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MASTER'S THESIS

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Optimization of Gas Lift System in Varg Field

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Abstract

The objective of this thesis work is to obtain the optimum gas injection rate which yields the maximum oil production. Obtaining the optimum gas injection rate is important because excessive gas injection rate reduces oil production rate and increases operation cost.

To obtain the optimum gas injection rate for achieving the maximum oil production, all wells had been modelled by Prosper program and network solver calculation had been performed by Gap program. Flash data of recombined reservoir fluid had been used for PVT matching.

All available well test data including current well test data had been considered for quality checking. Since the reservoir parameter is continuously changing from inception of production, current well test data was the focus for using in the well model. It was found that current well test data for all wells had been matched nicely with calculated data in Prosper. Deviation range was below 3%.

For correlation comparison of VLP, Petroleum Expert 2 was found very close to well test data for all well models. Parameter 1 and 2 was close to unity. While matching surface flow line in Gap program, Duckler Flanning was found the best fit correlation for production and test flow line. Calculated manifold pressure was compared with the measured well head pressure and found very close results.

Currently oil is producing from eight wells of Varg field on which seven wells are producing with gas lift system. Presently average oil production rate of Varg field is around 2500 Sm^3/day with gas lift injection rate around $600x10^3$ Sm^3/day. From simulation result of GAP program, maximum oil production rate was achieved 2867.0 Sm^3/day at gas lift injection rate of $661.4x10^3$ Sm^3/day. At $500x10^3$ Sm^3/day gas lift injection rate, Gap calculates 2686 Sm^3/day oil production rate. It has been observed from the simulation result that well A-05A is producing without gas lift injection due to low water cut. Production optimization and lift gas allocation rates achieved by this thesis work shows quite close results with current status of all producing wells.

In Varg field, all produced oil is processed by both production and test separators. For finding out the best combination for obtaining the maximum oil production, producing wells had been passed through different combinations of wells and separators. From this work, maximum oil production had been achieved by flowing well A-05A and well A-07 through the test separator and remaining six wells through the production separator.

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Above all, I thank to Almighty for providing me persistence, resilience and braveness for achieving the substantial results.

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Chapter 1 Introduction

1.1 Background Information

The Varg field is a complex field with several large faults isolating the different parts of the reservoir from each other. Most of the fault blocks have pressure support from water and/or gas injection whereas others are produced by primary depletion. [15]

During the life of reservoir, hydrocarbon production prompts to decrease the reservoir pressure and increase the water cut and consequently reduce the productivity. In the course of time, production becomes arrested by water break-through. Today high oil price stimulates oil companies to maximize their oil production. Optimizing oil production by using gas lift system is widely used technique around the world.

In 2006, Varg field experienced a massive water breakthrough in the Varg West segment. The water breakthrough was earlier than expected in the less mature Varg West panel. There caused both sea-water and formation water breakthrough. This led to reduced oil production in the Varg field compared to the production forecast. [15]

For increasing water cut and lack of pressure support from reservoir, many wells of Varg field suffered to lift the produced oil to the surface and consequently had been provoked to install the gas lift system. In the beginning of 2006, temporary gas lift was installed on three wells on Varg field. The gas lift project is being upgraded. Recently all producing wells of Varg field have been hooked up with gas lift system to enhance the oil production and minimise well downtime.

Obtaining the optimum gas injection rate is important because excessive gas injection reduces production rate and consequently increases the operation cost. Hence, there should be an optimum gas injection rate which yields maximum oil production. Finding out this optimum gas injection rate is the main challenge of gas lift allocation optimization problem. On this ground, the thesis work had been pursued to study on the gas lift allocation system of Varg field for finding out the optimum gas injection rate to achieve the maximum oil production.

1.2 Project Objectives and Scope of Work

The objective of this thesis work is to maximise the oil production rates by optimizing the lift gas injection rates for eight producing wells (A-01, A-03, A-05A, A-07, A-09A, A-10T2, A-12BT2 and A-15) of Varg field. The thesis work had been performed by the application of PROSPER and GAP software. Due to large volume of work for preparing well models for individual well, four well models (A-03, A-09A, A-10B, A-12BT2) had been prepared in this thesis work. Remaining four well models had been prepared by other fellow. Finally a complete production network had been developed by combining all eight well models. By running a simulation program in GAP, optimized lift gas injection rate had been determined for individual well system and the maximum oil production rate had been achieved for the whole production system.

Chapter 2 Concept and Overview

2.1 Theory and Concept

For production optimization and gas lift allocation of different wells, it is truly necessary to have conceptions of well hydraulics and inflow and outflow performances of wells. In the following sections, relevant theories and concepts have been outlined on which basis the thesis work had been performed.

2.1.1 Inflow Performance of a Well

The ability of a well to lift up fluid represents its inflow performance.

Inflow performance of a well with the flowing well pressure above the bubble point pressure can be expressed by Darcy's equation for a single well located in the centre of a drainage area, produces at steady state condition. [2]

<u>Darcy's equation</u>

$$q = \frac{2\pi kh}{\mu B} \frac{(p_e - p_{wf})}{\ln(r_e - r_w) + S} \qquad [2.1]$$

2.1.2 Productivity Index (PI)

PI is one of the important characteristics of a well's inflow performance. It depends on the reservoir and fluid properties. From Equation [2.1], we find

$$PI = \frac{q}{(p_e - p_{wf})} = \frac{2\pi kh}{\mu B} \frac{1}{\ln(r_e - r_w) + S} \qquad [2.2]$$

If the PI is known, evaluation of the expected inflow rate under specified flowing well pressure is straightforward:

$$q = PI(p_e - p_{wf}) \qquad [2.3]$$

2.1.3 IPR Curve

The relation between the production rate and the drawdown pressure is called Inflow Performance Ratio or IPR curve. Production rates at various drawdown pressures are used to construct the IPR curve. It reflects the ability of the reservoir to deliver fluid to the well bore.

2.1.3.1 IPR in Single Phase Flow

In case of a single phase flow, the relation between the production rate and the pressure drop is a straight line [10]. As follows from the figure, slope of the IPR is inversely proportional to the PI value; i.e. Slope = 1/PI= *Constant*

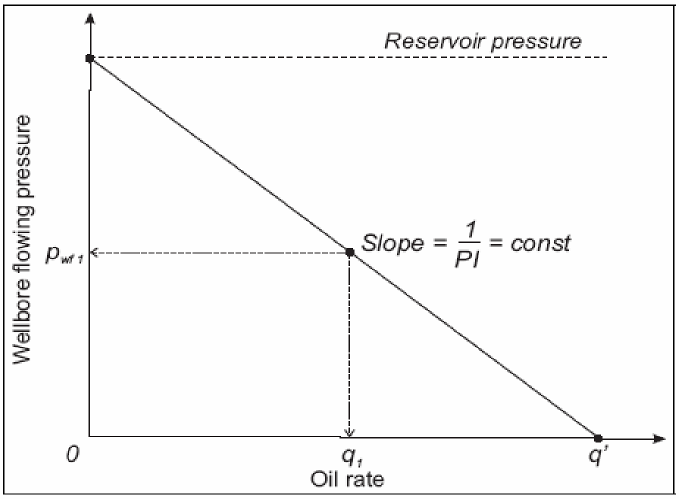


Figure-2.1.1: IPR Curve for Single Phase (Liquid) Flow

Equations (2.1) and (2.2) can not be used if the flowing well pressures pwf is below the bubble point pressure pb. At this condition (pwf ≤ pb), the IPR is no longer a straight line. It has been illustrated in Phase diagram (figure-2.2) which states that at such bottom hole conditions, a two phase flow occurs in a reservoir where both oil and gas flow together towards the well. This type of flow is called solution gas drive.

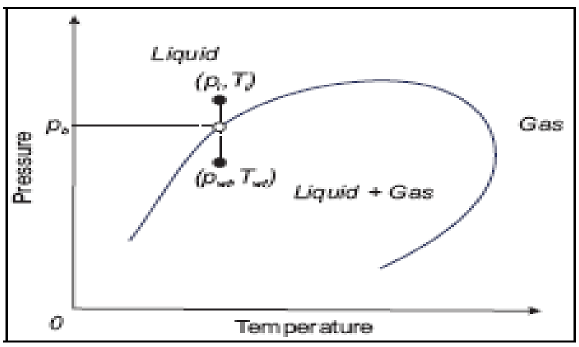


Figure-2.1.2: Phase Diagram for Two Phase Flow

2.1.3.2 IPR in Two Phase Flow

A two phase flow has effect on the IPR curve. It deviates from a straight line resulting in reduced values of the productivity index corresponding to reduced values of the flowing well pressure. [4]

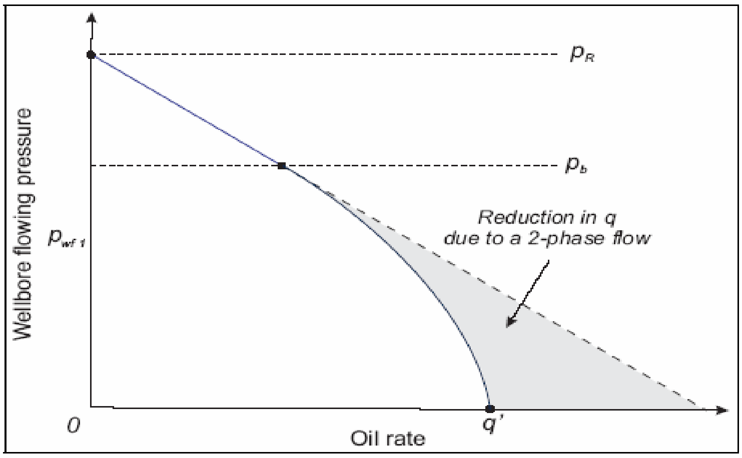


Figure-2.1.3: IPR Curve for Two Phase Flow

2.1.4 Vogel's Equation

One of the methods of predicting well's inflow performance under a solution gas drive (two phase flow) conditions (e.g. pwf ≤ pb) was developed by Vogel. In 1968, Vogel suggested the following equation for IPR for the solution gas drive conditions;

$$\frac{q}{q'} = 1 - 0.2\left(\frac{p_{wf}}{\bar{p}_R}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}_R}\right)^2 \qquad [2.4]$$

Here $\bar{p}_R$ = Average reservoir pressure or bubble point pressure, whichever is lower.

It is important that Vogel's equation gives the best fit for the results of well testing and simulation runs. Plotting these results on dimensionless form gives almost the same curve in all cases, as illustrated in figure-2.1.4.

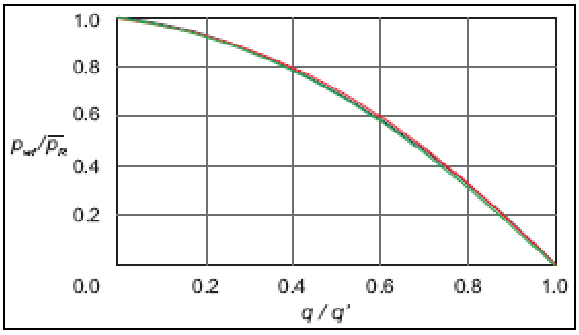


Figure-2.1.4: Results of Well Testing and Simulation Runs Plotted in Dimensionless Form

2.1.5 Tubing Performance of a Well

Production rates at various bottomhole pressures are used to construct the tubing performance curve which reflects the ability of the completion system to deliver production up the well bore and completion equipment. [17]

Analysis of a Tubing performance or vertical lift performance (VLP) of a well is an important part of the well design. It allows selecting the well completion correctly corresponding to lifting methods and to evaluate well's performance.

2.1.6 Gradient Curves

The pressure gradient in a pipe line or well bore is the summation of following components:

- Hydrostatic head
- Friction head

Thus the total pressure gradient can be written as: [4]

$$\frac{dp}{dl} = (\frac{dp}{dl})_{hs} + (\frac{dp}{dl})_{fr} \qquad [2.5]$$

The hydrostatic component is due to the density of fluid mixture at each point in the system and is a complex function of the relative velocity of the present phases. The gravity head loss is proportional to the fluid density corrected for slip. The slip correction to be applied depends on the flow regime and fluid viscosity.

Friction component is controlled by fluid viscosity and geometric factors such as pipe diameter and roughness. In the majority of the oil field application, the gravitational component s normally accounts for around 90% of the overall head loss. Therefore the total pressure drop function is not particularly sensitive to the value of friction loss coefficient.

Pressure gradients associated with these both terms can be written as:

Hydrostatic force: $$(\frac{dp}{dl})_{hs} = (E_g.\rho_g + E_l.\rho_l).g.\cos\theta \qquad [2.6]$$

Friction force: $$(\frac{dp}{dl})_{fr} = \frac{4}{d}.C.(\mathrm{Re}_m)^n.\tfrac{1}{2}(E_g.\rho_g + E_l.\rho_l).u_m^2 \qquad [2.7]$$

2.1.6.1 Liquid Flow Rate

As follows from equation (2.7), increased liquid rate (higher values of velocity um) results in friction losses increase. Rearranging equation [2.6],

$$(\frac{dp}{dl})_{hs} = \rho_g.g.\cos\theta + (\rho_l - \rho_g).E_l.g.\cos\theta \qquad [2.8]$$

We find from equation [2.8], hydrostatic pressure also increases with the increased liquid production. This effect has been illustrated by the following figure.

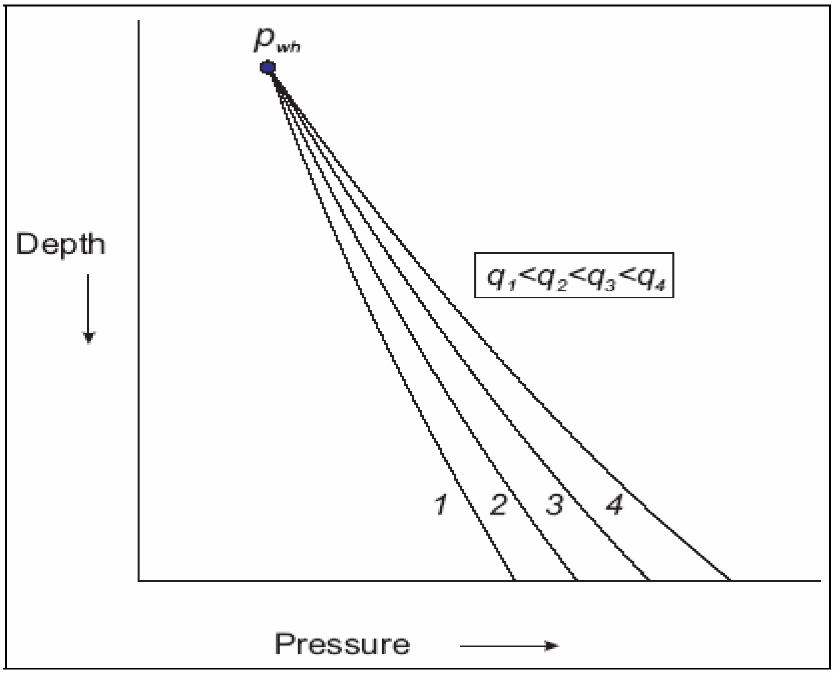


Figure-2.1.5: Effect of Increased Liquid Rate on Gradient Curves

2.1.6.2 Gas to Liquid Ratio (GLR)

Rearranging equation [2.8] we find,

$$(\frac{dp}{dl})_{hs} = \rho_l.g.\cos\theta - (\rho_l - \rho_g).E_g.g.\cos\theta \qquad [2.9]$$

Equation [2.9] shows that increased in gas to liquid ratio results in reduction of the pressure gradient. It mostly affects the hydrostatic component. . Increase in GLR while keeping a constant liquid rate ql, reduces the hydrostatic component resulting in the reduced bottomhole pressure to a certain degree. On the other hand, increased GLR increases friction forces and has a counter effect on the bottomhole pressure. When contribution of the friction forces higher than that of hydrostatic forces, the actual bottomhole pressure (Pwf) begins to grow. This effect has been illustrated by the following figure.

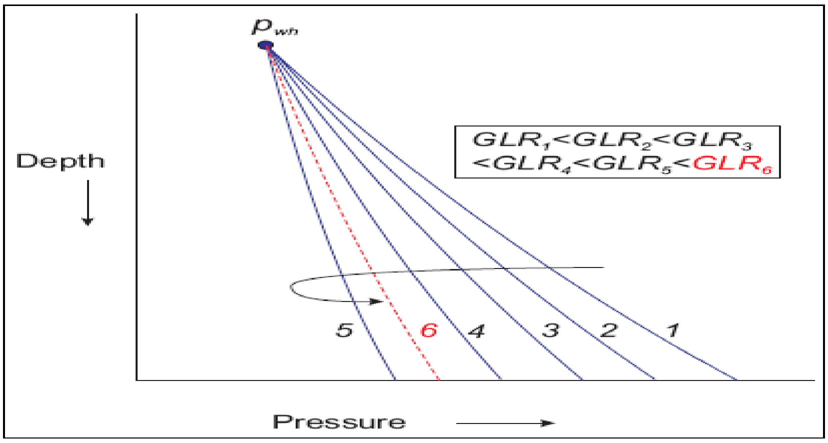


Figure-2.1.6: Effect of GLR on Gradient Curves

Combining figure 2.1.5 and 2.1.6 and expressing the flowing BHP as a function of GLR for different liquid rates, we obtain the following figure.

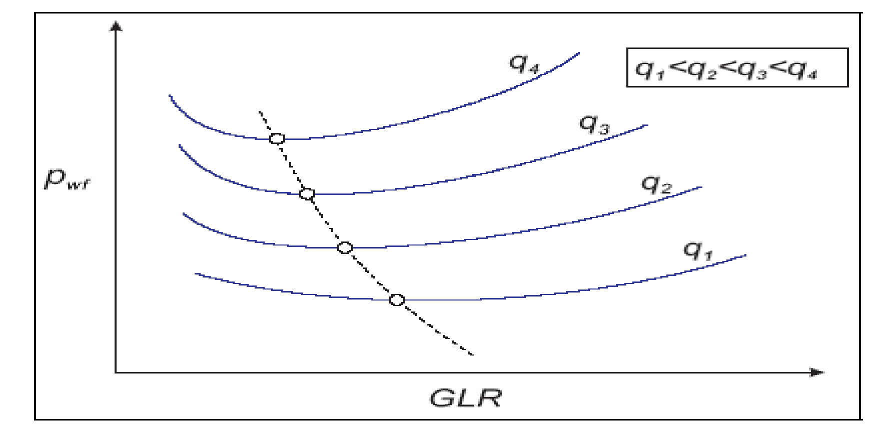


Figure-2.1.7: Flowing BHP as a function of GLR for different q_l and the same WHP

2.1.6.3 Operating Point

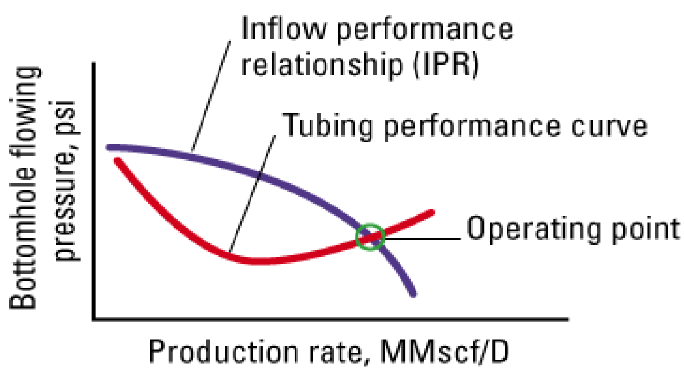


Figure-2.1.8: Operating point

Combining the tubing performance curve with a curve reflecting the inflow performance identifies the operating point. Optimum liquid production is achieved in this point. [17]

2.1.6.4 Favourable GLR

Re-plotting the figure 2.7 in addition to VLP/IPR curve, the crossing point of these two curves gives a value of the maximum possible liquid rate as illustrated in following figure.

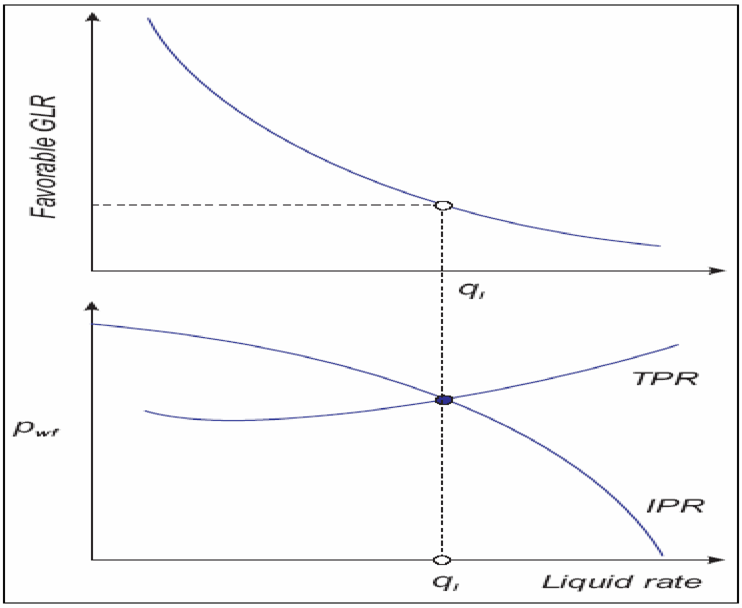


Figure-2.1.9: Favourable GLR and Corresponding Liquid Production Rate with VLP Curve

2.1.6.5 Water Cut

Effect of water cut on gradient curve is expressed by the following equations

$$\rho_l = \rho_0(1 - f_w) + \rho_w . f_w = \rho_o + (\rho_w - \rho_o). f_w \qquad [2.10]$$

Here, fw is water cut. It is follows from equation [2.10] that increased water cut results in increased water density which in its turn, increases hydrostatic forces. As a result, pressure gradient and bottomhole pressure increases, as illustrated in the following figure.

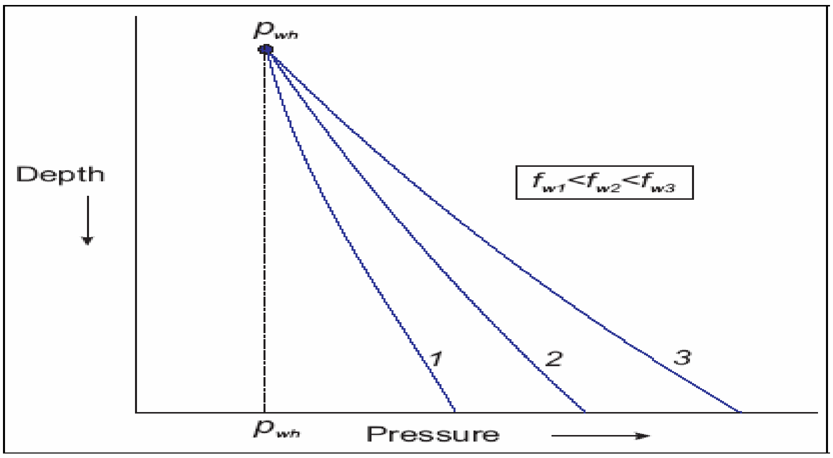


Figure-2.1.10: Effect of Water cut on Gradient Curves

2.2 Overview of Gas Lift System

2.2.1 Gas Lift System

Gas lift is a method of lifting fluid where relatively high pressure (250 psi minimum) gas is used as the lifting medium through a mechanical process [3]. It is a form of artificial lift. The need of artificial lift is required when the pressure of well is not enough as to maintain the oil production with satisfactory economic return. This situation is typical in mature oil field where increasing water cut or decreasing reservoir pressure eventually causes well to cease natural flow. Less reservoir pressure leads to less bottom hole flowing pressure means less energy to lift up the hydrocarbon liquid. In order to solve this problem, two different approaches are generally used. First, increasing bottomhole flowing pressure by bottomhole well pumping. Second, reducing fluid column density in the well bore by injecting compressed gas which is called gas lift.

In a typical gas lift system, compressed gas is injected through gas lift mandrels and valves into the production string. The injected gas lowers the hydrostatic pressure in the production string to re-establish the required pressure differential between the reservoir and well bore, thus causing the formation fluids to flow to the surface. [12]

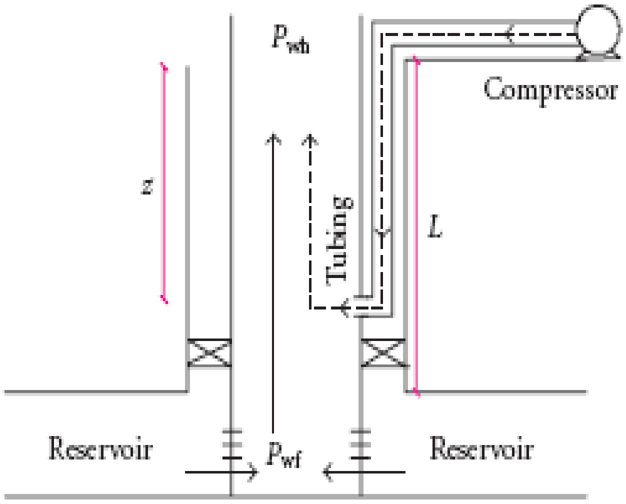


Figure-2.2.1: Simple Gas Lift Schematic

Produce fluid and gas along with injected gas is then flown into separator. Produced oil is pumped to storage while injected gas and produced gas is returned to the suction side of the compressor. After the gas is recompressed, the rotation cycle is completed. Make up gas from another gas producing well is used for compressor start-up. The typical general gas lift system is shown on following figure. [5]

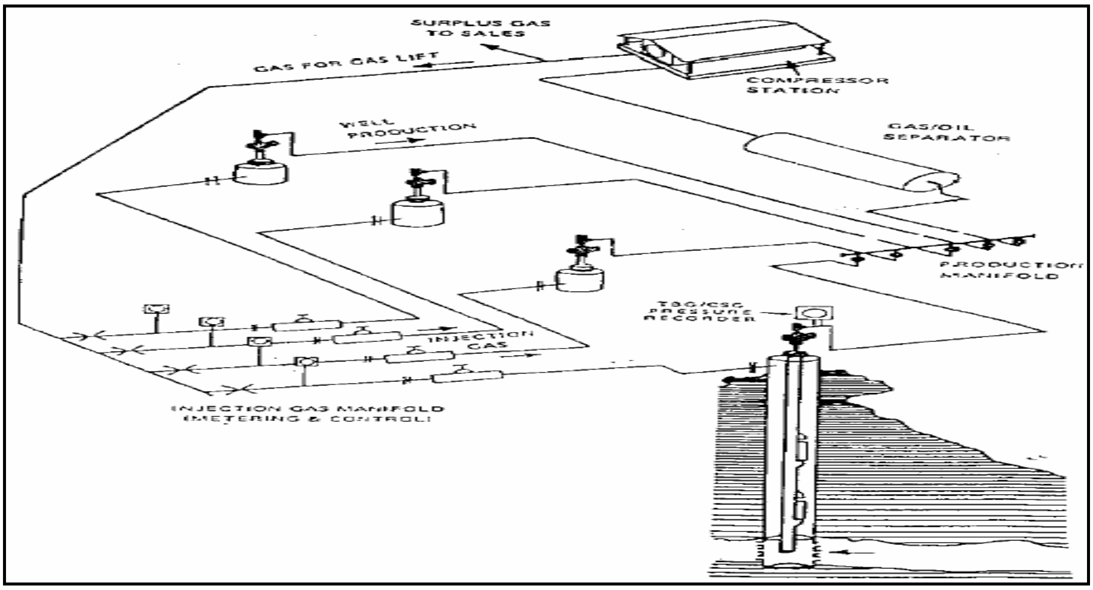


Figure 2.2.2: General Gas Lift system

2.2.2 Principle of Gas Lift

The mechanism of gas lift system is explained on figure 2.2.3 [7]. At time when the BHP lowers than hydrostatic head inside well bore, the liquid will not move up to the surface but it will stop at depth A. In this situation zero production rates occur. In order to overcome this problem, the hydrostatic head in the well bore needs to be decreased by injecting gas. When gas is injected through the annulus to gas lift mandrels and valves into the production string at depth H_i; the total density of fluid above injection point is decreased. Injection gas is then expanded so that it pushes the liquids ahead of it which further reduces the fluid column weight. Displacement of liquid slugs by large bubbles of gas act as pistons to push the produced fluids to the surface, thus causes liquid to flow to the surface, as shown in line G_{N+1}.

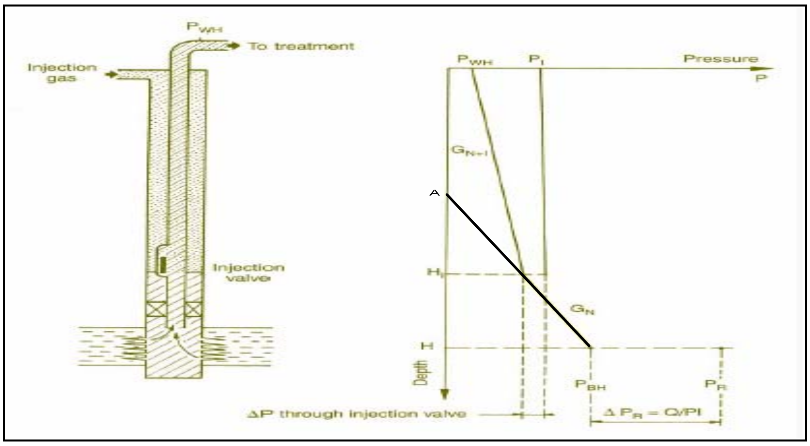


Figure 2.2.3: Principle of Gas Lift

2.2.3 Advantages of Gas Lift

Gas lift is the most preferable artificial lift especially when gas needed for injection is available. From the installation point of view, gas lift completion system is simple and not need big space especially in offshore field when space available very limited. Gas lift is rather inexpensive, easy to implement, very effective in the wide range of operation conditions and require less maintenance. Maximum liquid production is achieved by availing gas lift system. The performance comparison of different artificial lift method has been shown in figure 2.2.4 and figure 2.2.5. [1]

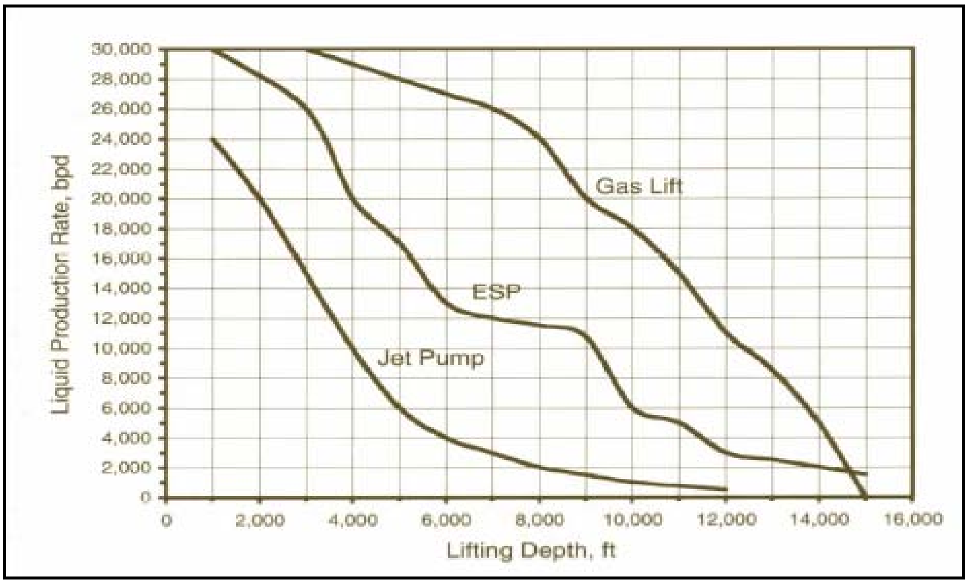


Figure 2.2.4: Gas Lift, ESP, and Jet Pump Performance Curve

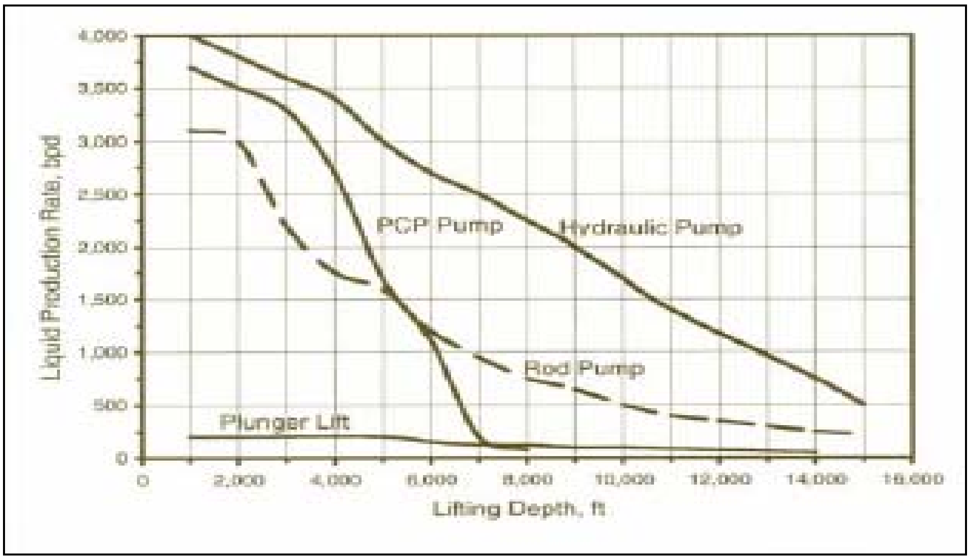


Figure 2.2.5: Hydraulic Pump, PCP Pump, Rod Pump, and Plunger Lift Performance Curve

2.2.4 General Classification of Gas Lift

There are two main concepts of gas lift according to gas injection point of view,

1. Continuous Gas Lift

In continuous flow gas lift, gas is injected continuously into the vertical fluid column. It is a very flexible form of artificial lift and can be used to produce liquid rates in excess of 75000 barrels per day in larger tubing or casing flow application down to 50 barrels per day or less in smaller tubing sizes [13].

2. Intermittent Gas Lift

In this method, gas is injected periodically. In wells that have very low reservoir pressures or producing rates, it may be desirable to gas lift the well intermittently. Intermittent lift is designed to produce the well at the actual rate that the fluid enters the wellbore from the reservoir. The system allows the fluids to accumulate in the production tubing at the bottom of the wellbore. Periodically, high pressure injection gas is rapidly injected into the production tubing under the accumulated fluids which rapidly displaces it to the surface. The frequency of gas injection is determined by the amount of time it takes for the fluids to enter the wellbore and tubing plus the duration of gas injection required to displace it to the surface.

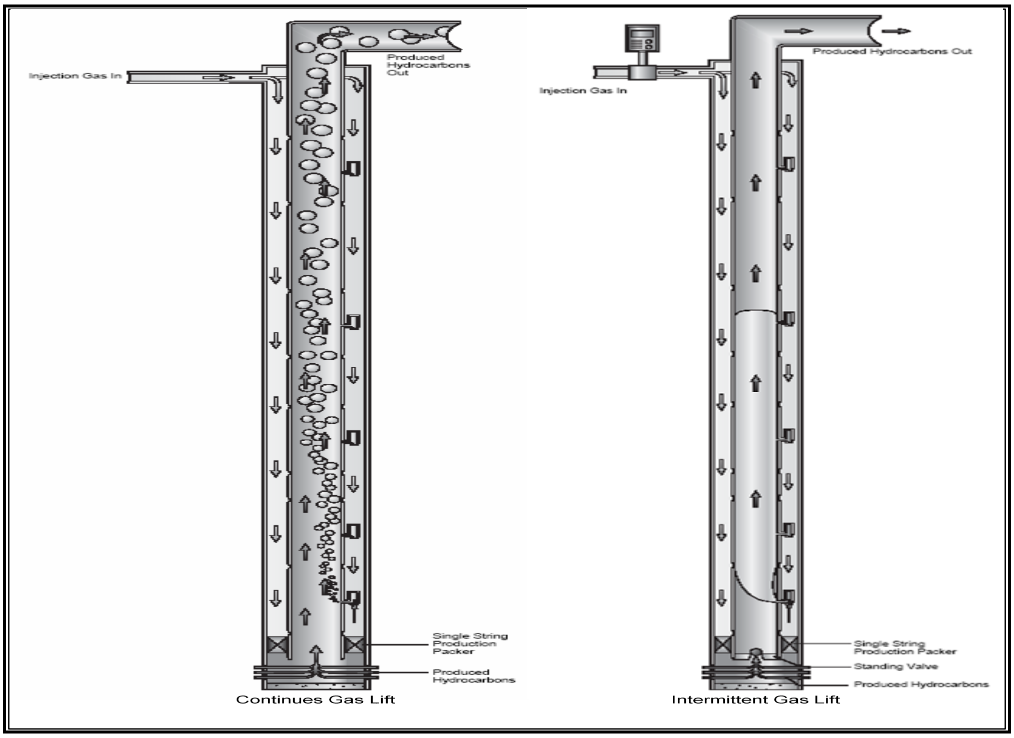


Figure 2.2.6: Continues and Intermittent Gas Lift

According to completion procedure, general gas lift classification has been shown in the figure 2.2.7.

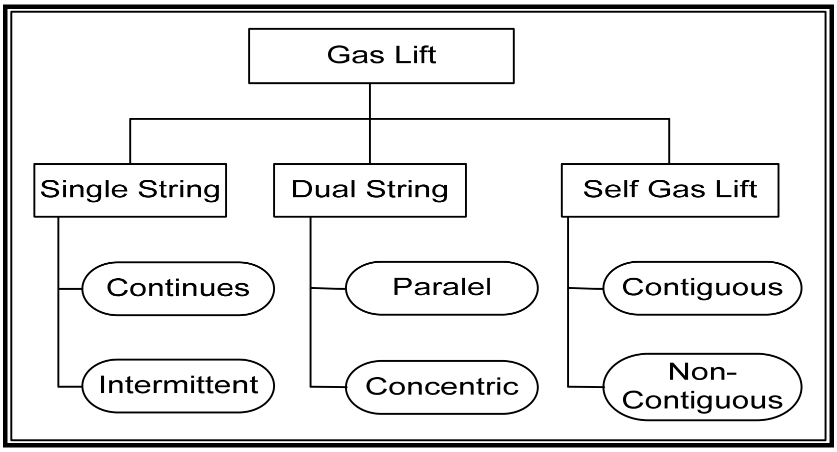


Figure 2.2.7: General Gas Lift Completion Classification

2.2.5 Gas Lift Optimization

The goal of gas lift is to deliver the fluid to the top of the wellhead while keeping the bottomhole pressure low enough to provide high pressure drop between the reservoir and the bottomhole. Reduction of bottomhole pressure due to gas injection will normally increase liquid (oil) production rate, because gas injection lighten the fluid column, therefore larger amount of fluid flow along the tubing. However, injecting too much amount of gas increases the bottomhole pressure which decreases the oil production rate. This is happened because high gas injection rate causes slippage, where gas phase moves faster than liquid, leaving the liquid phase behind. In this condition, less amount of liquid will flow along the tubing. Hence, there should be an optimum gas injection rate [6]. The optimum gas injection point for maximum oil production has been shown by a continuous gas lift Performance curve (GLPC) in figure 2.2.8.

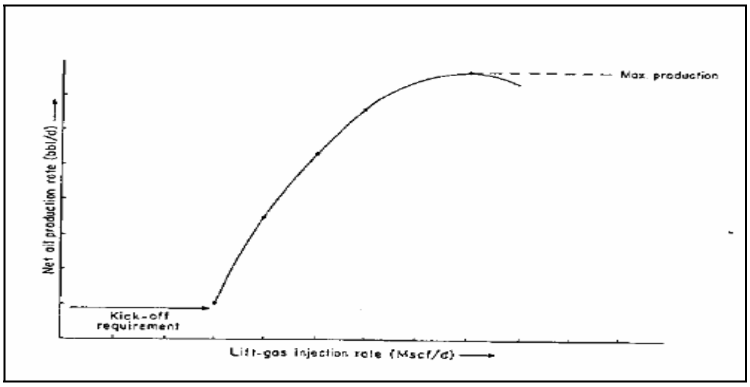


Figure-2.2.8: Gas Lift Performance Curve

Chapter 3 The Varg Field

3.1 Location and Installations

The Varg field is located in the North Sea, South West of Stavanger. Shortest distance to Norwegian coast is 225 km (Jæren). The field has a wellhead platform-Varg A. An FPSO-Petrojarl Varg, owned by Teekay Petrojarl AS, process all produced fluids from Varg A, on behalf of Talisman Energy. There are 10" production line, 6" test line, 5" gas injection line, 8" water injection line and umbilical between Varg A and Petrojarl Varg. The position of Varg-A: 58.078ºN - 1.890ºE and Petrojarl Varg: 58.078ºN - 1.911ºE [18]

3.2 History

The Varg field was discovered by exploration well 15/12-4 in 1984. This well is on the southern flank of the South segment and found good quality reservoir with a minor oil column. The Varg discovery was confirmed by appraisal wells 15/12-5 (E2 segment) in 1986 and 15/12-6s (N2 segment) in 1990. Well 15/12-9s was drilled on the crest of the South segment and proved a thick oil column. Production of the Varg field commenced in December 1998, with Saga as operator using the floating production vessel (FPSO) Petrojarl Varg. Peak production was reached in 1999 and maintained through 2000; since the beginning of 2001 the field experienced a steady decline. [14]

The Varg Field is operated by Talisman-Energy Norge A/S (65.0 %) on behalf of Petoro (30.0 %) and Pertra (5.0 %). Pertra drilled five wells in 2004, including the first wells on the West segment. Talisman drilled four wells in 2005, including the first producer in segment N1 and an excellent water injector in the West segment which arrested the steep production decline. Seawater has recently broken-through in Varg West. In 2005, Talisman worked over well A-10 to remove a sand blockage, successfully reinstating production. Well A-09A and A-12BT2 were drilled in 2006.

3.3 Geology

The field structure comprises a series of tilted fault blocks with a crest at 2700m TVDSS. The South and E2 segments are salt cored four way dip closures. A crestal collapse zone above a salt ridge is developed in the central part of the field. The field is heavily faulted with seismic scale faults within field segments and also numerous sub seismic faults are being identified on cores. [14]

The Varg reservoir is a shallow marine, shore face to offshore, Upper Jurassic (Oxfordian) Sandstone reservoir (Ula formation) developed between grounded Triassic pods. The sands are a series of parasequences with progradational, aggradational and retrogradational stacking patterns separated by field wide flooding surfaces. Reservoir thickness varies over the field, reflecting differing accommodation space resulting from halokinesis.

