FLOW/BUILDUP TEST REPORT #1359

HOME PIERSON 15-09-02-29W1 Copy 2 of 2
SPEARFISH (1020 - 1025 mKB)
TEST DATE: DECEMBER 20 - JANUARY 4, 2000

Prepared for:

ANDERSON EXPLORATION LTD.

Prepared by:

PETRO MANAGEMENT GROUP LTD.

JANUARY 2000

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P M G

Petro Management Group Ltd.

January 19, 2000

ANDERSON EXPLORATION LTD.
1600, 324 - 8th Ave. S.W.
Calgary, Alta., T2P 2Z5

Attn.: Mr. Larry Sopko

HOME PIERSON 15-09-02-29W1
SPEARFISH (1020 - 1025 mKB)
FLOW/BUILDUP TEST
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As requested, a flow/buildup test analysis was performed on the subject well. A summary of the test data and the analysis results is attached. The report marked ORIGINAL contains the test data on a diskette, if available. Three copies of the report are attached.

Should you have any questions, please feel free to contact me at (403) 216-5101.

Yours truly,
Petro Management Group Ltd.

COPY (Original Signed) S. IBRAHIM

Saad Ibrahim, P. Eng.
Principal Engineer

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Summay of Test Data & Results

Case Name : Vertical Model #1

Home Pierson 15-09-02-29W1

Spearfish (1020 - 1025 mKB)

Flow/Buildup Test

Test Date: Dec. 20 - Jan. 4, 1999

Model Parameters

Oil Permeability (k_o)	11.558 mD	Reservoir Length (X_e)	450.00 m
Gas Permeability (k_g)	0.041 mD	Reservoir Width (Y_e)	450.00 m
Water Permeability (k_w)	0.023 mD	Active Well At (X_w)	225.00 m
Total Mobility $(k/\mu)_t$	7.03 mD/mPa.s	Active Well At (Y_w)	225.00 m
Total Transmissivity $(kh/\mu)_t$	21.08 mDm/mPa.s		
Skin (s)	-2.612		

Formation Parameters

Net Pay (h)	3.00 m
Total Porosity (ϕ_t)	17.50 %
Oil Saturation (S_o)	60.00 %
Gas Saturation (S_g)	0.00 %
Water Saturation (S_w)	40.00 %
Wellbore Radius (r_w)	0.091 m
Formation Temperature (T)	42.0 °C
Formation Compressibility (c_f)	5.591e-7 kPa^{-1}
Total Compressibility (c_t)	1.137e-4 kPa^{-1}
Wellbore Storage Constant Dim. (C_D)	387.75

Fluid Properties

Oil Compressibility (c_o)	1.88235e-4 kPa^{-1}
Gas Compressibility (c_g)	4.06720e-4 kPa^{-1}
Water Compressibility (c_w)	4.55806e-7 kPa^{-1}
Oil Formation Volume Factor (B_o)	1.062
Gas Formation Volume Factor (B_g)	0.040194 m^3/m^3
Water Formation Volume Factor (B_w)	1.006
Oil Viscosity (μ_o)	3.353 mPa.s
Gas Viscosity (μ_g)	11.472 µPa.s
Water Viscosity (μ_w)	0.627 mPa.s
Solution Gas Ratio (R_s)	12 m^3/m^3
Oil Gravity (γ_o)	0.835
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{PVT})	2614.67 kPa
Bubble Point Pressure (P_{bp})	2614.67 kPa

Production and Pressure

Q_tB_t	7.792 m^3/d
Final Oil Rate	3.600 m^3/d
Final Gas Rate	0.140 $10^3m^3/d$
Final Water Rate	0.040 m^3/d
Final Flowing Pressure (p_{wfo})	403.00 kPa
Final Measured Pressure	2614.67 kPa
Initial Pressure (p_i)	2614.67 kPa

Synthesis Results

Average Error	-0.16 %
Synthetic Initial Pressure (p_i)	3678.71 kPa
Extrapolated Pressure at Specified Time	3423.49 kPa
Pressure Drop Due To Skin (Δp_s)	kPa
Flow Efficiency (FE)	1.503
Damage Ratio (DR)	0.665

Forecasts

Specified Flowing Pressure (p_{wfs})	403.00 kPa
3 - Month Constant Rate	3.848 m^3/d
6 - Month Constant Rate	3.547 m^3/d
Specified Forecast Time	12.00 month
Forecast Constant Rate @ Current Skin	3.287 m^3/d
PI / II (Total Liquids - Actual)	1.20e-3 $m^3/d/kPa$
Forecast Constant Rate @ Skin=0	2.138 m^3/d
PI / II (Total Liquids - Ideal)	7.57e-4 $m^3/d/kPa$
Forecast Constant Rate @ Skin=-4	4.596 m^3/d

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SUMMARY OF RESULTS

SUMMARY OF RESULTS

1. The average reservoir pressure (P_R) is 3 423 kPa.

2. The effective permeability to oil of the Spearfish formation is 11.6 mD.

3. The apparent wellbore skin factor of -2.6 confirms was stimulated.

4. Production forecast sensitivity indicates that the well will start declining after approximately 8 months.

5. The IPR plot indicates a maximum theoretical stabilized oil rate (AOF) of 3.7 m^3/d.

6. Radius of investigation is approximately 38 m.

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TEST ANALYSIS

DISCUSSION

1. Test Overview:

The Home Pierson 15-09-02-29W1 is completed in the Spearfish formation at 1020 - 1025 mKB and is equipped with a 60.3 mm tubing. The well was fractured during the initial completion to improve productivity.

During the test, the well produced at an oil rate of 3.6 m^3/d. Subsequently, the well was shutin for a 356 hour buildup period. The bottom hole pressures were calculated from the measurement of liquid levels, obtained from the Acoustic Wellsounder equipment by Otatco Inc. The oil gravity is 36 API. Other oil physical properties were calculated using various standard correlations.

2. Data Validation:

During the test, bottom hole pressures were measured using the Acoustic Wellsounder equipment.

The primary pressure derivative (PPD) plot was constructed for the measured pressures (Figure 1) as shown in the Section "Test Data Quality". The PPD showed only minor pressure anomalies. The PPD plot should be monotonically decreasing with time for valid buildup data. Pressure data was reported in absolute at MPP.

TEST INTERPRETATION

1. Pressure Buildup Analysis:

Pressure buildup analysis was performed on the shut-in period. The reservoir parameters were provided by Anderson Exploration Ltd., as shown in the attached form "Summary of Test Data and Results". The final oil rate flow rate prior to shutting in the well was 3.6 m^3/d at a sandface flowing pressure of 403 kPa, as shown in the Strip Chart (Figure 2) in the section "Pressure Transient Analysis".

Both the Horner Plot and the pressure derivative analysis were used in the analysis, as discussed below, and results were later fine tuned using the pressure history match techniques of the test pressure data.

Wellbore storage regime was identified by the unit slope straight of the pressure derivative as shown in the Diagnostic Derivative Analysis plot (Figure 3) in the section "Pressure Transient Analysis". The flattening of the pressure derivative, of the late time data, confirms that radial flow was reached.

Radial flow analysis was performed to determine the reservoir parameters using the semi-log straight line drawn through the late time pressure data, as shown in the Horner plot (Figure 4). The extrapolation of the last data points yielded a P^* of 3 903 kPa. The (P^*) was corrected for the shape, areal extent of the reservoir and the location of the well to determine the average reservoir pressure of 3 870 kPa. The results of the Horner plot and the pressure derivative are summarized below:

	Horner	Derivative
Effective Permeability, mD	9.6	10.3
Reservoir Pressure, kPa	3 870	n/a
Apparent Skin Factor	-3.0	-2.8

2. Pressure History Match:

The preliminary results from the Horner analysis were used as starting parameters for pressure history matching of the test data. The best match of the test data was obtained, using the Wellbore Storage/Skin Model. The overlay of simulated analysis results on the real test data is presented in the cartesian, semi-log and log-log plots (Figures 5, 6, and 7), in the section "Pressure History Match". The parameters used to achieve the history match are as follows:

	History Match	
Reservoir Pressure, P_r	3 423	kPa
Effective Permeability, k	11.6	mD
Skin Factor, S	-3.5	
Six-Month Stabilized Rate, q_s	3.5	m^3/d

3. Inflow Performance Relationship (I.P.R)

The Inflow Performance Relationship (I.P.R) was constructed using the Vogel equation, as shown in Figure 8, in the Section "I.P.R". The average reservoir pressure of 3 252 kPa and the test data were used to generate the I.P.R plot, at the current skin factor of -3.5. The well maximum theoretical oil rate is 2.7 m^3/d.

