CHAPTER II
LITERATURE REVIEW

The following studies are related to the in-situ gas lift technique and hydrocarbon production from commingled reservoirs.

Vasper [1] presented the basic theory behind in-situ gas lift and how to apply it. The in-situ gas lift system uses gas from a gas-bearing formation, or gas cap to artificially lift an oil producing zone. The completion design involves isolation of the gas zone from the oil zones using a packer. The flow rate of in-situ gas is controlled by an auto gas-lift valve which can be hydraulically cycled from surface to one of five open positions namely 20%, 40%, 60%, 80% or 100%, plus a 0% or closed position. The calculation of auto gas-lift valve setting depth and sizing was discussed and several auto gas-lift performance curves were plotted to determine the effect of the valve open positions on pressure ratio (pressures immediately downstream / upstream of a valve or orifice) and in-situ gas rate. The results suggested that in the right environment, the in-situ gas lift using auto gas-lift valve can provide significant financial benefits over conventional gas-lift systems through the elimination of capital cost items and ability to rejuvenate wells where space restrictions prevent installation of gas-lift compression facilities.

Al-Somali and Al-Aqeel [2] presented the first in-situ gas lift system equipment, gas lift operation principles utilizing the gas cap, installation procedure, production strategy and well performance utilizing online monitoring system. The completion was designed to isolate each of three hydrocarbon zones by a packer. All of two lower oil zones and a gas cap zone at the top were produced commingledly. Effective in-situ gas lift is achieved with sliding sleeves containing an orifice insert valve that controls the rate of in-situ gas flowing into the hydrocarbon stream. The sensitivity analysis on water cuts, tubing sizes, and completion skins was conducted to determine the effect on the amount of in-situ gas required or the total GLR required at a given production rate. The result indicated that the amount of oil delivered is a function of water cut, skin, and the amount of gas needed for lifting purpose at a given oil rate.

Betancourt, *et al.* [3] examined the concept of production of oil by in-situ gas from either contiguous or non-contiguous gas zone. They presented the results of numerical modeling of the contiguous gas-lift for horizontal wells to be drilled into reservoirs where the drive mechanism is dual drive (water encroachment at the bottom and gas expansion on top). The in-situ gas rate entering the tubing was controlled using a surface-controlled valve. The sensitivities on well placement (standoff) from water-oil contact and target liquid production rate were made to determine impact on total oil recovery and gas break through time. The results indicated that higher recoveries were achieved when the well was placed closer to the water-oil contact, and was produced at high rates and that gas breakthrough time is noticeably delayed by placing the well far from the gas cap. Another simple sensitivity was made to observe the impact of the gas cap and aquifer size on the production performance of the well. The results indicated that for a given size of gas cap, as the aquifer is stronger, there is a delay in the breakthrough time of the gas, and also the water-cut increases at a faster rate. The use of a deeper non-contiguous gas bearing zone to assist an upper oil zone was studied using a reservoir model. Both zones are commingled through a vertical well. The results indicated that a higher recovery using in-situ gas lift approach might be achieved by optimizing the valve position changes and in-situ gas lift is feasible provided that the pressure in the gas zone is in hydrostatic equilibrium or higher than the pressure in the oil zone. For both cases, the main advantage of in-situ gas lift process is the reduction in costs in artificial lift infrastructure, especially for offshore location.

Ferrer [4] summarized the applications, advantages, limitations, surveillance process and selection criteria for commingled production in the pilot test design. One of the selection criteria is that static pressure differences of the production intervals should not be greater than 300 psia. His paper suggested that the key factor for successful commingled production is to keep the bottom-hole flowing pressure of the system below the lowest static reservoir pressure to avoid cross flow. He also proposed a new methodology to estimate composite IPR curves for a commingled system, taken into account of distance between the zones, the tubing size, mechanical configuration of the well, and their distinct fluid properties that can have effect on the flowing pressure gradient along the tubing. To apply this methodology, all the pertinent data should be available including well completion diagram, producing intervals, individual IPR's and the fluid characteristics (oil gravity, GLR, water cut, etc.) for commingled production.

Larsen [5] presented a method to determine the wellbore-pressure behavior of wells producing two commingled zones with unequal initial pressures and reservoir properties. The paper also presented a method to determine the ratio of flow capacities or

$(kh)_1/(kh)_2$ if the initial pressures in two-layer are sufficiently different and in addition known. The result of analysis could be used to explain the behavior or wellbore pressure of commingled zones from the simulation results.

Raghavan [6] summarized understanding of multilayered reservoirs and examined a method to predict the performance and productivity of wells producing from commingled reservoirs which also permits consideration of the influence of interlayer communication or crossflow. This study helps explain some behavior of wells with commingled production.

Ryou *et al.* [7] presented new correlating parameters for boundary dominated constant rate production from multilayer reservoirs. They also examined the use of correlating parameters to model flow from multilayer reservoirs with constant bottom-hole pressure production.

Prabowo and Rinadi [8] presented a method to approximate the ratio of flow rate and cumulative production for each reservoir in a commingled gas completion. The numerical reservoir simulation was used to describe flow rate and pressure response of wells completed in multiple producing reservoirs without inter-layer crossflow. The simulated cases were for homogeneous multilayer systems with unequal initial reservoir pressures and properties with constant bottomhole flowing pressure but no crossflow.

Permadi *et al.* [9] presented a procedure to construct composite IPR of (two) multilateral wells and method to predict the production decline. There were two laterals which were produced commingledly with the same flowing pressure at the junction and no crossflow. Even though the paper focused on multilateral well, the concept for IPR can be used to explain the pressure or performance behavior of vertical well with commingled production.

Fetkovich *et al.* [10] analyzed commingled gas reservoirs using type-curve matching. While Arevalo *et al.* [11] extended the studies of El-Banbi and Wattenbarger [12, 13] on stabilized flow equation with gas material balance equation of multilayer gas reservoirs to match and forecast production rates for commingled gas wells. The approach used in commingled system is based on calculating the individual layer behavior and adding up the commingled performance. After solving each layer's commingled flow model for every time step, the total flow rate of the system can be evaluated by integrating the flow rate of each layer at the corresponding time. However, this approach may not be unique for the system consisting of more than 4 layers. These papers could help analyze simulation results for the wells with commingled production.

Kuppe *et al.* [14] developed a simple material balance model to estimate original gas in place (OGIP), layer productivity and recoverable reserves for well with commingled production, completed in multilayer tight gas reservoirs. The concept of grouping the various *kh* terms, from all "high permeability" layers into one model layer and all "low permeability" *kh* values into the tighter model layer is helpful for setting up the base case for this study, e.g. simplify the oil reservoirs into four oil layers or *kh* values.