

**FINGAL 41B
DRILL STEM TEST
FINAL REPORT
“G UPPER & G LOWER” ZONE COAL SEAMS
OPEN HOLE INTERVAL
453.7 – 455.1 & 462.6 – 463.6 mGL
JULY 1, 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 "G Upper & G Lower" Drill Stem Test Report

The following is a summary of the results obtained from the Drill Stem Test conducted from July 1, 2007 over the "G upper and G lower" Coals, open hole interval from circa 453.65 – 455.1 and 462.58 – 463.64 mGL

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 345 meters of water was displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a one hour flow and a 1.5 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 sharp increase in pressure followed by a long, slow falloff was noted below the packer suggesting that the reservoir has low permeability and is significantly under-pressured.

During the shut-in procedure (raising the drill string 70mm) for the downhole tool, a small drop in pressure was noted to start the buildup. This was the result of some upward movement by the packer, creating a small amount of suction in the wellbore.

The buildup data used in the well test analysis was truncated circa 15 minutes prior to the end of the downhole shut-in. It appeared that the late-time data was influenced by non-reservoir activity that has been attributed to the

commencement of operations to pull the gauges out of hole. This did not affect the overall interpretation of the test.

Comments and Conclusions

- The pressure response observed during the flow and buildup periods suggested a reservoir with very low 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 (< 1 cf) and was not used in the interpretation.
- The gross net pay of 7.9 ft (2.4 m) was obtained from the core samples (G upper 4.8 ft, G lower 3.1 ft). A default porosity of 2% was used for the interpretation.
- An average water rate of circa 0.5 bbl/d was calculated using the pressure increase from the inflow of water into the wellbore during the flow period.
- An initial estimated reservoir pressure of 273 psia was extrapolated from the late-time pressure fall-off data observed after the packers were inflated. The reservoir pressure (P_i) of 273 psia was also determined from the simulation match of the buildup and has been quoted throughout the report. The subject reservoir is significantly under-pressured with a reservoir gradient of 0.19 psi/ft.
- The pressure derivative indicated that wellbore storage dominated the entire buildup. For the purposes of this report, it was assumed that the late-time data was approaching radial flow (zero slope).
- Conventional analysis and Simulation were both conducted. The conventional estimates for permeability and skin were used to initiate the simulation match. An excellent match was obtained using a vertical model and the results have been quoted throughout this report. However, it should be noted that the match was non-unique and acceptable matches could also be obtained using other reservoir models and parameters. Therefore, these results should be used with some caution.
- The negative skin value is considered low and could be attributed to a slightly improved wellbore condition, or small natural fractures observed in the G upper section of core.

A summary of the Test Results is as follows:

Average Reservoir Pressure (Pr) @ 449.4 mGL	273 psia (simulation)
Apparent Skin Factor	-1.3
Average Permeability to Water	0.06 md
Flow Capacity to Water	0.5 md.ft
Radius of Investigation	3 ft

If further clarification of the test interpretation is required, please contact the undersigned on (08) 94749622.

