From: Merrill, Robert C
Sent: Mon Jul 26 01:29:49 2010
To: Levitan, Michael M.
Subject: Please Review
Importance: High
Attachments: USGS_Parameters_25July.ZIP; Bob_Match_25July.ZIP; Horner Plot USGS.ZIP; July25_30mbd_1.ZIP; July25_45mbd_1.ZIP

Mike:
Please review the enclosed presentation for errors or mis-statements. It reflects my own (feeble) efforts to become a PIE-meister.
I also enclose a PDF, which is what Paul Hsieh will present tomorrow. It follows on with a request from the Government (this is from a note from Cindy Yielding):
So.... Here is a new request from the Science team (Tom Hunter/Secretary Chu):
REQUEST: A plot of the pressure data using the SPE 1978 (or 1987, or 1980: the date was unclear) revision of Horner plot, generating the plot of the changing slope of the line using the derivative of delta pressure, delta T.
TIMING: for 8:00 am deliver for Monday's 11 am meeting.
If you could possibly come in a bit before 8am, it would help. I confirmed with James Dupree (who was at the meeting) that they want to see derivative plots of the data.
Bob
<<...>> <<...>> <<...>> <<...>> <<...>>

Bob Merrill
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Reservoir Engineering Community of Practice
BP EPT, Houston
Phone: +1 281-366-2049
Cell: +1 713-409-7340
email: merrilrc@bp.com

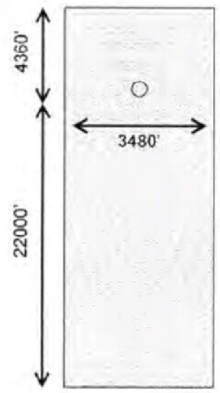
10924
Exhibit No. ____
Worldwide Court Reporters, Inc.

Draft: PIE Matches of 25 July

MC252

Rectangular Model – No Aquifer; 45 mbd

- Simplest model to capture key observations



Static Input Data:			
Bo	2.310	rb/stb	
Oil Viscosity	0.210	cP	
Well Bore Radius	0.350	ft	
Well Bore Storage	0.100	bbls	
Gauge Resolution	5.000	psi	
Fluid Compressibility	14	sips	
Water Compressibility	3	sips	
Rock Compressibility	6	sips	
Total	*23*	*sips*	
Net Thickness	93	ft	Includes M56D, M56E, M56F (v2)
Porosity	21.6%		NetH weighted Average
Water Saturation	12.2%		NetHxPorosity Average
Initial Pressure	11,856	psia	M56E Sand
Initial Pressure (WHP)	8,562		(corrected using 3294 psia)
Model	Linear (homogeneous)		
Wellbore Storage	1.07	bbl/psi	
Permeability	626	mD	
Skin	60.0		
Pi	8,562	psia	
+X	4,360	ft	26,360
-X	22,000	ft	
+Y	1,740	ft	3,480
-Y	1,740	ft	
Pore Volume	1.843E+09	ft3	
H/C Pore Volume	288	mmrb	
Original Oil In Place	125	mmstb	

2

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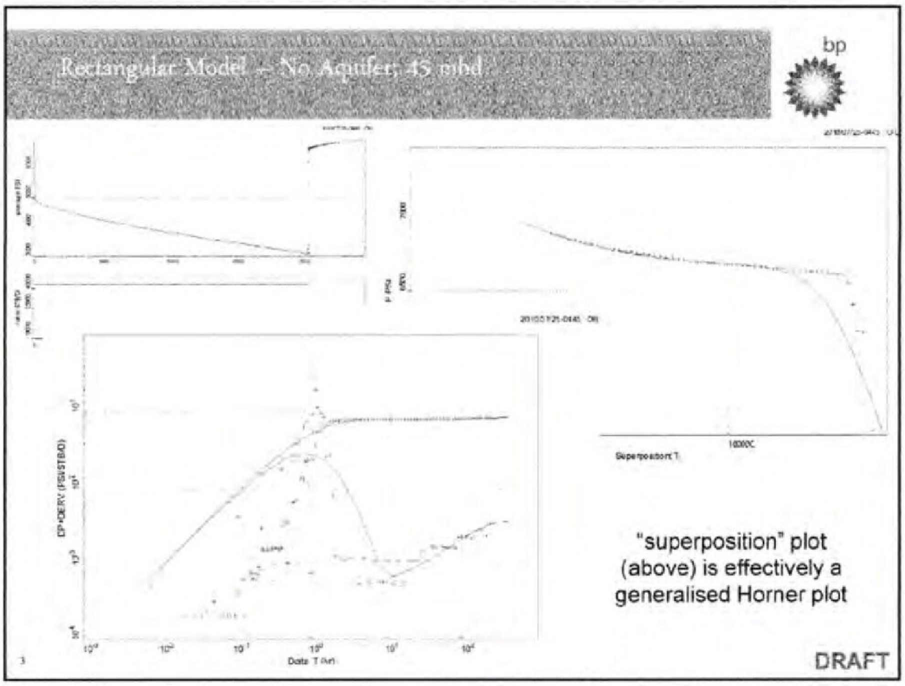
BP-HZN-2179MDL04890392

BPD344-090824

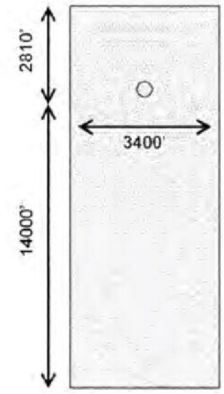
TREX 010924.0003



Rectangular Model – No Aquifer; 45 mbd
bp
"superposition" plot
(above) is effectively a
generalised Horner plot
3
DRAFT

Rectangular Model – No Aquifer: 30 mbd

- Simplest model to capture key observations



Static Input Data:			
Bo	2.310	rb/stb	
Oil Viscosity	0.210	cP	
Well Bore Radius	0.350	ft	
Well Bore Storage	0.100	bbls	
Gauge Resolution	5.000	psi	
Fluid Compressibility	14	sips	
Water Compressibility	3	sips	
Rock Compressibility	6	sips	
Total	*23*	*sips*	
Net Thickness	93	ft	Includes M56D, M56E, M56F (v2)
Porosity	21.6%		NetH weighted Average
Water Saturation	12.2%		NetHxPorosity Average
Initial Pressure	11,856	psia	M56E Sand
Initial Pressure (WHP)	8,562		(corrected using 3294 psia)
Model	Linear (homogeneous)		
Wellbore Storage	0.51	bbl/psi	
Permeability	363	mD	
Skin	50.0		
Pi	8,562	psia	
+X	2,810	ft	16,810
-X	14,000	ft	
+Y	1,700	ft	3,400
-Y	1,700	ft	
Pore Volume	1.148E+09	ft3	
H/C Pore Volume	180	mmrb	
Original Oil In Place	78	mmstb	

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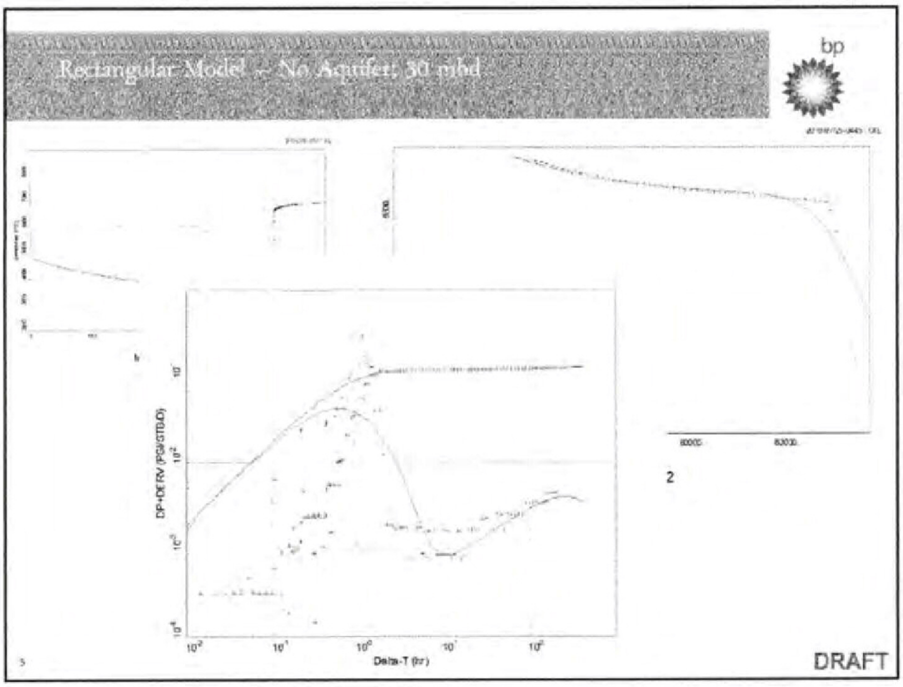
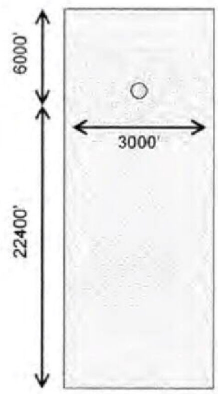

