CHAPTER III

THEORIES AND CONCEPTS

The software used for this study is Integrated Production Model that comprises of two main disciplines, being Material Balance and Nodal Analysis. This chapter will cover some of the key concepts of material balance and nodal analysis. Also included in this chapter are the software features of IPM which comprises of GAP, MBAL and Prosper, along with it a touch of history match techniques that is also used in this study.

3.1 Material Balance

A technique used to estimate the initial hydrocarbons in place for appropriate geological conditions when some of the reservoirs properties are known is called material balance. The material balance is defined by equation which comprises of several components in order to obtain the oil in place from the data. Most specifically, adequate geologic data must be available to permit estimation of the relative size of the gas cap and the oil zone. Field production data including cumulative oil, water, gas production and reservoir pressure as functions of time are also necessary. Appropriate laboratory data or empirical relationships for the physical properties of oil, water and gas are also needed to make accurate estimates. The physical property data needed are primarily volume factors and gas solubilities.

Apart from that, it is highly desirable to know the type of reservoir mechanism which is operative in order to expedite estimation of the volume of the initial hydrocarbons in the reservoir. If the type of reservoir mechanism is not known, lengthy and tedious trial and error calculations are necessary. However, the drive mechanism becomes evident after sometime that the fields have been produced. A study of field data, including geologic and well completion information, work-over reports, pressure surveys, production data, and decline curve analysis, may give an indication of the type of reservoir mechanisms. Most of the times, the necessary data are assembled in order to determine the probable drive mechanisms of the reservoir which consistently needs to be cross checked over time when the field starts producing for a period of time.

3.1.1 The General Material Balance Equation

The general material balance equation can be expressed as follows:

$$
\begin{aligned}
&N(B_t - B_{ti}) + \frac{NmB_{ti}}{B_{gi}}(B_g - B_{gi}) + (1+m)NB_{ti}\frac{(c_w S_{wi} + c_f)}{(1 - S_{wi})}\Delta\bar{p} + W_e \\
&= N_p\left[B_t + (R_p - R_{si})B_g\right] + B_w W_p
\end{aligned}
\tag{3.1}
$$

The geologic, field, and laboratory data are substituted in the equation and the value of the initial oil volume N is computed for each pressure and time observation. If the data and geological calculations are accurate and the reservoir mechanism is identified properly, the value of N calculated for each observation will remain approximately constant. In the event that the initial oil volume N is observed to change in one direction with increased cumulative withdrawals from the reservoir, it is probable that the reservoir mechanisms have been identified incorrectly or production, pressures, and/or laboratory data are incorrect. Ordinarily, although time-consuming, we may assume another type of reservoir mechanism and repeat the calculations for N. If the newly assumed mechanism does not give a constant value of N, the procedure can be repeated or the data reevaluated. It should be noted that the material balance equation does not take into consideration the rate of production of the various fluids. But it takes into consideration the cumulative production that related to the rate of production.

Furthermore, it is obvious that the equation contains three quantities which may not be measured directly: (1) initial oil in place N, (2) initial gas in place G, and (3) the cumulative water-influx W_e. As the material balance equation has a low power of resolution, it is necessary to define at least two of the aforementioned quantities independent of the material balance equation.

The early pressure history of an oil reservoir is meager or not known for most cases. In such a case the material balance equation will yield very erratic results. The basis of material balance equation is the law of conservation of mass. It's derived as an underground withdrawal, to the expansion of the fluid in the reservoir resulting from a finite pressure drop.

Due to the advent of sophisticated numerical reservoir simulation techniques, material balance equation has been well regarded by many engineers. One of those are Havlena and Odeh who presented the subject of applying the material balance equation and interpreted it as the equation of a straight line. To express the general equation of material balance in the way presented by Havlena and Odeh requires the definition of the following terms:

3.1.2 Material Balance Drive Mechanism

If none of term in the material balance equation can be neglected, then the reservoir can be described as having a combination drive in which all possible sources of energy contribute a significant part in producing the reservoir fluids and determining the primary recovery factor. In many cases, however, reservoir can be singled out as having predominantly one main type of drive mechanism in comparison to which all other all other mechanisms have a negligible effect. Some of mechanisms are:

3.1.2.1 Solution-gas drive

Many of the reservoirs do not need the entire material balance equation to describe their behavior. One of the simplest type of reservoir mechanism is the solution gas drive. The principle drive mechanism is the expansion of the oil and its originally dissolved gas. The increase in fluid volume during the process is equivalent to the production. It can divide into two phase: a) when the reservoir oil is undersaturated and b) when the pressure fallen below bubble point and a free gas phase exists in the reservoir.

Above bubble point pressure (undersaturated oil)

It is asssmed that there is no initial gas cap and the aquifer is relatively small in volume and the water influx is negligible. Since all the gas produced at the surface must have been dissolved in the oil in the reservoir.

Below bubble point pressure (saturated oil)

Below bubble point pressure gas will be liberated from the saturated oil and a free gas will develop in the reservoir.

3.1.2.2 Solution-gas and gas cap drive

A typical gas cap drive reservoir is under initial conditions the oil at the gas oil contact must be at saturation or bubble point pressure. Generally this effect is relatively small. It can be assuming that the natural water influx and injection are negligible, the change in pore volume is a small fraction of the total volume change that can be treated as zero, and the fluid properties of the gas cap and solution gas are the same.

3.1.2.3 Simple solution-gas, gas-cap, and water drive

Often petroleum reservoirs are found to have a combination of solution-gas, gas-cap, and water drive. When the reservoir has he water drives support. A drop in the reservoir pressure, due to the production of fluids, causes the aquifer water to expand and flow into the reservoir.

There are other forms of reservoirs drive mechanism combination which have not been mentioned as it is of very little importance for the field in consideration.

3.1.3 Material Balance in Oil Reservoir

Oil consists of a vide variety of chemicals species including large, heavy, nonvolatile molecule. When considering the properties of oil reservoir. We can divide into two type of state, undersaturated reservoir and saturated reservoir.

3.1.3.1 Material balance in undersaturated reservoir

From the general material balance equation (Equation 3.1), when there is no free gas, the material balance equation for undersaturated reservoir becomes.

$$N(B_t - B_{ti}) + NB_{ti}\frac{(c_w S_{wi} + c_f)}{(1 - S_{wi})}\Delta\bar{p} + W_e = N_p\left[B_t + (R_p - R_{si})B_g\right] + B_w W_p \quad (3.2)$$

When the material balance equation has been derive using the two-phase formation volume factor, B_t and B_o are related by Equation 3.3.

$$B_t = B_o + B_g(R_{si} - R_s) \quad (3.3)$$

Neglecting the change in porosity of rock with the change of internal fluid pressure, reservoir with zero or negligible water influx are constant volume. If the reservoir oil is initially undersaturated, then initially it contains only connate water and oil, with their solution gas. The solubility of gas in reservoir waters is generally quite low and is considering negligible. Because the water production from volumetric reservoirs is generally small, it will be considered as zero. From initial reservoir pressure down to the bubble point, oil is produced by liquid expansion. We get

$$N(B_t - B_{ti}) = N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right] \tag{3.4}$$

Equation 4.8 can be rearranged and solve for N, the initial oil in place as

$$N = \frac{N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right]}{(B_t - B_{ti})} \tag{3.5}$$

3.1.3.2 Material balance in saturated reservoir

When reservoir produced and pressure depleted to the bubble point pressure. The oil contains as much dissolved gas as it can hold. A reduction in pressure will release gas to form a free gas phase in the reservoir. This state is called saturated reservoir.

From the general material balance equation (Equation 3.1), if the expansion term due to the compressibilities of the formation and connate water can be neglected, as they usually are in a saturated reservoir, then Equation becomes

$$N(B_t - B_{ti}) + \frac{NmB_{ti}}{B_{gi}}(B_g - B_{gi}) + W_e = N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right] + B_w W_p \tag{3.6}$$

Equation 3.6 can be rearranged and solve for N, the initial oil in place as

$$N = \frac{N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right] - W_e + B_w W_p}{(B_t - B_{ti}) + \frac{mB_{ti}}{B_{gi}}(B_g - B_{gi})} \tag{3.7}$$

3.1.4 Material Balance in Gas Reservoir

Reservoirs containing only free gas are termed gas reservoirs. Such a reservoir contains a mixture of hydrocarbons which exists wholey in the gaseous state. The mixture may be dry, wet, or condensate gas, depending on the compositon and the pressure and the temperature at which the accumulation exists.

