SUBSURFACE

3 of 3

PERMIT RENEWAL APPLICATION
CLASS I NONHAZARDOUS WASTE INJECTION WELL
WDW NO. 1

Volume 2 of 3

NAVAJO REFINING COMPANY, L.L.C.
ARTESIA, NEW MEXICO
SUBSURFACE PROJECT NO. 60D6894

SUBSURFACE TECHNOLOGY, INC.
8212 KELWOOD AVE.
BATON ROUGE, LOUISIANA 70806
225-753-2561
PFBR@SUBSURFACEGROUP.COM

MARCH 2013

APPENDIX E-2

PREDICTW EQUATIONS

Mathematical Basis of Equations Used in Modeling Pressure Buildup

The following discussion reviews the mathematical and physical basis of determining reservoir pressure buildup. The model presented is based on the line source solution to the radial diffusivity equation for pressure behavior in a homogeneous reservoir. The model was implemented using the Visual Basic program PredictW.

Exponential-Integral Formulation

The pressure response for radial flow of a slightly compressible fluid in a planar (porous) injection layer with spatially-constant properties is determined by the well known diffusivity equation (Lee, 1982):

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{\phi \mu c_t}{0.000264\, k}\frac{\partial p}{\partial t} \qquad \text{Equation 1}$$

where ϕ, μ, c_t, and k refer to porosity, viscosity (cp), compressibility (psi^{-1}), and permeability (md), respectively. The pressure, p, is expressed in psi; radial distance, r, is in feet; and time, t, is indicated in days. For an infinite reservoir of thickness h (ft) with $p \rightarrow p_o$ (initial pressure) as $r \rightarrow \infty$, the transient pressure, p (r, t), for a single line source injector at r = 0 is determined from Equation 1 as (Muskat, 1982):

$$p(r,t) = p_o - \frac{70.6 q\mu}{kh}\, \mathrm{Ei}\left(\frac{-39.5\phi\mu c_t r^2}{kt}\right), \qquad \text{Equation 2}$$

where Ei represents the exponential integral defined by:

$$\mathrm{Ei}(-x) = -\int_x^\infty \frac{e^{-\varepsilon}}{\varepsilon}\, d\varepsilon \qquad \text{Equation 3}$$

and q represents the (constant) injection rate in barrels per day.

For the general case of multiple wells in a single layer, in which injection from each is represented by a succession of piece-wise constant flow rate intervals, the pressure response is readily obtained by superposition of elementary solutions given by Equation 2. In terms of Cartesian coordinates, the pressure transient at an arbitrary point (x, y) at time "t" is given by:

$$p(x,y,t) = p_o + \sum_{j=1}^{N} \frac{70.6 q_1^j \mu}{kh} \mathrm{Ei}\left(\frac{-39.5\phi\mu c_t[(x-x_j)^2 + (y-y_j)^2]}{kt} \right)$$
$$+ \sum_{j=1}^{N} \sum_{i=1}^{n_j - 1} 70.6[(q_{i-1}^j - q_i^j)\mu/kh]\, \mathrm{Ei}\left(\frac{-39.5\phi\mu c_t[(x-x_j)^2 + (y-y_j)^2]}{k(t - t_i^j)} \right)$$

Equation 4

for all $t_i^j < t$. In Equation 4, the following notation is employed:

N	=	number of wells injecting into the reservoir
n_j	=	number of constant flow rate increments for well j operative over time t
i	=	flow rate summation index ($1 < i < n_j$)
j	=	well number summation index ($1 < j < N$)
t_i	=	cumulative time corresponding to the end of injection rate interval i for well j
x_j, y_j	=	cartesian coordinates of well j
q_i^j	=	flow rate from well j during flow increment i

Equation 4 forms the basis for determining the COI for a general multi-well system.

To determine shutin or flowing pressures at a generic wellbore location, Equation 4 is modified to include a dimensionless skin factor, s_b, which reflects the effects of altered properties in the near-wellbore region (Van Everdingen, 1953). The associated augmentation, Δp_{skin}^b, of the theoretical flowing pressure is assumed to be of the form:

$$\Delta p_{skin}^b \text{ (psi)} = 141.2 \frac{q_i^b \mu}{kh} s_b$$

Equation 5

Incorporation of Equation 5 into Equation 4 and replacement of the quantity $[(x-x_b)^2 + (y-y_b)^2]$ in the Ei-function argument by $r_{w,b}^2$ (wellbore radius squared) leads to the following expression for the transient flowing pressure at a generic wellbore (b):

$$
\begin{aligned}
p_{wf}^{b}\left(x_b, y_b, t\right) = p_o &+ \sum_{j=1}^{N} \frac{70.6 q_1^j \mu}{kh} \mathrm{Ei}\left(\frac{-39.5\phi\mu c_t[(x_b - x_j)^2 + (y_b - y_j)^2]}{kt} \right) \\
&+ \sum_{j=1(j \neq b)}^{N} \sum_{i=1}^{n_{j-1}} \frac{70.6(q_{i+1}^j - q_i^j)\mu}{kh} \mathrm{Ei}\left(\frac{-39.5\phi\mu c_t[x_b - x_j)^2 + (y_b - y_j)^2]}{k(t - t_i^j)} \right) \\
&+ \frac{70.6 q_1^b \mu}{kh} \left[\mathrm{Ei}\left(\frac{-39.5\phi\mu c_t r_{w,b}^2}{kt} \right) - 2s_b \right] \\
&+ \sum_{i=1}^{n_{j-1}} \frac{70.6(q_{i+1}^b - q_i^b)\mu}{kh} \left[\mathrm{Ei}\left(\frac{-39.5\phi\mu c_t r_{w,b}^2}{k(t - t_i^b)} \right) - 2s_b \right]
\end{aligned}
$$

Equation 6

where x_b, y_b denote the wellbore coordinates at well b where the pressure response is evaluated.

Application of Equations 4 and 6 to address actual operational conditions often requires inclusion of many wells (including image injectors), each having several hundred flow rate increments. Accordingly, a Visual Basic computer program, PredictW, was created to evaluate these equations. The exponential integral is determined utilizing numerical methods (Abramowitz and Stegun, 1972). When isobaric contours at a given time in a given injection zone (unit) are desired, then Equation 4, actually $p - p_o$, is evaluated at each node of a predefined uniform grid. The resulting Δp-x-y array is then plotted to visualize the COI using Surfer (®Golden Software, Inc.). When the transient wellbore response is desired, Equation 6 is utilized by PredictW. The output in this case consists of a record of $\Delta p = p - p_o$ at a single well location over a specified time interval.

TECHNICAL REFERENCES

Lee, J., Well Testing, SPE Textbook Series, Vol. 1., Dallas, TX, 1982.

Muskat, M., The Flow of Homogeneous Fluids Through Porous Media, International Human Resources Development Corporation, 2nd Ed., Boston, 1982.

Van Everdingen, A.F., "The Skin Effect and its Influence on the Productive Capacity of a Well," Transactions, AIME, 1953.

Abramowitz, M., and Stegun, I.A., Handbook of Mathematical Functions, Dover, New York, 1972.

APPENDIX E-3

VISCOSITY CORRELATIONS

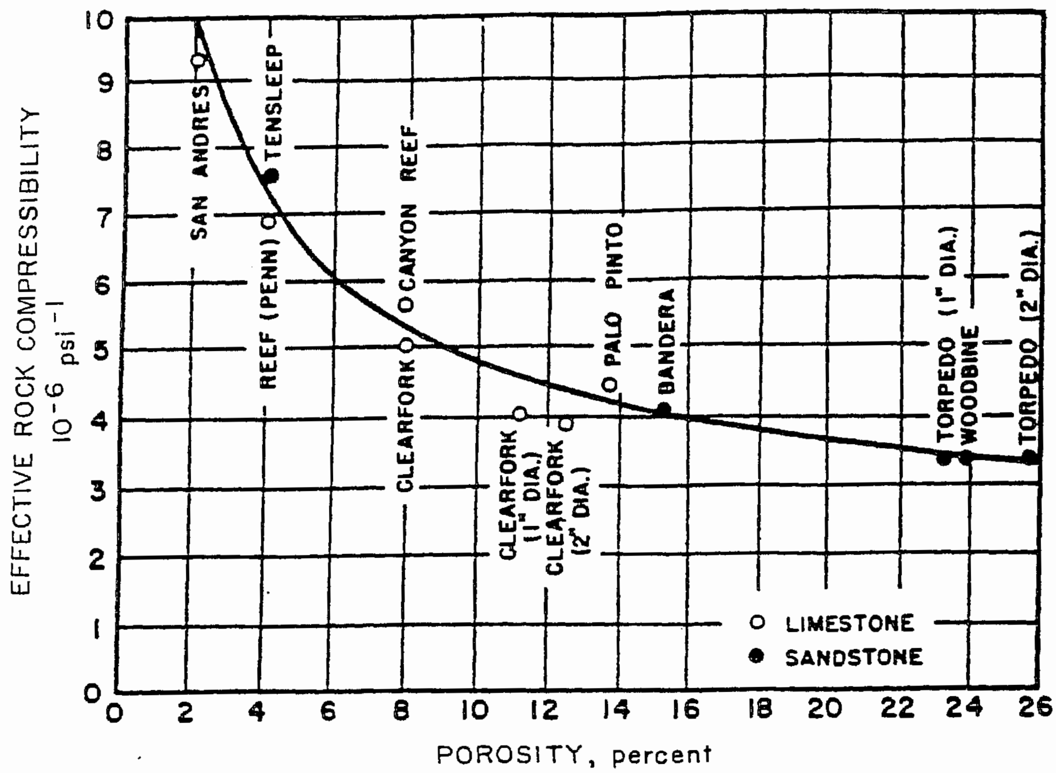


Fig. G.5 Effective formation (rock) compressibility. From Hall, *Trans.*, AIME (1953) **198**, 309.

Source: Matthews and Russell, 1967, Pressure Buildup and Flow Tests in Wells

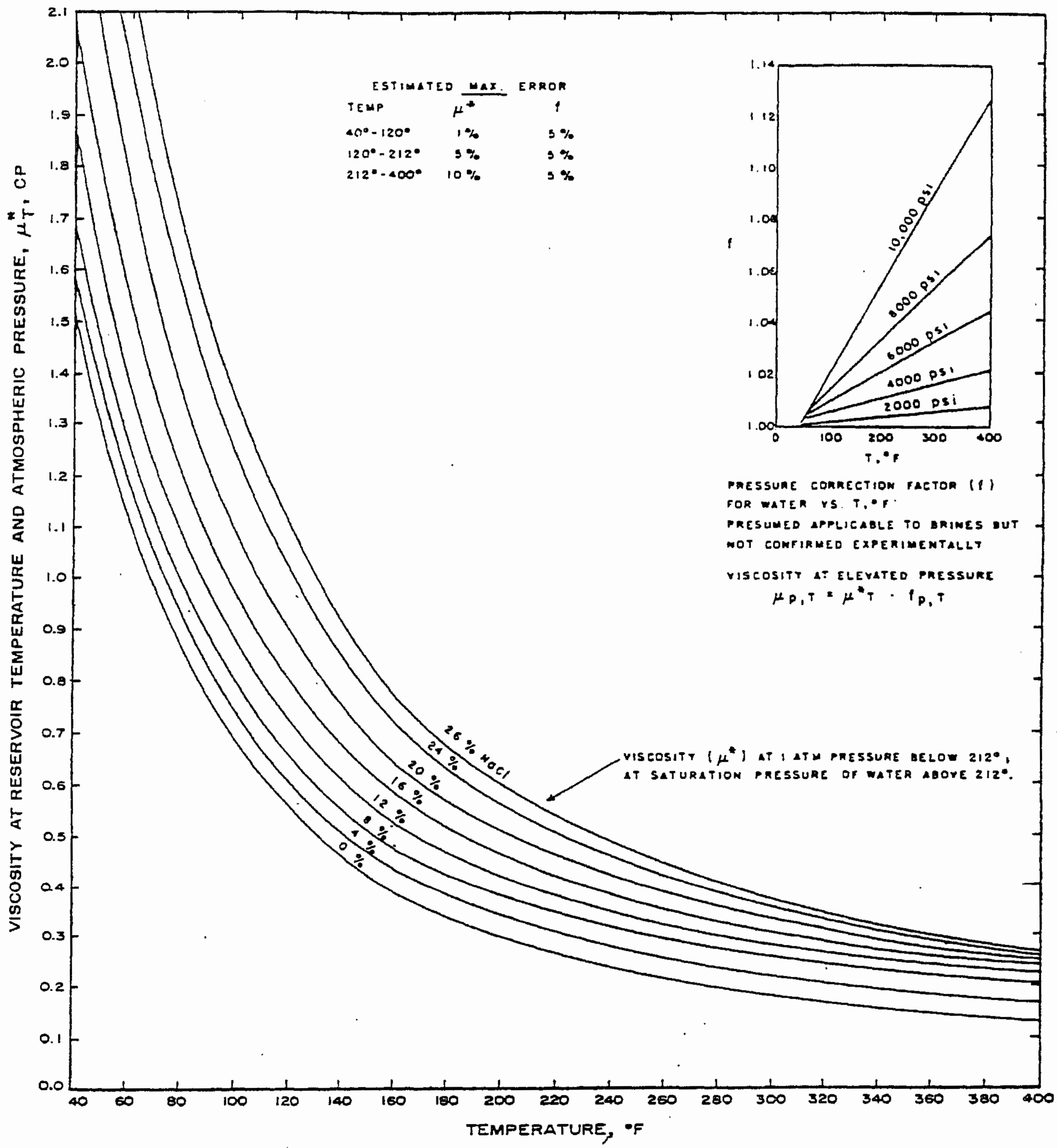


Fig. D.35 Water viscosity at various salinities and temperatures. After Matthews and Russell, data of Chesnut.[18]

