Low Pressure System Performance and Economic Analysis as a Production Enhancement Initiative for Bayan Field

by

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Petroleum Engineering

10867

Dissertation submitted in partial fulfillment of

the requirement for the

Bachelor of Engineering (Hons.)

(Petroleum Engineering)

MAY 2011

Universiti Teknologi PETRONAS

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

Geosciences and Petroleum Engineering Department

Universiti Teknologi PETRONAS

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Approved by,

(Mazlin Binti Idress)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

May 2011

CERTIFICATION OF ORIGINALITY

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

(MUHAMMAD SYAZWAN BIN SAARI)

ABSTRACT

This project is aimed to determine the reliability of a new generation production enhancement technique, which is Low Pressure System or LPS. It is currently implemented in two fields in Malaysia. Bayan is one of the fields which is the main concern in this project. Since LPS is a newcomer in oil and gas industry, it is not widely applied yet to the depleting oil fields worldwide. The main concerns are to determine how efficient is LPS in boosting oil production and reactivating idle wells at Bayan field. Besides, there is a need to determine the economic viability of the system's implementation at the field, as well as finding the most potential candidates to maximize oil production from LPS. Thus, this project comes with three solid objectives. First is to determine the performance efficiency of LPS at Bayan field. Next is to determine its economic viability by conducting engineering economic analysis. The third objective is to identify new potential wells to be connected to the system. The scopes of this project revolve around calculating the percentage of increase in oil production prior to and after being connected to LPS, as well as conducting a detailed engineering economic analysis on the implementation of the system. Another scope involves building well models using WellFlo™ 2010 to identify potential well candidates for the system. A strategic methodology is used throughout this project. The four major elements include data acquisition, LPS performance analysis, engineering economic analysis and building well models. The outcome of this project has shown that the system managed to increase production from the field by 209%, and successfully reactivated idle wells. The system has also been proven as economically viable with the calculated incremental Internal Rate of Return (IRR) being higher than the Minimum Attractive Rate of Return (MARR). Lastly, two wells were identified as potential candidates to flow through the system in order to maximize production from the field.

ACKNOWLEDGEMENTS

First and foremost, praise be to the Almighty God for giving an utmost opportunity for the author to accomplish this final year project as part of the requirements for Bachelors of Engineering (Hons.) in Petroleum Engineering at Universiti Teknologi PETRONAS.

Secondly the author is grateful for all the supports shown by parents. They have continuously provided moral and financial supports until the end of this project. Also a big 'thank you' to the assigned supervisor for this project, Mrs. Mazlin Binti Idress and co-supervisor, Dr. Zulkipli Bin Ghazali who have sacrificed their time in giving guidance and necessary improvements from time to time.

Not forgetting fellow engineers and trainee at PETRONAS Carigali Sdn. Bhd. Sarawak Operations, Saiful Azri Bin Jamian, Nurelea Binti Idris, Lim Jit Sen, Nur Suryaty Binti Nayan and Thian Hui Chie for all their precious help in providing the required data and information which are sufficient for the accomplishment of this final year project.

Last but not least, the author would like to express his gratitude to fellow colleagues who have always provided moral supports and a never-ending assistance in ensuring this final year project is finished within the given time frame.

Muhammad Syazwan Bin Saari,

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LIST OF ABBREVIATIONS

AOF	Absolute Open Flow
BOPD	Barrel of Oil per Day
BYDP-B	Bayan Drilling Platform-B
BYDP-D	Bayan Drilling Platform-D
ESP	Electric Submersible Pump
FTHP	Flowing Tubing Head Pressure

GOR	Gas-Oil Ratio
HAZID	Hazard Identification
HAZOP	Hazard and Operability
IPR	Inflow Performance Relationship
IRR	Internal Rate of Return
LPS	Low Pressure System
MARR	Minimum Attractive Rate of Return
MMSCFD	Million Standard Cubic Feet per Day
MSTB/D	Thousand Stock Tank Barrel Per Day
NPV	Net Present Value
PETRONAS	Petroliam Nasional Berhad
PCSB-SKO	Petronas Carigali Sdn. Bhd. Sarawak Operations
PCP	Progressive Cavity Pump
PI	Productivity Index
PVT	Pressure Volume Temperature
SSB	Sarawak Shell Berhad
THP	Tubing Head Pressure
VLP	Vertical Lift Performance

CHAPTER 1

INTRODUCTION

1.1 PROJECT BACKGROUND

Obviously, the days of easy oil have long gone. With soaring demand and depleting reserves, every oil company around the world is striving to maximize their production. Due to matured oil fields, many wells are no longer producing, or still producing with very little oil. This includes Bayan field, which is located offshore Bintulu, Sarawak. This field is 100% owned by PETRONAS Carigali Sdn. Bhd. (PCSB) after transfer of operatorship from Sarawak Shell Berhad (SSB). Now, it is operated under Sarawak Operations (SKO).

With the current oil production of about 8.4 MSTB/d from Bayan, this field is a significant contributor to Bintulu Cluster operations, and Sarawak Operations as a whole. However, due to the declining of reservoir pressure, few idle wells and low pressure/weak wells are affecting this field's productivity. In PETRONAS term, an idle well is defined as a well that has not been producing for three months or more. Meanwhile, low pressure wells are those with low Tubing Head Pressure (THP). In order to cater these low productivity wells, PCSB-SKO has taken initiative to implement Low Pressure System as part of production enhancement project for Bayan field.

The Low Pressure System or LPS in short, is a system that utilizes the well test unloading concept, using common well testing equipment package. The uniqueness of LPS is that it utilizes old technology but repackaged as a new solution [*M Anwar et al., 2009*]. LPS applies the basic concept of fluid dynamics where fluid flows from high pressure to low pressure regions. So, if the surface operating pressure can be lowered, then more fluid can be extracted from the reservoir. However, if critical drawdown pressure is exceeded, unwanted substance from the reservoir can be introduced at the surface, especially sand. Hence, in determining the best candidates to flow through LPS, it is vital to conduct reservoir evaluation.

As of today, two fields in Malaysia were tested and the gains were more than initially expected. One of the fields has had all of its idle wells flowing and producing more than 500 barrels of oil per day (BOPD) [*M Anwar et al., 2009*]. With the implementation of LPS at Bayan field which commenced its operation in October 2008, the efficiency of this system in reactivating idle wells and boosting production from low pressure wells will be discussed. This includes determining the cost-effectiveness of LPS by performing engineering economic analysis on the system to look at its profitability.

In addition, through this research project the author will identify new wells to be LPS candidates, other than the current wells tied-in to the system. This decision will be based on building well models using WellFlo™ 2010 using Bayan's wells and reservoir data. From the models generated, it can be seen for each individual well whether they have an operating point or not. A well which doesn't have an operating point simply means that it is unable to flow naturally and thus, needs artificial lift. This kind of well will be a potential candidate to flow through LPS.

1.2 PROBLEM STATEMENT

Bayan field was awarded by SSB to PCSB starting from 31st March 1999 in the Balingian Production Sharing Contract (PSC). It is currently producing 8.4 MSTB/d of oil and gas production of 11.9 MMSCFD. By implementing LPS at Bayan Drilling Platform-B (BYDP-B) and Drilling Platform-D (BYDP-D), the performance of LPS in reactivating idle wells and boosting production in Bayan must be analysed. Moreover, the cost-effectiveness of LPS implementation must be studied to know its economic viability in order to decide whether LPS is crucial for the future of oil and gas industry.

Generally, the current wells that are producing through LPS were previously selected based on analysis using an older version of WellFlo™ software. Its latest version which might be more accurate has not been applied yet to do well model and production history matching for this field. Thus, by modelling the wells using the latest version, we may get more suitable candidates to be connected to the system. New potential wells will be identified by evaluating the well models generated. A well without an operating point will be the best candidate to flow through LPS.

1.3 OBJECTIVES

The objectives of this research project are:

i) **To determine the performance efficiency of Low Pressure System as a production enhancement initiative for Bayan field.** The efficiency of this system will be based on the percentage of increase in production from LPS wells after being connected to LPS, and also the ability of LPS to reactivate idle wells

ii) **To determine the economic viability of LPS implementation.** For the economic viability, engineering economic analysis will be conducted. Incremental Analysis approach will be used to calculate the incremental Internal Rate of Return (IRR) for the case where LPS is installed at Bayan field. The study period would be eight years. If the incremental IRR is greater than the Minimum Attractive Rate of Return (MARR), then the implementation of LPS for the next eight years will be economically viable.

iii) **To identify new potential wells to be candidates for LPS.** This will be done through well modeling and matching production history for Bayan field by using WellFlo™ 2010 software. Based on the generated well models, wells without an operating point will be selected as potential candidates.

1.4 SCOPE OF STUDY

The scope of study for this research project revolves around determining the efficiency of LPS by analyzing oil production from several wells at Bayan prior to and after flowing through LPS. The production rates of those wells before tied-in to Low Pressure System will be based on the latest well test data, while their production rates after flowing through LPS will be based on LPS report prepared by Uzma Engineering Sdn. Bhd. after production has stabilized from the wells being tied-in to the system.

Economic viability of LPS will also be among the scope of study in this research project. Information on all the costs involved in implementing LPS at Bayan field from the initial until the final stage of producing reservoir fluids through LPS will be discussed later in the next section. Basically, the economic viability will be determined by conducting an engineering economic analysis on the system to look at its profitability. There will be two cases in this analysis. One is the case of not installing LPS, while the second one will be the implementation of LPS for a period of eight years at Bayan field. From these two cases, an incremental analysis approach will be used to calculate the incremental IRR. If the resulting incremental IRR is greater than the fixed MARR, it means the investment in installing LPS is economically justified. Besides that, an investment balance diagram will also be generated for both LPS units at BYDP-B and BYDP-D, where a discounted payback period can be determined.

Last but not least, building well models and analyzing well performance will be among the scopes of study for this project. WellFlo™ will be used for these purposes. WellFlo™ system analysis software is a powerful and simple-to-use stand-alone application to design, model, optimize and troubleshoot individual oil and gas wells, whether naturally flowing or artificially lifted. With this software, the engineer builds well models using a guided step-by-step well configuration interface. Using this software results in more effective capital expenditure by enhancing the design of wells and completions, reduces operating expenditure by finding and curing production problems and enhances revenues by improving well performance.

1.5 RELEVANCY OF PROJECT

In terms of the relevancy of this project, it poses a great deal of significance to the oil and gas industry. The world nowadays is in demand of oil as the most important source of energy. With the days of easy oil that have long gone, every oil and gas companies are striving towards the hard way to produce oil and gas.

For this project, the author is applying his theoretical and practical knowledge in petroleum engineering to solve the issue of maximizing hydrocarbon production by means of production enhancement. The basic principle involved ranges from reservoir studies, well completion and production, facilities engineering and production optimization. Hence, the outcome of this project is deemed crucial towards providing energy for the future.

1.6 FEASIBILITY OF PROJECT

All the objectives stated earlier are achievable and feasible in terms of this project duration and time frame. Field and production data will be acquired from PCSB-SKO personnel, while LPS data is available at Uzma Engineering Sdn. Bhd. Besides that, the software that is going to be used in this project is available in UTP, and there should be enough time to conduct well modeling and analyze well performance within the allocated time.

Previously during industrial internship, the author has already been part of the team for Bayan LPS project and been assigned to monitor and prepare a production trend for LPS wells. Since the author already acquired the basic understanding of Low Pressure System and its operation, it can be concluded that this research project is feasible and the stated objectives can be achieved within the scope of this Final Year Project.

CHAPTER 2

LITERATURE REVIEW AND THEORY

2.1 LITERATURE REVIEW

2.1.1 Basic Principle of LPS

Low Pressure System or LPS is an innovative total solution aimed at enhancing field production within a short time cycle. It is a unique integrated subsurface and surface approach encompasses engineering study, system design and system operation [*M Anwar et al., 2009*]. The key elements in each approach are summarized below.

