

**FINGAL 41B**  
**DRILL STEM TEST**  
**FINAL REPORT**  
**“C” ZONE COAL SEAM**  
**OPEN HOLE INTERVAL 328.1 – 330.8 mGL**  
**JUNE 19, 2007**

**Prepared for:**  
**Pure Energy Resources Limited**



**Prepared by:**  
**Focal Petroleum Engineering Pty Ltd.**

**July 11, 2007**

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Pure Energy Resources Limited  
P.O. Box 952  
SOUTH PERTH, WA 6951

**Attention: Mr. Steve Beardsall**

Dear Sir

***Re: Fingal 41b Coal "C" Drill Stem Test Report***

The following is a summary of the results obtained from the Drill Stem Test conducted on June 19, 2007 over the "C" Coal, open hole interval from circa 328.1 – 330.8 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 260 meters of water were displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a 1.3 hour flow and a 2.1 hour buildup. A low flow gas meter was used to measure the gas recovery and a fluid recorder in the drill pipe was used to establish daily water production volumes (bbl/day) from the inflow of water into the wellbore.

During the inflation of the isolation packers, a rapid falloff in pressure was noted below the packer suggesting that the permeability within the test interval was high and that the reservoir is significantly under-pressured.

**Comments and Conclusions**

- The pressure response observed during the flow and buildup periods suggested a reservoir with very high flow capacity to water. Since the inflow from the reservoir was predominantly water, the test was analysed as a water well. The gas volume recovered was insignificant (< 2 cf) and was not used in the interpretation.

- The net pay of 5.2 ft (1.6 m) was obtained from the core samples. A default porosity of 2% was used for the interpretation.
- An average water rate of circa 4.8 bbl/d was calculated using the pressure increase from the inflow of water into the wellbore during the flow period.
- A reservoir pressure ( $P_i$ ) of 223 psia was calculated from the simulation and has been quoted throughout the report. The subject reservoir is significantly under-pressured with a reservoir gradient of 0.21 psi/ft.
- The pressure derivative indicated that wellbore storage was overcome within the first minute of shut-in by a zero slope (radial flow) trend that remained for the duration of the buildup.
- Conventional analysis and Simulation were both conducted. The buildup was initially modelled with a vertical model, however the early time data was not well matched. A radial composite model was incorporated with an increasing (three times) flow capacity (kh) circa eight feet away from the wellbore region in order to match the early time data. The dominant outer region of the simulation (radial composite model) compared very well with the conventional results and has been quoted throughout this report.
- The large positive skin value is attributed to coal fines in the near wellbore area as a result of the rapid depressurising of the reservoir during the DST.

A summary of the Test Results is as follows:

**Average Reservoir Pressure (Pr) @ 322.6 mGL      223 psia (simulation)**

**Apparent Skin Factor      +8**

**Near Wellbore Zone**

**Average Permeability to Water      12.3 md**  
**Flow Capacity to Water      65 md.ft**  
**Radius of Investigation      7.5 ft**

**Outer Area Zone**

**Average Permeability to Water      33.5 md**  
**Flow Capacity to Water      176 md.ft**  
**Radius of Investigation      72 ft**

If further clarification of the test interpretation is required, please contact the undersigned on (08) 9474 9622.