Yours faithfully,

FOCAL PETROLEUM ENGINEERING PTY LTD

Ryan Gee

WELL TEST CONSULTANT

Terry Primeau

MANAGING DIRECTOR

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Fingal 41B
July 1, 2007

Packer Depth @ 453.3 mGL
Formation: Seam G upper & G lower

Validata

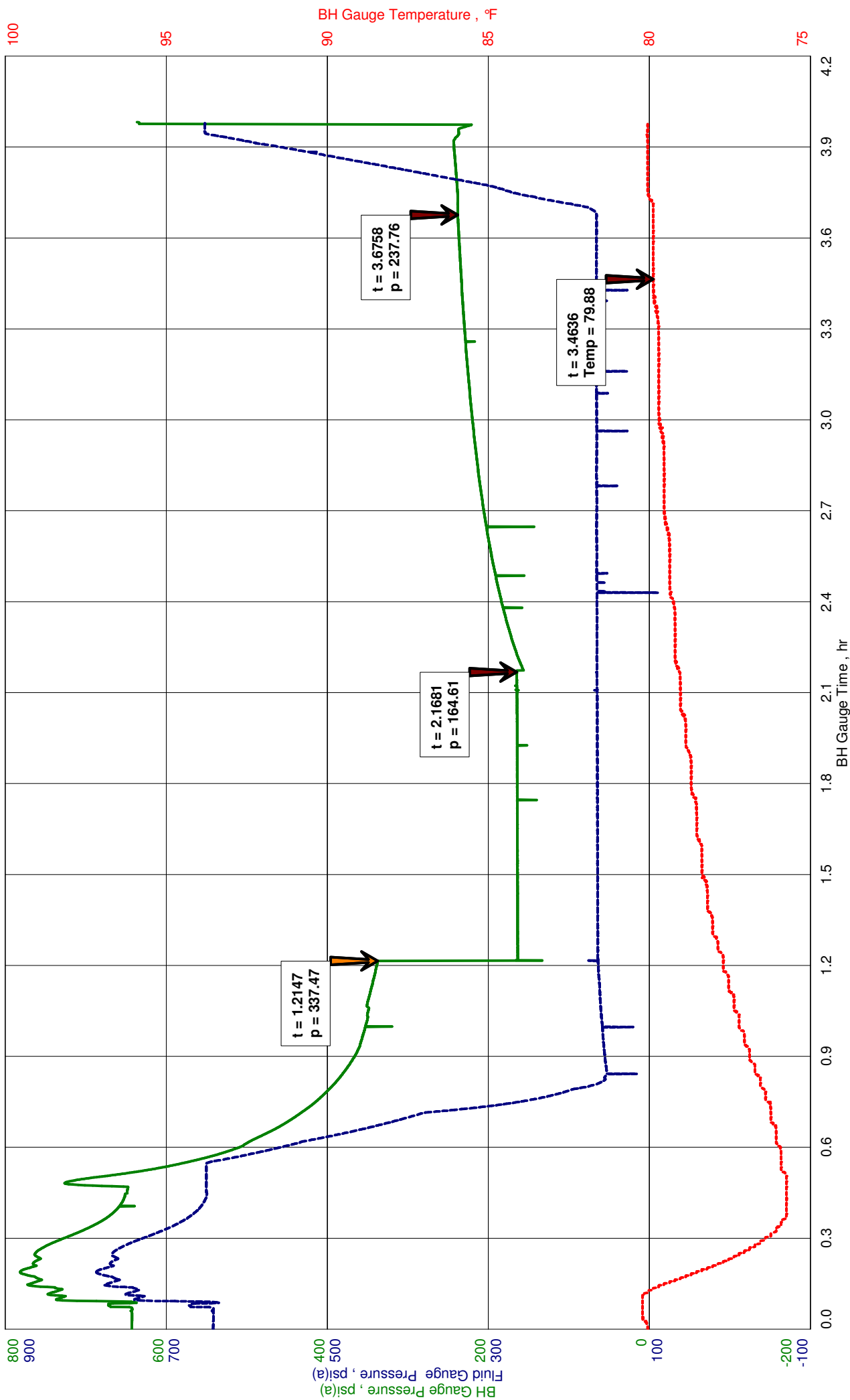


Figure 1

Validata (Late-Time Data)

