PRODUCTION ENHANCEMENT FROM SAND CONTROL MANAGEMENT

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Dissertation submitted in partial fulfillment of

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Universiti Teknologi PETRONAS

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Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

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Petroleum Engineering Programme

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UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

MAY 2011

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

NUR FARHANA BT MOHD JAMIL

ABSTRACT

This interim report is to finalize the Final Year Project II on the production enhancement from sand control management. The main objective of this report is to investigate the effectiveness of sand control, the classification and types of sand production, important factors that influencing the sand control selections and stimulate the process of sand control techniques in Tukau field using PROSPER software. Sand control is the limitation of sand production to an acceptable level. The purpose of sand control techniques are to control and manage sand production. The methodology of this project is by an enhanced gravel pack stimulation model and the screening of the sand control method. The project will do screening on the Tukau Field reservoir to find whether further study of sand control on mentioned field should be done. Initial model of using gravel pack is tested on some model as reference before applying to Tukau field model. This report will conclude the whole work done though out the semester.

ACKNOWLEDGEMENT

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CHAPTER 1

INTRODUCTION

1.1 Objectives

The objectives of this research are:

a) To investigate the effectiveness of sand control method in Tukau Field located in offshore of Malaysia.
b) To compare the performance of the wells between wells equipped with enhanced gravel pack compared to other methods.
c) To stimulate the process of enhanced gravel pack and stand-alone screen in Tukau reservoir using PROSPER software.

1.2 Problem Statement

Sand production in unconsolidated formations has brought heavy injury for the petroleum industry moving into the next century. The history of sand production dates back to the 1900's with the completion of water wells with sand control installations. Sand production problems in Tukau field have presented major obstacles to well performance and have resulted in significant lost production potential. Reduced production rates and chocking back of wells have been to control sand production to an acceptable level of less than 20 pounds per thousand barrels

Due to sand problems, this involves many challenges associated with drilling wells such as tubing erosion, mud losses, formation damage and wellbore instability.In terms of sand management, there are two main classes of techniques available; sand prevention by passive method and sand control using mechanical exclusion (gravel-packing) or screenless completion (sand stabilization by chemical consolidation or sandlock). Therefore, internal gravel pack has been the most commonly used sand control method for this field. Other methods that have been applied include external gravel pack (EGP/OHGP), chemical consolidation (SCON) and stand- alone (Stratapac) mainly installed after sand failure have been observed.

1.3 Scope of Studies

The scope of this study is to make a research on the use of production data available by using suitable and quickly method in modern production analysis on analyzing the well's problem to make a better sand control method. Techniques of sand sieve analysis have advanced significantly, over the past few years. There are many different methods available currently including passive sand control and also mechanical sand exclusion method. Due to the limitation of time, the scope of study of this project is just focusing on two methods only, which are enhanced gravel pack design and historical match in well model performance. However, the other method will also be covered to have a better understanding, such as Stratapac. This study will involve the case study specifically on Tukau field, theory and also the application in the software available.

Theoretical Knowledge:

- Study on the concepts and characteristic of sand control method selection and design.
- Research on petrography and mineralogy analysis.
- Study on the gravel pack sand sizing design and its factors.
- Sand sieve analysis and grain size analysis.

Hands on Knowledge:

- Training to use PROSPER 2008 package

CHAPTER 2

Literature Review

2.1 Definition and Mechanism of Sand Control

Sand Control is a balance between allowing a particular amount of sand to pass through the sand control solution, without plugging or eroding the solution. Retaining everything would lead to high skin values and probable plug. Sizing a solution too small – can lead to plugging or partial plugging, forcing hydrocarbon production through non-plugged sections "hot spotting" [2]. This in turn can lead to screen erosion. Sizing a solution too large – can lead to unacceptable production of sand, which can lead to erosion of not only the sand screens, but also surface equipment. Should the produced sand rates be excessive, the loss of the well may be inevitable should the wellbore fill with sand.

The most effective sand-control techniques are those implemented early in the life of the well before sand production becomes a problem. These techniques are carried out before the onset of water production or before formation damage occurs from formation disturbance or subsidence. High production rates cause excessive stress on weakly consolidated formations and exceed the capability of the cement material to bond the sand grains together. Once sand is produced as a result of formation damage, effective sand–control methods become more difficult and harder to justify. Marginal wells producing sand with poor reserves may not support the cost of a major workover program. Remedial options include sand bailing with wireline and sand washing with coiled tubing, but these only provide temporary solutions to sand production problems.

2.2 The Classification and the Types of Sand Production

The classification of field measurements of sand production is considered an essential part of sand prediction as it defines the situation assessed. The term sand production envelops a wide range of phenomena. A classification is developed, based on field observations, to allow for a better comparison and interpretation of sand production events. Subsequently, changes in the downhole producing geometry are considered on the basis of the cumulative sand volumes produced.

2.2.1 Transient Sand Production

Transient sand production refers to a sand concentration declining with time under constant well production conditions [3]. This phenomenon is frequently observed during clean-up after perforating or acidizing, after bean-up and after water breakthrough. The sand concentration, the cumulative sand volume and the decline period vary considerably. Fig. 1.1 shows three field examples with a sand volume between 1 and 200 L and a decline period between 1 and 500 hrs.

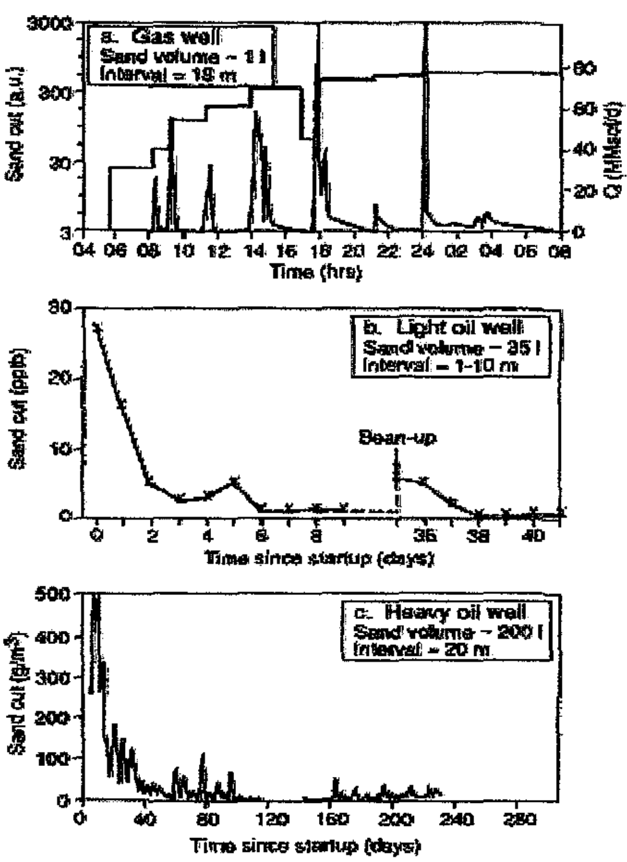


Figure 2.1: Transient sand production

2.2.2 Continous Sand Production

In a great number of fields, continuous levels of sand production are observed. The acceptable sand concentration depends on operational constraints with regard to erosion, separator capacity, sand disposal, artificial lift, well location. Typical tolerated sand cut levels are 6-6006g/m (2.1-210 pptb) in oil producers and 16 kg/l m (1 lb/MMscf) in gas producers [4]. The latter surface sand concentration is equivalent to a downhole sand concentration of about 4 g/m (1.5 pptb) (3900 m reservoir gas equivalent to106 m3 surface gas). Much higher acceptable sand cut levels of the order of 28,000 g/m (10,000 pptb) have also been reported [5, 6].

Part of the continuously produced sand settles inside the wellbore and increases the hold-up depth. Depending on the lifting capacity of the fluid flow and the sand concentration (part of) the (perforated) producing interval may eventually be blocked. Normal production is (temporarily) restored after wellbore clean-out. The volume of sand settling in the hole depends on the well design but can be several m^3.

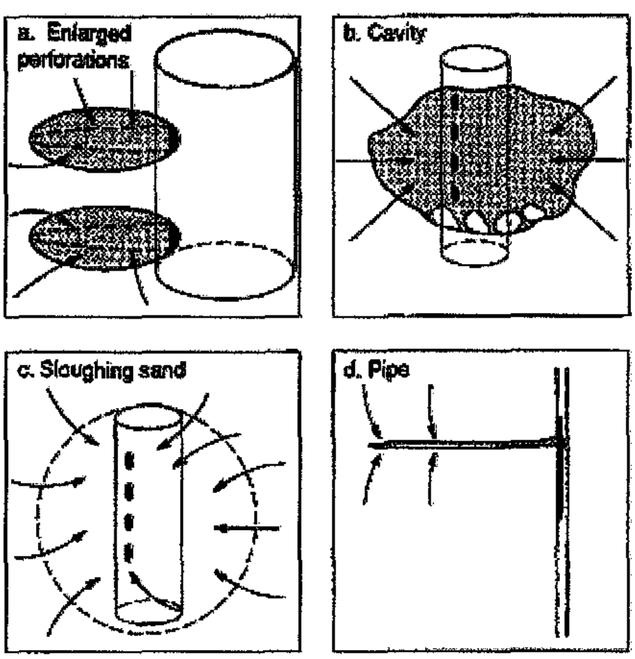


Figure 2.2: Sand production - downhole situation

2.3 Methods Selection

To restore production from the well, current economic realities favored through tubing intervention. Two major types of through remedial sand control solutions were considered namely mechanical and sand control solutions were considered namely mechanical and screen- less (chemical consolidation) methods. A proprietary HDR squeeze pack technique (mechanical method) was identified as the best solution that meets post intervention production requirements and also affords completion longevity.

2.3.1 Mechanical Methods

Enhanced Gravel Pack Technique

According to Yahaya I.O (2009)

Mechanical methods of through- tubing sand control involve the use of gravel pack screens design to be deployed through tubing, then set inside tubing, casing, or even another larger gravel- pack screen. In addition to the use of screens, a sand medium is often used to help keep the formation sand in place. The method is employed mostly for the following reasons:

i. Cost efficiency- the operation does not require a workover rig since the screen assembly can be deployed with standard coiled tubing equipment or wireline and the well returned to production faster.
ii. Effectiveness- sand production is controlled allowing production to match previous rate or better.
iii. Quick intervention- operation could be accomplished quickly without impacting existing well completion jewelry or deferred production in dual completion.
iv. Maintenance costs- maintenance costs associated with surface and downhole equipment due to sand production are now eliminated.

The HDR Squeeze Pack can be completed using various types of screens and packers and is available for various tubing sizes. The HDR tool design allows a squeeze pack to be performed with high rate and high density slurry pumped from surface, yet dependable mechanical isolation on the annulus when completed. Deployment system was a combination of a number of wireline and coil tubing runs.

System components from bottom to top are:

- Bull plug
- Screen assembly
- Flow diversion valve
- Blank pipes
- Polished nipple for HDR
- HDR vent top assembly
- Sealing overshot
- Top packer

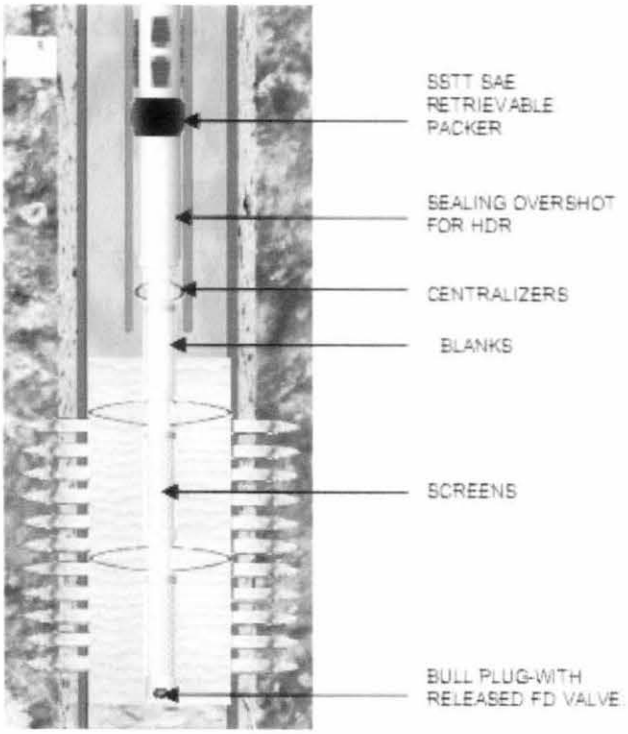


Figure 2.3: System Component of Gravel Pack

Stand- Alone Screen

Stand- Alone Screen (SAS) may be preferred because of their lower cost. Historically, SAS are used when there is a good chance of gravel pack failure due to incomplete packing with void pockets. SAS may effectively minimize the sand production. However, they have smaller inflow area, which may cause productivity decline. Also, SAS are vulnerable to being plugged by drilling mud cake, formation sand and fine particles. Preventing/ removing the damage to SAS may be the key to maximizing the well productivity. Screens may be partially or completely plugged. Localized partial plugging creates higher flow velocities at non- plugged screen sections, which in turn may initiate screen erosion. Several experimental studies have been dedicated to characterizing the damage to the screen. In several field applications where the screens were the preferred completion method, sharp declines in well productivity were reported after relatively short production periods. Therefore, the most widely used of SAS in the industry was *Stratapac* and *Stratacoil*

The screens were installed using through tubing operation at the onset of sand production, either due to gravel pack failure or where no sand control were installed previously. However it was reported in all cases, the Stratapac installations have reduced production rates after installation despite successfully preventing excessive sand production. Most of the wells were beaned-up but gross production had dropped significant compared to production prior to the installation. Screens that were pulled out of hole had shown evidence of plugging from wax and fines. Plugging due to wax is expected to be more serious in Tukau due to the high wax content of most of the Tukau crude

Stratacoil thru- tubing (TT) screens are designed for optimal flow distribution. The porous metal fiber (PMF) media, which consist of metal fibers sintered between two layers of woven wire mesh, make these screens ideal for controlling non-uniform sands. PMF media's engineered pore structure forms a specific range of pore sizes with an extremely high pore volume. *Stratacoil* screens also provide superior damage tolerance. The strength and flexibility of the PMF media better resist the crushing forces of compacting reservoirs and provide longer- lasting, more reliable sand control.

The design of *Stratacoil* screens advantages in the following applications:

a) Coiled- tubing gravel packs
b) Damaged gravel- packed screen repair
c) Marginal reservoirs requiring minimal investment
d) Compacting reservoirs.

Expandable Sand Screen

Expandable sand screen (ESS) is a relatively new sand control system, which combines many of the properties of gravel packs with the ease of installation of a stand- alone screen. Although they have been used in a wide variety of applications, they are not considered a panacea and have an operational envelope, which is clearer with time.

The productivity performance of the ESS has been shown to be very good, with an average skin on 0.3 being achieved in recent openhole applications. ESS completions generally perform better than the baseline models. Where field comparisons were possible, they also performed better than alternative sand control completions.

The frac- pac technique was chosen for its capability to provide stimulation in addition to its capability to reliability mitigate sand production, as shown by conventional internal gravel pack (IGPs). Some stand- alone (SAS) and expendable sand screen (ESS) in Tukau experienced severe screen plugging and sand production, especially in open hole completions. In one ESS completion, mechanical failure was experienced during initial installation.

Several advantages and benefits associated with frac packs are as follows:

i. Enlarged wellbore area. The wellbore area is connected to the reservoir with a highly conductive fracture, increasing the effective inflow and drainage area.
ii. Connects multiple sand layers. Typical formation sands in the Baram Delta area are lamintaed, with thin shale streaks. Good connectivity can e achieved by creating a propped fracture adjacent to stratighraphy pay.

iii. Reduced drawdown. Can flow at similar rates but at lower drawdown pressure because of good conductivity within the wellbore. Reduces production flow velocities and minimizes the risks of fine migration.

iv. Bypass near-wellbore damage. Connects to the virgin reservoir reservoir beyond the damaged region thriugh a proppant- packed fracture. This could be over 50-ft fracture length.

