

Koehler

11/30/2018

Frac Gradient and Max Surface Injection Pressure

Tompkins 41AWI Frac Gradient Info and 11/26/2018 Email		
ISDP =	2506	PSI/FT
WATER HEAD =	0.433	PSI/FT

Ursa: Tompkins 41AWI-08-07-95

API: 045-22551

COGCC Calculates based on Top Perforation. Ursa calculates on Mid-Point of perfs.		
TOP PERF =	6990.5	FT TVD
MID-PERF =	7263.5	

Bottomhole treating pressue = (ISDP) + (Head x Depth)		
Bottomhole treating pressue =	5533	psi
Frac Gradient = Bottom hole treating pressure/depth		
Frac Gradient =	0.791	psi/ft

However, Frac Gradient from Ursa "Tompkins 41AWI Frac Gradient Info" and 11/26/2018 Email = 0.77 psi/ft

Max Surface Injection Pressure Calculations

Option 1:		
ISDP x 80% =	2004.8	psi.
Option 2:		
Using Frac Gradient 0.791 psi/ft and Top Perf 6990.5 ft		
[(F.G. - Head) x Depth] x 80% =	2002	psi
[(F.G. - Head) x Depth] x 83% =	2077	% Used in Watson Ranch B 24AWI--17-07-95 calculation after rounding up.
Option 3:		
Using Frac Gradient 0.77 psi/ft and Mid Perf Zone 7263.4		
[(F.G. - Head) x Depth] x 80% =	1958	psi
[(F.G. - Head) x Depth] x 83% =	2032	% Used in Watson Ranch B 24AWI--17-07-95 calculation after rounding up.

Used in past by COGCC

045-22801

045-22801

For the Ursa: Tompkins 41AWI-08-07-95 COGCC will grant	
2050 psi as the Maximum Surface Injection Pressure	

TOP PERFORATION AT 7413 FT (6990.5 TVD)

Cozzette Perforations	7413-7658 ft MD	6990.5-7235.4 ft TVD
Corcoran Perforations	7699-7959 ft MD	7276.4-7536.3 ft TVD

Tompkins 41AWI-08-07-95

Frac Data

8/27/2018	Stage # 1 Well head pressure 350#. Pump 37,300, Bbls 1% KCL Treated Water, Pumped Avg. Job Rate: 54 BPM Avg. Job Psi 3,677# Max Rate 55 BPM Max Psi -3,752# Total Bbls Pumped 37,300 BBL, Flush Complete ISIP-2,915# FG – 0.81 5 Min- 2,880# 10 Min-2,862# 15 Min-2,852# 20 Min-2,839# 25 Min-2,829# 30 Min-2,819# Braden head pressure 69# @ shut in. Bled down to 0 psi.
8/28/2018	Stage # 1 (Continued) Well head pressure 2,220#. Pump 27,500, Bbls 1% KCL Treated Water, Pumped Avg. Job Rate: 58 BPM Avg. Job Psi 4,099# Max Rate 61 BPM Max Psi -4,364# Total Bbls Pumped 27,500 BBL, Flush Complete ISIP-2,998# FG – 0.82 5 Min- 2,984# 10 Min-2,967# 15 Min-2,954# 20 Min-2,942# 25 Min-2,934# 30 Min-2,924# Braden head pressure 69# @ shut in. Bled down to 0 psi.
8/30/2018	Stage # 2 Well head pressure 1,368#. Pump 38,500 Bbls 1% KCL Treated Water, Pumped Avg. Job Rate: 55 BPM Avg. Job Psi 3,273# Max Rate 60 BPM Max Psi - 5,127# Total Bbls Pumped 38,500 BBL, Flush Complete ISIP-2,599# FG – 0.78 5 Min- 2,592# 10 Min-2,570# 15 Min-2,528# 20 Min-2,503# 25 Min-2,503# 30 Min-2,495# Braden head pressure 116# @ shut in. Bled down to 0 psi.
9/1/2018	Stage # 2 Continued Well head pressure 1,763#. Pump 22,000 Bbls 1% KCL Treated Water, Pumped Avg. Job Rate: 50 BPM Avg. Job Psi 3,141# Max Rate 50 BPM Max Psi - 4,154# Total Bbls Pumped 22,000 BBL, Flush Complete ISIP-2,506# FG – 0.77 5 Min- 2,571# 10 Min-2,542# 15 Min-2,528# 20 Min-2,512# 25 Min-2,492# 30 Min-2,480# Braden head pressure 94# @ shut in. Bled down to 0 psi.