Gas reservoirs may have water influx from contiguous water-bearing portion of the formation or maybe volumetric (i.e., have no water influx). The general material balance equation applied to a volumetric gas reservoir is in the form of

$$G(B_g - B_{gi}) + GB_{gi}\frac{(c_w S_{wi} + c_f)}{(1 - S_{wi})}\Delta\bar{p} + W_e = G_p B_g + B_w W_p \qquad (3.8)$$

where

G = initial gas in place

G_p = cumulative gas production

Equation (3.8) is derived by applying the law of conservation of mass to the reservoir and associated production.

For most gas reservoirs, the gas compressibility term is much greater than the formation and water compressibilities, and the second term on the left-hand side of Equation (3.8) becomes negligible.

The new equation becomes

$$G(B_g - B_{gi}) + W_e = G_p B_g + B_w W_p \qquad (3.9)$$

When there is neither water encroachment into the reservoir nor water production from the reservoir, the reservoir is said to be volumetric. In this case Equation (3.9) reduces to

$$G(B_g - B_{gi}) = G_p B_g \qquad (3.10)$$

But

$$B_g = \frac{P_{sc} z T}{T_{sc} p} \qquad (3.11)$$

Substituting B_g into Equation (3.10), we have

$$\frac{p}{z} = -\frac{p_i}{z_i G} G_p + \frac{p_i}{z_i} \tag{3.12}$$

Because p_i, z_i and G are constants for a given reservoir, Equation (3.12) suggests that a plot of p/z as the ordinate versus G_p would yield a straight line with:

$$\text{slope} = -\frac{p_i}{z_i G}$$

$$\text{y intercept} = \frac{p_i}{z_i}$$

The p/z plot versus cumulative production is shown in Figure 3.1

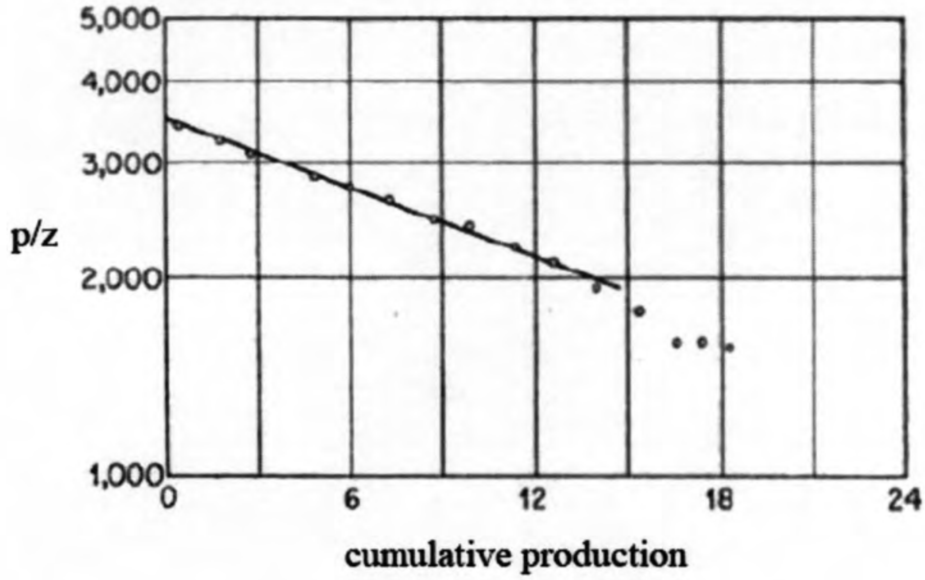

Figure 3.1: p/z plot versus cumulative production (Craft and Hawkins[6]).

If p/z is set equal to zero, which would represent the production of all the gas from reservoir, then the corresponding Gp equals G, the initial gas in place.

3.2 Nodal Analysis

For many years, nodal analysis has been used to analyze systems where various components are interactive. It can be applied to both oil and gas wells. The procedure consists of first selecting an appropriate division point or node. In the whole system, any point can be considered as a node and nodal analysis can be performed. All components upstream from the node comprise the inflow section, and all components downstream represent the outflow section.

A relation between flow rate and pressure drop must be developed for each component in both sections. The flow rate for the specific system or set of components can be determined by satisfying the following relationships:

1) Flow into node = Flow out of node
2) Only one pressure can exist at the note

The average reservoir pressure and the separator pressure are considered to be fixed for any given time in a well flow system. The basic procedure is to calculate the pressure at the node both ways from the fixed pressure points as follows:

Inflow to node:

$$p_R - \Delta p_{(upstream\_components)} = p_{node} \tag{3.13}$$

Outflow from node:

$$p_{separator} + \Delta p_{(downstream\_components)} = p_{node} \tag{3.14}$$

The pressure drop Δp, in any component varies with flow rate q, therefore, a plot of flow rate vs. node pressure for each section will produce two curves, the intersection of which gives the one flow rate which satisfies the two conditions above.

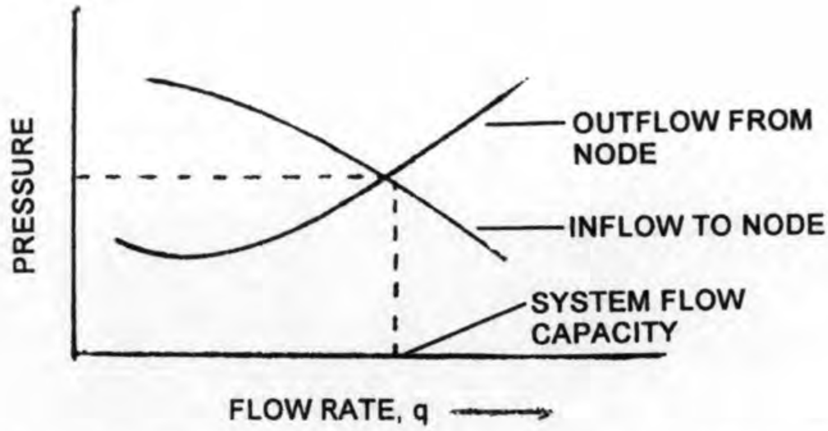

Figure 3.2: Inflow- Outflow crossplot (After Allen and Robert.[9])

A change in the pressure drop across an upstream component (inflow section) will leave the outflow curve unchanged, but the intersection point will change, and thus the flow rate will change. Likewise, a change in the pressure drop across a downstream component will result in an adjustment in the flow rate. Finally, a change in either of the fixed pressures (the average reservoir pressure or the separator pressure) occurring during the life of the well will result in a change in the flow rate.

A frequently used node or division point is inside the casing at the perforations; i.e., between the reservoir and the piping system. Thus, the flow through the rock, the perforations, and the gravel pack (if installed) is one system, and flow up the tubulars, through the wellhead and through the flow line and manifold to the separator is the second system.

The total system is optimized by selecting the combination of component characteristics which will maximize production rate for the lowest cost.

The system analysis approach is basically used to optimize flowing well performance, but can also be applied to artificial lift situations in oil wells if the effect of the artificial lift system on the pressure is a function of the flow rate. Possible applications include

1) Selection of tubing and/or flow line size
2) Surface choke or subsurface safety valve sizing
3) Analyzing effect of perforation density
4) Analyzing effect of gravel pack design
5) Artificial lift design
6) Predicting the effect of depletion on producing capacity

3.2.1 Inflow Performance Relationship

3.2.1.1 Inflow Performance Relationship for oil wells

The inflow performance relationship for a specific well represents the ability of that well to produce fluids against varying bottomhole or well intake pressures. Sometimes, this relation is assumed to be a straight line (Figure 3.3). However, except for wells producing above the bubble-point pressure, the flow rate usually drops off significantly from a straight line relation with two phase flow.