Engineering Study	System Design	System Operation
• Platform Screening • Reservoir and Well Evaluation • Well Modeling • Candidates Selection • Engineering Feasibility Study	• Site Visit • Equipment Package Design • HAZOP and HAZID Study • Fabrication and Construction • Hook Up and Commissioning	• Operations Management • Operations Personnel • Production Surveillance and Optimization

Table 1: Integrated Approach Involved in the LPS

LPS is actually a process of flowing wells to low surface pressure in a controlled and safe manner. Wells are usually selected in the batches of four, six or eight strings and will be connected to a custom build choke manifold from the wells' respective wellheads. In some cases, special crossovers may be required to connect the wellheads and LPS choke manifold. Next, fluids from the selected wells will be transferred to the LPS separator for separating three phase fluids. From here, the gas will flow to the knock-out drum vessel after which the gas is safely vented.

In the case where the gas is needed either for sale or gas lift purpose, a gas compressor can be installed in the system. The liquid will then flow to a surge tank before being transferred to the main platform liquid line via a specially designed fluid transfer pump [*M Anwar et al., 2009*]. The LPS flow diagram is shown in figure below.

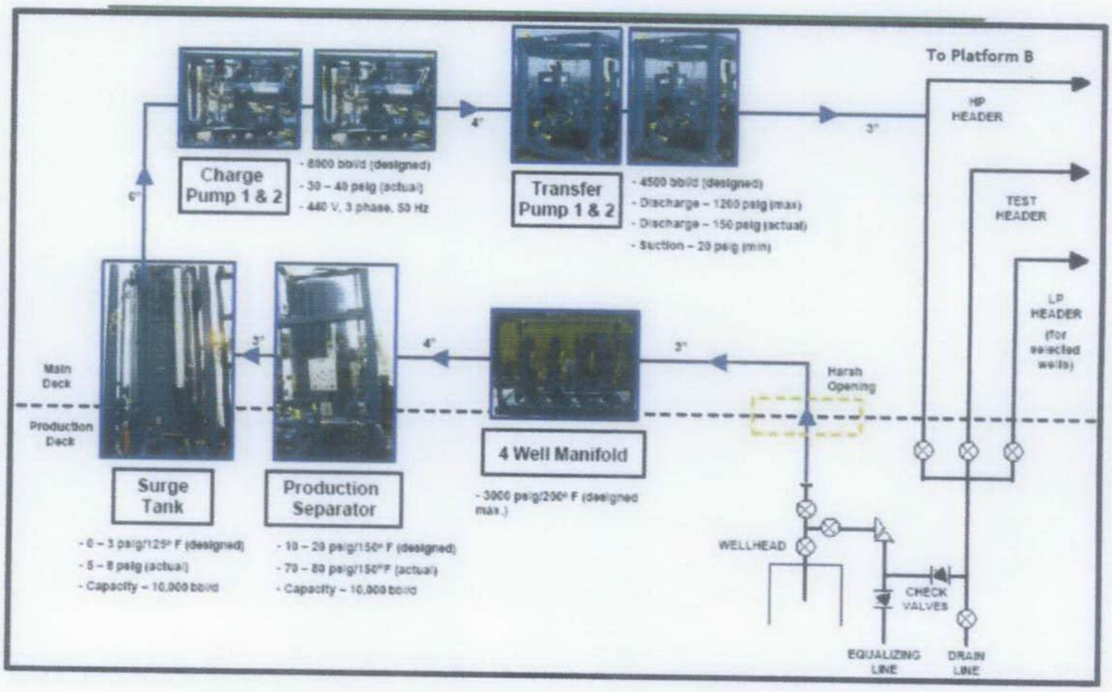

Figure 1: LPS Flow Diagram

If a shutdown occurs due to LPS failure, an emergency shutdown valve is also installed so that this event will not interfere with current platform operations. However, if platform production is interrupted, the LPS will be automatically shutdown. Gas vent lines are also available as part of the LPS unit when the platform's gas vent lines are not in operation or unavailable.

Optional equipment is available which includes a desander unit or a hydrocyclone unit to cater for potential sand production or if the current platform water handling facilities are approaching its handling capacity. The LPS equipment only uses very small footprint of around 130m^2 and weighing around 70 tons. The fabrication of the LPS system is between 12 to 16 weeks [*M Anwar et al., 2009*].

2.1.2 Why and When To Use LPS?

Oil is extracted by capitalizing on the basic concept of fluid dynamics where high pressure mass will flow to lower pressure regions. The inherently high pressure in reservoirs is used to provide the energy driving flow for pushing hydrocarbons out of the well onto the platform. The greater the pressure difference, the greater the flow rate will be.

Over time, as oil is being produced, well pressure will begin to drop and shall continue to drop. Eventually, certain well pressure levels will fall close to production line pressure, leaving insufficient pressure to drive hydrocarbon flow up to the main line. This well will then be shut in even when there are still reserves left in the reservoir. Based on the principal of fluid dynamics, by lowering the surface pressure significantly, these wells will flow again [*M Anwar et al., 2009*].

Normally many wells are grouped together and some wells could be producing healthily. Touching the main production line would be fool hardy and also the economics must be right too. This is the very essence of what LPS seeks to do, a total solution in the guise of a low pressure system that will rejuvenate mature field production within a short cycle.

The best reason to use LPS is when the backpressure of the platform export pipeline is higher than the wells with the lowest tubing head pressure, thus these wells are normally closed after production ceases. Using LPS, these wells can be enhanced to produce without interfering with the current platform production system. Moreover, no invasive downhole intervention is required.

The LPS can also help platforms with inadequate gas lift supply. These gas lifted wells can flow naturally into the LPS, thus the gas used before can now be utilized to gas lift other wells and further optimize production from these platforms. Furthermore, wells which are experiencing sub-optimal gas lift condition such as inappropriate gas lift valve design are also suitable candidates for LPS.

2.1.3 Integrated Approach

The integrated approach is divided into subsurface and surface approaches. Selection of potential candidates for LPS starts with careful platform screening. The LPS can be installed on most offshore platforms including boats or barges due to its small footprint and lightweight. Potential platforms for LPS installation are chosen based on the equipment's dry weight of 65,000 kg and its footprint of 132m^2 [*M Anwar et al., 2009*]. Information on the maximum load bearing strength of each platform will be the first criteria during the screening process.

The idea is to choose the platform with minimum or no platform modification required to ensure first oil from LPS is delivered as per the agreed schedule. The next is the availability of space on the platform to accommodate dedicated LPS equipment. This space can be scattered on the main deck or anywhere else on the platform. This information will then be used to determine the design, type and also size of the equipment that needs to be manufactured according to specification.

The next step is the selection of well candidates based on existing and historical production and reservoir data. The production data will be analyzed based on production rates, their choke sizes and tubing head pressures. If the well is producing at its maximum choke size and low tubing head pressure, then it will be an excellent candidate for LPS implementation [*M Anwar et al., 2009*].

Apart from that, information on the well's productivity index will help in predicting expected flow rates after LPS installation. This can be achieved via building a well model. Information on the expected flow rates of gas and liquid are vital in the design of the LPS equipment [*M Anwar et al., 2009*]. Ranking of potential well candidates is also based on established well productivity index and expected LPS rate.

Potential well candidates for LPS applications are screened based on a number of criteria such as maximum choke size, maximum well PI, low THP and low GOR. Further assessment by means of nodal analysis is then conducted for each well in order to predict potential barrel gain and subsequently filter the list of well candidates accordingly. Representative base case well model is established by matching it with the latest well test data. The base case model is then used to evaluate sensitivity of reducing THP to as low as 5 psi in predicting low, base and high case production gain. This analysis however, can only be done to wells with their latest production or test data.

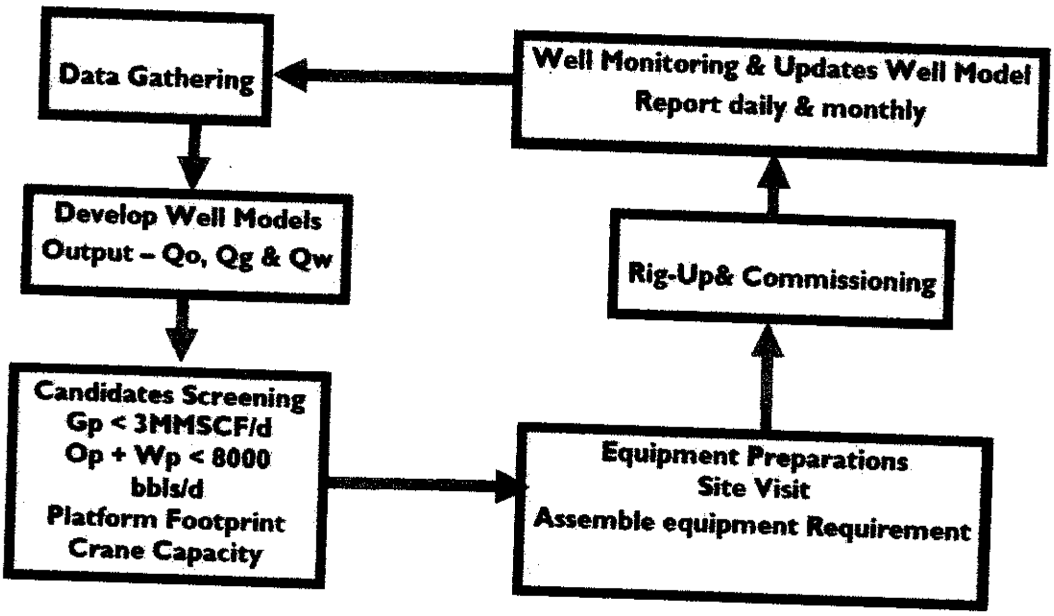

Figure 2: Process Workflow for the LPS

Once the subsurface approach is completed, the next course of action is the site survey at the identified location. The purpose of the site visit is to confirm deck space availability, potential weight limitation, tapping point where the platform pipeline header will be connected to the LPS and lastly wellhead connection type. This information will determine the design module sizes and crossover connections required. As with any new operation, the HAZOP and HAZID study will be conducted in order to identify potential hazards and mitigation measures as well as to address possible operational issues so that the LPS operation is made known to all platform production crews [*M Anwar et al., 2009*].

2.2 ENGINEERING THEORY

2.2.1 Gas Lift Robbing and Backpressure Effect

During the implementation of LPS at a field offshore Terengganu as a pilot project in 2008, a significant drop in total field production was observed after one month has elapsed. The major contributor to the production loss was actually coming from LPS wells. Two major factors such as gas lift robbing between LPS strings and non-LPS strings and additional back pressure at the main production line/header were suspected as the main reasons for the problem [*M Anwar et al., 2009*].

Gas lifted wells in the field received their gas supply from the main platform, piped in by the Gas Compression Module. The fact that this gas is being shared by four different platforms and there are no chokes available to control the gas rate being supplied to each of these platforms added further to the complications of this field gas lift network. Total gas lift network optimization can only be done the hard way, which is manual bean-up and bean-down of gas lift choke of individual wells.

Furthermore, this gas is injected into the annulus of the casing which comprised of 2 different individual strings; long and short. Hence, the amount of lift gas injected into each string's valve is beyond any control. For example, a well with a long string connected to the LPS and its short string connected to a normal line/header – obviously the string connected to LPS has much lower pressure the surface will consume or in other words, monopolize most of the gas injected into that particular well [*M Anwar et al., 2009*]. This phenomenon is called **gas lift robbing**. This left the other string in sub-optimal lift condition and consequently, experiences some production loss.

The second major factor to this drop in oil production was acute competition at the main production line/header where the LPS wells were connected back into the system and joined the rest of the non-LPS wells. The initial hypothesis suggested that LPS wells flowing with high amount of liquid are hampering the flow of the non-LPS wells at the main line/header. This can be defined as the **back pressure effect**.

2.2.2 Pressure Drop

Pressure drop would be one significant factor while producing through LPS. The pressure drop in the total system at any time will be the initial fluid pressure minus the final fluid pressure. This pressure drop is the sum of the pressure drops occurring in all of the components of the system. Since the pressure drop through any component varies with producing rate, the producing rate will be controlled by the components selected.