FROM: Earlougher, R.C., 1977, "Advances in Well Test Analysis", SPE of AIME, Dallas, Texas

APPENDIX E-4

COMPRESSIBILITY CORRELATIONS

SUBSURFACE

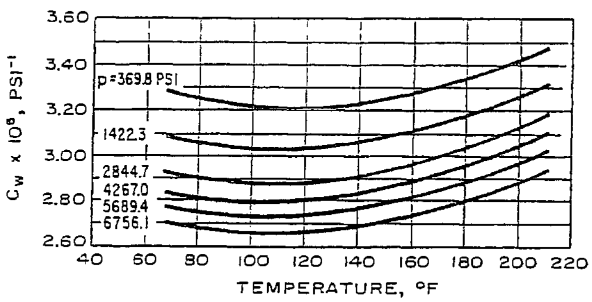


Fig. D.16 Average compressibility of distilled water. After Long and Chierici.[13]

Source: Earlougher, 1977, Advances in Well Test Analysis

COMPRESSIBILITY OF PORE VOLUME AND DISTILLED WATER

APPENDIX E-5

PREDICTED PRESSURE RISE CALCULATIONS

APPENDIX E-5
Predicted Bottomhole Pressure Rise Calculations
Navajo Refining Company, L.L.C.

Permeability	251 md
Porosity	10%
Thickness	85 feet
Compressability	8.4e-6 psi^{-1}

Pressure Buildup at a One-Mile Radius from WDW-1

	Case 1	Case 2	Case 3	Case 4
Rate in WDW-1	400 gpm	400 gpm	0 gpm	267 gpm
Rate in WDW-2	400 gpm	0 gpm	400 gpm	267 gpm
Rate in WDW-3	0 gpm	400 gpm	400 gpm	266 gpm

Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)
12/31/12	4849	154.88	12/31/12	4849	154.88	12/31/12	4849	154.88	12/31/12	4849	154.88
01/11/13	4860	177.04	01/11/13	4860	180.47	01/11/13	4860	150.16	01/11/13	4860	169.24
02/10/13	4890	201.76	02/10/13	4890	210.27	02/10/13	4890	164.24	02/10/13	4890	192.12
03/12/13	4920	214.26	03/12/13	4920	224.08	03/12/13	4920	174.66	03/12/13	4920	204.36
04/11/13	4950	222.70	04/11/13	4950	233.11	04/11/13	4950	182.22	04/11/13	4950	212.70
05/11/13	4980	229.08	05/11/13	4980	239.82	05/11/13	4980	188.11	05/11/13	4980	219.03
06/10/13	5010	234.22	06/10/13	5010	245.17	06/10/13	5010	192.94	06/10/13	5010	224.14
07/10/13	5040	238.52	07/10/13	5040	249.62	07/10/13	5040	197.03	07/10/13	5040	228.42
08/09/13	5070	242.22	08/09/13	5070	253.44	08/09/13	5070	200.57	08/09/13	5070	232.10
09/08/13	5100	245.48	09/08/13	5100	256.78	09/08/13	5100	203.71	09/08/13	5100	235.34
10/08/13	5130	248.38	10/08/13	5130	259.75	10/08/13	5130	206.52	10/08/13	5130	238.24
11/07/13	5160	251.00	11/07/13	5160	262.43	11/07/13	5160	209.06	11/07/13	5160	240.86
12/07/13	5190	253.40	12/07/13	5190	264.87	12/07/13	5190	211.39	12/07/13	5190	243.24
01/06/14	5220	255.60	01/06/14	5220	267.11	01/06/14	5220	213.55	01/06/14	5220	245.44
02/05/14	5250	257.65	02/05/14	5250	269.18	02/05/14	5250	215.54	02/05/14	5250	247.48
03/07/14	5280	259.55	03/07/14	5280	271.12	03/07/14	5280	217.41	03/07/14	5280	249.38
04/06/14	5310	261.34	04/06/14	5310	272.92	04/06/14	5310	219.16	04/06/14	5310	251.17
05/06/14	5340	263.02	05/06/14	5340	274.63	05/06/14	5340	220.81	05/06/14	5340	252.84
06/05/14	5370	264.60	06/05/14	5370	276.23	06/05/14	5370	222.37	06/05/14	5370	254.43
07/05/14	5400	266.11	07/05/14	5400	277.76	07/05/14	5400	223.85	07/05/14	5400	255.93
08/04/14	5430	267.54	08/04/14	5430	279.20	08/04/14	5430	225.27	08/04/14	5430	257.36
09/03/14	5460	268.91	09/03/14	5460	280.58	09/03/14	5460	226.61	09/03/14	5460	258.73
10/03/14	5490	270.22	10/03/14	5490	281.90	10/03/14	5490	227.90	10/03/14	5490	260.03

APPENDIX E-5
Predicted Bottomhole Pressure Rise Calculations
Navajo Refining Company, L.L.C.

Permeability	251 md
Porosity	10%
Thickness	85 feet
Compressability	8.4e-6 psi^{-1}

Pressure Buildup at a One-Mile Radius from WDW-1

Rate in WDW-1	400 gpm	Rate in WDW-1	400 gpm	Rate in WDW-1	0 gpm	Rate in WDW-1	267 gpm
Rate in WDW-2	400 gpm	Rate in WDW-2	0 gpm	Rate in WDW-2	400 gpm	Rate in WDW-2	267 gpm
Rate in WDW-3	0 gpm	Rate in WDW-3	400 gpm	Rate in WDW-3	400 gpm	Rate in WDW-3	266 gpm

Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)
11/02/14	5520	271.47	11/02/14	5520	283.17	11/02/14	5520	229.14	11/02/14	5520	261.29
12/02/14	5550	272.67	12/02/14	5550	284.38	12/02/14	5550	230.33	12/02/14	5550	262.49
01/01/15	5580	273.83	01/01/15	5580	285.55	01/01/15	5580	231.48	01/01/15	5580	263.64
01/31/15	5610	274.95	01/31/15	5610	286.68	01/31/15	5610	232.58	01/31/15	5610	264.76
03/02/15	5640	276.03	03/02/15	5640	287.76	03/02/15	5640	233.65	03/02/15	5640	265.84
04/01/15	5670	277.07	04/01/15	5670	288.81	04/01/15	5670	234.68	04/01/15	5670	266.88
05/01/15	5700	278.08	05/01/15	5700	289.83	05/01/15	5700	235.68	05/01/15	5700	267.89
05/31/15	5730	279.06	05/31/15	5730	290.81	05/31/15	5730	236.65	05/31/15	5730	268.86
06/30/15	5760	280.01	06/30/15	5760	291.77	06/30/15	5760	237.59	06/30/15	5760	269.81
07/30/15	5790	280.93	07/30/15	5790	292.70	07/30/15	5790	238.50	07/30/15	5790	270.73
08/29/15	5820	281.82	08/29/15	5820	293.60	08/29/15	5820	239.39	08/29/15	5820	271.63
09/28/15	5850	282.70	09/28/15	5850	294.48	09/28/15	5850	240.26	09/28/15	5850	272.50
10/28/15	5880	283.55	10/28/15	5880	295.33	10/28/15	5880	241.10	10/28/15	5880	273.35
11/27/15	5910	284.38	11/27/15	5910	296.17	11/27/15	5910	241.92	11/27/15	5910	274.18
12/27/15	5940	285.19	12/27/15	5940	296.98	12/27/15	5940	242.73	12/27/15	5940	274.99
01/26/16	5970	285.98	01/26/16	5970	297.78	01/26/16	5970	243.51	01/26/16	5970	275.78
02/25/16	6000	286.75	02/25/16	6000	298.55	02/25/16	6000	244.28	02/25/16	6000	276.55
03/26/16	6030	287.51	03/26/16	6030	299.31	03/26/16	6030	245.03	03/26/16	6030	277.31
04/25/16	6060	288.25	04/25/16	6060	300.05	04/25/16	6060	245.77	04/25/16	6060	278.05
05/25/16	6090	288.97	05/25/16	6090	300.78	05/25/16	6090	246.49	05/25/16	6090	278.77
06/24/16	6120	289.68	06/24/16	6120	301.49	06/24/16	6120	247.19	06/24/16	6120	279.48
07/24/16	6150	290.38	07/24/16	6150	302.19	07/24/16	6150	247.88	07/24/16	6150	280.18
08/23/16	6180	291.06	08/23/16	6180	302.88	08/23/16	6180	248.56	08/23/16	6180	280.86

APPENDIX E-5
Predicted Bottomhole Pressure Rise Calculations
Navajo Refining Company, L.L.C.

Permeability	251 md
Porosity	10%
Thickness	85 feet
Compressability	8.4e-6 psi^{-1}

Pressure Buildup at a One-Mile Radius from WDW-1

Rate in WDW-1	400 gpm		Rate in WDW-1	400 gpm		Rate in WDW-1	0 gpm		Rate in WDW-1	267 gpm	
Rate in WDW-2	400 gpm		Rate in WDW-2	0 gpm		Rate in WDW-2	400 gpm		Rate in WDW-2	267 gpm	
Rate in WDW-3	0 gpm		Rate in WDW-3	400 gpm		Rate in WDW-3	400 gpm		Rate in WDW-3	266 gpm	
Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)	Date	Time (hours)	Pressure (psi)
09/22/16	6210	291.73	09/22/16	6210	303.55	09/22/16	6210	249.23	09/22/16	6210	281.53
10/22/16	6240	292.39	10/22/16	6240	304.21	10/22/16	6240	249.88	10/22/16	6240	282.18
11/21/16	6270	293.03	11/21/16	6270	304.86	11/21/16	6270	250.52	11/21/16	6270	282.83
12/21/16	6300	293.67	12/21/16	6300	305.49	12/21/16	6300	251.15	12/21/16	6300	283.46
01/20/17	6330	294.29	01/20/17	6330	306.12	01/20/17	6330	251.77	01/20/17	6330	284.09
02/19/17	6360	294.90	02/19/17	6360	306.73	02/19/17	6360	252.38	02/19/17	6360	284.70
03/21/17	6390	295.50	03/21/17	6390	307.34	03/21/17	6390	252.98	03/21/17	6390	285.30
04/20/17	6420	296.10	04/20/17	6420	307.93	04/20/17	6420	253.57	04/20/17	6420	285.89
05/20/17	6450	296.68	05/20/17	6450	308.52	05/20/17	6450	254.15	05/20/17	6450	286.48
06/19/17	6480	297.25	06/19/17	6480	309.10	06/19/17	6480	254.73	06/19/17	6480	287.05
07/19/17	6510	297.82	07/19/17	6510	309.66	07/19/17	6510	255.29	07/19/17	6510	287.62
08/18/17	6540	298.38	08/18/17	6540	310.22	08/18/17	6540	255.84	08/18/17	6540	288.17
09/17/17	6570	298.93	09/17/17	6570	310.77	09/17/17	6570	256.39	09/17/17	6570	288.72
10/17/17	6600	299.47	10/17/17	6600	311.32	10/17/17	6600	256.93	10/17/17	6600	289.27
11/16/17	6630	300.00	11/16/17	6630	311.85	11/16/17	6630	257.46	11/16/17	6630	289.80
12/16/17	6660	300.53	12/16/17	6660	312.38	12/16/17	6660	257.99	12/16/17	6660	290.33
12/31/17	6675	300.79	12/31/17	6675	312.64	12/31/17	6675	258.32	12/31/17	6675	290.66