The sands are divided into 9 zones within the 3 main units RZ-1, RZ-2 & RZ-3. In both RZ-1 & RZ-2 sediment was input from the east and the reservoirs thin to the west, being absent over most of the West segment. In both zones the sandstones become muddier to the west and RZ-2 is dominated by mud rich sandstones. RZ-3 is present over the entire field and has a high net/gross. Reservoir quality improves upwards with the best reservoir quality developed at the top of RZ-3. Post-production reservoir pressure data show that the major flooding surfaces as well as some of the limestone are pressure barriers.

The reservoir quality is controlled by the original depositional facies with higher energy sands with the least detrital clay having the best reservoir quality. There is also a strong diagenetic overprint, in some places the reservoir have more secondary porosity than primary due to leaching of locally abundant sponge spicules. Moldic pores where spicules have been dissolved make a significant contribution to total porosity, though it is not well interconnected porosity. Average porosity ranges from 15% to 27% with average permeability around 100mD, sometimes reaches 1000mD.

3.4 Reservoir

The Varg field is compartmentalized seismic-scale faulting, with slightly varying hydrocarbon properties in each panel. The reservoir fluid can be broadly characterized as black oil, 35°API with solution gas-oil ratio in the range of 110 to 140 Sm^3/Sm^3 and viscosity of approximately 0.5cp. Oil FVF is in the range of 1.4 to 1.5 Rm^3/Sm^3. Dependent on the reservoir segment, various recovery mechanisms come in to consideration such as Depletion drive, Water flood, Gas injection and WAG. Most gas injection has been for the purpose of gas disposal rather than reservoir displacement and/or pressure support. [14]

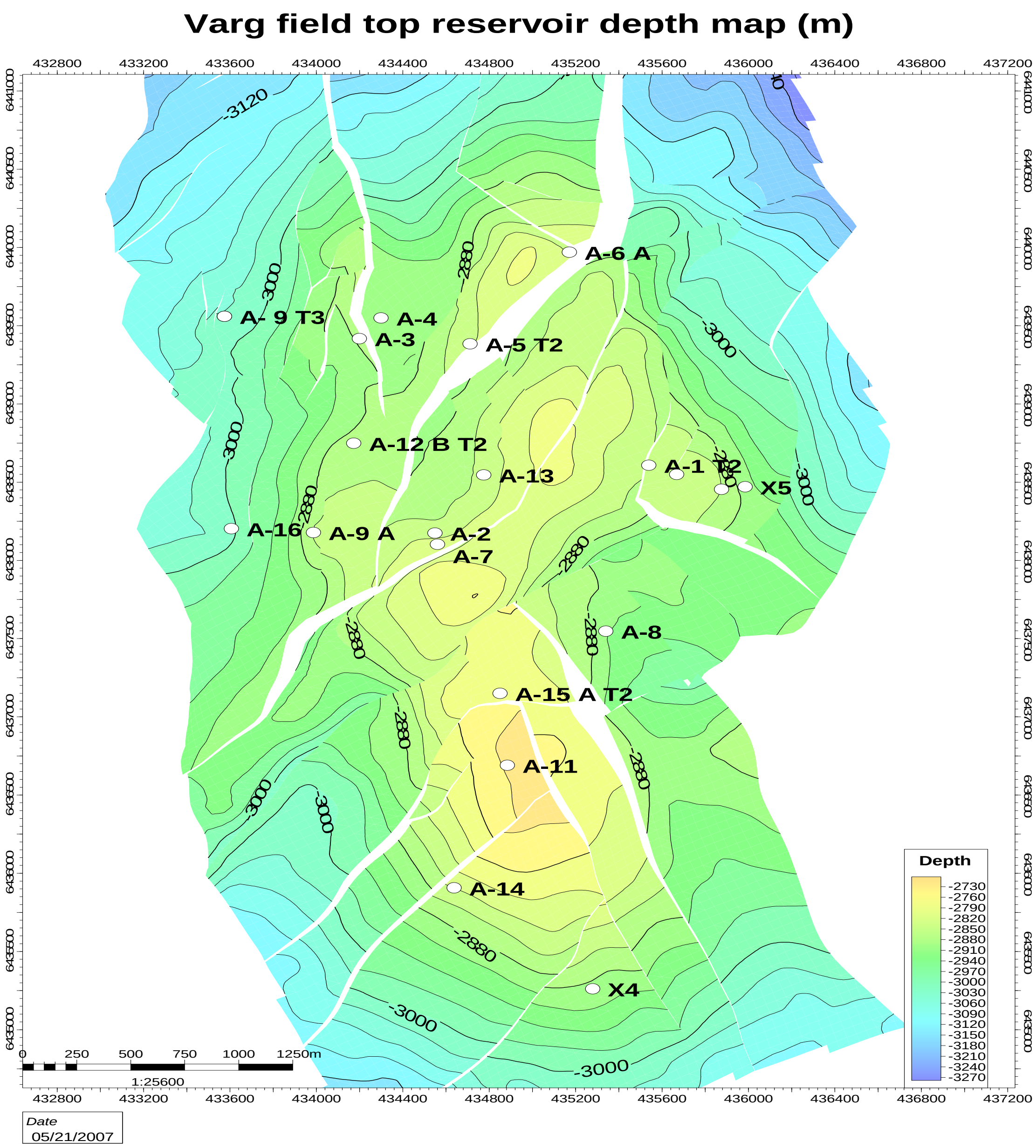


Figure-3.1: Top Reservoir Depth Map

3.5 Well Development in different Reservoir Segments West

The core of the Varg field lies in the water flood of the Western segment which makes up around 80% of the remaining value of the field. Currently oil is producing from A-03, A-09A, A-10T2 and A-12BT2 from this panel with gas lift system and A-16 is working as water injector. [14]

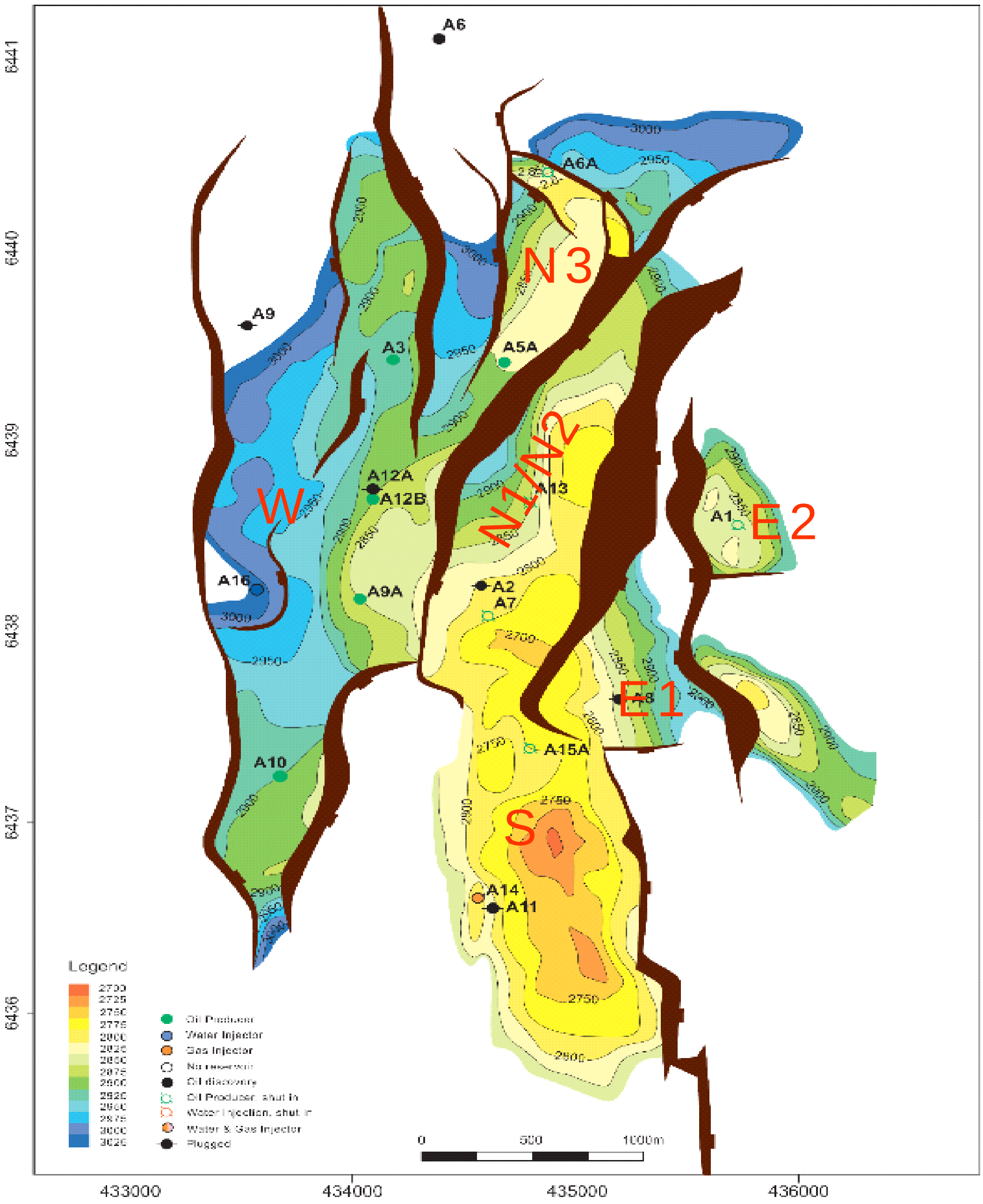


Figure-3.2: Reservoir Segments of Varg Field

South

The South segment, remains in production from well A-15A, produces on an intermittent basis. Modifications had been done to allow gas lift kick-off of well A-15A. Pressure in the South is supported by gas disposal to well A-14.

N3

The N3 panel is under production from wells A-05A and A-06A. A-06A suffers from high GOR and is shut-in to avoid back out of other wells' production by its high gas rate. Producer A-06 was converted to water injector in 2005.

N1/N2

The N1 and N2 panels are developed by producers A-07 and A-13. Well A-13 was converted to water injector to improve reservoir recovery.

E1/E2

The E1 panel has been fully developed by well A-08, which has been plugged.

The E2 panel is developed by well A-01, which is largely watered out and producing on continuous gas lift system.

3.6 Producing Wells in West Segment

The thesis work had been carried-out with all current producing wells in Varg West segment. The wells are A-03, A-09A, A-10T2 and A-12BT2 and all have been hooked-up with gas lift system. A short summery of these wells has been outlined below: [14]

Well: A-03

Well Summary

Well name:	15/12-A-03
Designation:	Oil Producer
ERT – MSL:	51.5m
Water Depth:	84m
TD:	3512 MD / 3076m TVD

Co-ordinates

Surface:	N 6 438 072.15 m,	E 434 558.13 m
Top Reservoir:	N 6 439 440.00 m,	E 434 200.00 m (Planned)

Hole size	**To**	**Casings**	**MW**	**From (m)**	**To (m)**
29.000	278 m	24.000	N/A	136	276
17.500	1499 m	13.375	1.65	136	1494
12.250	3305 m	9.625	1.55	136	3301
8.500	3512 m	5.500		3176	3514

Dates

Spud:	14 May 05
At TD:	09 June 05
Rig Released:	22 June 05

Well: A-09A

Well Summary

Well name:	15/12-A-09A
Designation:	Oil Producer
RKB – MSL:	52.2m
Water Depth:	84.0m
TD:	3009m TVDSS / 3267m MDBRT

Co-ordinates

Platform Reference:	N 6 438 071.30, E 434 556.60
Slot Location:	N 6 438 065.88, E 434 555.73
Target Location:	N 6 438 178.25, E 433 987.14

Hole Size	To (m)	Casing	MW	FIT
29.000	84-278	24.000		
17.500	1329	13 3/8		1.70SG
12.250	1329-3092	9 5/8	1.60SG	1.45SG
8.500	3092-3267	5 ½	1.23SG	

Dates

Start of slot recovery:	23 Jun 06
Start/kick-off Date:	2 Aug 06
TD Date:	11 Aug 06
Release Date:	30 Aug 06

Well: A-10T2

Well Summary

Well name:	15/12-A-10T2
Designation:	Oil Producer
RKB – MSL:	51.5m
Water Depth:	84m
TD:	2991.73m TVD RKB / 3900.0m MD RKB

Co-ordinates

Surface:	N 6 438 066.580m,	E 434 566.980m
Top Reservoir:	N 6 437 398.20m,	E 433 766.76m
TD A-10T2:	N 6 437 002.86m,	E 433 706.79m

Hole Size	To (m)	Casing	MW	Grade	From (m)	To (m)
17.500	277	24.000	245.6	X-56	24	277
17.500	558	13.375	72.0	L-80	24	1369
17.500	1369	9.625	53.5	P-110	24	3520
12.250	3522		17.0	L-80 13%	2903	3898
8.500	3930					
8.500	3900					
8.500	3859					

Dates

At TD:	12 Jul 04
Completed:	28 Jul 04

Well: A-12B T2

Well Summary

Well Name:	15/12-A-12BT2
Designation:	Oil Producer
RKB – MSL:	52.1 m
Water Depth:	84.0 m
TD:	3253 m MD

Co-ordinates

Surface:	N 6 438 068.330 UTM, E 434 560.100 UTM
Top Reservoir:	N 6 438 690.120 UTM, E 434 144.630 UTM
TD (npd):	3217m

Hole Sizes:	**Casings:**	**Depth(m)**	**MW**	**FIT**
12 ¼”	9 5/8”	N/A		1.64
8 ½” (12B)	5 ½”	2802-3242	1.31	
8 ½” (12BT2)	7”	2689-3107	1.49	1.64
6”	4 ½”	3107-3253	1.10	

Dates

Spud:	14 Sept 06 (2802m MD, 2612m TVDss)
At TD:	18 Sept 06
Completed:	1 Oct 06
Release:	3 Nov 06

Chapter 4 Well Models in PROSPER

4.1 PROSPER

PROSPER is a **PRO**duction and **S**ystem **PER**formance analysis software. It assists the production or reservoir engineer to predict tubing and pipeline hydraulics and temperature with accuracy and speed [8]. Prosper's powerful sensitivity calculation features enable existing design to be optimized. It helps petroleum producers to maximise their production earnings by providing the means of critically analysing the performance of each producing well.

4.1.1 Preparation of Well Model in Prosper

The well models in this work had been prepared by Prosper program. Prosper makes model for each component of the producing well system separately which contributes to overall performance, and then allows to verify each model subsystem by performance matching. In this way, the program ensures that the calculation is as accurate as possible. Once the system model has been tuned to real data, Prosper is confidently used to model the well in different scenarios and to make forward predictions of reservoir pressure based on surface production data.

4.1.2 Prosper's Approach and Systems Analysis

Prosper's approach is to first construct a robust PVT model for the reservoir fluid. The PVT model is constructed by entering laboratory PVT data and adjusting the correlation model until it fits the measured data for improving the accuracy of forward prediction. Well potential and producing pressure losses are both dependent on fluid (PVT) properties. The accuracy of system analysis calculation is therefore dependent on the accuracy of the fluid properties model.

In the VLP matching phase, Prosper divides the total pressure loss into friction and gravity components and uses a non-linear regression technique to separately optimize the value of each component. Not only does the matching process result in a more accurate model, it also highlights the inconsistencies in the PVT model or in equipment description.

When sufficient accurate field data is available, robust PVT, IPR and VLP models are prepared by performance matching. Each model component is separately validated; therefore dependency on the components of the model can be eliminated.

The following flow chart gives an outline of the calculation steps required to carry out a system analysis using Prosper and the thesis work had been performed according to this procedure.

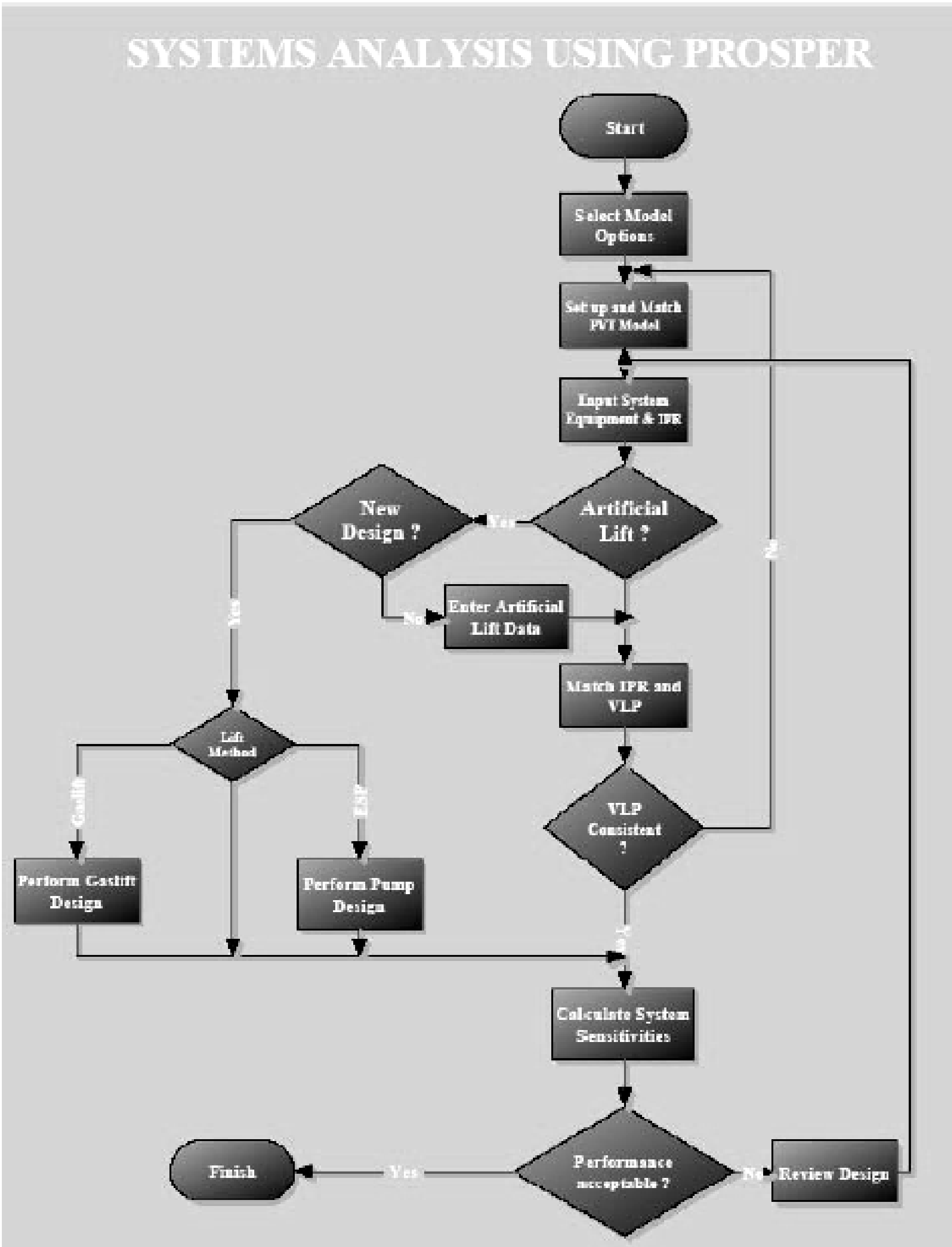


Figure: 4.1 Systems Analysis using Prosper

4.1.3 Prosper Main Menu

- **File Menu**: Prosper uses a flexible file structure that enables data to be easily exchanged between files and other application programs. In Prosper, information is grouped into the following categories and saved into the following types of data file:
    1. PVT Data (*. PVT)
    2. Input Data (*. SIN)
    3. Analysis Data (*. ANL)
    4. Output Data (*. OUT)
- **Option Menu:** This menu provides model options. Options summery of Prosper has been shown in figure 4.2
- **PVT Menu:** This menu is used to match the PVT input data with the laboratory measured data. The user must enter data that fully describes the fluid properties or enables the program to calculate them.
- System Menu: This menu describes well's completion, deviation survey, flowing temperature profile and gas lift data (for artificial lift case).
- Matching Menu: This menu is mainly used for the following objectives:
    1. Input data and model quality control
    2. Fine adjustment of the model parameters to enable well models to reproduce observed data.
    3. In case of artificial lift, system diagnostics and trouble shooting.
- **Calculation Menu:** This menu describes all the calculation methods available in PROSPER; such as to calculate system production rates, run sensitivity analyses, generate lift curve tables etc.
- **Design Menu:** This menu enables the user to perform various artificial lift designs.
- **Output Menu:** This menu is used to report, export and plot input data entered into PROSPER.
- **Unit Menu:** This menu describes the system of units. This feature allows modifying the units system so that it corresponds to data reports supplied by the service company or customising the units system to suit the user's own personal preferences. Prosper always work internally in Field units.
- **Wizard Menu:** This menu allows the user to set up models and perform certain tasks following a predefined sequence.

4.2 Working Procedure for Well Model Set-up

Well model set up of this thesis work had been approached systematically by working from left to right through the main screen of Prosper. The main screen is divided into following order:

- Options Summery
- PVT Data
- Equipment Data
- Gas Lift Data (for gas lift well)
- IPR Data
- Calculation Summary

This order reflects the recommended workflow to follow to set up the well model. The first five sections are input data screen and the last section mentions all the calculation and design features. Calculation menus are activated only when the necessary input data has been entered. In this section, print screens of well A-03 had been used as representative samples of Prosper program.

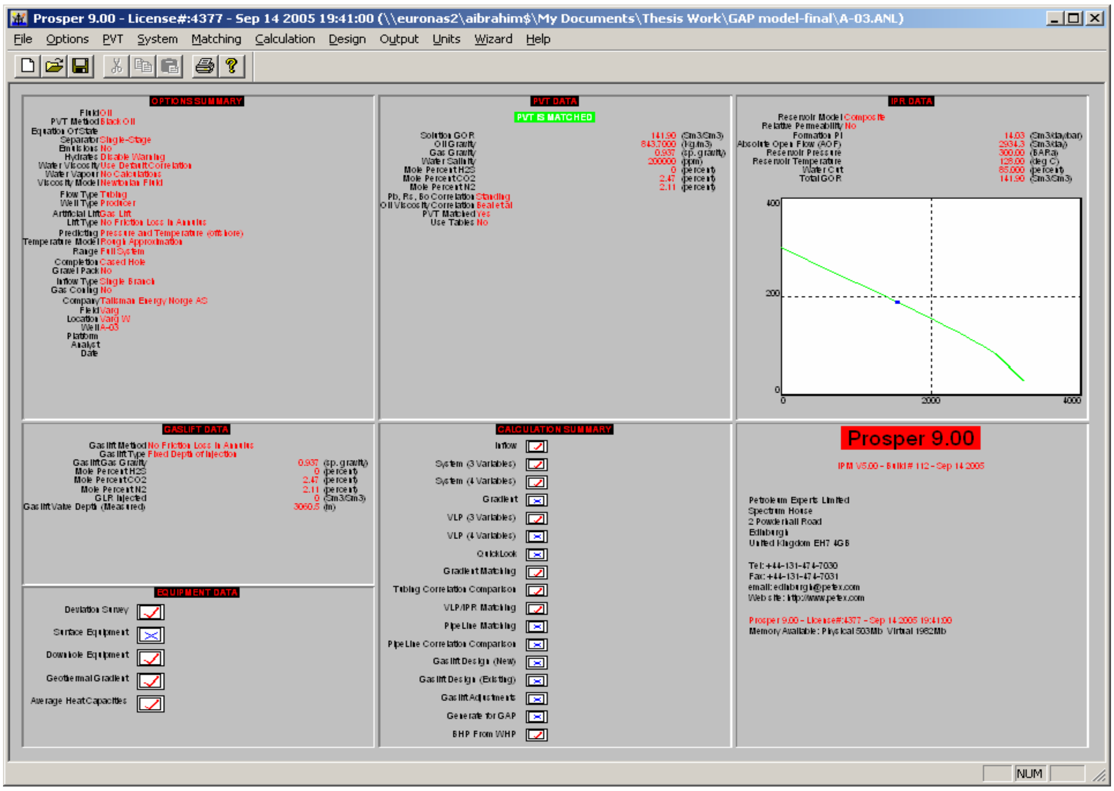


Figure 4.2: Menus and Options in Prosper Main Screen

4.2.1 Options Summery

The option menu is used to define the characteristics of the well. In this work, the following options had been selected to define the well model accurately:

- Fluid: Oil and Water
- PVT Method: Black Oil
- Separator: Single Stage Separator
- Flow Type: Tubing Flow
- Well Type: Producer
- Emulsions: No
- Viscosity Model: Newtonian Fluid
- Lift Method: Gas lift
- Prediction: Pressure and Temperature (Offshore)
- Model: Rough Approximation
- Calculation Range: Full System
- Output: Show Calculation Data
- Well Completion: Cased Hole
- Gravel Pack: No
- Reservoir Inflow Type: Single Branch
- Gas Coning: No

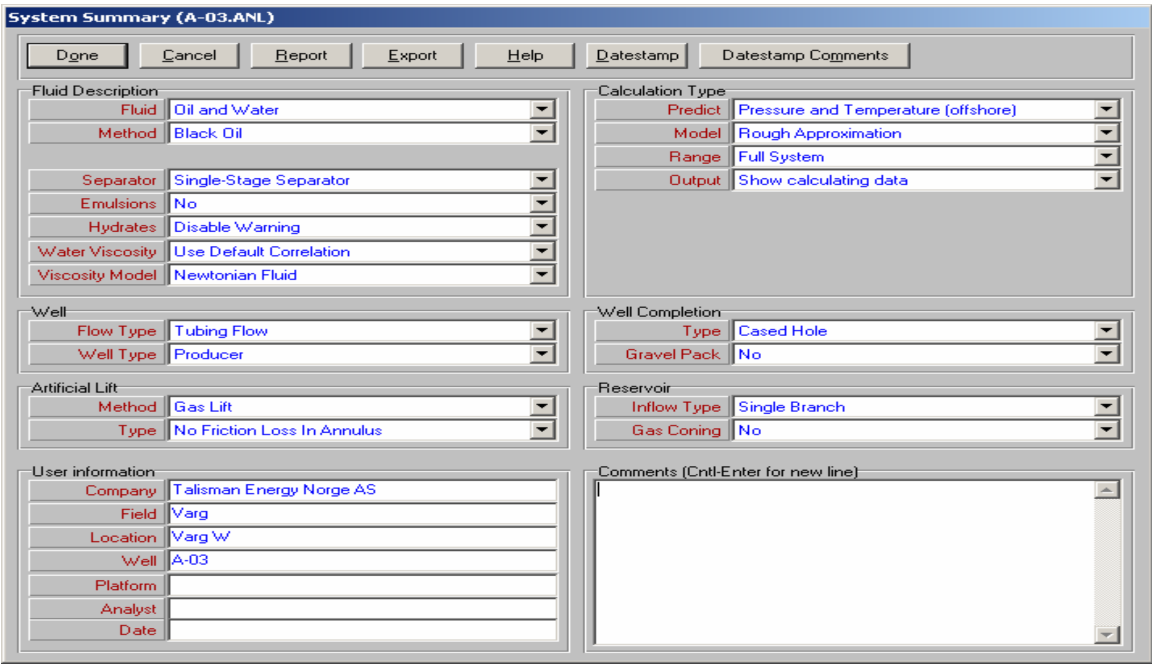


Figure 4.3: System Summery

4.2.2 PVT Data

To predict pressure and temperature changes from the reservoir along the well bore and flow line tubular, it is necessary to accurately predict fluid properties as a function of pressure and temperature. Full set of PVT data had been entered to describe the fluid properties properly and enable the program to calculate them. Necessary PVT data had been adopted from the report of Varg West reservoir where all the wells (A-03, A-09A, A-10T2, A-12BT2) are situated.

4.2.2.1 PVT Matching Procedures

To match the PVT correlations to real PVT data, the following steps had been maintained:

1. Entering PVT Black oil model
2. Entering PVT match data
3 Matching the PVT Black oil correlations to the PVT matched data entered and choosing the best fit correlation

1. Entering PVT Black oil model

The following are input parameters for PVT:

- Solution GOR
- Gas Gravity
- Oil Gravity
- Water Salinity

Mole percent for H_2S, CO_2 and N_2 refers to the separator gas stream composition.

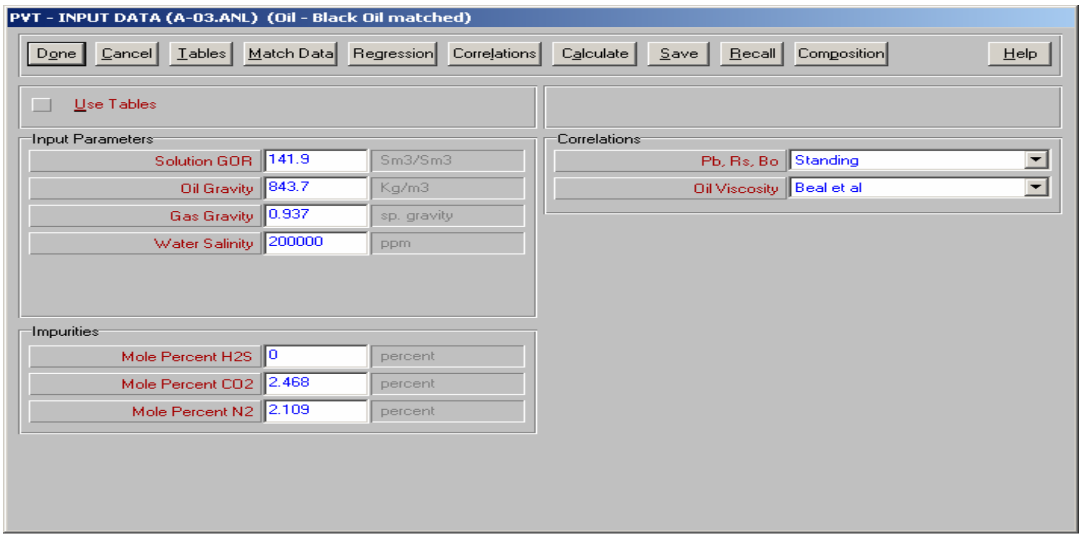


Figure 4.4: PVT Input Data

2. Entering PVT match data

Since gas evolution in the tubing is the constant composition process, the following Flash data, not differential liberation data had been used for matching. [15]

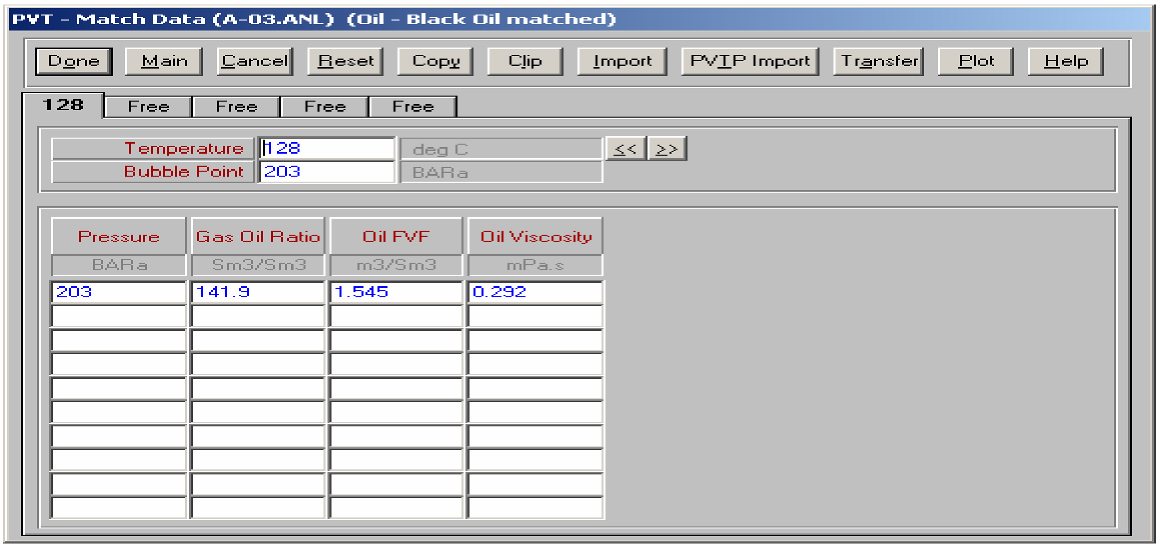


Figure 4.5: PVT Input Data

3. Matching the PVT Black oil correlations to the PVT matched data entered and choosing the best fit correlation

This step had been proceeded to tune the black oil correlations in order to match the lab data entered. In this way we can be sure that the PVT model that are going to be used will reproduce measured data. To match the correlation to the laboratory measured data, the Regression procedure had been carried out.

4.2.2.2 Regression

This option was used to perform the non-linear regression, which adjusted the correlations to best fit laboratory measured PVT data. In PROSPER; the following PVT properties were used as match variables:

Pb: Bubble point pressure

Rs: Gas oil ratio versus pressure

B_o: Oil formation volume factor versus pressure

μ_0: Oil viscosity versus pressure

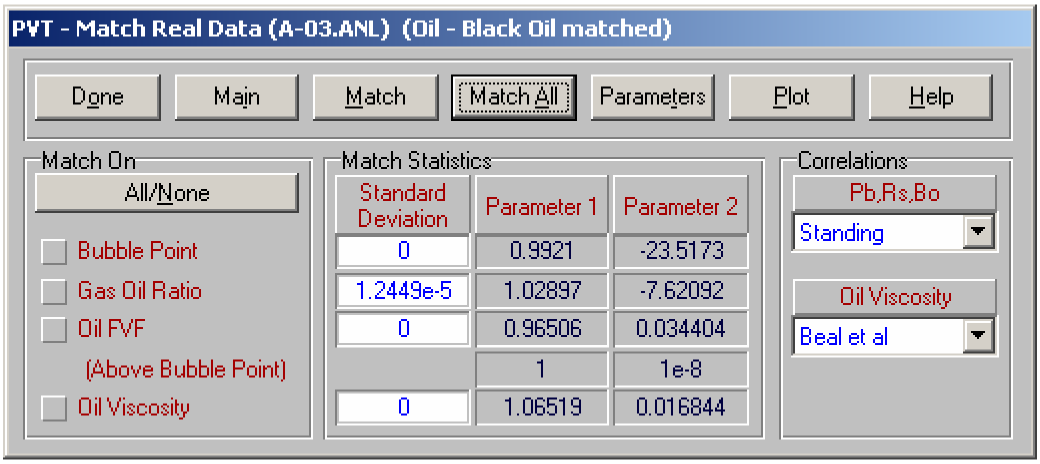


Figure 4.6: Regression Screen

4.2.2.3 Parameters

Prosper performs a non linear regression to adjust the correlations to best fit the laboratory data by applying a multiplier (parameter 1) and a shift (parameter 2) to each correlations. The less correction a correlation requires to fit the measured data, the better it is. The best overall model is the one that has parameter 1 closest to unity. The standard deviation represents the overall closeness of fit. The lower the standard deviation, the better the fit is.

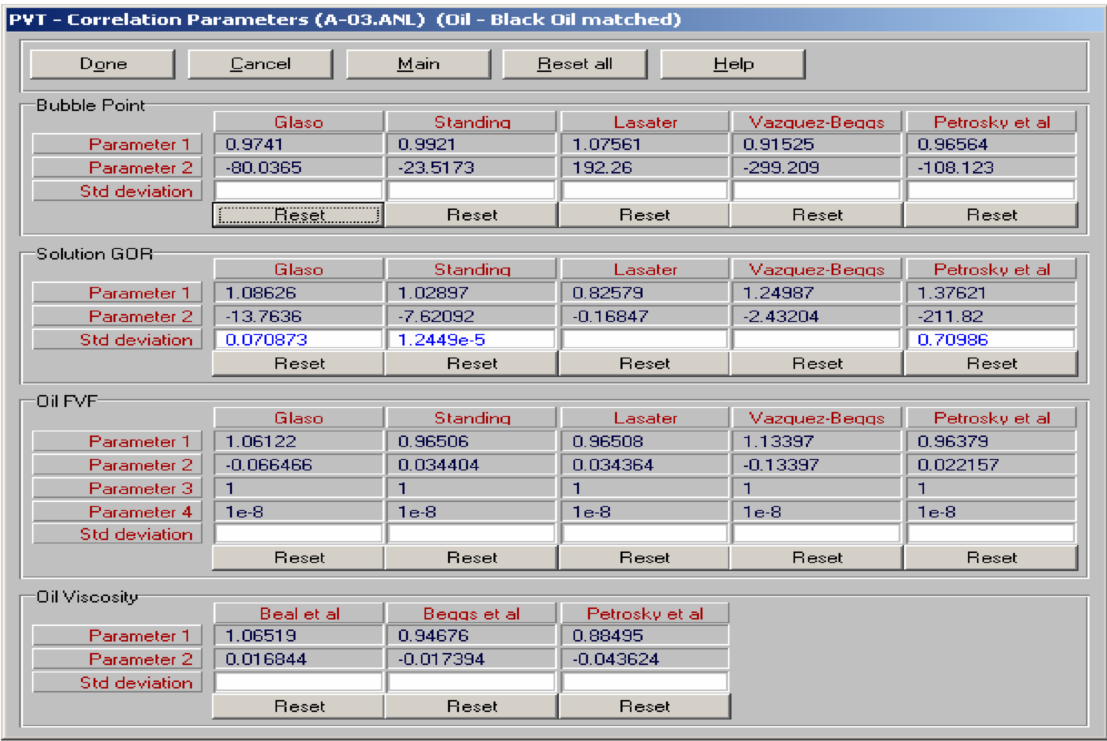


Figure 4.7: Correlation Parameters Screen

4.2.3 Equipment Data

This section consists of the following subsections:

1. Deviation Survey
2. Surface Equipment
3. Downhole Equipment
4. Geothermal Gradient
5. Average Heat Capacities

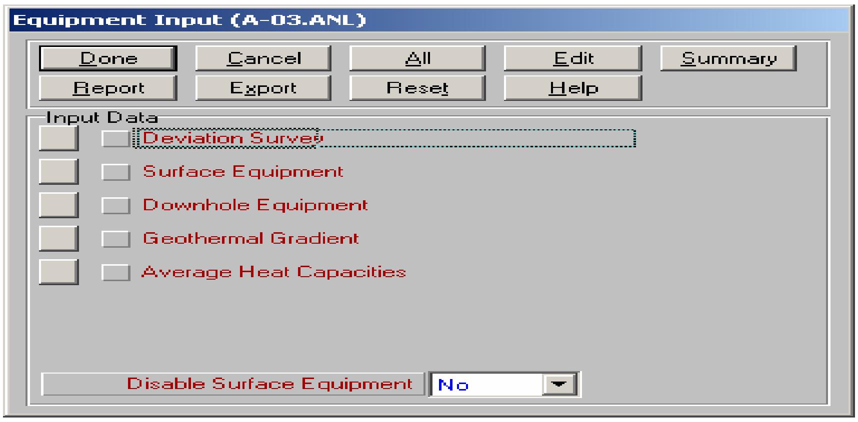
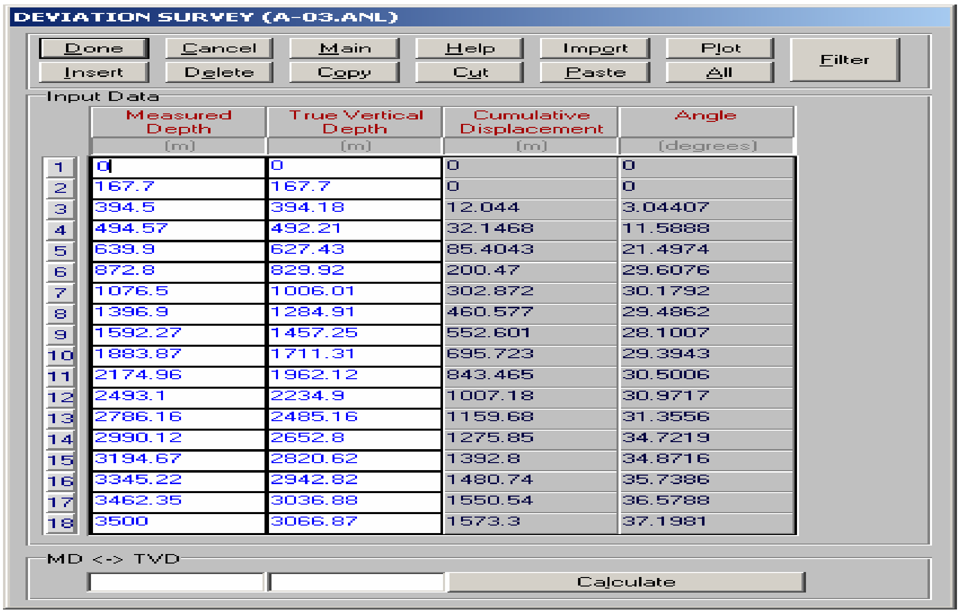


Figure 4.8: Equipment Input Data

1. Deviation Survey

Complete sets of deviation survey data of all wells had been attached in Appendix A-2. While entering the deviation survey data, Prosper calculates the cumulative displacement and the angle of the well.



