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Discriminating Geological Information by Interwell Connectivity and Heterogeneity

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Abstract

Analysis was carried out on the reservoir connectivity and its heterogeneity using the flow capacity plots of the producer wells. Lorentz coefficient (Lc) together with the modified Lorentz plots determine the heterogeneity of the reservoir and its connectivity. Flow capacity plots, and Lorentz coefficient are found useful to establish geological features surrounding producer well leading to the identification of heterogeneity orientation and degree of connectivity. Heterogeneity increases with increasing Lorentz coefficient (Lc). Slope of tangent to flow capacity plot gives the type of geological features surrounding producer wells. Orientation flow capacity plots, gives good understanding on how producer wells communicate with the surrounding injectors by either fast flow path, slow flow path or through fractures. In addition, flow capacity plots also suggest percentage influence of injectors on potential pore volume. The paper shows that production performance is affected when the reservoir heterogeneity is near homogeneity. Within this zone, production increases as heterogeneity increases. However, beyond this point, as heterogeneity increases there is sharp decline in production performance. This means that high reservoir heterogeneity has an inverse effect on the production performance of producer wells. Hence, essential methods for permeability improvement are required to enhance production.

Keywords*: Heterogeneity; Lorentz coefficient; Well connectivity; Flow paths; Performance.*

1. Introduction

Many available reservoirs are heterogeneous in nature with variability in geological situations in and around the neighborhood of injector-producer well pairs. Many approaches have been deployed to infer reservoir connectivity as a lead to delineate the degree of reservoir heterogeneity through performance comparison of production well with the surrounding injectors. Albertoni and Lake [1] approximated inter-well connectivity judging from coefficients produced through multiple linear regression. Quantitatively, coefficients in the model show the degree of relationship between wells (producer and the injectors) in a waterflood which can tell the degree of heterogeneity. The idea was furthered by [2] to produce understanding of geological characteristics and heterogeneity of reservoirs using well production data for a better decision tool in reservoir development. Some researchers including [3-7] explored the use of some geological characteristics such as clay-sand production and erosion, injection pressures and recovery rate to understand the degree of the reservoir flow paths and connectivity (thief zones) in different geological reservoirs and its implications on waterflooding performance. Common in their approach is that reservoirs with thief zones register early water breakthrough leading to uneven sweep efficiency and lower oil recovery because of poor injected water efficiency. These approaches can predict the degree of flow paths; however, they are always time consuming, expensive and results are only suited for near wellbore region.

The idea of connectivity was furthered through the understanding in reservoir storage-flow behaviour which was developed initially as an expression in sweep efficiency of injectors in layered reservoir. This approach dwells on the relativity flow in any layer as a function of pore volume, usually in a flow-storage diagram (Lorenz plots or flow capacity plots). Flow storage diagram ratably suggest the reservoir geology. For instance, when 50 % of flow comes from only 10 % of the pore volume of a reservoir or a layer, it indicates fast flow paths [8].

One sure flow-storage concept is the one developed by Lorenz. The Lorenz plots uses results obtained from reservoir core plug experiments in the form of permeability and porosity, while flow capacity plots are based dynamic data (injection and production). Generally, the said variables can tell a good description of properties variation in the reservoir in and around areas surrounding a producer. Shook [9] developed flow-storage diagram based on estimated results from tracer tests. The results show to some degree that the flow capacity plots, based on injection-production data, are likely to trail the flow paths and geological features in a reservoir. The Lorenz plot, suggested by [8] is used to form flow capacity plot which will provide a means for discriminating reservoir geological information. The Lorenz curve is a plot of cumulative flow capacity, Fm, versus cumulative thickness, Hm. The aim of the research is to provide an understanding of the physics of reservoir fluid flows using most basic field dynamic data (injection and production data) and use same to establish the communication between injector and producer pairs as means of delineating reservoir heterogeneities, preferential transmissibility trends, and the presence of flow barriers and oil saturations.

2. Materials and methods

2.1. The study area

Zhao Ao oilfield is a sub-basin of Nanxiang basin with an area of 10 km^2 is situated between 111° 00`and 113° 30`E longitude and between 31° 80`and 33° 00`N. Nanxiang is a small, rifted basin developed in the Mesozoic and Cenosoic Cras. This basin is 160 km long and 110 km wide, extending through two provinces of China, with a total area of approximately 17,000 km^2. The basin is filled with dominantly Paleogene strata, which serve as the main petroleum source and reservoir system. The Nanxiang Basin consists of three uplifts (Shigang Uplift, Sheqi Uplift and Xinye Uplift) and three sags (Nanyang Sag, Biyang Sag and Xiangzao Sag). Historically, the exploration of the Biyang Sag began in 1974. In 1975, the first well was completed, and it confirmed that there are thick layers of resource rocks and multiple layers indicating the presence of petroleum in the Paleogene Hetaoyuan Formation. In 1976, a high-capacity reservoir was found and the Shuanghe Oilfield began to be developed. Zhao Ao with 31 wells, is one of the eight oilfields which were developed after more than 30 years of exploration. Average permeability and porosity for the field in eight single sand layers, are shown in Table 1.

