

**FINGAL 41B**  
**DRILL STEM TEST**  
**FINAL REPORT**  
**“B” ZONE COAL SEAM**  
**OPEN HOLE INTERVAL 301.9 – 306.5 mGL**  
**JUNE 17 – 18, 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 “B” Drill Stem Test Report***

The following is a summary of the results obtained from the Drill stem test conducted from June 17 to 18, 2007 over the “B” Coal, open hole interval from circa 301.85 – 306.5 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 295 meters of water were displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a 10 minute pre-flow and 30 minute initial shut-in period followed by a 30 minute main flow and a 14.5 hour main buildup (recorders left overnight). 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 (< 5 cf) and was not used in the interpretation.

- The net pay of 9.2 ft (2.8 m) was obtained from the core samples. A default porosity of 2% was used for the interpretation.
- Average water rates of circa 33 bbl/d and 31 bbl/d were calculated using the pressure increase from the inflow of water into the wellbore during the pre-flow and main flow periods, respectively.
- An initial estimated reservoir pressure of 189 psia was extrapolated from the late-time pressure fall-off data observed after the packers were inflated. The best estimate of reservoir pressure ( $P_i$ ) of 187 psia was calculated from the simulation and has been quoted throughout this report. The subject reservoir is significantly under-pressured with a reservoir gradient of 0.19 psi/ft.
- The pressure derivative indicated that wellbore storage was immediately overcome by a zero slope (radial flow) trend and remained for the duration of the buildup. The late-time derivative on the log-log plot appears to begin an upward trend. However, this trend is not evident on the semi-log plot and is likely a function of the gauge resolution as the buildup approaches reservoir pressure (average step increase of circa 0.2 psi).
- Conventional analysis and Simulation were both conducted. A good match of the entire data set was achieved using a Vertical model. The simulation 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:

<b>Average Reservoir Pressure (Pr) @ 296.5 mGL</b>	<b>187</b>	<b>psia (simulation)</b>
<b>Apparent Skin Factor</b>	<b>+38</b>	
<b>Average Permeability to Water</b>	<b>179</b>	<b>md</b>
<b>Flow Capacity to Water</b>	<b>1645</b>	<b>md.ft</b>
<b>Radius of Investigation</b>	<b>135</b>	<b>ft</b>

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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# Validata

