PRACTICAL METHOD FOR ASSESSING RESERVOIR PERFORMANCE TO REVIVE CLOSED OIL WELLS

METODE PRAKTIS PENILAIAN KINERJA RESERVOIR UNTUK MEMPRODUKSIKAN KEMBALI SUMUR YANG DITUTUP

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ABSTRAK

Efisiensi adalah isu kunci dalam memproduksikan kembali sumur minyak yang telah ditutup. Tujuan penelitian ini adalah mengembangkan metode praktis untuk penilaian kinerja reservoar yang akan diproduksikan kembali. Metode tersebut terdiri dari pembuatan set kriteria, penilaian atas kriteria tersebut, dan pemeringkatan sumur yang akan diproduksikan kembali. Aplikasi metode ini pada lapangan minyak lepas pantai yang sedang dalam evaluasi untuk diproduksikan kembali menunjukan hasil yang selaras dengan histori kinerja produksi. Dari sembilan sumur yang dievaluasi, Sumur 3 dan 7 direkomendasikan tidak diproduksi kembali karena cadangan tersisa rendah dan prediksi tambahan perolehan minyak kecil. Metodologi yang telah dikembangkan fokus pada analisis petrofisika dan kinerja produksi sumuran sehingga lebih praktis dibandingkan metode yang umum digunakan yaitu integrasi data statis-dinamis reservoar, data sumuran, dan fasilitas permukaan. Aplikasi metode ini dapat mengurangi biaya dan waktu secara signifikan.

Kata kunci: Kriteria kinerja reservoir, memproduksikan sumur yang telah ditutup, minyak yang dapat diproduksikan, kinerja produksi

ABSTRACT

Efficiency is the key issue in reinstating of closed oil wells to production. The goal of this work is to develop practical workflow for assessing reservoir performance to revive closed wells. The workflow are generating the set of criteria, valuing the criteria, and making a ranked list of wells to be revived. Application to an offshore oil field, which under consideration to start producing again shown that the results are found to be reliable and consistent with the historical production performance. From the nine wells assessed, found that Well 3 and Well 7 are not recommended to be revived due to low remaining reserves and less predicted additional recoverable oil. The proposed methodology focus on petrophysical and production performance analysis associated with the wells probed rather than integrating static-dynamic reservoir data, well data, and operational issues as the commonly used one.,. Application of this methodology are expected to be beneficial to companies involved in field operations because the cost associated with the time spent for these types of processes could be reduced considerably.

Keywords: *Reservoir performance criteria, reviving closed wells, recoverable oil, production performance*

I. INTRODUCTION

Reviving closed oil fields is becoming an important aspect for increasing oil production at this time in which chance of discovering oil fields remarkably decreases (Babadagli 2005; Dunning et al. 2011). The oil industry's common goal is to put back these fields on production with impressive gains and do it safely in an environmental responsible, reliable, and cost-effective method. Although several innovations in term of technology have been implemented to revive these fields, it is very common to see huge hydrocarbon production potential still remains locked in the fields (Koshy et al. 2014; Soetikno et al. 2014).

Reviving this hydrocarbon potential covers a broad subject. It may involve identifying opportunities for production increases from reservoirs performance, from individual wells, and from surface equipment (Saputelli et al. 2007). Aspects related to reservoir subject that need to know may include the amount and location of the oil left and quantifying the recoverable amount accurately. It will involve understanding the initial reservoir fluid characterization and pressure distribution, rock properties distribution, reservoir boundaries, and aquifer support. The well issues may consist of well productivity, wellhead pressure and flow rates, completion strategy, and vertical lift design to produce the target oil. Surface facilities may involve undesired multiphase fluid interaction, gas, water, facilities, and drilling rig availabilities as well as regulatory compliance. Depending on the field type, history, and prospects, the reviving plans could be done to address either one or combination of them.

There is no standard or best practice for identifying, designing, and implementing the methodology to deliver the remaining oil reserves of closed oil fields. Each field has a specific problem, and the methodology has to be flexible enough to accommodate any condition. Several common methodologies include integrated asset modeling (Acosta et. al. 2005; Rodrigues et al. 2007), recognize production enhancement and optimization candidates (Arevalo et al. 2006), and global optimization approach (Solis et al. 2004). Those methodologies require complex technical data and can be time consuming and somewhat expensive process.

This paper is aimed to meet the challenges by developing a practical approach, focuses on reservoir engineering aspect, to screen the potential ceased wells to be revived for delivering the remaining oil reserves through assessing reservoir performances that was penetrated by the wells. A simple and powerful worksheets on EXCEL based is produced allows to do quickly this process. These worksheets comprise of material balance calculation (MBE), inflow performance relationship (IPR) construction, forecasting oil production, and scoring and ranking system. The produced worksheets enable to do quick judgment on the feasibility of wells revival hence make easier to someone who wants to screen a large number of closed wells rather than using the conventional costly optimization approach. It will much more save time and decrease works intensity.

Reservoir performance will be measured as a function of petrophysical properties and production performance history. Technical criteria on well-by-well basis are specifically developed to value reservoir performance and then employed to provide a ranked list of wells to be revived. Process to arrive at the list of promising well candidates using the developed worksheet will be described in this paper employing a real reservoir data. The data are obtained from an offshore oil field that was developed using 8 platforms contains almost 70 wells, most assembled with electrical submersible pump (ESP). The reservoir target is a carbonate build-up that was deposited unconformably over the ancient basement high. Based on core and log analysis, this reservoir is classified into three facies i.e: composed of grainstone, packstone, and wackestone. Grainstone represent the upper part of the carbonate and has the best porosity approaching 40%. After 20 years of production, the field was closed down as hydrocarbon production fallen below the economic limit. Recovery factor of oil and associated gas are 6.4% and 48.6% respectively. The driving mechanisms that control the recovery were a combination of solution gas, gas cap gas expansion, and partial water drive. A credible investigation of the recoverable amount of oil under primary stage is merely 7.0% due to its viscosity. Therefore the remaining oil for field revival is approximately 0.6% of original oil in place or equivalent to 3.8 million of stock tank barrel (MMstb). The opportunity reinstating wells to production intended to maximize the ultimate oil recovery is more reasonable.

