CERTIFICATION OF APPROVAL

Field Wide Gas Lift Optimization Method

by

Mohd Izwan Ariffin Bin Md Azmi

A project dissertation submitted to the
Petroleum Engineering Programme
Universiti Teknologi PETRONAS
in partial fulfilment of the requirement for the
BACHELOR OF ENGINEERING (Hons)
(PETROLEUM ENGINEERING)

Approved by,

. Muhannad Talib Shuker
ssociate Professor
eoscience & Petroleum Engineering Department
niversiti Teknologi PETRONAS
andar Seri Iskandar, 31750 Tronoh
rak Darul Ridzuan, Malaysia

(Dr. Muhannad Talib Shuker)

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
AUGUST 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.

MOHD IZWAN ARIFFIN BIN MD AZMI

ABSTRACT

Gas Lift is one of the most widely use artificial lift. However, in a real field cases, there will always be a constraint in the system such as limited amount of lift-gas that can be utilized. These constraints will become a drawback in order to achieve the maximum total oil production rate. Hence, the system needs a gas lift distribution optimization in order to maximize the production oil rate. The ultimate objective for this project is to determine how the distribution of the gas lift available can be done in order to achieve the maximum total oil production rate. The second objective is to study on different parameters that affect the behavior of the gas lift optimization result. In order to run this project, Schlumberger PIPESIM© will be utilized to establish a gas lift performance curve for all wells. Visual Basic for Application (VBA) Macros and mathematical coding will be utilized to compute the calculation for the optimization. The result generated will be analyzed by running sensitivity analysis on certain parameters which are water cut, gas oil ratio, well productivity index, reservoir pressure, reservoir temperature and oil API gravity. Case study had been done of by optimizing 5 wells with a constraint of 5.5 mmscf/d total injection rate. The result shows that by redistributing the available gas lift in optimum manner, the oil production manage to be increase by 21.03 bbl oil/day, or 0.36%. Optimizing using different case scenario had proved that the major factor that affects the result of the optimization is the gas oil ratio (GOR). Low GOR will make the well become more sensitive towards the changes of injection gas rate. Oil API gravity and reservoir temperature will not give significant impact towards the optimization results. The outcome from this project will benefit the oil and gas industry as the optimum distribution method can be used in order to increase total field oil production.

ACKNOWLEDGEMENT

I am grateful to Allah, my Lord and Cherisher, for guiding me to conceptualize, develop and complete my final year project, Field Wide Gas Lift Distribution Optimization Method. Indeed, without His Help and Will, nothing is accomplished.

I would like to express my tremendous appreciation to my supervisor, Dr. Muhannad Talib Shuker for his guidance and support throughout the process of completing this thesis. His willingness to spend his valuable time to supervise my project despite his workload is highly appreciated. I also gratefully acknowledge Dr. A'fza Binti Shafie, Mathematic Lecturer for giving me advice and idea on how to conduct the optimization calculation.

Thank you to my parents and family, for understanding the amount of time that I need to spend in order to complete this project. Without their support, I will not have the strong will to complete this project.

I would be remiss if I didn't pause to thank my industrial internship supervisor, Mr. Lee Hin Wong and colleagues in Schlumberger. Without their guidance, help and support within my internship period, this project will not be proposed by me as this project is related to my internship project.

And finally, thank you to my friends, classmates and others who had assisted me throughout completion of this project.

Table of Contents

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1

INTRODUCTION

1.1 Background of Study

In 2003, two major producers reported on the following contribution of gas lift to their total liquid production : Exxonmobil 31%, Shell 25% [*Martinez, J. "Downhole Gas Lift and Facility." Paper presented at the ASME/API Gas Lift Workshop, held in Houston, TX, February 4-5, 2003*][1]

This statement had proved that gas lift is one of the common artificial lift technique that been used in order to enhance oil recovery. However, in a real production field, limitation in providing gas for gas lift had always become the constraints for obtaining the maximum amount of oil recovery. Hence, in order to achieve the maximum field total oil production rate, the available gas lifts need to be optimally distributed in each of the gas lift wells in the field. This will increase the economic aspect of the operation by increasing the oil production and reduce the amount of gas use for lift-gas. This project will yield a workflow to optimally distribute the available amount of lift gas to the gas lift wells in the field.

1.2 Problem Identification

1. Limitation in providing gas for gas lift usage

In normal field, there is always a maximum amount of total gas provided for gas lift usage. This will hinder the operation to supply each gas lift wells with their own optimum requirement. For example, 5 wells need injection of 2 mmscf/d gas in order to produce at their optimum rate but the supplied total gas lift for injection is only 8 mmscf/d. This limitation is the drawback for the whole field to increase its production rate. Due to this constraint, the available gas lift needs to be optimally distributed to all gas lift wells in the field in order to achieve the maximum field total oil production rate while honoring the total gas injection rate limitation.

2. Lack of understanding on the behavior of gas lift optimization

   The studies on the gas lift optimization result is seems to be very limited. There are not many researches focus on the parameters that affect the behavior of the gas lift optimization. Many people just take the result without understanding the concept and science behind the optimization.

1.3 Significant of the project

This project outcome will yield a method to optimally distribute the available lift-gas to all gas lift wells in the field. This is very useful as by distributing optimally, using the limited amount of lift-gas, total oil production rate can be increase and reach the optimum value. This method may be applied to a real gas lift wells in a field in order to achieve the optimum economic value of the production process.

The analysis on different scenario results will increase the understanding on the behavior of the gas lift optimization. This project will explained why certain wells is given a high injection rate and why certain wells injection rate is being reduced. This understanding is very vital to the oil and gas industry in order to enhance the optimization method.

1.4 Objectives

1. The ultimate objective for this project is to determine how the distribution of the gas lift available can be done in order to achieve the maximum total oil production rate.
2. The second objective is to study on different parameters that affect the behavior of the gas lift optimization result.

1.5 Scope of study

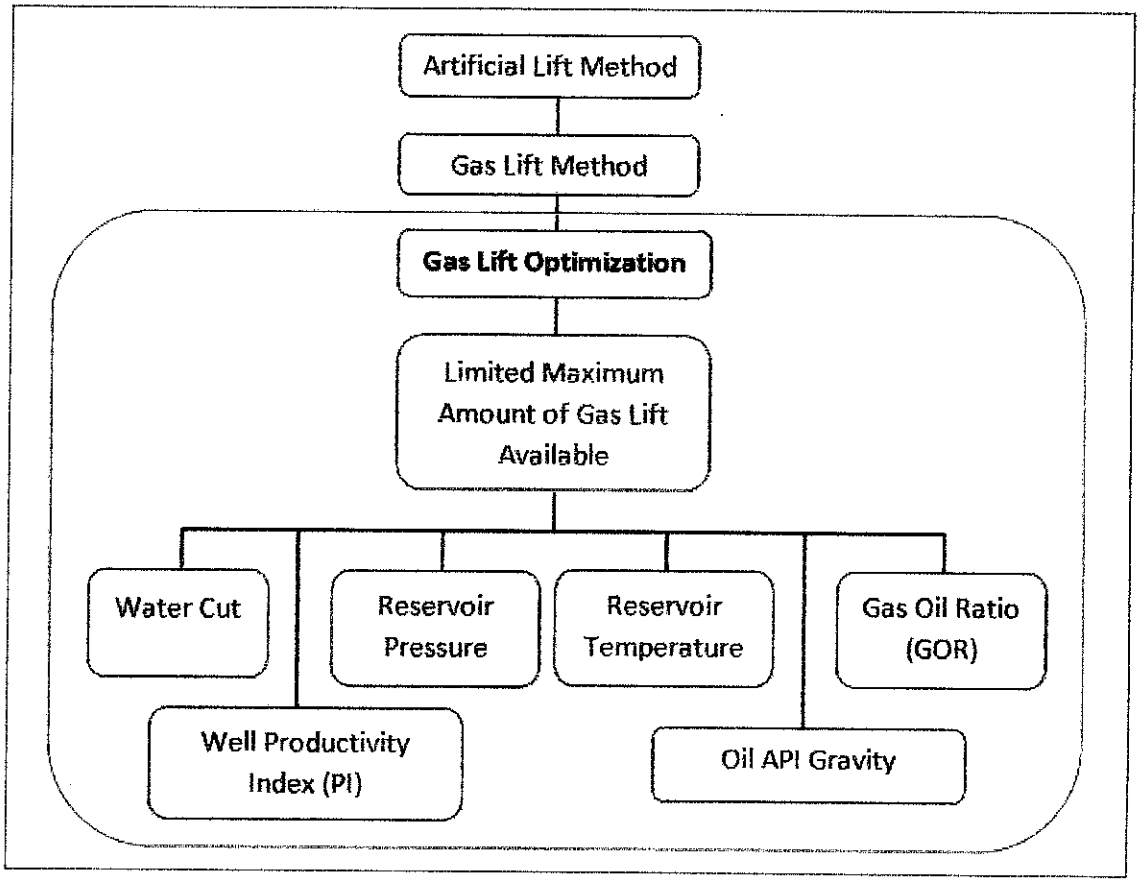


Figure 1.1 : Scope of study

The scope of study will be revolving around gas lift method. First, understanding what is artificial lift and it function is essential. The study will then proceed to gas lift method. After understand how the gas lift method operate, the study will then proceed with focusing area of gas lift optimization. This gas lift optimization will be study deeply and optimization study with limited maximum amount of gas lift available will be conducted. The study will then proceed with analyzing the effect of different parameter related to the optimization result. The parameters are water cut, reservoir pressure, reservoir temperature, gas oil ratio, well productivity index and oil API gravity.

1.6 Relevancy of the Project

Nowadays, most of the well requires artificial lift in order to obtain a higher oil production rate. Gas Lift is one of the most common artificial lift that had been used worldwide. Gas Lift Optimization is the key factor to enhance the production performance in a maturing environment.

In the field that used gas lift as one of its artificial lift method, there will always be constraints in the system. One of the most common constraints is the maximum available gas lift that can be used for reinjection. From this research project, the optimum distribution method for the gas lift can be identified. This will result in achieving the maximum total field oil production rate. This will be very beneficial to the operator in order to enhance their total field oil production rate.

The study on the parameters that affect the optimization result will also be very beneficial to the oil and gas industry. By knowing the concept and science behind the optimization process, the optimization method can be enhance and improved.

1.7 Feasibility of the Project

The project is feasible to be conducted based on these elements :

Time

The time allocated, approximately 20 weeks are sufficient in order to run 2 cases of optimization and analyze the result of the optimization.

Equipment

The tool requires is Schlumberger Software – PIPESIM©. PIPESIM© is a production analysis tools that will be used to run the sensitivity analysis and create the single branch well and network well models. This software is available in CAD Lab in C5.

Cost

The cost for conducting this project is estimated to be very minimal. This is because there is no need to use physical complex item like chemical substance or mechanical equipment.

Data

The input data for this project will be retrieve from the Internship Project that had been conducted by the author. However, the confidentiality of the data will be *maintained by not stating the real well name and its field name.*

References

The references for this project are considered sufficient. The references paper relating this project can be retrieved from ***http://www.onepetro.org*** as UTP already paid for this site. The training material and manual for '*Schlumberger PIPESIM©*' had already been retrieved during author's internship period in Schlumberger Information Solution, Schlumberger.

CHAPTER 2

LITERATURE REVIEW

2.1 Importance of Project

In ***Gas Lift Optimization Efforts and Challenges (SPE Paper) by Y.C Chia and Sies Hussain***[2], gas lift plays an important role in Esso Production Malaysia Inc. (EPMI) oil production. Gas Lift becomes critical to sustain production as oil fields mature. Increasing watercut and decreasing reservoir pressure eventually cause wells to cease natural flow. Subsequently, gas lift is required to kick off and sustain flow from these wells. 35% of EPMI oil production is gas lift dependent. Thus, Gas Lift Optimization is crucial to ensure maximum oil production within facility constraints. Gas Lift Optimization is the key factor to enhance the production performance in a maturing environment.

2.2 Gas Lift Artificial Lift

Gas Lift Concept

According to ***Petroleum Engineering Handbook : Chapter 5 - Gas Lift, by Herald W. Winkler***[3], gas lift is the method of artificial lift that uses an external sources of high-pressure gas for supplementing formation gas to lift the well fluids. Gas is injected continuously or intermittently at selected location, resulting in a reduction in the natural flowing gradient of the reservoir fluid. This will reduce the hydrostatic component of the pressure difference from the bottom to the top of the well. The purpose is to bring the fluids to the top at a desirable wellhead pressure while keeping the bottom hole pressure at a value that is small enough to provide good driving force in the reservoir.

Continuous-flow gas lift is the only method of artificial lift that fully utilizes the energy in the formation gas production. Most wells are gas lifted by continuous flow, which can be considered as an extension of natural flow by supplementing the formation gas with additional high-pressure gas from an outside source. Gas is injected continuously into the production conduit at a maximum depth on the basis of the available injection gas pressure. The injection gas mixes with the produced well fluids and decreases the flowing pressure gradient of the mixture from the point of gas injection to the surface. The lower bowing pressure gradient reduces the flowing bottomhole pressure (BHFP) to establish the drawdown required for attaining a design production rate from the well. If sufficient drawdown in the bottomhole pressure (BHP) is not possible by continuous flow, intermittent gas lift operation may be used.

Criteria for Gas Lift Selection

The primary consideration in the selection of gas lift system to lift a well, groups of wells or an entire field is the availability and compression cost of gas. A reliable, adequate supply of good quality high-pressure lift gas is mandatory. This supply is necessary throughout the producing life if gas lift is to be effectively maintained. Gas Lift is recommended for high volume and high static bottomhole pressure wells where major pumping problems will occur. It is an excellent applicant for offshore classic-type formations with water drive or water flood reservoirs with good productivity indices (PI) and high gas oil ratio (GOR).

Gas Lift Advantages

Selection of Artificial Lift (SPE Paper 52157) by James F. Lea and Henry V. Nickens[4] had highlighted the advantages of gas lift artificial lift compare to others artificial lift methods which are :

- Gas lift is the best artificial lift method for handling sand or solid materials. Many wells make some sand even if sand control is installed. The produced sand causes almost no mechanical problem to the gas lift valve.
- Deviated or crooked holes can be gas lifted with only minor lift problems. This is especially important for offshore platform wells which are directionally drilled.
- Gas lift permits the use of *wireline* equipment and such equipment is easily and economically serviced. This feature allows for routine repairs through the tubing.
- High formation GOR's are helpful rather than being a hindrance. Thus in gas lift, less injection gas is required; whereas, in all pumping methods, pumped gas reduces efficiency drastically.
- Gas lift is flexible. A wide range of volumes and lift depths can be achieved with essentially the same well equipment. In some cases, switching to annular flow can also be easily accomplished to handle exceedingly high volumes.
- A central gas lift system can be easily used to service many wells or operate an entire field. Centralization usually lowers total capital cost and permits easier well control and testing.
- Well subsurface equipment is relatively inexpensive and repair and maintenance of this subsurface equipment is normally low. The equipment is easily pulled and repaired or replaced. Also major well workovers occur infrequently.

2.3 Gas Lift Optimization

Concept and General Idea

In ***Gas Lift Optimization Under Facilities Constraints by H.A Djikpesse, B. Couet and D. Wilkinson***[5], it is stated that gas lift optimization is often used to enhance the production of mature oilfields consisting of multiple reservoirs. For efficiency, several of those reservoirs often share the same surface processing facilities.

In such context, it is vital to find the optimal allocation of gas lift over an entire network of wells and pipelines, while accounting for the constraints imposed by the reservoir operating conditions.

Oilfield production optimization problems are expensive to compute and typically have constraints, possibly nonlinear, on the control parameters. These constraints may include, in cases of gas lift optimization for instance, a limited amount of commodities that can be processed or a limited amount of available lift-gas per unit of time. In general, the constraints might be simulation-based and as costly to compute as the objective function. It is well known, for example that a single reservoir simulation could necessitate several hours or even days of computation time, depending on the size of the reservoir, the number of wells involved, and the complexity of the physical model to be considered.