	Measured Depth (m)	True Vertical Depth (m)	Cumulative Displacement (m)	Angle (degrees)
1	0	0	0	0
2	167.7	167.7	0	0
3	394.5	394.18	12.044	3.04407
4	494.57	492.21	32.1468	11.5888
5	639.9	627.43	85.4043	21.4974
6	872.8	829.92	200.47	29.6076
7	1076.5	1006.01	302.872	30.1792
8	1396.9	1284.91	460.577	29.4862
9	1592.27	1457.25	552.601	28.1007
10	1883.87	1711.31	695.723	29.3943
11	2174.96	1962.12	843.465	30.5006
12	2493.1	2234.9	1007.18	30.9717
13	2786.16	2485.16	1159.68	31.3556
14	2990.12	2652.8	1275.85	34.7219
15	3194.67	2820.62	1392.8	34.8716
16	3345.22	2942.82	1480.74	35.7386
17	3462.35	3036.88	1550.54	36.5788
18	3500	3066.87	1573.3	37.1981

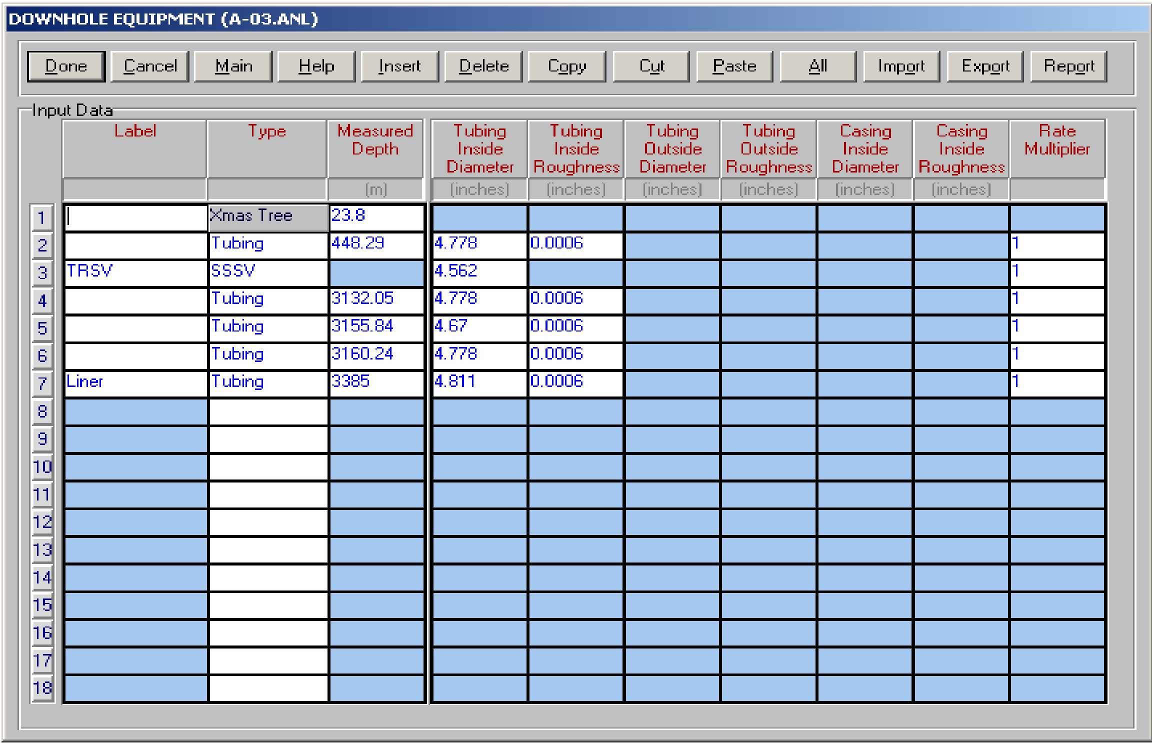
Figure 4.9: Deviation Survey Data

2. Surface Equipment

Surface network model had been built up in GAP program. No surface equipment data had been entered in Prosper.

3. Downhole Equipment

The equipment to specify in Prosper is the one that the fluid sees from the bottomhole up to the wellhead. Thus the equipment through which the fluid flows had been entered. Completion schematic of each well had been attached in Appendix A-6.



	Label	Type	Measured Depth (m)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (inches)	Tubing Outside Roughness (inches)	Casing Inside Diameter (inches)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	23.8							
2		Tubing	448.29	4.778	0.0006					1
3	TRSV	SSSV		4.562						1
4		Tubing	3132.05	4.778	0.0006					1
5		Tubing	3155.84	4.67	0.0006					1
6		Tubing	3160.24	4.778	0.0006					1
7	Liner	Tubing	3385	4.811	0.0006					1
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										

Figure 4.10: Downhole Equipment Data

4. Geothermal Gradient

The geothermal gradients that had been used to prepare the well model are listed in following table. Prosper finally calculated the overall heat transfer coefficient according to well test data

Geothermal Gradient Data		
Formation Measured Depth (m)	Formation Temperature (°C)	
15	10	
44	4	
128	4	
At Reservoir Depth	128	
Overall Heat Transfer Coefficient	19	W/m2/°K

Table 4.1: Geothermal Gradient Data

5. Average Heat Capacities

Default value in Prosper for average heat capacities had been used.

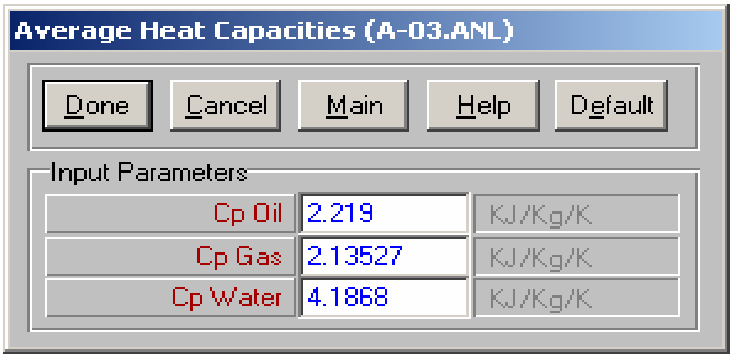


Figure 4.11: Average Heat Capacities Data

4.2.4 Gas Lift Data

All wells in this work are operated by gas lift. Gas lift method is fixed depth of injection. The following gas lift data had been used in this work:

Gas Lift Data	
Gas Lift Gas Gravity	0.937
Mole Percent H2S	0.000
Mole Percent CO2	2.468
Mole Percent N2	2.109

Table 4.2: Gas Lift Input Data

4.2.5 IPR Data

This option of the program describes how Prosper defines the reservoir inflow performance.

4.2.5.1 IPR Models for Oil Wells

The IPR model chosen depend upon the available data and the type of inflow sensitivities to be performed. The models which had been used in this work are highlighted below:

P.I Entry: A straight line inflow model is used above the bubble point based on the equation [2.3] in chapter 2. The Vogel empirical solution is used below the bubble point. The productivity index (PI) is used to calculate the IPR.

Vogel: This program uses the straight line inflow relationship above the bubble point and Vogel empirical solution below the bubble point. A single flowing bottom hole pressure and surface test rate is used to calculate the IPR below the bubble point. From this IPR, the rate and bubble point pressure are used to evaluate the PI for the straight line part of the inflow above the bubble point. When calculating the IPR sensitivities for reservoir pressure, Prosper retains the correct well productivity. On the other hand, changing the reservoir pressure changes the Vogel well productivity. Vogel's equation is presented in equation [2.4] in chapter 2.

Composite: This is the extension of the Vogel inflow solutions that accounts for water cut. Vogel decrease the inflow below the bubble point because of gas formation. When the water cut is higher, the inflow potential increases and approaches a straight line IPR due to single phase flow. Test flow rate, flowing bottomhole pressure and water cut are input parameters for the composite model.

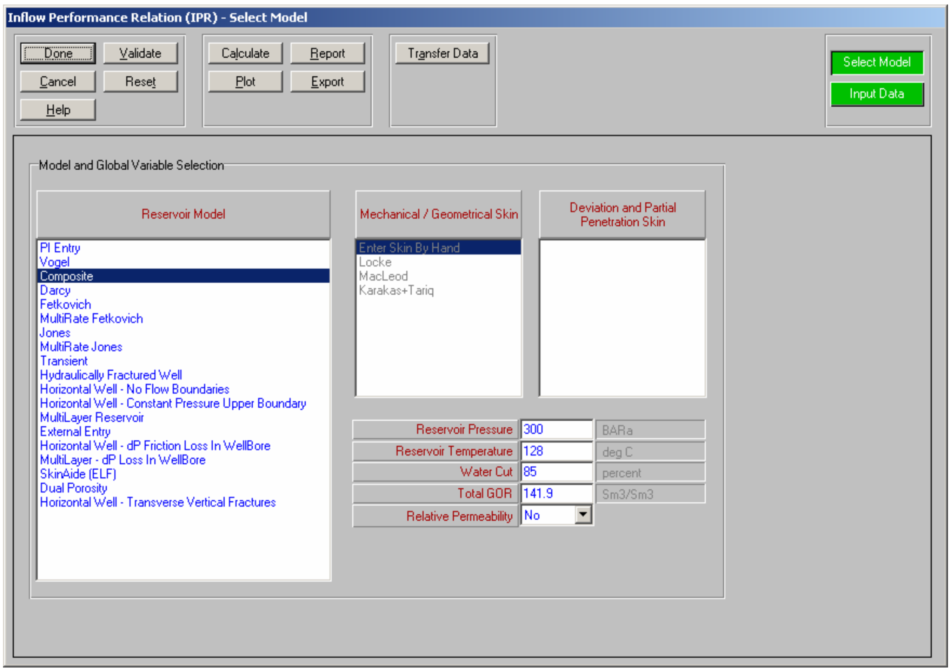


Figure 4.12: IPR Model Selection Screen

Chapter 5 Well Models in GAP

5.1 GAP

GAP is a **G**eneral **A**llocation **P**rogram. This software is a powerful tool offered in Petroleum Engineering to achieve many important tasks like as complete surface production / injection network modelling, production optimization, lift gas allocation and prediction (production forecast). The following flow chart outlines the general procedure for production optimization using GAP. [9]

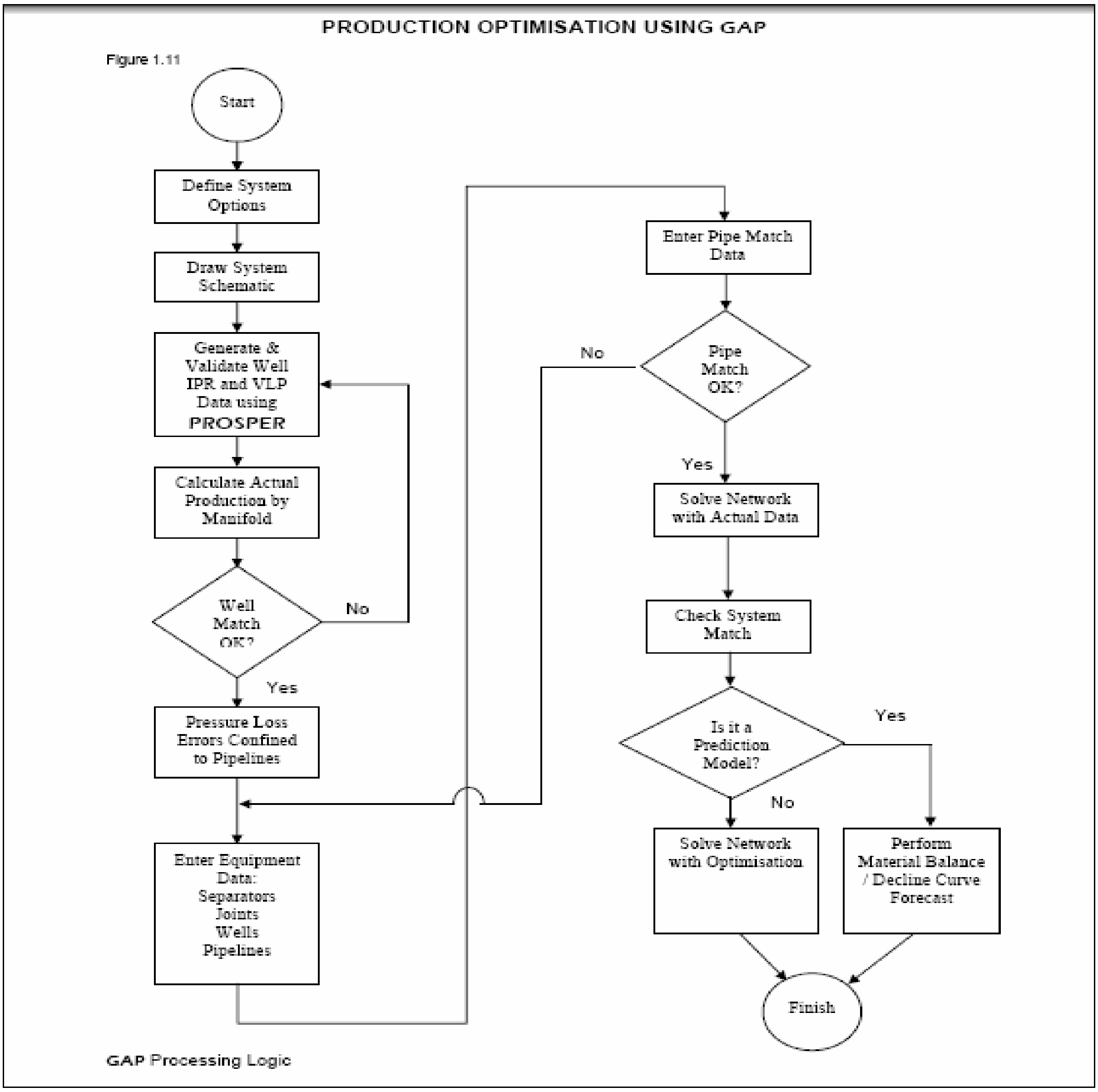


Figure 5.1: Production Optimization Procedure using GAP

5.2 Optimization Procedure

In this thesis work, lift gas allocation and production optimization of all (eight) producing wells of Varg field had been performed using GAP software. Stepwise production optimization procedures have been mentioned in the following sub-chapters.

5.2.1 Defining System Options

This option allows setting up overall system parameters. The following system options had been defined for this GAP model:

- System Type: Production
- Optimization Method: Production
- Prediction Method: Pressure and Temperature

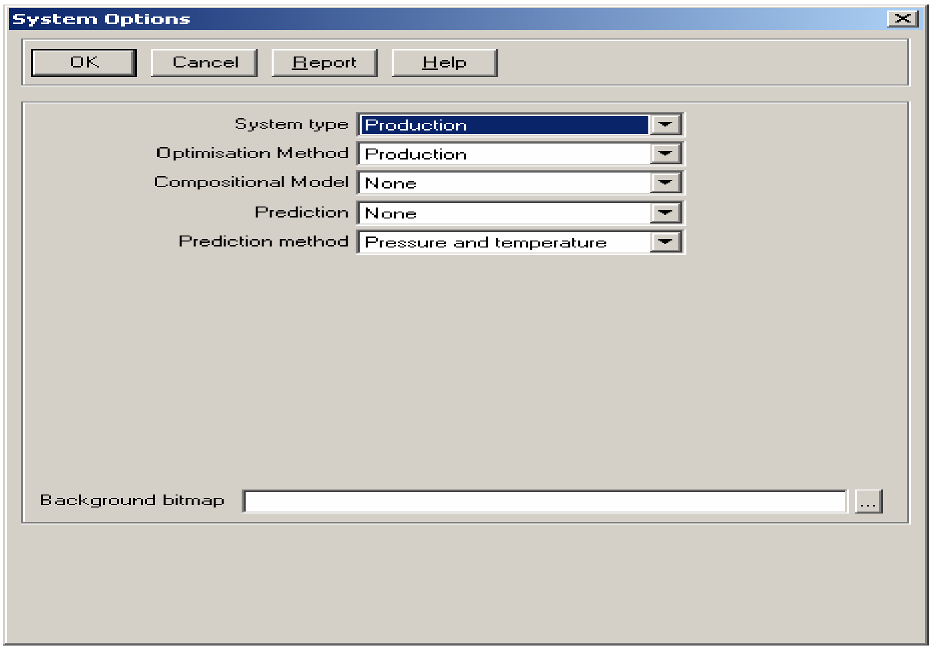


Figure 5.2: System Options

5.2.2 Drawing System Schematic

The system drawing had been prepared according to the production network of Varg platform and Petrojarl Varg (FPSO). The following network (***Figure 5.3)*** had been prepared for finding the gas lift allocation of each well from Gap program. Since optimization method in the thesis work is production model, not a prediction model, no reservoir had been linked in this system schematic.

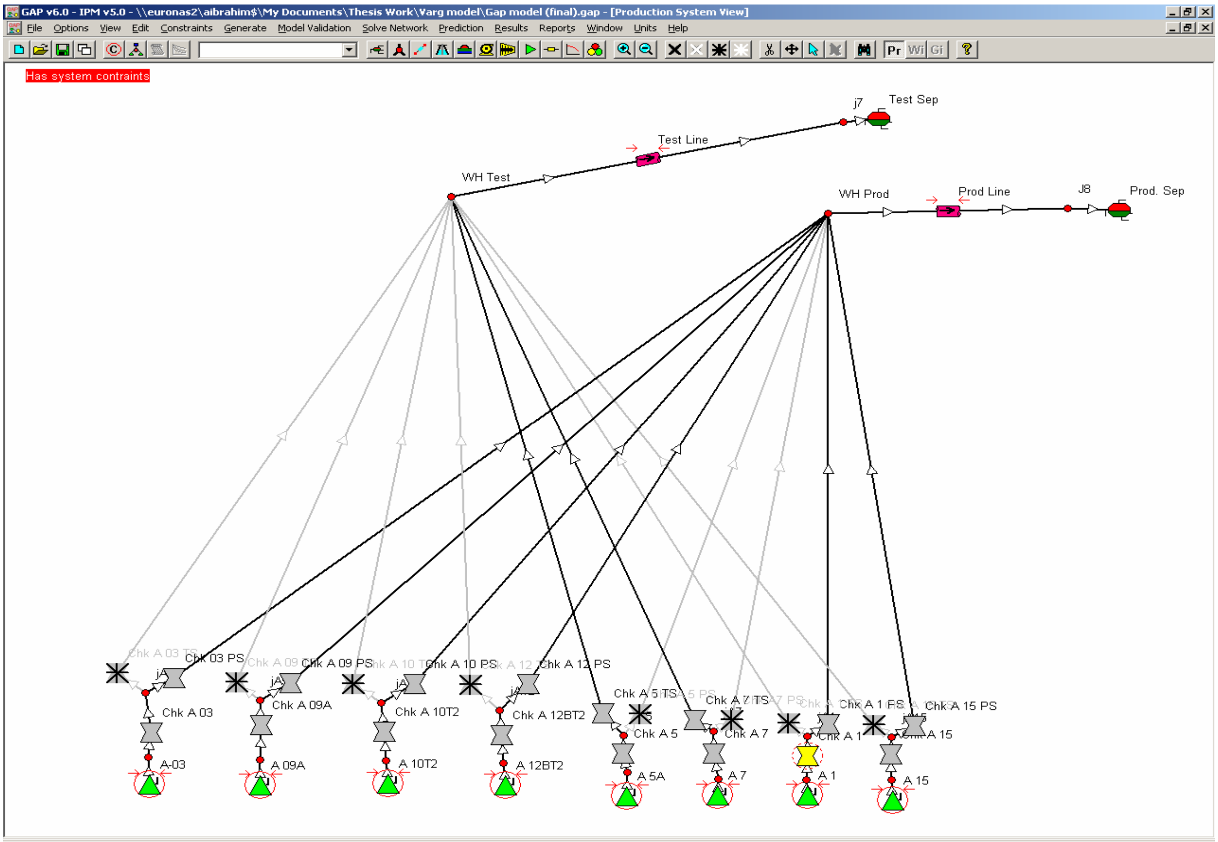


Figure 5.3: System Schematic

All producing wells have provisions to flow through both production separator and test separator. Each well is controlled by a choke at X-mass tree. For flowing through the production separator, each well is gathered in a production manifold (WH Prod). Similarly, for flowing through the test separator, each well is gathered in a test manifold (WH Test). There are provisions for chocking for every well before production manifold and test manifold. Both manifolds are on Varg platform. A production pipe line and a test pipe line are connected between Varg platform and Petrojarl Varg (FPSO). The FPSO have facilities of production separator and test separator where all produced fluid is processed.

5.2.3 Describing the Well

The well can be described in detail by summery screen. The summery screen is the master screen in which all data of well are entered. Appropriate tabs allow entering all the well input data required for system optimization or prediction runs. For describing the input data for individual well in Gap program, print screens of well A-03 had been used as representative samples in this section.

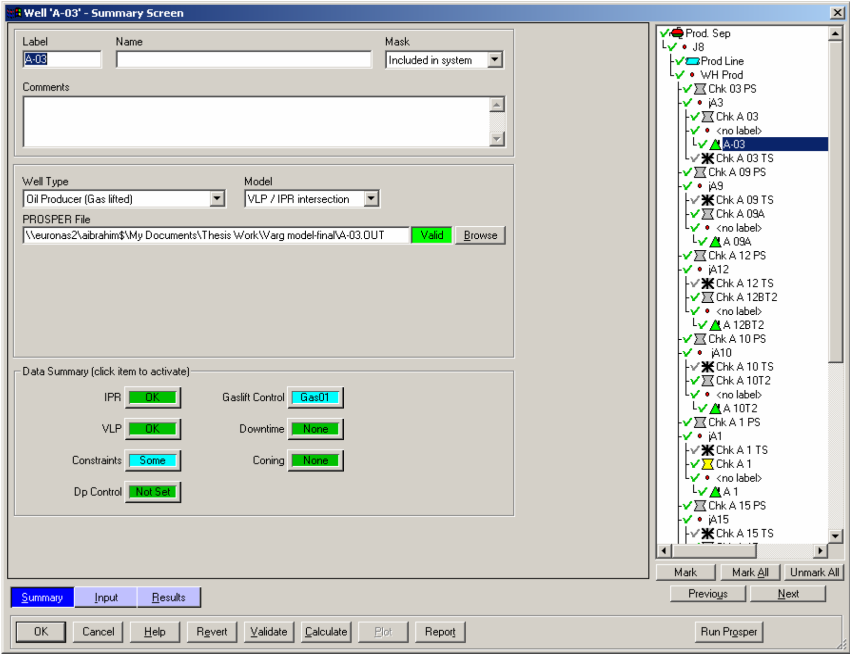


Figure 5.4: Summery Screen

Input tab button is followed with a detailed description of the input data that is required for a full description of a well model in Gap. The following represents the division of input data.

5.2.3.1 IPR Input

This screen allows the input of well performance data. The input data of Productivity Index had been gained from previous calculated data in Prosper. Oil properties from PVT report had been entered in this input screen.

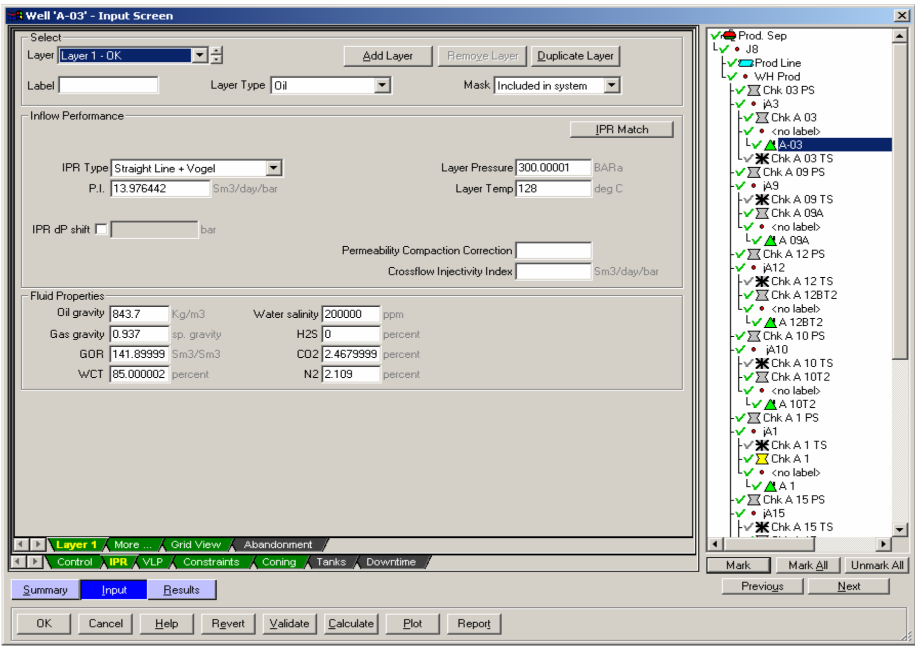


Figure 5.5: IPR Input Screen

5.2.3.2 VLP Input

This screen allows specifying the data file associated with the well considered and containing the VLP table. VLP table can be generated using the 'Generate' feature of Gap. When the VLP file is properly generated, the screen shows 'Valid' in green colour. The following screen is showing the valid VLP generation of this work.

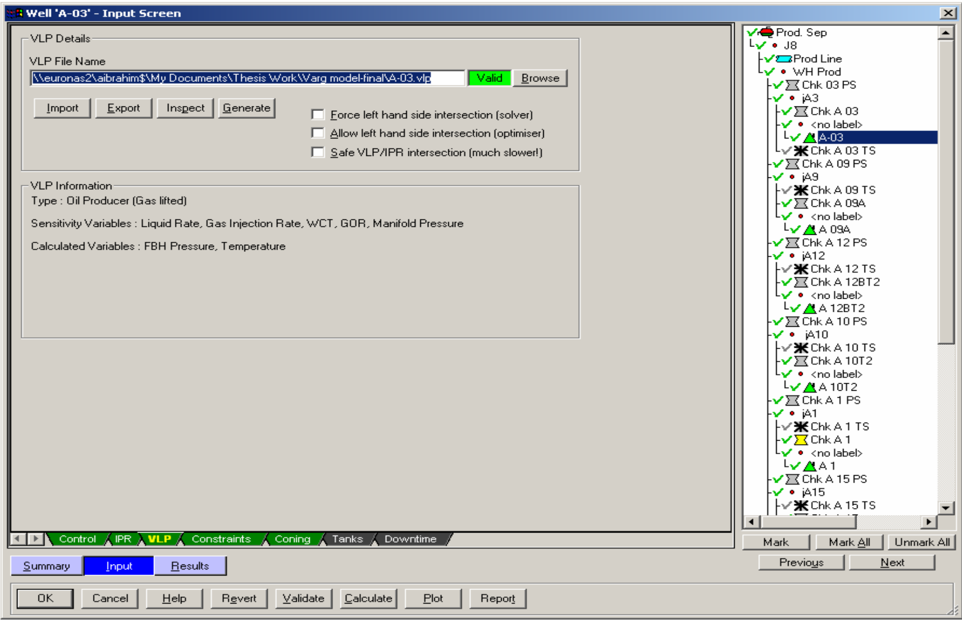


Figure 5.6: VLP Input Screen

5.2.3.3 Control

This screen allows setting choke values for the current well and for artificial lift control. The lift gas injection rate in the gas lifted wells can be controlled by setting the control mode in 'Calculated' option. The following screen is showing the gas lift control in this work.

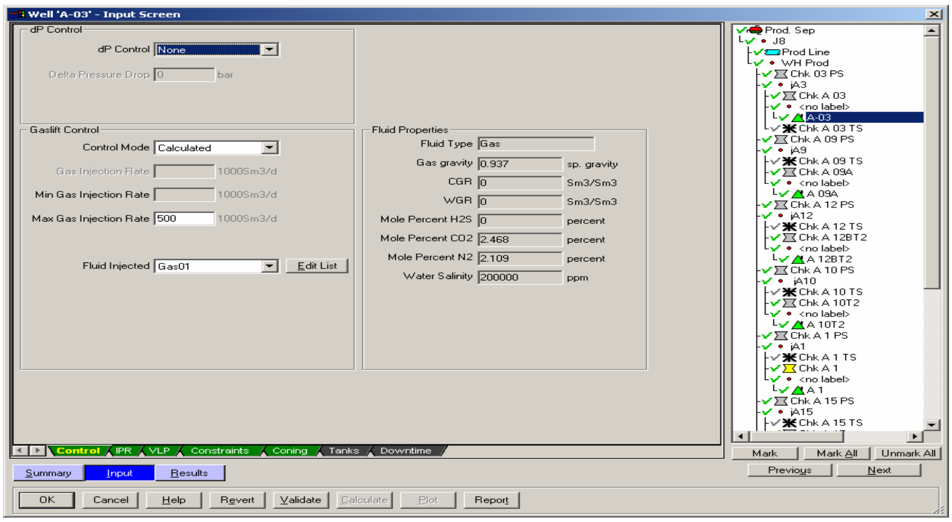


Figure 5.7: Control Input Screen

5.2.3.4 Well Constraints

This option is used to control a well to meet physical or contractual requirements forcing the well to produce at maximum potential or below it. The constraint screen of this work is showing in the following figure.

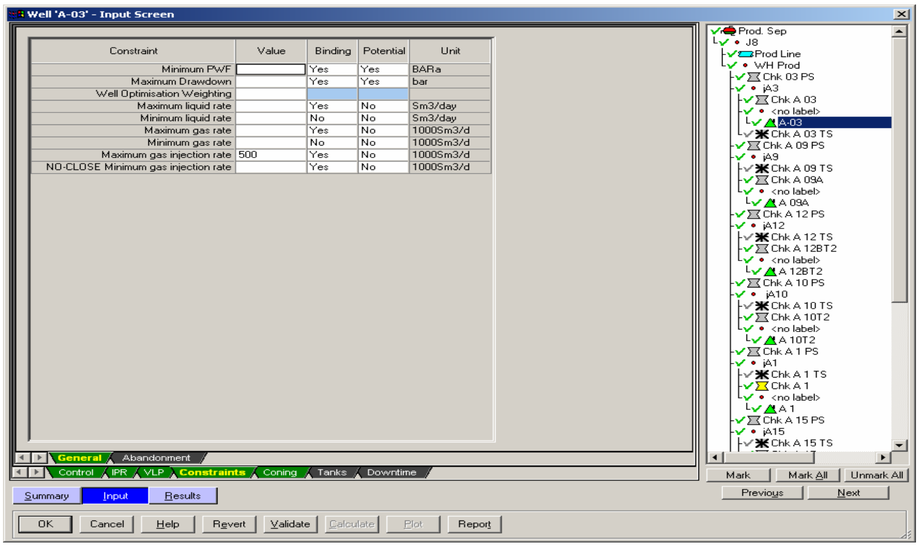


Figure 5.8: Well Constraint Screen

5.2.4 Describing the Pipe lines

There are 10” production pipe line and 6” test pipe line for flowing all producing oil from Varg platform to Petrojarl Varg (FPSO). Data of production pipeline and test pipe line had been taken from the pipe line drawing, attached in Appendix C-1. The following screens are showing the data table of production pipe line and test pipe line.

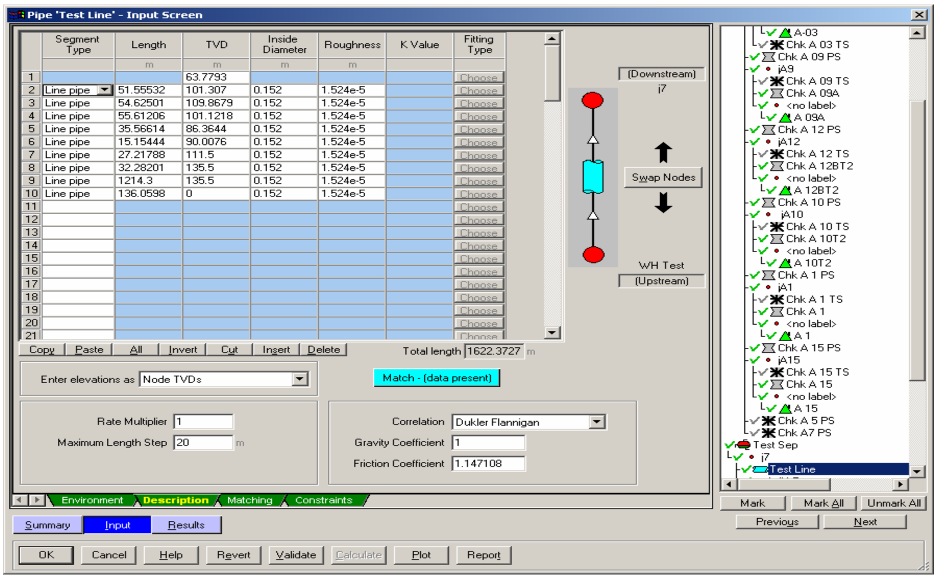


Figure 5.9: Production Pipe Line Data

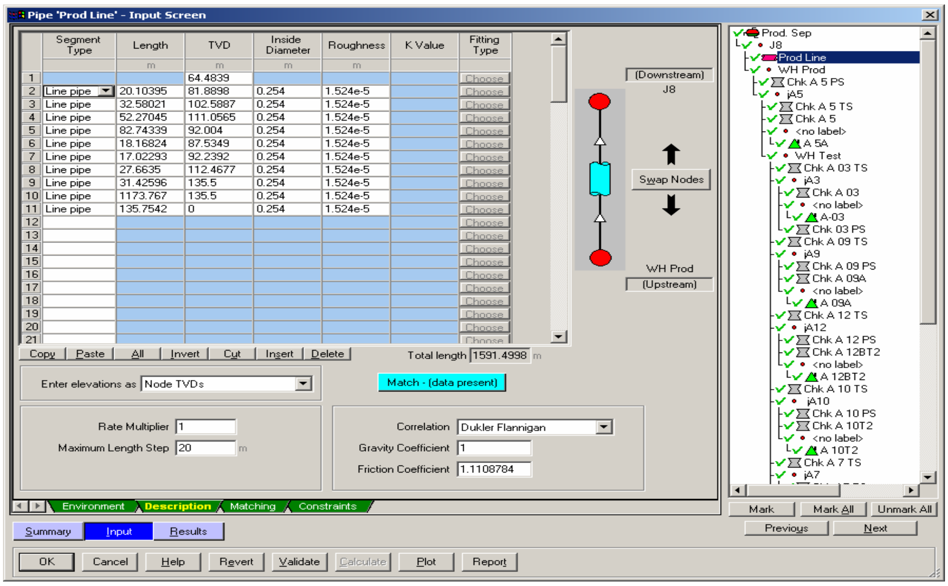


Figure 5.10: Test Pipe Line Data

According to this measured data, pipeline diagram had been plotted by the Gap and compared with the supplied drawing by the company. The pipe line plot diagram had been attached in Appendix C-2.

5.2.5 Import of IPR Data

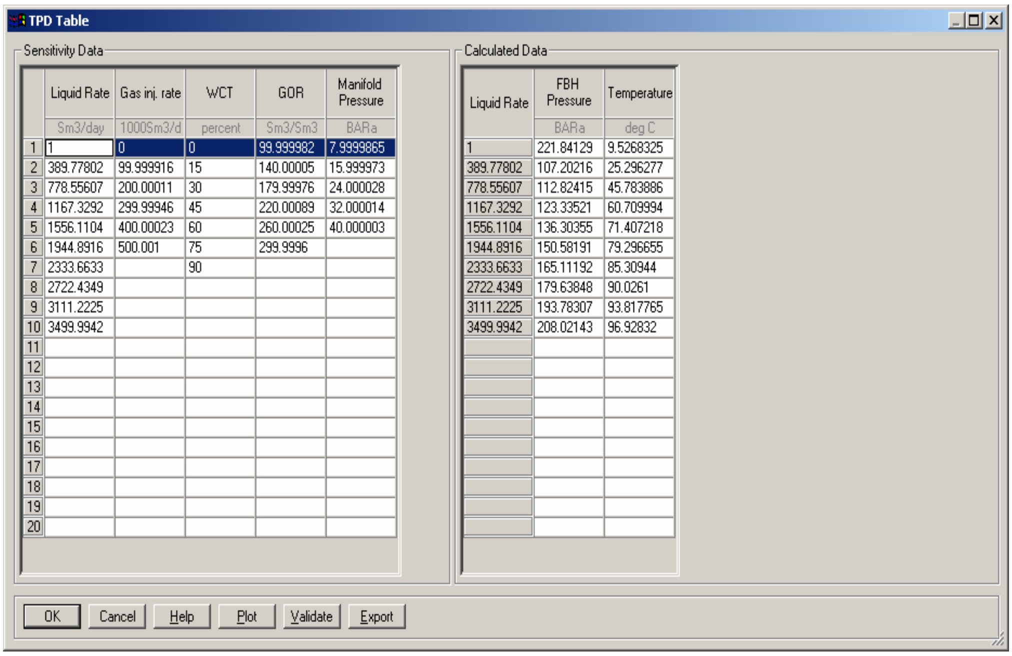
The IPR data from Prosper needs to be imported into Gap. When IPR is imported from Prosper to Gap, Gap takes three points from the Prosper IPR and fits the data points using a straight line (PI) above the bubble point and Vogel's equation below the bubble point. By selecting the 'Generate' button in Gap, IPR of all well models had been transferred to Gap.

5.2.6 Generation of Lift Curves (VLPs)

In order to generate the VLPs, the range of the variables should be defined. The range of sensitivity variables generated should cover the entire possible operating conditions of the wells. It is wise practice to prepare the lift curve table with all variables covered, because if conditions change, it will not be necessary to generate the lift curves again. For gas lifted wells of this work, the following variables had been entered for generating the lift curves.

- Liquid rate
- Gas injection rate
- Water cut
- GOR
- Manifold pressure

The following Gap screen is showing the ranges of sensitivity variables that had been used in this work for generating the lift curves.



TPD Table

Sensitivity Data

	Liquid Rate	Gas inj. rate	WCT	GOR	Manifold Pressure
	Sm3/day	1000Sm3/d	percent	Sm3/Sm3	BARa
1	1	0	0	99.999982	7.9999865
2	389.77802	99.999916	15	140.00005	15.999973
3	778.55607	200.00011	30	179.99976	24.000028
4	1167.3292	299.99946	45	220.00089	32.000014
5	1556.1104	400.00023	60	260.00025	40.000003
6	1944.8916	500.001	75	299.9996	
7	2333.6633		90		
8	2722.4349				
9	3111.2225				
10	3499.9942				
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

Calculated Data

Liquid Rate	FBH Pressure	Temperature
	BARa	deg C
1	221.84129	9.5268325
389.77802	107.20216	25.296277
778.55607	112.82415	45.783886
1167.3292	123.33521	60.709994
1556.1104	136.30355	71.407218
1944.8916	150.58191	79.296655
2333.6633	165.11192	85.30944
2722.4349	179.63848	90.0261
3111.2225	193.78307	93.817765
3499.9942	208.02143	96.92832

Figure 5.11: Range of Sensitivity Variables for Generating Lift Curves

5.2.7 Performing Network Solver Calculation

In Gap program, the network solver provides three modes for calculation

- No optimization
- Optimization and honour constraints
- Optimize, no constraints

According to the objective of this thesis work, network solver calculation had been performed with optimization and honour constraints.

Chapter 6 Results and Discussion

6.1 Result and Discussion in Prosper Work

In this section, the experimental findings and result in Prosper program have been discussed.

6.1.1 Quality Checking of PVT Data

For preparing the well model in Prosper, the PVT data had been taken from the report 'Composition and PVT analysis of separator samples from well 15/12-A-12A, Varg field' [16]. Well A-12A lies on the Varg West panel. All wells (A-03, A-09A, A-10T2, A-12BT2) in this thesis work are situated in the same reservoir panel. This is the only representative PVT report for Varg West reservoir. Thus, that PVT report had been used for all mentioned wells. The following PVT input data of Black oil model had been entered in Prosper program.

PVT Summary		
Wells	**A-03, A-09A, A-10T2, A-12BT2**	
PVT Method	**Single Stage Flash of**	
	Recombined Reservoir Fluid	
PVT Input Parameters		
Solution GOR	141.9	Sm3/Sm3
Oil Density at 15 C	843.7	Kg/m3
Ideal Gas Gravity	0.937	
Water Salinity	200000	ppm
Separator Gas Stream Compositions (Impurities)		
Mole Percent H2S	0.000	
Mole Percent CO2	2.468	
Mole Percent N2	2.109	
PVT Match Data		
Pressure	203	Bar
GOR	141.9	Sm3/Sm3
Oil FVF	1.545	m3/Sm3
Oil Viscosity	0.292	mPa.s
Reservoir Data		
Bubble Point Pressure	203	Bar
Reservoir Pressure (Static)	303	Bar
Reservoir Temperature (Static)	128	ºC

Table 6.1.1: PVT Summery

Since gas evolution in the tubing is the constant composition process, Flash data, not differential liberation data had been used for matching. Where only differential liberation data is available, a PVT simulation program can be used to calculate the flash properties using a model that has been matched to the lab data.

6.1.1.1 PVT Matching

For matching Bubble point pressure, Solution GOR and Oil FVF; Prosper uses following traditional Black oil correlations: Glaso, Standing, Lesater, Vazquez-Beggs and Petrosky.

For matching Oil Viscosity; Prosper uses Beal at el, Beggs at el and Petroskey at el.

Carefully inspecting the correlation parameters in Prosper, the following correlations had been identified for the best overall fit for the matched PVT:

- Pb, Rs and B_o ----------------Standing
- Oil viscosity ------------------Beal at el

After selecting the best fit correlations, PVT input data had been matched with measured data and Prosper was showing PVT is MATCHED in input screen.

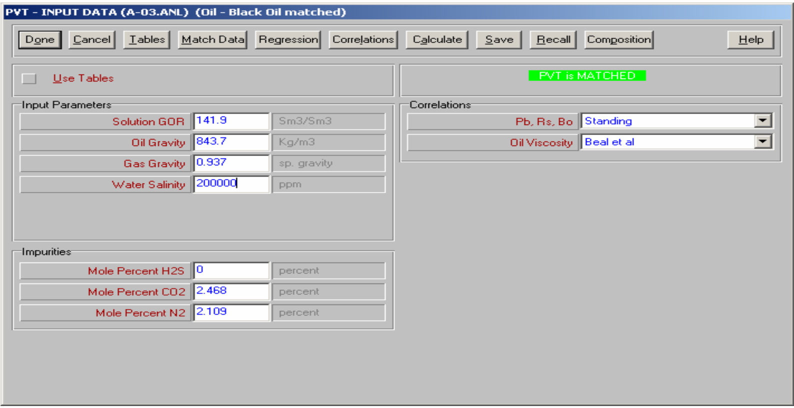


Figure 6.1.1: Matched PVT

6.1.1.2 PVT Plot

A PVT plot with GOR versus Pressure had been drawn to check the consistency with the match data. From the plot diagram, it had been observed that the Black oil model had been properly matched with the PVT match data.

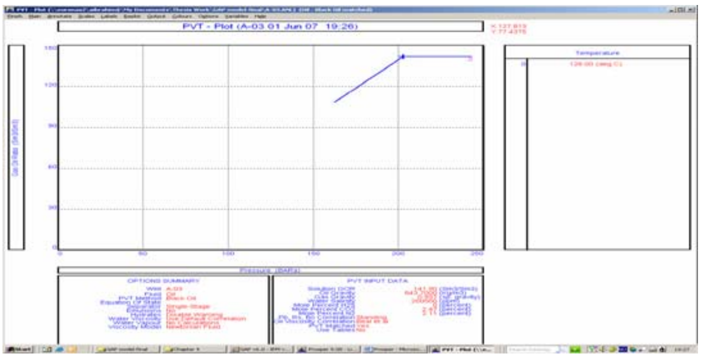


Figure 6.1.2: PVT Plot

6.1.2 Validity Checking of Equipment Data

To build-up the well model in Prosper, it is important to define the deviation survey data and downhole equipments data accurately. Deviation survey and completion schematic of all wells had been collected from Talisman Energy and studied carefully. The calculated result and diagram obtained from Prosper have been discussed in following sections.