APPENDIX E-6

PREDICTED PLUME CALCULATIONS

SUBSURFACE

APPENDIX E-6
PLUME RADIUS CALCULATIONS

$r_c = [\,(0.1337\ v\ t) / (0.8\ \pi\ \theta\ h)\,]^{1/2}$

$r_d = 2.3\ (C_d\ r_c)^{0.05} + r_c$

	WDW-1					
			Max 400 gpm			
(r_c) Radius of Concentrated Plume	Current Plume		Future Plume		Combined Plume	
(r_d) Radius of Dispersed Plume						
(v) Volume of Injected Fluid in Gallons	1,483,862,206		210,240,000		2,535,062,206	
Factor to compensate for Immovable Connate Water	0.80		0.80		0.80	
(θ) Formation Porosity	0.10		0.10		0.10	
(h) Thickness of the Injection Reservior	85		85		85	
(t) Time of Injection	1		5		1	
(cd) Coefficient of Dispersion; for limestone = 65	65		65		65	
Constant	2.30		2.30		2.30	
	r_c	r_d	r_c	r_d	r_c	r_d
	3048	3053	2566	2570	3984	3989
	Plume to 12/31/12		5-year Plume		Projected Plume to 12/31/17	

APPENDIX E-6
PLUME RADIUS CALCULATIONS

$r_c = [(0.1337\ v\ t) / (0.8\ \pi\ \theta\ h)]^{1/2}$

$r_d = 2.3\ (C_d\ r_c)^{0.05} + r_c$

	WDW-2					
			Max 400 gpm			
(r_c) Radius of Concentrated Plume	Current Plume		Future Plume		Combined Plume	
(r_d) Radius of Dispersed Plume						
(v) Volume of Injected Fluid in Gallons	913,126,057		210,240,000		1,964,326,057	
Factor to compensate for Immovable Connate Water	0.80		0.80		0.80	
(θ) Formation Porosity	0.10		0.10		0.10	
(h) Thickness of the Injection Reservior	85		85		85	
(t) Time of Injection	1		5		1	
(cd) Coefficient of Dispersion; for limestone = 65	65		65		65	
Constant	2.30		2.30		2.30	
	r_c	r_d	r_c	r_d	r_c	r_d
	2391	2395	2566	2570	3507	3512
	Plume to 12/31/12		5-year Plume		Projected Plume to 12/31/17	

APPENDIX E-6
PLUME RADIUS CALCULATIONS

$r_c = [\ (0.1337\ v\ t) / (0.8\ \pi\ \theta\ h)\ ]^{1/2}$

$r_d = 2.3\ (C_d\ r_c)^{0.05} + r_c$

	WDW-3					
			Max 400 gpm			
(r_c) Radius of Concentrated Plume	Current Plume		Future Plume		Combined Plume	
(r_d) Radius of Dispersed Plume						
(v) Volume of Injected Fluid in Gallons	413,481,362		210,240,000		1,464,681,362	
Factor to compensate for Immovable Connate Water	0.80		0.80		0.80	
(θ) Formation Porosity	0.10		0.10		0.10	
(h) Thickness of the Injection Reservior	85		85		85	
(t) Time of Injection	1		5		1	
(cd) Coefficient of Dispersion; for limestone = 65	65		65		65	
Constant	2.30		2.30		2.30	
	r_c	r_d	r_c	r_d	r_c	r_d
	1609	1613	2566	2570	3029	3033
	Plume to 12/31/12		5-year Plume		Projected Plume to 12/31/17	

APPENDIX F

FORMATION FLUID ANALYTICAL DATA

APPENDIX F-1

FORMATION FLUID ANALYTICAL DATA
NAVAJO REFINING COMPANY, L.L.C.
ARTESIA, NEW MEXICO

Chemical	Mewbourne Well No. 1	Chukka Well No. 2	Gaines Well No. 3	Average
Date	July 31, 1998	June 14, 1999	Nov 8, 2006	
Fluoride (mg/l)	2.6	9.7	Not Detected	6.15
Chloride (mg/L)	19,000	15,000	10,447	14,815.67
NO3-N (mg/L)	<10	<10	--	<10
SO4 (mg/L)	2,200	2000	1,908	2,036
CaCO3 (mg/L)	1000	1210	--	1105
Specific Gravity (g/L)	1.034	1.0249	--	1.0295
TDS (mg/L)	33,000	20,000	--	26,500
Specific Conductance (uMHOs/cm)	52,000	43,000	--	47,500
Potassium (mg/L)	213	235	85.5	177.83
Magnesium (mg/L)	143	128	155	142
Calcium (mg/L)	390	609	393	464
Sodium (mg/L)	12,770	8,074	6,080	8,974.67
pH (s.u.)	8.1	7.2	--	7.65

The data in the above table was referenced from "Discharge Plan Application and Application for Authorization to Inject per Oil Conservation Division Form C-108, into Class I Wells WDW-1 and Proposed WDW-2 and WDW-3" and the "Discharge Permit Approval Conditions", "Reentry and Completion Report Waste Disposal Well No. 2", and "Reentry and Completion Report Waste Disposal Well No. 3".

APPENDIX G

PRESSURE FALL-OFF TEST RESULTS

SUBSURFACE

2012 ANNUAL BOTTOM-HOLE PRESSURE SURVEY AND PRESSURE FALLOFF TEST FOR MEWBOURNE WELL NO. 1

NAVAJO REFINING COMPANY
ARTESIA, NEW MEXICO
PROJECT NO. 70D6835

REPORT SUBMITTED:
JANUARY 2013

PREPARED BY:

SUBSURFACE CONSTRUCTION CORP.
6925 PORTWEST DRIVE, SUITE 110
HOUSTON, TEXAS 77024
pfh@subsurfacegroup.com

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

TABLE OF CONTENTS (CONTINUED)

TABLES

TABLE OF CONTENTS (CONTINUED)

FIGURES

TABLE OF CONTENTS (CONTINUED)

APPENDICES

EXECUTIVE SUMMARY

Subsurface Construction Corp (Subsurface) was contracted by Navajo Refining Company (Navajo) to perform a pressure falloff test, bottom-hole pressure survey, and temperature survey on Navajo's Mewbourne Well No. 1. The test was performed according to New Mexico Oil Conservation Division (OCD) falloff test guidelines (*New Mexico Oil Conservation Division UIC Class I Well Fall-Off Test Guidance, December 3, 2007*).

The test provides the state regulatory agency with the necessary information to assess the validity of requested or existing injection well permit conditions and satisfy the permitting objective of protecting the underground sources of drinking water (USDW). Specifically, 40 CFR Part 146 states "the Director shall require monitoring of the pressure buildup in the injection zone annually, including at a minimum, a shutdown of the well for a time sufficient to conduct a valid observation of the pressure fall-off curve" (40 CFR§146.13 for Non-hazardous Class I Wells).

The falloff testing was conducted according to the test plan submitted and approved by the OCD. The test plan stated that all offset wells that inject into the injection interval would be shut-in for the duration of the test period. The testing consisted of a 30.77-hour injection period and a 36.03-hour falloff period. Bottom-hole pressure gauges were also placed in the offset wells Gaines Well No. 3 and Chukka Federal Well No. 2. These wells are owned by Navajo and are used to inject plant waste into the same intervals as the Mewbourne Well No. 1.

As prescribed by the guidelines, the report discusses supporting and background information in Sections 1 through 9. The one mile area of review (updated since the 2011 falloff testing) is discussed in Section 10 and geology is discussed in Section 11. Information on the offset wells is discussed in Section 12, daily testing activities in Section 13, and point of shut-in, in Section 14. The pressure falloff testing and analysis results are discussed in Section 15. The OCD required record keeping statement is discussed in Section 16.

1. FACILITY INFORMATION

a. Name: Navajo Refining Company (subsidiary of the Holly Corporation)
b. Facility Location: Highway 82 East, Artesia, New Mexico 88211
c. Operator's Oil and Gas Remittance Identifier (OGRID) Number: 223518

2. WELL INFORMATION

a. OCD UIC Permit Number: WDW-1 UIC I-8
b. Well Classification: Class I Non-hazardous
c. Well Name and Number: Mewbourne Well No. 1
d. API Number: 30-015-27592
e. Well Legal Location: 660 FSL, 2310 FEL

3. CURRENT WELLBORE SCHEMATIC

The Mewbourne Well No. 1 wellbore schematic is presented in Figure 1. The schematic has all data as requested by the guidelines and includes the following:

a. Tubing: 4-1/2-inch, 11.6 pound per foot, steel construction, API grade N-80, with long thread connections (LT&C).

b. Packer: Arrow X-1, 7-inch by 3-1/2-inch set in tension at 7,879 feet.

c. Tubing Length: 7,879 feet. There are no profile nipples in the tubing or the packer as this was not a requirement of the permit.

d. Size, Type, and Depth of Casing: There are three casing strings in the well. The information for these casing strings was obtained from OCD records on file with the state and geophysical logs. The casing strings are:

i. 13-3/8-inch, 48 pound per foot, steel construction, API grade J-55, with short thread connections (ST&C), set at a depth of 390 feet. The casing was cemented to the surface with 525 sacks of cement. The casing was set in open hole with a diameter of 17.5 inches. This information was obtained from OCD records.

ii. 9-5/8-inch, 36 pound per foot, steel construction, API grade J-55, ST&C, set at a depth of 2,555 feet. The casing was cemented to the surface with 1,000 sacks of cement. The casing was set in open hole with a diameter of 12.25 inches. This information was obtained from OCD records.

iii. 7-inch, 26 pound per foot and 29 pound per foot, steel construction, API grade N-80 and P-110, LT&C, set at a depth of 9,094 feet. The casing was cemented to surface in two stages with 1,390 sacks of cement. The casing was set in open hole with a diameter of 8.75 inches. The top cement was verified with a CBL run on July 23, 1998. The remainder of the information was obtained from OCD records.

iv. A cement plug at 9,004 feet isolates the lower section of the original borehole. This information was obtained from OCD records.

e. The top of cement was determined from a CBL run in the 7-inch casing string on July 23, 1998. The top of cement in the 7-inch casing was found at the surface. The top of cement in the 9-5/8-inch and 13-3/8-inch casing strings was verified through OCD records and volume calculations.

f. The 7-inch casing was perforated on July 24 and July 27, 1998. The casing was perforated with a 0.5-inch diameter hole at 2 shots per foot on a 60° phasing. The perforations are located between 7,924 feet and 8,188 feet and from 8,220 feet to 8,476 feet.

g. The total depth of the well is 10,200 feet with the plug back depth at 9,004 feet. On September 23, 2012, fill was tagged at 9,018 feet.

h. The bottom-hole pressure gauges run in the Mewbourne Well No. 1 for the pressure falloff testing consisted of two memory (top of the perforations) (MRO) pressure gauges were placed at 7,922 feet and the other was placed two feet lower at 7,924 feet

4. ELECTRIC LOG ENCOMPASSING THE COMPLETED INTERVAL

The dual induction log is presented in Appendix A and encompasses the completed interval between 7,924 feet and 8,476 feet. The dual induction log was submitted to the OCD with the original permit after the well was drilled by the Mewbourne Oil Company. The log was resubmitted to the OCD when the well was re-permitted as a Class I injection well.

