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Article

The Dynamics of Commingled Production

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Abstract. Commingled production strategies have been applied successfully worldwide because of the advantages they provide in terms of cost effectiveness and completion simplicity. However, a commingled production approach raises several challenges for reservoir management. The behavior of a commingled well is much more complicated than that of a single-layer well. However, there is little knowledge or experience sharing documented in the literature. The objectives of this study are to comprehensively review reservoir engineering knowledge and performance of commingled wells, and to propose tools for reservoir management decisions. This study summarizes the current knowledge of decline curve analysis (DCA) and material balance equations (MBE) for commingled production available in the literature, and reviews lessons learned from production logging and water shut-off lookback studies in Gulf of Thailand operations. Based on this information, this study proposes the use of a "risky-sand matrix", of perforation best practices, and of commingled well models. Through these approaches, petroleum and reservoir engineers will be better able to understand the performance characteristics of commingled wells and will be in a position to make better reservoir management decisions.

Keywords: Commingled production, perforation, production logging, water shut-off.

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1. Introduction

Commingled production is a method to produce fluids from multiple reservoirs simultaneously. Commingled wells are defined as those in which communication between these reservoirs occurs only via the wellbore, not within the reservoirs. Commingled production was prohibited by industry regulators in many countries in the past. More recently, the approach has been applied successfully worldwide, including Gulf of Thailand, offshore Malaysia, Bangladesh, Vietnam, Indonesia, onshore and offshore Australia, Oman, Saudi Arabia, Nigeria, West Africa, Venezuela, USA, and Canada [1-11]. Commingled production is also applied to produce multi-layer shale-gas reservoirs [12] and deep water multi-layer reservoirs [13].

In the Asia-Pacific region, hydrocarbons are frequently deposited in stacked-sand sequences for which a commingled completion approach is often appropriate. The technique is more commonly applied for gas production than for oil production. Commingled wells are normally completed as monobores across the pay window [14]. Monobore completions have been increasingly utilized because of their simplicity, lower cost, and ease of well intervention. The economic value is maximized by accelerating production, without the trade-off of reduced recovery factors [7]. However, commingled production raises several challenges in terms of reservoir management.

In term of reservoir performance, commingled wells behave very differently from conventional single-layer completions [1, 15]. The reservoir sizes do not yet have any impact on the flow rates during the infinite-acting flow period; at this time, productivities and differences in initial pressure control production contributions from individual layers [16]. The lower-productivity reservoir(s) will tend to produce less and will be depleted more slowly than the higher-productivity reservoirs. Depending on productivity contrast, different reservoirs will be depleted at different rates. This is the well-known differential depletion phenomenon. The production contributions from individual reservoirs are not constant but changing with production time.

Eventually, all reservoirs will reach boundary-dominated flow (BDF) or pseudo-steady state (PSS) flow during the late production period. The entire commingled system will reach the full dynamic flowing equilibrium (FDFE) condition. At this time, the wellbore pressure and the pressures in all reservoirs will deplete at the same rate, and the production contributions from individual reservoirs are controlled by their hydrocarbon-pore-volumes (HCPVs). The reservoir with highest HCPV will dominate the production [16].

After a period of production, different reservoirs have different pressures because of differential depletion. In general, a smaller reservoir will deplete more quickly than a bigger one, and a more-productive reservoir will deplete faster than a low-productive one. Thus, a small permeable reservoir will reach FDFE at a lower pressure than a big tight one. It explains why permeable reservoirs may be producing less than tight ones – if they are smaller in terms of HCPV. During a shut-in, fluid(s) will cross-flow from a higher-pressured reservoir via the wellbore into a lower-pressured reservoir. When the permeability contrast is significant, this can be a very slow process [17]. The time required for pressures to equilibrate between layers is impractically long. The wellbore pressure during shut-in period will tend to track the pressure of the layer with the highest productivity [1, 15].

Commingled production is applied to produce oil and gas reservoirs worldwide because it provides numerous benefits.