6.1.2.1 Deviation Survey

Prosper allows only 18 pairs of data points of measured depth and corresponding true vertical depth for calculation. In this work, 18 data points had been selected in that way which marked significant changes in deviation. Deviation survey data used in Prosper had been shown in Appendix A-1. Complete set of deviation survey data of 4 wells had been provided in Appendix A-2.

The deviation angles of all wells had been calculated by Prosper and the deviated well path had been plotted on Appendix A-3. For comparing those with the original well deviation schematic, deviation schematics of 4 wells had been attached in Appendix A-4. The calculated well deviation path had been matched with the provided deviation schematics. All the wells in this work are sub-sea well. Water depth is 84.0 meter and RKB-MSL is 52.2 meter.

6.1.2.2 Downhole equipment

In Prosper, only the equipment in which the fluid flows should be entered. Thus the downhole equipment from X-mass tree to top of perforation had been entered for calculation. Downhole equipment data used in Prosper had been attached in Appendix A-1. According to Prosper, the SSSV was considered to have no length and was modelled as a sharp-edged orifice inserted between adjacent tubing string elements. Tubing inside roughness was considered 0.0006 inches.

Downhole equipments diagram had been drawn by the Prosper and plotted in Appendix A-5. Well completion schematics of 4 wells had been attached in Appendix A-6. The position of gas lift valve had been automatically adjusted in the downhole equipment diagram from gas lift data in Prosper.

6.1.3 Quality Checking of Well Test Data

A properly matched model is a pre-requisite for accurate performance prediction and optimization studies. Thus quality checking of well test data is significant for accurate performance prediction of well model. In this work, well test data for different test dates had been considered for quality check. The test dates were ranged from January'06 to March'07 (up to performing time of thesis work). Complete sets of well test data have been attached in Appendix B-1. Since, reservoir parameters have been changing since inception of production, best result can be achieved by matching the well model with the latest well test data. By quality checking, it was found that current well test data for every well had good quality. Some old well test data were identified bad quality. The following current well test data for 4 mentioned wells had been found good quality and used for VLP/IPR matching in this work.

Wells	Date	Oil Rate (Sm3/d)	Gas Rate (Sm3/d)	H2O Rate (Sm3/d)	Liquid Rate (Sm3/d)	(GOR)Total (Sm3/Sm3)	(GOR)GLG (Sm3/Sm3)	GLG Rate (Sm3/d)	FBHP (Bar)	FWHP (Bar)	FWHT (Celsius)	P-Sep (Bar)
A-03	03/03/07	227.0	245991	1330	1557	1083.0	941.1	213630	165.0	30.0	97.0	10.5
A-09A	04/03/07	264.0	122821	283	547	465.2	323.3	85351	85.0	17.2	73.3	10.1
A-10T2	07/08/06	309.4	192240	1273	1582	621.0	479.1	148224	0.0	26.0	101.0	10.2
A-12BT2	02/03/07	636.8	285701	999	1635.8	449.0	307.1	195561	138	31.0	98.0	10.7

Table 6.1.2: List of Current well test data used for VLP/IPR Matching

6.1.4 Correlations Comparison and Selecting the Best-fit Correlation

Correlation comparison is the fundamental step in the quality check of the model. This option allows pressure gradient plots to be generated with different correlations to be compared with measured gradient survey data. The comparison enables to understand if the measurements make sense, i.e. violate or not the principle of physics and to select the flow correlation that best fits the experimental measurements.

Two most important correlations had been primarily considered for rough quality check. Those are Fancher Brown (FB) and Duns and Ros Modified (DRM) correlations. [8, 11]

Fancher Brown: The gradient correlation to the left is the Fancher Brown correlation which provides the minimum pressure losses. It is a no slip hold-up correlation that gives the lowest possible value of VLP. Since it neglects gas/liquid slips, it always predict a pressure which is less than the measured value. Thus, measured data falling to the left of Fancher Brown on the correlation comparison plot indicates that there is a problem with fluid density or with field pressure data.

Duns and Ros Modified: The gradient correlation to the extreme right is the Duns and Ros Modified correlation which provides the maximum pressure losses. This correlation usually performs better in mist flow cases and should be used in condensate wells. It tends to over predict VLP in oil wells. Thus, measured data falling to the right of Duns and Ros Modified on the correlation comparison plot indicates that the measured data points are not consistent.

Some other relevant correlations that had been compared are mentioned below:

Hagedorn Brown: This correlation performs well for slug flow at moderate to high production rates. It should not be used for condensate and whenever mist flow is the main flow regime. Hagedorn Brown under predicts VLP at low rates and should not be used for predicting minimum stable rates.

Petroleum Experts: This correlation combines the best features of exiting correlations. It uses the Gould et al flow map and the Hagedorn Brown correlation in slug flow and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist result is used.

Petroleum Expert 2: This correlation includes the features of Petroleum Experts correlation with original work on predicting low rate VLP and well stability.

Petroleum Expert 3: This correlation includes the features of Petroleum Experts 2 correlation with original work for viscous, volatile and foamy oils.

Petroleum Experts 4: The correlation is an advanced mechanistic model for any angled wells, suitable for any fluid (including retrograde condensate).

Beggs and Brill: This is primarily a pipe line correlation. It generally over predicts pressure drops in vertical and deviated wells.

Hydro 3P (internal): This correlation is a mechanistic model and considers three phase flow.

6.1.5 Correlation Comparison Schematics

Correlation comparison schematics for well A-03, A-09A, A-10T2 and A-12BT2 have been shown in the following figure.

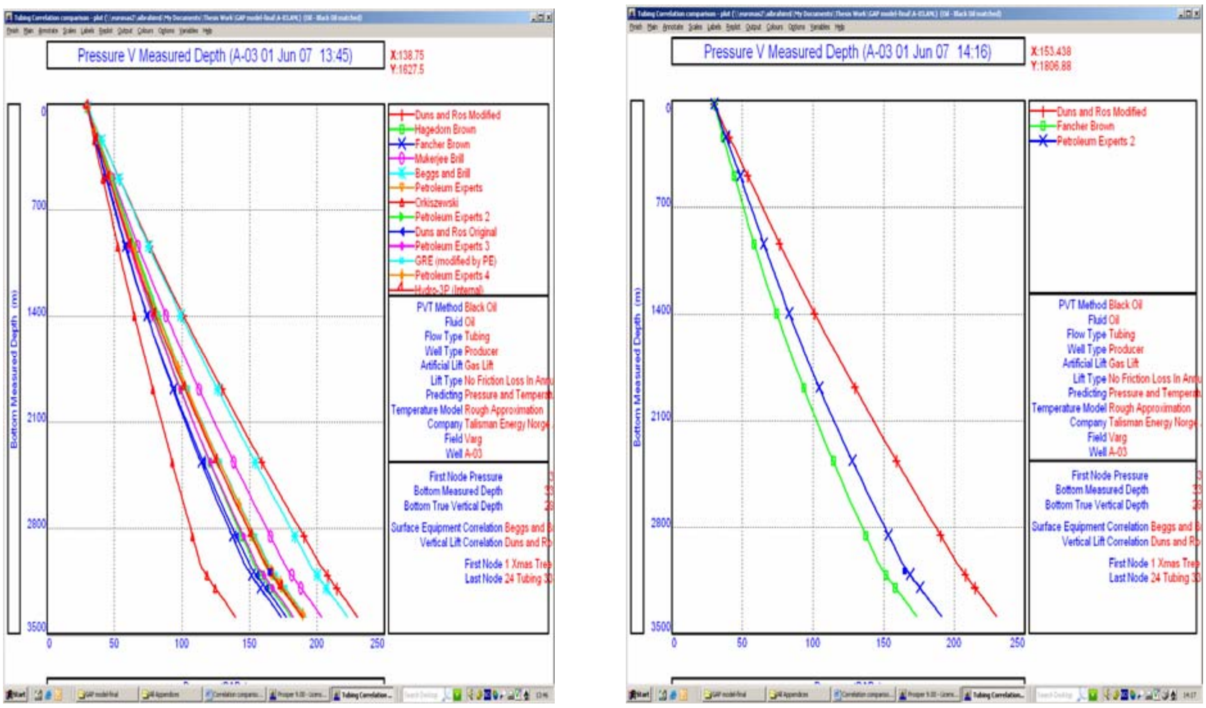


Figure: 6.1.3 Well A-03 Correlations Comparison

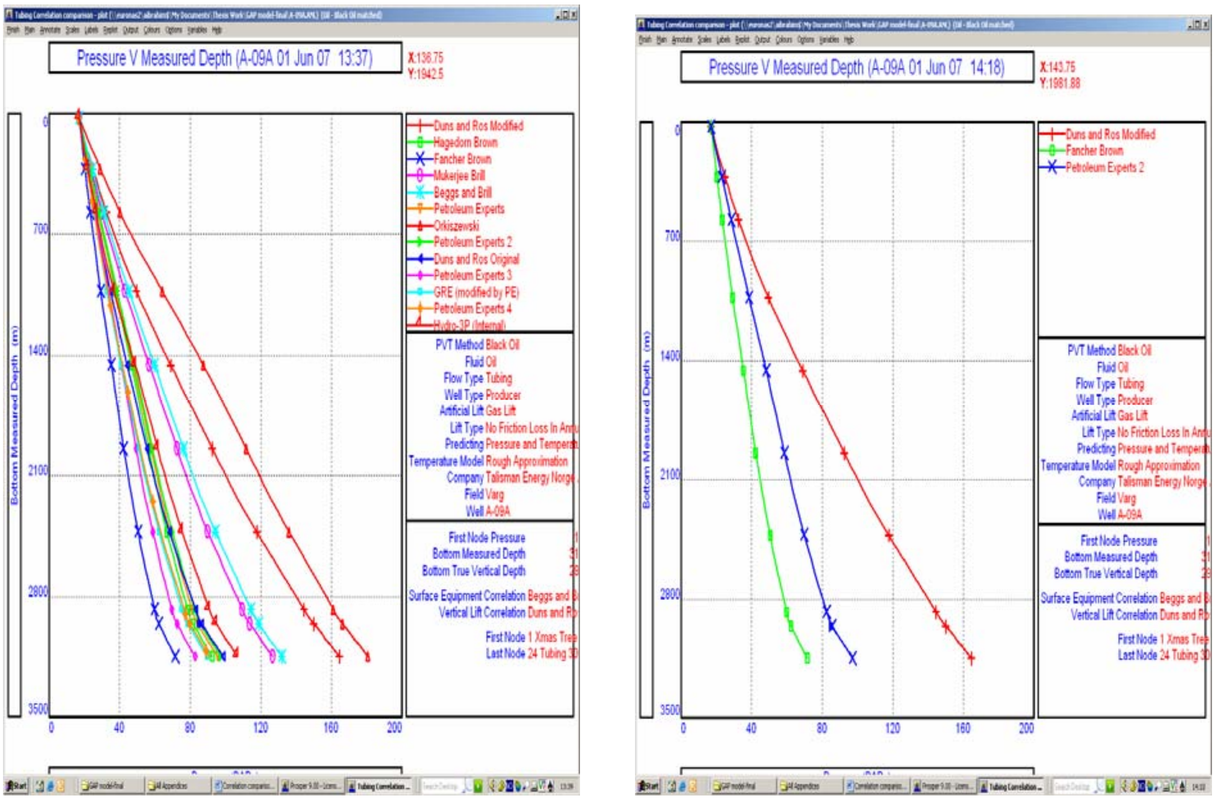


Figure 6.1.4 Well A 09A Correlations comparison

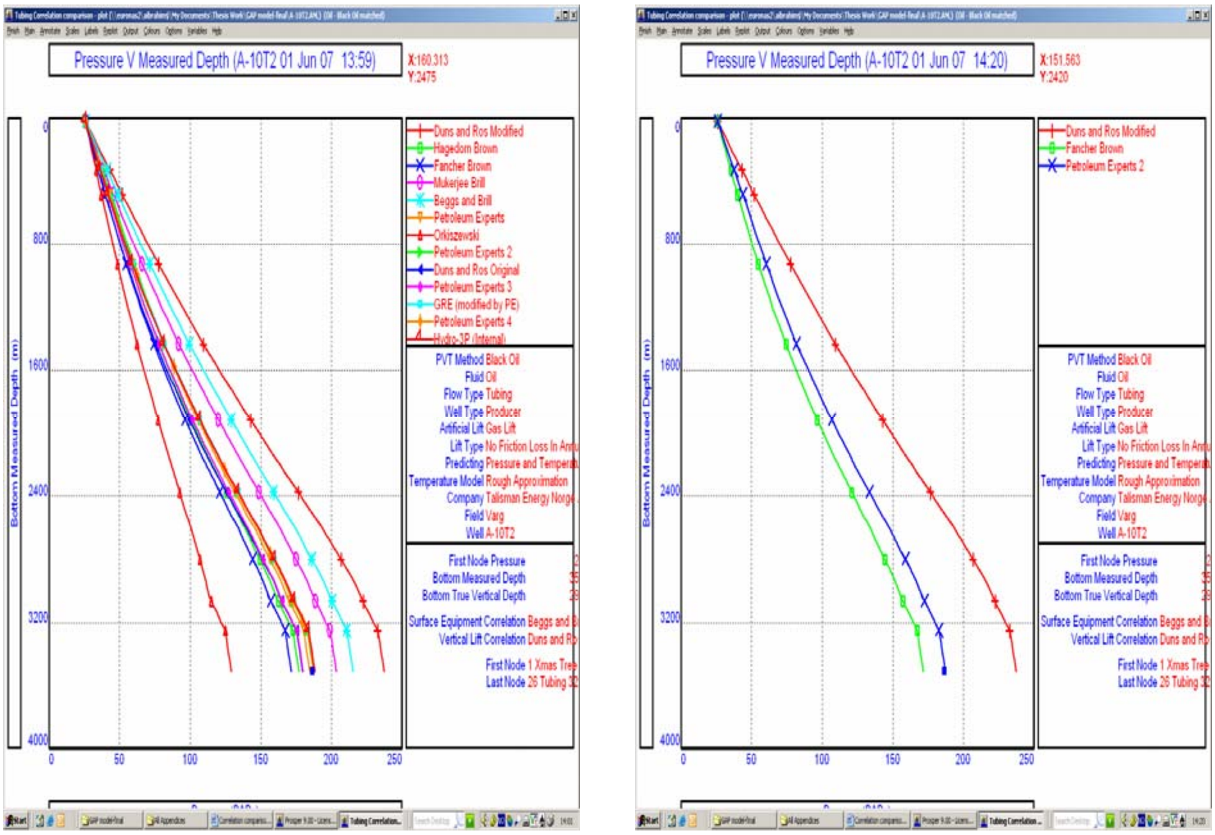


Figure: 6.1.5 Well A-10T2 correlations comparison

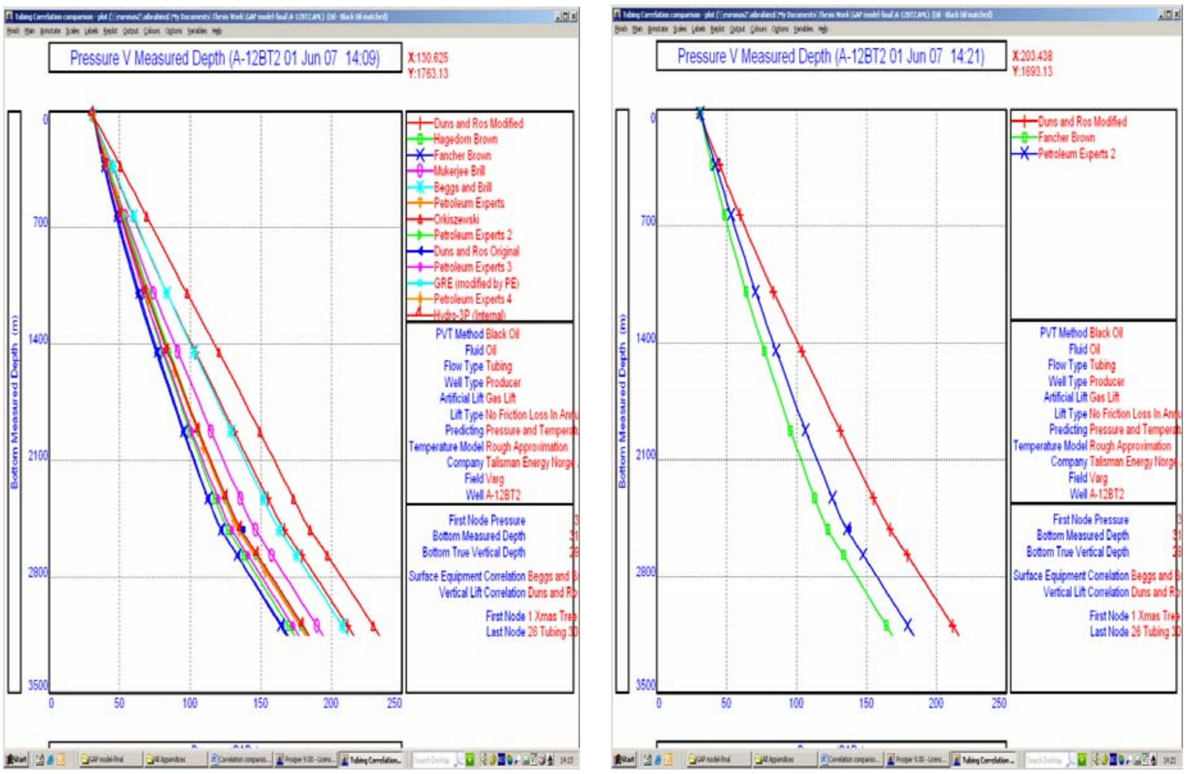


Figure: 6.1.*6 *Well A-1*2BT2 *correlations comparison

Figure 6.1.3-6.1.6 (left side figure) show the measured depth versus pressure plots with the different multiphase flow correlations of 4 wells. The right hand side figures had been drawn to get the clear view of test data points matching with PE-2. The blue point on each figure indicates the data point. All data points lie between Fancher Brown and Duns and Ros Modified correlations. Based on the procedure on quality checking, the test data were evaluated with the following conclusions:

Well A-03: Best fit correlation-Petroleum Expert 2

Well A-09A: Best fit correlation-Petroleum Expert 2

Well A-12BT2: Best fit correlation-Petroleum Expert 2

6.1.6 Correlation Comparison for Well A-10T2

Well A-10T2 was shut down since 2006 due to DHSV problem. So no current well test data and FBHP had been gained for Well A-10T2 (during the period of thesis work). For quality check of well test data in Prosper, the data for FBHP should have to be provided. Thus it had not been possible for correlation comparison for Well-A10T2 with respect to FBHP.

Another approach was carried out for predicting the best fit correlation for Well-A10T2. FBHP (at depth of perforation) was calculated by Prosper with respect to WHP and that data had been used for correlation comparison (Figure: 6.1.5). This approach did not provide accurate result since calculated data had been used instead of measured data; it was performed just for predicting the closest correlation. In this case, PE-2 was found very close to the data point. Since all remaining wells had best fit with PE-2 correlation, it was concluded that the same correlation (PE-2) could be considered for modelling of well A-10T2.

6.1.7 Pressure Comparison at Gauge Depth

Another approach of correlation comparison was performed by comparing the measured gauge pressure with the calculated pressure from Prosper at the gauge depth. The following condition had been taken into consideration:

- Current and all previous well test data were compared.
- Preference was given for current well test result for selecting the correlations.
- Due to problem of downhole safety valve of Well A-10T2, no pressure comparison at gauge depth was achieved.

* Best correlation for Well A-10T2 had been predicted with the best correlation results for other wells.

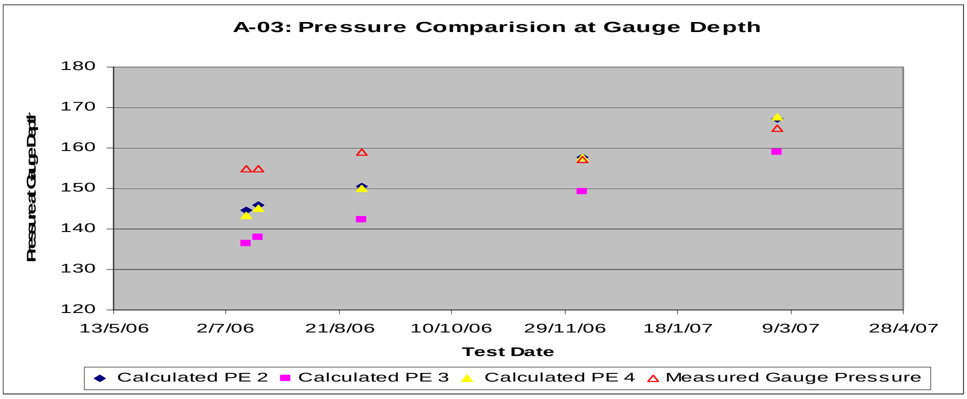


Figure 6.1.7: Pressure Comparison for Well A-03

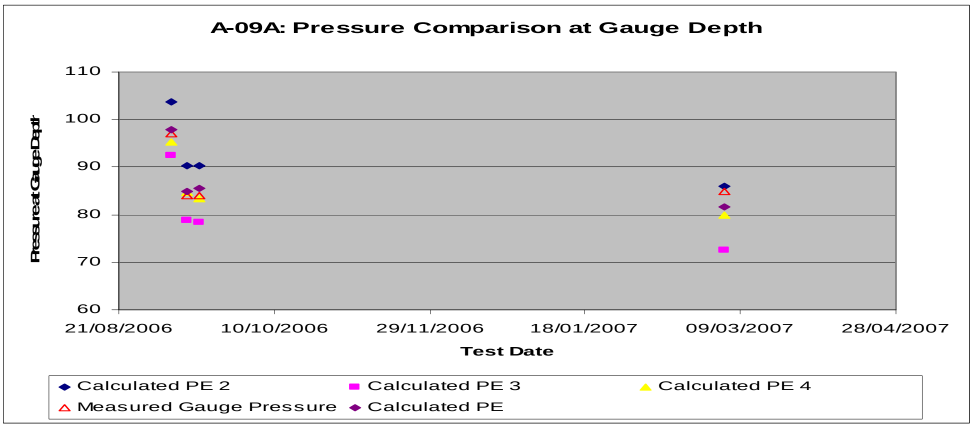


Figure 6.1.8: Pressure Comparison for Well A-09A

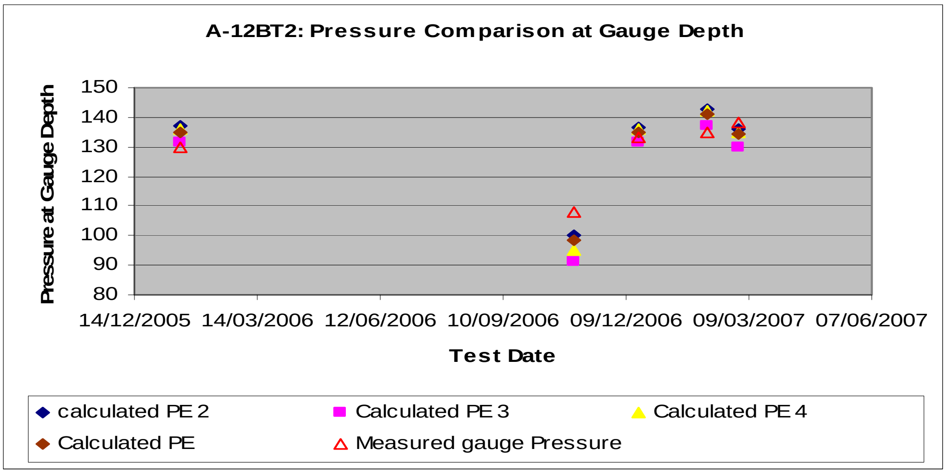


Figure 6.1.9: Pressure Comparison for Well A-12BT2

From figure 6.1.7-6.1.9, it had been concluded that Petroleum Expert 2 was the best fit correlation for all mentioned wells.

6.1.8 Matching the Correlation to the Test

This feature in Prosper enables to adjust the multiphase flow correlations to match the flowing bottomhole pressure. Prosper uses a non-linear regression to tune the VLP correlations to best match the measured data. This is done by calculating a pressure traverse using a correlation and determining the error between measured and calculated pressures. The gravity and friction terms of the pressure loss equations are then adjusted and the process is repeated until the measured and calculated results agree within 1 psi or 50 iterations have been completed.

- **Parameter 1 (Gravity term):** This is the multiplier for the gravity term in the pressure drop correlation. Provided that the PVT has been correctly matched, the greatest source of uncertainty in the VLP calculation for oil wells is usually the hold up correlations. Prosper attempts to make a gravity component match by adjusting the hold up correlation. If a match is not obtained with a parameter 1 more than 5% away from the value 1, the density is adjusted. For single phase applications, no hold up correction is possible. So any significant deviation from 1.0 for parameter 1 indicates a PVT problem. If Prosper has to adjust parameter 1 by more than +-10%, there is probably an inconsistency between the fluid density predicted by the PVT model and the field data.
- **Parameter 2 (Friction term):** This is the multiplier for the friction term in the pressure drop correlation. If parameter 2 requires a large correction, it is likely that there is an error in equipment description or the flow rates are incorrect. As the effect of a shift in the friction component on the overall pressure loss is less than for the gravity term, a larger range in the value of parameter 2 is expected. If Prosper has to adjust the parameter 2 by more than +-10%, there is probably an error in the value of roughness entered of the equipment.

In this work, once the matching process was completed, the match parameters had shown alongside each of the correlations that had been matched. Parameter 1 and 2 were found very much close to unity with PE-2 correlation for current well test data of all wells. Data of correlation match parameters have been attached in Appendix B-2.

6.1.9 VLP Matching

VLP matching provides a logically consistent means to adjust flow correlations to reproduce the measured pressure. Combined with the IPR matching, Prosper provides the means to create a robust well model that is capable of reproducing observed pressures and rates. This is a necessary condition for making accurate performance predictions and optimization studies.

6.1.10 IPR Matching

This feature allows to check the consistency of the bottomhole pressure data used in the VLP matching and to adjust the IPR to match the measured data. When the desired correlation (PE 2) had been selected, Prosper calculated the VLP for a range of rates and pressure at the sand face for each active test point that had been entered in the VLP matching screen. Once the calculation was completed, the IPR input screen was represented.

When the test point was not consistent with the IPR model, Productivity index (PI) had been adjusted in PI entry model until a match is obtained. Matching both the VLP and IPR to actual test data ensured that the Prosper well model was capable of accurately reproducing the currently known producing conditions. VLP/IPR matching curves of 4 wells have been attached in Appendix B-3.

6.1.11 Comparison of Well Test Data with Prosper Data

For accuracy checking of well test data; all production parameters of the well test data had been compared with the calculated data in prosper. Deviation was found less than 3% for all well tests. It indicated that the wells had been modelled in Prosper accurately. The comparison data have been provided in the following tables:

Well A-03					
	Liquid Tate	Oil Rate	Water Rate	Total Gas Rate	WHT
Well test data	1557	227.0	1330	245991	97
Prosper data	1557.2	233.6	1323.7	246778	96.9
Deviation (%)	-0.01	-2.91	0.47	-0.32	0.10

Table 6.1.3: Data Comparison for Well A-03 in Prosper

Well A-09A					
	Liquid Tate	Oil Rate	Water Rate	Total Gas Rate	WHT
Well test data	547	264.0	283.0	122821	73.30
Prosper data	546.8	262.5	284.3	122597	73.14
Deviation (%)	0.04	0.57	-0.46	0.18	0.22

Table 6.1.4: Data Comparison for Well A-09A in Prosper

Well A-10T2					
	Liquid Tate	Oil Rate	Water Rate	Total Gas Rate	WHT
Well test data	1582	309.0	1273	192240	101
Prosper data	1581.7	316.3	1265.4	193115	102.76
Deviation (%)	0.02	-2.36	0.60	-0.46	-1.74

Table 6.1.5: Data Comparison for Well A-10T2 in Prosper

Well A-12BT2					
	Liquid Tate	Oil Rate	Water Rate	Total Gas Rate	WHT
Well test data	1635.8	636.8	999	285701	98
Prosper data	1635.5	637.8	997.6	286073	97.96
Deviation (%)	0.02	-0.16	0.14	-0.13	0.04

Table 6.1.6: Data Comparison for Well A-12BT2 in Prosper

6.1.12 Gas Lift Performance Curves

From Prosper calculation; optimized gas lift injection rate for individual well had been determined from gas lift performance curves as shown in figure 6.1.10. This rate can be compared with the allocated gas lift rate in Gap network.

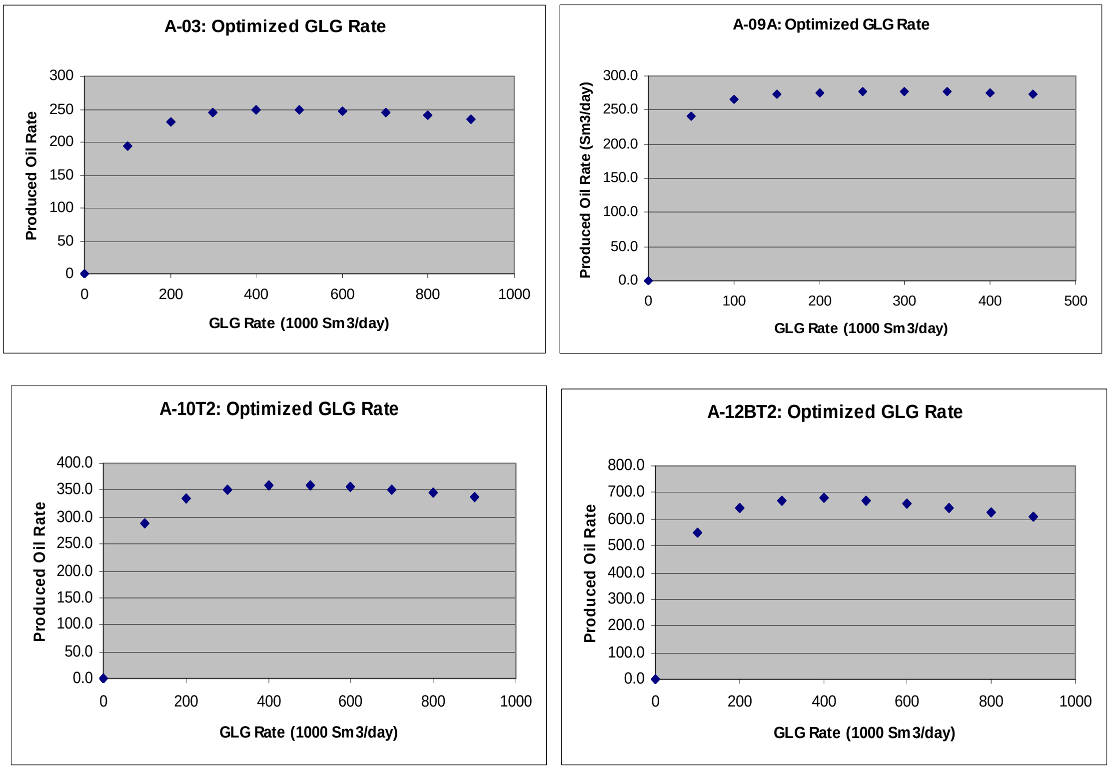


Figure 6.1.10: Gas Lift Performance Curve of Individual Well

6.2 Results and Discussion in Gap Work

In this section, the experimental findings and results in Gap program have been discussed.

6.2.1 Defining the System

The thesis work had been carried out for allocating optimum gas injection rate for maximizing oil production. The defined system is production. Since the work is not involved in prediction model, performing material balance for reservoir is out of scope of this work. Thus, in present production network, reservoir was not connected with the well system.

6.2.2 Defining System Constraints

GAP's powerful optimization tool allocates lift gas for gas lifted wells to maximize the oil production while honouring the constraints at any level. The following constraints are currently existed in production system network of Varg field.

- Flow pipe line (test line/production line) design pressure: 245 bara
- Compressor export capacity for total (Produced+Lift) gas: 1.3 million sm3/day
- DP control at choke point in Well A-01: 7 bar

In this work, those constraints had been considered for optimizing gas allocation and oil production.

6.2.3 Defining the Pipe Lines

Pipe line models were prepared by investigating the technical documents of pipe line, provided by Talisman Energy. Technical drawings of pipe lines have been attached in Appendix C-1. Due to absence of survey data of pipe lines, a DigXY software was used to generate a table of survey data from that drawing. The pipe line survey data was corrected to the well's datum as the drawing was provided with different datum. Entering the obtained pipe line data into Gap, Gap prepared the pipe line diagram for test pipe line and production pipe line. Calculated pipe line diagrams have been attached in Appendix C-2. Comparing the diagrams in Appendix C-1 and C-2, it was verified that both pipe lines had been defined accurately.

6.2.4 Multiphase Flow Correlations Comparison

Both test pipe line and production pipe line data had been compared with multiphase flow correlations. Dukler Flannigan correlation was found the best fit correlation for multiphase flow for both test pipe line and production pipe line. Parameter 1 (gravity coefficient) was found 1.00 for both pipe lines and Parameter 2 (friction coefficient) was found 1.14 and 1.11 respectively, which showed very close to unity. Calculated surface pipe line matching parameters have been attached in Appendix C-3.

6.2.5 Validity Checking of Correlation with Well Test Data

For validity checking of multiphase flow correlations with the well test data, production from individual well was run through test pipe line by isolating the remaining production network Solver summery result for individual well has been attached in Appendix C-4. For accuracy checking of flow correlation of individual well with the test pipe line, the obtained result from Gap had been compared with the well test data. From the comparison data provided in table 6.2.1-6.2.4; it was found that deviation was in acceptable ranges. It implied that surface pipe lines had been matched with multiphase flow correlation properly and consequently the wells had been modelled in Gap program satisfactorily.

Well A-03				
	Liquid Tate	Oil Rate	Water Rate	Manifold Pressure
Well test data	1557	227.0	1330	30.00
Solver Summery Data	1549.4	232.4	1317.0	29.88
Deviation (%)	0.49	-2.38	0.98	0.40

Table 6.2.1: Data Comparison for Well A-03 in Gap

Well A-09A				
	Liquid Tate	Oil Rate	Water Rate	Manifold Pressure
Well test data	547	264.0	283	17.20
Solver Summery Data	506.6	243.2	263.4	16.16
Deviation (%)	7.39	7.88	6.93	6.05

Table 6.2.2: Data Comparison for Well A-09A in Gap

Well A-10T2				
	Liquid Tate	Oil Rate	Water Rate	Manifold Pressure
Well test data	1582	309.4	1273	26.00
Solver Summery Data	1538.3	307.8	1230.6	26.75
Deviation (%)	2.76	0.52	3.33	-2.88

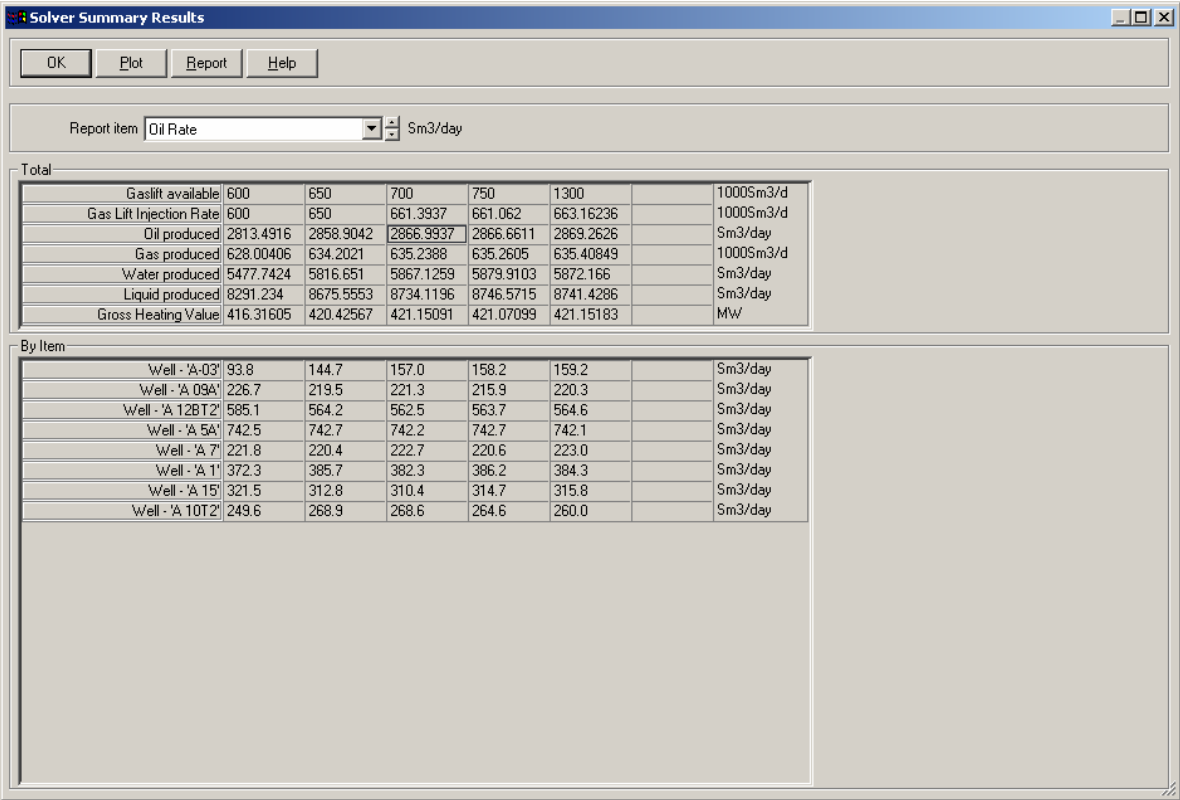
Table 6.2.3: Data Comparison for Well A-10T2 in Gap

Well A-12BT2				
	Liquid Tate	Oil Rate	Water Rate	Manifold Pressure
Well test data	1635.8	636.8	999	31.00
Solver Summery Data	1612.8	629.0	983.8	31.81
Deviation (%)	1.41	1.22	1.52	-2.61

Table 6.2.4: Data Comparison for Well A-12BT2 in Gap

6.2.6 Production Optimization

In Varg field, all produced oil is processed by both production and test separators. For finding out the best combination for obtaining the maximum oil production, producing wells had been passed through different combinations of wells and separators. From this work, maximum oil production had been achieved by flowing well A-05A and well A-07 through the test separator and remaining six wells through the production separator. Optimum oil production rate and lift gas injection rate achieved by gap calculation have been presented in figure 6.2.1.



Gaslift available	600	650	700	750	1300		1000Sm3/d
Gas Lift Injection Rate	600	650	661.3937	661.062	663.16236		1000Sm3/d
Oil produced	2813.4916	2858.9042	2866.9937	2866.6611	2869.2626		Sm3/day
Gas produced	628.00406	634.2021	635.2388	635.2605	635.40849		1000Sm3/d
Water produced	5477.7424	5816.651	5867.1259	5879.9103	5872.166		Sm3/day
Liquid produced	8291.234	8675.5553	8734.1196	8746.5715	8741.4286		Sm3/day
Gross Heating Value	416.31605	420.42567	421.15091	421.07099	421.15183		MW

Well - 'A-03'	93.8	144.7	157.0	158.2	159.2		Sm3/day
Well - 'A 09A'	226.7	219.5	221.3	215.9	220.3		Sm3/day
Well - 'A 12BT2'	585.1	564.2	562.5	563.7	564.6		Sm3/day
Well - 'A 5A'	742.5	742.7	742.2	742.7	742.1		Sm3/day
Well - 'A 7'	221.8	220.4	222.7	220.6	223.0		Sm3/day
Well - 'A 1'	372.3	385.7	382.3	386.2	384.3		Sm3/day
Well - 'A 15'	321.5	312.8	310.4	314.7	315.8		Sm3/day
Well - 'A 10T2'	249.6	268.9	268.6	264.6	260.0		Sm3/day

Figure 6.2.1: Optimized Oil Production Rate

From the above solver summery result, the obtained result of this thesis work is as follows:

Optimum Gas Lift Injection Rate: $(661.4 \times 1000) Sm^3 / day$

Maximum Oil Production Rate: $(2867.0 \times 1000) Sm^3 / day$

Gas lift injection rate of individual well has been provided in figure 6.2.2. From that figure; it has been observed that well A-05A is producing without gas lift injection. In practical situation, the well is currently producing without gas lift system due to low water cut.