5. RELEVANT PORTIONS OF THE POROSITY LOG USED TO ESTIMATE FORMATION POROSITY

The neutron density log is presented in Appendix B and encompasses the completed interval between 7,924 feet and 8,476 feet. The neutron density log was submitted to the OCD with the original permit after the well was drilled by Mewbourne Oil Company. The log was resubmitted to the OCD when the well was re-permitted as a Class I injection well. The porosity of the formation, 10%, and the reservoir thickness, 175 feet, were determined from this log. These values were used in the analysis of the pressure falloff data (Section 15). Additional information concerning the geology of the injection reservoir is discussed in Section 11.

6. PVT DATA OF THE FORMATION AND INJECTION FLUID

The Mewbourne Well No. 1 was recompleted in July 1998, prior to the issuance of the current well testing guidelines (December 3, 2007). At the time, no directives were in place to test formation fluids or derive formation characteristics from cores. However, reservoir fluid samples were obtained during the recompletion and the average density and average total dissolved solids (TDS) were measured at 1.03 g/l and 26,500 mg/l, respectively. The analytical results of the analysis of the formation fluid are summarized in Table I.

The viscosity of the formation fluid, formation water compressibility, and total system compressibility were estimated in reference to bottom-hole temperature using industry accepted correlations. These correlations are found in the Society of Petroleum Engineer's "Advances in Well Test Analysis, Monograph Volume 5" and "Pressure Buildup and Flow Tests in Wells, Monograph Volume 1".

a. Estimation of formation fluid and reservoir rock compressibility:

   The fluid compressibility of the formation brine was estimated for a sodium chloride solution (26,500 mg/l) at the bottom-hole temperature of 127°F using Appendix C (Figure D.16 SPE Monograph 5). This value was 2.9×10^{-6} psi^{-1}. The formation pore volume compressibility was estimated using Appendix D (Figure G.5 SPE Monograph 1). This value was 5.5×10^{-6} psi^{-1}. The total system compressibility is the sum of the fluid compressibility and the pore volume compressibility, 8.4×10^{-6} psi^{-1}. The temperature used with the correlations was recorded during the temperature survey conducted in the Mewbourne Well No. 1 on July 23, 1998, and included in this report as Appendix E.

b. Formation fluid viscosity with reference temperature:

   The formation fluid had a TDS concentration of 26,500 mg/l. This equates to an approximate equivalent percentage of NaCl of 4.5%. The average viscosity of the formation fluid was estimated using Appendix F (Figure D.35 SPE Monograph 5). This value was 0.57 centipoise (cp) at 127°F.

c. Formation fluid specific gravity/density with reference temperature:

   The average formation fluid density was measured at 1.03 g/l at 70°F (Table I).

d. Injection fluid specific gravity, viscosity and compressibility with reference temperature:

The specific gravity and pH of the refinery waste water were measured during the injection portion of the reservoir testing. The specific gravity was 1.01 (8.41 pounds per gallon). This equates to an approximate equivalent percentage of NaCl of 4%. Using the same methodology described above, the viscosity of the injected fluid was 0.54 cp at 127°F. The compressibility of the injected plant waste was 2.9×10^{-6} psi^{-1} at 127°F.

7. DAILY RATE HISTORY DATA (MINIMUM OF ONE MONTH PRECEDING THE FALLOFF TEST)

The rate history used in the analysis of the pressure falloff data began on November 14, 2011 following the 2011 falloff testing completed on November 13, 2011. The daily rate history is summarized in Appendix G.

8. CUMULATIVE INJECTION INTO THE FORMATION FROM TEST WELL AND OFFSET WELLS

The total volume of fluid injected into all three wells as of September 21, 2012, was 2,755,143,650 gallons. The volume of fluid injected into the Mewbourne Well No. 1 was 1,466,030,030 gallons. The volume of fluid injected into the Chukka Well No. 2 was 890,772,418 gallons. The volume of fluid injected into the Gaines Well No. 3 was 398,341,202 gallons. The area of review (AOR) indicates that there are no other wells injecting into the intervals in which the Navajo wells inject. The volumes injected were obtained from plant records.

9. PRESSURE GAUGES

Two (2) down hole pressure gauges and one surface pressure gauge were used for the Mewbourne Well No. 1 buildup and falloff testing. The down hole pressure gauges were set at 7,922 feet and 7,924 feet. Bottom-hole pressure gauges were also placed in each of the offset wells: Gaines Well No. 3 and Chukka Well No. 2. The pressure gauges were set at 7,660 feet in the Gaines Well No. 3 and at 7,570 feet in the Chukka Well No. 2.

a. Describe the type of down hole surface pressure readout gauge used including manufacture and type:

In the Mewbourne Well No. 1, two MRO pressure gauges were used to record the pressure and temperature data during the injection/falloff testing. Both gauges were sapphire crystal gauges. The manufacturer of the MRO pressure gauges (Serial Nos. 76120 and 76404) is Spartek Systems. The surface pressure gauge was a quartz crystal gauge (Serial No. 10469) manufactured by Spartek Systems.

In the Gaines Well No. 3, two MRO pressure gauges were used to monitor the bottom-hole pressure and temperature during the testing of the Mewbourne Well No. 1. Both gauges were sapphire crystal gauges with Serial Nos. 76171 and 75900. Both gauges are manufactured by Spartek Systems.

In the Chukka Well No. 2, two MRO pressure gauges were used to monitor the bottom-hole pressure and temperature during the testing of the Mewbourne Well No. 1. Both gauges were sapphire crystal gauges with Serial Nos. 76222 and 76077. Both gauges are manufactured by Spartek Systems.

b. List the full range, accuracy and resolution of the gauge:

In Mewbourne Well No. 1, the MRO pressure gauges, Serial Nos. 76120 and 76404 has a full range of 0 psi to 6,000 psi, an accuracy of 0.022% of full scale, and a resolution of 0.0003% of full scale. The surface pressure gauge (Serial No. 10469) has a full range of 0 psi to 6,000 psi, an accuracy of 0.03% of full scale, and a resolution of 0.0003% of full scale.

In Gaines Well No. 3, the MRO pressure gauge, Serial No. 76171, has a full range of 0 psi to 6,000 psi, an accuracy of 0.022% of full scale, and a resolution of 0.0003% of full scale. The MRO pressure gauge, Serial No. 75900, has a full range of 0 psi to 6,000 psi, and accuracy of 0.022% of full scale, and a resolution of 0.0003% of full scale.

In Chukka Well No. 2, the MRO pressure gauge, Serial No. 76222, has a full range of 0 psi to 6,000 psi, an accuracy of 0.022% of full scale, and a resolution of 0.0003% of full scale. The MRO pressure gauge, Serial No. 76077, has a full range of 0 psi to 6,000 psi, an accuracy of 0.022% of full scale, and a resolution of 0.0003% of full scale.

c. Provide the manufacturer's recommended frequency of calibration and a calibration certificate showing date the gauge was last calibrated:

   The certificate of calibration for each of the pressure gauges used during the testing are included as Appendix H. The manufacturer's recommended calibration frequency is one year.

10. ONE MILE AREA OF REVIEW (AOR)

Federal Abstract Company was contracted by Subsurface and instructed to undertake a review of well changes made within a one-mile area of review (AOR) of the Mewboume Well No. 1, Chukka Well No. 2, and Gaines Well No. 3. In 2009, an update of the original AOR, submitted with the Discharge Application Permit 2003, was completed within the one-mile AOR for all three wells. The current update includes all existing wells within the one-mile AOR and any changes that have occurred to these wells since the 2011 update.

No new fresh water wells were reported within the search area since the submittal of the 2011 report. The discharge application lists the water wells located in the Area of Review.

a. Identify wells located within the one mile AOR:

   Table II also contains a listing of all wells within the one-mile AOR of Mewbourne Well No. 1, Chukka Well No. 2, and Gaines Well No. 3. Figure 6 is a Midland Map Company base map of the area containing the one mile AOR.

b. Ascertain the status of wells within the one mile AOR:

Table II contains a listing of all wells within the one-mile AOR, with their current status. Tables III through VIII contain a list of all wells within the one-mile AOR that have had modifications to the current permit or have had new drilling and/or completion permits issued since the 2011 pressure falloff report.

Twenty-eight (28) wells were found in which the owner had changed. One (1) new plugged and abandoned oil and gas well was found. Two (2) wells were placed in temporarily abandoned status. Four (4) wells were found that were returned to production status. Six (6) wells were found that had been recompleted.

There were twenty-nine (29) new drills and permits to drill, of which none penetrated the Wolfcamp interval. All plugged and abandoned wells were successfully plugged and isolated from the Mewbourne Well No. 1, Chukka Well No. 2, and Gaines Well No. 3 injection intervals according to current OCD records.

c. Provide details on any offset producers and injectors completed in the same interval:

Navajo has two injection wells in the same interval. Mewbourne Well No. 1 is listed as ID No. 59 in Table II and no changes have occurred to this well. Chukka Well No. 2 is listed as ID No. 120 in Table II and no changes have occurred to this well. The Gaines Well No. 3 is listed as ID No. 157 in Table II. The wellbore schematics for the Gaines Well No. 3 and Chukka Well No. 2 are presented as Figure 3 and Figure 4, respectively.

11. GEOLOGY

The injection zones are porous carbonates of the lower portion of the Wolfcamp Formation, the Cisco Formation, and the Canyon Formation. These formations occur in the Mewbourne Well No. 1, the Chukka Well No. 2, and the Gaines Well No. 3 at the depths shown in the table below.

Injection Zone Formation	Mewbourne Well No. 1 (KB = 3,693 ft)		Chukka Well No. 2 (KB = 3,623 ft)		Gaines Well No. 3 (KB = 3,625 ft)	
	MD below KB (ft)	SS Depth (ft)	MD below KB (ft)	SS Depth (ft)	MD below KB (ft)	SS Depth (ft)
Lower Wolfcamp	7,450	-3,757	7,270	-3,647	7,303	-3,678
Cisco	7,816	-4,123	7,645	-4,022	7,650	-4,025
Canyon	8,475	-4,782	8,390	-4,767	8,390	-4,765
Base of Injection Zone (base of Canyon)	9,016	-5,323	8,894	-5,271	8,894	-5,269

a. Description of the geological environment of the injection interval:

The lower portion of the Wolfcamp Formation (Lower Wolfcamp) is the shallowest porous unit in the proposed injection interval. The Wolfcamp Formation (Permian-Wolf campaign age) consists of light brown to tan, fine to medium-grained, fossiliferous limestones with variegated shale interbeds (Meyer, 1966, page 69). The top of the Wolfcamp Formation was correlated for this study to be below the base of the massive, dense dolomites of the overlying Abo Formation. The base of the Wolfcamp coincides with the top of the Cisco Formation. The thickness of log porosity greater than 5% in the entire Wolfcamp Formation ranges from 0 feet to 295 feet in a band three miles wide that trends northeast-southwest across the study area.

The Cisco Formation (Pennsylvanian-Virgilian age) of the Northwest Shelf is described by Meyer (1966, page 59) as consisting of uniform, light colored, chalky, fossiliferous limestones interbedded with variegated shales. Meyer (1966, page 59) also describes the Cisco at the edge of the Permian basin as consisting of biothermal (mound) reefs composed of thick, porous, coarse-grained dolomites. Locally, the Cisco consists of porous dolomite that is 745 feet thick in Chukka Well No. 2, 659 feet thick in Mewbourne Well No. 1, and 720 feet in Gaines Well No. 3.

The total thickness of intervals with log porosity greater than 5% is approximately 310 feet in Mewbourne Well No. 1, 580 feet in Chukka Well No. 2, and 572 feet in Gaines Well No. 3. The total thickness with log porosity greater than 10% is approximately 100 feet in Mewbourne Well No. 1, 32 feet in Chukka Well No. 2, and 65 feet in Gaines Well No. 3. The thickness of the porous intervals in the Cisco ranges from 0 feet in the northwestern part of the study area to nearly 700 feet in a band three miles wide that trends northeast-southwest.

