CHAPTER 1

INTRODUCTION

The approach taken towards each field and each well varies depending on number of factors but the main objective for an oil field still remains the same and that is to maximize oil recovery. In order to produce efficiently from a well, the next step should be considered during the time the well is producing naturally and that decision made will effect the forecoming production from that well and will affect the field as well. So, the decision for a proper artificial lift is important.

Reservoirs in the Gulf of Thailand are typically multi-layered (Figure 1.1). Most of which are driven by radial aquifer drive apart from its solution GOR. These wells have a tendency to die around 40 to 60% water cut. It is generally observed that natural flow periods of these marginal fields are short and the operating costs of artificial lift have a great impact on these economically burdened fields. Running the sensitivity tests will enable us to select a favorable artificial lift method. For this kind of environment, the two artificial lifts which will be compared for performances are Gas Lift and Electrical Submersible Pump (ESP). The high water cut in the Gulf of Thailand holds a bright prospect for ESP to be used successfully. Certain criteria need to be developed to make sure the ESPs go to the most deserving wells. There have already been 6 ESPs installed and more are on the way to be installed in the next few years. The sensitivities to be tested are as follows:

• Solution GOR	(200,500,800) SCF/STB
• Gas Injection Rate	(0.5, 0.75, 1) MMSCF/D
• k_{rw} End Point Saturation	(0.3, 0.5, 0.7)
• k_{rw} Corey Exponent	(1, 2, 3)
• Productivity Index	(2, 6, 10)
• Artificial Lift Depth	(4000, 6000, 8000) feet MD or (3400, 5000, 6600) feet TVD

Varying these sensitivities gives rise to many different combinations which needs to be run. Many other factors associated with the simulation runs needed to be kept constant and one such factor is the design of the ESP which will be later discussed. The model is made on a base case on which the runs are made and the conclusions will be drawn.