- It maximizes the net present value (NPV) of a well by accelerating production [4, 7, 18] and extending its economic life [4, 7, 19]. For a given abandonment rate at the well level, the rate at the reservoir level is much lower. Therefore, each reservoir's life can be extended, leading to abandonment at lower reservoir pressures and therefore higher recovery factors in individual reservoirs.
- It is a practical approach because of its simplicity, reliability, low cost, and ease of well intervention [1].
- It enhances liquid lifting efficiency [4, 7, 19]. Since production is from several sands, water breaking through at a particular sand will not immediately cause liquid loading as there are still many other sands producing hydrocarbons.
- It requires less pressure drawdown. For any required rate at the well level, a commingled well requires less pressure drawdown since the production is from several reservoirs. It leads to a slowing of various processes within the reservoir, including pressure depletion, water movement, and fines migration. Thus, problems with coning & cusping, early water breakthrough, formation damage, and sand production will be minimized [4, 7].

Despite many benefits, commingled production raises several challenges for reservoir management:

- The performance of a single-layer well is quite different from that of a multi-layer well, and it is more difficult to evaluate the performance of commingled wells [20]. Commingled wells usually require regular production logs to be run to find rates and productivities of individual layers [4].
- It is more difficult to analyze welltest data. The analysis of well test data in a multi-layer well is usually a challenging problem due to the complexity of interlayer flow. These problems are partly because of insufficient data concerning individual layer flow into the wellbore, and partly because of the mathematical consequences of commingled inflow, especially when different layers have different skin values [21, 22]. Also, these kinds of tests often cannot be interpreted during the shut-in period. Conventional buildup

tests from layered reservoirs often suffer adverse data quality consequences from cross-flow between layers, particularly if the permeability contrast between layers is high. And, in the best case when good quality data are obtained, conventional draw down and buildup tests usually reveal only the behavior of the total system [23, 24], while in some cases even the interpreted total system behavior can be misleading [21, 22].

- Different reservoirs are depleted to different degrees [23]. As discussed, a higher-productivity layer is depleted faster than a lower-productivity layer with the same HCPV. Water breakthrough normally occurs more quickly in a shallow layer with higher productivity [25]. Normally, we try to shut off a water-producing sand. However, the historical data shows that water shut-off (WSO) jobs have low success rates. It is not well documented what the critical success factors are.
- Production allocation is another issue [7, 18]. A surface production test shows the production rate at the well level but does not provide the production contributions from individual reservoirs. For resource characterization, reserve and productivity for each reservoir are obscured [9, 14].
- In some cases, sand production from shallower and more productive zones, causes wellbore plug up and obstruction in wellbore. This would lead to long and expensive well intervention and/or reserves loss. While fluid compatibility issue, which could lead to wellbore scaling, should also be considered.
- It is very difficult to create the optimal perforation plan for commingled wells. How many stages of perforations should we have? How many sands per stage of perforation should we have? There are no clear answers for these kinds of questions.
- There is probably bypassed hydrocarbon in a multi-layer well [2, 8]. Therefore, the recovery factors of individual reservoir are not maximized.

Surprising, several of these challenges have not been sufficiently addressed in the literature, despite the worldwide application of the commingled approach. This study tries to solve these issues by examining a lot of available empirical data from commingled wells in the Gulf of Thailand. The objectives of this study are to comprehensively review reservoir engineering knowledge and performance of commingled wells, and to propose tools for reservoir management decisions.

2. Decline Curve Analysis (DCA)

DCA is regarded as a standard Petroleum Engineering tool for production forecasting and for reserves estimation. The following empirical model was proposed by Arps (1945) [26] for a volumetric, single-phase reservoir produced at a constant bottom-hole pressure during pseudo-steady-state flow. A flow rate (q) is defined in terms of an initial flow rate (q_i), an initial decline rate (D_i), and a decline exponent (b) as

$$q(t) = q_i(1 + b\, D_i t)^{-1/b} \tag{1}$$

The value of b is assumed to be constant throughout the production life. Several studies [15, 27, 28] showed that the value of b is less than 0.5 for a single-layer system during BDF period. A higher value of b means a lower decline rate.