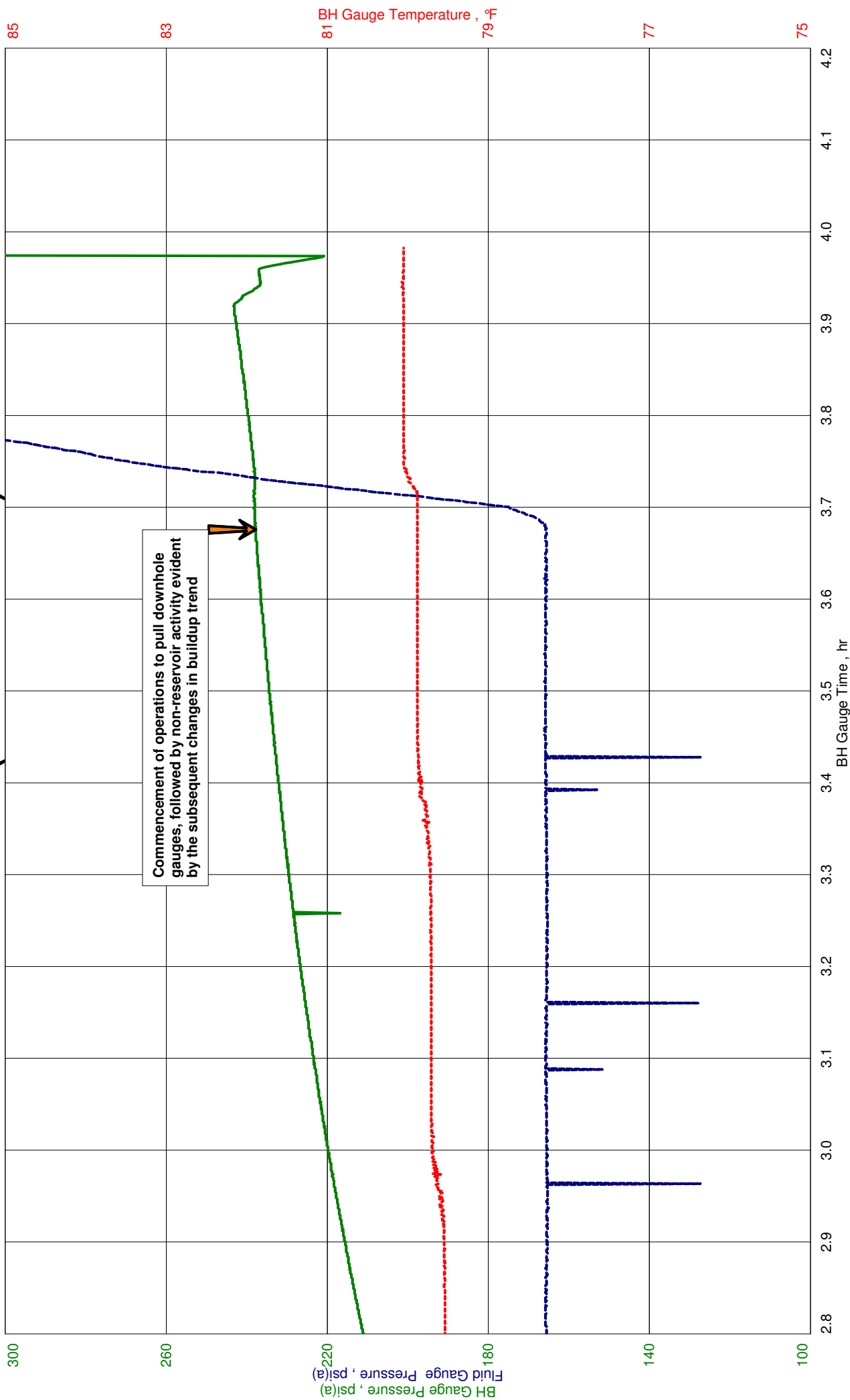


Figure 2

Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007

Analysis 1
