K, MO

Second Bone Springs
Full Choke 2H DFIT Analysis

David P. Craig, Ph.D., P.E.

08 MAY 13

RDC RESERVOIR DEVELOPMENT CONSULTING

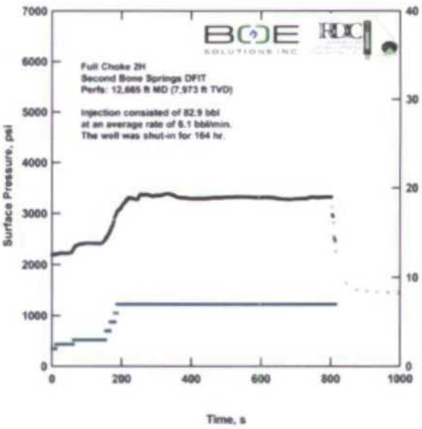
refrac.net

BOE SOLUTIONS INC.

Oil Conservation Division
Case No. ______
Exhibit No. 8

Short-Flow Transient Analysis
Full Choke 2H DFIT

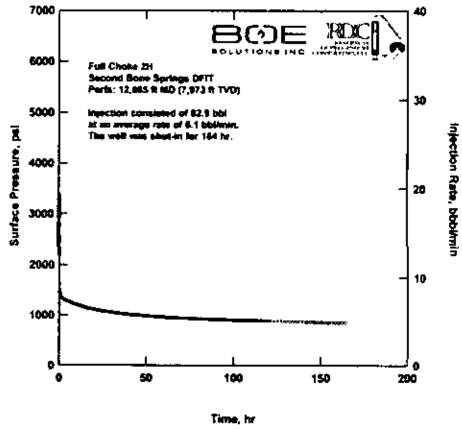
- Depth
  - 12,665 ft MD
  - 7,973 ft TVD
- Injection Volume = 82.9 bbl
- Injection Rate = 6.1 bbl/min
- Injection Fluid = Water
- Shut-in Time
  - 164 hr



A DFIT was pumped in the Second Bone Springs formation on 30 APR 2013. The injection consisted of 82.9 bbl of water pumped at an average rate of 6.1 bbl/min. The well was shutin for 164 hours following the injection. There is some uncertainty about the injection rates. The service company meter was not working, so the service company operator "hard entered" the injection rate in the computer. The calculated volume and the tank straps recorded before and after the injection were consistent, so any error due to injection volume should be minimal.

Short-Flow Transient Analysis
Full Choke 2H DFIT

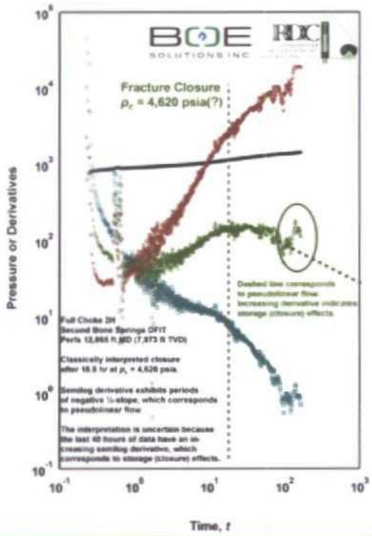
- Depth
  - 12,665 ft MD
  - 7,973 ft TVD
- Injection Volume = 82.9 bbl
- Injection Rate = 6.1 bbl/min
- Injection Fluid = Water
- Shut-in Time
  - 164 hr



As shown in the above slide, the falloff was very smooth with no obvious problems observed in the recorded data.

Short-Flow Transient Analysis
Full Choke 2H DFIT

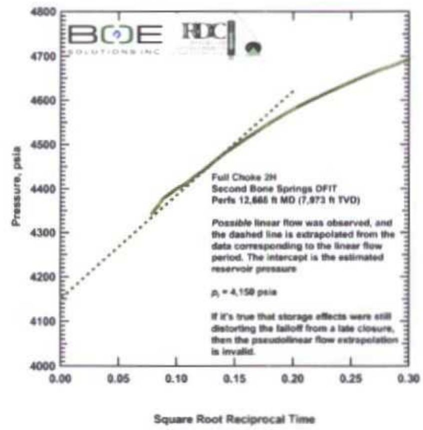
- Depth
  - 12,665 ft MD
  - 7,973 ft TVD
- Shut-in Time
  - 95 hr
  - Closure = 4,620 psi
  - Semilog and Impulse Derivatives Suggest Pseudolinear Flow Observed After 40 hr
  - Possible Storage Effects Continuing After 100 hr



