



Incremental and acceleration production estimation and their effect on optimization of well infill locations in tight gas reservoirs

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Abstract

The main role of infill drilling is either adding incremental reserves to the already existing one by intersecting newly undrained (virgin) regions or accelerating the production from currently depleted areas. Accelerating reserves from increasing drainage in tight formations can be beneficial considering the time value of money and the cost of additional wells. However, the maximum benefit can be realized when infill wells produce mostly incremental recoveries (recoveries from virgin formations). Therefore, the prediction of incremental and accelerated recovery is crucial in field development planning as it helps in the optimization of infill wells with the assurance of long-term economic sustainability of the project. Several approaches are presented in literatures to determine incremental and acceleration recovery and areas for infill drilling. However, the majority of these methods require huge and expensive data; and very time-consuming simulation studies. In this study, two qualitative techniques are proposed for the estimation of incremental and accelerated recovery based upon readily available production data. In the first technique, acceleration and incremental recovery, and thus infill drilling, are predicted from the trend of the cumulative production (G_p) versus square root time function. This approach is more applicable for tight formations considering the long period of transient linear flow. The second technique is based on multi-well Blasingame type curves analysis. This technique appears to best be applied when the production of parent wells reaches the boundary dominated flow (BDF) region before the production start of the successive infill wells. These techniques are important in field development planning as the flow regimes in tight formations change gradually from transient flow (early times) to BDF (late times) as the production continues. Despite different approaches/methods, the field case studies demonstrate that the accurate framework for strategic well planning including prediction of optimum well location is very critical, especially for the realization of the commercial benefit (i.e., increasing and accelerating of reserve or assets) from infilled drilling campaign. Also, the proposed framework and findings of this study provide new insight into infilled drilling campaigns including the importance of better evaluation of infill drilling performance in tight formations, which eventually assist on informed decisions process regarding future development plans.

Keywords Incremental recovery · Acceleration recovery · Infill drilling · Tight gas · Blasingame type curve

List of symbols

ct Total compressibility (1/psi)
 G Initial gas in place (bscf)
 G_p Cumulative gas production (bscf)
 P_p Pseudopressure (psi)

P Pressure (psi)
 q Gas flow rate (Mscf/d)
 qD Dimensionless rate
 t Time (day)
 tD Dimensionless time
 \bar{t}_{tot} Total material balance time (day)
 X_f Fracture half length (ft)
 Z Compressibility factor

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Greek letters

μ Viscosity (cp)

Subscripts

g Gas
 i Initial
 k Single well

pavg	Average pressure
sc	Standard conditions
tot	Total
wf	Well flowing pressure (sandface)

Abbreviations

BDF	Boundary dominated flow
CGIP	Contacted gas in place (bscf)
DCA	Decline curve analysis
EUR	Estimated ultimate recovery (bscf)
GIP	Gas in place (bscf)
IWLC	Infill well locator calculator
MHF	Massive hydraulic fracture
NPV	Net present value
OPEX	Operational cost

Introduction

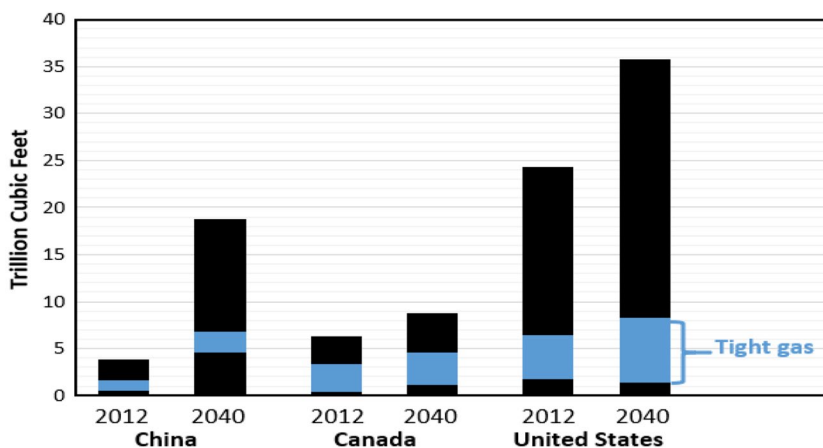
World demand for energy is expected to increase by around 25% more than the current levels by 2040 (ExxonMobil 2017), and the trend of clean natural gas has been growing due to low CO₂ emission (Al-Fatlawi et al. 2017a; Esfahani et al. 2015; Hefner 1993; Sadeq et al. 2018). To meet this demand, the hydrocarbon industry has raised its investment in exploration and production operations. However, with the depletion of the world's conventional resources, the interest in the exploitation of unconventional plays has increased over the past decades (Leimkuhler and Leveille 2012; Wang et al. 2015; Zahid et al. 2007). In the 1970s, such assets were not considered as economically viable resources for development mainly due to their low permeability (Eftekhari 2016). Despite the technical and economic challenges associated with these assets, many references have indicated that unconventional resources have far more hydrocarbon reserves than conventional ones (Abbasi et al. 2014; Al-Fatlawi et al. 2017b; Hossain et al. 2018; Sadeq et al. 2017).

It is obvious that natural gas will continue to play its vital role in meeting the growing energy demand, remain as the most feasible option to minimize the greatest concerns of high emission from coal and/or oil, and play the vital role towards successful transitioning from the current high emission fossil-based energy to the green energy (Hafeznia et al. 2017; Yang et al. 2017). According to the 2016 International Energy Outlook (IEO2016), as shown in Fig. 1, the gas supply from unconventional resources is expected to increase substantially in the future to meet the global need for energy (Eia 2016). Figure 1 also demonstrates that tight gas reservoirs will contribute significantly to the global natural gas production pool.

Due to the depletion of most of the conventional gas reservoirs, the interest in the exploitation of unconventional tight gas has been increased significantly in the last few decades. Consequently, the research and development initiatives as well as the number of publications associated with tight gas reservoirs especially for cost-effective optimum production have significantly increased (Al-Fatlawi et al. 2019). Due to the complex nature of tight gas reservoirs characteristics, and very low permeability (Al-Fatlawi et al. 2016; Bahrami et al. 2012a), the economic recovery of gas production of these reservoirs requires conducting expensive and complex hydraulic fracturing operations (Bahrami et al. 2012b; Bocora 2012; Hossain et al. 2000; Leal et al. 2014) combined with a drilling large number of wells (100–1000 s) (Al-Fatlawi et al. 2017c; Naik 2003). Thus, there is no doubt that the development of infill drilling and/or proper management of infill drilling campaigns is necessary not only to exploit the unconventional resources but also to ensure the recovery of profitable reserves, and avoid unnecessary costs of over the drilling operations.

The determination of the accurate number of infill wells and their placement towards cost-effective optimum productions from tight gas reservoirs become a critical challenge for the energy companies. Driven by the industry's need to solve this issue, numerous techniques/methods have

Fig. 1 Natural gas production in United States, Canada, and China classified based on the type of the resource. *Note:* the black bars refer to the conventional and unconventional resources other than tight gas reservoirs. After (Eia 2016)



emerged. The traditional technique for predicting the infill drilling potential involves carrying out detailed reservoir studies, which requires the gathering of geological, petrophysical, and geophysical data to perform analysis and interpretation for the reservoir performance studies through full scale reservoir simulations (Newsham and Rushing 2001). The simulation involves building the static model, performing history matching, and conduction production forecasting to evaluate the potentials of infill drilling programs placed arbitrarily with numbers determined by the trial and error process. While this process appears to work reasonably well, it is very tedious and utterly time consuming, and not all the operators have the luxury of implementing such a time consuming and expensive studies (Bagheri and Masihi 2016; Turkarslan et al. 2010). Such an issue is particularly important in unconventional assets. Usually, these resources have complex geology and typically 100 to 1000 wells are being operated by small size operators (Guan et al. 2007). Thus, the economical constraints of carrying out the detailed reservoir studies may opt out those operators to leave significant quantities of untapped hydrocarbon. Another industry practice is related to the use of decline curve analysis coupled with the volumetric estimation of in-place hydrocarbon. In this method, decline curve analysis is used to forecast the Estimated Ultimate Recovery (EUR). Utilizing this EUR per well and total hydrocarbon in place, one can predict the required number of wells, and consequently, their spacing to drain the hydrocarbon reservoir (Huang and Arii 2016). This approach seems to be relatively simple and can only be used when the production data with are radially available, but the fact that decline curve analysis (DCA) is mainly based on curve fitting, and has no physical basis, makes the results obtained based upon DCA is often questionable (Gaskari et al. 2006; McCain et al. 1993) and misleading. As a result, robust but simplified model or framework is essentially desirable.

French et al. (1991) used an empirical model for investigating the infill drilling potential and prediction of ultimate recovery for the Permian Basin Clearfork and San Andres layers in West Texas carbonate reservoirs. The model forecasted results, and the field data appeared to fit each other reasonably well (evident by relatively high values of R2 and F). Then, Soto et al. (1999) conducted a statistical study on the same units in West Texas (i.e., Clearfork and San Andres) to determine the infill ultimate oil recovery by integrating multivariate statistical analyses, and neural network models. Cipolla and Wood (1996) implemented statistical analysis to evaluate the well placement in tight gas fields using limited single-well one-layer reservoir modeling; and investigated the infill potentials of Ozona field, Crockett County, TX. The authors used the data of 51 randomly selected samples (wells) out of 1500 wells to determine the distribution of ultimate hydrocarbon recovery and drainage

area. The reason behind taking only 51 wells is the difficulty of conducting the detailed analysis of all the 1500 wells in the field. The authors concluded that developing Ozona field with 40 acres spacing expected to add extra 400 Bcf to the current reserve with the 80 acres spacing. To determine the optimum well placement in low permeability tight gas reservoirs, Cipolla and Wood (1996) have further developed the McCain et al. (1993) approach, and they named it “Moving domain”. Basically, this method tries to perform the steps that reservoir engineers follow when encounters the task of evaluating single infill well location. This is done through a set of comparisons, approximations, and statistical tests. The authors applied this method to the Ozona field, and they identified 1246 infill locations that are expected to add 636 Bcf to the field. Guan et al. (2004) evaluated the accuracy of the moving window method in determining the optimum infill well placement by creating several synthetic reservoir models. Their paper showed that the accuracy of this method in determining the performance of a group of infill candidates is within 10%. However, this value is very dependent on the level of heterogeneity in the reservoir. Also, in the case of prediction of individual candidate performance, the percentage of error can increase to more than 50%, which is neither acceptable nor sensible.

Other methods such as the genetic algorithm (GA), an optimization technique developed based upon the principle of Darwinian natural evolution, may be considered to define an optimal well placement. The GA was firstly introduced by Holland (1975). This optimization technique seeks for a mix of the controlling factors that maximize the objective function which is often chosen as the net present value (NPV) or the cumulative production within a specified timeframe (Montes et al. 2001). Although there is a growing interest in GA, there is limited experience with these methods to be applied on a field scale (Nasrabadi et al. 2012). The reason behind this limitation is the fact that the application of this method is rather expensive in terms of simulation time and computational power (Bagheri and Masihi 2016), which may not be appropriately fit for routine industry works.

Another method that is used to assess the infill drilling potentials is the rapid inversion technique. This method is a simulation-based technique that was introduced by Gao and McVay (2004). This method tries to combine the accuracy of reservoir simulation and the speed and cost efficiency of statistical techniques. Gao and McVay (2004) showed that their proposed method could achieve better results than that obtained using the moving window approach particularly for a group of infill candidates. However, they pointed out that this technique can have the percentage of error of almost 30% when used to predict optimum well placement for individual wells and this percentage depends on the reservoir heterogeneities.

Teufel et al. (2004) conducted a study to determine the applicability of developing an area located in the Mesaverde Group in the San Juan Basin with 80 acres spacing. In that study, the authors used IWLC simulator (Infill Well Locator Calculator) in predicting the infill potentials and compared the results with actual infill wells. The IWLC was developed by Kelly (2000), and it aims to help operators to determine the infill wells location in low permeability reservoirs. This simulator requires values of porosity, water saturation, formation thickness, and permeability of the wells located around an infill well. By supplying these data, the simulator can predict the recovery factors of all the grid blocks surrounded by present wells. With these results, the user would be able to make a qualitative judgment regarding the optimum infill location. However, this tool does not take into account the effect of heterogeneity in the study area leading to inherent uncertainties that can affect simulation predictions (McVay and Bickel 2011; Prada 2012).

From the above discussion, it appears that several optimization and statistical methods have endeavored to determine optimal well placement. However, many of these approaches are either expensive simulation based or require a significant amount of data. Moreover, most of these techniques are being implemented with a high level of error and uncertainties; and unable to quantify the incremental and accelerated reserves of infill wells that contribute to its total production.

Compared to the reviewed studies, the current work offers a simple yet efficient workflow that is applicable to the most dominant flow regimes in wells life cycle (transient and BDF). This workflow required only routinely gathered production data without the need for computationally expensive calculations or simulation studies. The workflow focuses on quantifying the incremental and accelerated reserves of infill wells using analytical methods with the emphases on improving the accuracy and minimizing the level of uncertainty.

The structure of this paper is as follows: first, the problem under study will be described. In the subsequent section, the importance of incremental and acceleration recoveries is presented using two extreme numerical simulation cases. Next, a rigorous workflow for the determination of incremental and acceleration recovery is developed using two simple analytical methods. Finally, the workflow is practiced to demonstrate its applicability.

Problem statement

Infill drilling is an improved hydrocarbon recovery method that aims to add additional new wells to the currently existing wells in a field that is being produced under primary and/or secondary development methods (Thakur and Satter 1998). By increasing well density and decrease spacing,

infill wells provide an effective means for enhancing hydrocarbon production rates, accelerate reservoir drainage and add new reserves (Cheng et al. 2006; Wu et al. 1989). In homogenous reservoirs, infill drilling will serve by accelerating the production but will not add new reserves. However, in the case of heterogeneous deposits, infill drilling will have the benefit of adding extra hydrocarbon reserves as new wells will be able to intersect with and drain previously undrained areas of the reservoirs. Generally speaking, as well density increases, well spacing decreases; therefore, formation continuity improves and enhances well connectivity. Wu et al. (1989) showed that there is a correlation between the well spacing and hydrocarbon recovery.