The selection and sizing of the individual components is very important, but because of the interaction among the components, a change in the pressure drop in one may change the pressure drop behavior in all the others. This occurs because the flowing fluid is compressible, and therefore, the pressure drop in a particular component depends not only on the flow rate through the component, but also on the average pressure that exists in the component.

The final design of a production system cannot be separated into reservoir performance and piping system performance and handled independently. The amount of oil and gas flowing into the well from the reservoir depends on the pressure drop in the piping system, and the pressure drop in the piping system depends on the amount of fluid flowing through it. Therefore, the entire production system must be analyzed as a unit [*H. Dale Beggs, 2003*].

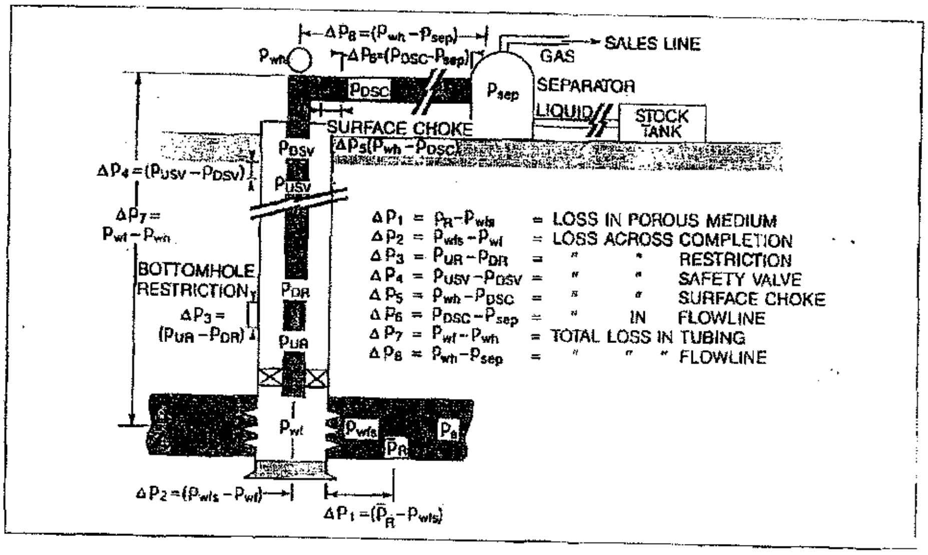

Figure 3: Possible Pressure Losses in Complete System

2.2.3 Well Productivity Index

Each formation is different in its response to back pressure or a reduction of back pressure. The producing formations that have good porosity and a good Productivity Index (PI) will give the best results when the back pressure is reduced. The PI is defined as the amount of increased fluid the well will give up for each pound of drawdown achieved at the formation.

In other words, if a well has a PI of one, then for each pound of pressure relieved from the face of the formation the well will give up one barrel of fluid. So when looking for an increase in production, we look at wells that have a high PI. For example, a well with a PI of 0.5 and a wellhead back pressure of 50 psi will increase 25 barrels a day when the wellhead pressure is reduced to 0 psi [*Charlie McCoy, 2005*].

The relationship between well inflow rate and pressure drawdown has often been expressed in the form of Productivity Index, J.

$$J = \frac{0.00708 k_o h}{\mu_o B_o \ln(0.472 \frac{r_e}{r_w})}$$

The inflow equation for oil flow can then be written as

$$q_o = J(\overline{P_r} - P_{wf}) \text{ or } J = \frac{q_o}{\overline{P_r} - P_{wf}}$$

Solving for P_{wf} in terms of q_o reveals that a plot of P_{wf} versus q_o on Cartesian coordinates results in a straight line having a slope of -1/J and an intercept of P_r at q_o= 0. If conditions are such that J is constant with drawdown, once a value of J is obtained from one production test, it may be used to predict inflow performance for other conditions.

The PI concept could also be applied to gas well inflow performance by defining a gas PI as

$$J_g = \frac{q_g}{P_r^2 - P_{wf}^2}$$

PI is the ratio of the total liquid flow rate to the pressure drawdown. It is generally measured during a production test on the well. The well is shut in until the static reservoir pressure is reached. The well is then allowed to produce at a constant flow rate of q and a stabilized bottom hole flowing pressure of P_{wf}. Since a stabilized pressure at surface does not necessarily indicate a stabilized P_{wf}, the bottom hole flowing pressure should be recorded continuously from the time the well is to flow.

It is important to note that the productivity index is a valid measure of the well productivity potential only if the well is flowing at pseudosteady-state conditions. Therefore, in order to accurately measure the productivity index of a well, it is essential that the well is allowed to flow at a constant flow rate for a sufficient amount of time to reach the pseudosteady-state as illustrated in figure blow. The figure indicates that during the transient flow period, the calculated values of productivity index will vary depending upon the time at which the measurements of P_{wf} are made.

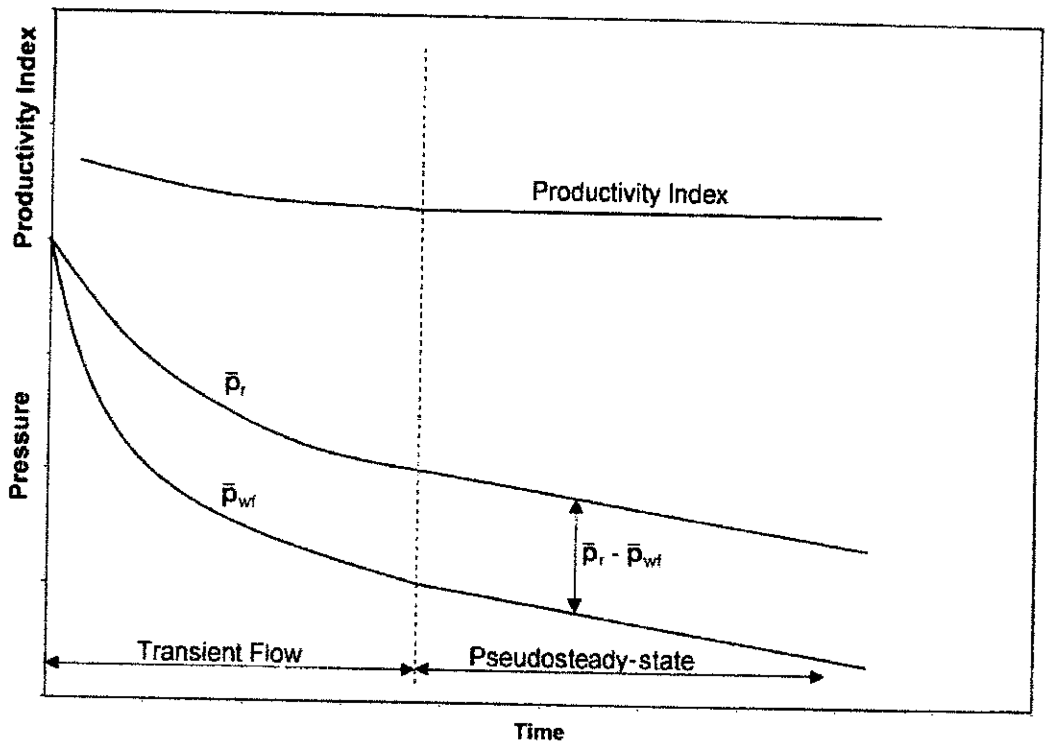

Figure 4: Productivity Index during Flow Regimes

2.2.4 Inflow Performance Relationship

The Inflow Performance Relationship (IPR) for a well is the relationship between flow rate into the wellbore and wellbore flowing pressure P_{wf}. The IPR is illustrated graphically by plotting P_{wf} versus q. If the IPR can be represented by a constant Productivity Index J, the plot will be linear and the slope of the line will be -1/J, with intercepts of $P_{wf} = P_r$ and $q = q_{max}$ at values of $q = 0$ and $P_{wf} = 0$, respectively.

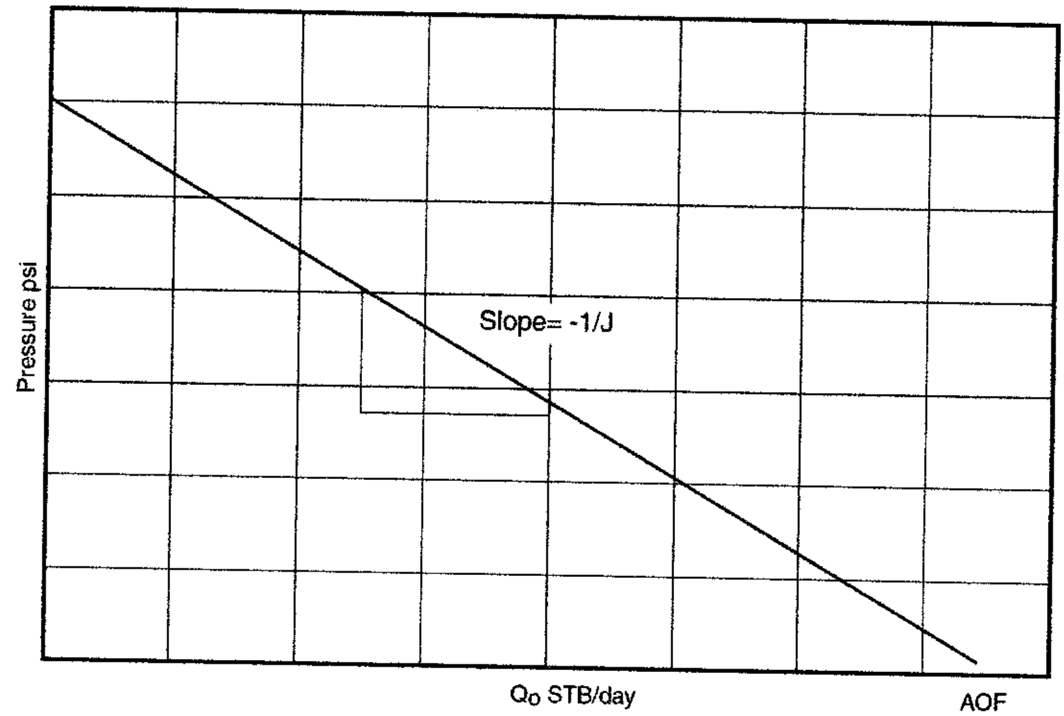

Figure 5: Inflow Performance Relationship

As shown in figure above, the plot P_{wf} against Q_o is a straight line with a slope of -1/J. This graphically representation of the relationship that exists between the oil flow rate and bottom hole flowing pressure is called the inflow performance relationship and referred to as IPR. Based on figure 5:

- When P_{wf} equals average reservoir pressure, the flow rate is zero due to the absence of any pressure drawdown.
- Maximum rate of flow occurs when P_{wf} is zero. This maximum rate is called absolute open flow and referred to as AOF. Although in practice this may not be the condition at which the well can produce, it is a useful definition that has widespread applications in the petroleum industry.

IPR equation is extensively used because of concision and utility, which is also mainly theoretical based on analysis of production performance, fluids rate forecast, lift technological design and optimization.

2.2.5 Choke Manifold

The production system begins at the wellhead, which should include at least one choke, unless the well is on artificial lift. Most of the pressure drop between the flowing tubing head pressure (FTHP) and the initial separator operating pressure occurs across this choke. The size of the opening in the choke determines the flow rate, because the pressure upstream is determined primarily by the well FTHP, and the pressure downstream is determined primarily by the pressure control valve on the first separator in the process [*Ken Arnold, 1998*].

For high pressure wells it is desirable to have a positive choke on series with an adjustable choke. The positive choke takes over and keeps the production rate within limits should the adjustable choke fail. Whenever flows from two or more wells are commingled in a central facility, it is necessary to install a manifold to allow flow from any one well to be produced into any of the bulk or test production systems. For LPS, the selected wells which usually in the batches of four, six or eight strings will be connected to a custom build choke manifold from the wells' respective wellheads. Special crossovers may be required to connect the wellheads and LPS choke manifold.