II. METHODOLOGY

Development of practical workflow for assessing reservoir performance to select the appropriate wells to be revived relies on a set of technical criteria that has been specifically created for case studied here according to reservoir engineering technique. The scoring and ranking methodology used 9 criteria listed in Table 1 that divided into petrophysical and production performance criteria. The petrophysical factors include facies, net pay (h), porosity (ϕ), permeability (k), and production interval to net pay ratio (h_p). The second criteria consists of oil recovery factor as of ceased date (*RF*), initial oil rate at the time a well revived (q_{oi}), estimated recoverable oil (*Np*) on a well basis, and the time of period to recover it (*t*). Each criterion is given a weight that reflects its relative importance among the set of criteria. They are made on the basis of empirical data and judged quantitatively, with the exception of the facies which valued qualitatively. The closed wells assessed are measured against each criterion which ranging from 4 for possible situation to 15 for preferred situation. The relative scoring and the adjustments to these scores are made on the basis of experiences and judgment (Usman et al, 2014; Usman et al. 2010; Parkinson et al, 1993).

Table 1
Reservoir performance assessment criteria

Facies -1-	h (ft) -2-	ϕ (%) -3-	k (mD) -4-	h_p (%) -5-
thick grainstone	$h \geq 50$	$\phi \geq 30$	$k \geq 200$	$x \leq 50$
thin grainstone	$30 \leq h < 50$	$20 \leq \phi < 30$	$30 \leq k < 200$	$50 < x \leq 70$
grainstone packstone	$10 < h < 30$	$15 < \phi < 20$	$5 < k < 30$	$70 < x < 85$
Wackestone	$h \leq 10$	$\phi \leq 15$	$k \leq 5$	$x \geq 85$

RF (%) -6-	q_{oi} @p_{wf} 400 (bopd) -7-	N_p (Mstb) -8-	t (year) -9-	Grade -10-	Score -11-
$RF \leq 10$	$q_{oi} \geq 200$	$N_p \geq 200$	$t \leq 3$	Preferred	15
$10 < RF \leq 15$	$150 \leq q_{oi} < 200$	$150 \leq N_p < 200$	$3 < t \leq 5$	Good	10
$15 < RF < 20$	$100 < q_{oi} < 150$	$100 < N_p < 150$	$5 < t < 7$	Fair	6
$RF \geq 20$	$q_{oi} \leq 100$	$N_p \leq 100$	$t \geq 7$	Possible	4

At the end of scoring, the total weighted score are tallied, and then normalized to 100% that representing the certainty factor (CF). These values are then used to produce a ranked list of well revival candidates and to eliminate the unlikely candidate(s). The ranked list is generated by utilizing RANK function of EXCEL so that each change can be recalculated rapidly to generate a new ranked list. A CF of 80 has been set up as the threshold value. Greater than this value, the well is considered feasible to be revived, and vice versa. If more than one candidate exist within the same rank, the candidate that scored with the criterion has greater the weighting factor is ranked higher. Following are discussion on establishment of criteria for the case example presented here.

A. Petrophysical criteria

Observation on density log data, core, cutting, and thin-section description suggested that the carbonate rock assessed can be classified into three facies comprised of grainstone, packstone, and wackestone. These facies have in a certain limitation to the density of log reading (ρ) i.e: grainstone for $\rho < 2.15$, packstone for $2.15\ \rho \leq \rho \leq 2.25$, and wackestone for $\rho > 2.25$. The density unit is in gram per cm^3. Low density associated with large particle sizes and tends to produce high porosity and permeability rock as seen in Figure 1. Hence rock dominated by grainstone is preferred situation to have. While rock dominated by wackestone is possible situation.

Net pay, porosity, permeability, and ratio of perforated intervals to net pay parameters are established by plotting the values of parameters against number of data in ascending order. Lumping results of 54 evaluated wells are used to establish the criteria for net pay and production interval to net pay ratio. Ratio of production intervals to net pay reflects recompletion opportunity from bypassed potential pay zone in a well. The criterion for this parameter is based on our judgment and response to experts on production engineering. Less number means higher opportunity to improve flow capacity (kh) and helped in enhancing well's productivity. The criteria for porosity and permeability are established utilizing the results of core measurement on 97 samples. Large range of permeability data associated with high heterogeneity reservoir is honored by applying logarithmic scale at the permeability axis. Figure 2 reveals the plots included threshold lines for each criterion according to Table 1.

B. Production Performance Criteria

Criteria to assess production performance comprise current oil recovery factor, initial oil rate at the time revived, estimation of recoverable oil on a well basis, and period of production time. Threshold values for these criteria are created based on our experience and response to experts on reservoir and production engineering. The current recovery factor is defined as the ratio of cumulative oil produced to the oil volume contacted by a well. High contacted

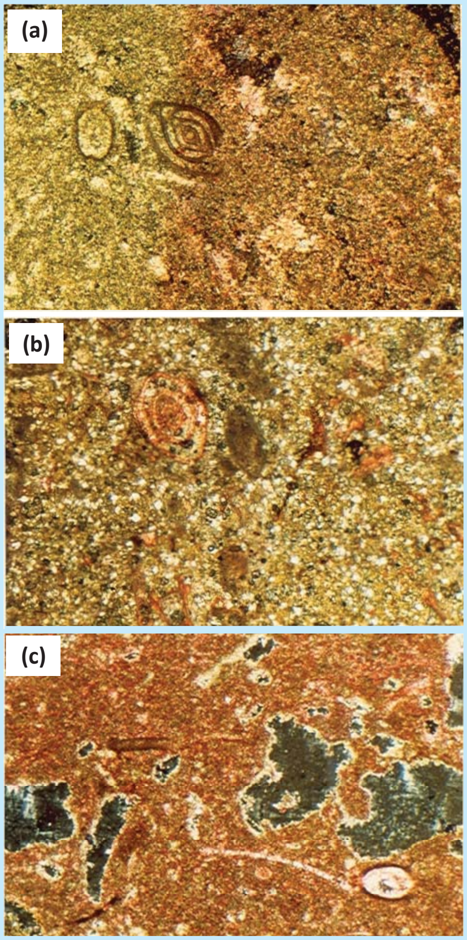


Figure 1
Thin-section photomicrographs show: (a) wackestone, (b) packstone, (c) grainstone. Enhanced porosity observed in the grainstone rock