Rectangular Model – No Aquifer; 30 mbd
bp
DP-DERV (PSI/STB/D)
Delta-T (hr)
2
DRAFT

USGS Parameters – Increased C_t 50 mbd

bp

- Simplest model to capture key observations



Static Input Data:		
Bo	2.350 rb/stb	
Oil Viscosity	0.168 cP	
Well Bore Radius	0.350 ft	
Well Bore Storage	0.100 bbls	
Gauge Resolution	5.000 psi	
Fluid Compressibility	14.6 sips	
Water Compressibility	3.0 sips	
Rock Compressibility	8.0 sips	
Total	*26 sips*	
Net Thickness	90 ft	Includes M56D, M56E, M56F (v2)
Porosity	21.0%	NetH weighted Average
Water Saturation	10.0%	NetHxPorosity Average
Initial Pressure	11,856 psia	M56E Sand
Initial Pressure (WHP)	8,562	(corrected using 3204 psia)
Model	Linear (homogeneous)	
+X	1,500	3,000
-X	1,500	
+Y	6,000	28,400
-Y	22,400	
Pore Volume	1.610E+09 ft3	
H/C Pore Volume	258 mmrb	
Original Oil In Place	110 mmstb	

Note: +/- X split assumed

6

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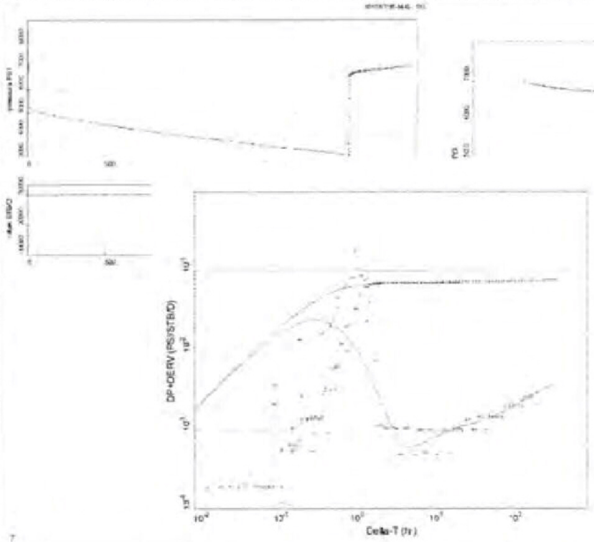
BP-HZN-2179MDL04890396

BPD344-090828

TREX 010924.0007

USGS Parameters -- Increased C, 50 mbd



Note: wellbore storage and skin values not specified in USGS model

Chosen values give good match to observed pressure data

7

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Conclusions

bp

- Observed pressure behaviour consistent with "normal" well behaviour:
  - Elongated reservoir
  - Limited support

- Numerous subsurface realisations can match the data reasonably well, considering:
  - Uncertainty in flow rate
  - Uncertainty in static parameters (C_t, connected volume)
  - Uncertainty in flowing bottom hole pressure
  - Uncertainty in final static bottom hole pressure

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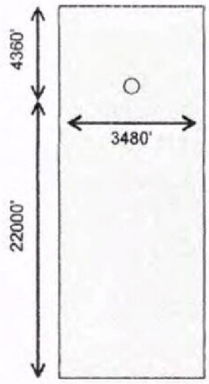
Draft: PIE Matches of 25-July

MC252

Rectangular Model – No Aquifer; 45 mbd

- Simplest model to capture key observations



Static Input Data:		
Bo	2.310 rb/stb	
Oil Viscosity	0.210 cP	
Well Bore Radius	0.350 ft	
Well Bore Storage	0.100 bbls	
Gauge Resolution	5.000 psi	
Fluid Compressibility	14 sips	
Water Compressibility	3 sips	
Rock Compressibility	6 sips	
Total	*23 sips*	
Net Thickness	93 ft	Includes M53D, M56E, M56F (v2)
Porosity	21.6%	NetH weighted Average
Water Saturation	12.2%	NetHxPorosty Average
Initial Pressure	11,856 psia	M56E Sand
Initial Pressure (WHP)	8,562	(corrected using 3294 psia)
Model	Linear (homogeneous)	
Wellbore Storage	1.07 bbl/psi	
Permeability	626 mD	
Skin	60.0	
P_i	8,562 psia	
+X	4,360 ft	26,360
-X	22,000 ft	
+Y	1,740 ft	3,480
-Y	1,740 ft	
Pore Volume	1.843E+09 ft3	
H/C Pore Volume	288 mmrb	
Original Oil In Place	125 mmstb	

2

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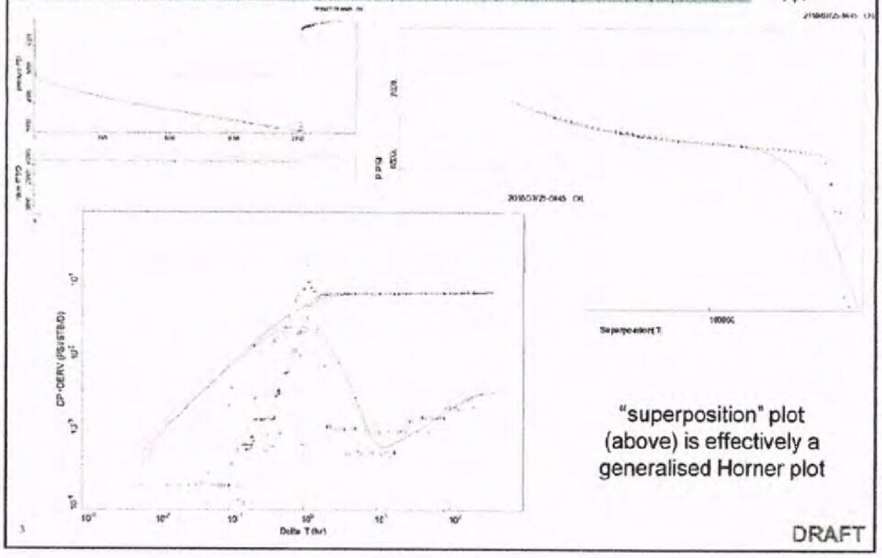
BP-HZN-2179MDL04890400

BPD344-090832

TREX 010924.0011

Rectangular Model – No Aquifer, 45 mbd



"superposition" plot (above) is effectively a generalised Horner plot

3

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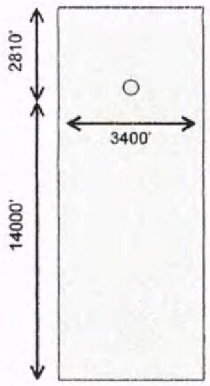
Rectangular Model – No Aquifer; 30 mbd

- Simplest model to capture key observations



Static Input Data:		
Bo	2.310 rb/stb	
Oil Viscosity	0.210 cP	
Well Bore Radius	0.350 ft	
Well Bore Storage	0.100 bbls	
Gauge Resolution	5.000 psi	
Fluid Compressibility	14 sips	
Water Compressibility	3 sips	
Rock Compressibility	6 sips	
Total	*23 sips*	
Net Thickness	93 ft	Includes M56D, M56E, M56F (v2)
Porosity	21.8%	NetH weighted Average
Water Saturation	12.2%	NetHxPorosty Average
Initial Pressure	11,856 psia	M56E Sand
Initial Pressure (WHP)	8,562	(corrected using 3294 psia)
Model	Linear (homogeneous)	
Wellbore Storage	0.51 bbl/psi	
Permeability	363 mD	
Skin	50.0	
Pi	8,562 psia	
+X	2,810 ft	16,810
-X	14,000 ft	
+Y	1,700 ft	3,400
-Y	1,700 ft	
Pore Volume	1.148E+09 ft3	
H/C Pore Volume	180 mmrb	
Original Oil In Place	78 mmstb	