Calculation for Frac Gradient as follows:

Top Perf (TVD): 6990

Bottom Perf (TVD): 7533

Mid Perf (TVD, Calculated): **7261**

Hydrostatic at Mid Perf: $7261 \times .433 = 3144$ psi

Now add Shut down pressure, in our case 2506 psi. $3144 + 2506 = 5650$ psi at Mid Perf

$5650 \text{ psi} / 7261' = 0.778 \text{ psi/ft Frac Gradient}$

From: [Duke Cooley](#)
To: [Bob Koehler - DNR](#)
Cc: [Pake Younger](#); [Chris McRickard](#)
Subject: RE: Ursa: Tompkins 41AWI-08-07-95 (API: 045-22551) Max Injection Pressure
Date: Monday, November 26, 2018 9:54:03 AM
Attachments: [image001.png](#)
[Tompkins 41AWI Frac Gradient Info.xlsx](#)
[IPT DFIT Analyses Ursa Watson Ranch B 24AWI-17-07-95.pdf](#)

Bob,

Thanks for the email back, hope you had a good Thanksgiving!

As I mentioned in my voice mail using the fracture closure pressure gradient is not the pressure that should be used when determining the frac gradient or fracture initiation pressure. The closure pressure is equal to the minimum horizontal stress. The fracture closure pressure for the Tompkins 41AWI (045-22551) was 4,003 psi compared to the closure pressure for the Watson Ranch B 24AWI (045-22801) which was 3,565 psi (report attached). If using fracture closure pressure alone the Tompkins 41AWI should have a higher surface injection pressure than the Watson Ranch B 24AWI which is set at 1,900 psi due to it having a higher closure pressure.

The goal we are trying to achieve is to not initiate new fractures while injecting into the disposal well. The frac gradient or fracture initiation pressure is the pressure we need to inject below to not induce new fractures. I have included a spreadsheet (Tompkins 41AWI Frac Gradient Info) which we used to calculate the pressure it takes to initiate new fractures or hydraulically fracture the rock. On this spreadsheet on 9/1/2018 the ISIP (instantaneous shut-in pressure), pressure it took while hydraulically fracturing to initiate and propagate fractures, was 2506 psi while the entire injection interval was being frac'd (no plugs between stage 1 and 2). When we add the hydrostatic pressure we calculate the frac gradient to be 0.77 psi/ft for the Tompkins 41AWI. Using the .77 psi/ft frac gradient, $(.77 \text{ pfs/ft} - .433 \text{ psi/ft}) \times 7233 \text{ TVD} = 2437 \text{ psi}$ surface injection pressure.

Ursa therefore request that the maximum surface injection pressure for the Tompkins 41AWI (045-22551) be set at 2100 psi. This is well below the calculated frac gradient yet will allow us to inject at an acceptable rate. The currently proposed 1208 psi (calculated using .6 psi/ft) would not allow us to inject at an economic rate.

I am sorry this write up and specific request for an injection pressure was not presented with our initial submittal of the form 31/33, it will be our policy to provide this summary to you at time of submittal going forward.

Thanks you for your consideration. Please reach out to me should you have any further questions.

Sincerely,

Duke Cooley

Vice President - Geosciences



1600 Broadway, Suite 2600
Denver, CO 80202

Direct: (720) 508-8358

Cell: (720) 375-6957

dcooley@ursaresources.com



August 14, 2018

Derek Pake Younger
Ursa Operating Company
1050 17th Street, Suite 2400
Denver, Colorado 80265

RE: Diagnostic Fracture Injection Test Analyses
Tompkins 41AWI-08-07-95
Cozzette/Corcoran members of the Iles Formation
Garfield County, CO

Dear Mr. Younger:

Attached is the summary report for the analyses of the Diagnostic Fracture Injection Test (DFIT) performed on the Cozzette/Corcoran completion in the Tompkins 41AWI-08-07-95, Garfield County, CO.