2.3.2 Chemical Method (Sand Consolidation Technique)

In Figure 2.2, a simplified, schematic reaction pattern of the organosilane is given. The organosilane chemicals will react with water and hydrolyze. The chemical will then react with the hydroxyl groups on the surface of the silica sand. The molecules can also react with each other to form a network. The degree of consolidation achieved will vary with the concentration and possibly the volume of the chemical injected. The chemical is hydrophobic in nature and can be mixed in a hydrocarbon phase, preferentially diesel. The treatment package can be bullheaded in the well. The package consists of a pre-flush consisting of a hydrocarbon phase, the main chemical pill in hydrocarbon phase and a post-flush placement volume. Usually the pre- and post-flush is the same fluid as the mixing fluid for the chemical.

A simplified concept of the organosilane administration is shown in Figure 2.3. The organosilanes have the advantage that they are oil-soluble and the reaction is induced by water. This is why a hydrocarbon preflush is used to establish Swi or to reduce the water saturation in the near wellbore area. In this way, the organosilanes will not be able to react before the chemical is placed in, or reaches, the porous matrix. The objective is to get the organosilane to react with the irreducible water around the sand grains and not in the bulk volume in the porous matrix.

The polymerized organosilane network will increase the residual strength of the failed formation in the near wellbore. The stabilized sand matrix can therefore withstand higher hydrodynamic forces from the fluid flow and thereby prevent the erosion and transport of sand grains into the wellbore and possibly all the way to the process facilities top-side. A bi-product of the chemical reaction between the organosilane and the water is an alcohol. During start-up of a well after a sand consolidation treatment samples can be taken at the flowline and analyzed for alcohol. Furthermore, in order to calculate a mass balance on pumped and returned chemical, Si in both the oil- and water phase can be analyzed in the return. The chemistry and details regarding the chemical can be found in other publications [7, 8].

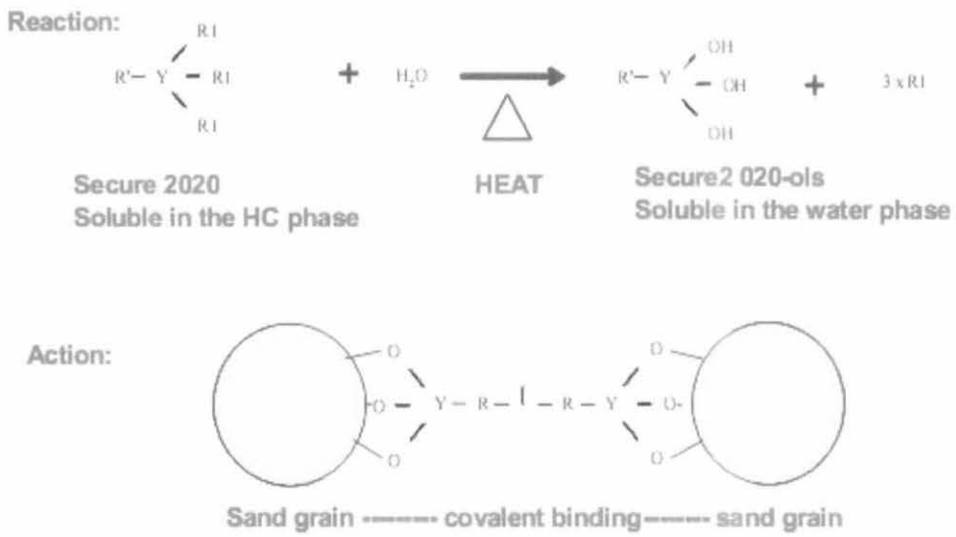


Figure 2.4: Simplified schematic reaction pattern of the organosilane

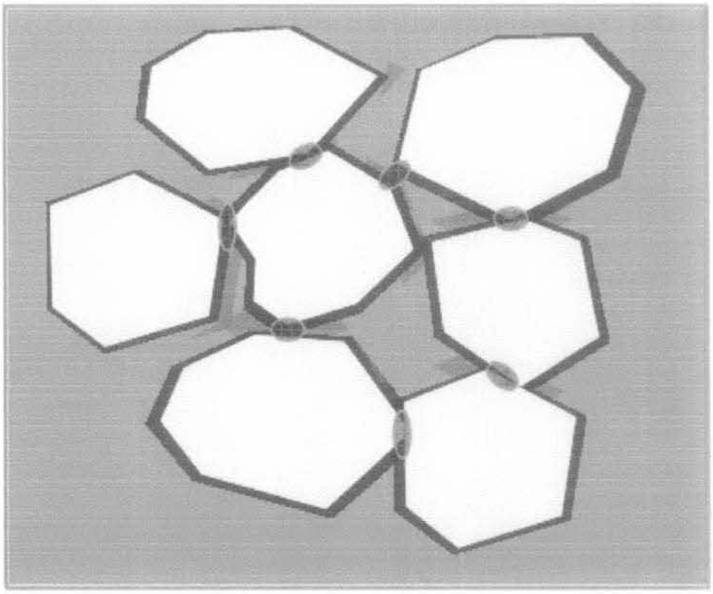


Figure 2.5: Concept of the organosilane administration

2.4 The Important Factors of Through Tubing Sand Control

2.4.1 Wash Pipe Size

One of the important considerations of all sand control done with either squeeze or circulation gravel packs is to keep the flow of slurry to the area on the outside of the screen. In order to ensure that the preferred flow path is in the casing and screen annulus instead of the screen, a wash pipe is usually placed inside of the screen to decrease the area open to flow on the inside of the screen. Figure 3.1 shows these two flow areas.

Under normal circumstances the wash pipe is sized such that the OD of the wash pipe is approximately 80 percent of the ID of the screen base pipe. A list of the most common wash pipe size used with each different screen size is given in Table 3. As long as the diameter of the OD of the screen is at least one inch less than the diameter of the ID of the pipe it is placed inside, this 80 percent guideline gives a larger area open to flow outside of the screen than inside of the screen [9].

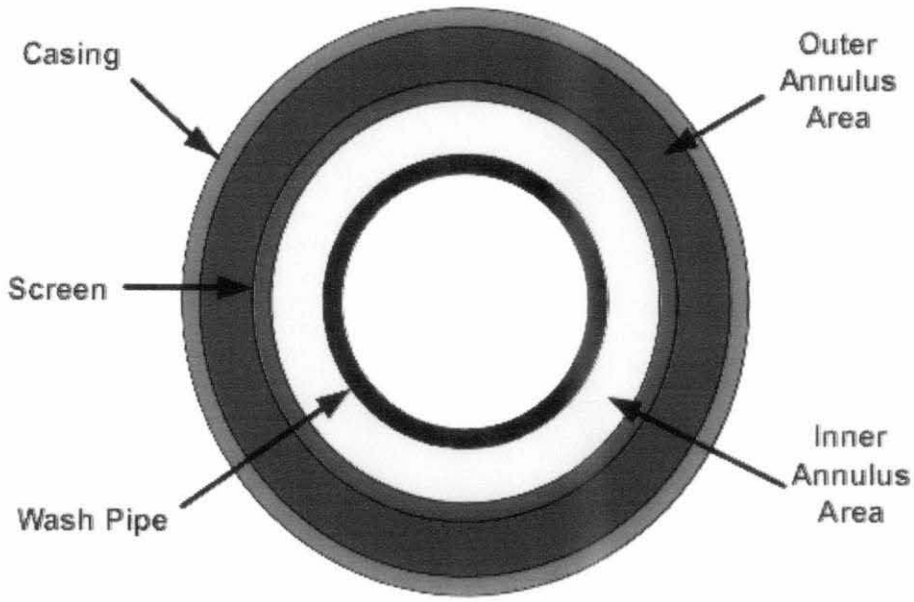


Figure 2.6: Drawing of flow areas for fluid flow during sand transport.

Screen Base Pipe Size, inches	Wash Pipe Size, inches
2.375	1.315
2.875	1.900
3.500	2.375
4.000	2.875
4.500	2.875
5.000	3.500
5.500	4.000
6.675	4.500

Table 2.1: Common Wash Pipe Sizes.

Screen Base Pipe Size, inches	Wash Pipe Size, inches
2.375	1.315
2.875	1.900
3.500	2.375
4.000	2.875
4.500	3.500
5.000	4.000
5.500	4.500
6.675	5.500

Table 2.2: Recommended Wash Pipe Sizes.

2.4.2 Wellbore Deviation

With low viscosity fluid systems the placement of gravel inside of the wellbore is controlled by the fluid velocity and by gravity. As long as the fluid velocity is below the critical transport velocity for sand particles in the slurry, the controlling factor for gravel placement is gravity itself. For vertical wells or wells with wellbore deviation less than 55 degrees, this means that any sand particles placed in the screen/ casing annulus will simply fall to the bottom of the wellbore.

However in wellbores with small clearances on the outside of the screen, it takes only a few sand grain thickness to cause a bridge in the annulus. Once this bridge starts, it can perpetuate itself up the wellbore and around the outside of the screen. So for wells with deviations other than vertical, it is recommended that the screen be centralized to minimize the chance of this bridge starting to form.

2.4.3 Sand Concentration

The concentration of sand in the gravel slurry also has an effect on the likelihood of bridging to occur in the screen annulus. In the tests that were conducted, the sand concentration was varied between 1.0 ppa and 0.25ppa.

At the higher sand concentrations in deviated wells, the higher concentrations of sand caused some duning of the sand along the bottom of the wellbore. This duning causes extra friction of the sand particles and further decreases the effects of gravity on their movement to the bottom of the wellbore. This allows other particles to accumulate and soon a bridge starts along the low side.

2.4.4 Flow Rates

There are two flow rates that can be controlled during any circulation gravel pack: pump rate going down the tubing and the amount of flow that is returned back at the surface. However, the amount of flow that enters the perforations can also be critical to the success of the completion.

One of the critical factors for high productivity in any cased hole sand control operation is being able to effectively place sufficient high permeability gravel pack sand into each formation sand. To accomplish his objective, it is critical to get sufficient flow of slurry into the perforation tunnel to carry the sand particles. A good general guideline to follow for this flow rate is to allow at least 0.2 gallons per minute of slurry leak off into each perforation.

2.4.5 Turbulence

Another factor that was observed during simulator testing was the effect of turbulence on sand hold- up, particularly at the bottom of the wellbore and at couplings. In regions at the end of the screen and wash pipe, there were portions of the wellbore where there is virtually no fluid movement. The fluid flow just above these 'dead' regions creates a turbulent effect. This effect is really magnified in situations with the small clearances.

The sand would tend to be suspended by this turbulence and would accumulate in the small annular area. Eventually, the amount of sand being kept in this turbulent area would start to bridge. Once this occurred, the bridge would rapidly expand and would encircle the entire screen. Once this happened, the bridge would continue up the wellbore, leaving an area at the bottom with incomplete sand pack. Once the gravel placement was completed, the sand would redistribute itself to fill these voids. This situation should always be avoided because it will lead to possible screen erosion or screen plugging when the well is placed on production.

CHAPTER 3

METHODOLOGY

3.1 Project Procedure

FIRST SEMESTER

Perform Literature Review

- Understand the fundamentals of Tukau field and its rock formations.
- Understand grain size distribution and perform preliminary screening
- Study the various types of sand control method for cased hole completion
- Research on petrology and mineralogy analysis.
- Identify important parameters from Sensitivity Analysis

SECOND SEMESTER

Model Case Study

- Stimulate and construct well model performance of Tukau Field
- Conduct sensitivity analysis to determine the effect of varying injection rate strategies, prediction of skin, reservoir rock properties, the value of productivity index and well deliverability.
- Propose the best sand control method for Tukau Field based on the analysis
- Identify important parameters for Sensitivity Analysis

Final Report write up and Oral Presentation

3.2 Project Process Flow

3.2.1 Diagnostics

Diagnostic production data is an important step that should be taken seriously before we want to analyze any production data. This vital step is just like pre-analysis and pre-modeling to ensure the data that to be analyzed is in good quality, consistent and complete. Hence, the meaningful result can be obtained. However, if the quality of the data is questionable, inconsistent, and poor quality, the production analysis data method should be used with caution. This process ensures that errors in each step are identified and minimized before proceeding. The matching technique also highlights inconsistencies in the input. If this systematic approach is not applied, there is no way to identify the source of possible errors in the final result.

By ensuring that well models are matched to historical data, the quality of forward prediction is enhanced. The accuracy of any prediction cannot be guaranteed under all circumstances, but a minimum requirement is that model can reproduce current observed conditions.

3.2.2 PVT data input and Analysis

The next method is interpretation and analysis of the production data. This is the part that this project focusing on. The modeling options are first established. This sets up the data input screens so that only the data required for the problem need be entered. The author is then guided through the steps of entering PVT data. Since all subsequent steps use the PVT data in some form or other it is essential that the PVT model is accurate.

3.2.3 Modeling and History Matching

The next steps (Equipment and IPR) can then be approached in the knowledge that potential errors in the PVT have already be identified and minimized. In the matching module, VLP correlations are adjusted so that measured bottom hole pressures can be reproduced by the model. The IPR can also be adjusted so that the measured bottomhole flowing pressures can be reproduced by working from both the surface and reservoir pressures.

3.2.4 Analyzing Result

After all the analysis, interpretation and the modeling had done, the result will be analyzed to make decision either the well is needed to be stimulated or not. It depends on the parameter that come out from the analysis, which are skin damage, permeability, and also the reserves to make sure the stimulation jobs are economical to be done.

3.3 Tool

The tool used in this project is PROSPER software provided by Petroleum Experts toolkit is designed to build and study a complete integrated modeling aspect. PROSPER has been designed to approach a system analysis application in a systematic and efficient manner. By ensuring that well models are matched to historical data, the quality of forward prediction is enhanced. Basically, the output of the modeling is to construct a well model performance in order to see the effect of PI value, prediction of skin, and the production rate from different techniques.

3.4 Gantt Chart/ Key Milestone of Project

PROPOSED GENERAL GANTT CHART FOR FINAL YEAR PROJECT																																			
	NO	DETAIL/WEEK	1	2	3	4	5	6	7		8	9	10	11	12	13	14	15	1	2	3	4	5	6	7		8	9	10	11	12	13	14	15	16
	1	Selection of project topic																																	
	2	Preliminary research work			PART 1																														
	3	Submission of preliminary report					X																												
Sem 1	4	Project work					PART 1				PART 2, 3, 4 & 5																								
	5	Submission of progress report									X																								
	6	Seminar (compulsory)									X																								
	7	Submission of interim report final draft															X																		
	8	Oral presentation								Midsem Break								X								Midsem Break									
	10	Project work continues																	PART 5, 6, 7								PART 8								
	11	Submission of progress report 1																			X														
	13	Submission of progress report 2																									X								
Sem 2	14	Seminar (compulsory)																									X								
	16	Poster exhibition																											X						
	17	Submission of dessertation final draft																															X		
	18	Oral presentation																																X	
	19	Submission of dessertation (hard bound)																																	X

CHAPTER 4

RESULTS AND DISCUSSION

4.0 Reviews on Field Background

The Tukau field was discovered in 1966 by the appraisal well TK-2. First oil was produced in August 1975. The current PSC is valid for the period 2003-2018. PCSB is the operator with 60% participation and the balance 40% by Shell.

The Tukau structure is a north-south elongated anticline dissected by a system of WNW-ESE trending synthetic/antithetic normal faults at the shallow levels and complicated by growth faults at deeper levels. The major hydrocarbon accumulations are between 2400 ft ss and 7500 ft ss in the E,F,I,J and N sands. Oil columns range from 10 to 150 ft. The main prospective sequence consists of fine to very fine grained sand of the Upper Cycle V of late Miocene age, deposited in a deltaic, fluviomarine, coastal and near-shore environment.

Most reservoirs are characterized as moderate to strong water drive with varying amounts of energy from gas cap expansion. Recovery factors range from around 11% to almost 100%, based on historic volumetric STOIIP estimates. Based on the new geologic interpretation and correlations many oil-bearing sands have not been perforated.

The Tukau field consists of unconsolidated reservoirs which require active sand control. Conventional Internal Gravel Packed (IGP) technique has been widely applied as it has provided a reliable means of abating sand production. These completions however, have shown high skins (>15) which had increase with time due to fines migration into the packed area especially with the advent of water production. In many cases, flow efficiencies were reduced by 70% and this had severely affected well performances with aging.