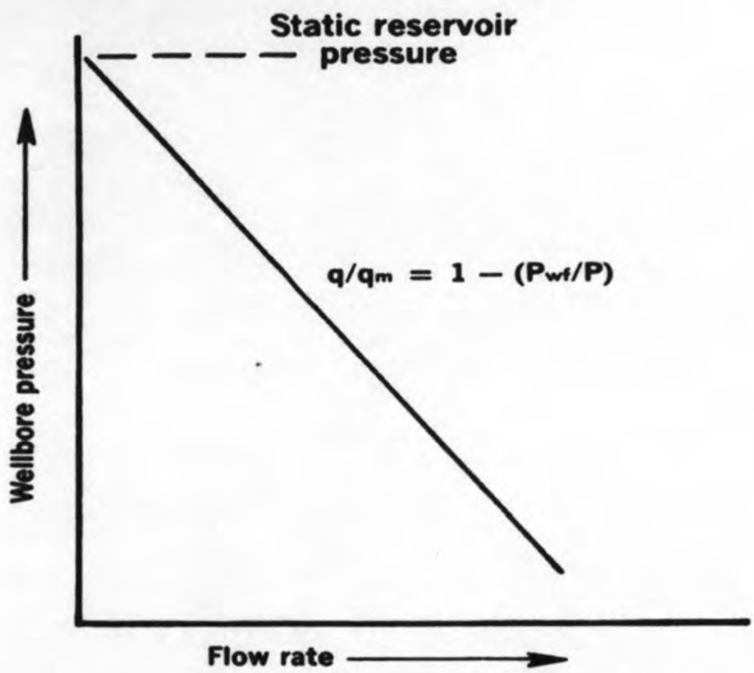

Figure 3.3: Generalized inflow performance relationship. (After Allen and Robert.[9])

The inflow performance relationship declines with cumulative production from the reservoir. For dissolved gas drive or gas drive reservoirs, this decline may be rapid. The occurrence of formation damage or stimulation also affects the inflow performance relationship.

The inflow performance relationship can best be determined by flow after flow or isochronal tests. Several method may be used to fit the data obtained from such test.

Predicting present time IPR's for oil wells

Several of the most widely used empirical methods for predicting an IPR for a well are presented widely. Most of those methods require at least one stabilized test on well, and some require several tests. One of the methods that used in this work is Jones, Blount and Glaze[10] method. Jones, Blount and Glaze discussing the effect of turbulence or non-Darcy flow on well performance. Methods were presented to analyze well completion efficiency and to isolate the rate dependent component of the total pressure drawdown. Details f this method are use of their plotting procedure to determine the real time IPR's.

With the turbulence term, Equation can be written as:

$$\overline{P}_R - P_{wf} = Aq_o + Bq_o^2 \tag{3.15}$$

Where

$$A = \frac{141.2\mu_o B_o}{k_o h}\left[\ln(0.472\, r_e / r_w) + s\right] \tag{3.16}$$

$$B = \frac{2.3 \times 10^{-14} \beta B_o^2 \rho_o}{h^2 r_w} \tag{3.17}$$

ρ_o = oil density evaluated at T_R and $0.5(\overline{P_R} + P_{wf})$, lbm/ft3

β = velocity coefficient, ft^{-1}

And β can be calculated using Equation 4.6:

$$\beta = \frac{2.329 \times 10^{10}}{k_o^{1.2}} \tag{3.18}$$

Where k_o is I millidacies

A plot of $(\overline{P}_R - P_{wf})/q_o$ versus q_o on catesian coordinates should yield a straight line of slope B and intercept A as q_o approaches zero. Once A and B are determined, a complete IPR can be constructed using Equation 3.15. Finally, Equation 3.15 can be solve for flow rate to yield:

$$q_o = \frac{-A + [A^2 + 4B(\overline{p}_R - p_{wf})]^{0.5}}{2B} \tag{3.19}$$

3.2.1.2 Inflow Performance Relationship for gas wells

Gas well deliverability is usually determined using either the traditional four point flow after flow test or where low formation permeability requires long time periods to achieve stabilized conditions, an isochronal test. Figure 3.4 shows a plot of results obtained from typical four point flow after flow deliverability test. Figure 3.5 shows a plot for an isochronal test. An inflow performance relation can then be established by selecting several values for P_{wf} and reading corresponding value of q_{sc} from the fitted line. Figure 3.6 shows an IPR curve constructed from the isochronal test in Figure 3.5.

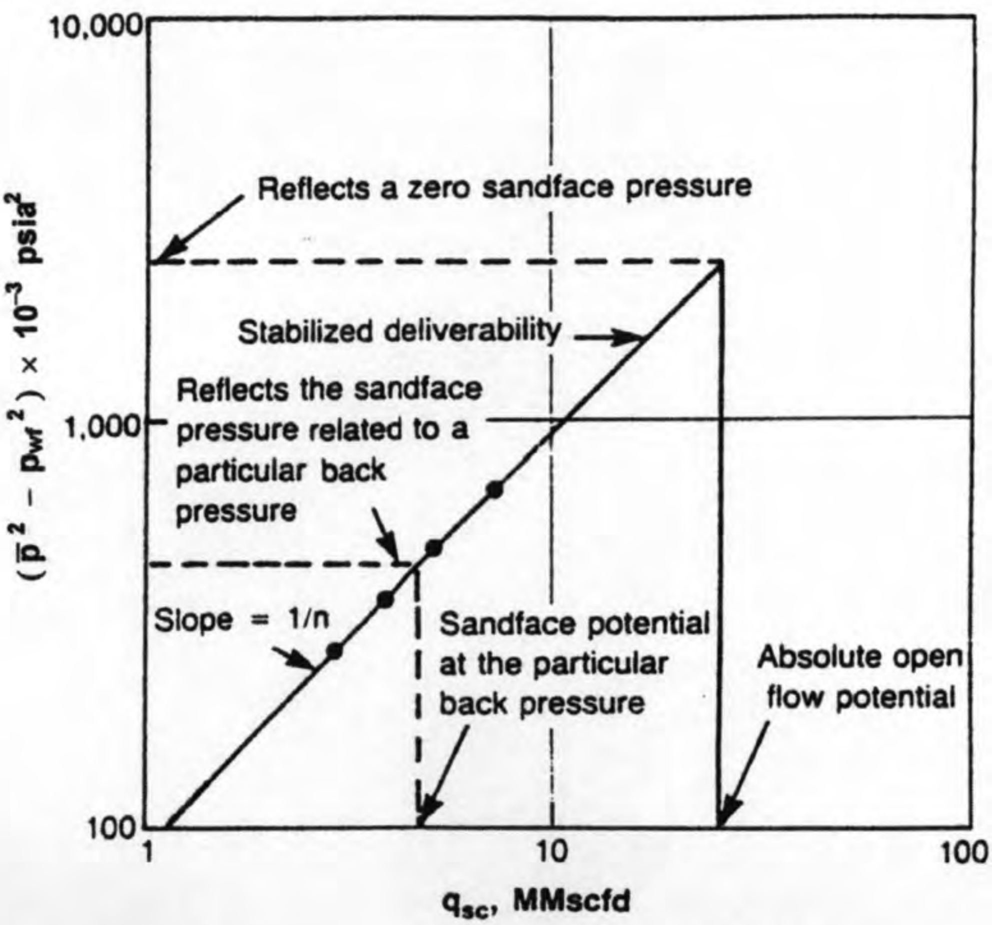

Figure 3.4: Deliverability test plot (After Allen and Robert.[9])