For a multi-layer well without inter-layer crossflow in the reservoir, the value of b is not constant and can be greater than 0.5 [15, 28]. This is due to differential depletion. The higher production from the higher-permeability layer causes an early rapid rate decline. After that there is an extended period of low rate decline which is from the lower production of the lower-permeability layer. Normally, a multi-layer well has an unusually long production life. Application of DCA (1-layer model) to analyze production data from a multi-layer well often yields misleading results.

In a multi-layer well, the values of D and b are not constant. The non-uniqueness problem is more pronounced. A new methodology [28] has been proposed to analyze production data from a multi-layer well. The instantaneous values of decline rate (D) and decline exponent (b) are explicitly estimated from the production data. History matching on the profiles of q, D, and b are performed simultaneously. The results are unique sets of decline parameters (q_i, D_i, and b) for individual reservoirs. The new technique provides reliable production forecasts and reserves estimation for both oil and gas wells.

3. Material Balance Equation (MBE)

Because of its simplicity, MBE has long been regarded as one of the fundamental tools for interpreting and forecasting reservoir performance [29, 30]. The technique requires only cumulative production and averaged reservoir pressure. The reservoir properties, production history or wellbore completion details are not relevant. For a volumetric reservoir, the general MBE states that the volume of underground withdrawal, resulting in a pressure drop in the reservoir, equals the expansion of reservoir fluid(s) plus reduction in hydrocarbon-pore volume (connate water expansion plus pore volume reduction). The technique can be applied to estimate reserves and the hydrocarbons initially-in-place. For a volumetric gas reservoir without water encroachment, the general material balance is

$$\frac{(p/z)}{(p_i/z_i)} = 1 - \frac{G_p}{G} \tag{2}$$

A plot of (p/z) versus cumulative gas production (G_p) yields a straight line with a x-intercept of gas initially-in-place (G) and a y-intercept of (p_i/z_i) [31].

For a multi-layer system, MBE may yield unreliable results [1, 32]. The p/z plot underestimates (overestimates) gas initially-in-place (G) during the early (late) production period [17]. This technique requires the average system pressure which can be measured during shut-in period. But differential depletion of different layers causes cross-flow during the shut-in period, and the wellbore pressure during the shut-in period is always lower than the equilibrium system pressure. Lefkovits et al. [33] discussed the typical characteristics of pressure build-up for a 2-layer system, illustrated in Figure 1. It could take several decades to reach an equilibrium condition.

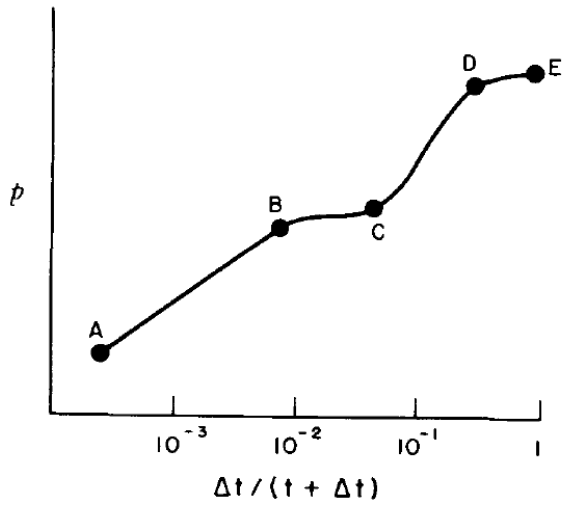

Fig. 1. Pressure build-up for a 2-layer reservoir (Lefkovits et al., 1961).

For a 2-layer system, the relationship between productivity index of each layer (J), the wellbore-flowing pressure (p_{wf}), pressure in each layer (p), and the average system pressure ($\bar{p}$) during the shut-in period is expressed as [31]:

$$p_1 < p_{wf} = \sqrt{\frac{J_1 p_1^2 + J_2 p_2^2}{J_1 + J_2}} < \bar{p} < p_2 \quad (3)$$

The wellbore pressure is always closer to the pressure of the more permeable layer.