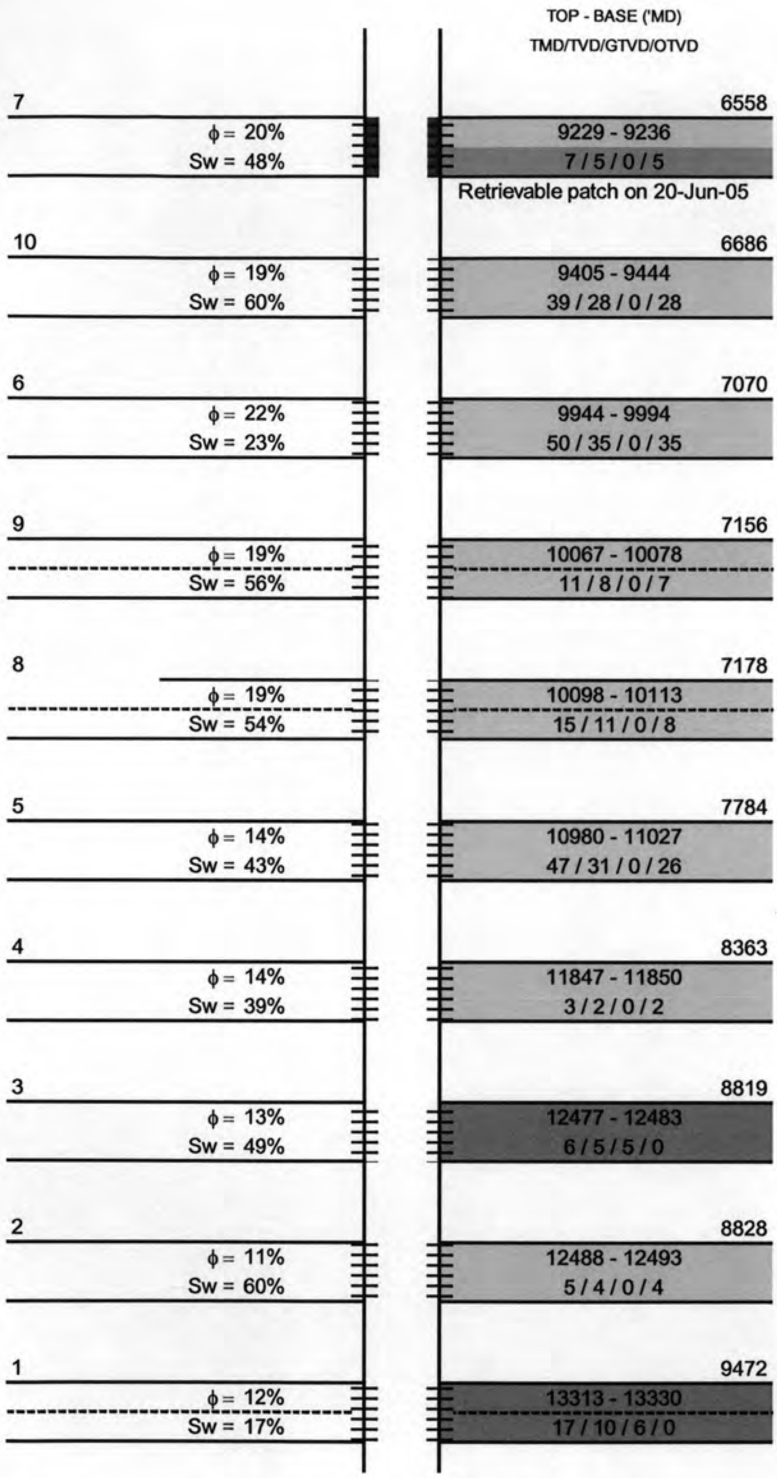

Figure 1.1 Multiple Stacked Sand Schematic

Integrated Production Model (IPM) Toolkit

The tool used for this research is known as Integrated Production Model (by PetEx). The tool itself has three main parts being GAP, MBAL and PROSPER. Some of the features of this software are briefly mentioned in the following section.

General Allocation Package (**GAP**) is an extremely powerful and useful tool offered to the Petroleum Engineering community. Some of the tasks GAP can achieve are complete Surface Production and Injection Network Modeling. It also has a powerful optimizer that is capable of handling a variety of wells in the same network such as naturally flowing oil wells, gas-lifted wells, ESP operated wells etc. The optimizer controls production rates using wellhead chokes, ESP operating frequencies or allocating lift gas to maximize the hydrocarbon production while honoring constraints at the gathering system, well and reservoir levels. GAP models both production and injection systems simultaneously, containing oil, gas, condensate and/or water wells to generate production profiles.

GAP'S powerful optimization engine can, for example, allocate gas for gas lifted wells, alter the frequency of ESP pumps or sets wellhead chokes for naturally flowing wells to maximize revenue or oil production while honoring constraints at any level. GAP can also model and optimize injection networks associated with the production system (both together).

Production Forecasting

GAP calculates full field production forecasts including gas or water injection volumes required to meet reservoir unit pressure constraints. Reservoir pressures are obtained from decline curves, material balance or simulation models. The associated injection systems can be modeled and optimized so as to achieve injection targets for pressure maintenance programs. Apart from that it also can be linked to MBAL and Prosper for integrated calculations.

Fully Compositional or Compositional Tracking Modes

GAP can calculate the PVT fully compositionally and track compositions from the well/source level through to the separators. In a prediction, GAP can take compositions calculated by MBAL and record the evolution of compositions throughout the system with time.

MBAL is in a package made up of various tools designed to gain a better understanding of the reservoir behavior and perform prediction run. Some of the tools are material balance, reservoir allocation, decline curve analysis, Monte Carlo volumetrics and multilayer.

Material Balance

This incorporates the classical use of material balance calculations for history matching through graphical methods (like Havlena-Odeh, Campbell, Cole etc.). Detailed PVT models can be constructed for oils, gases and condensates. Furthermore, predictions can be made with or without well models and using relative permeabilities to predict the amount of associated phase productions. MBAL can also be tied into GAP for integrated production modeling studies, providing an accurate and fast reservoir model as long as the assumptions of material balance are valid for the real situation to be modeled.

PROSPER is a fundamental element in the Integrated Production Model (IPM) mainly used for all the calculations in the tubing section including various artificial lift designing capabilities. Its PVT section can generate fluid properties using standard correlations and allows them to be modified to better fit the measured lab data. It allows detailed PVT data in the form of tables to be imported for use in the calculations.

Apart from that the tool can also be used to model reservoir inflow performance (IPR) for single, multilayer, or multilateral wells with complex and highly deviated completions, optimizing all aspects of a completion design including perforation details and gravel packing. It can be used to accurately predict both pressure and temperature profiles in producing wells and along surface flow lines. There are also sensitivity calculation capabilities to model and optimize tubing as well as surface flow line performance.

The multiphase flow correlations implemented can be adjusted to match measured filed data to generate vertical lift performance curves (VLP) for use in simulators and network models.