Table 1. Average porosity and permeability values

Well type	Well name	Average porosity	Average permeability	Well type	Well name	Average porosity	Average permeability
P1	Ann 6	0.15	185.0	P17	Ann 99	0.12	272.5
P2	Ann 7	0.13	260.0	P18	Ann 100	0.13	170.3
P3	Ann 8	0.16	368.0	P19	Ann 101	0.12	84.0
P4	Ann 10	0.14	64.3	I1	Ann 4	0.14	260.0
P5	Ann 39	0.10	65.0	I2	Ann 5	0.15	313.3
P6	Ann 42	0.14	126.7	I3	Ann 25	0.06	11.0
P7	Ann 45	0.14	107.2	I4	Ann 31	0.14	105.0
P8	Ann 49	0.15	120.7	I5	Ann 41	0.13	75.0
P9	Ann 78	0.11	106.2	I6	Ann 44	0.16	245.0
P10	Ann 79	0.08	217.5	I7	Ann 47	0.14	115.6
P11	Ann 86	0.13	192.0	I8	Ann 51	0.14	80.2
P12	Ann 55	0.06	34.0	I9	Ann 57	0.14	173.8
P13	Ann 91	0.11	192.0	I10	B 76	0.16	179.6
P14	Ann 95	0.10	250.0	I11	B 98	0.14	173.8
P15	Ann 96	0.15	164.3	I12	B 70	0.11	221.7
P16	Ann 97	0.13	252.5				

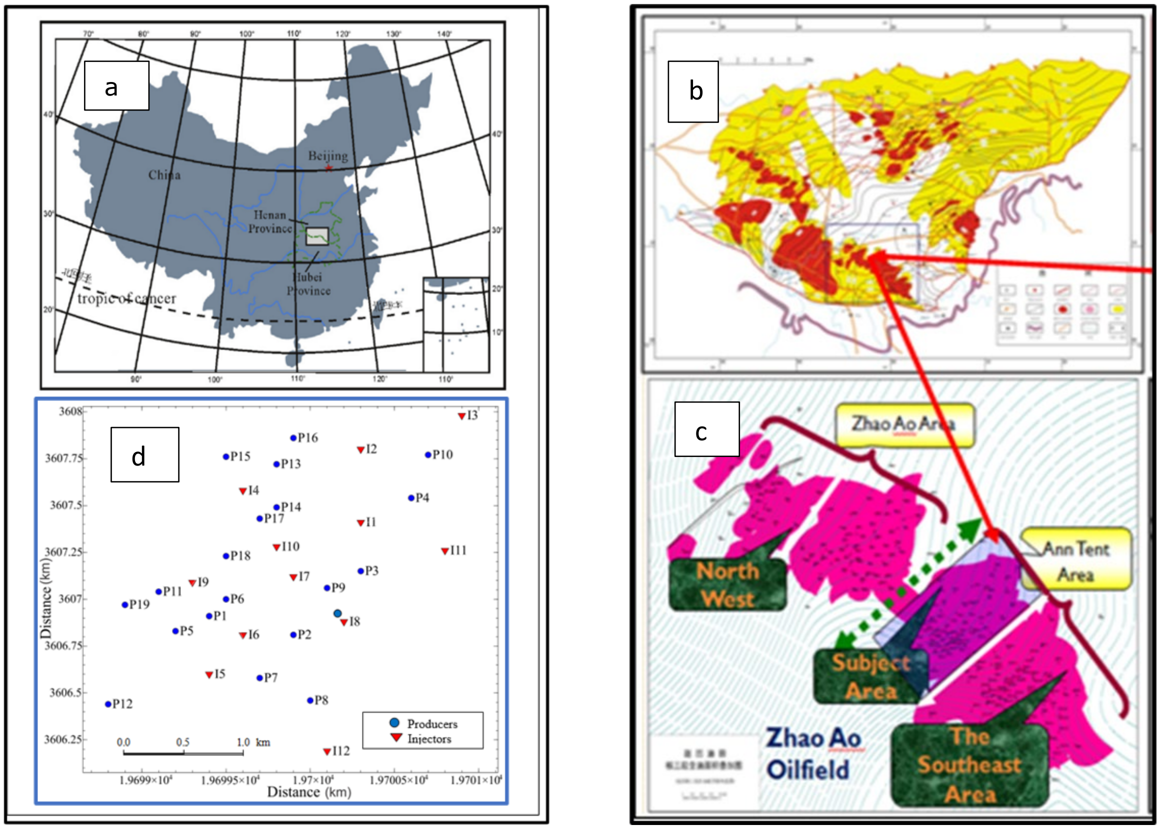


Figure 1. Maps showing the: (a) Location of the Nanxiang Basin in China. (b) Location of the Zhao Ao Oil field (c) Location of Ann Tent Area. (d) Location and distribution of wells used in the study

2.2. Lorenz model

The Lorenz curve (Fig. 2) is a plot of cumulative flow capacity, Fm, versus cumulative thickness, H_m, and computed as shown in Eq. 1 and 2.

$$F_m = \sum_{i=1}^{i=m} k_i h_i / \sum_{i=1}^{i=n} k_i h_i \quad (1)$$

$$H_m = \sum_{i=1}^{i=m} h_i / \sum_{i=1}^{i=n} h_i \quad (2)$$

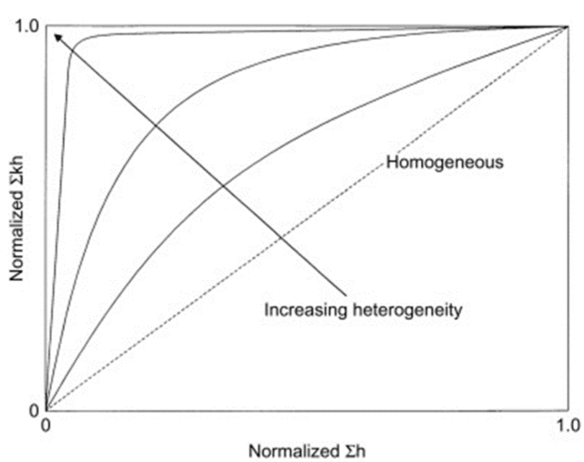


Figure 2. Flow capacity storage

The concept is that for any n layers in a reservoir, layer permeability are arranged in decreasing order so that m = 1 is the layer with thickness h_1 and the largest permeability k_1 whereas m = n is the layer with thickness h_n and the smallest permeability k_n. For a reservoir with m to n layers, $0 \leq F_m \leq 1$ and $0 \leq H_m \leq 1$ for $1 \leq m \leq n$. Due to the layer ordering, the Lorenz plot monotonically increases from m = 1 to m = n with a monotonically decreasing slope. If the medium is homogeneous, all the permeability values are similar, and the Lorenz plot is indicated by straight line. Increasing levels of heterogeneity are indicated by a departure of the Lorenz plot away from the straight line.

