Research Summary

Analysis of Transient Tight-Gas Well Data with Pressure-Dependent Rock and Fluid Properties

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Outline

- Problem statement
- Scope of research
- Approach
- Results and Discussion
- Status
- Conclusions

Problem Statement

- Hydrulic diffusivity,

$$\eta = \frac{k}{\phi \mu_g c_g}$$

- Hydraulic diffusivity values are mostly constant throughout the production life of the oil reservoirs.
- However, in gas reservoirs, the strong dependence of $\mu_g c_g$ product on pressure depletion highly affect hydraulic diffusivity term.
- Gas diffusivity equation;

$$\frac{\partial^2 m(P)}{\partial x^2} = \frac{\phi \mu_g c_g}{k} \frac{\partial m(P)}{\partial t}$$

Scope of Research

- Verifying the perturbation solution developed earlier for linear gas flow toward a fractured well with pressure-dependent fluid properties
- Testing the new superposition time developed based on the new perturbation solution
- Developing a method for the analysis of production data of tight-gas wells with strongly pressure dependent fluid properties and providing a practical analysis tool
- Demonstration of the application of the new method to field data

Approach

- Perturbation approach is used to solve the nonlinear gas diffusivity equation.
- The new superposition time definition for the gas well performances when $\mu_g c_g$ is a function of pressure:

$$\frac{m(0,t)}{q(t)} = \frac{200.5T}{(x_f\sqrt{k})h\sqrt{(\emptyset\mu c_t)_i}}\left\{\frac{q_1}{q(t)}(1+\kappa_1)\sqrt{t} + \sum_{i=1}^{n}\left[\frac{q_{i+1}}{q(t)}(1+\kappa_{i+1}) - \frac{q_i}{q(t)}(1+\kappa_i)\right]\sqrt{t-t_i}\right\}$$

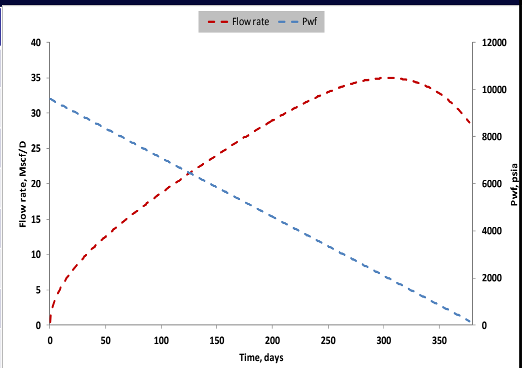
$$+\frac{\eta_i}{2}\left(\frac{2844T\pi}{x_f kh}\right)^2\left(\frac{\omega^1}{m^0}m^0\frac{\partial\omega^0}{\partial m^0}\right)_{0,t} q(t)$$

where $\kappa_i(t_i) = \left[(\omega_i^1 - 1)\left(\omega_i^0 + m^0\frac{\partial\omega_i^0}{\partial m^0}\right)\right]$

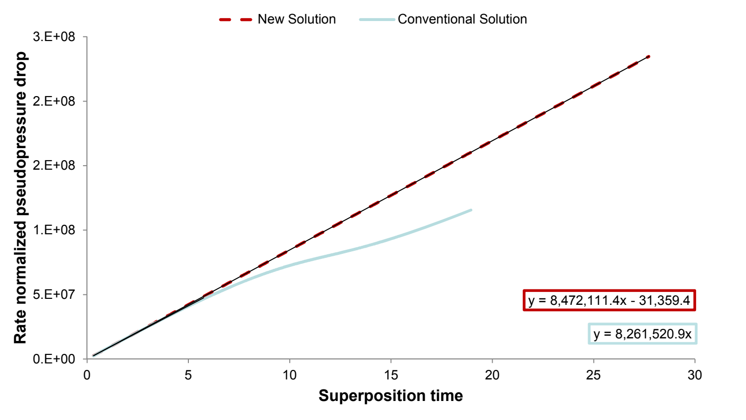
Results

Case 1 – Synthetic Data

RESERVOIR ROCK AND FLUID PROPERTIES	
Formation height, h(ft)	37.15
Fracture half lenght, x_f (ft)	70
Matrix permeability, k (mD)	$3.584*10^{-4}$
Matrix porosity, ϕ	0.08
Reservoir length, L_e (ft)	1000
Specific gravity, SG(lb/ft^3)	0.57
Initial reservoir pressure, P_i(psia)	9597
Initial reservoir temperature, T_i (F)	258