A heterogeneous cross section of a reservoir is shown in Fig. 2. There are two currently existing producer wells on the extreme right and left of the graph. Also, there is one infill well in the middle. By drilling this infill well, the production will be accelerated from layers 1, 2, 3, 5, and 6 because these layers are already being produced by one or both of the currently existing producers. However, due to the heterogeneous nature of this reservoir, it seems that the infill well adds new reserve to the field by intersecting one virgin layer (i.e., strata 4). Hence, the improvement of lateral continuity by infill drilling results in recovery increase in this discontinuous layered reservoir. When an infill well contributes to accelerate the production, it can still be beneficial if the cost is justified. By accelerating the production, less long-term operational cost (OPEX) will be needed, and a higher value of money (NPV) can be achieved (ASCORRA IBARRA KA 2016). However, maximum benefit can be Realized out of these wells when they are mostly producing incremental recoveries (recoveries from virgin formations) (Luo and Kelkar 2010). This study focuses to develop a workflow with

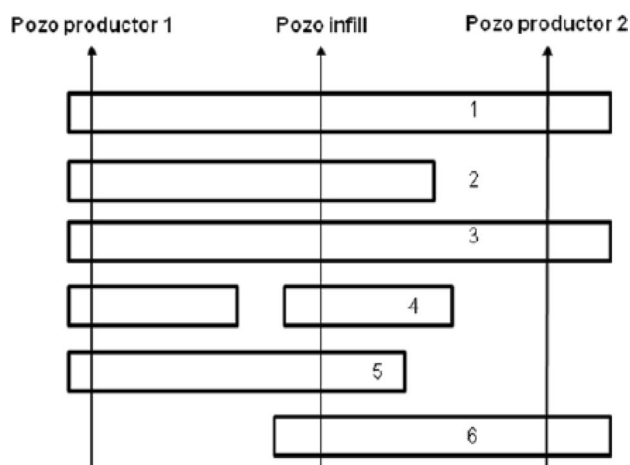


Fig. 2 Heterogenous reservoir cross section. After (ASCORRA IBARRA KA 2016)

which it becomes possible to determine incremental and acceleration production of infill drilling campaigns.

Incremental and accelerated recovery

An illustration of the importance of incremental and acceleration recovery in infill drilling operations can be made by using the idea of Luo and Kelkar (2010). In this idea, two cases are considered as shown in Fig. 3. The first case (Fig. 3a) is a homogeneous reservoir with one parent well in the center and four child wells near the corners. when the infill wells start production (around 65 months) the production rate of the parent well has declined rapidly, as indicated by solid black line overlapped by infill wells production rate in Fig. 3a. However, it is clear that when only the parent well is put on production, the result will be the dashed black curve. This behavior suggests that there is obvious interference between parent well and its child wells. The intensity of this interference determines the amount of the production loss of parent well as this loss represents the amount of acceleration in production that has been produced by subsequent infill wells. Also, note that initial production of the child wells is much less than the initial production of the parent well which indicates that these wells are producing from the depleted zone by the original parent well. Additionally, the production rate overlapping of the parent and child wells confirms the fact that this zone is homogenous.

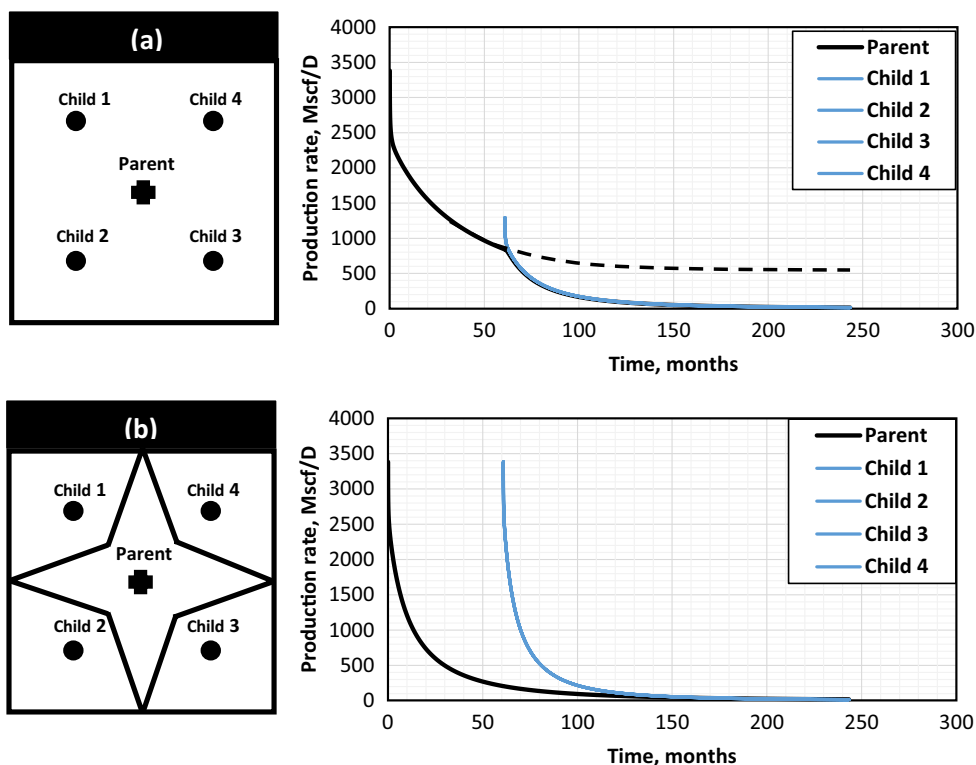
In the second case as shown in Fig. 3b, a heterogeneous reservoir is considered. In this example, the parent well has been separated from the surrounding child wells by impermeable faults that prevent communication between these wells. By looking at the production rate, it can be seen that all the wells (parent and child wells) start at the same production rate which indicates that the infill wells are producing from virgin areas. Thus, the benefit from these infill wells was maximized as they are only producing incremental production.

In homogenous reservoirs, infill drilling will serve by accelerating the production but will not add new reserves unless it is accessed in nondepleted areas. However, in the case of heterogeneous deposits, infill drilling will have the benefit of adding extra hydrocarbon reserves as new wells will be able to intersect with and drain previously undrained virgin areas/layers of the reservoir. Therefore, it is clear that identifying incremental and accelerated production will have a significant impact on the infill drilling campaigns.

Theory and calculation

In this section, two methods are presented to determine acceleration and incremental production based on the wells flow regimes.

Fig. 3 Illustration of incremental and accelerated production. **a** Represents homogenous reservoir (showing acceleration production), and **b** shows heterogeneous reservoir where infill and parent wells are producing incremental production



Luo and Kelkar (2010) method

Many reservoir formations have a relatively low permeability which restricts the hydrocarbon flow and thus prevents the extraction of these resources in commercial quantities. Therefore, massive hydraulic fracturing (MHF) in these reservoirs is a crucial component of the reservoir development cycle (Bostic et al. 1980; Nashawi and Malallah 2007). This is because MHF can boost hydrocarbon production by establishing the high permeability conduit to facilitate the flow, and increase the surface area of the well exposed to the low permeability formation (Agarwal et al. 1979). Well fracturing operations have been practiced extensively in shale and tight gas reservoirs. Therefore, understanding hydrocarbon flow behavior in these fractures and their performance is a must for the optimal development of these tight formations. Several flow regimes have been identified in fractured wells depending on the reservoir and well properties. These are (a) fracture linear flow, (b) bilinear flow, (c) formation linear flow, (d) pseudo-radial flow. The most common flow regime in tight formations is formation linear flow as it can last for years (Almarzooq 2012; Helmy and Wattenbarger 1999).

Linear flow regime

This flow regime is characterized by parallel flow lines perpendicular to the hydraulic fracture (Arevalo-Villagran et al. 2001). Many authors reported that this flow regime could extend for long period (Ammer 1984; Boardman and Knutson 1981; Hale 1986; Hale and Evers 1981; Nott and Hara 1991; Stright and Gordon 1983; Wattenbarger et al. 1998). This flow regime occurs when the high conductivity fracture is created near the reservoir formation (Ramey 1970). This flow regime is observed in almost all the tight formations (Branajaya 2005). Also, Stright and Gordon (Stright and Gordon 1983) mentioned that this type of flow tends to exist in elongated reservoirs, vertical flow to high permeability layer, and naturally fractured reservoirs (Ammer 1984). This flow type can be observed in the channel and bar sands,

reservoirs bonded by impermeable faults, and reservoirs producing by bottom water drive (Kohlhaas et al. 1982). This type of flow can occur in high conductivity fractures wells in tight formations. The constant pressure solution for this flow type was presented by Cinco-Ley and Samaniego-V (1981) as follow:

$$q_D(t_D) = \frac{2}{\sqrt{\pi^3 t_D}} \quad (1)$$

where q_D and t_D are dimensionless rate and time, respectively. It was shown that plotting the $\frac{Gp_{sc}}{pp_i - pp_{wf}}$ versus $t^{0.5}$ on Cartesian plot will produce straight line which can be used to predict Estimated Ultimate Recovery (EUR) with the assumption that well is producing with constant pressure (Kelkar 2008). The validation of this relation was performed using a numerical simulation model shown in Table 1. This model was configured to show a long period of linear flow regime.

The diagnostic plot (half slope) shown in Fig. 4 confirms the long period of the linear flow regime. Additionally, the predicted EUR using the linear relationship of Gp versus $t^{0.5}$ is close to the EUR predicted by the simulation as can be seen in Fig. 5.

Also, several field cases (shown in Fig. 6) were collected by digitizing production data presented in the literature. These cases clearly, validated the existence of the linear relationship when the Gp is plotted against $t^{0.5}$. Moreover, an early part of the data was used to fit the linear relationship and the trend line equation was used to forecast later production and compared to the presented data in the literature.

Table 2 summarizes the results obtained from the field cases and their comparison to the reported EUR values (i.e., extracted values from the published papers). The results obtained from the linear relationship are in good agreement with the reported data. Also, by looking at the time column it is obvious that the transient linear flow period in these tight formations has extended to no less than 20 years. Although this may not be general, it gives us a sense that

Table 1 Linear model configuration and its properties

Reservoir Length in X-direction	500	ft
Reservoir Length in y-direction	5000	ft
Net thickness	100	ft
Fracture conductivity	infinite	
Matrix permeability	0.01	md
Fracture half-length (X_f)	249	ft

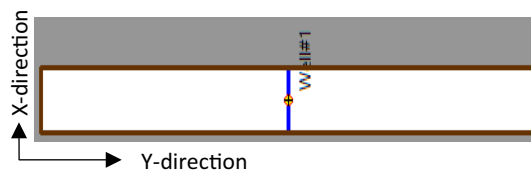


Fig. 4 Linear flow extends along all the production data

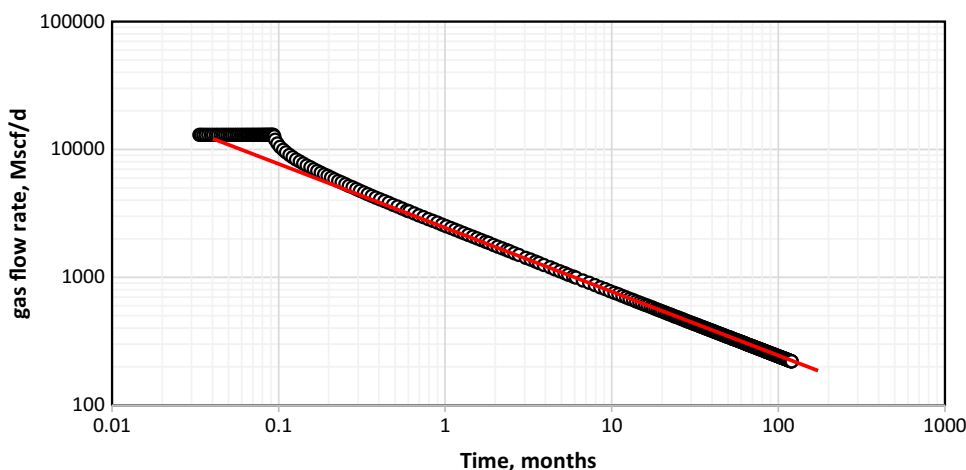
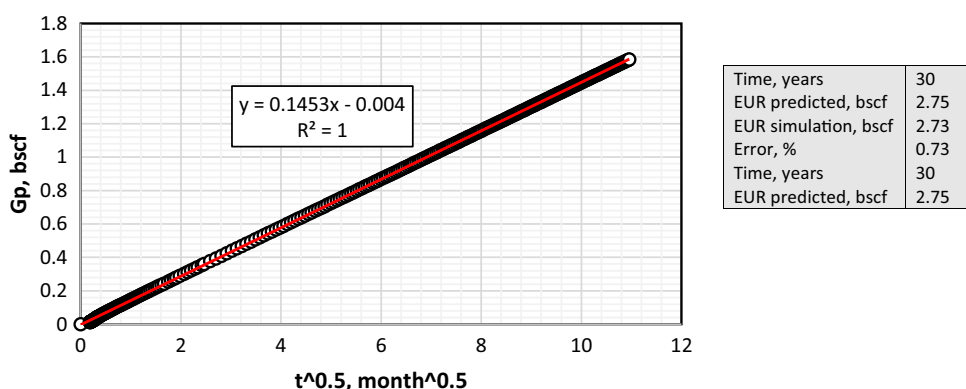


Fig. 5 Linear trend extrapolation and result compared with the numerical simulation



these formations show a long period of the linear flow, and thus it is reasonable to use this method to forecast the EUR values along the life of the wells in tight formations.

Workflow for finding acceleration and incremental recovery

The workflow followed to estimate the acceleration and incremental reserve was introduced by Luo and Kelkar (2010). It depends on a basic idea of finding a linear relationship between G_p and a certain time function ($t^{0.5}$). This is because it is easier to extrapolate a straight line and it is clear to notice the deviation from that line as infill groups are put on production. This method is used with the assumption that linear flow can extend for a considerable period as was discussed earlier.

The following flowchart shown in Fig. 7 summarizes the steps needed to apply this method and it was used in the application of the field case that will be shown later (Sect. 5.1). Also, by applying this flow chart on several areas in the reservoir the acceleration and incremental potential of that section can be assessed and this will aid in the decision making of whether more infill wells are beneficial or not.

Progressive multi-well Blasingame analysis

The work of Marhaendrajana and Blasingame (2001) forms the basis of the methodology presented in this paper. Marhaendrajana and Blasingame (2001) showed that with a minor adjustment to previous Blasingame type curves, a new type curve analysis can be made with more accurate calculations of in-place gas volume. Marhaendrajana and Blasingame (2001) developed type curves analysis that uses the early developed single well model to account for a reservoir with multi-wells. This was done by including the total production of the wells in the pseudomaterial balance time function of the single well type curve. With these data transformations, the predicted Estimated Ultimate Recovery (EUR) and Contacted or original Gas In Place (GIP), extracted from data matching, become representative of the group of wells.

Single well performance in multi-well system

In his work, Marhaendrajana (2000) showed that single well behavior of an arbitrary well located in a multi-well system could be described using the following expression.