It is not practical to shut-in a well until the equilibrium condition is reached. A new approach [32] suggests using data from production logging to establish selective inflow performance (SIP). SIP analysis yields pressures and productivities of individual layers. The average reservoir pressure is calculated from individual reservoir pressures weighted by their hydrocarbon pore volumes. The new approach corrects the misleading results from application of MBE to a multi-layer system.

4. Lessons Learned from Production Logging (PL) Lookback

Down-hole information at different stages of production is essential for proper reservoir management. PL is routinely run to estimate flowing pressures and flowing rates of individual producing reservoirs. A multi-rate PL provides additional information which can be used to construct SIP plots for individual reservoirs. SIP plot reveals each reservoir's productivity and pressure [14].

A comprehensive study [25] reviewed several hundred sets of production logging results from both oil and gas commingled wells in the Gulf of Thailand. The results show that the sands with the following characteristics have a high probability of producing reservoir fluid(s) at high rates.

- High porosity (ϕ)
- Low water saturation (S_w)
- Shallow depth

These parameters are not independent but are significantly correlated. A deep sand tends to have lower ϕ and higher S_w (excluding sands in a transition zone for the moment and considering only sands above the transition zone). Low ϕ and high S_w imply low permeability, i.e. tight rock. For a given pressure drawdown, Darcy's law implies that lower permeability means lower production rate. Therefore, the empirical data is not in conflict with our conventional reservoir engineering knowledge.

One main objective for running PL is to locate water-producing sand(s). Early water breakthrough means less hydrocarbon production, lower recovery factor, and lower economic value. Therefore, identification of the probability of water production for each reservoir is a critical task for better reservoir management. The study [25] showed that water-producing sands share some or all of the following characteristics.

- gas-water contact or oil-water contact sands
- High ϕ
- Low S_w
- Shallow depth

The sands with either gas-water or oil-water contact obviously have the highest probability of producing water. Partial perforation can only slow down the water coning process, and not eliminate it entirely. Water will finally breakthrough at the perforation interval. The correlation of higher probability of water production with lower S_w seems at first to be counter intuitive. It can be explained as follows: Above the transition zone, water is immobile. Tight sands (low ϕ) with low permeability have higher S_w than porous sands (high ϕ). Therefore, high S_w does not predict high water production but implies low permeability instead. In summary, high permeability correlates with both high ϕ and (at least above the transition zone) low S_w. (Note that this discussion does not consider sands that correlate to a down-dip aquifer). The tendency of sands with these characteristics to produce high levels of water is because any fluid can flow easily through the high-permeability sand. When a well is opened for production, a higher-permeability reservoir will contribute more. Water will break through first in this reservoir if it is connected to an aquifer.

Tighter sands usually have low production rates. They have low probability of producing water in significant quantities, regardless of high S_w. They are at higher risk of load up, especially for deep sands without significant lift from below [34].

5. Lessons Learned from Water Shut-Off (WSO) Lookback

The objective of WSO is to reduce water production and wellbore hydrostatic pressure. With lower water production, a lower wellbore-flowing pressure can be achieved, leading to higher hydrocarbon production. Therefore, WSO can enhance economic value. A WSO lookback study [34] evaluated the statistics and economic outcomes of WSO jobs. About a hundred WSO jobs in both oil and gas wells under commingled production in the Gulf of Thailand were reviewed. The pre- and post-well performances were carefully analyzed. WSO tools are mainly tubing patch and plug. The jobs are classified as "failure" if there are insignificant reserves added by the WSO intervention (termed "WSO reserves"). The overall probability of success (POS) is about 37%. POSs of WSO in gas and oil wells are approximately the same.

The distribution of WSO reserves approximately follows a log-normal distribution. Many jobs yield insignificant WSO reserves. Only a few jobs give very large WSO reserves. Economic analysis (focusing on WSO reserves and PL & WSO costs) shows a positive NPV across the whole portfolio. The successful WSO jobs with large WSO reserves have the following common characteristics.