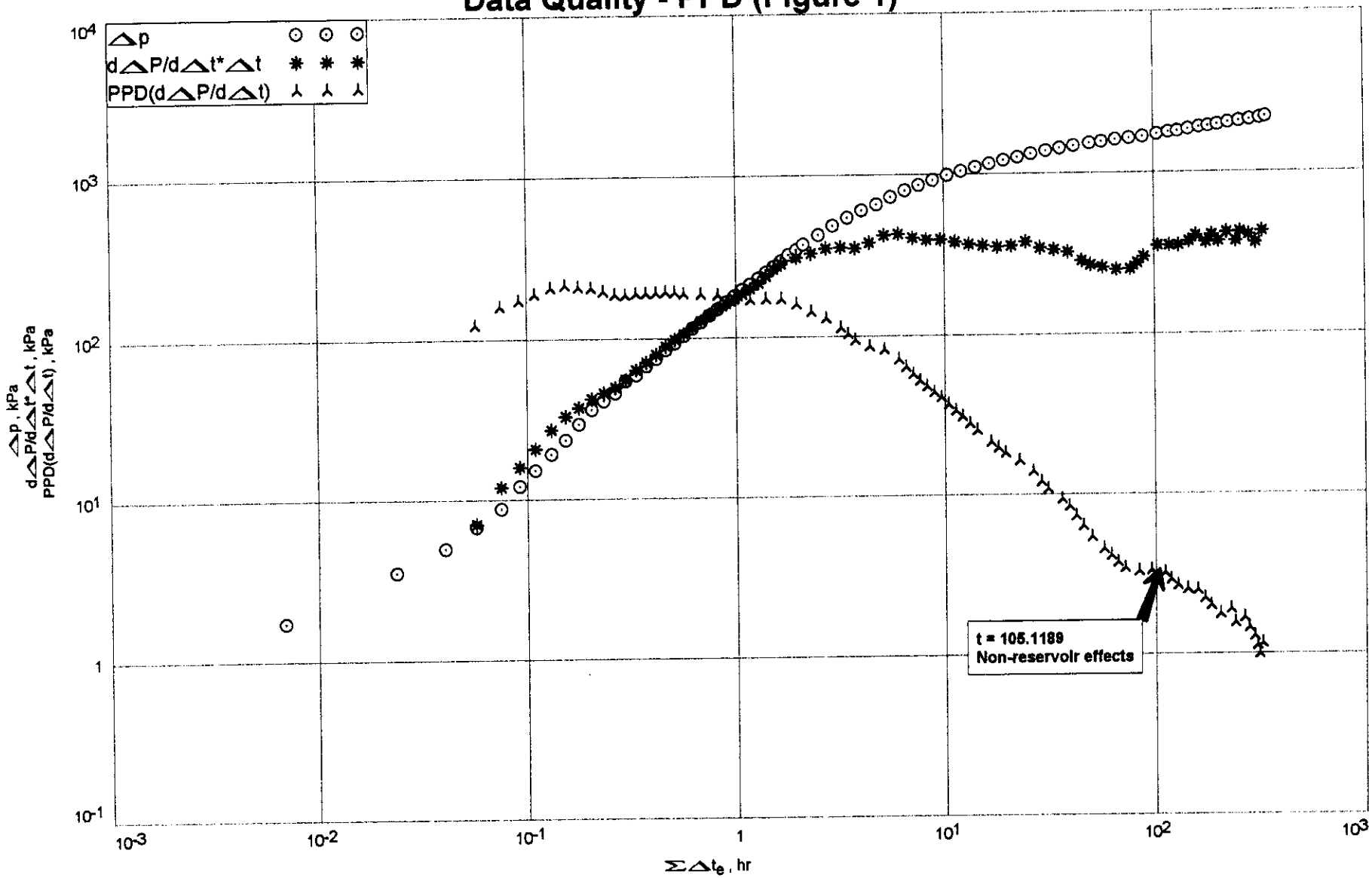
4. Production Forecast Sensitivity Analysis:

Production forecasts were generated for the well using the reservoir parameters obtained from the test history match. Sensitivity analysis was performed in attempt to maximize the oil recovery and to establish a reasonable gas production plateau. The bottom hole flowing pressure (BHFP) was used as a sensitivity parameter, and the various generated production forecasts are shown in Figure 9 in the section "Pressure History Match".

TEST DATA
QUALITY

Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 1999

Data Quality - PPD (Figure 1)



Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 1999

	Time	Cum Time	Pressure	Gas Rate	Oil Rate	Water Rate
	hr	hr	kPa(a)	$10^3m^3/d$	m^3/d	m^3/d
1	-8000.0000	8000.0000	403.00	0.140	3.600	0.040
2	-0.0100	8000.0100	403.00			
3	0.0169	8000.0169	404.72	0.000	0.000	0.000
4	0.0336	8000.0336	406.51			
5	0.0503	8000.0503	407.92			
6	0.0669	8000.0669	409.71			
7	0.0847	8000.0847	411.72			
8	0.1017	8000.1017	415.09			
9	0.1189	8000.1189	418.19			
10	0.1400	8000.1400	422.18			
11	0.1628	8000.1628	426.55			
12	0.1872	8000.1872	432.52			
13	0.2139	8000.2139	439.38			
14	0.2425	8000.2425	444.23			
15	0.2733	8000.2733	448.80			
16	0.3067	8000.3067	457.56			
17	0.3428	8000.3428	462.48			
18	0.3819	8000.3819	470.49			
19	0.4239	8000.4239	477.84			
20	0.4694	8000.4694	488.11			
21	0.5183	8000.5183	496.58			
22	0.5711	8000.5711	506.95			
23	0.6283	8000.6283	518.22			
24	0.6900	8000.6900	529.15			
25	0.7567	8000.7567	541.73			
26	0.8283	8000.8283	555.23			
27	0.9061	8000.9061	570.52			
28	0.9903	8000.9903	584.81			
29	1.0808	8001.0808	601.12			
30	1.1783	8001.1783	617.17			
31	1.2839	8001.2839	635.86			
32	1.3981	8001.3981	655.47			
33	1.5217	8001.5217	675.74			
34	1.6539	8001.6539	699.03			
35	1.7972	8001.7972	726.56			
36	1.9519	8001.9519	751.34			
37	2.1203	8002.1203	778.35			
38	2.3008	8002.3008	803.21			
39	2.4956	8002.4956	831.21			
40	2.7072	8002.7072	859.95			
41	2.9325	8002.9325	891.44			
42	3.1775	8003.1775	917.68			

Print Filter Used: Nth Line = 1.000

Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 1999

	Time	Cum Time	Pressure	Gas Rate	Oil Rate	Water Rate
	hr	hr	kPa(a)	$10^3m^3/d$	m^3/d	m^3/d
43	3.4425	8003.4425	948.90			
44	3.7300	8003.7300	976.38			
45	4.0389	8004.0389	1005.61			
46	4.3722	8004.3722	1033.14			
47	4.7344	8004.7344	1059.64			
48	5.1233	8005.1233	1100.37			
49	5.5431	8005.5431	1132.90			
50	5.9981	8005.9981	1168.92			
51	6.4878	8006.4878	1201.88			
52	7.0194	8007.0194	1234.75			
53	7.5903	8007.5903	1264.07			
54	8.2064	8008.2064	1296.89			
55	8.8719	8008.8719	1327.28			
56	9.5903	8009.5903	1358.17			
57	10.3664	8010.3664	1387.69			
58	11.2039	8011.2039	1421.78			
59	12.1050	8012.1050	1447.24			
60	13.0872	8013.0872	1476.36			
61	14.1425	8014.1425	1507.76			
62	15.2800	8015.2800	1535.57			
63	16.5217	8016.5217	1560.44			
64	17.8456	8017.8456	1589.45			
65	19.2789	8019.2789	1618.17			
66	20.8267	8020.8267	1643.35			
67	22.5081	8022.5081	1672.83			
68	24.3194	8024.3194	1698.56			
69	26.1317	8026.1317	1730.49			
70	26.4017	8026.4017	1737.09			
71	28.5058	8028.5058	1760.59			
72	30.7789	8030.7789	1785.41			
73	33.2308	8033.2308	1810.87			
74	35.8808	8035.8808	1839.80			
75	38.7392	8038.7392	1864.63			
76	41.8475	8041.8475	1889.33			
77	45.1831	8045.1831	1913.19			
78	49.6981	8049.6981	1938.75			
79	52.6622	8052.6622	1952.32			
80	56.8581	8056.8581	1972.60			
81	61.4206	8061.4206	1992.37			
82	66.3122	8066.3122	2014.96			
83	71.5997	8071.5997	2030.82			
84	77.3414	8077.3414	2048.30			

