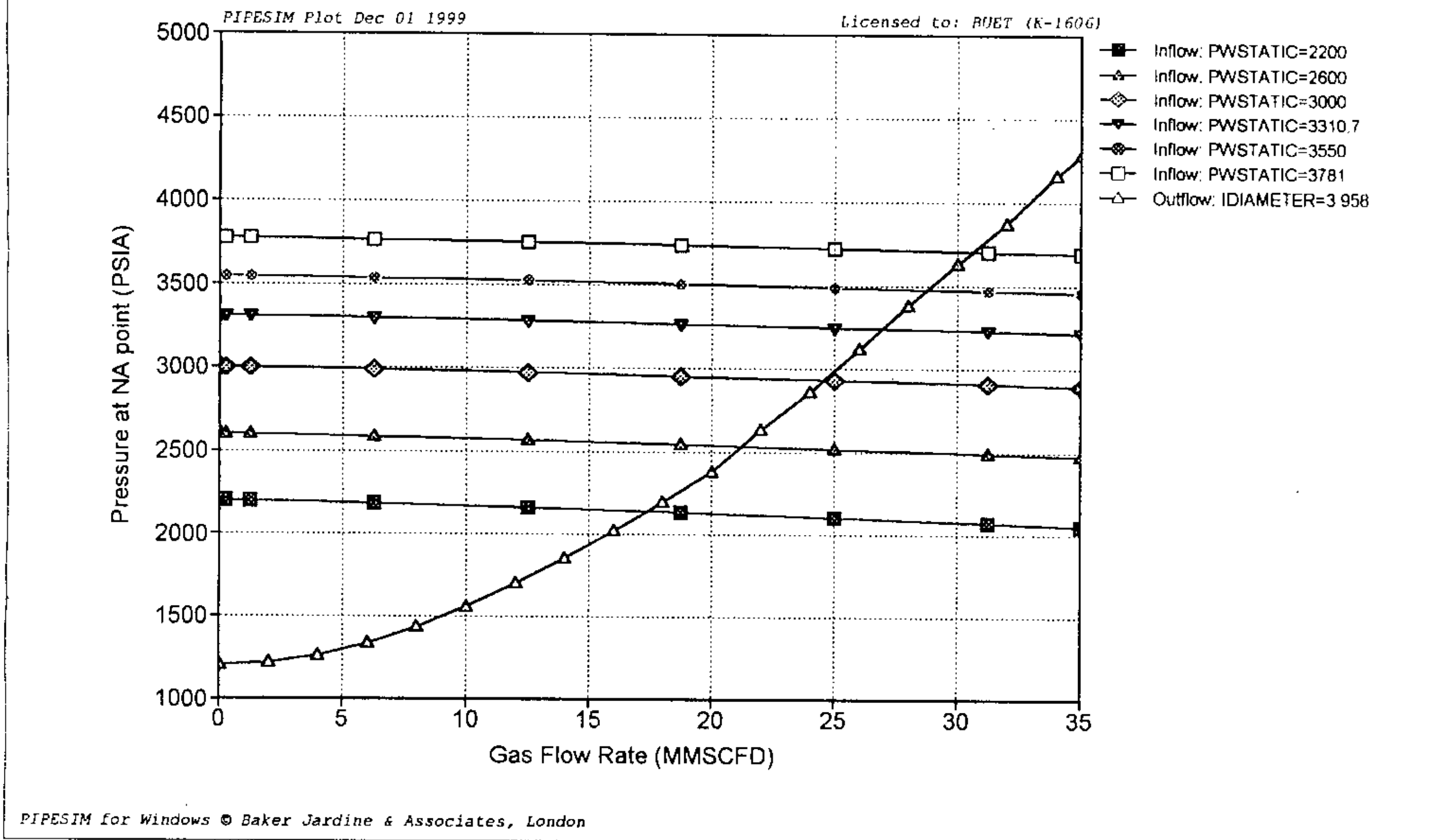


Figure 7.62: Effect of Back Pressure Coefficient on the Performance of Well TT-6

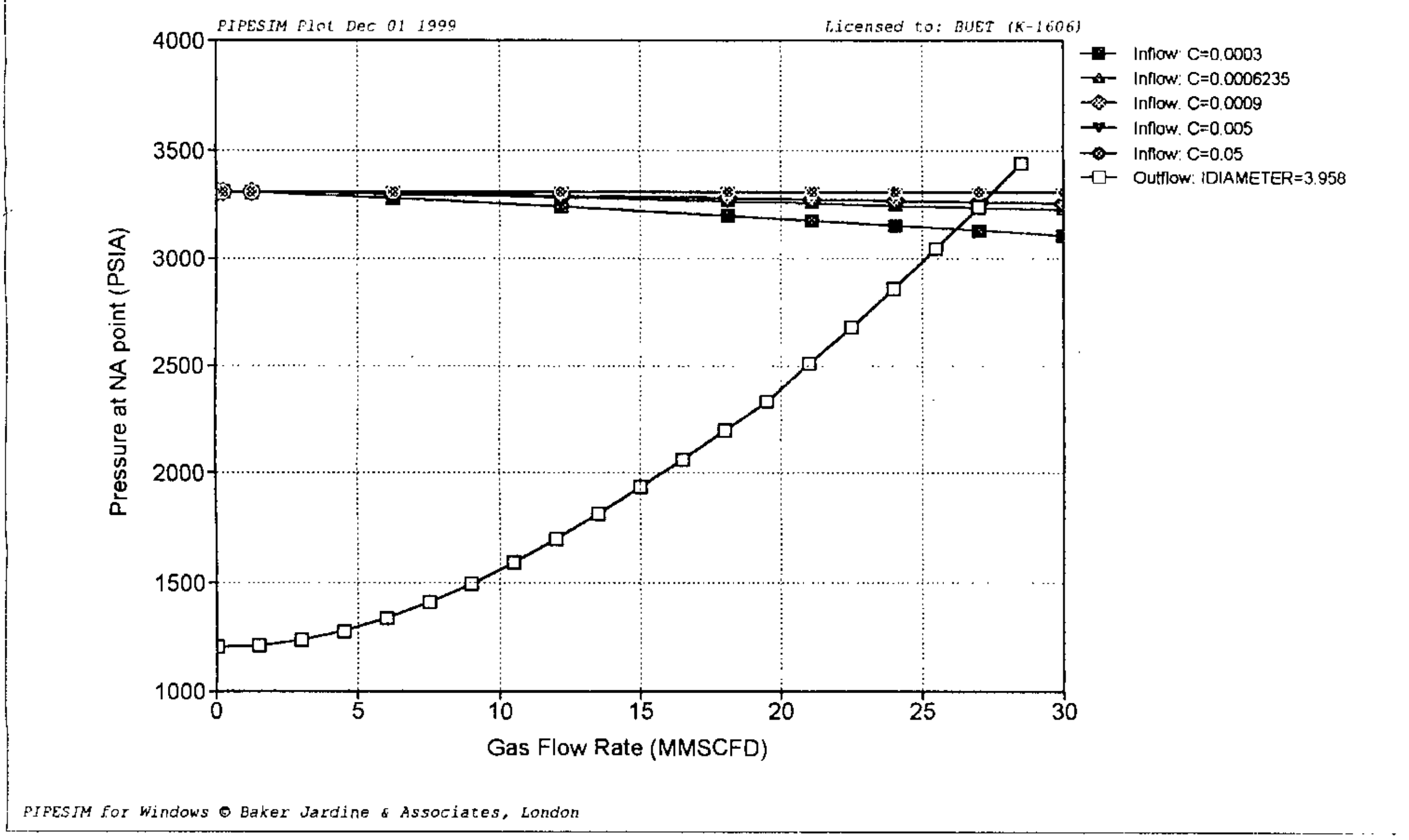


Figure 7.63: Effect of Back Pressure Exponent on the Performance of Well TT-6

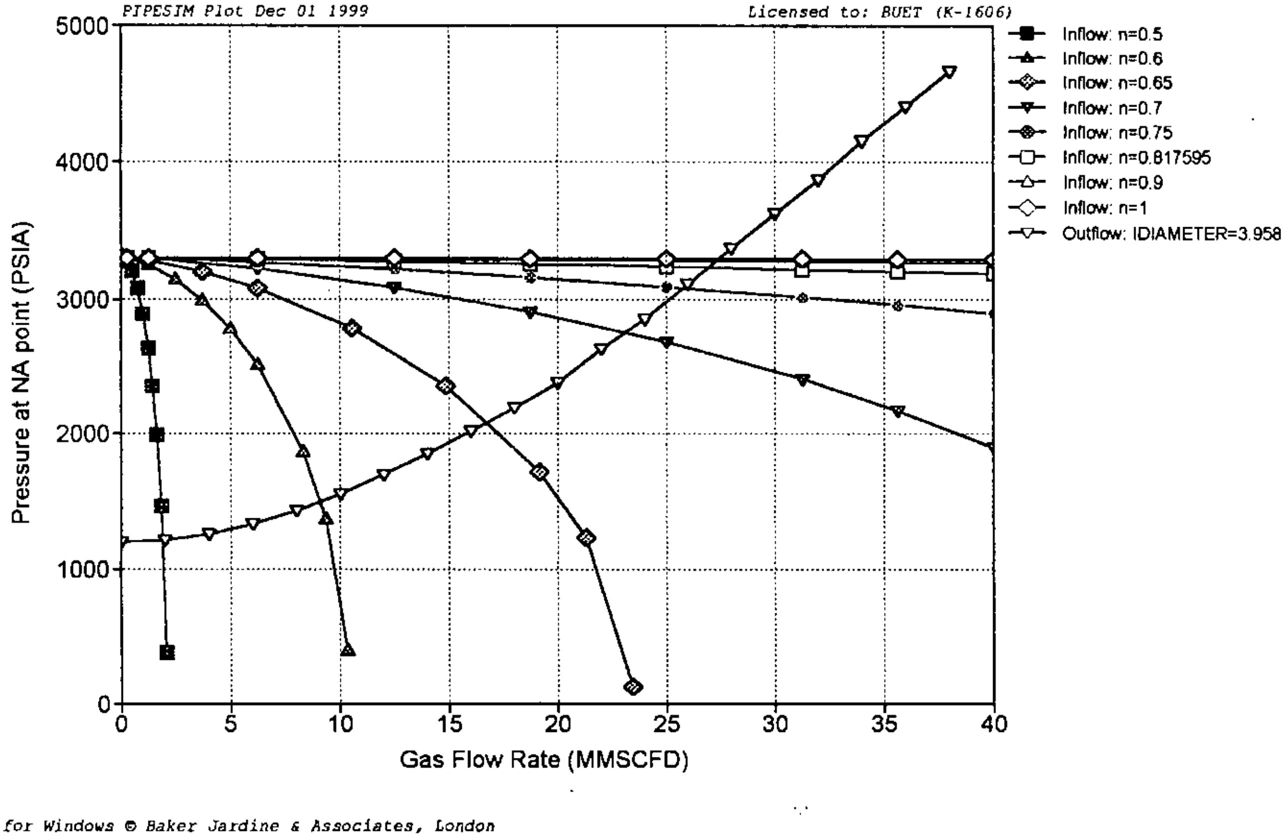
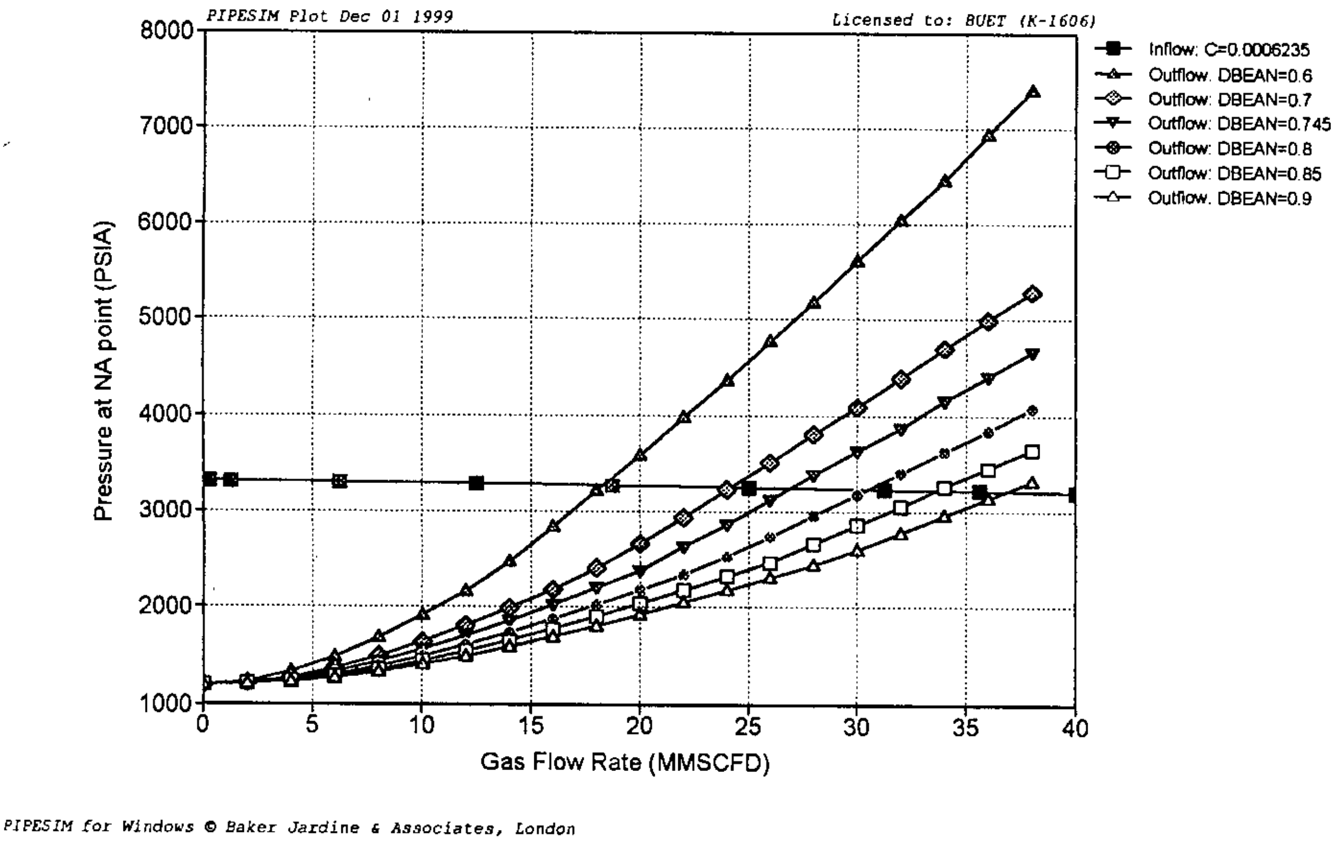


Figure 7.64: Effect of Choke Size on the Performance of Well TT-6



0.5 inch, the flow rate increases to almost 24 MMSCFD. For the next increment of 0.5 inch, flow rate further increases by further 2 MMSCFD. The current tubing size of 3.958 inches sustains a production of 27 MMSCFD but any further increase will not effect the flow rate. A tubing of size 4.5-inches will increase the production by only 0.1 MMSCF/D.

Figure 7.66 shows the effect of flowline diameter on the flow rate. A diameter of 2 inches produces at a rate of 25.5 MMSCFD and a 2.5-inches diameter produces 27 MMSCFD, which is the existing flow rate. So existing flow line diameter of 3.438 inches is more than adequate for the current condition.

One way of controlling the flow rate is to control the separator pressure. Figure 7.67 shows the effect of separator pressure on the flow rate. At high separator pressure of 1600 psia, flow rate is 25.5 MMSCFD and at 1400 psia, the flow rate increases to 27 MMSCFD. For a separator pressure of 1400 psia and below, the choke is in critical range. As separator pressure is decreased, gas velocity increases, also increasing the gas friction. As a result, decreasing the separator pressure below 1400 psia has no positive effect on the flow rate. So, it is possible maintain a maximum pressure of 1400 psia at the downstream side of the choke instead of current pressure of about 1010 psia without sacrificing any flow.

Figures 7.68 through 7.70 show the effect of tubing inner diameter, flowline inner diameter and separator pressure, respectively for a larger choke size of 0.9 inch. The system will be requiring a tubing diameter of 4.7 inches to sustain a production rate instead of current size of 3.958 inches. In this case, the present flow line diameter of 2.8 is just enough to sustain a flow of 36.5 MMSCFD. Figure 7.70 suggests that at a bottom hole pressure of 2000 psia, the well produces 8.5 MMSCFD against a separator pressure of 1600 psia, and 21.2 MMSCFD against 1010 psia. These values are 6 MMSCFD and 16 MMCF/D, respectively for current choke size of 0.745 inch. A maximum separator pressure of 1300 psia can be maintained without sacrificing the flow rate.