Results

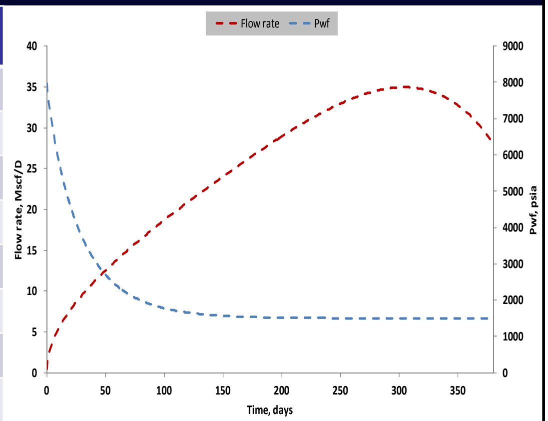


Solution method	Calculated values	Original inputs	Error (%)
Conventional superposition method	1.399	1.325	5.54
New superposition time method	1.327	1.325	0.15

Results

Case 2 – Synthetic Data

RESERVOIR ROCK AND FLUID PROPERTIES	
Formation height, h(ft)	37.15
Fracture half lenght, x_f (ft)	100
Matrix permeability, k (mD)	$3.584*10^{-4}$
Matrix porosity, ϕ	0.08
Reservoir length, L_e (ft)	1000
Specific gravity, SG(lb/ft^3)	0.57
Initial reservoir pressure, P_i(psia)	9597
Initial reservoir temperature, T_i (F)	258



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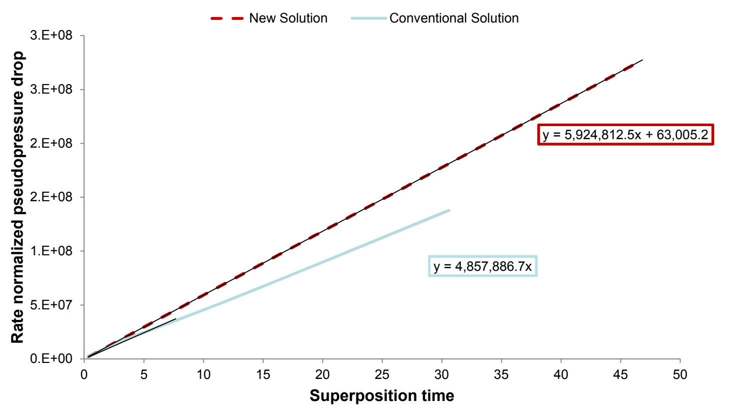
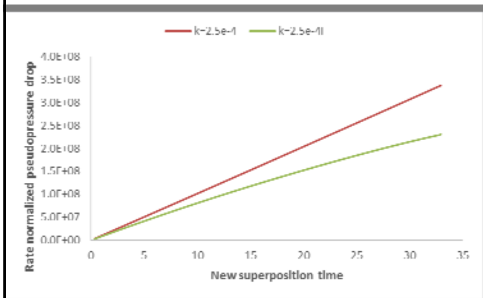
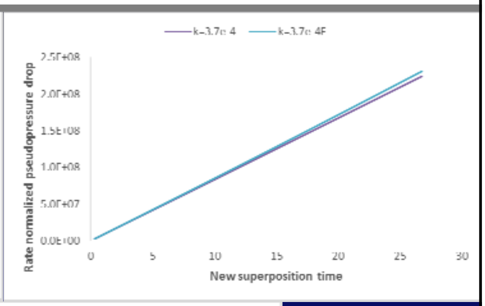
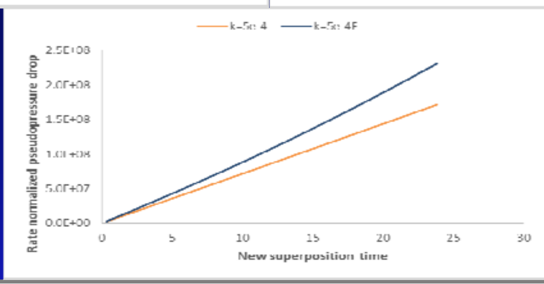


Solution method	Calculated values	Original inputs	Error (%)
Conventional superposition method	2.489	1.893	31.5
New superposition time method	1.894	1.893	0.03