Fig. 6 Application of linear relationship on several field cases and use the best fit equation to predict EUR assuming linear flow

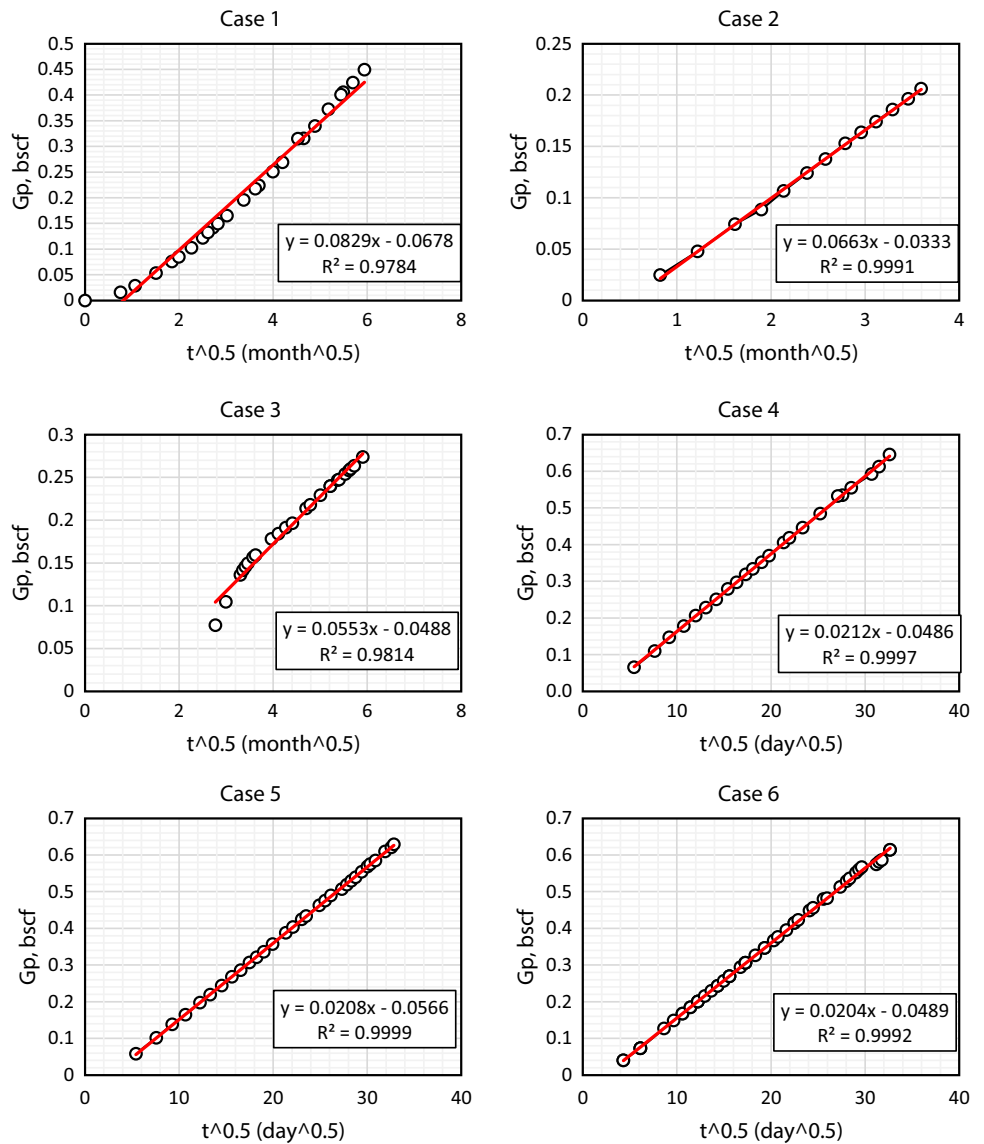


Table 2 The predicted (using equations from Fig. 6) and reported EURs from several field cases

Cases	Prediction Time (years)	EUR predicted (Bcf)	EUR actual (Bcf)	References
1	20.2	1.22	1.31	Cheng et al. 2007)
2	20.1	0.99	0.845	Maley 1985)
3	21.35	0.83	0.65	Stright and Gordon 1983)
4	23	1.88	2	Helmy 1999)
5	23.1	1.84	2	Helmy 1999)
6	23	1.8	1.94	Arevalo-Villagran et al. 2006)

$$\frac{Pp_i - Pp_{wf,k^{(i)}}}{q_{k^{(i)}}} = \frac{1}{Gc_t} \bar{t}_{tot} + f_{k^{(i)}} \quad (2)$$

From Eq. (2) it is clear that variables on the left side of the equation belong to single well performance. However,

this equation includes the effect of the total number of wells through terms \bar{t}_{tot} and $f_{k^{(i)}}$.

In Eq. (2), G is the initial gas in place, Pp is gas pseudo-pressure and \bar{t}_{tot} is the total material balance time for the group of wells (entire field). Pp and \bar{t}_{tot} can be found for gas

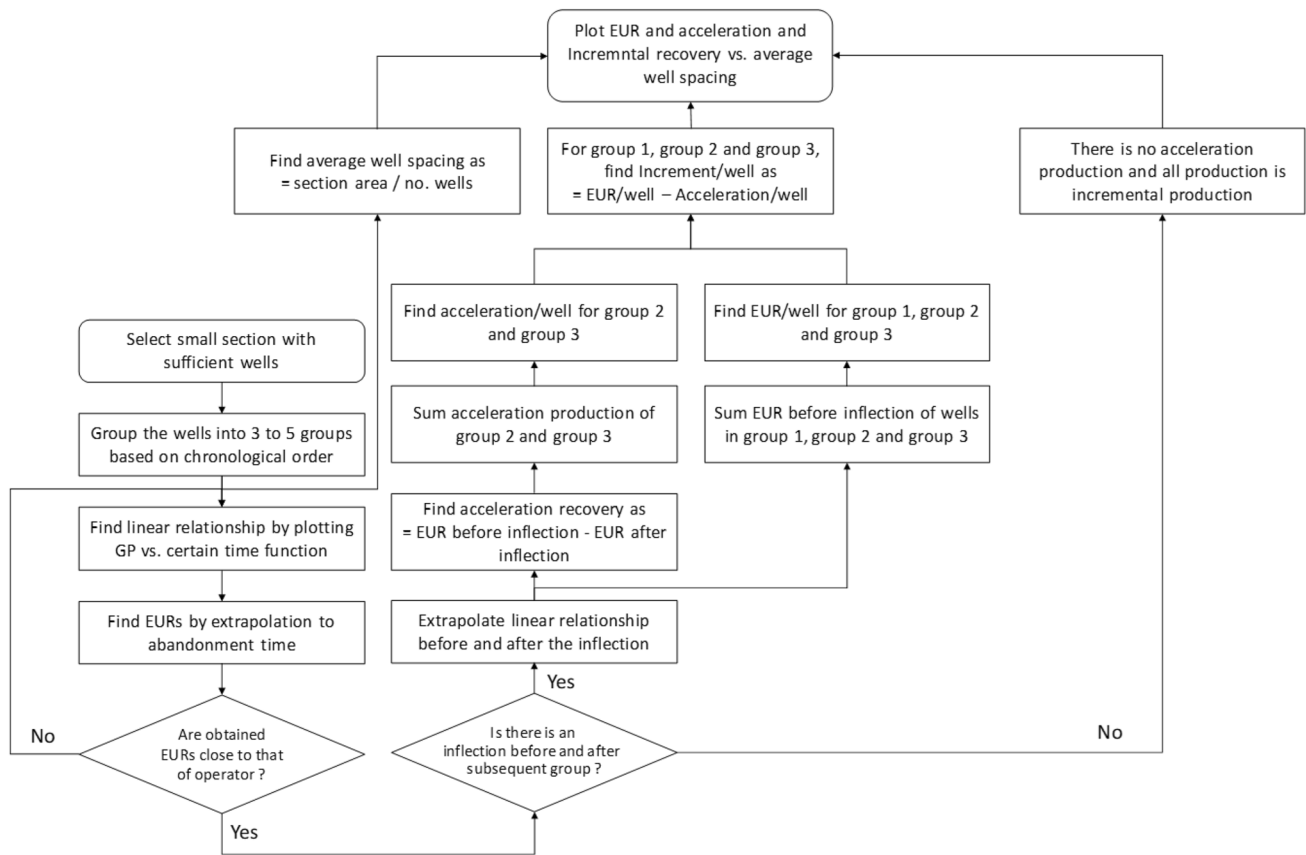


Fig. 7 Flowchart shows steps needed to apply Thakur and Satter (1998) method assuming that wells in the region are divided chronologically to three groups

through Eqs. (3) and (4), respectively, $f_{k(t)}$ in Eq. (2) is time-dependent variable; however, its value becomes constant during the boundary dominated flow. Also, note that the authors proved that Eq. (2) is a general equation and works under different production profiles (constant pressure/rate and variable pressure/rate).

$$Pp = \left[\frac{\mu z}{P} \right] \int_{P_{base}}^P \frac{P}{\mu z} dP \tag{3}$$

$$\bar{t}_{tot} = \frac{[\mu c_t]_i}{q_g} \int_0^t \frac{q_{g,tot}}{[\mu c_t]_{P_{avg}}} dt \tag{4}$$

Therefore, by incorporating the single well production data (pressure and flow rate) with the total group (field) material balance pseudo-time, the single well decline type curves can be used to extract flow properties (kh) from transient flow period and in place fluid during boundary dominated flow regime (Elgmami 2015).

Single versus multi-well approach

To demonstrate the usefulness of the multi-well approach against the single well approach, Fig. 8 is taken from Marhaendrajana (2000).

From Fig. 8, it is clear that well production data of a single well approach deviate to the left from the $b=1$ stem during boundary dominated flow (BDF). Such behavior can be an indication of well interference (Anderson and Mattar 2004). Single well approach matching can yield significantly lower CGIP than the actual values and therefore multi-well approach will be needed to correct the interference effect. This can be done by incorporating the total production of the wells in the material balance time function. By using the multi-well approach, better matching can be obtained as it is evident from Fig. 8.

Additionally, Anderson and Mattar (2004) demonstrate that in the case of a well accesses new reserves there will be a shift in the production date to the right of the $b=1$ stem in Blasingame type curves which indicates an increase in the drainage area and CGIP. Figure 9 provides a clear idea about

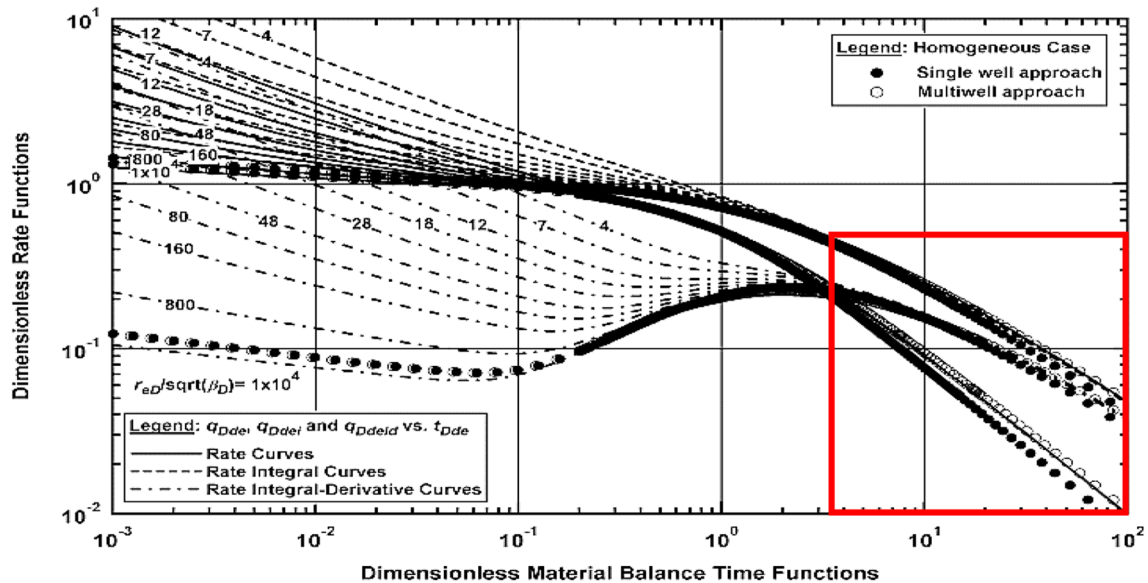


Fig. 8 Single versus multi-well approach. After (Maley 1985)

the effect of acceleration and incremental effect on production data when plotted on Blasingame type curve using the single well approach.

Work flow for finding the acceleration and incremental recovery

The calculation of incremental and acceleration production using this method depends on the identification of deviation (left or right) from the $b=1$ stem line during boundary dominated flow regime. The workflow for this method was provided by Wong et al. (2010) and was followed in this paper. This method starts with performing parent multi-well analysis where we find two EURs from matches prior to infill one (match A), prior to infill two (match B), and post infill two (match C) as shown in Fig. 10a. Then, parent and infill one multi-well analysis is done to find EURs from

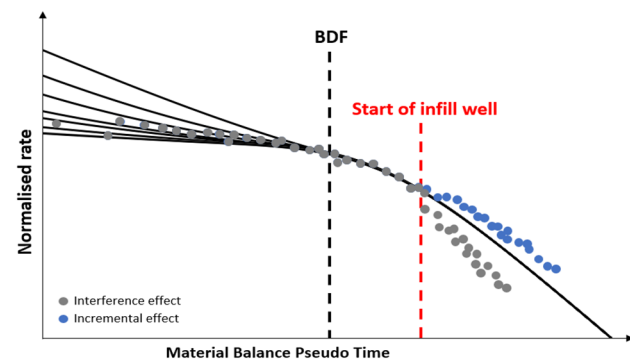


Fig. 9 Acceleration and incremental production effect during boundary dominated flow

matching of data prior to infill two (match D) and post infill two (match E) as in Fig. 10b. In the case of three infill stages as in this paper, all wells multi-well analysis is implemented at last and the type curve is matched (match F) as Fig. 10c and EUR are estimated.

After obtaining EURs from the different matches, incremental and acceleration recovery can be calculated as shown in Table 3.

To successfully apply this method, parent wells need to reach boundary dominated flow before the start of the subsequent infill programs. Also, the accuracy of this method can increase if the wells selected for analysis are located in isolated regions (as will be shown later in the field example in Sect. 5.2) to prevent the interference of wells in the neighboring regions. Also, this method is based on the assumption that infill wells will intersect similar layers to those intersected by parent wells in their properties. Therefore, it is possible to assume similar economic limits to assess the EUR values.