A diagnostic plot is used to identify the end of storage effects caused by fracture closure and flow regimes for straight-line analysis. The semilog derivative of observed pressure (green curve) is the primary curve used in an interpretation. The semilog derivative shows an increasing trend until approaching a peak at about 18.8 hours. A classical interpretation would suggest fracture closure was observed after 18.8 hours and at a closure pressure of 4,620 psi. However, at the end of the data set during the final 40 hours of recorded data, the semilog derivative begins increasing again, which also suggests storage effects. It's possible that the final recorded data was distorted and should have followed the previously identified pseudolinear flow trend. My analysis assumes pseudolinear flow was observed, and the final 40 hours of falloff data are somehow distorted.

Short-Flow Transient Analysis
Full Choke 2H DFIT

- Straight-Line Analysis
  - p_i = 4,150 psia



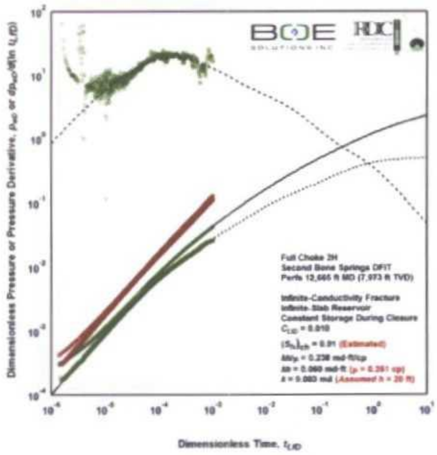
Straight-line analysis of the data in pseudolinear flow results in an initial reservoir pressure extrapolation of 4,150 psia. WARNING: if the data at the end of the test were indeed indicating storage, then the pore pressure extrapolation is invalid.

During the design phase, we assumed a normally-pressured reservoir with a reservoir pressure of 3,500 psia. Consequently, the pore pressure extrapolation of 4,150 psia (0.52 psi/ft) seems high.

Straight line analysis to determine permeability-thickness is not possible without knowing or estimating fracture geometry.

Short-Flow Transient Analysis
Full Choke 2H DFIT

- Type Curve Analysis
  - Good Type Curve Match
    - Minimal Choked-Fracture Skin
    - Ignores Final 40 hr of Falloff Data
  - kh/μ = 0.238 md·ft/cp
  - kh = 0.060 md·ft (μ=0.251 cp)
  - k = 0.003 md (Assuming h = 20 ft)



Type curve analysis can be used to estimate permeability-thickness. The graph shows the semilog derivative from the diagnostic curve plotted on a negative second derivative type curve. The integrated reservoir pressure difference and derivative curves are also matched to a type curve corresponding to a dimensionless storage coefficient of CD = 0.010 with a choked-fracture skin of 0.01. NOTE: two integrated reservoir pressure curves are shown. The green curve assumes 4,150 psia is the correct reservoir pressure and the red curve assume a reservoir pressure of 3,500 psia. With the lower reservoir pressure, the data cannot be matched to a type curve because storage dominates the entire falloff period.

From the type curve match point using the green curves, the transmissibility is 0.238 md ft/cp, which assuming a reservoir oil viscosity of 0.251 cp, results in a permeability-thickness of 0.060 md ft. ASSUMING the fracture height is 20 ft, the permeability is 0.003 md.

Clearly the permeability-thickness is two orders of magnitude lower than expected; consequently, I suggest carefully reviewing the drilling path to confirm the toe interval was in the targeted reservoir. As shown in the figure, the type curve match is very good. If, however, the reservoir pressure is closer to 3,500 psia, then the interval permeability-thickness must decrease to match the falloff response, that is, the permeability-thickness will decrease by another order of magnitude into the nanodarcy-ft range.

Short-Flow Transient Analysis
Full Choke 2H DFIT

- Comments
  - Valid Test
    - Some Uncertainty In Analysis
      - Possible Storage Effects In Final 40 hr of Falloff
        - If True, Invalidates Pore Pressure and Type Curve Match – Pressure And Permeability-Thickness Will Decrease
    - Minimal Choked-Fracture Skin
  - Results
    - p_i = 4,150 psia (0.52 psi/ft)
    - kh/μ = 0.238 md·ft/cp (Type Curve Analysis)
    - kh = 0.060 md·ft (Type Curve Analysis)
    - k = 0.003 md (Type Curve Analysis)