p* 272.9 psi

Initial Pressure Falloff
Radial

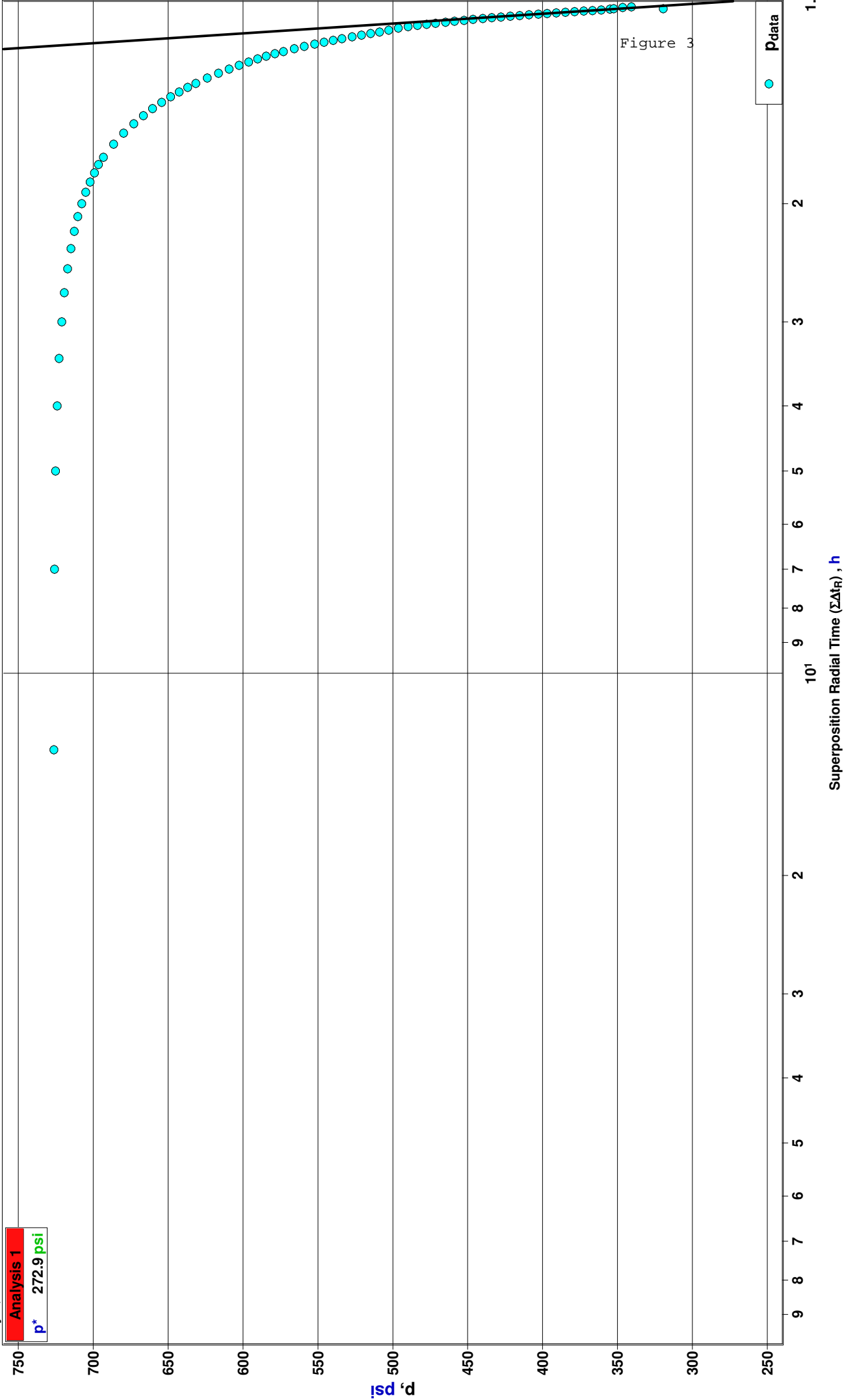
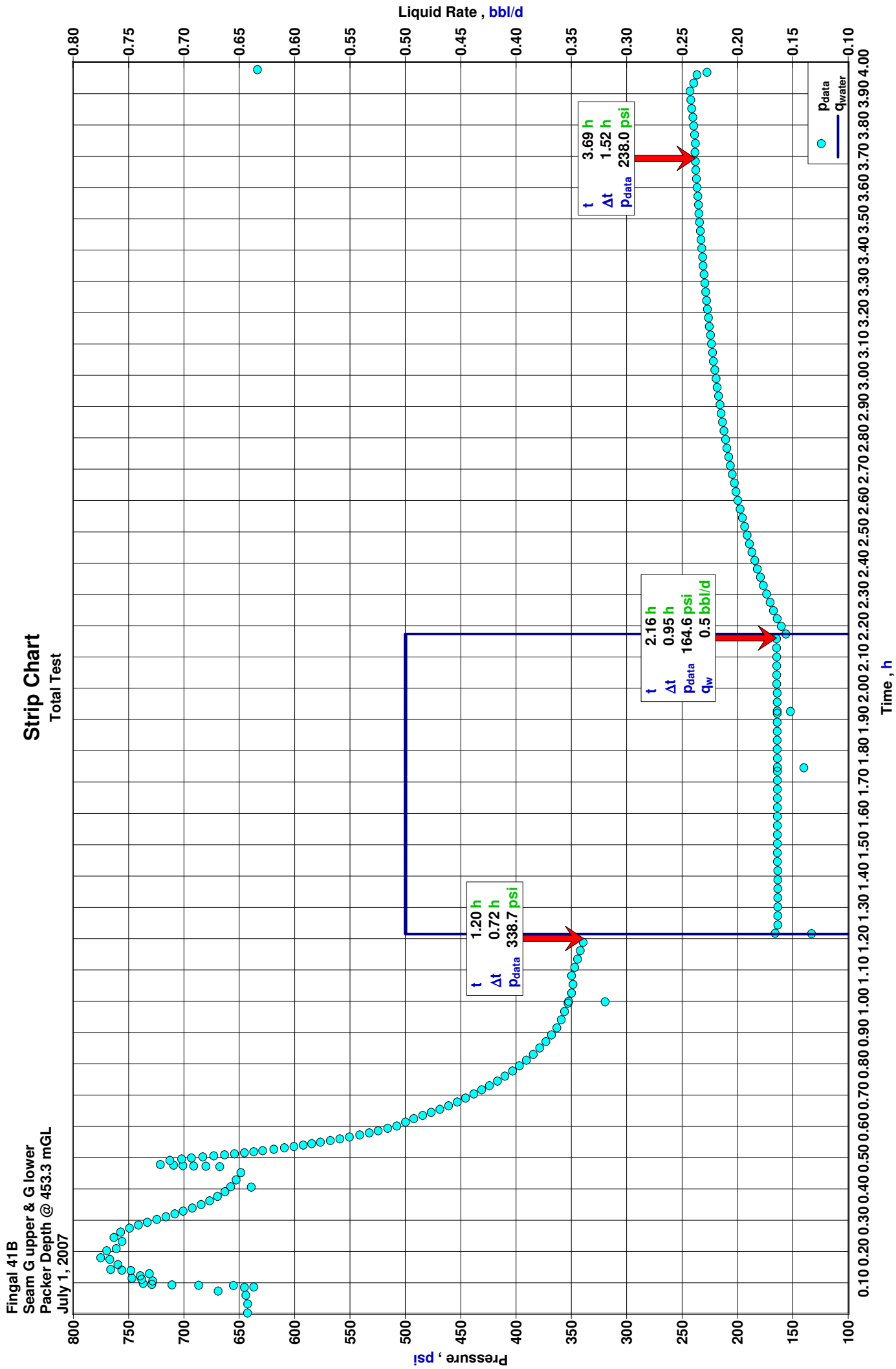