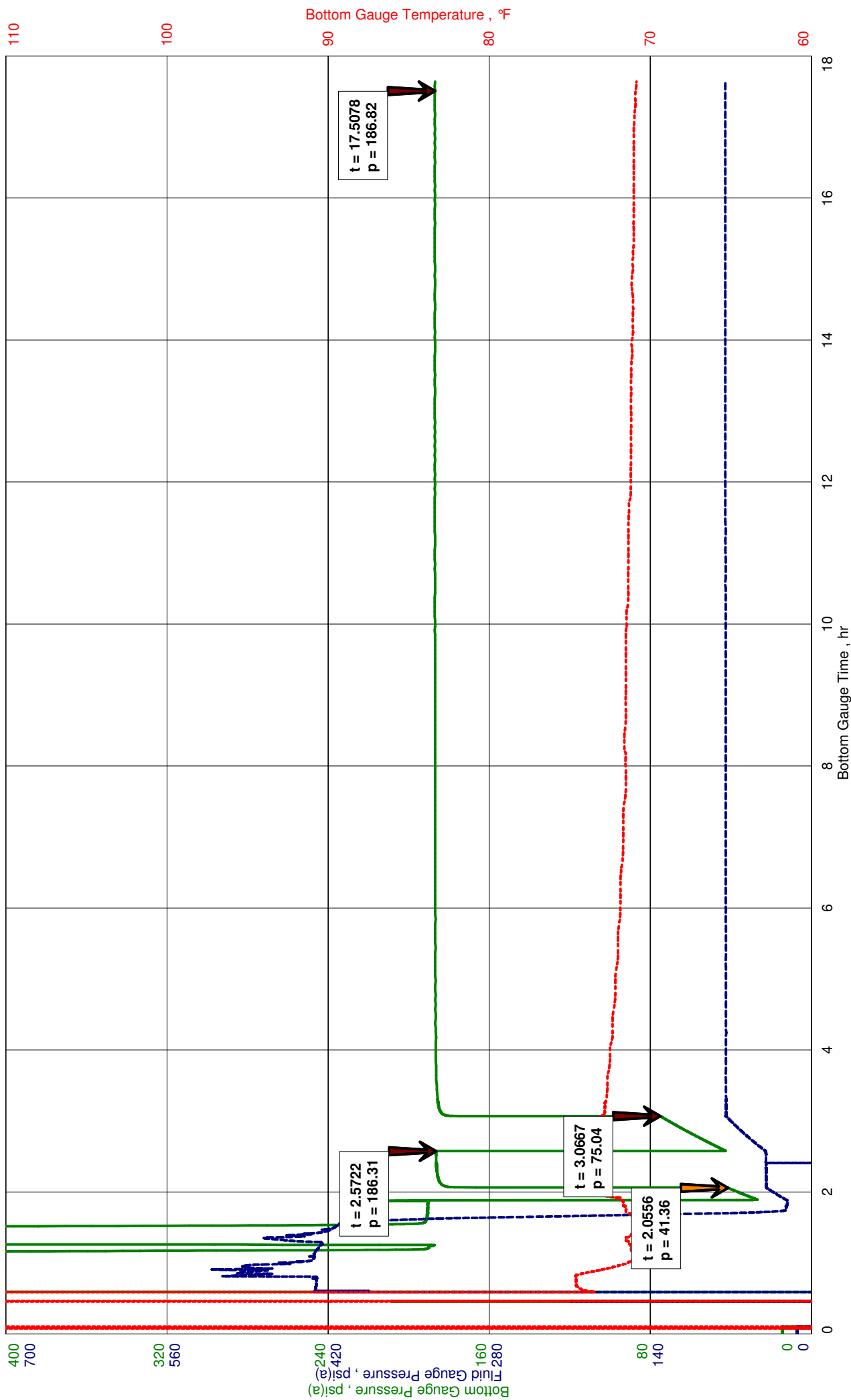


Figure 1

Fingal 41B  
Seam B  
Packer Depth @ 300.4 mGL  
June 17, 2007