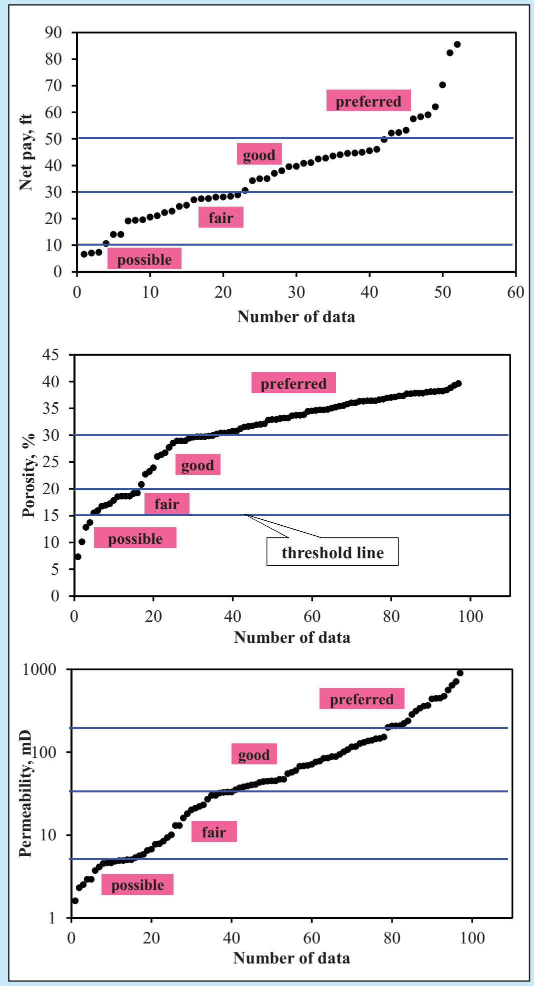


Figure 2
Established petrophysical criteria based on plot of parameter values in ascending order versus number of data

volume and low recovery factor are preferred situation to have, and vice versa. The cumulative production of each well is obtained straightforward from reliable production report. The contacted oil volume is estimated using the straight line method of MBE (Havlena & Odeh 1963). Application of the straight line method along with production/pressure histories and fluid properties to estimate the original oil in place can be found in several literatures (Havlena & Odeh, 1964; Ahmed & McKinney 2005). Key assumptions are the reservoir considered to have the same pressure and fluid properties at any location surrounded wellbores. The assumptions are quite reasonable provided that quality production/pressure histories and fluid properties are obtained. Therefore, a quality review of the pressure data and fluid properties should be taken before performs material balance calculations. A simplified form of material balance as equation of straight line for determination of original oil in place is given in Appendix.

Initial oil rate at the well-reservoir interface is predicted using a Cartesian plot of bottom hole flowing pressure versus flow rate, which termed the IPR curve. The Vogel generalized equation is applied to construct such curve. This equation was originally developed for oil well producing from solution gas drive reservoir such as the case study presented here. The Vogel equation is expressed as (Vogel 1968):

$$q_o = \frac{k_o h p_{ws}\left[1 - 0.2\left(\frac{p_{wf}}{p_{ws}}\right) - 0.8\left(\frac{p_{wf}}{p_{ws}}\right)^2\right]}{254.2 B_o \mu_o \left[\ln\left(0.472\, r_e / r_w\right) + s\right]} \quad (1)$$

Refer to Nomenclature for explanations. Oil flow rate is a function of the formation characteristics, k_o and h, the fluid characteristics, B_o and μ_o and the system characteristics, r_e, r_w, dan s. The r_e is a well drainage radius represented by a circle and given by (Ahmed & McKinney 2005):

$$r_e = \sqrt{\frac{5.615 N B_{oi}}{\pi \phi h \left(1 - S_{wi}\right)}} \quad (2)$$

The k_o is calculated using absolute permeability obtained from the well test analysis and relative permeability which derived from production data as a ratio of oil rate to the total rate. The h represents net pay, p_{ws} is obtained using matched pressure model, and B_o and μ_o are obtained from the representative sample. Improved skin factor of s to -4 is expected to take place once the wells acidized based on experiences in the field. Three cases of bottom-hole flowing pressure at pump intake, p_{wf}, are considered in predicting the initial oil rate at the well-reservoir interface that could be obtained from a well revived. The cases are 300 per square inch gauge (psig) for optimistic, 400 psig for moderate, and 500 psig for pessimistic.

Evaluation of each well's performance over time shows that an initial oil rate as higher as 200 barrel oil per day (bopd) is achievable with current pressure support. Initial oil rate deliverability of lower than 100 bopd is considered uneconomic. Final oil production rate of 25 bopd is applied. Those numbers are established locally and are figured from the oil price and the production expenses for a well revived. Discussion to get the numbers is beyond the scope of this paper. Diagnostic plots of historical rate/time and rate/cumulative production are carried out to select the appropriate decline rate for a given well. Decline rate characteristic is identified using Arps's decline curve (Arps 1944; Ahmed & McKinney 2005). By incorporating the initial oil rate and decline rate characteristic, the amount of recoverable oil as well as production time of period can be estimated.

III. RESULTS AND DISCUSSIONS

The case study is an offshore oil field under consideration to start producing again after it closed down due to production below economic limit. Recent rise in price of crude oil has prompted to put back this field on production. The ceased wells were screened carefully for the least-cost of tied back to the existing pipe line. Nine wells scattered on three platforms were selected as candidates to be revived. Further assessment in practical way is necessary to provide a ranked list of the nine wells and screened out the less potential wells. The case study presented outlined the assessment based on the criteria previously described. Reliable pressure and PVT models on which the MBE are based will be constructed first

A. Pressure and PVT Models

A quality review of the entire pressure data is carried out in order to produce proper pressure profile. Figure 3 shows the field pressure history normalized to reservoir datum. Due to confidential reason, horizontal axis is hided. Pressure anomalies were examined for further verification. Found that high-pressure anomalies were mostly measured at the wells which closed for a long period. Low-pressure anomalies corresponding to the wells having perforated gas cap zone. Neglecting outlier data and using merely the stabilized pressure buildup data leads to the historical field pressure trend citied in Figure 4. This trend is a typical combination of drive mechanisms consist of gas solution and gas cap expansion, and partial water drive (Howard et al. 2005). The pressure initially declined sharply because of the low compressibility of reservoir system but this decline is retained once gas cap and water influx began to expand and flow into reservoir. Matched pressure model is also attached in the figure with t represents the numerical value of given date. Estimated current reservoir pressure using the model is around 698 psia.