The Canyon Formation (Pennsylvanian-Missourian age) consists of white to tan to light brown fine grained, chalky, fossiliferous limestone with gray and red shale interbeds (Meyer, 1966, page 53). Locally, the Canyon occurs between the base of the Cisco dolomites and the top of the Strawn Formation (Pennsylvanian-Desmoinesian age). The total thickness of intervals with log porosity greater than 5% is 34 feet in Mewbourne Well No. 1, 30 feet in Chukka Well No. 2, and 10 feet in Gaines Well No. 3. No intervals appear to have log porosity greater than 10% in any of the three injection wells.

b. Discuss the presence of geological features, i.e., pinchouts, channels, and faults, if applicable:

From the geological study completed and submitted in the Discharge Plan Application and Application for Authorization to Inject, the reservoir appears to be continuous, with the possibility of anisotropic conditions extending to the west-southwest. The injection intervals that were studied are well confined by the Abo and Yeso low porosity carbonate beds, Tubbs shale, and Salado salt. The Cisco and Wolfcamp formations follow the Vacuum arch and have a southeasterly dip. No faults existed in the study area although, the study also shows that faulting occurs via the K-M fault located 6 miles northwest of Artesia and trends northeast-southwest. The distance to this fault line occurs no closer than 16 miles. No faults are known to exist in the confining zone within the AOR.

c. Provide a portion of relevant structure map, if necessary:

The structure map for Strawn is presented as Appendix I. The structure map for the Wolfcamp presented as Appendix J. The structure map for the Cisco is presented as Appendix K.

12. OFFSET WELLS

There are only two offset wells identified in the AOR that inject into the same interval: the Gaines Well No. 3 and the Chukka Well No. 2. Both wells were shut-in during the buildup and falloff portions of the testing.

a. Identify the distance between the test well and any offset well completed in the same injection interval:

The Mewbourne Well No. 1 is approximately 7,900 feet from Gaines Well No. 3, the test well. The Chukka Well No. 2 is approximately 10,860 feet from the Mewbourne Well No. 1.

b. Report the status of the offset wells during both the injection and shut-in portions of the test:

Both the Gaines Well No. 3 and Chukka Well No. 2 were shut-in during the buildup and falloff portions of the testing. Bottom-hole pressure gauges were lowered into each well approximately 48 hours before shutting in the Mewbourne Well No. 1. The bottom-hole pressure and temperature data are graphically depicted in Figure 5 for the Gaines Well No. 3 and Figure 2 for the Chukka Well No. 2.

c. Describe the impact, if any, the offset wells had on the testing:

The offset wells were shut in prior to beginning the 30-hour injection period and remained shut-in during the falloff portion of the testing.

13. CHRONOLOGICAL LISTING OF THE DAILY TESTING ACTIVITIES (OPERATIONS LOG)

Appendix L contains the formal Chronology of Field Activities. This chronology was developed from the field activity reports.

a. Date of the testing:

The buildup portion of the testing started on September 20, 2012, at 3:15 p.m. and continued until September 21, 2012, at 10:01 p.m., when the Mewbourne Well No. 1 was shut-in. The falloff test ended on September 23, 2012, at 10:02 a.m. The total depth of the well was tagged at 9,018 feet and five-minute gradient stops were made while pulling the pressure gauges out of the wellbore. After the pressure gauge was pulled out of the well on September 23, 2012, the well was turned over to Navajo plant operations personnel.

b. Time of the injection period:

The buildup portion of the testing began on September 20, 2012, when the injection rate was set at an average injection rate of 140 gallons per minute (gpm). The injection rate was held constant for 30.77 hours.

c. Type of injection fluid:

The injected fluid was non-hazardous waste water from the plant. The density of the injection fluid was periodically measured and averaged 8.34 pounds per gallon during the 30.77-hour injection period.

d. Final injection pressure and temperature prior to shutting in the well:

The final flowing pressure (P_{wf}) and temperature (T_{wf}) were 4,167.06 psia and 92.2°F, respectively.

e. Total shut-in time:

The Mewbourne Well No. 1 was shut-in with offset wells shut-in for 36.03 hours.

f. Final static pressure and temperature at the end of the fall-off portion of the test:

The final static pressure at 7,924 feet was 4,015.90 psia. The final temperature was 99.9°F.

14. DESCRIBE THE LOCATION OF THE SHUT-IN VALVE USED TO CEASE FLOW TO THE WELL FOR THE SHUT-IN PORTION OF THE TEST

There are two, 4-inch motor controlled valves installed on the incoming pipeline to Mewbourne Well No. 1. The valves are located before the pod filters. Two 4-inch valves are installed between the pod filters and the wellhead. There is one 6-inch valve installed in the main line between the pod filters and the wellhead. A 4-1/16-inch wing valve is installed on the wellhead. All valves were closed during the falloff portion of the testing. A diagram of the wellhead is shown in Figure 7 and a diagram of the valve locations are shown in Figure 8.

15. PRESSURE FALLOFF ANALYSIS

The following discussion of the analysis of the pressure data recorded during the falloff testing of the Mewbourne Well No. 1 satisfies Sections 15 through 19 of Section IX, Report Components, of the OCD's falloff test guidelines. Where appropriate, the specific guideline addressed is annotated. Specific parameters used in the equations and discussed previously in this report are also annotated. The plots included with this report are summarized in Table IX. The inclusion of these plots in this report satisfies OCD Guideline Section IX.18.

The pressure data obtained during the falloff test were analyzed using the commercially available pressure transient analysis software program PanSystem©. Appendix M contains the output from this software program. Figure 9 shows the pressure data recorded by the bottom-hole pressure gauge from the time the tool was in place through the 36.03 hour total shut-in period. Figure 10 shows the pressure and temperature data recorded by the bottom-hole pressure gauge from the time the tool was in place through the 36.03 hour falloff shut-in period. Figure 11 is a Cartesian plot of the injection rates versus time for the injection period used in the pressure falloff analysis. The superposition time function was used to account for all rate changes during the injection period. Figure 12 is a plot of the surface pressures and injection rates versus time for the stabilized injection period of the testing. Figure 13 is a plot of the historical injection rates and surface pressures versus calendar time.

Figure 14 is a log-log diagnostic plot of the falloff data, showing change in pressure and pressure derivative versus equivalent shut in time. The different flow regimes, wellbore storage, radial flow and change in reservoir characteristics, are indicated on the log-log plot and the superposition Horner plot (OCD Guideline Section IX.18.c and IX.18.d)

Wellbore storage begins at 0.0024 hours and continues to an elapsed shut in time of 0.031 hours. Radial flow begins at an elapsed shut in time of 15.34 hours and continues until 33.05 hours (OCD Guideline Section IX.15.b).

The reservoir permeability was determined from the radial flow region of the superposition Horner plot, Figure 15. The radial flow regime begins at a Horner time of 297.84 and continues until a Horner time of 143.88, at which time the pressure data departs the semi-log straight-line. Figure 16 shows an expanded view of the radial flow regime. The slope of the radial flow period, as calculated by the analysis software, was 3.807719 psi/cycle (OCD Guideline Section IX.15.c). The injection rate just prior to shut in was 139.0 gpm which is equivalent to 4,752.14 barrels per day (bbl/day).

An estimate of mobility-thickness (transmissibility, OCD Guideline Section IX.15.d), kh/μ, for the reservoir was determined to be 202,929 md-ft/cp using the following equation:

$$\frac{k\ h}{\mu} = 162.6 \frac{q\ B}{m}$$

where,

kh/μ	=	formation mobility-thickness, millidarcy-feet/centipoise
q	=	rate prior to shut in, bpd
B	=	formation volume factor, reservoir volume/surface volume
m	=	slope of radial flow period, psi/cycle

$$\frac{k\ h}{\mu} = 162.6 \frac{(4{,}752.14)(1.0)}{3.807719}$$

$$= 202{,}929 \text{ md-ft/cp}$$

The permeability-thickness (flow capacity, OCD Guideline Section IX.15.i), kh, was determined to be 115,670 md-ft by multiplying the mobility-thickness, kh/μ, by the viscosity of the reservoir fluid (see Section 6), $\mu_{reservoir}$, of 0.57 centipoises:

$$kh = \left(\frac{kh}{\mu}\right) \mu_{reservoir}$$

$$= (202{,}929) * (0.57)$$

$$= 115{,}670 \text{ md-ft}$$

The reservoir permeability (OCD Guideline Section IX.15.e) using the total thickness (see Section 5 and Section 11) of 175 feet was 661 md:

$$k = \frac{kh}{h}$$

$$= \frac{115,670}{175}$$

$$= 661\,\text{md}$$

To determine whether the proper viscosity was used in arriving at this permeability, the travel time for a pressure transient to pass beyond the waste front needs to be calculated (OCD Guideline Section VIII.5). The distance to the waste front is determined from the following equation:

$$r_{waste} = \left(\frac{0.13368\ V}{\pi h\ \phi} \right)^{1/2}$$

where,

r_{waste}	=	radius to waste front, feet
V	=	total volume injected into the injection interval, gallons
h	=	formation thickness, feet
ϕ	=	formation porosity, fraction
0.13368	=	constant

A cumulative volume of approximately 1,466,030,030 gallons of waste has been injected into Mewbourne Well No. 1 (see Section 8). The formation has a porosity of 0.10 (see Section 5 and Section 11).

The distance to the waste front was determined to be 1,888 feet:

$$r_{waste} = \left(\frac{(0.13368)(1{,}466{,}030{,}030)}{(\pi)(175)(0.10)} \right)^{\frac{1}{2}}$$

$$= 1{,}888 \text{ feet}$$

The time necessary for a pressure transient to traverse this distance is calculated from the following equation:

$$t_{waste} = 948 \frac{\phi \, \mu_{waste} \, c_t \, r^2_{waste}}{k}$$

where,

t_{waste}	=	time for pressure transient to reach waste front, hours
ϕ	=	formation porosity, fraction
μ_{waste}	=	viscosity of the waste at reservoir conditions, centipoise
r_{waste}	=	radius to waste front, feet
c_t	=	total compressibility of the formation and fluid, psi
k	=	formation permeability, millidarcies
948	=	constant

The pore volume compressibility is 8.4 x 10^{-6} psi^{-1} (see Section 6). The time necessary for a pressure transient to traverse the distance from the wellbore to the leading edge of the waste front would be 2.45 hours:

$$t_{waste} = 948 \frac{(0.10)(0.57)(8.4 \times 10^{-6})(1{,}888)^2}{661}$$

$$= 2.45 \text{ hours}$$

Since the time required to pass through the waste is less than the 15.34 hours required to reach the beginning of the radial flow period, the assumption that the pressure transient was traveling through reservoir fluid during the period of the semi-log straight line was correct.

The near wellbore skin damage (OCD Guideline Section IX.15.f) was determined from the following equation:

$$s = 1.151\left[\frac{p_{wf} - p_{1hr}}{m_1} - \log\left(\frac{k}{\phi\,\mu\,c_t\,r_w^2}\right) + 3.23\right]$$

where,

s	=	formation skin damage, dimensionless
1.151	=	constant
p_{wf}	=	flowing pressure immediately prior to shut in, psi
p_{1hr}	=	pressure determined from extrapolating the first radial flow semi-log line to a Δt of one hour, psi
m_1	=	slope of the first radial flow semi-log line, psi/cycle
k	=	permeability of the formation, md
ϕ	=	porosity of the injection interval, fraction
μ	=	viscosity of the fluid the pressure transient is traveling through, cp
c_t	=	total compressibility of the formation plus fluid, psi^{-1}
r_w	=	radius of the wellbore, feet
3.23	=	constant

The final measured flowing pressure was 4,167.06 psia. The pressure determined by extrapolating the radial flow semi-log line to a Δt of one hour, p_{1hr}, was 4,021.86 psia (calculated from the analysis software). The wellbore radius, r_w, is 0.3646 feet (completion records). Using these values in addition to the previously discussed parameters results in a skin of 36.08:

$$s = 1.151\left[\frac{4{,}167.06 - 4{,}021.86}{3.807719} - \log\left(\frac{661}{(0.10)(0.57)(8.4\times10^{-6})(0.3646)^2}\right) + 3.23\right]$$

$$= 36.08$$

The change in pressure, Δp_{skin}, in the wellbore associated with the skin factor (OCD Guideline Section IX.15.g) was calculated using the following equation:

$$\Delta p_{skin} = 0.869(m)(s)$$

where,

0.869	=	constant
m	=	slope from superposition plot of the well test, psi/cycle
s	=	skin factor calculated from the well test

