A Method for EUR Forecasting in Unconventional Reservoirs Using Early Flow Back Data

Ihab S. Mahmoud and Nouf M. Alsulaiman

Abstract / Evaluating the estimated ultimate recovery (EUR) and production forecasting in multi-fractured horizontal wells completed in unconventional shale reservoirs during early exploration and appraisal stages is very challenging. With the absence of suitable production facilities to handle produced fluids, production data are limited to short flow backs and extended production for some key wells to the early production facility.

This method uses the flow capacity as an intrinsic parameter that captures and reflects the major drainage mechanism and recovery characteristics of the well within the unconventional reservoir. Therefore, the flow capacity may serve as a reference parameter that can be estimated from early-time data. This parameter may have the ability to reflect the future production behavior of the well in terms of cumulative production through the proportional comparison of flow capacity to the EUR.

To show applicability of the workflow, it was applied to an existing unconventional project and showed consistent results. The workflow incorporates rate transient analysis (RTA) for several wells to create a single correlation that describes the relationship between Ac.sqrt(k) and the EUR. Plotting the gas flow capacity (Ac.sqrt(k)), estimated during the early 3 to 4 weeks of flow back vs. the EUR from modeling techniques showed a strong correlation.

The proposed workflow is designed to estimate the EUR for wells completed in unconventional reservoirs during the early phases of development, where there is no production facility to handle produced hydrocarbons, and the flow back period is limited to cleanup only. The advantages of the proposed workflow over the currently available methods are: (1) Incorporating several well analyses to create a single correlation that describes the relationship between Ac.sqrt(k) and the EUR, and (2) The ability to evaluate EUR from as early as 1 to 2 weeks of flow back data. The early evaluation of these wells will expedite critical completion and development decisions, which will impact project economics.

Introduction

Several models have been presented to estimate the ultimate recovery for multi-fractured horizontal wells completed in unconventional reservoirs. These methods range from simple decline curve analysis to very sophisticated numerical models, passing through analytical and semi-analytical methods.

The decline curve analysis techniques have evolved from Arps' decline models, which define exponential, hyperbolic, and harmonic declines in hydrocarbon production. These models have been the standard in wells with boundary dominated flow, but may not apply as optimally for sites that are characterized by long-duration transient flow. Advanced models, such as Stretched Exponential[1, 2] and modified Duong[3] were presented to model this transient flow. Subsequently, these methods require more than six months of historical production data to produce accurate forecasts.

A simplified approach was suggested by Nobakht et al. (2010)[4]. The method relies on the use of the linear flow plot and the identification of the end of linear flow. After the end of linear flow, the forecast was continued with a hyperbolic decline. Although, Anderson and Thompson (2014)[5] questioned the estimated end of linear flow time and therefore, the EUR.

Rate transient analysis (RTA) methods were utilized to estimate ranges for key model parameters, like permeability, fracture half-length, and fracture conductivity that can be used in analytical and numerical models to easily achieve history match. For a dry gas well, analytical models are likely sufficient, but for liquid-rich wells (retrograde condensate, volatile oil, black oil, etc.), numerical models will be needed to capture the more complex fluid behavior. The key challenge with these models is the non-uniqueness in model solutions that match field data. A solution to the uncertainty that complicates the EUR estimations has been offered by Anderson et al. (2012)[6] in the form of a probabilistic analysis utilizing the key input parameters' uncertainty ranges, to obtain the EUR ranges.

Using performance indicators to estimate long-term performance has been addressed and analyzed. Bosch and Paiva (2012)[7] used the peak month production and 3/6/12/24 cumulative month production, and evaluated their potential for a reliable indication of long-term well performance. Lowry et al. (2016)[8] presented the use of the two main RTA derived parameters, Ac√k and stimulated reservoir volume to assess well performance in Eagle Ford. Lougheed et al. (2017)[9] complemented the previous work by validating the significance of operating pressure when using early-time metrics. Muralidharan and Joshi (2018)[10] presented a robust workflow to estimate individual well EUR to improve the relationship between performance indicators and the EUR.

The workflow in this article is intended for estimating the EUR from limited flow back data due to the absence of suitable production facilities to handle produced fluids during the early stages of field development. A robust workflow has been developed that combines the use of a performance indicator, Ac√k, and probabilistic EUR estimation to estimate the EUR for future wells in a selected area of interest. The advantages of the proposed workflow over the currently available methods are: (1) Incorporating several well analyses to create a single correlation that describes the relationship between Ac√k and the EUR, and (2) The ability to evaluate the EUR from as early as 3 to 4 weeks of flow back data. The early evaluation of these wells will expedite critical completion and development decisions, which will impact project economics.

