CHAPTER II

LITERATURE REVIEWS

There have been several figures proposed for recovery factor of a specific type of reservoir. Cosse[1] stated that recovery factor of oil reservoir with dissolved gas drive mechanism is approximately 5-25% depending on properties of the fluids, the thermodynamic conditions, the petrophysical properties, and the variations due to the architecture and the heterogeneity of the reservoir. He also mentioned that the recovery factor of the petroleum reservoir was subject to the production rate.

In addition to the proposed figures for recovery factor of reservoirs, the studies of the effect of production rate on ultimate oil recovery of several reservoir types had been published.[2,3,4] Those studies used numerical reservoir simulators with several assumptions. However, unanimous conclusions had been made. There were two major conclusions about the relationship between oil production rate and ultimate oil recovery made from those studies. The first conclusion was that oil production rate affected the ultimate oil recovery and the other conclusion was that ultimate oil recovery was not affected by oil production rate.

The first paper about the relationship between oil production rate and ultimate recovery was the study of Heuer *et al.*[2]. They developed a mathematical model for studying behavior of a solution gas drive. Two-phase, unsteady-state equations were used in the model. The effects of capillary pressure and gravitational force were neglected. The study comprised two models having drainage areas of 40 and 80 acres respectively. The effect of producing rate was studied by setting initial maximum flow rate conditions of 100 and 200 STB/D. The limitation was only set to the sand face pressure of 100 psi. They concluded that cutting the allowable rate in half increased the length of time to reach an economic limit but it did not increase recovery. However, they did not investigate on the effect of fluid properties on recovery.

Morse *et al.*[3] mentioned that Culter had published a study of field data in 1924 with the conclusion that higher oil production rate yielded higher ultimate oil recovery. However, they found that subsequent studies of reservoir performance from various fields showed that no unanimous conclusion about the effect of production rate on ultimate oil recovery could be reached. Therefore, they conducted a study to investigate the quantitative effect of oil production rate on ultimate recovery of oil from a solution gas drive reservoir. The major tool in this study was the two dimensional numerical reservoir model with the oil production rate being varied in six steps from 0.1 to 50 STB/D. In the study, they investigated the difference in oil saturation as a function of height above bottom of producing zone. It was found that lowering production rate caused greater variation of oil saturation between top and bottom cells. The very low oil saturation in the top of the model provided a bypassing channel so gas could escape without displacing oil. This was the result of vertical segregation of oil and gas during depletion. They concluded that ultimate oil recovery by solution gas drive reservoir could be greatly affected by variations in production rates, i.e., higher production rates resulted in higher oil recoveries.

Sawage *et al.*[4] presented the results of their study concerning ultimate recovery and production rate of selected reservoirs having initial gas cap and aquifer support. The numerical reservoir models were created for the selected reservoirs. Each reservoir model was allowed to produce under natural depletion process at a constant oil production rate until it declined to a specified economic limit. In addition, limitations of gas oil ratio and water oil ratio as well as minimum bottom hole pressure were set. The conclusion was that ultimate recovery increased with decreasing reservoir production rate. In addition, they proposed that the concept of MER (Maximum Efficient Rate) should be considered when determining the maximum sustainable rate. MER referred to the maximum sustainable daily oil and gas withdrawal rate from a reservoir which will permit economic development of that reservoir without detriment to ultimate oil recovery.

From the aforementioned literature, the relationship between oil production rate and ultimate oil recovery had not been consistently concluded. This is probably due to differences in basic conditions specified for each study. It would, therefore, be useful if a thorough study about the relationship between oil production rate and ultimate oil recovery has been conducted.

Petroleum production industry has utilized numerical reservoir simulation as a conventional tool to determine possible reservoir development plans under various constraints. The purpose of using the simulator in this phase of development is to find the most appropriate development strategies in order to gain the maximum ultimate oil recovery under given constraints. Satter *et al.*[5] presented three examples concerning planning reservoir development strategies using the application of reservoir simulators. Those examples included an application of a commercial black oil simulator to a newly discovered offshore oil field, a thermal simulator applied to a thermal recovery project, and a compositional simulator to a CO_2 flood project. In the newly discovery field, the commercial black oil simulator was used to forecast production performance and reserves for developing a depletion and development strategy. The predicted results from the simulator could be updated as more reservoir and production data were available. In the second example, the thermal simulator was used to determine the cause of poor oil production response to steam stimulation of wells in a fault block. The commercial compositional simulator was used for developing a plan for the CO_2 flood project in the last example. The CO_2 flood was considered after the reservoir had depleted and waterflood had been unsuccessful. The simulator was used to history match primary and waterflood performance of the reservoir. Then the model was used to simulate CO_2 flood performance and to optimize the field operation.