Initial Pressure Falloff

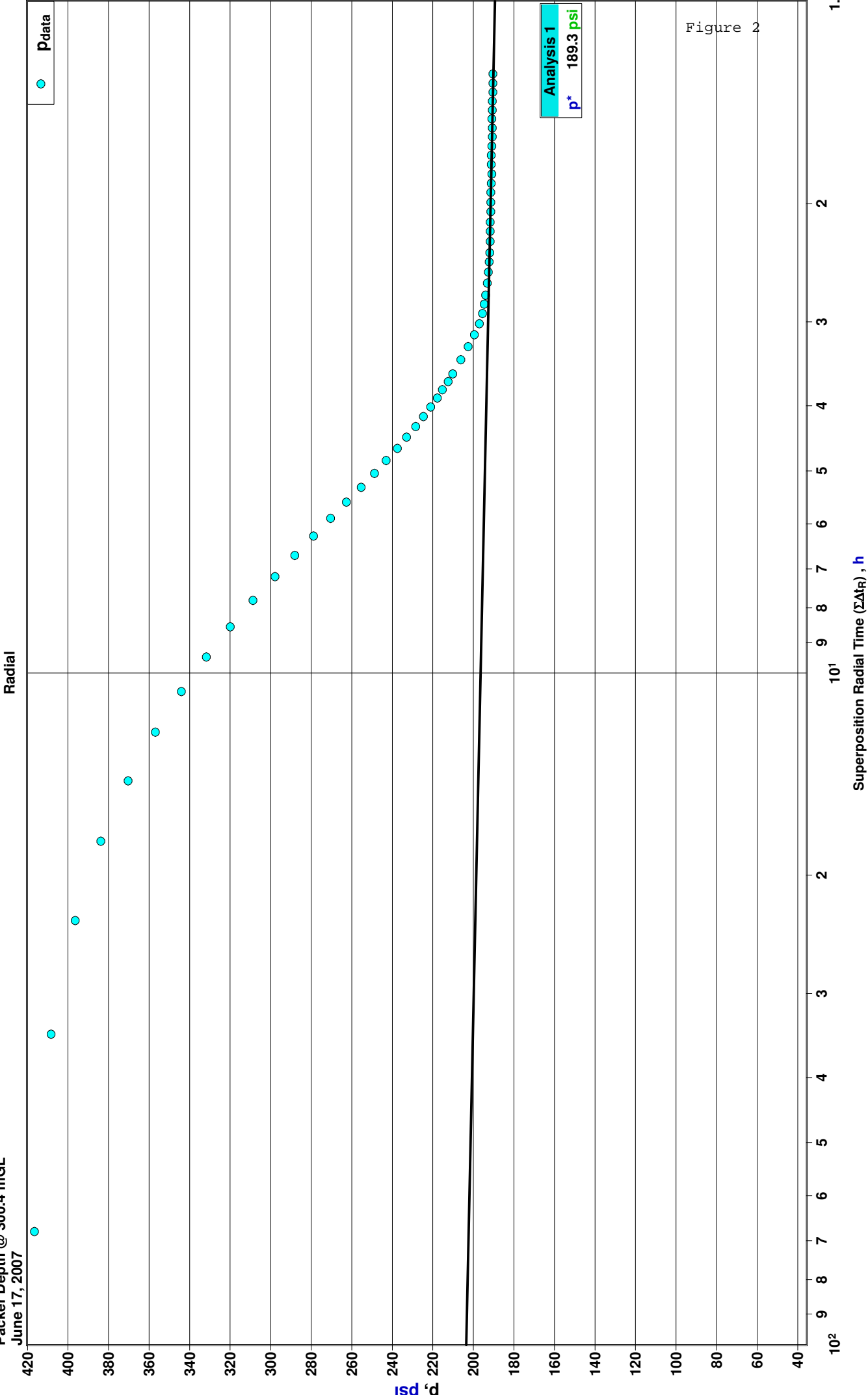
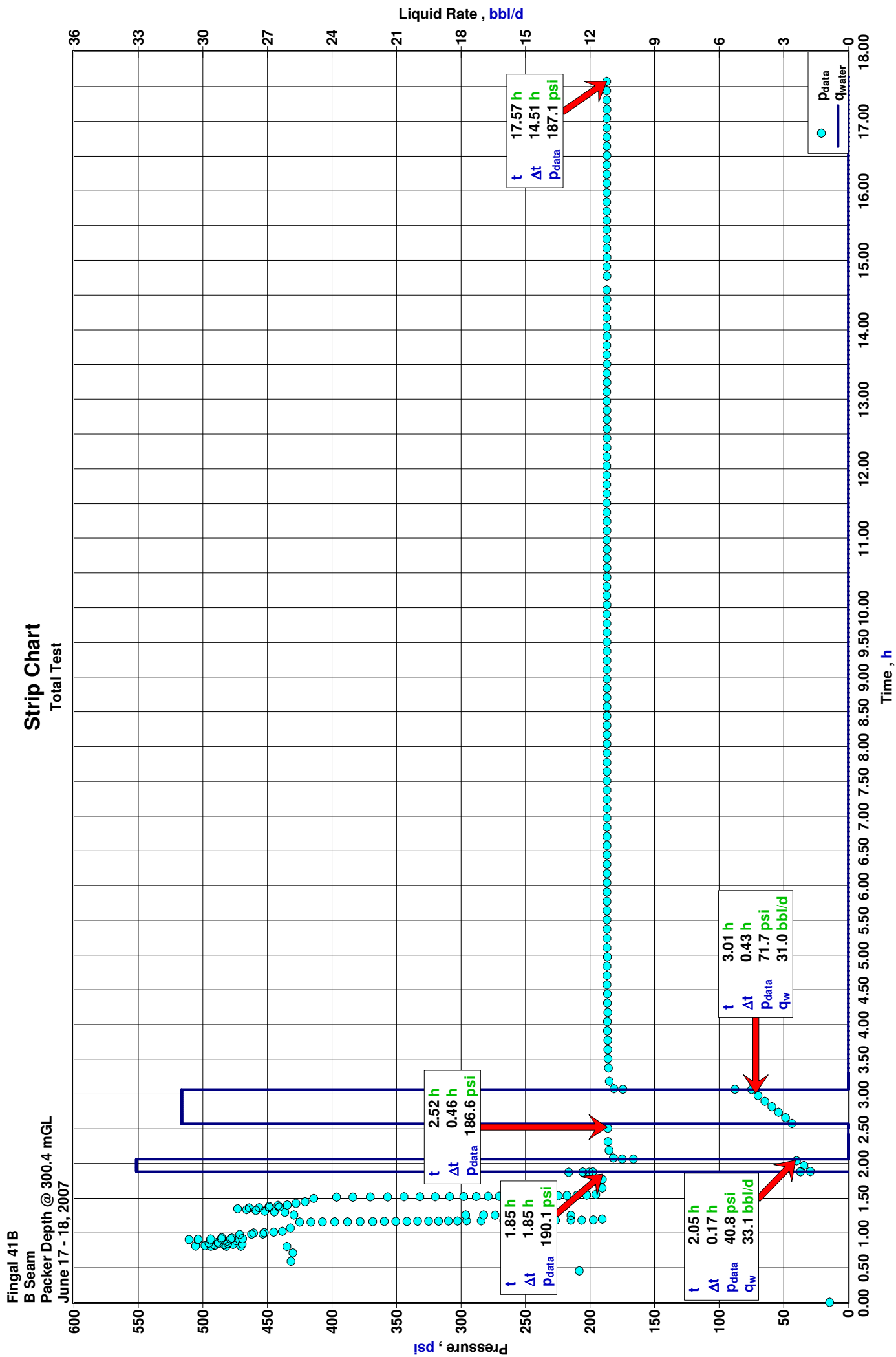