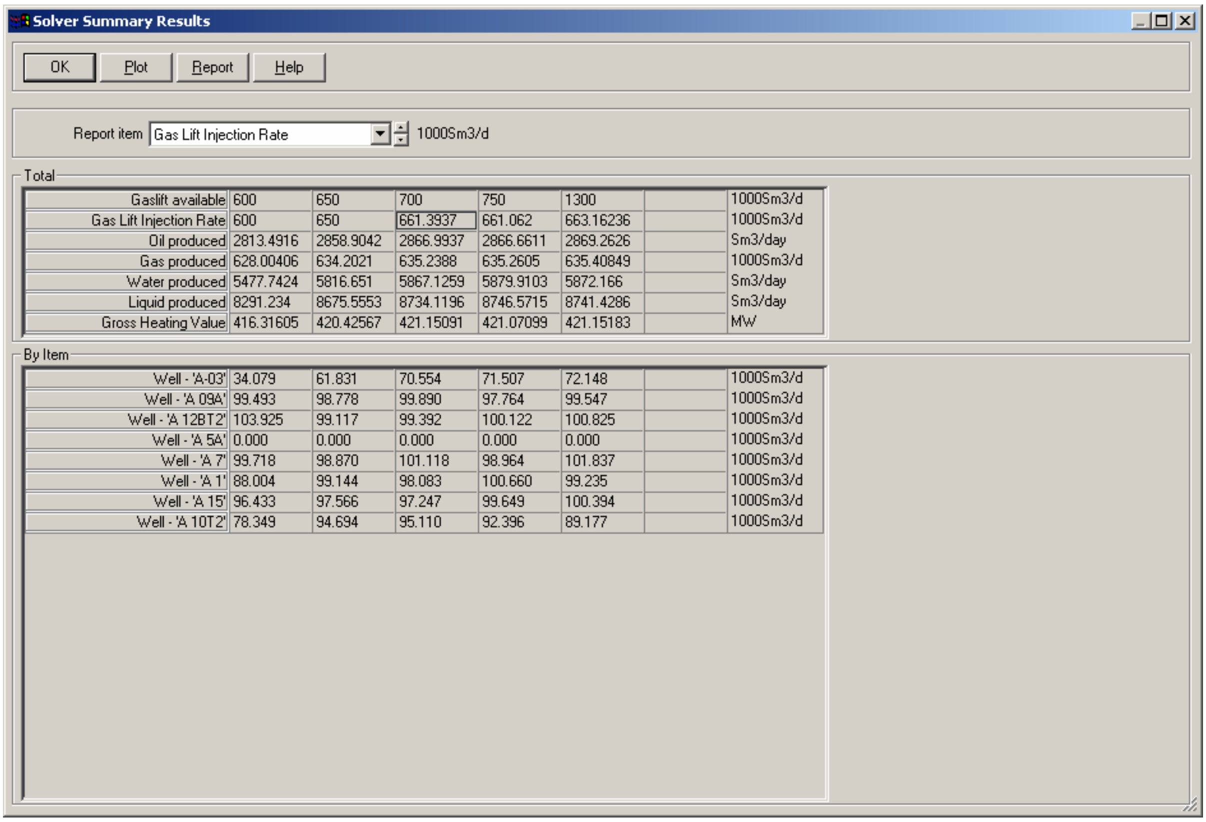


Figure 6.2.2: Optimized Gas Lift Injection Rate

6.2.7 Solver Summery Results for different Combinations

Network solver calculation had been performed for different combinations of wells flowing through the test separator and production separator. Solver summery result of some different cases had been mentioned below. In every case, maximum gas lift gas available rate (1300x1000 Sm3/day) had been considered for production optimization.

Wells flowing through test separator	Wells flowing through production separator	Maximum oil production rate (Sm3/day)	Optimum gas injection rate (1000 Sm3/day)
All (8) wells	No wells	1315	500.0
No wells	All (8) wells	2644	686.5
3,9,10,12	1,5,7,15	2188	362.7
1,5,7,15	3,9,10,12	2540	727.6
5,7	**1,3,9,10,12,15**	**2867**	**661.4**

Table 6.2.5: Solver Summery Results

Conclusion

Obtaining the optimum gas injection rate is important because excessive gas injection rate reduces oil production rate and increases operation cost. To obtain the optimum gas injection and oil production rate, all wells had been modelled properly. Flash data of recombined reservoir fluid had been used for PVT matching. Standing and Beal et al correlations were found best-fit correlation for PVT matching.

All available well test data including current well test data had been considered for quality checking. Since the reservoir parameter is continuously changing from inception of production, current well test data was the focus for quality checking of well test data. In this work, it was found that current well test data for all wells had been matched with calculated data in Prosper.

For correlation comparison of VLP, Petroleum Expert 2 was found very close to well test data for all well tests. Parameter 1 and 2 was close to unity. Thus PE-2 correlation had been used for VLP matching in Prosper. While matching surface flow line in Gap program, Dukler Fannigan was found the best-fit correlation for production and test flow line. Calculated manifold pressure was compared with the measured wellhead pressure and found very close results.

Currently oil is producing from eight wells of Varg field on which seven wells are producing with gas lift system. Presently average oil production rate of Varg field is around 2500 Sm^3/day with gas lift injection rate around $600 x 10^3$ Sm^3/day. From simulation result of GAP program, maximum oil production rate was achieved 2867.0 Sm^3/day at gas lift injection rate of $661.4 x 10^3$ Sm^3/day. At $500 x 10^3$ Sm^3/day gas lift injection rate, Gap calculates 2686 Sm^3/day oil production rate. It has been observed from the simulation result that well A-05A is producing without gas lift injection due to low water cut. Production optimization and lift gas allocation rates achieved by this thesis work shows quite close results with current status of producing wells of Varg field.

Nomenclature

q	Oil flow rate, Sm^3/day
q’	Absolute open flow rate, Sm^3/day
k	Effective oil permeability, md
h	Reservoir thickness, m
r_e	Drainage area radius, m
r_w	Well bore radius, m
P_e	Pressure at $r = r_e$, bara
P_{wf}	Well bore flowing pressure at $r = r_w$, bara
μ	Oil viscosity, cp
B	Oil formation volume factor, Rm^3/Sm^3
R_s	Solution gas oil ratio, Sm^3/Sm^3
S	Skin factor
P_b	Bubble point pressure, bara
$\overline{P_{\mathrm{Res}}}$	Average reservoir pressure, bara
$\overline{P_R}$	Minimum (P_b , $\overline{P_{\mathrm{Res}}}$), bara
ρ_l	Density of liquid, kg/m^3
ρ_g	Density of gas, kg/m^3
E_l	Fraction of liquid, in two phase flow
E_g	Fraction of gas, in two phase flow
u_m	Velocity of two phase flow (liquid-gas mixture), m/sec
C	Coefficient (Ducker’s value C= 0.046)
Re_m	Reynold’s number for the mixture
n	Ducker’s value, n= -0.2
d	Tubing diameter, m
θ	Well deviation angle, degree

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Appendix A-1: Deviation and Equipment Dat

Well: A-03			
Well Head Datum	23.80	m	
SCSSV	450.98	m	
Gas Lift Valve Depth	3060.48	m	
DHPG Depth	3092.47	m	
Top of Perforation	3385.00	m	
Deviation Survey Data			
Measured Depth (m)	**True Vertical Depth (m)**	**Cumulative Displacement (m)**	**Angle (degrees)**
0.00	0.00	0.00	0.00
167.70	167.70	0.00	0.00
394.50	394.18	12.04	3.04
494.57	492.21	32.15	11.59
639.90	627.43	85.40	21.50
872.80	829.92	200.47	29.61
1076.50	1006.01	302.87	30.18
1396.90	1284.91	460.58	29.49
1592.27	1457.25	552.60	28.10
1883.87	1711.31	695.72	29.39
2174.96	1962.12	843.47	30.50
2493.10	2234.90	1007.18	30.97
2786.16	2485.16	1159.68	31.36
2990.12	2652.80	1275.85	34.72
3194.67	2820.62	1392.80	34.87
3345.22	2942.82	1480.74	35.74
3462.35	3036.88	1550.54	36.58
3500.00	3066.87	1573.30	37.20
Downhole Equipment Data			
Label	**Type**	**Measured Depth (m)**	**Tubing Inside Diameter (inches)**
	Xmas Tree	23.8	
	Tubing	448.29	4.778
TRSV	SSSV		4.562
	Tubing	3132.05	4.778
	Tubing	3155.84	4.67
	Tubing	3160.24	4.778
Liner	Tubing	3385	4.811

Well: A-09A			
Well Head Datum	27.70	m	
SCSSV	438.01	m	
Gas Lift Valve Depth	2927.12	m	
DHPG Depth	2957.86	m	
Top of Perforation	3149.00	m	
Deviation Survey Data			
Measured Depth (m)	**True Vertical Depth (m)**	**Cumulative Displacement (m)**	**Angle (degrees)**
0.00	0.00	0.00	0.00
268.66	268.66	0.00	0.00
439.46	439.02	12.25	4.11
576.96	576.52	12.25	0.00
917.46	917.00	15.94	0.62
1028.76	1027.69	27.58	6.00
1202.06	1197.22	63.53	11.97
1344.40	1330.70	112.96	20.32
1515.90	1490.02	176.44	21.72
1720.30	1667.01	278.69	30.01
1946.60	1851.64	409.54	35.33
2150.20	2018.04	526.86	35.19
2354.20	2198.71	621.59	27.67
2642.70	2474.78	705.37	16.88
2874.40	2692.68	784.13	19.87
3081.90	2887.48	855.61	20.15
3267.00	3061.08	919.84	20.30
Downhole Equipment Data			
Label	**Type**	**Measured Depth (m)**	**Tubing Inside Diameter (inches)**
	Xmas Tree	27.7	
	Tubing	435.99	4.892
DHSV	SSSV		4.562
	Tubing	1946.6	4.892
	Tubing	2956.49	4.778
DHPG Mandrel	Tubing	2957.86	4.77
	Tubing	3009.04	4.778
Liner	Tubing	3149	4.892

Well: A-10T2			
Well Head Datum	22.62	m	
SCSSV	460.20	m	
Gas Lift Valve Depth	3036.16	m	
DHPG Depth	3068.15	m	
Top of Perforation	3514.00	m	
Deviation Survey Data			
Measured Depth (m)	**True Vertical Depth (m)**	**Cumulative Displacement (m)**	**Angle (degrees)**
0.00	0.00	0.00	0.00
279.70	279.70	0.00	0.00
444.50	443.53	17.85	6.22
755.82	739.93	113.08	17.81
925.61	896.53	178.69	22.73
1068.60	1027.62	235.80	23.54
1209.54	1155.86	294.27	24.51
1435.12	1362.25	385.32	23.80
1719.38	1631.18	477.40	18.90
1918.26	1817.74	546.31	20.27
2145.36	2030.67	625.28	20.35
2314.75	2192.16	676.40	17.57
2599.67	2461.47	769.42	19.05
2940.09	2741.08	963.59	34.78
3253.22	2918.36	1221.71	55.52
3590.66	2970.29	1555.13	81.15
3761.55	2984.90	1725.39	85.10
3900.00	2991.73	1863.67	87.17
Downhole Equipment Data			
Label	**Type**	**Measured Depth (m)**	**Tubing Inside Diameter (inches)**
	Xmas Tree	22.62	
	Tubing	457.08	4.778
TRSV	SSSV		4.562
	Tubing	487.77	4.778
	Tubing	2507	4.892
	Tubing	3067.05	4.778
Gauge Carrie	Tubing	3068.15	4.77
	Tubing	3103.16	4.778
	Tubing	3129.91	4.67
	Tubing	3514	4.778

Well: A-12BT2			
Well Head Datum	24.02	m	
SCSSV	441.73	m	
Gas Lift Valve Depth	2486.71	m	
DHPG Depth	2518.06	m	
Top of Perforation	3152.00	m	
Deviation Survey Data			
Measured Depth (m)	**True Vertical Depth (m)**	**Cumulative Displacement (m)**	**Angle (degrees)**
0.00	0.00	0.00	0.00
262.16	262.16	0.00	0.00
406.16	405.77	10.59	4.22
561.16	559.72	28.60	6.67
706.16	703.99	43.13	5.75
1028.16	1024.43	74.79	5.64
1231.16	1226.26	96.55	6.15
1422.86	1416.56	119.68	6.93
1449.58	1442.77	124.88	11.21
1676.96	1661.96	185.35	15.42
1875.65	1842.19	268.99	24.89
2073.36	2019.00	357.46	26.58
2274.06	2198.56	447.12	26.53
2442.61	2348.82	523.48	26.94
2670.86	2550.26	630.81	28.05
2854.20	2704.96	729.21	32.46
3094.60	2902.51	866.20	34.74
3253.00	3032.37	956.90	34.93
Downhole Equipment Data			
Label	**Type**	**Measured Depth (m)**	**Tubing Inside Diameter (inches)**
	Xmas Tree	24.02	
	Tubing	438.61	4.892
DHSV	SSSV		4.562
	Tubing	1975.76	4.892
	Tubing	2516.96	4.778
DHPG Mandrel	Tubing	2518.06	4.77
	Tubing	2567.98	4.778
Liner	Tubing	3152	3.958

Figure A-1-1: Set of Prosper Data

Appendix A-2: Complete Deviation Survey Data

WELL : 15/12-A-03
DATUM ELEVN :
VSDIR :

Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect	Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect	Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect	Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect
135,5	0,0	135,5	0,0	0,0	1047,4	30,7	981,2	0,4	204,0	2175,0	30,7	1962,1	0,3	656,7	3345,2	36,1	2942,8	0,2	1279,2
147,2	0,2	147,2	0,4	0,0	1076,5	32,1	1006,0	1,4	213,8	2204,2	31,6	1987,1	0,9	671,1	3403,8	36,6	2990,0	0,3	1313,9
157,6	0,3	157,6	0,4	0,0	1105,8	32,2	1030,8	0,3	223,9	2233,3	31,5	2011,9	0,3	685,7	3433,1	36,8	3013,5	0,2	1331,4
167,7	0,3	167,7	0,2	0,0	1134,8	30,6	1055,6	1,6	233,8	2261,9	31,6	2036,3	0,6	699,9	3462,4	37,0	3036,9	0,3	1349,0
177,9	0,3	177,9	0,3	-0,1	1163,7	30,1	1080,6	1,2	243,7	2290,1	31,1	2060,5	1,1	713,8	3485,1	37,3	3055,0	0,7	1362,7
187,3	0,2	187,3	0,2	-0,1	1192,8	28,1	1106,0	2,1	253,4	2319,6	30,9	2085,7	1,0	727,9	3511,0	37,3	3075,6	0,0	1378,4
197,6	0,3	197,6	0,1	-0,1	1221,9	28,0	1131,6	0,8	263,0	2346,5	31,1	2108,7	0,3	740,8	3512,0	37,3	3076,4	0,0	1379,0
207,6	0,1	207,6	0,5	-0,1	1251,0	29,9	1157,1	1,9	273,1	2377,3	31,4	2135,1	0,3	755,7					
217,8	0,3	217,8	0,7	-0,1	1280,2	29,3	1182,5	0,7	283,3	2406,1	30,3	2159,9	1,3	769,4					
227,4	0,3	227,4	0,1	-0,2	1309,1	29,0	1207,7	0,5	293,3	2435,2	29,7	2185,0	1,1	782,8					
230,9	0,2	230,9	1,3	-0,2	1338,5	29,2	1233,4	0,8	303,3	2464,3	30,7	2210,2	1,5	796,6					
231,0	0,2	231,0	0,0	-0,2	1396,9	27,2	1284,9	1,1	322,3	2493,1	31,0	2234,9	1,1	810,6					
276,5	0,8	276,5	0,5	0,0	1426,2	26,9	1311,0	0,3	331,6	2522,6	31,3	2260,1	0,3	825,2					
279,0	0,8	279,0	0,5	0,0	1435,9	27,1	1319,7	0,6	334,7	2551,9	31,5	2285,2	0,2	839,8					
308,8	2,8	308,8	2,0	0,7	1455,9	26,7	1337,5	0,7	341,0	2577,3	31,8	2306,8	0,4	852,5					
336,6	4,0	336,5	1,3	2,0	1493,6	28,0	1371,0	1,3	353,3	2610,7	31,7	2335,2	0,1	869,3					
366,0	5,2	365,8	1,2	3,9	1533,9	29,4	1406,4	1,3	367,6	2639,9	30,5	2360,2	1,2	883,8					
394,5	6,8	394,2	1,8	6,5	1563,2	29,5	1431,9	1,2	378,6	2669,2	30,6	2385,4	0,4	898,1					
463,1	12,7	461,8	2,6	16,5	1592,3	28,9	1457,3	1,5	389,9	2698,6	31,0	2410,7	1,2	912,6					
494,6	16,6	492,2	3,8	23,3	1621,0	29,7	1482,3	1,0	401,3	2727,7	31,4	2435,6	3,6	927,5					
523,3	17,8	519,7	2,2	30,2	1648,1	29,7	1505,9	0,3	412,3	2756,9	31,9	2460,4	2,3	942,7					
552,4	19,0	547,2	1,2	37,5	1679,1	29,4	1532,8	0,3	424,9	2786,2	32,8	2485,2	2,7	958,3					
581,6	21,5	574,7	2,6	45,3	1708,1	28,7	1558,2	3,0	437,0	2844,8	34,4	2534,0	0,8	990,8					
610,7	25,2	601,4	4,0	54,1	1737,5	29,2	1583,9	2,2	449,7	2873,6	34,9	2557,6	0,6	1007,1					
639,9	28,5	627,4	3,4	63,9	1766,7	28,8	1609,4	0,4	462,6	2902,8	35,4	2581,5	1,4	1023,9					
669,0	30,0	652,8	1,5	74,4	1796,1	29,3	1635,2	0,8	475,6	2931,7	35,0	2605,2	1,4	1040,6					
698,3	30,6	678,1	0,6	85,4	1825,4	29,8	1660,7	1,0	489,0	2960,8	35,5	2628,9	0,7	1057,3					
727,6	29,6	703,5	1,0	96,3	1854,6	30,1	1685,9	1,2	502,6	2990,1	35,8	2652,8	0,3	1074,4					
756,6	29,5	728,7	0,9	106,8	1883,9	30,0	1711,3	0,4	516,5	3019,4	34,6	2676,7	1,2	1091,2					
785,7	28,3	754,2	1,1	116,9	1912,4	29,7	1736,1	0,4	530,0	3048,4	34,1	2700,6	0,5	1107,5					
814,9	30,0	779,7	1,9	127,0	1942,3	30,9	1761,8	1,2	544,3	3076,9	35,2	2724,1	1,2	1123,8					
843,8	29,9	804,7	0,5	137,1	1971,4	30,8	1786,8	0,2	558,5	3107,3	35,5	2748,9	0,4	1141,3					
872,8	29,4	829,9	0,6	147,0	2000,5	30,6	1811,9	0,2	572,5	3136,5	34,9	2772,8	0,6	1158,2					
901,8	29,6	855,2	0,7	156,8	2029,4	30,2	1836,8	0,4	586,4	3165,9	34,1	2797,0	1,1	1174,8					
931,0	29,9	880,5	1,4	166,4	2058,8	30,7	1862,1	0,5	600,5	3194,7	35,7	2820,6	1,9	1191,3					
960,3	29,2	906,0	0,6	175,7	2087,9	30,7	1887,2	0,0	614,6	3224,6	35,9	2844,9	0,3	1208,8					
989,0	30,0	931,0	0,8	184,9	2116,9	30,6	1912,1	0,2	628,7	3258,4	35,4	2872,4	0,5	1228,5					
1018,2	31,1	956,1	1,2	194,4	2145,8	30,4	1937,0	0,3	642,6	3297,0	35,7	2903,8	0,2	1250,9					

Table A-2-1: Complete Deviation Survey Data of Well A-03

WELL : 15/12-A-9A
DATUM ELEVN : 52.2
VSDIR : 185

Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect
136.2	0.0	136.2	0.0	0.0
140.9	0.0	140.9	0.1	0.0
170.8	0.5	170.8	0.5	0.1
201.1	0.5	201.1	0.1	0.2
241.7	0.1	241.7	0.3	0.3
268.7	0.6	268.7	0.8	0.3
296.7	4.0	296.6	3.6	0.4
325.5	5.5	325.3	1.6	0.5
354.2	5.2	353.9	0.5	0.8
382.5	5.3	382.1	0.9	1.4
411.3	2.1	410.8	3.4	2.0
439.5	0.4	439.0	1.9	2.2
467.7	0.2	467.2	0.3	2.2
496.4	0.3	495.9	0.2	2.1
519.0	0.2	518.5	0.1	2.0
548.6	0.2	548.1	0.3	2.0
577.0	0.3	576.5	0.1	2.0
605.6	0.2	605.1	0.2	2.1
634.0	0.2	633.5	0.1	2.1
662.4	0.3	661.9	0.1	2.1
690.6	0.2	690.1	0.1	2.2
719.3	0.2	718.8	0.0	2.3
747.2	0.2	746.7	0.0	2.4
775.8	0.2	775.3	0.1	2.5
804.2	0.2	803.7	0.1	2.6
832.6	0.3	832.1	0.1	2.7
860.9	0.4	860.4	0.1	2.8
889.2	0.7	888.7	1.1	2.7
917.5	2.4	917.0	1.8	2.1
945.9	4.1	945.4	1.9	0.9
974.2	5.8	973.6	1.8	-1.0
1002.2	7.4	1001.4	1.7	-3.4
1028.8	8.9	1027.7	1.8	-6.1
1059.8	10.6	1058.2	1.7	-10.0
1088.6	11.1	1086.5	0.6	-14.1
1116.8	11.7	1114.2	0.7	-18.4
1145.1	11.9	1141.9	0.6	-23.0
1173.6	13.5	1169.7	1.8	-28.2
1202.1	16.1	1197.2	2.8	-34.3
1230.6	17.9	1224.5	1.8	-41.2
1258.3	19.1	1250.8	1.4	-48.6
1286.6	21.1	1277.3	2.3	-56.6
1313.4	23.4	1302.1	2.7	-64.7
1344.4	22.8	1330.7	2.1	-74.7
1366.0	21.8	1350.7	1.6	-81.7
1399.9	20.4	1382.3	1.3	-92.2
1430.4	20.7	1410.9	1.8	-101.2
1459.2	21.4	1437.8	2.0	-109.3
1488.6	22.8	1465.0	1.9	-117.5
1515.9	24.5	1490.0	2.1	-125.3
1544.3	26.2	1515.7	2.4	-133.6
1575.2	27.5	1543.3	2.8	-142.2
1604.5	28.4	1569.1	2.8	-149.6
1633.3	30.4	1594.2	2.8	-156.2
1662.2	32.4	1618.9	2.3	-162.7
1691.2	34.4	1643.1	2.4	-169.0
1720.3	35.1	1667.0	1.5	-175.0
1749.1	35.3	1690.6	0.4	-180.5
1777.7	35.9	1713.8	0.7	-186.0
1806.4	34.8	1737.2	1.1	-191.3
1835.1	34.7	1760.8	0.3	-196.5
1863.9	35.8	1784.4	1.2	-201.8
1889.1	35.4	1804.8	0.5	-206.7
1917.2	35.2	1827.8	0.2	-212.0
1946.6	36.2	1851.6	1.3	-217.9
1976.3	35.2	1875.8	1.0	-224.0
2006.6	34.9	1900.6	0.5	-230.1
2034.3	35.5	1923.2	2.1	-235.1
2065.7	34.8	1948.9	0.8	-240.3
2094.0	35.0	1972.1	0.3	-244.8
2121.4	35.4	1994.5	0.7	-249.4
2150.2	34.7	2018.0	0.8	-254.3
2179.4	32.5	2042.4	2.4	-259.1
2208.5	30.3	2067.2	3.0	-262.8
2237.7	27.9	2092.7	3.1	-265.5
2267.9	26.1	2119.6	1.9	-267.3
2296.7	24.6	2145.7	2.1	-268.5
2325.5	22.6	2172.1	2.5	-269.0
2354.2	20.8	2198.7	2.7	-268.6
2383.2	19.1	2226.0	2.9	-267.3
2411.8	17.7	2253.1	2.5	-265.2
2440.8	16.4	2280.8	2.2	-262.3
2469.8	15.6	2308.7	2.2	-258.8
2498.5	15.4	2336.4	2.4	-254.5
2526.8	15.9	2363.6	3.6	-249.1
2556.5	16.2	2392.2	2.8	-242.3
2585.3	16.4	2419.8	3.0	-234.9
2614.2	16.2	2447.6	1.3	-227.2
2642.7	18.1	2474.8	3.0	-218.9
2672.1	19.6	2502.6	1.6	-209.5
2701.1	20.1	2529.9	1.1	-199.7
2730.0	19.9	2557.1	1.9	-189.8
2758.7	20.7	2584.0	0.9	-179.9
2787.6	20.0	2611.1	1.0	-169.8
2816.5	20.0	2638.2	0.1	-159.9
2845.5	19.7	2665.5	0.5	-150.1
2874.4	20.0	2692.7	0.7	-140.3
2903.3	19.7	2719.9	0.4	-130.5
2932.1	19.7	2747.0	0.2	-120.8
2960.8	20.0	2774.0	0.4	-111.0
2989.5	19.5	2801.0	0.7	-101.3
3018.2	20.4	2828.0	0.9	-91.6
3047.0	21.6	2854.9	1.4	-81.2
3081.9	20.0	2887.5	1.4	-68.8
3116.0	20.3	2919.5	0.4	-57.1
3145.0	20.4	2946.7	0.2	-47.0
3174.9	20.3	2974.7	0.1	-36.6
3204.1	20.3	3002.1	0.2	-26.5
3224.7	20.4	3021.4	0.2	-19.3
3251.6	20.3	3046.6	0.3	-10.0
3267.0	20.3	3061.1	0.0	-4.7

Table A-2-2: Complete Deviation Survey Data of Well A-09A

WELL : 15/12-A-10T2
DATUM ELEVN :
VSDIR :

Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect
135,5	0,0	135,5	0,0	0,0
140,0	0,1	140,0	0,5	0,0
150,0	0,1	150,0	0,0	0,0
160,0	0,2	160,0	0,3	0,0
170,0	0,0	170,0	0,5	0,0
180,0	0,2	180,0	0,7	0,1
190,0	0,2	190,0	0,6	0,1
200,0	0,2	200,0	0,3	0,1
210,0	0,3	210,0	0,3	0,1
220,0	0,2	220,0	0,3	0,1
230,0	0,2	230,0	0,5	0,1
240,0	0,3	240,0	0,2	0,2
250,0	0,3	250,0	0,5	0,2
253,1	0,3	253,1	0,3	0,2
279,7	0,6	279,7	0,7	0,4
307,1	3,0	307,1	2,7	1,1
336,2	4,9	336,1	2,0	2,6
364,4	5,9	364,2	1,1	4,5
393,5	7,1	393,1	1,9	6,7
421,1	8,6	420,5	2,8	8,3
444,5	10,4	443,5	3,1	9,2
472,3	12,2	470,8	2,0	9,9
500,8	13,0	498,6	1,1	10,4
529,2	13,7	526,3	0,7	10,8
557,9	15,8	554,0	2,2	11,1
586,3	18,0	581,2	2,6	11,1
614,7	19,6	608,0	1,7	10,8
643,0	20,3	634,7	0,8	10,3
670,9	20,3	660,8	0,1	9,7
699,1	21,4	687,2	1,1	9,1
727,5	21,3	713,6	0,1	8,5
755,8	22,4	739,9	1,2	8,0
784,2	21,8	766,3	0,7	7,6
812,5	22,8	792,5	1,0	7,1
840,9	23,1	818,6	0,6	6,7
869,2	23,1	844,6	0,5	6,2
897,4	23,0	870,6	0,2	5,7
925,6	23,0	896,5	0,2	5,2
954,3	23,0	922,9	0,2	4,6
982,8	23,0	949,1	0,1	4,0
1011,8	23,4	975,9	0,4	3,3
1040,5	24,1	1002,1	0,9	2,4
1068,6	25,4	1027,6	1,4	1,2
1096,7	24,7	1053,1	0,8	-0,1
1124,9	24,4	1078,8	1,4	-0,9
1153,2	24,3	1104,5	0,1	-1,4
1182,4	24,3	1131,2	0,2	-1,8
1209,5	24,5	1155,9	0,6	-2,2
1238,6	24,3	1182,4	0,4	-3,0
1266,7	24,3	1207,9	0,3	-3,8
1295,0	24,1	1233,8	0,2	-4,7
1323,8	24,1	1260,0	0,2	-5,6
1351,8	24,0	1285,6	0,1	-6,4
1369,3	25,0	1301,5	1,7	-6,9
1406,7	22,4	1335,7	2,2	-7,8
1435,1	20,3	1362,3	2,2	-8,2
1463,7	18,9	1389,2	1,5	-8,5
1492,4	18,0	1416,4	1,0	-8,6
1520,8	18,0	1443,4	0,5	-8,8
1557,0	18,4	1477,8	0,4	-9,2
1577,7	18,8	1497,4	0,6	-9,4
1606,1	18,8	1524,3	0,4	-9,8
1634,3	19,0	1550,9	0,2	-10,0
1662,6	19,3	1577,7	0,3	-10,3
1690,9	19,6	1604,4	0,4	-10,6
1719,4	20,3	1631,2	0,7	-10,8
1747,9	20,7	1657,9	0,5	-11,0
1776,2	21,1	1684,4	0,5	-11,1
1804,7	20,6	1711,0	0,6	-11,1
1833,2	19,7	1737,7	0,9	-11,0
1861,5	19,6	1764,4	0,5	-11,1
1890,0	20,0	1791,2	1,2	-11,5
1918,3	20,0	1817,7	0,7	-12,3
1946,6	20,3	1844,3	0,3	-13,4
1984,6	20,8	1880,0	0,4	-14,9
2003,3	20,9	1897,4	0,4	-15,7
2031,7	20,9	1924,0	0,8	-16,6
2060,3	20,7	1950,7	0,7	-17,2
2096,3	20,2	1984,4	0,7	-17,5
2117,2	19,5	2004,1	1,5	-17,5
2145,4	19,0	2030,7	2,3	-16,7
2174,0	18,4	2057,8	1,7	-15,1
2202,4	17,7	2084,8	1,5	-12,9
2230,6	17,5	2111,6	1,7	-10,1
2258,8	16,9	2138,6	1,4	-6,7
2287,3	16,9	2165,9	1,9	-2,7
2314,8	16,9	2192,2	2,6	2,0
2344,1	17,4	2220,2	1,6	7,9
2370,2	17,4	2245,1	2,1	13,7
2400,7	17,0	2274,3	1,9	21,0
2429,6	16,8	2301,9	1,6	28,3
2456,9	17,6	2328,0	2,6	35,7
2486,4	20,0	2355,9	3,4	44,8
2514,8	20,3	2382,6	2,1	54,5
2543,2	20,7	2409,2	1,3	64,4
2571,7	21,5	2435,8	1,1	74,6
2599,7	25,0	2461,5	3,8	85,7
2637,6	27,0	2495,6	1,5	102,3
2657,2	27,5	2513,0	1,4	111,3
2685,3	29,1	2537,7	1,8	124,6
2712,7	32,8	2561,2	4,1	138,7
2740,2	33,8	2584,2	1,1	153,7
2769,5	34,9	2608,4	1,3	170,3
2798,6	36,2	2632,1	1,6	187,2
2826,5	37,9	2654,3	2,0	204,0
2855,3	39,1	2676,9	1,2	221,9
2883,6	40,0	2698,7	1,0	239,9
2911,9	41,4	2720,2	1,6	258,4
2940,1	42,8	2741,1	1,6	277,3
2968,4	44,4	2761,6	1,8	296,7
2996,7	46,0	2781,6	1,7	316,8
3025,4	48,1	2801,1	2,3	337,7
3054,0	50,2	2819,9	2,2	359,4
3082,6	52,6	2837,6	2,6	381,6
3111,2	55,6	2854,4	3,1	404,8
3139,9	58,7	2870,0	3,6	428,9
3168,2	62,1	2884,0	3,9	453,5
3196,6	63,6	2897,0	1,6	478,8
3224,5	68,0	2908,4	4,8	504,2
3253,2	71,5	2918,4	3,6	531,1
3281,6	74,2	2926,7	3,0	558,2
3309,9	76,1	2934,0	2,0	585,5
3391,8	81,3	2950,0	2,7	665,8
3420,5	82,7	2954,0	3,1	694,1
3448,3	84,2	2957,2	1,9	721,7
3477,0	84,7	2960,0	1,3	750,2
3506,4	84,8	2962,7	0,3	779,4
3534,6	84,9	2965,2	0,8	807,6
3563,3	84,9	2967,8	0,5	836,1
3590,7	84,5	2970,3	2,7	863,3
3619,2	84,8	2973,0	0,5	891,8
3648,4	85,0	2975,5	0,2	920,8
3675,9	84,0	2978,2	1,3	948,2
3704,3	85,0	2980,9	1,0	976,5
3732,7	86,0	2983,1	1,5	1004,8
3761,6	87,0	2984,9	2,0	1033,6
3790,0	87,0	2986,4	1,1	1061,9
3824,1	87,8	2987,9	1,4	1095,9
3846,8	86,9	2989,0	1,8	1118,5
3874,8	87,1	2990,4	0,5	1146,5
3889,6	87,1	2991,2	0,1	1161,3
3900,0	87,1	2991,7	0,0	1171,7

Table A-3-3: Complete Deviation Survey Data of Well A-10T2

WELL : 15/12-A-12B T2
DATUM ELEVN : 52.2
VSDIR : 320

Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect
136.2	0.0	136.2	0.0	0.0
222.2	0.6	222.2	0.2	0.4
233.2	0.6	233.2	0.2	0.5
262.2	0.6	262.2	0.5	0.8
291.2	1.3	291.2	0.9	0.9
320.2	3.2	320.1	2.0	0.9
349.2	4.9	349.1	1.9	0.6
377.2	5.9	376.9	1.3	-0.2
406.2	6.3	405.8	1.2	-1.1
446.2	7.3	445.5	1.8	-1.3
475.2	7.6	474.3	0.3	-0.8
504.2	6.7	503.0	1.0	-0.3
533.2	5.8	531.9	1.0	0.3
561.2	5.5	559.7	0.3	0.7
589.2	5.6	587.6	0.2	1.1
619.2	5.8	617.4	0.2	1.5
648.2	6.0	646.3	0.2	1.9
677.2	6.0	675.1	0.2	2.2
706.2	5.3	704.0	1.0	2.6
735.2	5.3	732.9	0.1	3.2
765.2	5.3	762.7	0.1	3.8
795.2	5.3	792.6	0.1	4.4
825.2	5.2	822.5	0.1	4.9
853.2	5.3	850.4	0.1	5.3
883.2	5.2	880.2	0.1	5.9
912.2	5.6	909.1	0.7	6.3
941.2	5.7	938.0	0.3	6.6
970.2	6.3	966.8	0.9	6.9
999.2	6.7	995.6	0.4	7.5
1028.2	6.6	1024.4	0.2	8.0
1057.2	6.5	1053.2	0.2	8.5
1086.2	6.4	1082.1	0.3	9.0
1114.2	6.4	1109.9	0.1	9.6
1144.2	6.3	1139.7	0.4	10.0
1173.2	6.1	1168.5	0.3	10.3
1202.2	6.1	1197.4	0.2	10.6
1231.2	6.2	1226.2	0.1	10.7
1261.2	5.9	1256.0	0.3	10.8
1289.2	5.9	1283.9	0.1	10.9

Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect
1318.2	5.9	1312.7	0.1	11.0
1334.2	5.9	1328.7	0.4	11.0
1343.0	6.0	1337.4	0.2	11.0
1348.2	6.0	1342.6	0.2	11.0
1422.9	11.2	1416.6	4.2	17.7
1449.6	11.1	1442.8	1.8	22.6
1479.2	11.2	1471.8	0.3	28.1
1506.5	13.4	1498.5	2.5	33.8
1534.8	15.1	1525.9	1.9	40.7
1563.3	14.5	1553.5	0.7	47.9
1591.8	15.4	1581.0	1.1	55.2
1620.6	17.0	1608.7	1.6	63.2
1649.1	19.1	1635.8	2.2	71.9
1677.0	21.1	1662.0	2.2	81.5
1705.4	22.5	1688.3	1.7	92.0
1734.2	24.2	1714.8	2.2	103.4
1763.4	25.9	1741.2	2.0	115.7
1790.9	26.1	1765.9	0.4	127.8
1819.5	25.9	1791.6	0.2	140.3
1847.8	25.9	1817.1	0.1	152.7
1875.7	26.0	1842.2	0.1	164.8
1903.9	26.1	1867.6	0.2	177.2
1932.4	26.4	1893.1	0.3	189.8
1960.9	26.6	1918.6	0.2	202.5
1989.3	26.7	1944.0	0.1	215.2
2018.2	27.1	1969.8	0.5	228.3
2045.2	26.9	1993.8	0.3	240.5
2073.4	26.7	2019.0	0.2	253.2
2101.9	26.3	2044.5	0.4	265.9
2130.6	26.3	2070.2	0.1	278.6
2158.8	26.1	2095.5	0.3	291.1
2187.2	26.3	2121.0	0.2	303.6
2215.6	26.8	2146.4	0.7	316.3
2244.4	27.0	2172.1	0.2	329.3
2274.1	27.1	2198.6	0.1	342.8
2300.1	27.5	2221.7	0.4	354.7
2328.8	27.5	2247.1	0.2	367.9
2357.4	26.9	2272.6	0.6	381.0
2386.0	26.4	2298.1	0.6	393.8

Meas. Depth	Inc. Deg.	TVD Depth	Dog Leg	Vert Sect
2414.3	26.4	2323.5	0.1	406.4
2442.6	26.7	2348.8	0.3	419.1
2471.3	27.2	2374.4	0.5	432.1
2500.2	27.7	2400.0	0.6	445.4
2528.9	27.8	2425.4	0.2	458.7
2556.4	28.0	2449.7	0.3	471.6
2585.0	28.1	2474.9	0.3	485.0
2613.3	28.5	2499.9	0.4	498.4
2641.8	28.9	2524.9	0.4	512.1
2670.9	29.5	2550.3	0.6	526.3
2698.4	28.9	2574.3	0.6	539.7
2727.1	29.1	2599.4	0.2	553.6
2755.4	29.8	2624.0	0.8	567.5
2783.8	30.4	2648.6	0.7	581.7
2802.0	30.4	2664.3	0.1	590.9
2883.8	29.0	2735.4	1.2	631.3
2912.6	28.4	2760.7	1.3	644.9
2918.0	28.5	2765.5	1.3	647.4
2942.0	28.6	2786.5	1.1	658.7
2953.9	29.4	2796.9	2.3	664.4
2971.6	30.7	2812.3	2.2	673.0
2999.5	33.5	2835.9	3.2	687.6
3028.0	35.9	2859.3	2.6	703.6
3056.4	36.8	2882.2	1.1	720.2
3085.1	36.2	2905.3	0.7	737.0
3113.7	36.3	2928.3	1.5	753.7
3143.2	34.2	2952.4	2.2	770.3
3171.9	34.3	2976.1	0.5	786.0
3200.8	32.5	3000.3	2.2	801.7
3230.0	30.5	3025.2	2.8	816.7
3242.0	30.5	3035.5	0.0	822.8