Yours faithfully,

**FOCAL PETROLEUM ENGINEERING PTY LTD**

Ryan Gee

**WELL TEST CONSULTANT**

Terry Primeau

**MANAGING DIRECTOR**

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Fingal 41B  
June 19, 2007

# Validata

Packer Depth @326.5 mGL  
Formation: Seam C

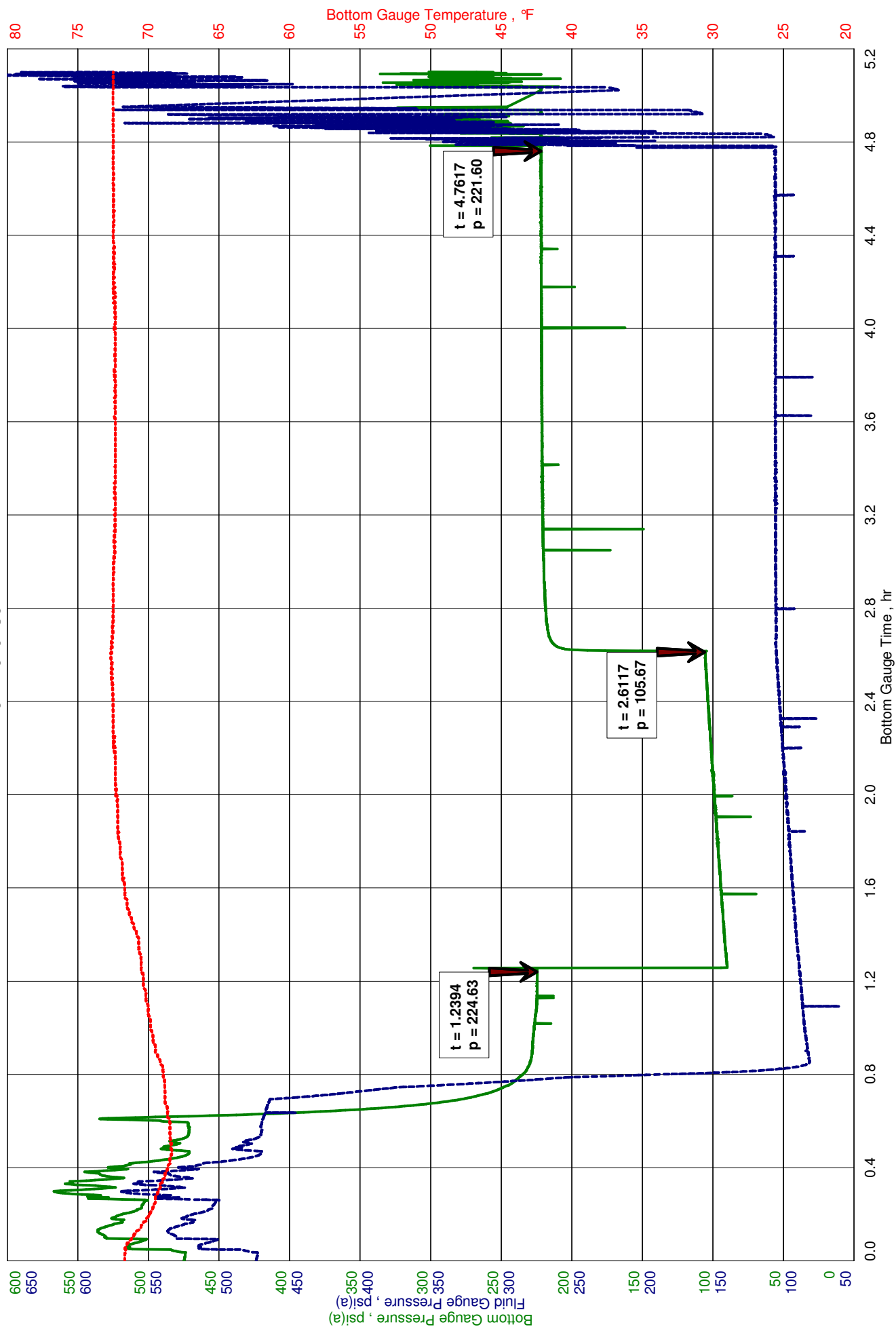
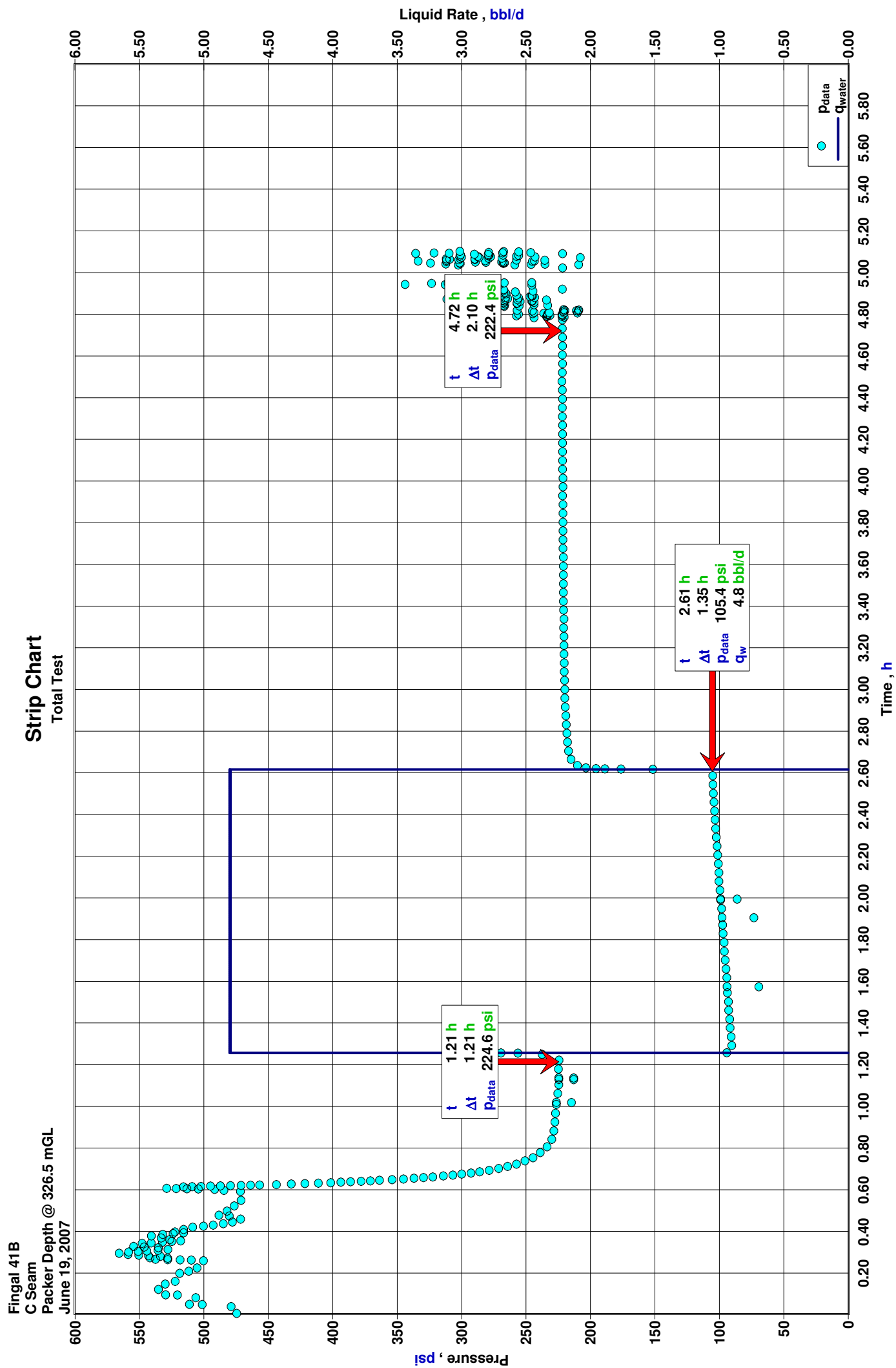