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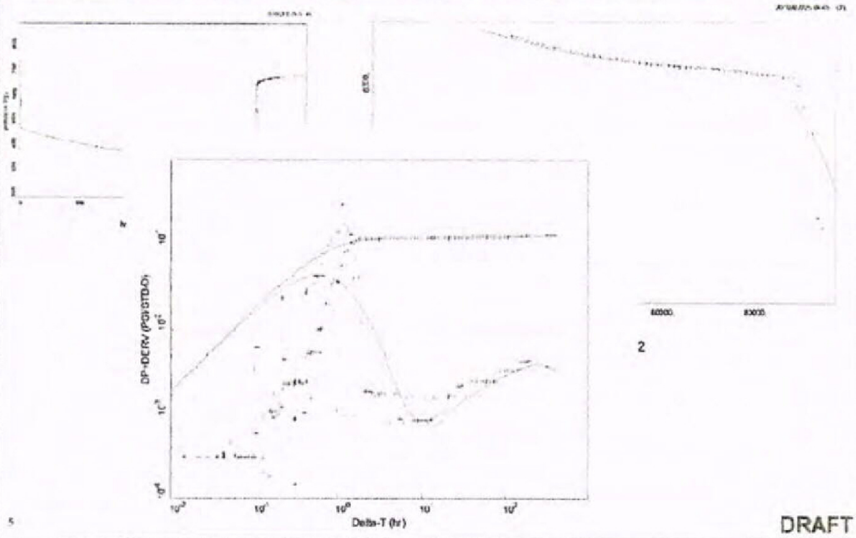
BP-HZN-2179MDL04890402
BPD344-090834

TREX 010924.0013

Rectangular Model – No Aquifer; 30 mbd



5

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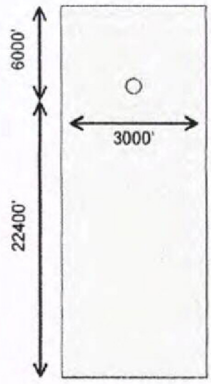
USGS Parameters – Increased C_t, 50 mbd

- Simplest model to capture key observations



Static Input Data:			
Bo	2.350	rb/stb	
Oil Viscosity	0.166	cP	
Well Bore Radius	0.350	ft	
Well Bore Storage	0.100	bbls	
Gauge Resolution	5.000	psi	
Fluid Compressibility	14.6	sips	
Water Compressibility	3.0	sips	
Rock Compressibility	8.0	sips	
Total	*26*	*sips*	
Net Thickness	90	ft	Includes M56D, M56E, M56F (v2)
Porosity	21.0%		NetH weighted Average
Water Saturation	10.0%		NetHxPorosity Average
Initial Pressure	11,856	psia	M56E Sand
Initial Pressure (WHP)	8,562		(corrected using 3294 psia)
Model	Linear (homogeneous)		
+X	1,500		3,000
-X	1,500		
+Y	6,000		28,400
-Y	22,400		
Pore Volume	1.810E+09	ft3	
H/C Pore Volume	258	mmrb	
Original Oil In Place	110	mmstb	

Note: +/- X split assumed

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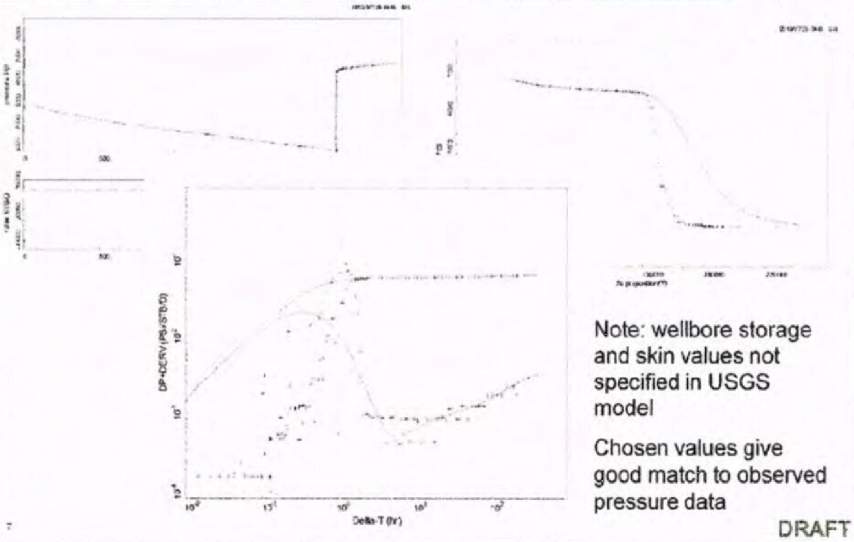
BP-HZN-2179MDL04890404
BPD344-090836

TREX 010924.0015

USGS Parameters – Increased C_t, 50 mbd



Note: wellbore storage and skin values not specified in USGS model

Chosen values give good match to observed pressure data

7

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Conclusions

- Observed pressure behaviour consistent with "normal" well behaviour:
  - Elongated reservoir
  - Limited support

- Numerous subsurface realisations can match the data reasonably well, considering:
  - Uncertainty in flow rate
  - Uncertainty in static parameters (C_t, connected volume)
  - Uncertainty in flowing bottom hole pressure
  - Uncertainty in final static bottom hole pressure

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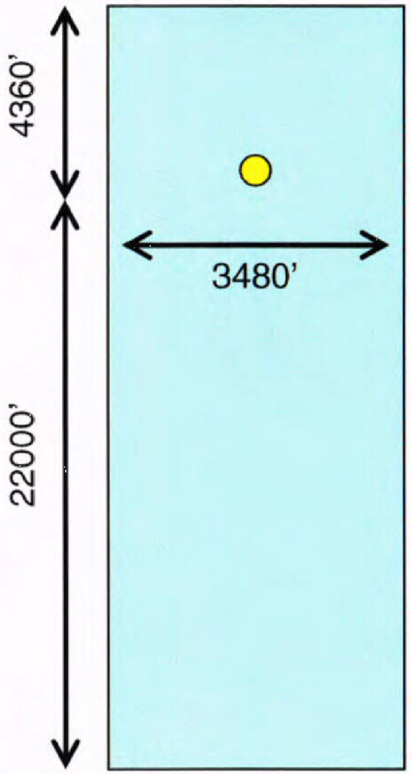
Draft: PIE Matches of 25-July

MC252

Rectangular Model – No Aquifer; 45 mbd

- Simplest model to capture key observations



Static Input Data:		
Bo	2.310 rb/stb	
Oil Viscosity	0.210 cP	
Well Bore Radius	0.350 ft	
Well Bore Storage	0.100 bbls	
Gauge Resolution	5.000 psi	
Fluid Compressibility	14 µsips	
Water Compressibility	3 µsips	
Rock Compressibility	6 µsips	
Total	*23 µ sips*	
Net Thickness	93 ft	Includes M56D, M56E, M56F (v2)
Porosity	21.6%	NetH weighted Average
Water Saturation	12.2%	NetHxPorosity Average
Initial Pressure	11,856 psia	M56E Sand
Initial Pressure (WHP)	8,562	(corrected using 3294 psia)

Model	Linear (homogeneous)	
Wellbore Storage	1.07 bbl/psi	
Permeability	626 mD	
Skin	60.0	
Pi	8,562 psia	
+X	4,360 ft	26,360
-X	22,000 ft	
+Y	1,740 ft	3,480
-Y	1,740 ft	
Pore Volume	1.843E+09 ft3	
H/C Pore Volume	288 mmrb	
Original Oil In Place	125 mmstb	