Print Filter Used: Nth Line = 1.000

Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 1999

	Time	Cum Time	Pressure	Gas Rate	Oil Rate	Water Rate
	hr	hr	kPa(a)	$10^3m^3/d$	m^3/d	m^3/d
85	83.5039	8083.5039	2069.88			
86	89.5042	8089.5042	2086.25			
87	96.1583	8096.1583	2112.24			
88	105.1289	8105.1289	2141.38			
89	111.1292	8111.1292	2160.76			
90	113.5039	8113.5039	2169.60			
91	119.5042	8119.5042	2188.82			
92	122.5539	8122.5539	2198.19			
93	128.5542	8128.5542	2211.92			
94	132.3789	8132.3789	2221.53			
95	138.3792	8138.3792	2237.90			
96	142.9289	8142.9289	2253.46			
97	148.9292	8148.9292	2263.96			
98	154.3206	8154.3206	2278.92			
99	160.3208	8160.3208	2289.11			
100	167.8564	8167.8564	2316.21			
101	173.8439	8173.8439	2328.12			
102	179.8039	8179.8039	2339.03			
103	185.8042	8185.8042	2349.94			
104	191.8044	8191.8044	2360.00			
105	194.1872	8194.1872	2370.05			
106	200.1875	8200.1875	2382.40			
107	206.1878	8206.1878	2392.86			
108	209.5539	8209.5539	2398.83			
109	215.5542	8215.5542	2409.09			
110	221.5544	8221.5544	2415.37			
111	226.3539	8226.3539	2424.55			
112	232.3542	8232.3542	2439.94			
113	238.3544	8238.3544	2450.33			
114	244.5206	8244.5206	2460.26			
115	250.5208	8250.5208	2471.12			
116	256.5211	8256.5211	2472.97			
117	263.8706	8263.8706	2489.42			
118	269.8708	8269.8708	2494.97			
119	275.8711	8275.8711	2509.16			
120	281.8714	8281.8714	2520.02			
121	285.0372	8285.0372	2520.62			
122	291.0375	8291.0375	2531.90			
123	297.0378	8297.0378	2536.89			
124	303.0381	8303.0381	2546.47			
125	307.9039	8307.9039	2556.53			
126	313.9042	8313.9042	2558.00			

Print Filter Used: Nth Line = 1.000

Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 1999

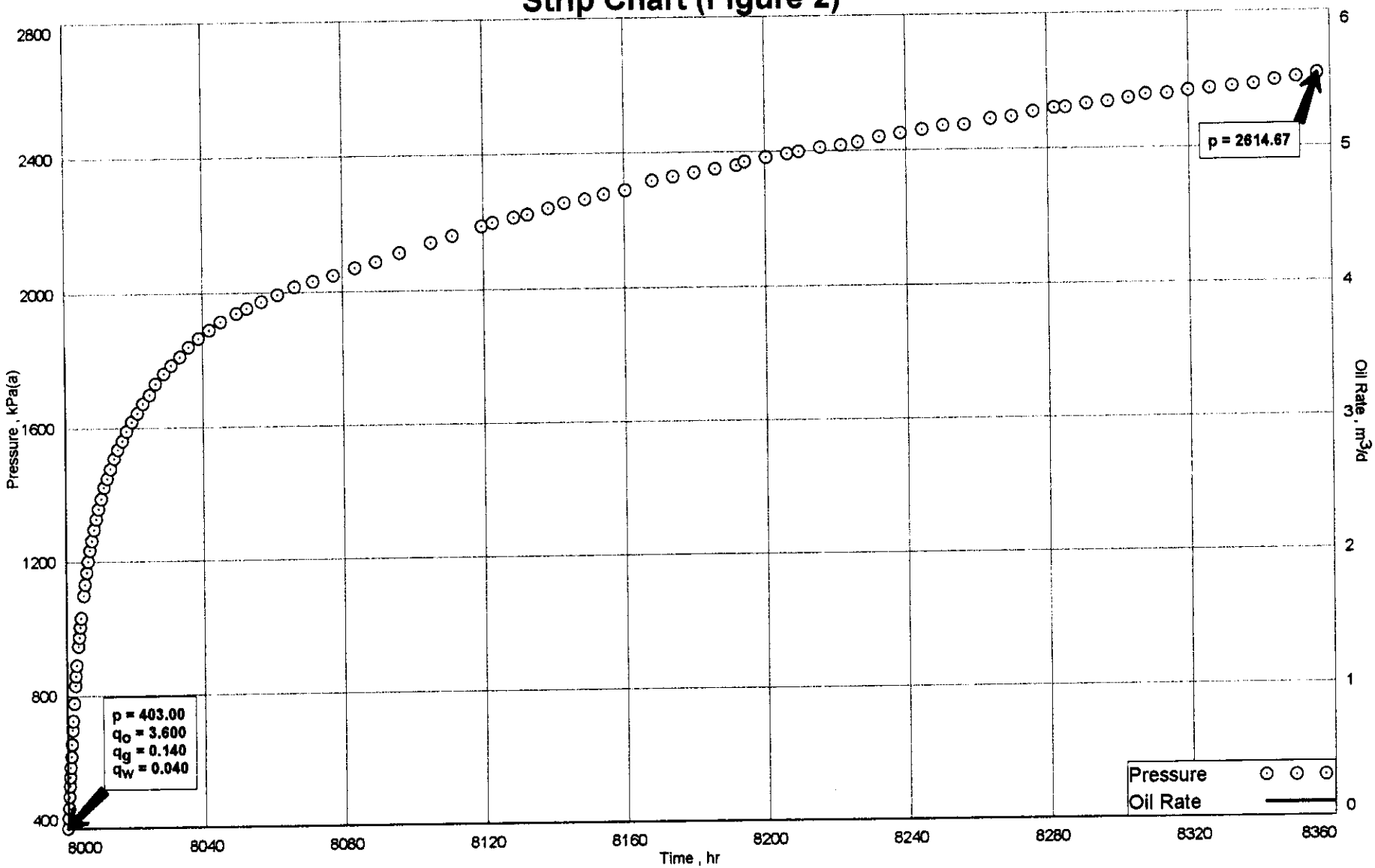
	Time	Cum Time	Pressure	Gas Rate	Oil Rate	Water Rate
	hr	hr	kPa(a)	$10^3m^3/d$	m^3/d	m^3/d
127	319.9044	8319.9044	2567.44			
128	325.9047	8325.9047	2572.64			
129	332.2706	8332.2706	2577.88			
130	338.2708	8338.2708	2584.21			
131	344.2711	8344.2711	2594.99			
132	350.2714	8350.2714	2603.56			
133	356.2717	8356.2717	2614.67			

Print Filter Used: Nth Line = 1.000

PRESSURE TRANSIENT ANALYSIS

Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 1999

Strip Chart (Figure 2)



Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
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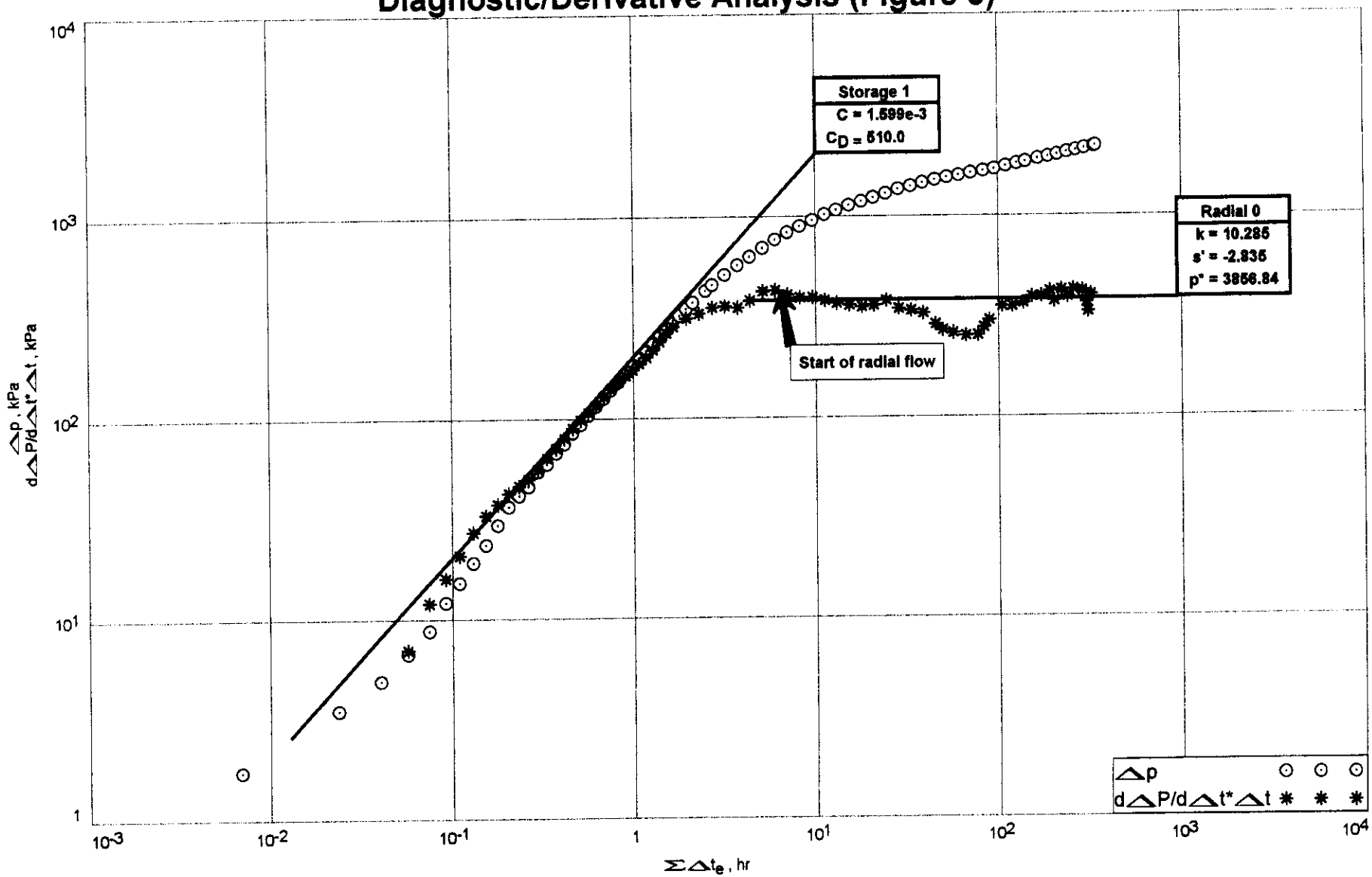
Diagnostic/Derivative Analysis (Figure 3)



Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
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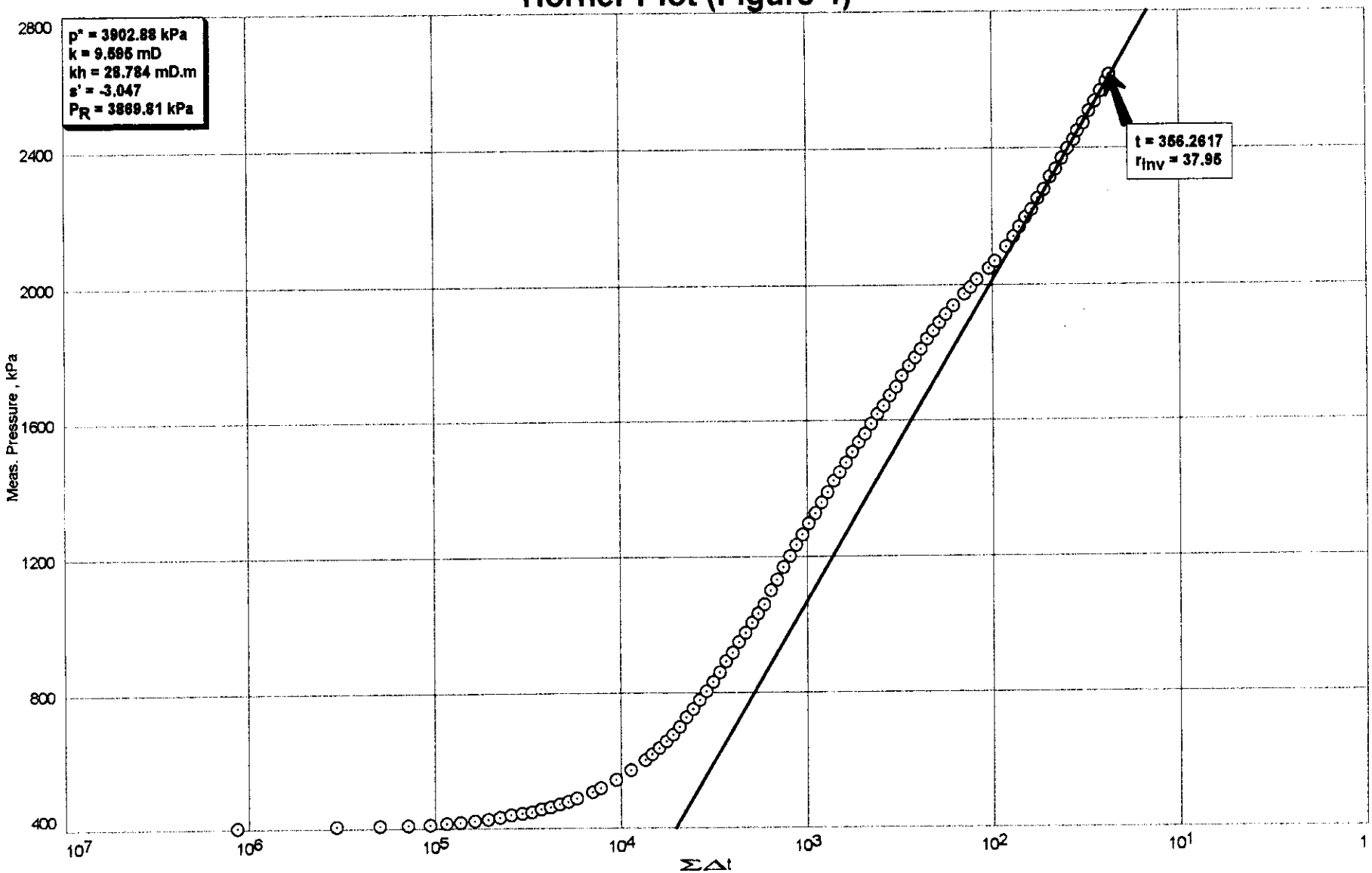
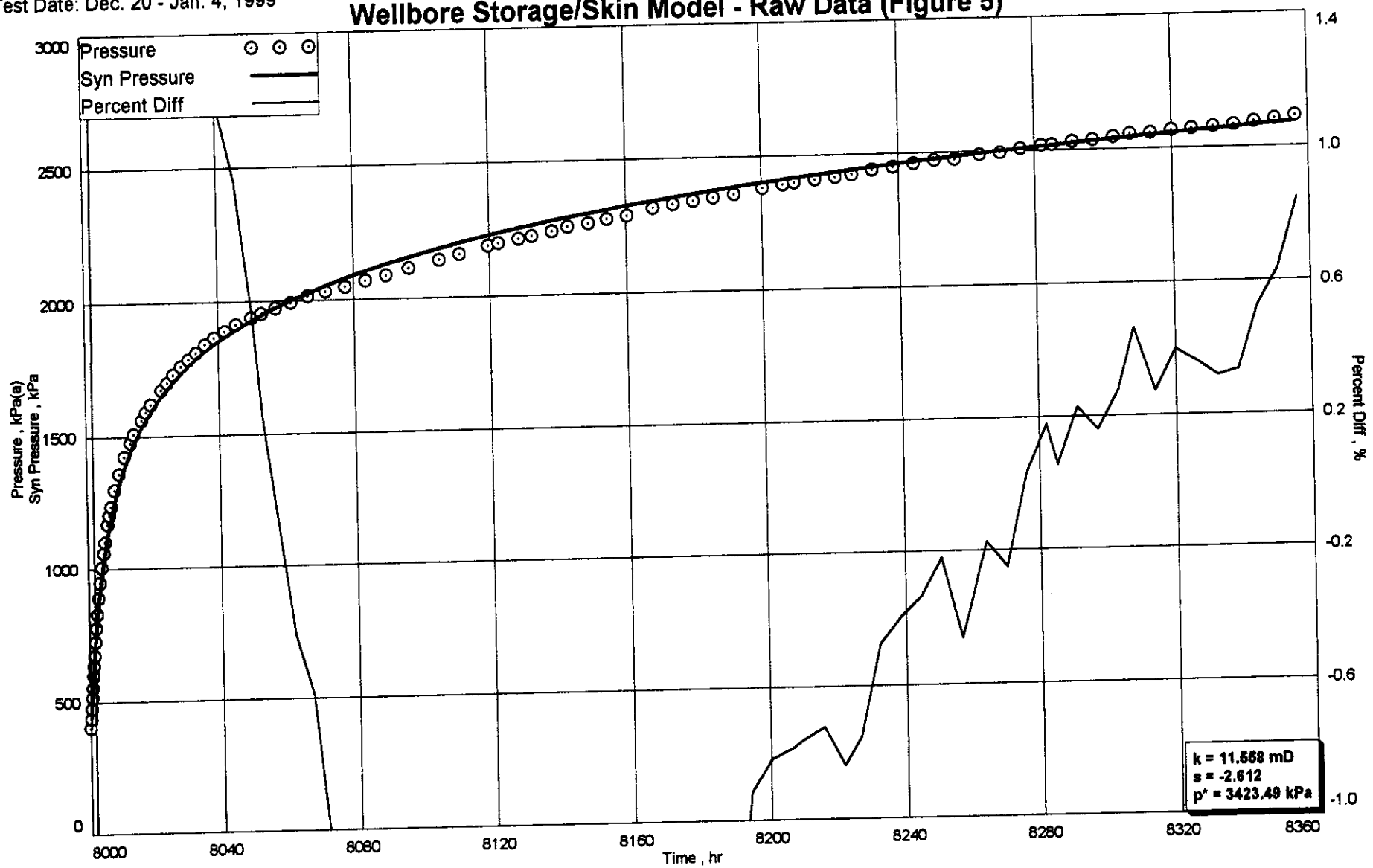
Horner Plot (Figure 4)