Figure 1

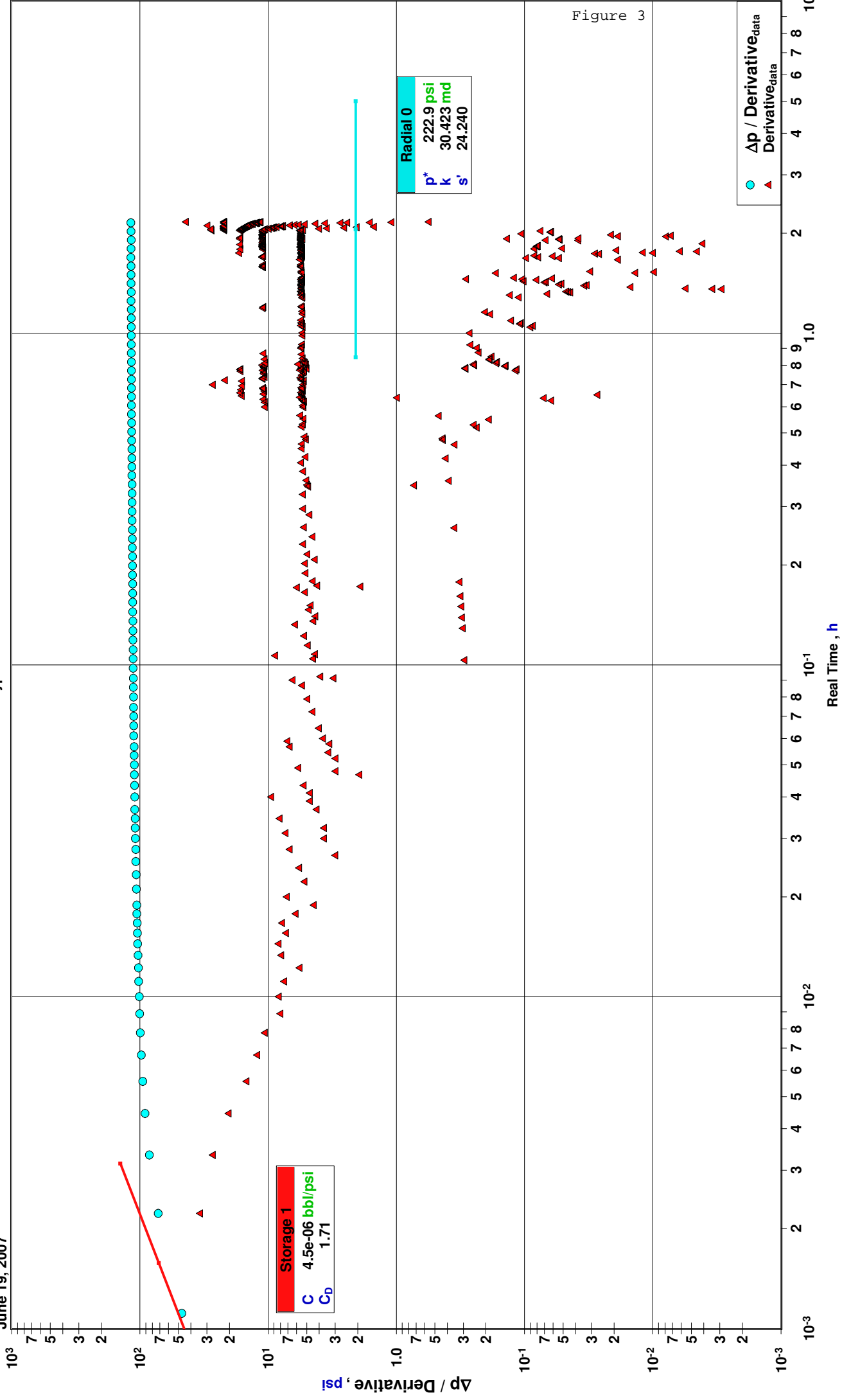
Figure 2



Fingal 41B  
C Seam  
Packer Depth @ 326.5 mGL  
June 19, 2007

# Diagnostic Analysis

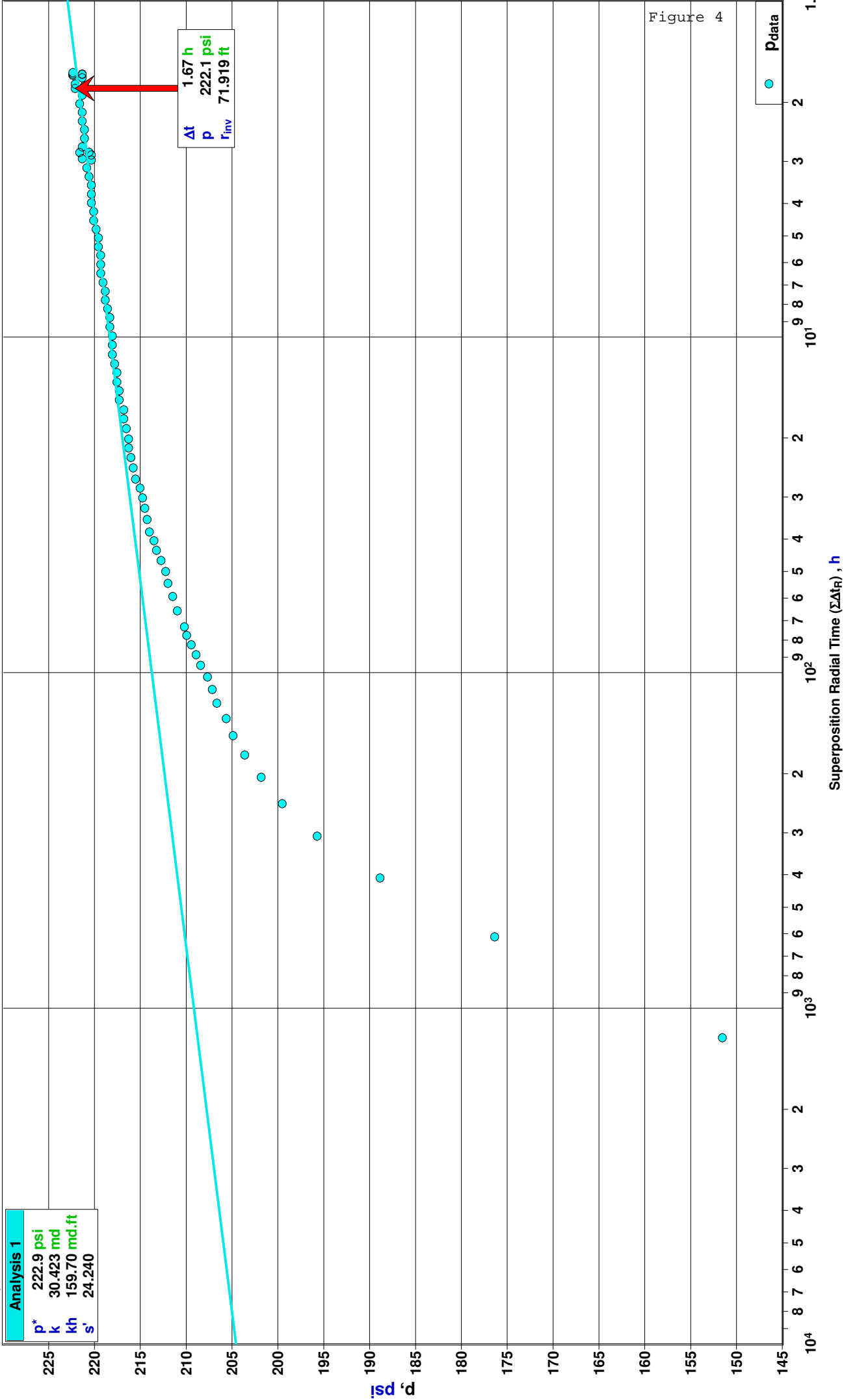
Typecurve





Fingal 41B  
C Seam  
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Diagnostic Analysis  
Radial