IPT appreciates the opportunity to work with you and Ursa on this project. Please do not hesitate to call if you have any questions or require any additional assistance.

Sincerely,

Ross Johnson, P.E.
Senior Completions Engineer

Neal Hageman, P.E.
Engineering Manager



1.0 Executive summary

IPT analyzed and evaluated the diagnostic fracture injection test conducted on the Corcoran/Cozzette completion in the Tompkins 41AWI-08-07-95. This analysis was performed to obtain an accurate estimate of reservoir parameters and rock fracturing characteristics. Both the pre-closure and post-closure pressure response suggests average reservoir flow capacity is approximately 111 md-ft. Based upon 56.2 ft net pay, reservoir permeability is calculated to be 1.98 md. Reservoir pressure is calculated to be approximately 3,052 psia (0.422 psi/ft).

The injection test was conducted through the perforations at 7,656' – 959' (7,233' TVD) and was performed by pumping approximately 1,680 gallons of 2% KCl water at about 3.3 bpm. Following the injection, the pressure fall-off was monitored for ~17 hours with a digital surface gauge. The pressure response was analyzed with pre-closure fracture evaluation techniques and post-closure pressure transient analysis (PTA) methods. The results of the analysis are shown in Table 1.

The following are the general conclusions and observations of these evaluations:

- The pre-closure analysis demonstrates a fracture closure pressure of 4,003 psi (0.553 psi/ft) Utilizing this fracture closure pressure, the observed net pressure character is matched with a leakoff coefficient of $0.0015 \text{ Ft/Min}^{1/2}$, which corresponds to an average reservoir permeability of 1.99 md across a net pay thickness of 56.2 feet.
- The post-closure PTA analysis suggests the Cozzette/Corcoran interval has moderate reservoir permeability. Based upon the analysis of the late time pressure data trends, average reservoir permeability is estimated to be 1.98 md and reservoir pressure is calculated to be 3,052 psi (0.422 psi/ft pressure gradient).
- After 325 minutes of data collection, surface pressure fell to zero due to the slightly under pressured nature of the formation. The models utilized the first 325 minutes of data due to inaccurate bottomhole pressure calculations after the pressure fell to zero.



Table 1: Reservoir parameters.

Reservoir Parameter	Injection Test Analyses	
	Pre-Closure Analysis	Post-Closure Analysis
Model	Fracture	Radial
Fracture propagation pressure (psi)	4,522	N/A
Propagation pressure gradient (psi/ft)	0.625	N/A
Fracture closure pressure (psi)	4,003	N/A
Closure pressure gradient (psi/ft)	0.553	N/A
Leakoff coefficient (ft/min ^{1/2})	0.0015	N/A
Effective reservoir permeability (md)	1.99	1.98
Flow capacity (md-ft)	111.8	111.3
Net pay thickness (ft)	56.2	56.2
Reservoir pressure (psi)	N/A	3,052
Reservoir pressure gradient (psi/ft)	N/A	0.422



2.0 Discussion of pre-closure analysis of injection test

IPT analyzed and evaluated the pre-closure portion of the pressure response from the fall-off test performed on the Cozzette/Corcoran in the Tompkins 41AWI-08-07-95. This analysis was performed to determine the fracturing mechanics parameters for the Cozzette/Corcoran members of the Iles Formation.