Results and discussion

Luo and Kelkar (2010) method

This method was applied to a 3D model of Whicher Range tight gas reservoir, WA. The model was developed using ECRIN-model (v4.30.08) from Kappa engineering Software Company. The development of the 3D model of this field was an essential step as this field was underdeveloped with only a few wells (5 wells) drilled in it and hence this model

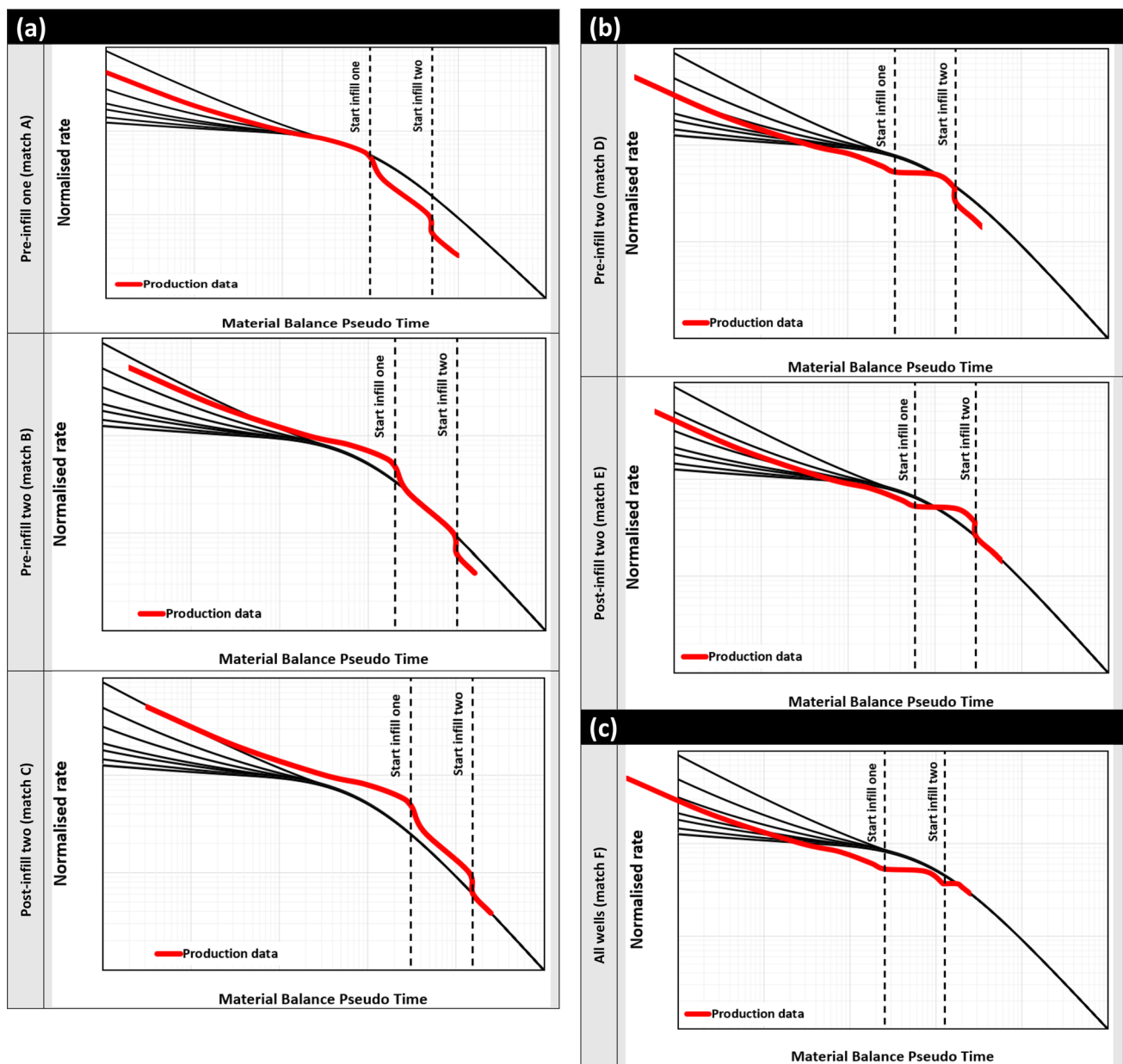


Fig. 10 Multi-well Blasingame Analysis. **a** Using data from parent well to get matches A, B and C. **b** Using data of parent and infill one to get matches D and E. **c** Using data of parent, infill one and infill two to get match F

Table 3 Incremental and acceleration calculations

Infill one acceleration recovery from parent (MMscf)	A-B
Infill two acceleration recovery from parent (MMscf)	B-C
Infill two acceleration recovery from parent and infill one (MMscf)	D-E
Infill two acceleration recovery from infill one (MMscf)	[D-E]-[B-C]
Infill one incremental recovery (MMscf)	D-A
Infill two incremental recovery (MMscf)	F-D

was used to generate the needed production data to apply this method.

The development of the model was started with petrophysical data analysis, followed by the preparation of dynamic properties using the available data. Finally, the dynamic reservoir model was built, and history matched. More explanation of the process can be found in the work of Al-Fatlawi et al. (2017c). The 3D model consists of 28 layers with average permeabilities that fall in the range of 0.01 to 0.1 mD.

To show the applicability of this method on a multi-layer heterogeneous reservoir, a study area was arbitrarily selected from the Whicher Range tight gas field model as shown in Fig. 11. This area was selected such that it is not bounded by faults so that wells in this area will show long-term transient linear flow. Additionally, the wells in this area were fractured

with multiple fractures of infinite conductivity and fracture half-length of 250 ft.

The wells, in this field case, were assigned with arbitrary production starting dates. These dates and well grouping process are presented in Fig. 12.

As per workflow described in Luo and Kelkar (2010) (Fig. 7), the EUR was estimated after 30 years by extrapolation of the linear relationship developed earlier (shown in Appendix 1). Also, these EURs were compared to the EURs from the decline curve analysis (shown in Appendix 1), and the results are presented in Fig. 13. From Fig. 13, it can be seen that a relatively good overall match was achieved.

Then, incremental and acceleration calculations were performed as shown in Appendix 1 and the results are plotted in Fig. 14. Best trend line was fitted to the data points in Fig. 14 and an arbitrary extrapolation was done to 100.18 acres spacing assuming two infill wells to be drilled in the future in this region. Using equations from Fig. 14 operator can readily determine average EUR as 7.4 bcf, Incremental recovery as 84.48%, and acceleration recovery as 15.52%. It can be seen that extra infill drilling in this zone is expected to further decrease incremental and increase acceleration recovery. When obtained values from this section are compared with other regions in the field, the operator can select the best potential area for infill drilling operations that provides the highest average EUR combined with the highest incremental recovery.

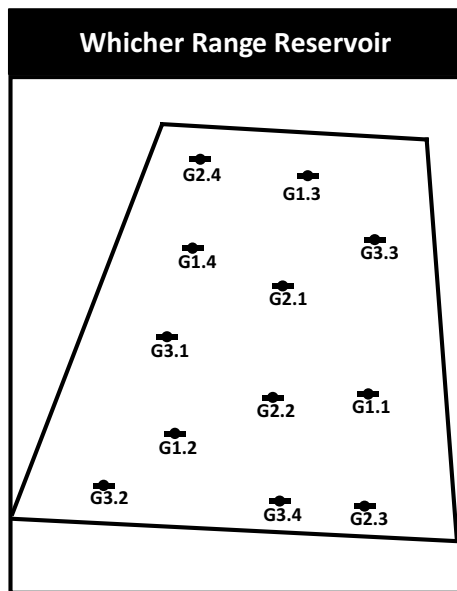


Fig. 11 Study area of 1402.58 acres was taken from Whicher Range tight gas reservoir model to apply Thakur and Satter (1998) method

Progressive multi-well Blasingame analysis

In this case, Whicher Range simulation model which was built earlier was used to apply this method. One region was selected from this model such that it is bounded by faults to ensure that boundary dominated flow is reached before the production start of the first infill program. A 2D map of the selected section can be seen in Fig. 15 along with the development stages. The wells' locations in this region were chosen arbitrarily.

Fig. 12 Well Dates and grouping process

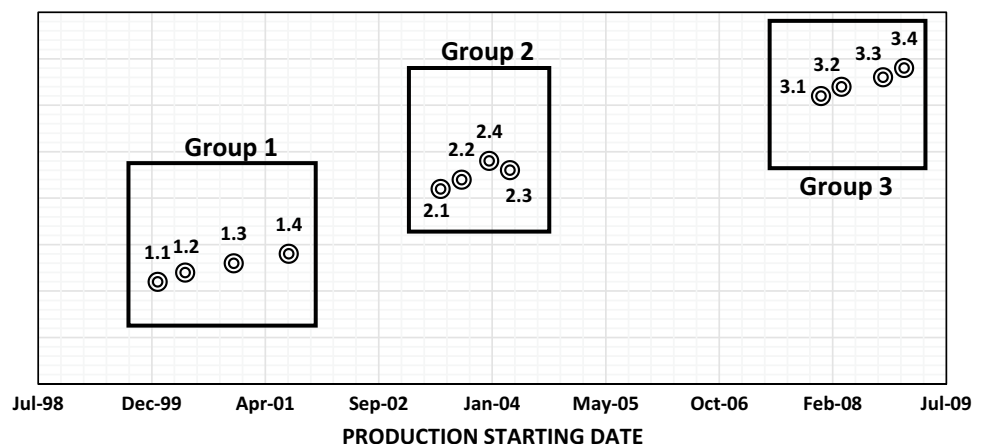


Fig. 13 comparison of EURs obtained from linear relationship and the decline curve analysis

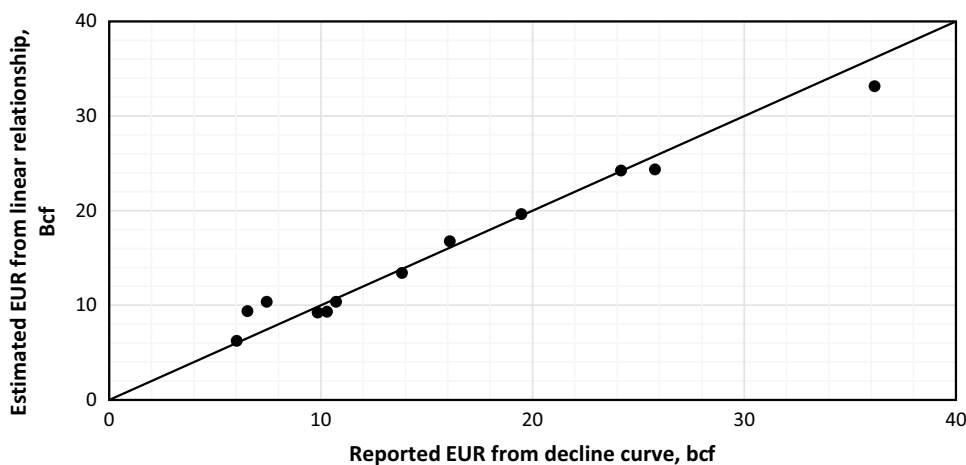


Fig. 14 Extrapolation of EUR, incremental and acceleration recovery to 50 acres spacing

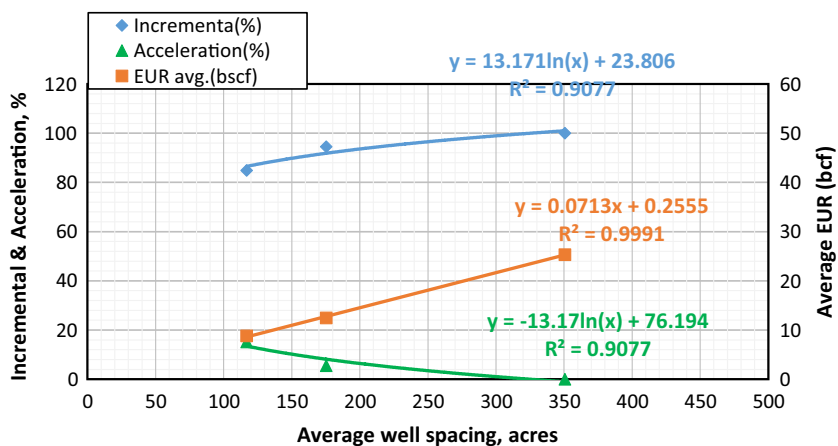
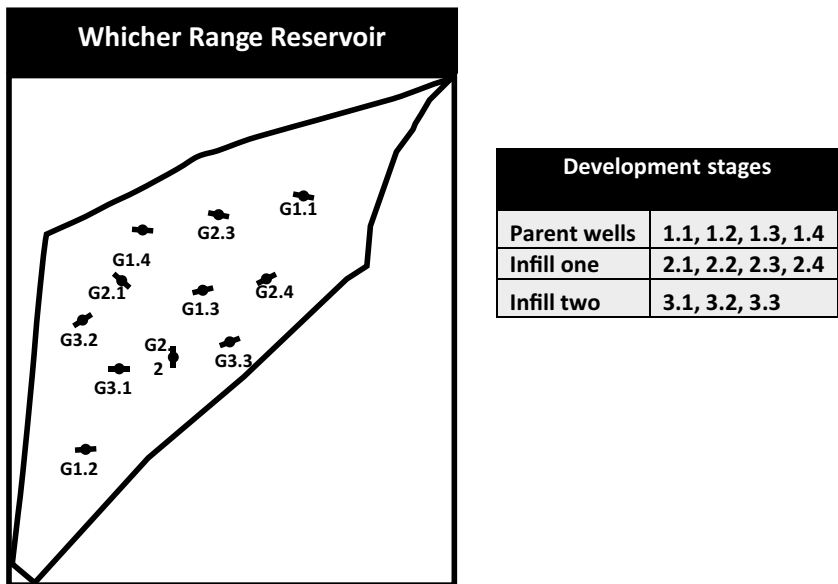


Fig. 15 2D map and development stages of the region selected from Whicher Range simulation model to apply Progressive Multi-well Blasingame Analysis (Marhaendrajana and Blasingame 2001)



The application of this method to this region was started by analyzing the production data of the parent wells with multi-well analysis, and the GIIP of the first match (pre infill one) was checked and compared against that of the Agarwal-Gardner flowing material balance and simulation model (as shown in Appendix). During parent multi-well analysis, three distinctive matches were obtained as shown in Appendix. These matches are used to obtain the EURs of matches A, B, and C, respectively, by assuming a recovery factor of 80%.

Then, another multi-well analysis was conducted but this time with the inclusion of the infill one well and EUR values of matches D and E were estimated. After that infill two was added to the multi-well pool and match F was determined.

The obtained EURs through different matches are summarized in Table 4.

Following these steps, acceleration and incremental recovery of various infill stages was calculated for this case and is presented in Table 5 and summarized in Fig. 16.

As it was expected, Fig. 16 indicates that overall EUR is reducing as a result of adding additional wells in the region. Also, it shows that wells in group three (infill two) have accessed additional reserve which caused the incremental recovery to increase and this was expected as wells in this group were fractured in three virgin zones with relatively good properties and one partially depleted zone by infill one. While group two (infill one) has only accessed 3 layers with less reserve than those layers accessed by infill two.