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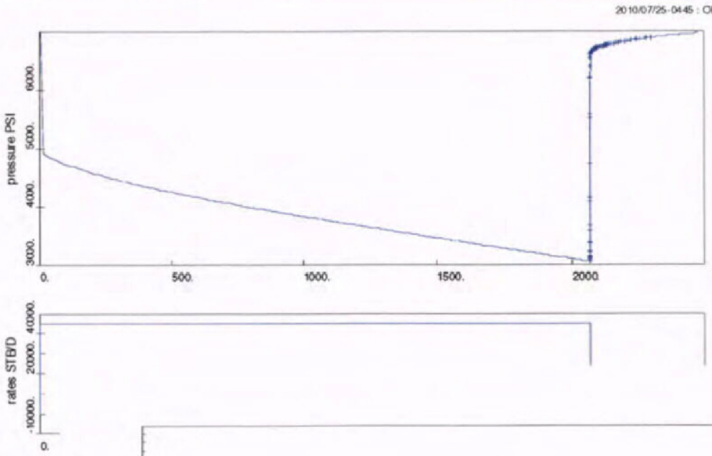
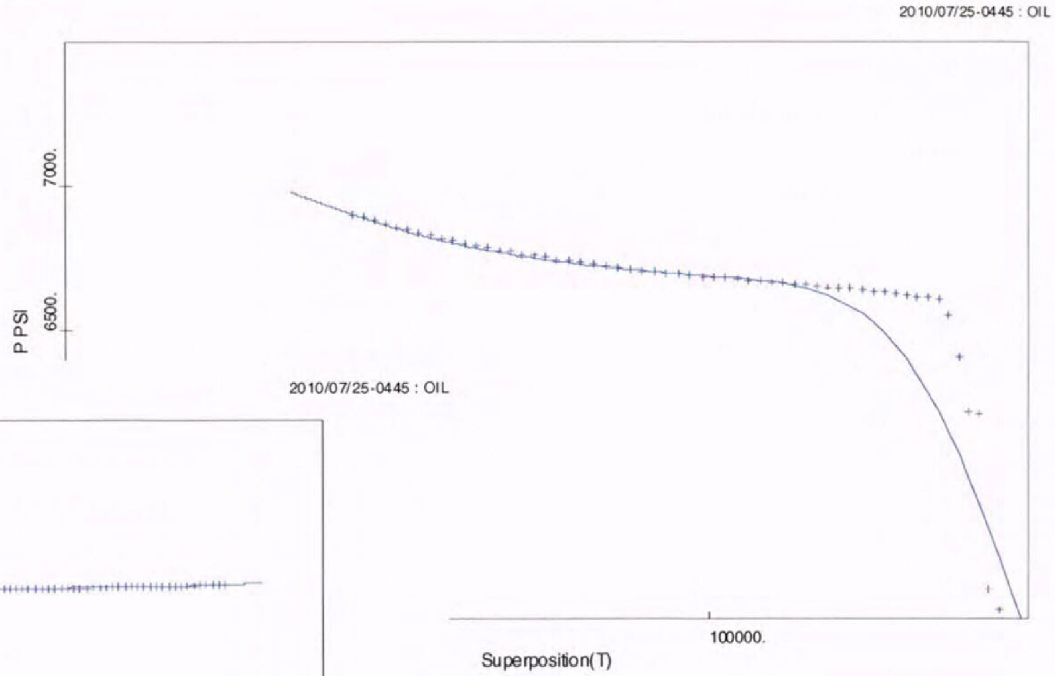
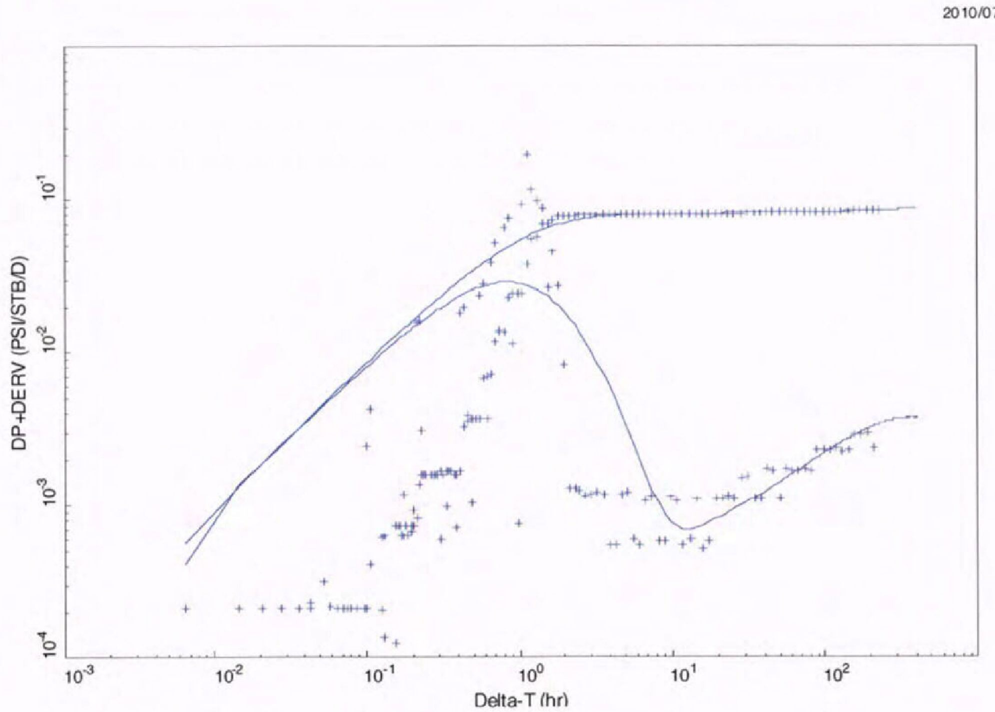
Rectangular Model – No Aquifer; 45 mbd







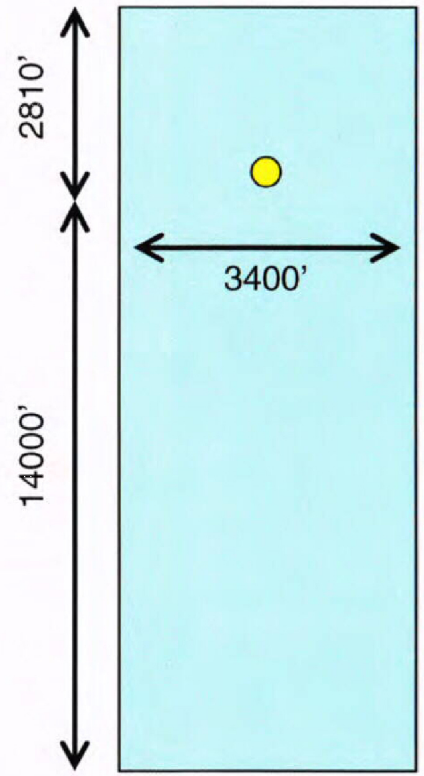
"superposition" plot (above) is effectively a generalised Horner plot