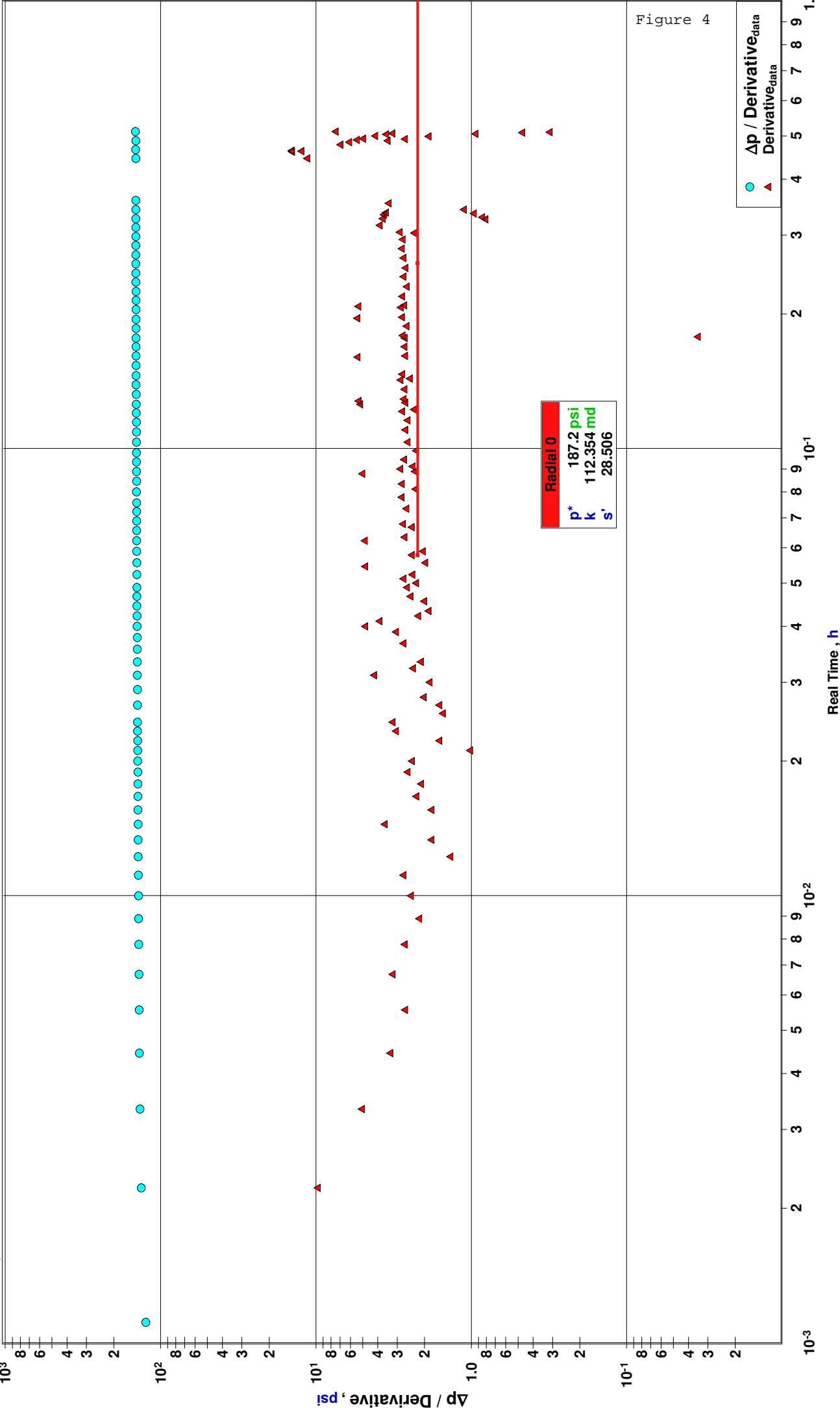
Figure 3





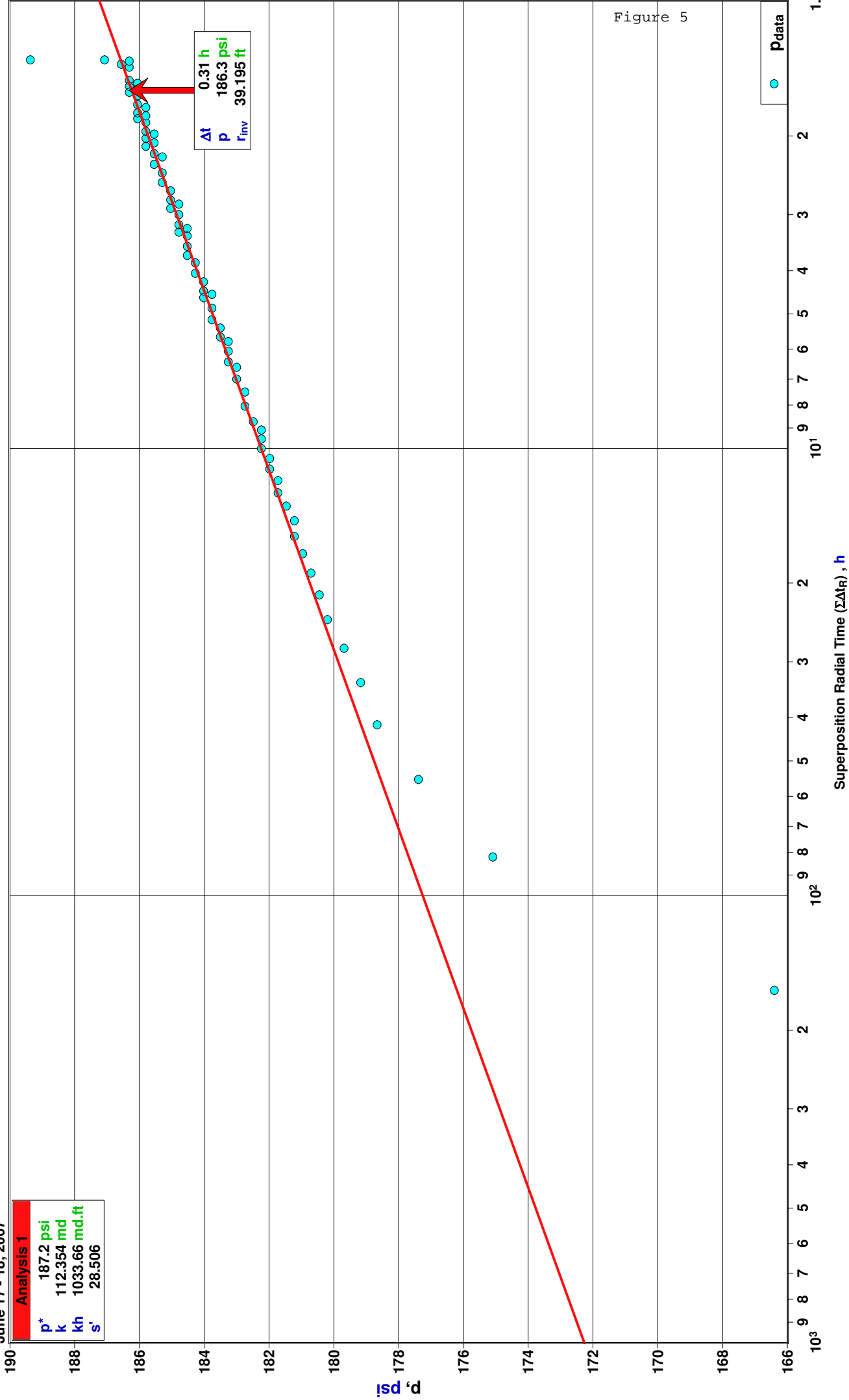
Fingal 41B  
B Seam  
Packer Depth @ 300.4 mGL  
June 17 - 18, 2007