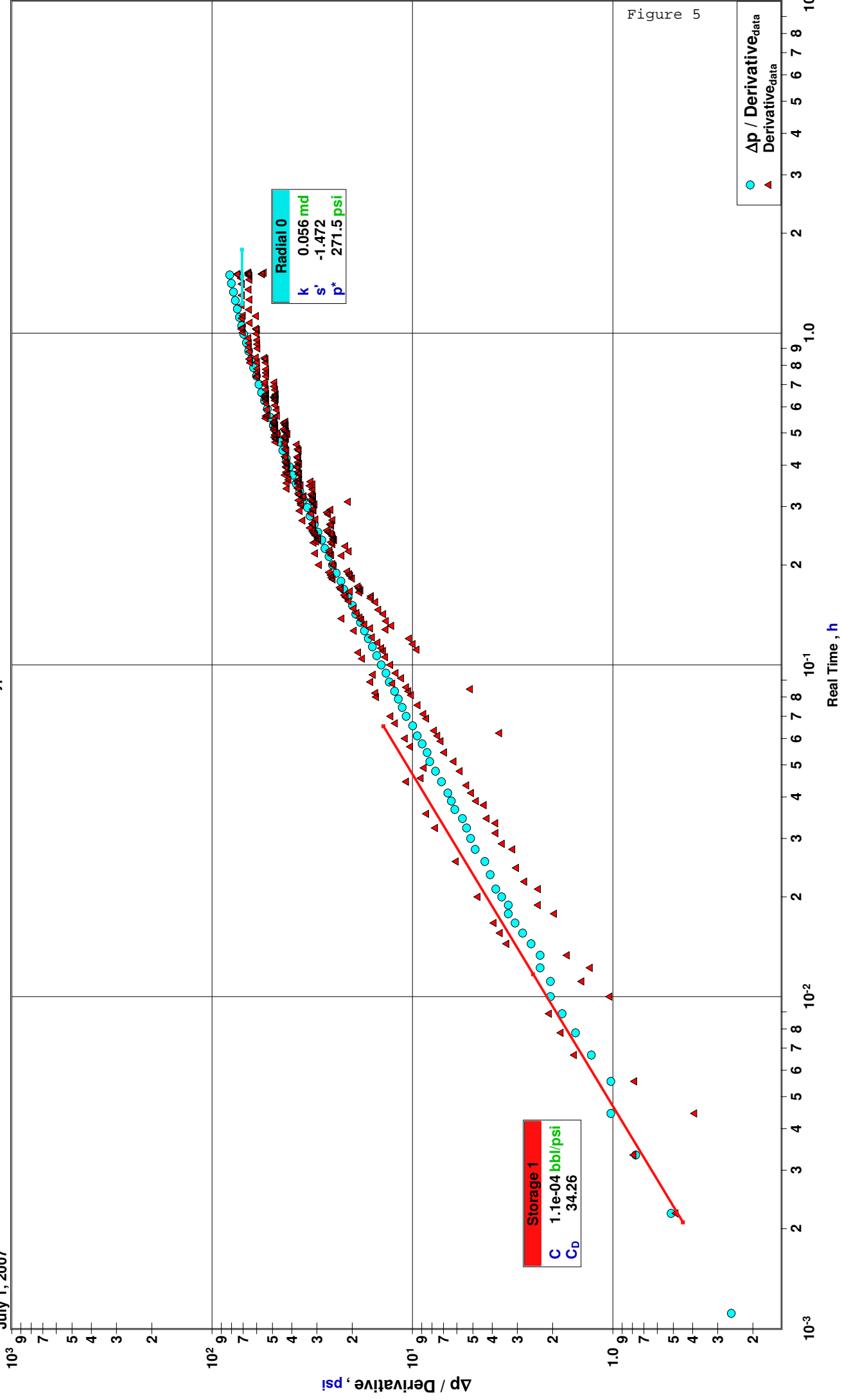
Figure 4



Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007

Diagnostic Analysis

Typecurve



Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007

Diagnostic Analysis
Radial

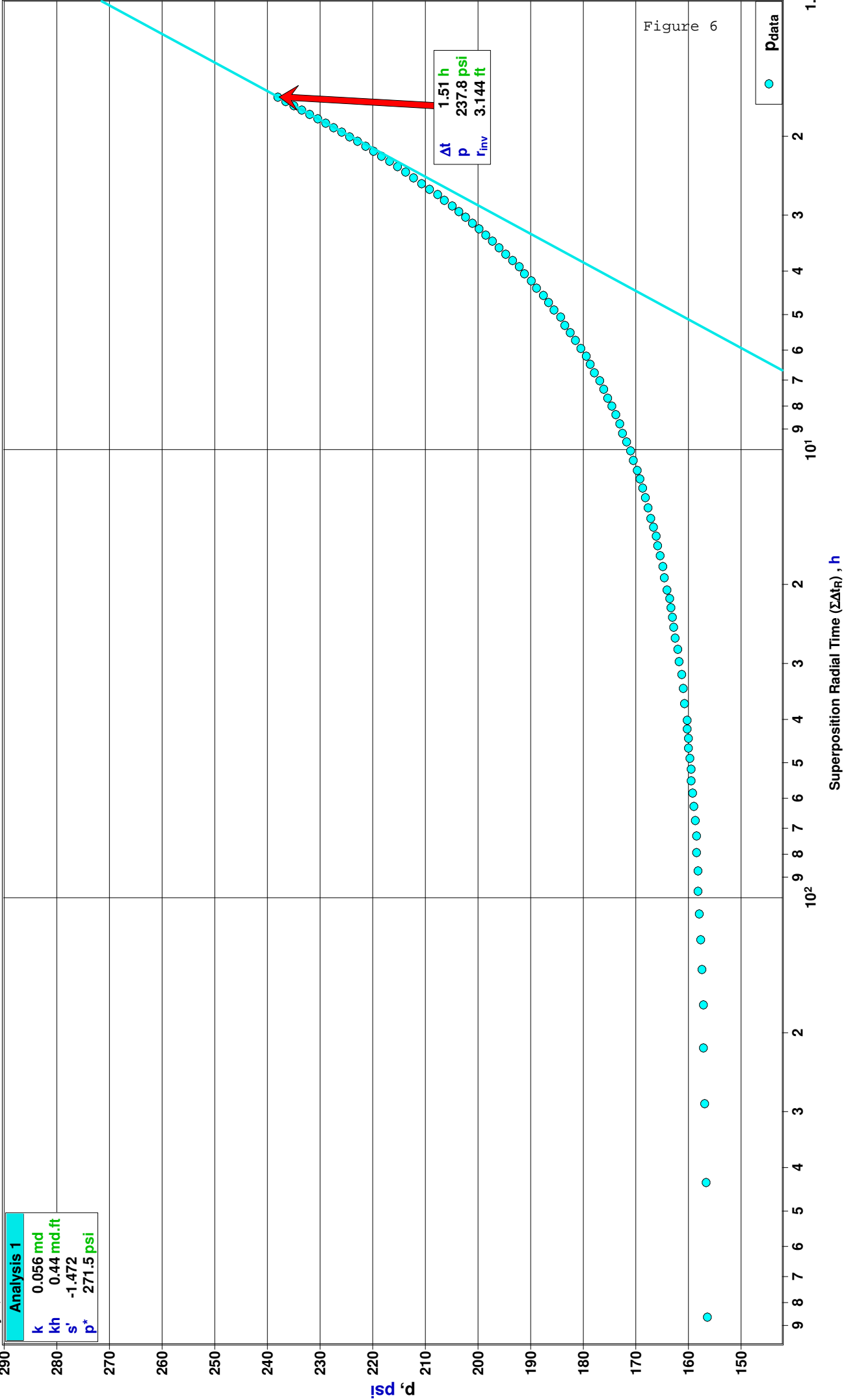


Figure 6

Water Well Test - Buildup

Radial Flow Analysis

Fingal 41B

Packer Depth @ 453.3 mGL

Seam G upper & G lower

July 1, 2007

Analysis Results

Total Sandface Rate ($q_t B_t$)	0.500 bbl/d	Apparent Skin (s')	-1.472
Semilog Slope (m)	157.05	Skin - Damage	-1.475
Gas Permeability (k_g)	md	Skin - Inclination	
Oil Permeability (k_o)	md	Skin - Partial Penetration	
Water Permeability (k_w)	0.056 md	Pressure Drop Due to Skin (Δp_s)	psi
Flow Capacity (kh)	0.443 md.ft	Damage Ratio (DR)	0.381
Total Mobility (k/μ_t)	0.07 md/cp	Flow Efficiency (FE)	2.626
Total Transmissivity (kh/μ_t)	0.52 md.ft/cp		

Reservoir Parameters

Net Pay (h)	7.874 ft
Total Porosity (ϕ_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)	79.9 °F
Formation Compressibility (c_f)	9.482e-6 psi ⁻¹
Total Compressibility (c_t)	2.000e-4 psi ⁻¹

Pressures

Initial Pressure (p_i)	280.00 psi
Extrapolated Pressure (p^*)	271.49 psi
Final Flowing Pressure (p_{wfo})	156.16 psi

Production and Times

Corrected Flow Time (t_c)	0.9562 hr
Cumulative Water Production	0.020 bbl
Final Water Rate	0.500 bbl/d

Fluid Properties

Water Compressibility (c_w)	3.23639e-6 psi ⁻¹
Water Formation Volume Factor (B_w)	1.001
Water Viscosity (μ_w)	0.855 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{pVT})	280.00 psi

Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007

Fingal 41 B
Total Test

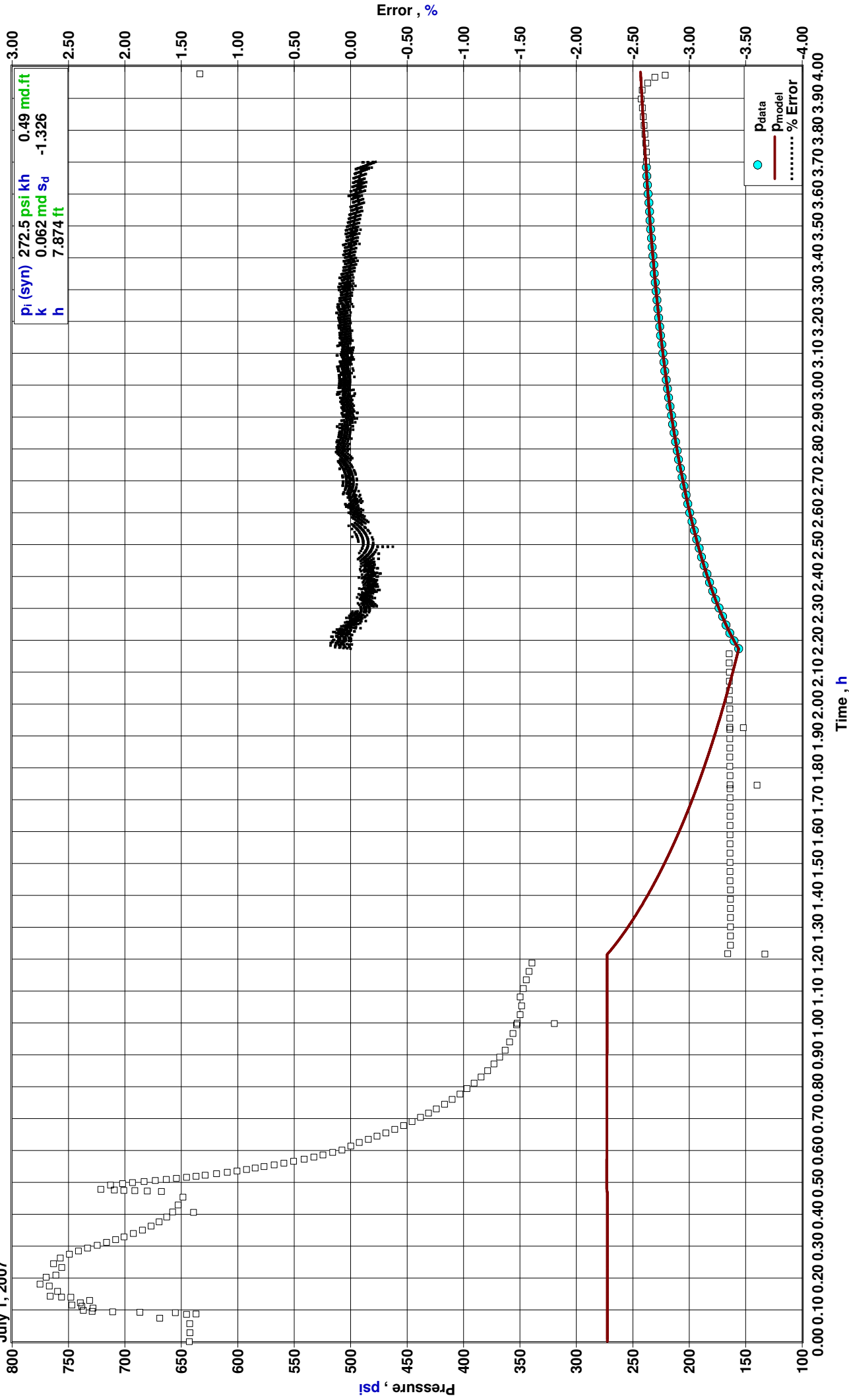
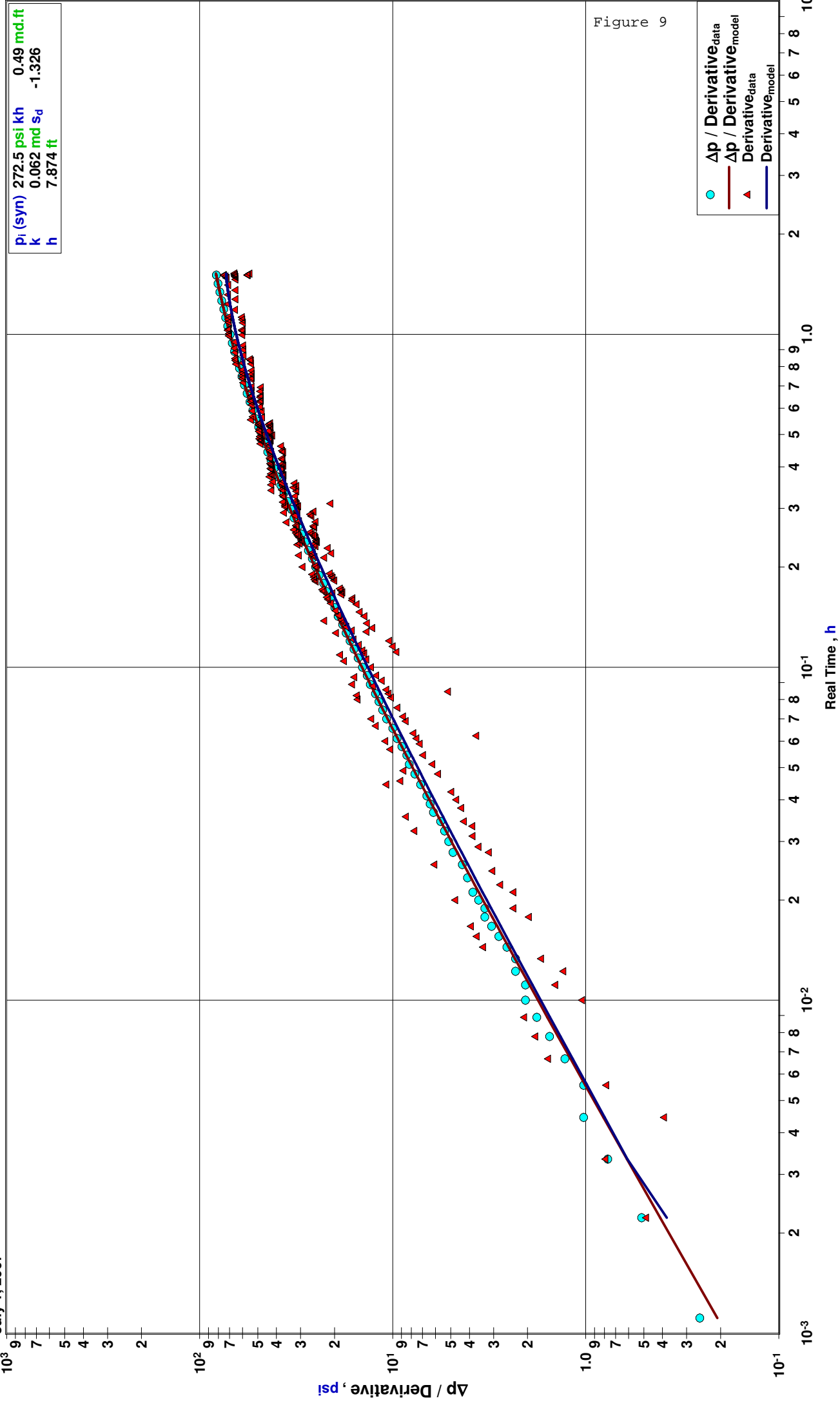