Stand Alone Screens (SAS) and Expandable Sand Screens (ESS) had also been applied in some fields with mixed success especially for high angle or horizontal wells. Experience gathered from these previous sand control measures coupled with the emergence of improved design and production of SAS has enabled a shift in our sand control philosophy.

Proper sizing of the screen slot size is critical to ensure that screens are not plugged as commonly experienced in SAS applications. Annular flow was minimized by running constrictors suitably placed with the screen assembly. Finally, strict enforcement of slow bean-up policy during the initial production of the new wells has maintained the screen's integrity in the wells completed so far.

This project is to investigate the impact of stimulation strategy on the improved well performance, examined the different sand control methods by looking at several parameters.

4.1 Sonic Log Cut off

Most of Tukau wells completed in the shallower reservoir such as D, E, F, G, H, I, J, and K were completed with sand control. The sonic transit times above this level is above 90 usec/ft are considered unconsolidated. The SW Ampa SPADE study has been applied to Tukau which uses the sonic transit time (dT) of 90 microseconds per foot as the boundary of sand consolidation,i.e., when dT was lower than 90us/ft, the formation was considered consolidated and sand control installation was not recommended. The sonic transit time versus depth plot suggested that formations shallower than 5300ft TVD would be unconsolidated, and therefore 5300 ft had been used as cut-off depth for sand control exclusion.

This cut- off criteria is further confirmed where sand failure was observed in the shallower reservoirs that were completed conventionally i.e. without sand control. TK-46L was completed in reservoir 2-J2.0/J6.0 without sand control due to operational problems and experienced sand failure soon after it came to production. TK-54L completed in reservoir 1A-H2/H3 reservoirs without sand control (zone was perforated through tubing) showed sand failure and Stratapac had to be installed in order to produce the well. Another well, TK-15 (1-F6/G1) that was treated with Eposand also reported sand failure.

Wells which were completed in the deeper reservoirs i.e L, N, and O completed conventionally without sand control. Excessive sand production was reported in TK-53L (1-L2/L3 reservoirs) later in production life where stratacoil was installed to control sand. Sand failures were also reported in TK-9, 10 and 29L in earlier reviews but data could not be found to support omservation. No other sand failure were reported in the deeper sands. This observation leads to question of the validity of a single cut-off depth as the sand control area.

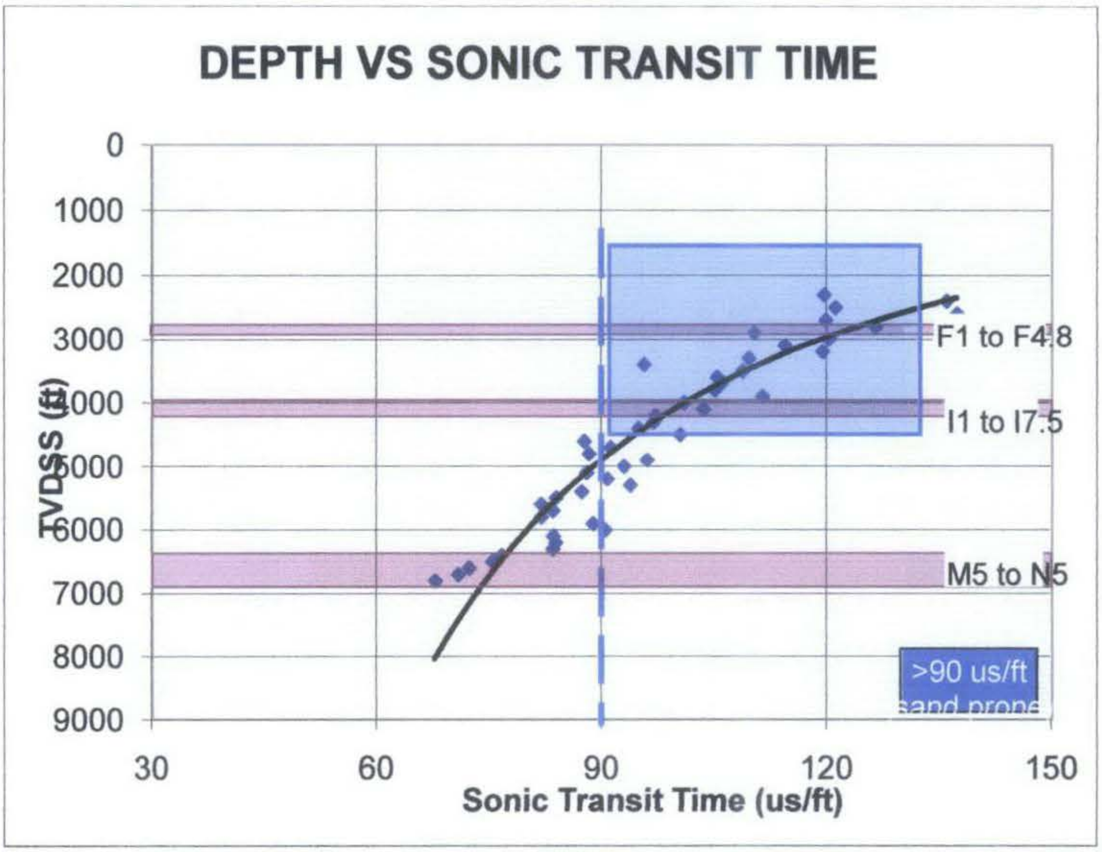


Figure 4.1: Depth versus sonic transit time.

Basically, if sonic transit more than 90us/ft, there is a tendency to have sand prone. From the graph of sonic transit time, we can see that the transition time between 90us/ft. Normally, between this transition some of the wells are using other than internal gravel pack (IGP) since mostly of Tukau wells used EHGP.

4.2 Data Gathering and Sand Analysis

There are several case studies had been selected to be analyzed by using modern production analysis are presented. The objective is to analyze this well is to see the effect of performance for different method based on the value of Productivity Index (PI), production rate and skin value and to determine whether a remedial stimulation could increase production.

4.2.1 Well history

In order to get a good overview of all well data relevant for surveillance, optimization and well intervention purposes, well histories have been compiled for all producing wells. Information was as much as possible retrieved from its original source. Based on these a written section on the well's history covering drilling and completion, production trends and well interventions such as stimulations and zone changes were developed. The information from well history is important due to latest well performance is reviewed and potential opportunities and data acquisition requirements are highlighted.

4.2.2 Wellbore Diagram

Wellbore diagrams have been stated using tubing tallies (components and depth), completion and perforation reports and wireline reports (status of SSD open/ closed, screens, plugs, insert strings). From this report we can see the depth of perforation and the allocation of each valve. This is important when we want to key in the data in deviation survey.

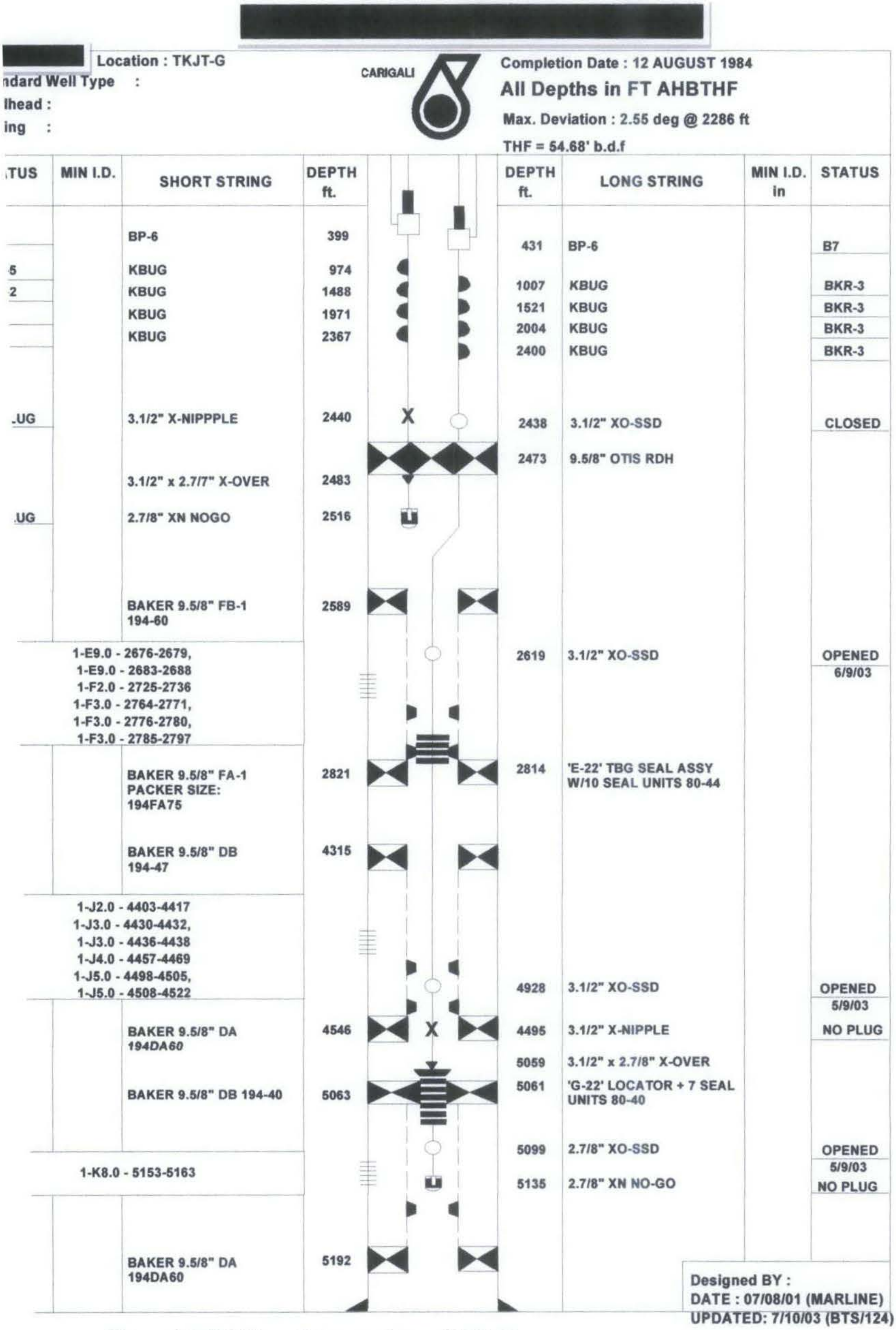


Figure 4.2: Wellbore Diagram for well TK-X.

4.2.3 PVT Data

In order to see the reservoir properties of the well, we need PVT data to proceed with further analysis. From Black Oil PVT data we could see the value of GOR, oil gravity, gas gravity and water salinity.

4.2.4 Well Deviation Data

Basically, well deviation data is important to get the measured depth (MDT) and true vertical depth (TVD) data.

TK-X		TK-Y	
MD	TVD	MD	TVD
0.0	0.0	0.0	0.0
500.0	500.0	400.0	400.0
900.0	899.9	700.0	699.4
1300.0	1299.9	1000.0	999.2
1700.0	1699.9	1300.0	1298.3
2100.0	2099.9	1600.0	1595.5
2500.0	2499.9	1900.0	1891.8
2900.0	2899.9	2200.0	2180.8
3300.0	3299.9	2500.0	2457.4
3700.0	3699.8	2800.0	2721.2
4100.0	4099.8	3100.0	2978.1
4500.0	4499.7	3400.0	3246.1
4900.0	4899.7	3700.0	3514.8
5300.0	5299.4	4000.0	3785.3
5700.0	5699.2	4300.0	4061.1
6100.0	6099.1	4600.0	4336.4
6500.0	6499.1	4874.0	4589.0
6700.0	6699.1	4966.0	4674.9
6883.0	6882.1	5150.0	4847.6
7003.0	7002.1	5217.0	4910.6

Table 4.1: Well Deviation Data for TK-X

4.2.4 Well Test Data

A review of the production history can be performed using basic plots of oil, water and gas production, water- cut and cumulative production. These decline curve analyses were done at both the reservoir and the well level. This overview helps in understanding of how the field was historically developed and may identify significant events or anomalies. The production performance trends were heavily relied on estimating future additional production for successful inflow enhancement (stimulation).

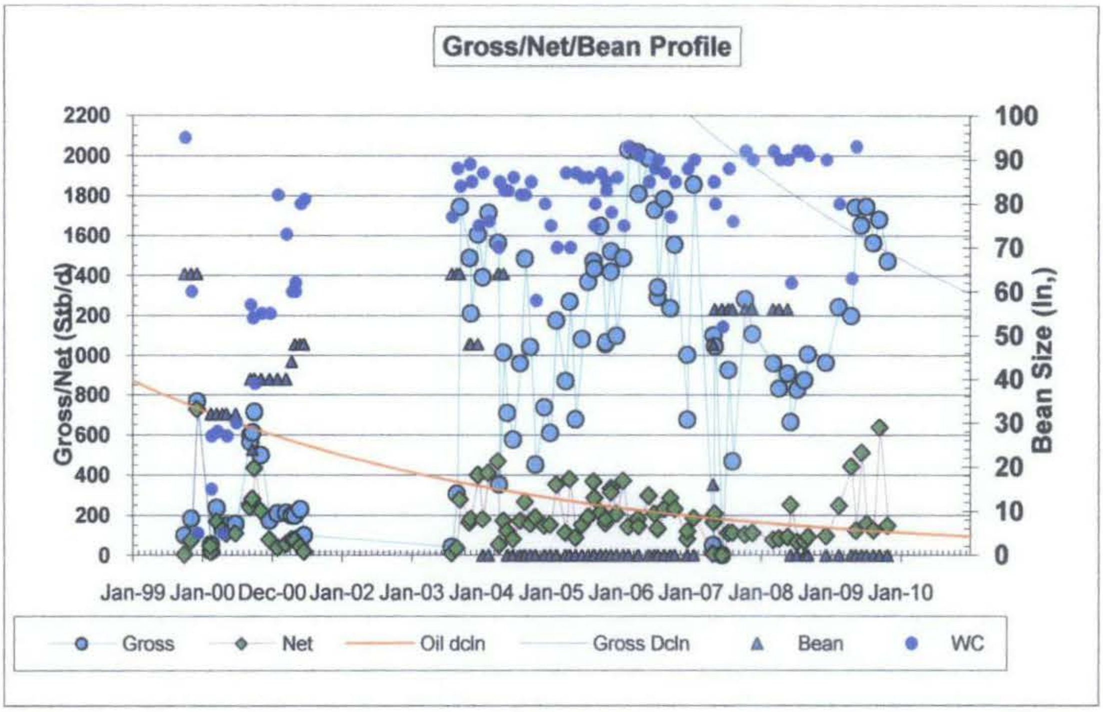


Figure 4.3: Well Test Data Based on Certain Parameters

4.3 Construction of Enhanced Gravel Pack Model

Step by step of model construction is made through the example. There is no exact model that can be used as reference for the real model. Therefore trial and error of the example need to be done by changing the parameter and the dimension. The construction of the model started with the 1 dimensional model of sand control to identify the keywords used.

Enhanced gravel-pack techniques apply fracturing technology to soft, high permeability formations requiring sand control. Traditionally, propped fracturing was applied to low permeability, hard rock formations where the goal was to create fracture-length dimensions to provide a conductive path for production. With the advent of tip-screen-out fracture designs, fracture length is arrested, and fracture inflation occurs, achieving significantly higher fracture conductivities that are in the order of 10s of thousands of md-ft. This allows the fracturing application envelope to be expanded to include higher permeability formations where achieving fracture width and near-wellbore conductivity is paramount. Since high permeability formations where sand exclusion treatments are necessary might sustain damage during the drilling and completion operations, a short, propped, highly-conductive fracture can produce wells with higher productivity and reduced skin values.