Table A-4-4: Complete Deviation Survey Data of Well A-12BT2

Appendix A-3: Deviated Well Path

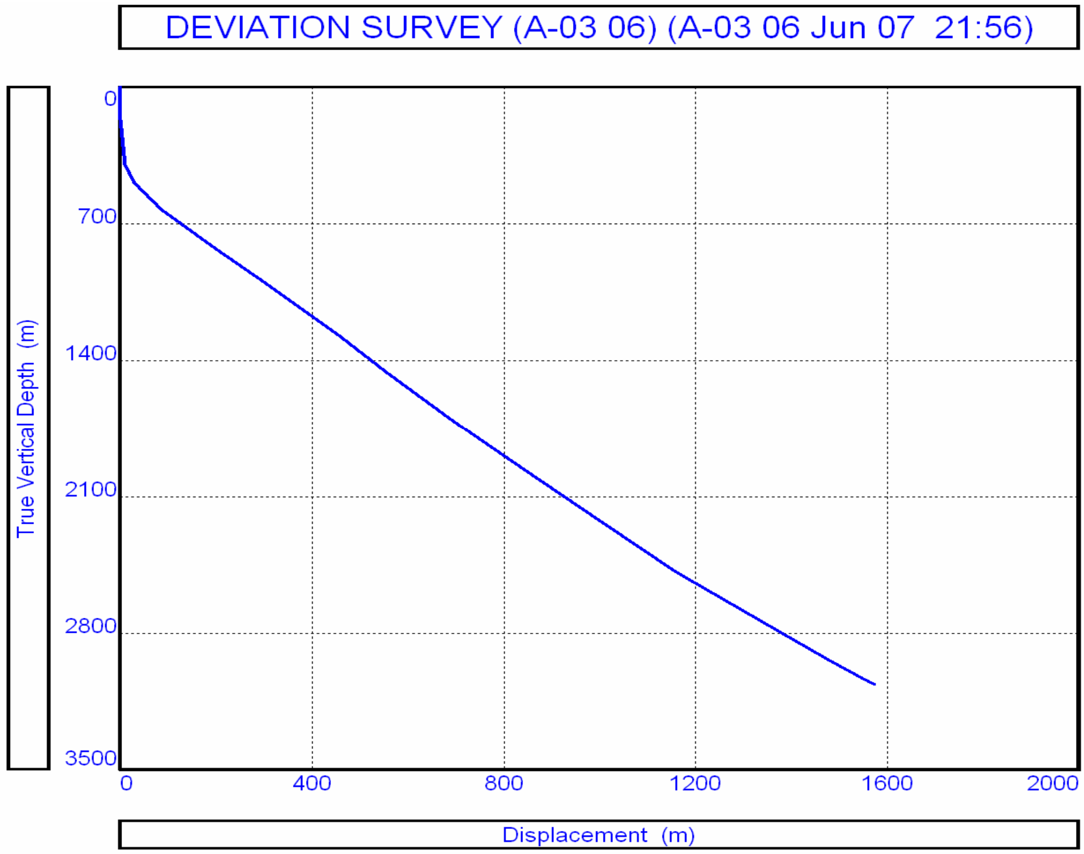


Figure A-3-1: Deviation path of Well A-03

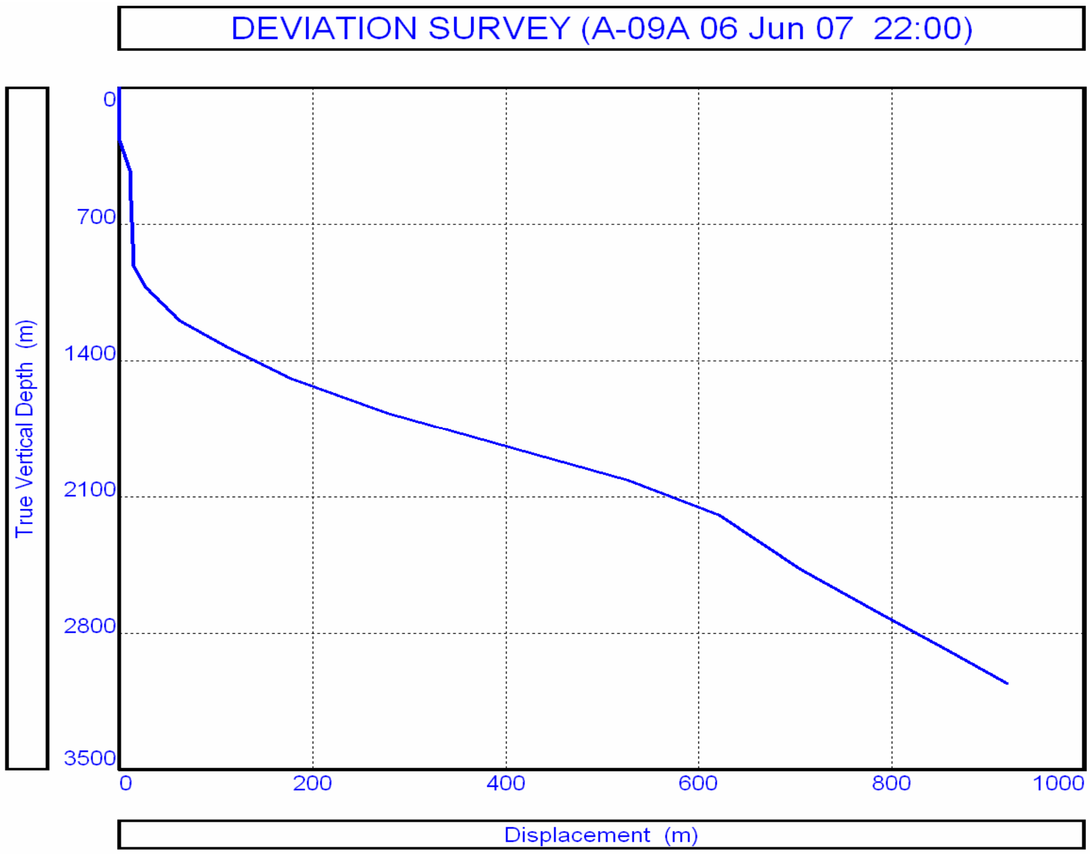


Figure A-3-2: Deviation path of Well A-09A

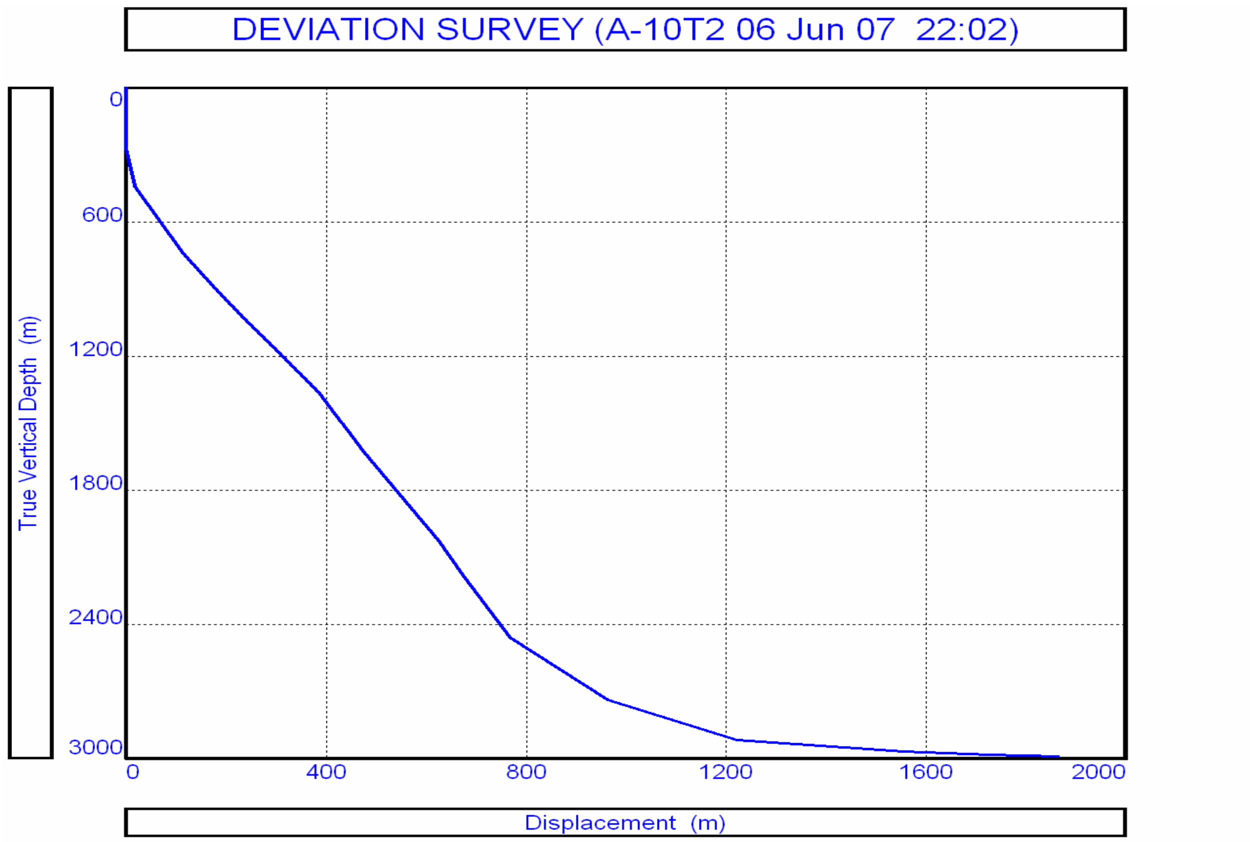


Figure A-3-3: Deviation path of Well A-10T2

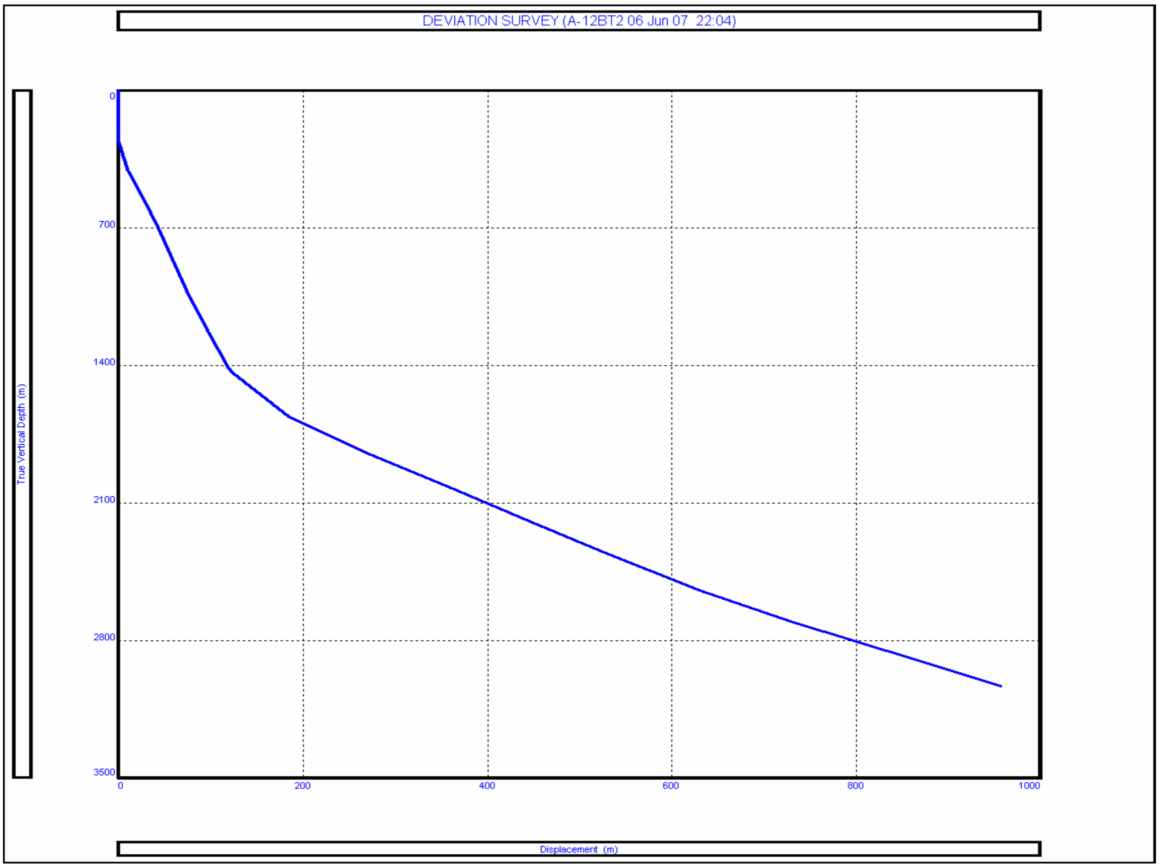


figure A-3-4 : Deviation path of Well A-12BT2

Appendix A-4: Well Deviation Schematics

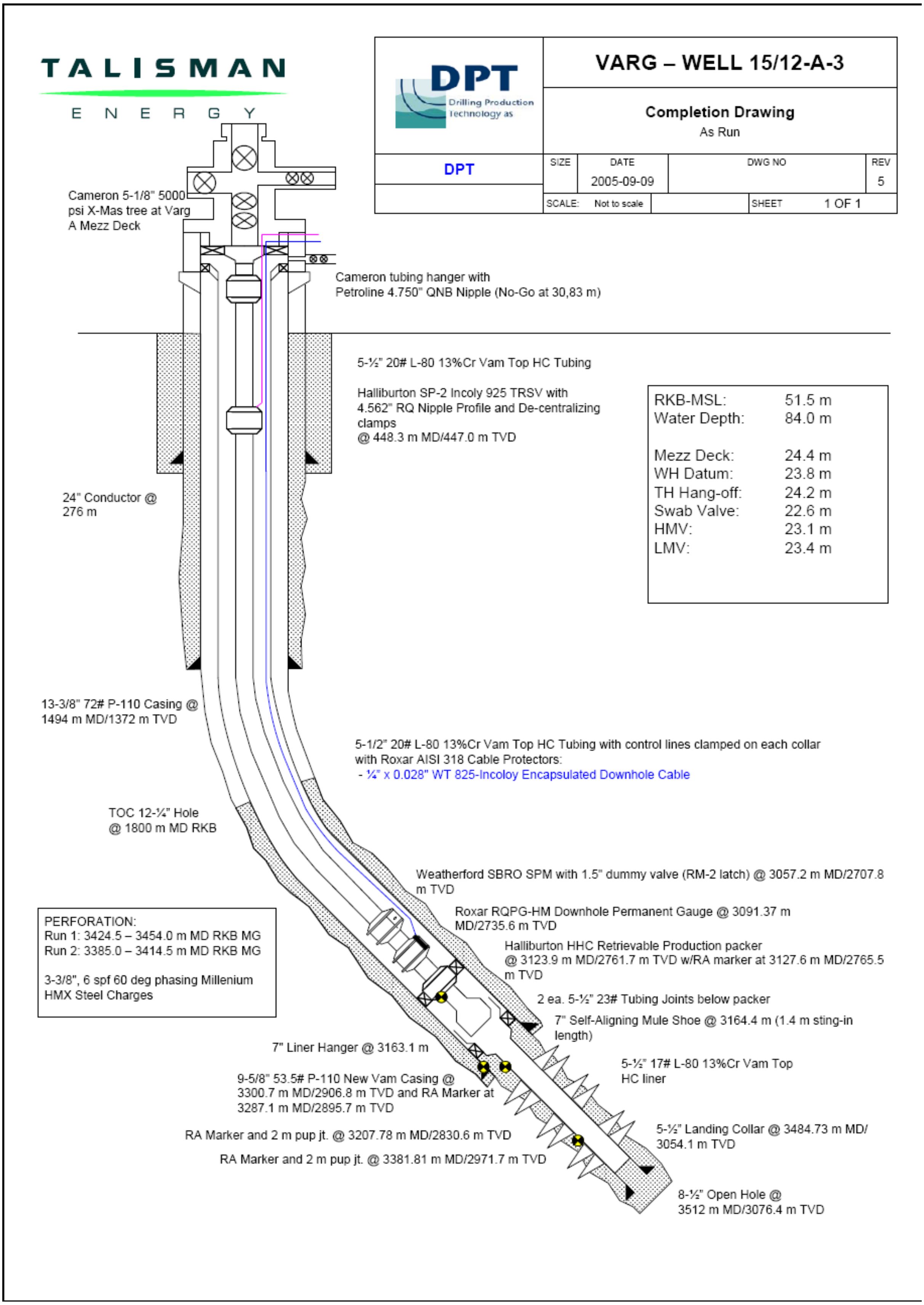


Figure A-4-1: Deviation Schematic of Well A-03

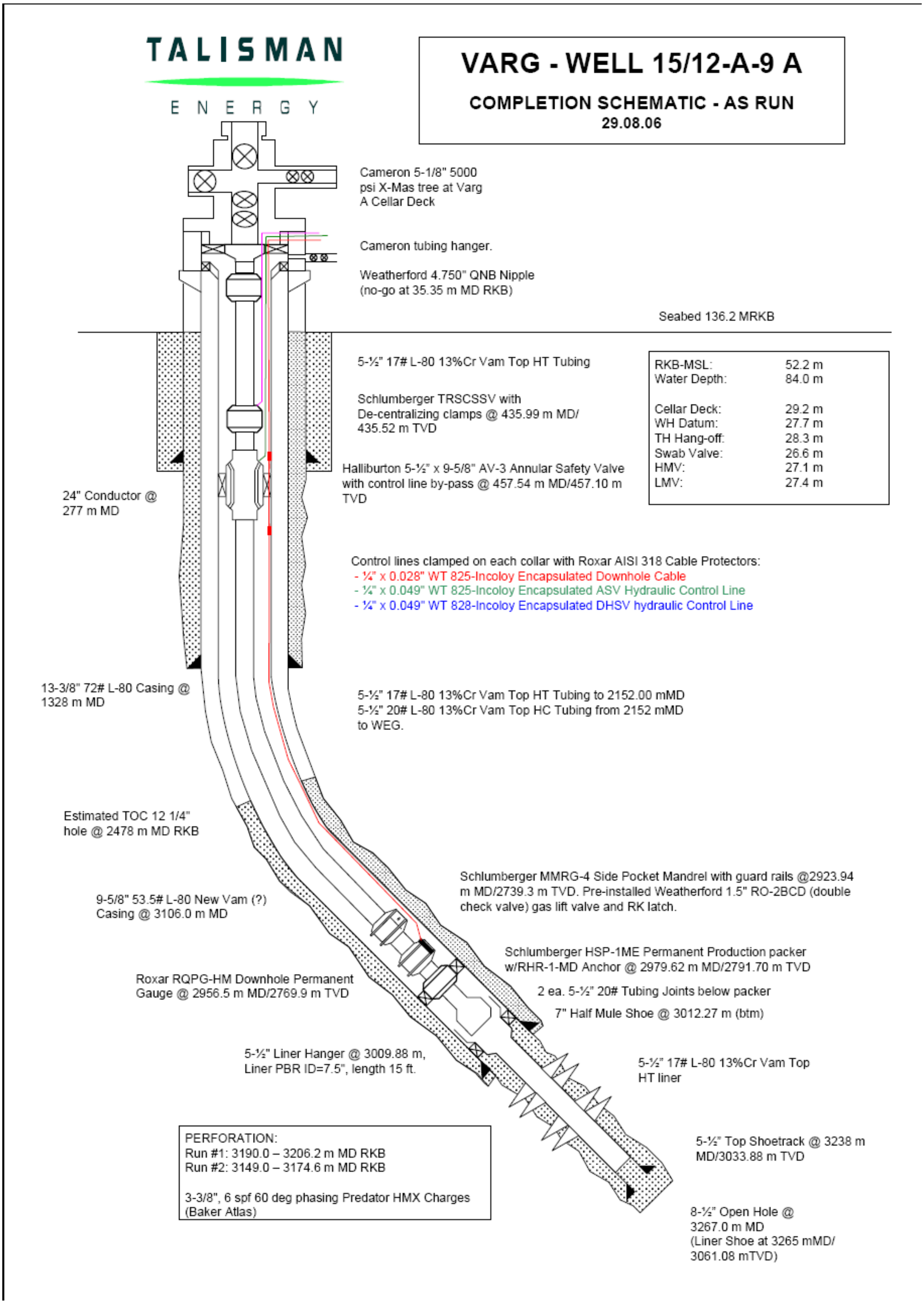


Figure A-4-2: Deviation Schematic of Well A-09A

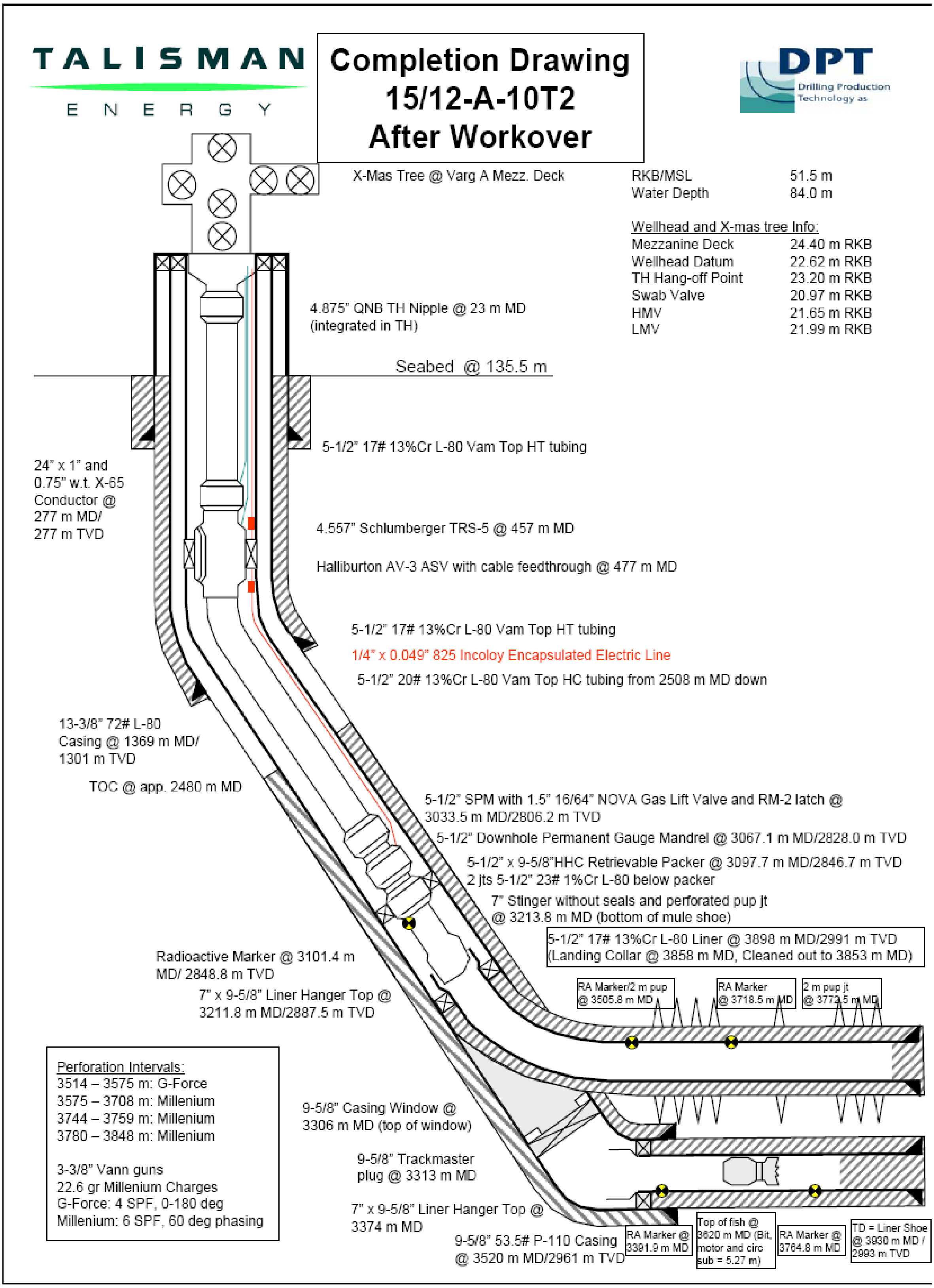


Figure A-4-3: Deviation Schematic of Well A-10T2

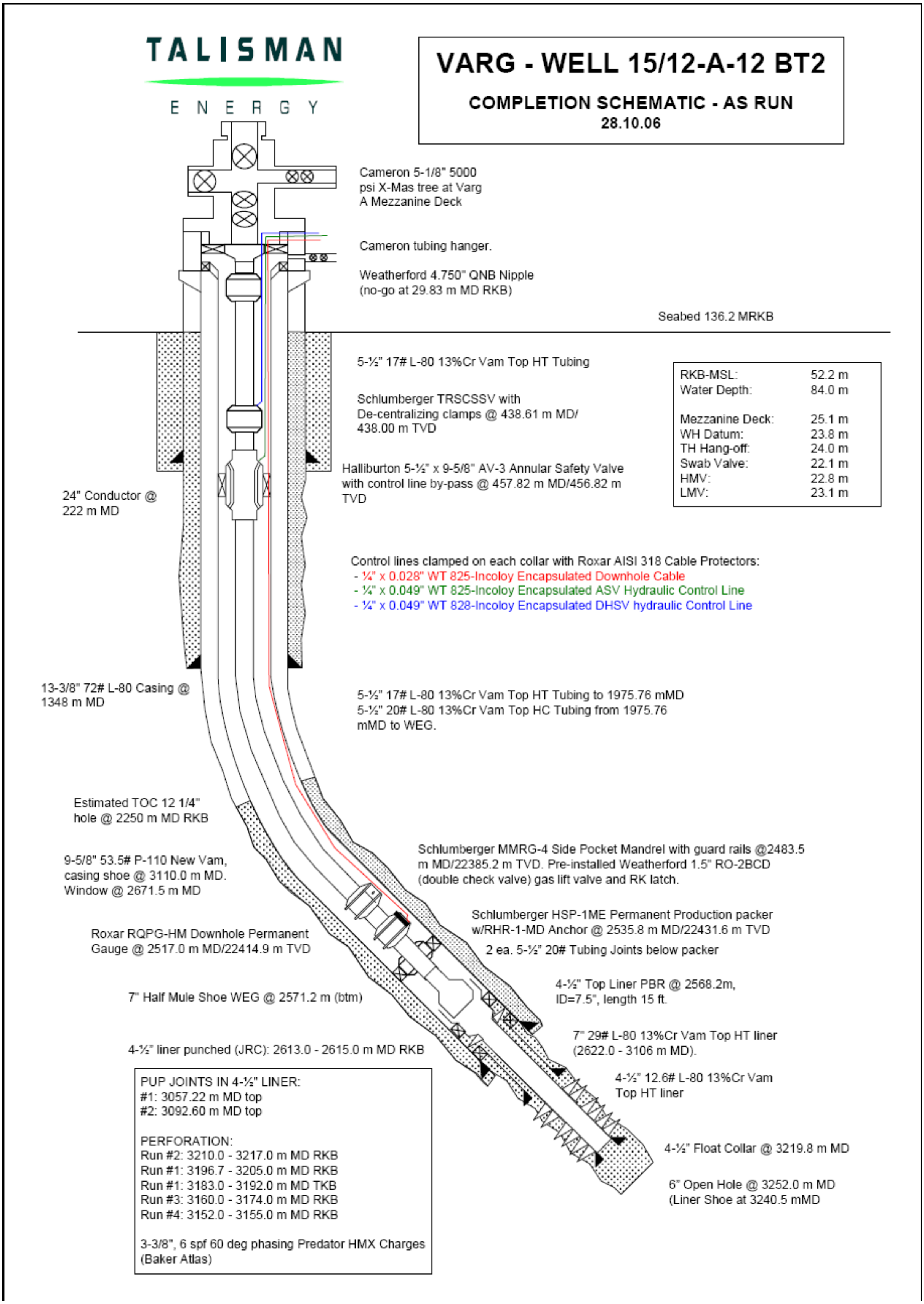


Figure A-4-4: Deviation Schematic of Well A-12BT2

Appendix A-5: Downhole Completion Diagram

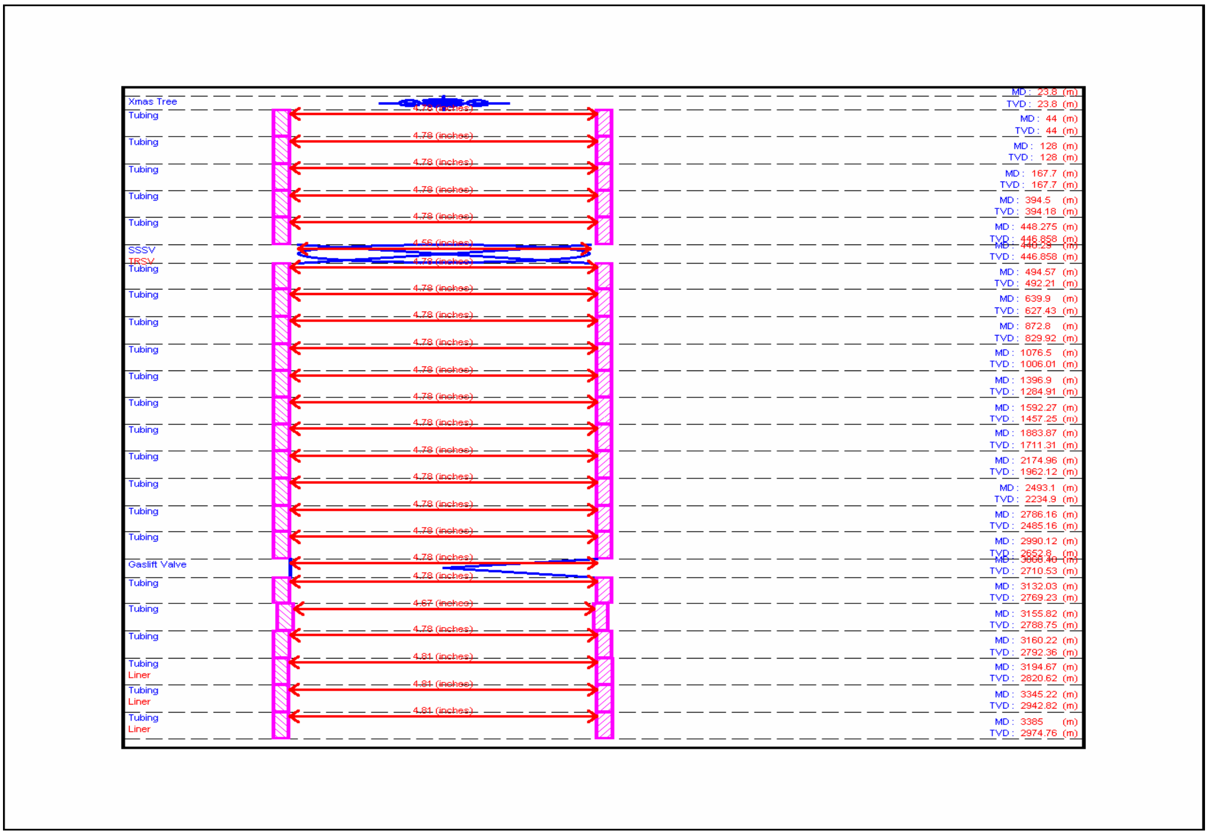
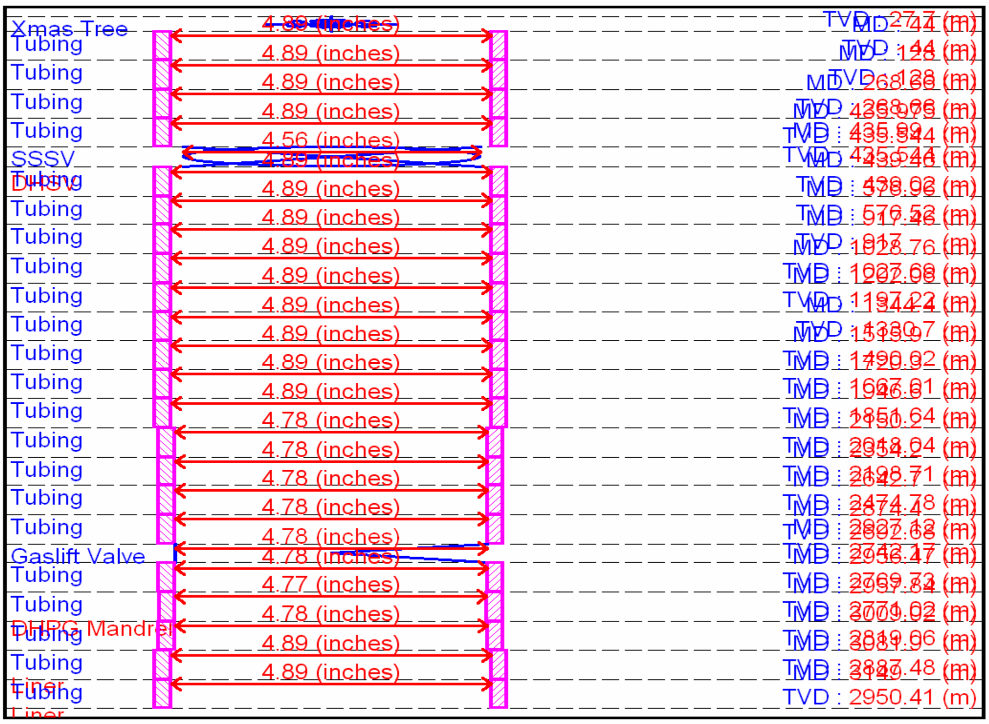
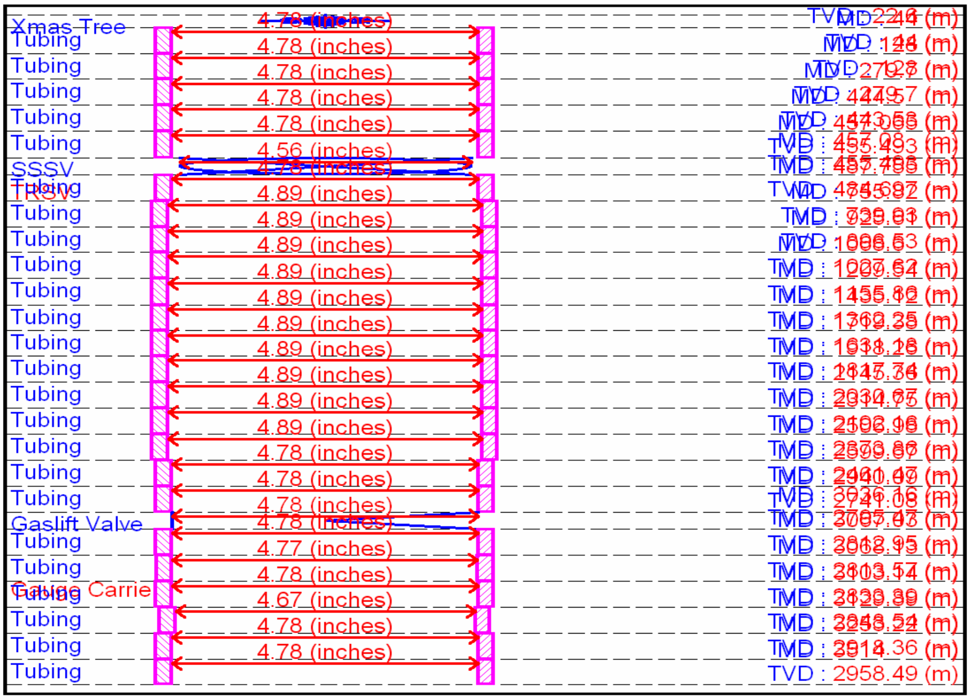


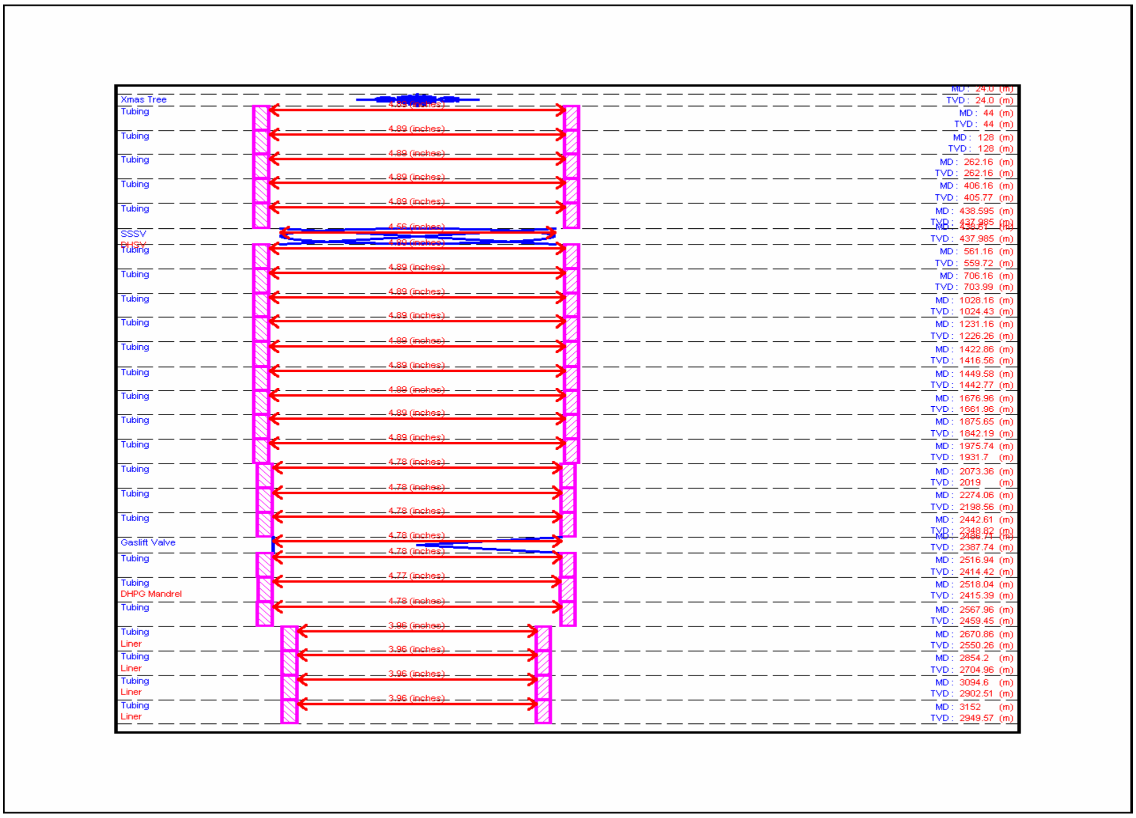
Figure A-5-1: Downhole Completion Diagram of Well A-03



FigureA-5-2 Downhole Completion Diagram of Well A-09A



FigureA-5-3: Downhole Completion Diagram Well A-10T2



FigureA-5-4: Downhole Completion Diagram of Well A-12BT2

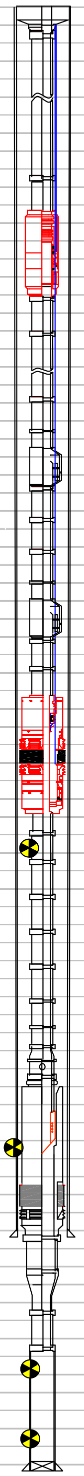
Appendix A-6: Well Completion Schematics

Talisman, VARG 15/12-A-3 — COMPLETION SCHEMATIC

Date: 18 06 2004 | Prepared: Martin Slater | Revision 8.0

Notes
RKB-MSL Mærsk Giant: 51.5 m
Well Located on Mezanine Deck
Based on Final Survey Data
RKB-Tubing hanger hang-off point: 23.25m.

AS RUN



Assy	Info	MD RKB TOP [m]	MD RKB BOT [m]	Length [m]	Max OD [inch]	Min ID [inch]	Drift ID [inch]	Description	TVD RKB [m]	Angle [deg]
Assy # 8		22.50	23.46	0.96	13.552	4.892	4.767	Tubing Hanger (Cameron)		
	1/4 inch encapsulated	23.46	30.24	6.78	5.500	4.892	4.767	X-over 5 1/2" 13Cr-110 17# Vam Top P x 17# Vam Top HC P		
	control line to TRSV	30.24	30.98	0.74	6.010	4.660	4.653	Landing Nipple 5 1/2" 20# 13Cr-80 17# Vam Top HC B x P		
								Distance from top nipple to no-go = 0,59m		
		30.98	32.66	1.68	6.071	4.778	4.653	X-over 5 1/2" 13Cr-80 17# Vam Top HC B x 20# Vam Top HC P		
		32.66	445.75	413.09	6.071	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
Assy # 7		445.75	448.29	2.54	6.071	4.778	4.653	X-over 5 1/2" 13Cr-80 20# Vam Top HC B x 17# New Vam P		
		448.29	450.98	2.69	7.990	4.562	4.545	Halliburton type SP-2 TRSV Incoloy 925	447.0	11.2
	9 5/8" 53.5# Casing							4.562 'RQ' Nipple Profile		
	ID= 8,535"							Part number 78oo610-ASG		
	Drift= 8,500"							5 1/2" 17# New Vam B x P		
	NB Special drift ID = 8,5"	450.98	453.11	2.13	6.071	4.778	4.653	X-over pup 5 1/2" 13Cr-80 17# New Vam B x 20# Vam Top HC P		
		453.11	3055.28	2602.17	6.071	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
Assy # 6		3055.28	3057.17	1.89	6.071	4.778	4.653	X-over 5 1/2" 20# 13Cr-80Vam Top HC B x NS-CC P		
		3057.17	3060.48	3.31	8.369	4.670	4.653	Weatherford SPM, SBRO-2CR 410 mod	2707.8	34.1
								1.5" Dummy + RM latch Kick over tool KOT-2 or OM-1		
		3060.48	3062.13	1.65	6.071	4.778	4.653	X-over 5 1/2" 20# 13Cr-80 NS-CC B x Vam Top HC P		
		3062.13	3087.97	25.84	6.071	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
Assy # 5		3087.97	3091.09	3.12	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
		3091.09	3091.37	0.28	6.071	4.778	4.653	Collar 5 1/2" 20# 13Cr-80 Vam Top HC B x B		
	1/4 inch encapsulated	3091.37	3092.47	1.10	6.900	4.778	4.653	Roxar Gauge Carrier 420 mod	2735.6	35.4
	cable to gauge carrier							5 1/2" 20# Vam Top HC P x P		
		3092.47	3095.50	3.03	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
		3095.50	3120.92	25.42	6.071	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
Assy # 4		3120.92	3123.92	3.00	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
		3123.92	3127.32	3.40	8.300	4.700	4.653	Halliburton HHC Packer 9 5/8" 47,0-53,5# 5K WP	2761.7	35.1
								Part Number: 912HHC95001		
								Space out 1,83 +/- 0.21m pip tag to cut zone.		
								5 1/2" 20# Vam Top HC B x P		
		3127.32	3129.87	2.55	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	RA Marker: 3127,60 m MD									
Assy # 3		3129.87	3132.05	2.18	6.071	4.778	4.653	X-over 13%CR 20# Vam Top HC B x 23# Vam Top P		
Assy # 2		3132.05	3143.46	11.41	6.071	4.67	4.545	Tubing 5 1/2" 23# 1Cr-80 Vam Top B x P	2769.1	35.0
		3143.46	3155.84	12.38	6.071	4.67	4.545	Tubing 5 1/2" 23# 1Cr-80 Vam Top B x P	2778.1	34.5
		3155.84	3157.35	1.51	6.071	4.778	4.653	X-over 13%CR 23# Vam Top B x 20# Vam Top HC P		
Assy # 1	7.5" PBR w/15ft sealbore	3157.35	3159.76	2.41	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
		3159.76	3160.24	0.48	7.050	4.778	4.653	XO 5 1/2" 20# 13Cr-80 Vam Top HC B x 7" 32# Vam Top P		
		3160.24	3163.12	2.88	7.717	6.094	5.969	Pup 7" 32# 13Cr-80 Vam Top B x 6 3/4"-8 UNS P		
		3160.40	3160.40	0.00	8.310	7.050		Fixed No go. Pinned to 7" tubing.		
	RA Marker: 3287.1 m MD	3163.12	3164.43	1.31	7.460	6.025	5.900	Self Aligning Muleshoe Guide Part No: 912SG75000	2794.6	34.1
	TVD 2895.7 m							PEAK Liner Hanger System		
	9 5/8" 53.5 # Casing Shoe	3163.08	3174.08	11.00	8.400	7.500	7.470	7.5" PBR Sealbore		
	3301 m MD / 2906.7 m TVD	TOL						JMPH Liner Top Packer		
								HPS Hydraulic Set Pocket Slips Hanger		
		3174.08	3174.58	0.50	7.717	4.811	4.767	Crossover 7" 29# XX B x 5 1/2" 17# Vam Top HT P		
		3174.58	3177.58	3.00	5.978	4.811	4.767	Pup Joint 5 1/2" 17# 13Cr-80 Vam Top HC B x P		
		3177.58	3470.08	292.50	5.978	4.811	4.767	Tubing 5 1/2" 17# 13Cr-80 Vam Top HC B x P		
	RA Marker 3207.78 m MD							25 Joints 11,7m ea.		
	TVD 2830.6 m									
	RA Marker 3381.81 m MD									
	TVD 2971.7 m									
		3484.73						Landing Collar Depth from Liner Running List	3054.1	37.3

Figure A-6-1: Completion Schematic of Well A-03

VARG: WELL 15/12-A-09A COMPLETION SCHEMATIC - AS RUN

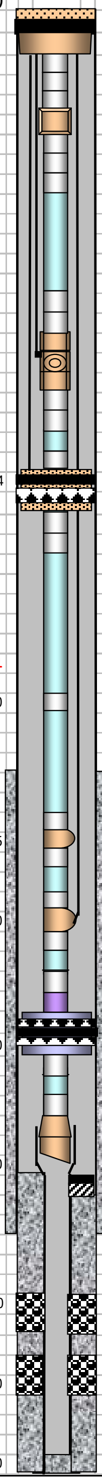
Completion date 29.08.06

General Data		Wellhead & Xmas Tree System	Size	Lb/ft	Grade	Top (md)	Bottom (md)	TTOC (md)
Well Type:	Oil producer	XT: Cameron 5-1/8", 5k	24"	246	X-65	136.16	277	Seabed
Water Depth:	84 m	HMV actuator capable of cutting 7/16" braided wire.	13-3/8"	72	L-80	27	1328	Seabed
RTE (ref. MSL):	52.2 m	WHD: Cameron	9-5/8"	53.5	L-80	27	3106	
RKB - wellhead (no-go)	28.3 m	Tubing hanger: Cameron	5-1/2"	17	13Cr	3010	3265	

(Casing Scheme: Size, Lb/ft, Grade, Top (md), Bottom (md), TTOC (md))

		Annulus Contents				Tubing Scheme		
RTE - Seabed	136.2 m							
Rig: Mærsk Giant		Existing: Gas	5-1/2"	17.0	L80 13Cr	VTHT	2,074	m
		Proposed: N/A	5-1/2"	20.0	L80 13Cr	VTHC/HT	827	m

Notes: Hydraulic control line fluid Esso UNIVIS N32. Max fluid rate through GLV 150 lpm. ASV control line pressure max 520 bar. DHSV control lione pressure max 570 bar.