# Water Well Test - Buildup

## Radial Flow Analysis

Fingal 41B

Packer Depth @ 326.5 mGL

C Seam

June 19, 2007

### Analysis Results

Total Sandface Rate ( $q_{tB_t}$ )	4.799 bbl/d	Apparent Skin ( $s'$ )	24.240
Semilog Slope (m)	4.59	Skin - Damage	24.240
Gas Permeability ( $k_g$ )	md	Skin - Inclination	
Oil Permeability ( $k_o$ )	md	Skin - Partial Penetration	
Water Permeability ( $k_w$ )	30.423 md	Pressure Drop Due to Skin ( $\Delta p_s$ )	96.69 psi
Flow Capacity (kh)	159.701 md.ft	Damage Ratio (DR)	5.619
Total Mobility ( $k/\mu_t$ )	32.38 md/cp	Flow Efficiency (FE)	0.178
Total Transmissivity( $kh/\mu_t$ )	169.99 md.ft/cp		

### Reservoir Parameters

Net Pay (h)	5.249 ft
Total Porosity ( $\phi_t$ )	2.00 %
Water Saturation ( $S_w$ )	95.00 %
Oil Saturation ( $S_o$ )	0.00 %
Gas Saturation ( $S_g$ )	5.00 %
Wellbore Radius ( $r_w$ )	0.30 ft
Formation Temperature (T)	72.5 °F
Formation Compressibility ( $c_f$ )	9.482e-6 psi <sup>-1</sup>
Total Compressibility ( $c_t$ )	2.471e-4 psi <sup>-1</sup>

### Pressures

Initial Pressure ( $p_i$ )	222.00 psi
Extrapolated Pressure ( $p^*$ )	222.92 psi
Final Flowing Pressure ( $p_{wfo}$ )	104.37 psi