PRESSURE
HISTORY
MATCHING

Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 1999

Wellbore Storage/Skin Model - Raw Data (Figure 5)



Home Pierson 15-09-02-29W1
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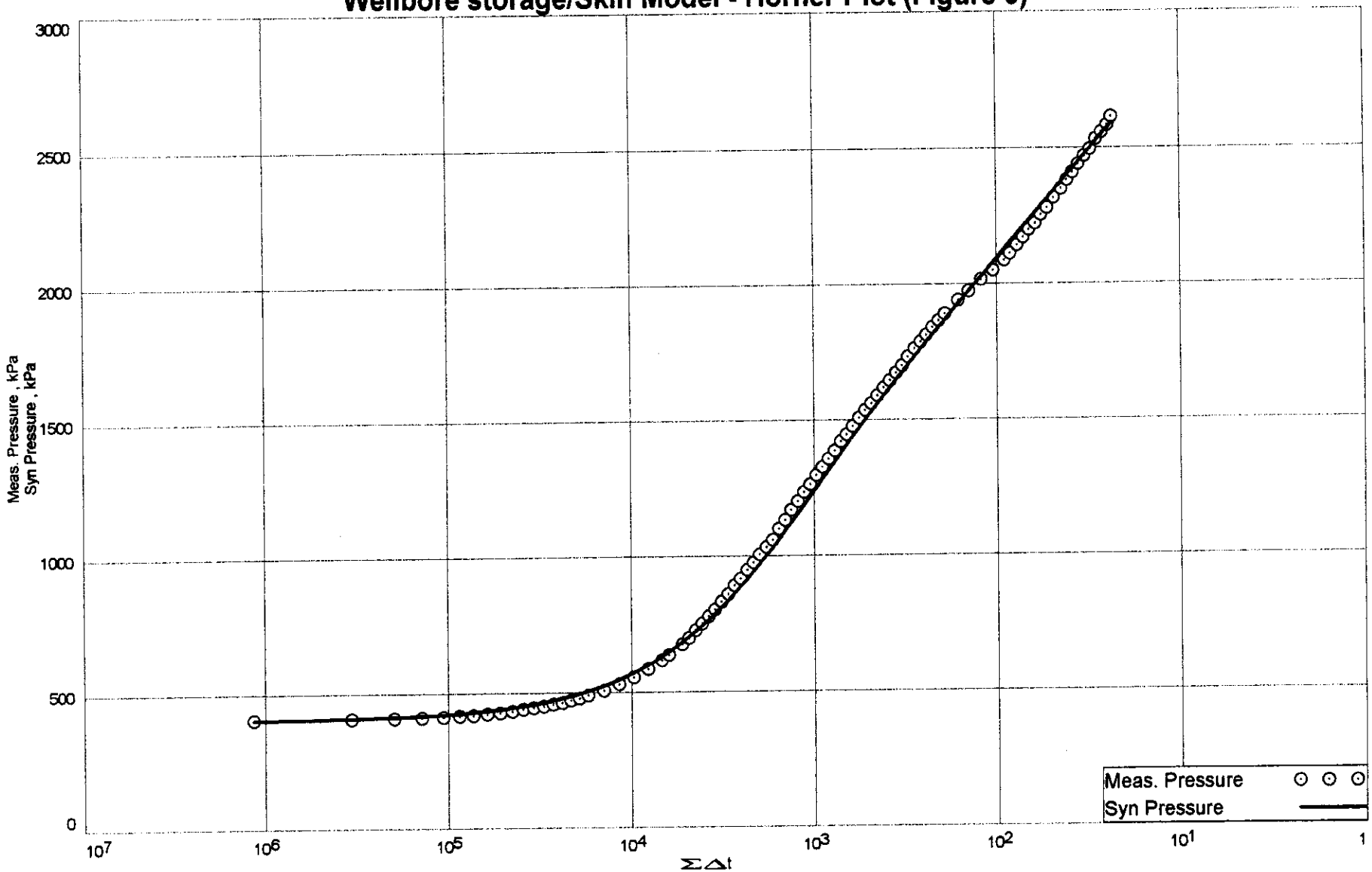
Wellbore storage/Skin Model - Horner Plot (Figure 6)



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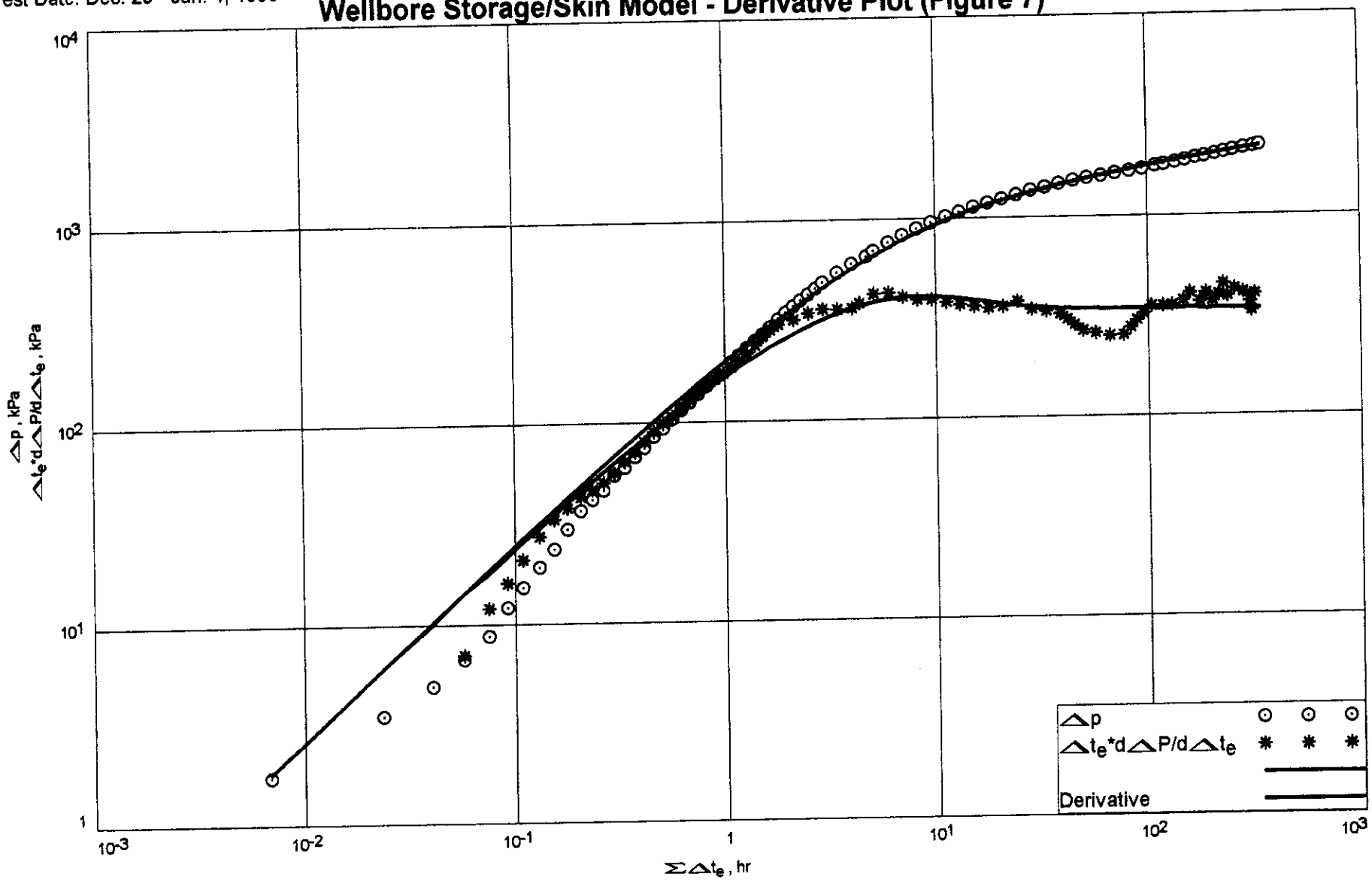
Wellbore Storage/Skin Model - Derivative Plot (Figure 7)