Figure 6: LPS Choke Manifold

2.2.6 Gas-Oil Ratio

While implementing LPS, it is necessary to understand the basic concept of Gas-Oil Ratio or GOR. Among the criteria of an LPS candidate well is a well with low GOR. Hence, the understanding of this concept is deemed crucial.

The produced GOR at any particular time is the ratio of the standard cubic feet of total gas being produced at any time to the stock-tank barrels of oil being produced at that same instant [*Tarek Ahmad, 2000*]. Thus, it is known as instantaneous GOR, and can be described mathematically by the following expression:

$$GOR = R_s + \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{\mu_o B_o}{\mu_g B_g}\right)$$

Where; GOR = instantaneous gas-oil ratio, scf/STB

R_s = gas solubility, scf/STB

k_{rg} = relative permeability to gas

k_{ro} = relative permeability to oil

B_o = oil formation volume factor, bbl/STB

B_g = gas formation volume factor, bbl/scf

μ_o = oil viscosity, cp

μ_g = gas viscosity, cp

The instantaneous GOR equation is of fundamental importance in reservoir analysis. There are three types of GOR, all expressed in scf/STB, which must be clearly distinguished from each other. They are:

- Instantaneous GOR
- Solution GOR

- Cumulative GOR

The solution GOR is a PVT property of the crude oil system. It is commonly referred to as gas solubility and denoted by R_s. it measures the tendency of the gas to dissolve in or evolve from the oil with changing pressures. It should be pointed out that as long as the evolved gas remains immobile, the instantaneous GOR is equal to the gas solubility.

$$GOR = R_s$$

The cumulative GOR R_p,should be clearly distinguished from the producing instantaneous GOR. The cumulative GOR is defined as:

$$R_p = \frac{G_p}{N_p}$$

Where; R_p = cumulative gas-oil ratio, scf/STB

G_p = cumulative gas produced, scf

N_p = cumulative oil produced, STB

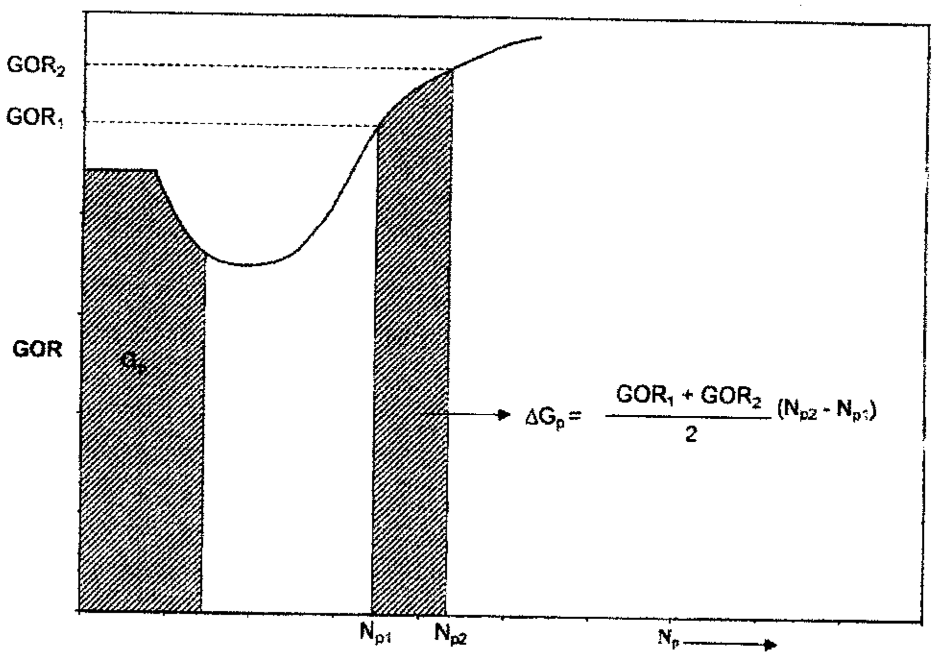

Figure 7: Relationship between GOR and G_p

2.3 ECONOMIC ANALYSIS CONCEPTS

2.3.1 Minimum Attractive Rate of Return (MARR)

The MARR is usually a policy issue resolved by the top management of an organization in view of numerous considerations. Among these considerations are the following:

- The amount of money available for investment, and the source and cost of these funds (i.e., equity funds or borrowed funds)
- The number of good projects available for investment and their purpose (i.e., whether they sustain present operations and are essential, or whether they expand on present operations and are elective)
- The amount of perceived risk associated with investment opportunities available to the firm and the estimated cost of administering projects over short planning horizons versus long planning horizons.
- The type of organization involved (i.e., government, public utility, or private industry)

In theory, the MARR, which is sometimes called the hurdle rate, should be chosen to maximize the economic well-being of an organization, subject to the types of considerations just listed. How an individual firm accomplishes this in practice is far from clear-cut and is frequently the subject of discussion.

2.3.2 Internal Rate of Return (IRR)

IRR is the discount rate often used in capital budgeting that makes the net present value of all cash flows from a particular project equal to zero. Generally speaking, the higher a project's internal rate of return, the more desirable it is to undertake the project. As such, IRR can be used to rank several prospective projects a firm is considering. Assuming all other factors are equal among the various projects, the project with the highest IRR would probably be considered the best and undertaken first.

IRR can be defined as the rate of growth a project is expected to generate. While the actual rate of return that a given project ends up generating will often differ from its estimated IRR rate, a project with a substantially higher IRR value than other available options would still provide a much better chance of strong growth. IRRs can also be compared against prevailing rates of return in the securities market. If a firm can't find any projects with IRRs greater than the returns that can be generated in the financial markets, it may simply choose to invest its retained earnings into the market.

When analyzing two investments, one more expensive than the other, the internal rate of return on the difference (increment) in their prices; that is, a measurement of the extra potential return of the more expensive investment. An internal rate of return is an estimate for the potential yield on an investment; calculating the incremental internal rate of return is a tool to help an investor decide whether the added risk of increased expenditure is worth the potential reward. Generally, if the incremental internal rate of return is higher than the minimum acceptable rate of return, the more expensive investment is considered the better one.

2.3.3 Discounted Payback Period

It is a capital budgeting procedure used to determine the profitability of a project. In contrast to an NPV analysis, which provides the overall value of a project, a discounted payback period gives the number of years it takes to break even from undertaking the initial expenditure. Future cash flows are considered are discounted to time "zero." This procedure is similar to a payback period; however, the payback period only measure how long it take for the initial cash outflow to be paid back, ignoring the time value of money.

Projects that have a negative net present value will not have a discounted payback period, because the initial outlay will never be fully repaid. This is in contrast to a payback period where the gross inflow of future cash flows could be greater than the initial outflow, but when the inflows are discounted, the NPV is negative.

2.3.4 Sensitivity Analysis

This analysis is a technique used to determine how different values of an independent variable will impact a particular dependent variable under a given set of assumptions. This technique is used within specific boundaries that will depend on one or more input variables, such as the effect that changes in interest rates will have on a bond's price. Sensitivity analysis is a way to predict the outcome of a decision if a situation turns out to be different compared to the key prediction(s).

Sensitivity analysis is very useful when attempting to determine the impact the actual outcome of a particular variable will have if it differs from what was previously assumed. By creating a given set of scenarios, the analyst can determine how changes in one variable(s) will impact the target variable.

For example, an analyst might create a financial model that will value a company's equity (the dependent variable) given the amount of earnings per share (an independent variable) the company reports at the end of the year and the company's price-to-earnings multiple (another independent variable) at that time. The analyst can create a table of predicted price-to-earnings multiples and a corresponding value of the company's equity based on different values for each of the independent variables.

CHAPTER 3

METHODOLOGY

3.1 RESEARCH METHODOLOGY

Basically, there are eight strategic approaches involved in this project research methodology. Those elements will be further discussed below.

3.1.1 Problem Statement

- Idle wells and low pressure wells at Bayan are giving low production
- The efficiency of LPS as a production enhancement technique must be determined
- The economic viability of LPS implementation must be determined
- New potential wells must be identified to be the next LPS well candidates

3.1.2 Project Objectives

- To determine the performance efficiency of Low Pressure System as a production enhancement initiative for Bayan field
- To determine the economic viability of LPS implementation
- To identify potential wells to be candidates for LPS

3.1.3 Background Study

- Identify the relevancy of LPS implementation at Bayan field
- Research on LPS related case study

3.1.4 Literature Review & Theory

- Research on the mechanism of LPS, its basic principle and process flow
- Go through the theories involved in LPS operation
- Study on engineering economic analysis

3.1.5 Data Acquisition

- Acquire Bayan wells production history data and latest idle strings inventory
- Acquire Bayan LPS daily report from Uzma Engineering Sdn. Bhd.
- Acquire data on costs involved in implementing LPS at Bayan field

3.1.6 Data Analysis & Calculation

- Analyze production from Bayan wells before and after flowing through LPS
- Calculate the percentage of idle wells reactivation and increment in production
- Perform engineering economic analysis on the system
- Analyze the current LPS design and operational procedures
- Generate well models using WellFlo™ software

3.1.7 Discussion of Results & Recommendations

- Discuss the efficiency of LPS from the analysis on production gain
- Discuss the economic viability and profitability of the system
- Analyzing well models generated using WellFlo™
- Identify potential wells to be LPS cadidates

3.1.8 Conclusion

- Conclude on the efficiency of LPS as a production enhancement initiative for Bayan field
- Conclude on the economic viability of LPS
- Propose wells that have been identified as a potential LPS candidates

3.2 PROJECT ACTIVITIES

In realizing the goals of this research project, a well-planned and strategic methodology approach will be used. Based on the provided duration and timeline, it is possible to accomplish and meet all the objectives, through accurate time management. Some of the activities will involve personnel from oil and gas industry, which in this case, PETRONAS Carigali Sdn. Bhd. Sarawak Operations (PCSB-SKO) and Uzma Engineering Sdn. Bhd. The author will personally meet the engineers involved in LPS by means of attachment and visits. Below are among the project activities involved, based on chronological order.

3.2.1 Conduct research on Low Pressure System and related case study.

This will be done by means of studying SPE papers, textbook references, petroleum society and technical papers which are related to LPS. From this research, it is expected that a deep understanding in LPS mechanism, basic principle and process flow would be gained which will make it easier to proceed with the next course of action. An understanding in the process flow of LPS is crucial in order to determine which element can be further optimized to enhance the efficiency of the system.

3.2.2 Acquire Bayan production history data and idle strings inventory.

The author will request these data from Bayan Field Engineer and Production Analyst from PCSB-SKO side to serve as references for this project. From the well production history data, the production rate of each well in Bayan can be known. Meanwhile, the latest idle strings inventory will give a clear sight on the list of idle wells at Bayan and future action plans to reactivate those wells. In order to calculate the percentage of idle wells reactivation by using LPS, it is important to have these data.

3.2.3 Acquire Bayan LPS daily report from Uzma Engineering Sdn. Bhd.

In this report, every wells tied-in to LPS is mentioned as well as the daily oil and gas production from the system. The flow rate of oil is usually recorded every two hours. Besides that, all activities done by the contractors are written in the report for clarification purpose. From these daily reports, oil production trend from LPS wells will be prepared in a Microsoft Excel document.

By analyzing and comparing production rate from selected wells prior to and after being tied-in to LPS, the efficiency of LPS in enhancing production and reactivating idle wells from Bayan field can be determined. The wells' production rate before tied-in to the system will be based on the latest well test data.

3.2.5 Acquire data on costs involved in installing LPS unit at Bayan field.

A discussion will be made with Bayan LPS Project Engineer from PCSB-SKO side regarding all costs involved. Then, the costs will be used to generate cash flows for the purpose of engineering economic analysis. From here, it can be determined whether the implementation of LPS at Bayan is economically viable or not.

3.2.6 Discussion on selecting LPS candidate wells.

A discussion will also be made with Bayan Production Analyst and Production Technologist from PCSB side in the process of selecting the next candidates for LPS. Here, the author will identify new potential wells by analyzing the wells' characteristics such as its THP, production rate, productivity index, choke size and GOR. There may be a need to use software such as PROSPER and GAP or other related software in order to analyze well performance by means of studying its inflow and outflow curves. By using these software, new well models for Bayan field will be generated. From here, it can be determined which wells are most suited to be LPS candidates so that total production from this field can be optimized and revenue can be maximized.

