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Research Paper

Effect of the Derivative Interval on Dimensioned Pressure Transient Analysis under Different Oil Well Conditions

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***Abstract*:** There is no doubt that Well Testing is known for its powerful capacity to detect the production values of drilled wells and to optimize their production methods from oil reservoirs, due to pressure and rate variations inside the wells. Oil reservoirs are heterogeneous and unknown hydrocarbon formations that require precise evaluation and specialized techniques for better understanding. After applying Well Testing on each drilled well in real reservoirs, pressure and time data are plotted together on different diagrams using logarithmic, semi-logarithmic, or Cartesian scales. These plots allow us to interpret initial models and extract important factors such as Flow Regime Types (linear, radial, or spherical, based on plotting different straight lines with slopes of 1, 0.5, 0.25, and 0) and the area of the reservoir, among others. In this paper, we focus on Dimensional Pressure Transient Analysis Diagrams and their derivative diagrams based on the common logarithm scale. We have defined a variable Alpha parameter and a constant Alpha parameter (the maximum variable Alpha parameter) in Python code. The constant Alpha parameter in fractured reservoirs is higher than in ideal oil reservoirs. Using these parameters, we plot different PTA diagrams under various conditions to perform critical comparisons. The results indicate that assuming a constant Alpha parameter on pressure derivative plots shows greater spacing between the final points of the pressure derivative diagrams, known as "End Effect" points, clearly demonstrating the constant behavior of the pressure derivative points at the end.

Keywords: Alpha parameter, Pressure transient analysis, Pressure derivative, Logarithmic scale.

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INTRODUCTION

In this paper, we analyze differential pressure and pressure-derivative versus time plots in real (dimensional) units on a base-10 logarithmic scale—a method that is independent of conventional dimensionless type-curve plots—to address two questions: What is the primary cause of the scatter observed in pressure-derivative points on log-time plots? And can we define a parameter or pattern that has a direct and significant effect on reducing this scatter?

In the 1970s, extensive efforts focused on formulating the Wellbore-Storage Effect—reflecting how wellbore fluid compressibility influences transient pressure in producing or shut-in wells—and the skin factor in homogeneous reservoirs, using dimensionless parameters and their corresponding plots [1].

Mr Tiab, by introducing pressure-derivative diagnostic plots in the late 1970s, opened a window to clearer interpretation of differential pressure and pressure-derivative behaviour [2].

Aghia and Kuchuk, together with colleagues, showed that integrating geophysical data with logarithmic pressure-drawdown and pressure-derivative plots can substantially improve reservoir characterization and quality assessment [3].

Sui and co-workers analysed horizontal, hydraulically fractured wells in shale-gas reservoirs and developed a semi-analytical model to forecast future production, interpret well production pressure-transient behaviour, and estimate reservoir flow parameters. Their results indicated close agreement between numerical simulations and their calculations [4].

In this study, two forms of the alpha parameter are employed:

1) a variable, automatically assigned alpha that the Python routine updates across successive windows of the log–log plot,

2) and a fixed alpha, manually specified as the final—and largest—value reached by the variable alpha. The influence of these choices on the resulting plots is then evaluated.

Within the workflow, a parameter termed ‘alpha’ is introduced in the Python code to control sampling density. Alpha specifies the maximum acceptable natural-log difference between two adjacent time points (each time compared with its immediate predecessor and successor). Using real production-well data, plots are generated based on this parameter, and the effects of varying alpha on the displacement of points in the pressure-derivative plot are examined.

METHODS

The framework methods employed are as follows:

1) Hypothesis of Wellbore Storage together with a mid-peak effect and Infinite-Acting reservoir behavior (the most comprehensive long-duration, time-based well test): The type-curve–matched pressure-derivative plot, using an automatically varying α parameter, alongside the pressure-change (Δp) plot, was generated in Python by sweeping across multiple time windows with 51 raw pressure–time data points.

2) Hypothesis of no Wellbore Storage (with a mid-peak effect and Infinite-Acting reservoir behavior): The primary type-curve–matched plot with a varying α parameter was generated in Python using 48 input records (i.e., all data except the first three raw pressure–time points from the previous hypothesis) by sweeping across the recorded time windows.

3) Hypothesis of a pure mid-peak effect (absence of Wellbore Storage and Infinite-Acting reservoir behavior): The primary matched plot with a varying α parameter was produced in Python by sweeping across the recorded time windows, using 52 pressure–time inputs. It was observed that the pressure-derivative curve was matched to the varying α values, with the maximum computed α equal to 0.1842.

4) Hypothesis of no Infinite-Acting reservoir behavior (presence of Wellbore Storage together with a mid-peak effect) (short-duration well test): The primary type-curve–matched plot with a varying α parameter was generated in Python using 50 pressure–time inputs by sweeping across the recorded time windows. It was observed that the pressure-derivative curve was matched to the varying α values, with the maximum computed automatic α equal to 0.01439.