Diagnostic Analysis - Initial Shut-in  
Typecurve



Fingal 41B  
B Seam  
Packer Depth @ 300.4 mGL  
June 17 - 18, 2007

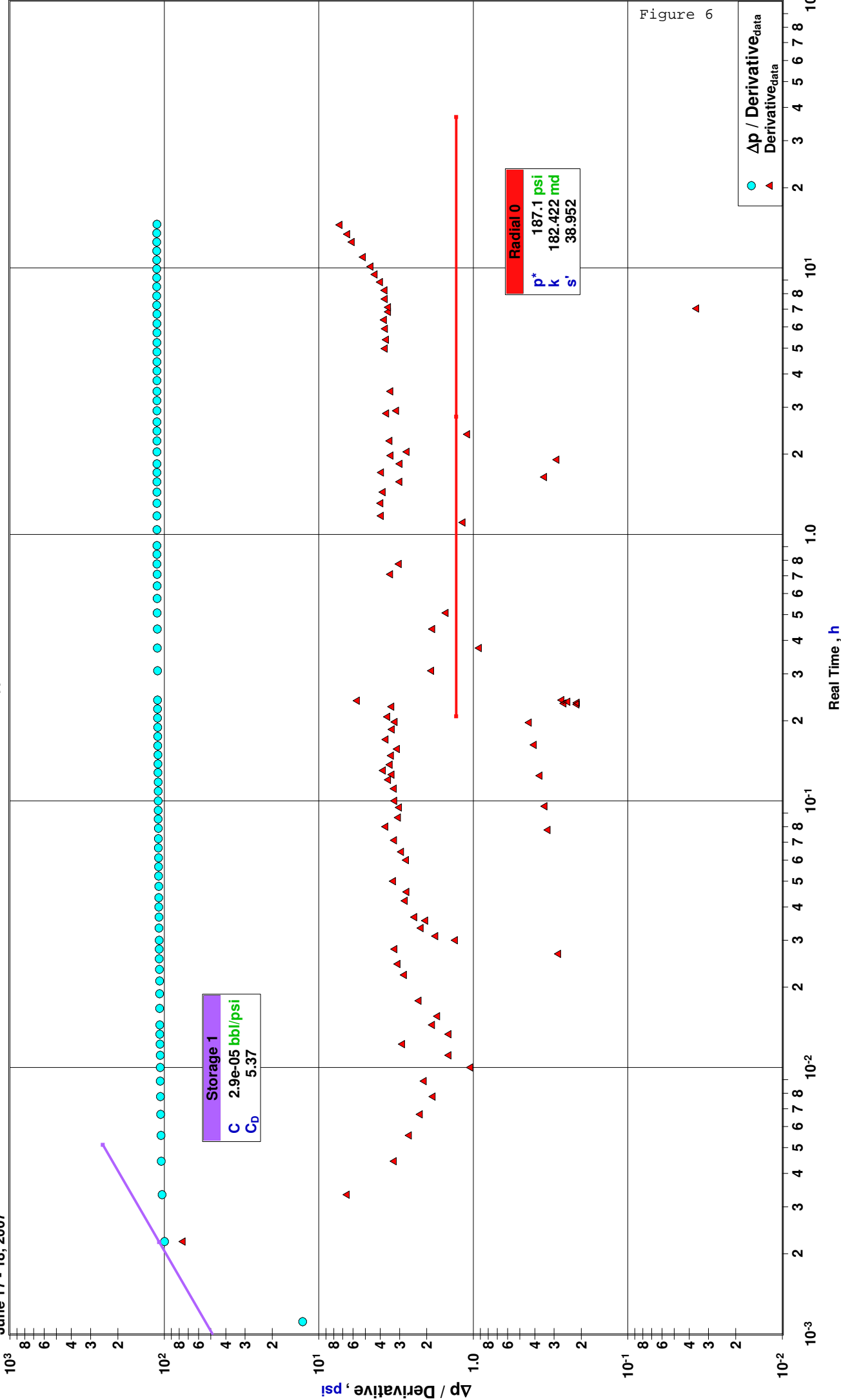
Diagnostic Analysis - Initial Shut-in  
Radial