<u>Optimization Idea for Procedure</u>

Wang et al. (2002) [6] developed a procedure to integrate this optimization problem into VIP (Landmark 2003). This procedure is presented as below :

1. Start with pressure and fluid compositions in reservoir grid blocks calculated in the previous Newton iteration. Use well lift-gas rates from the previous Newton iteration as the initial guesses.
2. Solve the SPN problem, and convert pressure constraints to flow-rate constraints. This step was presented in detail by Litvak and Darlow (1995).
3. Perform production and lift-gas rate allocation optimization if the number of newton iterations performed in the current timestep is below a predetermined number.
4. Determine the active constraints in wells and nodes. Linearize multi-phase fluid flow equations for well tubing strings and the SPN system (numerical derivatives are used). Add these equations to the linearized fluid-flow equations for reservoir grid blocks.
5. Solve the linearized system of equations established in Step 4.

6. Repeat step 1 through 5 until converges.
7. March to the next timestep.

Wang et al. (2002) adopted the separable-programming (SP) method of Fang and Lo (1996) to solve the rate-allocation problem in Step 3. This method works as follows :

1. Construct a gas lift performance curve (oil rate vs lift-gas rate curve) and inflow performance curves (oil rate vs water rate curve & oil rate vs formation gas rate curve) for every well on automatic gas lift allocation. In current implementation, a minimum gas lift efficiency parameter (defined as the oil-rate increase fo a unit of lift-gas injection) can be specified. A gas lift performance curve is constructed in such a way that its slope at the end of the curve should be larger than or equal to user-specified minimum gas lift efficiency.
2. Approximate the gas lift and inflow performance curves with piecewise linear curves.
3. Formulate the constraints gas lift optimization problem as a linear-programming problem.
4. Solves the linear-programming problem, and obtain the optimal lift-gas rates.

When Wang et al. (2002) procedure was applied to several field cases studies, two major limitations of that procedure were exposed.

1. The SP method requires a gas lift performance curves and two inflow performance curves for each well on gas lift optimization. Each curves has to be established after the corresponding well is isolated from the SPN by ignoring the backpressure imposed by other wells. Consequently, the method may produce significantly suboptimal solutions when the flow interactions among wells are significant.
2. The gas lift optimization problem is solved in selected Newton iterations. Fluctuations of reservoir and operation conditions can cause significant oscillations of lift-gas rate allocated in different iterations may lead to convergence difficulties for a reservoir simulation.

In a ***Gas Lift Optimization for Long Reservoir Simulations, Pengju Wang and Michael Litvak***[6] had proposed a procedure to conducting the Gas Lift Optimization. The gas lift optimization method developed in their studies take into account flow interactions among wells and through common surface pipelines. The method works as follows :

1. Start with the existing lift-gas rates for all wells on automatic lift-gas allocation. Solve the multiphase flow problem in the SPN. Build a linear-programming model to scale production and lift-gas rates to satisfy flow-rate and velocity constraints. Denote the objective function value obtained in this step as f^{0}.
2. Select a well on automatic lift-gas rate allocation. Well *i Denote its lift-gas rate at this stage as* $q^{o}_{lg.i.}$ Increase its lift-gas rate by $\delta q_{lg.i}$. Solve the multiphase-flow problem in the SPN with the updated lift-gas rates, and scale production and lift-gas rates to satisfy the flow-rate constraints. The value of the objective function obtained in this step is f^{1}.
3. Compute the gas lift efficiency for Well i using Equation 1 :

$$e = \frac{f^1 - f^0}{\delta q_{lg.i}}$$

If $e \geq e_{min}$, where e_{min} is the user specified minimum gas lift efficiency coefficient, update f^0 by setting $f^0 = f^1$, and go to step 6 with the increased lift-gas rate for Well i . If $0 \leq e \leq e_{min}$, reset the lift-gas rate for *Well i* to $q^{o}_{lg.i}$ and go to step 6. If $e \leq 0$, reset the lift-gas rate for Well i to $q^{o}_{lg.i}$ and go to step 4.

4. Decrease the lift-gas rate of Well i by $q_{lg.i}$, where $\delta q_{lg.i} > 0$. Solve the multiphase flow problem in the SPN with the updated lift-gas rates. Optimally scale the production rates and lift gas rates to satisfy flow-rate constraints. The value of the objective function in this step is f^2.

5. Compute the gas lift efficiency for *Well i* with Equation 2 :

$$e = \frac{f^2 - f^0}{-\delta q_{lg.i}}$$

If $e \geq e_{min}$, update f^0 by setting $f^0 = f^2$, and go to Step 6 with the decreased lift-gas rate for *Well i.* Otherwise, reset the lift-gas rate of *Well i* to $q^o{}_{lg.i}$.

6. Repeat Steps 2 through 5 for every well on automatic lift-gas allocation.
7. Repeat Steps 2 through 6 until no lift-gas rate change can be made or the maximum number of iterations allowed is reached.

In ***A Gas-Lift Optimization and Allocation Model for Manifold Subsea Wells SPE Paper, R.Edwards, D.L. Marshall and K.C.Wade***[7] had proposed an optimization procedure.

A multiphase fluid flow simulator was used to generate a system performance curve, artificial quantity versus liquid flowrate, for each well. The system performance curves for each of the wells, operating under their current condition are constructed. From this data base the performance curve for a well j, is selected and a mathematical function of the form;

$$f_j(x) = \sum_{i=1}^{n} (\mathrm{b}_{\mathrm{j,i}}) x^i$$

Where x is the gas injection rate and the coefficients are determined by least squares. A function of the above form is provided for every well in the system.

The next stage in the optimization is to find the unconstrained optimum assuming an unlimited supply of lift gas. The optimization can be performed on either the gross liquid produce or on stocktank barrels of oil. This is defined as the sum of the individual wells producing at their local maximum. Mathematically this is where the gradient of a performance curve is 0. Thus for well j,

$$\frac{df_j(x_j)}{dx} = 0$$

where x_j is the optimal gas lift quantity for well j.

The Newton Raphson method was used to locate the optimal quantity x_j for each well. Clearly, for any numerical method there are conditions for which it may not converge. The use of smooth polynomial ensures that a solution can be found. If the total quantity of available gas is less than the unconstrained optimum, as defined above, then the problem reduces to allocating the available lift gas most efficiently between wells.

The definition of constrained optimum is that the gradient of all producing wells are equal. For example, all wells would increase their flowrate by the same quantity if an extra incremental amount of gas was injected, Thus ;

$$\frac{df_1(x_1)}{dx} = \frac{df_2(x_2)}{dx} = \ \dots \ = \frac{df_m(x_m)}{dx} = G$$

where G (bbl/d per mmscf injected) is the gradient of all wells (m) in the system. This optimum can be obtained for all wells providing that each well, j :

1. Can flow at specified gas lift value, x_j and
2. Is not bound by any other overriding constraints

There are many numerical techniques available for solving linear system of the form;

$$Max: \ f_1(x_1) + \ f_2(x_2) + \ \dots + \ f_m(x_m)$$

these range from sophisticated optimization methods to simple iteration procedures. However, the introduction of more complicated non-linear constraints (eg: maximum flow down any given flow line) makes the setting up of more constraints mathematically complex. Thus an iterative technique is employed to provide greater flexibility and speed of solution.

Ronald Schoenberg in his paper, ***"Constrained Optimization (September 2001)"*** [8] had discussed an optimization method using Constraint Maximum Likehood (CML) method.

Nearly all statistical models contain constrained parameters. Even the simplest models contain them. For example, in ordinary least squares the estimates of the residual variance are constrained to be positive. Many methods have been devised to enforce these restrictions. For example, the use of concentrated log-likehoods, or standard deviations are estimates rather than variances. Other techniques for positivity include estimating the square root or log of a parameter. The hyperbolic cosine function can be used for correlations and the logistic function for intervals. However, constraints are often ignored. Coefficient matrices in simultaneous equation models with lagged variables require specific constraints to ensure stationarity of the system, but this constraint is enforced by rejection.

CML is a set of procedures written in the GAUSS programming language (Schoenberg, 1995) for the estimation of the parameters of models via the maximum likelihood method with general constraints on the parameters.

CML solves the general weighted maximum likelihood problem

$$L = \sum_{i=1}^{N} \log P(Y_i; \theta)^{w_i},$$

where N is the number of observations, w_i is a weight. $P(Y_i; ')$ is the probability of Y_i given θ , a vector of parameters, subject to the linear constraints,

$$A\theta = B,$$
$$C\theta \geq D,$$

The non linear constraints

$$G(\theta) = 0,$$
$$H(\theta) \geq 0,$$

and bounds

$$\theta_l \leq \theta \leq \theta_u.$$

G(θ)and H(θ) are functions provided by the user and must be differentiable at least once with respect to θ .

2.4 Visual Basic for Application (VBA)

Robert L. McDonald had explained briefly about Visual Basic for Application (VBA) in his ***Tutorial Paper: "An Introduction to VBA in EXCEL", November 2000, Northwestern University***[9].

Visual Basic for Applications, Excel's powerful built-in programming language, permits user to easily incorporate user-written functions into a spreadsheet. User can easily calculate and store data systematically using this software. VBA is now the core macro language for all Microsoft's office products, including Word. It has also been incorporated into software from other vendors. User need not write complicated programs using VBA in order for it to be useful.

CHAPTER 3

METHODOLOGY

3.1 Research Methodology

Here are the research methodologies that had been taken in order to complete this project:

1. Understanding the Artificial Lift.
2. Understanding the Gas Lift Process and behavior.
3. Understanding the Gas Lift Optimization concept.
4. Input data acquisition.
5. Create a Single Well Model and Network Model
6. Established gas lift performance curves for all wells.
7. Established the optimization workflow using Microsoft VBA by writing the coding and using macros.
8. Input data and constraint value in the VBA optimization workflow.
9. Run the optimization.
10. Analyze on the optimization result.
11. Changed desired parameter to see its effect on the optimization result.
12. Conclude the optimization results.

Here is the flow chart showing the methodologies of the project :

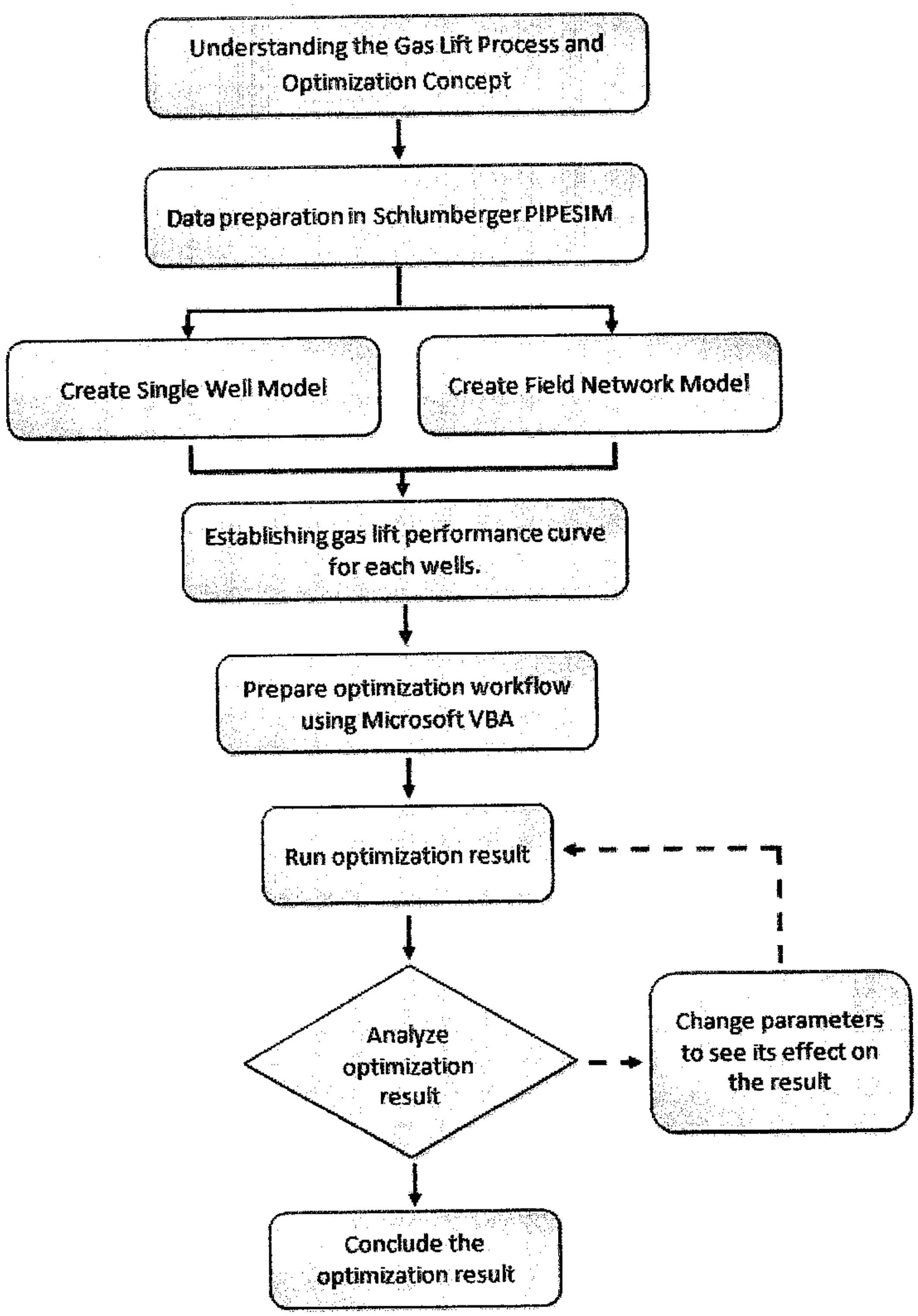


Figure 3.1 : Methodology workflow for this project

3.2 Project Activities

Understanding the Artificial Lift

Artificial lift is a system that adds energy to the fluid column in a wellbore with the objective of initiating and improving production from the well [*Canadian Oilwells System Company, Basics Artificial Lift*]. Generally this is achieved by the use of a mechanical device inside the well (pump or velocity string) or by decreasing the weight of the hydrostatic column by injecting gas into the liquid some distance down the well.

Artificial lift is needed in wells when there is insufficient pressure in the reservoir to lift the produced fluids to the surface, but often used in naturally flowing wells (which do not technically need it) to increase the flow rate above what would flow naturally. The produced fluid can be oil or water, typically with some amount of gas included.

Artificial-lift methods fall into two groups, those that use pumps and those that use gas.

Pump Types :

- Beam Pumping / Sucker Rod Pumps (Rod Lift)
- Progressive Cavity Pumps
- Subsurface Hydraulic Pumps
- Electric Submersible Pumps

Gas Method :

- Gas Lift

Understanding the Gas Lift Process and behavior

Gas Lift is the method of artificial lift that uses an external source of high-pressure gas for supplementing formation gas to lift the well fluids [*Petroleum Engineering Handbook, Chapter 5 – Gas Lift*].

Lift gas is continuously injected in at the proper depth into the wellstream from casing-tubing annulus or the tubing string into the flow string, which can be the tubing string or the annulus, respectively. The injection of the proper amount of lift gas greatly reduces the density of the wellstream as well as the following pressure loses occurring above the injection point because the major part of vertical multiphase pressure drop is due to the change of potential energy.

Accordingly, total pressure loses in the entire tubing string will also decrease, allowing the existing pressure at the well bottom to overcome them and to lift the wellstream to the surface. Continous flow gas lift, therefore, may be considered as the continuation of flowing production, and its basic operational mechanism is the reduction of flow resistance of the production string.

Understanding the Gas Lift Optimization concept

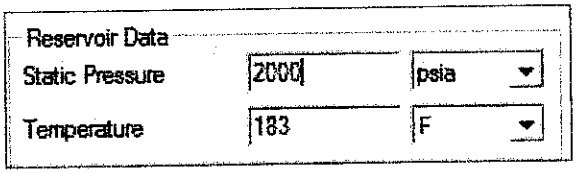
Every well has an optimal gas lift operating point at which it will produce the most fluid. Optimization of the complete system necessitates an optimal *allocation of the available (and usually limited) lift gas among all the gas lifted* wells. Due to the complexity of well/network/processing plant interactions and operating constraints, optimizing gas lift is far from being a simple task.