Observations from the pre-closure evaluation are shown below:

- Hydraulic fracture propagation is confirmed by the typical diagnostic plots for an injection/falloff test: semi-log-of-time (Figure 1) and square-root-of-time (Figure 2) as discussed in SPE 29599. The semi-log-of time plot confirms fracture closure has occurred. The square-root-of-time plot determines fracture closure pressure to be at approximately 13 minutes with a calculated fracture closure pressure of 4,003 psi (0.553 psi/ft).
- The G-Function plot (Figure 3) also suggests fracture closure pressure to be at approximately 4,003 psi (0.553 psi/ft).
- The bottom hole pressure response and net pressure history match are shown in Figure 4. Utilizing the fracture closure pressure determined from the injection test, the observed net pressure character is matched with a leakoff coefficient of $0.0015 \text{ ft/min}^{1/2}$. This relates to a reservoir permeability of 1.99 md utilizing a net pay thickness of 56.2 feet.
- The fracture dimensions created during the subject injection test are shown in Figure 5.

The following are the graphical presentations used in the analysis:

Figure 1: Injection test pressure falloff analysis, semi-log-of-time plot.

Figure 2: Injection test pressure falloff analysis, square-root-of-time plot.

Figure 3: Injection test pressure falloff analysis, G-Function plot.

Figure 4: Injection test data and net pressure history match.

Figure 5: Profile of created fracture.

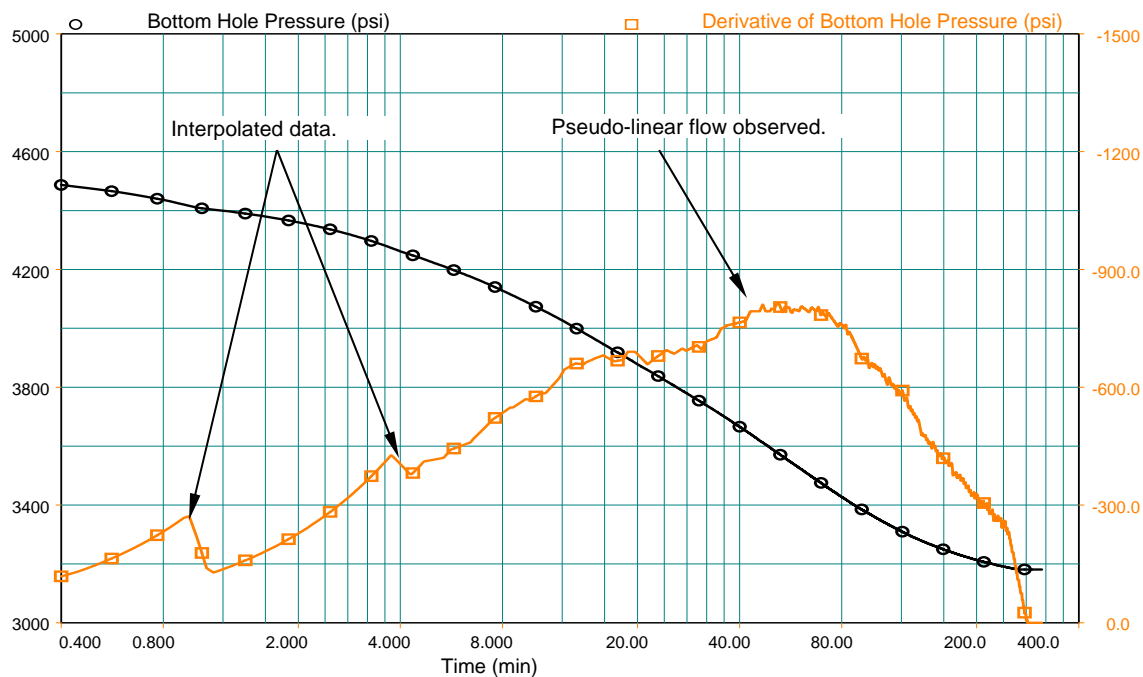


Figure 1: Injection test pressure falloff analysis, semi-log-of-time plot.