The change in pressure, Δp_{skin}, using the previously calculated and defined values was determined to be 119.39 psi:

$$\begin{aligned}\Delta P_{SKIN} &= 0.869(m)(s)\\ &= 0.869(3.807719)(36.08)\\ &= 119.39 \text{ psi}\end{aligned}$$

The flow efficiency (E, OCD Guideline Section IX.15.h) was determined from the following equation:

$$E = \frac{p_{wf} - \Delta p_{skin} - p_{static}}{p_{wf} - p_{static}}$$

where,

E = flow efficiency, fraction

p_{wf} = flowing pressure prior to shutting in the well for the fall-off test,

p_{static} = final pressure from the pressure falloff test

Δp_{skin} = pressure change due to skin damage

Using the previously determined parameters, the flow efficiency was calculated to be 0.21:

$$E = \frac{4{,}167.06 - 119.39 - 4{,}015.9}{4{,}167.06 - 4{,}015.9}$$

$$= 0.21$$

The radius of investigation (OCD Guideline Section IX.15.a) was calculated using the following equation:

$$R_{inv} = 0.029\sqrt{\frac{k\,\Delta t_s}{\phi\,\mu\,C_t}}$$

where,

k = formation permeability, millidarcies

Δt_s = elapsed shut-in time, hours

ϕ = formation porosity, fraction

μ = viscosity of the fluid the pressure transient is traveling through, cp

c_t = total compressibility of the formation plus fluid, psi^{-1}

0.029 = constant

The radius of investigation, r_{inv}, using the previously defined values was determined to be 6,112 feet:

$$R_{inv} = 0.029\sqrt{\frac{(685)(31.03)}{(0.10)(0.57)(8.4 \times 10^{6})}}$$

$$R_{inv} = 6{,}468\ ft$$

As indicated on Figure 14, the pressure data departs the radial flow region at an elapsed time from shut in of 21.704 hours. No pressure or temperature anomalies were noted that would cause this type of pressure response observed on the derivative log-log plot (OCD Guideline Section VIII.9). A review of the geology of the injection zones (see Section 11) indicates that all three of the formations in which the Mewbourne Well No. 1 injects into have varying thicknesses and porosities within the mapped area. Changes in formation thickness, porosity, and fluid viscosity can cause the slope changes seen on the derivative log-log plot. Because these changes occurred during the duration of the pressure falloff test, the reservoir analysis results are considered heterogeneous as opposed to homogeneous (OCD Guideline Section IX.17.b).

The Hall plot (OCD Guideline Section IX.18.h) is presented as Figure 17. No slope changes are seen in the plotted data.

A comparison of the current analysis results with previous analysis results as well as with the reservoir parameters submitted with the permit application is presented in Table X (OCD Guideline Section IX.19).

On September 23, 2012, a static pressure gradient survey was conducted while pulling the pressure gauges out of the well. Static gradient stops were conducted at 9,000 feet, 8,000 feet, 7,924 feet, 7,000 feet, 6,000 feet, 5,000 feet, 4,000 feet, 3,000 feet, 2,000 feet, 1,000 feet, and at the surface. The bottom-hole pressure and temperature, after 36.03 hours of shut-in at 7,924 feet, were 4,015.90 psia and 99.9°F, respectively. The gradient survey is summarized in Table XI. The data are graphically depicted in Figure 18.

16. NEW MEXICO OIL CONSERVATION DIVISION THREE YEAR RECORDING KEEPING STATEMENT

Navajo will keep the raw test data, generated during the testing, on file for a minimum of three years. The raw test data will be made available to OCD upon request.

TABLE X

Comparison of Permeability, Transmissibility, Skin, False Extrapolated Pressure, and Fill Depth

Date of Test	Permeability (k)	Transmissibility (kh/u)	Skin (s)	False Extrapolated Pressure (p*)	Fill Depth
September 21 – 23, 2012	661 md	202,929 md-ft/cp	36.08	4,007.98	9,018 feet
January 22 - 27, 2012	597 md	183,293 md-ft/cp	27.26	3,792.34 psia	8,986 feet
November 10 - 13, 2010	568 md	174,376 md-ft/cp	14.64	3,622.16 psia	8,986 feet
August 27 – 30, 2009	719 md	233,008 md-ft/cp	54.07	3,475.68 psia	8,986 feet
April 1 – 2, 2008	1,322 md	321,411 md-ft/cp	107	3,430.27 psia	N/A
Permit Parameters	251 md	37,430 md-ft-cp	N/A	N/A	N/A

Production Optimization Systems	Report File:	2012 WDW-1 PFO.pan	
PanSystem Version 3.5	Analysis Date:	11/26/2012	
Well Test Analysis Report		APPENDIX M	

Company:	Navajo Refining Company
Location:	Artesia, New Mexico
Well Name:	Mewbourne Well No. 1
Testing Date:	September 21-23, 2012
Gauge Depth:	7924 feet RGL
Injection Interval:	7924 feet - 8476 feet
Completion Type:	Perforations
Top Of Fill:	9018 feet
Analyst:	TJJ
Subsurface Project No.:	70D6835

Remarks:

Reservoir Description
Fluid type : Water
Well orientation : Vertical
Number of wells : 1
Number of layers : 1

Layer Parameters Data

	Layer 1
Formation thickness	175.0000 ft
Average formation porosity	0.1000
Water saturation	0.0000
Gas saturation	0.0000
Formation compressibility	0.000000 psi-1
Total system compressibility	8.4000e-6 psi-1
Layer pressure	0.000000 psia
Temperature	0.000000 deg F

Well Parameters Data

	Well 1
Well radius	0.3646 ft
Distance from observation to active well	0.000000 ft
Wellbore storage coefficient	0.0000 bbl/psi
Storage Amplitude	0.000000 psi
Storage Time Constant	0.000000 hr
Second Wellbore Storage	0.000000 bbl/psi
Time Change for Second Storage	0.000000 hr
Well offset - x direction	0.0000 ft
Well offset - y direction	0.0000 ft

Fluid Parameters Data

	Layer 1
Oil gravity	0.000000 API
Gas gravity	0.000000 sp grav
Gas-oil ratio (produced)	0.000000 scf/STB
Water cut	0.000000
Water salinity	0.000000 ppm
Check Pressure	0.000000 psia
Check Temperature	0.000000 deg F
Gas-oil ratio (solution)	0.000000 scf/STB
Bubble-point pressure	0.000000 psia
Oil density	0.000 lb/ft3
Oil viscosity	0.000 cp
Oil formation volume factor	0.000 RB/STB
Gas density	0.000 lb/ft3
Gas viscosity	0.0 cp
Gas formation volume factor	0.000 ft3/scf
Water density	0.000 lb/ft3
Water viscosity	0.570 cp
Water formation volume factor	1.000 RB/STB
Oil compressibility	0.000000 psi-1
Initial Gas compressibility	0.000000 psi-1
Water compressibility	0.000000 psi-1

Layer 1 Correlations
Not Used

Layer Boundaries Data
Layer 1 Boundary Type : Infinitely acting

	Layer 1
L1	0.000000 ft
L2	0.000000 ft
L3	0.000000 ft
L4	0.000000 ft
Drainage area	0.000000 acres
Dietz shape factor	0.000000

Layer 1 Model Data
Layer 1 Model Type : Radial homogeneous

	Layer 1
Permeability	0.0000 md
Skin factor (Well 1)	0.0000

Rate Change Data

Time Hours	Pressure psia	Rate STB/day
-7462.016667	0.000000	-4857.924603
-7438.016667	0.000000	-4816.628968
-7414.016667	0.000000	-4720.523892
-7390.016667	0.000000	-4626.136822
-7366.016667	0.000000	-4916.095238
-7342.016667	0.000000	-5021.615079
-7318.016667	0.000000	-4901.156746
-7294.016667	0.000000	-5000.728175
-7270.016667	0.000000	-4743.950480
-7246.016667	0.000000	-4728.999835
-7222.016667	0.000000	-4562.281746
-7198.016667	0.000000	-4522.918651
-7174.016667	0.000000	-4639.880952
-7150.016667	0.000000	-4400.404762
-7126.016667	0.000000	-4747.982226
-7102.016667	0.000000	-4969.876984
-7078.016667	0.000000	-4970.305159
-7054.016667	0.000000	-4595.689683
-7030.016667	0.000000	-4142.720238
-7006.016667	0.000000	-4190.392940
-6982.016667	0.000000	-4384.097140
-6958.016667	0.000000	-5532.918651
-6934.016667	0.000000	-1.3666e4
-6910.016667	0.000000	-8418.916749
-6886.016667	0.000000	-4774.755870
-6862.016667	0.000000	-4655.553571
-6838.016667	0.000000	-4375.392857
-6814.016667	0.000000	-4622.575314
-6790.016667	0.000000	-4613.392940
-6766.016667	0.000000	-4633.942378
-6742.016667	0.000000	-4635.577464
-6718.016667	0.000000	-4728.694362

Rate Change Data (cont)

Time Hours	Pressure psia	Rate STB/day
-6694.016667	0.000000	-4755.400876
-6670.016667	0.000000	-4573.541667
-6646.016667	0.000000	-4709.555556
-6622.016667	0.000000	-4595.347305
-6598.016667	0.000000	-4986.553489
-6574.016667	0.000000	-3737.966270
-6550.016667	0.000000	-4180.829365
-6526.016667	0.000000	-3852.105159
-6502.016667	0.000000	-3892.000083
-6478.016667	0.000000	-8312.144759
-6454.016667	0.000000	-1.1297e4
-6430.016667	0.000000	-7603.813575
-6406.016667	0.000000	-5281.293734
-6382.016667	0.000000	-4486.837302
-6358.016667	0.000000	-4752.307540
-6334.016667	0.000000	-4610.543568
-6310.016667	0.000000	-4527.043734
-6286.016667	0.000000	-4286.608962
-6262.016667	0.000000	-4765.748181
-6238.016667	0.000000	-4498.799521
-6214.016667	0.000000	-4765.990079
-6190.016667	0.000000	-4463.734127
-6166.016667	0.000000	-4294.168651
-6142.016667	0.000000	-4130.430473
-6118.016667	0.000000	-3844.089368
-6094.016667	0.000000	-4045.087302
-6070.016667	0.000000	-4028.724206
-6046.016667	0.000000	-3902.507937
-6022.016667	0.000000	-4132.162698
-5998.016667	0.000000	-4038.309524
-5974.016667	0.000000	-4071.115079
-5950.016667	0.000000	-3894.226190

Rate Change Data (cont)

Time Hours	Pressure psia	Rate STB/day
-5926.016667	0.000000	-3802.496114
-5902.016667	0.000000	-3982.900711
-5878.016667	0.000000	-3910.216187
-5854.016667	0.000000	-4039.916749
-5830.016667	0.000000	-3526.704282
-5806.016667	0.000000	-3175.521908
-5782.016667	0.000000	-3412.128968
-5758.016667	0.000000	-3308.321429
-5734.016667	0.000000	-2731.023810
-5710.016667	0.000000	-2743.605159
-5686.016667	0.000000	-3680.333333
-5662.016667	0.000000	-4047.462302
-5638.016667	0.000000	-4321.942378
-5614.016667	0.000000	-4308.925678
-5590.016667	0.000000	-4273.619048
-5566.016667	0.000000	-3999.404679
-5542.016667	0.000000	-4122.962384
-5518.016667	0.000000	-4064.174603
-5494.016667	0.000000	-4167.900794
-5470.016667	0.000000	-4282.379167
-5446.016667	0.000000	-4216.404960
-5422.016667	0.000000	-4027.476389
-5398.016667	0.000000	-4255.795718
-5374.016667	0.000000	-4298.228092
-5350.016667	0.000000	-4230.071429
-5326.016667	0.000000	-4269.164881
-5302.016667	0.000000	-4229.751984
-5278.016667	0.000000	-4237.285714
-5254.016667	0.000000	-4055.571429
-5230.016667	0.000000	-3923.180556
-5206.016667	0.000000	-3908.255870
-5182.016667	0.000000	-3885.357226
-5158.016667	0.000000	-4068.138608
-5134.016667	0.000000	-4003.837467
-5110.016667	0.000000	-3709.366981
-5086.016667	0.000000	-3886.024223
-5062.016667	0.000000	-4010.135896
-5038.016667	0.000000	-3995.996114
-5014.016667	0.000000	-4040.476108
-4990.016667	0.000000	-4031.009921
-4966.016667	0.000000	-4053.926505
-4942.016667	0.000000	-3976.027860
-4918.016667	0.000000	-3974.511905
-4894.016667	0.000000	-4065.880952
-4870.016667	0.000000	-4113.563575
-4846.016667	0.000000	-3975.831266
-4822.016667	0.000000	-4034.926587
-4798.016667	0.000000	-4072.807540
-4774.016667	0.000000	-4024.690476