- Clear indication of water from PL data
- Strong aquifer support (high reservoir pressure)

The target sand must produce a lot of water that is clearly identifiable by the PL data. Note that production logging is not a measurement tool: interpretation yields ranges of uncertainties. In multi-phase flow, it is difficult to evaluate low fluid rates. A WSO job should have higher POS and WSO reserves when the target sand produces a higher water rate. Strong aquifer support means a water-producing sand with relatively high pressure are active during both flowing and shut-in periods. During the shut-in period, water will cross-flow from the target sand via the wellbore into other hydrocarbon-producing sand(s). The sand with higher pressure tends to control future wellbore pressure. Without shutting off this kind of sand, the hydrocarbon and water rates will soon follow decreasing and increasing trends, respectively. Shutting off the sand with strong aquifer support will lower the water rate and the wellbore-flowing pressure and will extend the life of the remaining sands. The study also suggested that we should also consider the following factors:

- The wells with poor performance prior to WSO jobs tend to have lower POS and WSO reserves.
- The quality of the remaining sands after WSO jobs is another critical parameter. If the remaining sands have poor qualities, the POS and WSO reserves tend to be low.
- WSO jobs without PL data tend to have lower POSs. Under this situation, the asset team can only guess where the water production comes from.
- Performing WSO jobs on no-flow wells leads to lower POS and low WSO reserve. It implies that the timing of performing WSO job is another critical parameter (in other words, do not wait until the well dies).

There are additional two operational challenges [35].

- Most of the time, the target sands are producing both hydrocarbon and water. Early shut off may lead to lower production rates for both types of fluids. On the other hand, leaving WSO too late or leaving the target sand on production indefinitely may lead to liquid loading and an eventual no-flow condition.
- Because of limited manpower and resources, as well as logistical constraints in the field, not all the requested well interventions can be performed. Therefore, we need to prioritize the requested jobs and work on the ones with higher economic impact first. POS and WSO reserves can be regarded as proxies for economic value of the job. Failure to properly predict them means poor manpower and resources allocation.

6. Risky Sand Matrix

Water production causes severe problems for both oil and gas wells. With higher density, water in a wellbore generates higher hydrostatic pressure across all production intervals which leads to lower pressure drawdowns and lower production rates. Ultimately, water may load the wellbore, especially in the deeper section of the wellbore. This is the well-known "liquid loading" problem. The well may die prematurely with significant unproducible reserves. Therefore, we should avoid or try to slow down water breakthrough at the wellbore. A sand with a high probability of early water breakthrough is classified as a risky sand.

Based on the results of PL and WSO, a risky sand matrix is created. It illustrates the risk of water production in the ϕ-S_w domain, as in Fig. 2. The analysis concentrates only on the reservoirs' ϕ and S_w, without information about their possible connection to down-dip aquifers or other factors (such as a high-permeability layer or fracture) that can lead to early water breakthrough. The conclusions of the matrix can be summarized as follows: A sand (above the transition zone) with high ϕ and low S_w always has high productivity. A high-productivity sand has a high probability of producing hydrocarbon(s) at a high rate and, eventually, a high probability of producing water at a high rate. The study [25] of several hundred production logs demonstrated that sands in the highest ϕ & lowest S_w category are 4 times more likely than average (excluding oil-water contact and gas-water contact sands) to produce water at a rate greater than 100 barrels per day.

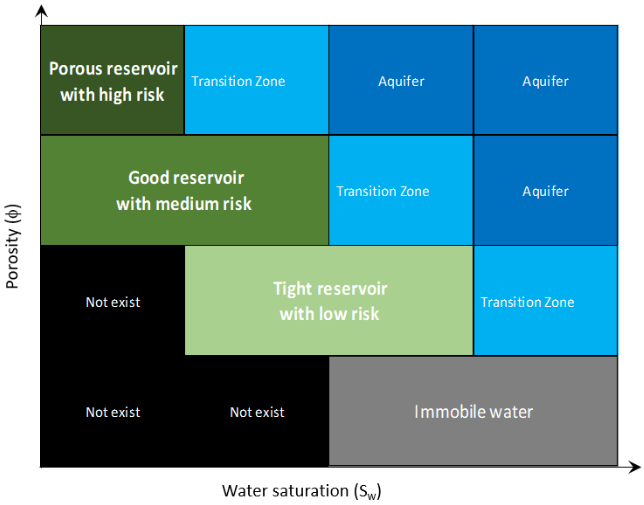

Fig. 2. Risky sand matrix.