The early-surface-recombined PVT sample suggested that crude is nearly saturated at the time of discovery with bubble point pressure of 1164 psia, which is slightly less than original reservoir pressure of 1168 psia. The crude is categorized as heavy oil with an average gravity of 21 ^{o}API. For generating the crude properties, an average method is employed to obtain one crude type from the collected samples. The properties and associated PVT data used in the MBE are reported in Tables 2 and 3. The PVT data have been condensed for brevity.

B. Valuing Criteria

Determination of each criterion value for a well of interest is described in the following section. Data from Well 1 are used to accomplish this step.

Petrophysical criteria

Detailed, foot-by-foot petrophysical and geological evaluations on each well were made. Results of petrophysical analysis of Well 1 are shown in Figure 5. A user-defined log termed FAC stands for facies was created on the basis of density log as defined previously. The defined FAC log scaled from 1 to 3, where FAC 1 for grainstone, FAC 2 for packstone, and FAC 3 for wackestone. It can be seen that facies distribution in the vicinity of well dominated by grainstone especially at the upper zone covering 107.5 feet of net sand. Only permeable intervals with porosity greater than 12% and water saturation less than 70% were considered as net pay. Applying these cutoffs to reservoir properties come up with the net pay of 52 feet. It is a zone that assumed can produce hydrocarbons at economic rate. This pay has 31.5% of average porosity, 37.4% of water saturation, and 280 mD of permeability. Production interval of Well 1 was from 3,780 to 3,810 feet as showed by Figure 6. This gave the production interval to net pay ratio of about 58%, which suggests the possibility of recompletion in this well.

Production performance criteria

Figures 7 presents in a graphical form the nine years production history of Well 1. Oil production rate gradually decreased from the beginning and then rebound at the fourth and fifth years before it continued decreasing up to the end of production.

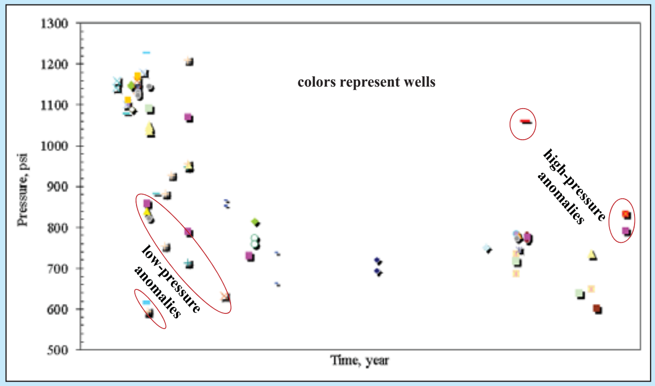


Figure 3
Historical pressure data obtained from DST, SBHP, and RFT measurements normalized to datum

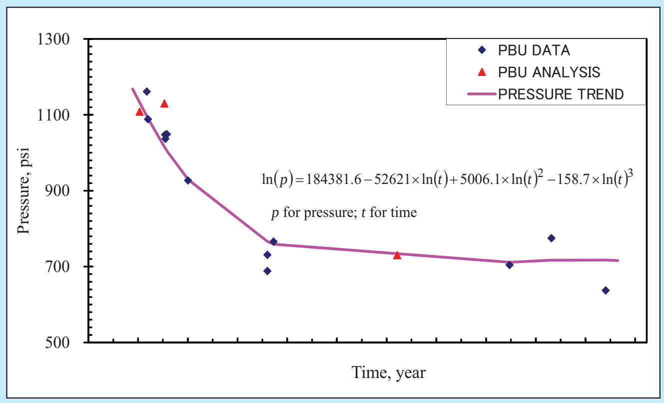


Figure 4
Historical pressure trend and matched pressure model

Table 2
Fluid and reservoir properties

Original reservoir temperature	^{o}F @ 2512 ftss	152
Original reservoir pressure	psia	1168
Bubble point pressure	psia	1164
Oil gravity	^{o}API @ 60 ^{o}F	20.7
Solution gas oil ratio (R_{sb})	scf/stb	204.5
Gas gravity	air = 1.0	0.63
Oil formation volume factor (B_o)	bbl/stb	1.139
Oil viscosity (μ_{ob})	cp	21.8
Gas formation volume factor (B_g)	bbl/scf	0.0034
Gas viscosity (μ_g)	cp	0.01464
Water formation volume factor (B_w)	bbl/stb	1.021
Water compressibility (c_w)	1/psia	3.0E-6
Formation compressibility (c_f)	1/psia	3.3E-6

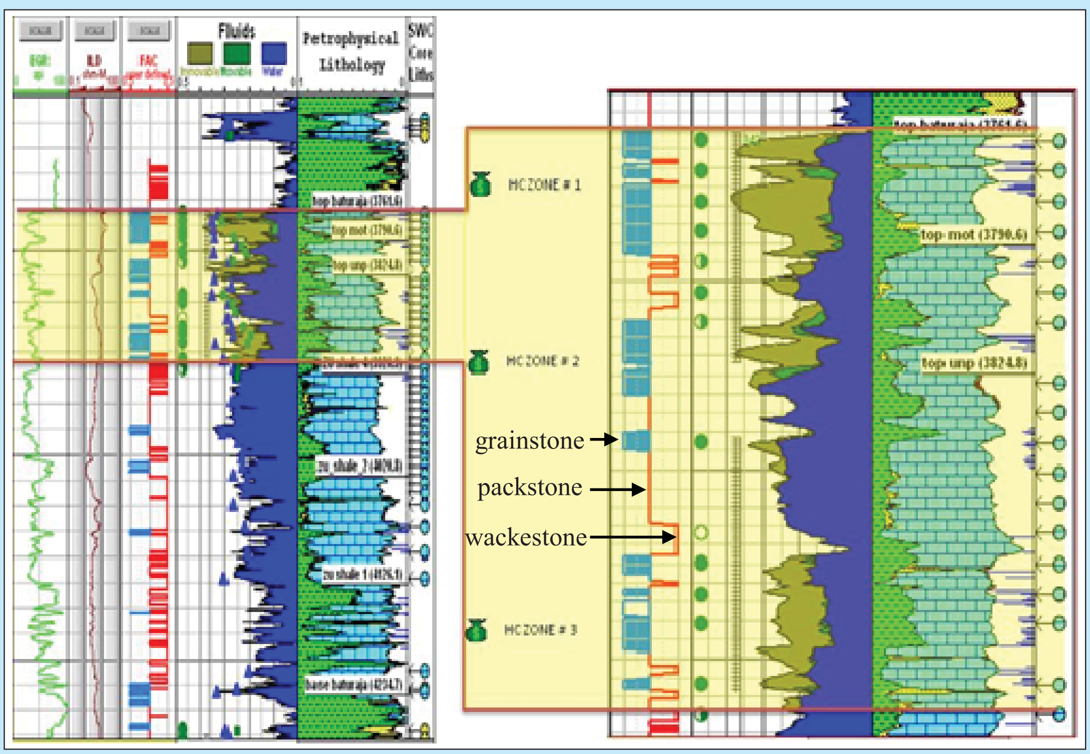
(Figure 7a). These rebounds are most likely a result of less bottom-hole pressure as gas production increased significantly after gas cap blow down activities (Figure 7b). With lower bottom-hole pressure, the pressure drops at the reservoir-well interface tended to be higher leads to increase the fluid production rate within a short period as seen in Figures 7a and 7c in which both the oil and water production rates increased. Water production increased quickly as soon as the production commenced and then began to fluctuate at an average rate of 60 barrel water per day (bwpd) (Figure 7c). The cumulative production amounted to 451 thousand barrel of oil (MBO), 544 million cubic feet of gas (MMscf), and 160 thousand barrel of water. Average oil rate at the end of production was 100 bopd.