The Lorenz procedure can be modified to include porosity in the calculation [10-11]. In place of the cumulative thickness, H_m, the cumulative storage capacity, C_m, is used, Eq. 3:

$$C_m = \sum_{i=1}^{i=m} \emptyset_i h_i / \sum_{i=1}^{i=n} \emptyset_i h_i \quad (3)$$

Like the Lorentz plot, flow capacity plot can be obtained through set of connectivity βij's and time lag and attenuation t_{ij} that occurs between stimulus (injection) and production response. The physical interpretation of βij's of an injector-producer (ij) is given by Eq. 4.

$$\hat{q}_j(t) = \beta_{oj} + \sum_{i=1}^{I} \beta_{ij} i_i(t) \qquad (j = 1,2 \ldots . N) \quad (4)$$

On the other hand, Eq. 5 gives the corresponding time constant

$$t = \frac{948\emptyset \mu C_t r_t^2}{k} \quad (5)$$

Details of Eq. 4 and 5 are N is the total number of producers and I is the total number of injectors. Eq. 4 states that for any given time period, the total production rate of well j $\hat{q}_j(t)$ is linear combination of the rates of every injector in the field $\hat{\imath}_i(t)$ plus a constant β_{oj} term. The β_{oj} term is a constant that tries to account for the unbalance in the field.

Similar to Eq. 1 and 3, the new developed flow capacity curve is given as shown in Eq. 6 and 7.

$$F_m = \sum_{i=1}^{i=m} \beta_{ij} / \sum_{i=1}^{i=n} \beta_{ij} \quad (6)$$

$$C_m = \sum_{i=1}^{i=m} \beta_{ij} t_{ij} / \sum_{i=1}^{i=n} \beta_{ij} t_{ij} \quad (7)$$

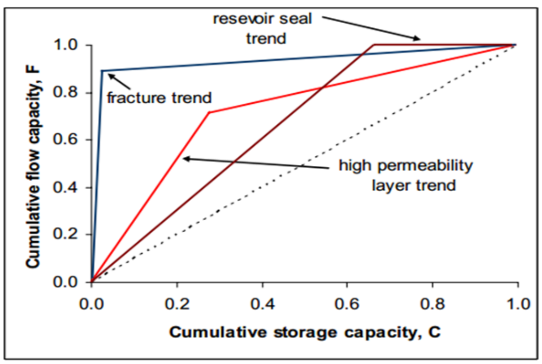


Figure 3. Different trends of the flow capacity curve in the vicinity of a producer

To illustrate flow capacity and its differential trends with accompanying geological features in the vicinity of the producer, [12] presented three major flow trends as shown in Fig. 3. The first curve indicates a secondary porosity (a presence of fractures) in the drainage volume of a producer represented by the steeper segment of the curve; the second indicates that certain injectors communicate with producer through high permeability layers and the other injectors communicate through low permeability layers. For the last curve, the flat behavior shows that a fraction of the total storage capacity or the total pore volume swept by injectors provides a negligible fraction of the total flow capacity. This is a typical aspect of nonpay zone or a reservoir seal.

2.3. Connectivity and heterogeneity

Many studies have been extensively reported to quantify the reservoir complexity (connectivity/heterogeneity) either statically or dynamically.

Connectivity is the fraction of connected reservoir volume (above a permeability/transmissibility threshold) and connected to wells [13]. Connectivity can be quantified as nondirectional or directional. Directional connectivity is quantified by connectivity function [14]. Connectivity function is similar to semi-variogram function; the connectivity function decreases with the increase of lag distance till it reaches a constant Plateau. Connectivity function derived from continuous properties depends on the property cutoff (such as permeability cut off). Non-directional connectivity is more commonly used.

McLennan and Deutsch [15] used static connectivity parameters which defines the fraction of total connected pore volume. Larue *et al.* [16] quantified reservoir connectivity using static connected volume. Connected pore volume directly reflects the well drainage volume as a good indicator of reservoir flow capacity [15].

As a dynamic response, heterogeneity is defined as the dispersity of displacement front of flooding process [17]. Statically, heterogeneity is the measure of complexity of flow path and contrast of permeability. Within geological framework, heterogeneity can either be at core scale, well scale or reservoir scale.

Dykstra-Parson coefficient (V_{dp}) and Lorenz coefficient (Lc) are two most used parameters for heterogeneity quantification. V_{dp} is computed by using quintiles of permeability log-normal distribution. Even though V_{dp} is robust to log normally assumption, it lacks uniqueness. As such multiple static models could have the same V_{dp} although, dynamically, they may be different. Again, V_{dp} has low sensitivity of models to variations in V_{dp}, when V_{dp} <0.5 and high sensitivity of models to variation when Vdp >0.5. Schmalz and Rahme [8] introduced Lc, which is defined by the Lorenz plot, a cross plot between flow capacity versus storage capacity. Lc is computed from the area under Lc curve less the area bounded by homogeneity. Lc ranges from 0 to 1 (homogenous to heterogeneous). Like V_{dp}, Lc is not a unique parameter for characterization of reservoir heterogeneity. However, [17] stated that Lc is better than V_{dp} because it includes porosity or storage capacity and weight.

2.4. Discriminating reservoir flow and heterogeneity

Reservoir get heterogenous due to the alteration of composition and structure of rocks by natural geological processes. Using a relative scale of heterogeneity coupled with the unaltered depositional environments, [18] and [19] have shown that a substantial moveable hydrocarbons get trapped in reservoirs of varying heterogeneity. [20-24] evaluated the effects of heterogeneity on hydrocarbon recovery at the bed-scale level. Reservoir heterogeneity is used here to describe the geological complexity of a reservoir and the relationship of that complexity to the flow of fluids through it [25] .