4.3.1 Screening of Diffrent Methods

Criteria	Internal Gravel Pack (IGP)	Stand -Alone Screen (SAS)
°API	22.8	29
Viscosity, cp	2.9	0.41
Oil Gradient (psi/ft)	0.372	0.29
Gas Gradient (psi/ft)	0.026	0.023
Porosity (%)	21-30	25
Average Permeability (mD)	10-800	640
Datum Depth (ft.ss)	2795	5772
Average Reservoir Temperature	140-200	119
Bgi(rb/Mscf)	2.254	2.345
GOR	600	600
Water Cut (%)	90	70

Table 4.2: Parameters of Both Methods

Based on the screening criteria to the Tukau field, studies on the sand control method should be further embark. Studies will be conducted referring to the mechanics of sand control mentioned in the literature review.

Well model performance on the Tukau field reservoir will be constructed after the author has undergone the training on using the PROPER 7.1. The training will be on using the stimulation in PROSPER and identifying the effects of well performance based on certain parameters.

The parameters identified are on prediction on skins, the production rates, and the value of productivity index (PI). Author is currently doing sample model by using the keywords before implementing to Tukau stimulation model.

4.3.2 Analysis Procedure in PROSPER Model

Step 1: Key in the system summary

The first step is to key in the data to the software to be loaded into the program. In the step, we have to make sure the unit used in the data is correct. From this option summary, the author can select which method will be used in the well model construction.

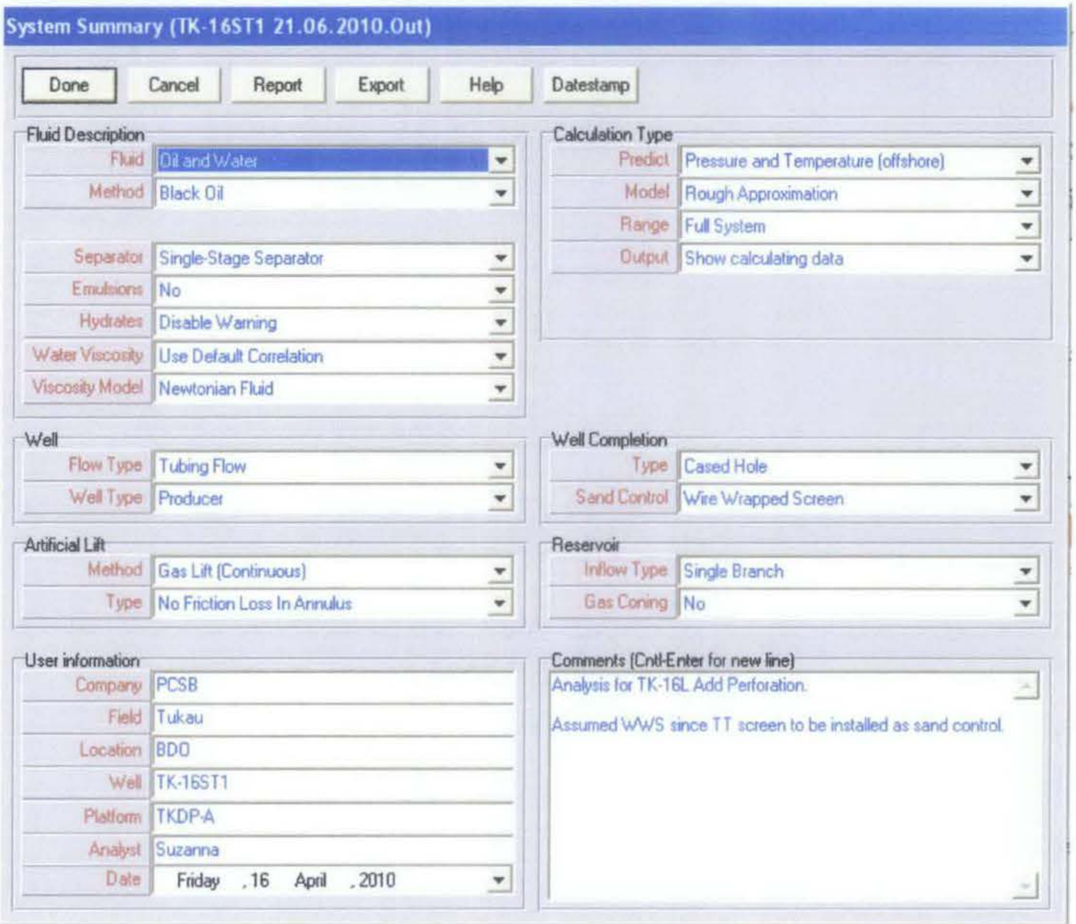


Figure 4.4: Summary Data of TK-Y

Step 2: Input PVT Data

Enter parameters data as listed at the begining of this section. Solution GOR, oil gravity, gas gravity and water salinity are the minimun data required to be able to continue with the analysis.

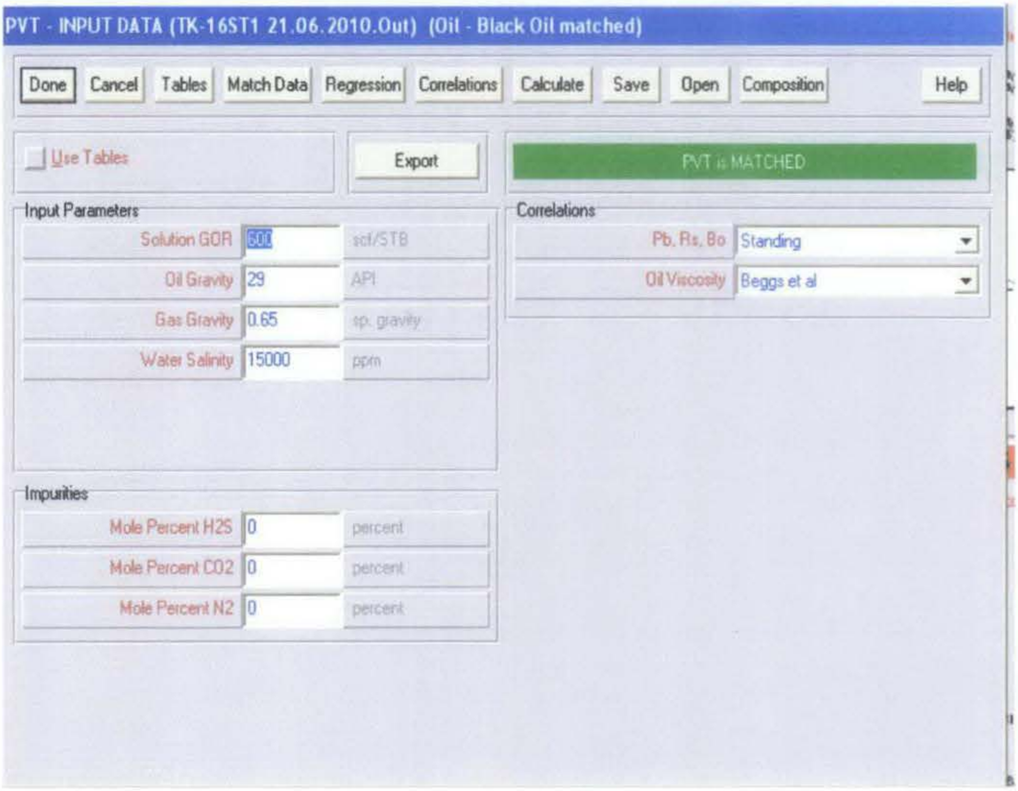


Figure 4.5: PVT Matching Data

Step 2: Select Reservoir Model

By using this software, it is recommended to select the better reservoir model based on sand control method being used. This is because to optimize the efficiency of this software for analysis purposes and history matching.

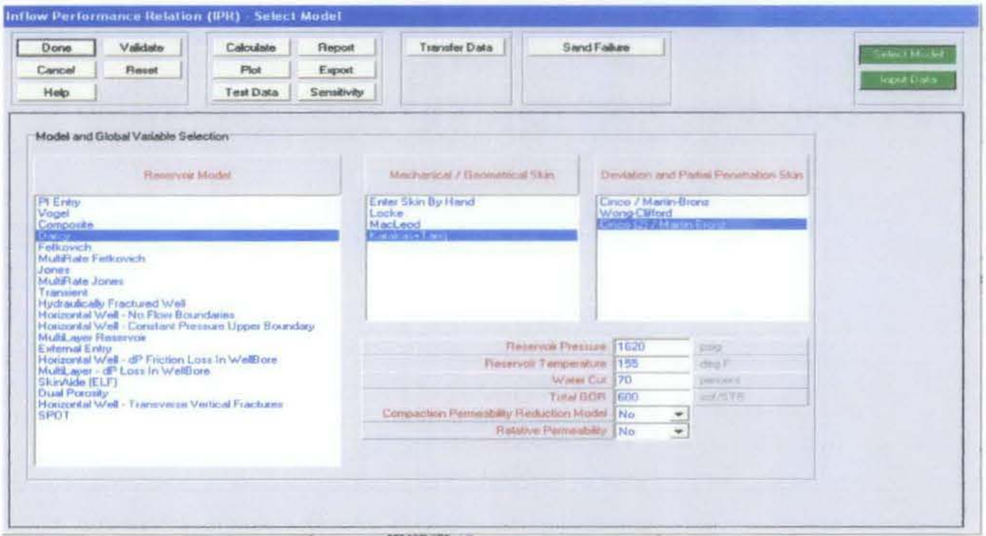
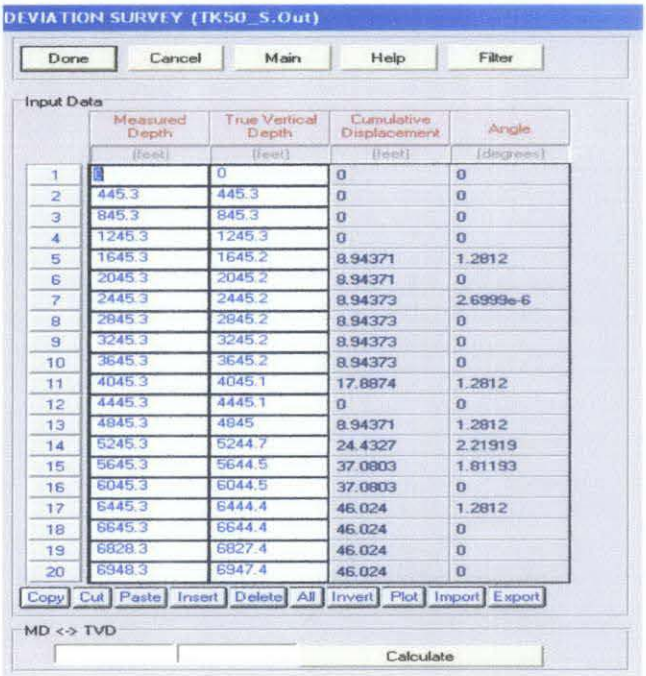


Figure 4.6: Reservoir Model of IPR.

Step 4: Importing data

The next step is to import the production data of deviation survey to the software to be loaded into the program. In the step, we have to make sure the unit used in the data is correct.


DEVIATION SURVEY (TK50_S.Out)

Done | Cancel | Main | Help | Filter

Input Data

	Measured Depth (feet)	True Vertical Depth (feet)	Cumulative Displacement (feet)	Angle (degrees)
1	0	0	0	0
2	445.3	445.3	0	0
3	845.3	845.3	0	0
4	1245.3	1245.3	0	0
5	1645.3	1645.2	8.94371	1.2812
6	2045.3	2045.2	8.94371	0
7	2445.3	2445.2	8.94373	2.6999e-6
8	2845.3	2845.2	8.94373	0
9	3245.3	3245.2	8.94373	0
10	3645.3	3645.2	8.94373	0
11	4045.3	4045.1	17.8874	1.2812
12	4445.3	4445.1	0	0
13	4845.3	4845	8.94371	1.2812
14	5245.3	5244.7	24.4327	2.21919
15	5645.3	5644.5	37.0803	1.81193
16	6045.3	6044.5	37.0803	0
17	6445.3	6444.4	46.024	1.2812
18	6645.3	6644.4	46.024	0
19	6828.3	6827.4	46.024	0
20	6948.3	6947.4	46.024	0

Copy | Cut | Paste | Insert | Delete | All | Invert | Plot | Import | Export

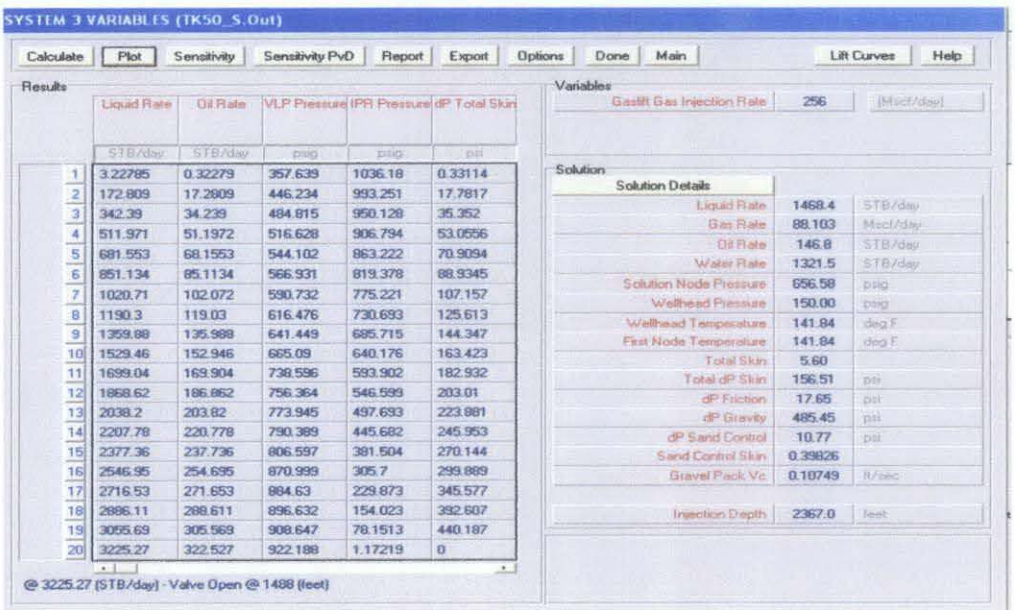
MD <-> TVD

Calculate

Figure 4.7: Deviation Survey

Step 4: Well Model Performance Calculations

This PROSPER software is will calculate the liquid rates and perform Inflow Perform Realtion (IPR) plot and hence the production performance of the well.


SYSTEM 3 VARIABLES (TK50_S.Out)

Calculate | Plot | Sensitivity | Sensitivity PvD | Report | Export | Options | Done | Main | Lift Curves | Help

Results

	Liquid Rate (STB/day)	Oil Rate (STB/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)
1	3.22785	0.32279	357.639	1036.18	0.33114
2	172.809	17.2809	446.234	993.251	17.7817
3	342.39	34.239	484.815	950.128	35.352
4	511.971	51.1972	516.628	906.794	53.0556
5	681.553	68.1553	544.102	863.222	70.9094
6	851.134	85.1134	566.931	819.378	88.9345
7	1020.71	102.072	590.732	775.221	107.157
8	1190.3	119.03	616.476	730.693	125.613
9	1359.88	135.988	641.449	685.715	144.347
10	1529.46	152.946	665.09	640.176	163.423
11	1699.04	169.904	738.596	593.902	182.932
12	1868.62	186.862	756.364	546.599	203.01
13	2038.2	203.82	773.945	497.693	223.881
14	2207.78	220.778	790.389	445.682	245.953
15	2377.36	237.736	806.597	381.504	270.144
16	2546.95	254.695	870.999	305.7	299.889
17	2716.53	271.653	884.63	229.873	345.577
18	2886.11	288.611	896.632	154.023	392.607
19	3055.69	305.569	908.647	78.1513	440.187
20	3225.27	322.527	922.188	1.17219	0

@ 3225.27 (STB/day) - Valve Open @ 1488 (feet)

Variables

Gaslift Gas Injection Rate	256	(Mscf/day)

Solution

Solution Details		
Liquid Rate	1468.4	STB/day
Gas Rate	88.103	Mscf/day
Oil Rate	146.8	STB/day
Water Rate	1321.5	STB/day
Solution Node Pressure	656.58	psig
Wellhead Pressure	150.00	psig
Wellhead Temperature	141.84	deg F
First Node Temperature	141.84	deg F
Total Skin	5.60	
Total dP Skin	156.51	psi
dP Friction	17.65	psi
dP Gravity	485.45	psi
dP Sand Control	10.77	psi
Sand Control Skin	0.39826	
Gravel Pack Vc	0.10749	ft/sec
Injection Depth	2367.0	feet

Figure 4.8: Production Performance of Well Modelling.