When dealing with several wells placed on continuous flow gas lift, the objective of optimization must be modified. With other fixed parameter that had been set (tubing and flowline sizes, compressor pressure), the operator's aim is now to reach optimum utilization of the injection gas volume at their disposal. In conjunction with the gas lift performance curves, different wells respond differently to the injection of the same amount of lift gas. It is now the engineer responsibility to allocate the total available gas volume to the individual wells in fashion to achieve the maximum possible profit that comes from the sale of the oil produced.

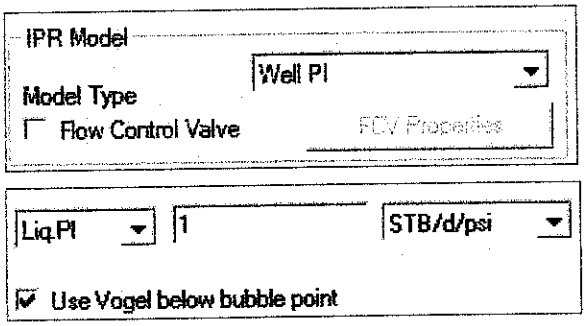
Input data acquisition

The data were retrieved during the author's internship period. Some of the data that are needed for this projects are :

1. Static reservoir pressure and temperature



2. Well productivity index (PI)



3. Well deviation survey

	MD	TVD	Angle
-	ft	ft	(Deg)
1	0	0	0.525784
2	2375	2374.9	1.811927
3	2575	2574.8	0
4	2775	2774.8	0
5	3025	3024.8	2.443285
6	3575	3574.3	6.943111
7	4025	4021	13.92775
8	4525	4506.3	25.33785
9	5025	4958.2	34.08572
10	5525	5372.3	30.50329
11	6025	5803.1	28.5213
12	6474.9	6198.4	27.74477
13	7022	6682.6	27.5802
14	7308	6936.1	27.46112
15	7592	7188.1	
16			
17			

4. Well geothermal survey

	MD	Ambient Temperature	U Value
-	ft	F	Btu/hr/ft2
1	0	86	8
2	7253	183	8
3			
4			

5. Tubing configuration

Tubing Sections

	Bottom MD	ID	Wall Thickness	Roughness	Casing ID	Flow Type	Label
-	ft	inches	inches	inches	inches		
1	452	2.992	0.5	0.0006		Tubing	pipe#1_Tubi
2	7218	2.992	0.5	0.0006		Tubing	pipe#2_Tubi
3	7253	6.184	0.5	0.0006		Tubing	casing

6. Downhole equipment

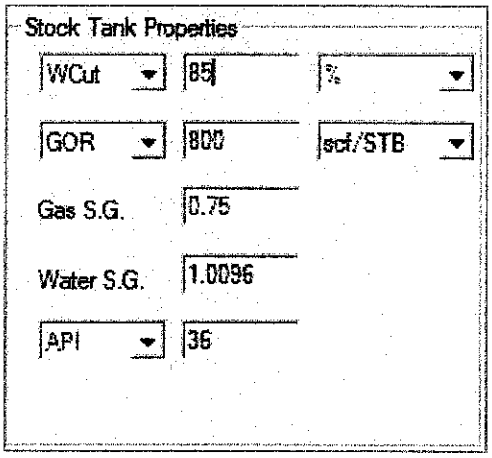
	Equipment	MD	Properties	Label
-		ft		
1	SSSV	452	Properties	#1_Tubing_1
2	Gas Lift Injection	3122	Properties	#2_Tubing_1
3	Gas Lift Injection	4346	Properties	#3_Tubing_1
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				

SSSV Properties

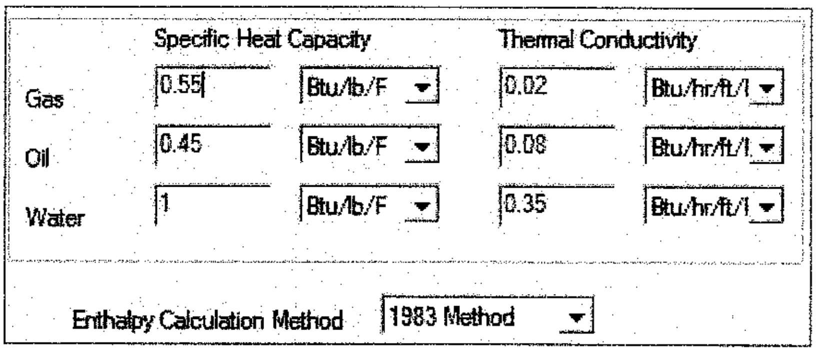
Bean ID 2.812 inches

OK Cancel

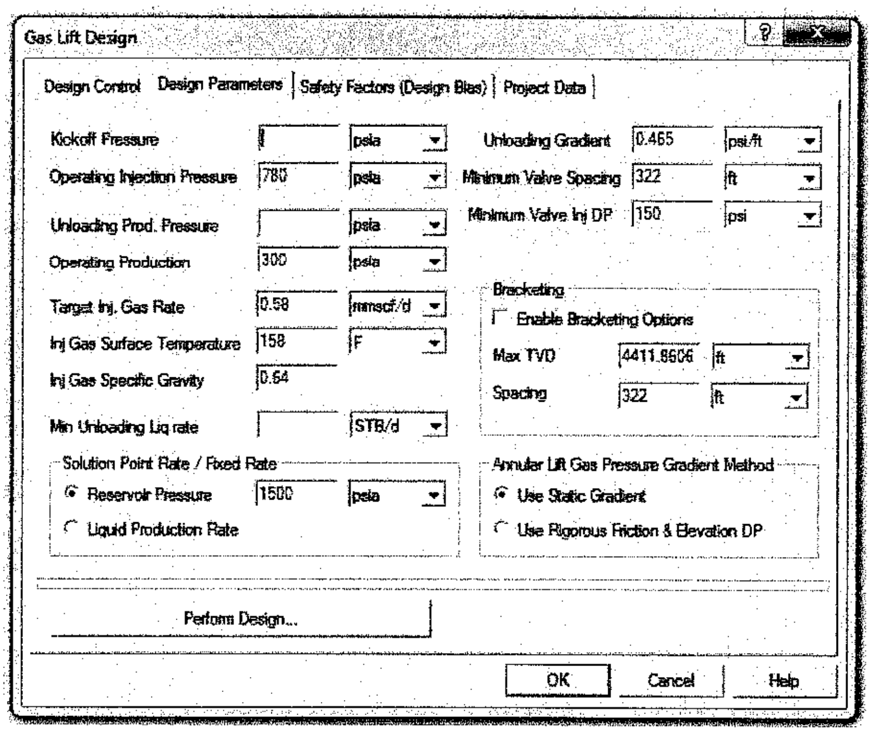
7. Black Oil Properties



8. Black Oil thermal data



9. Gas Lift data



Create a Single Well Model and Network Model

Using the data that had been retrieved, each single well model had been constructed using PIPESIM© Single Branch. This is to allow the performance curve analysis be generated by PIPESIM© engine.

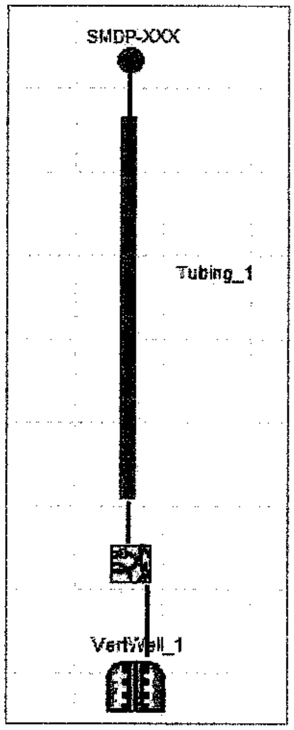


Figure 3.2 : PIPESIM© Single Branch Well Model

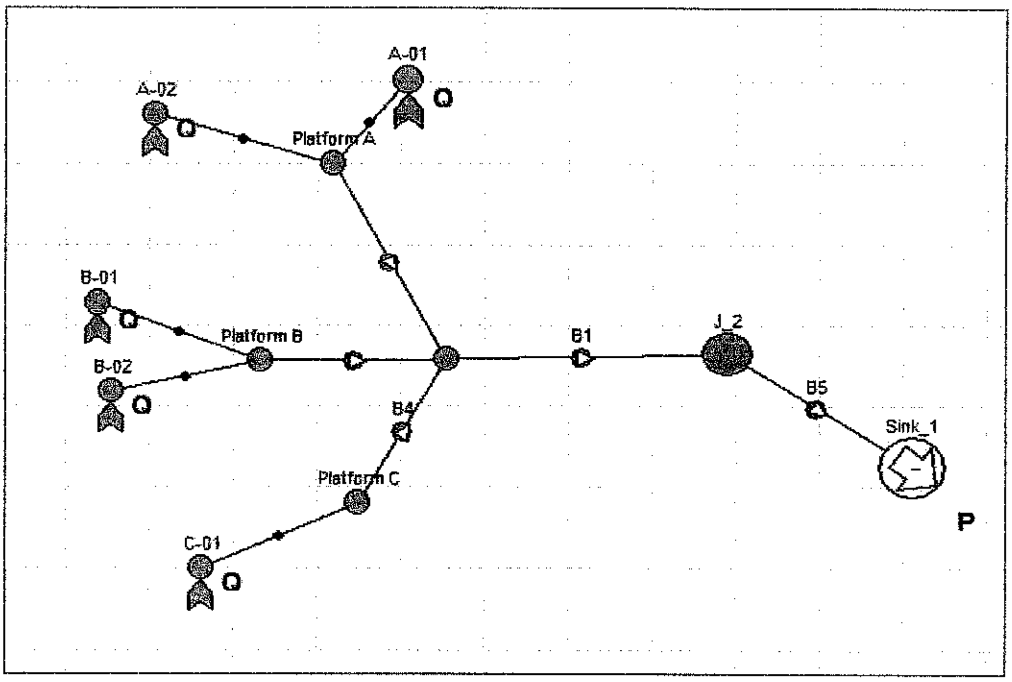


Figure 3.3 : PIPESIM© Network Model

Constructing the macros and coding using Microsoft Visual Basic

Microsoft Visual Basic had been used in order to run the optimization. The concept and idea is to sum all possibilities from each of sensitivities run for each wells. If the summation result exceed the constraint that had been set, the computer will prompt out *'Reject'* to show that the result will not be taken. After all the summation had been done, computer will retrieve the maximum value. By doing this, optimum production rate will be obtained and the constraint will be honor.

Analyze on the optimization result

After the optimization had been done, the result need to be analyze. Some of the important aspect that needs to be studied deeply is why certain wells are given more injection rate than others. The analysis is vital as it will make us understand the true science and concept behind the optimization.

Change parameters to see its effect on the optimization result

In order to know the parameters are affecting the optimization result, sensitivity analysis on the parameters need to be done. The parameters that had been studied in this project are gas oil ratio (GOR), water cut, reservoir pressure, reservoir temperature, oil API gravity and well productivity index. Using the same data for each well except for the parameter that need to be studied, sensitivity analysis on the production rate is done. The production curve data are then enter the Excel workflow in order to be optimized.

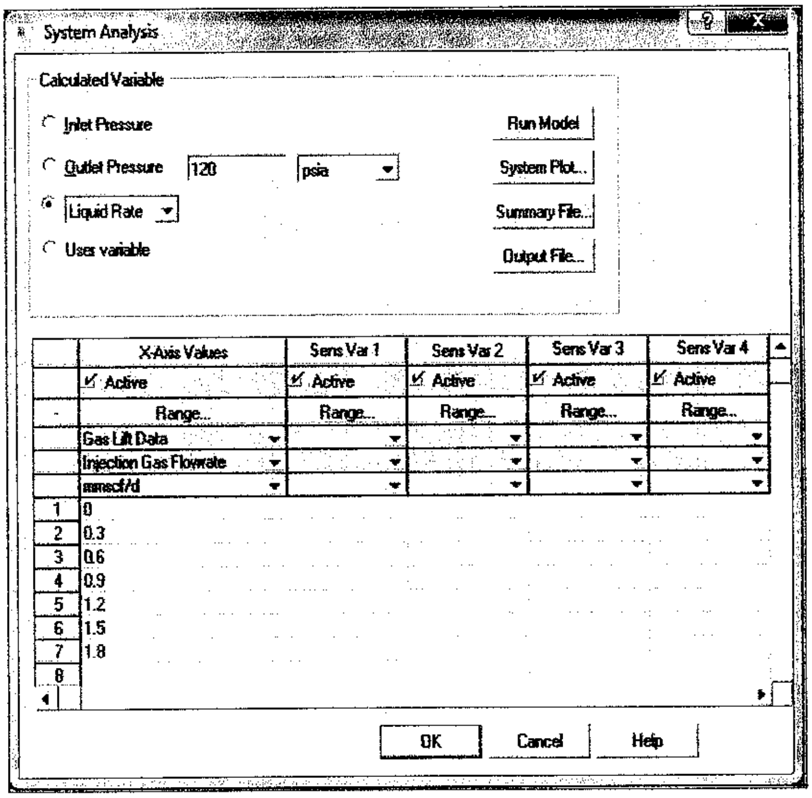
Conclude the optimization results

Lastly, the optimization result will be concluded whether the optimization is successful or need improvement.

3.3 EXCEL VBA Optimization Method

The steps in generating the optimization using EXCEL VBA are as follow.

1. Generate sensitivity analysis using PIPESIM©, liquid production rate versus gas lift injection rate. The injection rate value had been varied to get different corresponding liquid production rate.



2. Result generated and the data required were imported into EXCEL worksheet. The data required are :

   i. Well ID (Name)
   ii. Water Cut
   iii. Gas Lift Injection Rate
   iv. Liquid Production Rate

3. Oil Production Rate for each corresponding gas injection rate was calculated using equation :

$$Oil\ Production = Liquid\ Production \times (1 - Water\ Cut)$$

The VBA Coding are written as follow :

```
' Equation for Oil Production Rate
Function Oil_Prod(Liq_Prod As Double, Water_Cut As Double)
    Oil_Prod = Liq_Prod * (1 - Water_Cut)
End Function
```

4. Represent

$$I_i\ = gas\ lift\ injection\ rate\ for\ well\ i$$

$$P_i = oil\ production\ rate\ for\ well\ i$$

5. Calculate the total injection rate for entire 5 wells

$$\sum I = I_1 + I_2 + I_3 + I_4 + I_5$$

The VBA coding are written as follow :

```
' Equation for Optimize Total Gas Injection Rate
Function Total_Inj(I1 As Double, I2 As Double, I3 As Double, I4 As Double, I5 As Double)
    Total_Inj = I1 + I2 + I3 + I4 + I5
End Function
```

6. Calculate the total oil production rate for entire 5 wells

$$\sum P = P_1 + P_2 + P_3 + P_4 + P_5$$

7. Fix the cell in EXCEL that will be used for user to enter the maximum amount of lift gas available for the whole field. VBA will take the value of this cell as max.

$$max = maximum\ amount\ of\ lift\ gas\ available\ for\ entire\ field$$

8. Condition for total oil production for entire wells is set.

   If $\sum I > max$, the value of corresponding $\sum P$ will not be taken. Instead, the computer will prompt 'reject' as the result.

   The VBA Coding are as follow :

```
' Equation for Optimize Total Oil Production Rate

Function Total_Prod(P1 As Double, P2 As Double, P3 As Double, P4 As Double, P5 As Double, Total_Inj As Double)

Dim Reject As String

Dim max As Double

max = Sheet1.Cells(16, 7)

    If Total_Inj < max Then

        Total_Prod = P1 + P2 + P3 + P4 + P5

    Else

        Total_Prod = "Reject"

    End If

End Function
```

9. The $\sum I$ for each combination that is possible is calculated. It needs to be done in stages and systematically in order to avoid any error.

   The concept of the calculation will be explained using an example with 3 wells. A1 is representing the value on injection rate for well A, data number 1.