Figure 7.71 and 7.72 show the pressure and temperature profiles along the vertical tubing for different flow rate. It is evident from Figure 7.71 that for flow rates up to 35

Figure 7.65: Effect of Tubing Inner Diameter on the Performance of Well TT-6

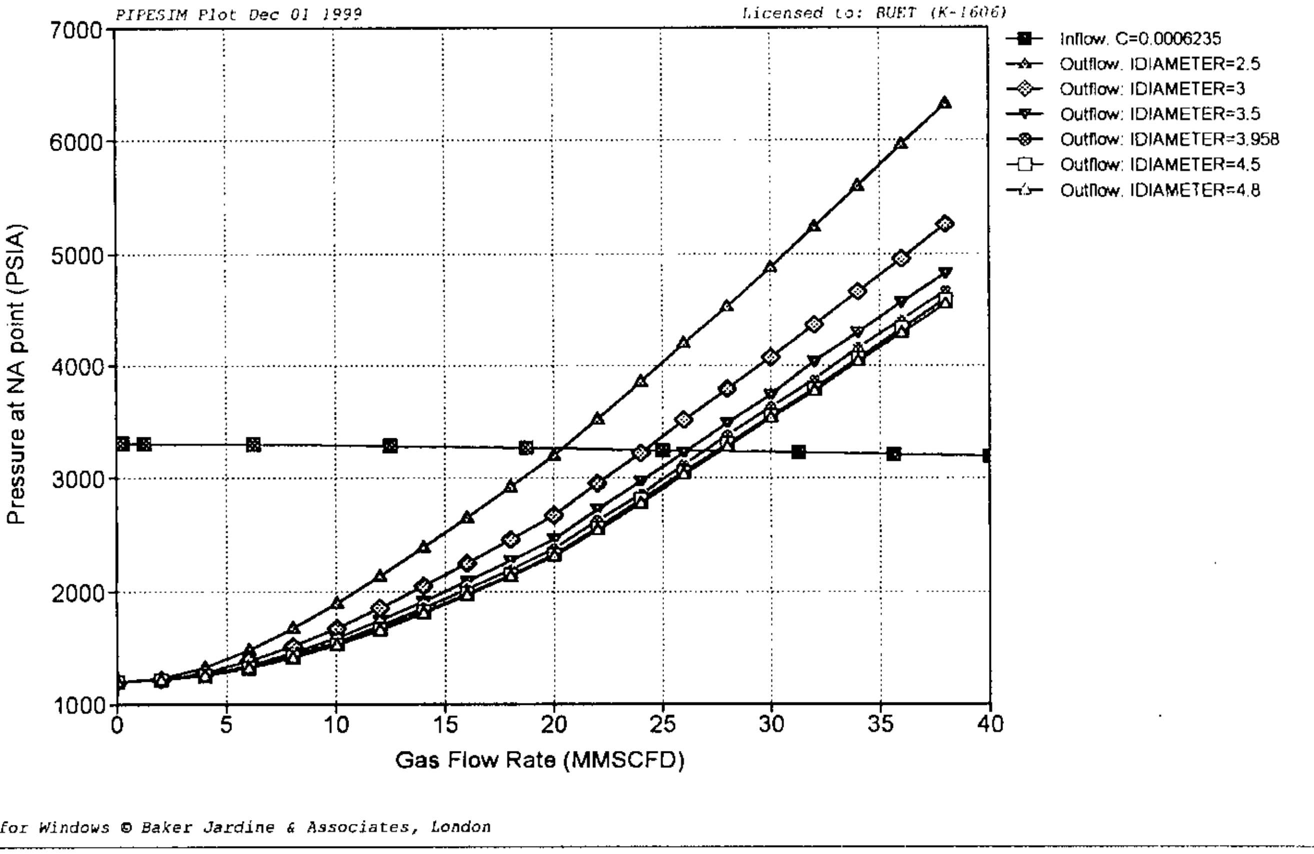


Figure 7.66: Effect of Flow Line Inner Diameter on the Performance of Well TT-6

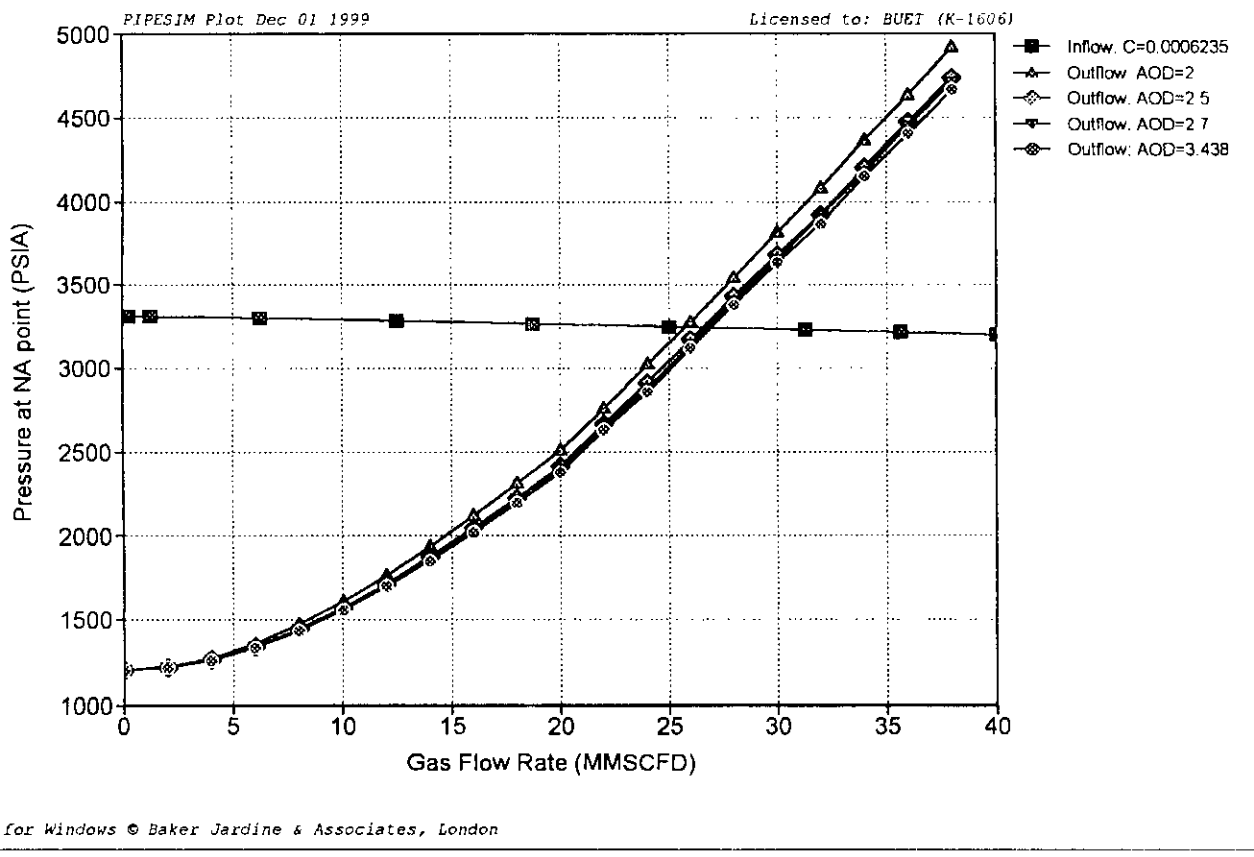


Figure 7.67: Effect of Separator Pressure on the Performance of Well TT-6

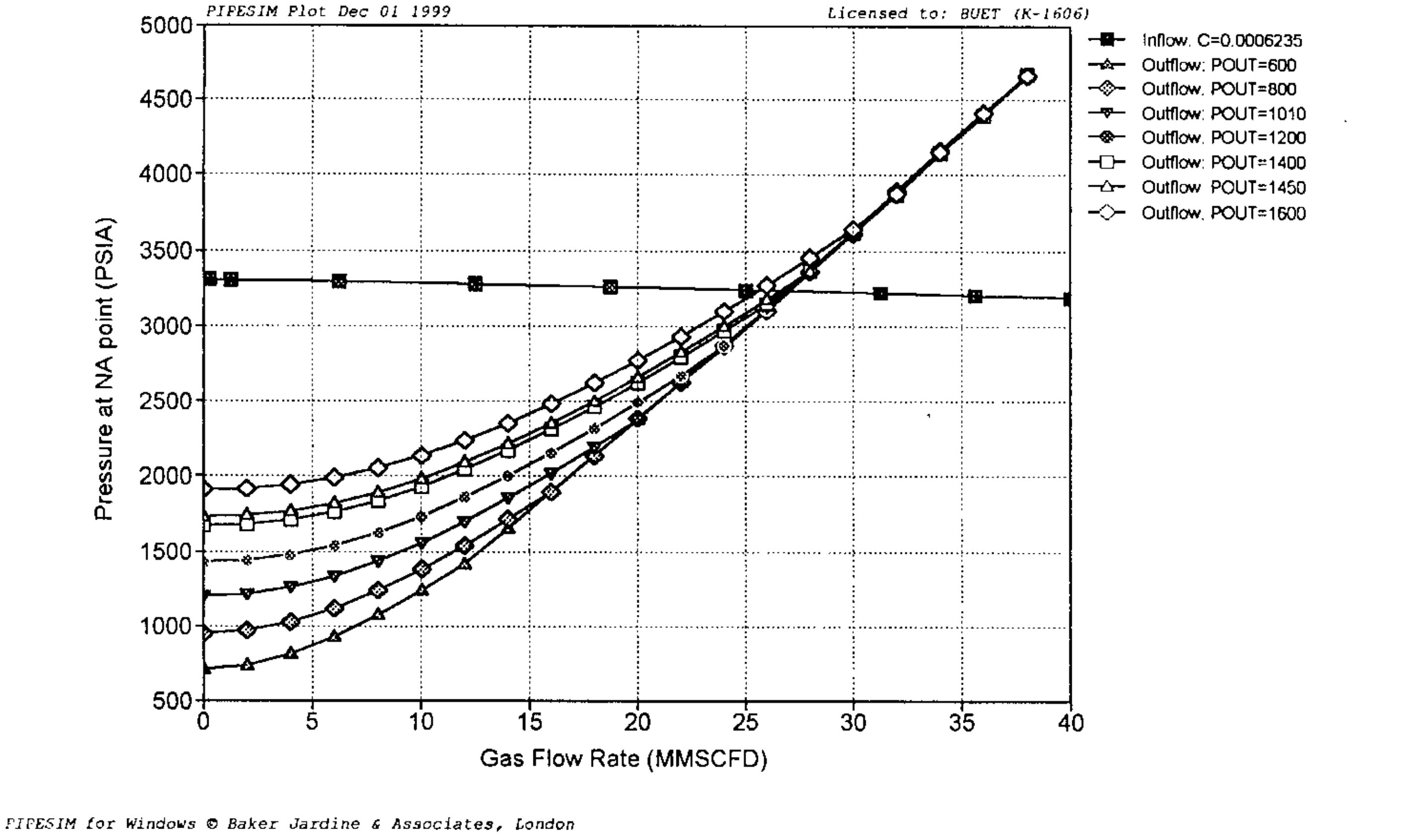


Figure 7.68: Effect of Tubing Inner Diameter on the Performance of Well TT-6

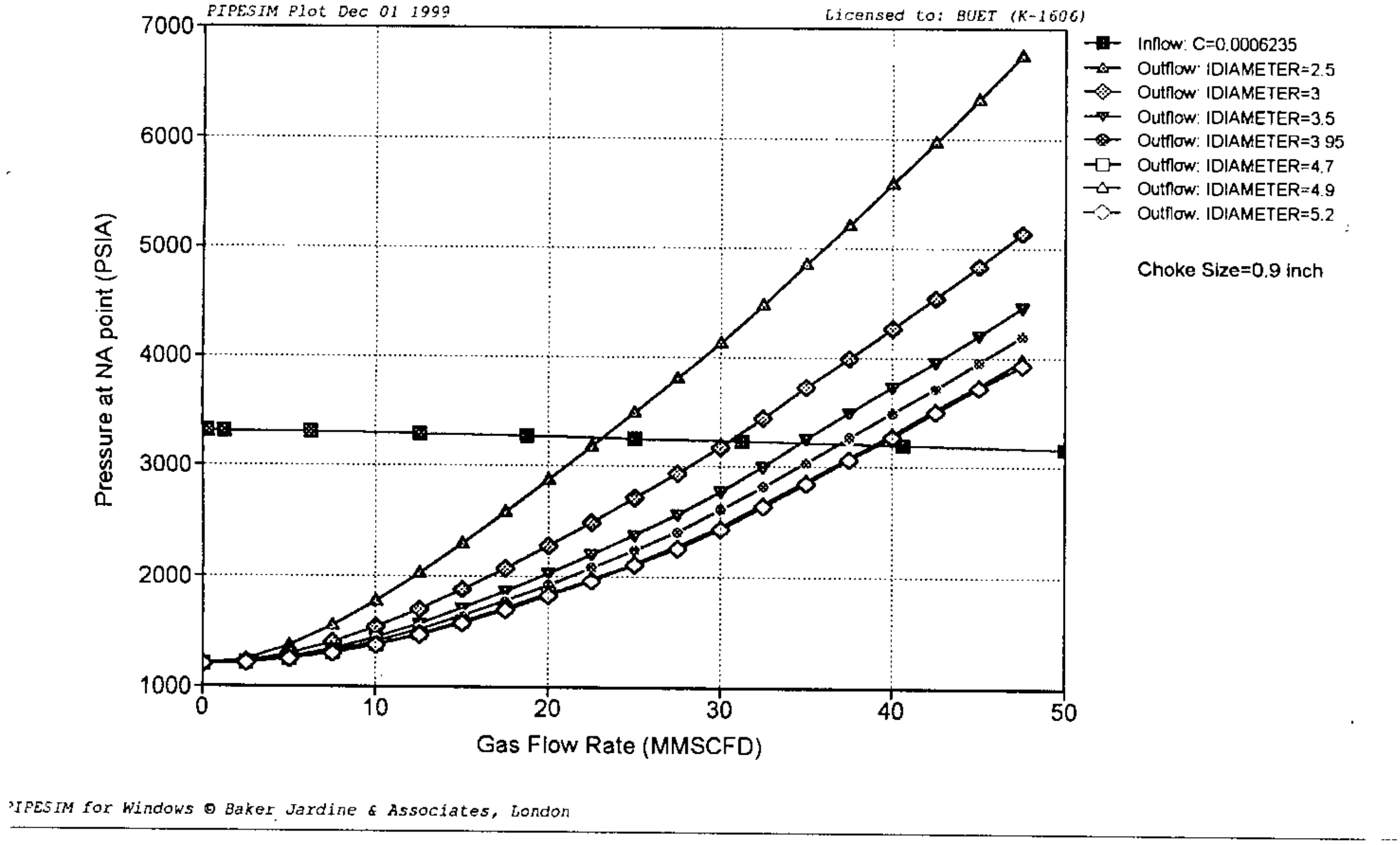


Figure 7.69: Effect of Flow Line Inner Diameter on the Performance of Well TT-6

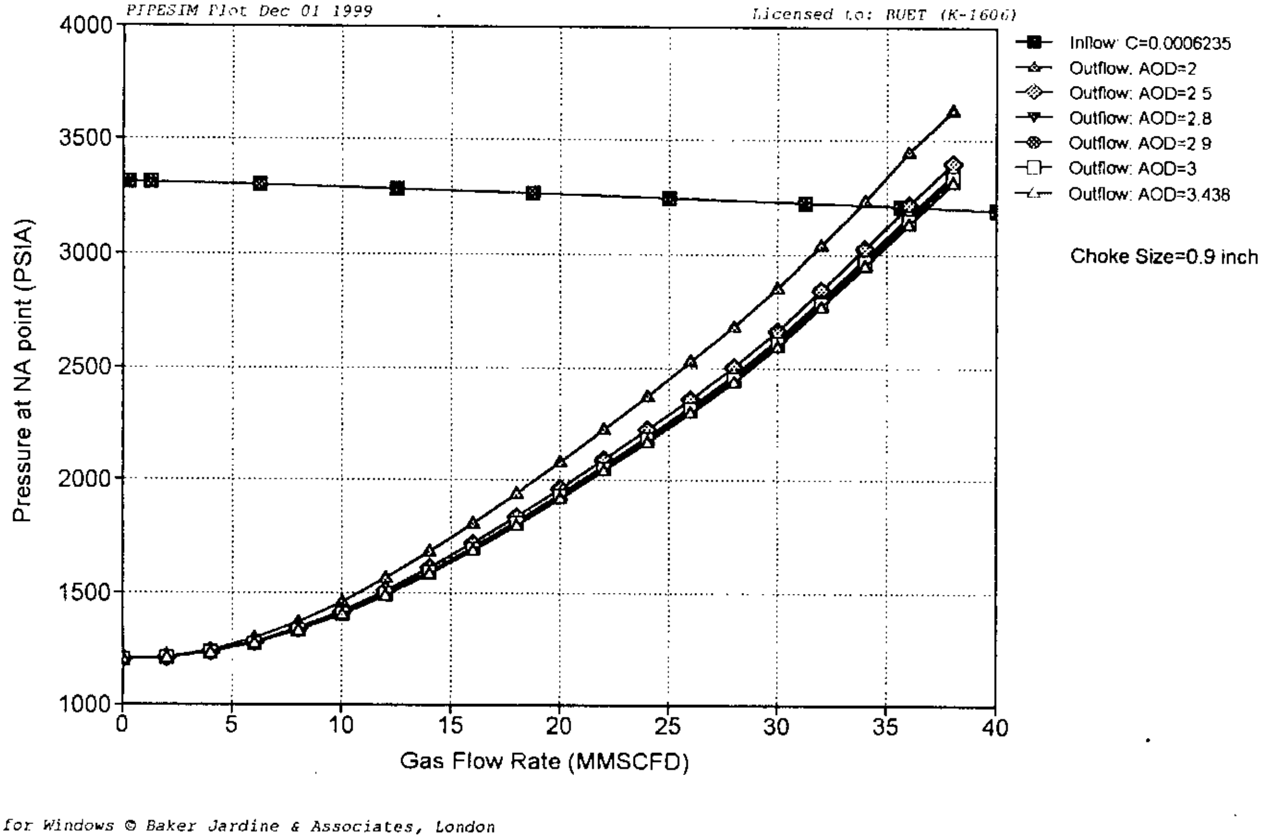


Figure 7.70: Effect of Separator Pressure on the Performance of Well TT-6

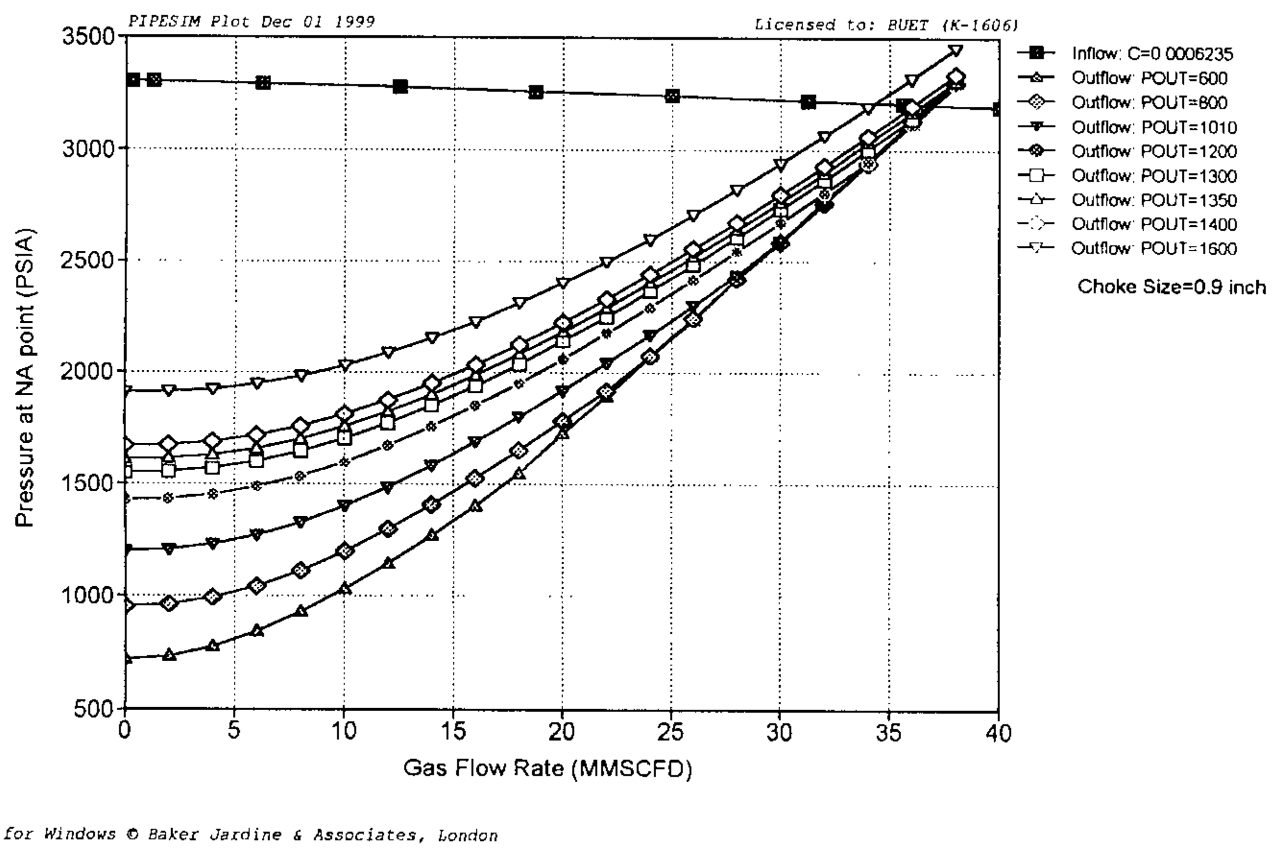


Figure 7.71: Effect of Flow Rate on Pressure Profile in Tubing of Well TT-6

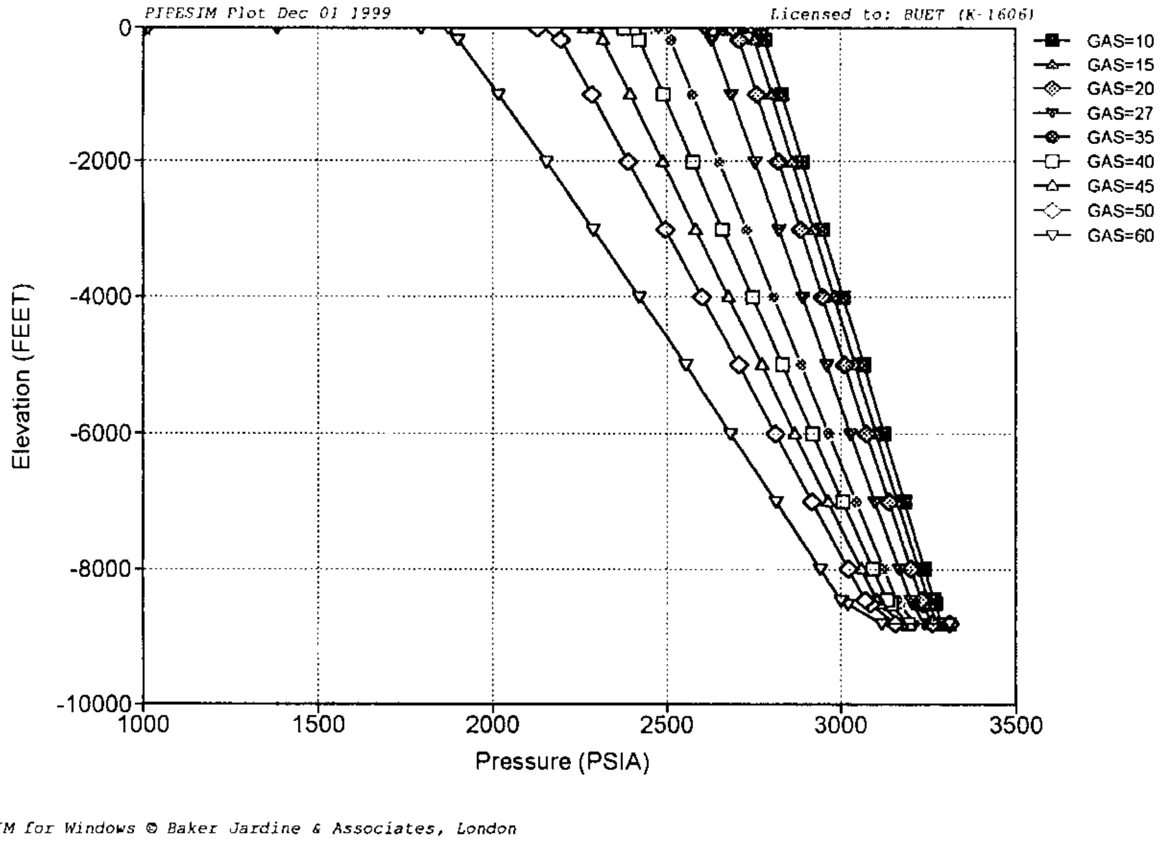
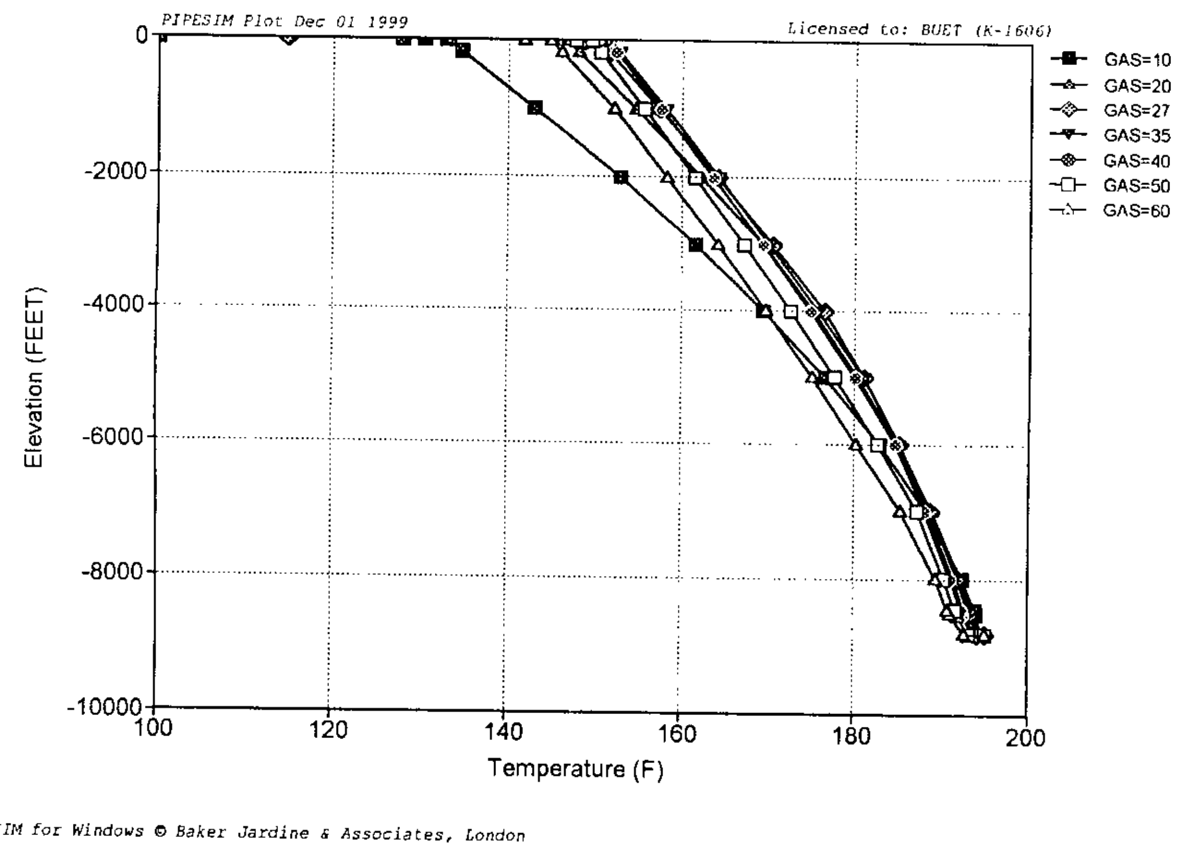


Figure 7.72: Effect of Flow Rate on Temperature Profile in Tubing of Well TT-6



MMSCFD, the friction loss per unit length of tubing is moderate and well head pressure above 2500 psia is available. But beyond the flow rate of 35 MMSCFD, frictional losses become significant. At a flow of 60 MMSCFD, wellhead pressure becomes only 1900 psia. Figure 7.72 shows that the well head temperature for the existing flow rate is about 150^0 F, which coincides with the actual value.

7.5.7 Well TT-7

Average reservoir pressure: 3350 psia

Average reservoir temperature: 195.0 ^{0}F

Back-pressure equation coefficient C = 0.00028

Back-pressure equation exponent n = 0.82

For an initial reservoir pressure of 3722 psia, recorded in March 1985, the flow rate was about 29.2 MMSCFD at a wellbore pressure of 3540 psia. The well is now producing at 26.3 MMSCFD at the current reservoir pressure of 3350 psia. For a low reservoir pressure of 2200 psia, the flow will be as low as 16.2 MMSCFD in future, assuming all other parameters remain the same.

For C value of 0.0001, production rate is only 23.0 MMSCFD, which increases to 27.5 MMSCFD when C increases to 0.0006. Increasing the value of C beyond 0.0006 will not increase the production rate.

When n is 0.5; a very low flow rate of 1.0 MMSCFD is obtainable. The flow rate increases to 4.0 MMSCFD, 17.1 MMSCFD and 26.3 MMSCFD as n is increased to 0.6, 0.70 and 0.82 respectively. Beyond the value of n = 0.82, an increase in n will hardly increase the production rate.

Flow rate increases from 15.5 MMSCFD to 35.2 MMSCFD as bean size is increased from 0.55 inch to 0.90 inch. The well is now producing at a rate of 26.3 MMSCFD at a bean size of 0.745 inch.

For a tubing diameter of 2.0 inches, a flow rate of only 13.0 MMSCFD is possible. For a tubing size of 3.958 inches, the flow rate increases to 26.3 MMSCFD. An increase in the current tubing size of 3.958 inches will not increase the flow rate any further.

A flow line inner diameter of 2.0 inches produces at a rate of 23.8 MMSCFD while 3.0-inches diameter flowline produces 26.3 MMSCFD, which is the existing flow rate. So existing flow line diameter of 3.438 inches is more than adequate for the current condition.

At high separator pressure of 1800 psia, flow rate is 23.0 MMSCFD and at 1600 psia and 1400 psia; the flow rate increases to 25.0 MMSCFD and 26.3 MMSCFD, respectively, the latter being the current flow rate. For a separator pressure of 1400 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1400 psia has no positive effect on the flow rate. So, it is possible maintain a maximum pressure of 1400 psia at the downstream side of the choke instead of current pressure of about 1010 psia without having any effect on the flow rate.

Separator plays an important role as the average reservoir pressure gets lower. At a bottom hole pressure of 2000 psia, a separator pressure of 1800 does not produce any gas. A separator pressure of 1600 psia produces only 6.0 MMSCFD whereas a separator pressure of 1010 produces 15.8 MMSCFD.

Analysis of the effect of tubing size on the flow rate shows that a 2.0 inches and a 3.0 inches tubing will produce 13.6 MMSCFD and 28.5 MMSCFD, respectively and a tubing size of 4.2 inches will produce 36 MMSCFD, when the choke size is 0.9 inch. In this case, the flow line diameter of 3.0 inches can sustain a flow of 34.8 MMSCFD while 3.438 inches produces 36 MMSCFD. Increasing the size beyond 3.438 inches will not be productive.

At this larger choke size, a maximum separator pressure of 1250 psia can be maintained without reducing the flow. At a lower bottom hole pressure of 2000 psia, the well will produce 8.7 MMSCFD against a separator pressure of 1600 psia and 21.0 MMSCFD against 1010 psia. These values are 6.0 MMSCFD and 15.8 MMSCFD respectively for current choke size of 0.745 inch.