4.4 Result and Discussion

4.4.1 Comparison between Different Techniques

Internal Gravel Pack (IGP)

1. Karakas and Tariq Mech/Geom Skin Model

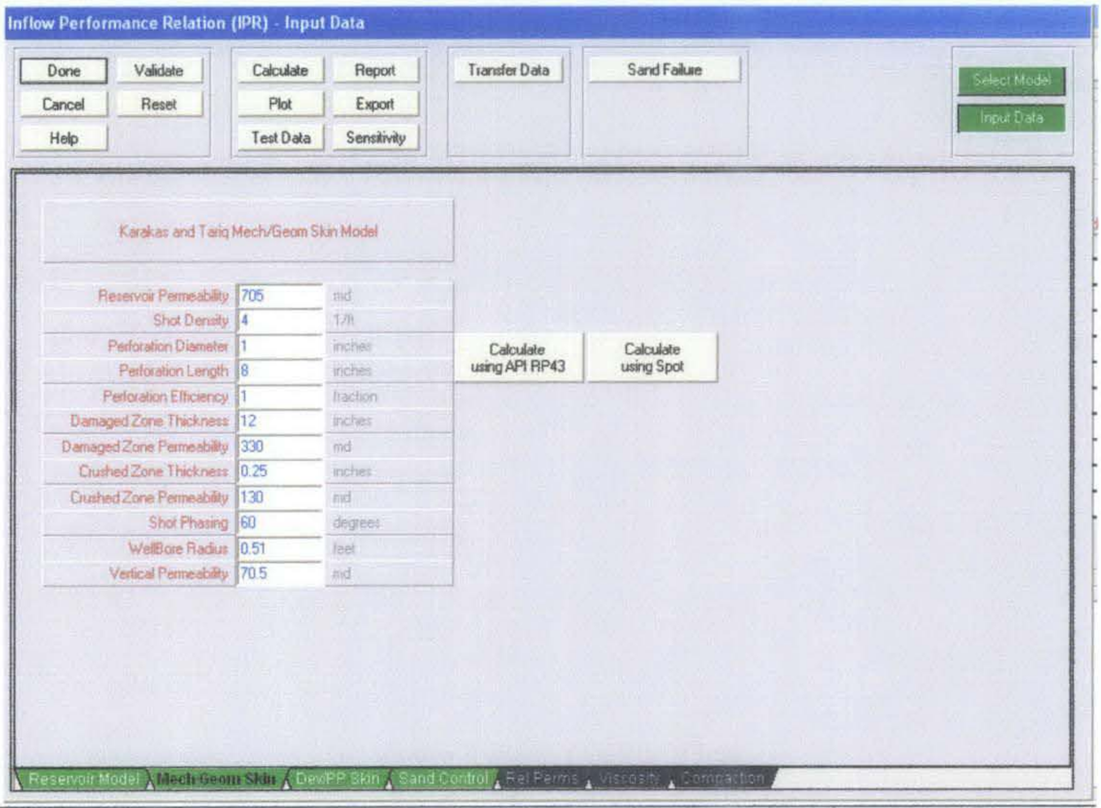


Figure 4.9: Inflow Performance Relation (Geom Skin Model)

2. Inflow Performance Relation Analysis

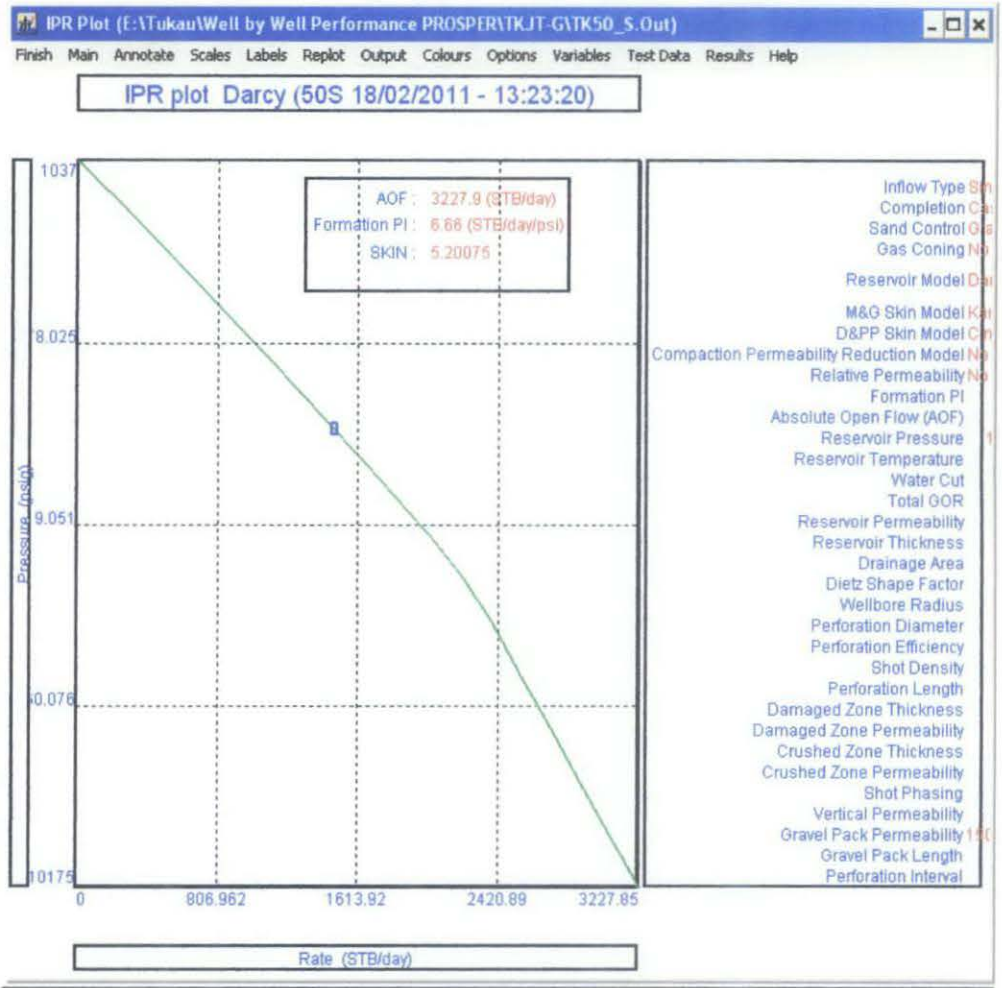


Figure 4.10: Graph of Inflow Performance Relation (IPR) plot

3. Well Model Production Performance

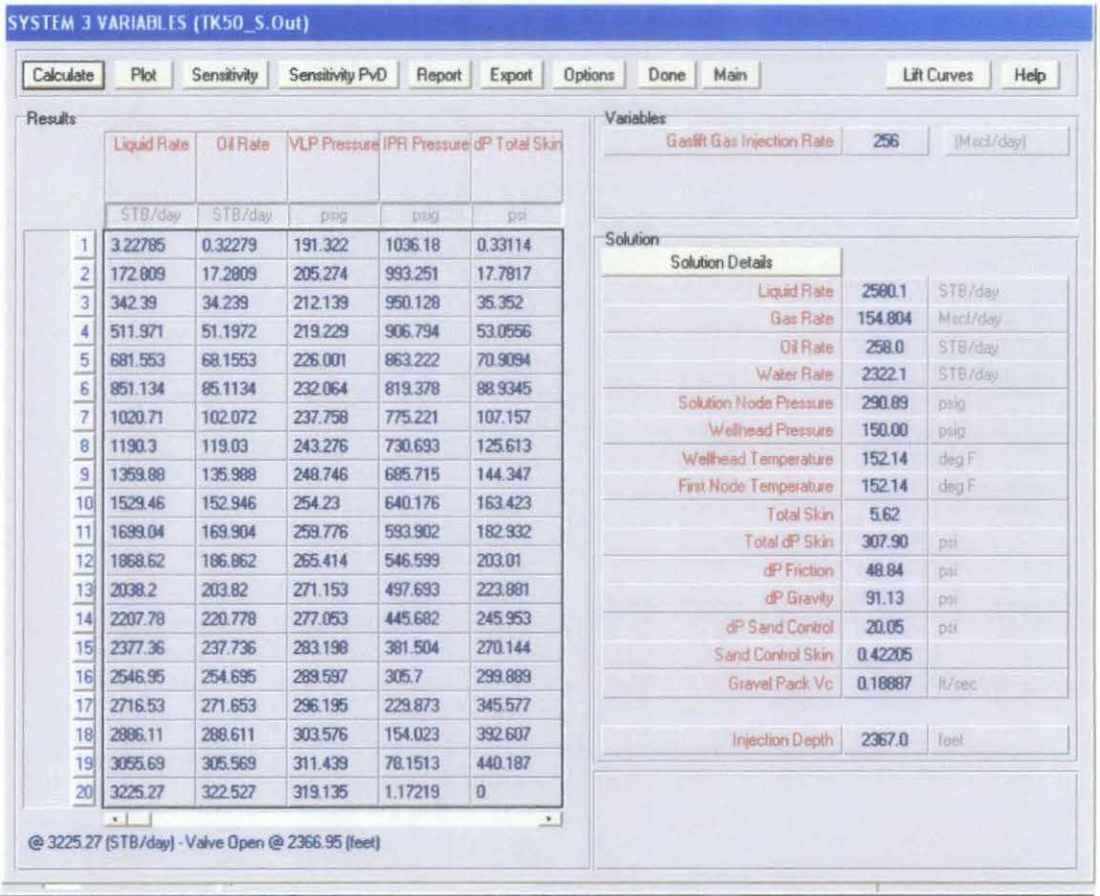


Figure 4.11: Result of production rate for IGP

4. History Matching Analysis

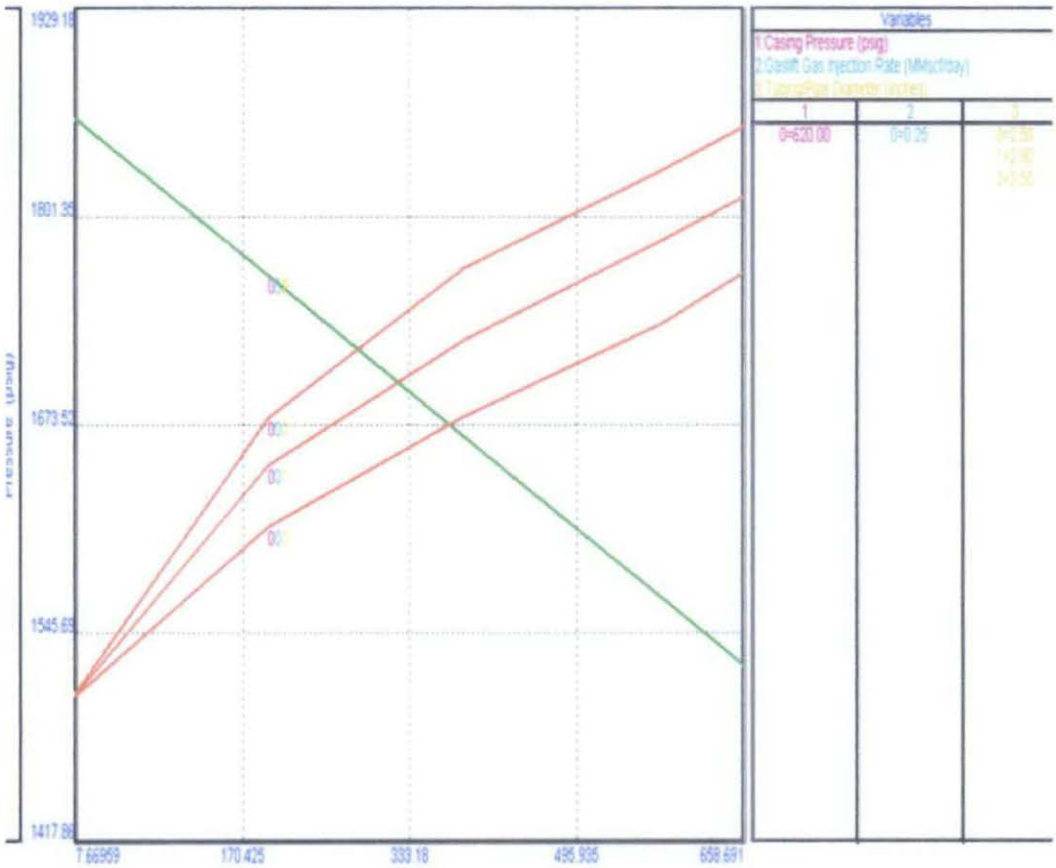


Figure 4.12: Inflow (IPR) versus Outflow (VLP) Curves

Stand-Alone Screen (SAS)

1. Karakas and Tariq Mech/Geom Skin Model

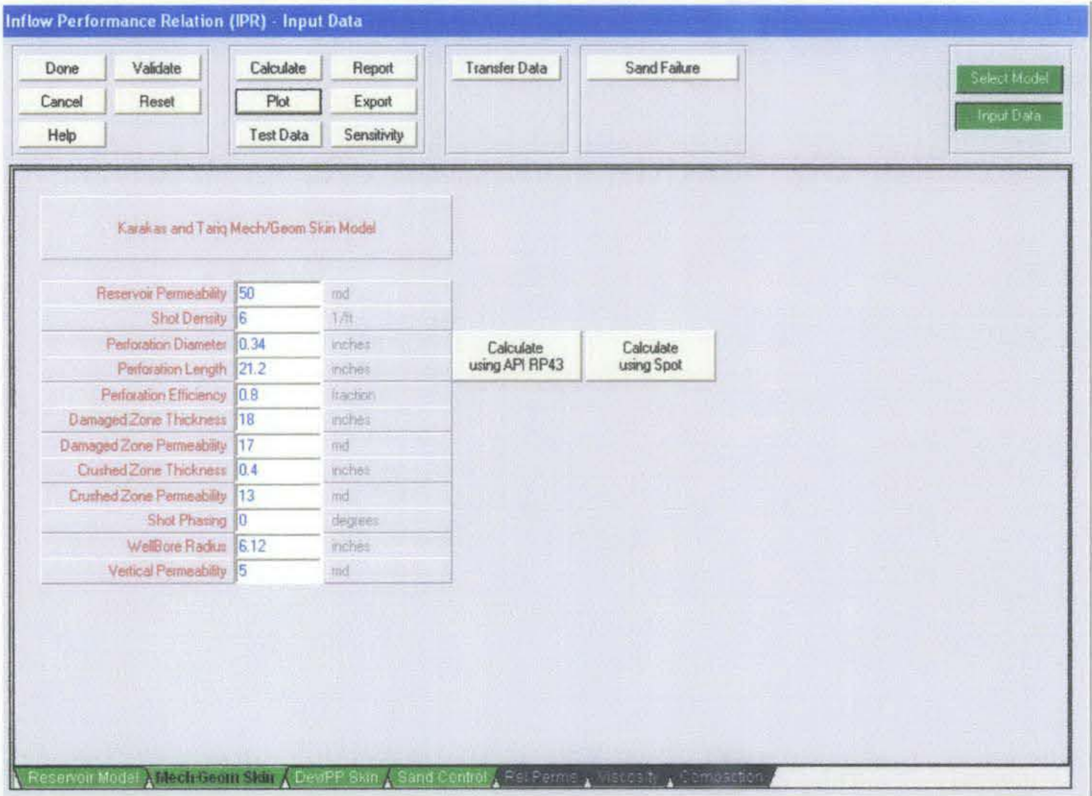


Figure 4.13: Inflow Performance Relation (Geom Skin Model)