A recent study [36] summarized knowledge of other mechanisms that can lead to water production. The study considers reservoir parameters, cement bond quality, sand correlation to water down-dip, aquifer above and below the target sand, and S_w from log equations (which could identify certain high ϕ and high S_w sands as being in a transition zone, meaning that water is mobile rather than bound). Different magnitudes of risk are discussed for the different factors.

7. Field Case Study and Best Practices

In the Gulf of Thailand fields, proactive and bottom-up perforation strategies have been implemented during different periods. With the proactive strategy, most of the pay sands were perforated and produced from day 1. In contrast, for the bottom-up perforation strategy, a group of sands are perforated, depleted and occasionally plugged before the next sand group is produced. Prior to 2006, the proactive strategy was standard among teams. Starting in 2006, a bottom-up strategy was adopted as the best practice. That led to a decline in the percentage of reserves perforated during the initial round of perforation. During the period that this initial perforation percentage declined, the frequency of gas deliverability shortages increased. There are many factors that contributed to the high shortage volume; perforation strategy was one of them. Therefore, since 2012, the proactive perforation has become standard practice once again.

For gas wells, general practice is to commingle low and medium risk sands with similar pressure regimes together, then high risk sands will be perforated in later batch(es). A low-reserve well, with expected reserves less than 25% of the field average, should be limited to one batch only, while a higher-reserve well could have several batches as appropriate. One goal is to optimize (i.e. minimize) water production which is the most critical factor for this producing environment. Closely monitoring well behavior is essential for commingled production. During perforation batches, additional intervention(s) may be required, e.g. PL, WSO, or pressure surveys. Perforating more sands increases well deliverability and improves well liquid lifting capability. An additional benefit is lower abandonment pressure which leads to higher recovery than single zone production.

Low-reserve wells should have minimal downside impact on reserves from commingling, and can be depleted faster. Once the well is depleted and abandoned, the slot can be used for an infill prospect with better reserves. For wells with decent reserves, perforation batches should be decided based on desired well productivity/sustainability, number of trips to platform, risk of losing reserves from early water breakthrough, erosional velocity, sand production risk, and/or %CO_2 constraints.

This study reviews the performance of gas wells in Gulf of Thailand. There are 180 wells with bottom-up perforation strategy and 179 wells with proactive perforation strategy. Results from a retrospective review show that proactive perforation does not degrade value, as a result of Estimated Ultimate Recovery (EUR) reduction. This is demonstrated, in Fig. 3, by the comparison of distribution of EUR growth between bottom-up and proactive perforation strategies. EUR growth is determined by the most recent performance based EUR (EUR_f) divided by an initial volumetric EUR (EUR_0). It is apparent that their distributions of EUR growth are approximately the same. The averages of EUR growth for the 2 strategic approaches show no significant difference.

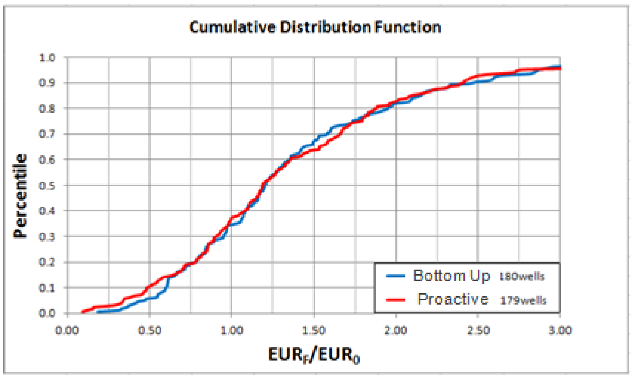

Fig. 3. Distribution of Estimated Ultimate Recovery (EUR) growth for sand-by-sand and commingled perforation strategies of gas wells in Gulf of Thailand.