The applications of the reservoir simulators, however, are time consuming and probably do not have capability for some specific tasks. There have been, therefore, studies to improve the capability of the simulators.[6,7] Lefevre *et al.*[6] proposed a new reservoir simulation system aiming at better reservoir management which finally yields maximum ultimate oil recovery. They suggested the options to modify reservoir simulation system which some of them could be applicable for other simulators. In addition, the study of improving reservoir simulation study process has been performed.

Another study was made by Salerl.[7] He presented the concept of applying parallel planning approach to predict reservoir performance. He concluded that the classical reservoir simulation study was not appropriate for timely forecast. He proposed parallel planning strategies and suggested that it offered an alternative to the classical approach and can significantly accelerate forecasting.

However, reservoir simulation study may not be applicable to certain field types. El Hamalawy *et al.*[8] mentioned the failure of a simulation study of a reservoir having combined drive mechanisms. The production history of the field showed discrepancies between actual and predicted well performance. They believed that the failure was due mainly to an unreliable description of the deep reservoir. The application of conventional reservoir engineering approach to manage this particular field was introduced instead. This approach included reservoir monitoring, fluid level contour maps, direct volumetric calculations of oil remaining in the reservoir, and aquifer support. In addition, material balance applications and gravity drainage performance evaluation were also performed. They emphasized the importance of comprehensive reservoir monitoring program for proper management by applying conventional reservoir engineering approach.

Besides the application of reservoir simulators to planning reservoir management strategy, applications of other mathematical approaches to reservoir studies had been performed.[9,10,11,12,13] These studies included the concept of differentiation to determine reservoir properties from pressure transient analysis, application of time series analysis to forecast reserves, and application of linear programming to manage production rate under facility constraints.

Bourdet *et al.*[9] proposed the application of differentiation algorithm for well-test interpretation. An analysis of the derivative of pressure with respect to the appropriate time function was discussed. They stated that the advantage of using the derivative of pressure was that it incorporated all flow regime instead of only portion or part of flow regime that had been interpreted by conventional methods.

Clark *et al.*[10] concluded in their work that the pressure derivative approach had theoretically proved to be well adapted to high permeability reservoirs because it had clearer distinction of flow regimes from more characteristic response forms. In addition, it provided high accuracy in reservoir parameter evaluation. The benefit of using pressure derivative approach is that it gives a clearer visualization of a complex reservoir or complex flow regime.

Ayeni and Pilat[11] presented the application of a time-series approach using autoregressive integrated moving average (ARIMA) method to estimate crude oil reserves. Reserve estimates from this approach in combination with the application of various error analysis tools was found to be better than those from the conventional decline curve method. In addition, it was also demonstrated that ARIMA was applicable where the decline curve had failed, such as in water-drive reservoirs.

Another approach to managing petroleum production that had been studied was the application of Linear Programming (LP). Lo and Holden[12] presented the forecasting production rates of petroleum field by using LP. They suggested that the well management problem could be formulated as a linear programming which could be solved by either Simplex method or approximation method. The formulation will always yield a solution to maximize total constrained oil rate.

Lo *et al.* [13] concluded that the linear programming model can be used to resolve benefits and impacts from production streams originating from multiple reservoirs through capacity of a common facility. The model may be used for a large number of wells and provide forecasts using relatively little computer time compared to the application of reservoir simulations for the same purpose. Note, however, that the application of linear programming was applied in optimizing use of production facility. It had not been concerned with the reservoir.

Petroleum production could be considered as one kind of industrial processes in which the process control concept should be applicable. Process control concept has been widely used in particular industries, such as chemical industries, for a number of years. One of the objectives of the process control study is to achieve better control of existing plants.[14] In principle, virtually all industrial processes are candidates for the application of control systems.[15] This leads to the concept of using process control concept in petroleum production. This study is aimed to investigate possible application of process control concept to the petroleum production.