3.2.4 Analyze production prior to and after flowing through LPS.

3.3 KEY MILESTONES

The key milestones for Final Year Project II have been planned and organized in detail, as summarized below:

Week 1	: Acquiring cost data for LPS installation
Week 2	: Acquiring latest LPS production report
Week 3	: Analyzing performance of LPS wells
Week 4	: Calculating percent of increase in production & idle well reactivation
Week 5-6	: Conducting engineering economic analysis
Week 7	: Acquiring LPS wells & reservoir data
Week 8	: Submission of Progress Report
Week 8-9	: Building well models using WellFlo™
Week 9	: Performing Nodal Analysis on LPS wells
Week 9-10	: Analyzing suitable wells to be LPS candidates
Week 10	: Identify new LPS candidate wells
Week 11	: Pre-EDX, submission of draft Final Report & Technical Paper
Week 12	: EDX & Submission of Final Report
Week 13	: Oral presentation

3.4 FINAL YEAR PROJECT GANTT CHART

No.	Detail / Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Topic selection / confirmation														
2	Preliminary literature review on LPS														
3	Submission of extended proposal														
4	Research study on LPS														
5	Acquire Bayan well production history data and latest idle strings inventory														
6	Acquire Bayan daily LPS report from Uzma Engineering Sdn. Bhd.														
7	Project defense and progress evaluation														
8	Acquire data on costs involved in installing LPS unit at Bayan field														
9	Study the design of LPS and its operation														
10	Discussion on selecting LPS candidate wells														
11	Analysis on research findings														
12	Submission of interim draft report														
13	Submission of interim report														

Figure 8: FYP I Gantt Chart

No.	Detail / Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Acquiring cost data for LPS installation														
2	Acquiring latest LPS production report														
3	Analyzing performance of LPS wells														
4	Calculating percentage of increase in production & idle well reactivation														
5	Conducting engineering economic analysis														
6	Acquiring LPS wells and reservoir data														
7	Submission of Progress Report														
8	Building well models using WellFlo														
9	Performing Nodal Analysis on LPS wells														
10	Analyzing suitable wells to be LPS candidates														
11	Propose new LPS candidate wells														
12	Suggest improvements in LPS														
13	Pre-EDX & draft Final Report Submission														
14	Submission of Technical Paper														
15	EDX														
16	Submission of Final Report														
17	Oral Presentation														

Figure 9: FYP II Gantt Chart

3.5 TOOLS / EQUIPMENTS REQUIRED

3.5.1 WellFlo™ Software

In this project, there is a need to use WellFlo™ software to build well models and perform Nodal Analysis such as optimizing the pressure drop in LPS by changing the tubing size and see its effect on production rate.

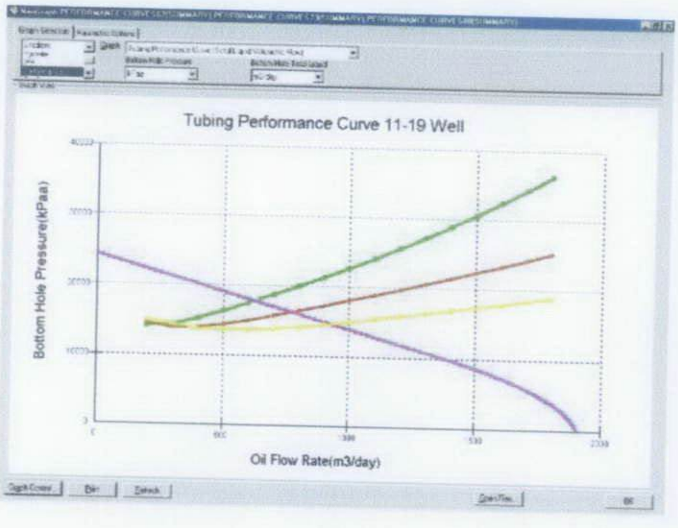

Figure 10: Data Generated Using WellFlo™

WellFlo™ systems analysis software is a powerful and simple-to-use stand-alone application to design, model, optimize and troubleshoot individual oil and gas wells, whether naturally flowing or artificially lifted. With this software, the engineer builds well models, using a guided step-by-step well configuration interface. These accurate and rigorous models display the behavior of reservoir inflow, well tubing and surface pipeline flow, for any reservoir fluid. Using WellFlo software results in more effective capital expenditure by enhancing the design of wells and completions, reduces operating expenditure by finding and curing production problems and enhances revenues by improving well performance [*Weatherford, 2008*].

3.5.2 PROSPER Software

PROSPER is a well performance, design and optimization program which is part of the Integrated Production Modeling Toolkit (IPM). This tool is the industry standard well modeling with the major operators worldwide.

This software is designed to allow the building of reliable and consistent well models, with the ability to address each aspect of wellbore modeling viz, PVT (fluid characterization), VLP correlations (for calculation of flowline and tubing pressure loss) and IPR (reservoir inflow).

It provides unique matching features, which tune PVT, multiphase flow correlations and IPRs to match measured field data, allowing a consistent well model to be built prior to use in prediction (sensitivities or artificial lift design). PROSPER enables detailed surface pipeline performance and design; Flow regime, hydrates flag, pipeline stability studies, slug size and frequency [*Petroleum Experts Ltd, 2010*].

In PROSPER, a logical interface is available to help the user, with the engineer working left to right, top to bottom, along the menu to build the model. In this way only the relevant data screens are displayed for the engineer to populate.

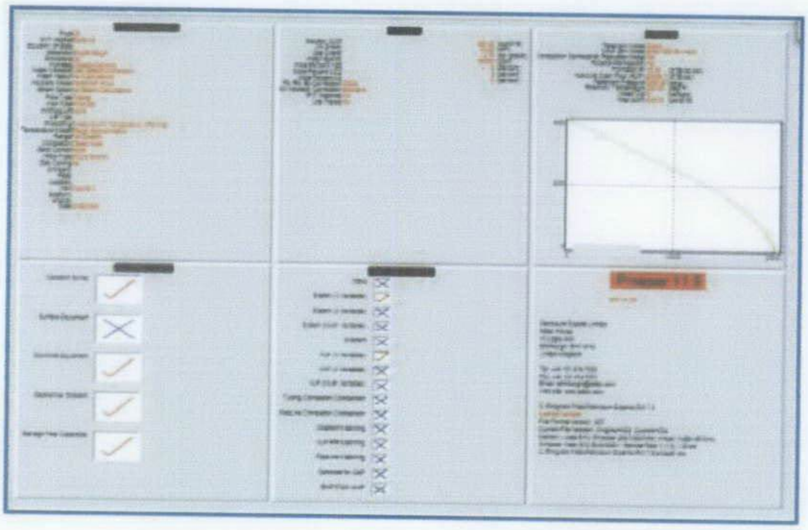

Figure 11: PROSPER Logical Interface

3.5.3 GAP Software

GAP is a multiphase optimizer of the surface network which links with PROSPER and MBAL to model entire reservoir and production systems. GAP can model production system containing oil, gas and condensate, in addition to gas or water injection systems.

GAP enables the engineer to build representative field models, that include the reservoirs, wells and surface pipeline production and injection system. The production and injection system can be optimized to maximize production or revenue, while honouring field and system constraints at any level.

Moreover, production forecast can be run to optimize the system overtime, with the changing field and operating system conditions accounted for as part of the forecast. GAP has the most powerful and fastest optimization engine in the industry [*Petroleum Experts Ltd, 2010*].

Among the applications of GAP software are:

- Full field surface network design.
- Naturally flowing plus artificial lifted – gas lift, PCP, HSP, Jet and Rod Pump, ESP, plus intermittent gas lift; wells can all be included in the same production system model.
- Field Optimization studies with mixed naturally flowing and artificial lift systems.
- Multiphase Looped Network Optimization.
- Fast and robust Global Optimization algorithm using Non-Linear Programming, NLP.
- Advices on wellhead choke setting to meet reservoir management target.
- GAP links to PROSPER (well models) and MBAL (reservoir tank model) to allow entire production systems to be modeled and optimized over the life of the field.
- Pipeline Flow Assurance studies.
- Centrifugal and reciprocating compressor and pump system modeling.

CHAPTER 4

RESULTS / FINDINGS

4.1 PERFORMANCE OF LOW PRESSURE SYSTEM

The performance of LPS is measured using two methods, first is by looking at the percentage of increase in production and secondly by the number of idle wells reactivated. In Bayan field, there are two units of LPS which are installed at two platforms, namely Bayan Drilling Platform-B (BYDP-B) and Bayan Drilling Platform-D (BYDP-D). Thus in this project the performance of LPS will be evaluated on both platforms.

It should be pointed out that the performance of this system is determined based on the availability of the data. For BYDP-B, the data available is only from April 2010 until October 2010. Meanwhile, for BYDP-D the data acquired is from August 2008 until February 2009. So, only these ranges of production data will be used to analyze the performance of LPS.

Generally, it is more relevant and representative to measure the performance of LPS based on percentage of increase in production, rather than the second method. However, that is not the case for BYDP-D. Before being connected to LPS, the well candidates at BYDP-D were not producing at all which made them idle wells. With oil production of 0 STB/D from those wells previously, it is not possible to calculate the percentage of increase in production after being tied-in to LPS. Thus, for BYDP-D the performance of LPS will be measured by looking at whether those idle wells were reactivated or not after being connected to LPS.

Tabulated below is the oil production data from LPS wells on both platforms, before being connected to the system.

BYDP-B		BYDP-D	
Well: 209S, 211 & 213S		**Well: 404S, 405S, 406L & 408L**	
Date	**STB/D**	**Date**	**STB/D**
April 2010	202	August 2008	0
May 2010	229	September 2008	0
June 2010	445	October 2008	0

Table 2: Oil Production from BYDP-B & BYDP-D (Pre-LPS)

After the above wells were tied-in to their respective LPS unit, a highly significant increase in oil production was observed. It is important to note that LPS candidate wells are never permanent, and are changing from time to time depending on each well's performance while producing through the system. Therefore, to generate a reliable result, pre-LPS and post-LPS production will only be based on the same well candidates. The post-LPS production data is summarized in the table below.

BYDP-B		BYDP-D	
Well: 209S, 211 & 213S		**Well: 404S, 405S, 406L & 408L**	
Date	**STB/D**	**Date**	**STB/D**
August 2010	753	December 2008	1015
September 2010	1079	January 2008	780
October 2010	876	February 2008	1575

Table 3: Oil Production from BYDP-B & BYDP-D (Post-LPS)

Now, the percentage of increase in oil production from LPS wells at BYDP-B can be calculated, with the following assumptions:

- Average pre-LPS production = (202 + 229 + 445) / 3 = 292 STB/D
- Average post-LPS production = (753 + 1079 + 876) / 3 = 903 STB/D

Thus,

$$\% \, of \, increase \, in \, production = \frac{(Average \, post \, LPS) - (Average \, pre \, LPS)}{Average \, pre \, LPS \, production} \, x \, 100$$

$$= \frac{903 - 292}{292} \, x \, 100$$

$$= 209\%$$

It is shown that the implementation of LPS at BYDP-B has increased production from three wells by 209%.

As for BYDP-D, it can be observed that the four well candidates namely 404S, 405S, 406L and 408L were reactivated after flowing through LPS and not only that, they were producing with a very high rate which signifies the success of Low Pressure System in reactivating idle wells.

Figure 12: A Well Being Tied-in To LPS

4.2 ECONOMIC VIABILITY OF LOW PRESSURE SYSTEM

In order to determine the economic viability of LPS, a detailed engineering economic analysis has been conducted. In this analysis, the aim was to evaluate whether the implementation of the new system which is LPS would be more profitable or not compared to the case of "do nothing". The method that has been used was called Incremental Analysis. From this analysis, the Internal Rate of Return (IRR) of the resulting cash flows was determined. If the calculated IRR is greater than the Minimum Attractive Rate of Return (MARR), then the implementation of LPS is economically justified.