2. Inflow Performance Relation Analysis

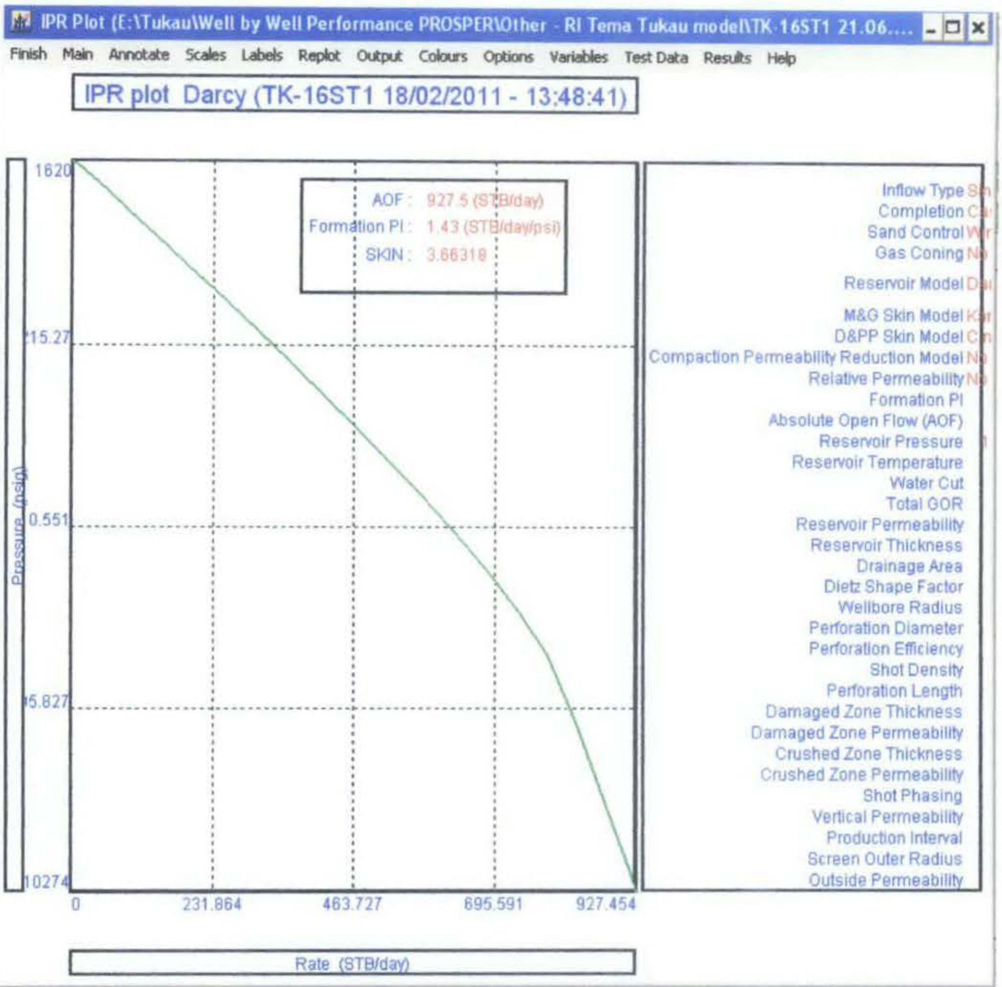


Figure 4.14: Inflow Performance Relation (IPR) plot

3. Well Model Production Performance

	Liquid Rate (STB/day)	Oil Rate (STB/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)
1	0.8052	0.8052	701.367	1619.04	0.39767
2	1.15819	1.15819	699.909	1618.62	0.57247
3	1.66593	1.66593	697.803	1618.01	0.82355
4	2.39625	2.39625	694.756	1617.14	1.18519
5	3.44674	3.44674	690.338	1615.88	1.70483
6	4.95776	4.95776	683.906	1614.07	2.4538
7	7.13119	7.13119	674.488	1611.47	3.53316
8	10.2574	10.2574	660.586	1607.72	5.08851
9	14.7542	14.7542	639.802	1602.31	7.3326
10	21.2222	21.2222	608.148	1594.5	10.5762
11	30.5258	30.5258	505.271	1583.23	15.2724
12	43.908	43.908	337.61	1566.9	22.0935
13	63.1568	63.1568	298.904	1543.19	32.0478
14	90.8441	90.8441	321.405	1508.58	46.6735
15	130.669	130.669	352.201	1457.72	68.3981
16	187.953	187.953	381.304	1382.11	101.234
17	270.35	270.35	410.173	1267.52	152.368
18	388.868	388.868	444.262	1087.52	236.622
19	559.344	559.344	480.041	780.914	394.669
20	804.554	804.554	515.832	5.84281	951

Solution Details		
Liquid Rate	650.3	STB/day
Gas Rate	0.3902	MMscf/day
Oil Rate	650.3	STB/day
Water Rate	0	STB/day
Solution Node Pressure	493.32	psig
Wellhead Pressure	70.00	psig
Wellhead Temperature	102.65	deg F
First Node Temperature	102.65	deg F
Total Skin	4.46	
Total dP Skin	513.74	psi
dP Friction	11.57	psi
dP Gravity	410.50	psi
dP Sand Control	57.35	psi
Sand Control Skin	0.79633	
Injection Depth	2548.0	feet

Figure 4.15: Result of production rate for SAS

4. History Matching Analysis

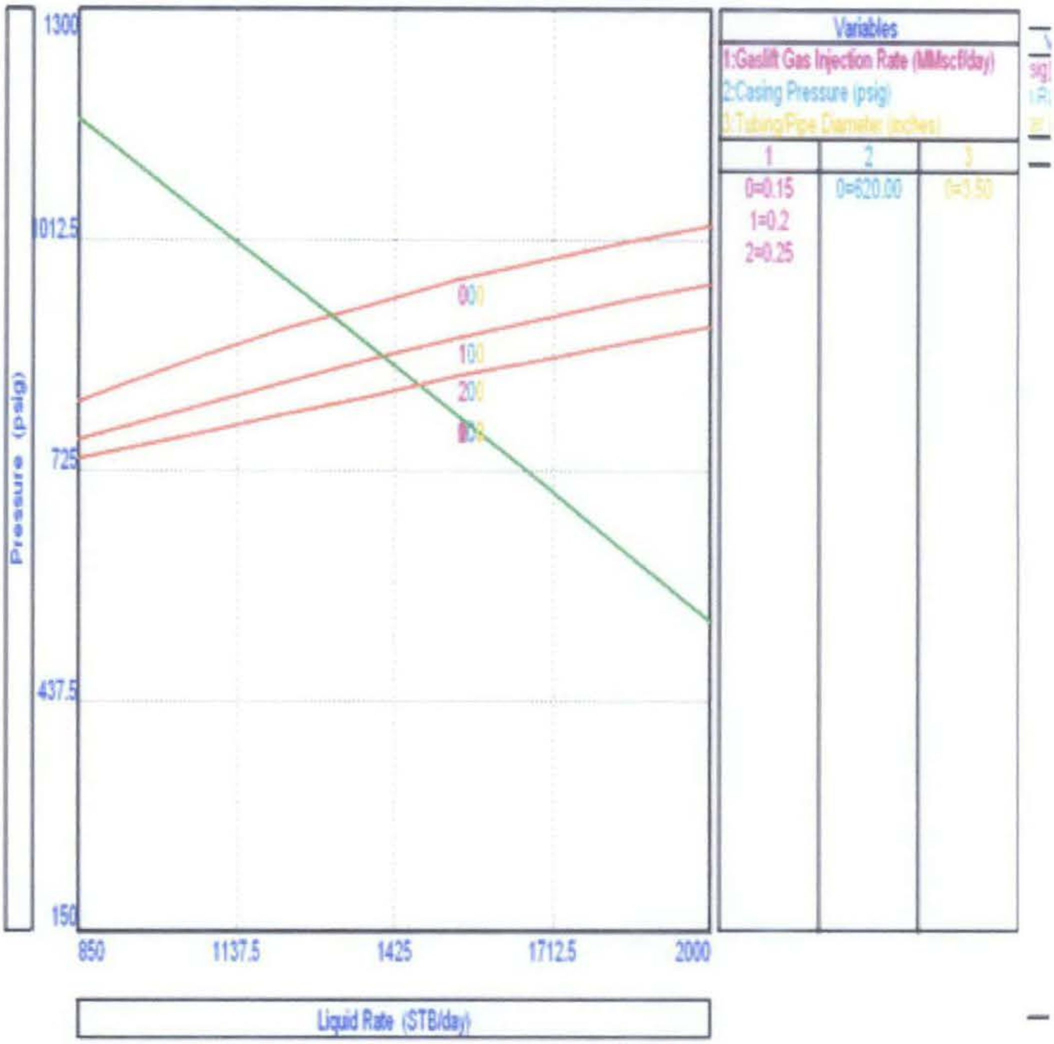


Figure 4.16: Inflow (IPR) versus Outflow (VLP) Curves

Result of both wells:

Parameter of Analysis	Internal Gravel Pack (IGP)	Stand- Alone Screen (SAS)
Skin	5.20	3.66
PI (stb/day/psi)	6.66	1.43
AOF (stb/day)	3227.90	927.50
Liquid Rate (stb/day)	2580.10	650.30
Gas Rate (Mscf/day)	154.80	0.3902
Friction (psi)	48.84	11.57

Table 4.3: Analysis Result of both wells

Discussion on the result of IGP

From the interpretation and analysis that had been done, as stated in the table above, The production rate for IGP is larger than stand –alone screen (SAS) which means that the techniques of IGP is much better than any other sand control method. From this analysis, the author compared some of the parameter such as skin value, productivity index (PI), liquid rate and friction. As we all know, when the skin is high it may cause less restriction. That is the reason why the production performance IGP is more productive rather than SAS or any other sand control method.

According to the Table 4, that summarizes the result of each method, it indicates the value of PI is 6.66 stb/day/psi. With the high PIs, the well can initially be produced at desired rate with low drawdown so that with some inherent strength in the relatively unconsolidated formation, there would still be no physical movement of the sand. As the reservoir pressure depletes under the scenario of weak to medium aquifer support, the total drawdown could exceed the critical drawdown sanding prediction (CDP) whence at this point there will be sand movement. At this stage, the IGP, properly designed and sized would serve as the active down hole sand control device.

In order to ensure success in the new sand control strategy, changes in well operation was eminence. The wells were drilled with high angles in the reservoir section using specially designed mud (DIF) and well bore clean-up were closely scrutinized especially prior to running the screen assembly. In order to avoid shocking the well bore, the well bean-up during initial production followed strict procedures and close monitoring.

The next parameter that we concern is the liquid rate,q. As shown in the table, by applying the reservoir model of Darcy and history matching we can calculate the the liquid rate which is 2580.10 stb/day. It shows that, by using the technique of IGP, the well could produce higher production rate compared to the other. From both methods, it is clearly indicates that a big number of liquid rate even the values of absolute open flow (AOF) is having a larger different.

Discussion on the result of SAS

In order to maximize the wells productivities in the main reservoir target, I-65 sand, the wells were drilled highly deviated using drill in fluid (DIF) along the I-65 sand. This will ensure that there will be maximum exposure and minimum formation damage to the well bore. The cased IGP option was replaced with properly designed SAS in open hole completions to avoid recurrence of plugging and impairment as seen in the previous IGP installations in Tukau. As no GP solids and damaging fluids were introduced, the SAS option should provide maximum productivity.

However, we should expect movement of the sand at later stage as the reservoir pressure depletes and the SAS should provide an active control, retaining the coarse sand for natural packing. According to the table, the value of PI is 1.43 (stb/day/psi) which is quite different compared to IGP. The PIs are expected to be reduced at this stage and therefore the onus is to delay this situation as long as possible, hopefully assisted by the moderate aquifer support.

For the next parameter which is liquid rate, as shown in the table, the well model by using SAS is only produced 650.30 stb/day. Instead of low production rate, the result also shows that the skin is quite low. Postive sign of skin means that the formation does really need the remedial stimulation plan to improve the production. This direct wire wrapped screens has higher mechanical strength compared to the WWS used in gravel packing operations. As such, the screen and base pipe behave as one unit whereby both end connections and screen jacket will still be intact in tension and compression conditions.

Based on the analysis result, this well is suitable candidate to have stimulation treatment to improve the future production. The declining of the production rate was because of the formation damage. Hence, the stimulation treatment is needed to increase the well performance. For the economic point of view, we have to look at the type of screen and the restriction of the well. This means that the reserve is still high and this well is economical to have a stimulation treatment. According to the resulted permeability, skin factor and type of formation, other sand control techniques should be applied as the appropriate stimulation method.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

Based on the results obtained from the case study presented before, it is showing that modern production analysis is a worthy tool to evaluate well performance. In addition, it enables the engineer to choose or select the suitable well candidate for stimulation treatment by seeing the parameters such as PI value and skin factor. However, a perfect match or most accurate match should be done in each method to have a good quality result of interpretation. A big different result from each analysis shows that the match is less accurate. Thus, it has to be careful and pay full attention to make a good match.

As can be seen from the above comparison, it is quite conclusive that IGP completed wells would have higher PI compared to SAS The method of Internal Gravel Pack (IGP) completion has proven to deliver maximum productivity in the new wells completed in the J2-J9 sand. With the much improved PIs, the wells have faster clean up time (within 24 hours) in comparison to SAS well in Tukau. Well production averaging 2000bopd per well is higher that forecasted in the field development (FDP). No sand production has been observed on the surface so far as the current total drowdown pressure has not exceeded CDP and this is supported by the sustained excellent performance of the wells. Therefore, it is concluded that the method of IGP is most effective and be a major contributor for production performance in Tukau field.

5.2 Recommendation

Based on this pilot result, it is recommended to seriously considered applications of the new sand control philosophy in other similar reservoirs in Tukau to emphasis on study rock properties, screen design, drive mechanism and grain size distribution. The comparison of any methods would be made using the history matching analysis. By doing this, we can compare certain parameters which will be included in the modeling. IGP should be considered for future wells for bottom zones where zonal isolation is not an issue. More modeling is required to evaluate the benefits of IGP relative to other methods.

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APPENDICES

Nomenclature

IGP	= internal gravel pack
SAS	= stand alone sand screens
ESS	= expandable sand screens
CDP	= critical drawdown sanding pressure
OH	= open hole
WWS	= wire wrapped sand screens
LPSA	= laser particle size distribution analysis
PST	= production screen tester
PSD	= particle size distribution
FTHP	= flowing tubing head pressure
GOR	= gas oil ratio
PBU	= pressure build up survey
PI	= productivity index
GOC	= gas oil contact
PDG	= permanent downhole gauge

Zones/Depth (ft)	D50 (um)	D40	D90	D10	Fine content<44um(%)	UC(D40/D90)	Definition	Lithology
3578	125	150	10	200	35	15	Highly non uniform	SS
3583	150	175	10	250	30	18	Highly non uniform	SS

*Definition:
UC=d40/d90
UC<3 Uniform
3<UC<5 Non uniform
UC> highly non uniform

Adapted from HELIX RDS Sand Management Training Course Manual

Figure : Dry Sieve and Uniformity Coefficient (UC)