DRAFT

TREX 010924.0020

Rectangular Model – No Aquifer; 30 mbd

- Simplest model to capture key observations

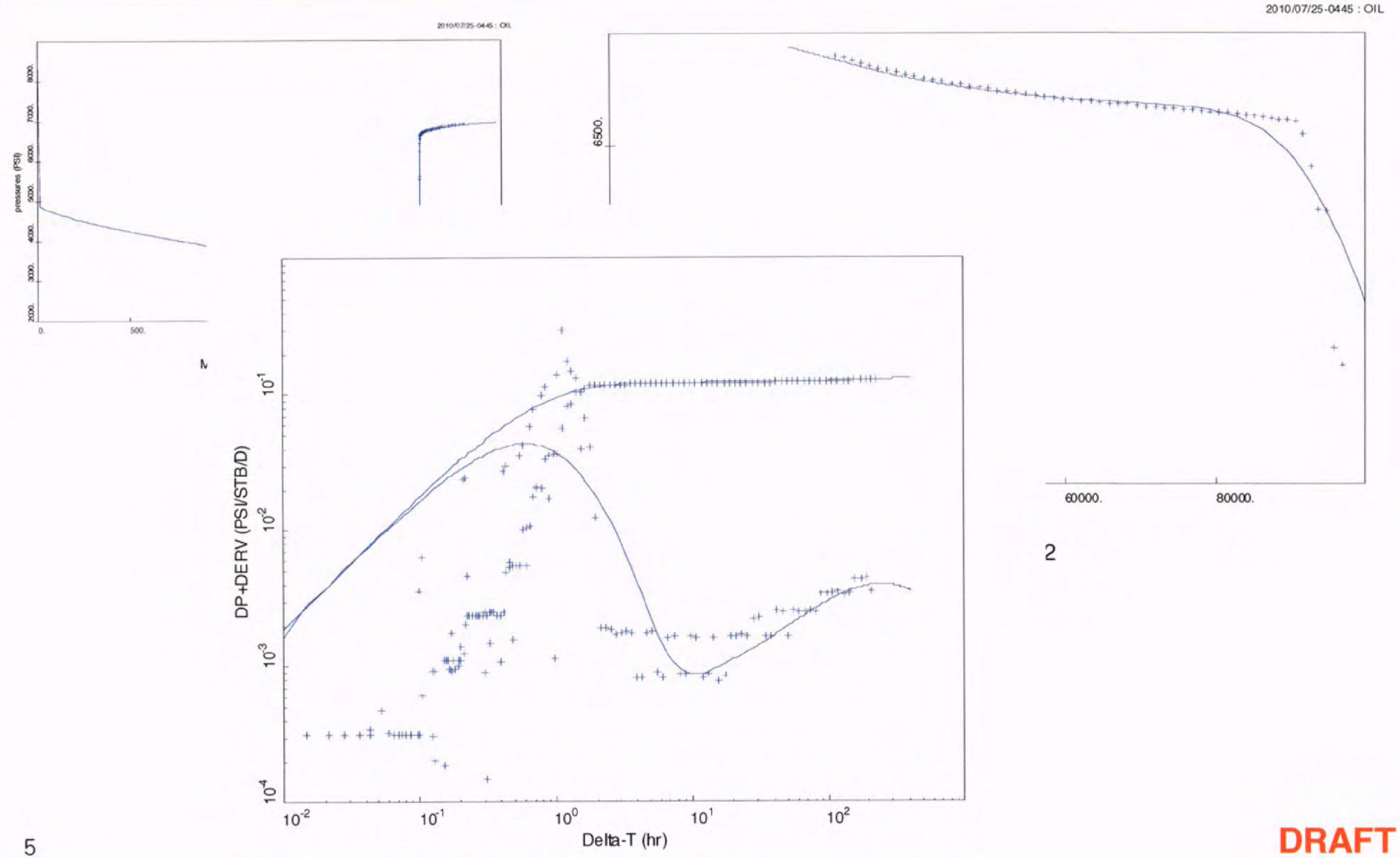


Static Input Data:		
Bo	2.310 rb/stb	
Oil Viscosity	0.210 cP	
Well Bore Radius	0.350 ft	
Well Bore Storage	0.100 bbls	
Gauge Resolution	5.000 psi	
Fluid Compressibility	14 µsips	
Water Compressibility	3 µsips	
Rock Compressibility	6 µsips	
Total	*23 µ sips*	
Net Thickness	93 ft	Includes M56D, M56E, M56F (v2)
Porosity	21.6%	NetH weighted Average
Water Saturation	12.2%	NetHxPorosity Average
Initial Pressure	11,856 psia	M56E Sand
Initial Pressure (WHP)	8,562	(corrected using 3294 psia)
Model	Linear (homogeneous)	
Wellbore Storage	0.51 bbl/psi	
Permeability	363 mD	
Skin	50.0	
Pi	8,562 psia	
+X	2,810 ft	16,810
-X	14,000 ft	
+Y	1,700 ft	3,400
-Y	1,700 ft	
Pore Volume	1.148E+09 ft3	
H/C Pore Volume	180 mmrb	
Original Oil In Place	78 mmstb	

DRAFT

TREX 010924.0021

Rectangular Model – No Aquifer; 30 mbd



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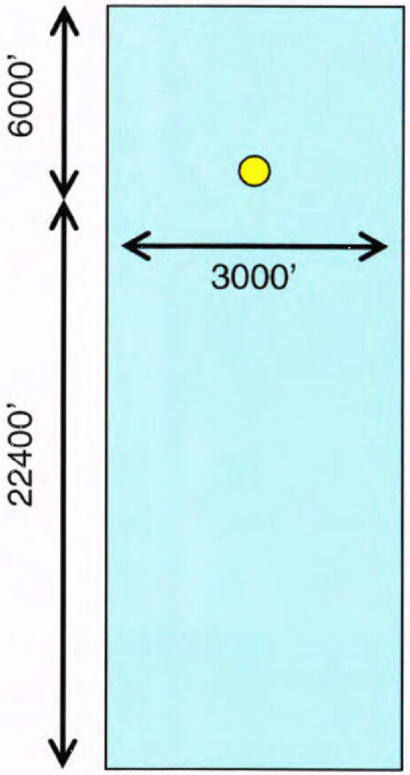
TREX 010924.0022

USGS Parameters – Increased C_r, 50 mbd

- Simplest model to capture key observations



Static Input Data:			
Bo	2.350	rb/stb	
Oil Viscosity	0.168	cP	
Well Bore Radius	0.350	ft	
Well Bore Storage	0.100	bbls	
Gauge Resolution	5.000	psi	
Fluid Compressibility	14.6	µsips	
Water Compressibility	3.0	µsips	
Rock Compressibility	8.0	µsips	
Total	*26*	*µ sips*	
Net Thickness	90	ft	Includes M56D, M56E, M56F (v2)
Porosity	21.0%		NetH weighted Average
Water Saturation	10.0%		NetHxPorosity Average
Initial Pressure	11,856	psia	M56E Sand
Initial Pressure (WHP)	8,562		(corrected using 3294 psia)
Model	Linear (homogeneous)		
+X	1,500		3,000
-X	1,500		
+Y	6,000		28,400
-Y	22,400		
Pore Volume	1.610E+09	ft3	
H/C Pore Volume	258	mmrb	
Original Oil In Place	110	mmstb	

Note: +/- X split assumed

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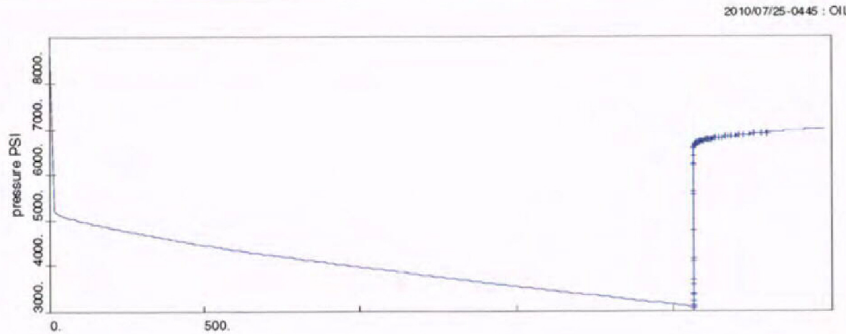
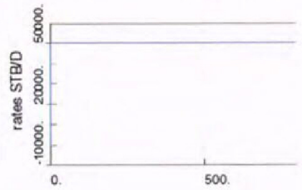
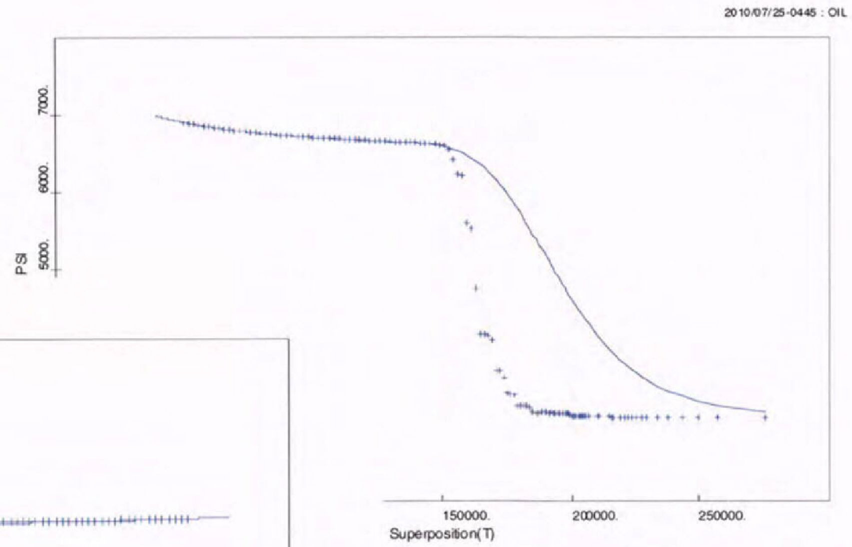
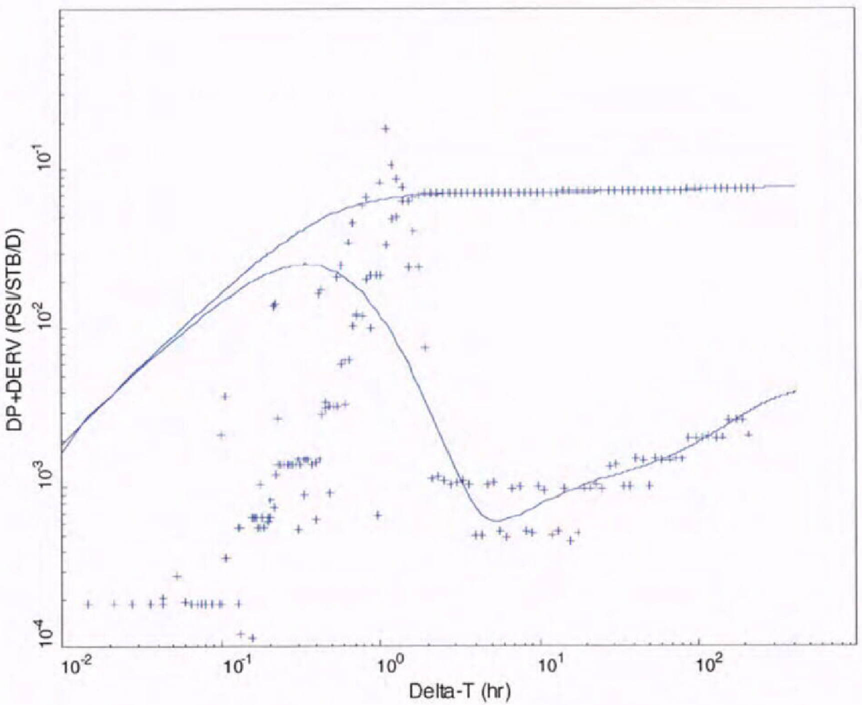
USGS Parameters – Increased C_r, 50 mbd









Note: wellbore storage and skin values not specified in USGS model

Chosen values give good match to observed pressure data

DRAFT

Conclusions

- Observed pressure behaviour consistent with "normal" well behaviour:
  - Elongated reservoir
  - Limited support

- Numerous subsurface realisations can match the data reasonably well, considering:
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  - Uncertainty in static parameters (C_r, connected volume)
  - Uncertainty in flowing bottom hole pressure
  - Uncertainty in final static bottom hole pressure

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Discussion on Shut-In Pressure and Horner Plot

Paul Hsieh, USGS
July 24, 2010

For the purpose of illustration, downhole pressure is simulated in a well in a sand-channel reservoir as shown in Figure 1. The well is assumed to produce at a constant rate of 50,000 stb/day. After 85 days, the well is shut in.