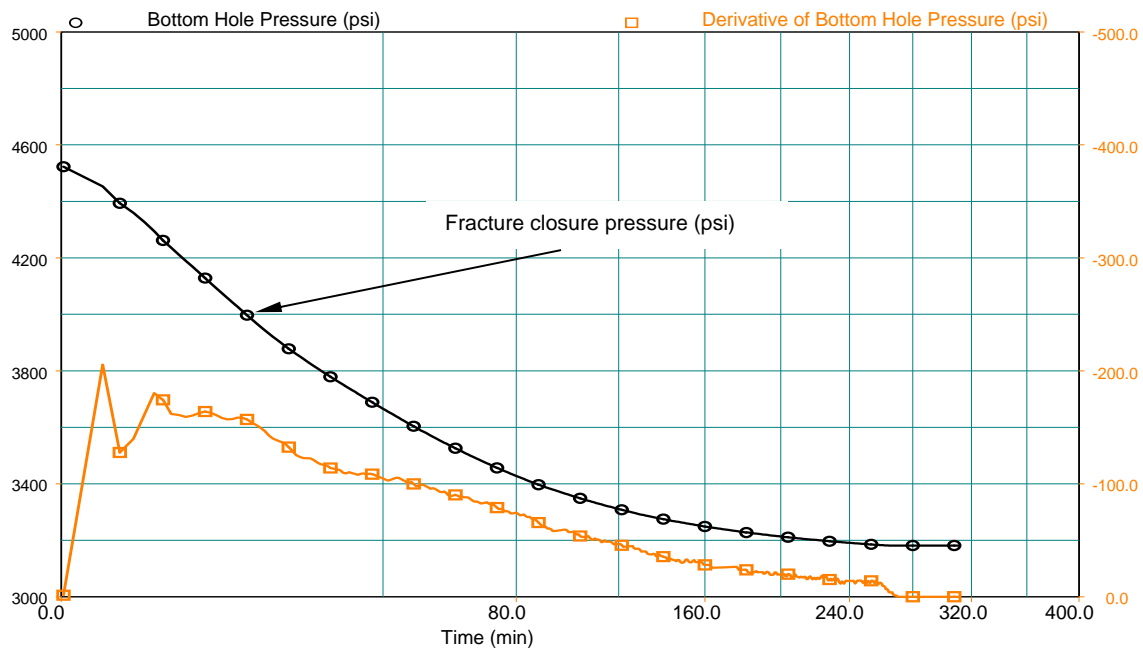


Figure 2: Injection test pressure falloff analysis, square-root-of-time plot.