Workflow

The proposed workflow in this work is intended for wells that are:

- Located in the same geologic setting.
- Have similar geometries and spacing.
- Are operated similarly.
- Lacking production facilities to handle long-term production. The production data are limited to short flow backs and extended production for some key wells to the early production facility.

For each individual well, flow capacity (Ac√k) is estimated from early flow back data and the EUR is probabilistically estimated. As has been indicated by Lougheed et al. (2017)[9], flow capacity, or the Linear Flow Productivity Index, is the best early-time metric correlated with the EUR. A correlation between the EUR and Ac√k can be created, which then can be used to estimate the EUR for new wells by only knowing their Ac√k from flow back data.

Flow Capacity Estimation

The flow capacity is easily obtained when the well is in linear flow and provides valuable insight into transient well productivity. It can be a useful metric when a large enough data set is available to baseline, compare, and subsequently relate it to the actual performance.

Linear flow can be identified from a log-log plot of normalized rate vs. material balance time, Fig. 1. After well cleanup, the expected flow regimen for a multi-fracture horizontal well completed in an unconventional shale reservoir is the linear flow. The linear flow regimen is identified by the negative half slope line.

The flow capacity can be estimated from the plot of the rate normalized pressure vs. the square root of (linear superposition or material balance) time, Fig. 2. A straight line is drawn through the data to estimate Ac√k:

$$Ac\sqrt{k} = \frac{630.8\mathrm{T}}{\mathrm{m}} * \frac{1}{\sqrt{(\emptyset \mu_g C_t)_i}} \quad (1)$$

where m is the slope of square root time plot, T is the reservoir temperature, $\emptyset$ is reservoir porosity, μ_g is gas viscosity, and C_t is total compressibility.

EUR Estimation

For consistency and to remove bias from the EUR estimates, a probabilistic approach was used to estimate the EUR[6]. The P50 EUR from this method was used to be correlated with the flow capacity to create the corresponding correlation.

A numerical, base-case model is to be built, history matched, Fig. 3, and forecasted, Fig. 4. This model will be

Fig. 1 *The log-log diagnostic plot — normalized rate vs. material balance time.*

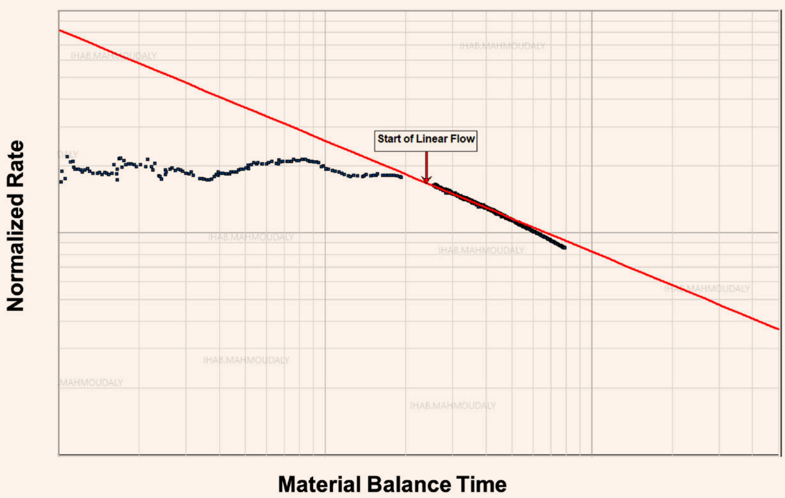


Fig. 2 The linear flow analysis plot — normalized pressure vs. gas material balance square root time.