Analysis of pressure and temperature profiles along the tubing show that for flow rates up to 32 MMSCFD, using existing choke size, the friction loss per unit length of tubing is moderate and well head pressure above 2400 psia is available. But beyond 32 MMSCFD, frictional losses become significant. At a flow of 60 MMSCFD, wellhead pressure becomes only 1350 psia. Wellhead temperature for the existing flow rate is about 150^0 F, which coincides with the actual value.

7.5.8 Well TT-8

Average reservoir pressure: 3260 psia
Average reservoir temperature: 205.0 ^{0}F
Back-pressure equation coefficient C = 0.00025
Back-pressure equation exponent n = 0.82

For an initial reservoir pressure of 4311 psia, recorded in September 1985, the flow rate was about 35.0 MMSCFD at a wellbore pressure of 4081 psia. The well is now producing 26.2 MMSCFD at the current reservoir pressure of 3260 psia. Analysis shows that for a low reservoir pressure of 2200 psia, the flow will be as low as 16.3 MMSCFD in future, assuming all other parameters remain the same.

Effect of the coefficient C on flow rate shows that for a C value of 0.0001, production rate is only 23.1 MMSCFD which increases to 27.8 MMSCFD when C increases to 0.0008. Increasing the value of C beyond 0.0008 will not increase the production rate.

Effect of the exponent n on flow rate shows that when n is 0.5; a very low flow rate of 1.0 MMSCFD is obtainable. The flow rate increases to 3.8 MMSCFD, 15.1 MMSCFD and 27.5 MMSCFD as n is increased to 0.6, 0.70 and 0.90 respectively. Beyond the value of n = 0.90, an increase in n will hardly increase the production rate.

Analysis shows that the flow rate increases from 15.0 MMSCFD to 33.5 MMSCFD as bean size is increased from 0.55 inch to 0.90 inch. The well produces 26.2 MMSCFD at a choke size of 0.77 inch.

Effect of the tubing size on the flow rate shows that for a tubing inner diameter of 2.0 inches a flow rate of only 12.4 MMSCFD is possible. For a tubing size of 2.5 and 3.0 inches, the flow rate increases to 18.6 and 22.9 MMSCFD, respectively. An increase in the current tubing size of 3.958 inches will not increase the flow rate further.

Regarding the flowline size, analysis shows that a diameter of 2-inches produces at a rate of 25.0 MMSCFD while a 2.5 inches and a 2.8 inches diameter produces 25.7 MMSCFD and 26.3 MMSCFD, respectively, the latter being the existing flow rate. So existing flow line diameter of 3.438 inches is more than adequate for the current condition.

At high separator pressure of 1600 psia, flow rate is 24.2 MMSCFD and at1300 psia, the flow rate increases to 26.2 MMSCFD, the current value. For a separator pressure of 1300 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1300 psia has no positive effect on the flow rate. So, it is possible maintain a maximum pressure of 1300 psia at downstream side of the choke instead of current pressure of about 1010 psia.

Separator pressure plays an important role as the average reservoir pressure gets lower. At a bottom hole pressure of 2000 psia, a separator pressure of 1600 psia produces only 5.0 MMSCFD but a separator pressure of 1010 psia produces 16.1 MMSCFD.

For a choke size of 0.9 inch, 2.5-inches, 3.958-inches and 4.4-inches tubing will produce at 20 MMSCFD, 33 MMSCFD and 34.9 MMSCFD, respectively. In this case, the smaller flow line diameter of 2.0 can sustain a flow of 30.0 MMSCFD and 3-inches diameter can produce 34.8 MMSCFD.

At a lower bottom hole pressure of 2000 psia, the well will produce at 7.0 MMSCFD against a separator pressure of 1600 psia and 20.0 MMSCFD against 1010 psia. These values are 5.0 MMSCFD and 16.1 MMCF/D respectively for current choke size of 0.77 inch. A high separator pressure of 1200 psia can be maintained without sacrificing the flow rate.

For flow rate up to 30 MMSCFD, using existing choke size, the friction loss per unit length of tubing is moderate and well head pressure above 2280 psia is available, but beyond that losses become significant. At a flow of 50 MMSCFD, wellhead pressure becomes only 1570 psia. Wellhead temperature for the existing flow rate is about 150^0 F, which coincides with the actual value.

7.5.9 Well TT-9

Average reservoir pressure: 3260 psia

Average reservoir temperature: 205.0 ^{0}F

Back-pressure equation coefficient C = 0.000225

Back-pressure equation exponent n = 0.82

For an initial reservoir pressure of 4300 psia, recorded in 1985, the flow rate was about 35.7 MMSCFD at a wellbore pressure of 4050 psia. The well is now producing at 27.0 MMSCFD at the current reservoir pressure of 3260 psia. This study shows that for a low reservoir pressure of 2200 psia, the flow will be 16.3 MMSCFD in future, assuming all other parameters remain the same.