Well A
A1
A2
A3

Well B
B1
B2
B3

Well C
C1
C2
C3

i. 1st stage, the value for Well A and Well B will be fixed while value for Well C will be increase.

$$\sum I = A1 + B1 + C(n+1)$$

The increment for 1st stage will be done until all Well C value had been calculated. For this example, until C3.

ii. The calculation will move on to 2nd stage, where the value of Well A will be fixed while value of Well B will be increasing. Value of Well C will follow the stage 1 pattern.

$$\sum I = A1 + B(n+1) + C(n+1)$$

The increment for 1st stage will be done until all Well B value had been calculated. For this example, until B3.

iii. The calculation will then move to 3rd stage, where the value of Well A will be increasing. Value of Well C will follow the stage 1 pattern and Well B follow the stage 2 pattern.

$$\sum I = A(n+1) + B(n+1) + C(n+1)$$

The increment for 3rd stage will be done until all Well A value had been calculated. For this example, until A3.

iv. After 3rd stage had been completed, all possibilities of combination possible had been calculated.

v. The total number of combination that possible can be calculated by simple probability calculation. 3 wells, each well had 3 data. $3^3 = 27$. Thus, possible combination are 27.

10. The $\sum P$ for each corresponding $\sum I$ was calculated.

For example, if the

$$\sum I = I_{1,3} + I_{2,2} + I_{3,3} + I_{4,1} + I_{5,4}$$

Then the corresponding $\sum P$ is

$$\sum P = P_{1,3} + P_{2,2} + P_{3,3} + P_{4,1} + P_{5,4}$$

* $I_{1,3}$ is the I for well number 1, data number 3.

11. All the data calculated are tabulated in systematic table form for ease of troubleshooting and data reviewing.

12. The maximum amount of $\sum P$ is identified by using a MAX function in EXCEL. This maximum amount will be the optimum amount of total production rate. This is because all the values that had been calculated are already abide to the constraints set earlier.

13. The maximum $\sum P$ cell is selected and the function "Trace Precedents" in EXCEL is utilized. This will allow user to identified the precedents and the value for each wells that contribute to the $\sum P$. User will know at which rate should the injection gas being injected into each of the wells in order to achieve the maximum $\sum P$.

14. The value of maximum $\sum P$ from the optimization is being compared with the $\sum P$ before the optimization. The differences and the percentage increase are then calculated.

    The EXCEL VBA coding are as follow :

```
' Result Differences Calculation

    Dim x, n As Double

    n = Range("G22").Value - Range("O22").Value

    n = Format(n, "$,$$0.00")

    x = ((Range("G22").Value - Range("O22").Value) / Range("O22").Value) * 100

    x = Format(x, "$,$$0.00")

    MsgBox "Total Oil Production Have increased by  " & n & " bbl/d"

    MsgBox "Total Oil Production Have increased by  " & x & " %"
```

3.4 Key Milestone

No	Milestone	Date
1	Proposing the FYP topic	01/02/2011
2	Planning the flow of the project	4 23/02/2011
3	Understand artificial lift process	02/03/2011
4	Understand Gas Lift behavior	09/03/2011
5	Acquiring input data	16/03/2011
6	Creating a single branch well and network model	23/03/2011
7	Establish gas lift performance curve	30/03/2011
8	Find the most effective way to do the optimization	25/05/2011
9	Preparing optimization in VBA	07/06/2011
10	Run Optimization	21/06/2011
11	Run different cases	05/07/2011
12	Interpret result	13/07/2011
13	Project Submission	03/08/2011

Table 3.1 : Project's Key Milestone

3.5 Gantt Chart

NO	Activities/Week	1	2	3	4	5	6	7	8	9	10	11-15	16	17	18	19	20	21	22	24	24	25	26	27
1	Proposing the FYP topic																							
2	Confirmation of the FYP topic																							
3	Retrieve relevant references																							
4	Planning the flow of the project																							
5	Understand artificial lift process																							
6	Understand Gas Lift behavior																							
7	Acquiring input data																							
8	Creating a single branch well and network model																							
9	Establish gas lift performance curve																							
10	Find the most effective way to do the optimization																							
11	Preparing optimization in VBA																							
12	Input data and constraint into workflow																							
13	Run Optimization																							
14	Analyze result																							
15	Run different cases																							
16	Interpret result																							
17	Project Submission and presentation																							

* Week 1 started on 1 February 2011 / Week 11 – 15 is the Exam and Break Period

3.6 Tools

The tool that will be utilized is Schlumberger PIPESIM©, Production system analysis software that provides steady-state multiphase flow. Using this software, single well and network model will be created. Using the PIPESIM© engine, the sensitivity analysis for each of the wells will be conducted.

Microsoft Excel VBA will also be utilized in order to run the optimization calculation. Script will be write inside the VBA system and the coding will be use in order to run the calculation inside the Excel.

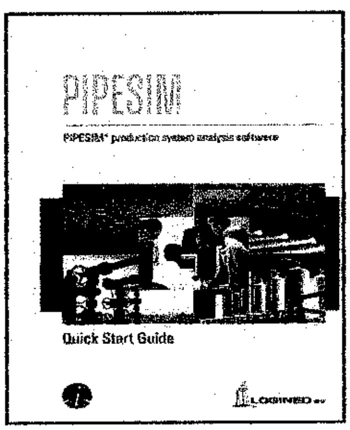


Figure 3.4 : Schlumberger PIPESIM©

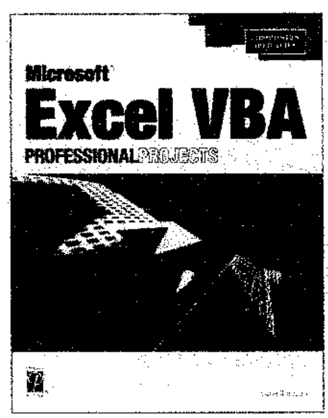


Figure 3.5 : Microsoft Excel VBA

CHAPTER 4

RESULT AND DISCUSSION

PART 1

4.1 Project Assumptions

Few assumptions have been made prior to completion of this project. They are :

1. All the gas lift wells are operating perfectly without any problems.

   In the real Gas Lift Management (GLM) workflow, the first step is to do the Welltest Update. This is to ensure that the current well models are representing the real wells in the field. Some parameters might need to be changed in order to match the welltest data. Next step is to run the Gas Lift Diagnostic. This is the step where the performance of the gas lift system in each wells are being evaluated. From this diagnostic, problems in the gas lift system can be detected like casing leakage or malfunction gas lift valves. The problems were then solved prior to running the Gas Lift Optimization.

   However in this project, only the gas lift optimization has been done without any welltest update and diagnostic. Thus, all the gas lift wells had been assumed to be working perfectly without any problems. The current simulation well models have also been assumed to represent the real well in the field.

2. Total oil production is purely combination of each wells' oil production.

   In order to calculate the total oil produce, each wells' oil production is been summed up without took into account any flow disturbance and restriction when the flow combine in a single pipeline to surface facilities. Combining flow in pipeline may cause pressure drop and disrupt the flow rate. However in this project, the disturbance and disruption had been neglected.

4.2 Result and Discussion

The result from the optimization show that there will be increasing amount of total oil production rate after the optimization process had been done. The optimization process also abides with the constraint that had been set. These have proved that the optimization is successful.

Successful Optimum Distribution of Available Lift Gas

Well ID :	A1
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	355.970
0.50	658.510
0.80	703.541
1.10	732.029
1.40	751.438
1.70	765.136
2.00	773.487

Well ID :	A2
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	538.723
0.50	923.756
0.80	949.327
1.10	957.447
1.40	958.021
1.70	950.958
2.00	940.386

Well ID :	A3
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	369.694
0.50	911.741
0.80	956.885
1.10	982.024
1.40	993.529
1.70	999.182
2.00	1004.022

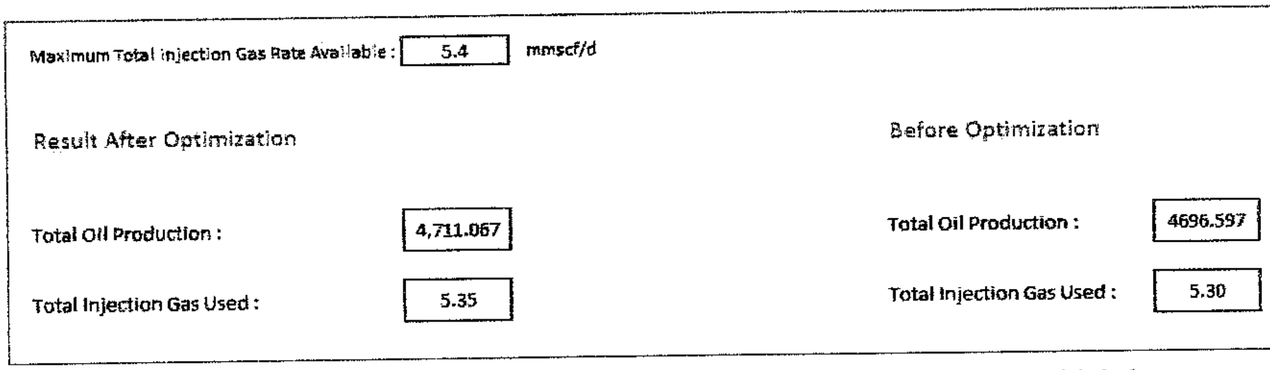
Well ID :	B1
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	972.797
0.25	1018.409
0.50	1042.239
0.75	1059.677
1.00	1070.195
1.25	1076.712
1.50	1080.338

Well ID :	B2
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	777.863
0.25	895.703
0.50	925.514
0.75	942.996
1.00	954.903
1.25	963.200
1.50	969.046

Table 4.1 : Optimization distribution result for Case 1

The result shows that the distribution had been successfully completed without any error.

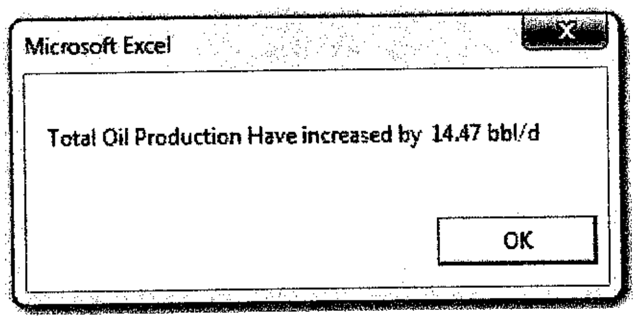
The Optimization Has Been Honoring the Constraint

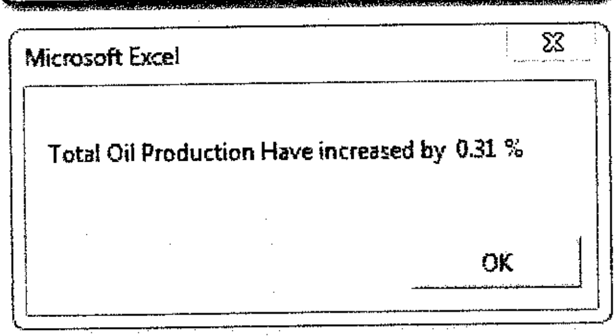


The total injected gas been used after the optimization is 5.35 mmscf/day which is lower than the constraint (5.4 mmscf/day) that had been set.

Production Increment

For the first case of optimization, the result shows that there will be an increment of 14.47 bbl oil/day, or 0.31%.





The result for the first case of optimization show that increment of 14.47 oil bbl/day or 0.31 %. This number may seem to be small. However, by considering that there are no other additional cost or equipment changes, this can be very favorable. By redistributing the available resources, the production can be increase by 14.47 oil bbl/day.

If consider a cumulative monthly production (14.47 x 30 days) , additional 434.1 barrel oil can be obtain for each month and (14.47 x 365 days) 5251.8 barrel oil per year. This result is obtains by optimizing only 5 wells. If the optimization process is done on every single gas lift wells in the field (estimate 60 wells) , the optimization result will surely be higher.

Runtime

The time required to run 5 wells optimization is 5 minutes and 27 seconds (00:05:27). The runtime undertake for the optimization depend highly on the processor speed. Using the *AMD Phenom II Quad Core 3.2 gHz,* the time needed to run the optimization is 5 minutes and 27 seconds (00:05:27).

However, using the *Intel i5-2500 Quad Core 3.30 gHz* processor, the run time was reduced to 4 minutes and 37 seconds (00:04:37). This proves that the run time can be reduced by increasing the processing capabilities and speed of the computer processor.

Distribution of Available Gas Lift

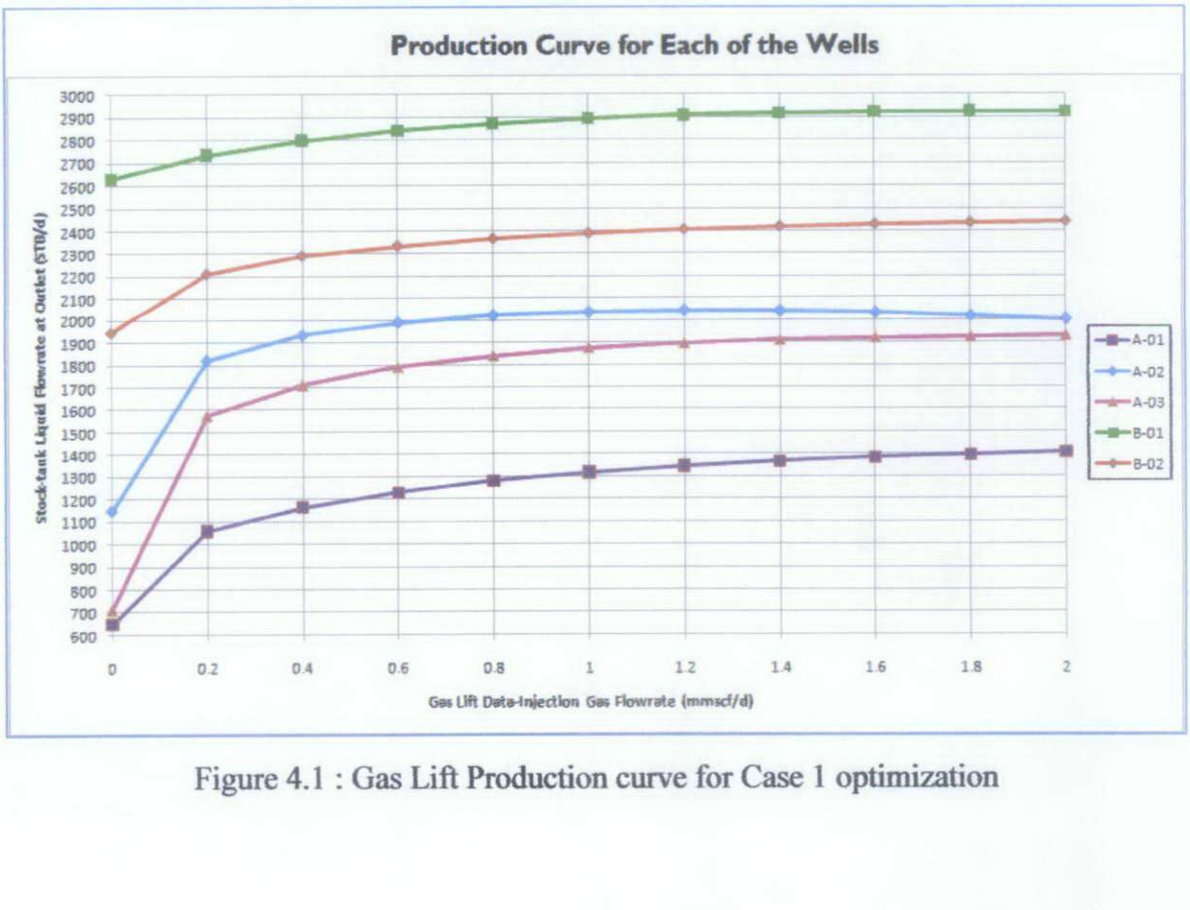


Figure 4.1 : Gas Lift Production curve for Case 1 optimization

The distribution of the available gas is closely related to the value of production curve slope for each of the wells. The optimum distribution will favor the highest slope value as the injection gas will be more significant towards the production rate. The slope for each production curve is depending on each well's fluids properties and reservoir properties.

PART 2

4.3 Effect of specific parameter on optimization result

The optimization had been done using 5 wells that have exactly the same input data except the parameter that is intended to be studied. This is in order to check solely on the effect of that certain parameter on the optimization result without the influence of other parameter.