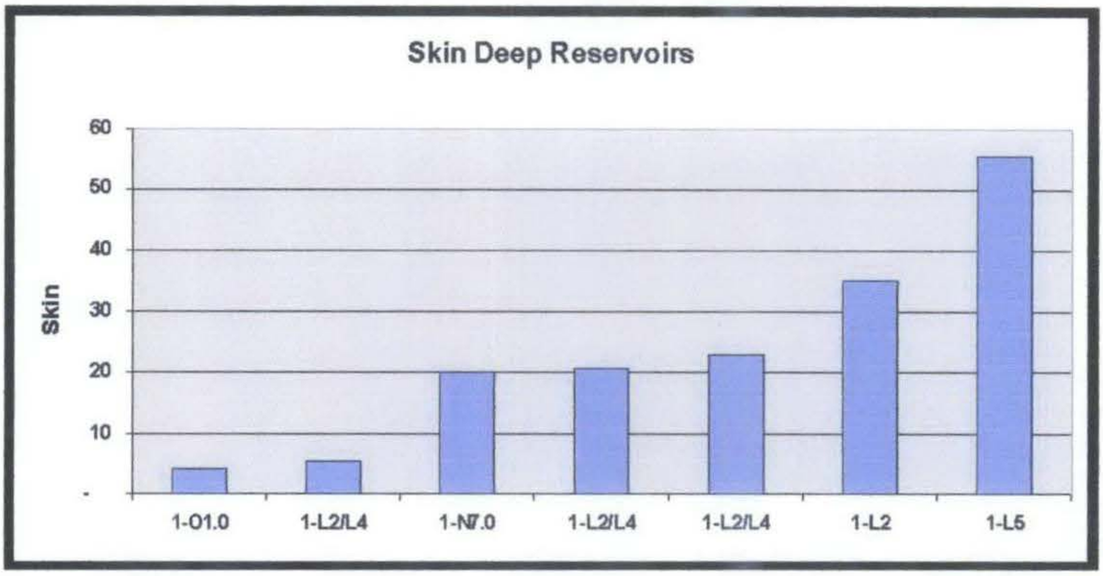


Figure: Prediction of Skin for Deep Reservoirs

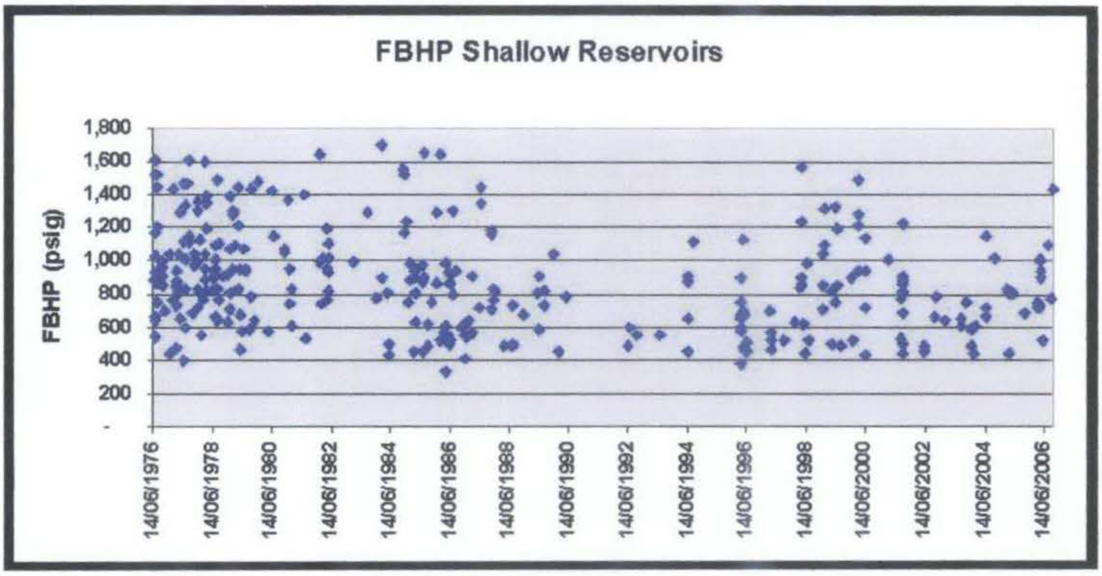


Figure: Flowing Bottom Hole Pressure for Shallow Reservoir

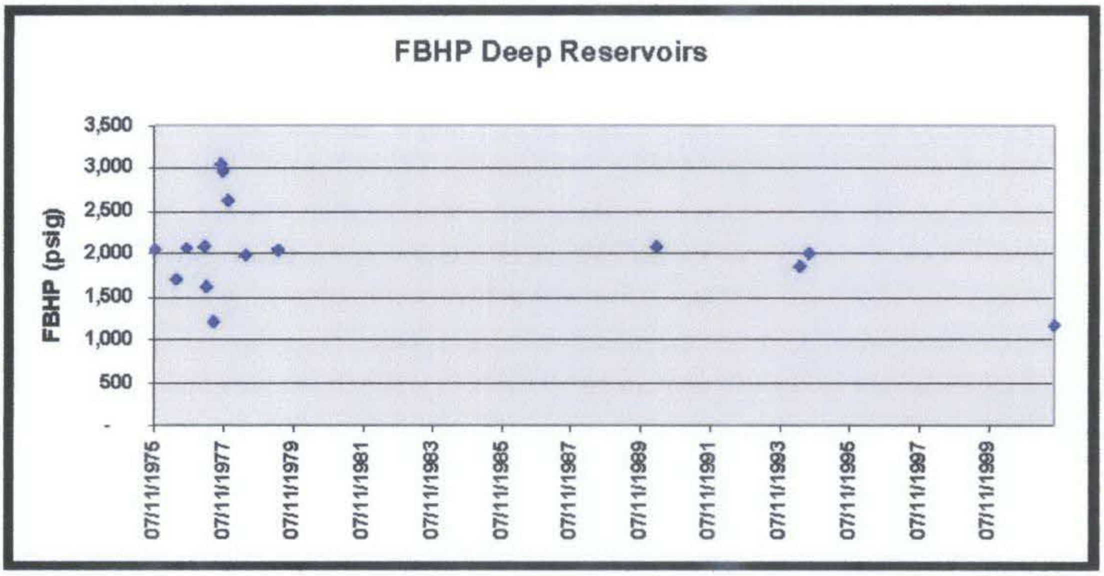


Figure: Flowing Bottom Hole Pressure for Deep Reservoir

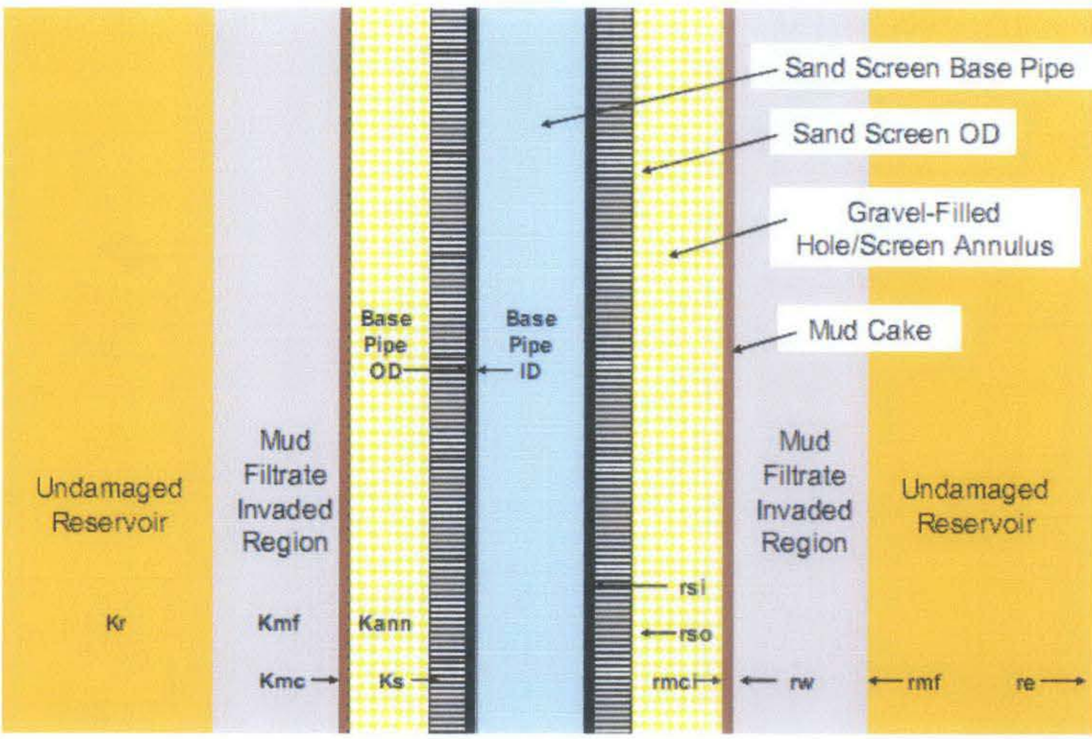


Figure: Gravel packs flow elements.

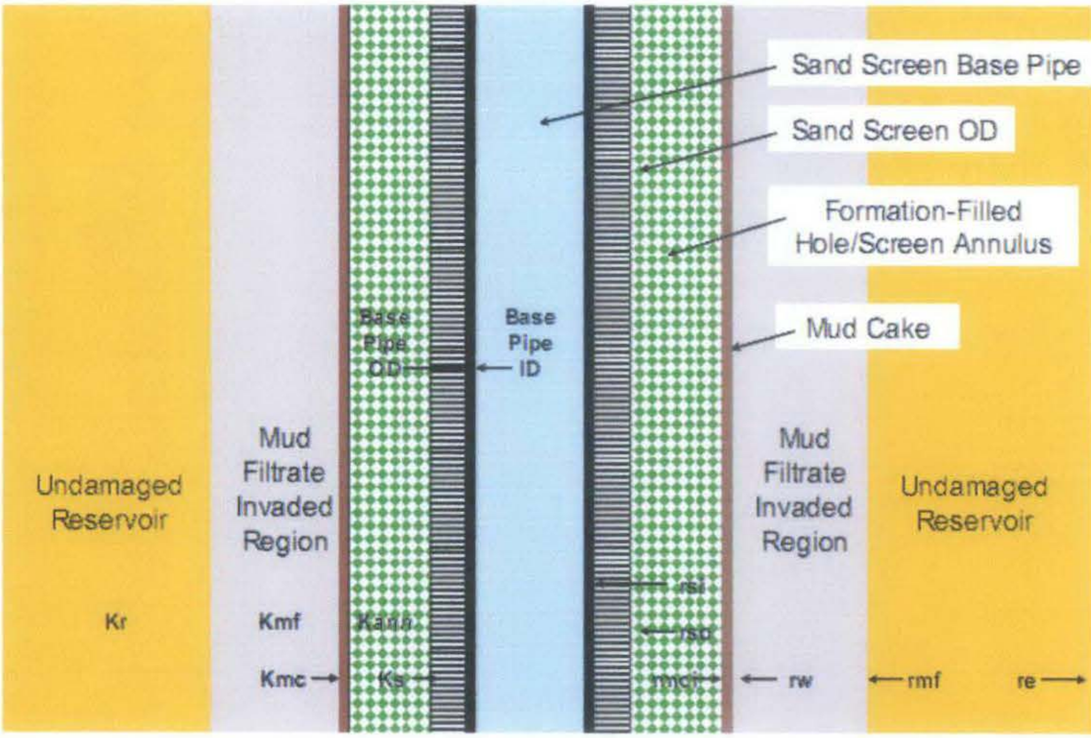


Figure: Stand- Alone Screen flow elements

al Well			Reservoir Group					Pressure	Remarks
r	Measured Pressure (psig)	Date	Reservoir (psig)	Ave. Pressure (psig)	Datum (FT TVDSS)	Delta P (psig)	Cutoff +- 100 psig	for prosper (psig)	
	711	Aug-93	2-D9/E9	750	2570	39		750	Use average due to within 100 psig.
	1315	Jul-06	1-H1/H3.5	1325	3280	10		1325	Use average due to within 100 psig.
	1103	Apr-08	1-E9/F4.8	1100	2795	3		1100	Use average due to within 100 psig.
	1722	May-08	1-I7/I8	1700	4210	22		1700	Use average due to within 100 psig.
	-	-	2-H4.5/H8	1350	3505			1350	Use average due to within 100 psig.
	1025	Aug-08	1AB-F6/G5.5	1050	3000	25		1050	Use average due to within 100 psig.
'F8	966	May-08	1AB-F6/G5.5	1050	3000	84		1050	Use average due to within 100 psig.
	895	Feb-04	1AB-E6/F4.8	900	2920	5		900	Use average due to within 100 psig.
	1116	Aug-03	1AB-F6/G5.5	1050	3000	66		1050	Use average due to within 100 psig.
	1097	Jun-05	1-E9/F4.8	1100	2795	3		1100	Use average due to within 100 psig.
	1096	Sep-98	1-E9/F4.8	1100	2795	4		1100	Use average due to within 100 psig.
	1145	May-06	1-F6/G3	1200	2895	55		1200	Use average due to within 100 psig.
	1428	Apr-06	1-H4/H9	1400	3570	28		1400	Use average due to within 100 psig.
	1048	Dec-08	1-E9/F4.8	1100	2795	52		1100	Use average due to within 100 psig.
	-	-	1AB-E6/F4.8	900	2920			900	Use average due to within 100 psig.
	1198	Apr-06	1-F6/G3	1200	2895	2		1200	Use average due to within 100 psig.
	1066	Apr-06	1-E9/F4.8	1100	2795	34		1100	Use average due to within 100 psig.
	-	-	2-J2/J9	1800	4390			1800	Use average due to within 100 psig.
	1276	Mar-09	1-H4/H9	1400	3750	**124**	use well data	1276	Localised pressure depletion.
	-	-	1-E9/F4.8	1100	2795			1100	Use average due to within 100 psig.
	913	Apr-99	2-D9/E9	750	2520	**163**	use well data	913	Local pressure higher than the rest.
	791	Feb-09	2-D9/E9	750	2520	41		750	Use average due to within 100 psig.
	-	-	1AB-F6/G5.5	1050	3000			1050	Use average due to within 100 psig.
	-	-	1AB-E6/F4.8	900	2920			900	Use average due to within 100 psig.
	1050	Jan-08	2-F1/F6	1035	2790	15		1035	Use average due to within 100 psig.
	920	Jan-08	2-F8/G5.5	1120	2940	**200**	use well data	920	Localised pressure depletion.
	770	Jan-08	2-D9/E9	750	2570	20		750	Use average due to within 100 psig.
	1772	Nov-07	2-J2/J9	1800	4390	28		1800	Use average due to within 100 psig.
	943	Nov-07	1AB-E6/F4.8	900	2920	43		900	Use average due to within 100 psig.
	1292	Jul-04	1-G4/G6	1250	3080	42		1250	Use average due to within 100 psig.
	1362	Jul-04	H1/H3.5	1325	3280	37		1325	Use average due to within 100 psig.
	1167	Nov-95	1-F6/G3	1200	2895	33		1200	Use average due to within 100 psig.
	1451	Sep-03	1-H4/H9	1400	3570	51		1400	Use average due to within 100 psig.
	2197	Apr-86	1-K8	2200	5120	3		2200	Use average due to within 100 psig.
	1075	Aug-89	1-E9/F4.8	1100	2795	25		1100	Use average due to within 100 psig.
	977	Jul-98	1AB-E6F4.8	900	2920	77		900	Use average due to within 100 psig.
	1106	Jul-07	1-E9/F4.8	1100	2795	6		1100	Use average due to within 100 psig.
	1498	Apr-08	2-I1/I6	1500	3840	2		1500	Use average due to within 100 psig.
	1070	Dec-06	2-F8/G5.5	1120	2940	50		1120	Use average due to within 100 psig.
	646	Oct-08	2-D9/E9	750	2570	**104**	use well data	646	Localised pressure depletion.

Figure: Summary of Reservoir Pressure for PROSPER Well Modelling.