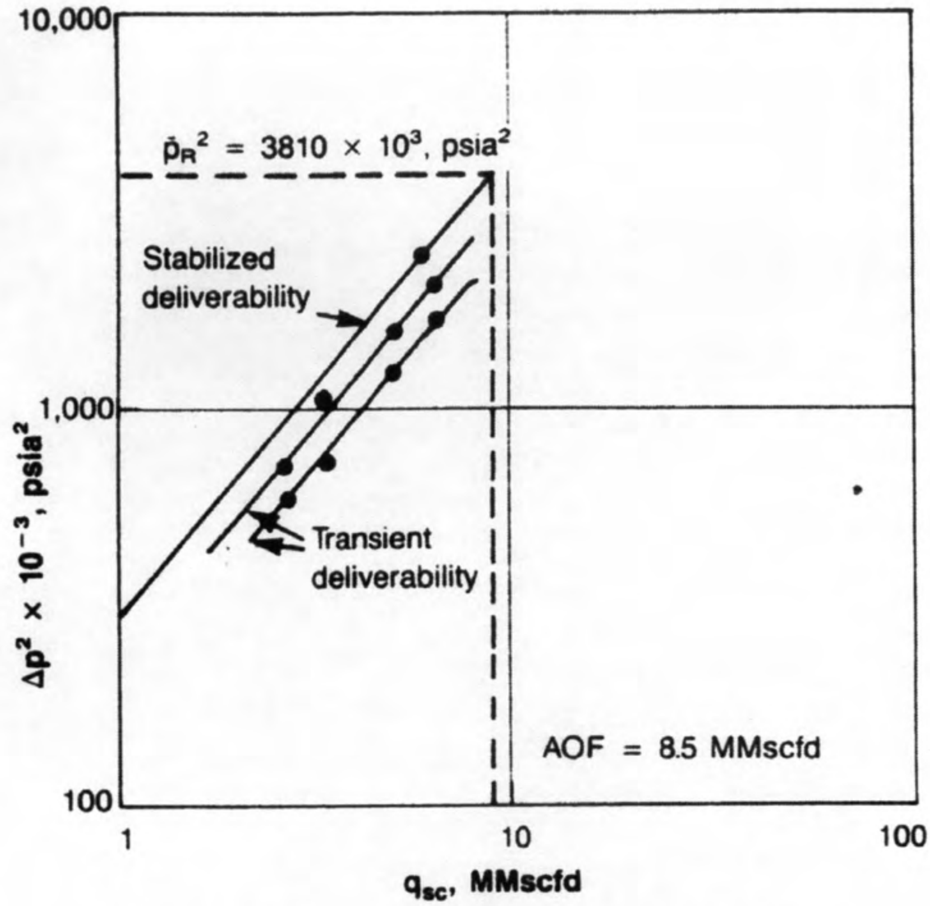

Figure 3.5: Isochronal Test (After Allen and Robert.[9])

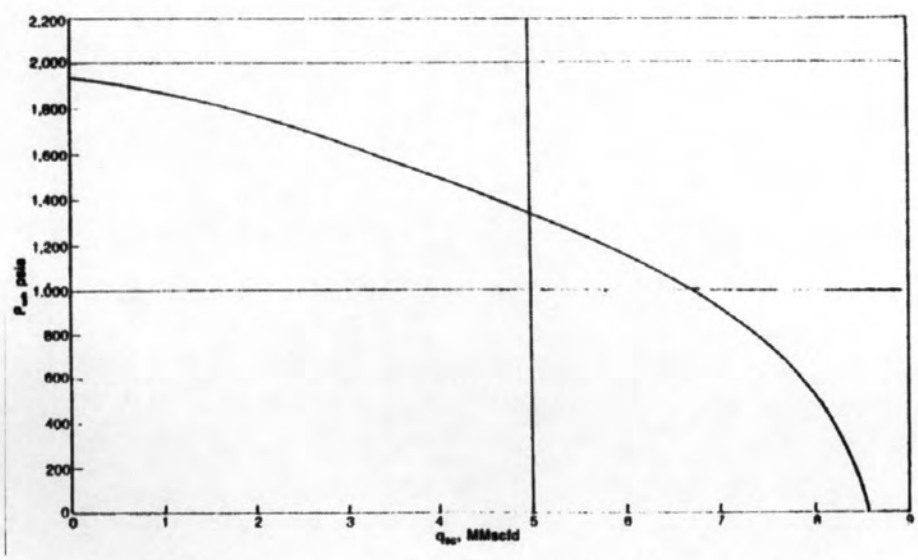

Figure 3.6: Inflow Performance Curve (After Allen and Robert.[9])

Predicting present time IPR's for gas wells

The method of plotting test data, which was proposed by Jones, et al[10]., can be applied to gas well testing to determine present time inflow performance relationships. The analysis procedure allows determination of turbulence or non-Darcy effects on completion efficiency irrespective of skin effect and laminar flow. The data required are either two or more stabilized flow tests or two or more isochronal flow test. If the turbulent effects were excessive, Equation can be written as:

$$\frac{\overline{P}_R^2 - P_{wf}^2}{q_{sc}} = A + Bq_{sc} \tag{3.20}$$

Where A and B are the laminar and turbulent coefficients. From Equation 3.20, it is apparent that a plot of $(\overline{P}_R^2 - P_{wf}^2)/q_{sc}$ or $(\Delta P^2 / q_{sc})$ versus q_{sc} on cartesian coordinates will yield a straight line of slope B and intercept $A = \Delta P^2 / q_{sc}$ as q_{sc} approaches zero. These plot apply to both linear and radial flow.

3.2.2 Outflow Performance Relationship

3.2.2.1 Outflow performance relationship for oil wells

Tubing performance data for oil wells involving two phase or three phase vertical flow is difficult to calculate since the average density and the velocity of the fluid is usually unknown due to gas breakout and fluid slip.

Poetmann and Carpenter[11] developed empirical correlations which can be used to approximate multiphase vertical flow. Generally, this correlation applies to 2 3/8" to 3 ½" inch OD tubing and flow rates greater than 400 bpd with minimum slippage.

Since this original work, Dun and Ros[12], Hagedorn and Brown[13], Beggs and Brill[14], and others have developed additional vertical flow correlations aimed at improving the accuracy of pressure loss calculations. Most are applicable to all conditions including annular flow. Also, vertical flow relations can be used in deviated holes up to 15° to 20° from vertical if suitable corrections are made.

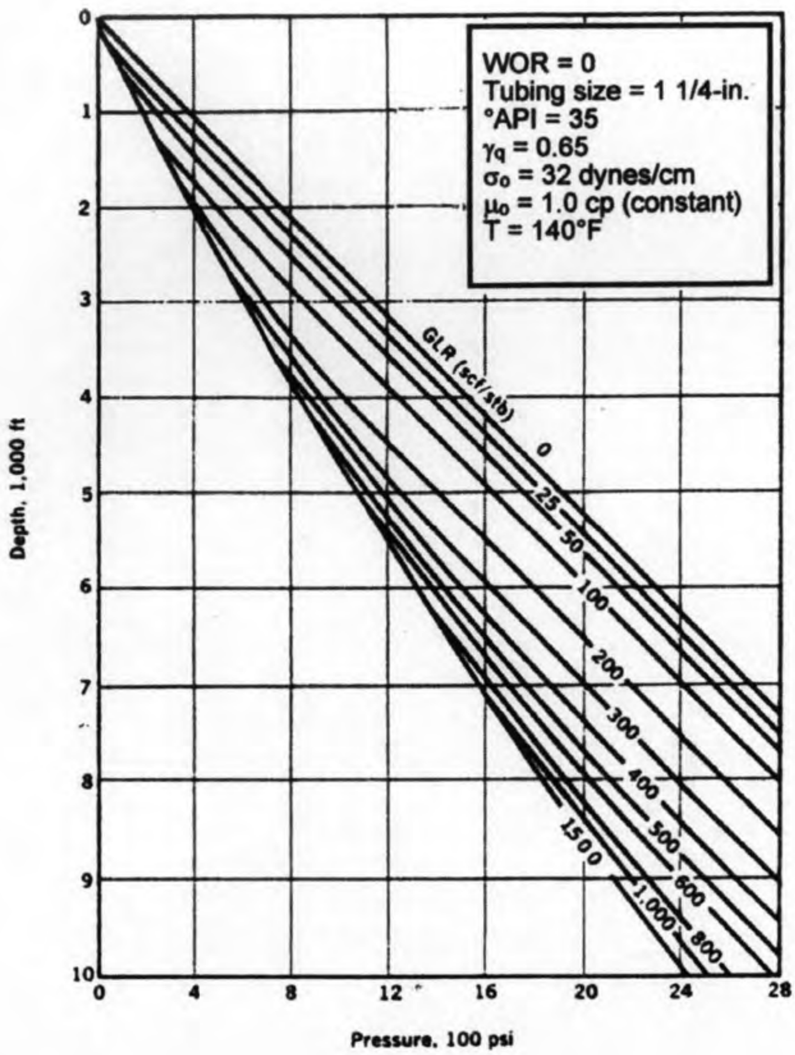

Figure 3.7: Vertical Pressure Transverse curves (After Allen and Robert.[9])

No single correlation satisfies all well conditions. Field checks to compare predictions with measured results may be needed to select the most suitable correlation. Figure 3.7 shows typical pressure traverse curves from the Hagedorn and Brown[13] correlation. Use of curves to obtain flowing pressure drop where the surface pressure is known involves the following steps:

1) Pick a proper curve to fit the situation, i.e., flow rate, pipe size, WOR etc.
2) Draw a vertical line from the surface pressure intersecting gas-liquid ratio to determine a pseudo depth.
3) To this pseudo depth, add well depth to determine the pressure depth.