The Well 1 was produced under solution gas drive indicated by increased gradually of gas oil ratio (GOR) with limited support from aquifer showed by low water cut of around 30%, and gas cap gas expansion revealed by increased GOR significantly from around 2000 standard cubic feet per stock tank

Table 3
PVT data

Pressure Psia	B_g bbl/csf	B_o bbl/stb	R_s scf/stb
1164 (p_b)	0.0034	1.139	204.5
1114	0.0036	1.137	197.3
1064	0.0038	1.134	190.4
964	0.0042	1.129	175.5
864	0.0048	1.123	159.8
764	0.0055	1.117	143.4
664	0.0064	1.110	126.1
564	0.0077	1.104	108.2
464	0.0096	1.097	89.6
364	0.0125	1.089	70.5
264	0.0177	1.082	50.8
164	0.0293	1.075	29.6
64	0.0775	1.068	81.7
14.7	0.0343	1.000	0.0

Figure 5
Petrophysical analysis results from Well 1



barrel (scf/stb) to value close to 4000 scf/stb after the fourth year (Figures 7b and 7d). Figures 7 suggested that the former is dominant at the early phase of production, while the latter contributes significant energy at the late phase of production. The MBE are performed in the tabulated form that specifically constructed running under ECXEL base as shown in Table 4. Plot of the underground withdrawal term F against the total expansion term Et on a Cartesian scale resulted in a straight line going through the origin as revealed in Figure 8. The early part, up to point 5 corresponding to five years production resulted in a straight line going to origin with the slope gave the oil volume contacted by Well 1 is 4.25 MMstb. The points deviate considerably from linear after gas cap blow down activities that changed the production condition. These points are neglected from the MBE (Havlena and Odeh, 1964). Using solution gas ratio at bubble point pressure given in Table 3 results in the original dissolved gas in place of 0.869 Bscf. The volumetrically determined gas cap value is 0.139 Bscf. Thus, the oil and gas recovery factors as of the ceased date are 10.6% and 53.9%, respectively.