MD BRT (m) top	TVD BRT (m)	Incl. (deg)	Schematic	Description	Nominal ID (in)	Drift ID (in)	OD (in)	Length (m)	Material	Comments
27.72	27.72	0.00		**Tubing hanger, 5-1/2" 23# Vam Ace box bottom**	4.886	4.767	13.250	0.58	HH-Class	2-1/4Cr 1Mo 80ksi Inc 625 cladded
28.30				Tubing hanger landing shoulder				0.23		
28.53				Pup joint, 5-1/2" 17# Vam Ace pin up x 17# VTHT pin down	4.892	4.767	5.500	2.79	L-80 13Cr	Coupling OD=6.071"
31.32				Saver sub, pup joint, 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	0.94	L-80 13Cr	Coupling OD=6.071"
32.26				Pup joint, 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	3.09	L-80 13Cr	Coupling OD=6.071"
35.35	35.35			**4.75" QNB landing nipple, 5-1/2" 17# VTHT box x pin**	4.750	4.660	6.051	0.73	L-80 13Cr	Weatherford
36.08				Pup joint, 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	1.91	L-80 13Cr	Coupling OD=6.071"
37.99				Space-out pup joint, 5-1/2" 17# VTHT	4.892	4.767	5.500	4.52	L-80 13Cr	Coupling OD=6.071"
42.51				Space-out pup joint, 5-1/2" 17# VTHT	4.892	4.767	5.500	3.00	L-80 13Cr	Coupling OD=6.071"
45.50										
136.20	**136.20**	0.00		**Seabed**						
				Hydraulic control lines					Inc 825	
				Tubing, 5-1/2" 17# VTHT box x pin (31 jnt`s)	4.892	4.767	5.500	385.42	L-80 13Cr	Coupling OD=6.071"
430.92				Pup joint, 5-1/2" 17# VTHT box x 20# VTHT pin				2.15	L-80 13Cr	Coupling OD=6.071"
433.07				Pup joint, 5-1/2" 20# VTHT box x 20# New Vam pin			5.500	2.92	L-80 13Cr	Coupling OD=6.071"
435.99	435.52	0.36								
				DHSV; 5-1/2" 20# New Vam box x pin w/4.562 DB	4.562	4.558	7.500	2.02	L-80 13Cr	Schlumberger TRM-4P-CF
										(Control line protector OD=8.25")
438.01				Pup joint; 5-1/2" 20# New Vam box x 20# VTHT pin			5.500	2.94	L-80 13Cr	Coupling OD=6.071"
440.95				Pup joint, 5-1/2" 20# VTHT box x 17# VTHT pin				2.05	L-80 13Cr	Coupling OD=6.071"
443.00				Tubing; 5-1/2", 17# VTHT box x pin			5.500	12.49	L-80 13Cr	Coupling OD=6.071"
455.50				Pup joint; 5-1/2" 17# VTHT box x pin			5.500	2.04	L-80 13Cr	Coupling OD=6.071"
457.54	457.10	0.24		**ASV, AV-3, 9-5/8", 53.5# casing, 5-1/2" 17# VTHT incl. communication sub and splice sub`s.**	4.625	4.500	8.280	11.96	L-80 13Cr	Halliburton AV-3 w/splice sub communication sub
469.50				Pup joint; 5-1/2" 17# VTHT box x pin			5.500	1.74	L-80 13Cr	Coupling OD=6.071"
471.24				Pup joint; 5-1/2" 17# VTHT box x pin			5.500	4.51	L-80 13Cr	Coupling OD=6.071"
475.74										
				Tubing, 5-1/2" 17# VTHT box x pin (134 jnt`s)	4.892	4.767	5.500	1676.26	L-80 13Cr	Coupling OD=6.071"
				Control lines secured w/Roxar control line clamps						
1946.60		**36.21**		**Max deviation**						
2152.00	2019.54	33.00		**X-O**, 5-1/2" 17# VTHT box up x 20# VTHC/HT pin down	4.778	4.653	5.500	3.05	L-80 13Cr	Coupling OD=6.071"
2155.05										
				Tubing, 5-1/2", 20# VTHC/HT box x pin (61 jnt`s)	4.778	4.653	5.500	765.84	L-80 13Cr	Coupling OD=6.071"
2478.00				**TOC 9-5/8" csg**						
2920.89				Pup joint, 5 1/2" 20# VTHC box up x 20# VTHC pin down	4.778	4.653	5.500	3.05	L-80 13Cr	Coupling OD=6.071"
2923.94	2739.30	19.65		**SPM;, 5-1/2", 20# VTHC box x pin, Schlumberger**	4.735	4.735	8.409	3.18	L-80 13Cr	1.5" RO-2BCD GLV w/RK latch installed.
2927.12				Pup joint, 5-1/2" 20# VTHC box up x 20# VTHC pin down	4.778	4.653	5.500	1.84	L-80 13Cr	Coupling OD=6.071"
2928.96				2 x Tubing, 5-1/2", 20# VTHC box x pin	4.778	4.653	5.500	24.49	L-80 13Cr	Coupling OD=6.071"
2953.45				Pup joint, 5-1/2" 20# VTHC box x box	4.778	4.653	5.500	3.04	L-80 13Cr	Coupling OD=6.071"
2956.49	2769.93	20.00		**DHPG Mandrel; 5 1/2" 20# VTHC pin x pin**	4.770	4.767	6.620	1.37	L-80 13Cr	Roxar w/RQPG-HM gauge.
2957.86				Pup joint, 5-1/2" 20# VTHC box x pin	4.778	4.653	5.500	1.85	L-80 13Cr	Coupling OD=6.071"
2959.71				1 x Tubing, 5-1/2", 20# VTHC box x pin	4.778	4.653	5.500	12.60	L-80 13Cr	Coupling OD=6.071"
2972.31				Pup joint, 5 1/2" 20# VTHC box x pin	4.778	4.653	5.500	5.05	L-80 13Cr	Coupling OD=6.071"
2977.36				**Anchor; 5 1/2" 20" VTHC box up**	4.778	4.773	8.265	0.31	L-80 13Cr	Schlumberger RHR-1-MD
2977.67										
2979.62	2791.70	19.50		**Packer; 5 1/2" 20# Vam Ace pin down**	4.778	4.773	8.250	1.95	L-80 13Cr	Schlumberger HSP-1ME
2979.62				Pup joint, 5 1/2" 20# Vam Ace box x 20# VTHC pin	4.778	4.653	5.500	1.95	L-80 13Cr	Coupling OD=6.071"
2981.57				2 x Tubing, 5-1/2", 20# VTHC box x pin	4.778	4.653	5.500	23.96	L-80 13Cr	Coupling OD=6.071"
3005.54				Pup joint, 5 1/2" 20# VTHC box x pin	4.778	4.653	5.500	3.05	L-80 13Cr	Coupling OD=6.071"
3008.59				X-O, 5-1/2" 20# VTHC box up x 7" 29# VTHT pin down	4.778	4.653	5.500	0.45	L-80 13Cr	Coupling OD=7,644"
3009.04				WEG half mule-shoe, 7" 29" VTHT box up				3.23	L-80 13Cr	
3012.27	2822.41	20.00								
3009.88				**Top of 5-1/2" liner PBR. ID=7.5", L=15 ft=4.57m.**	7.500					
				7" OD WEG 2.39 m inside liner PBR.						
				Liner, 5 1/2" 17# VTHT	4.892	4.767			L-80 13Cr	
3149.00	2950.43	20.40		**Top perforation**						Run #2: Perf. Date 29.08.06
3174.60				**Bottom perforation**						
				Baker Atlas 3-3/8" 6 spf 60 deg phazing Predator guns.						
3190.00				**Top perforation**						Run #1: Perf. Date 29.08.06
3206.20	3012.14	20.40		**Bottom perforation**						
3238.00	3033.88			**Float Collar (drifted w/slickline to 3236 m wl depth)**						
3265.00				**Liner shoe**						
3267.00	3061.08	20.30		**TD**						

Figure A-6-2: Completion Schematic of Well A-09A

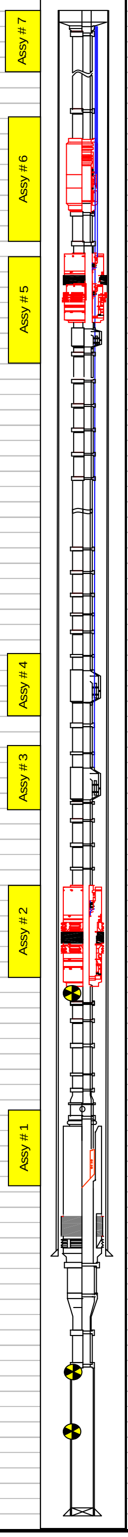
TALISMAN VARG 15/12-A-10 COMPLETION SCHEMATIC

AFTER WORKOVER SEPT-2005

Date: 29 11 2005 | Prepared: Arve Huse | Revision 6 0

Notes
RKB-MSL Mærsk Giant: 51.5 m
Well Located on Mezzanine Deck
Based on final survey data
RKB-Tubing hanger hang-off point: 23.2 m.

As Run



Info	MD RKB TOP [m]	MD RKB BOT [m]	Length [m]	Max OD [inch]	Min ID [inch]	Drift ID [inch]	Description	TVD RKB [m]	Angle [deg]
	23.20	23.52	0.32	13.552	4.892	4.767	DrillQuip Tubing Hanger 20# Vam Top B w/4.875" QNB Nipple		
Dual 1/4 inch encapsulated control line to TRSV and ASV	23.52	25.41	1.89	6.071	4.778	4.653	X-over 5 1/2" 13Cr-110 20# Vam Top P x 20# Vam Top HC P		
	25.41	454.53	429.12	6.071	4.892	4.767	Tubing 5 1/2" 17# 13Cr-80 Vam Top HT B x P		
	454.53	457.08	2.55	6.071	4.778	4.653	X-over 5 1/2" 20# 13Cr-80 Vam Top HC B x 17# New Vam P		
9 5/8" 53.5# Casing ID= 8,535" Drift= 8,379" NB Special drift ID = 8,5"	457.08	460.20	3.12	7.990	4.562	4.545	TRSV Schlumberger type TRSP-5-CF-HO-RH 4.557 'DB-6' Nipple Profile 5 1/2" 17# New Vam B x P	455.8	11.0
	460.20	461.86	1.66	6.075	4.778	4.653	X-over 5 1/2" 17# 13Cr-80 New Vam B x 20# Vam Top HC P		
	461.86	474.77	12.91	6.190	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
Cable splices above and below ASV	474.77	477.32	2.55	6.071	4.778	4.653	Pup joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	477.32	482.45	5.13	8.250	4.68	4.653	Halliburton ASV Type 510AV3965314 420 mod 5 1/2" 20# Vam Top HC B x P	475.7	11.0
	482.45	484.50	2.05	6.071	4.778	4.653	Pup joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	484.50	485.73	1.23	8.250	4.625	4.545	Communication sub Type 234CS2965304 420 mod 5 1/2" 20# Vam Top HC B x P		
	485.73	487.77	2.04	6.071	4.778	4.653	Pup joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	487.77	2507.00	2019.23	6.071	4.892	4.767	Tubing 5 1/2" 17# 13Cr-80 Vam Top HT B x P		
	2507.00	2509.11	2.11	6.071	4.778	4.653	X-over 5 1/2" 17# 13Cr-80 Vam Top HT B x 20# Vam Top HC P	2375.3	20.1
	2509.11	3030.52	521.41	6.190	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	3030.52	3033.04	2.52	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x 17# New Vam P		
	3033.04	3036.16	3.12	8.369	4.670	4.610	Weatherford SPM, SBRO-2CRA With 1.5" Nova valve and RM 2 lock	2806.2	48.5
	3036.16	3038.71	2.55	6.075	4.778	4.653	Pup Joint 5 1/2" 17# 13Cr-80 New Vam B x 20# Vam Top HC P		
	3038.71	3064.24	25.53	6.071	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	3064.24	3067.05	2.81	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x B		
1/4 inch encapsulated cable to gauge carrier	3067.05	3068.15	1.10	6.900	4.770	4.653	Roxar Gauge Carrier PN = 2002036 SN = 111096-03	2828.0	50.3
	3068.15	3069.90	1.75	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	3069.90	3095.43	25.53	6.071	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	3095.43	3097.73	2.30	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	3097.73	3101.13	3.40	8.310	4.700	4.653	Halliburton HHC Packer 9 5/8" 47,0-53,5# 5K WP Part Number: 912HHC95001 Space out PIP tag to centre cut zone = 1.84 +- 0.21 m	2846.7	54.0
RA Marker: 3101.40 m MD. TVD 2848.8 m	3101.13	3103.16	2.03	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	3103.16	3129.91	26.75	6.071	4.67	4.545	2 joints 5-1/2" 23# 1%Cr Vam Top HC B x P		
	3129.91	3206.48	76.57	6.071	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	3206.48	3209.09	2.61	6.071	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top HC B x P		
	3209.09	3209.56	0.47	7.029	4.778	4.653	XO 5 1/2" 20# Vam Top HC B x 7" 32# Vam Top P		
	3209.56	3212.44	2.88	7.700	6.094	5.969	Pup Joint 7" 32# New Vam B x 12 Stub Acme P		
7.5" PBR w/15ft sealbore	3209.58	3209.73	0.15	8.310	7.050		Fixed No go. Pinned to 7" tubing. Length nogo to tip SAM = 3.90m		
	3212.44	3213.75	1.31	7.460	6.025	5.900	Self Aligning Muleshoe Guide Part No: 912SG75000		
	3211.80	3220.64	8.84	8.400	7.500	7.470	PEAK Liner Hanger System 7.5" PBR Sealbore JMPH Liner Top Packer HPS Hydraulic Set Pocket Slips Hanger	2905.0	65.3
9 5/8" 53.5# Casing Shoe 3457m MD 2959m TVD									
	3220.64	3221.85	1.21	7.717	4.778	4.653	Crossover 7" 29# XX B x 5 1/2" 20# Vam Top P		
	3221.85	3505.82	283.97	5.978	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top B x P		
RA Marker 3505,82 m MD TVD 2962.5 m	3505.82	3507.90	2.08	5.978	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top B x P	2962.7	84.8
	3507.90	3772.53	264.63	5.978	4.778	4.653	Tubing 5 1/2" 20# Vam Top B x P		
RA Marker 3718,53 m MD TVD 2982.2 m	3772.53	3774.57	2.04	5.978	4.778	4.653	Pup Joint 5 1/2" 20# 13Cr-80 Vam Top B x P	2985.0	87.0
	3774.57	3852.01	77.44	5.978	4.778	4.653	Tubing 5 1/2" 20# 13Cr-80 Vam Top B x P		
	3858.00	3898.00					Shoetrack	2991.0	87.0

Figure A-6-3: Completion Schematic of Well A-10T2

VARG WELL A12BT2 COMPLETION SCHEMATIC - AS RUN

Completion date 28.10.06

General Data		Wellhead & Xmas Tree System	Size	Lb/ft	Grade	Top (md)	Bottom (md)	TTOC (md)
Well Type:	Oil producer							
Water Depth:	84 m	XT: Cameron 5-1/8", 5k	24"	246	X-65	136.16	277	Seabed
RTE (ref. MSL):	52.2 m	HMV actuator capable of cutting 7/16" braided wire.	13-3/8"	72	L-80	27	1328	Seabed
RKB - wellhead (no-go)	24.02 m	WHD: Cameron	9-5/8"	53.5	L-80	27	3106	
RTE - Seabed:	136.2 m	Tubing hanger: Cameron	4-1/2"	13	13Cr	2568	3241	
Rig: Mærsk Giant		**Annulus Contents**			**Tubing Scheme**			
		Existing: Gas	5-1/2"	17.0	L80 13Cr	VTHT	1,918	m
		Proposed: N/A	5-1/2"	20.0	L80 13Cr	VTHC/HT	567	m

Notes: Hydraulic control line fluid Esso UNIVIS N32. Max fluid rate through GLV 150 lpm. ASV control line pressure max 520 bar, DHSV control line pressure max 570 bar.

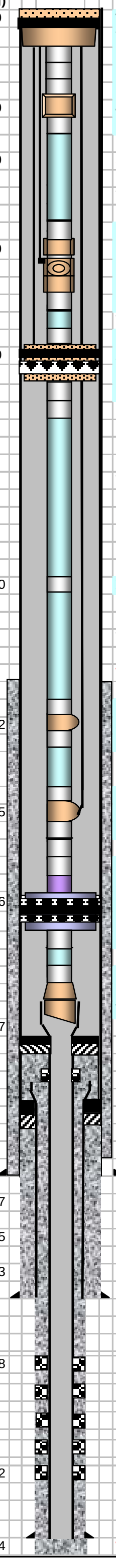
MD BRT (m) top	TVD BRT (m)	Incl. (deg)	Schematic	Description	Nominal ID (in)	Drift ID (in)	OD (in)	Length (m)	Mtl	Comments
23.44	27.48	0.00		**Tubing hanger, 5-1/2" 20# Vam Top box down**	4.886	4.767	13.250	0.58	HH-Class	2-1/4Cr 1Mo 80ksi Inc 625 cladded.
24.02				Tubing hanger landing shoulder				0.21		
24.23				Pup joint, 5-1/2" 17# Vam Top pin up x 17# VTHT pin down	4.892	4.767	5.500	2.82	L-80 13Cr	Coupling OD=6.071"
27.05				Saver sub, pup joint, 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	0.93	L-80 13Cr	Coupling OD=6.071"
27.98				Pup joint, 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	1.85	L-80 13Cr	Coupling OD=6.071"
29.83	29.83	0.00		**4.75" QNB landing nipple, 5-1/2" 17# VTHT box x pin**	4.750	4.660	6.051	0.73	L-80 13Cr	Weatherford
30.56				Pup joint, 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	1.81	L-80 13Cr	Coupling OD=6.071"
32.37										
131.20	**131.20**	0.00		**Seabed**						
				Hydraulic control lines					Inc 825	
				Tubing, 5-1/2" 17# VTHT box x pin (31 jnt`s)	4.892	4.767	5.500	402.94	L-80 13Cr	Coupling OD=6.071"
435.31				Pup joint, 5-1/2" 17# VTHC box x 23# Vam Ace pin	4.892	4.767	5.500	3.30	L-80 13Cr	Coupling OD=6.071"
438.61	438.00	7.00								
				DHSV; 5-1/2" 23# Vam Ace box x pin w/4.562 DB	4.562	4.558	7.937	3.12	L-80 13Cr	Schlumberger TRSP-5-CF-HO-RH
										(Control line protector OD=8.49")
441.73				Pup joint; 5-1/2" 23# Vam Ace box x 17# VTHT pin	4.892	4.767	5.500	1.87	L-80 13Cr	Coupling OD=6.071"
443.60				Tubing; 5-1/2", 17# VTHT box x pin			5.500	12.45	L-80 13Cr	Coupling OD=6.071"
456.05				Pup joint; 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	1.77	L-80 13Cr	Coupling OD=6.071"
457.82	456.82	7.30		**ASV, AV-3, 9-5/8", 53.5# casing, 5-1/2" 17# VTHT incl. communication sub and splice sub`s.**	4.625	4.560	8.280	10.06	L-80 13Cr	Halliburton AV-3 w/splice sub & communication sub.
467.88				Pup joint; 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	1.74	L-80 13Cr	Coupling OD=6.071"
469.62				Pup joint; 5-1/2" 17# VTHT box x pin	4.892	4.767	5.500	3.58	L-80 13Cr	Coupling OD=6.071"
473.20										
				Tubing, 5-1/2" 17# VTHT box x pin (134 jnt`s)	4.892	4.767	5.500	1502.56	L-80 13Cr	Coupling OD=6.071"
				Control lines secured w/Lassalle control line clamps						
1975.76	1931.87	26.60		**X-O**, 5-1/2" 17# VTHT box up x 20# VTHC/HT pin down	4.778	4.653	5.500	3.05	L-80 13Cr	Coupling OD=6.071"
1978.81										
				Tubing, 5-1/2", 20# VTHC/HT box x pin (41 jnt`s)	4.778	4.653	5.500	501.67	L-80 13Cr	Coupling OD=6.071"
2250.00				**Theoretical top of cement**						
2480.48				Pup joint, 5 1/2" 20# VTHC box up x 20# VTHC pin down	4.778	4.653	5.500	3.05	L-80 13Cr	Coupling OD=6.071"
2483.53	2385.17	27.42		**SPM;, 5-1/2", 20# VTHC box x pin, Schlumberger**	4.735	4.735	8.409	3.18	L-80 13Cr	1.5" RO-2BCD GLV w/RK latch installed
2486.71				Pup joint, 5-1/2" 20# VTHC box up x 20# VTHC pin down	4.778	4.653	5.500	1.84	L-80 13Cr	Coupling OD=6.071"
2488.55				2 x Tubing, 5-1/2", 20# VTHC box x pin	4.778	4.653	5.500	25.08	L-80 13Cr	Coupling OD=6.071"
2513.63				Pup joint, 5-1/2" 20# VTHC box x box	4.778	4.653	5.500	3.33	L-80 13Cr	Coupling OD=6.071"
2516.96	2414.88	27.75		**DHPG Mandrel; 5 1/2" 20# VTHC pin x pin**	4.770	4.767	6.620	1.10	L-80 13Cr	Roxar w/RQPG-HM gauge.
2518.06				Pup joint, 5-1/2" 20# VTHC box x pin	4.778	4.653	5.500	1.86	L-80 13Cr	Coupling OD=6.071"
2519.92				1 x Tubing, 5-1/2", 20# VTHC box x pin	4.778	4.653	5.500	12.54	L-80 13Cr	Coupling OD=6.071"
2532.46				Pup joint, 5 1/2" 20# VTHC box x pin	4.778	4.653	5.500	3.05	L-80 13Cr	Coupling OD=6.071"
2535.51				**Anchor; 5 1/2" 20" VTHC box up**	4.778	4.773	8.265	0.32	L-80 13Cr	Schlumberger RHR-1-MD
2535.83	2431.56	27.86		**Packer; 5 1/2" 20# Vam Ace pin down**	4.778	4.773	8.250	1.95	L-80 13Cr	Schlumberger HSP-1ME
2537.78										
2537.78				Pup joint, 5 1/2" 20# Vam Ace box x 20# VTHC pin	4.778	4.653	5.500	1.92	L-80 13Cr	Coupling OD=6.071"
2539.70				2 x Tubing, 5-1/2", 20# VTHC box x pin	4.778	4.653	5.500	24.79	L-80 13Cr	Coupling OD=6.071"
2564.48				Pup joint, 5 1/2" 20# VTHC box x pin	4.778	4.653	5.500	3.05	L-80 13Cr	Coupling OD=6.071"
				X-O, 5-1/2" 20# VTHC box up x 7" 29# VTHT pin down	4.778	4.653	5.500	0.45	L-80 13Cr	Coupling OD=7,644"
2567.98				WEG half mule-shoe, 7" 29" VTHT box up	6.184	6.059	7.500	3.19	L-80 13Cr	
2571.17	2462.77	28.07		**btm 7" OD WEG approx 2.5 m inside liner PBR.**	7.500				L-80 13Cr	Half muleshoe
2568.20				**Top of 4-1/2" liner PBR. ID=7.5", L=15 ft=4.57m.**						
				4-1/2" 13.5# pup jnt below liner hanger	3.920	3.795				
2613-1615				**4-1/2" liner punched in a 2 m intervall, 12 shots**						JRC 2" punch gun
2622.00				**Top 7" liner**						
2671.50				**9-5/8" csg window for sidetrack**						
3026.70		35.97		**Max deviation**						
3057.22	2871.84	35.55		4-1/2" liner pup joint 12.6#, rad.marker in box (top)	3.958	3.833	4.500	1.78		
3092.60	2900.86	34.33		4-1/2" liner pup joint 12.6#, rad.marker in box (top)	3.958	3.833	4.500	1.79		
3106.00				**7" liner shoe**						
				Liner, 4 1/2" 12.6# VTHT	3.958	3.833	4.500		SM95 13Cr	
Top perf	**Btm perf**									
3152.00	***3155.00***	34.98		**Baker Atlas 2-7/8" 6 spf 60 deg phazing Predator guns**						Run #4 Perf.date: 27.10.06
3160.00	***3174.00***			**Baker Atlas 2-7/8" 6 spf 60 deg phazing Predator guns**						Run #3 Perf.date: 27.10.06
3183.00	***3192.00***			**Baker Atlas 2-7/8" 6 spf 60 deg phazing Predator guns**						Run #1 Perf.date: 26.10.06
3196.70	***3205.00***			**Baker Atlas 2-7/8" 6 spf 60 deg phazing Predator guns**						Run #1 Perf.date: 26.10.06
3210.00	***3217.00***	35.02		**Baker Atlas 2-7/8" 6 spf 60 deg phazing Predator guns**						Run #2 Perf.date: 26.10.06
3219.78				**Float Collar (drifted w/slickline to 3211 m mdrkb wl, correlated depth 3217.5 m mdrkb, clean-out string run to 3212.5 m mdrkb)**						
3240.50				**Liner shoe**						
3252.00		35.24		**TD**						

Figure A-6-4: Completion Schematic of Well A-12BT2

Appendix B-1: Well Test Data

Varg Field Well Test-Well: A03															
	Oil Rate	Gas Rate	H2O Rate	Liquid Rate	(GOR)Total	(GOR)GLG	GLG Rate	WCT	Choke	FBHP	FBHT	FWHP	FWHT	P-Sep	T-Sep
Date	(Sm3/d)	(Sm3/d)	(Sm3/d)	(Sm3/d)	(Sm3/Sm3)	(Sm3/Sm3)	(Sm3/d)	(%)	(%)	(Bar)	(Celsius	(Bar)	(Celsius)	(Bar)	(Celsius)
22/01/2006	575.3	91883	615	1191	159.7	17.8	10251	51.7	99.6	198.8		14.0	99.2	3.6	87.1
11/07/2006	552.0	245232	816	1368	444.3	302.4	166903	59.6	100.0	155.0	126	28.0	90.0	10.0	82.0
16/07/2006	528.0	233808	840	1368	442.8	300.9	158885	61.4	100.0	155.0		28.0	91.0	10.0	89.0
06/08/2006	478.8	236544	862	1341	494.0	352.1	168604	64.3	100.0	158.9	124	27.7	92.1	10.2	85.6
08/08/2006	433.3	258259	993	1427	596.0	454.1	196768	69.6	79.7	171.2		27.9	91.2	10.2	89.5
31/08/2006	408.0	206760	960	1368	506.8	364.9	148865	70.2	100.0	159.0		26.0	93.0	10.0	80.0
07/12/2006	293.0	192856	1097	1390	659.2	517.3	151569	78.9	100.0	157.1		25.9	94.6	9.6	86.3
03/03/2007	227.0	245991	1330	1557	1083.0	941.1	213630	85.0	100.0	165.0	127	30.0	97.0	10.5	86.0

Table: B-1-1

Varg Field Well Test-Well: A09A															
	Oil Rate	Gas Rate	H2O Rate	Liquid Rate	GOR)Tota	(GOR)GLG	GLG Rate	WCT	Choke	FBHP	FBHT	FWHP	FWHT	P-Sep	T-Sep
Date	(Sm3/d)	(Sm3/d)	(Sm3/d)	(Sm3/d)	(Sm3/Sm3	(Sm3/Sm3)	(Sm3/d)	(%)	(%)	(Bar)	(Celsius	(Bar)	(Celsius)	(Bar)	(Celsius)
02/09/2006	664.0	314016	557	1221	472.9	331.0	219757	0.46		130		30.7			74
03/09/2006	774.0	307632	89	863	397.5	255.6	197801	0.10		122		40.1		10.0	76
07/09/2006	602.0	274584	120	722	456.2	314.3	189197	0.17		97		33.0	69	9.8	61
12/09/2006	541.4	163608	110	652	302.0	160.1	86685	0.17		84		22.9	73	10.0	68
16/09/2006	490.3	178680	113	603	364.0	222.1	108900	0.19		84		24.8	66	10.0	72
09/11/2006	496.0	142781	229	725	287.9	146.0	72397	0.32	100.0	81	126	19.3	71	10.1	77
06/12/2006	373.0	90314	233	606	242.2	100.3	37422	0.38	100.0	79		15.3	75	9.5	79
04/03/2007	264.0	122821	283	547	465.2	323.3	85351	0.52	40.4	85.0		17.2	73.3	10.1	73.8

Table: B-1-2

Varg Field Well Test-Well: A10T2															
	Oil Rate	Gas Rate	H2O Rat	Liquid Rate	(GOR)Total	(GOR)GLG	GLG Rate	WCT	Choke	FBHP	FBHT	FWHP	FWHT	P-Sep	T-Sep
Date	(Sm3/d)	(Sm3/d)	(Sm3/d)	(Sm3/d)	(Sm3/Sm3)	(Sm3/Sm3)	(Sm3/d)	(%)	(%)	(Bar)	Celsius	(Bar)	(Celsius)	(Bar)	(Celsius)
10/08/2004	2045	425280	0	2045	208.0	66.1	135161	0.00	85.9	180.3		60.0	99.0	8.6	79.7
11/08/2004	2054	392400	0	2054	191.0	49.1	100871	0.00	85.9	178.0		60.0	99.0	10.5	66.0
31/03/2005	2142	458200	314	2456	213.9	72.0	154224	12.80	27.0	131.5		29.8	97.5	8.8	77.9
14/11/2005	1274	192360	578	1853	150.9	9.0	11523	0.31	47.0			26.1	104.0	9.9	86.0
24/12/2005	722	239724	1660	2382	332.0	190.1	137250	0.70	0.0	0.0		36.4	107.3	8.6	97.6
13/01/2006	705	157632	1144	1849	223.6	81.7	57602	0.62	100.0	0.0		30.4	106.5	8.6	89.2
28/01/2006	479	187494	1261	1740	391.8	249.9	119586	0.72	97.4	0.0		27.8	103.8	9.8	93.7
08/02/2006	380	71538	1198	1578	188.4	46.5	17654	0.76	54.3	0.0		23.1	106.3	10.2	89.4
26/05/2006	514	207902	1222	1735	404.8	262.9	135023	0.70	100.0	0.0		30.1	103.5	9.9	93.9
08/06/2006	415	208810	1183	1598	502.9	361.0	149893	0.74	100.0	0.0		22.3	102.8	9.6	93.3
17/07/2006	338	195636	1229	1567	578.0	436.1	147605	0.80	100.0	0.0		26.0	100.6	10.2	96.0
07/08/2006	309	192240	1273	1582	621.0	479.1	148224	0.80	100	0.0		26.0	101.0	10.2	94.0

Table: B-1-3

Varg Field Well Test-Well: A12BT2															
Date	Oil Rate (Sm3/d)	Gas Rate (Sm3/d)	H2O Rate (Sm3/d)	Liquid Rate (Sm3/d)	(GOR)Total (Sm3/Sm3)	(GOR)GLG (Sm3/Sm3)	GLG Rate (Sm3/d)	WCT (%)	Choke (%)	FBHP (Bar)	FBHT (Celsius	FWHP (Bar)	FWHT (Celsius)	P-Sep (Bar)	T-Sep (Celsius)
01/11/2006	765.6	273300	352	1117.6	357	215.1	164661	0.31	100	108	118	26	79	10.8	70
09/11/2006	941.5	187773	692	1633.5	199	57.1	53760	0.42	100	130	118	28	94	10.0	81
18/12/2006	976.9	226043	830	1806.9	231	89.1	87042	0.46	100	133	118	24	102	9.9	92
17/01/2007	841.7	251311	949	1790.7	299	157.1	132231	0.53	100	130	118	26	101	9.9	89
07/02/2007	741.5	335498	1106	1847.5	452	310.1	229939	0.60	100	135	118	32	98	10.1	87
02/03/2007	636.8	285701	999	1635.8	449	307.1	195561	0.61	100	138	118	31	98	10.7	87

Table: B-1-4

Appendix B-2:Correlation Match Parameters

Correlation Match Parameters (A-03.ANL) (Matched PVT)

Done | Cancel | Main | Reset all | Report | Export | Help

	Correlation	Parameter 1	Parameter 2	Standard Deviation
Reset	Duns and Ros Modified	0.85542	0.2	0.00097656
Reset	Hagedorn Brown	1.02535	1.16115	0.00024414
Reset	Fancher Brown	1.05311	1.25619	0.00024414
Reset	Mukerjee Brill	0.95621	0.62966	0.00097656
Reset	Beggs and Brill	0.90199	0.47172	0.00024414
Reset	Petroleum Experts	1.00043	1.00234	0
Reset	Orkiszewski	1.28626	2.28328	0.00048828
Reset	Petroleum Experts 2	0.99247	0.95947	0.00024414
Reset	Duns and Ros Original	1.03568	1.21587	0.00024414
Reset	Petroleum Experts 3	1.02029	1.08951	0.00097656
Reset	GRE (modified by PE)	0.98866	0.95606	0
Reset	Petroleum Experts 4	0.99109	0.96534	0.00073242
Reset	Hydro-3P (Internal)	1	1	

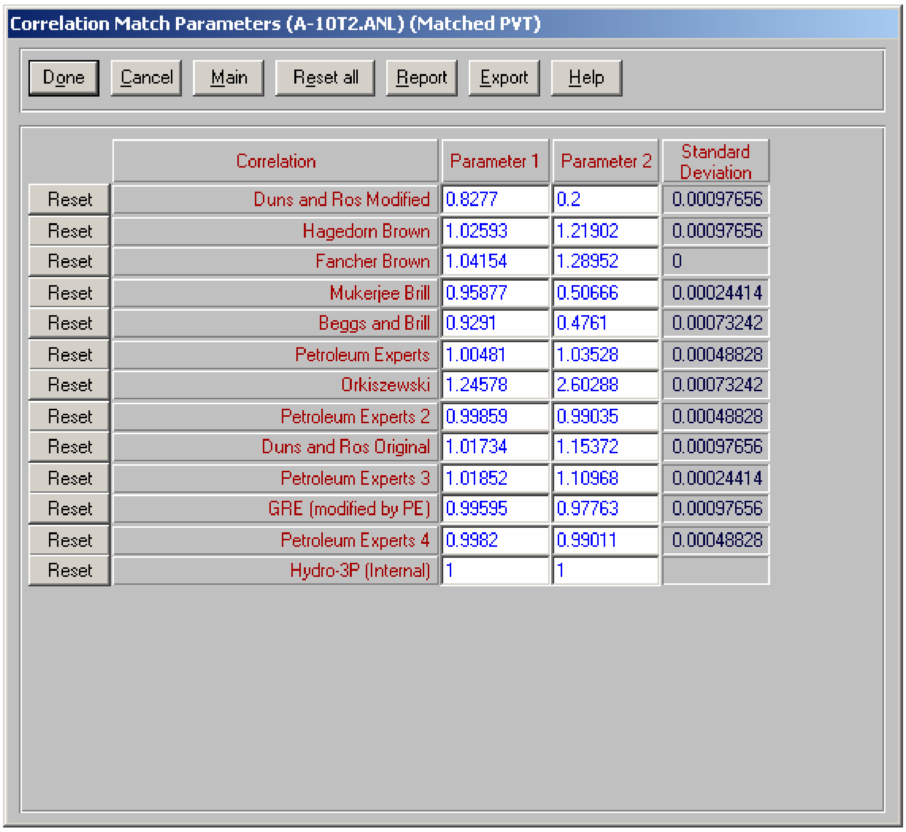
Figure B-2-1: Correlation Match Parameter for Well A-03

Correlation Match Parameters (A-09A.ANL) (Matched PVT)

Done | Cancel | Main | Reset all | Report | Export | Help

	Correlation	Parameter 1	Parameter 2	Standard Deviation
Reset	Duns and Ros Modified	0.61405	0.5429	0.00036621
Reset	Hagedorn Brown	1.01972	1.38647	0.00012207
Reset	Fancher Brown	1.17216	2.31032	0.00036621
Reset	Mukerjee Brill	0.7702	1	0.00012207
Reset	Beggs and Brill	0.79322	0.2	0.00024414
Reset	Petroleum Experts	1.00324	1.04375	0.00036621
Reset	Orkiszewski	0.50518	0.2	0
Reset	Petroleum Experts 2	0.99501	0.93116	0.00012207
Reset	Duns and Ros Original	0.98405	1	0.00012207
Reset	Petroleum Experts 3	1.08386	1.69425	0.00036621
Reset	GRE (modified by PE)	1.03745	1.31862	0.051147
Reset	Petroleum Experts 4	1.02762	1.2465	0.00012207
Reset	Hydro-3P (Internal)	1	1	

Figure B-2-2: Correlation Match Parameter for Well A-09A

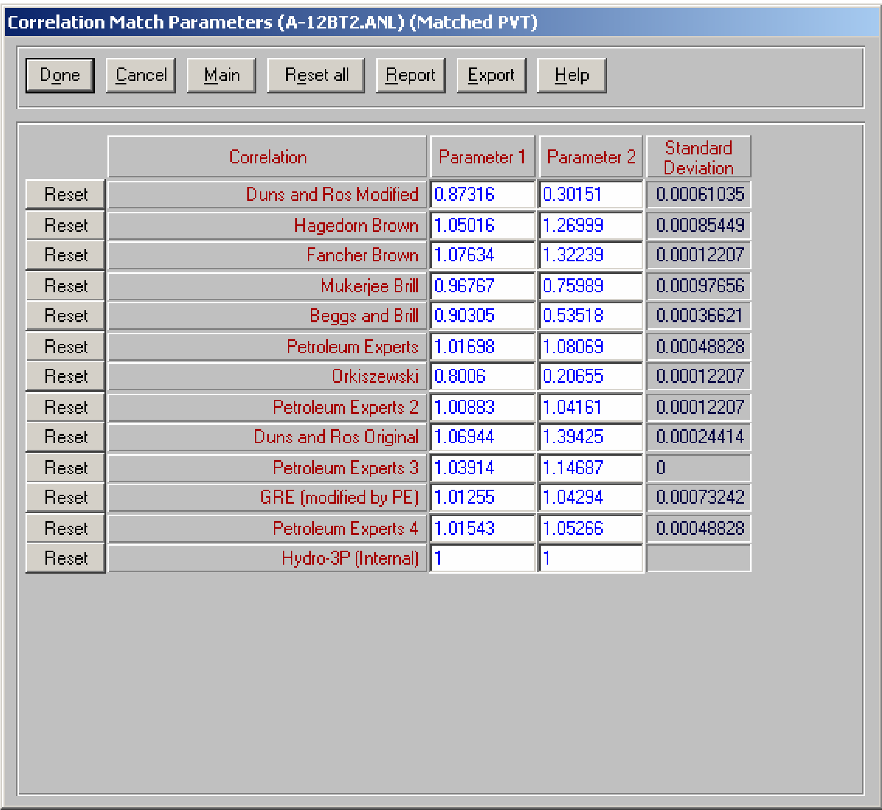


Correlation Match Parameters (A-10T2.ANL) (Matched PVT)

Done | Cancel | Main | Reset all | Report | Export | Help

	Correlation	Parameter 1	Parameter 2	Standard Deviation
Reset	Duns and Ros Modified	0.8277	0.2	0.00097656
Reset	Hagedorn Brown	1.02593	1.21902	0.00097656
Reset	Fancher Brown	1.04154	1.28952	0
Reset	Mukerjee Brill	0.95877	0.50666	0.00024414
Reset	Beggs and Brill	0.9291	0.4761	0.00073242
Reset	Petroleum Experts	1.00481	1.03528	0.00048828
Reset	Orkiszewski	1.24578	2.60288	0.00073242
Reset	Petroleum Experts 2	0.99859	0.99035	0.00048828
Reset	Duns and Ros Original	1.01734	1.15372	0.00097656
Reset	Petroleum Experts 3	1.01852	1.10968	0.00024414
Reset	GRE (modified by PE)	0.99595	0.97763	0.00097656
Reset	Petroleum Experts 4	0.9982	0.99011	0.00048828
Reset	Hydro-3P (Internal)	1	1	

Figure B-2-3: Correlation Match Parameter for Well A-10T2



Correlation Match Parameters (A-12BT2.ANL) (Matched PVT)

Done | Cancel | Main | Reset all | Report | Export | Help

	Correlation	Parameter 1	Parameter 2	Standard Deviation
Reset	Duns and Ros Modified	0.87316	0.30151	0.00061035
Reset	Hagedorn Brown	1.05016	1.26999	0.00085449
Reset	Fancher Brown	1.07634	1.32239	0.00012207
Reset	Mukerjee Brill	0.96767	0.75989	0.00097656
Reset	Beggs and Brill	0.90305	0.53518	0.00036621
Reset	Petroleum Experts	1.01698	1.08069	0.00048828
Reset	Orkiszewski	0.8006	0.20655	0.00012207
Reset	Petroleum Experts 2	1.00883	1.04161	0.00012207
Reset	Duns and Ros Original	1.06944	1.39425	0.00024414
Reset	Petroleum Experts 3	1.03914	1.14687	0
Reset	GRE (modified by PE)	1.01255	1.04294	0.00073242
Reset	Petroleum Experts 4	1.01543	1.05266	0.00048828
Reset	Hydro-3P (Internal)	1	1	