4) Move horizontally from the pressure depth to the line with the proper GLR and read the bottomhole pressure.

5) Subtract the surface pressure from the BHP to determine the pressure drop in tubing.

With gas in the flow stream, the effect of increasing surface pressure is to increase pressure loss in the tubing. Thus, back pressure against the formation is increased due to

1) The higher pressure loss in the tubing
2) The higher surface pressure

Curves similar to Figure 3.7 are useful for most engineering work where approximate pressure drop calculations are required. Computer solutions of various correlations permit more detailed look at the effect of changing variables.

3.2.2.2 Outflow performance relationship for gas wells

Several methods are available to calculate bottomhole pressure, or tubing performance relation, for gas well. The Cullender and Smith method is most common; however, the method to determine the solution is iterative and is best performed with a computer. Commonly, pressure vs. depth curves are prepared for a given tubing size and wellhead flowing pressure, Pwh Figures 3.8 and 3.9 from Beggs[14] are such examples for 2" and 2 ½" tubing and a well head flowing pressure, P_{wh}, of 1000 psi.

A nodal analysis for a gas well using the inflow performance relation in Figure 3.7 and the tubing pressure traverse curves in Figure 3.7 and 3.8 is illustrated in Figure 3.10. With 2 ½" tubing, the flow rate is increased by 25% when compare to that obtained with 2" tubing.

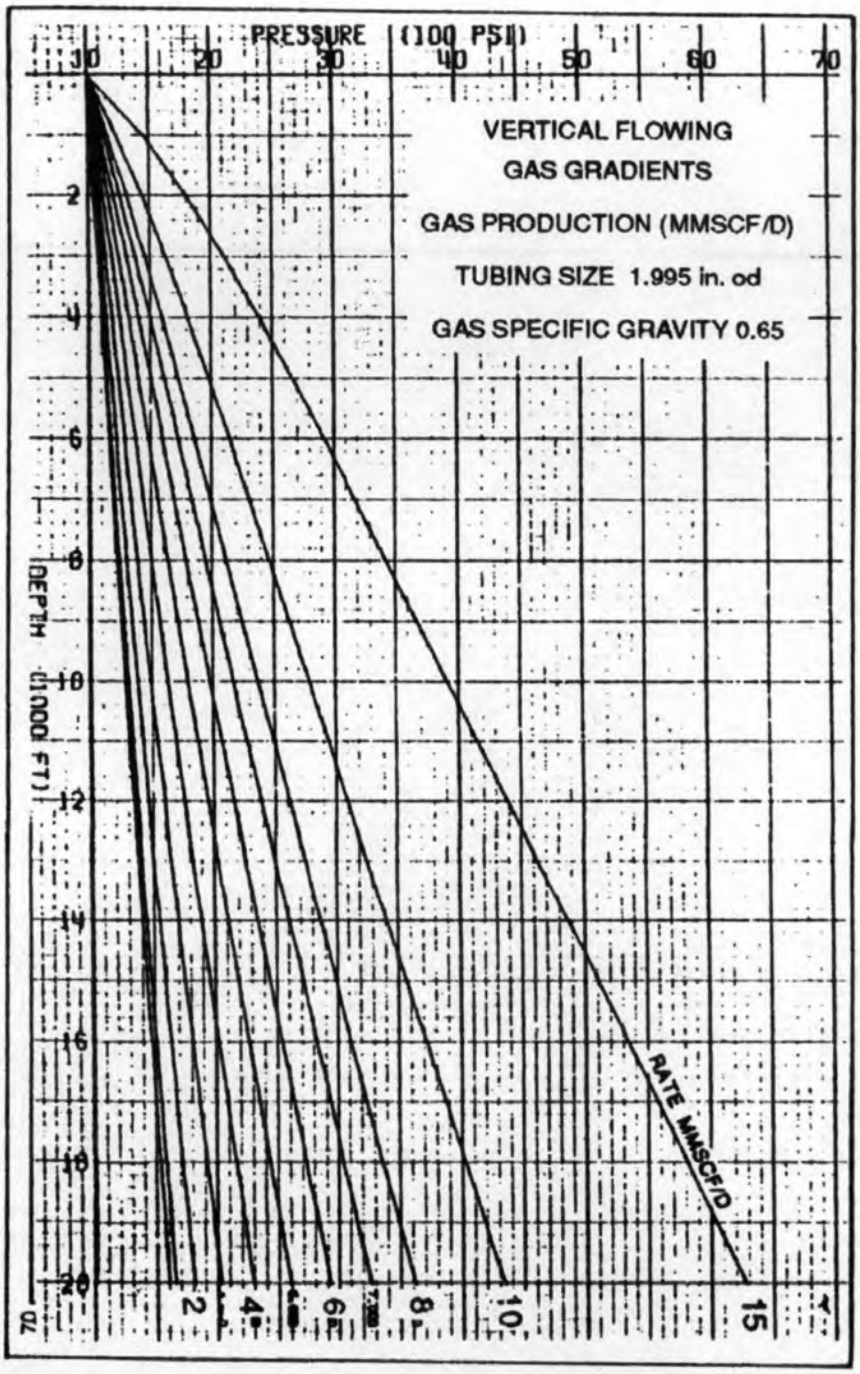

Figure 3.8: Vertical flowing gas gradients for 2" tubing (After Allen and Robert.[9])

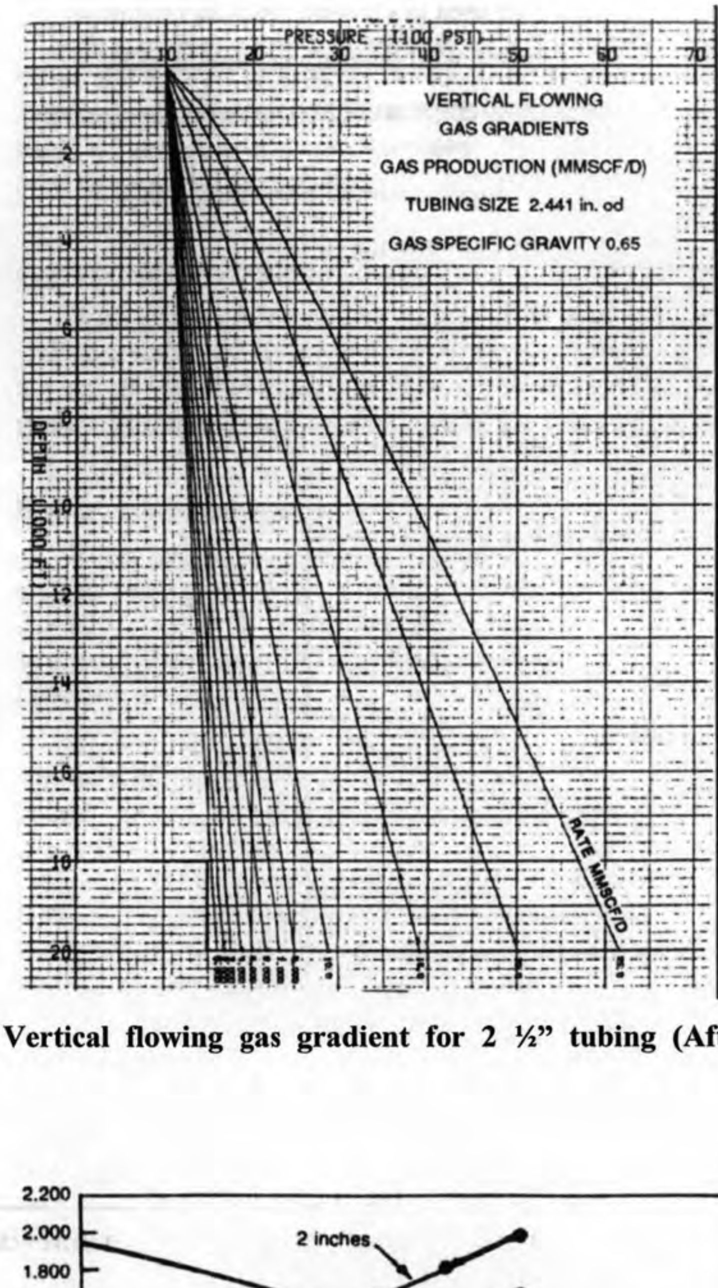

Figure 3.9: Vertical flowing gas gradient for 2 ½" tubing (After Allen and Robert.[9])