Rate Change Data (cont)

Time Hours	Pressure psia	Rate STB/day
-4750.016667	0.000000	-4106.561425
-4726.016667	0.000000	-3934.890956
-4702.016667	0.000000	-3999.799603
-4678.016667	0.000000	-4093.150794
-4654.016667	0.000000	-4056.730159
-4630.016667	0.000000	-4241.938409
-4606.016667	0.000000	-4404.599289
-4582.016667	0.000000	-4295.126901
-4558.016667	0.000000	-4370.490162
-4534.016667	0.000000	-4396.369048
-4510.016667	0.000000	-4442.827381
-4486.016667	0.000000	-4367.390873
-4462.016667	0.000000	-4421.089203
-4438.016667	0.000000	-4130.708416
-4414.016667	0.000000	-4110.761905
-4390.016667	0.000000	-3944.224124
-4366.016667	0.000000	-3757.756118
-4342.016667	0.000000	-3395.638806
-4318.016667	0.000000	-3766.162616
-4294.016667	0.000000	-4170.486276
-4270.016667	0.000000	-3775.418568
-4246.016667	0.000000	-4065.380870
-4222.016667	0.000000	-3653.027860
-4198.016667	0.000000	-3537.751984
-4174.016667	0.000000	-3791.673363
-4150.016667	0.000000	-4065.523065
-4126.016667	0.000000	-3962.212302
-4102.016667	0.000000	-3918.621032
-4078.016667	0.000000	-3935.097222
-4054.016667	0.000000	-4099.166749
-4030.016667	0.000000	-3894.936425
-4006.016667	0.000000	-3911.789683
-3982.016667	0.000000	-3975.924603
-3958.016667	0.000000	-4092.482143
-3934.016667	0.000000	-3992.418651
-3910.016667	0.000000	-4061.009921
-3886.016667	0.000000	-3906.656746
-3862.016667	0.000000	-3547.388889
-3838.016667	0.000000	-3509.178571
-3814.016667	0.000000	-3503.363095
-3790.016667	0.000000	-3298.164683
-3766.016667	0.000000	-3488.242063
-3742.016667	0.000000	-3436.248016
-3718.016667	0.000000	-3685.323330
-3694.016667	0.000000	-3395.652778
-3670.016667	0.000000	-3953.563492
-3646.016667	0.000000	-3962.732226
-3622.016667	0.000000	-3502.503886
-3598.016667	0.000000	-3649.309606

Rate Change Data (cont)

Time Hours	Pressure psia	Rate STB/day
-3574.016667	0.000000	-3864.533730
-3550.016667	0.000000	-3762.434524
-3526.016667	0.000000	-3934.313492
-3502.016667	0.000000	-4079.543733
-3478.016667	0.000000	-4112.238013
-3454.016667	0.000000	-4107.642857
-3430.016667	0.000000	-4012.208333
-3406.016667	0.000000	-4102.601190
-3382.016667	0.000000	-4026.142857
-3358.016667	0.000000	-4035.275711
-3334.016667	0.000000	-4101.894841
-3310.016667	0.000000	-4145.510003
-3286.016667	0.000000	-4147.619048
-3262.016667	0.000000	-4114.547619
-3238.016667	0.000000	-4063.942372
-3214.016667	0.000000	-4076.629051
-3190.016667	0.000000	-4016.214286
-3166.016667	0.000000	-4086.260119
-3142.016667	0.000000	-4305.748016
-3118.016667	0.000000	-4254.012302
-3094.016667	0.000000	-4353.741981
-3070.016667	0.000000	-4378.892692
-3046.016667	0.000000	-4169.151042
-3022.016667	0.000000	-4304.013294
-2998.016667	0.000000	-4293.309359
-2974.016667	0.000000	-4383.438657
-2950.016667	0.000000	-4271.801505
-2926.016667	0.000000	-4436.545800
-2902.016667	0.000000	-4271.795552
-2878.016667	0.000000	-4146.047619
-2854.016667	0.000000	-3244.355159
-2830.016667	0.000000	-3346.059524
-2806.016667	0.000000	-4348.204365
-2782.016667	0.000000	-4240.797619
-2758.016667	0.000000	-4256.533730
-2734.016667	0.000000	-4162.714368
-2710.016667	0.000000	-4086.476108
-2686.016667	0.000000	-4193.571429
-2662.016667	0.000000	-4118.009921
-2638.016667	0.000000	-4130.309524
-2614.016667	0.000000	-4033.771743
-2590.016667	0.000000	-4125.642940
-2566.016667	0.000000	-3999.835400
-2542.016667	0.000000	-4065.025628
-2518.016667	0.000000	-4149.557622
-2494.016667	0.000000	-4079.656746
-2470.016667	0.000000	-4003.007771
-2446.016667	0.000000	-4057.111359
-2422.016667	0.000000	-4033.968171

Rate Change Data (cont)

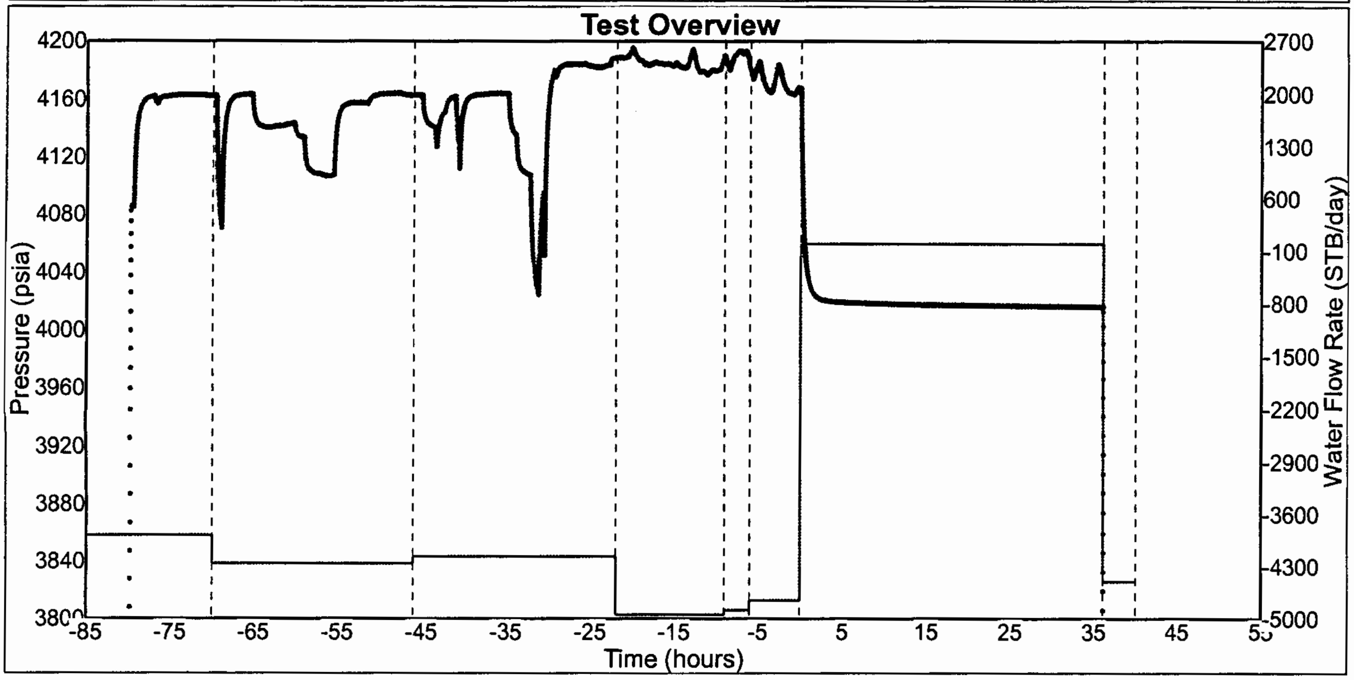
Time Hours	Pressure psia	Rate STB/day
-2398.016667	0.000000	-4031.472222
-2374.016667	0.000000	-4077.242146
-2350.016667	0.000000	-4093.085235
-2326.016667	0.000000	-3919.557540
-2302.016667	0.000000	-4070.061508
-2278.016667	0.000000	-4125.464286
-2254.016667	0.000000	-4113.142857
-2230.016667	0.000000	-4078.331349
-2206.016667	0.000000	-4137.847222
-2182.016667	0.000000	-4068.400711
-2158.016667	0.000000	-4066.613178
-2134.016667	0.000000	-4120.248016
-2110.016667	0.000000	-4124.976190
-2086.016667	0.000000	-4060.620949
-2062.016667	0.000000	-4110.809524
-2038.016667	0.000000	-4075.224289
-2014.016667	0.000000	-4103.248016
-1990.016667	0.000000	-4065.932540
-1966.016667	0.000000	-4044.607226
-1942.016667	0.000000	-4039.347140
-1918.016667	0.000000	-4033.523810
-1894.016667	0.000000	-4050.619048
-1870.016667	0.000000	-4038.100083
-1846.016667	0.000000	-4027.805390
-1822.016667	0.000000	-4047.452546
-1798.016667	0.000000	-4029.166584
-1774.016667	0.000000	-4032.938492
-1750.016667	0.000000	-4034.394841
-1726.016667	0.000000	-4028.728175
-1702.016667	0.000000	-3920.213294
-1678.016667	0.000000	-3870.309524
-1654.016667	0.000000	-5117.027778
-1630.016667	0.000000	-5039.456349
-1606.016667	0.000000	-4945.297702
-1582.016667	0.000000	-4822.412698
-1558.016667	0.000000	-4927.253968
-1534.016667	0.000000	-4374.289600
-1510.016667	0.000000	-4733.238095
-1486.016667	0.000000	-4659.095238
-1462.016667	0.000000	-4777.962301
-1438.016667	0.000000	-4688.037698
-1414.016667	0.000000	-4557.960317
-1390.016667	0.000000	-4515.335317
-1366.016667	0.000000	-4772.928571
-1342.016667	0.000000	-4555.563492
-1318.016667	0.000000	-4662.607143
-1294.016667	0.000000	-4782.982631
-1270.016667	0.000000	-4942.563041
-1246.016667	0.000000	-4893.084281

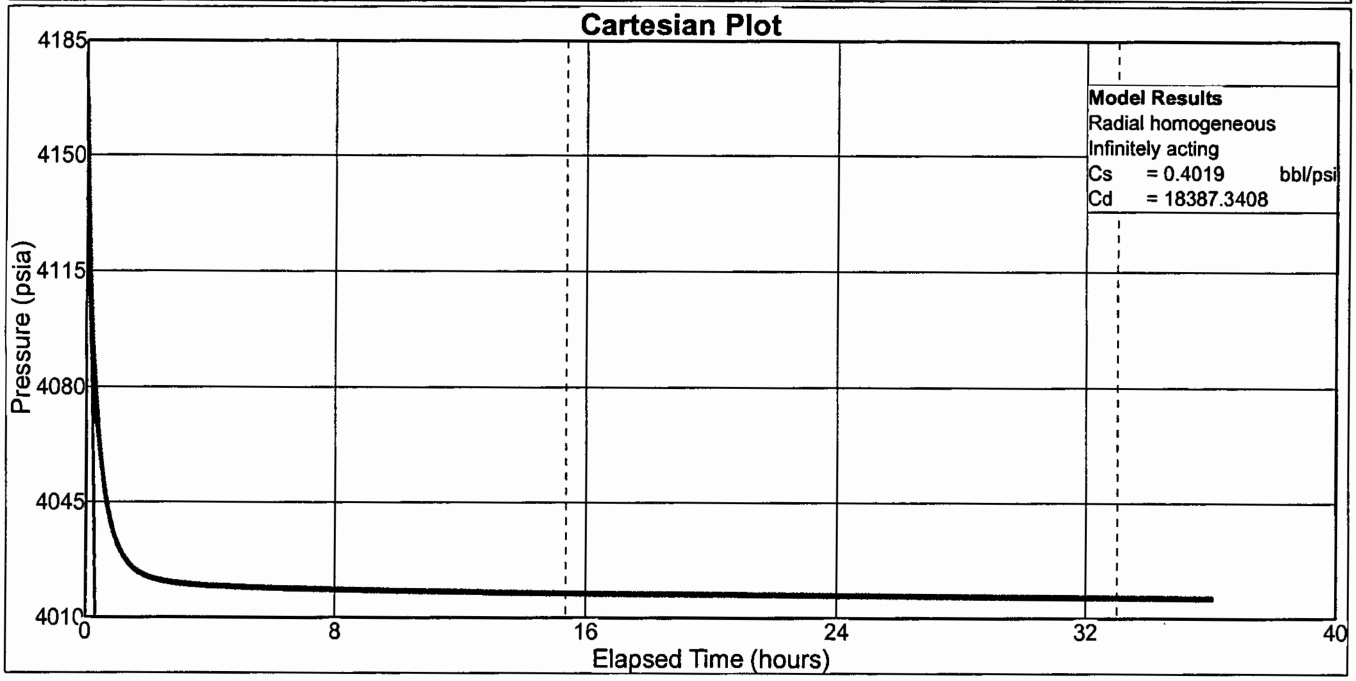
Rate Change Data (cont)