Fingal 41B  
B Seam  
Packer Depth @ 300.4 mGL  
June 17 - 18, 2007

# Diagnostic Analysis - Main Buildup

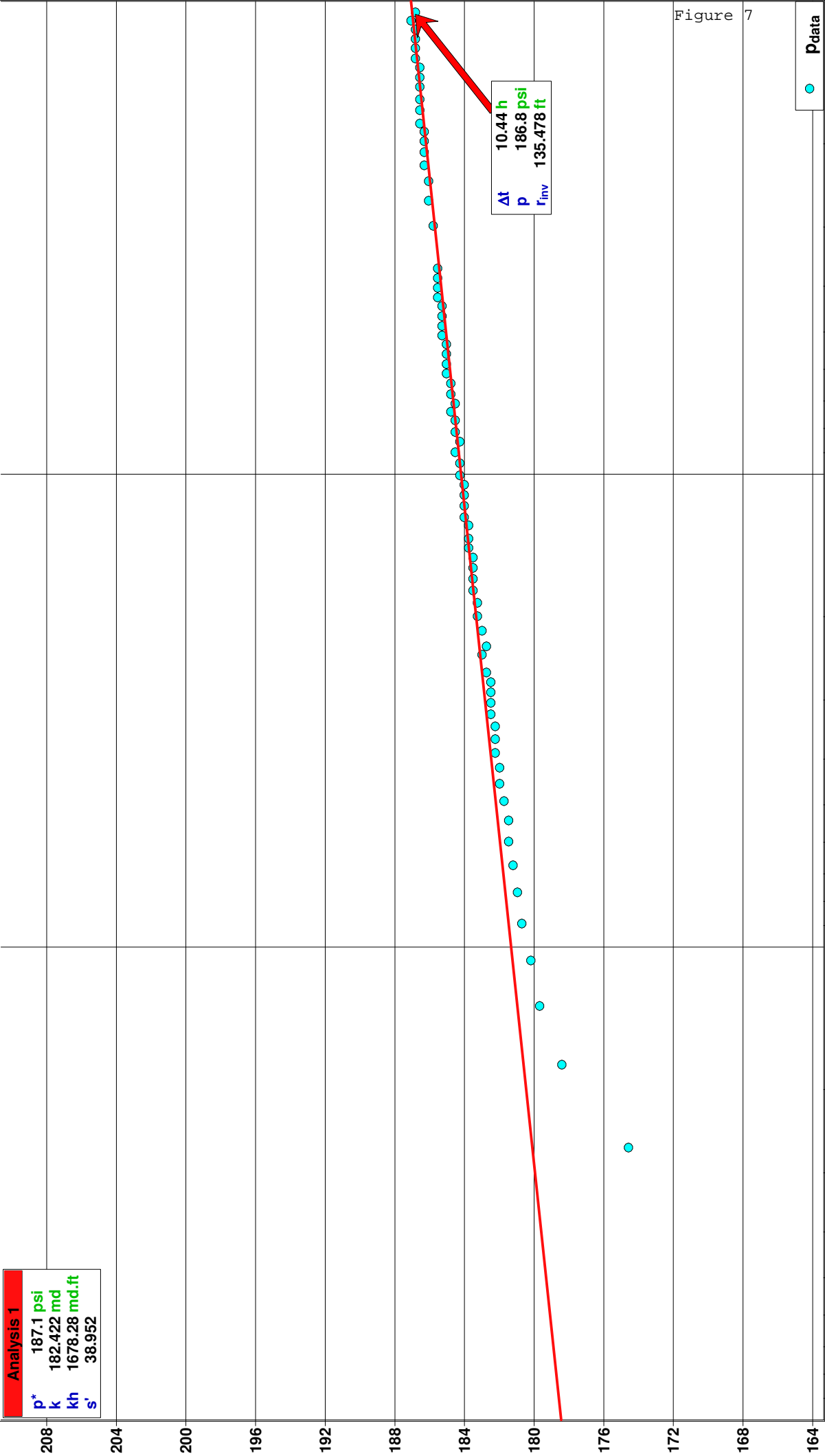
Typecurve



Fingal 41B  
B Seam  
Packer Depth @ 300.4 mGL  
June 17 - 18, 2007

Diagnostic Analysis - Main Buildup  
Radial

Analysis 1	
p*	187.1 psi
k	182.422 md
kh	1678.28 md.ft
s'	38.952



# Water Well Test - Buildup

## Radial Flow Analysis

Fingal 41B  
B Seam

Packer Depth @ 300.4 mGL  
June 17 - 18, 2007

### Analysis Results

Total Sandface Rate ( $q_t B_t$ )	30.989 bbl/d	Apparent Skin ( $s'$ )	38.952
Semilog Slope (m)	2.88	Skin - Damage	38.952
Gas Permeability ( $k_g$ )	md	Skin - Inclination	
Oil Permeability ( $k_o$ )	md	Skin - Partial Penetration	
Water Permeability ( $k_w$ )	182.422 md	Pressure Drop Due to Skin ( $\Delta p_s$ )	97.38 psi
Flow Capacity (kh)	1678.283 md.ft	Damage Ratio (DR)	7.677
Total Mobility ( $k/\mu_t$ )	190.38 md/cp	Flow Efficiency (FE)	0.130
Total Transmissivity( $kh/\mu_t$ )	1751.53 md.ft/cp		

### Reservoir Parameters

Net Pay (h)	9.200 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)	71.0 °F
Formation Compressibility ( $c_f$ )	9.482e-6 psi <sup>-1</sup>
Total Compressibility ( $c_t$ )	2.893e-4 psi <sup>-1</sup>

### Pressures

Initial Pressure ( $p_i$ )	187.00 psi
Extrapolated Pressure ( $p^*$ )	187.07 psi
Final Flowing Pressure ( $p_{wfo}$ )	75.04 psi

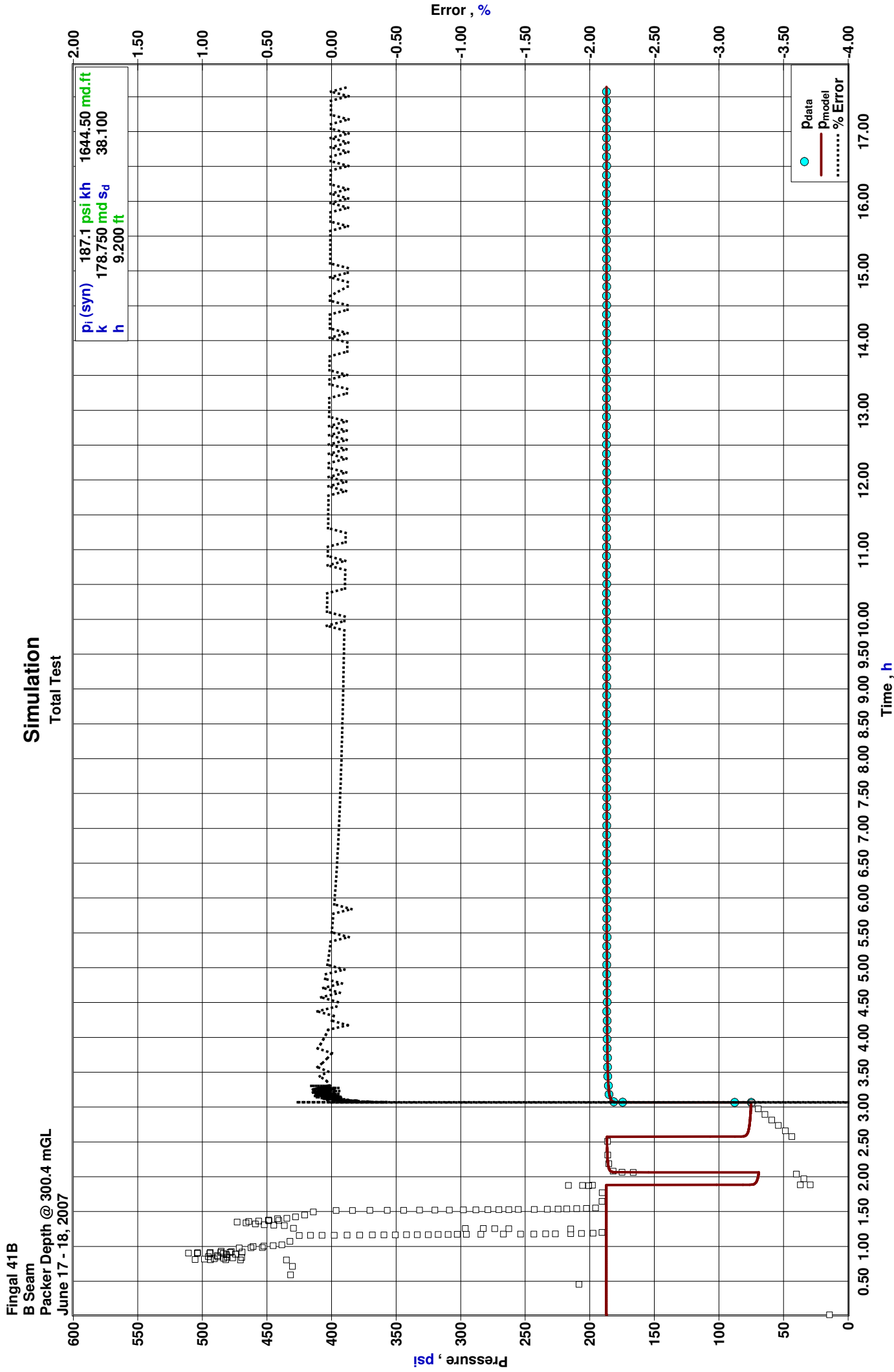
### Production and Times

Corrected Flow Time ( $t_c$ )	0.6844 hr
Cumulative Water Production	0.884 bbl
Final Water Rate	31.000 bbl/d