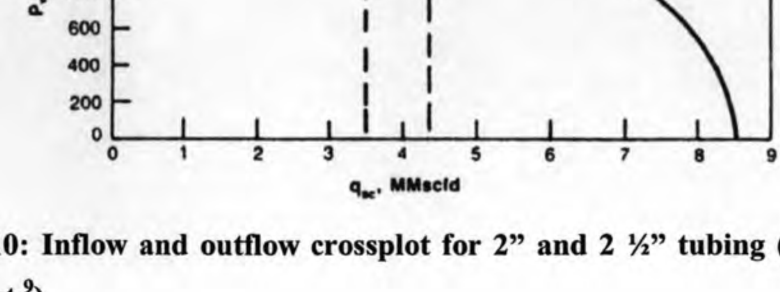

Figure 3.10: Inflow and outflow crossplot for 2" and 2 ½" tubing (After Allen and Robert.[9])

Flow in gas well

Another criterian affecting selection of tubing size for a gas well is that the flow velocity of the tubing must be sufficient to continuously remove hydrocarbon liquids and water. Otherwise, the well will gradually load up and the liquid accumulation will kill the well. In low pressure gas wells, load up can be a significant problem. Many times, condensed water vapor is the primary source of the liquid. In some marginal situations, periodic blow down, in which the well is flowed to a low pressure system, can prolong well life. Sucker rod pumps are used in some fields to periodically or continuously remove excess water.

Turner et al.[15] proposed an equation for estimating the minimum gas rate required to keep a well unloaded if water or condensates is being produced for particular tubing size and well head pressure as following:

$$q_{sc\,(\min)} = \frac{3.06\, v_{\min}\, A p_{wh}}{TZ} \tag{3.21}$$

where:

q_{sc}	=	the minimum rate, MMscf
p_{wh}	=	wellhead flowing pressure, psia
v_{min}	=	minimum velocity, ft/sec
A	=	area of tubing, ft^2
T	=	surface flowing temperature, °R
Z	=	gas compressibility factor

The two equation were given for v_{min} depending on whether the liquid is water or condensate.

$$v_{\min(\,water\,)} = \frac{5.62\,(67 - 0.0031\, p_{wh})^{0.25}}{(0.0031\, p_{wh})^{0.5}} \tag{3.22}$$

$$v_{\min(\,condensate\,)} = \frac{4.02\,(45 - 0.0031\, p_{wh})^{0.25}}{(0.0031\, p_{wh})^{0.5}} \tag{3.23}$$

The chart of Figure 3.11 shows the minimum gas flow rate depending on flowing wellhead pressure and tubing size.

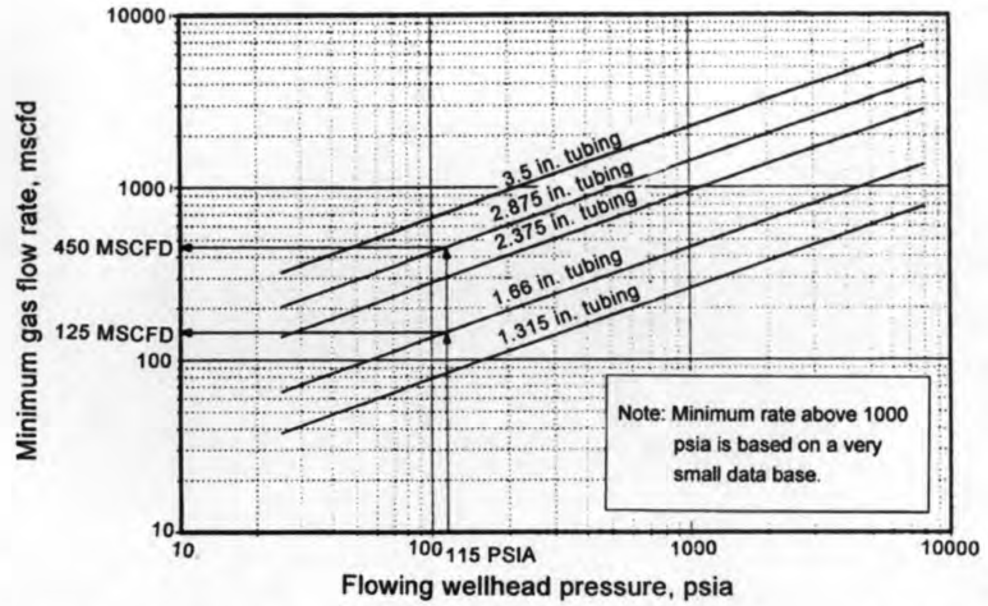

Figure 3.11: Minimum gas flow rate vs. wellhead flowing pressure to prevent load up. (After Allen and Robert.[9])

3.3 History Matching

3.3.1 Objectives of history matching

The primary objectives of history matching are to improve and to validate reservoir simulation model. In general, the simulation results based on the initial simulation input data do not match historical reservoir performance to the level that is acceptable for making accurate future forecasts. To improve the quality of the match, an iterative procedure shown in Figure 3.12 can be used to adjust the initial simulation data systematically to provide an improved match. Once the historical production data are matched, a much greater confidence can be placed in the predictions made with the model.

There are also several beneficial byproducts or secondary objectives of a successful history match. The history matching process invariably leads to a better understanding of the processes occurring in the reservoir. Levels of aquifer support, parts of fluid migration, and areas of bypassed oil can be identified during the history-matching phase of a simulation study. In addition, communication between different well pairs and reservoir areas are identified. The improved understanding is a result of the required observation of how changes in reservoir data affect simulated production.