Figure 8

Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007

Simulation
Typecurve

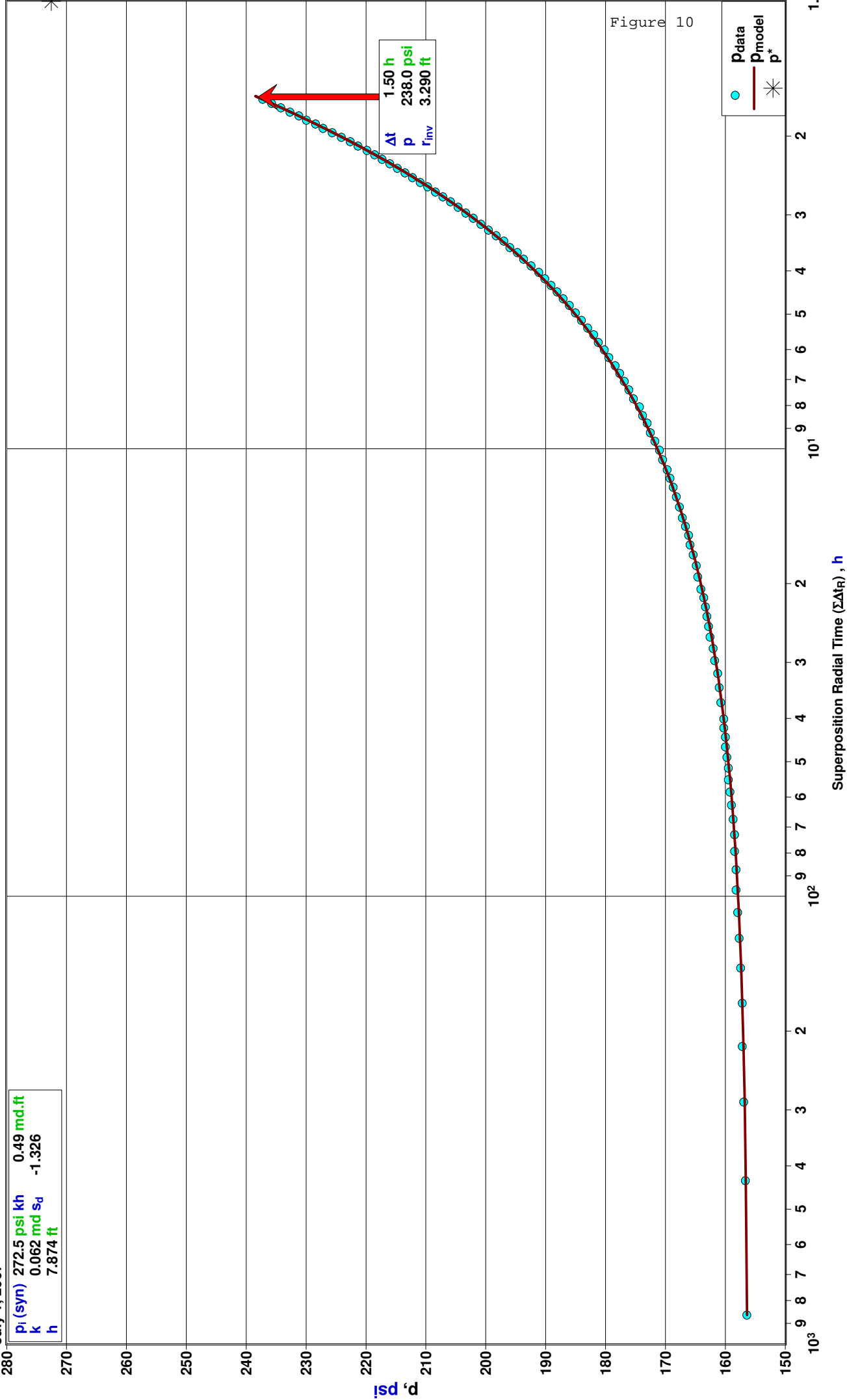
p_i (syn)	272.5	psi	kh	0.49	md.ft
k	0.062	md	s_d	-1.326	
h	7.874	ft			



Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007

p_i (syn)	272.5 psi	kh	0.49 md.ft
k	0.062 md	s_d	-1.326
h	7.874 ft		

Simulation
Radial



Vertical Water Well Model

Case Name : Simulation

Fingal 41B

Packer Depth @ 453.3 mGL

Seam G upper & G lower

July 1, 2007

Model Parameters

Water Permeability (k_w)	0.062 md	Reservoir Length (X_e)	1000000.000 ft
Gas Permeability (k_g)	md	Reservoir Width (Y_e)	1000000.000 ft
Skin (s)	-1.326	Active Well At (X_w)	ft
Total Mobility (k/μ_t)	0.07 md/cp	Active Well At (Y_w)	ft
Total Transmissivity (kh/μ_t)	0.57 md.ft/cp		
Wellbore Storage Constant Dim. (C_D)	25.03		

Formation Parameters

Net Pay (h)	7.874 ft
Total Porosity (ϕ_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)	79.9 °F
Formation Compressibility (c_f)	9.482e-6 psi ⁻¹
Total Compressibility (c_t)	2.000e-4 psi ⁻¹

Fluid Properties

Water Compressibility (c_w)	3.23639e-6 psi ⁻¹
Water Formation Volume Factor (B_w)	1.001
Water Viscosity (μ_w)	0.855 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{pvt})	280.00 psi

Production and Pressure

$Q_t B_t$	0.500 bbl/d
Final Water Rate	0.500 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	156.16 psi
Final Measured Pressure	636.34 psi
Cumulative Water Production	0.020 bbl

Synthesis Results

Average Error	0.07 %
Synthetic Initial Pressure (p_i)	272.54 psi
Extrapolated Pressure at Specified Time	272.53 psi
Pressure Drop Due To Skin (Δp_s)	psi
Flow Efficiency (FE)	1.424
Damage Ratio (DR)	0.702

Forecasts

Forecast Flowing Pressure (P_{flow})	156.16 psi
3 - Month Constant Rate Forecast @ Curr. Skin	0.096 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	0.090 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	0.084 bbl/d
PI / II (Actual)	0.001 bbl/d/psi
Constant Rate Forecast @ Skin=0	0.068 bbl/d
PI / II (Ideal)	0.001 bbl/d/psi
Constant Rate Forecast @ Skin=-4	0.161 bbl/d