However, there were a number of assumptions that needed to be taken into consideration. In this project, we actually want to determine whether the use of LPS at BYDP-B and BYDP-D over the next eight years would be beneficial or not in terms of economic return. But as we know, accurate results would be impossible considering that oil price is always fluctuating, USD-MYR exchange rate would not be constant over time and oil production would not necessarily follow the one forecasted. So, the involved assumptions were as follows:

- Oil price was assumed to stay at 80 USD/bbl over the next eight years
- USD-MYR exchange rate would be constant at 3.5
- Oil production from BYDP-B and BYDP-D without installing LPS would follow the baseline at 200 STB/D, which is an ideal case
- After producing through LPS, the production rate from LPS wells would follow the forecasted production

To cater for the uncertainty in the investment, sensitivity analysis is carried out within ±20% of the best estimates. Sensitivity analysis is a way to predict the outcome of the expected economic return if the above assumptions turn out to be different compared to the best estimates. So to determine the economic viability of LPS, Incremental Analysis was applied to calculate the IRR, payback period of the system and also to generate an Investment Balance Diagram.

Prior to conducting Incremental Analysis, we will now take a look at the baseline production (without LPS) and the forecasted production (with LPS) from June 2011 until May 2019 as shown in Appendix I. The figures were prepared by PCSB's engineers and Production Analysts who were involved in this LPS project.

Those figures in Appendix I were used to generate cash flow for the Incremental Analysis. The analysis was done to both BYDP-B and BYDP-D. For each platform, there were two alternatives being taken into consideration, which were A1 and A2. A1 was the alternative of not using LPS, while A2 was the alternative of using LPS. Note that the aim of this analysis was to determine whether the implementation of LPS would be economically viable or not for the next eight years. Thus the study period of the Incremental Analysis would be eight years. Before generating the cash flow, all costs involved in installing LPS should be identified. The installation and monthly costs for the system were tabulated in the table below:

Cost	Amount (RM)
Once Off	
Site visit	69,000.00
Preparation for basic package	220,000.00
Transportation (return)	779,700.00
Work barge	1,050,000.00
Upgrading cost	1,000,000.00
Once off total	**3,118,700.00**
Monthly	
POB cost	18,000.00
Basic rental	823,200.00
Cabin	3,378.00
Diesel (per month)	2,000.00
Vent stack rental	19,958.00
Monthly total	**866,536.00**

Table 4: Total LPS Costs

Based on the stated assumptions previously, and using the figures in Table 4 and Table 5, detailed cash flows have been generated in Microsoft Excel. IRR for the implementation of LPS at both BYDP-B and BYDP-D were also calculated using the IRR function in Microsoft Excel.

The theory behind IRR is, if the calculated IRR is greater than MARR, then the proposed project is economically justified. IRR is commonly used to evaluate the desirability of investments or projects. The higher a project's IRR, the more desirable it is to undertake the project. Assuming all projects require the same amount of up-front investment, the project with the highest IRR would be considered the best and undertaken first. Thus in this case, if the value of IRR is greater than MARR which is 15%, the implementation of LPS is proven to be economically viable.

Two cash flows were generated using Microsoft Excel. The respective IRR for both cash flows were also calculated, as shown below:

MARR =	15%	
Study Period =	8 years	
	A1 (Not using LPS)	A2 (Using LPS)
Capital Investment	$0.00	$3,985,236.00

EOY	A1	A2	A2 - A1
0	$0.00	-$3,985,236.00	-$3,985,236.00
1	$20,160,000.00	$35,584,324.06	$15,424,324.06
2	$20,160,000.00	$33,193,107.29	$13,033,107.29
3	$20,160,000.00	$28,240,448.96	$8,080,448.96
4	$20,160,000.00	$23,850,487.55	$3,690,487.55
5	$20,160,000.00	$19,959,292.16	-$200,707.84
6	$20,160,000.00	$16,510,195.44	-$3,649,804.56
7	$20,160,000.00	$13,452,968.28	-$6,707,031.72
8	$20,160,000.00	$10,743,088.37	-$9,416,911.63
		IRR =	367%

Figure 13: LPS Cash Flow at BYDP-B

MARR =	15%	
Study Period =	8 years	
	A1 (Not using LPS)	A2 (Using LPS)
Capital Investment	$0.00	$3,985,236.00

EOY	A1	A2	A2 - A1
0	$0.00	($3,985,236.00)	($3,985,236.00)
1	$20,160,000.00	$68,814,035	$48,654,035.44
2	$20,160,000.00	$59,814,301	$39,654,300.79
3	$20,160,000.00	$51,837,072	$31,677,072.15
4	$20,160,000.00	$44,766,177	$24,606,177.36
5	$20,160,000.00	$38,498,643	$18,338,643.19
6	$20,160,000.00	$32,943,196	$12,783,195.72
7	$20,160,000.00	$28,018,931	$7,858,931.12
8	$20,160,000.00	$23,654,137	$3,494,137.49
		IRR =	1202%

Figure 14: LPS Cash Flow at BYDP-D

From Figure 13 and Figure 14, it is observed that the values of incremental IRR for LPS implementation at BYDP-B and BYDP-D are 367% and 1202%, respectively. Since these values are far greater than MARR of 15%, this investment is viable. Hence, this clearly signifies that Low Pressure System should be implemented at both platforms for the next eight years.

Based on the cash flows for both LPS implementation at both platforms, two Investment Balance Diagrams have been generated, as shown in Appendix II. An Investment Balance Diagram describes how much money is tied up in a project and how the recovery of funds behaves over its estimated life. Referring to the diagram, the upward lines represent annual returns, while the dashed lines represent opportunity cost of interest.

The discounted payback period for implementation of LPS is also indicated in the Investment Balance Diagram. Out of eight years, it can be seen that only 1 year is required for the investment in LPS to achieve break even or in other words, to start generating income for both BYDP-B and BYDP-D. Thus LPS installation is highly economical and able to generate profits in a short period of time.

To cater for the uncertainty in the investment, sensitivity analysis is carried out within ±20% of the best estimates. Parameters taken into consideration in this analysis are oil price, USD-MYR exchange rate and useful life of LPS, which in this case are the uncertainties. The spider-plot generated is as shown below:

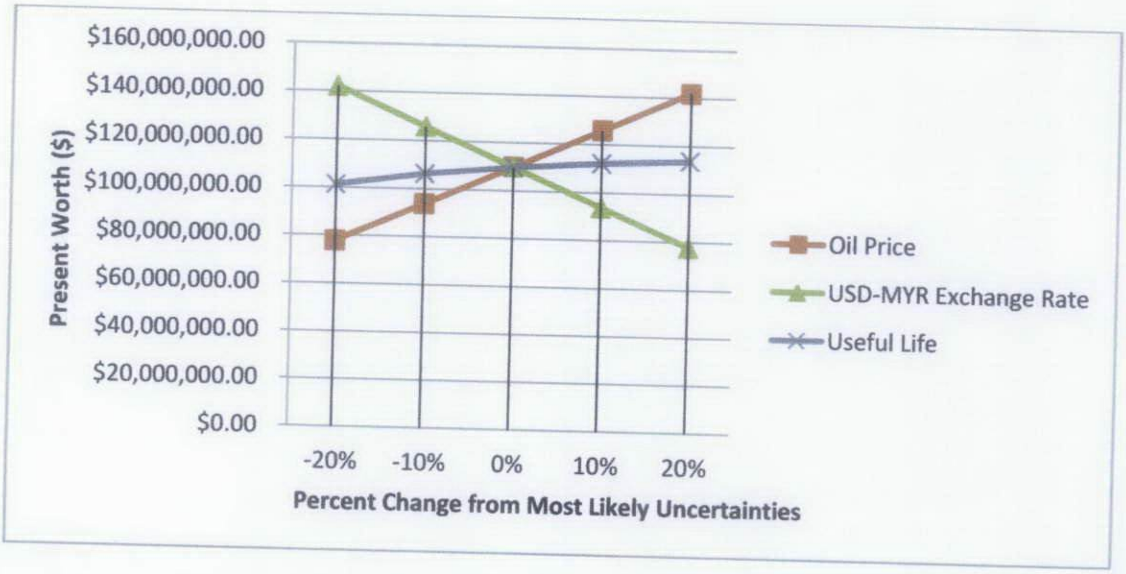

Figure 15: Sensitivity Analysis for LPS Implementation

From the plot, it can be concluded that the most sensitive variables in running LPS are oil price and USD-MYR exchange rate. Changes in these values may give a great impact to the economics of LPS. As long as oil price and exchange rate stay sufficiently high, profits generated from LPS is maximized. Also, it is seen that the useful life of LPS only creates a minor effect towards the profitability of the system. And of course, the longer it is implemented, the more profits are gained.

4.3 POTENTIAL LPS WELL CANDIDATES

Several well models have been generated using WellFlo™ 2010. Among the candidates for BYDP-B are well 204, 206, 209 and 211. Meanwhile, for BYDP-D the candidates are well 404, 405, 406 and 410. All these wells have been modeled based on their respective well data, in order to choose which of them are unable to flow naturally or in other words, having low reservoir pressure and low THP.

The aim of the modeling was to generate flow curve for each well and observe whether there is an operating point for natural flow. If there is, those wells will be kept to produce on its own or either by the current gas lift support. If a gas lifted well is unable to flow, it can even become an LPS candidate.

Upon conducting well modeling, two wells were identified as potential candidates. One of them was BYDP-B's 209 and the other one was BYDP-D's 410. They were selected due to the fact that these two wells have no operating points. Thus, they needed artificial lift to flow. This made them the best and most suitable candidates to flow through LPS. The flow curves for both wells are shown in figures below:

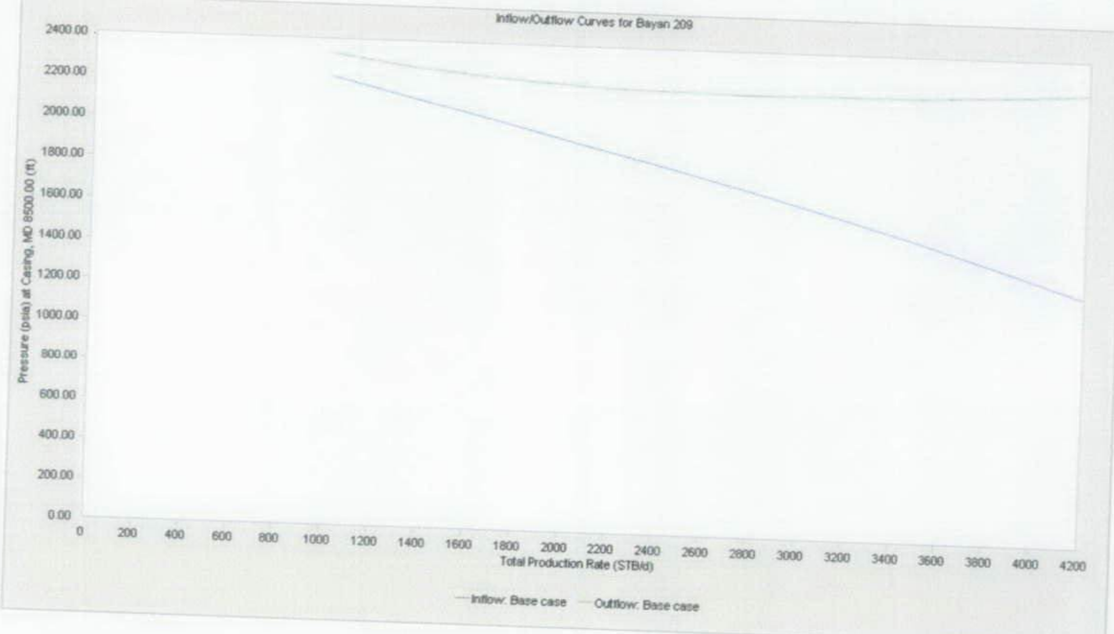

Figure 16: BY-209 Well Model

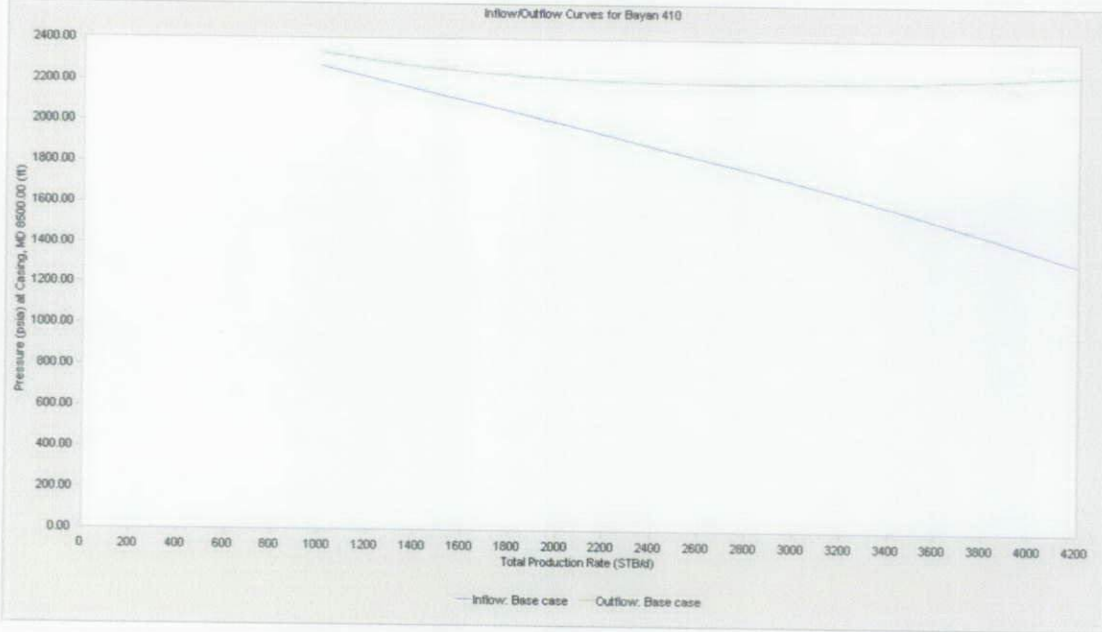

Figure 17: BY-410 Well Model

From Figure 16 and 17, it can be seen that the inflow and outflow curves didn't intersect each other, thus not generating operating points for both wells. Without an operating point, a well is unable to flow. That was the best reason well 209 and 410 being chosen as potential candidates for LPS. With the aid of LPS, the outflow curves of both wells were shifted downwards, intersecting with the inflow curves thus creating operating points. Inflow curves were not affected by the implementation of LPS since it only involves fluid flow from the reservoir into the wellbore. Our concern here was the flow from the wellbore to the surface, which was the outflow. So, Low Pressure System plays with the outflow part in generating a suitable condition for hydrocarbons to flow upwards.

4.4 CONSTRAINTS OF LPS IMPLEMENTATION

Although LPS poses a major role in enhancing oil production, there are still some challenges faced while running the system. First, all produced gas from LPS wells are vented, which means that there is no gas sale from LPS wells. The reason is that an extra unit of compressor must be installed on the system if the produced gas is to be compressed and sent via pipeline for sale. However, due to second constraint where LPS facilities which include manifold, gas-liquid separator, surge tank and pumps consume a very large area on the platform. Thus, even a unit of compressor would become a big deal.

The space-consuming LPS facilities have also lead to another problem, whereby they provide limitation for wireline intervention. Wireline equipments are difficult to be placed on the platform due to the presence of LPS facilities. Lastly, the implementation of LPS has posed an extra hazard since it requires day and night manning. However, this problem has been solved where personnel were made available to run the system.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

LPS is an innovative skid based oil production system that allows idle wells and low THP wells to be enhanced within a short lead time without well intervention. The process involves channeling well flows into a production separator that is set at a low surface pressure to separate liquids and gas. High pressure pumps, connected to the production separator, are used to transfer the liquid into the production system or the main pipeline.

In this project, all the objectives are met. The performance efficiency of Low Pressure System at Bayan field has been determined, with a very convincing result. The system is proven to be efficient in enhancing oil production, whereby a 209% increase in production is observed from three wells at BYDP-B after being connected to LPS. On top of that, four idle wells at BYDP-D namely 404S, 405S, 406L and 408L have been successfully reactivated after being tied-in to the system. Not only reactivated, they are producing with a high rate soon after LPS took its role.

The second objective is also achieved with the outcome that LPS is economically viable to be implemented at Bayan field as a production enhancement initiative. Based on the calculated incremental IRR of 367% and 1202% for BYDP-B and BYDP-D respectively, compared to the best estimated MARR of 15%, this shows that the investments in LPS for both platforms are economical. From the generated

Investment Balance Diagram, it indicates that the discounted payback period for LPS is only 1 year after installation.

Potential LPS candidate is initially screened based on surface parameters such as platform weight and space limitation. The key subsurface screening criteria considered during the candidate selection are well THP, choke size, production rate, productivity index and GOR. The list of well candidates is subsequently matured via well performance analysis prior to actual implementation at site. Upon conducting well modeling, it is found that well BY-209 and BY-410 are suitable candidates to flow through this system.

This initiative has provided immediate benefits to PETRONAS by unlocking production from idle wells as well as enhancing production from low THP wells. This technology has been successfully applied at two platforms in offshore Terengganu and offshore Sarawak. Based on the two proven applications, one LPS unit is able to produce on average, 1,500 BOPD from a few idle and low THP wells.

Despite the challenges faced during the implementation of LPS, continuous improvement on the key processes in the integrated approach such as screening, design, implementation and optimization is the key to the long term contribution of success in this new generation production enhancement initiative.

Referring to this project's objectives, the accomplishment of this final year project is deemed crucial for the production life of Bayan field. With matured reservoirs, further means of maintaining production is either by secondary or tertiary recovery. Hence, the implementation of Low Pressure System as a production enhancement initiative serves as a great effort towards extending the life of the field.

That is the main reason the efficiency and economic viability of LPS must be determined. The wells which are tied-in to the system must also be the most appropriate wells so that optimum production and maximum revenue could be achieved. Finally, if the current design or operating conditions of LPS can be enhanced, the overall efficiency of the system could be improved, which secures its role as one of the most crucial new generation production enhancement in oil and gas industry.

5.2 RECOMMENDATIONS

Low Pressure System is currently implemented at Bayan field, and recently installed at D35 field which is also located offshore Bintulu, Sarawak. One of the recommendations would be to introduce this system to other fields. With this, production from low pressure wells could be enhanced and idle wells could also be reactivated.

Secondly, future work that could be expanded from this project is to analyze the performance of LPS at D35 field, after the accomplishment of this project which put Bayan field as its main concern. Since LPS unit was newly installed at D35, its production trend is still fluctuating and it is hard to determine the system's true efficiency. Therefore, it is hoped that performance analysis on D35 field can later be conducted as a continuation of this final year project.

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APPENDIX I

BASELINE AND FORECASTED LPS PRODUCTION AT BYDP-B AND BYDP-D

Month	Forecasted (STB/D)		Baseline	Total Yearly Production (STB)		
	LPS at BYDP-B	LPS at BYDP-D	(STB/D)	LPS at BYDP-B	LPS at BYDP-D	Without LPS
Jun-11	300	830	200			
Jul-11	400	821.7	200			
Aug-11	450	813.483	200			
Sep-11	500	805.3482	200			
Oct-11	495	797.2947	200			
Nov-11	490.05	789.3217	200			
Dec-11	485.1495	781.4285	200			
Jan-12	480.298	773.6142	200			
Feb-12	475.495	765.8781	200			
Mar-12	470.7401	758.2193	200			
Apr-12	466.0327	750.6371	200			
May-12	461.3723	743.1308	200	164,224	282,902	72,000
Jun-12	456.7586	735.6994	200			
Jul-12	452.191	728.3424	200			
Aug-12	447.6691	721.059	200			
Sep-12	443.1924	713.8484	200			
Oct-12	438.7605	706.71	200			
Nov-12	434.3729	699.6429	200			
Dec-12	430.0292	692.6464	200			
Jan-13	425.7289	685.72	200			
Feb-13	421.4716	678.8628	200			
Mar-13	417.2569	672.0741	200			
Apr-13	413.0843	665.3534	200			
May-13	408.9535	658.6999	200	155,684	250,760	72,000
Jun-13	404.8639	652.1129	200			
Jul-13	400.8153	645.5917	200			
Aug-13	396.8071	639.1358	200			
Sep-13	392.8391	632.7445	200			
Oct-13	388.9107	626.417	200			
Nov-13	385.0216	620.1528	200			
Dec-13	381.1714	613.9513	200			
Jan-14	377.3596	607.8118	200			
Feb-14	373.586	601.7337	200			
Mar-14	369.8502	595.7163	200			
Apr-14	366.1517	589.7592	200			
May-14	362.4902	583.8616	200	137,996	222,270	72,000
Jun-14	358.8653	578.023	200			
Jul-14	355.2766	572.2427	200			
Aug-14	351.7238	566.5203	200			
Sep-14	348.2066	560.8551	200			
Oct-14	344.7245	555.2466	200			

Nov-14	341.2773	549.6941	200			
Dec-14	337.8645	544.1972	200			
Jan-15	334.4859	538.7552	200			
Feb-15	331.141	533.3676	200			
Mar-15	327.8296	528.034	200			
Apr-15	324.5513	522.7536	200			
May-15	321.3058	517.5261	200	122,318	197,016	72,000
Jun-15	318.0927	512.3508	200			
Jul-15	314.9118	507.2273	200			
Aug-15	311.7627	502.155	200			
Sep-15	308.6451	497.1335	200			
Oct-15	305.5586	492.1622	200			
Nov-15	302.503	487.2405	200			
Dec-15	299.478	482.3681	200			
Jan-16	296.4832	477.5444	200			
Feb-16	293.5184	472.769	200			
Mar-16	290.5832	468.0413	200			
Apr-16	287.6774	463.3609	200			
May-16	284.8006	458.7273	200	108,420	174,632	72,000
Jun-16	281.9526	454.14	200			
Jul-16	279.1331	449.5986	200			
Aug-16	276.3417	445.1026	200			
Sep-16	273.5783	440.6516	200			
Oct-16	270.8425	436.2451	200			
Nov-16	268.1341	431.8826	200			
Dec-16	265.4528	427.5638	200			
Jan-17	262.7982	423.2882	200			
Feb-17	260.1703	419.0553	200			
Mar-17	257.5686	414.8647	200			
Apr-17	254.9929	410.7161	200			
May-17	252.4429	406.6089	200	96,102	154,792	72,000
Jun-17	249.9185	402.5428	200			
Jul-17	247.4193	398.5174	200			
Aug-17	244.9451	394.5322	200			
Sep-17	242.4957	390.5869	200			
Oct-17	240.0707	386.681	200			
Nov-17	237.67	382.8142	200			
Dec-17	235.2933	378.9861	200			
Jan-18	232.9404	375.1962	200			
Feb-18	230.611	371.4443	200			
Mar-18	228.3049	367.7298	200			
Apr-18	226.0218	364.0525	200			
May-18	223.7616	360.412	200	85,184	137,205	72,000

Jun-18	221.524	356.8079	200			
Jul-18	219.3088	353.2398	200			
Aug-18	217.1157	349.7074	200			
Sep-18	214.9445	346.2103	200			
Oct-18	212.7951	342.7482	200			
Nov-18	210.6671	339.3207	200			
Dec-18	208.5604	335.9275	200			
Jan-19	206.4748	332.5683	200			
Feb-19	204.4101	329.2426	200			
Mar-19	202.366	325.9502	200			
Apr-19	200.3423	322.6907	200			
May-19	198.3389	319.4637	200	75,505	121,616	72,000