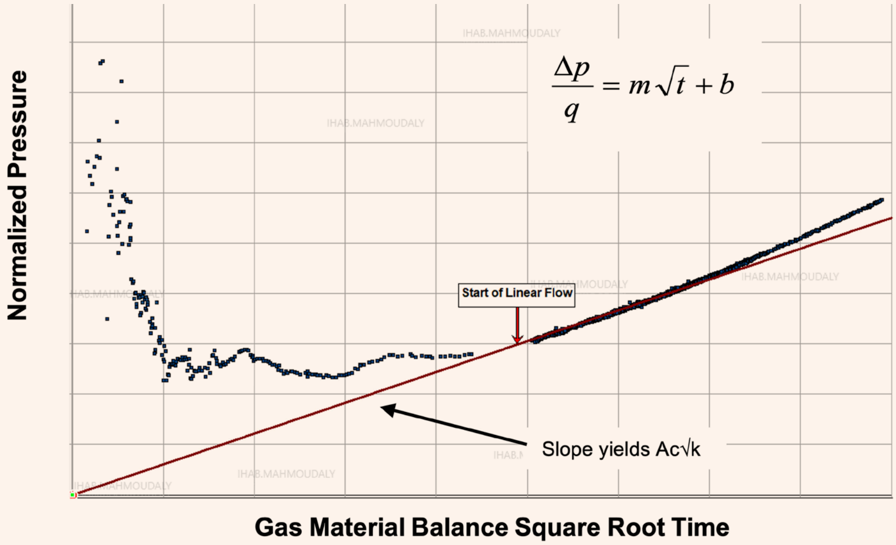
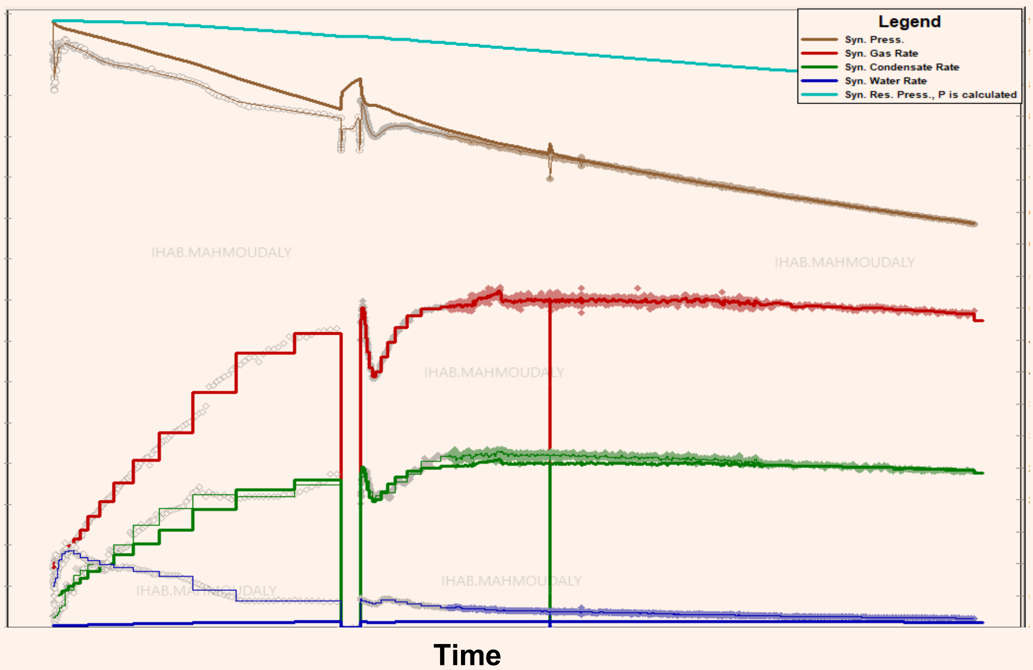


Fig. 3 The numerical model match.



utilized probabilistically, applying reservoir and fracture geometry variable uncertainties, to estimate the expected range of the EUR, Fig. 5.

Data Set

The previous two steps were applied to 34 wells in an area of interest. Only five of these wells have more than three months of production data. The rest of the wells have one month or less of flow back data.

Short Time Flow Back EUR Correction

For the few wells that have been produced for three months or more, the EURs were estimated at different times from flow back to understand the change in the EUR estimates with time. For consistency, the reference time used is the start of linear flow.

This reference is used because this time indicates the beginning of a known reservoir behavior. Figure 6

Fig. 4 The numerical model forecast.

