CHAPTER I
INTRODUCTION

Typically, reservoirs in Pattani Basin in the Gulf of Thailand are highly faulted, relatively small compared to other reservoirs elsewhere, and most of the time they are multiple and stacked. In order to make the marginal reservoirs economically attractive, there is limited development option and almost by default the slim monobore completion is selected to justify the small reserves. Basically, this monobore completion allows one single well to accommodate as many hydrocarbon zones as possible. There could be up to 20-40 zones per well. Most of the time, all zones are perforated and produced commingledly.

Even though commingled production has several advantages, it results in several difficulties in reservoir management, for examples, a difficulty in predicting the production performance and reserve allocation, high pressure differences between zone inducing cross flow, difficulty in identifying water sources for water shut-off, problem with fluid compatibility from each zone, and requiring of close monitoring and surveillance.

It is generally observed that natural flow periods of these marginal reservoirs in the monobore oil wells are short. In some cases, these monobore oil wells can be completed with the conventional gas lift, i.e. the lower section of the well is still completed in basic monobore while the upper section of the well can have gas lift mandrels installed. This type of completion is called monotrip gas lift (MTGL) completion for monobore oil wells as shown in Figure 1.1.

According to the MTGL completion procedure, once the open hole is drilled to desired total depth, the monotrip completion string consisting of a float shoe, a float collar, a hydraulically set packer, a hydrostatic close circulating valve (HCCV), three to five cement-thru-side pocket mandrels and a cement-safe tubing retrievable safety valve (TRSV) is run. The pre-determined volume of cement is then pumped into the monotrip gas lift string up the annulus with the desired top of cement approximately 500 ft above the 7” shoe. After the cement is pumped, the special design of a cement wiper plug is launched to displace the cement in the tubing.

Once the wiper plug is bumped, the hydraulically set packer will be set. As the packer is set, the tubing pressure continues to increase until the rupture disc in the HCCV is burst to allow the circulation between the tubing and the annulus so that the excessive cement above the 7" case shoe in the annulus can be circulated out. Once the annulus is clear of excessive cement, the outer sleeve of the HCCV will be closed to regain tubing-annulus integrity.

However, in some cases, both capital and operating costs of artificial lift have a great impact on these economically burdened fields, especially the offshore environment. As a result, it is not always economic to drill and complete oil wells with MTGL completion.

Instead, several monobore oil wells are completed without gas lift or a typical monobore completion (Figure 1.2) for economic reason – cost saving is not only from lower drilling and completion cost, but mainly from no expensive gas lift surface facilities, such as gas lift compressors and flow lines. As stated previously, these monobore oil wells only rely on natural depletion or solution gas-oil ratio (GOR), resulting in low reserve recovery and they would be dead or loaded up very soon as the water cut increases up to 40 to 60%. As a result, the gas zones in these monobore oil wells are very important because these gas zones, if managed properly, can provide additional in-situ gas to increase or optimize the well's GOR or GLR, thus increased oil production rate or reserve recovery.