Within reservoirs, heterogeneity is assemblages of depositional facies and subfacies; Clastic lithofacies and carbonate lithofacies, with unique characteristics differentiating sediment textures, stratification types, and bedding architectures. Heterogeneity variability is compounded by factors such as post burial alterations of the strata, compaction, cementation, and tectonic deformation. Geological heterogeneities have been classified according to their size or scale, such as wellbore, interwell, and fieldwide scales of heterogeneity (Fig. 4).

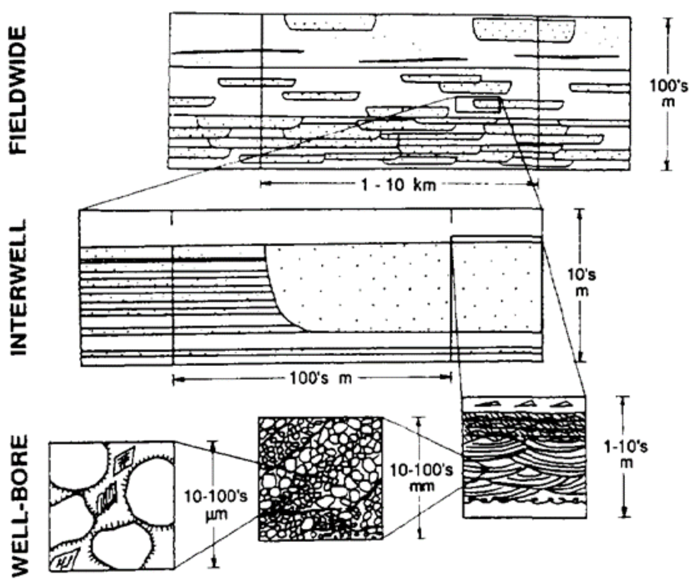


Figure 4. Levels of reservoir heterogeneity (modified from Weber [20])

Reservoir property variability at the wellbore scale affect matrix permeability, distribution of residual oil, directional flow of fluids, potential fluid-rock interactions, and formation damage [26-27]. Interwell scale heterogeneities affect fluid flow patterns, drainage efficiency of the reservoir, and vertical and lateral sweep efficiency of secondary and tertiary recovery projects [28-29]; [30-33]. Heterogeneities at the fieldwide scale affect the in-place hydrocarbon volume, areal distribution, and trend of hydrocarbon production [34-38].

Modelling reservoir heterogeneity provides the opportunities for understanding in successful improving performance predictions and interventions in heterogeneous reservoirs.

3. Results and discussion

3.1. Distribution of reservoir heterogeneity

During the waterflooding period, heterogeneity is an intrinsic factor that determines swept volume and sweep efficiency.

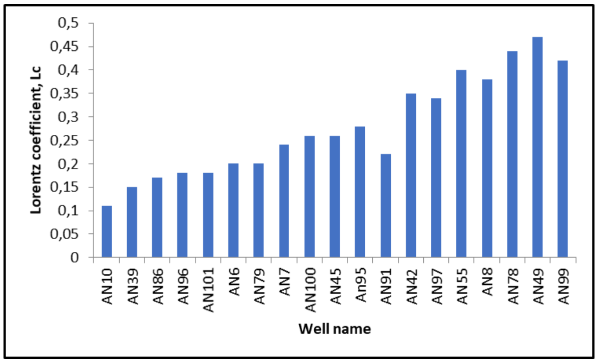


Figure 5. Reservoir heterogeneity

To some extent, injection performance of injector and production performance of its offsetting producers are the evidence of heterogeneity. The degree of reservoir heterogeneity was therefore evaluated using the Lorentz model as indicated by Eq. 1 and 3. The reservoir categorize into heterogeneous groups and hence its effects on displacement. Fig. 5 shows the heterogeneity distribution of the reservoir with respect to the producer wells. It is obvious that the reservoir heterogeneity is skewed towards reservoir seal trend. The heterogeneity is categorized into three distributions.

3.2. The log-log plot

From Eq. 5, the time for attenuation t_{ij} between producer j and injector i is inversely proportional to permeability. Hence the connectivity β_{ij} and the corresponding t_{ij} are inversely related. For reservoirs with similar properties, each producer communicates with all injectors, a log-log plot of the connectivity and lag time for each producer with the affected injectors should give a straight line with negative slope. Non-homogeneous reservoirs therefore will show a deviation from the straight indicating specific geological conditions in these reservoirs.

The log-log plots of connectivity against lag time for three scenarios; non diffusivity, one month diffusivity and six-month diffusivity conditions indicate three different groups Fig. 6 to 8. Group 1 represents well pairs with large connectivity and low lag time, group 2 represents well pairs with lag time larger than group 1 but with lower connectivity. The last group 3 represents well pairs with the largest lag time with a much lower connectivity. The three groups have cumulative lag time of 42.9 months, 45.73 months, and 80.9 months respectively. Similarly cumulative connectivity for the three groups are 9.81, 4.26 and 7.79. Hence there is cumulative lag time to cumulative connectivity ratio of 4.373, 10.73 and 10.4 respectively.