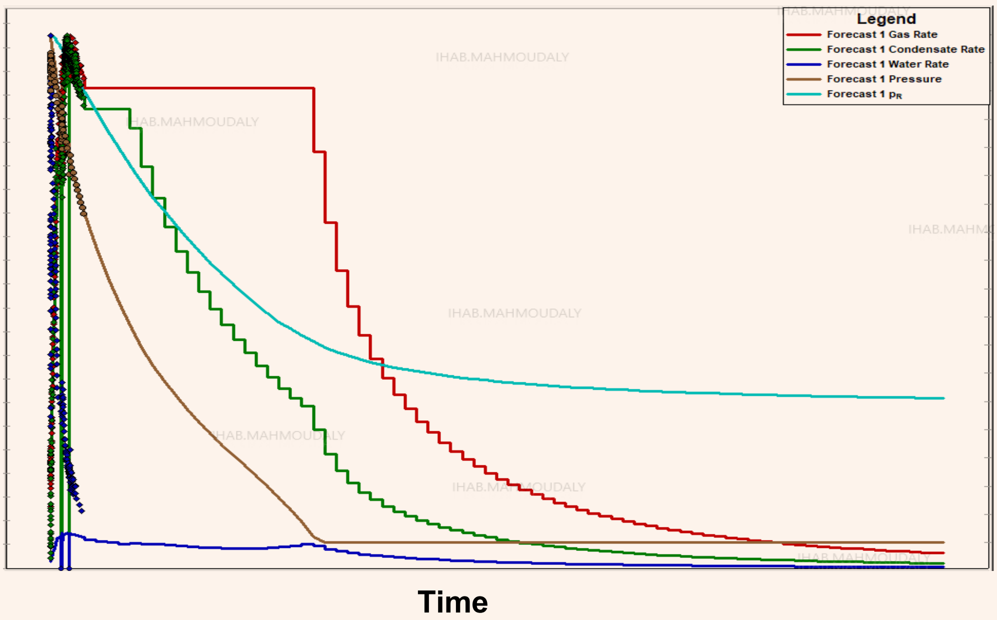
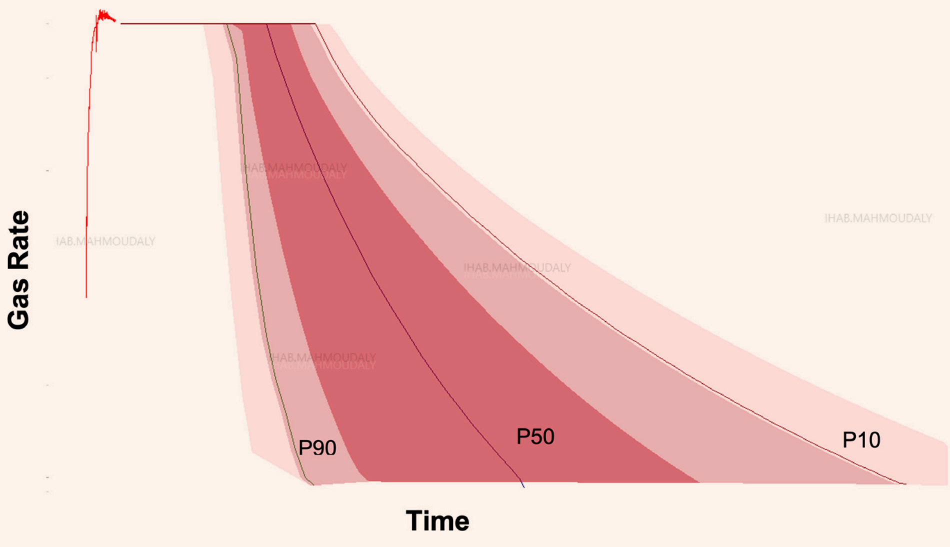


Fig. 5 The probabilistic analysis results — gas rate vs. time.



shows the EUR as a percentage of the EUR estimated after one week of linear flow (on y-axis), and the x-axis represents days after the start of linear flow. From this plot, a correction percentage can be estimated to correct the EUR estimates for wells producing for a very short flow back duration — ~4 weeks.

P50 EUR vs. Flow Capacity Correlation

Figure 7 shows a plot of the P50 EUR vs. the Ac√k. A regression straight line passing through the data shows a strong relationship between the two: $R^2 = 0.933$. This straight line relationship can be used to estimate the EUR for new tested wells, provided that the linear flow has been established for one or two weeks, without the need to build a numerical and probabilistic model to estimate the EUR for these new wells.

Following the same flow back strategy, data from the 34 wells showed that linear flow can be established within the first 4 weeks of flow back.

Fig. 6 The EUR estimate with time.