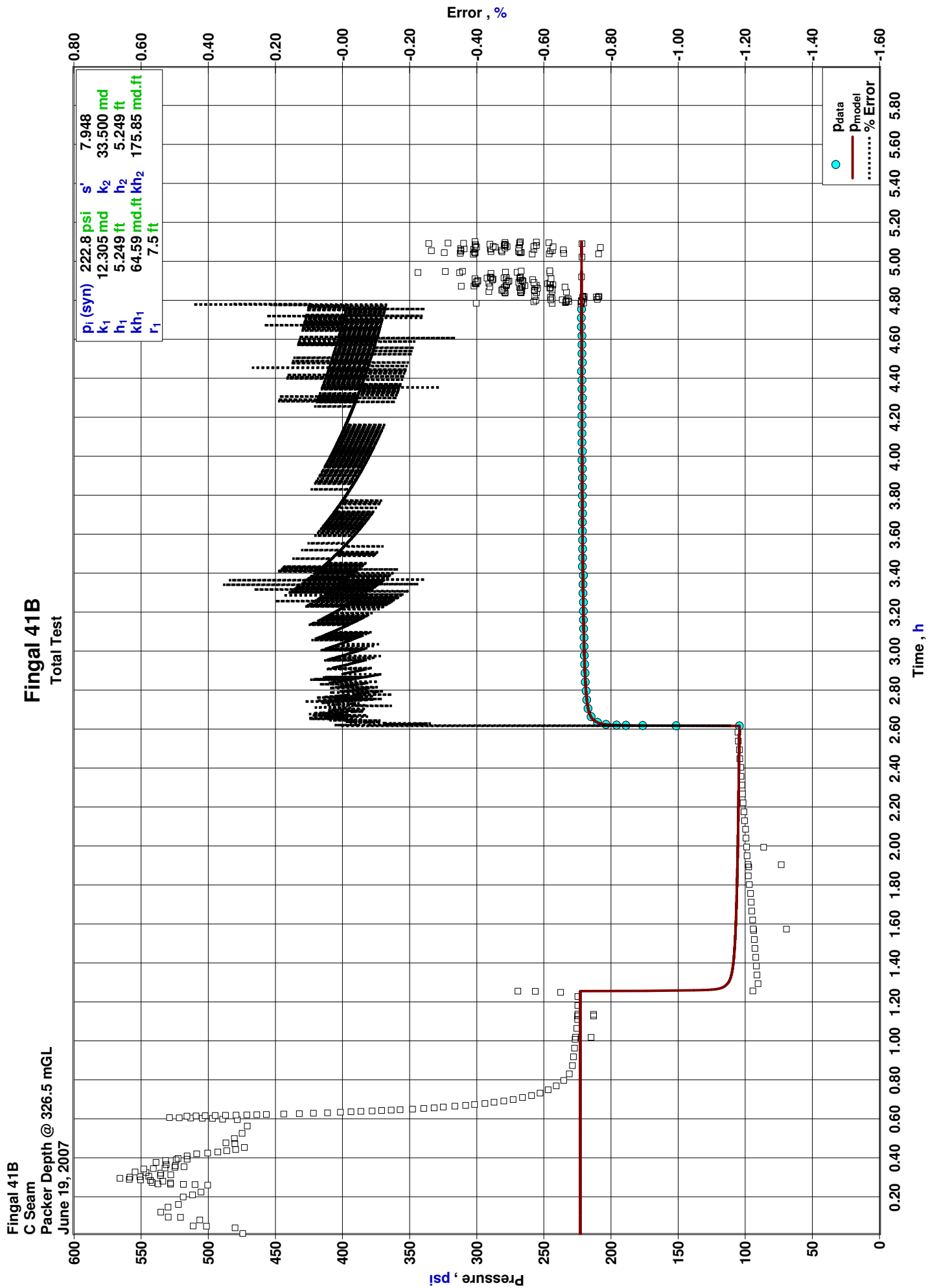
### Production and Times

Corrected Flow Time ( $t_c$ )	1.3600 hr
Cumulative Water Production	0.272 bbl
Final Water Rate	4.800 bbl/d