For C value of 0.0001, production rate is only 23.5 MMSCFD, which increases to 28.3 MMSCFD when C is 0.0006. Increasing the value of C beyond 0.0008 will not increase the production rate.

When n is 0.5; a very low flow rate of 1.0 MMSCFD is obtainable. The flow rate increases to 3.5 MMSCFD, 14.1 MMSCFD and 27.0 MMSCFD as n increases to 0.6, 0.70 and 0.82 respectively. Beyond the value of n = 0.90, an increase in n will hardly increase the production rate.

Flow rate increases from 15.0 MMSCFD to 32.9 MMSCFD as bean size is increased from 0.55 inch to 0.90 inch. The well now produces 27 MMSCFD at a choke size of 0.788 inch.

For a tubing inner diameter of 2.5 inches a flow rate of only 17.8 MMSCFD is possible. For a tubing size of 3.0 and 3.5 inches, the flow rate increases to 23 and 26, MMSCFD respectively. An increase in the current tubing size of 3.958 inches will not increase the flow rate any further.

A flow line diameter of 2-inches produces at a rate of 25 MMSCFD while that of 2.4-inches produces at 27.0 MMSCFD, the existing flow rate. So existing flow line diameter of 3.438 inches is more than adequate for the current condition.

At high separator pressure of 1800 psia, flow rate is 23.1 MMSCFD and at1600 psia; the flow rate increases to 25.0 MMSCFD. For a separator pressure of 1250 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1250 psia has no positive effect on the flow rate. So, it is possible to maintain a maximum pressure of 1250 psia at the downstream side of the choke instead of current pressure of about 1010 psia without decreasing the flow rate.

Separator plays an important role as the average reservoir pressure gets lower. At a bottom hole pressure of 2000 psia, a separator pressure of 1600 psia produce only 5.0 MMSCFD but a separator pressure of 1010 produces at 16.8 MMSCFD.

For a larger choke size of 0.9 inch, a 2-inches, 2.5-inches and 3.0-inches tubing will produce at 13.0 MMSCFD, 20 MMSCFD and 26.8 MMSCFD, respectively. The existing tubing size of 3.958 inches will produce at 34.0 MMSCFD. Using a tubing of size 4.5 inches will produce 35.3 MMSCFD. Increasing the tubing size beyond 4.5 inches will not have much positive effect. For the choke size of 0.9 inch, the smaller flow line diameter of 2.0 inches can sustain a flow of 30.0 MMSCFD and 2.6-inches diameter can produce at 35.3 MMSCFD. Increasing the size beyond 2.6 inches will not be productive. At a lower bottom hole pressure of 2000 psia, the well will produce at 7.0 MMSCFD against a separator pressure of 1600 psia and at 20.0 MMSCFD, against 1010 psia. These values are 5.0 MMSCFD and 16.8 MMSCFD respectively for current choke size of 0.788 inch. A maximum separator pressure of 1150 can be maintained without affecting the flow rate.

For flow rate up to 30 MMSCFD, for the existing choke size, the friction loss per unit length of tubing is moderate and well head pressure above 2300 psia is available. But beyond a flow of 30 MMSCFD the frictional losses become significant. At a flow of 60 MMSCFD, wellhead pressure becomes only 500 psia. Wellhead temperature for the existing flow rate is found to be about 150^0 F, which coincides with the actual value.

7.5.10 Well TT-10

Average reservoir pressure: 3097 psia

Average reservoir temperature: 208.9 ^{0}F

Back-pressure equation coefficient C = 0.0001504

Back-pressure equation exponent n = 0.841867

When the reservoir pressure was 3400 psia, the flow rate was about 30.0 MMSCFD at a wellbore pressure of 3100 psia. The well is now producing at 27.1 MMSCFD at the current reservoir pressure of 3097 psia. For a low reservoir pressure of 2200 psia, the flow will be as low as 17.3 MMSCFD in future, assuming all other parameters remain the same.

Effect of the coefficient C on flow rate shows that for a C value of 0.0001504, production rate is 27.1 MMSCFD which increases to 29.0 MMSCFD when C is 0.0006. Increasing the value of C beyond 0.0006 will not increase the production rate.

Effect of the exponent n on flow rate shows that when n is 0.5; a very low flow rate of 0.8 MMSCFD is obtainable. The flow rate increases to 2.2 MMSCFD, 9.3 MMSCFD and 17.5 MMSCFD as n is increased to 0.6, 0.70 and 0.75 respectively. Beyond the value of n = 0.841857, an increase in n to maximum value of 1.0 will increase the production rate by only 1.5 MMSCFD.

Flow rate increases from 13.8 MMSCFD to 32.8 MMSCFD as bean size is increased from 0.55 inch to 0.95 inches. The well now produces at 27.1 MMSCFD at a choke size of 0.825 inch

For a tubing inner diameter of 2.0 inches a flow rate of only 11.1 MMSCFD is possible. For a tubing size of 2.5, 3.0 and 3.958 inches, the flow rate increases to 17.5, 23 and 27.1 MMSCFD, respectively. An increase in the current tubing size of 3.958 inches will not increase the flow rate any further.

A flow line diameter of 2-inches produces at a rate of 25.0 MMSCFD while a 2.5-inches and a 3.0-inches diameter produces at 26.5 MMSCFD and 27.1 MMSCFD, respectively, the later being the existing flow rate. So the existing flow line diameter of 3.438 inches is more than adequate for the current condition.

At high separator pressure of 1600 psia, flow rate is 23.6 MMSCFD and at 1400 psia, the flow rate is 25 MMSCFD. The flow rate increases to 27.1 MMSCFD when the separator pressure is reduced to 1150 psia. For a separator pressure of 1150 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1150 psia has no positive effect on the flow rate. So, it is possible to maintain a maximum pressure of 1150 psia at the downstream side of the choke instead of current pressure of about 1010 psia.

Separator pressure plays an important role on the flow rate as the average reservoir pressure gets lower. At a bottom hole pressure of 2000 psia, a separator pressure of 1600 psia produces only 5.3 MMSCFD but a separator pressure of 1010 produces 18.0 MMSCFD.

For a larger choke size of 0.95 inches, 3.0-inches, 3.958-inches and 4.5-inches tubing will produce at 25 MMSCFD, 32.5 MMSCFD, 34.5 MMSCFD, respectively. After that the rate does not increase much with the increase in tubing size. The smaller flow line diameter of 2.0 inches can sustain a flow of 27.8 MMSCFD. A 2.5 inches and a 3.438 inches diameter can produce at 31.2 and 34.5 MMSCFD, respectively. Increasing the size beyond 3.438 inches will not be productive. At a lower bottom hole pressure of 2000 psia, the well will produce at 7.0 MMSCFD against a separator pressure of 1600 psia and at 22.2 MMSCFD against 1010 psia. These values are 5.3 MMSCFD and 18.0 MMSCFD, respectively for the current choke size of 0.825 inch. In this case, a maximum separator pressure of 1050 psia can be maintained without affecting the flow rate.

Using the existing choke size a for flow up to 30 MMSCFD, the frictional loss per unit length of tubing is moderate and wellhead pressure above 2000 psia is available. But beyond the flow of 30 MMSCFD, frictional losses become significant. At a flow of 50 MMSCFD, wellhead pressure becomes only 1130 psia. Wellhead temperature for the current flow rate is about 150^0 F, which coincides with the actual value.

7.5.11 Well TT-11

Average reservoir pressure: 3350 psia

Average reservoir temperature: 195.0 ^{0}F

Back-pressure equation coefficient C = 0.000153

Back-pressure equation exponent n = 0.80

Figure 7.73 shows the variation of flow rate with reservoir pressure for a tubing diameter of 3.958 inches. For an initial reservoir pressure of 3682 psia, recorded in April 1990, the flow rate was 26.4 MMSCFD at a wellbore pressure of 3165 psia. The well is now producing 23.6 MMSCFD at the current reservoir pressure of 3350 psia. For a low reservoir pressure of 2200 psia, the flow will be producing 13.0 MMSCFD in future, assuming all other parameters remain the same.

From Figure 7.74, it is evident that for increasing the C value from current value of 0.000153 to 0.0006 will increase the production rate to 27.4 MMSCFD. Increasing the value of C beyond 0.0006 will not increase the production rate much.

Figure 7.75 shows that, when n is 0.5, a very low flow rate of 0.8 MMSCFD is obtainable. The flow rate increases to 2.5 MMSCFD, 11.0 MMSCFD and 23.6 MMSCFD as n is increases to 0.60, 0.70 and 0.80 respectively. Beyond the value of n = 0.90, an increase in n will hardly increase the production rate.

Figure 7.76 shows the effect of the choke diameter on the flow rate. Flow rate increases from 15.0 MMSCFD to 26.8 MMSCFD as bean size is increased from 0.55 inch to 0.90 inch. The well now produces 23.6 MMSCFD at a choke size of 0.78 inch.

Figure 7.77 shows the variation of flow rate with tubing size. For a tubing inner diameter of 2.0 inches a flow rate of only 12.7 MMSCFD is possible. An increase in the current tubing size of 3.068 inches certainly increases the production rate. A tubing size of 4 inches will increase the flow rate by about 2.5 MMSCFD. So, the flow in this well is restricted due to smaller size of tubing and a larger tubing, preferably, 4-inches tubing should be used.

Figure 7.73: Effect of Average Reservoir Pressure on the Performance of Well TT-11

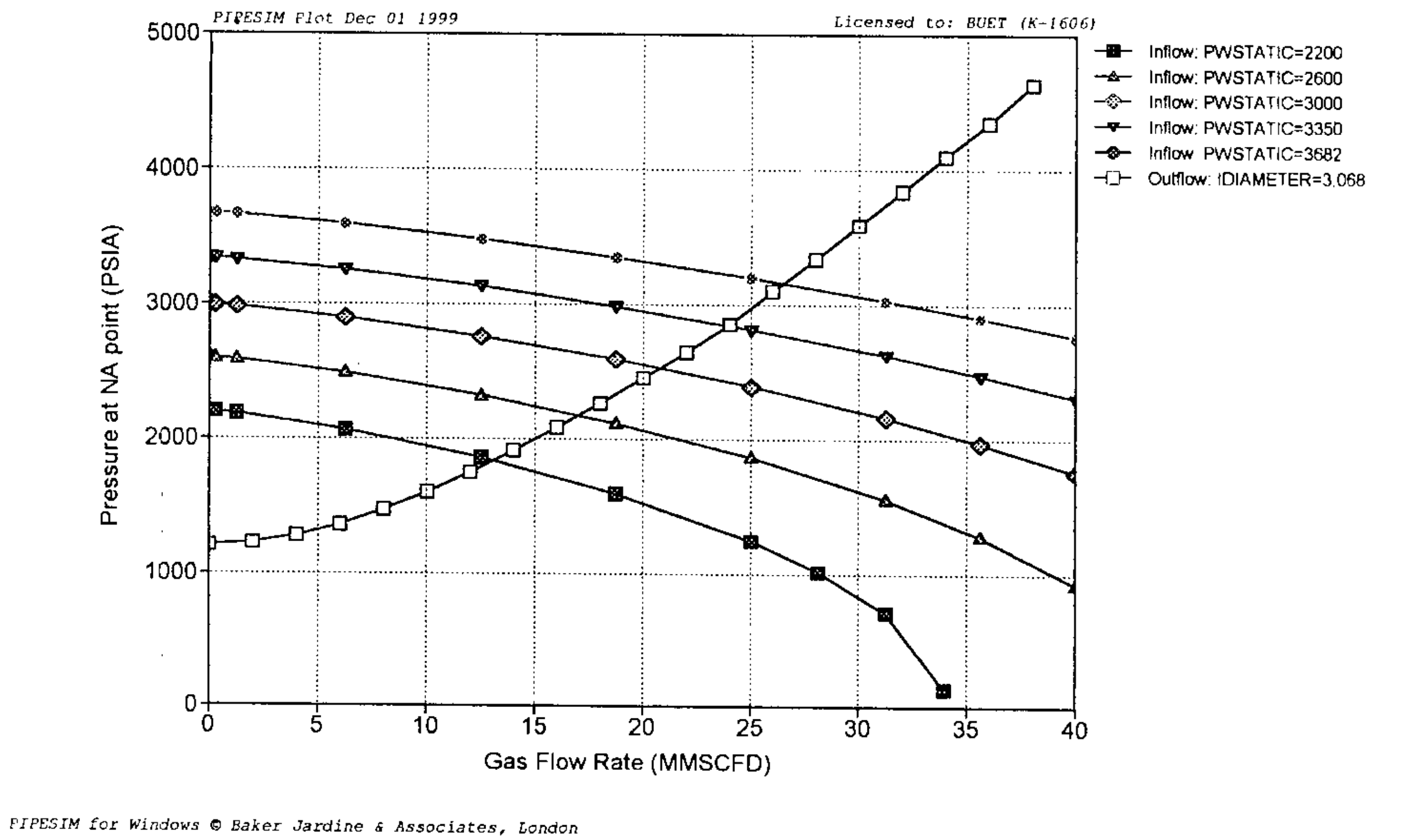


Figure 7.74: Effect of Back Pressure Coefficient on the Performance of Well TT-11