For oil wells, commingled production should be planned carefully regarding reservoir management strategy. Recommendation is to limit a batch to nearby reservoirs with similar drive mechanism to avoid reserves loss from early water encroachment. This is also critical to improve recovery decision, for example, waterflooding potential. Combining oil and gas sands in the same perforation batch could improve production rate due to in-situ gas lift.

Major concerns from commingled perforation operations include differential sticking and "gun blow-up" of perforation assemblies due to different levels of depletion. This risk is normally mitigated by a trigger shot for pressure equalization, and careful selection of commingled sands in each batch (high pressure sands in early batch, then lower pressure regime together).

8. Commingled Well Models

Production allocation to individual zones is critical for better reservoir management decisions which include well intervention or the location and timing of infill or step-out drilling. There are two available approaches in the literature for commingled well modeling; one without PL data and another with PL data. El-Banbi and Wattenbarger (1997) [37] presented the layered stabilized flow model for reserves estimation and production forecasts without using PL data. It takes into account non-Darcy flow and variations in p_{wf}. The required input data are flow rate (q_g), p_{wf}, initial reservoir pressure and gas properties. History matching yields G and flow equation parameters for each layer. Then production forecast can be easily performed. This method is suitable for moderate to high permeability reservoir (above 0.1 md). The approach may face a non-uniqueness problem.

Last (2012) [14] showed how PL results can be used, in conjunction with dynamic modeling techniques, to define G for each layer. PL data can be used to establish the SIP of each layer, which provides each layer's deliverability and pressure at the time of the PL survey. Production to individual layer can then be allocated while calculation of associated G is completed by coupling well information (production data and initial reservoir pressure) and SIP results. The essential elements of a commingled well model, as used in this approach are:

- Definition of zones with independent characteristics
- Defining inflow performance separately for each zone
- Defining PVT relations based on reservoir fluid properties for each zone
- Calculation of the production profile versus time for each zone using an appropriate sequence of time steps
- Calculation of the pressure profile versus time for each zone
- Calculation of pressure loss in the wellbore from friction and hydrostatic gradients

These two approaches in the literature focus on matching only gas flow rate at a well level. Jongkittinarukorn et al. (2020) [28] showed that history-matching process could yield the well-known non-uniqueness problem; i.e. several models could match historical performances but yield different production forecasts. The problem is more severe for a multi-layer well. To mitigate the non-uniqueness problem, this study proposes the history matching is performed not only on a profile of q but also on the profiles of D and of b simultaneously. For a system with n layers, without reservoir cross-flow, the flow rate at the well level (q_w) is the summation of gas flow rates from individual reservoirs (q_j).

$$q_w = \sum_{j=1}^{n} q_j \tag{4}$$

For a DCA method, the flow rate in each layer is expressed as

$$q_j = q_{ji}\left(1 + b_j D_{ji} t\right)^{-1/b_j} \quad \text{for } j = 1, \ldots, n \tag{5}$$

A set of decline parameters for each layer is (q_i, D_i, b). There is a total of 3n parameters. For a MBE method, a gas material balance equation, Eq. (2), and a stabilized gas flow rate, Eq. (6) are coupled to model the dynamic behavior of each reservoir.

$$q_j = J_j\left[m(\bar{p}_j) - m(p_{wf})\right] \quad \text{for } j = 1, \ldots, n \tag{6}$$

where J is a gas productivity index and the real gas pseudopressure, m(p), is defined by Al-Hussainy et al. (1966) [38] as

$$m(p) = 2\int_{p_0}^{p} \frac{p'}{\mu z} dp' \tag{7}$$

A set of parameters for each layer is (J, G). There is a total of 2n parameters. Differentiate Eq. (4) with respect to time yields the following relationship.

$$q_w D_w = \sum_{j=1}^{n}\left(q_j D_j\right) \tag{8}$$

Differentiate the above equation again with respect to time yields the following relationship.