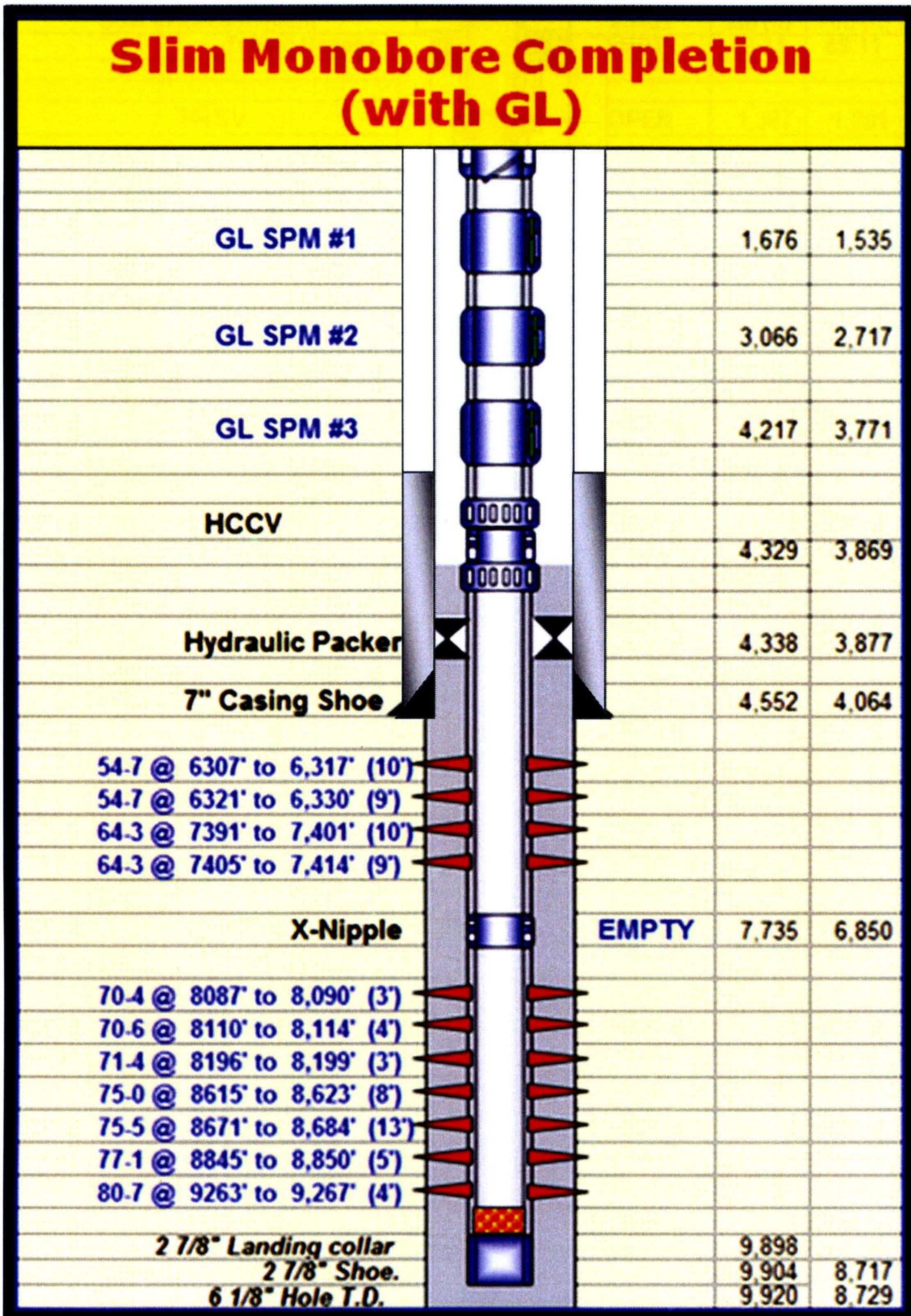

Figure 1.1 Well Schematic for Commingled Reservoirs in Slim Monobore Completion with Gas Lift Mandrels