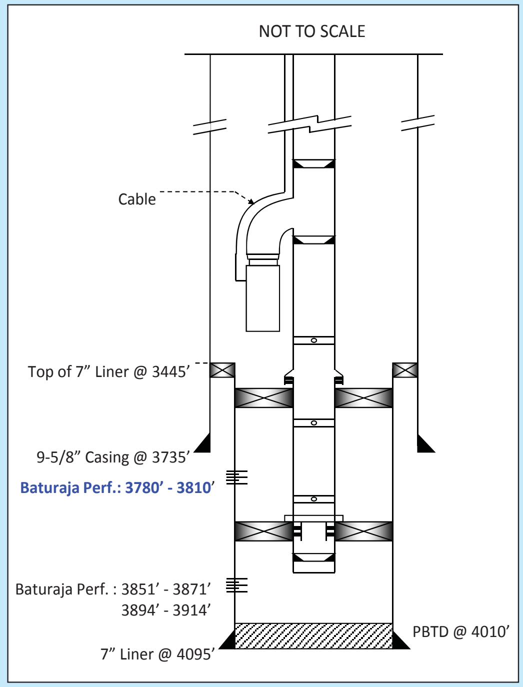


Figure 6
Completion diagram of Well 1

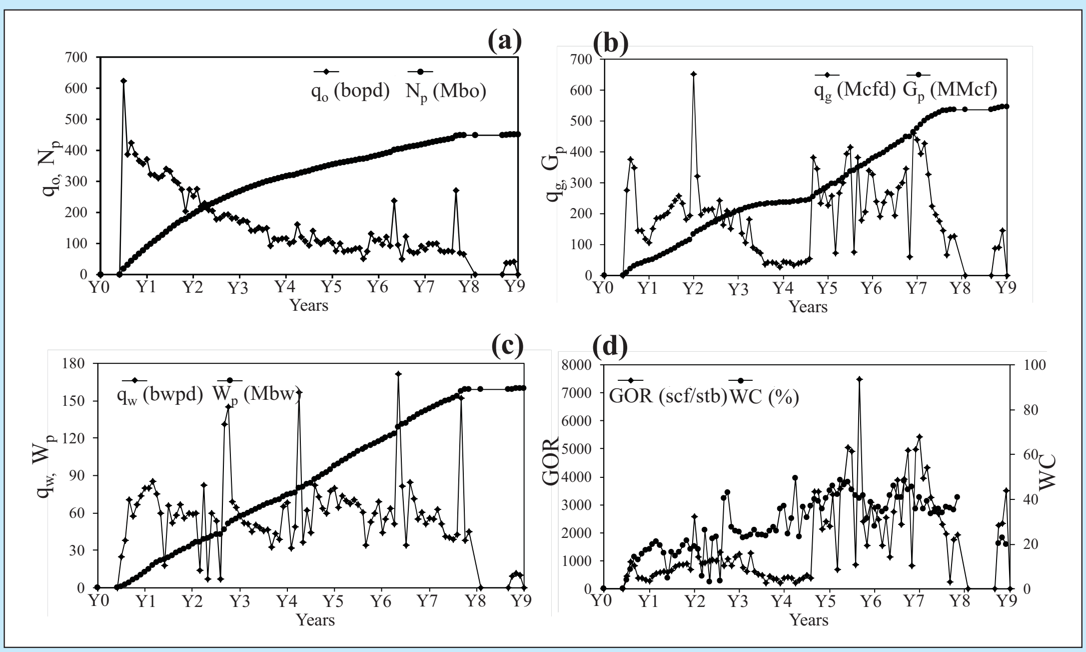


Figure 7
Production history of Well 1

Table 4
MBE sheet for Well 1

Time	p_r	N_p	G_p	W_p	R_p	B_g	B_o	R_s	F	E_o	E_g	$E_{f,w}$	E_t
Year	psia	Mstb	MMscf	Mstb	scf/stb	bbl/scf	bbl/stb	scf/stb	MMbbl	bbl/stb	bbl/stb	bbl/stb	bbl/stb
Y0	1047	0	0	0	0.000	0.0038	1.133	188.0	0.000	0.0	0.1464	0.0000	0.0715
Y1	950	89.5	46.3	12.6	517.9	0.0043	1.128	173.4	0.445	0.1221	0.2954	0.0009	0.1518
Y2	877	195.7	133.5	34.5	681.8	0.0047	1.124	161.9	0.732	0.1846	0.4337	0.0015	0.2283
Y3	822	268.4	209.0	57.0	778.8	0.0050	1.120	153.0	1.207	0.2417	0.5562	0.0020	0.2979
Y4	781	316.8	235.6	74.5	743.6	0.0054	1.118	146.2	1.444	0.2914	0.6590	0.0024	0.3579
Y5	751	354.8	287.8	97.4	811.0	0.0056	1.116	141.1	1.827	0.3323	0.7412	0.0026	0.4071
Y6	729	385.1	378.9	118.6	983.8	0.0058	1.115	137.4	2.438	0.3644	0.8044	0.0028	0.4456
Y7	714	421.0	476.6	143.5	1132.0	0.0059	1.114	134.9	3.100	0.3870	0.8474	0.0029	0.4725
Y8	705	448.8	537.4	159.0	1197.4	0.0060	1.113	133.3	3.532	0.4023	0.8783	0.0030	0.4909
Y9	700	451.4	543.7	159.7	1204.4	0.0061	1.114	132.4	3.598	0.4116	0.8948	0.0031	0.5018

Initial oil rate at the time revived is evaluated by constructing IPR curves according to Equation (1). The current pressure is 698 psia or equivalents to 683 psig. The additional required data is given in Table 5. Estimation of oil relative permeability that corresponds to the ratio of oil rate to total rate is shown in Figure 9. The IPR curve for Well 1 that generated by assuming various values for p_{wf} and the corresponding q_o is depicted in Figure 10. Notice that the average B_o is calculated from Table 3 at every individual pwf point. Estimated initial oil rate for optimistic, moderate, and pessimistic cases are attached in that figure. It can be seen that an initial oil rate of 175 bopd could be obtained at moderate case for this Well.

To forecast recoverable oil, Np, requires information on the oil production decline characteristic in addition to the initial oil rate at the time revived. Decline characteristic is derived by analyzing past production performance using Arps's decline curve. Examination of the past production of Well 1 suggests that its production history data matched favorable with the exponential decline behavior as cited in Figure 11 and resulted in the initial decline rate of 0.00113 per day, D_i.. Having the required information, the oil production rate over time and the corresponding recoverable oil till the economic limit is reached could be forecasted. Shown in Figure 12 are the forecasted oil production rates for different initial oil rate. The associated recoverable oils for, optimistic, moderate, and pessimistic cases are 166,

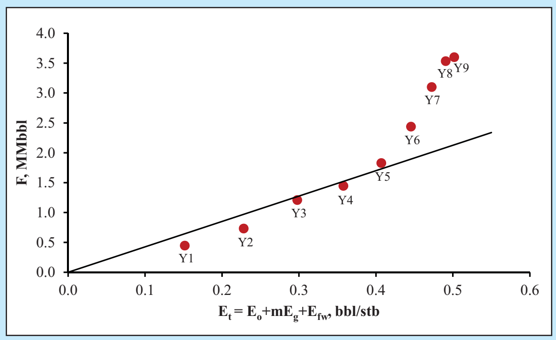


Figure 8
Determination of initial contacted oil volume by Well 1

Table 5
Required data for IPR curve construction

Parameters	Unit	Value
Current average reservoir pressure (p_{ws})	psig	683.3
Initial contacted oil volume (N)	MMstb	4.25
Initial oil formation volume factor (B_{oi})	bbl/stb	1.133
Average oil viscosity (μ_o)	cp	21.8
Net pay (h)	ft	204.5
Porosity (ϕ)	fraction	0.32
Initial water saturation (S_{wi})	fraction	0.37
Drainage radius (r_e)	ft	920
Wellbore radius (r_w)	ft	0.265
Absolute permeability (k)	mD	280
Oil relative permeability (k_{ro})	-	0.6
Oil effective permeability (k_o)	mD	168

131, and 84 Mstb, respectively. Production time of period is approximately four to five years.

C. Scoring and Ranking

Having the values of criteria, the process of reservoir performance assessment associated with a ceased well in question is proceeded by giving a score to every criterion according the rules established in Table 1. This is accomplished by entering a value of criteria into the worksheet scoring system. A background color reflecting the grade assigned for that value is then automatically displayed along with its score. As an example of the scoring system, consider Well 1 in Figure 13. The facies, h, ϕ criteria are all preferred, colored blue and all score 15. Values of k, h_p, RF, and q_{oi} fall in good grade, assigned with a green color, so it gets a score of ten. The N_p with value of 131 Mstb get a score of 6 for fair which colored yellow. And the last of t with value of 5.0 years has a good grade, assigned with green color and gets a ten. If all criteria have been filled a value, then the total score is computed by the program. For the case of Well 1, the total score is 10.9.