4.3.1 Gas Oil Ratio (GOR)

Analysis had been done using 5 wells having a different GOR value range from 1000 to 3000 scf/stb with increment of 500. Here are the optimum distribution of the available lift gas in different GOR wells :

Well ID :	A1
GOR :	1000.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	569.675
0.30	643.770
0.60	694.931
0.90	723.323
1.20	742.038
1.50	754.025
1.80	**760.835**

Well ID :	A2
GOR :	1500.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	707.591
0.30	746.269
0.60	766.816
0.90	782.723
1.20	792.425
1.50	**798.296**
1.80	801.268

Well ID :	A3
GOR :	2000.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	775.660
0.30	796.910
0.60	807.966
0.90	815.259
1.20	**819.346**
1.50	821.312
1.80	821.744

Well ID :	B1
GOR :	2500.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	819.261
0.30	827.018
0.60	**832.291**
0.90	835.016
1.20	836.063
1.50	835.891
1.80	834.808

Well ID :	B2
GOR :	3000.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	840.491
0.30	**844.081**
0.60	845.760
0.90	846.013
1.20	845.304
1.50	843.833
1.80	841.710

Table 4.2 : Optimization result for different GOR value

The result shows that the optimum distribution of the injection gas will be higher in a lower GOR well. This is because if the fluid in the well had a high GOR value, the injection gas rate for gas lift will give less impact on the increment of the production rate. This can be proven by the graph (Figure 1) that had been generated. It clearly shows that low GOR well will produce the highest slope value. This means that in the low GOR well, a small increment of injection gas rate will result in high increment of oil production rate.

This can be explained by the solubility concept. The purpose of gas lift is to reduce the hydrostatic load in the fluid column in the well. In a high GOR oil, the percentage of gas miscible in the oil is less due to high amount of gas are already in the oil. This will make the gas injected for gas lift is less miscible with the oil in the well. Thus, the hydrostatic load reduction will also decrease. Due to this, high GOR oil will react less with the injected gas, thus make it less sensitive to the changes of injection gas rate.

High GOR oil will shift the starting point of the curve upwards, mean that the well will produce at high rate even when there is no gas being injected. High GOR oil will reduce the density of the oil. This will reduce the hydrostatic load of the fluid column in the well and make the fluid easier to flow despite having a low differential pressure between wellhead and bottomhole. This is why high GOR will result in higher oil production.

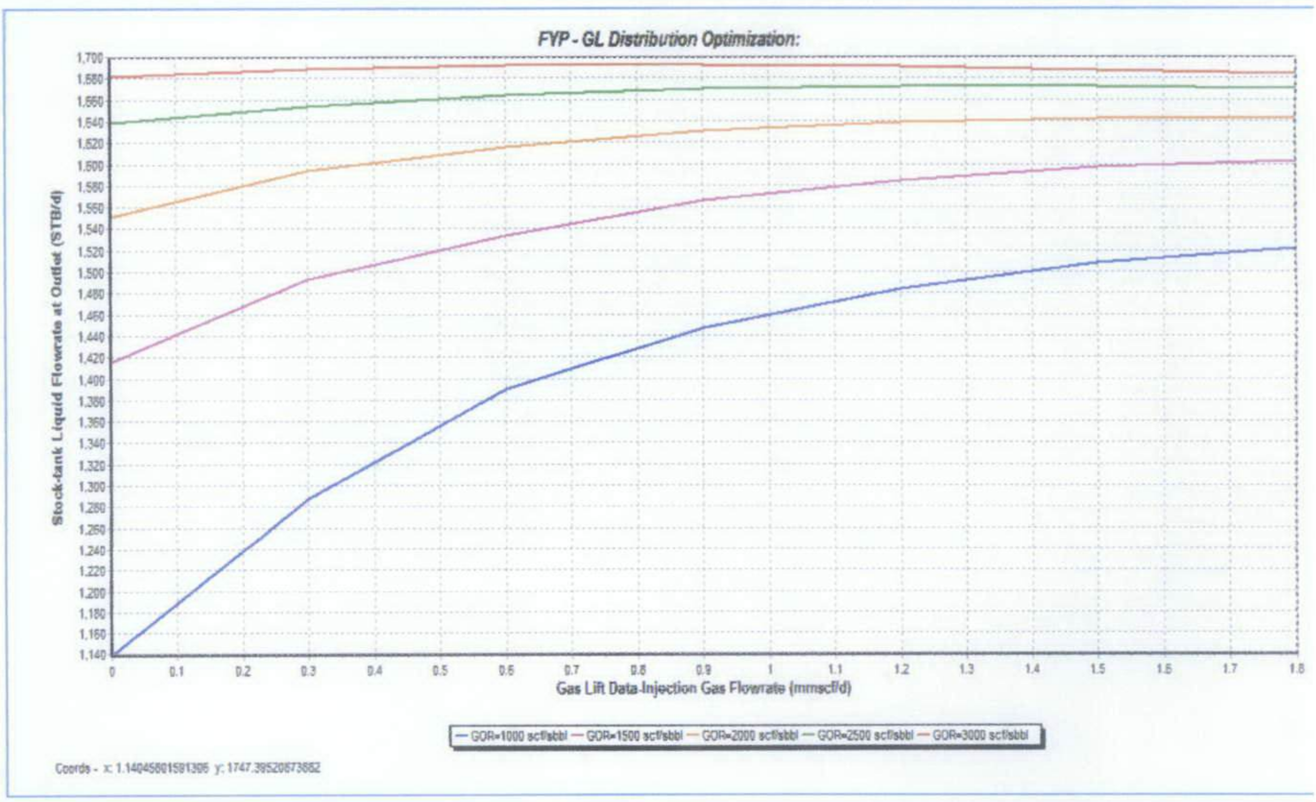


Figure 4.2 : GOR sensitivity performance curve

It can be conclude that higher GOR oil will increase the oil production but is less sensitive to the changes of gas lift injection rate. Hence, optimum distribution will provide less injection gas to the high GOR oil well. Higher GOR will result in lower gas injection rate by the gas lift distribution optimizer.

4.3.2 Water Cut

Analysis had been done using 5 wells having different water cut value range from 30% to 50% with increment of 5. Here are the optimum distribution of the available lift gas in different Water Cut wells :

Well ID :	W-01	Well ID :	W-02	Well ID :	W-03	Well ID :	W-04	Well ID :	W-05
Water Cut :	30%	Water Cut :	35%	Water Cut :	40%	Water Cut :	45%	Water Cut :	50%
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)	Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)	Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)	Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)	Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d
0.00	1118.619	0.00	1107.011	0.00	1092.970	0.00	1077.123	0.00	1059.682
0.30	1122.246	0.30	1111.517	0.30	1099.692	0.30	1086.063	0.30	1070.413
0.60	**1124.372**	0.60	1114.915	0.60	1104.204	0.60	1092.300	0.60	1078.745
0.90	1125.243	**0.90**	**1116.227**	0.90	1106.962	0.90	1096.448	0.90	1084.546
1.20	1125.029	1.20	1116.555	**1.20**	**1108.266**	1.20	1098.899	1.20	1089.499
1.50	1123.867	1.50	1116.810	1.50	1109.444	**1.50**	**1101.152**	**1.50**	**1091.863**
1.80	1121.822	1.80	1115.801	1.80	1109.040	1.80	1101.462	1.80	1093.000

Table 4.3 : Optimization result for different water cut value

The result shows that the optimum distribution of available gas lift will be higher towards the higher water cut well. This is because if the fluid in the well had a high water cut value, the injection gas rate for gas lift will give more impact on the increment of the production rate. This can be proven by the graph (Figure 2) that had been generated. It shows that high water cut well will produce the highest slope value and the production will be more sensitive towards the changes in gas lift injected value. This means that in the high water cut well, a small increment of injection gas rate will result in high increment of oil production rate.

Water is denser and heavier than oil. High fluid water cut value will lead to high total fluid density and weight, thus will lead to a high hydrostatic load in the fluid column in the well. This will make the fluid difficult to flow upwards and result in decrease in production rate. Due to high density, high water cut well needs the assistance from the gas-lift gas in order to reduce its density and hydrostatic load. Heavier fluid will benefit more from the injected gas-lift gas as the gas will mix with the fluid, reduce its hydrostatic load and make it easier to flow upwards. However, in a less heavy and dense fluid (low water cut), the flow rate of the fluid upward is already good. Hence, it does not need the assist from the gas-lift gas as much as the heavier fluid does. This makes low water cut fluid less sensitive with difference in the gas lift injection rate.

Lower water cut well will makes the fluid less dense and easier to flow upwards. This will shift the starting point of the graph (Figure 2) upwards, means that liquid will be produce at a higher rate even when there is no gas-lift gas being injected.

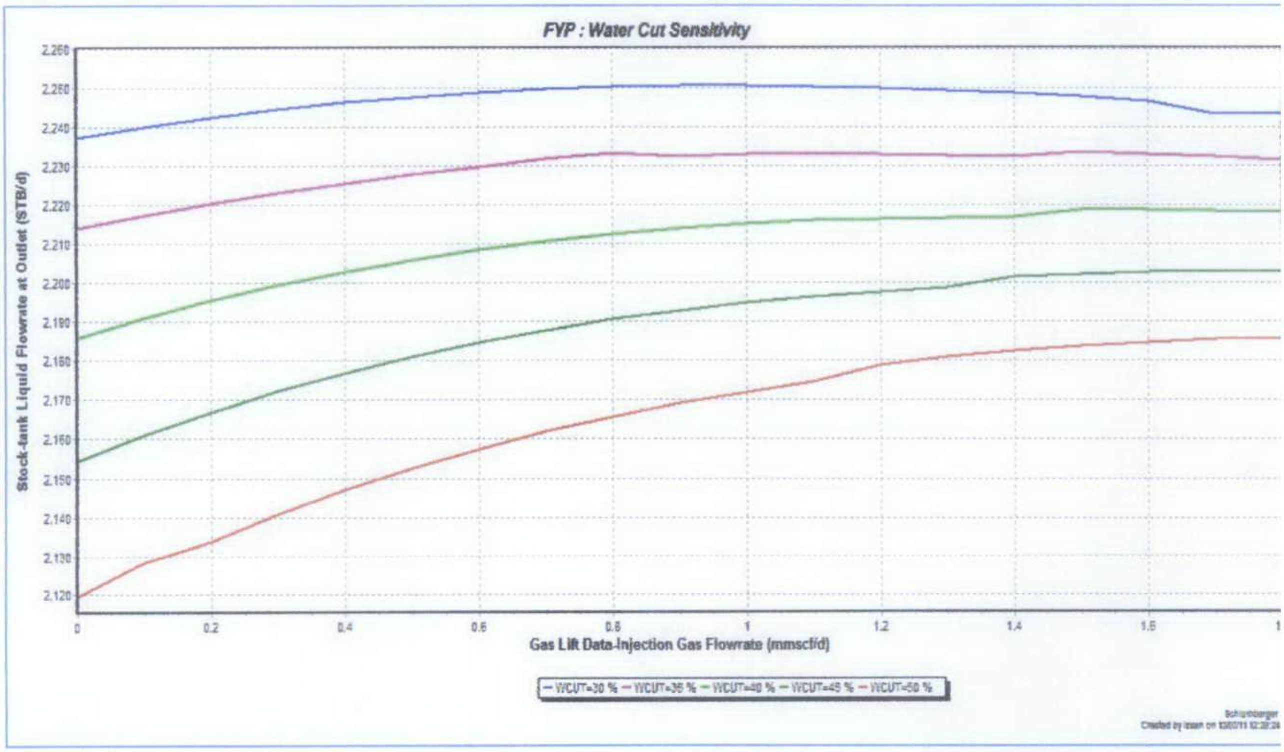


Figure 4.3 : Water Cut sensitivity performance curve

It can be conclude that lower water cut fluid will increase the oil production but is less sensitive to the changes of gas lift injection rate. Hence, optimum distribution will provide less injection gas to the lower water cut fluid well. Lower water cut value will result in lower gas injection rate by the gas lift distribution optimizer.

4.3.3 Oil API Gravity

Analysis had been done using a different oil API gravity range from 27 API to 39 API with increment of 3. Here are the optimum distribution of the available lift gas in different Oil API Gravity wells :

Well ID :	W-01
Oil API :	27
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	980.154
0.30	994.461
0.60	1010.269
0.90	1018.269
1.20	**1023.409**
1.50	1026.519
1.80	1028.227

Well ID :	W-02
Oil API :	30
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1012.036
0.30	1027.525
0.60	1038.523
0.90	1045.990
1.20	**1050.817**
1.50	1053.798
1.80	1055.336

Well ID :	W-03
Oil API :	33
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1032.341
0.30	1046.926
0.60	1057.284
0.90	1064.489
1.20	**1069.336**
1.50	1072.351
1.80	1073.929

Well ID :	W-04
Oil API :	36
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1047.302
0.30	1061.388
0.60	1071.049
0.90	1077.980
1.20	**1082.730**
1.50	1085.787
1.80	1087.485

Well ID :	W-05
Oil API :	39
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1059.767
0.30	1073.123
0.60	1081.758
0.90	1088.616
1.20	**1093.375**
1.50	1097.565
1.80	1098.057

Table 4.4 : Optimization result for different oil API value

The result shows that the optimum distribution of available gas lift will be the same for each well. From the graph (Figure 3), it can be seen that the slope for each different oil API gravity wells are the same. The increment in oil API gravity will only shift the graph upward without affecting the slope.

Oil API gravity is inversely proportional with specific gravity and density of the oil. Higher oil API gravity will make the oil become lighter and less dense. This will result in less hydrostatic load of the oil in the well. Hence, a little pressure differences are needed to carry the oil up to the surface. That is the reason why higher oil API gravity will lead to increasing in production rate. Higher oil API gravity will shift the starting point of the graph upwards, means that liquid will be produce at a higher rate even when there is no gas-lift gas being injected.

The gas injected via gas lift method will reduce the hydrostatic load of the fluid in the wellbore. However, the hydrostatic load reduction is same and follows the same pattern for each of the difference Oil API in the well. The slope for each of the cases is the same.

Due to this, the optimization will distribute the same amount of lift gas into each of the wells. This is because the optimization is based on the slope, and if there is no slope difference between each well productivity curve, then the optimization will not give any significant impact on the system.

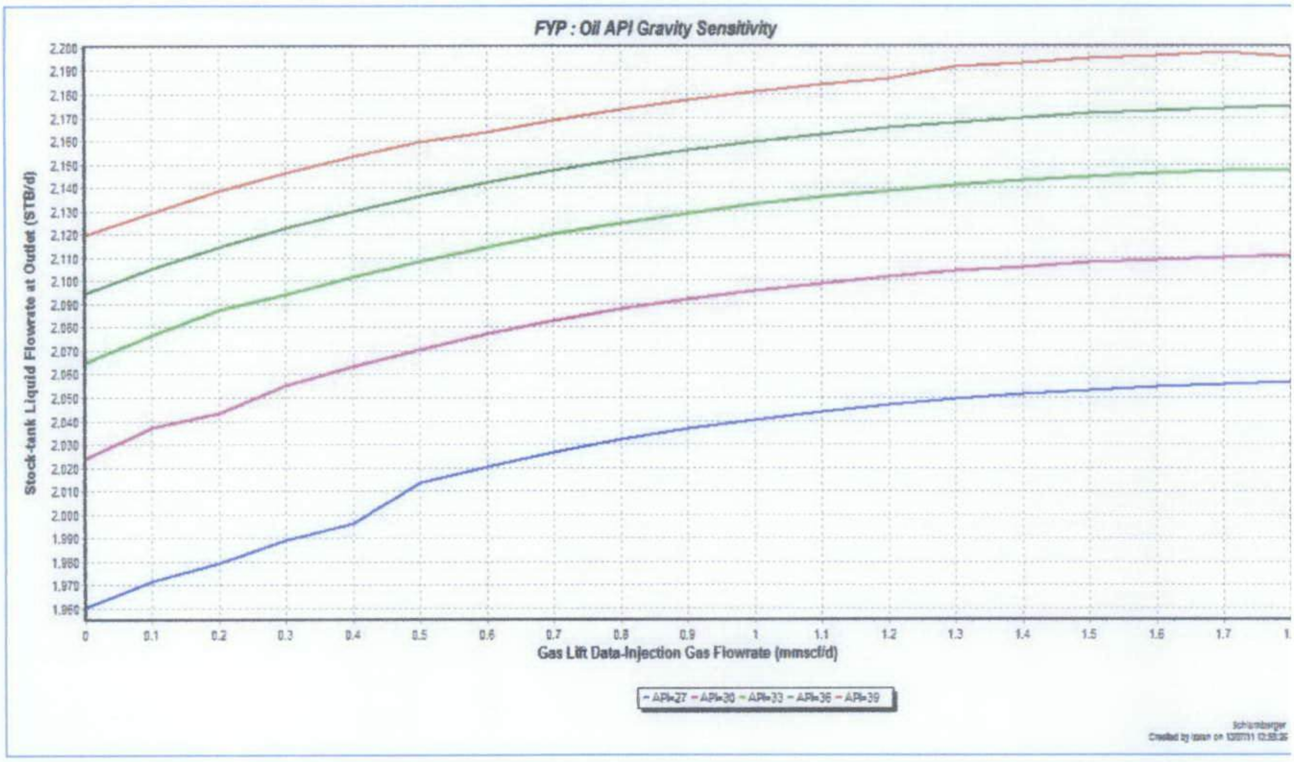


Figure 4.4 : Oil API Gravity sensitivity performance curve

It can be conclude that higher oil API gravity will increase the oil production but does not affect the sensitivity of the production rate towards the changes of gas lift injection rate. Hence, optimum distribution will provide equal injection gas to the every well. Oil API gravity does not give any significant impact to the optimization result.