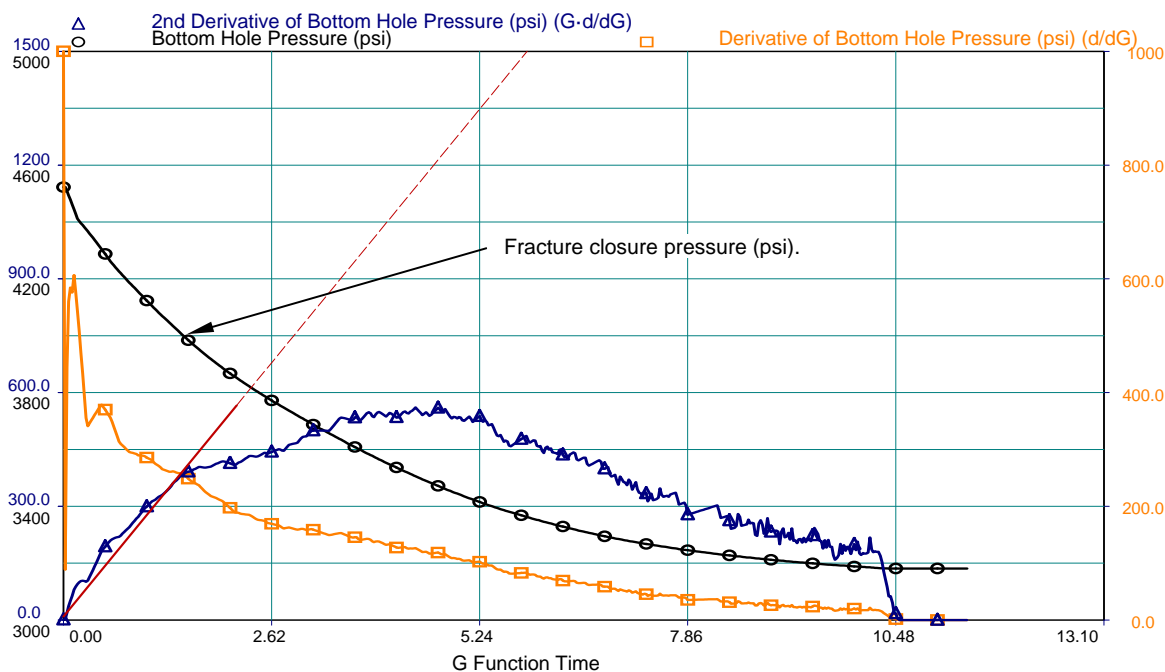


Figure 3: Injection test pressure falloff analysis, G-Function plot.

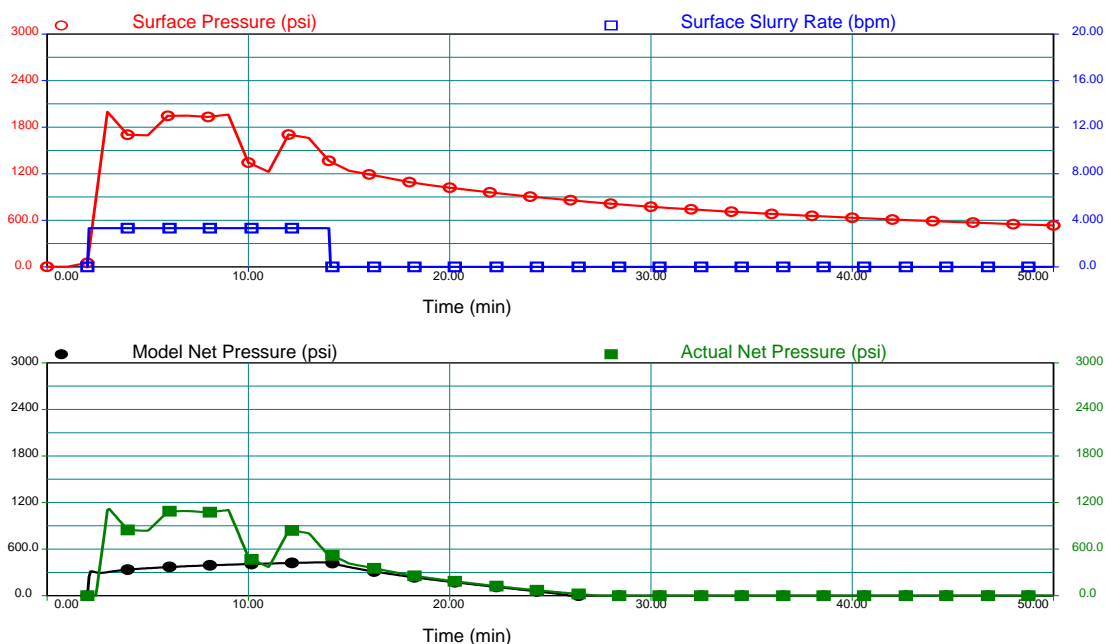


Figure 4: Injection test data and net pressure history match.