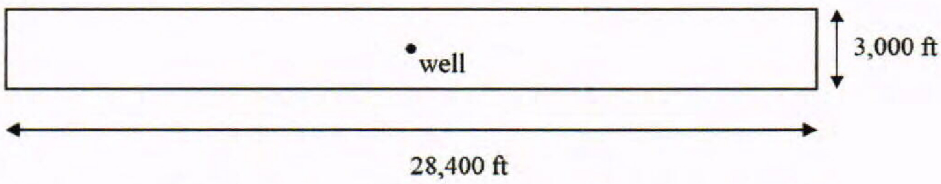

Fig. 1. Map view of sand-channel reservoir and well.

Assumed reservoir properties:

Reservoir thickness = 90 ft
Porosity = 21%
Original oil in place = 110 million stock tank barrels
Formation Volume factor = 2.35 reservoir barrels /stock tank barrel
Permeability = 516 md
Rock compressibility = $c_r = 8 \times 10^{-6}$ psi^{-1}
Oil compressibility = $c_o = 14.6 \times 10^{-6}$ psi^{-1}
Water compressibility = $c_w = 3 \times 10^{-6}$ psi^{-1}
Water saturation = Sw = 10%
Oil density = 0.568 gm/cc
Oil viscosity = 0.168 cp

During production, the pressure drawdown in the well can be divided into 3 periods, each with its own distinctive characteristics. These periods are also manifested during shut-in.

Radial Flow Period. This occurs for a short period after the start of production. Pressure drawdown occurs in a more-or-less circular region of radius ~1,500 ft and centered about the well. Flow is primarily radial towards the well (Fig. 2). During this period, downhole pressure varies linearly with log(t), where t is time since start of production.

Fig. 2. Radial flow in the vicinity of the well.

For the assumed reservoir properties, the radial flow period lasts for approximately 0.35 day after the start of production. This can be seen in the plot of simulated downhole pressure versus log(t) (Fig. 3). The derivative curve, $\Delta p/\Delta \log(t)$, is included to help estimate the period when p varies linearly with log(t)—when the derivative is constant.

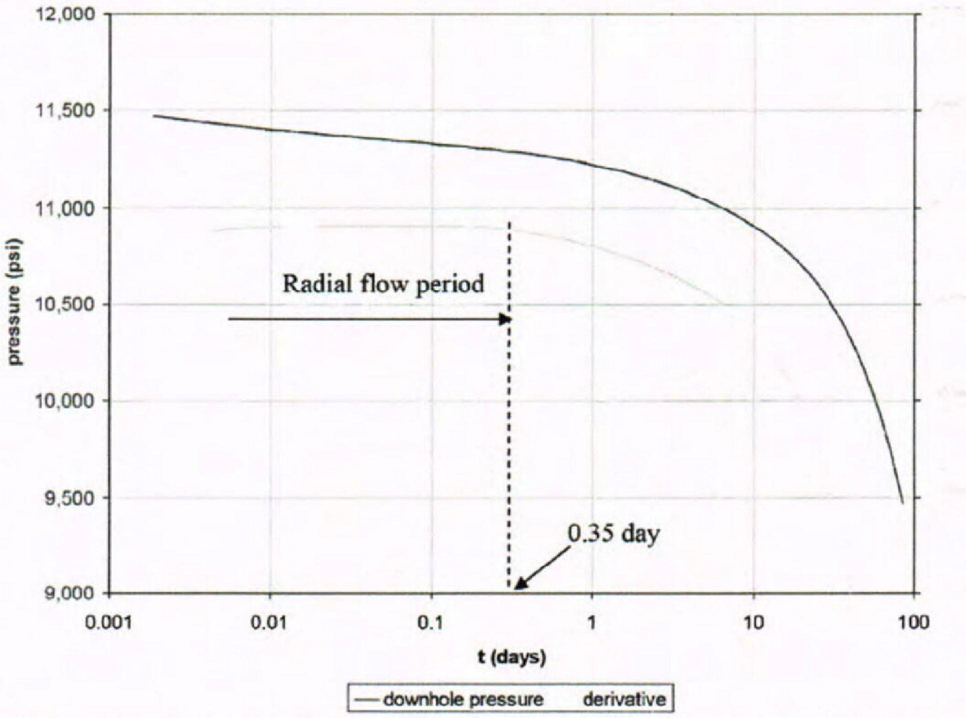

Fig. 3. Plot of simulated downhole pressure p, and derivative $\Delta p/\Delta \log(t)$, versus log(t). The radial flow period occurs when pressure varies linearly with log(t). During this period, the derivative is constant.

Linear Flow Period. This occurs after the radial flow period ends. Pressure drawdown propagates along the reservoir channel. Although radial flow still occurs in the vicinity of the well, the predominant flow in the reservoir is unidirectional, along the longitudinal axis of the channel (Fig. 4). During this linear flow period, pressure drawdown varies linearly with $t^{0.5}$.

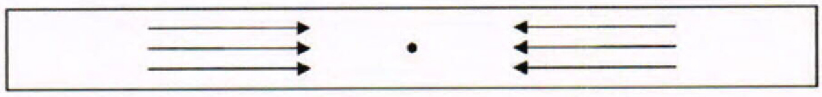

Fig. 4. Linear flow in the sand channel reservoir.

For the assumed reservoir properties, the linear flow period occurs from approximately t = 0.35 day to 12 days. This can be seen in the plot of simulated downhole pressure and the derivative $\Delta p/\Delta(t^{0.5})$ versus $t^{0.5}$ (Fig. 5).

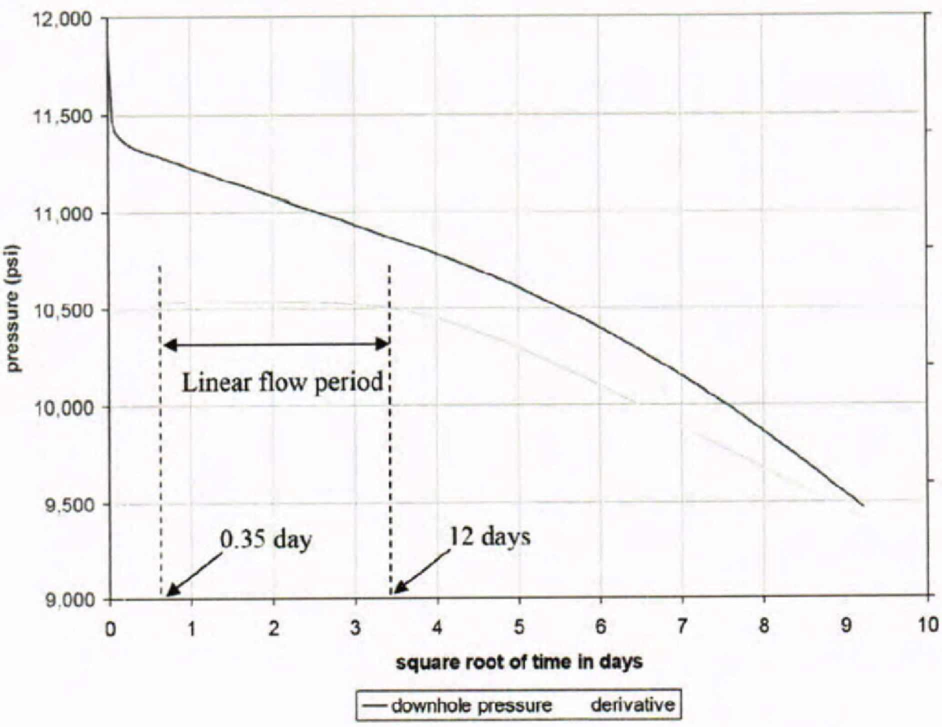

Fig. 5. Plot of simulated downhole pressure p, and derivative $\Delta p/\Delta(t^{0.5})$, versus $t^{0.5}$. The linear flow period occurs when pressure varies linearly with $t^{0.5}$.

Pseudo-Steady State. During this period, pressure everywhere in the reservoir drops at a constant rate. In other words, pressure is a linear function of time. For the assumed reservoir properties, pseudo-steady state begins at about t = 12 days (Fig 6).