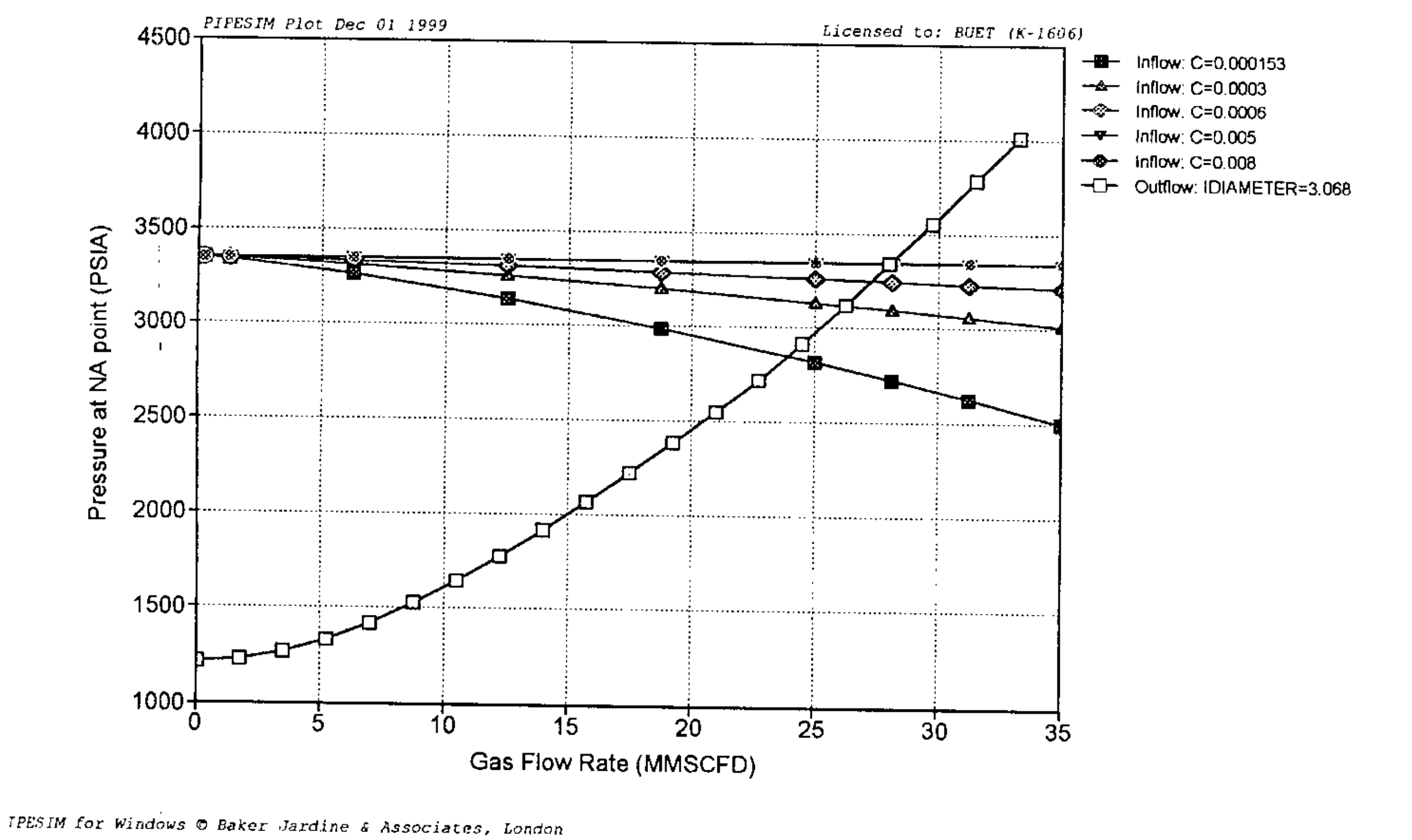


Figure 7.75: Effect of Back Pressure Exponent on the Performance of Well TT-11

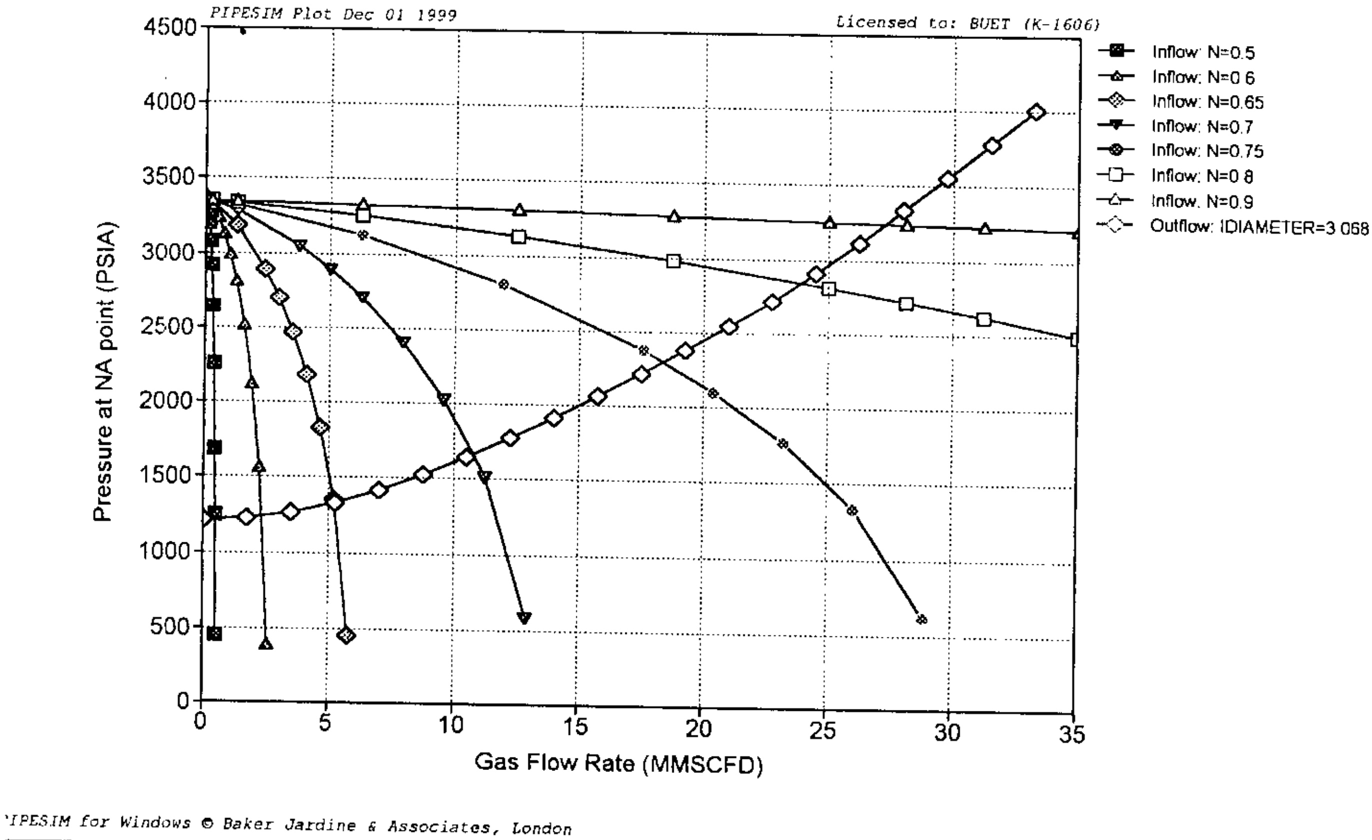


Figure 7.76: Effect of Choke Size on the Performance of Well TT-11

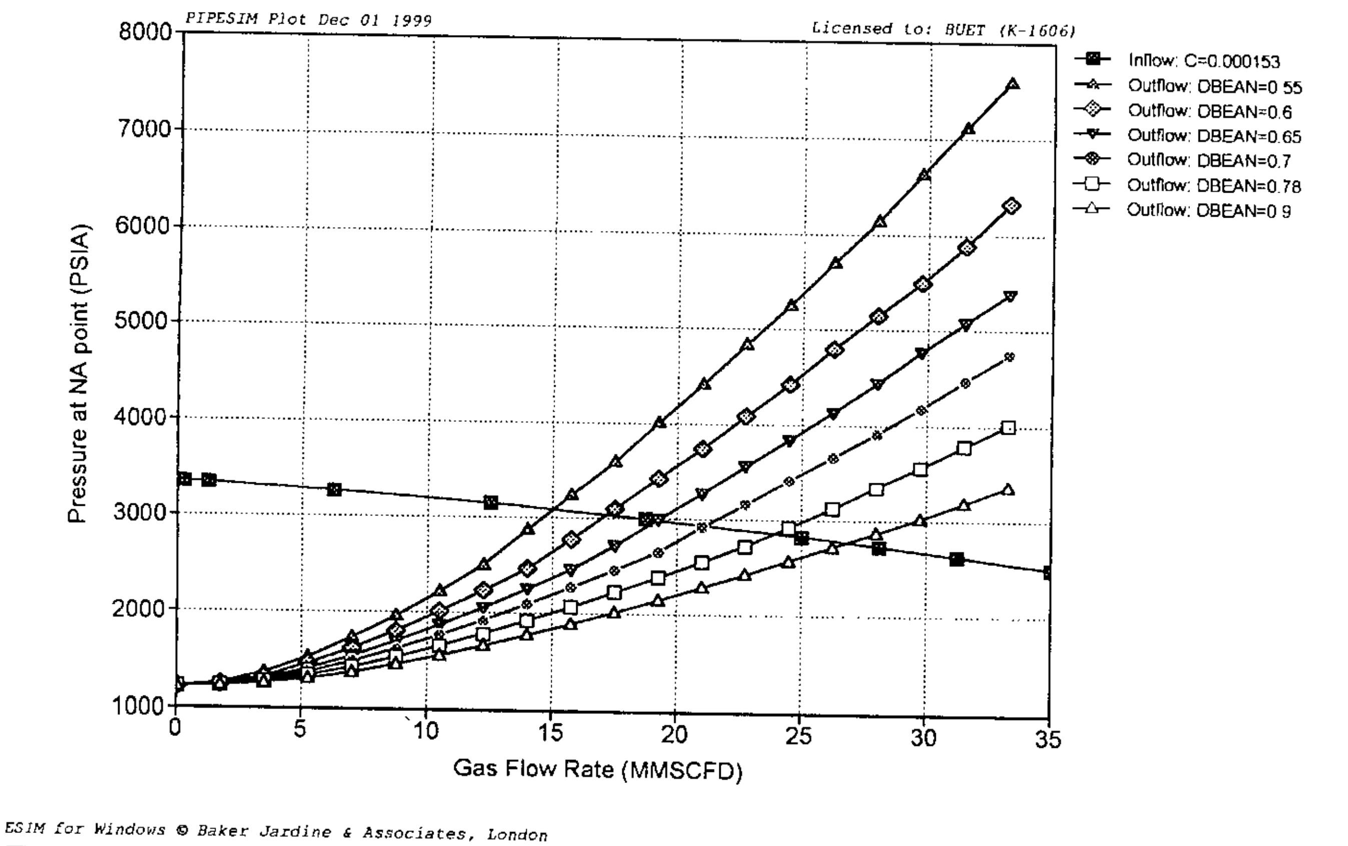


Figure 7.78 shows the effect of flow line diameter on the flow rate. A diameter of 3-inches produces at a rate of 19.5 MMSCFD while 5.2-inches produces 23.6 MMSCFD, the existing flow rate. So existing flow line diameter of 7.625 inches is more than adequate for the current condition.

Figure 7.79 shows the effect of separator pressure on the flow rate. At a high separator pressure of 1600 psia, flow rate is 21.0 MMSCFD and at 1100 psia, the flow rate increases to 23.6 MMSCFD. For a separator pressure of 1100 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1100 psia has no positive effect on the flow rate. So, it is possible maintain a maximum pressure of 1100 psia at downstream side of the choke instead of current pressure of about 1100 psia.

Analysis of the same figure shows that separator plays an important role as the average reservoir pressure gets lower. At a bottom hole pressure of 2000 psia, a separator pressure of 1600 psia produce only 5.0 MMSCFD but a separator pressure of 1020 produces 15.0 MMSCFD. A maximum separator pressure of can be maintained without decreasing the flow rate.

Figures 7.80 through 7.82 show the effect of tubing and flow line inner diameter, and separator pressure, respectively, for a larger choke size of 0.9 inch, other parameters remaining the same. According to Figure 7.80, a tubing of 4.5 inches will produce at 32.5 MMSCFD, whereas existing tubing size of 3.068 inches will produce at 30 MMSCFD, so the existing tubing will not be adequate if the choke size is increased. According to Figure 7.81, the smaller flow line diameter of 3.0 inches can sustain a flow of 21.0 MMSCFD and 5.5-inches diameter can produce 27.5 MMSCFD. Current flow line size is still more than adequate for high production scenario, as shown in Figure 7.81. Using a 5.5 in flow line will be adequate for this case.

Figure 7.82 suggests that at a lower bottom hole pressure of 2000 psia, the well will produce at 7.2 MMSCFD against a separator pressure of 1600 psia, and at 17.7 MMSCFD against 1020 psia. These values are 5.0 MMSCFD and 15 MMSCFD,