Repeating the same workflow demonstrated above to all remaining eight wells candidate come up with the results showed in Figure 13. It can be seen that the higher total score is 10.9 of Well 1. This higher score corresponds to 100%. All total score are then divided by 10.9 to obtain their index CF and to produce a ranked list of the nine well candidates. The obtained CF ranges from 77 to over 100%. The Well 7 and Well 3 are not recommended to be revived due to their score is less than the threshold. Well 7 has the lowest additional recoverable oil, N_p, while Well 3 has the lowest net pay, h, and has the highest current recovery factor, RF, which are assigned to fair. The top three highest scoring are Well 1, Well 4, and Well 8. Well 1 is a first ranked due to the fact that this well has one criterion categorized fair without possible situation. The rests are preferred and good ratings. The Well 4 is attractive in terms of highest permeability reflecting higher flow capacity. This is indicated by higher initial oil flow rate, qoi, than other and resulted in large recoverable oil predicted. Whereas the Well 8 got a third ranked since all its criteria fall in preferred and good situations with the exception of the ratio of net pay to perforated zone, hp, in possible rating. With permeability value in second, it is logic if this well becomes one of the best revived well candidates.

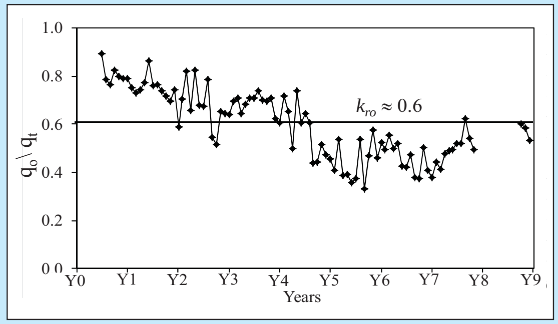


Figure 9
Determination of average oil relative permeability using production data

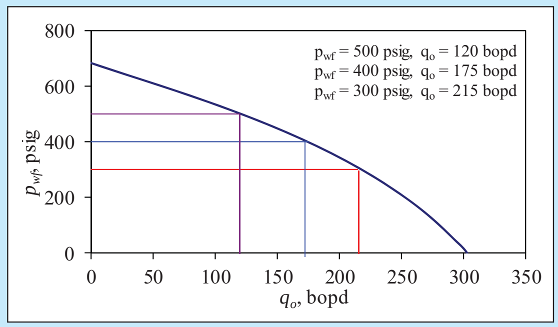


Figure 10
IPR curve for Well 1

IV. CONCLUSIONS

Practical workflow for assessing reservoir performance to revive closed wells has been developed and consisted of three steps i.e: generating the set of criteria, valuing the criteria, and making a ranked list of wells to be revived. Testing using a real field data outlined the applicability of developed methodology for integrating static-dynamic reservoir data on worksheets based. Application to an offshore oil field, which under consideration to start producing again after it closed down shown that the results are found to be reliable and consistent with the historical production performance. From the nine wells assessed, Well 7 and Well 3 are not recommended to be revived. The Well 7 has the lowest additional recoverable oil while Well 3 has the highest current recovery factor that means less remaining recoverable oil. The top three scoring are Well 1, Well 4, and Well 8. Well 1 is the only well allowing for recompletion, Well 4 and Well 8 are attractive in terms of highest permeability reflecting higher flow capacity.

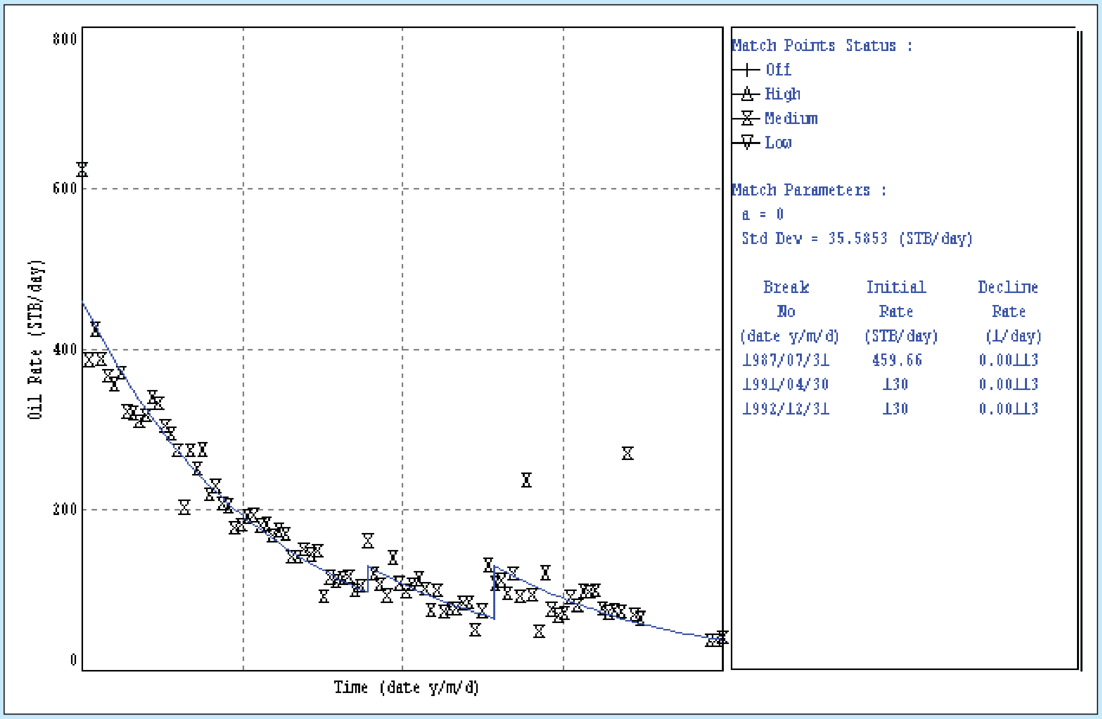


Figure 11
Decline curve analysis for Well 1

NOMENCLATURE

B_g = gas formation volume factor, bbl/scf
B_{gi} = initial gas formation volume factor, bbl/scf
B_o = oil formation volume factor, bbl/stb
B_{oi} = initial oil formation volume factor, bbl/stb
B_w = water formation volume factor, bbl/stb
c_f = formation (rock) compressibility, psia^{-1}
c_w = water compressibility, psia^{-1}
D_i = initial decline rate, day^{-1}
E_{fw} = expansion of the initial water and the reduction in the pore volume, bbl/stb
E_g = expansion of gas cap gas, bbl/stb
E_o = expansion of oil and its originally dissolved gas, bbl/stb
E_t = total expansion ($E_o + E_g + E_{fw}$), bbl/stb
F = underground withdrawal, bbl
G_p = cumulative gas production, scf
h = net pay, ft
h_p = production interval to net pay ratio, %
k = absolute permeability, mD
k_o = effective permeability, mD