Model Setup

The simulation runs were made in big numbers prior to the setting up of the base model by which the results will be recorded and conclusions drawn. The earlier model had gas sand and oil sand but running the ESP in a well having an open gas layer results in a lot of cross flow and gas intake into the pump. The gas present in the gas sand and its contribution to the GOR of the well can be translated to a single oil tank having high GOR. It became evident that in order to install an ESP, all the gas sands had to be shut. The base model is as shown below:

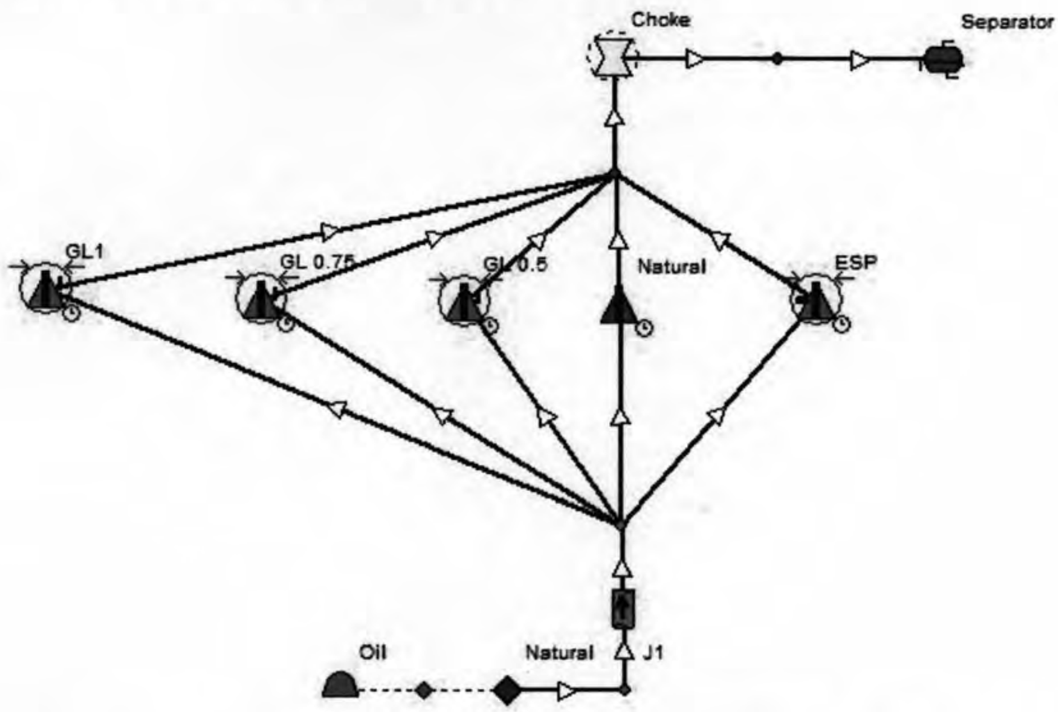

Figure 1.2 Base model for nodal analysis in IPM

The diagram represents the well connected from the reservoir to the choke and then to the separator. Five different paths from the reservoir (oil tank) to the choke are shown in the diagram but only one is operational at a time. The five options shown in Figure 1.2 are (from left to right) gas injection rate of 1 MMSCF/D, 0.75 MMSCF/D, 0.5 MMSCF/D, Natural flow and ESP. A schedule is set when we need to switch from natural flow to either gas lift or ESP installed well.

The deviation of the well, the pressure depth correlation and the temperature profile is picked up from one of the existing wells. The pressure, as we understand has an impact on the natural flow period only and does not impact the result to be obtained by either gas lift or ESP; hence the initial pressure was kept the same for all the runs while varying other sensitivities. Most of the other parameters which were not among the chosen sensitivities were kept constant throughout the simulation runs.

Comparisons

In the existing wells in the Gulf of Thailand the dummy valves have been set and are not subjected to change hence giving an additional benefit to ESP as it can be installed deeper than the gas lift operating valve. However in practice, the deepest ESP is installed no lower than the casing shoe. Some of the key overall comparisons of the ESP and Gas Lift are given in the table below.

Table 1.1 ESP and Gas Lift Comparison Table[1]

	ESP's	Gas Lift
Capital Cost	Relatively low capital cost if commercial electrical power available. Costs increases as horsepower increases.	Well Equipment costs low but lines and compression costs maybe high.
Down-hole Equipment	Good Design plus good operating practices essential.	Good valve design and spacing essential.
Efficiency	Good for high rate wells but decreases significantly for < 1000 BFPD.	Fair: increases for wells that require small injection GLR's. Low: for wells requiring high GLR's.
Water Cut	Excellent for high water cut wells.	Fair for high water cut wells.
High Volume Lift Capabilities	Excellent: limited by needed horsepower and can be restricted by casing size.	Excellent: restricted by tubing size, injection gas rate and depth.
Testing	Good: simple with few problems. High water cut and high rate wells may require free water knock-out.	Fair: well testing complicated by injection gas volume/rate.
Noise Level	Excellent: low noise. Often preferred in urban areas if production rate high.	Fair: Low at well but noisy compressor.
Offshore Application	Good: must provide electrical power and service pulling unit.	Good: Depends on the injection gas available and depth.
Reliability	Excellent for ideal lift cases. Poor for problem areas.	Excellent if compression system properly designed and maintained.

Making use of the above properties, criteria will be developed and hence making an efficient use of artificial lift in the Gulf of Thailand.