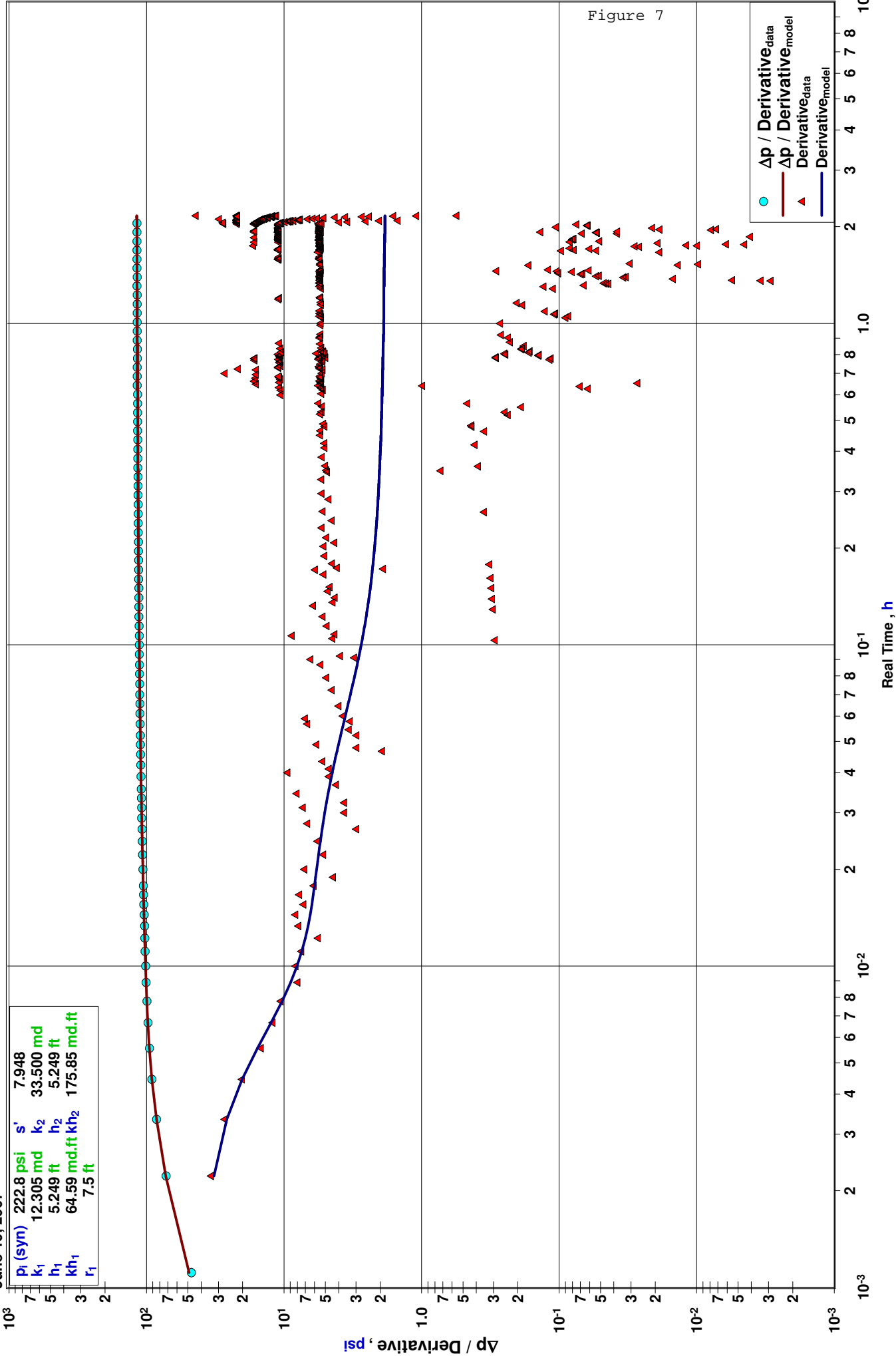
### Fluid Properties

Water Compressibility ( $c_w$ )	3.27519e-6 psi <sup>-1</sup>
Water Formation Volume Factor ( $B_w$ )	1.000
Water Viscosity ( $\mu_w$ )	0.939 cp
Solution Gas Ratio ( $R_{sw}$ )	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure ( $p_{pVT}$ )	222.00 psi