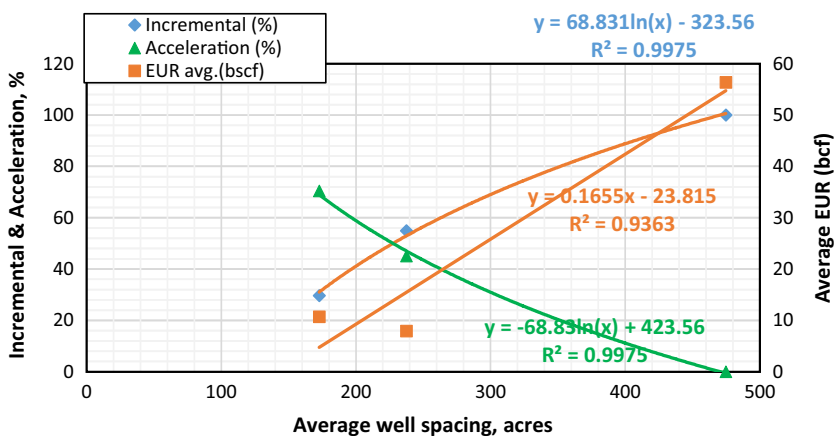
Table 4 EURs (MMscf) values at recovery factor of 80%

Wells	Pre-infill one	Pre-infill two	Post infill two	All wells
Parent	(A) 56.35	(B) 52.78	(C) 46.80	
Parent + infill one		(D) 60.71	(E) 53.20	
Parent + infill one + infill two				(F) 63.87

Table 5 Acceleration and incremental recovery calculations

Infill one acceleration recovery from parent (MMscf)		A–B	3.58
Infill two acceleration recovery from parent (MMscf)		B–C	5.97
Infill two acceleration recovery from parent and infill one (MMscf)		D–E	7.51
Infill two acceleration recovery from infill one (MMscf)		[D–E]–[B–C]	1.53
Infill one incremental recovery (MMscf)		D–A	4.36
Infill two incremental recovery (MMscf)		F–D	3.16
	G1	G2	G3
Spacing (Acres)	474.75	237.38	172.64
EUR avg.(bscf)	56.35	7.93	10.67
Acceleration (bscf)	0.00	3.58	7.51
Incremental (bscf)	56.35	4.36	3.16
Acceleration (%)	0.00	45.08	70.37
Incremental (%)	100.00	54.92	29.63

Fig. 16 Acceleration and incremental recovery



However, it is also clear that this area is depleting at a fast pace. For example, drilling extra two wells in the region will result in an average EUR, incremental and acceleration recovery of 0.359 bcf, 19.499%, and 80.501%, respectively.

Similar to the previous method, comparative studies can be performed by applying this method on different regions of the field to calculate incremental and acceleration reserve and thus selecting optimum areas for infill drilling programs that have the highest projected average EUR and the largest estimated incremental production.

Advantages and limitations of the proposed workflow

It is known that linear flow is the most dominant transient flow regime that appears in almost all tight formations (Branajaya 2005). This fact was also observed in this study by checking the time column of the linear flow period as shown in Table 2. This in turn makes the first proposed method (Luo and Kelkar 2010 method) a valuable asset for analyzing incremental and acceleration production in these formations. However, this method is limited in its application to transient flow regime. Also, to get sensible impact from successive infill drilling groups there should be a sufficient time gap between them. Additionally, the lower the number of groups and the higher the number of wells in each group, the better the analysis results.

Since the flow regime eventually will reach the BDF, the second method (Progressive Multi-well Blasingame Analysis) becomes of great interest in estimating additional and accelerated reserves. The applicability of this method to different production schemes (constant and variable pressure/rate) has made it even more powerful. However, this method is best applied when the first parent group has established BDF before successive wells are put on production to get noticeable impact on wells drainage areas and CGIP. Therefore, this method is more applicable to compartmentalized regions where wells are drilled in abounded regions of the reservoirs. The above-mentioned limitations were observed from the previous filed models and several others synthetic simulations cases (Dheyauldeen 2017), and not demonstrated here to avoid double dipping.

Summary, conclusions, and recommendations

Field cases presented before demonstrated the capabilities of the proposed methods to quantify the incremental and acceleration reserves which can be of significant importance in determining the qualitative infill potential of various regions. The following conclusions can be drawn from the study conducted above.

Luo and Kelkar method

- This method applies to cases in which the linear flow regime remains the dominant flow regime for a considerable period to ensure the applicability of the linear relationship developed earlier. Such cases are pronounced in tight formations with hydraulically fractured wells.
- The smaller the study area, the more accurate the results, knowing that a sufficient number of wells are present to provide statistical results. It was demonstrated that the existence of 10 wells in the analysis region suffice this requirement.
- The grouping process of wells in this method is arbitrary. However, the wells that start their production at close dates are placed in the same well group. Fewer the number of groups the more robust the results as the impact of the subsequent group on production data of the previous group will be more noticeable. Additionally, there should be a sufficient time gap between the first parent group and subsequent infill wells.

Progressive multi-well Blasingame analysis

- Successful application of this method requires that parent wells achieve boundary dominated flow prior to the production start of the first infill group to prevent underestimation of match A and D and thus avoid overestimation of incremental production of subsequent infill drilling.
- Geologically isolated regions are the best candidates to apply this method as there will be no interference from the wells in the surrounding areas which in turn result in more accurate results.
- The applicability of multi-well Blasingame type curves to various production profiles makes this method valid for constant rate, constant pressure, variable rate, and variable pressure schemes.

To improve on the accuracy of the predicted regions for infill drilling operations deep economic analysis of the different controlling factors (e.g., drilling cost, stimulation cost...etc.) should always be included in the decision-making process of field development planning. This is because parameters such as NPV (Net Present Value) are the only ones that make long term value for shareholders.

Appendix 1

Luo and Kelkar (2010) method

See Fig. 17.

Fig. 17 Linear relationship of the wells in Field case. Note orange box represents wells production during group one only. Green and blue boxes are wells production of group 2 and 3, respectively

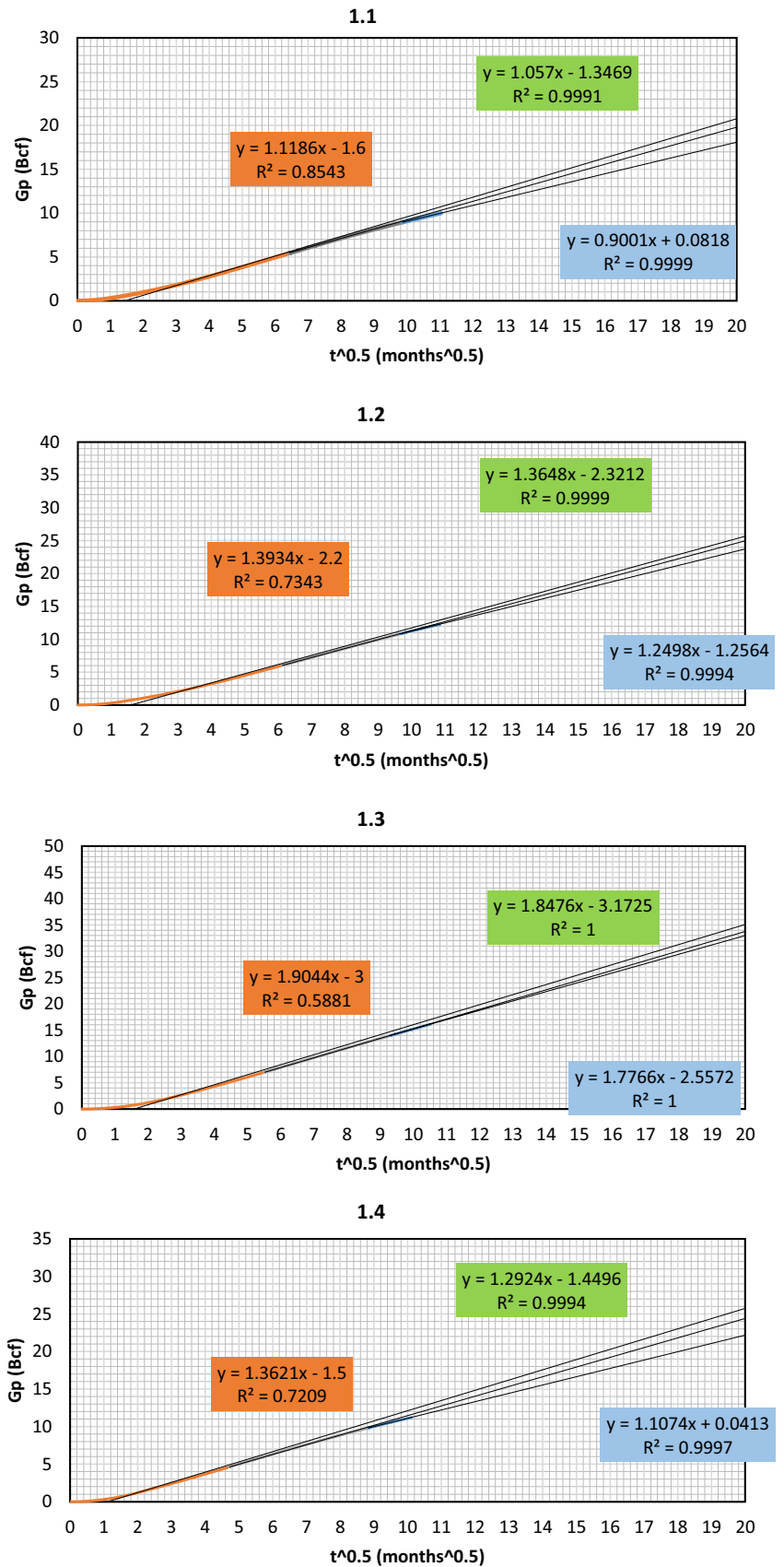


Fig. 17 (continued)

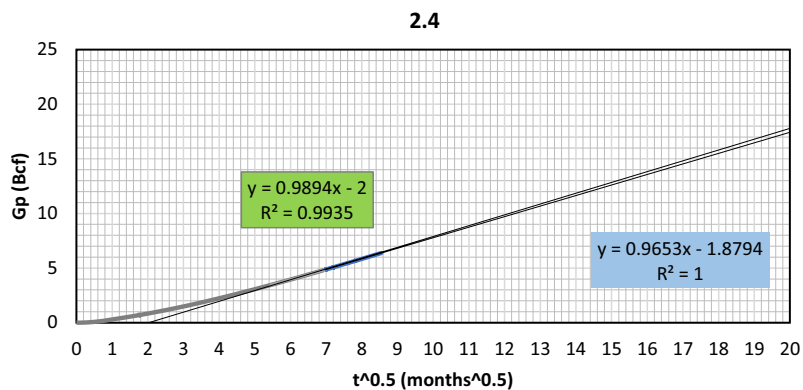
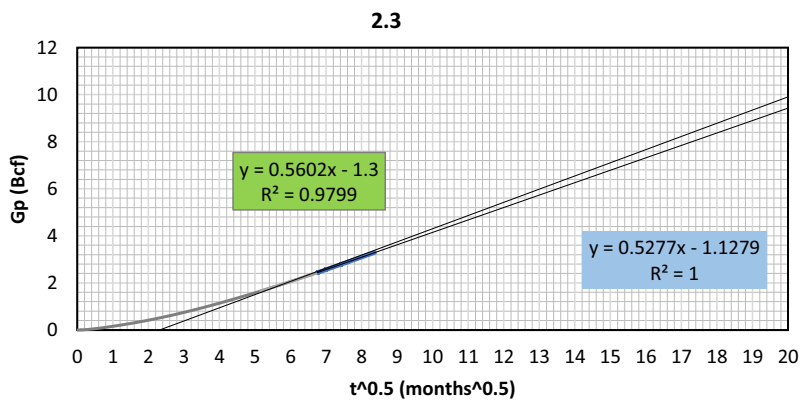
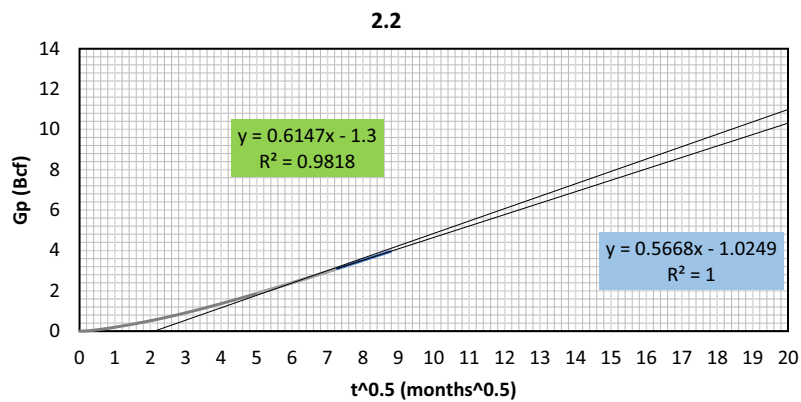
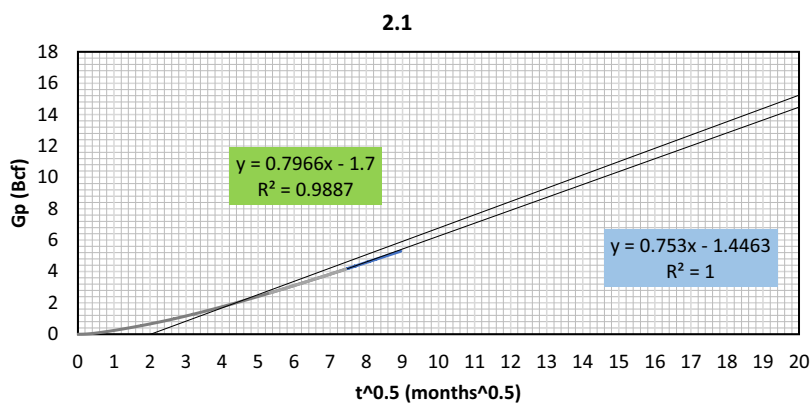
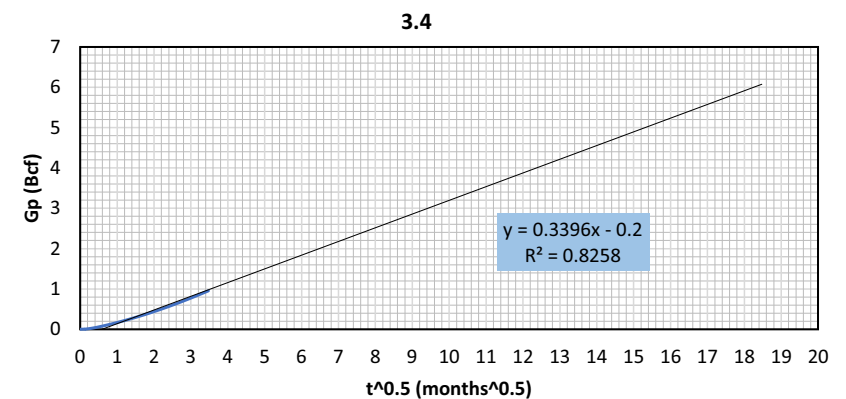
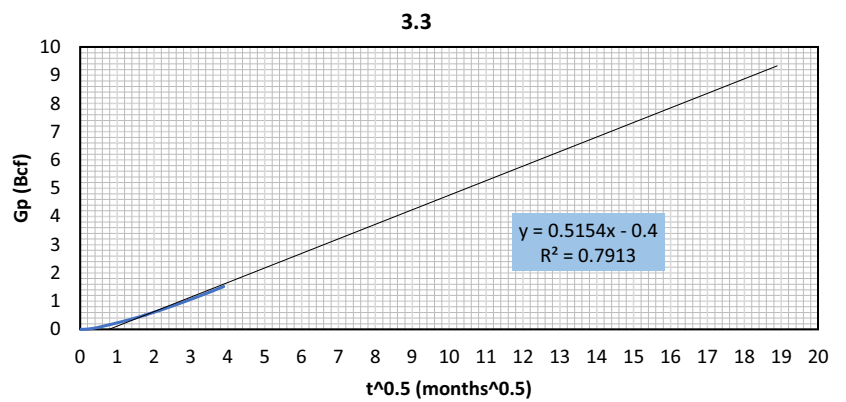
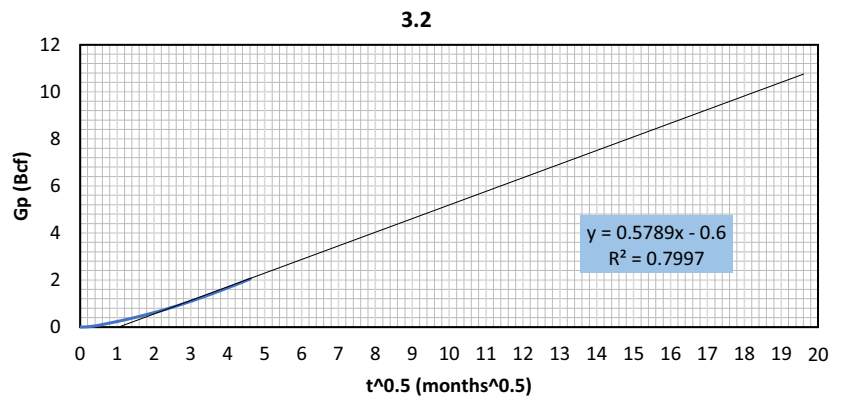
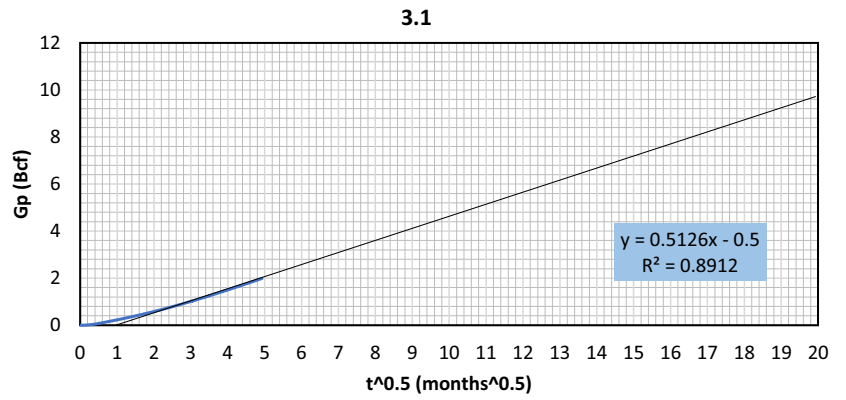