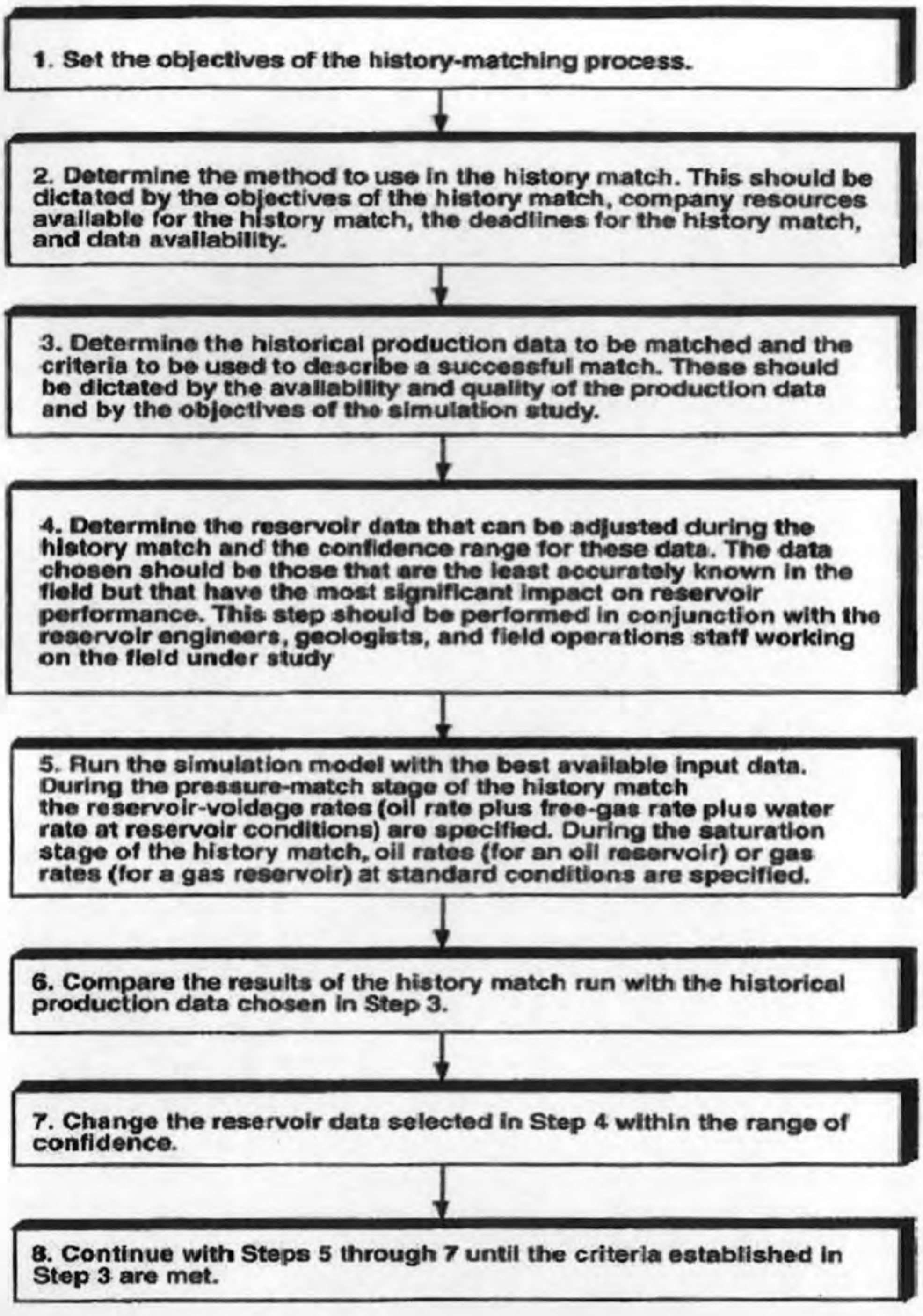

Figure 3.12: Step by step procedure for history matching (after Ertekin et al.,[16])

A successful history match can identify opportunities to improve the reservoir description and the data acquisition program. For example, it may become apparent during the history match that the simulation model is sensitive to data that are not currently available. These data can be collected in the field to improve the history match, model predictions, and general understanding of the reservoir.

Finally, the history matching procedure may identify unusual operating conditions. For example, if the water cut or GOR from an individual well appears to go against areal trends, problems (such as behind-pipe communication) may be identified. Also, if production from an individual well appears to be significantly lower than that from offset wells, reservoir damage (skin) or mechanical well-bore problems may be suspected. On a field scale, areas of bypassed oil may be identified. This will greaty benefit the in-fill drilling program. Problems of this type are identified easily during a history match because the history matching process forces the engineers to look for a real and temporal trends in production data that may be overlooked otherwise.

3.3.2 Properties and the uncertainty parameters of reservoir

There are many properties of the reservoir that generate uncertainty due to the fact that there are many approaches taken in order to determine these properties. Properties of produced fluid such as density, solution gas/oil ratio and condensate gas ratio can be obtained from production test data.

Geological reservoir model can be constructed from sand map, well log, and available core analysis data. Essential parameters which are porosity, permeability, and water saturation can be defined for each layer.

- Porosity can be obtained from available well log data
- Permeability can be obtained from permeability versus porosity correlation.

An example of permeability versus porosity correlation is shown in Figure 3.13 and can be expressed by the equation below:

$$\begin{aligned} \log K &= m\phi + c \\ K &= e^{m\phi + c} \\ K &= ne^{m\phi} \end{aligned} \tag{3.24}$$

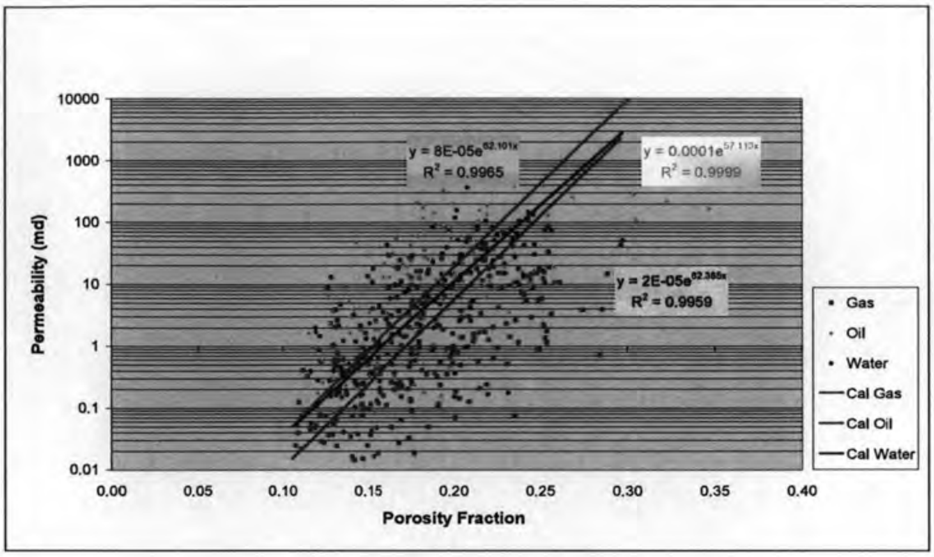

Figure 3.13: Permeability vs. porosity plot.

As we see the plot of permeability vs. porosity, many data scatter out of the correlation line. When we try to history matching, the value of permeability that obtained from the correlation can be changed to another. But the value of the changing permeability should not be out of the range of the scattered data.

When performing history matching, many parameters will be adjusted. Many of these data come from correlation or Monte Carlo simulation. Thus, there are uncertainties associated with the parameter. Initial values of some parameters are input into the model based on availability of information as follows:

- Absolute permeability: using permeability-porosity correlation.
- Area: using P50 of Monte Carlo simulation to input into the model.
- GOR and CGR: using P50 of Monte Carlo simulation to input into the model.
- Size of aquifer: sometimes, we drilled into the zone that doesn't show the aquifer contact. The software requires the size of the aquifer to manage the aquifer drives. An initial number of 1.5 times the reservoir size is typically used.
- Relative Permeability: A very sensitive parameter causing an early or delayed water breakthrough. Since exact value is unknown so varying this parameter introduces high uncertainty.

While we are still matching the historical performance, We need to change the value of the data sets until a good match is obtained.

3.3.3 History matching by zonal isolation

The technique used for history matching is briefly discussed for this type of complex reservoirs in which different zones are perforated at different times. Consider a reservoir with two perforated zones. The two zones are perforated at different times. Each zone may consist of multiple layers. The initial history match is done by adjusting the properties in the layers perforated in the first zone. Once matched, the properties of zone 1 are not changed. Then the history match for the period after the second zone is perforated is done by adjusting the properties of the layers in the second zone without adjusting the properties of the first zone. Figure 3.14 shows an idea of history match technique.

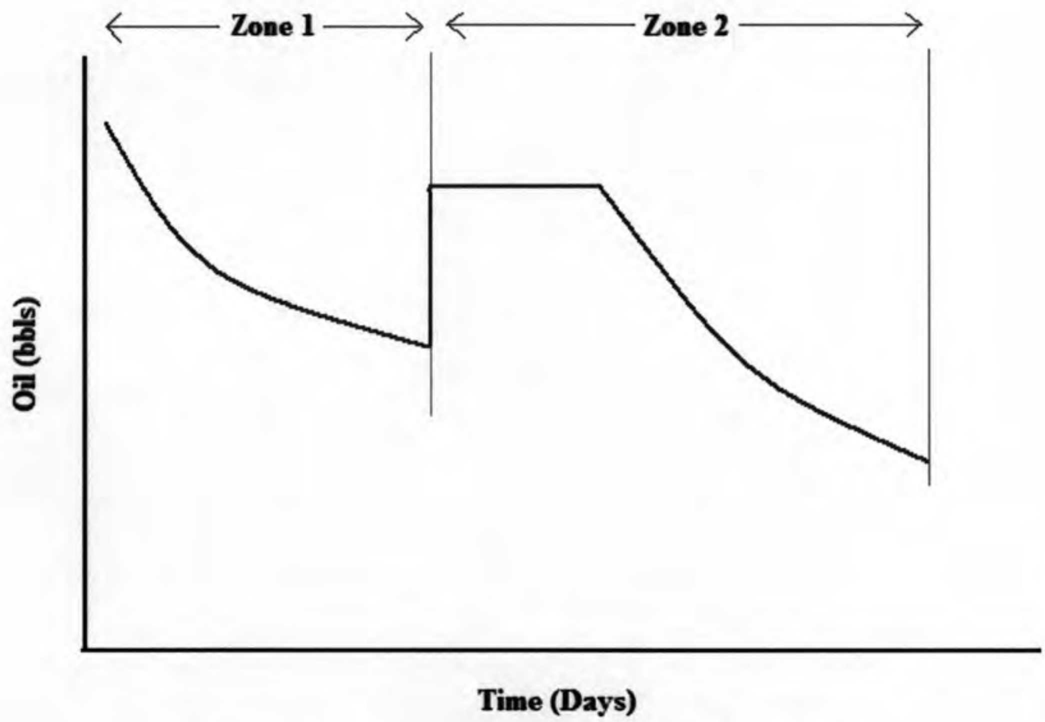

Figure 3.14: Diagram on zonal isolation matching

The uniqueness of the obtained properties depends on a lot of factors such as the complexity of the reservoir, the well life and the drive mechanisms present. The combination obtained for a single layer would be more accurate than that of multiple layers provided that the well has been on production for some time.