$$q_w D_w^2(1 + b_w) = \sum_{j=1}^{n}\left[q_j D_j^2 (1 + b_j)\right] \tag{9}$$

At any production data point "k", the residuals (R) with respects to Eqs. (4, 8, and 9) are defined, respectively, as

$$R_{1k} = \frac{\left|q_w - \sum_{j=1}^{n} q_j\right|}{q_w} \tag{10}$$

$$R_{2k} = \frac{\left|q_w D_w - \sum_{j=1}^{n} q_j D_j\right|}{q_w D_w} \tag{11}$$

$$R_{3k} = \frac{\left|q_w D_w^2 (1 + b_w) - \sum_{j=1}^{n} q_j D_j^2 (1 + b_j)\right|}{q_w D_w^2 (1 + b_w)} \tag{12}$$

The average residual for a data point "k" is defined as

$$R_k = \frac{\left(R_{1k} + R_{2k} + R_{3k}\right)}{3} \tag{13}$$

The weights of R_{1k}, R_{2k}, and R_{3k} are the same since we would like a model that fits the profiles of q, D, and b simultaneously. This can help reduce the well-known non-uniqueness problem from history matching [28].

An average residual for a set of production data is defined as

$$R = \frac{1}{m}\sum_{k=1}^{m} R_k \tag{14}$$

where m is a number of production data points. The task is to find sets of reservoir parameters for individual reservoirs such that the R is minimized.

Fetkovich et al. (1996) [27] and Jongkittinarukorn et al. (2020) [28] recommended reducing from n layers to 2 layers by combining layers with similar value of (q_i/G). The intentions of this are to simplify the matching process and to mitigate the non-uniqueness problem.

9. Conclusions

- The performance of a commingled well is complicated and is significantly different from that of a single-layer well. Therefore, decline curve analysis (DCA) and material balance equation (MBE) methods cannot be directly applied to analyze production data from a commingled well. Some modifications are required.
- Production logging (PL) data shows that a shallow sand with high porosity and low water saturation has high probability of early water breakthrough.
- Water shut-off (WSO) analysis shows that a water shut-off job with clear indication of water from PL data, and strong aquifer support, has a high probability of success with high WSO reserve.
- This study proposes a risky sand matrix based on the lessons learned from PL and WSO studies.
- A history of perforation practices is documented. A retrospective study indicates that, compared with a bottom-up strategy, there is no detectable loss in EUR from implementing commingled production in gas wells, while there are considerable practical benefits in adopting a commingled approach. The reservoir management plan should be considered and implemented on a case-by-case basis in oil wells.
- This study proposes a commingled well model which is applicable for both DCA and MBE methods. History matching on profiles of flow rate (q), decline rate (D), and decline exponent (b) are performed simultaneously. This helps in reducing the non-uniqueness problem.

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Nomenclature

b : decline exponent, dimensionless
D : instantaneous decline rate, d^{-1}
D_i : initial decline rate, d^{-1}
EUR : Estimated Ultimate Recovery, MMscf
EUR_f : the most recent performance based EUR, MMscf
EUR_0 : initial volumetric EUR, MMscf
G : gas initially-in-place, MMscf
G_p : cumulative gas production, MMscf
J_1 : productivity index in layer 1, stb/d/psi or MMscf/d/psi^2
J_2 : productivity index in layer 2, stb/d/psi or MMscf/d/psi^2
$m(p)$: pseudopressure, psi^2/cp
p : reservoir pressure, psia
p_i : reservoir pressure at the initial condition, psia
p_o : reference pressure, psia
p_{wf} : wellbore-flowing pressure, psia
p_1 : pressure in layer 1, psia
p_2 : pressure in layer 2, psia
$\overline{p}$: the average reservoir pressure of a system, psia
q : flow rate, MMscf/d or stb/d
q_i : initial flow rate, MMscf/d or stb/d
R : residual from estimation, fraction
S_w : water saturation, %
t : time, day
z : gas compressibility factor, dimensionless
z_i : gas compressibility factor at the initial condition, dimensionless
ϕ : porosity, %

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