Fig. 17 (continued)



Decline curve analysis

See Fig. 18 and Tables 6 and 7.

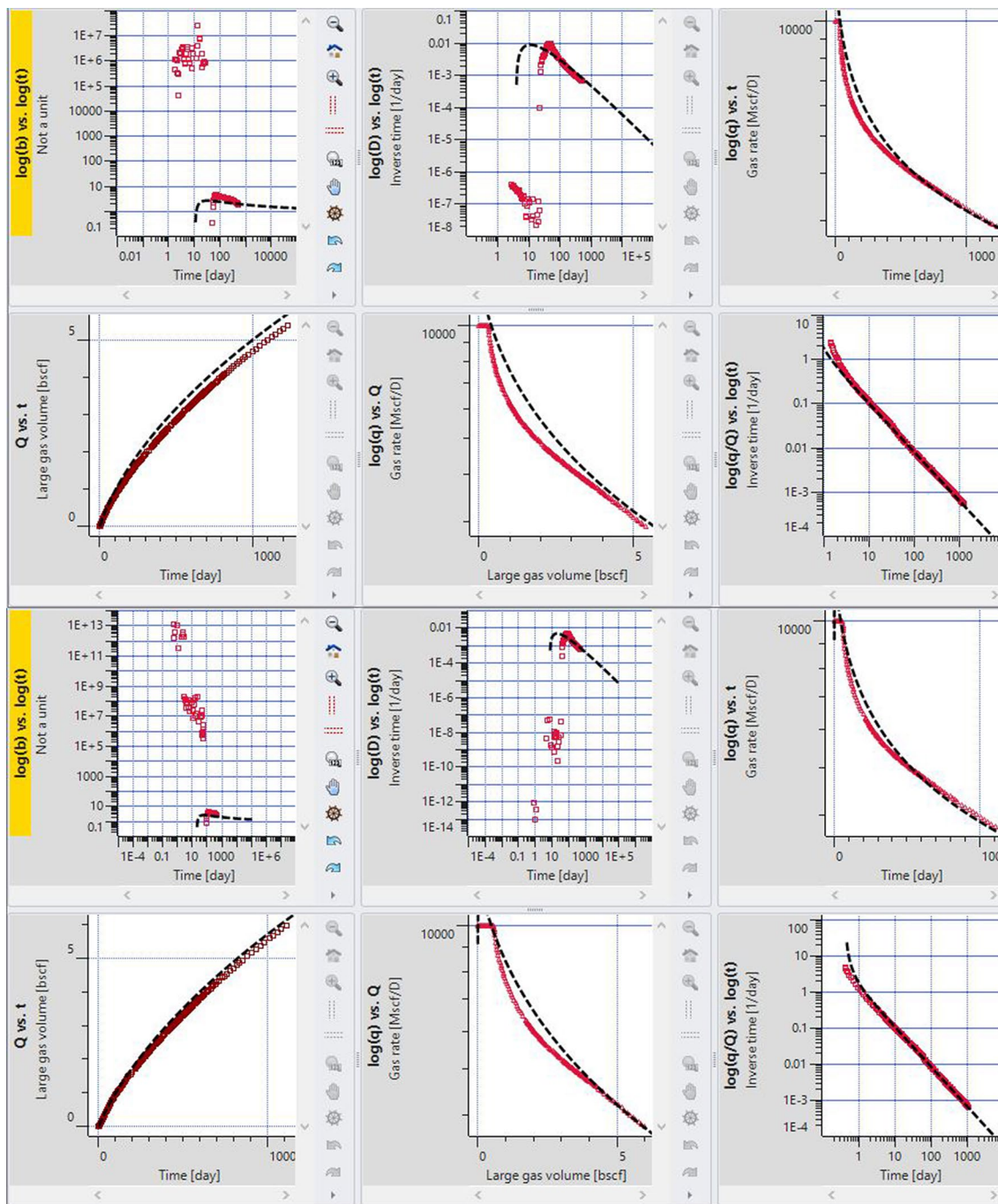


Fig. 18 Decline Curve Analysis performed for each well

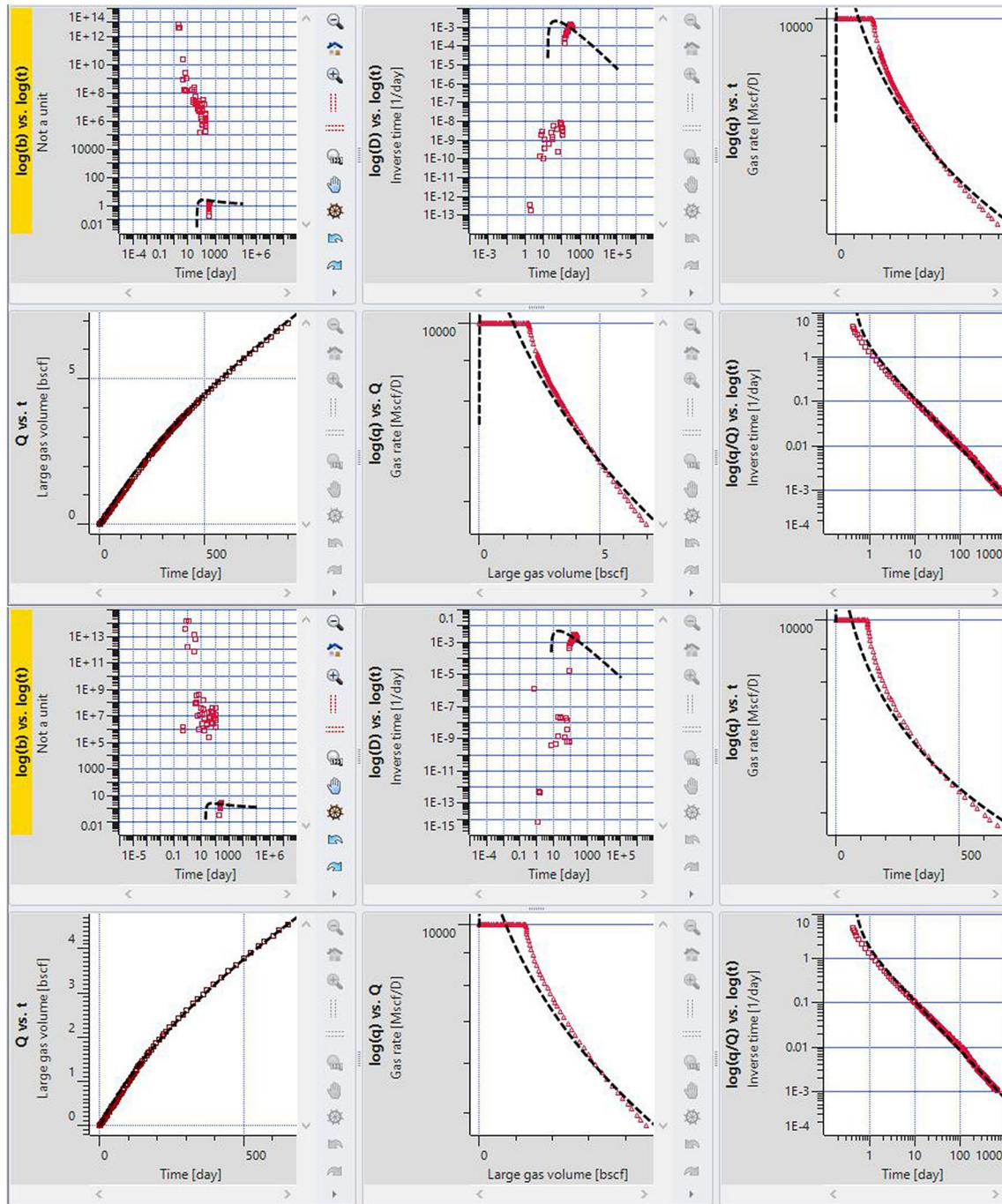


Fig. 18 (continued)

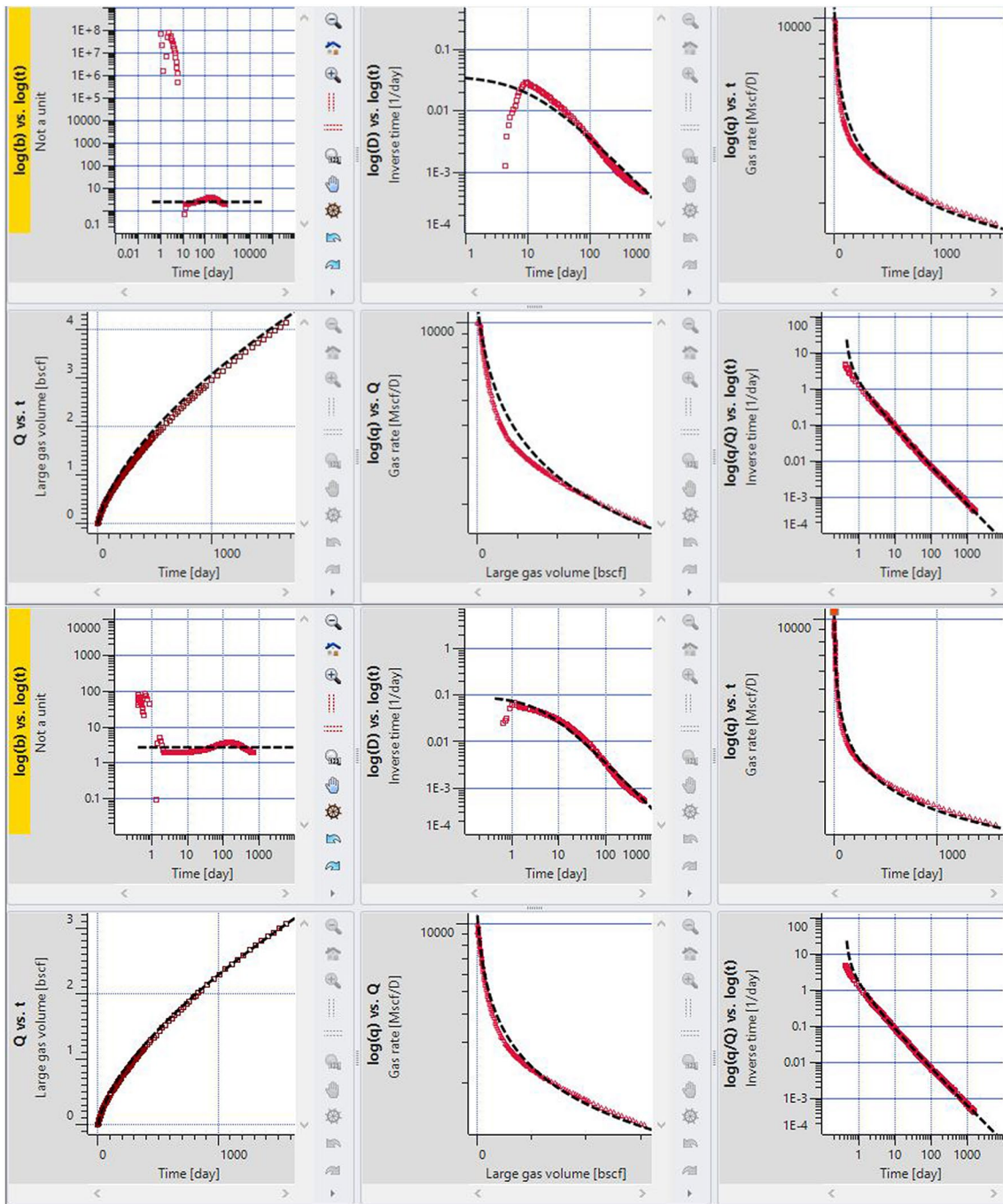


Fig. 18 (continued)