3.4 Integrated Production Model

The IPM suite of tools is the industry standard for integrated field modeling and production optimization. Moreover, the tools provide production forecasts.

The IPM suite models the reservoirs, the production and injection wells and the surface gathering system. Multiple reservoirs, naturally and artificially lifted wells, plus single and looped surface pipelines networks can be handled in an integrated way.

The simulation of each well is done using software named Integrated Production Model (IPM by PetEx). This software is integrated with three parts: Gap, Prosper and MBal.

3.4.1 GAP

This part of the software is used to define the wells, reservoir, tubing, perforation depths, surface facilities etc. It also calculates full filed production forecast including gas or water injection volumes required to meet reservoir unit pressure constraints. The wellhead pressure, separator pressures and the schedule of various elements are also determined in this part of the software.

An example of using GAP to integrate PROSPER and MBAL of some wells on the platform for performing history matching models and finding the best depletion strategy are shown in Figure 3.15.

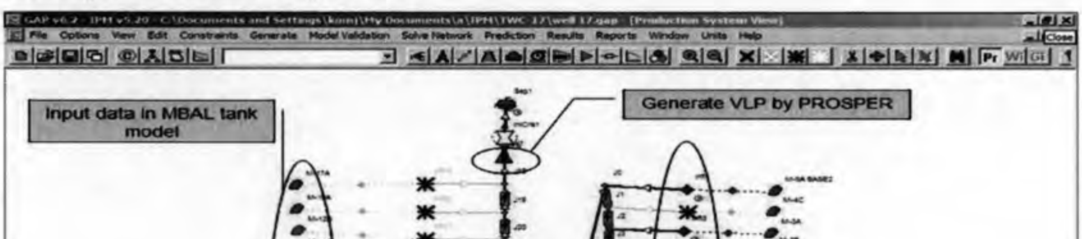

Figure 3.15: Model of GAP software integrated with PROSPER and MBAL.

3.4.2 PROSPER

It is an element which links to GAP and has the ability to define PVT properties of the fluid and is used to generate Vertical Lift Performance (VLP) using standard correlations. It also can vary the range of different parameters that tends to change during the production life of the well. The other features used are to model the inflow performance for single layer, multilayer or multilateral wells with complex and highly deviated completions, optimizing all aspects of completion design including perforation details and gravel packing.

According to the inflow model, the following data are required:

a. Oil and gas PVT properties
b. Initial pressure and temperature
c. Permeability
d. Reservoir thickness
e. Drainage area
f. Perforation interval
g. Skin

According to the vertical lift performance, the following data are required:

a. Top node pressure
b. Water gas and water oil ratio
c. Condensate gas ratio and gas oil ratio
d. Deviation survey of the well
f. Temperature gradient

3.4.3 MBAL

The package is made up of various tools designed to perform prediction run of the production profile. However, it has the ability to perform prediction run only for natural flow and has to be linked to GAP in order to perform predictions for more complex well models. A picture of MBAL software window is shown in Figure 3.16.

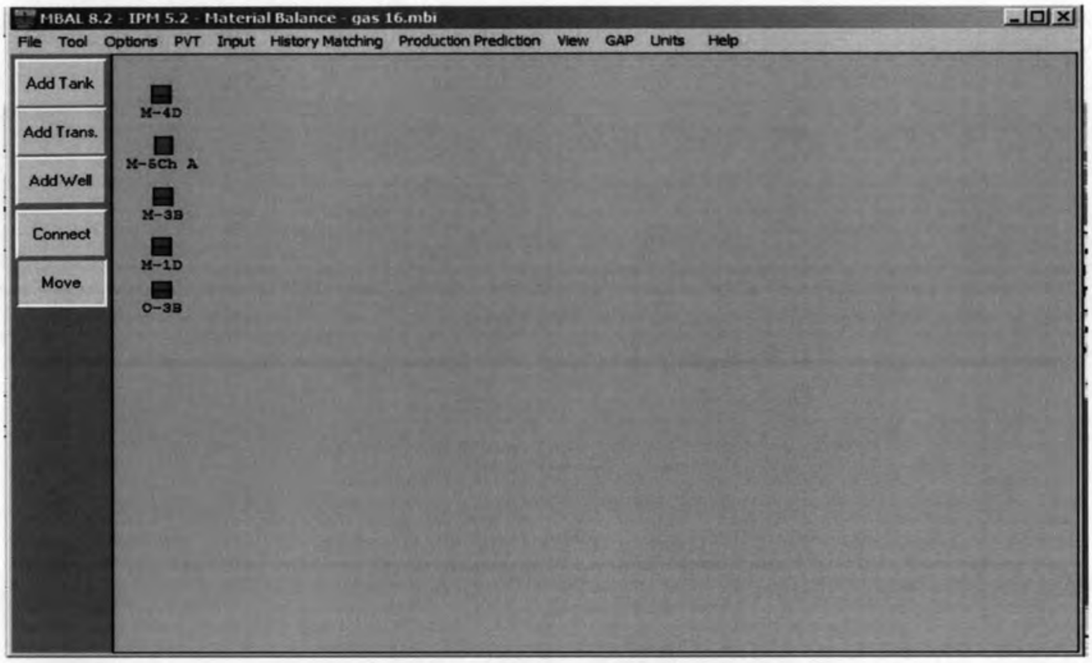

Figure 3.16: Window of MBAL software

The MBAL part is mainly used for assigning the reservoir properties such as the oil or gas in place, aquifer size or type and strength along with relative permeability. It can also perform history match given the luxury of reservoir pressure tests after some period of time for the well on production. To use this tool, the following data are required:

a. Oil and gas PVT properties
b. Initial pressure and temperature
c. Porosity
d. Connate water saturation
e. GIIP and OIIP
f. Aquifer thickness
g. Reservoir radius

The main parameters which introduce uncertainty and are the most sensitive to the outcome are the absolute permeability, area, GOR, size of the aquifer and relative permeability. The details of the history match have been discussed next section.

3.5 Perforation Strategies

The performance of six different perforation strategies are investigated in this study. These strategies are briefly explained as follows:

1) **Actual Completion history**

This strategy just imitates the real perforation and observes the results comparative to other strategies.

2) **Simultaneously perforating all sands at the same time**

In this strategy, all the hydrocarbon bearing sands are perforated at the same time.

3) **Simultaneously perforating full to base hydrocarbon sands followed by contact sands**

This strategy perforates the sands having the hydrocarbons full to base, and when the well loads up, the contact sands (like OWC sands) will be perforated without plugging the layers produced earlier.

4) **Simultaneously perforating oil sands, then gas sands, and followed by contact sands.**

All full to base oil sands are perforated first, and when the well loads up, the gas sands are perforated. When the well loads up again, contact sands are perforated without plugging the previous producing layers.

5) **Simultaneously perforating gas sands, followed by oil sands, and then the contact sands**

This strategy is slightly opposite to strategy 4 in that we perforate gas sands first and when the well loads up, the oil sands are perforated, and when the well loads up again, and then the contact sands are perforated.

6) **Bottoms up Perforation**

The strategy is to perforate each layer at a time from the bottom of the well and when the layer stops producing it is plugged and isolated from the rest of the layers followed by the perforation of the next to bottom layer and so forth.

Strategy 2 to strategy 6 are modeled based on fixed choke size, fixed pressure drop across choke, and the wellhead pressure is equal to the separator pressure.

Also that water shut off and gas lift are not used in strategies 2 to 6. In addition, the AZI zones are also excluded in all models.