4.3.4 Reservoir Pressure

Analysis had been done using a different reservoir pressure range from 1600 psi to 2800 psi with increment of 300. Here are the optimum distribution of the available lift gas in wells that have different corresponding reservoir pressure :

Well ID :	W-01
Res Pressure :	1600
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	859.659
0.30	895.900
0.60	919.541
0.90	948.845
1.20	961.731
1.50	972.000
1.80	**978.759**

Well ID :	W-02
Res Pressure :	1900
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1209.933
0.30	1236.961
0.60	1255.409
0.90	1268.492
1.20	1277.871
1.50	**1284.490**
1.80	1288.892

Well ID :	W-03
Res Pressure :	2200
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1557.604
0.30	1571.448
0.60	1582.084
0.90	1602.235
1.20	**1609.867**
1.50	1615.376
1.80	1619.224

Well ID :	W-04
Res Pressure :	2500
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1778.913
0.30	1789.408
0.60	**1796.991**
0.90	1801.190
1.20	1804.872
1.50	1807.306
1.80	1809.350

Well ID :	W-05
Res Pressure :	2800
Injection Gas Flowrate (mmscf/d)	Oil Productio Flowrate (STB
0.00	**1150.591**
0.30	1154.668
0.60	1157.591
0.90	1159.426
1.20	1161.028
1.50	1161.863
1.80	1162.243

Table 4.5 : Optimization result for different reservoir pressure value

The result shows that the optimum distribution of available gas lift will be higher towards the lower reservoir pressure well. This is because in the low reservoir well, the injection gas rate for gas lift will give more impact on the increment of the production rate. This can be proven generated graph (Figure 4), showing that low reservoir pressure well will produce the highest slope value and the production will be more sensitive towards the changes in gas lift injected value. This means that in the low reservoir pressure well, a small increment of injection gas rate will result in high increment of oil production rate.

The main function of gas lift system is to artificially lift fluid from wells where there is insufficient reservoir pressure to produce the well. In a high reservoir well, the drawdown pressure value is high. Drawdown pressure is the differential pressure that drives fluids from the reservoir into the wellbore. When drawdown pressure is higher, the production rate towards the surface is higher. Hence, high pressure reservoir did not depend on gas-lift gas as much as low pressure reservoir. High pressure reservoir can produce at a high rate without the assistant of the gas-lift gas. This make high pressure reservoir less sensitive with the changes of injection gas rate.

High pressure reservoir will provide a high value of differential pressure which will lead to high production rate and shift starting point of the graph (Figure 4) upwards.

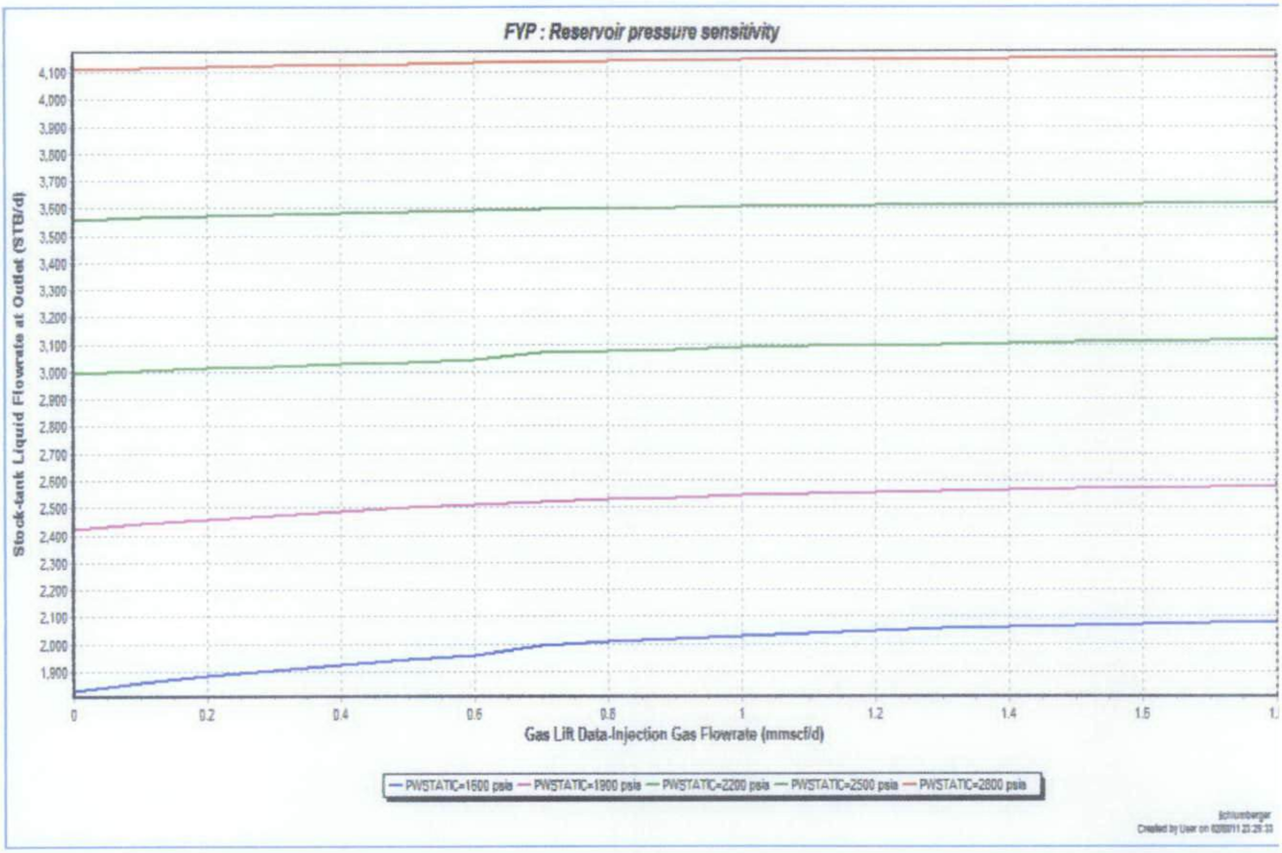


Figure 4.5 : Reservoir Pressure sensitivity performance curve

It can be conclude that high reservoir pressure will increase the oil production but make it less sensitive to the changes of gas lift injection rate. Hence, optimum distribution will provide less injection gas to the high reservoir pressure well. High reservoir pressure value will result in lower gas injection rate by the gas lift distribution optimizer.

4.3.5 Reservoir Temperature

Analysis had been done using a different reservoir temperature range from 100 °F to 200 °F with increment of 25. Here are the optimum distribution of the available lift gas in wells that have different corresponding reservoir temperature :

Well ID :	W-01
Res Temperature :	100.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1056.179
0.30	1115.277
0.60	1151.649
0.90	1176.400
1.20	**1193.717**
1.50	1205.753
1.80	1214.225

Well ID :	W-02
Res Temperature :	125.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1080.679
0.30	1139.088
0.60	1175.192
0.90	1199.818
1.20	**1217.119**
1.50	1229.196
1.80	1237.204

Well ID :	W-03
Res Temperature :	150.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1104.755
0.30	1162.194
0.60	1197.806
0.90	1222.102
1.20	**1239.192**
1.50	1251.122
1.80	1259.085

Well ID :	W-04
Res Temperature :	175.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1128.312
0.30	1184.545
0.60	1219.482
0.90	1242.521
1.20	**1261.365**
1.50	1271.721
1.80	1279.506

Well ID :	W-05
Res Temperature :	200.0
Injection Gas Flowrate (mmscf/d)	Oil Productic Flowrate (STB
0.00	1151.299
0.30	1204.435
0.60	1241.464
0.90	1263.571
1.20	**1279.893**
1.50	1291.186
1.80	1298.678

Table 4.6 : Optimization result for different reservoir temperature value

The result of the optimization shows that the distribution of the available gas-lift gas will be the same for each of the wells. Upon further investigation on the graph (Figure 5) that had been generated, it can be see that the slope of the performance curve will decrease when the reservoir temperature increase. However, the differences in the slope value are very small and did not pose any significant impact on the optimization process. Hence, optimizer will distribute equally amount of available gas-lift gas to all of the wells.

Increment of reservoir temperature will increase the volume of the fluid and make it less dense. This will reduce the hydrostatic load of the fluid column in the well and less pressure differences are needed in order to flow the fluid upwards to the surface. Increment of reservoir temperature will increase the production rate, shifting the starting point of the graph upwards without affecting the slope value.

Hydrostatic reduction from the gas-lift injected gas is nearly equal and follows the same pattern for each of the different reservoir temperature cases. The slope of the performance curve will be nearly the same for each case. Due to this, the optimization will distribute the same amount of lift gas into each of the wells. This is because the optimization is based on the slope, and if the slope difference between each well productivity curve is very small, then the optimization will not give any significant impact on the system.

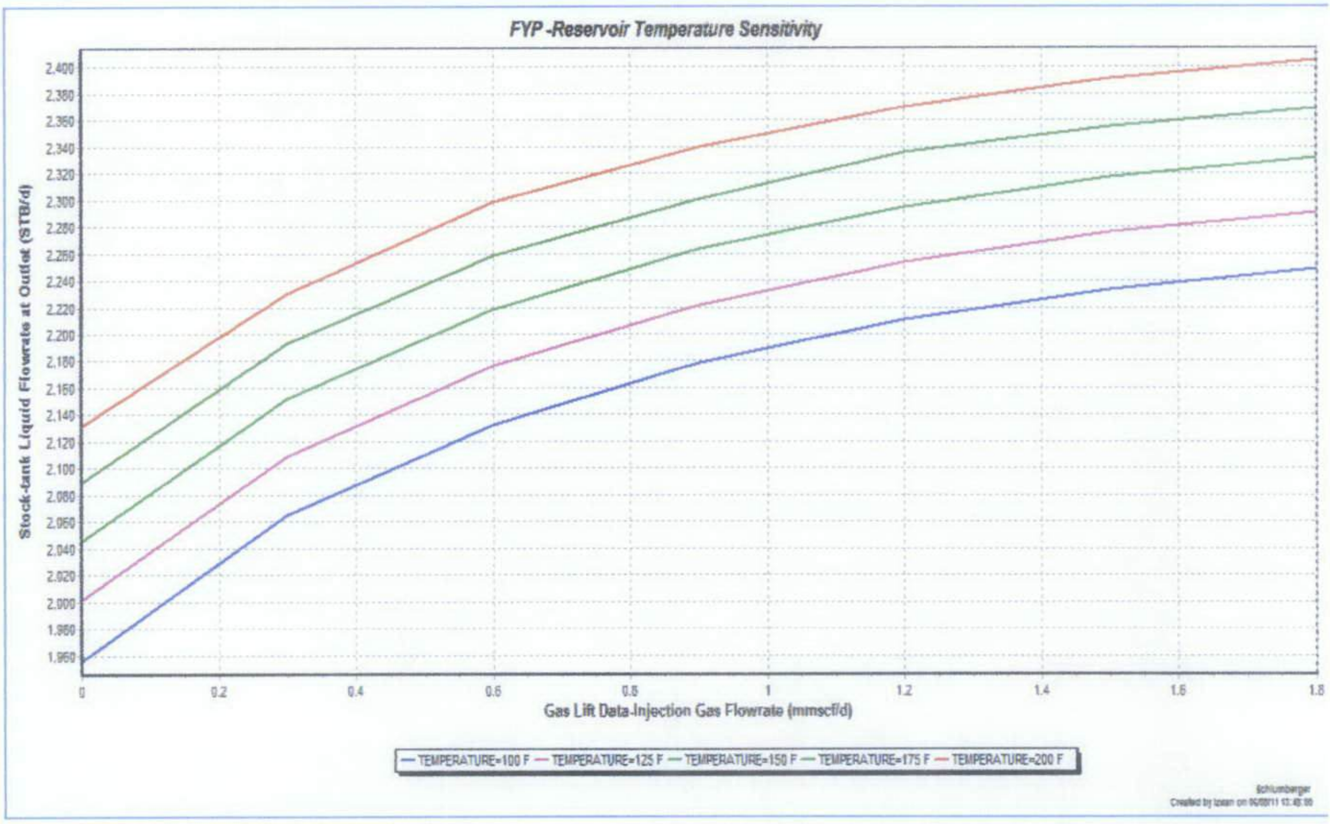


Figure 4.6 : Reservoir Temperature sensitivity performance curve

It can be conclude that higher reservoir temperature will increase the oil production but does not affect the sensitivity of the production rate towards the changes of gas lift injection rate. Hence, optimum distribution will provide equal injection gas to the every well due to no significant differences in each cases slope. Reservoir temperature does not give any significant impact to the optimization result.

4.3.6 Well Productivity Index (PI)

Analysis had been done using a different productivity index range from 1.0 to 3.0 with increment of 0.5. Here are the optimum distribution of the available lift gas in wells that have different corresponding productivity index :

Well ID:	A1
PI:	1.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	296.611
0.30	318.368
0.60	327.095
0.90	331.785
1.20	334.463
1.50	336.434
1.80	337.739

Well ID:	A2
PI:	1.5
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	427.579
0.30	455.419
0.60	469.550
0.90	477.333
1.20	482.683
1.50	486.331
1.80	488.803

Well ID:	A3
PI:	2.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	548.146
0.30	581.937
0.60	599.758
0.90	611.017
1.20	618.572
1.50	623.603
1.80	627.845

Well ID:	B1
PI:	2.5
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	661.069
0.30	698.501
0.60	719.860
0.90	733.963
1.20	743.727
1.50	750.556
1.80	755.595

Well ID:	B2
PI:	3.0
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	766.684
0.30	802.141
0.60	823.288
0.90	847.006
1.20	858.473
1.50	866.638
1.80	872.377

Table 4.7 : Optimization result for different productivity index value

The result shows that the optimum distribution of available gas lift will be higher towards the higher productivity index well. This is because if the well had a high productivity index value, the injection gas rate for gas lift will give more impact on the increment of the production rate. This can be proven by the graph (Figure 6) that had been generated. It shows that high productivity index well will produce the highest slope value and the production will be more sensitive towards the changes in gas lift injected value. This means that in the high productivity index well, a small increment of injection gas rate will result in high increment of oil production rate.

Productivity index is a function of production rate over drawdown pressure. $J = q/(P_R - P_{wf})$. Hence, productivity index is inversely proportional to drawdown pressure. Lower drawdown pressure results in higher productivity index value. The gas-lift gas function is to decrease the liquid density in the tubing and therefore increase the drawdown. In a high productivity index wells, the drawdown are small due to high flowing well pressure (P_{wf}) and high liquid density in the tubing. The injected gas-lift gas will have a higher capacity to reduce the density of the fluid in the tubing as the fluid is high in density. However, in a low productivity index, the drawdown value is higher and the density of the fluid in the tubing is already small.