Figure 7.77: Effect of Tubing Inner Diameter on the Performance of Well TT-11

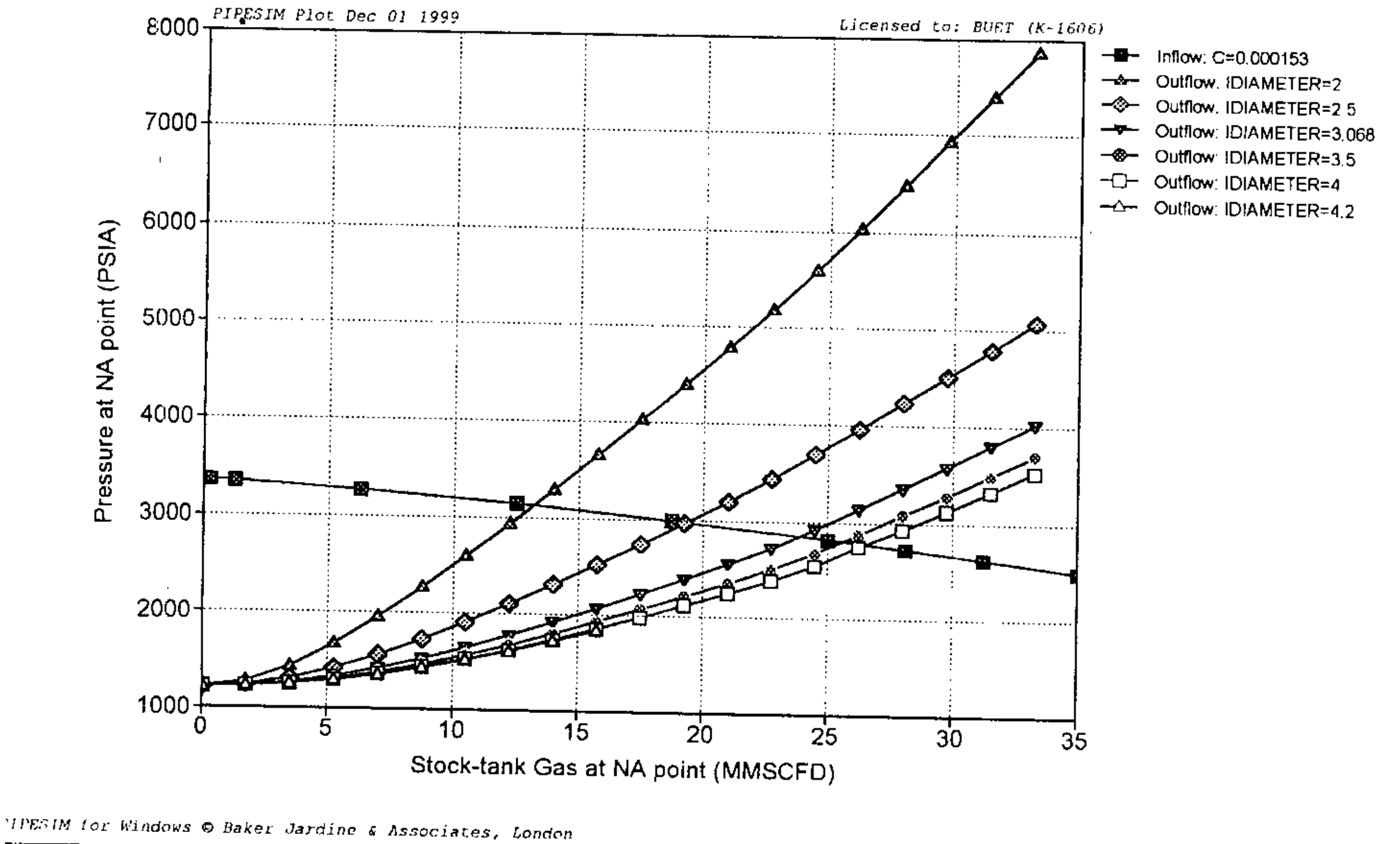


Figure 7.78: Effect of Flow Line Inner Diameter on the Performance of Well-11

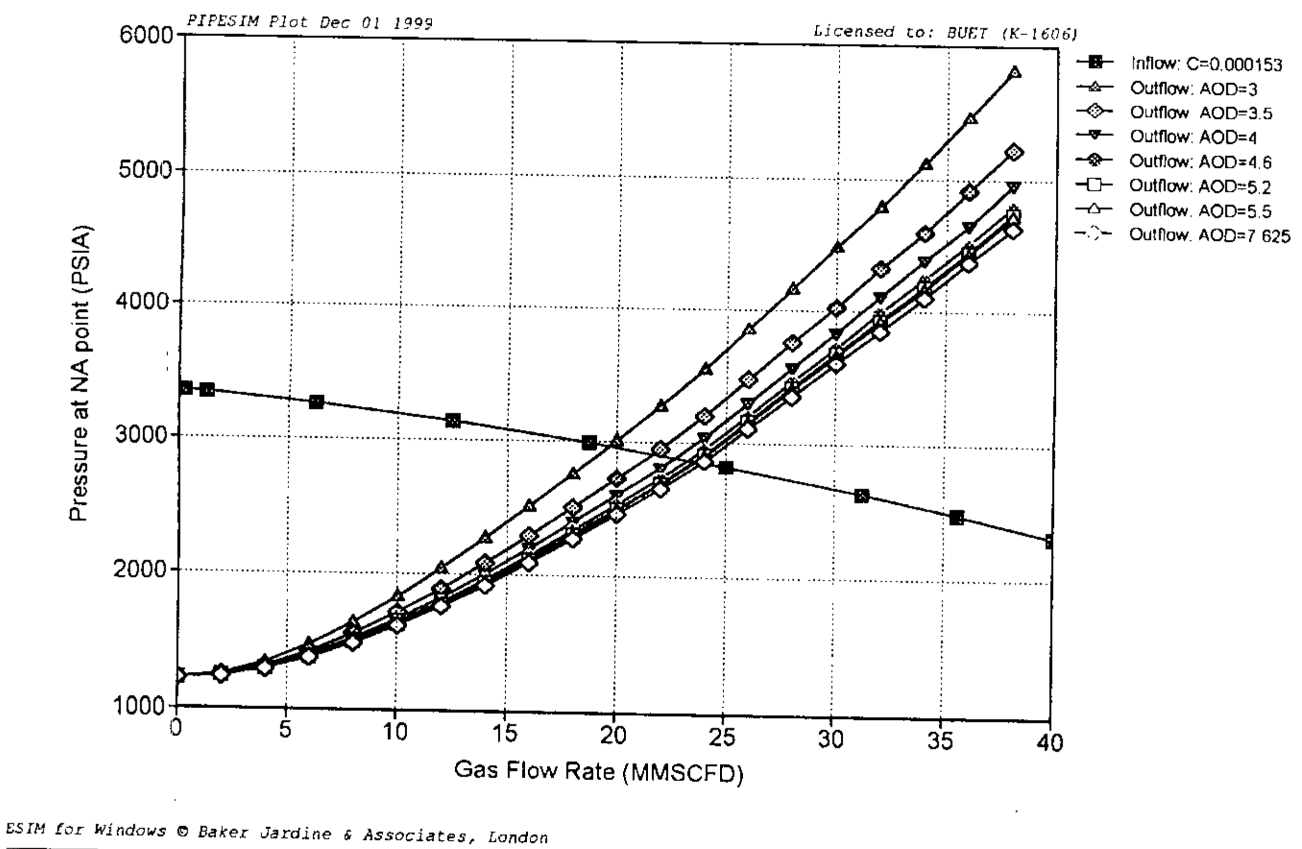


Figure 7.79: Effect of Separator Pressure on the Performance of Well TT-11

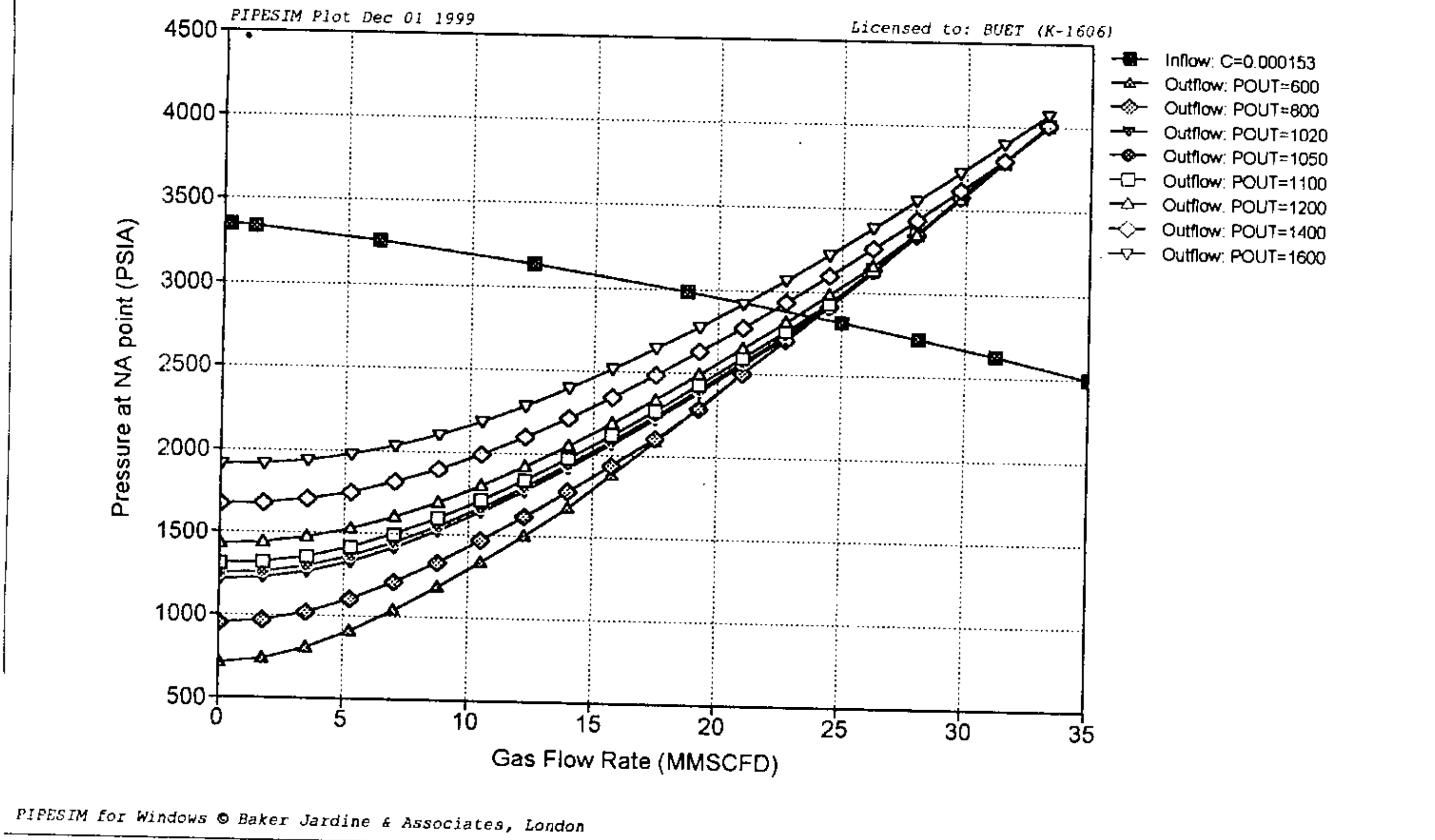


Figure 7.80: Effect of Tubing Inner Diameter on the Performance of Well TT-11

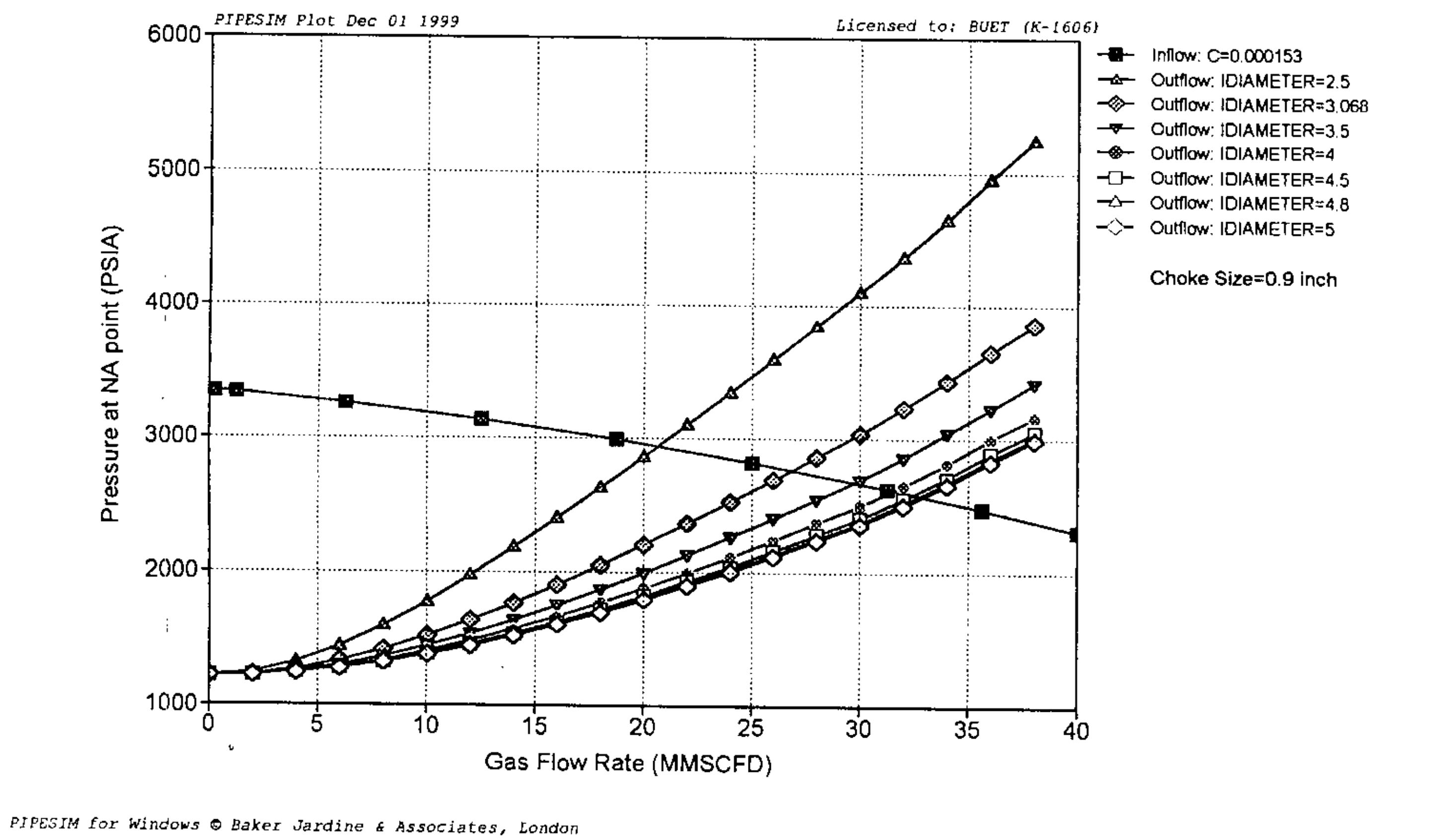


Figure 7.81: Effect of Flow Line Inner Diameter on the Performance of Well TT-11

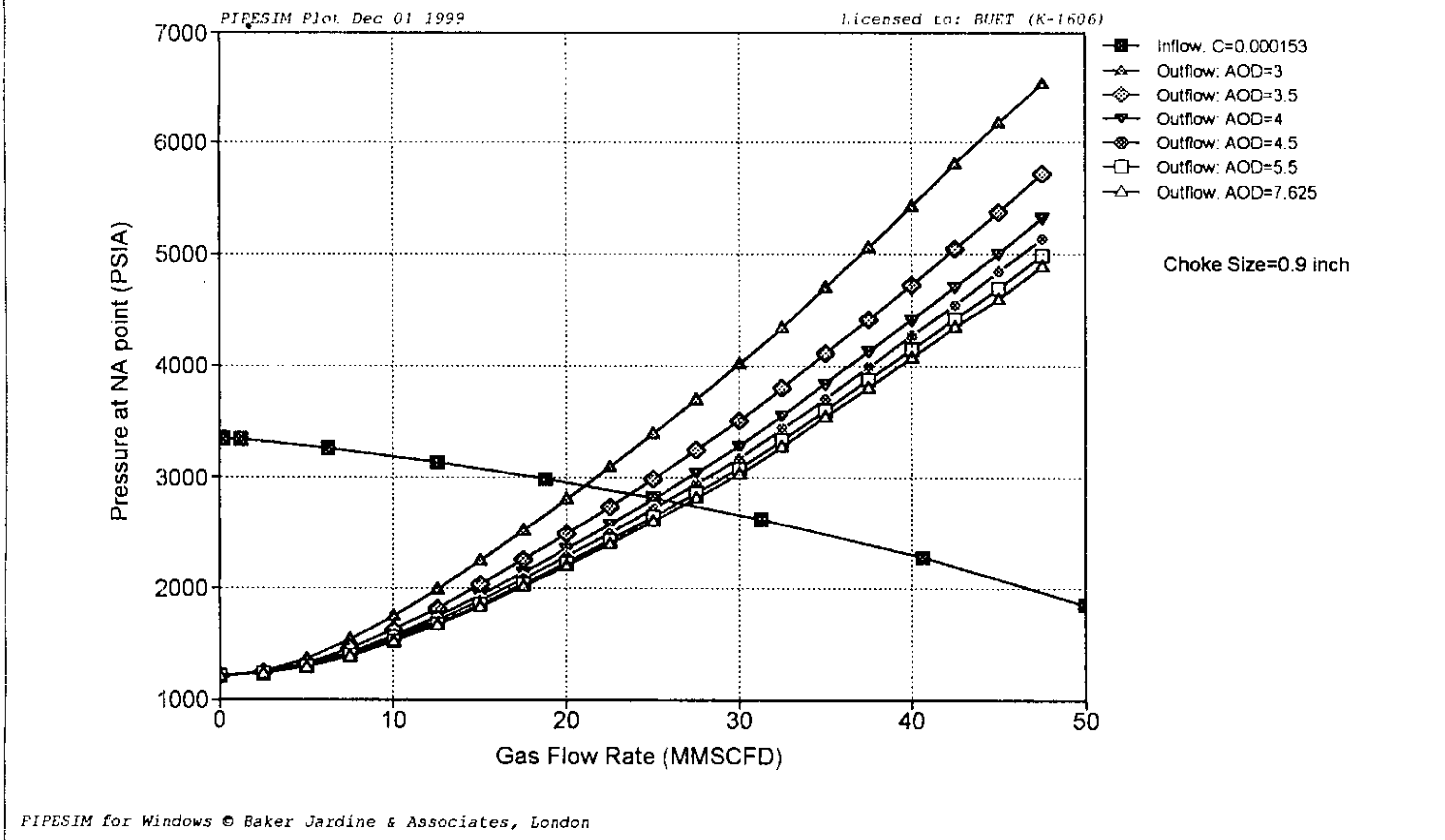
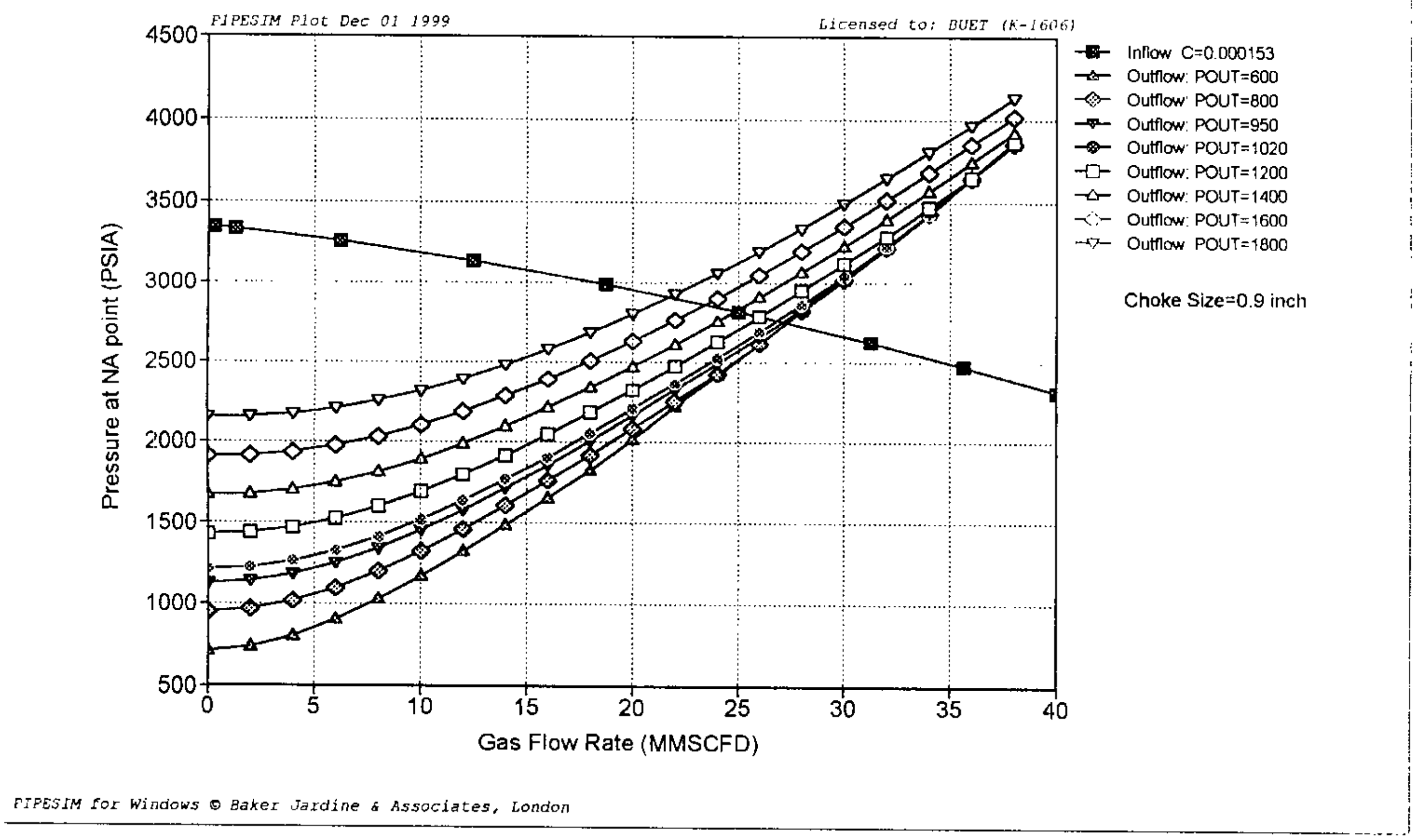


Figure 7.82: Effect of Separator Pressure on the Performance of Well TT-11



respectively for the current choke size of 0.788 inch. It is also evident that decreasing the separator pressure to 950 psia will slightly increase the flow rate.

Figures 7.83 and 7.84 show the pressure and temperature profiles along the vertical tubing for different flow rate, for the existing choke size. It is evident from Figure 7.83 that for flow rates up to 25 MMSCFD, the frictional loss per unit length of tubing is moderate and a wellhead pressure above 2000 psia is available. But beyond the flow rate of 25 MMSCFD, frictional losses become significant. At a flow of 35 MMSCFD, wellhead pressure becomes only 600 psia. Figure 7.84 shows that wellhead temperature for the current flow rate is about 142^0 F, which is close to the actual value of 150^0 F.

The values of the existing and suggested tubing size and flow line size and maximum separator pressure that can be maintained without sacrificing the flow rate are given in the following table:

Table 7.1: Existing and Recommended Tubing and Piping Size and Maximum Separator Pressure

Well	Tubing, inches		Piping, inches		Separator Pressure, psia	
	Existing	Recommended	Existing	Recommended	Existing	Recommended*
TT-1	3.958	3.958	5.187	2.5	1010	1300
TT-2	3.958	4.5000	5.187	2.5	1015	1400
TT-3	4.408	4.408	5.187	3.0	1010	1400
TT-4	4.408	4.000	3.438	3.0	1010	1350
TT-5	3.958	3.958	3.438	3.0	1010	1400
TT-6	3.958	3.958	3.438	2.5	1010	1400
TT-7	3.958	3.958	3.438	3.0	1010	1400
TT-8	3.958	3.958	3.438	2.8	1010	1300
TT-9	3.958	3.958	3.438	2.4	1010	1250
TT-10	3.958	3.958	3.438	3.0	1010	1150
TT-11	3.068	4.000	7.625	5.2	1020	1100

*Maximum separator pressure that can be maintained without affecting the flow rate