Home Pierson 15-09-02-29W1
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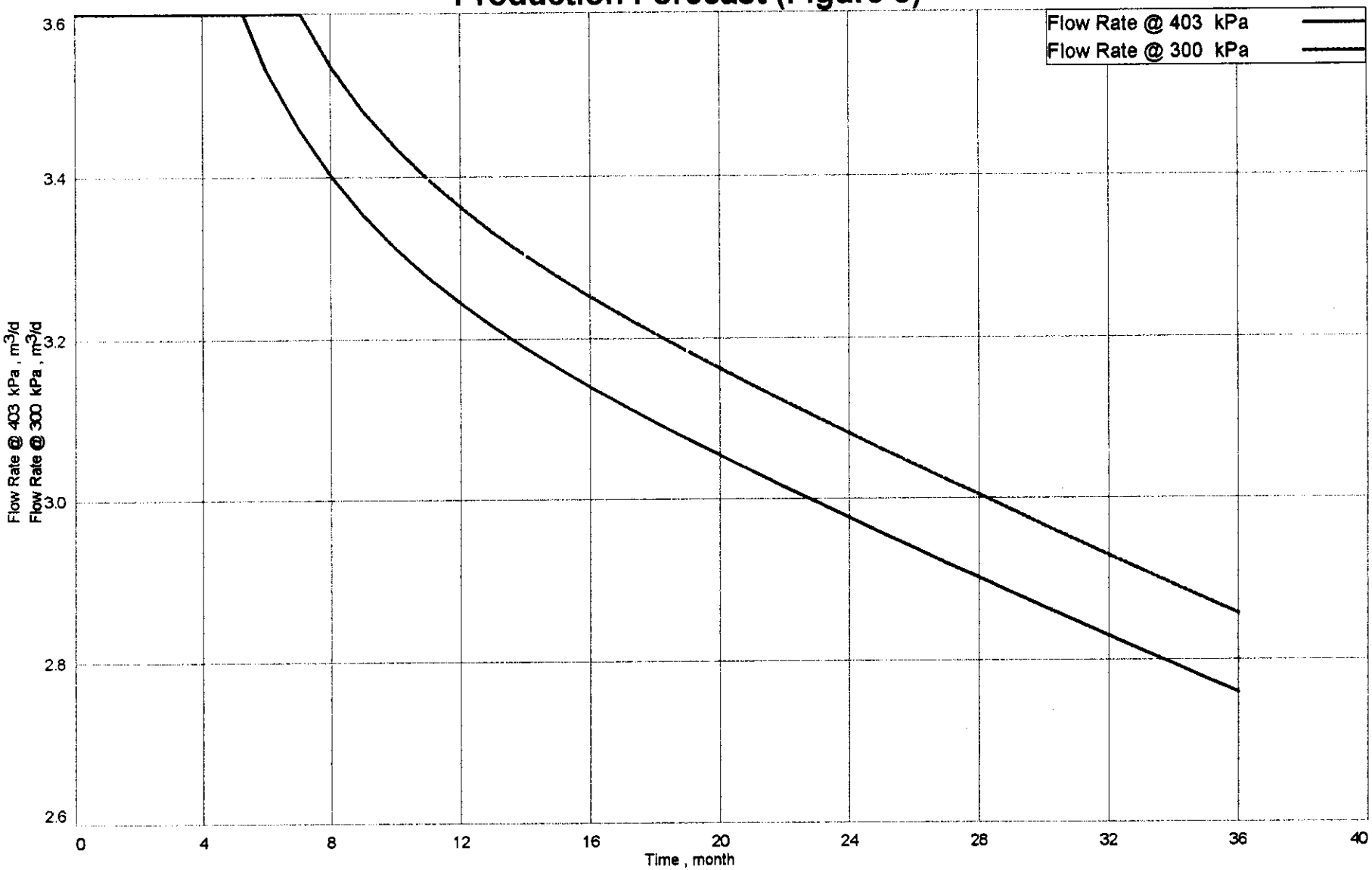
Production Forecast (Figure 8)



I.P.R.

Inflow Performance Relationship
(I.P.R.)

Home Pierson 15-09-02-29W1
Spearfish (1020 - 1025 mKB)

Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 1999

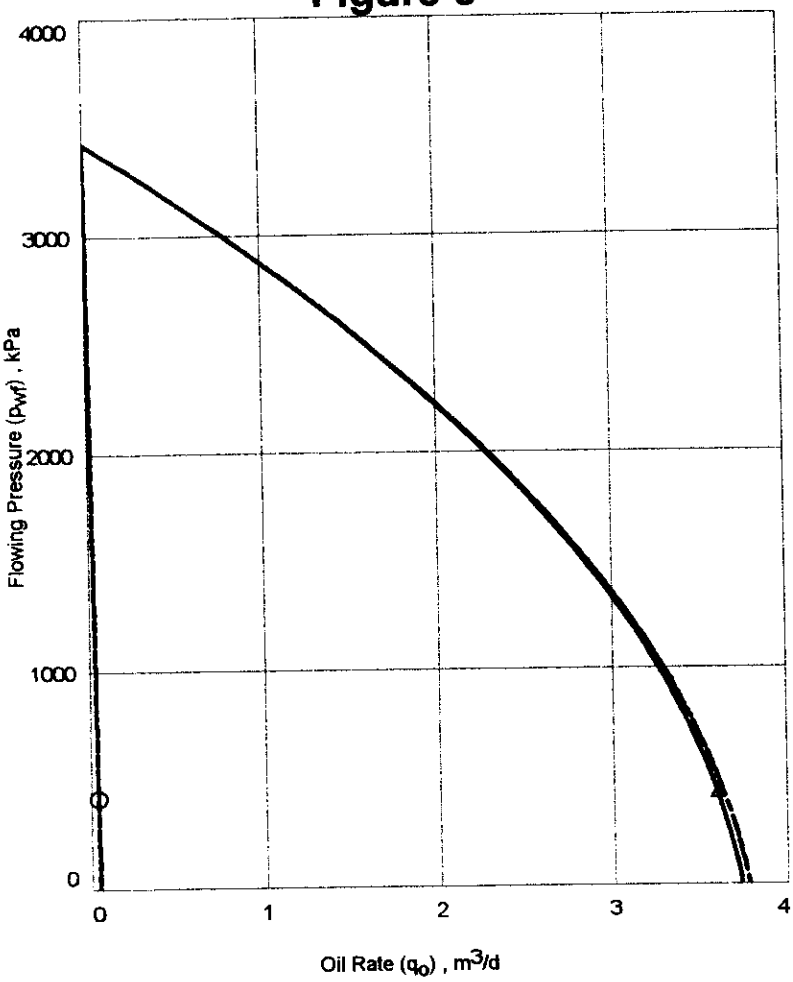
Test Data

Reservoir Pressure (p_R)	3424.00	kPa
Bubble Point Pressure (p_{bp})		kPa
Test Pressure (p_{wf})	418.00	kPa
Oil Test Rate (q_o)	3.600	m^3/d
Water Test Rate (q_w)	0.040	m^3/d