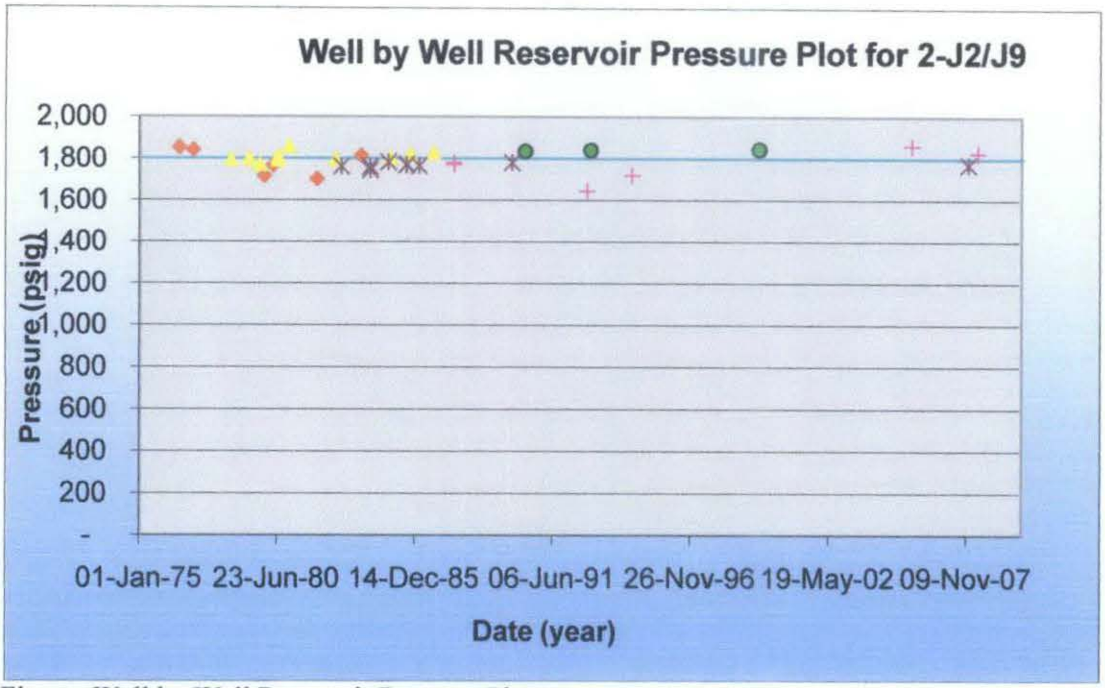
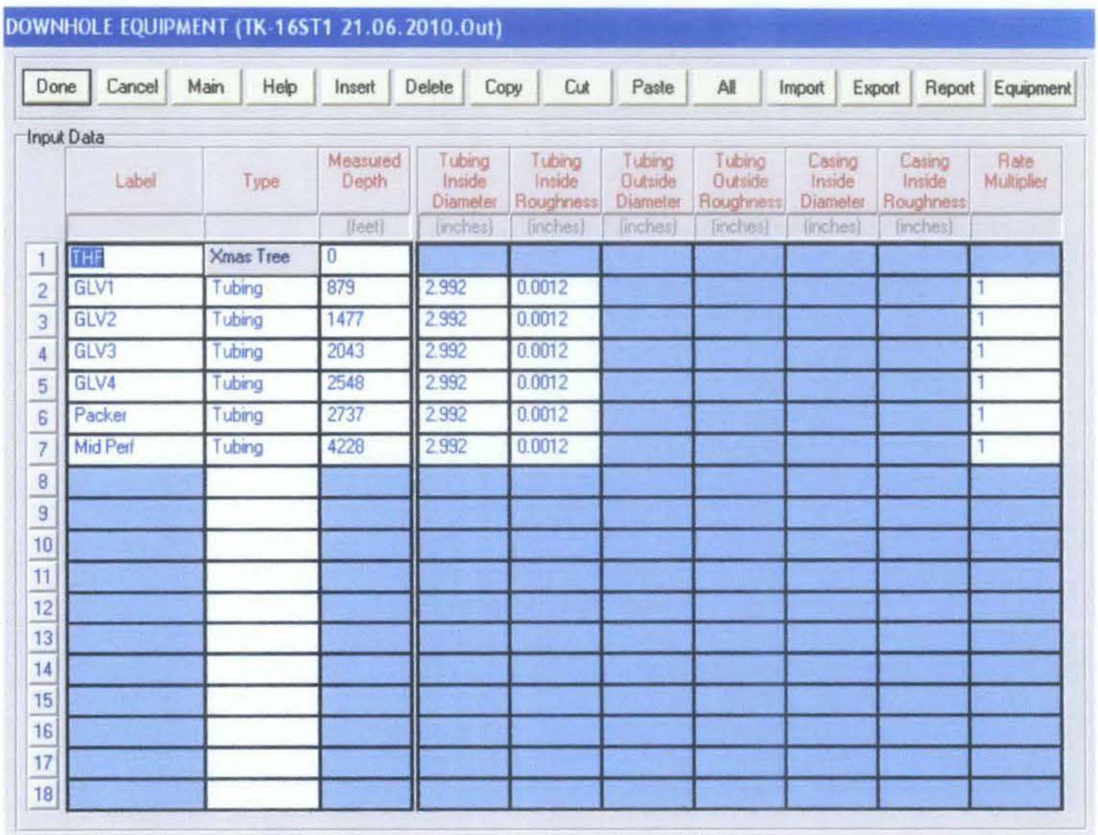


Figure: Well by Well Reservoir Pressure Plot.



	Label	Type	Measured Depth	Tubing Inside Diameter	Tubing Inside Roughness	Tubing Outside Diameter	Tubing Outside Roughness	Casing Inside Diameter	Casing Inside Roughness	Rate Multiplier
			(feet)	(inches)	(inches)	(inches)	(inches)	(inches)	(inches)	
1	THF	Xmas Tree	0							
2	GLV1	Tubing	879	2.992	0.0012					1
3	GLV2	Tubing	1477	2.992	0.0012					1
4	GLV3	Tubing	2043	2.992	0.0012					1
5	GLV4	Tubing	2548	2.992	0.0012					1
6	Packer	Tubing	2737	2.992	0.0012					1
7	Mid Perf	Tubing	4228	2.992	0.0012					1
8										
9										
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18										

Figure: Downhole Equipment Data

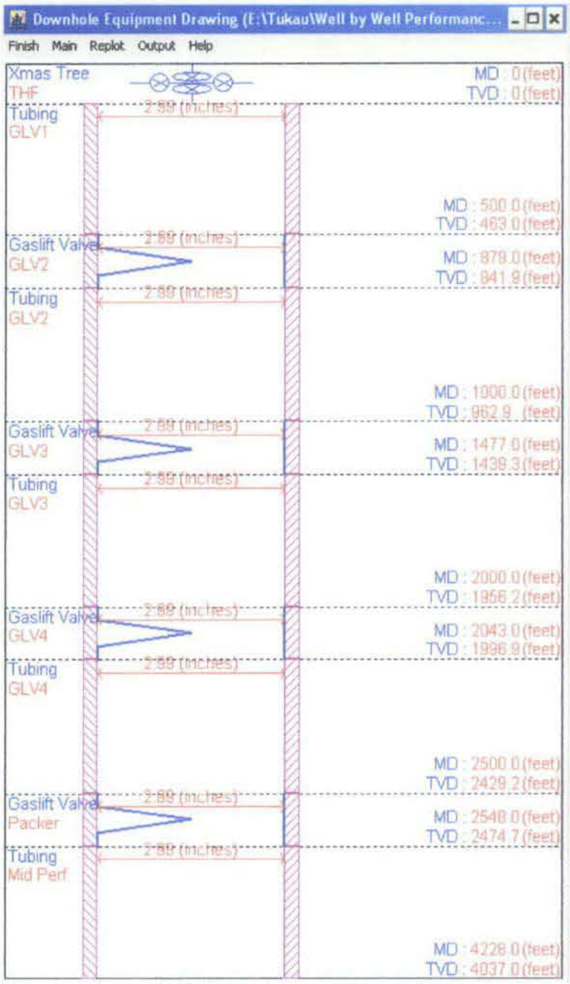

Figure: Downhole Equipment Drawing.

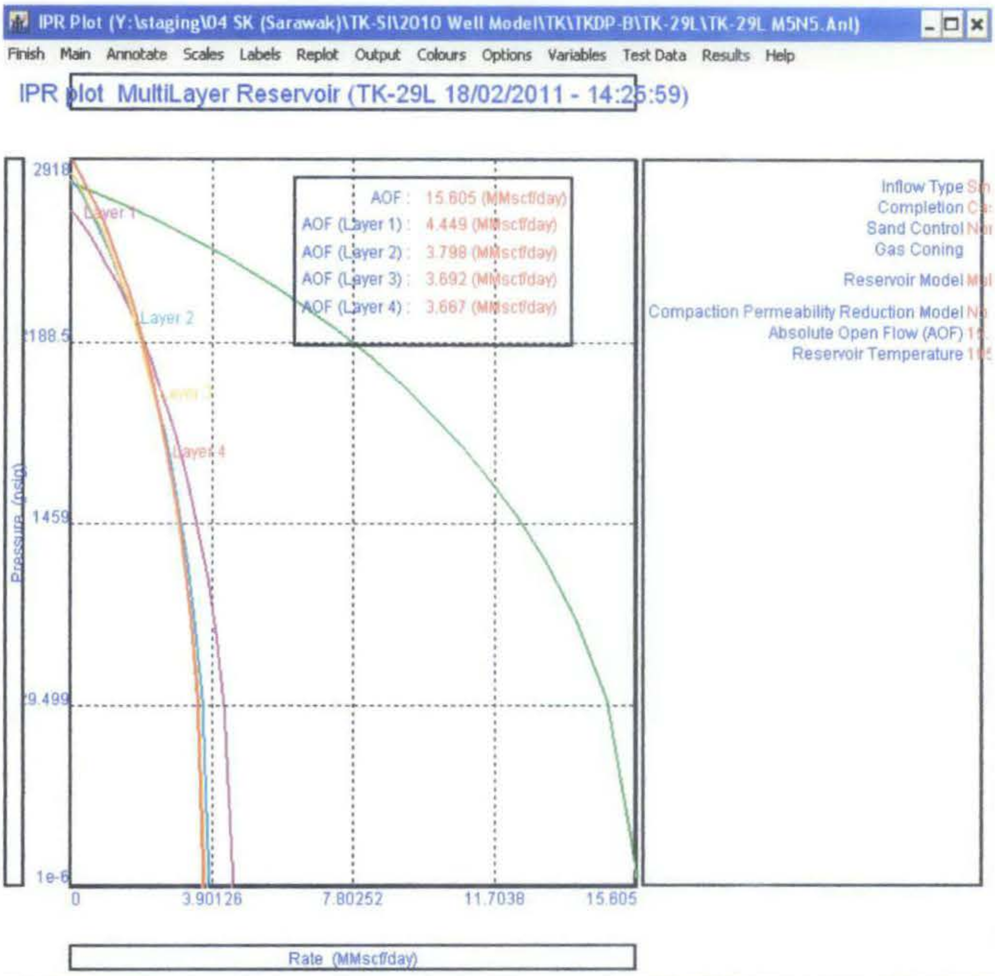

Figure: IPR plot for multi layer reservoir

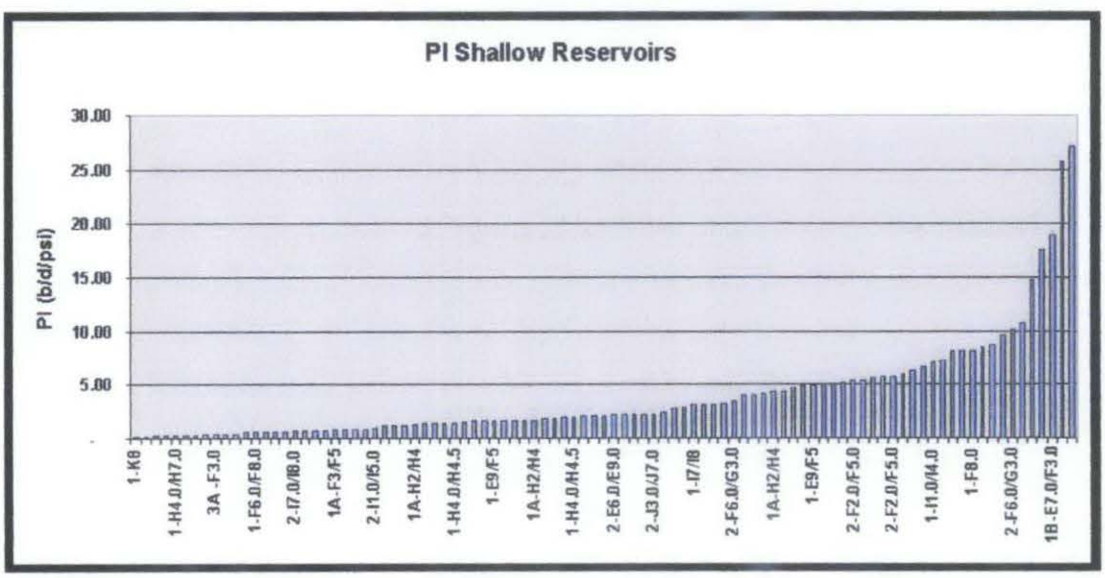

Figure : Productivity (PI) for Shallow Reservoirs

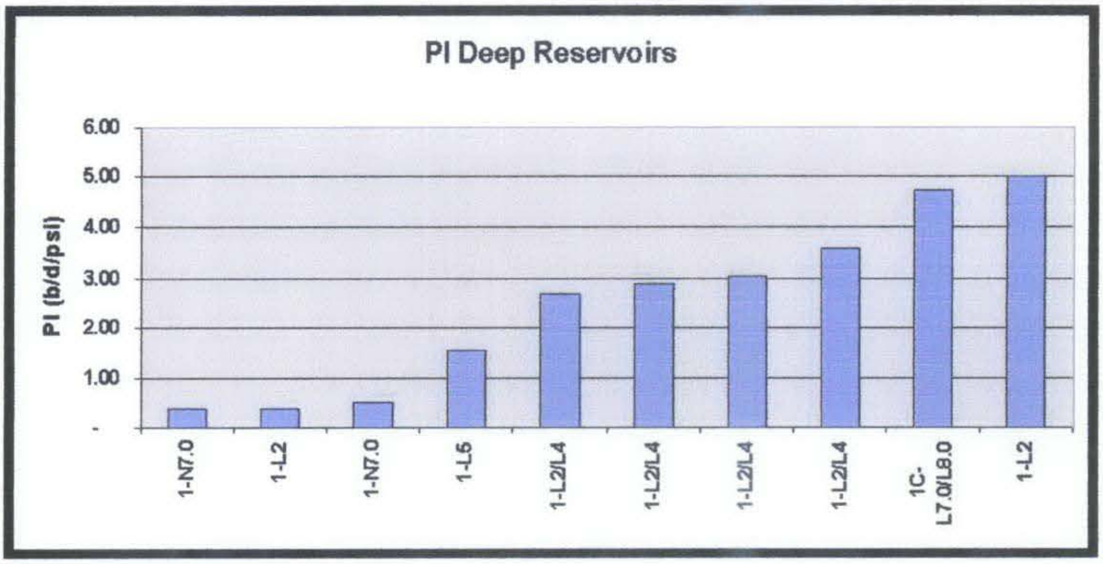

Figure: Productivity (PI) for Deep Reservoirs

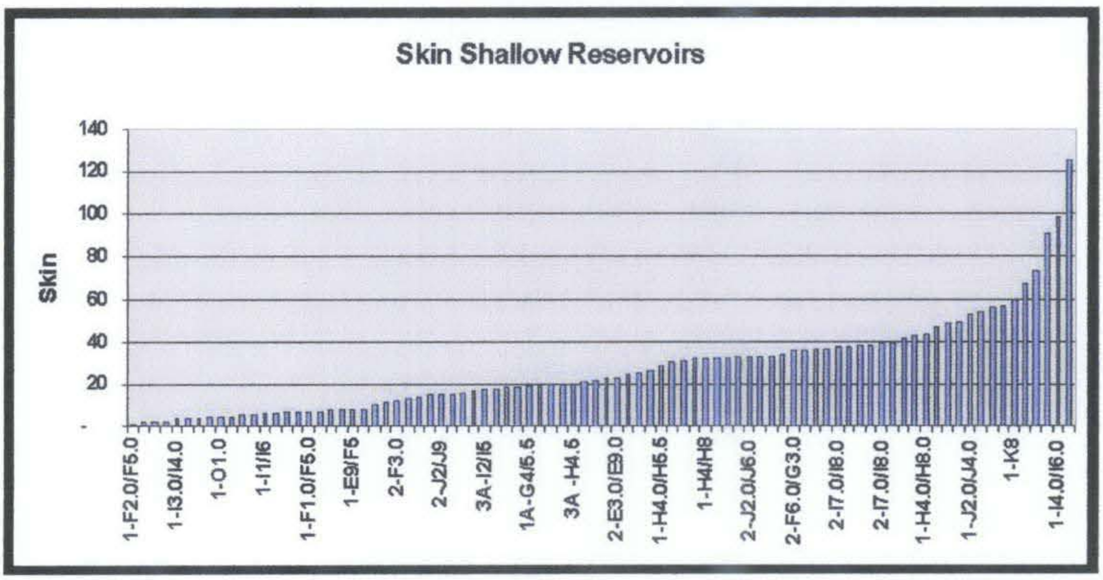

Figure: Prediction of Skin for Shallow Reservoirs