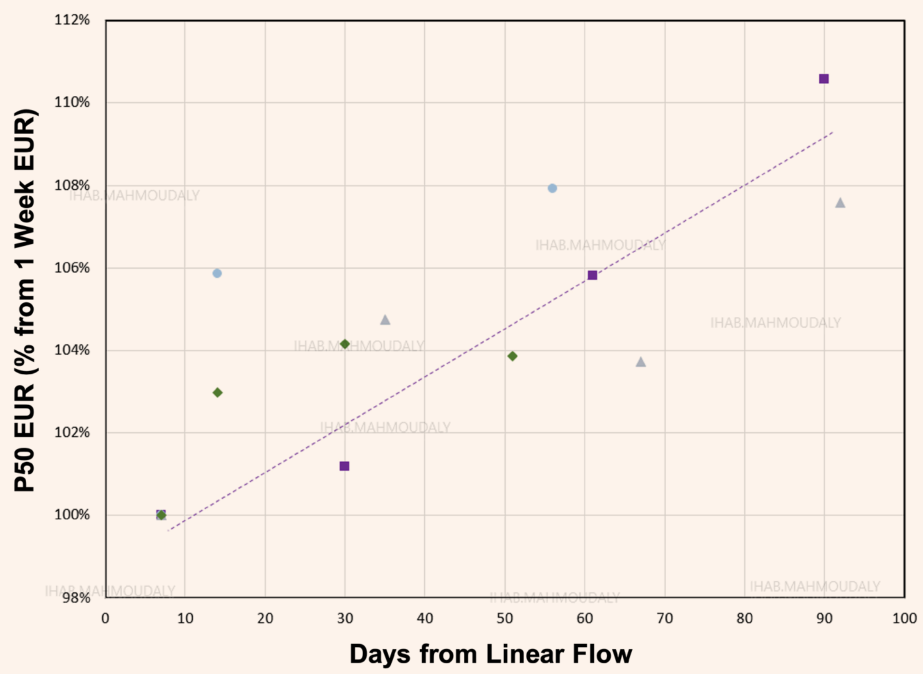


Fig. 7 The P50 EUR vs. the Ac√k.

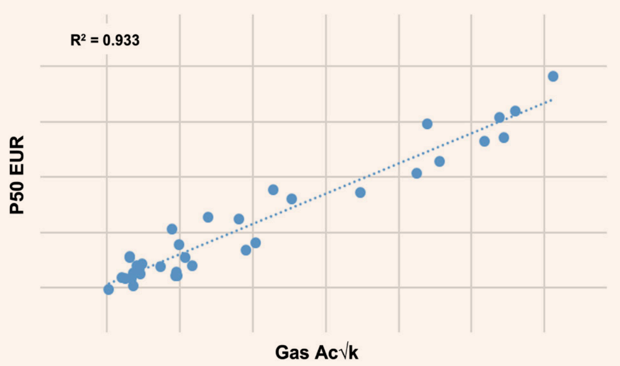
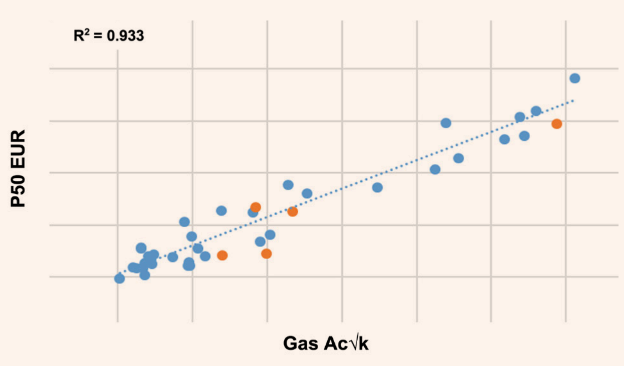


Fig. 8 The P50 EUR vs. Ac√k — validation.



Testing and Validation

To test the validity of the estimated correlation, five new wells (in orange), with less than a month of flow back, were added to the correlation plot, Fig. 8. The same workflow, previously discussed, was used to estimate the P50 EUR and the Ac√k for the new wells.

The plot shows that the new data points are following the estimated correlation. This confirms the validity of using the estimated correlation to estimate the EUR for new wells using Ac√k values estimated from short flow back data.

Conclusions

A workflow to estimate the EUR from the limited flow back data of multi-fracture horizontal wells completed in unconventional shale reservoirs was presented. The workflow integrates RTA, numerical modeling, and probabilistic analysis.

The proposed workflow is designed to estimate the EUR for wells completed in unconventional reservoirs during the early phases of development, where there is no production facility to handle produced hydrocarbons, and the flow back period is limited to cleanup only.

The workflow incorporates several well analyses to create a single correlation that describes the relationship between Ac√k and the EUR. Utilizing this correlation, it was possible to estimate the EUR during early flow back. The early evaluation of these wells will expedite critical completion and development decisions, which will impact project economics.

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