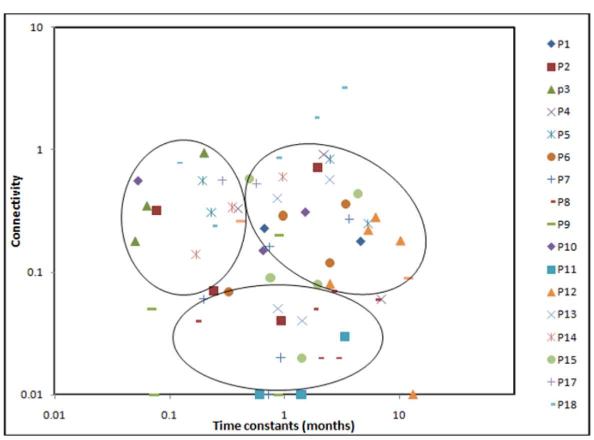


Figure 6. Log-log plot of connectivity versus lag time for non-diffusivity

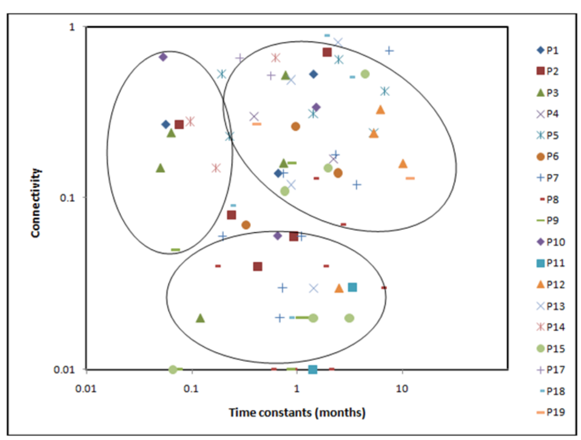


Figure 7. Log-log plot of connectivity versus lag time for one month diffusivity

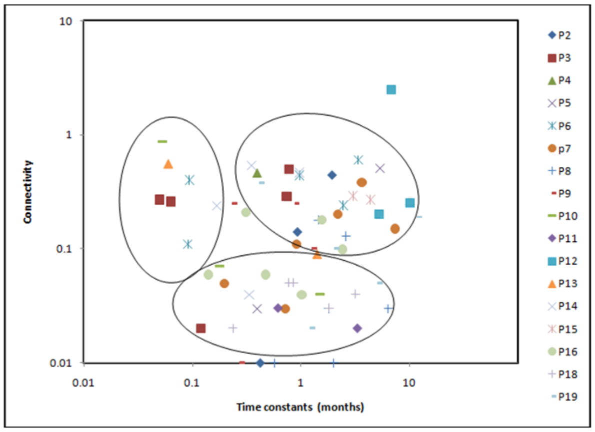


Figure 8. Log-log plot of connectivity versus lag time for six-month diffusivity

3.3. Reservoir connectivity and heterogeneity with fractures

Flow capacity plots using the new approach that combines the connectivity and the lag time was developed for the producer and their surrounding injectors. The flow capacity plots for P1, P4 and P12 show a large deviation from 45° line (homogeneous reservoir) Fig. 9.

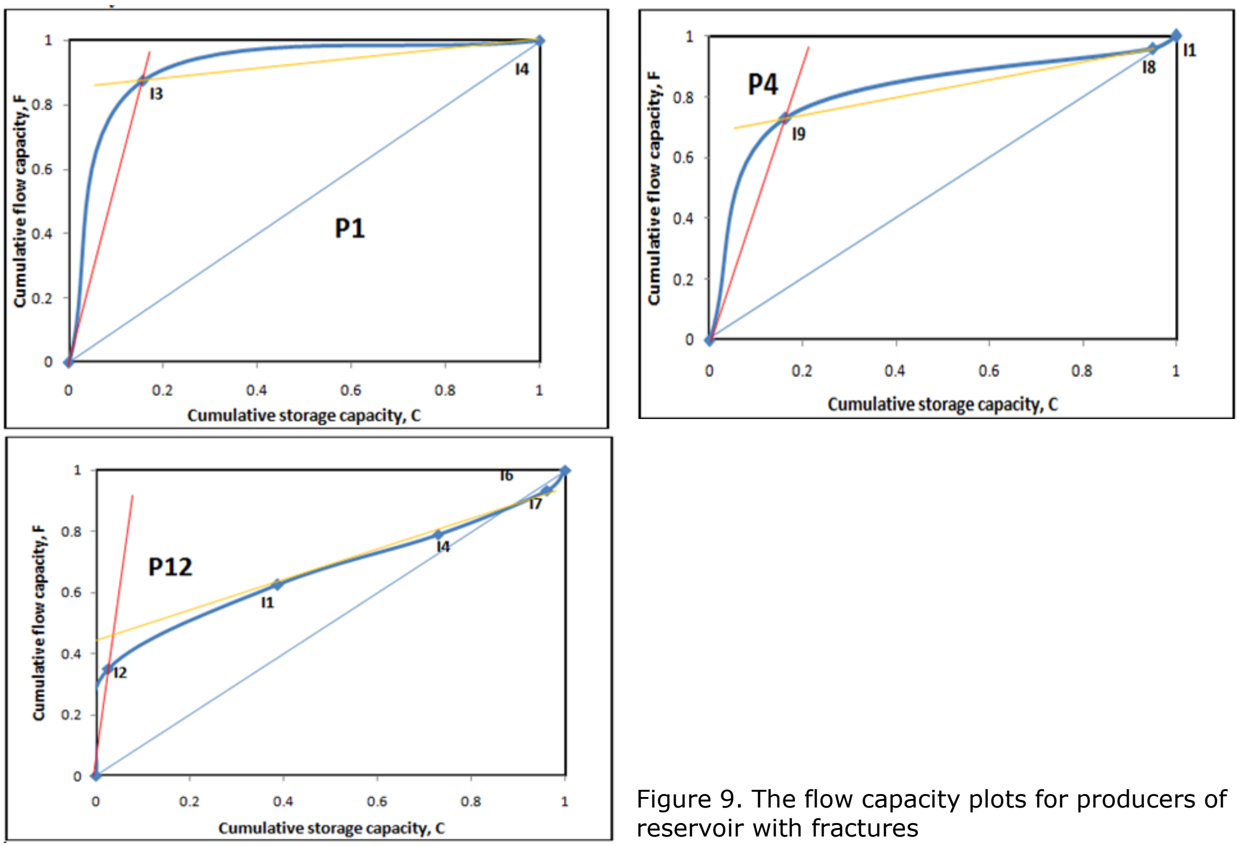


Figure 9. The flow capacity plots for producers of reservoir with fractures

The flow capacity plots of P1, P4 and P12 indicate two distinct geological conditions in the vicinity of these producers. Two straight lines can be fitted to the flow capacity curve; the first is steeper than the second straight. The steep straight line suggests a large fraction of the total flow capacity is provided by a very small fraction of the total pore volume swept by the surrounding injectors, which is usually an indication of existing fractures in the vicinity of the producers. The second straight line indicates that a little proportion total flow capacity is supported by a large fraction of the total volume of the field; this describes the situation of injectors communicating through the reservoir matrix. The producers in this part of the reservoir have the best of interwell connectivity.