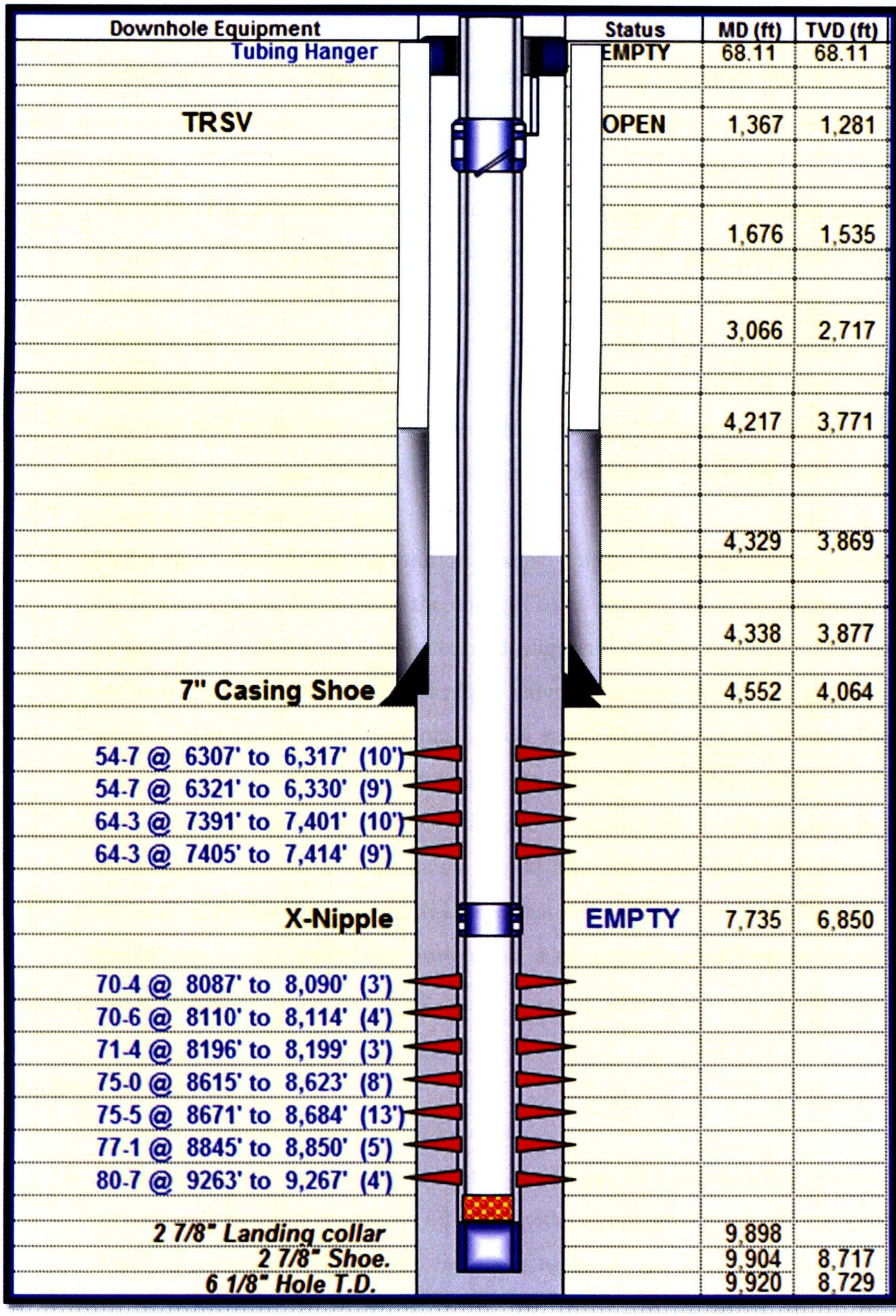

Figure 1.2 Well Schematic for Commingled Reservoirs in Slim Monobore Completion without Gas Lift Mandrels

Apart from understanding difficulties in reservoir management in commingled reservoirs in monobore oil wells, determining the following variables that affect the effectiveness of the in-situ gas lift in term of optimizing oil reserve recovery is also very crucial:

(i) Variables that affect inflow performance of in-situ gas zone: reservoir pressure (or depth of the reservoir), permeability and total net pay thickness. Other variables that affect inflow performance are assumed constant or follow certain correlations.

(ii) Variables that affect outflow or tubing performance. In this study, most variables that affect outflow or tubing performance are assumed constant, such as tubing size, gas viscosity; however, the liquid viscosity varies with temperature and solution gas.

(iii)Perforation schedule and perforation design. Papers related to in-situ gas lift in the literature survey examined the concept of in-situ gas lift or production of oil by in-situ gas using such a completion design with packers to isolate a gas zone and using surface-controlled downhole valve to control the in-situ gas rate to achieve optimal recovery and production rate. However, such a completion design is very expensive for marginal fields. Therefore, the perforation schedule and perforation design will be used instead to control the in-situ gas rate in the commingled reservoirs. This thesis should also provide a good opportunity to evaluate any other alternatives available that can optimize or control the in-situ gas lift rate in slim monobore completion, such as perforation interval on an in-situ gas zone.

1.1 Thesis Objectives:

The objectives for this study are as follows:

(i) To evaluate some variables on using the in-situ gas lift technique that impact the oil recovery factor of monobore oil wells with commingled production in Pattani Basin by comparing oil recovery factors using in-situ gas lift to conventional gas lift.

(ii) To come up with recommendations for using the in-situ gas lift in monobore oil wells with commingled production in Pattani Basin based on the studied variables.

1.2 Outline of Methodology

This thesis is to study variables that affect the oil recovery factor using the in-situ gas lift technique in monobore oil wells with commingled production in Pattani Basin. The oil recovery factors as a result of using in-situ gas lift techniques in different scenarios will be compared to the base case well that is a monobore oil well producing with a conventional gas lift.

The approach to conduct the systematic analysis consists of the following steps:

1. Gather and prepare data required to construct the reservoir model. The representative fluid and rock properties using available PVT and some core analysis data.
2. Refine the simulation cases and range of the data. This step is to validate the gathered data in step #1.
3. Construct the reservoir well model that represents the base case which is the monobore completion type consisting of commingled or multilayered oil reservoirs with a single gas lift orifice valve.
4. Perform simulation runs to validate the base case well model. Record the oil recovery for this base case, both in natural flow and with gas lift.
5. Construct the reservoir well model that represents the well with the presence of an in-situ gas zone of which variables are varied.
6. Perform simulation runs to predict the oil recovery factors in each of pre-determined scenarios.
7. Analyze the results and perform additional simulation studies if required. Compare the oil recovery factors from using in-situ gas lift technique in all scenarios to that of the base case.
8. Make conclusion and recommendation.

1.3 Outline for this thesis

This thesis consists of 6 chapters.

Chapter 2 reviews previous studies that are related to the in-situ gas lift technique and commingled production from multi-layered reservoirs.

Chapter 3 describes all principles and basic theories related to this study as follows:

Section 3.1 discusses nodal analysis and the effect of various variables on the inflow performance relationship (IPR) and tubing performance relationship (TPR).

Section 3.2 describes the principle and basic theory of material balance and explains the technique developed by Havlena and Odeh which is relevant to the simulation software.

Section 3.3 reviews the principle of reservoir drive mechanisms to explain different types of driving energy which depends on the original characteristics of hydrocarbon reservoirs.

Section 3.4 describes the principle and basic theory of gas lift theory and the in-situ gas lift.

Chapter 4 explains the basic introduction of a reservoir simulator used in this study which is the Integrated Production Model (IPM) Toolkit and describes how to set up the reservoir model for the base case and other scenarios for sensitivity runs.

Chapter 5 analyzes the results of the simulation runs in each pre-determined scenarios and attempts to explain what affect the recovery factors.

Chapter 6 concludes the results of the study and comes up with recommendations for using the in-situ gas lift technique to optimize oil production in monobore oil wells with commingled production.