Figure 7.83: Effect of Flow Rate on Pressure Profile in Tubing of Well TT-11

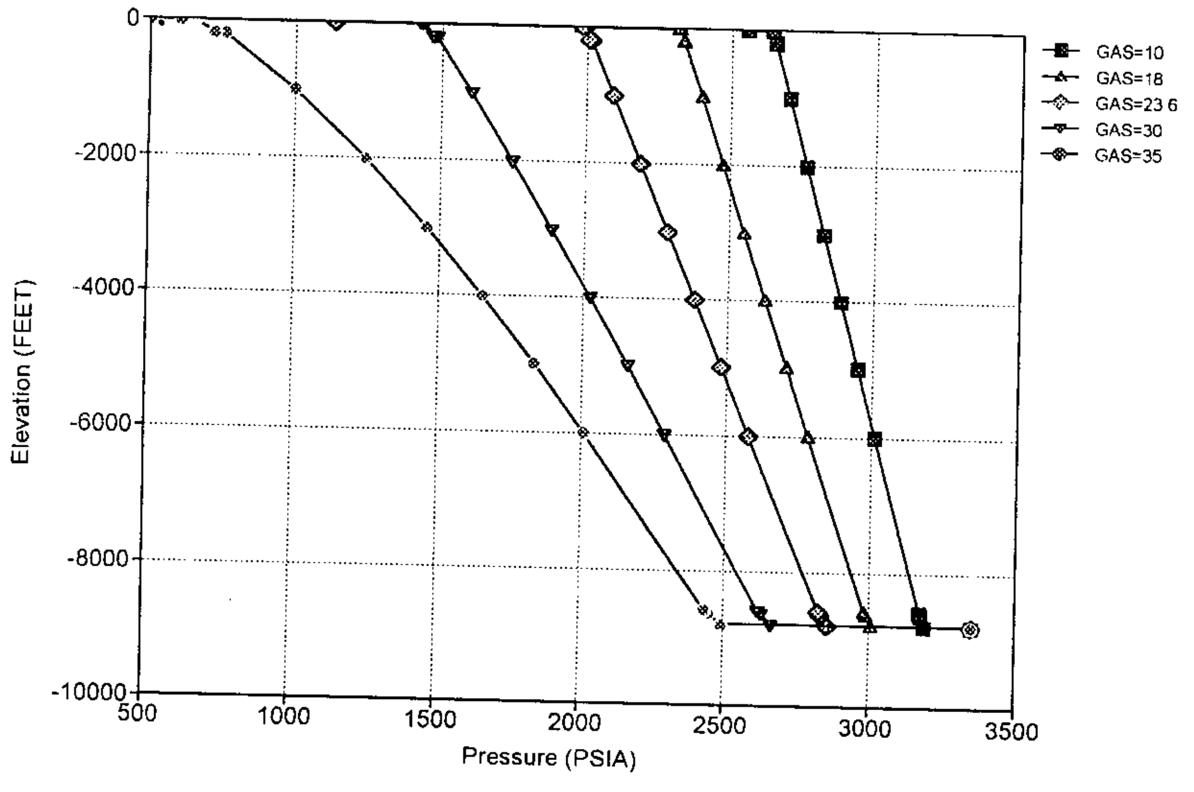
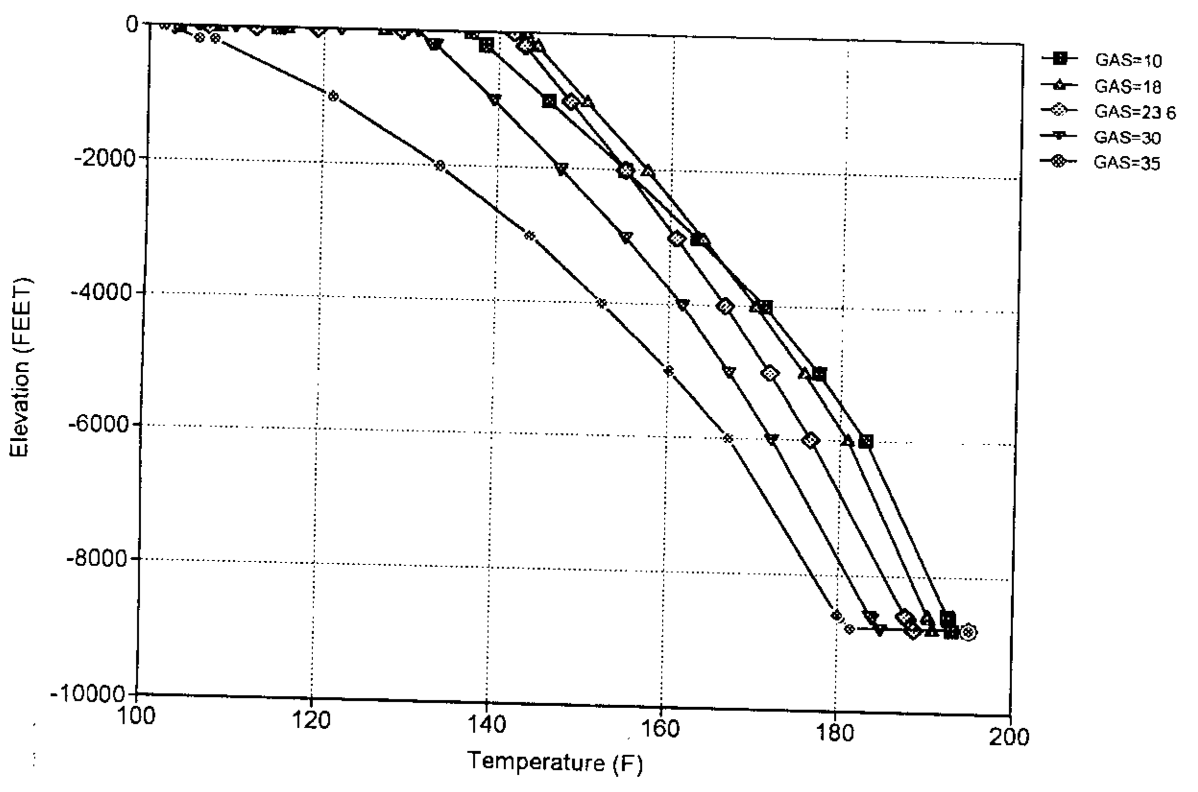


Figure 7.84: Effect of Flow Rate on Temperature Profile in Tubing of Well TT-11



CHAPTER 8

SIMULATION OF THE INTEGRATED MODEL

8.1 INTRODUCTION

The eleven wells of the Titas Gas Field are situated in 4 different locations. The arrangement of the wells are shown in Figures 8.1 and 8.2, respectively. The models have been set up and simulated with PIPESIM-Net software. The first model, consisting of six wells supplies gas to sales line 1 and the second model consisting of five wells is connected to sales line 3.

8.2 SOLUTION ALGORITHM

Input data consists of well inflow performance relationships (IPR), flow line and production tubing geometry data and system outlet or sales line pressure.

The following sequence is followed:

1. Bottom hole pressure is calculated by assuming a small finite drawdown for each well producing zone and a corresponding flow rate is calculated from IPR.

2. With flow rates defined at every inlet node, material balance calculations are performed in each junction in gathering systems. At this point flow rates in each well and line in the entire production system are defined.

3. Pressure drop throughout the gathering system is calculated using the pressure drop correlations. Calculation begins at the fixed pressure of the system outlet and proceeds back through the network to the inlet nodes on the bottom of the wells.

4. Bottom hole pressure at the various producing zones obtained from the IPR and the system hydraulics calculations are compared. If these pressures have converged, the system nodal analysis has converged.

If it does not converge, then for different draw down, for each well steps 1 to 4 are repeated.

8.3 SIMULATION STEPS

The simulation consists of the following steps:

1. The models have been simulated for existing values and a good match has been obtained with the field values.

2. The average reservoir pressures of different sands are changed one at a time and the effect on overall model is observed. So it gives an indication of the change of flow rate and other parameters with time.

3. The sales lines pressure have been changed and its effect on the system is observed.

4. The choke sizes of different wells have been changed one at a time and its effect on the whole model is observed.

5. The tubings and flow lines have been changed to optimum values and the over all effect is observed.

6. The tubings and flow lines of two wells (TT-1 and TT-11) have been changed and its effect on model one and two, respectively is observed.

It should be mentioned that when one variable was changed, all other parameters remained the same.

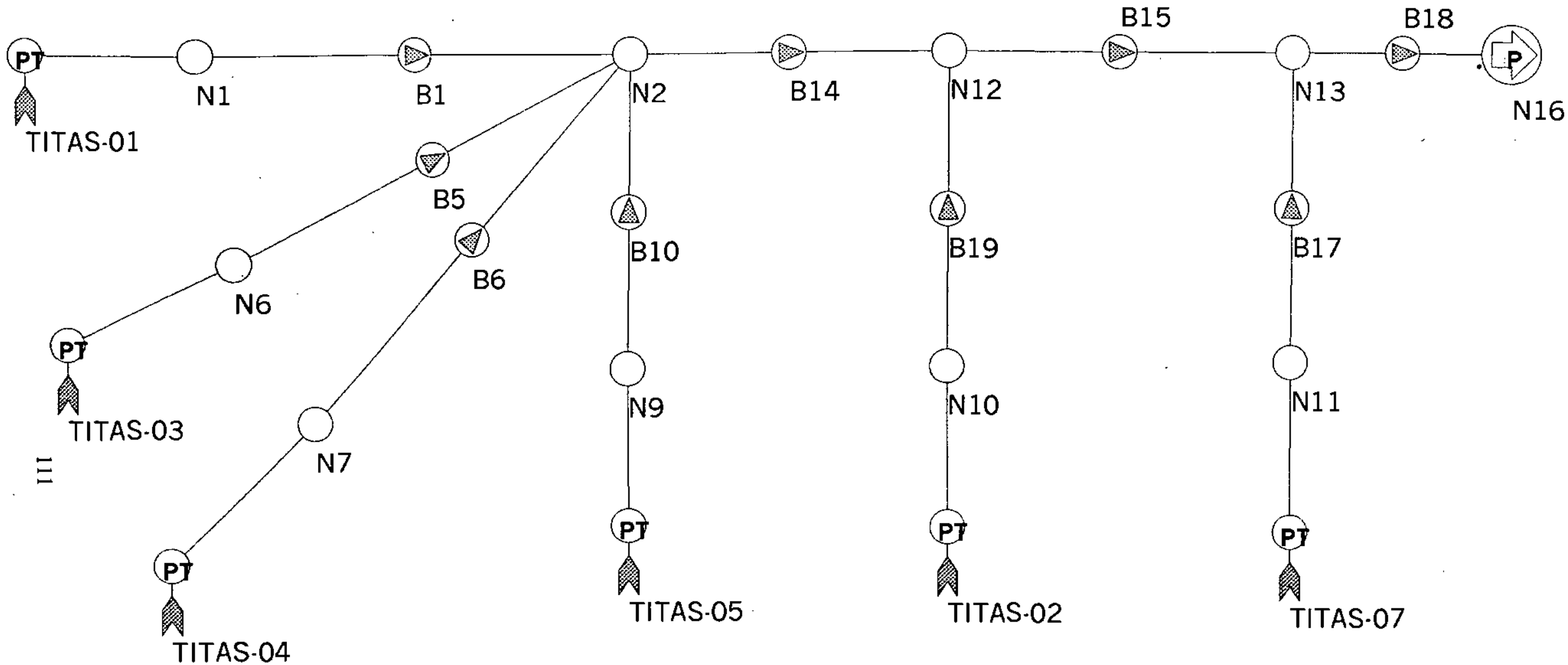


Figure 8.1: Model-1, Location 1 and 2 of Titas Gas Field

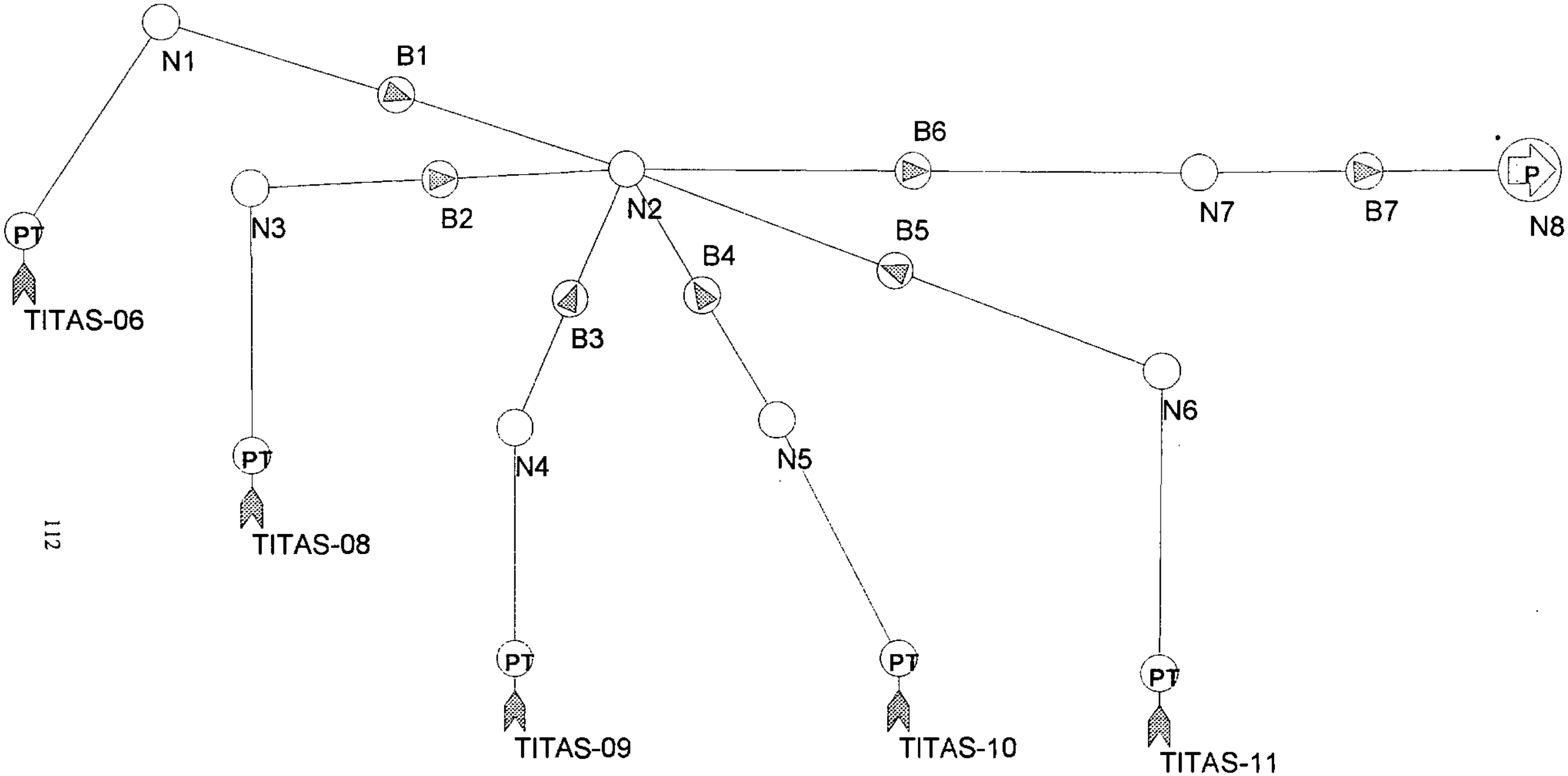


Figure 8.2: Model-2, Location 3 and 4 of Titas Gas Field

8.4 ANALYSIS OF THE MODELS

1. Data have been collected from the field and simulated with the PIPESIM-Net software. Table 8.1 shows a good match between actual and simulated data. Simulated wellhead temperature, wellhead pressure and flow rate were close to that of the observed data.

Table 8.1: Comparison of Simulated and Observed Data at the Existing Condition

Well	WHP psia, Simulated	WHT ^{0}F, Simulated	Q MMSCFD, Simulated	WHP psia, Observed	WHT ^{0}F, Observed	Q MMSCFD, Observed
TT-1	2422.4	145.6	23.61	2415	150	23.4
TT-2	2619.5	150.9	28.59	2615	150	28.2
TT-3	2612.8	149.9	30.16	2615	150	30
TT-4	2538.0	147.5	28.32	2530	150	28
TT-5	2560.2	150.3	29.99	2565	150	29.8
TT-6	2618.1	150.4	26.98	2531	150	27.2
TT-7	2548.9	145.9	26.44	2556	150	26.2
TT-8	2382.2	148.1	26.4	2399	150	26.2
TT-9	2337.6	148.0	27.1	2347	150	26.9
TT-10	2138.7	148.7	27.15	2116	150	27
TT-11	2018.3	142.4	23.18	2010	150	23.6

Note: WHP: Wellhead pressure, psia

WHT: Wellhead temperature,^{0}F

Q: flow rate at standard condition, MMSCFD

2. Table 8.2 shows a decline in production rate in wells TT-1 through TT-5 and TT-7 as average reservoir pressure declines. Average reservoir pressure has been changed to 3000, 2500, 2000 and 1500 psia and its effects on wellhead pressure and temperature and flow rate have been observed. These parameters have been observed to reduce drastically. When this pressure is around 1400 psia, the flow rates in those wells are between 6 and 9 MMSCFD and are close to abandonment. Analysis have shown that at 1400 psia, some of the wells will have to be

abandoned as wellhead pressure become very close to 1000 psia, whereas sales line pressure must be maintained at 1000 psia. In such situation, artificial lift method might be introduced to avoid abandonment.

As the wells are producing from the same sand, their average reservoir pressure is assumed to be the same.

Table 8.2: Effect of Average Reservoir Pressure (of Wells TT-1 through TT-5 and TT-7) on Well Performance, Model-1

Data	T-1	T-2	T-3	T-4	T-5	T-7	*P_{AVG}, psia
WHP	2228.1	2333.1	2322.8	2252.7	2281.8	2268.3	3000
WHT	144.1	147.1	146.4	144.8	146.3	142.9	
Q	21.78	25.68	27.08	25.27	26.88	23.55	
WHP	1833.1	1931.4	1919.1	1852.7	1889.1	1869.9	2500
WHT	140.1	145.2	143.8	141.1	145	139.4	
Q	17.9	21.37	22.35	20.78	22.3	19.52	
WHP	1473.6	1551.7	1536.4	1845.7	1524.7	1503.5	2000
WHT	133.6	137.9	136.6	134.4	137.7	132.6	
Q	12.82	15.71	16.33	14.88	16.25	14.11	
WHP	1146.9	1192.7	1179.2	1150.8	1181	1164	1500
WHT	118.8	124.3	122.4	119.5	125.2	118.5	
Q	6.92	8.87	9.08	8.01	9.11	7.72	

*TT-1 through TT-7 and TT-11 are all connected to same sands. That is why, they have more or less the same average reservoir pressure

3. Tables 8.3 through 8.5 show on model 2, the effect of average reservoir pressure. Average reservoir pressure has been changed from 3000 psia to 1500 psia and its effect on the performance of different wells has been observed. Change in the average reservoir pressure of one sand does not the affect the wells producing from different sands as all the wells are operating in the critical range, i.e., the disturbance in the down stream of the choke is not affecting the upstream conditions of the choke. As in the previous case, the flow rate decreases with

average reservoir pressure and also gives an indication when the well might have to be abandoned.