Hence, injected gas-lift gas will not have a significant impact in reducing the density of the fluid in low productivity index. Higher productivity index will increase the liquid production flow rate when the drawdown value is the same. Hence, high productivity index will shift the graph starting point upwards.

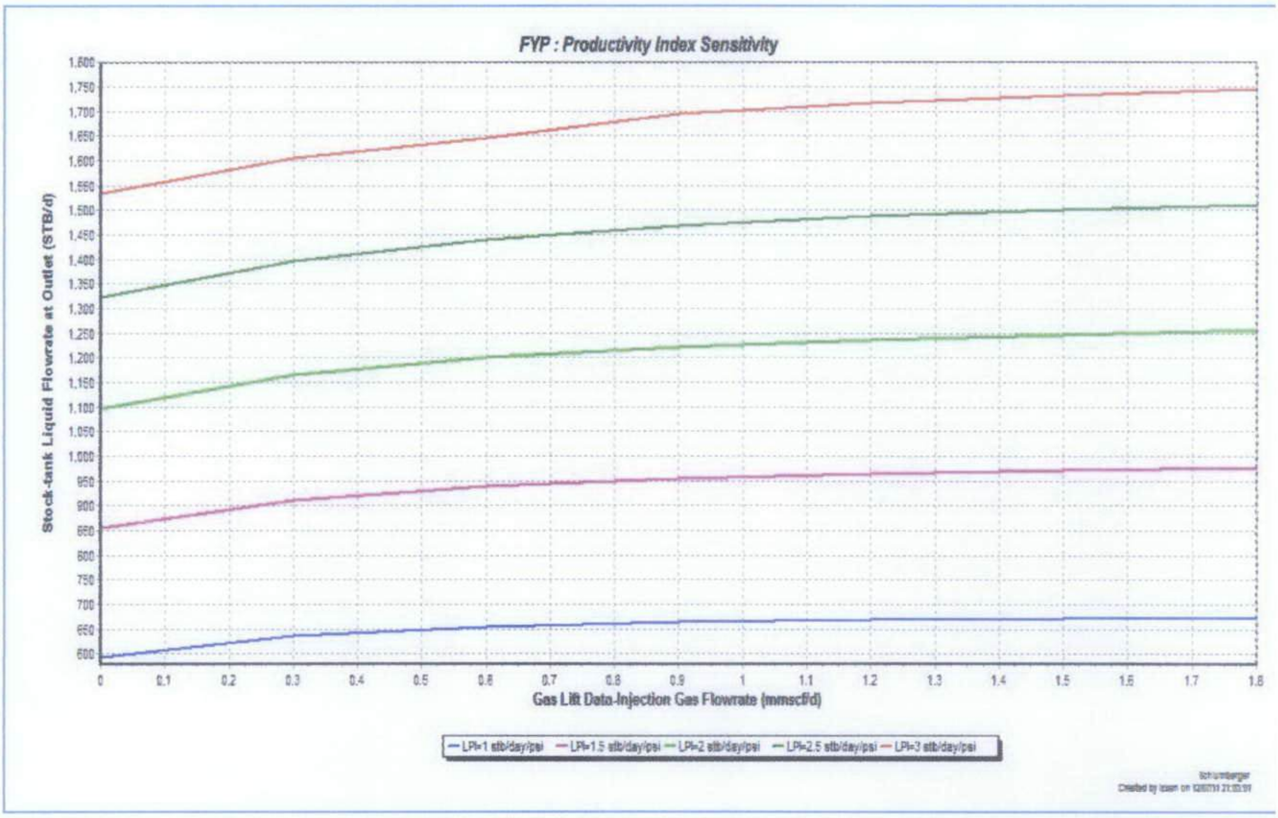


Figure 4.7 : Well Productivity Index sensitivity performance curve

It can be conclude that high productivity index will increase the oil production and make it more sensitive to the changes of gas lift injection rate. Hence, optimum distribution will provide more injection gas to the high productivity index well. High productivity index value will result in higher gas injection rate by the gas lift distribution optimizer.

4.3.7 Conclusion of Analysis

Conclusion of the above analysis can be tabulated in a table.

Parameter	**Influence on Optimization Result**	**Parameters effect on optimization result**
Gas oil Ratio	Very High	High GOR, low gas lift injection rate
Water Cut	High	High Water Cut, high gas lift injection rate
Oil API Gravity	None	None
Reservoir Pressure	Low	High Reservoir Pressure, low gas lift injection rate
Reservoir Temperature	Very Low	High Reservoir Temperature, low gas lift injection rate
Well Productivity Index	Low	High Productivity Index, high gas lift injection rate

Table 4.8 : Optimization analysis summary

PART 3

4.4 Real Field Case Study Results and Discussion

Case study had been done using 5 gas-lift wells from the Samarang field, Sabah. The case study had been commenced in order to check on the feasibility of the system workflow to optimize the available gas lift distribution in these 5 wells. The wells parameters are as follow :

WELL ID	A-01	A-02	B-01	B-02	C-01
GOR	1800	2100	680	750	1000
WATER CUT (%)	53	50	48	50	72
RESERVOIR PRESSURE (psi)	1950	1900	1200	1400	1400
OIL API GRAVITY (API)	30	32	32	32	18.5
PRODUCTIVITY INDEX	4	3.5	4.8	5	5.3
DEPTH (ft)	6328	6827.7	3929.9	3595.1	3856.7
RESERVOIR TEMPERATURE (F)	178	172	134	139	148

Table 4.9 : Case study wells' parameters

The result of the optimization are as follow :

Well ID :	A-01
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1214.925
0.30	1222.155
0.60	1226.901
0.90	1229.647
1.20	1230.893
1.50	1231.148
1.80	1230.729

Well ID :	A-02
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1329.749
0.30	1332.665
0.60	1334.949
0.90	1336.098
1.20	1336.375
1.50	1335.991
1.80	1335.074

Well ID :	B-01
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1215.440
0.30	1259.677
0.60	1286.180
0.90	1301.959
1.20	1309.415
1.50	1313.852
1.80	1317.465

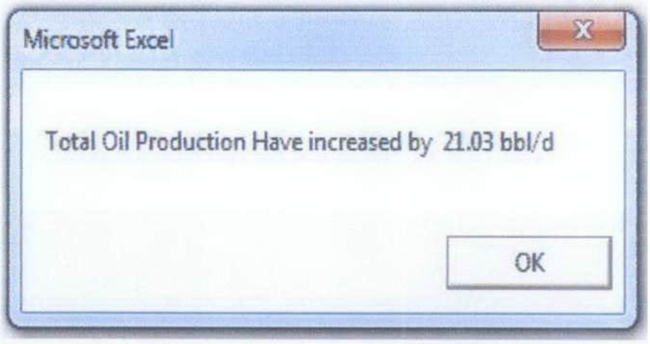
Well ID :	B-02
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	1180.815
0.30	1207.784
0.60	1225.276
0.90	1237.174
1.20	1245.252
1.50	1250.406
1.80	1253.300

Well ID :	C-01
Injection Gas Flowrate (mmscf/d)	Oil Production Flowrate (STB/d)
0.00	693.620
0.30	722.265
0.60	738.511
0.90	747.966
1.20	753.217
1.50	755.702
1.80	756.251

Table 4.10 : Optimization distribution result for case study

Maximum Total Injection Gas Rate Available : 5.5 mmscf/d

Result After Optimization		Before Optimization	
Total Oil Production :	5,880.653	Total Oil Production :	5859.618
Total Injection Gas Used :	5.40	Total Injection Gas Used :	5.40



Here are the performance curve for each of the wells :

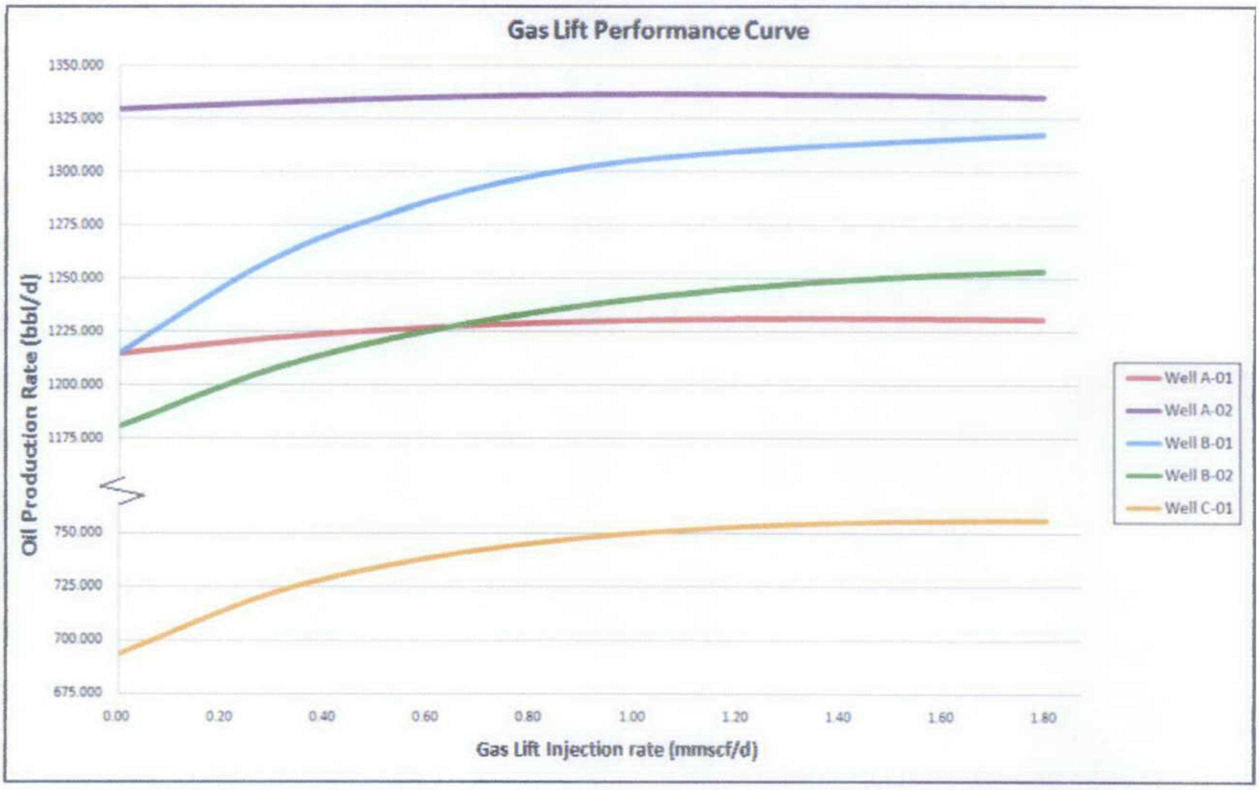


Figure 4.8 : Gas Lift Performance curve for case study optimization

<u>Discussion</u>

The result of optimization shows that there will be an increment of 21.03 oil bbl/day or 0.36 %. The total injected gas been used after the optimization is 5.4 mmscf/day which is lower than the constraint (5.5 mmscf/day) that had been set.

Well B-01 will be given the highest gas injection rate as the slope value for Well B-01 curve is the highest. This is because this well is having the lowest GOR value. Low reservoir pressure and high productivity index is also contributed to the high slope value of the curve. Although Well B-01 is having the lowest water cut value and this should reduce the slope value, however the effects of GOR, reservoir pressure and productivity index are sufficient to maintain the high slope value.

Well A-02 will be given the lowest gas injection rate as the injected gas does not plays a vital role in enhancing the well's production rate. Well A-02 is having the highest GOR value and the lowest productivity index value. Due to these factors, the performance curve for Well A-02 is nearly flat (low slope value). Increasing the injection rate of the gas will not increase much of production rate. Thus, the available gas should be given to other wells where the impact will be more significant.

The slope value for Well C-01 performance curve is quite high, make the oil production sensitive to the changes of the gas injection rate. This is due to high water cut of the well's fluid and high well productivity index value. This well is having the lowest oil API gravity value. However, this parameter did not affect the optimization result.

Well A-01 production rate is less sensitive with the changes of gas lift injection rate and can be seen from its performance curve's slope. This is because the GOR of the fluid for this well is high. High reservoir pressure and temperature also contribute in the reduction of the slope for this well's performance curve.

Well B-02 will be given a high value of gas injection rate as this well will react significantly with the changes of the gas injection rate. This can be proven by the high slope value of this well's performance curve. This is cause by the low GOR and high productivity index value.

In conclusion, the parameter that gives the most significant impact on the behavior of the gas lift distribution optimization result is the Gas Oil Ratio.

CHAPTER 5

RECOMMENDATION

5.1 Suggested future work for expansion and continuation

Increase the number of wells in the optimization studies

The number of wells in the optimization studies can be increase in order to simulate the real cases in the real oilfield. In certain field, the gas lift wells in the field that connected to a single gas distribution system can go up to 100 wells. The difference in optimization between few wells and lots of well is significant. This can be clearly seen in the well network model. This huge number of wells surely will cause a lot of error and time consuming while doing optimization. The calculation data are also will be increased with the increasing number of well in optimization. Optimization using 20 wells can generate more than 3 millions calculated data. This huge amount of data is very difficult to be stored systematically and analyzed. However, it is worth studying as it will simulate the real cases in industry.

Increase the number of constraints in analysis

In this project, the number of constraint for each optimization run is only one. It is the maximum amount of lift-gas can be injected per unit time. However, in certain real cases, there might be more than one constraint in the system. For example, the system may have a limited amount of lift-gas and also its separator cannot process more than 3000 bbl/d fluid. Thus, the optimization analysis should be modified in order to honor both of the constraints that exist within the system.

Automation calculation

In this project, the calculation step was done manually one by one. For future development, these steps can be integrate and automatically pass one calculation result to another calculation. From generating the performance curve, calculating all the possible combinations, constraining the result and up to finding the maximum oil rate, all these steps can be integrated and done by using one click button. This can be done by using a complex mathematical script. This will make the calculation time become faster and less prone to human error. However, this will also make the process to identify errors and problems more difficult. Hence, this should be done very carefully and tested several time in order to ensure that the result generate is accurate.

Refining and enlarging the range of gas lift injection rate for each wells

Refining can be done by reducing the increment rate of the injection gas rate. For this project, the increment that had been taken is 0.3 mmscf/d. For example, it can be refine to 0.1 mmscf/d so that the injection gas rate will be 1.0, 1.1, 1.2 and 1.3 mmscf/d. Refining and enlarging the range of gas lift injection rate for each well will produce more accurate and desirable results.

Study on the Pre-Optimization Process

The study on this topic can be broadened by starting the research with the post optimization process. The post optimization process are involving well test update and gas lift diagnostic. Well test update will update the current well model using a latest well test data obtained. The data will also will be validated. Gas lift diagnostic will cover the study on the single well gas lift system. The performance of the gas lift well will be diagnosed to see if the system is run in an optimum manner or not. Once the well had been confirmed that it had no problem, gas lift optimization process be implemented.

Utilize Other Calculation Method

The optimization calculation and method can be done using different type of method. The result and calculation runtime can be compared using the result done in this project. This will open up the path to see where the improvement can be done. Both of the method can also be integrate in order to create another method which will be more efficient and effective.

CHAPTER 6

CONCLUSION

This project outcome will yield a method to optimally distribute the available lift-gas to all gas lift wells in the field. One of the most common constraints in a gas lift field is the maximum available gas lift that can be used for reinjection. From this research project, the optimum distribution method for the lift gas available can be identified. This will result in achieving the maximum total field oil production rate. This will be very beneficial to the operator in order to enhance their total field oil production rate. The optimization calculation and workflow had been done utilizing production analysis software PIPESIM and Microsoft Excel VBA. The project will then proceed with analysis of different parameters that will affect the optimization result. This is essential in order to understand the concept behind the optimization process. The result yield had proved that the optimization distribution is successful as the total oil production rate had been increased and the constraint limitation of available gas lift injection rate had been honored. Analysis had shown that production fluid gas oil ratio and water cut have a great influence on the optimization result. This project will be very beneficial to the oil and gas industry as the demand for gas lift optimization is high conjunction with the depleting oil field worldwide.

REFERENCES

[1] Martinez, J. February 4-5, 2003. *"Downhole Gas Lift and Facility."* Paper presented at the ASME/API Gas Lift Workshop, held in Houston, TX.