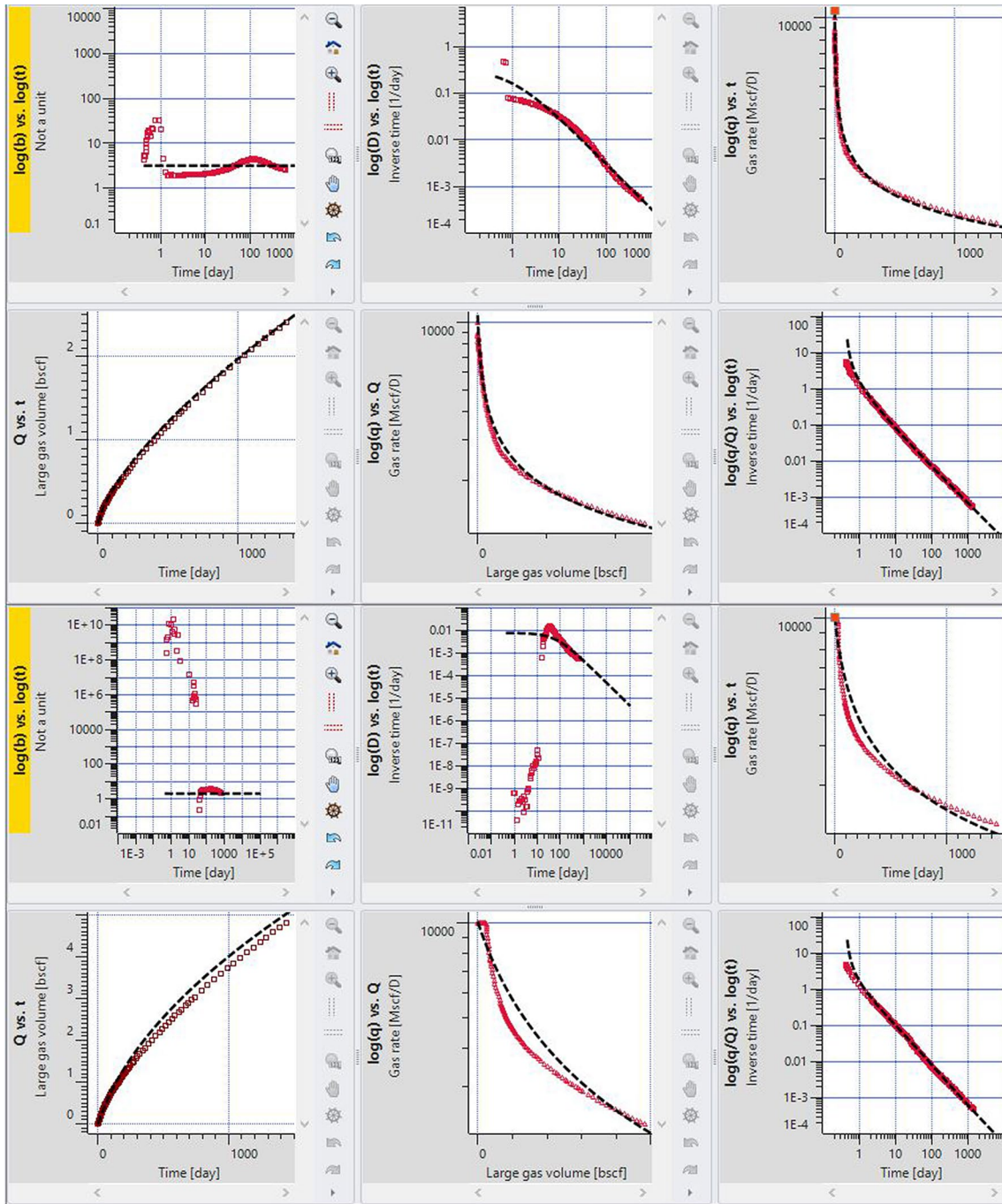


Fig. 18 (continued)

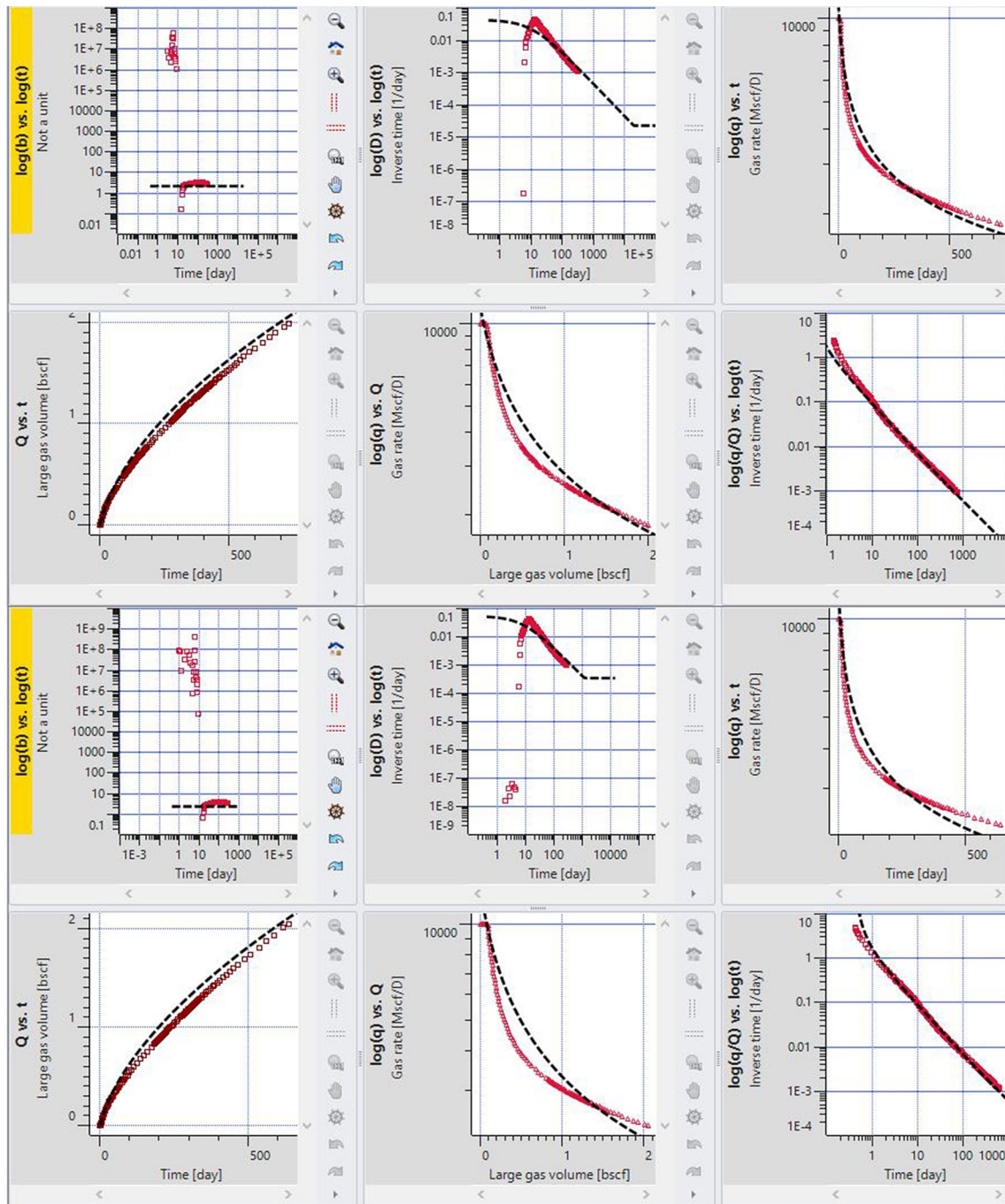


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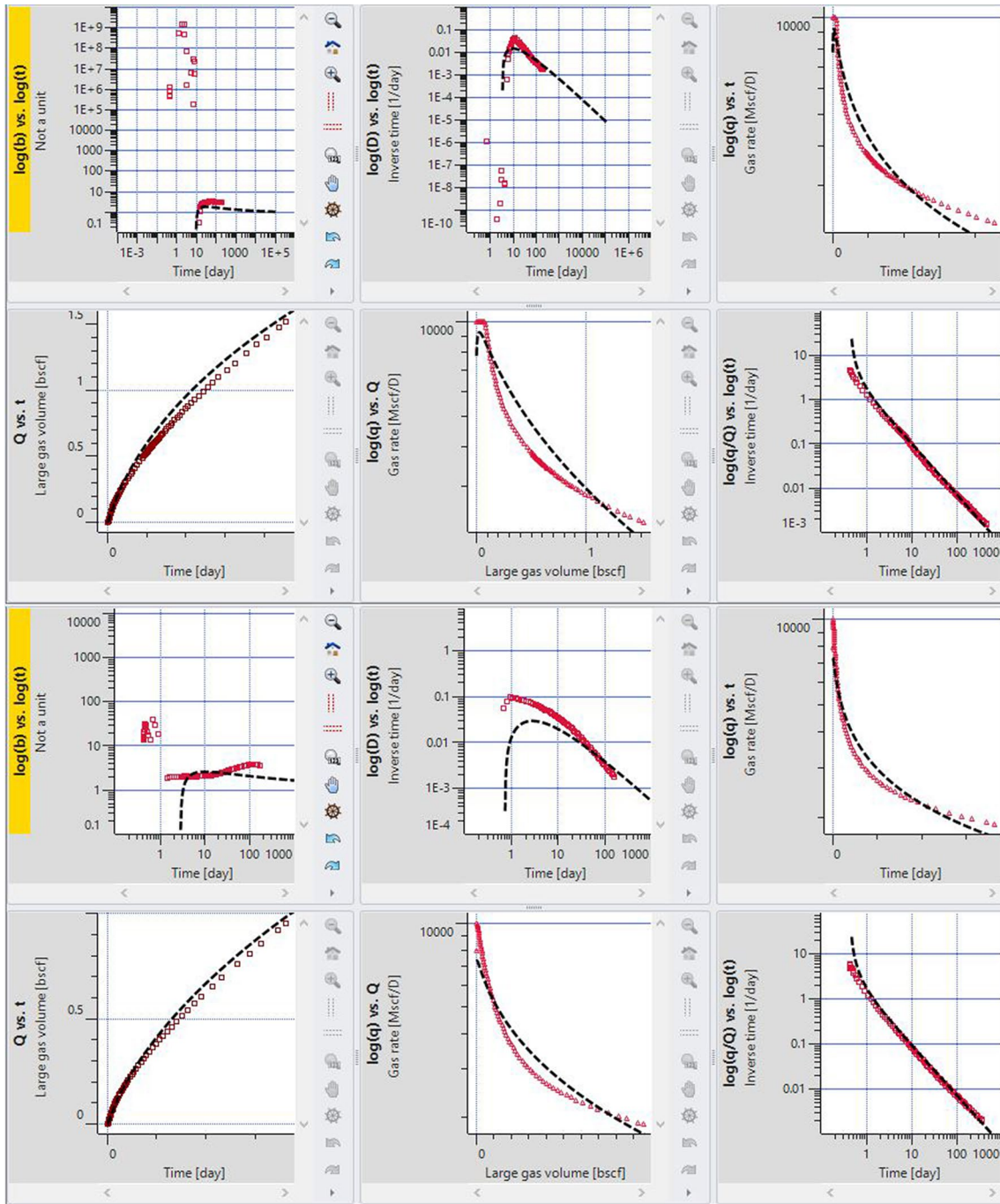


Fig. 18 (continued)

Table 6 EUR values obtained from Decline Curve Analysis for each well based on the method that provides best fit of the historical data

	Well	Analysis	EUR (Gas) Bscf
1	Well 1.1	Duong	19.4754
2	Well 1.2	Duong	24.1716
3	Well 1.3	Duong	36.1501
4	Well 1.4	Duong	25.7899
5	Well 2.1	Modified hyperbolic	13.8391
6	Well 2.2	Modified hyperbolic	10.7259
7	Well 2.3	Modified hyperbolic	10.2888
8	Well 2.4	Modified hyperbolic	16.0948
9	Well 3.1	Modified hyperbolic	9.84267
10	Well 3.2	Modified hyperbolic	7.44940
11	Well 3.3	Duong	6.53779
12	Well 3.4	Duong	6.02973

Table 7 Incremental versus acceleration calculations of wells in Field case. Note that EUR values are in Bcf. colorful cells are indicative that these values are based on equations from Fig. 17 with same color

Group	Well no.	Date	EUR during G1	EUR during G2	EUR during G3	EUR linear relation	Acc. G2	Acc. G3	EUR decline curve	Error%
G1	1.1	1/1/2000	19.62	18.70	17.16	19.624	0.916	1.548	19.47	0.791
	1.2	5/1/2000	24.23	23.57	22.45	24.238	0.664	1.117	24.17	0.281
	1.3	12/1/2000	33.13	31.88	31.15	33.133	1.250	0.732	36.15	8.345
	1.4	8/1/2001	24.34	23.07	21.05	24.344	1.272	2.019	25.78	5.570
G2	2.1	6/1/2003		13.41	12.84	13.414		0.574	13.83	3.005
	2.2	9/1/2003		10.36	9.72	10.363		0.634	10.72	3.329
	2.4	1/1/2004		16.77	16.43	16.773		0.337	16.09	4.242
	2.3	4/1/2004		9.32	8.88	9.329		0.445	10.28	9.251
G3	3.1	1/1/2008			9.22	9.226			9.84	6.241
	3.2	4/1/2008			10.38	10.384			7.44	39.568
	3.3	10/1/2008			9.37	9.379			6.53	43.630
	3.4	1/1/2009			6.24	6.243			6.02	3.712
			G1	G2	G3					
Spacing (Acres)			350.645	175.323	116.882					
EUR avg.(bscf)			25.335	12.470	8.808					
Acceleration (bscf)			0.000	0.684	1.336					
Incremental (bscf)			25.335	11.786	7.472					
Acceleration (%)			0.000	5.482	15.167					
Incremental (%)			100.000	94.518	84.833					

Appendix 2

See Figs. 19 and 20 and Table 8.