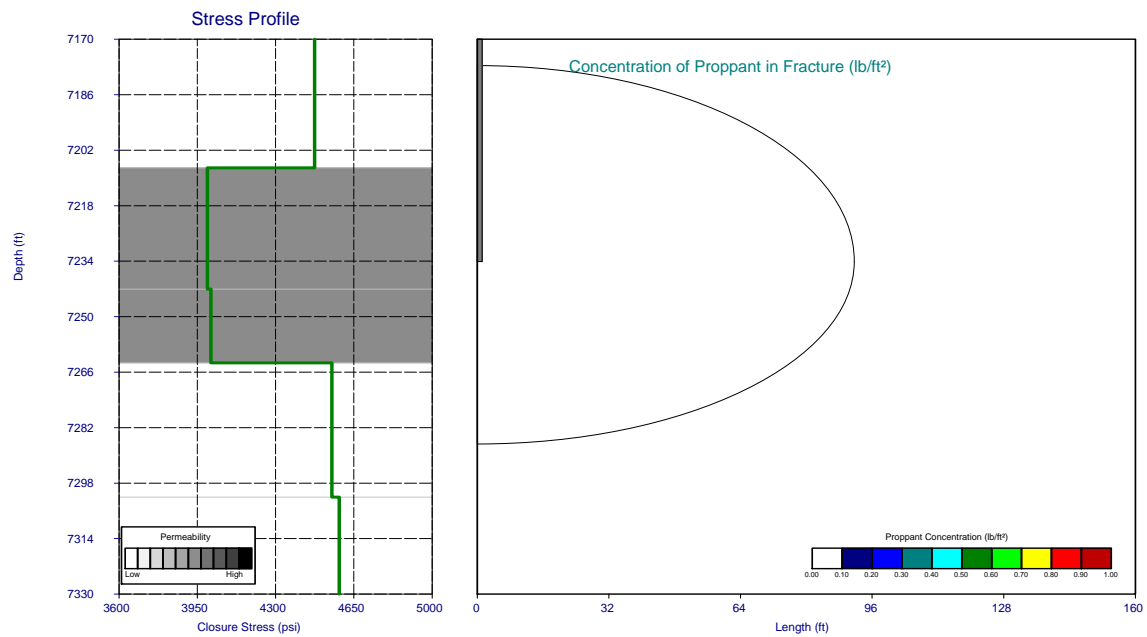


Figure 5: Profile of created fracture.



3.0 Review of post-closure analysis of injection test

The reservoir parameters calculated from the surface pressure fall-off analysis (PTA) of the injection/falloff test are shown in Table 1.

The following figures are used in the analysis:

Figure 6: Cartesian plot of surface and bottom-hole pressure.

Figure 7: Diagnostic log-log plot.

Figure 8: Model match of pressure history.

Observations from the pressure fall-off (PTA) evaluation are shown below:

- The PTA log-log diagnostic plot (Figure 7) indicates several changes in flow regime: 1.) Pre-fracture closure early time period demonstrates an open fracture response. 2.) A post-fracture closure transition period. 3.) Test reaches infinite acting radial flow.
- The type curve match of the late-time pressure trends (Figure 7) suggests a reservoir flow capacity of 111 md-ft. Based upon 56.2 ft net pay, reservoir permeability is calculated to be 1.98 md.
- Based upon the late time pressure trends (Figures 7 and 8), current reservoir pressure is approximately 3,052 psia (0.422 psi/ft).