[2] Y.C. Chia and Sies Hussain. 1999. *Gas Lift Optimization Effort and Challenges (SPE 57313).* October 1999 SPE Asia Pacific Improved Oil Recovery Conference, Kuala Lumpur, Malaysia.

[3] Herald W. Winkler. 1987. *Petroleum Engineering Handbook, Gas Lift (Chapter 5)*

[4] James F. Lea and Henry V. Nickens. 1999, *Selection of Artificial Lift (SPE 52157)*, SPE Symposium Paper , Oklahoma.

[5] H.A Djikpesse, B. Couet and D. Wilkinson. 2010. *Gas Lift Optimization Under Facilities Constraints (SPE 136977).* August 2010 Annual SPE International Conference and Exhibition, Tinapa-Calabar, Nigeria.

[6] Pengju Wang and Michael Litvak. 2008. *Gas Lift Optimization for Long Term Reservoir Simulations.* Febuary 2008 SPE Reservoir Evaluation and Engineering Symposium.

[7] R.Edwards, D.L. Marshall and K.C.Wade. 1990. *A Gas-Lift Optimization and Allocation Model for Manifold Subsea Wells (SPE 20979),* Europec 90, The Hague, Netherlands.

[8] Ronald Schoenberg, September 2001. *Constraint Optimization.* Aptech System Inc. Maple Valeey, WA.

[9] Robert L. McDonald. November, 2000. *An Introduction to VBA in Excel*

[10] H. Dale Beggs. 1991. *Production Optimization : Using NODAL Analysis,* OGCI and Petroskills Publication, Tulsa, Oklahoma.

[11] Mohammed A. Mian. *Petroleum engineering handbook for the practicing engineer, Volume 2.*

[12] R. Salazar-Mendoza. 2006. *New Representative Curves for Gas Lift Optimization (SPE 104069).* September 2006 International Oil Conference and Exhibition, Cancun, Mexico.

[13] Fernando Gutierrez, Aron Hallquist, Mack Shippen and Kashif Rashid. 2007. *A New Approach to Gas Lift Optimization Using an Integrated Asset Model (IPTC 11594).* December 2007 International Petroleum Technology Conference, Dubai, U.A.E.

[14] T.C. Handfield, T. Nations and S.G. Noonan. 2008. *SAGD Gas Lift Completions and Optimization : A Field Case Study at Surmount (SPE 117498).* October 2008 International Thermal Operations and Heavy Oil Symposium, Calgary.

[15] G. Kartoatmodjo, R. Strasser, F. Caretta, M. Jadid, G. Bakar and J. Liew. 2008. *An Integrated Approach to Field Surveillence Improve Efficiency in Gas Lift Optimization in Bokor Field, East Malaysia (IPTC 12225).* December 2008 International Petroleum Technology Conference, Kuala Lumpur, Malaysia.

[16] Yasser A. Abdallah, Nabil S. Gaber, EmadEldin A. Saad, Elsayed A. Bedair and R.E Soegiyono. 2010. *Gulf Of Suez Continuous Gas Lift Real-Time Optimization Strategy.*

[17] *Schlumberger Avocet Gas Lift Optimization Module : Improved Optimization.* Copyright © 2008 Schlumberger.

[18] Schlumberger, Services and Products, Gas Lift website. *http://www.slb.com/services/artificial_lift/gas_lift.aspx*

[19] OilGasGlossary.com, Gas Lift Definition and term related to Gas Lift website.

http://oilgasglossary.com/gas-lift.html

APPENDICES

Appendix 1.

Equation defined in VBA Coding.

```
' Equation for Oil Production Rate

Function Oil_Prod(Liq_Prod As Double, Water_Cut As Double)

    Oil_Prod = Liq_Prod * (1 - Water_Cut)

End Function
```

```
' Equation for Total Gas Injection Rate

Function Total_Inj(I1 As Double, I2 As Double, I3 As Double, I4 As Double, I5 As Double)

        Total_Inj = I1 + I2 + I3 + I4 + I5

End Function
```

```
' Equation for Total Oil Production Rate

Function Total_Prod(P1 As Double, P2 As Double, P3 As Double, P4 As Double, P5 As Double, Total_Inj As Dou

Dim Reject As String

Dim n As Double

n = Sheet1.Cells(16, 7)

    If Total_Inj < n Then

        Total_Prod = P1 + P2 + P3 + P4 + P5

    Else

        Total_Prod = "Reject"

    End If

End Function
```

Appendix 2.

VBA Coding written to select the maximum oil production rate

```
Sub maximum oil()
'
' maximum oil Macro
'

'
    Range("F22").Select
    ActiveCell.FormulaR1C1 = _
        "=MAX(Sheet2!R[-6]C[-3]:R[2736]C[-3],R[-6]C:R[2736]C,R[-6]C[3]:R[2736]C[3],R[-6]C[6]:,R[-6]C[15]:R[2736]C[
    Range("I24").Select
    Sheets("Sheet2").Select

    ActiveWindow.ScrollRow = 2746
    Range("I2765").Select
    ActiveCell.FormulaR1C1 = "Max Oil"
    Range("K2765").Select
    ActiveCell.FormulaR1C1 = "=MIN(R[7]C[2])"
    Range("K2765").Select
    Selection.ClearContents
    Range("K2765").Select
    ActiveCell.FormulaR1C1 = _
        "=MAX(R[-2749]C[-8]:R[-7]C[-8],R[-2749]C[-5]:R[-7]C[-5],R[-2749]C[-2]:R[-7]C[7],R[-2749]C[10]:R[-7]C[10])'
    Range("K2765").Select


    ActiveCell.FormulaR1C1 = _
        "=MAX(R[-2749]C[-8]:R[-7]C[-8],R[-2749]C[-5]:R[-7]C[4],R[-2749]C[7]:R[-7]C[7],R[-2749]C[10]:R[-7]C[10])"
    Range("K2765").Select
    Selection.Cut Destination:=Range("L2765")

End Sub
```

Appendix 3.

VBA Coding for result difference calculation and displayed in message box.

```
Sub extra2()

' Result Differences Calculation


    Dim x, n As Double

    n = Range("G22").Value - Range("O22").Value

    n = Format(n, "#,##0.00")

    x = ((Range("G22").Value - Range("O22").Value) / Range("O22").Value) * 100

    x = Format(x, "#,##0.00")

    MsgBox "Total Oil Production Have increased by  " & n & " bbl/d"

    MsgBox "Total Oil Production Have increased by  " & x & " %"


End Sub
```

Appendix 4.

VBA Coding for prompting computer to run simultaneous macros at one click.

```
Sub Injection_Total()
'
' Injection_Total Macro
'

    Application.Run "stadi.xlsm!Inj_Total_1"
    Application.Run "stadi.xlsm!Inj_Total_2"
    Application.Run "stadi.xlsm!Inj_Total_3"
    Application.Run "stadi.xlsm!Inj_Total_4"
    Application.Run "stadi.xlsm!Inj_Total_5"
    Application.Run "stadi.xlsm!Inj_Total_6"
    Application.Run "stadi.xlsm!Inj_Total_7"
    Application.Run "stadi.xlsm!Inj_Total_8"
    Application.Run "stadi.xlsm!Inj_Total_9"
    Application.Run "stadi.xlsm!Inj_Total_10"
    Application.Run "stadi.xlsm!Inj_Total_11"
    Application.Run "stadi.xlsm!Inj_Total_12"
    Application.Run "stadi.xlsm!Inj_Total_13"
    Application.Run "stadi.xlsm!Inj_Total_14"

End Sub
Sub Production_Rate_Total()
'
' Production_Rate_Total Macro
'
    Application.Run "stadi.xlsm!Prod_Total_1"
    Application.Run "stadi.xlsm!Prod_Total_2"
    Application.Run "stadi.xlsm!Prod_Total_3"
    Application.Run "stadi.xlsm!Prod_Total_4"
    Application.Run "stadi.xlsm!Prod_Total_5"
    Application.Run "stadi.xlsm!Prod_Total_6"
    Application.Run "stadi.xlsm!Prod_Total_7"
    Application.Run "stadi.xlsm!Prod_Total_8"
    Application.Run "stadi.xlsm!Prod_Total_9"
    Application.Run "stadi.xlsm!Prod_Total_10"
    Application.Run "stadi.xlsm!Prod_Total_11"
    Application.Run "stadi.xlsm!Prod_Total_12"
    Application.Run "stadi.xlsm!Prod_Total_13"
    Application.Run "stadi.xlsm!Prod_Total_14"

End Sub
```

Appendix 5.

Screenshot on how the calculation module will be.

Total Liquid Production Flowrate (STB/d)	Total Injection Gas Flowrate (mmscf/d)	Total Liquid Production Flowrate (STB/d)	Total Injection Gas Flowrate (mmscf/d)	Total Liquid Production Flowrate (STB/d)	Total Injection Gas Flowrate (mmscf/d)	Total Liquid Production Flowrate (STB/d)	Total Injection Gas Flowrate (mmscf/d)	Total Liquid Production Flowrate (STB/d)	Total Injection Gas Flowrate (mmscf/d)	Total Liquid Production Flowrate (STB/d)	Total Injection Gas Flowrate (mmscf/d)	Total Liqu Productio Flowrate (STB/d)
5521.225	0.30	5574.361	0.60	5611.390	0.90	5633.497	1.20	5649.819	1.50	5661.111	1.80	5668.603
5580.322	0.60	5633.458	0.90	5670.487	1.20	5692.594	1.50	5708.916	1.80	5720.208	2.10	5727.700
5616.694	0.90	5669.830	1.20	5706.859	1.50	5728.966	1.80	5745.288	2.10	5756.581	2.40	5764.072
5641.445	1.20	5694.581	1.50	5731.610	1.80	5753.717	2.10	5770.039	2.40	5781.332	2.70	5788.824
5658.762	1.50	5711.898	1.80	5748.927	2.10	5771.034	2.40	5787.356	2.70	5798.649	3.00	5806.140
5670.798	1.80	5723.934	2.10	5760.964	2.40	5783.071	2.70	5799.393	3.00	5810.685	3.30	5818.177
5679.270	2.10	5732.406	2.40	5769.436	2.70	5791.543	3.00	5807.865	3.30	5819.157	3.60	5826.649
5579.633	0.60	5632.769	0.90	5669.798	1.20	5691.905	1.50	5708.227	1.80	5719.519	2.10	5727.011
5638.730	0.90	5691.866	1.20	5728.895	1.50	5751.002	1.80	5767.324	2.10	5778.616	2.40	5786.108
5675.102	1.20	5728.238	1.50	5765.267	1.80	5787.374	2.10	5803.696	2.40	5814.989	2.70	5822.480
5699.853	1.50	5752.989	1.80	5790.019	2.10	5812.125	2.40	5828.447	2.70	5839.740	3.00	5847.232
5717.170	1.80	5770.306	2.10	5807.335	2.40	5829.442	2.70	5845.764	3.00	5857.057	3.30	5864.548
5729.206	2.10	5782.342	2.40	5819.372	2.70	5841.479	3.00	5857.801	3.30	5869.093	3.60	5876.585
5737.678	2.40	5790.814	2.70	5827.844	3.00	5849.951	3.30	5866.273	3.60	5877.565	3.90	5885.057
5615.737	0.90	5668.873	1.20	5705.902	1.50	5728.009	1.80	5744.331	2.10	5755.624	2.40	5763.116
5674.834	1.20	5727.970	1.50	5765.000	1.80	5787.106	2.10	5803.428	2.40	5814.721	2.70	5822.213
5711.206	1.50	5764.342	1.80	5801.372	2.10	5823.479	2.40	5839.801	2.70	5851.093	3.00	5858.585
5735.958	1.80	5789.094	2.10	5826.123	2.40	5848.230	2.70	5864.552	3.00	5875.844	3.30	5883.336
5753.274	2.10	5806.410	2.40	5843.440	2.70	5865.547	3.00	5881.869	3.30	5893.161	3.60	5900.653
5765.311	2.40	5818.447	2.70	5855.476	3.00	5877.583	3.30	5893.905	3.60	5905.197	3.90	5912.689
5773.783	2.70	5826.919	3.00	5863.948	3.30	5886.055	3.60	5902.377	3.90	5913.669	4.20	5921.161
5657.665	1.50	5710.801	1.80	5747.830	2.10	5789.937	2.40	5786.259	2.70	5797.551	3.00	5805.043
5716.762	1.80	5769.898	2.10	5806.927	2.40	5829.034	2.70	5845.356	3.00	5856.648	3.30	5864.140
5753.134	2.10	5806.270	2.40	5843.299	2.70	5865.406	3.00	5881.728	3.30	5893.020	3.60	5900.512
5777.885	2.40	5831.021	2.70	5868.050	3.00	5890.157	3.30	5906.479	3.60	5917.771	3.90	5925.263
5795.202	2.70	5848.338	3.00	5885.367	3.30	5907.474	3.60	5923.796	3.90	5935.088	4.20	5942.580
5807.238	3.00	5860.374	3.30	5897.403	3.60	5919.510	3.90	5935.832	4.20	5947.125	4.50	5954.617
5815.710	3.30	5868.846	3.60	5905.875	3.90	5927.982	4.20	5944.304	4.50	5955.597	4.80	5963.089
5669.741	1.80	5722.877	2.10	5759.906	2.40	5782.013	2.70	5798.335	3.00	5809.628	3.30	5817.119
5728.838	2.10	5781.974	2.40	5819.003	2.70	5841.110	3.00	5857.432	3.30	5868.725	3.60	5876.217
5765.210	2.40	5818.346	2.70	5855.376	3.00	5877.482	3.30	5893.804	3.60	5905.097	3.90	5912.589
5789.961	2.70	5843.097	3.00	5880.127	3.30	5902.234	3.60	5918.556	3.90	5929.848	4.20	5937.340
5807.278	3.00	5860.414	3.30	5897.444	3.60	5919.551	3.90	5935.873	4.20	5947.165	4.50	5954.657
5819.315	3.30	5872.451	3.60	5909.480	3.90	5931.587	4.20	5947.909	4.50	5959.201	4.80	5966.693
5827.787	3.60	5880.923	3.90	5917.952	4.20	5940.059	4.50	5956.381	4.80	5967.673	5.10	5975.165
5677.750	2.10	5730.886	2.40	5767.915	2.70	5790.022	3.00	5806.344	3.30	5817.636	3.60	5825.128
5736.847	2.40	5789.983	2.70	5827.012	3.00	5849.119	3.30	5865.441	3.60	5876.733	3.90	5884.225
5773.219	2.70	5826.355	3.00	5863.384	3.30	5885.491	3.60	5901.813	3.90	5913.105	4.20	5920.597
5797.970	3.00	5851.106	3.30	5888.135	3.60	5910.242	3.90	5926.564	4.20	5937.857	4.50	5945.348
5815.287	3.30	5868.423	3.60	5905.452	3.90	5927.559	4.20	5943.881	4.50	5955.173	4.80	5962.665
5827.323	3.60	5880.459	3.90	5917.489	4.20	5939.595	4.50	5955.917	4.80	5967.210	5.10	5974.702
5835.795	3.90	5888.931	4.20	5925.961	4.50	5948.067	4.80	5964.389	5.10	5975.682	5.40	5983.174
5578.664	0.60	5631.800	0.90	5668.829	1.20	5690.936	1.50	5707.258	1.80	5718.550	2.10	5726.042
5637.761	0.90	5690.897	1.20	5727.926	1.50	5750.038	1.80	5766.355	2.10	5777.647	2.40	5785.139
5674.133	1.20	5727.269	1.50	5764.298	1.80	5786.405	2.10	5802.727	2.40	5814.020	2.70	5821.511
5698.884	1.50	5752.020	1.80	5789.050	2.10	5811.156	2.40	5827.478	2.70	5838.771	3.00	5846.263
5716.201	1.80	5769.337	2.10	5806.366	2.40	5828.473	2.70	5844.795	3.00	5856.088	3.30	5863.579
5728.237	2.10	5781.373	2.40	5818.403	2.70	5840.510	3.00	5856.832	3.30	5868.124	3.60	5875.616
5736.709	2.40	5789.845	2.70	5826.875	3.00	5848.982	3.30	5865.304	3.60	5876.596	3.90	5884.068