Table 8.3: Effect of Average Reservoir Pressure (of Wells TT-6 and TT-11) on Well Performance, Model-2

Data	T-6	T-8	T-9	T-10	T-11	*P_{AVG}, psia
WHT	146.9	148.1	148.0	148.7	139.4	3000
WHP	2362.9	2382.6	2337.3	2138.7	1795.7	
Q	24.52	26.39	27.11	27.15	20.33	
WHT	145.1	148.1	148	148.7	136.8	2500
WHP	1959.6	2382.9	2337.3	2138.9	1519.9	
Q	20.42	26.37	27.11	27.14	15.74	
WHT	137.4	148.1	148.0	148.7	131.1	2000
WHP	1573.0	2383.2	2337.4	2138.9	1271.0	
Q	15.16	26.36	27.11	27.14	10.94	
WHT	134.3	148.1	148.0	148.7	127.9	1800
WHP	1423.7	2383.1	2337.6	2139.0	1183.6	
Q	12.76	26.36	27.10	27.13	8.89	

*Average reservoir pressure of only TT-6 and TT-11 were changed, simultaneously

Table 8.4: Effect of Average Reservoir Pressure (of Wells TT-8 and TT-9) on Well Performance, Model-2

Data	T-6	T-8	T-9	T-10	T-11	*P_{AVG}, psia
WHT	150.4	146.2	146.3	148.7	142.4	3000
WHP	2618.1	2181.4	2137.0	2138.7	2018.2	
Q	26.98	24.14	24.85	27.14	23.18	
WHT	150.4	141.2	141.0	148.7	142.4	2500
WHP	2618.3	1800.3	1764.9	2138.6	2018.2	
Q	26.96	19.74	20.12	27.15	23.18	
WHT	150.4	134.1	133.8	148.7	142.4	2000
WHP	2618.3	1452.3	1426.5	2138.8	2018.3	
Q	26.97	14.12	14.31	27.14	23.18	

* Average reservoir pressure of only TT-8 and TT-9 were changed, simultaneously

Table 8.5: Effect of Average Reservoir Pressure (of Well TT-8) on Well Performance, Model-2

Data	T-6	T-8	T-9	T-10	T-11	*P_{AVG}, psia
WHT	150.4	148.1	148.0	148.3	142.4	3000
WHP	2618.1	2382.3	2337.6	2066.2	2018.3	
Q	26.97	26.4	27.10	26.22	23.18	
WHT	150.4	148.1	148.0	142.1	142.4	2500
WHP	2618.1	2382.5	2337.3	1709.9	2018.2	
Q	26.98	26.39	27.12	20.91	23.18	
WHT	150.4	148.1	148	134.0	142.4	2000
WHP	2618.2	2382.9	2337.3	1386.7	2018.3	
Q	26.97	26.37	27.12	14.74	23.18	
WHT	150.4	148.1	148.0	117.9	142.4	1500
WHP	2618.2	2383.0	2337.3	1106.2	2018.3	
Q	26.97	26.37	27.12	7.47	23.18	

*Average reservoir pressure of only TT-10 was changed

4. Tables 8.6 and 8.7 show the effect of sales line pressure on the model 1 and 2, respectively. Sales line pressure have been changed from 600 to 1600 psia in both cases to observe the effect on wellhead pressure, wellhead temperature and flow rate. As the wells are producing in the critical zone, reducing the sales pressure from existing 1000 psia to 600 psia will not increase the production rate. On the other hand, if the pressure in sales line is maintained above 1300 or 1400 psia, only then the rate starts declining.

Table 8.6: Effect of Sales Line-1 Pressure on Model-1

Data	T-1	T-2	T-3	T-4	T-5	T-7	*Pressure
WHT	145.5	150.9	149.9	147.5	150.3	145.9	
WHP	2423.1	2619.4	2613	2538	2560.7	2550.1	600
Q	23.58	28.60	30.11	28.33	29.97	26.37	
WHT	145.4	150.8	149.9	147.4	150.2	145.8	
WHP	2435.3	2620.6	2614.9	2543.8	2567.4	2555.2	1400
Q	23.02	28.51	29.96	27.97	29.57	26.10	
WHT	144.9	150.5	149.5	147	150	145.4	1600
WHP	2461.7	2638.7	2631.8	2565.8	2587.3	2577.7	
Q	21.78	27.19	28.56	26.59	28.36	24.84	

* Sales line pressure were changed from 600 to 1600 psia

Table 8.7: Effect of Sales Line-3 Pressure on Model-2

Data	T-6	T-8	T-9	T-10	T-11	*Pressure
WHT	150.4	148.1	148.0	148.7	142.3	
WHP	2618.5	2383.7	2337.2	2140	2016	600
Q	26.95	26.33	27.12	27.1	23.21	
WHT	150.4	147.7	147.6	147.8	142.9	
WHP	2619.5	2401.1	2361.1	2188.1	2113.9	1400
Q	26.87	25.52	26.09	25.28	21.69	
WHT	149.8	147	146.9	146.8	143.3	
WHP	2635.7	2430.4	2394.3	2231.2	2185.5	1600
Q	25.6	24.08	24.61	23.55	20.49	

* Sales line-3 pressure was changed from 600 to 1600 psia

5. Tables 8.8 and 8.9 show the effect of changing choke size of any well from the existing size to 0.9 inch for model 1 and 2, respectively. As the size of the choke of a well is increased, the flow rate of that well increases. The change affect only that

well as all the wells are producing in the critical range of the choke so that downstream disturbance does not affect the upstream condition.

Table 8.8: Effect of Choke Size of Individual Wells on Model-1

Data	T-1	T-2	T-3	T-4	T-5	T-7	*Choke
WHT	146.4	150.9	149.9	147.5	150.3	145.9	
WHP	2175.9	2620	2612.5	2536.3	2560.3	2548.8	TT-1=0.9″
Q	33.16	28.55	30.16	28.43	29.99	26.44	
WHT	145.6	151.6	149.9	147.5	150.3	145.9	
WHP	2422.4	2479	2612.3	2537.9	2560.2	2549.0	TT-2=0.9″
Q	23.61	37.3	30.17	28.33	30.0	26.44	
WHT	145.6	150.8	151.1	147.5	150.3	145.9	
WHP	2421.7	2620.4	2510	2537.8	2560.4	2548.9	TT-3=0.9″
Q	23.65	28.52	37.69	28.33	29.98	26.44	
WHT	145.6	150.9	149.9	148.6	150.3	145.9	
WHP	2422.4	2620.2	2612.4	2401.5	2560.1	2549.0	TT-4=0.9″
Q	23.61	28.54	30.16	35.91	30.0	26.44	
WHT	145.6	150.9	149.9	147.5	150.7	145.9	
WHP	2421.3	2619	2612.8	2537.1	2442.5	2548.8	TT-5=0.9″
Q	23.66	28.63	30.13	28.38	36.21	26.44	
WHT	145.6	150.9	149.9	147.5	150.3	147.1	
WHP	2422.4	2619.9	2612.7	2538.2	2560.1	2356.7	TT-7=0.9″
Q	23.61	28.56	30.14	28.31	30.0	35.44	

* The effect of increasing choke size from existing values to 0.9 inch was observed. Only one choke size was changed one at a time.

Table 8.9: Effect of Choke Size of Individual Wells on Model-2

Data	T-6	T-8	T-9	T-10	T-11	*Choke
WHT	151.7	148.1	148.0	148.7	142.4	TT-6=0.9
WHP	2462.1	2383	2337.4	2138.2	2018.3	
Q	36.98	26.37	27.11	27.16	23.18	
WHT	150.4	149.7	148.0	148.7	142.4	TT-8=0.9
WHP	2618.1	2213.1	2337.6	2138.4	2018.3	
Q	26.97	33.36	27.1	27.16	23.18	
WHT	150.4	148.1	149	148.7	142.4	TT-9=0.9
WHP	2618.1	2382.3	2138.3	2138.9	2018.4	
Q	26.97	26.4	33.0	27.14	23.17	
WHT	150.4	148.1	148.0	149.8	142.4	TT-10=0.9
WHP	2618.1	2382.3	2337.6	2037.2	2018.3	
Q	26.97	26.4	27.1	30.62	23.18	
WHT	150.4	148.1	148	148.7	138.0	TT-11=0.9
WHP	2618.1	2382.9	2337.3	2138.9	1767.6	
Q	26.98	26.37	27.11	27.14	26.53	

* The effect of increasing choke size from existing value to 0.9 inch was observed. Only one choke size was changed one at a time.

6. Tables 8.10 and 8.11 show the effect of using optimum size of tubing and piping in model 1 and 2, respectively. For the existing choke size, it is observed that TT-1 through TT-10 is producing at the optimum rate. Comparing these two tables with Table 8.1 shows that the flow has hardly increased. But tubing in TT-4 and flow lines in all the wells are oversized. This may be to compensate for higher production in the future.

   On the other hand, TT-11 is producing at a lower rate than the minimum. Changing the tubing diameter from existing 3.068 inches to optimum size of 4.0 inches will increase the production rate from 23.18 MMSCFD to 25.47 MMSCFD.

Table 8.10: Effect of Optimum Size of Tubing and Piping on Model-1

Data	T-1	T-2	T-3	T-4	T-5	T-7
WHT	145.6	150.9	149.9	147.5	150.3	145.9
WHP	2422.4	2619.5	2612.8	2538.0	2560.2	2548.9
Q	23.61	28.59	30.13	28.32	29.99	26.44

Table 8.11: Effect of Optimum Size of Tubing and Piping on Model- 2

Data	T-6	T-8	T-9	T-10	T-11
WHP	149.7	148	148	148.6	144.5
WHT	2675	2385.5	2343.5	2143.8	2229.4
Q	26.98	26.25	26.98	26.96	25.47

7. In the analysis of the models, it has been observed that as all the wells are producing in the critical zone of the choke, a change in one well does not affect the other wells. In the future, as the average reservoir pressure gets lower and lower, the wells will have to operate at a larger choke opening to maintain a moderate flow rate, i.e., the wells may not be operating in the critical zone. In that case, a change in one well will be affecting the performance of other wells.

   In all the analysis, if otherwise not mentioned, the choke size of the wells should be assumed to be constant throughout their life.

CHAPTER 9

CONCLUSIONS AND RECOMMENDATIONS

9.1 CONCLUSIONS

After analyzing the wells individually and their integrated networks, the following conclusions can be made:

1. Simulated results compare well with the actual data. Therefore, the individual well models can be used to predict the future production under changing reservoir and/or tubing conditions.

2. The study shows that the wells might be able to produce until the average reservoir pressure is about 1400 psia although at a much-reduced rate.

3. Reducing the sales line pressure will not increase the flow rate as the wells are producing in the critical range of the choke. On the other hand, higher sales line pressure than the existing 1000 pisa, can be maintained up to certain limit without sacrificing the flow rate. However, the effect of high pressure on gas processing plant should be considered.

4. Changing the choke size of any well affects the flow rate of that well only. Flow rates of all the wells can be increased up to certain limit by changing the existing choke settings.

5. Wells TT-1 through TT-10 are producing at the optimum rate but with larger tubing size. Same flow rate can be obtained from these wells with a smaller size tubing.

6. TT-11 has a bottleneck in the form of smaller size of tubing. Flow rate of TT-11 can be increased by increasing the tubing size

7. Increasing the choke size increases the flow rate of the individual well. Most of the wells can produce as high as 60 MMSCFD. But due to friction effect it should be limited to 35 MMSCFD.

8. At lower flow rates, as flow rate increases, the well head temperature increases due to frictional effect and because of lower heat losses due to decreased residence time. But at higher rates, the friction effect is over shadowed by Joule-Thompson effect. So therefore, after a certain flow rate, wellhead temperature decreases with flow.

9. The individual well analysis shows that the stimulating of wells would not significantly increase the flow from the reservoir.

10. The analysis of the integrated models shows that as the wells are operating in the critical zone, changing the choke size of any well does not affect the performance of other wells. In future, if the wells operate beyond the critical zone, change in one well will affect other wells.

9.2 RECOMMENDATIONS

1. Comprehensive pressure survey should be conducted in each well to find out the up to date values of reservoir parameters.

2. Many of the piping in TT-1 through TT-10 are oversized. During next work over, they can be changed with much smaller sizes.

3. Production of TT-11 is restricted due to presence of smaller tubing of 3.068-inches diameter. It should be replaced with 4.0 inches tubing, which will increase the production, by 2.3 MMSCFD.

4. Production of individual wells should be limited to about 35 MMSCFD to avoid large frictional drop. This is more so for wells TT-7 through TT-10 where higher wellhead pressure is required for efficient Joule-Thompson expansion. The presence of water table also limits the maximum rate of production.

5. There should be a provision to measure the exact size of the choke. Presently, choke sizes are adjusted through adjustable choke valves, from which exact choke sizes can not be read.

6. The analysis is based on compositional data from IKM report of 1991. The phase envelope based on the composition does not exactly match the field condition. So detailed compositional analysis at the existing conditions should be made.

7. Most of the wells at the Titas Gas Field are completed in more than one sands resulting in commingled production from various sands. While this practice reduces the cost of production in some cases, this also makes individual wells/sand performance monitoring more difficult and complicated. Commingling the wells should be avoided where possible.

8. Recommendations are based solely on Nodal Analysis method. No cost analysis has been done in this connection. Decision to change piping and tubing should also be based on economic analysis as well as on future demand.

APPENDIX A

Table A.1: Physical Property Table of Triethylene Glycol

Source: Kohl, A.L. and Riesenfeld, F.C., Gas Purification

Molecular Weight	150.2
Boiling Point @ 760 mm Hg	550.4^0 F
Initial Decomposition Temperature	404^0 F
Freezing Point	19.04^0 F
Density @ 77^0 F, g/ml	1.119
Viscosity, abs, cp @ 77^0 F	37.3
@140^0 F	9.6
Surface tension @ 77^0 F, Dyne/cm	45
Specific heat @ 77^0 F	0.53
Heat of Vaporization (760 mm Hg) Btu/lb	174
Heat of solution of water in infinite Amount of Glycol (approx. 80^0 F) Btu/lb	86
Flash point, ^{0} F	320

APPENDIX B

```
#include<iostream.h>
#include<math.h>

//calculation of flowing bottom hole pressure from
flowing well head pressure by avg.temp and z
method for a vertical well
void main()
{
float sg,pc,tc,q,pt,l,tw,d,pw1,pavg,tavg,ppr,tpr,z,tt;
float u,k,x,y,a,n,f,s;
float pw2;
sg=0.584;
pc=669.6;
tc=351.2;
q=23600;
pt=1964.7;                          //psia
l=8801;
tw=195;
d=3.068;
tt=150.0;
pw1=pt+(0.25*pt*l)/(100*100);
pw2=pw1;

for(int i=1; i<3;i++)
{
pavg=(pw2+pt)/2.0;
tavg=(tt+459+tw+459)/2.0;
ppr=pavg/pc;
tpr=tavg/tc;
cout<<ppr<<endl<<tpr<<endl;
z=ppr*(-0.0284*tpr+0.0625)+0.4714*tpr-0.0011;
cout<<z<<endl;
a=1.4935*0.001*(pavg*16.90)/(z*tavg);
k=(9.379+0.01607*16.9)*(pow(tavg,1.50))/(209.2+19.26*16.9
+tavg);
x=3.448+986.4/tavg +0.01009*16.9;
y=2.447-0.224*x;
u=0.0001*k*exp((x)*pow(a,y));
n=(20*0.584*q)/(u*d);
f=4.0*pow((2.28-4.0*log10(0.0006/d+21.25/(pow(n,0.9)))),-
2);
s=(0.0375*0.584*l)/(z*tavg);
pw2=sqrt(pt*pt*exp(s)+6.67*0.0001*q*q*f*z*z*tavg*tavg*(ex
p(s)-1)/(pow(d,5.0)));
}

cout<<f<<endl<<pw2<<endl;           //bottom hole pressure
}
```

```
#include<iostream.h>
#include<math.h>
// avg. temp and z method to determine flowing bottom
hole pressure from flowing well head pressure
for a deviated well


void main()
{
float sg,pc,tc,q,pt,tw,d,pw1,pavg,tavg,ppr,tpr,z,md,tvd,t
t;
float u,k,x,y,a,n,f,s;
float pw2;
sg=0.584;
pc=669.6;
tc=351.2;
q=27100;
pt=2166.7;
pw2=pt;
tw=208.940;
d=3.958;
tt=150.0;


for(int i=1;i<29;i++)            //tubing divided
                                   into 28 segments
{cin>>md;
cin>>tvd;
if(tvd>md)
cout<<"error"<<endl;
else
{

pt=pw2;
pw1=pt+(0.25*pt*md*tvd/md)/(100*100);

pw2=pw1;
tavg=(tt+(tw-tt)*i/28.0+tt+(tw-tt)*(i-1)/28.0)/2.0+459;
//cout<<tavg<<endl;
for(int j=0;j<3;j++)
{
pavg=(pw2+pt)/2.0;

//cout<<pavg;
ppr=pavg/pc;
tpr=tavg/tc;
cout<<ppr<<endl<<tpr<<endl;
z=ppr*(-0.0284*tpr+0.0625)+0.4714*tpr-0.0011;
//cout<<z;
a=1.4935*0.001*(pavg*16.90)/(z*tavg);
```

```
k=(9.379+0.01607*16.9)*(pow(tavg,1.50))/(209.2+19.26*16.9
+tavg);
x=3.448+986.4/tavg +0.01009*16.9;
y=2.447-0.224*x;
u=0.0001*k*exp((x)*pow(a,y));
n=(20*sg*q)/(u*d);
f=4.0*pow((2.28-4.0*log10(0.0006/d+21.25/(pow(n,0.9)))),-
2);

s=(0.0375*sg*md*tvd/md)/(z*tavg);
pw2=sqrt(pt*pt*exp(s)+6.67*0.0001*q*q*f*z*z*tavg*tavg*(ex
p(s)-1)/((pow(d,5.0)*tvd/md)));
cout<<pw2<<endl;
}
}
}

cout<<pw2<<endl;

}
```

NOMENCLATURE

C	Back-pressure equation coefficient
C_d	Drag coefficient
d	Inner diameter, inch
f	Moody friction factor
f'	Darcy friction factor
h	Height of pay zone, feet
K_g	Relative permeability to gas
L	Length, feet
M	Molecular weight, lb_m/lb-mole
n	Back-pressure equation exponent
P	Pressure, psia
P_{avg}	Average reservoir pressure, psia
Pwh	Wellhead pressure, psia
ΔP	Pressure drop, psia
Q	Flow rate, MMSCFD (million standard cubic feet per day)
Q	Flow rate, MSCF/D
S'	Skin effect
T	Temperature
T_{avg}	Average temperature
V	Specific volume, ft^3/lb_m
WHP	Wellhead pressure, psia
WHT	Wellhead temperature, ^0F
Z	Gas compressibility
Z_{AVG}	Average gas compressibility
α	Flow coefficient for choke
γ	Heat capacity ratio
γ_g	Specific gravity of Gas
ρ	Density, gm/cm^3
μ	Gas viscosity, cp
θ	Angle of deviation from vertical plane

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