3.4. Reservoir connectivity and heterogeneity with sealing trends

The degree of heterogeneity of the reservoir where these wells are located is shown in Fig. 10. The plots show flow capacity plots of each producer.

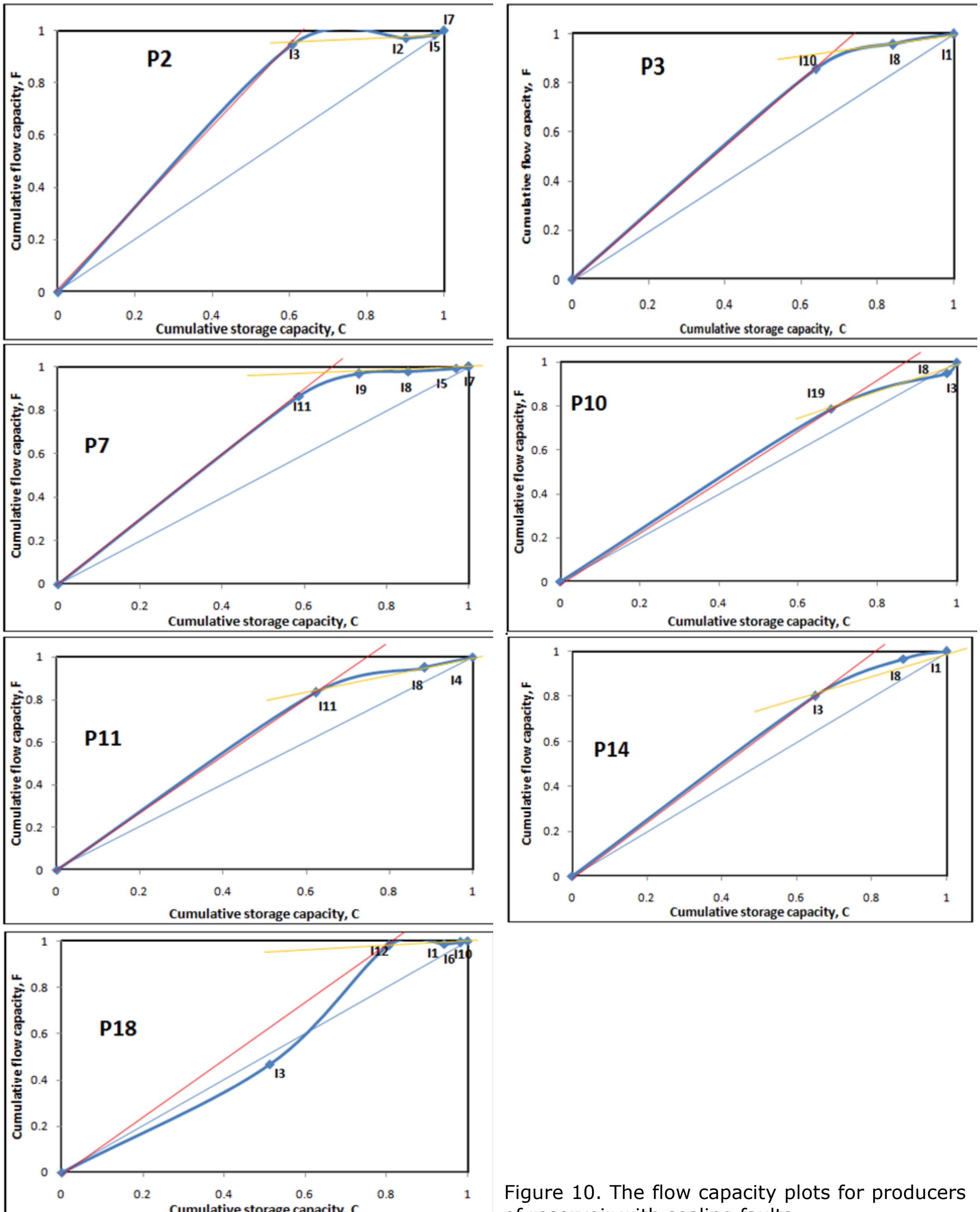
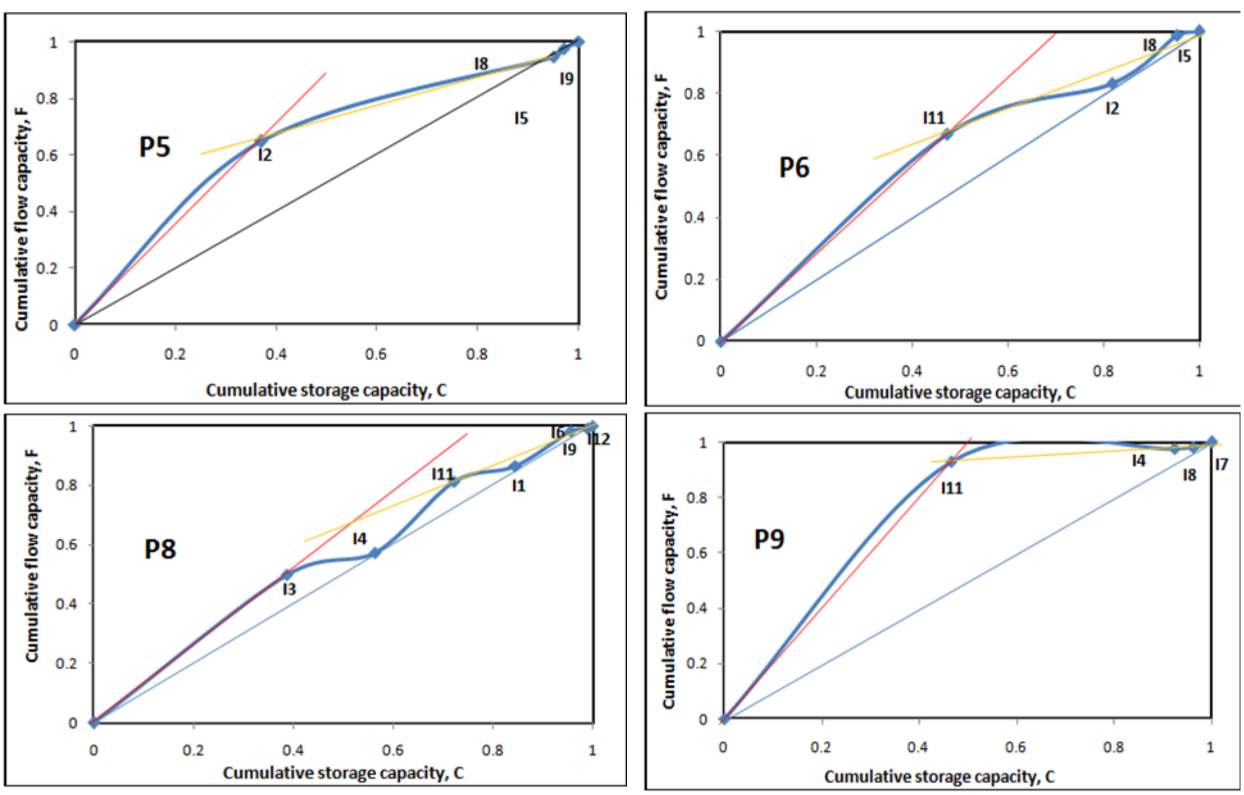