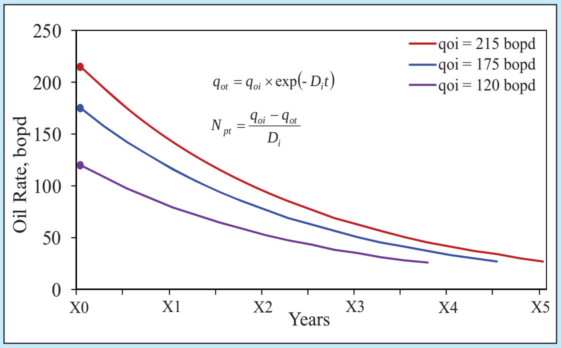


Figure 12
Forecasted oil production rate among the three cases

k_{or} = oil relative permeability, dimensionless
m = ratio of initial gas cap gas volume to initial oil volume, bbl/bbl
N = initial oil volume or initial contacted oil volume, stb
N_p = cumulative oil production, stb
N_{pt} = cumulative oil production at time t, stb

No.	Well	Facies 5%		h (ft) 15%		ϕ (%) 10%		k (mD) 15%		h_p (%) 5%		RF (%) 10%		q_{oi} (bopd) 10%		Np (Mstb) 15%		t (year) 15%		Total 100%		Rank
		Type	Score	Value	Score	Value	Score	Value	Score	Value	Score	Value	Score	Value	Score	Value	Score	Value	Score	Score	CF	
1	Well 1	thick grainstone	15	52	15	32	15	280	10	58	10	10.6	10	175	10	131	6	5.0	10	10.9	100	1
2	Well 2	thin grainstone	10	78	15	29	10	265	10	88	4	7.1	15	170	10	181	10	6.5	6	9.5	87	6
3	Well 3	thin grainstone	10	11	6	36	15	185	10	92	4	16.3	6	185	10	435	15	20.5	4	8.5	78	8
4	Well 4	thin grainstone	10	31	10	31	15	1000	15	119	4	13.0	10	245	15	243	15	7.0	4	10.7	98	2
5	Well 5	thick grainstone	15	104	15	33	15	180	10	111	4	15.0	10	200	15	139	6	3.5	10	9.6	88	5
6	Well 6	thick grainstone	15	45	10	33	15	180	10	108	4	12.2	10	165	10	225	15	8.5	4	9.7	89	4
7	Well 7	grainstone packstone	6	83	15	33	15	148	10	101	4	10.4	10	175	10	46	4	3.0	15	8.4	77	9
8	Well 8	thin grainstone	10	62	15	33	15	667	15	89	4	13.9	10	175	10	179	10	3.5	10	10.2	94	3
9	Well 9	thin grainstone	10	45	10	32	15	563	15	115	4	6.1	15	175	10	138	6	4.5	10	9.4	86	7

Preferred Good Fair Possible

Figure 13
Scoring and ranking system of well revival candidates

p_b = bubble point pressure, psia
p_r = average reservoir pressure, psia
p_{wf} = flowing bottom hole pressure, psig
p_{ws} = static bottom hole pressure, psig
PV = pore volume, bbl
q_g = gas rate, scf/day
q_o = oil rate, bbl/day
q_{oi} = initial oil rate, bbl/day
q_{ot} = oil rate at time t, bbl/day
q_w = water rate, bbl/day
R_p = cumulative gas oil ratio, scf/stb
R_s = gas solubility, scf/stb
R_{sb} = gas solubility at bubble point pressure, scf/stb
r_e = drainage radius, ft
r_e = wellbore radius, ft
S_{wi} = initial water saturation, fraction
t = time, year
W_e = cumulative water influx, bbl
W_p = cumulative water production, stb
Δp = change in reservoir pressure, psia
μ_g = gas viscosity, cp
μ_o = oil viscosity, cp
μ_{ob} = oil viscosity at bubble point pressure, cp
ρ = rock density, gram/cm^3
ϕ = porosity, fraction
API = American Petroleum Institute
DST = drill stem test
GOR = gas oil ratio, scf/stb
MBE = material balance equation
PBU = pressure build up
PVT = pressure volume temperature
RFT = repeat formation test, psia
SBHP = static bottom hole pressure, psia
WC = water cut, %

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APPENDIX

For a detailed derivation of MBE, the Reader is referred to the Reference by Ahmed and McKinney, 2005. A condensed form of the equation assuming no pressure maintenance by gas or water injection can be written as:

$$F = NE_t + W_e \tag{A1}$$

in which the terms F, E_o, E_g, and $E_{f,w}$ are defined by the following relationships:

- F represents the underground withdrawal and is given by:

$$F = N_p\left[B_o + \left(R_p - R_s\right)B_g\right] + W_p B_w \tag{A2}$$

- E_t is the total expansion terms defined as:

$$E_t = E_o + E_g + E_{\mathrm{f,w}} \tag{A3}$$

- Eo describes the expansion of oil and its originally dissolved gas and is defined in terms of the oil formation volume factor as:

$$E_o = \left(B_o - B_{oi}\right) + \left(R_{si} - R_s\right)B_g \tag{A4}$$

- E_g express the expansion of the gas cap gas and is expressed by:

$$E_g = B_{oi}\left[\left(B_g / B_{gi}\right) - 1\right] \tag{A5}$$

- $E_{\mathrm{f,w}}$ depicts the expansion of the initial water and the reduction in the pore volume as given by:

$$E_{f,w} = (1+m)B_{oi}\left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right]\Delta p \qquad \text{(A6)}$$

In case of no water influx, Equation A1 indicates that a plot of F versus E_t on a Cartesian scale would produce a straight line through the origin with a slope of N. Havlena and Odeh are credited with being the first to apply the straight-line method of solving MBE (Havlena & Odeh, 1963). Various material balance applications as well as the method of analysis and interpretation and discussions can be found in Havlena & Odeh, 1964.