Time Hours	Pressure psia	Rate STB/day
-1222.016667	0.000000	-4843.605783
-1198.016667	0.000000	-4724.392604
-1174.016667	0.000000	-4750.761905
-1150.016667	0.000000	-4516.122933
-1126.016667	0.000000	-4451.000083
-1102.016667	0.000000	-4650.142857
-1078.016667	0.000000	-4479.309524
-1054.016667	0.000000	-4563.888889
-1030.016667	0.000000	-4591.442543
-1006.016667	0.000000	-4431.130870
-982.016667	0.000000	-4472.396627
-958.016667	0.000000	-4514.797619
-934.016667	0.000000	-4438.642940
-910.016667	0.000000	-4322.648644
-886.016667	0.000000	-4473.083416
-862.016667	0.000000	-4339.595155
-838.016667	0.000000	-4550.585400
-814.016667	0.000000	-4389.642940
-790.016667	0.000000	-4561.692461
-766.016667	0.000000	-4352.736028
-742.016667	0.000000	-4494.009921
-718.016667	0.000000	-4506.397024
-694.016667	0.000000	-4459.321743
-670.016667	0.000000	-4438.571511
-646.016667	0.000000	-4498.507937
-622.016667	0.000000	-4525.492063
-598.016667	0.000000	-4434.110714
-574.016667	0.000000	-4450.696429
-550.016667	0.000000	-4431.908730
-526.016667	0.000000	-4672.319444
-502.016667	0.000000	-4482.513889
-478.016667	0.000000	-4607.180556
-454.016667	0.000000	-4617.642063
-430.016667	0.000000	-4636.071346
-406.016667	0.000000	-4651.738178
-382.016667	0.000000	-4596.051505
-358.016667	0.000000	-4568.837385
-334.016667	0.000000	-4714.228257
-310.016667	0.000000	-4684.591106
-286.016667	0.000000	-4679.077464
-262.016667	0.000000	-4518.948495
-238.016667	0.000000	-4448.023727
-214.016667	0.000000	-4261.817460
-190.016667	0.000000	-4091.295635
-166.016667	0.000000	-4168.835235
-142.016667	0.000000	-4090.966353
-118.016667	0.000000	-3725.589286
-94.016667	0.000000	-4351.418651
-70.016667	0.000000	-3880.916667

Rate Change Data (cont)

Time Hours	Pressure psia	Rate STB/day
-46.016667	0.000000	-4258.894758
-22.016667	0.000000	-4163.095321
-9.016667	0.000000	-4941.476192
-6.016667	0.000000	-4881.378968
-0.000317	4167.062992	-4752.142844
36.031235	4015.899600	0.000000
39.983330	0.000000	-4501.605159


Test Overview
Pressure (psia)
4200
4160
4120
4080
4040
4000
3960
3920
3880
3840
3800
Water Flow Rate (STB/day)
2700
2000
1300
600
-100
-800
-1500
-2200
-2900
-3600
-4300
-5000
-85
-75
-65
-55
-45
-35
-25
-15
-5
5
15
25
35
45
Time (hours)



Cartesian Plot Model Results
Radial homogeneous - Infinitely acting

Classic Wellbore Storage

	Value
Wellbore storage coefficient	0.401913 bbl/psi
Dimensionless wellbore storage	1.8387e4

Cartesian Plot Line Details
Line type : Wellbore storage
Slope : -492.659
Intercept : 4167.38
Coefficient of Determination : 0.972351
Number of Intersections = 0

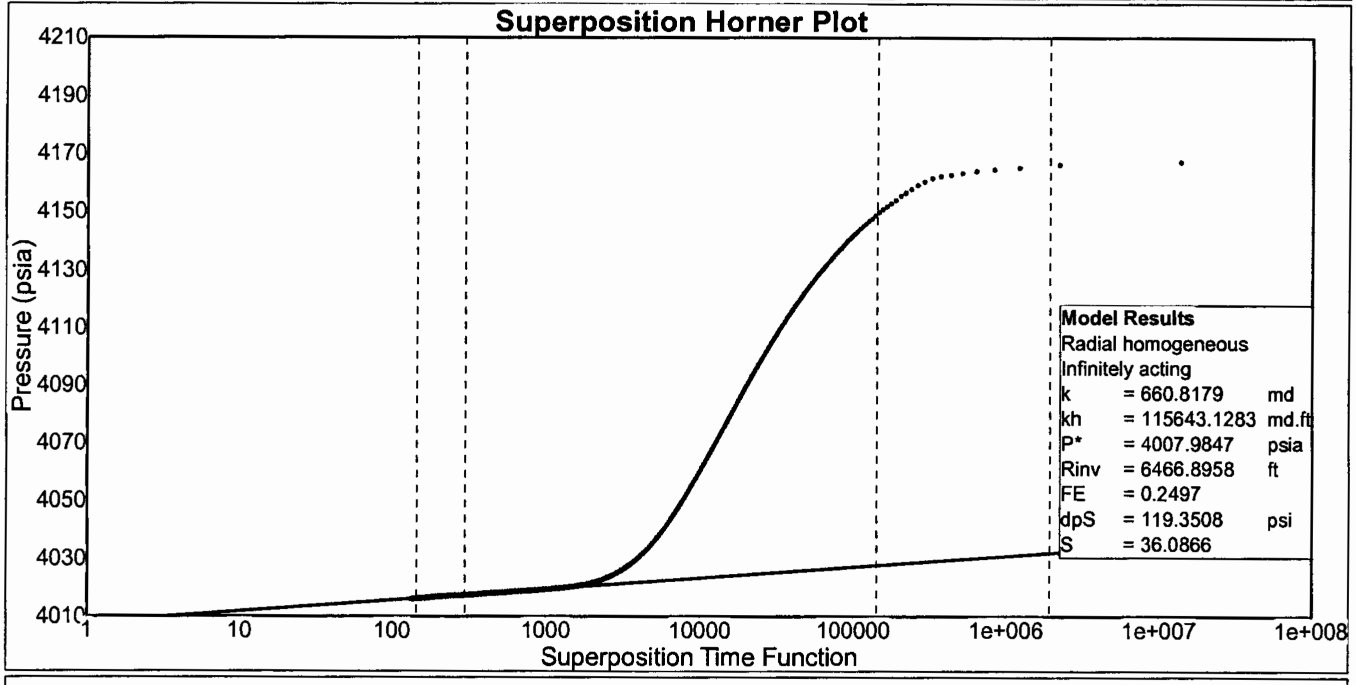


FIGURE 16

Superposition Horner Plot Model Results
Radial homogeneous - Infinitely acting

Classic Wellbore Storage

	Value
Permeability	660.817876 md
Permeability-thickness	1.1564e5 md.ft
Extrapolated pressure	4007.984739 psia
Radius of investigation	6466.895767 ft
Flow efficiency	0.249736
dP skin (constant rate)	119.350763 psi
Skin factor	36.086602

Superposition Horner Plot Line Details
Line type : Radial flow
Slope : 3.80772
Intercept : 4007.98
Coefficient of Determination : 0.972659

	Radial flow
Extrapolated pressure	4007.984739 psia
Pressure at dt = 1 hour	4021.863011 psia

Number of Intersections = 0

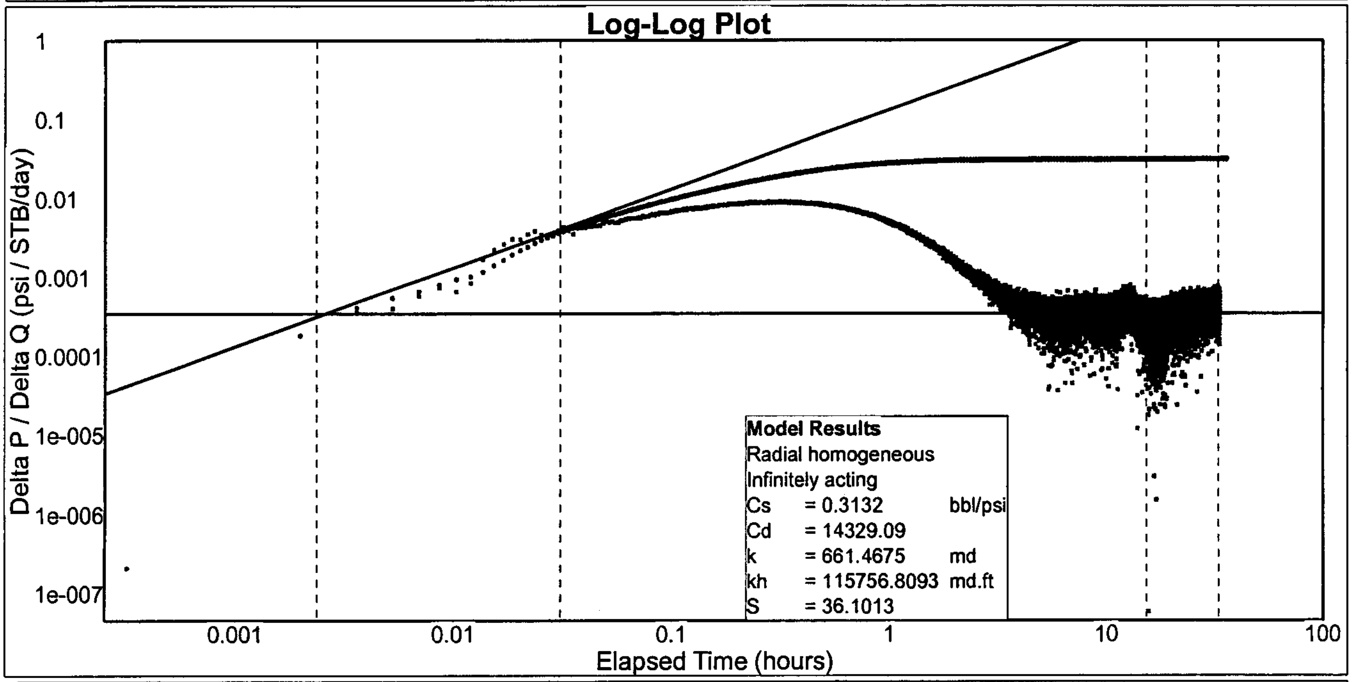


FIGURE 14

Log-Log Plot Model Results
Radial homogeneous - Infinitely acting

Classic Wellbore Storage

	Value
Wellbore storage coefficient	0.313207 bbl/psi
Dimensionless wellbore storage	1.4329e4
Permeability	661.467482 md
Permeability-thickness	1.1576e5 md.ft
Skin factor	36.101314

Log-Log Plot Line Details
Line type : Radial flow
Slope : 0
Intercept : 0.000347643
Coefficient of Determination : Not Used

Line type : Wellbore storage
Slope : 1
Intercept : 0.133032
Coefficient of Determination : Not Used

Number of Intersections = 0