Figure 10. The flow capacity plots for producers of reservoir with sealing faults

All flow capacity plots are nonlinear which means that they are heterogeneous in nature. The first straight line parallel to the 45^o line, represent a homogeneous reservoir flow capacity with $L_c = 0$. Increasing level of heterogeneity is indicated by movement of flow capacity plot away from the 45^o line with L_c increasing but less than unity. The producers such as ANN7 (P2), ANN8 (P3), and ANN45 (P7) are completed in six layers, ANN86 (P11) is also completed in five layers, and whiles ANN100 (P18) is completed in four layers. Only ANN79 (P10) is completed in two layers. Each flow capacity plot is made up of two straight lines, which indicate their respective geological feature of the layers the producer is connected to. The first straight line in each plot represents the fraction of total flow capacity provided by the set of injectors surrounding the producers. This straight line with long flat behavior indicates that a fraction of the total storage capacity provides a negligible fraction of the total flow capacity. This is a typical aspect of presence of s reservoir seal. Therefore, all flat straight lines indicate the presence of sealing faults in the vicinity of the producers. The second straight line in all plots suggests that a small fraction of total flow capacity is provided by some fraction of the total volume of the field; this usually contributes from injectors communicating through matrix of the reservoir. The section of the reservoir contained by these well is said to be low reservoir heterogeneity.

3.5. Reservoir connectivity and heterogeneity for different flow paths

The reservoir heterogeneity for this category is shown Fig. 11. The figure shows flow capacity plots for some producers. Producers ANN42 (P6), ANN39 (P5), ANN49 (P8) and ANN78 (P9) are completed in six layers; ANN91 (P13), are completed in four layers, whiles producers ANN96 (P15) is completed in three layers. The flow capacity plots show different geological features in surrounding injectors. Some injectors communicate with the corresponding producer through fast flow paths or high permeability layers and other injectors communicate through slow paths or low permeability layers. This type of heterogeneity of the field indicates that the producers will have significant degree of connectivity. Such heterogeneities at the interwell scale enhances fluid flow patterns, drainage efficiency of the reservoir, and vertical and lateral sweep efficiency of secondary and tertiary recovery projects.



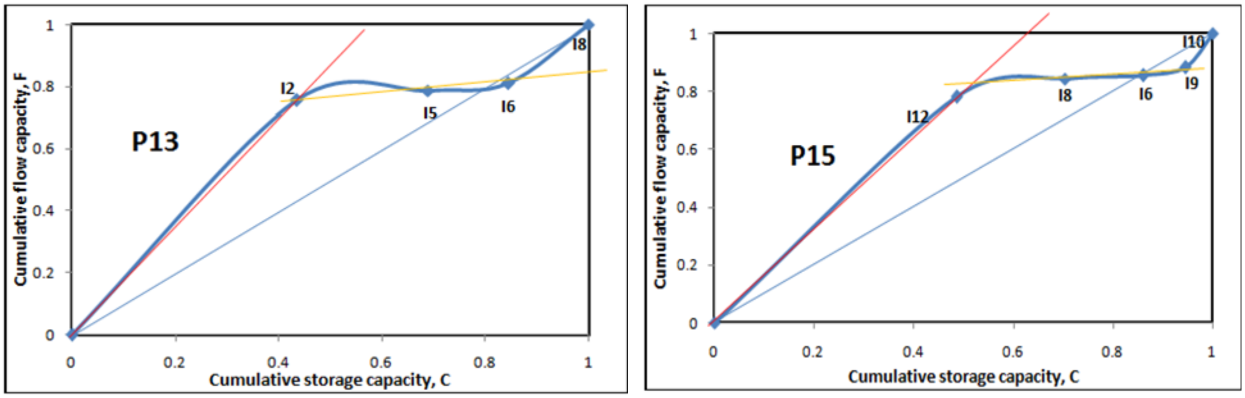


Figure 11. The flow capacity plots for producers of reservoir with high permeability