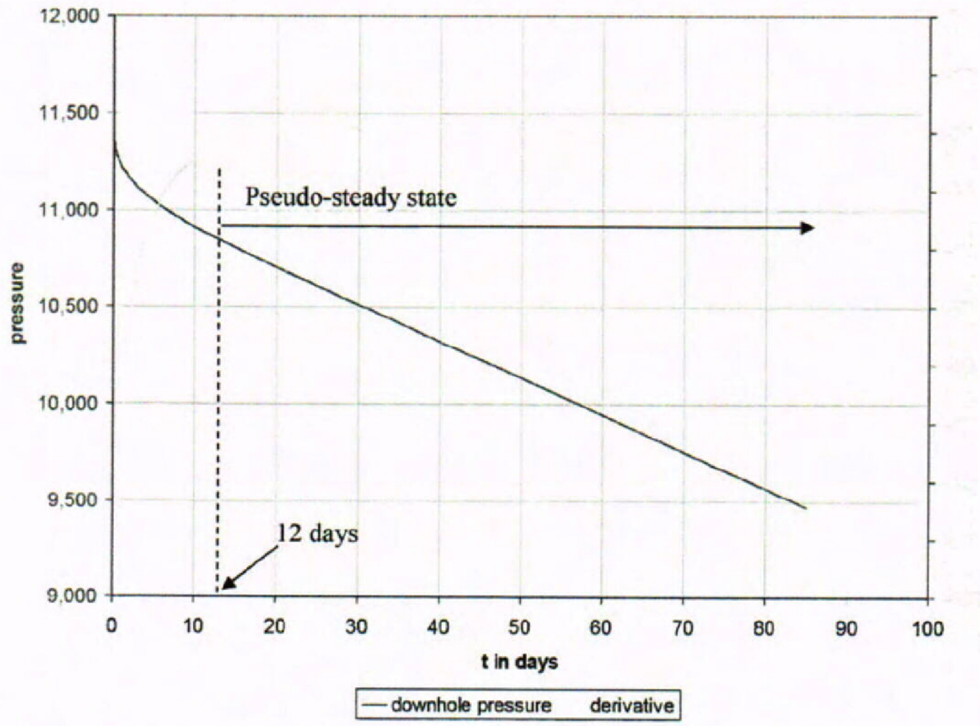

Fig. 6. Plot of simulated downhole pressure p, and derivative $\Delta p/\Delta t$, versus t. Pseudo-steady state occurs when pressure varies linearly with t.

Fig. 7 shows simulated pressure profiles along the longitudinal axis of the channel reservoir. These profiles illustrate the pressure at the start and end of the three periods discussed above.

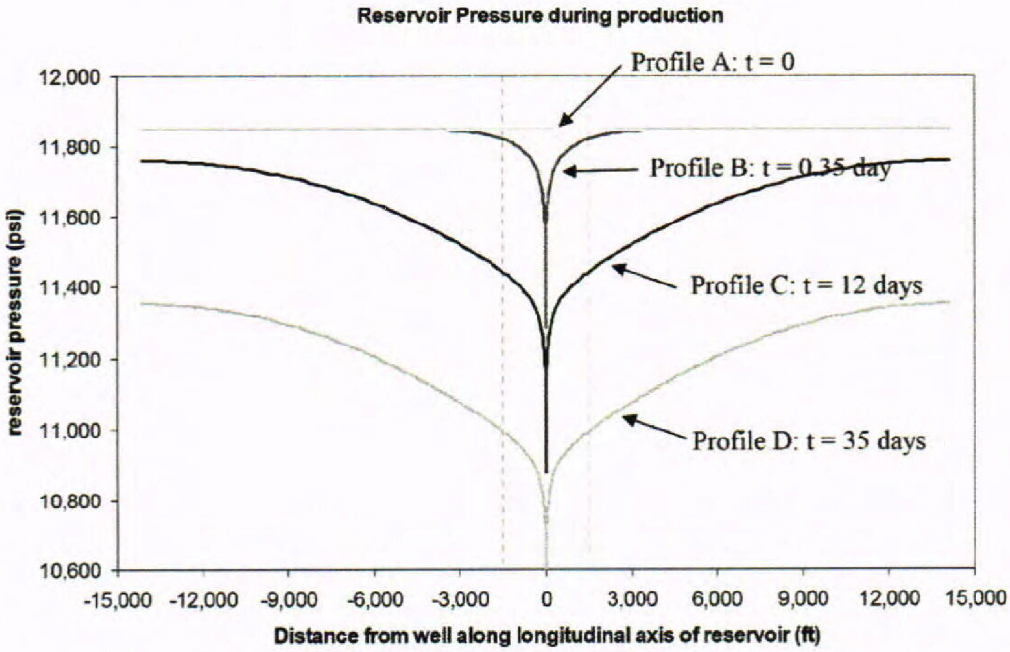

Fig. 7. Simulated pressure profiles along the longitudinal axis of the channel reservoir during production.

Profile A: t = 0. Reservoir pressure prior to production

Profile B: t = 0.35 days. End of radial flow period. Pressure drawdown occurs primarily within a distance of about 1,500 ft of the well (vertical dashed lines).

Profile C: t = 12 days. The propagation of pressure drawdown from profile B to profile C occurs during the linear flow period.

Profile D: t = 35 days. Note that profile D is essentially a downward translation of profile C. This uniform drop in pressure throughout the reservoir occurs during pseudo steady state.

Shut-in Pressure

Fig. 8 shows pressure profile during shut-in. These profiles are have a direct correspondence to the profiles during production (Fig. 7).

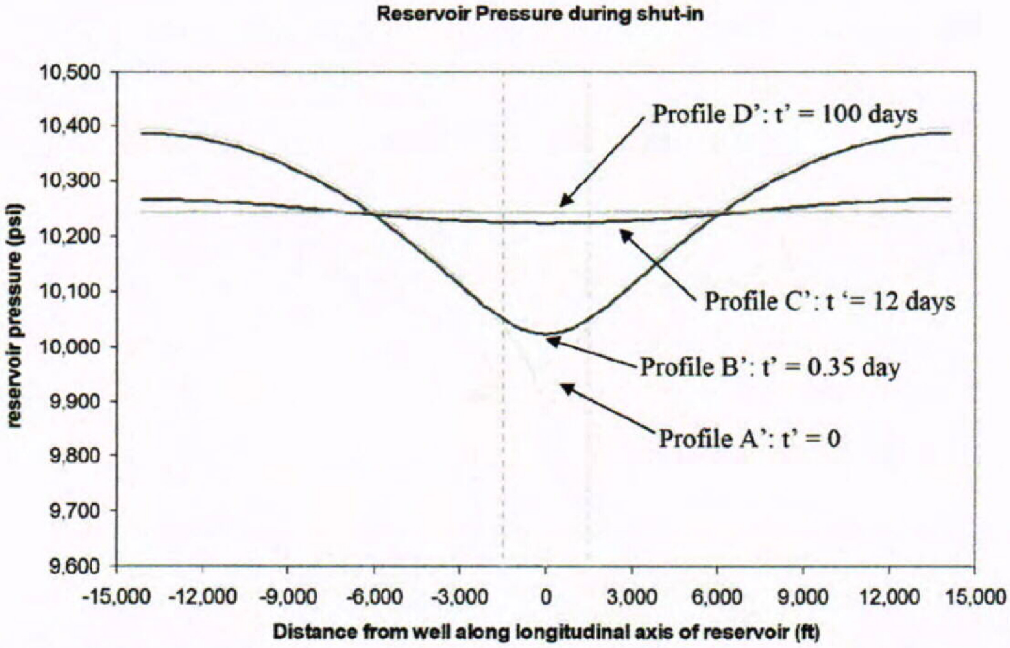

Fig. 8. Simulated pressure profiles along the longitudinal axis of the channel reservoir during shut-in. Time since shut-in is indicated by t'.

Profile A': t' = 0. Reservoir pressure at shut-in.

Profile B': t' = 0.35 day. Pressure recovery from profile A' to B' occurs primarily within a distance of about 1,500 ft of the well (vertical dashed lines). This is analogous to the radial flow period.

Profile C': t' = 12 days. The propagation of pressure recovery from profile B' to profile C' occurs throughout the length of the reservoir. This is analogous to the linear flow period.

Profile D': t' = 100 days. Pressure recovery from profile C' to profile D' occurs gradually as the entire reservoir reaches the final shut-in pressure.

Fig. 9 shows the simulated shut-in downhole pressure on a Horner Plot. The "upward deflection" of the curve to the left of the straight-line segment occurs at t' = 0.35 day, which corresponds to the transition from pressure recovery in a circular region (radius = 1500 ft) around the well to pressure recovery along the entire length of the channel reservoir.

At t' = 12 days, pressure throughout the reservoir is close to the final shut-in pressure and the curve approaches a flat line.