Results







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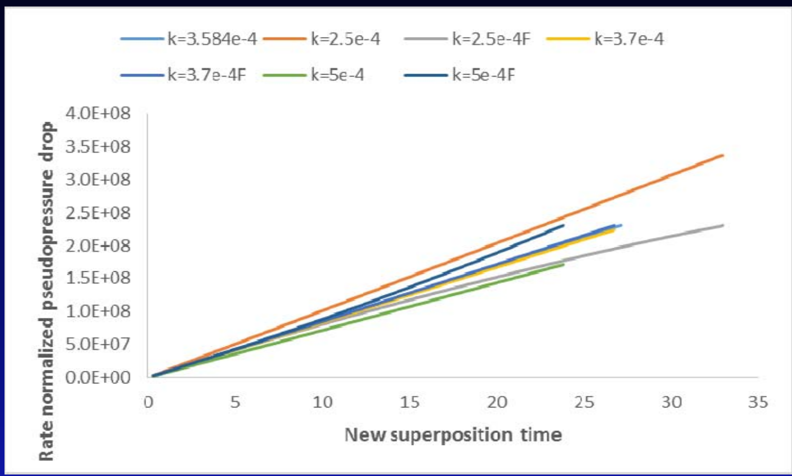

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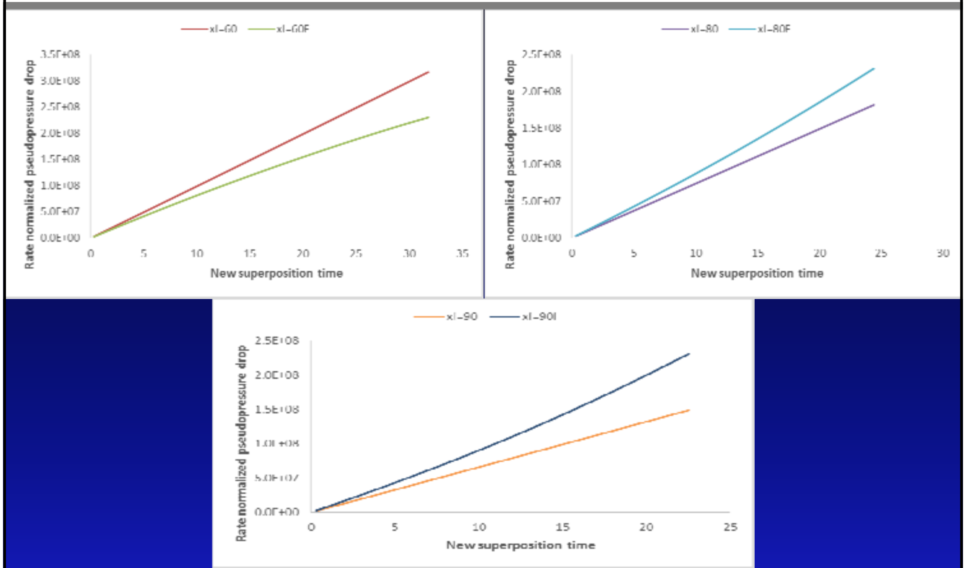

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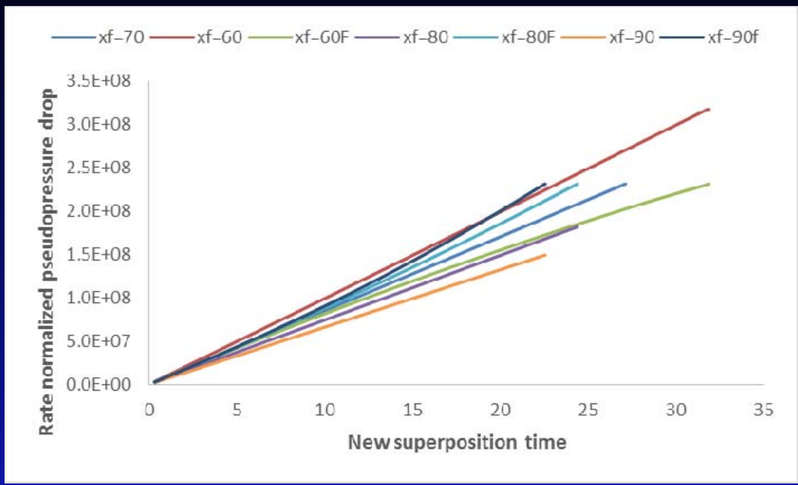

Status

- Regression analysis will be implemented to the new solution to estimate the k, x_f from the field data.
- Non-Darcy flow effects will be added to the new solution.
- The new solution will be extended to apply under boundary dominated flow conditions

Conlusions

- The normalized presudo-pressure versus conventional superposition time plot deviates from the straight-line behavior.
- The use of the new gas superposition time makes the data to display a straight-line trend for all times.
- The use of the new superposition time defined in this study has improved the accuracy in the estimation of $x_f\sqrt{k}$ in synthetic examples.