Table 5: Baseline and Forecasted LPS Production at BYDP-B and BYDP-D

APPENDIX II

INVESTMENT BALANCE DIAGRAMS FOR LPS IMPLEMENTATION AT BYDP-B AND BYDP-D

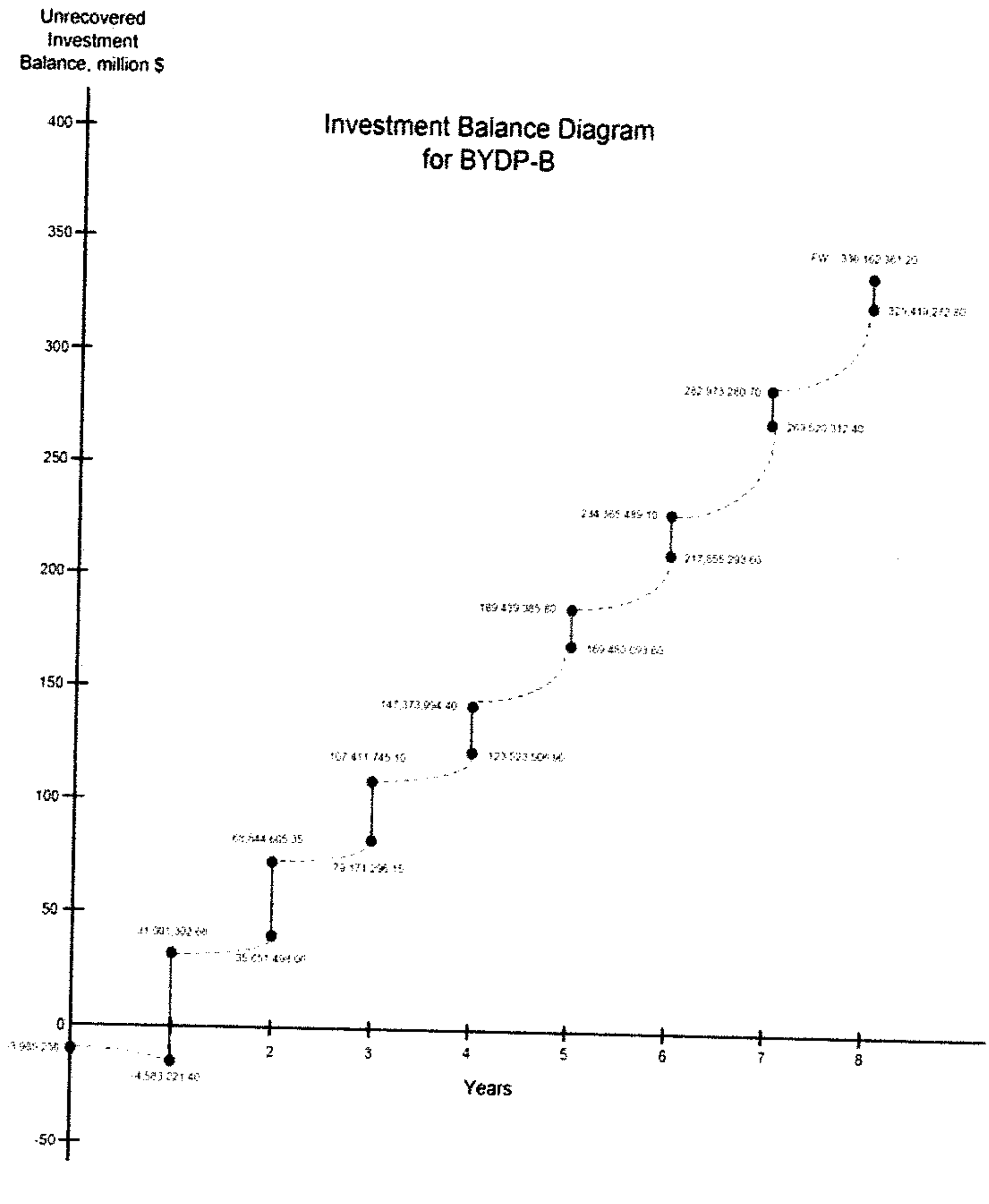

Figure 18: Investment Balance Diagram for LPS Implementation at BYDP-B

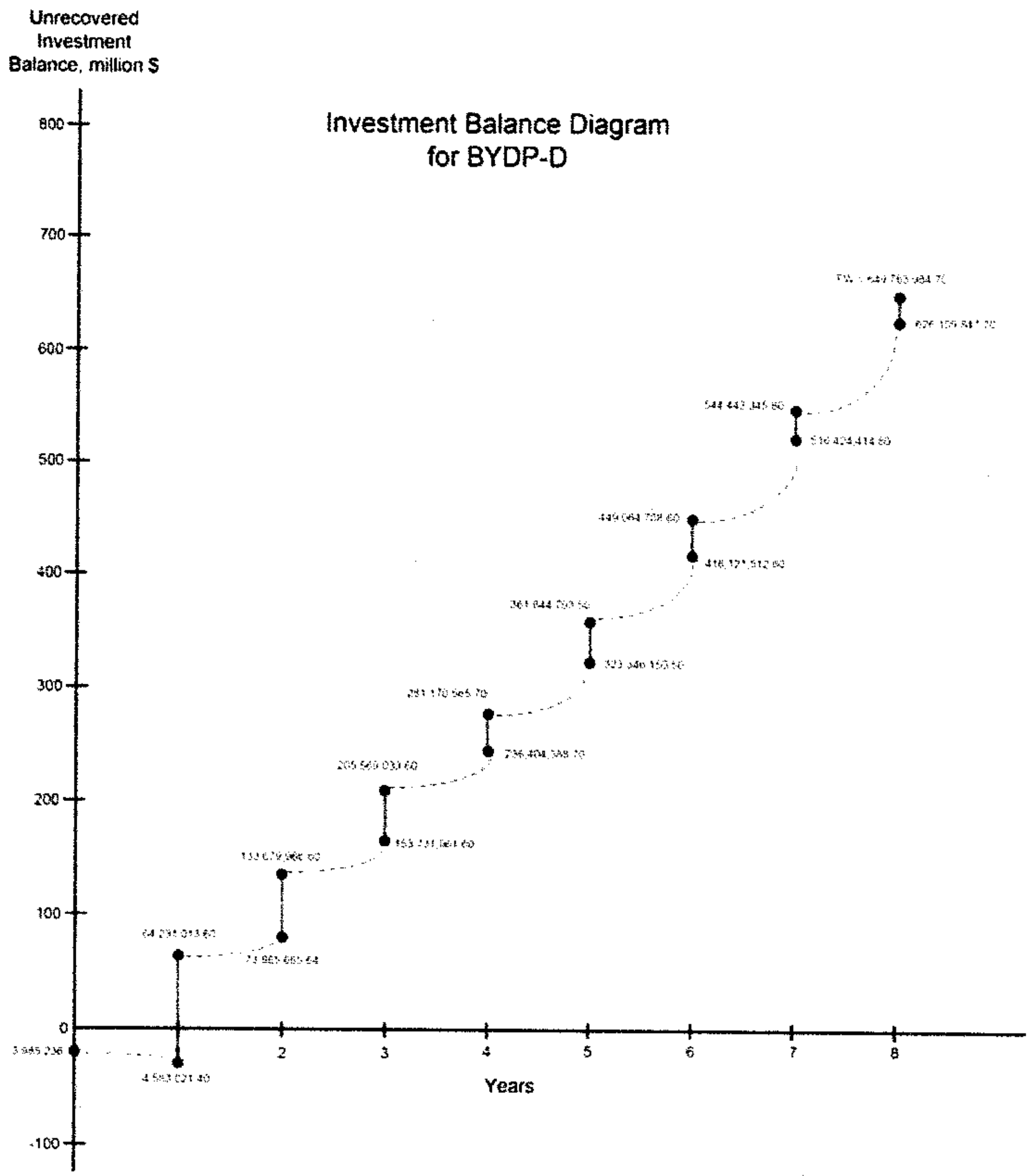

Figure 19: Investment Balance Diagram for LPS Implementation at BYDP-D

APPENDIX III

MECHANISM OF LOW PRESSURE SYSTEM

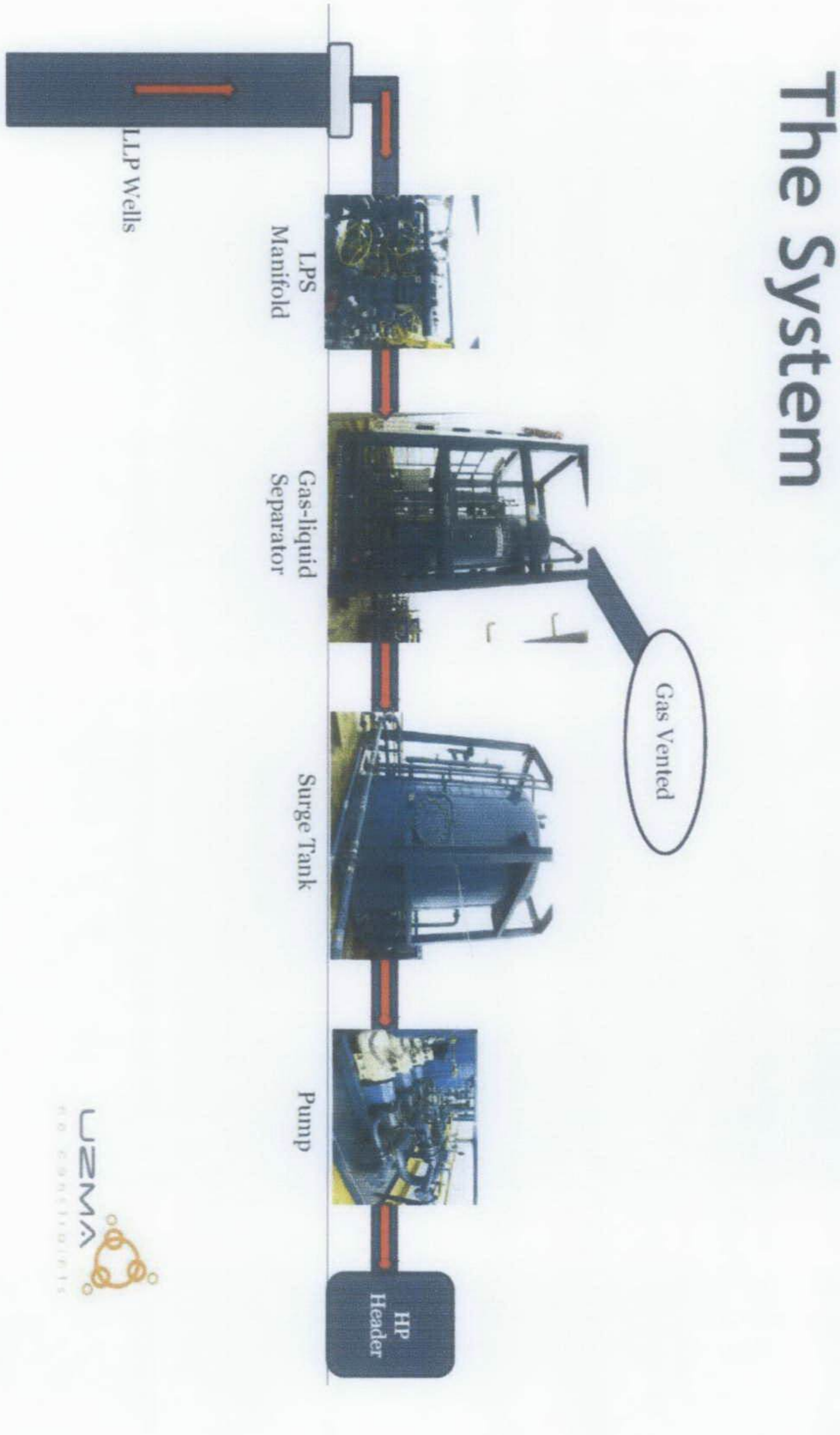

Figure 20: Mechanism of Low Pressure System

APPENDIX IV

LOW PRESSURE SYSTEM PACKAGES

Figure 21: Wellhead Connection

Figure 22: LPS Manifold

Figure 23: LPS Separator

Figure 24: LPS Surge Tank

Figure 25: LPS High Pressure Pumps