Results

Maximum Oil Rate	3.736	m^3/d
Maximum Water Rate	0.046	m^3/d
Maximum Total Rate	3.781	m^3/d

Figure 8



Flowing Pressure	Oil Rate	Water Rate	Total Rate
kPa	m^3/d	m^3/d	m^3/d
0.00	3.736	0.046	3.781
300.00	3.647	0.042	3.689
418.00*	3.600	0.040	3.640
600.00	3.513	0.038	3.551
900.00	3.333	0.034	3.366
1200.00	3.107	0.030	3.136
1500.00	2.835	0.026	2.860
1800.00	2.517	0.022	2.539
2100.00	2.153	0.018	2.171
2400.00	1.744	0.014	1.757
2700.00	1.288	0.010	1.298
3000.00	0.787	0.006	0.793
3300.00	0.240	0.002	0.241
3424.00	0.000	0.000	0.000

Note : * Test Point
** Bubble Point
Oil IPR based on Vogel's Equation.
(Quadratic Curve Factor=0.2)

SUBSURFACE
PRESSURES

EQUATIONS

and

NOMENCLATURE

(METRIC UNITS)

PMG

BASIC TIME FUNCTIONS

Flow Time t

Shut-In Time Δt

Horner Time $\frac{t + \Delta t}{\Delta t}$

Superposition Time $t_n = \sum_{j=1}^{n} \frac{q_j - q_{j-1}}{q_n} \log(t - t_{j-1})$

$$\Delta t_n = \sum_{j=1}^{n} \frac{q_j}{q_n} \log \frac{t_n + \Delta t - t_{j-1}}{t_n + \Delta t - t_j}$$

Equivalent Time $\Delta t_e = \frac{t \cdot \Delta t}{t + \Delta t}$

Root Time $\sqrt{t}$

$\sqrt{\Delta t}$

Tandem Root Time $\sqrt{t + \Delta t} - \sqrt{\Delta t}$

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BASIC TIME FUNCTIONS (cont'd)

Quad Root Time $\sqrt[4]{t}$

$\sqrt[4]{\Delta t}$

Tandem Quad Root Time $\sqrt[4]{t+\Delta t} - \sqrt[4]{\Delta t}$

TYPECURVES - DIMENSIONLESS VARIABLES

$$\Delta p_D = \frac{(kh/\mu)_t \, \Delta p}{141.2 \, q_t \, B_t}$$

$$t_D = \frac{2.637E{-}4(k/\mu)_t \, t}{\phi c r_w^2}$$

$$\frac{t_D}{C_D} = 0.000295 \, (\frac{kh}{\mu})_t \frac{t}{C}$$

$$C_D e^{2s} = \frac{0.8936 \, C \, e^{2s}}{\phi c h r_w^2}$$

$$t_{DA} = \frac{2.637E{-}4 \, (k/\mu)_t \, t}{\phi c A}$$

$$t_{Dxf} = \frac{2.637E{-}4 \, (k/\mu)_t \, t}{\phi c x_f^2}$$

$$(k_f w)_D = \frac{k_f w}{k x_f}$$

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McKINLEY ANALYSIS

Wellbore Capacity

$$F = \left(\frac{\Delta p\ F}{qB}\right)\left(\frac{qB}{\Delta p}\right)$$

Alpha

$$\alpha = \frac{F}{5.615}$$

Note: Alpha is the same as C

Wellbore Storage Constant
Compressible Fluid

$$C = c_{ws} V_{ws}$$

Wellbore Storage Constant
Changing Liquid Level

$$C = \frac{cross\text{-}sectional\ area}{5.615\ liquid\ gradient}$$

Transmissivity

$$\frac{kh}{\mu} = \left(\frac{T}{F}\right) F$$

Pressure Drop Skin

$$\Delta p_s = \left[1 - \frac{kh_{(wellbore)}}{kh_{(formation)}}\right] \Delta p_{(departure)}$$

Flow Efficiency

$$FE = \frac{p^* - p_{wf} - \Delta p_s}{p^* - p_{wf}}$$

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SEMILOG ANALYSIS

Transmissivity

$$\left(\frac{kh}{\mu}\right)_t = \frac{162.6\ q_t\ B_t}{m}$$

Permeability

$$k = \frac{162.6\ q_o\ B_o\ \mu_o}{mh}$$

Skin Factor

$$s' = 1.151\left[\frac{p_{ws} - p_{wfo}}{m} - \log\frac{t\Delta t}{t+\Delta t} - \log\left(\frac{(k/\mu)_t}{\phi_t c_t r_w^2}\right) + 3.23\right]$$

Pressure Drop due to Skin

$$\Delta p_s = 0.869\ ms'$$

Flow Efficiency

$$FE = \frac{\bar{p}_R - p_{wfo} - 0.869\ ms'}{\bar{p}_R - p_{wfo}}$$

Damage Ratio

$$DR = \frac{1}{FE}$$

Radius of Investigation

$$r_{inv} = \sqrt{\frac{(k/\mu_t)\ t}{948\phi_t c_t}}$$

Time to Stabilization

$$t_s = \frac{\phi\ c\ A}{2.637E{-}4\ (k/\mu)_t}(t_{DA})_{pss}$$

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SEMILOG ANALYSIS (cont"d)

Stabilized Rate

$$q_s = \frac{p_i - p_{wfo}}{\frac{162.6\ B_o}{(k/\mu)_o\ h}\left[\log\left(\frac{4A}{1.781\ r_w^2 C_A}\right) + \frac{4\pi(t_{DA})_{pss}}{2.303} + \frac{2s'}{2.303}\right]}$$

Productivity Index

$$PI = \frac{q}{\bar{p}_R - p_{wfo}}$$

MBH Average Pressure

$$\bar{p}_R = p^* - \frac{m}{2.303}\ (MBH\ function)$$

DIETZ Average Pressure

$$(\Delta t)_{\bar{p}_R} = \frac{\phi\ c_t\ A}{2.637E{-}4\ C_A (k/\mu)_t}$$

LINEAR ANALYSIS

Fracture half-length

$$x_f = \frac{4.064\ q_t\ B_t}{mh(\phi ck/\mu)_t^{1/2}}$$

Channel width

$$W = \frac{8.128\ q_t\ B_t}{mh(\phi ck/\mu)_t^{1/2}}$$

Skin Factor

$$s = \ln \frac{2\ r_w}{x_f}$$

BI-LINEAR ANALYSIS

Fracture Conductivity

$$k_f w = \left[\frac{44.1\ qB\mu}{mh(\phi\mu ck)^{1/4}}\right]^2$$

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NOMENCLATURE

Symbol	Description	Metric (SI)	Field
a	LIT flow equation coefficient	-	-
A	drainage area	m^2	ft^2
AOF	absolute open flow potential (gas)	$10^3m^3/d$	MMcfd
b	LIT flow equation coefficient	-	-
B	formation volume factor	-	-
c	compressibility	kpa^{-1}	psi^{-1}
c_{ws}	compressibility of wellbore fluids	kpa^{-1}	psi^{-1}
C	wellbore storage/unloading constant	m^3/kPa	bbl/psi
C	simplified flow equation coefficient	-	-
C_A	shape factor	-	-
C_{aD}	apparent wellbore storage constant	-	-
C_D	dimensionless wellbore storage constant	-	-
C_{pD}	storage pressure parameter	-	-
DR	damage ratio	-	-
F	wellbore capacity (McKinley)	m^3/kPa	ft^3/psi
FE	flow efficiency	-	-
G	relative density (gas)	-	-
GOR	gas-oil ratio	m^3/m^3	ft^3/bbl
h	net pay	m	ft
k	permeability	mD	md
$k_{(x,y,z)}$	permeability in the x,y,z direction	mD	md
k_f	fracture permeability	mD	md
k_fw	fracture conductivity	mD.m	md.ft
kh	flow capacity	mD.m	md.ft
k/μ	mobility	-	-
kh/μ	transmissivity	-	-