Figure 6



# Fingal 41B C Seam Packer Depth @ 326.5 mGL June 19, 2007 Simulation - Radial Composite Typecurve



Fingal 41B

C Seam

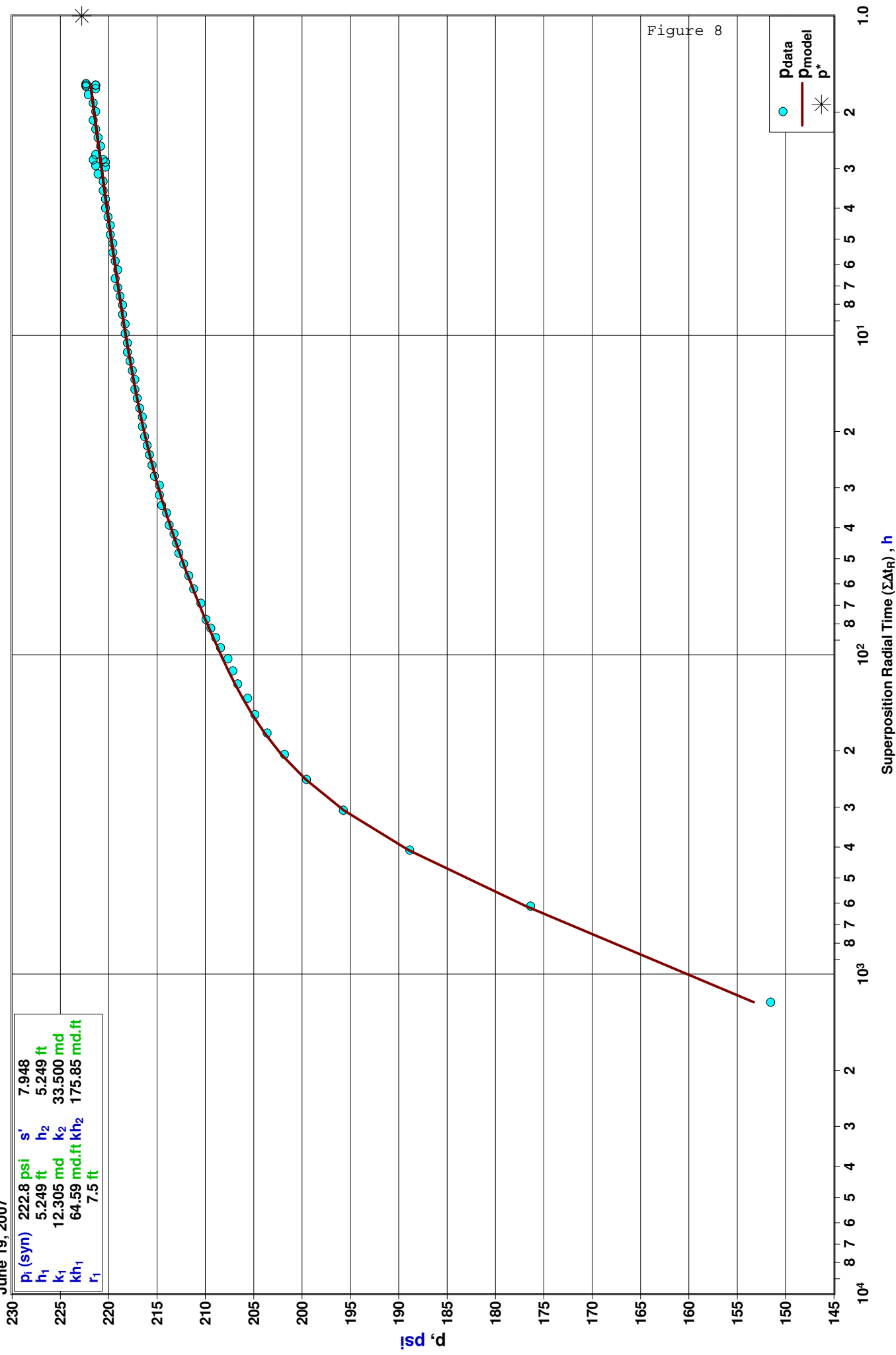
Packer Depth @ 326.5 mGL

June 19, 2007

## Simulation

Radial

$p_i$ (syn)	222.8 psi	$s'$	7.948
$h_1$	5.249 ft	$h_2$	5.249 ft
$k_1$	12.305 md	$k_2$	33.500 md
$kh_1$	64.59 md.ft	$kh_2$	175.85 md.ft
$r_1$	7.5 ft		



# Composite Water Well Model

Case Name : Radial Composite

Fingal 41B  
C Seam

Packer Depth @ 326.5 mGL  
June 19, 2007

## Model Parameters

## Formation Parameters

### Region 1

### Region 2

Total Mobility ( $k/\mu$ ) <sub>t</sub>	13.10 md/cp
Permeability (k) <sub>1</sub>	12.305 md
Net Pay (h) <sub>1</sub>	5.25 ft
Total Porosity ( $\phi$ ) <sub>1</sub>	2.00 %
Viscosity ( $\mu$ ) <sub>1</sub>	0.939 cp
Total Compressibility (c <sub>t</sub> ) <sub>1</sub>	2.471e-4 psi <sup>-1</sup>
Region Radius (r) <sub>1</sub>	7.494 ft
Skin (s)	7.948

Total Mobility ( $k/\mu$ ) <sub>t</sub>	35.66 md/cp
Permeability (k) <sub>2</sub>	33.500 md
Net Pay (h) <sub>2</sub>	5.25 ft
Total Porosity ( $\phi$ ) <sub>2</sub>	2.00 %
Viscosity ( $\mu$ ) <sub>2</sub>	0.939 cp
Total Compressibility (c <sub>t</sub> ) <sub>2</sub>	2.471e-4 psi <sup>-1</sup>
Region Radius (r) <sub>2</sub>	ft

Gas Saturation (S <sub>g</sub> )	5.00 %
Water Saturation (S <sub>w</sub> )	95.00 %
Oil Saturation (S <sub>o</sub> )	0.00 %
Wellbore Radius (r <sub>w</sub> )	0.30 ft
Formation Temperature (T)	72.5 °F

Apparent Wellbore Storage Dim. (C <sub>aD</sub> )	1.71
Wellbore Storage Constant Dim. (C <sub>D</sub> )	1.20