### Fluid Properties

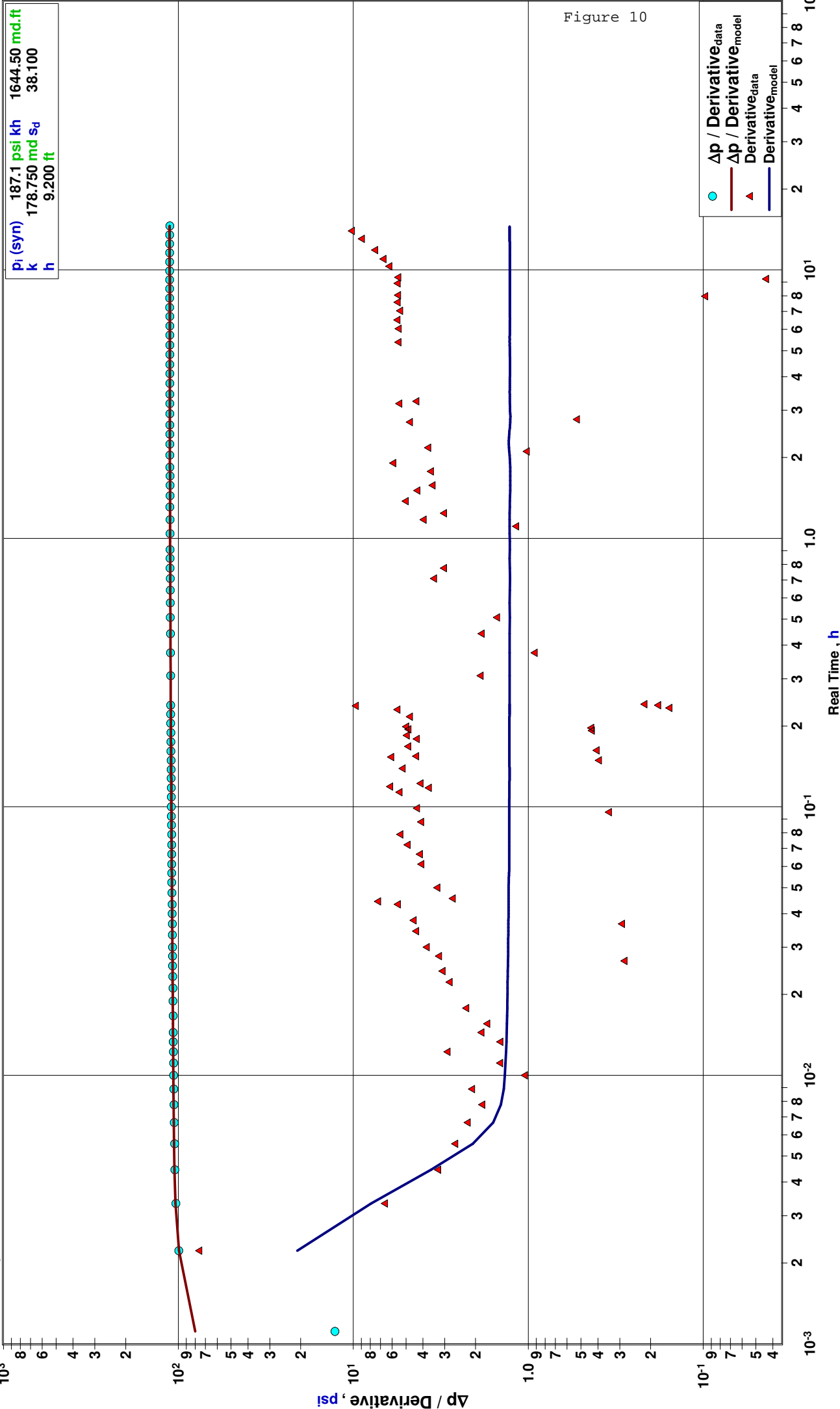
Water Compressibility ( $c_w$ )	3.28607e-6 psi <sup>-1</sup>
Water Formation Volume Factor ( $B_w$ )	1.000
Water Viscosity ( $\mu_w$ )	0.958 cp
Solution Gas Ratio ( $R_{sw}$ )	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure ( $p_{pVT}$ )	187.00 psi