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Symbol	Description	Metric (SI)	Field
L	length of horizontal well	m	ft
L_e	effective length of horizontal well	m	ft
m	slope of transient plots	-	-
n	simplified flow equation coefficient	-	-
p	pressure	kPa	psia
p_{bp}	bubble point pressure	kPa	psia
p_c	gas pseudo-critical pressure	kPa	psia
p_i	initial pressure	kPa	psia
p_R	average reservoir pressure	kPa	psia
p_{tf}	flowing wellhead pressure	kPa	psia
p_{ts}	shut-in wellhead pressure	kPa	psia
p_{wf}	flowing sandface pressure	kPa	psia
P_{wfo}	final flowing pressure	kPa	psia
p_{ws}	shut-in sandface pressure	kPa	psia
p^*	extrapolated pressure	kPa	psia
Δp_D	dimensionless pressure	-	-
Δp	pressure drop	kPa	psi
PI	productivity index	$m^3/d/kPa$	bbl/d/psi
q	flow rate - gas - liquid	$10^3m^3/d$ m^3/d	MMcf/d bbl/d
q_j	j^{th} flow rate	m^3/d	bbl/d
q_n	n^{th} flow rate	m^3/d	bbl/d
q_s	stabilized rate - gas - liquid	$10^3m^3/d$ m^3/d	MMcf/d bbl/d
r_e	external radius	m	ft
r_{inv}	radius of investigation	m	ft
r_w	wellbore radius	m	ft
R_s	solution gas ratio	m^3/m^3	ft^3/bbl

Symbol	Description	Metric (SI)	Field
s	skin factor	-	-
s'	apparent skin factor	-	-
S	saturation (oil, gas, water)	-	-
t	time	hr	hr
t_D	dimensionless time	hr	hr
t_a	pseudo-time	hr	hr
t_{DA}	dimensionless time (based on drainage area)	hr	hr
t_{Dxf}	dimensionless time (based on fracture 1/2 length)	hr	hr
t_n	n^{th} flow period, or superposition time	-	-
Δt	shut-in time	hr	hr
Δt_a	shut-in pseudo-time	hr	hr
Δt_e	equivalent time	hr	hr
$(t_{DA})_{pss}$	dimensionless time at pseudo-steady state	-	-
t_s	time to stabilization	hr	hr
T	temperature	K	°R
T_c	gas pseudo-critical temperature	K	°R
V_{ws}	wellbore volume - gas - liquid	m^3 m^3	ft^3 bbl
W	channel width	m	ft
w	fracture width	m	ft
x_e	length of reservoir	m	ft
x_f	fracture half-length	m	ft
x_o	x -location of observation well	m	ft
x_w	x- location of centre of active well	m	ft
y_e	width of reservoir	m	ft
y_o	y- location of observation well	m	ft
y_w	y- location of centre of active well	m	ft
Z	gas compressibility factor	-	-
z_w	z-location of centre of active well	m	ft

Symbol	Description	Metric (SI)	Field
α	wellbore storage/unloading constant	m^3/kPa	bbl/psi
μ	viscosity - gas	μPa.s	cp
	- liquid	mPa.s	cp
λ	inter-porosity flow coefficient	-	-
T	transmissivity (McKinley)	mD.m/mPa.s	md.ft/cp
ϕ	porosity	-	-
Ψ	pseudo-pressure	$kPa^2/\mu Pa.s$	$psia^2/cp$
ω	storativity ratio	-	-

Subscripts

D	dimensionless
DA	dimensionless based on area
Dxf	dimensionless based on fracture half -length
f	formation or flowing
g	gas
i	initial
o	oil
R	reservoir
s	shut-in, skin, stabilized or storage
t	total, transient, or wellhead (tubing head)
w	water or wellbore (sandface)
ref	evaluated at reference pressure

Superscripts

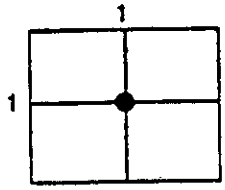
-	average

DIETZ SHAPE CODES

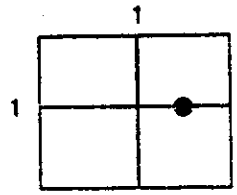
AVERAGE RESERVOIR PRESSURE - MBH CORRECTIONS

NO FLOW OUTER BOUNDARY

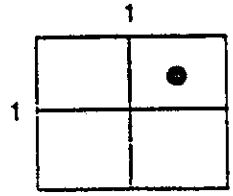
R1A



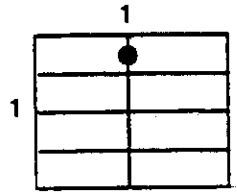
R1B



R1C

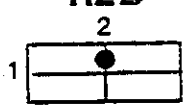


R1D

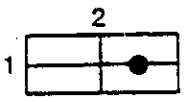


R2A

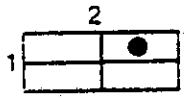
R2B



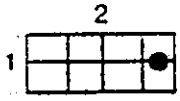
R2C



R2D

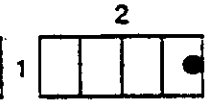


R2E



R2F

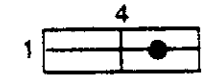
R2G



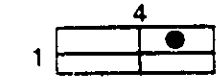
R4A

R4B

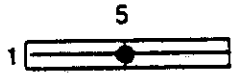
R4C



R4D

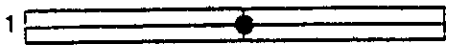


R5A



R8A

R16A

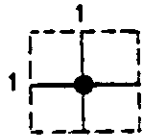


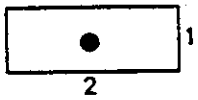
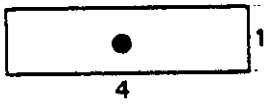
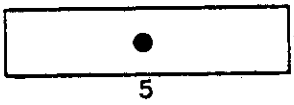
HA

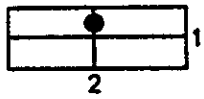
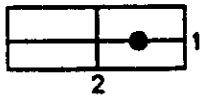
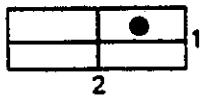
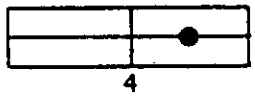
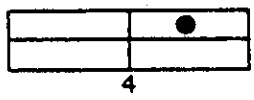
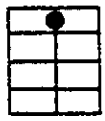
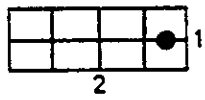
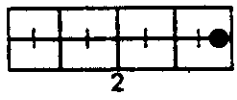
TA

CONSTANT PRESSURE OUTER BOUNDARY

R1AW



	$\ln C_A$	C_A	STABILIZED CONDITIONS FOR t_{DA} >
IN BOUNDED RESERVOIRS			
	3.45	31.6	0.1
	3.43	30.9	0.1
	3.45	31.6	0.1
	3.32	27.6	0.2
	3.30	27.1	0.2
	3.09	21.9	0.4
	3.12	22.6	0.2
	1.68	5.38	0.7
	0.86	2.36	0.7
	2.56	12.9	0.6
	1.52	4.57	0.5

	$\ln C_A$	C_A	STABILIZED CONDITIONS FOR t_{DA} >
	2.38	10.8	0.3
	1.58	4.86	1.0
	0.73	2.07	0.8
	1.00	2.72	0.8
	-1.46	0.232	2.5
	-2.16	0.115	3.0
	1.22	3.39	0.6
	1.14	3.13	0.3
	-0.50	0.607	1.0
	-2.20	0.111	1.2
	-2.32	0.098	0.9
IN WATER DRIVE RESERVOIRS			
	2.95	19.1	0.1
IN RESERVOIRS OF UNKNOWN PRODUCTION CHARACTER			
	3.22	25	0.1

PSEUDO-STEADY STATE SHAPE FACTORS FOR VARIOUS RESERVOIRS

FROM DIETZ (1965)

PMG

UNITS CONVERSION AND PREFIXES

METRIC (SI) UNIT	FIELD UNIT	DIVIDED BY
$10^3m^3/d$	MMcfd	2.817 399 E+01
kPa	psia	6.894 757 E+00
mD	md	9.869 233 E-01
mD.m	md.ft	3.008 142 E-01
m	ft	3.048 E-01
m^3	bbl (35 Imp gal) (42 US gal)	1.589 873 E-01
Pa.s	cp	1.0 E+03
°C	°F	(°F-32)5/9 E+00
K	°R	5/9 E+00
m^2	section (640 acres)	2.589 988 E+06
ha	section (640 acres)	2.589 988 E+02
m^3	gallon (Imp)	4.546 09 E-03
m^3	gallon (US)	3.785 412 E-03
$m^3/10^3m^3$	bbl/MMcf	5.643 052 E-03

Standard conditions: Metric (SI) 15°C, 101.325 kPa
Field 60°F, 14.65 psia

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