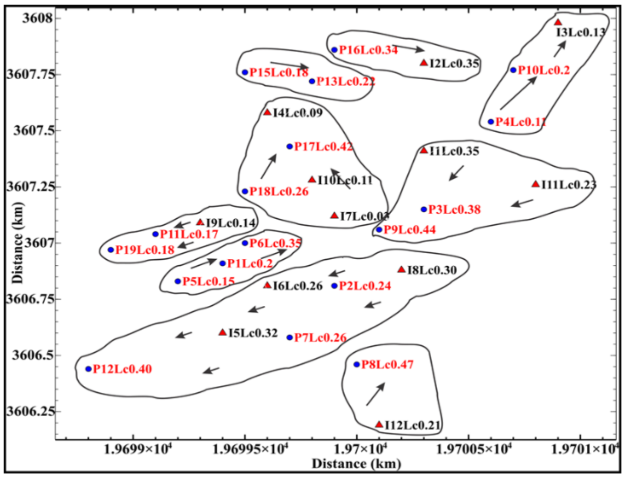


Figure 12. Field heterogeneity distribution

The field wide heterogeneity distribution for both the injector and producers in the reservoir is shown in Fig. 12. From Fig. 12, the injectors with lower degree of heterogeneity are more prone to homogeneous environment. These injectors communicate better with their surrounding producers. However, the dynamic nature of reservoir heterogeneity, the surrounding producers with higher degree of heterogeneity than the injector affects the performance of these reservoirs. There is some degree of backflow or bypass around these producers. This phenomenon makes interwell connectivity more complicated.

3.6. Production performance and heterogeneity

The effect of heterogeneity on production performance is shown in Fig. 13. It is apparent from the Fig. 13 that production performance increases when the reservoir heterogeneity is less than 0.26. Within this region the reservoir behaves more homogeneous, and the well production increases steadily as heterogeneity factor increases.

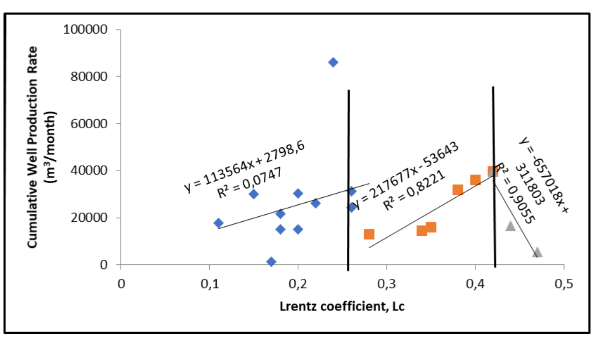


Figure 13. Effect of heterogeneity on production

The well production performance increases sharply beyond 0.26 as the reservoir gets more heterogeneous. However, as heterogeneity factor gets bigger, increase in heterogeneity lead to a sharp decline in production. This means that the higher the reservoir heterogeneity there is an inverse telling effect on the production performance of the producers. Hence it is essential that methods toward permeability improvement are considered to enhance production.

3.7. Discussion

From the analysis of connectivity and heterogeneity, the pattern of the flow capacity curve is indicative of the geological features present in the surrounding area of a producer well pairs. The reservoir can be said to be divided into three areas. The first case showing a flow capacity curve which indicates an area of fractures in the drainage volume of a producer represented by the steeper segment of the curve. In the second case, two specific trends are established. The first trend indicates curve showing presence of long flat behavior which shows the fraction of the total storage capacity, or the total pore volume swept by surrounding injectors has negligible effect of the total flow capacity. This is synonymous to nonpay zone or reservoir seal. This means that producers within this part of the reservoir have poor communication with the surrounding injectors leading to poor production performance. The second trend in this case is the straight line in all plots suggesting that a small proportion of total flow capacity is supported by some fraction of the total volume of the field contributed from injectors communicating through matrix of the reservoir.

The flow capacity plots of the third case show how injectors surrounding the producers within this vicinity communicate with producers through fast flow paths and slow flow paths (higher and lower permeability layers). The performance of the producers in terms of their production rate as a function of degree of heterogeneity shows that production performance is affected when the reservoir heterogeneity is near homogeneity. Within this zone production increases as heterogeneity increases though marginal. However, beyond this point, as heterogeneity increases production assumes a near constant value.

This means that the higher the reservoir heterogeneity there is an inverse telling effect on the production performance of the producers. On another hand, the logarithm plot of connectivity coefficients and lag time attenuation, (β_{ij}'s versus t_{ij}'s) shows the degree of the imposed geology in the reservoir.

4. Conclusion

The flow capacity plots, and Lorentz coefficient were found useful in establishment of the geological features surrounding the producer well leading to the identification of heterogeneity orientation and hence the degree of connectivity. Heterogeneity increases with increasing Lorentz coefficient (Lc). Production performance is affected when the reservoir heterogeneity is near homogeneity. Within this zone production increases as heterogeneity increases. However, beyond this point, as heterogeneity increases there is a sharp decline in production performance. This means that the high reservoir heterogeneity has an inverse effect on the production performance of the producers. Hence, essential methods for permeability improvement should be considered to enhance production.

Symbols

$k_i = layered\ permeability,$ m^2
$h_i = layered\ thickness, m$
$m, n, = number\ layers$
$F_m = cumulative\ flow\ capacity$
$H_m =\ cumulative\ thickness, m$
$\emptyset_i = layered\ porosity, \%$
$C_m =\ cumulative\ storage\ capacity$
$\beta_{ij} = connectivity\ coeeficient$
$t_{ij} = time\ lag\ and\ attenuation, months$
$\hat{q}_j = total\ production\ of\ layered\ thickness$, m^3/d
$\mu = fluid\ viscosity,$ cp
$C_t = total\ \ ompressibility, 1/psi$
$r_t = distance\ between\ wells, m$

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