Figure 9



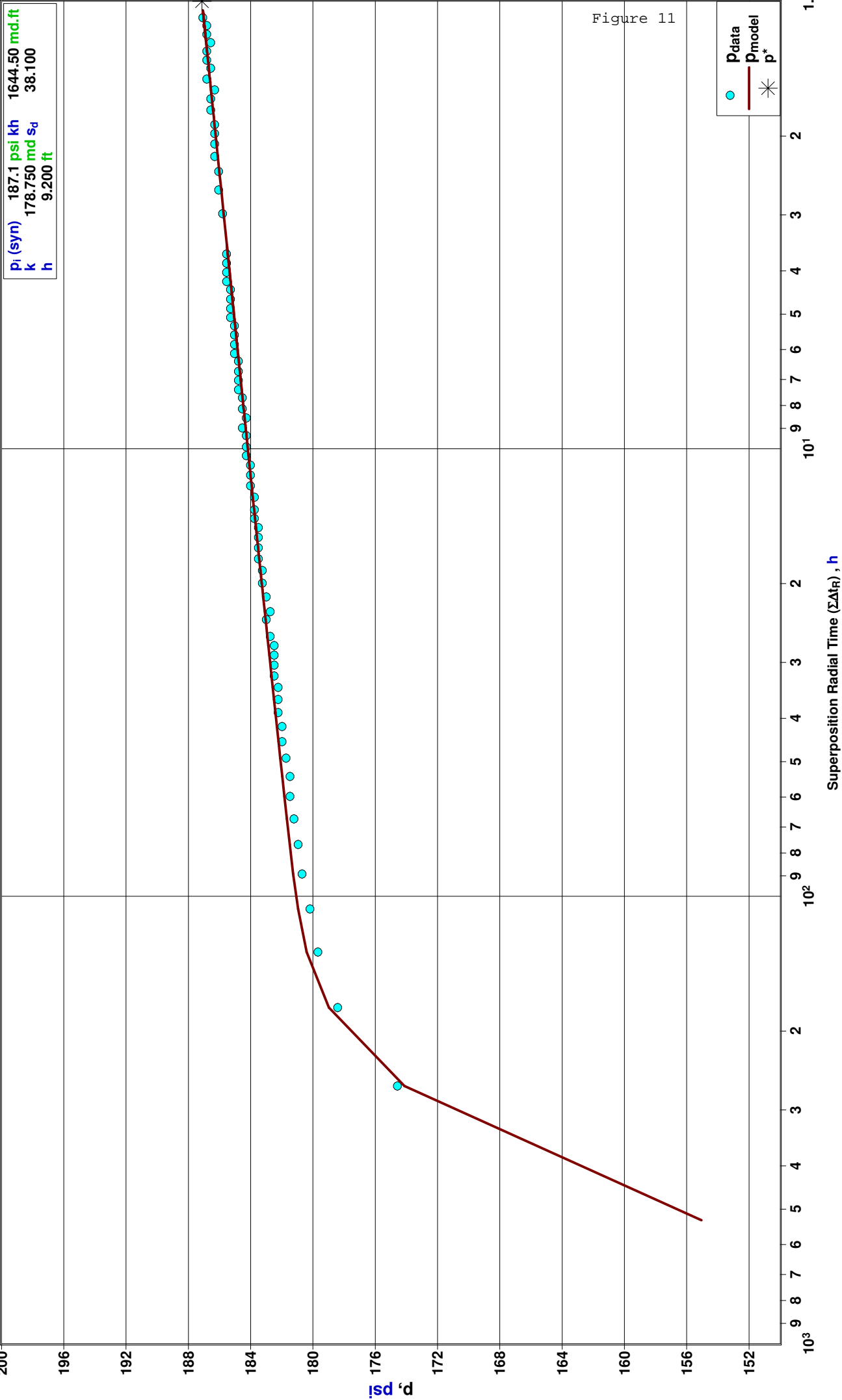
Fingal 41B  
B Seam  
Packer Depth @ 300.4 mGL  
June 17 - 18, 2007

Simulation  
Typecurve



Fingal 41B  
B Seam  
Packer Depth @ 300.4 mGL  
June 17 - 18, 2007

Simulation  
Radial





# Vertical Water Well Model

Case Name : Simulation

Fingal 41B  
B Seam

Packer Depth @ 300.4 mGL  
June 17 - 18, 2007

## Model Parameters

Water Permeability ( $k_w$ )	178.750 md	Reservoir Length ( $X_e$ )	1000000.000 ft
Gas Permeability ( $k_g$ )	md	Reservoir Width ( $Y_e$ )	1000000.000 ft
Skin (s)	38.100	Active Well At ( $X_w$ )	ft
Total Mobility ( $k/\mu$ ) <sub>t</sub>	186.55 md/cp	Active Well At ( $Y_w$ )	ft
Total Transmissivity ( $kh/\mu$ ) <sub>t</sub>	1716.27 md.ft/cp		
Wellbore Storage Constant Dim. ( $C_D$ )	1.75		

## Formation Parameters

Net Pay (h)	9.200 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)	71.0 °F
Formation Compressibility ( $c_f$ )	9.482e-6 psi <sup>-1</sup>
Total Compressibility ( $c_t$ )	2.893e-4 psi <sup>-1</sup>

## Fluid Properties

Water Compressibility ( $c_w$ )	3.28607e-6 psi <sup>-1</sup>
Water Formation Volume Factor ( $B_w$ )	1.000
Water Viscosity ( $\mu_w$ )	0.958 cp
Solution Gas Ratio ( $R_{sw}$ )	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (ppVT)	187.00 psi

## Production and Pressure

$Q_t B_t$	30.989 bbl/d
Final Water Rate	31.000 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure ( $p_{wfo}$ )	75.04 psi
Final Measured Pressure	186.82 psi
Cumulative Water Production	0.884 bbl

## Synthesis Results

Average Error	0.24 %
Synthetic Initial Pressure ( $p_i$ )	187.13 psi
Extrapolated Pressure at Specified Time	187.13 psi
Pressure Drop Due To Skin ( $\Delta p_s$ )	97.13 psi
Flow Efficiency (FE)	0.133
Damage Ratio (DR)	7.495

## Forecasts

Forecast Flowing Pressure ( $P_{flow}$ )	75.04 psi
3 - Month Constant Rate Forecast @ Curr. Skin	28.347 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	28.144 bbl/d
Forecast Flow Duration ( $t_{flow}$ )	12.00 month
Constant Rate Forecast @ Curr. Skin	27.945 bbl/d
PI / II (Actual)	0.251 bbl/d/psi
Constant Rate Forecast @ Skin=0	127.716 bbl/d
PI / II (Ideal)	1.178 bbl/d/psi
Constant Rate Forecast @ Skin=-4	204.290 bbl/d