5) Hypothesis of a purely Infinite-Acting reservoir behavior (no Wellbore Storage and no mid-peak effect) (incomplete well test): The primary type-curve–matched plot with a varying α parameter was generated in Python by sweeping across the recorded time windows, using 59 pressure–time inputs. It was observed that the pressure-derivative curve was matched to the varying α values, with the maximum

computed α equal to 0.2231.

FINDINGS AND ARGUMENT

By examining five example cases with different datasets and well-testing conditions, it can be seen that the α parameter has a significant influence on the shape and configuration of the dimensionless transient pressure-derivative plot, which is obtained as the derivative of the normalized pressure change with respect to time on a logarithmic scale.

In the table below, the cited examples and their outcomes are reviewed: Example 1 represents a fully developed case exhibiting all possible effects in the pressure-derivative plot, whereas Examples 3 and 5 illustrate the most incomplete cases among those presented; the remaining examples correspond to intermediate conditions.

Table 1. Overview of the proposed hypotheses and influence of the α parameter in them

Example no.	Wellbore storage effect present	Mid-peak effect present	Infinite-acting reservoir boundary	Location of maximum plot change
1	✓	✓	✓	Early and late parts of the plot
2	✓	✓	×	Early and late parts of the plot
3	×	✓	×	Early part of the plot
4	✓	✓	×	Early part of the plot
5	×	×	✓	Nearly the entire plot

Given the Pressure Transient Analysis plots that were generated, the results do not depend on the well-test type (Pressure Drawdown or Pressure Build-Up). Accordingly, the test type is not reiterated for the examples in the table above.

For example, in Hypothesis 1—the most complete case—the output plot figures are as follows:

With a varying α parameter:

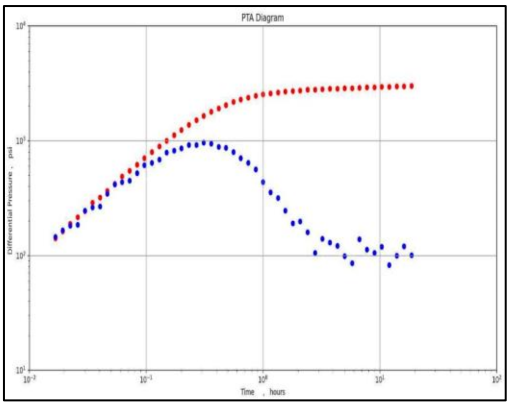

Figure 1. Pressure-Transient Analysis plot with the variable, automatically updated alpha parameter applied under idealized (full) assumptions

With a constatnt α parameter:

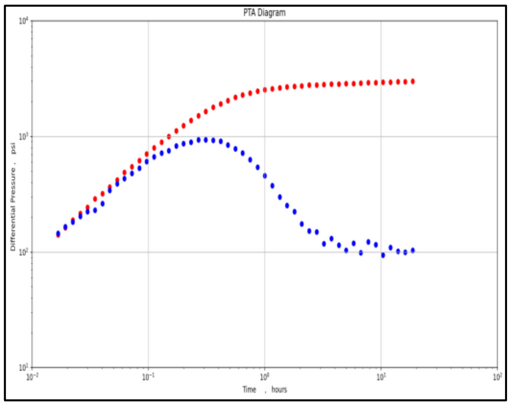

Figure 2. Pressure-Transient Analysis plot with the fixed maximum alpha parameter applied under idealized (full) assumptions

CONCLUSIONS

This study analyzed five field well tests using raw pressure–time data and showed that both data quality and density strongly govern point placement on log-time pressure-derivative plots. The derivative window, parameterized by α, was implemented in two modes: a varying α that increments (Δα = 0.0001) as time windows sweep—its terminal value defining α_max—and a fixed α set to α_max, which primarily affects the plot tail. Importantly, derivative-window behavior was independent of well-test type (drawdown vs.

build-up). Interpretation should always verify three signatures to judge test sufficiency: Wellbore Storage, the mid-peak, and Infinite-Acting Radial Flow (IARF).

The α-based schemes are presently applicable to oil reservoirs and not to gas systems (dry gas, wet gas, gas condensate, retrograde gas condensate). Practical limitations of the Python workflow include the inability to plot when inputs contain large gaps in time or pressure, weak characterization of Wellbore Storage when only the first three points exist, and unreliable estimation of permeability, mechanical skin, and Wellbore-Storage coefficient when only mid-interval (peak-region) data are available.

Future work should extend the variable-α and fixed-α concepts to gas reservoirs; evaluate a five-point hypothesis against Horne's (1990) three-point assumption; test whether the derived expressions for permeability, skin, and Wellbore-Storage have analogous, equally placement-sensitive forms in non-oil reservoirs; and examine whether analyses in dimensionless variables (parameter-vs-parameter) reproduce the conclusions obtained here with dimensional plots.

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