Storage Pressure Param. Dim. (C <sub>pD</sub> )	

Water Compressibility (c <sub>w</sub> )	3.27519e-6 psi <sup>-1</sup>
Oil Compressibility (c <sub>o</sub> )	1.50000e-6 psi <sup>-1</sup>
Gas Compressibility (c <sub>g</sub> )	4.69021e-3 psi <sup>-1</sup>
Water Formation Volume Factor (B <sub>w</sub> )	1.000
Gas Formation Volume Factor (B <sub>g</sub> )	0.011565 bbl/scf
Water Viscosity ( $\mu_w$ )	0.939 cp
Gas Viscosity ( $\mu_g$ )	0.0107 cp
Solution Gas Ratio (R <sub>sw</sub> )	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p <sub>pVT</sub> )	222.00 psi

## Fluid Properties

## Production and Pressure

Q <sub>t</sub> B <sub>t</sub>	4.799 bbl/d
Final Water Rate	4.800 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p <sub>wfo</sub> )	104.37 psi
Final Measured Pressure	301.34 psi
Cumulative Water Production	0.272 bbl

## Forecasts

## Synthesis Results

Average Error	0.05 %
Synthetic Initial Pressure (p <sub>i</sub> )	222.78 psi
Extrapolated Pressure at Specified Time	222.78 psi
Pressure Drop Due To Skin ( $\Delta p_s$ )	78.33 psi
Flow Efficiency (FE)	0.338
Damage Ratio (DR)	2.955

Forecast Flowing Pressure (P <sub>flow</sub> )	104.37 psi
3 - Month Constant Rate Forecast @ Curr. Skin	4.312 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	4.271 bbl/d
Forecast Flow Duration (t <sub>flow</sub> )	12.00 month
Constant Rate Forecast @ Curr. Skin	4.231 bbl/d
PI / II (Actual)	0.036 bbl/d/psi
Constant Rate Forecast @ Skin=0	10.151 bbl/d
PI / II (Ideal)	0.088 bbl/d/psi
Constant Rate Forecast @ Skin=-4	25.794 bbl/d