Fig. 19 Agarwal-Gardner flowing material balance (AG FM) showing GIIP of the first match (A)

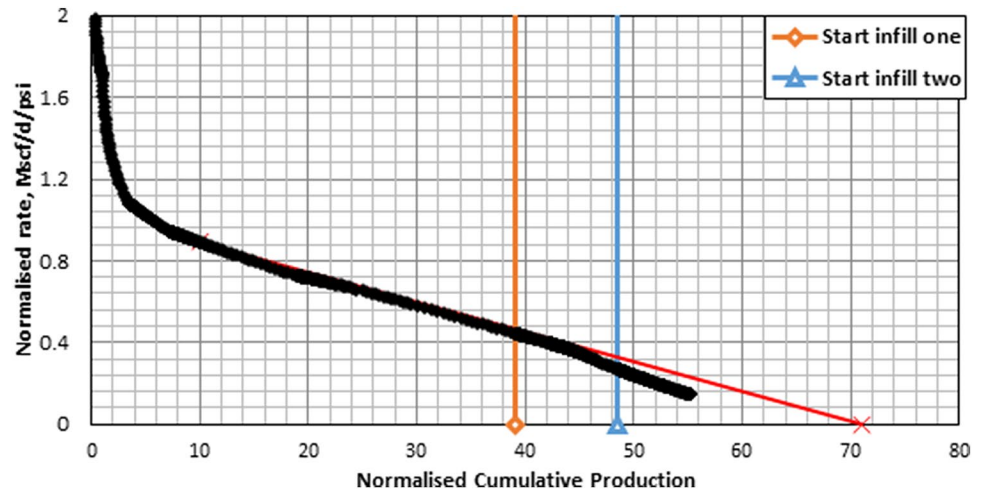


Fig. 19 (continued)

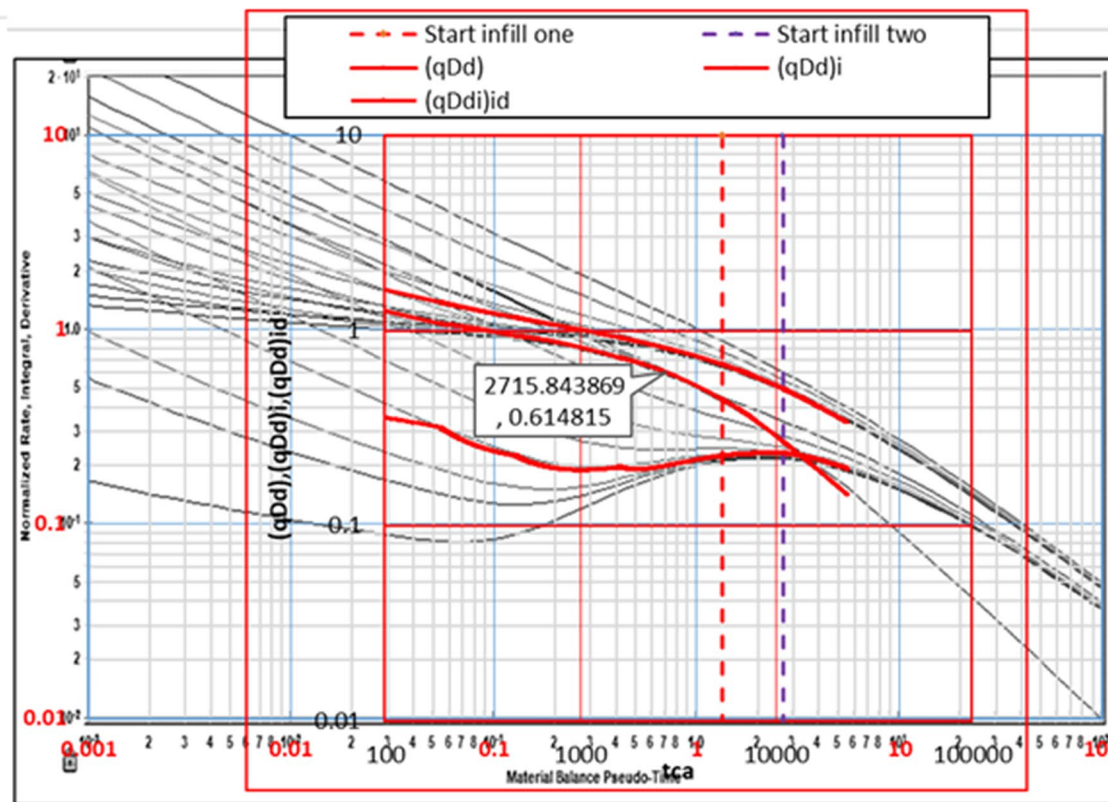
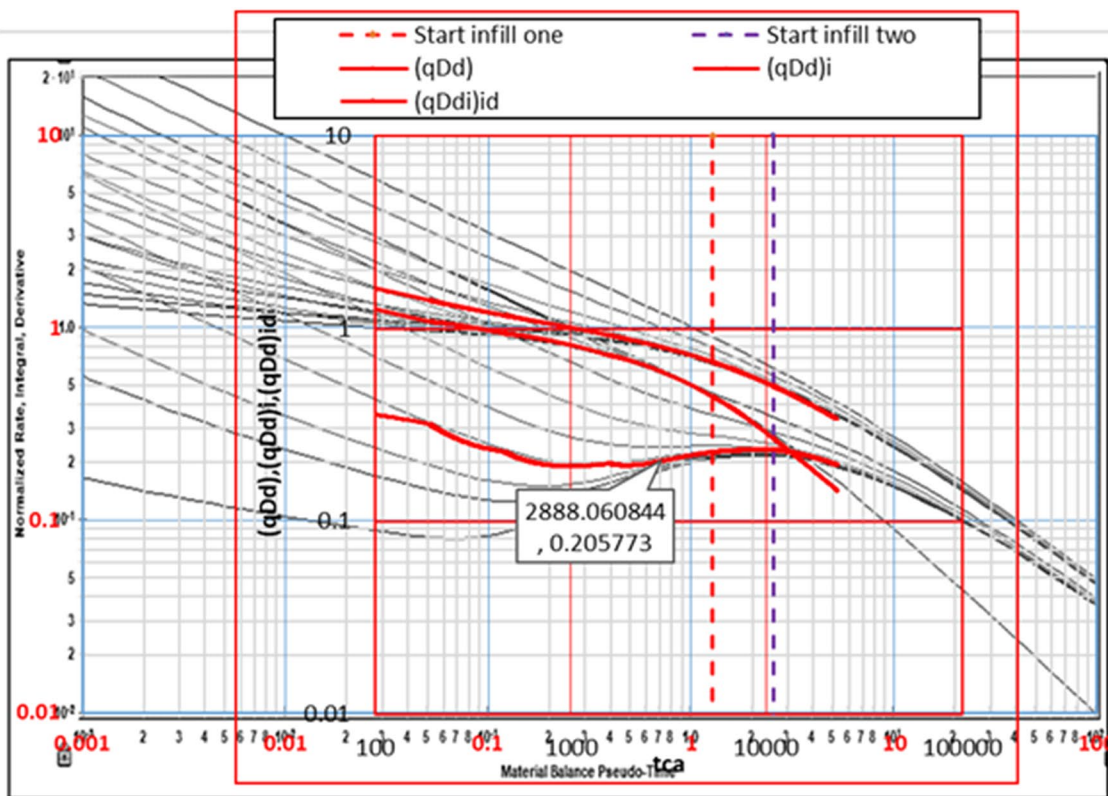
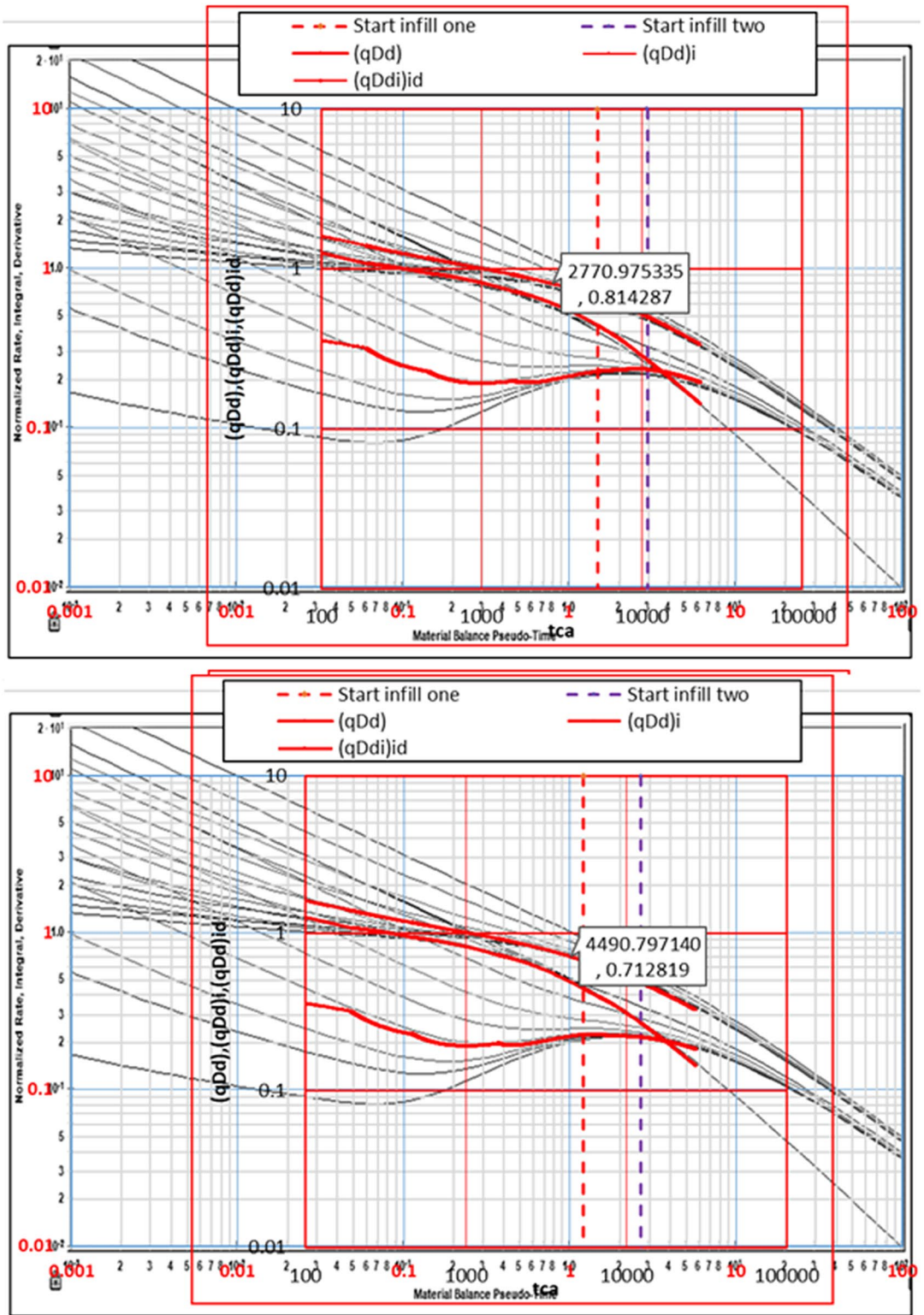


Fig. 19 (continued)



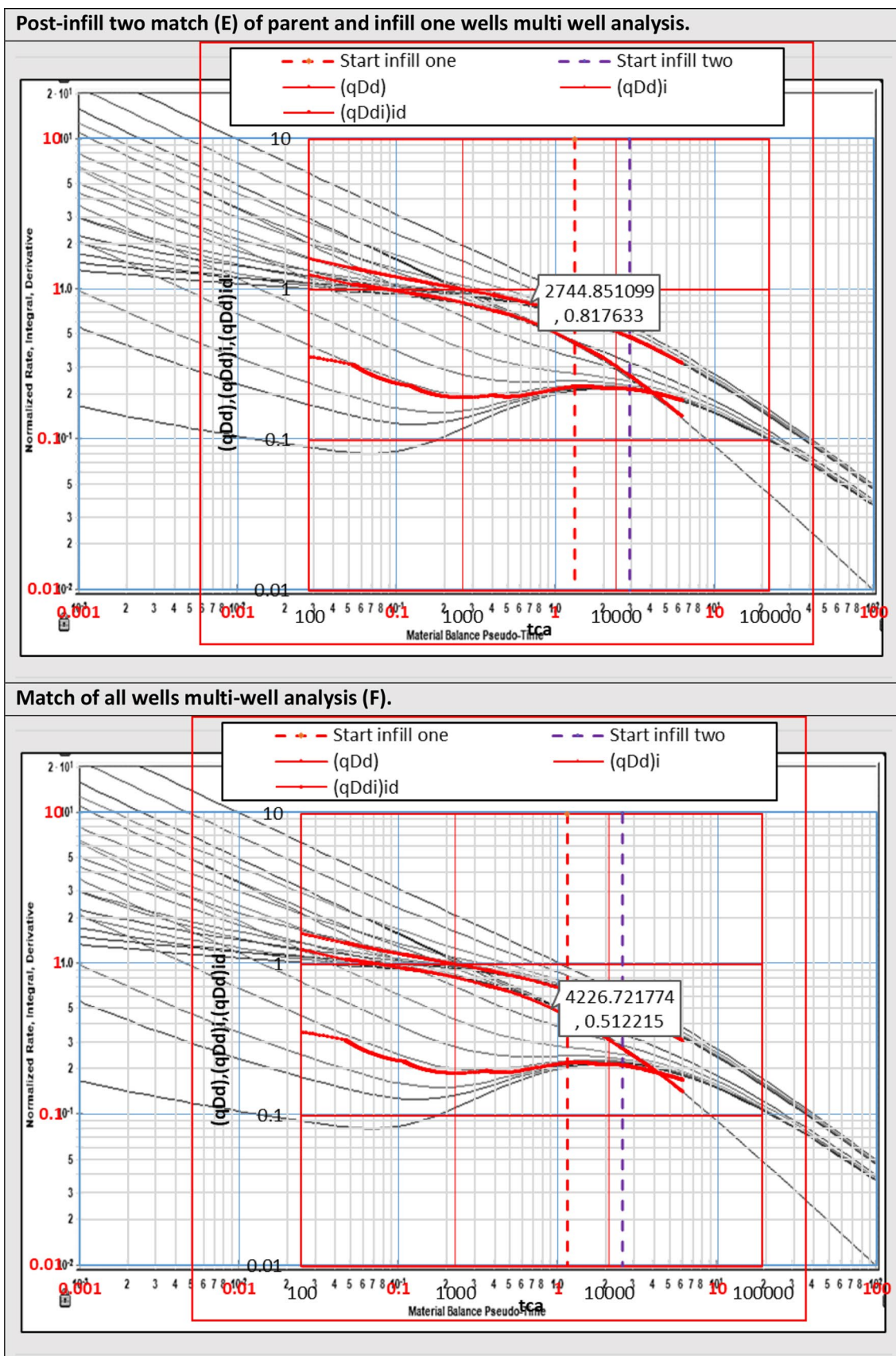


Fig. 20 Different matches of progressive multi-well Blasingame analysis method

Table 8 Comparison of GIIP of the first match (Match A)

	G, Bcf (from match A)
Blasingame type curve	70.44
AG FM	71
Numerical simulation	72.2

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