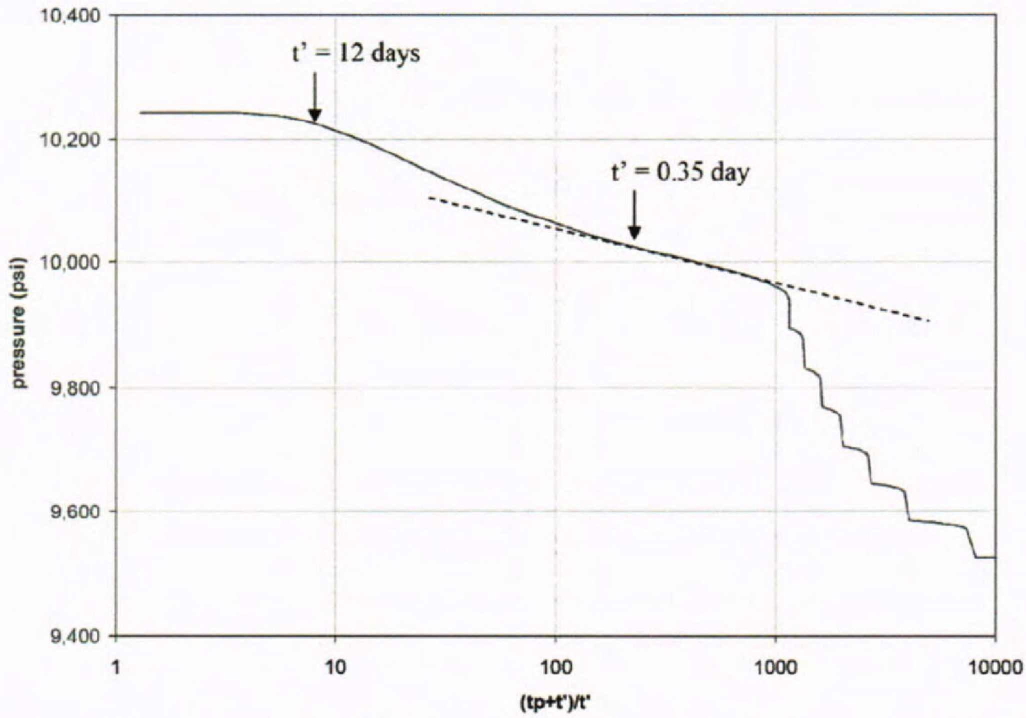

Fig. 9. Horner plot of simulated downhole pressure. Time of production (85 days) is indicated by tp, Time since shut-in is indicated by t'.

Comparison with Observed Shut-in Pressures at Well Head

The simulated downhole pressures are converted to wellhead pressures by subtraction of 3350 psi (= 13,000 ft x 0.257 psi/ft). Fig. 10 compares simulated wellhead pressures with observed wellhead pressures as recorded by gage PT_3K_2. The simulated pressures match the observed pressures for $(t_p + t')/t' > 20$, which corresponds to $t' < 4.5$ days, after which the simulated pressures are lower than the observed pressures.

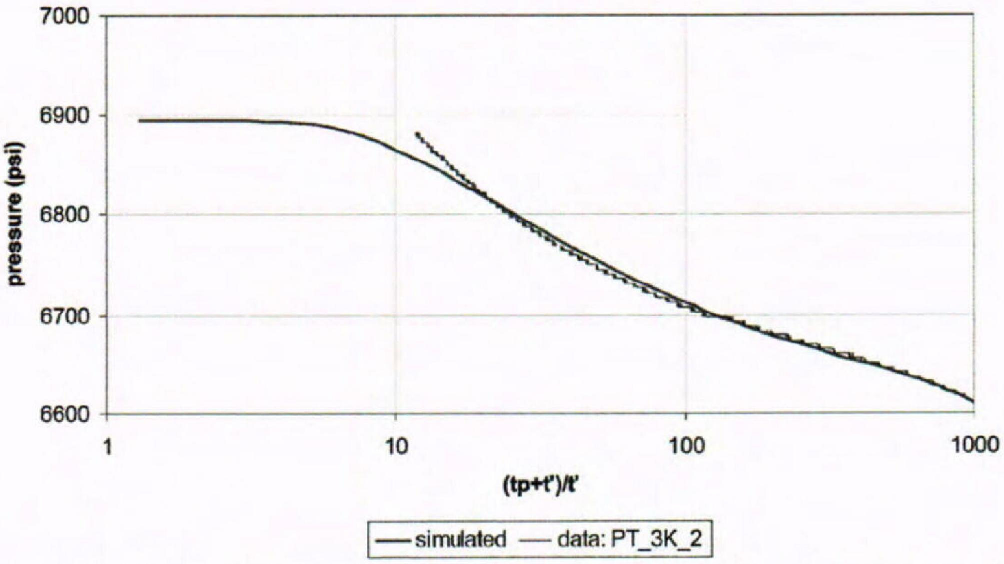

Fig. 10. Comparison between simulated and observed pressures at wellhead during shut in.

To obtain a better match, the well is displaced towards one end of the channel (Fig. 11), permeability is reduced to 490 md, and rock compressibility (r_c) is increased to 14 x 10^{-6} psi^{-1}.

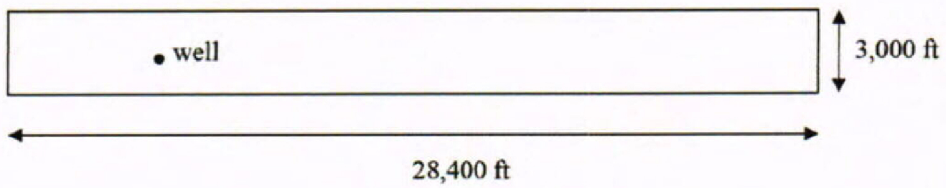

Fig. 11. Reservoir and well setting for the revised model.

The match using the revised model is shown in Fig. 12. The revised model suggests that the wellhead pressure could eventually rise to 7,250 psi. However, there are likely many other models that can fit the data equally well.

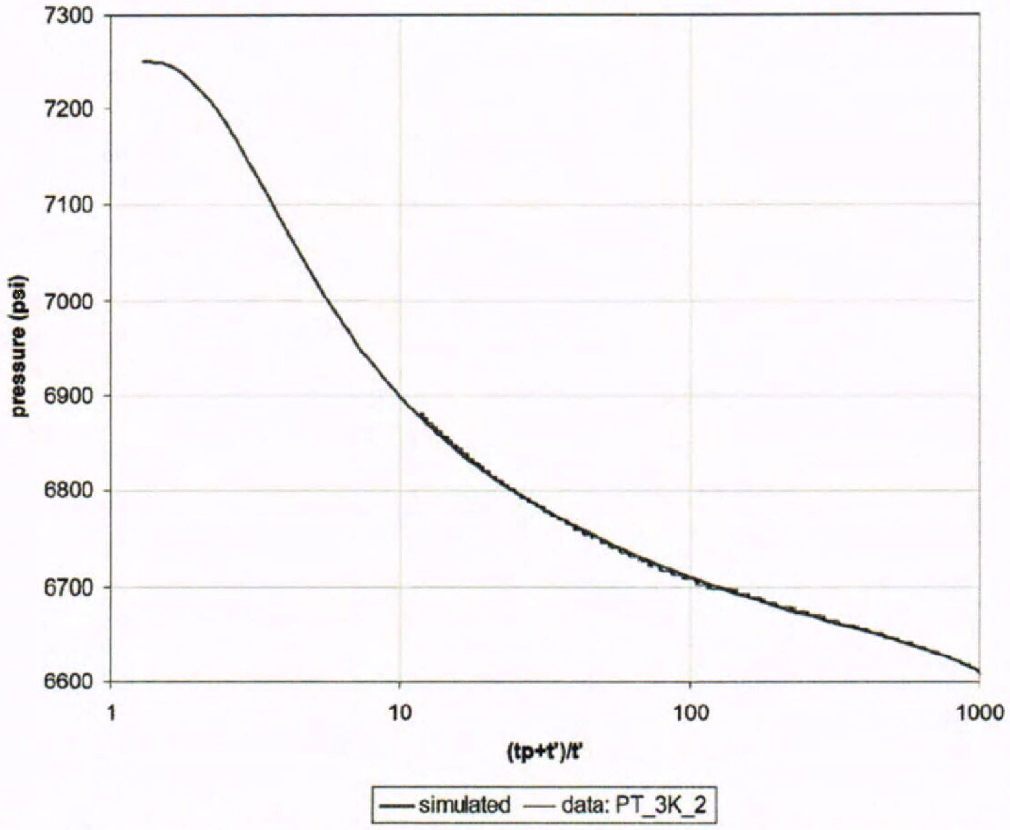

Fig. 12. Comparison between observed and simulated wellhead pressures using revised model.

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