Figure B-2-4: Correlation Match Parameter for Well A-12BT2

Appendix B-3: VLP/IPR Matching Curves

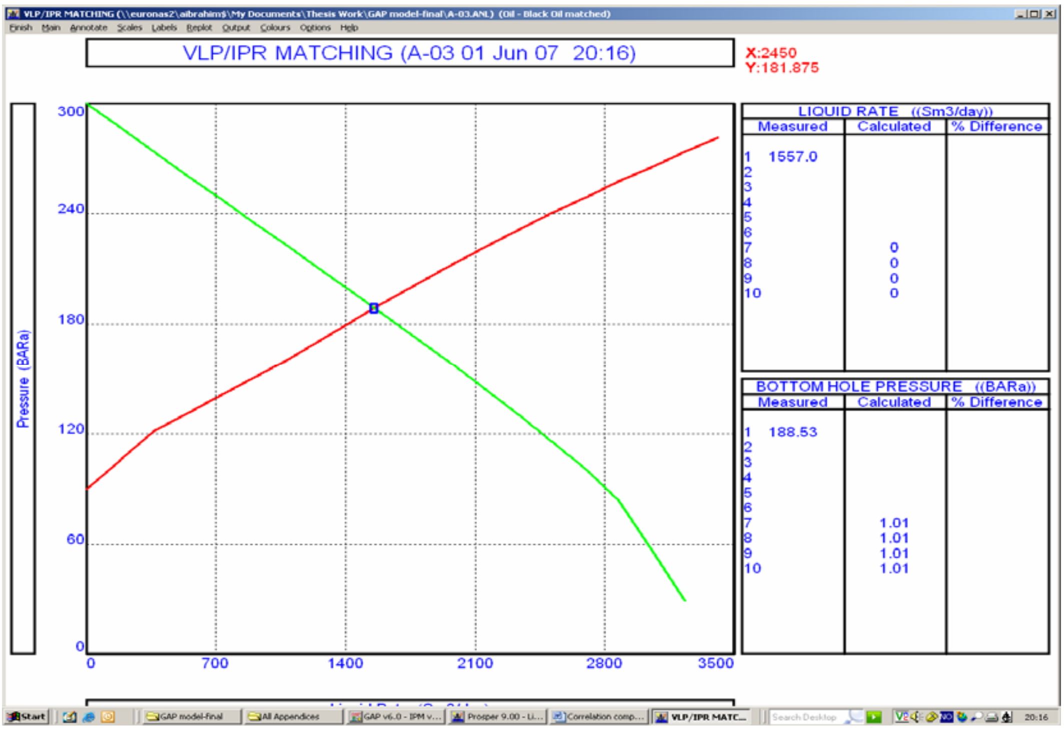


Figure B-3-1: VLP/IPR Matching of Well A-03

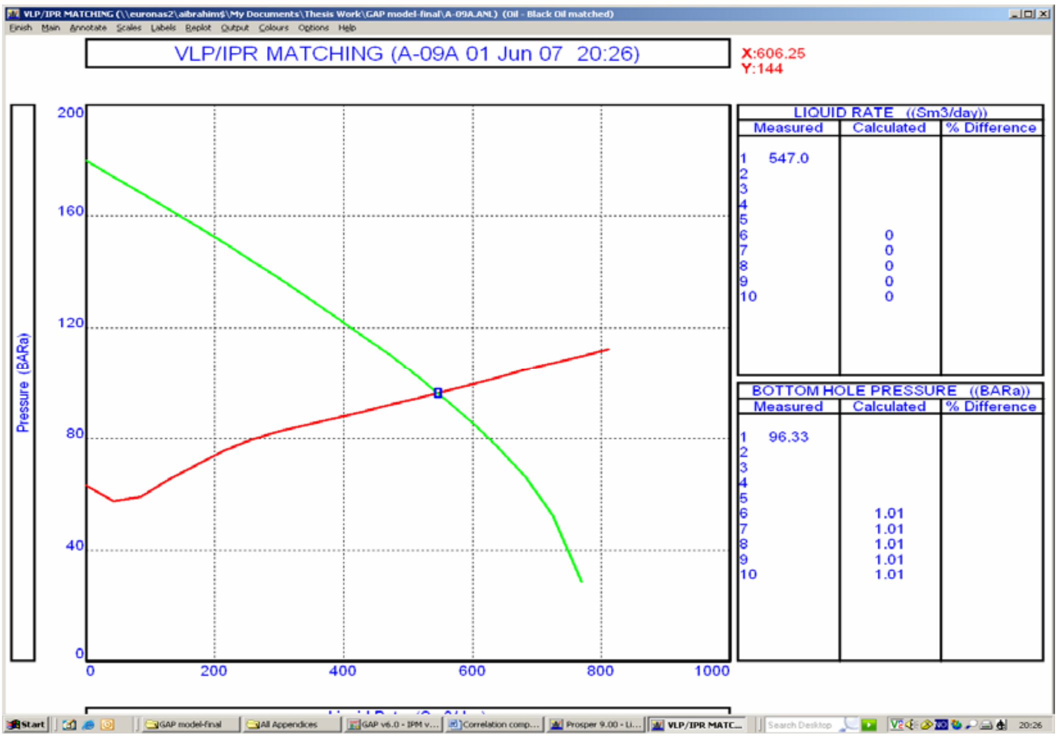


Figure B-3-2: VLP/IPR Matching of Well A-09A

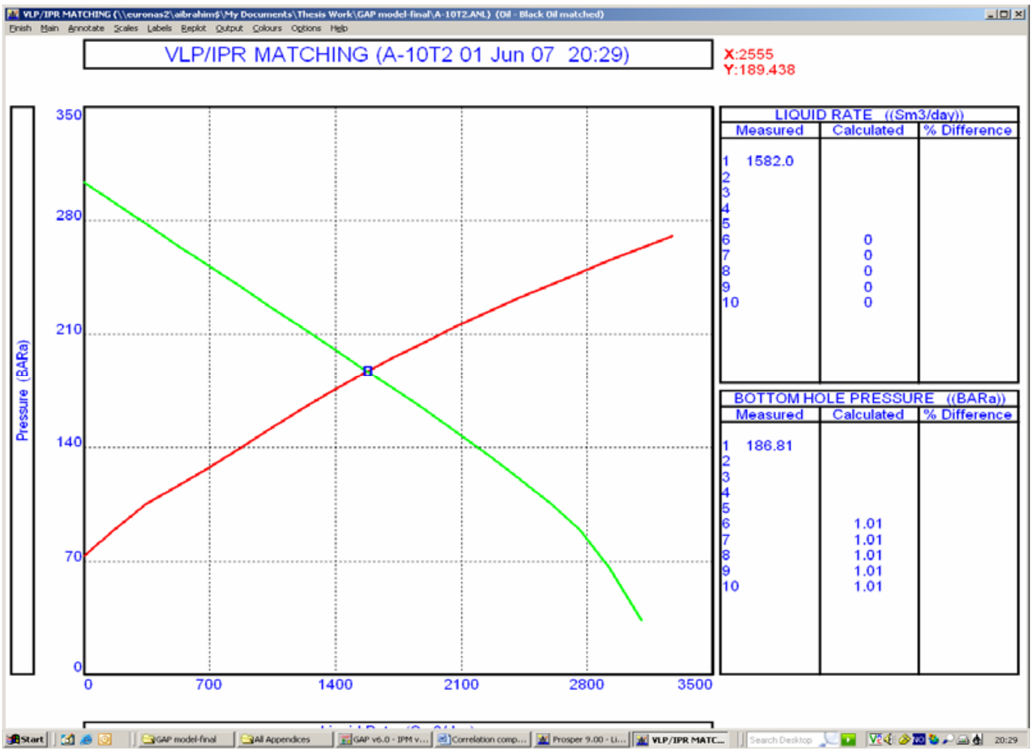


Figure B-3-3: VLP/IPR Matching of Well A-10T2

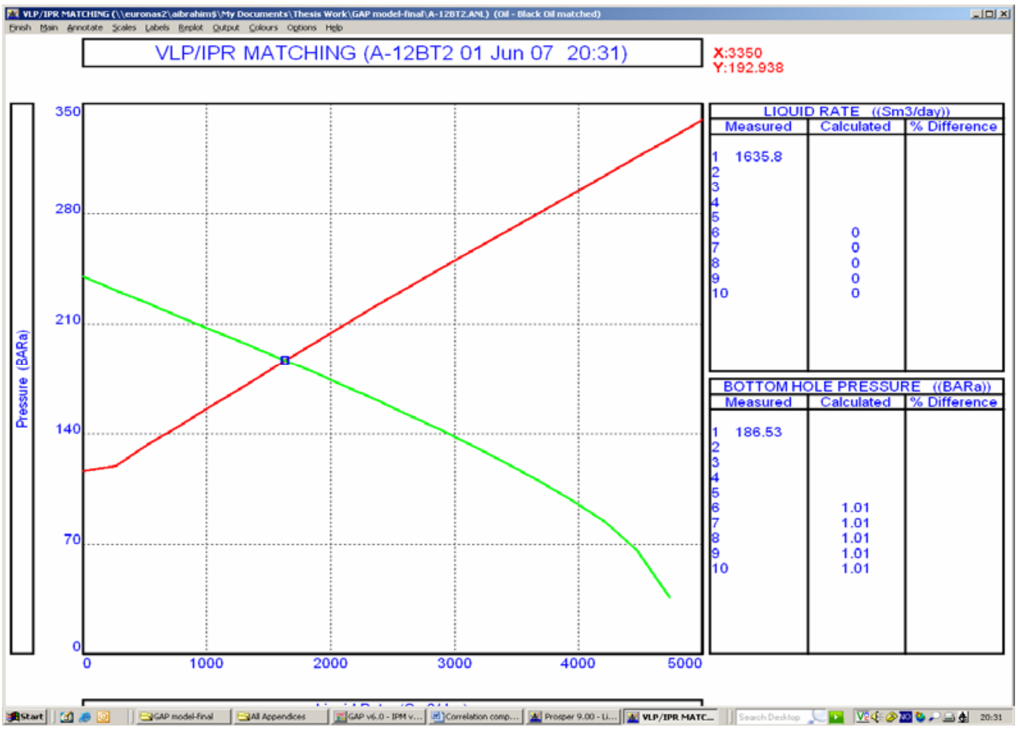


Figure B-3-4: VLP/IPR Matching of Well A-12BT2

Appendix C-1: Pipe Line Drawing

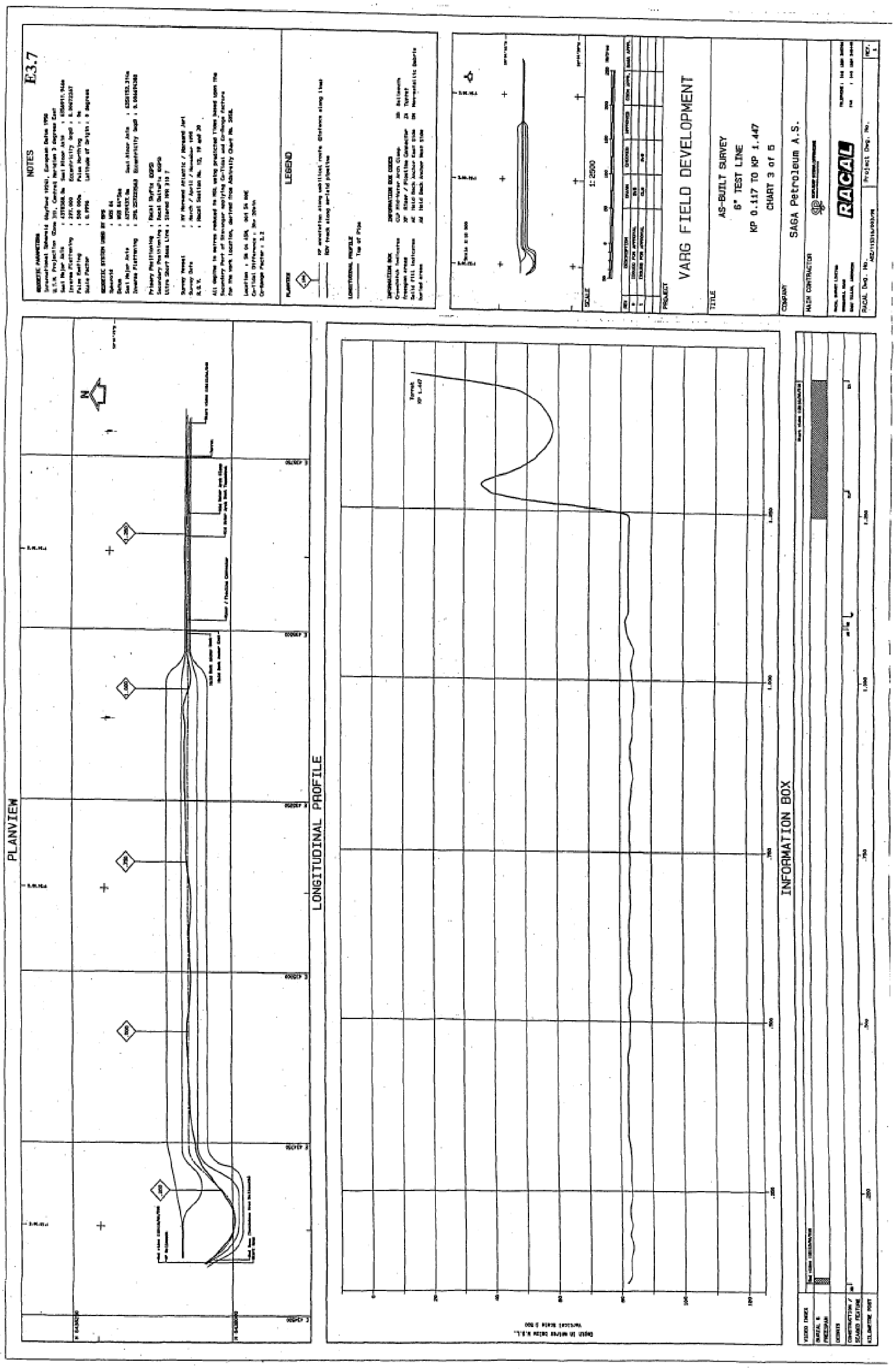


Figure C-1-1: Test Pipe Line Drawing

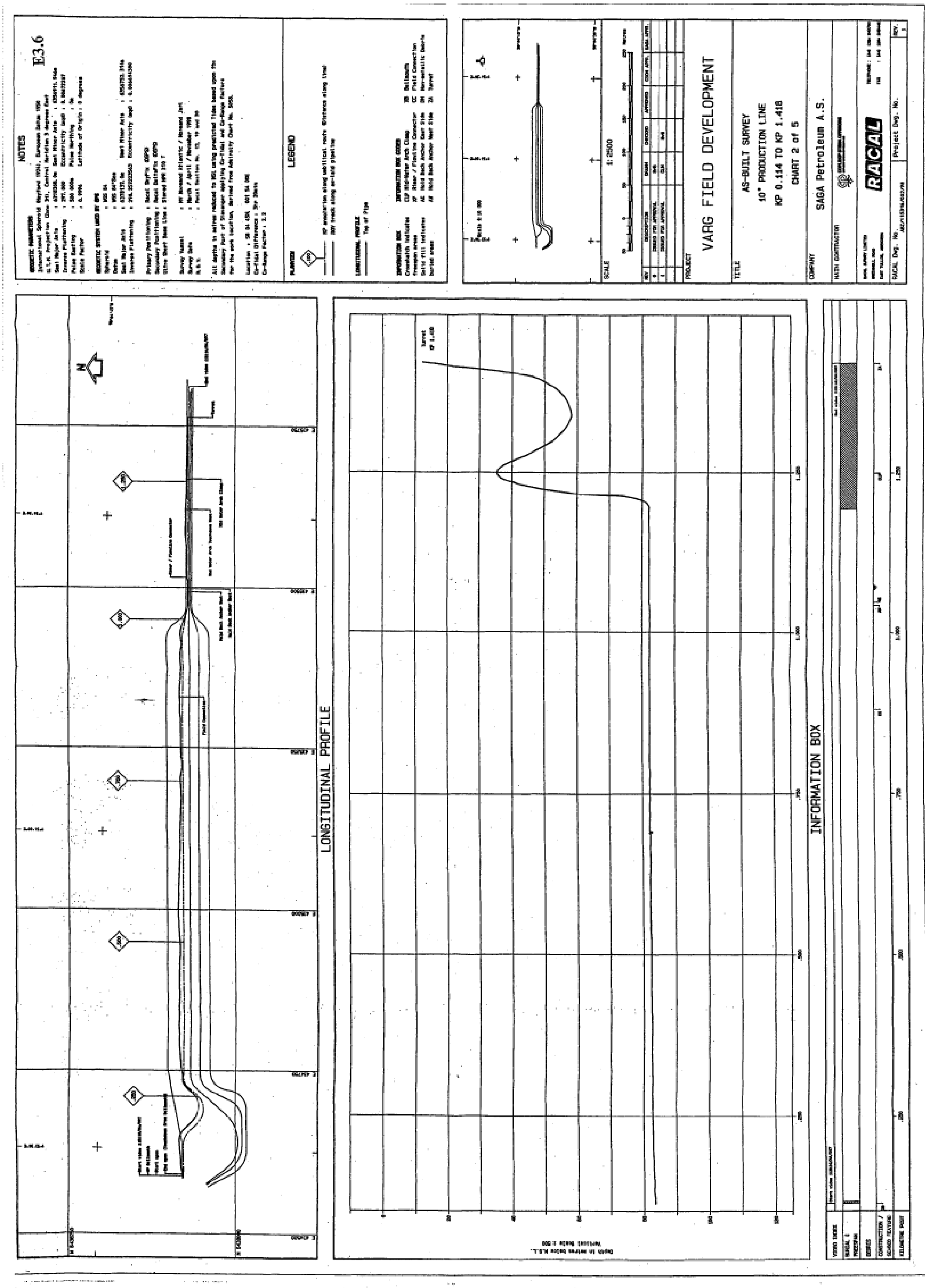


Figure C-1-2: Production Pipe Line Drawing

Appendix C-2: Pipe Line Diagram

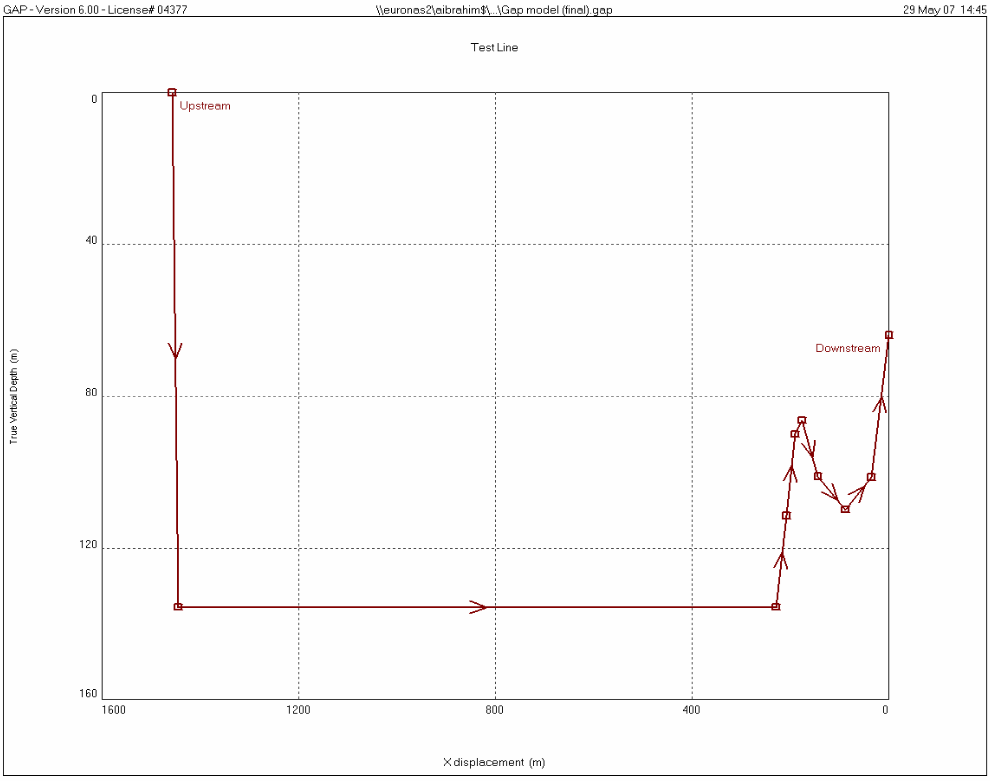


Figure: C-2-1: Test Pipe Line Diagram

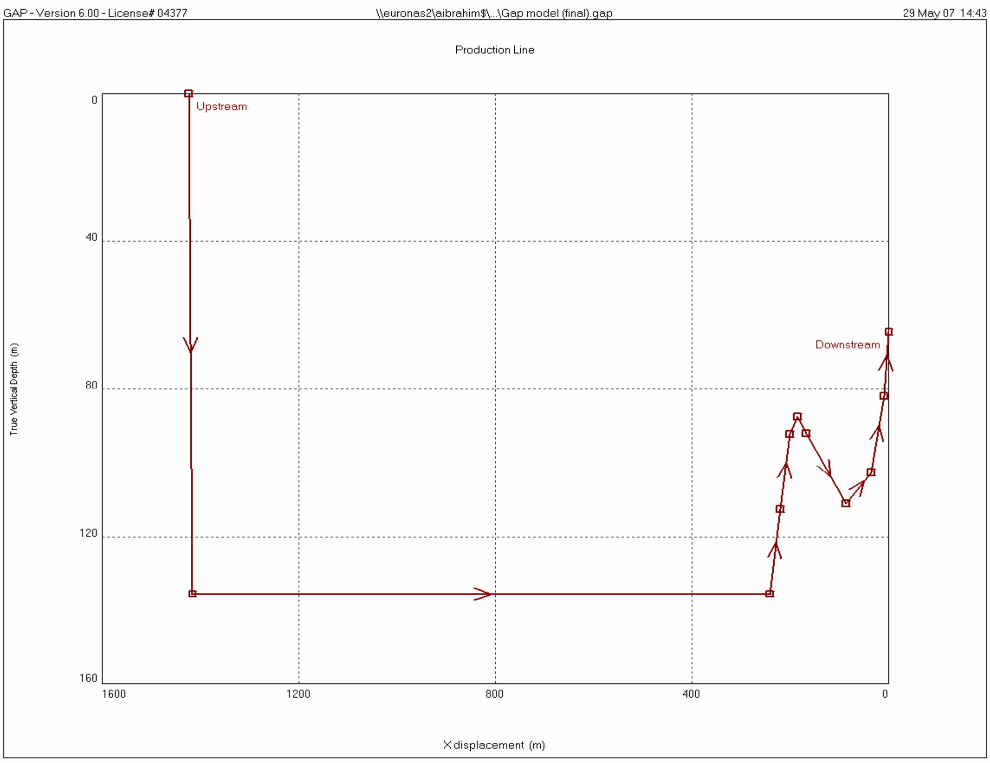
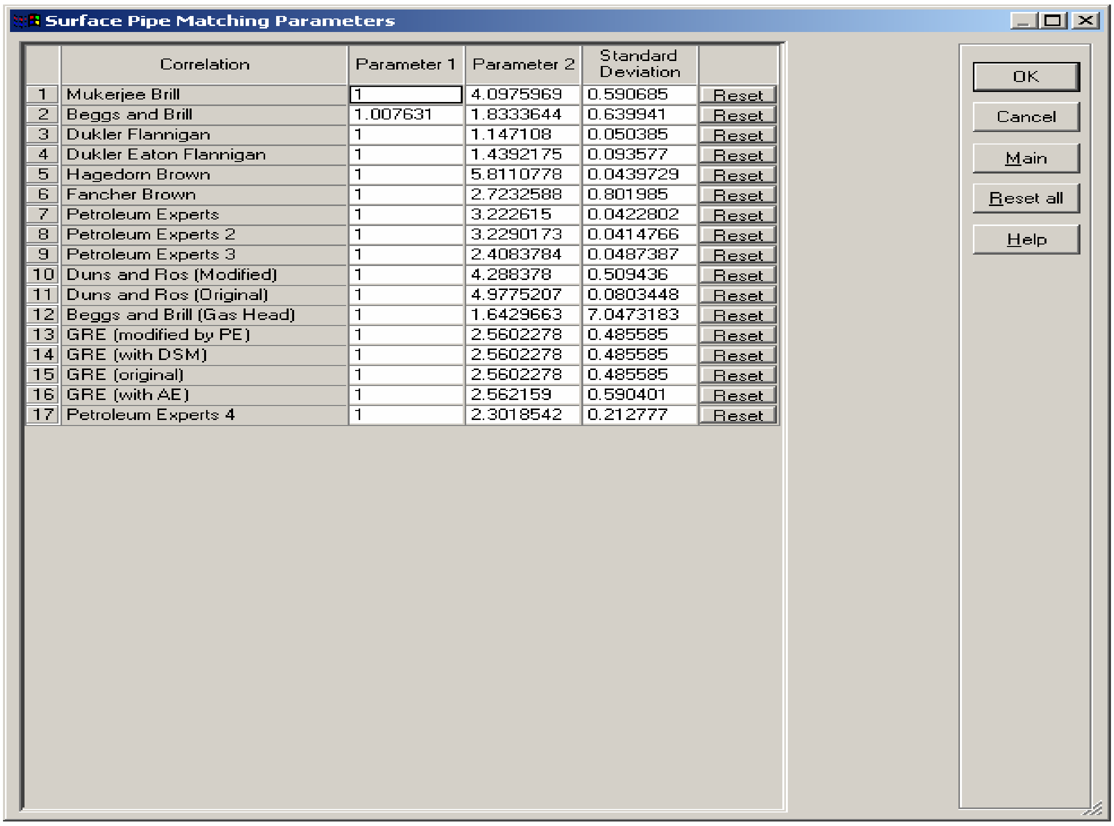


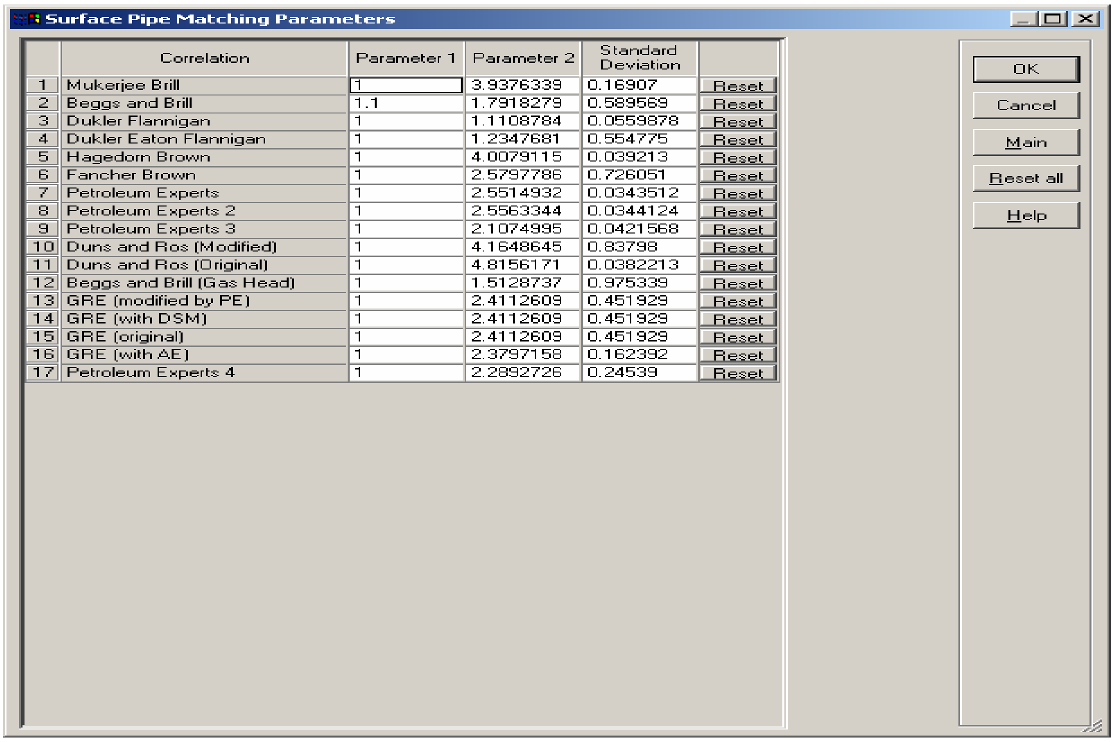
Figure: C-2-2: Production Pipe Line Diagram

Appendix C-3: Surface Pipe Line Matching Parameters



	Correlation	Parameter 1	Parameter 2	Standard Deviation	
1	Mukerjee Brill	1	4.0975969	0.590685	Reset
2	Beggs and Brill	1.007631	1.8333644	0.639941	Reset
3	Dukler Flannigan	1	1.147108	0.050385	Reset
4	Dukler Eaton Flannigan	1	1.4392175	0.093577	Reset
5	Hagedorn Brown	1	5.8110778	0.0439729	Reset
6	Fancher Brown	1	2.7232588	0.801985	Reset
7	Petroleum Experts	1	3.222615	0.0422802	Reset
8	Petroleum Experts 2	1	3.2290173	0.0414766	Reset
9	Petroleum Experts 3	1	2.4083784	0.0487387	Reset
10	Duns and Ros (Modified)	1	4.288378	0.509436	Reset
11	Duns and Ros (Original)	1	4.9775207	0.0803448	Reset
12	Beggs and Brill (Gas Head)	1	1.6429663	7.0473183	Reset
13	GRE (modified by PE)	1	2.5602278	0.485585	Reset
14	GRE (with DSM)	1	2.5602278	0.485585	Reset
15	GRE (original)	1	2.5602278	0.485585	Reset
16	GRE (with AE)	1	2.562159	0.590401	Reset
17	Petroleum Experts 4	1	2.3018542	0.212777	Reset

Figure C-3-1: Test Pipe Line Matching Parameters



	Correlation	Parameter 1	Parameter 2	Standard Deviation	
1	Mukerjee Brill	1	3.9376339	0.16907	Reset
2	Beggs and Brill	1.1	1.7918279	0.589569	Reset
3	Dukler Flannigan	1	1.1108784	0.0559878	Reset
4	Dukler Eaton Flannigan	1	1.2347681	0.554775	Reset
5	Hagedorn Brown	1	4.0079115	0.039213	Reset
6	Fancher Brown	1	2.5797786	0.726051	Reset
7	Petroleum Experts	1	2.5514932	0.0343512	Reset
8	Petroleum Experts 2	1	2.5563344	0.0344124	Reset
9	Petroleum Experts 3	1	2.1074995	0.0421568	Reset
10	Duns and Ros (Modified)	1	4.1648645	0.83798	Reset
11	Duns and Ros (Original)	1	4.8156171	0.0382213	Reset
12	Beggs and Brill (Gas Head)	1	1.5128737	0.975339	Reset
13	GRE (modified by PE)	1	2.4112609	0.451929	Reset
14	GRE (with DSM)	1	2.4112609	0.451929	Reset
15	GRE (original)	1	2.4112609	0.451929	Reset
16	GRE (with AE)	1	2.3797158	0.162392	Reset
17	Petroleum Experts 4	1	2.2892726	0.24539	Reset

Figure C-3-2: Production Pipe Line Matching Parameters

Appendix C-4: Calculated Production Data

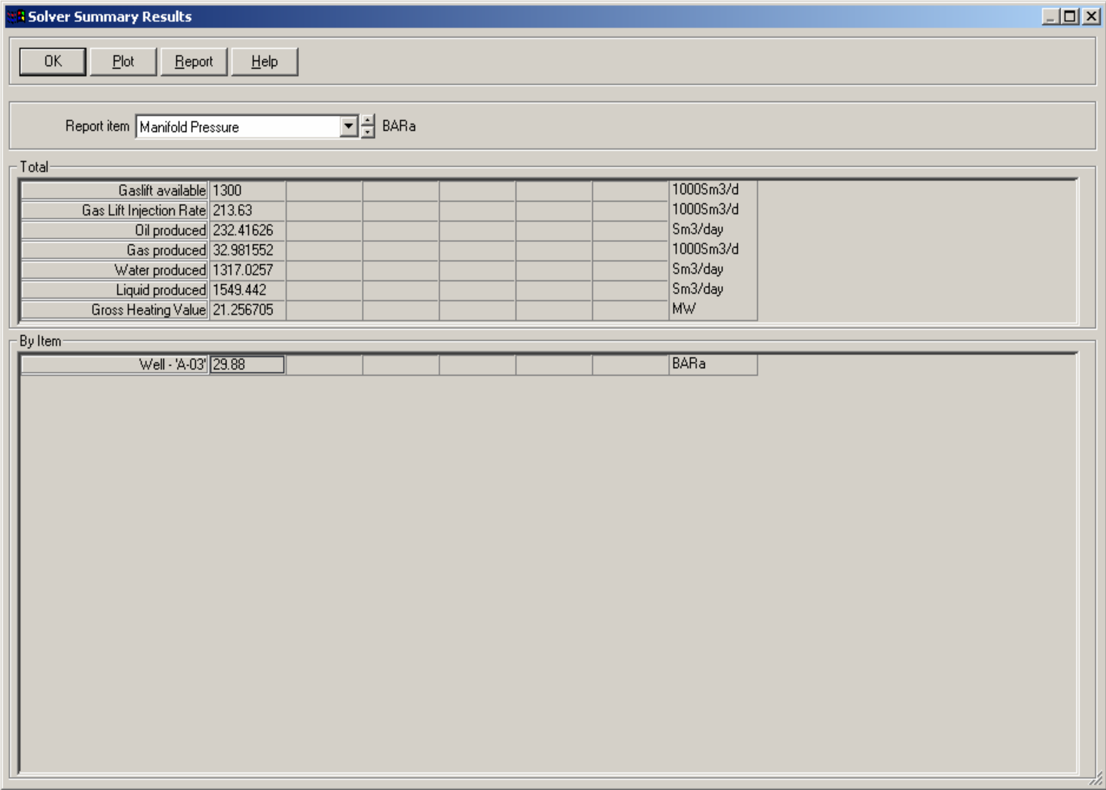


Figure C-4-1: Calculated Production Data of Well A-03

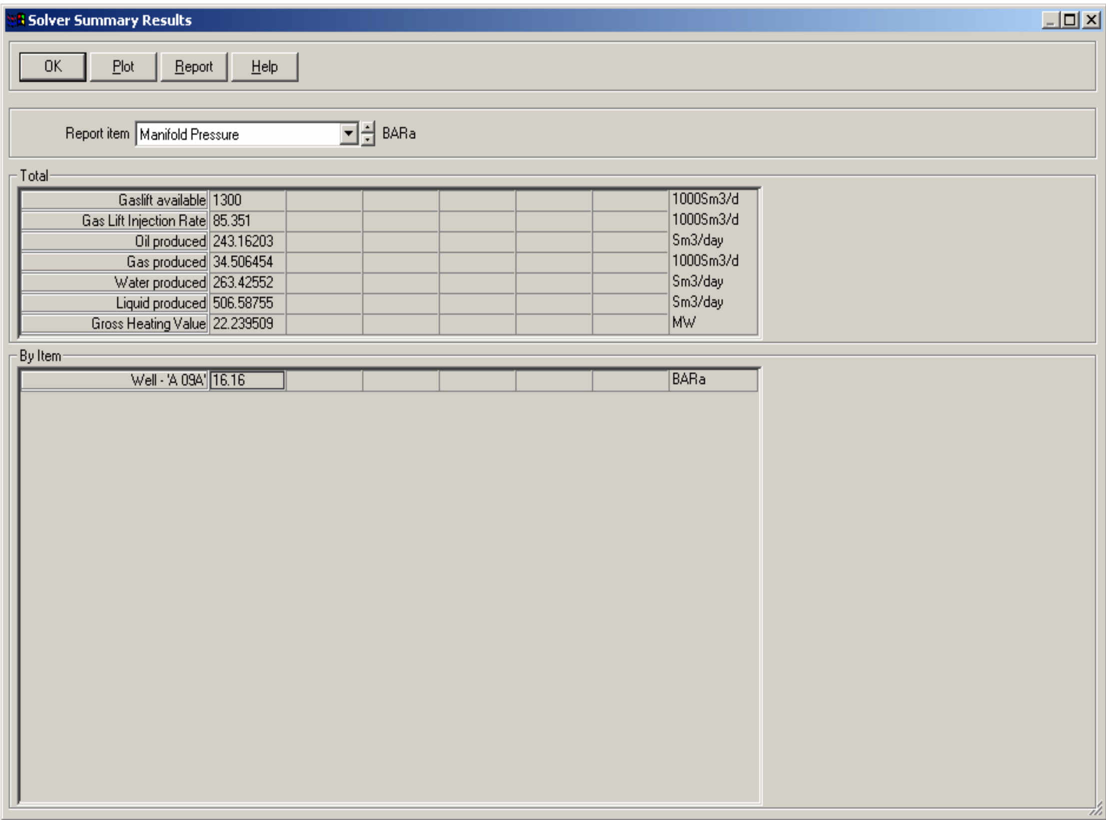


Figure C-4-2: Calculated Production Data of Well A-09A

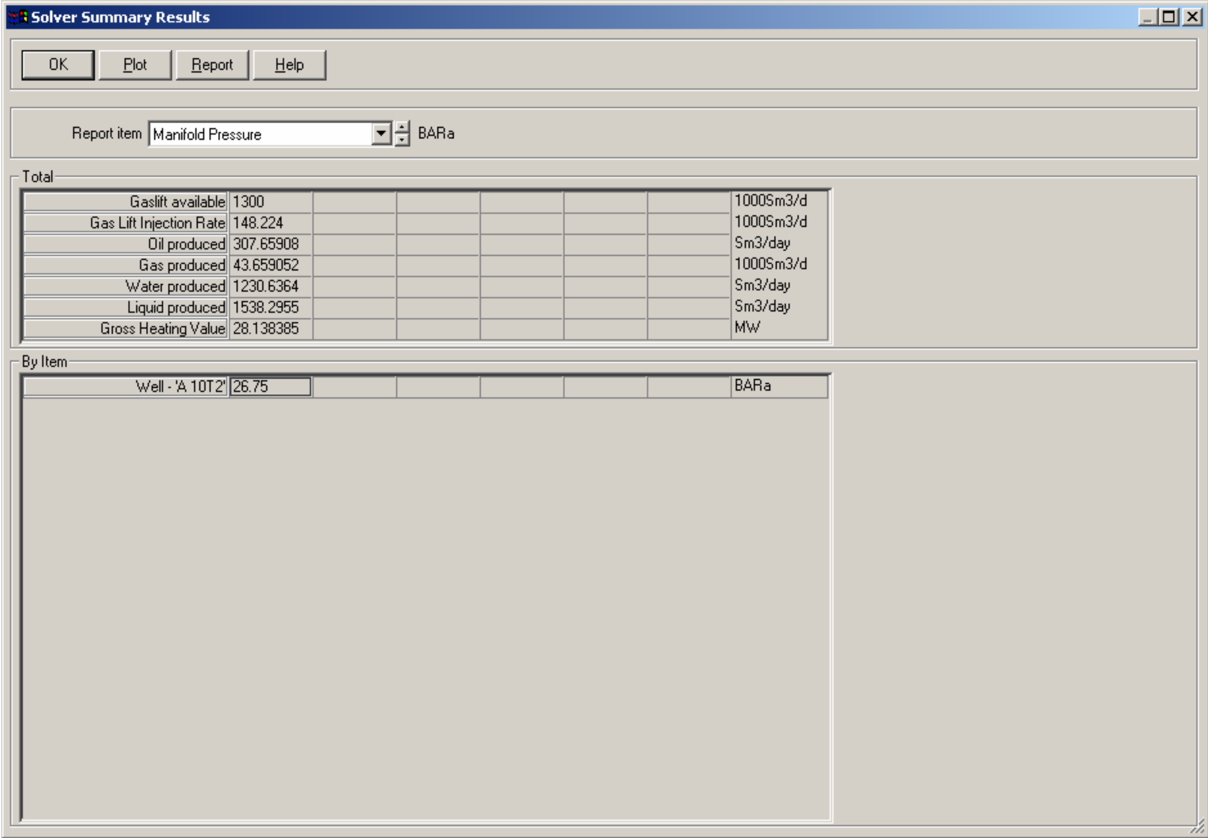


Figure C-4-3: Calculated Production Data of Well A-10T2

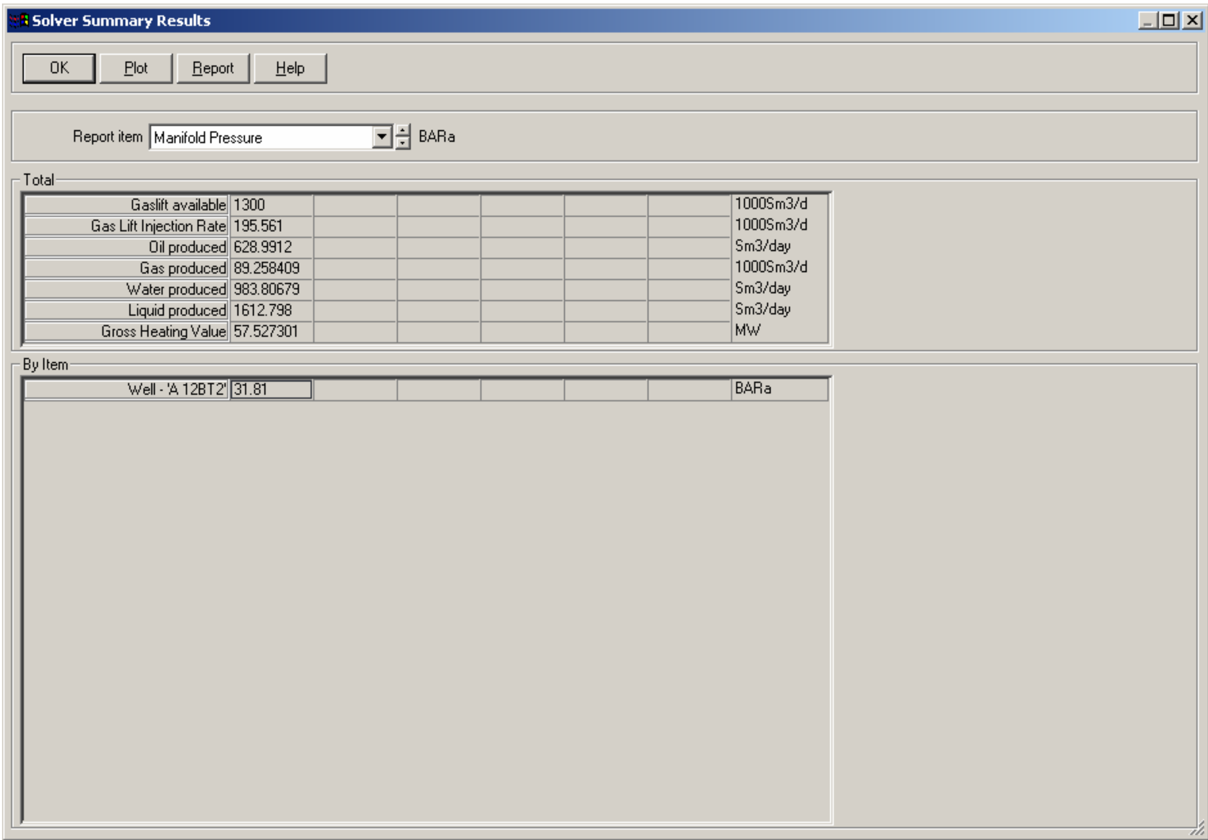


Figure C-4-1: Calculated Production Data of Well A-12BT2