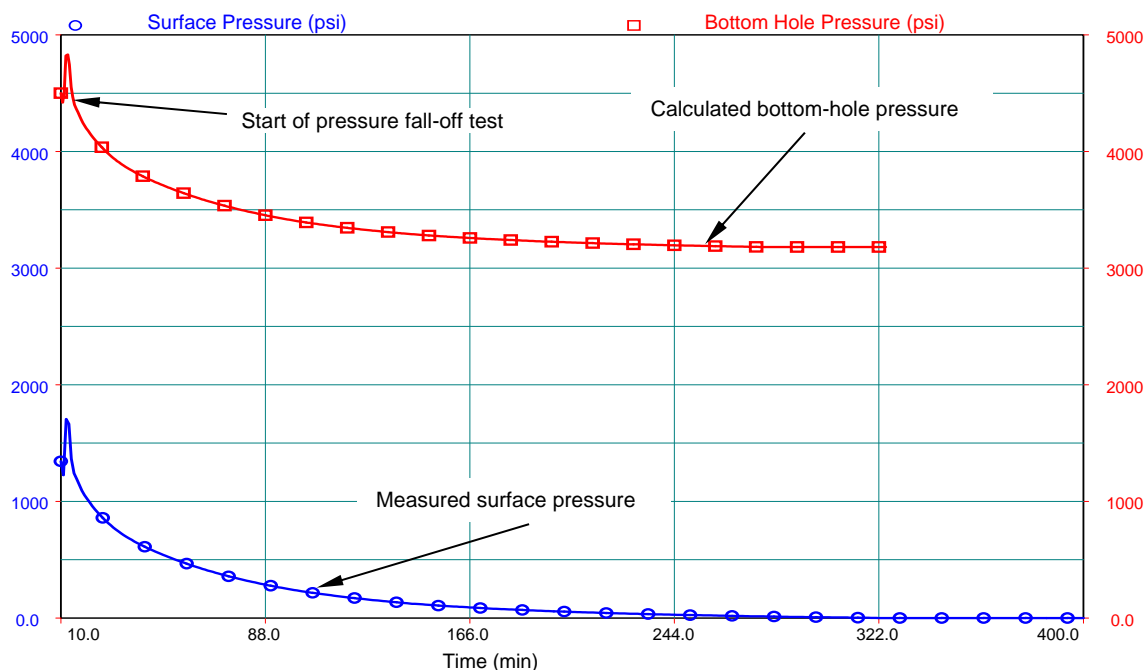


Figure 6: Cartesian plot of surface pressure and bottom-hole pressure.

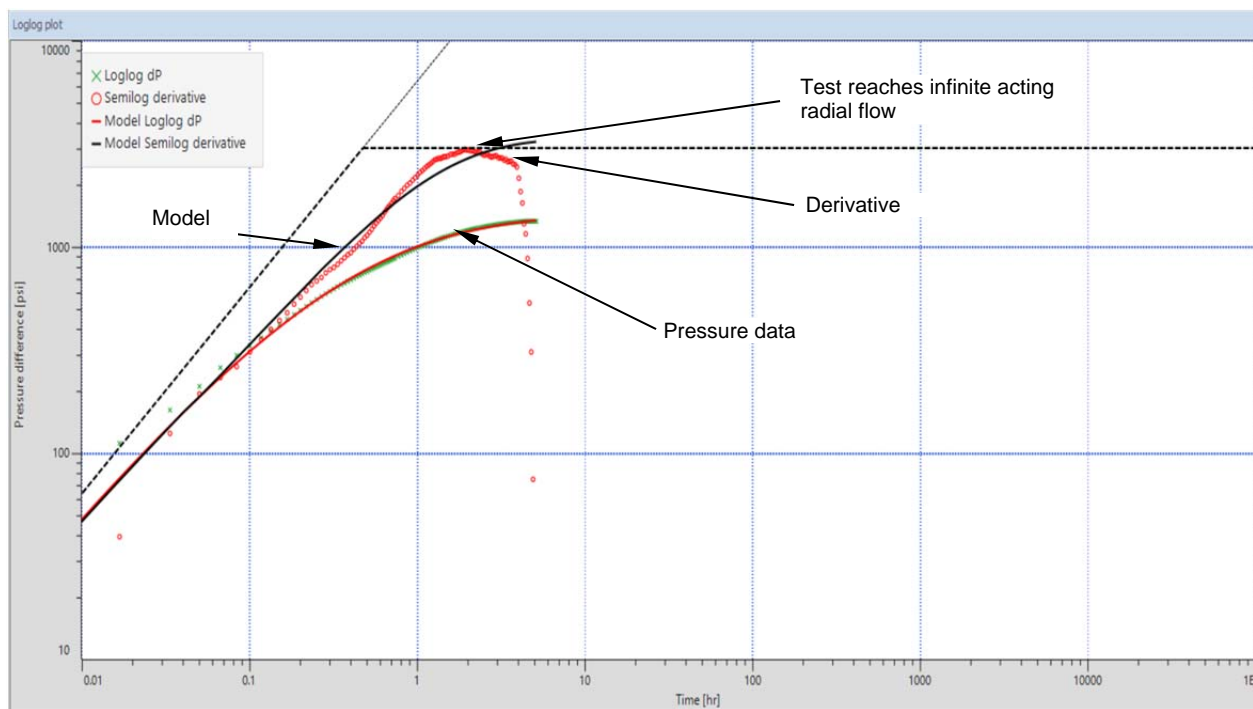


Figure 7: Diagnostic log-log plot.

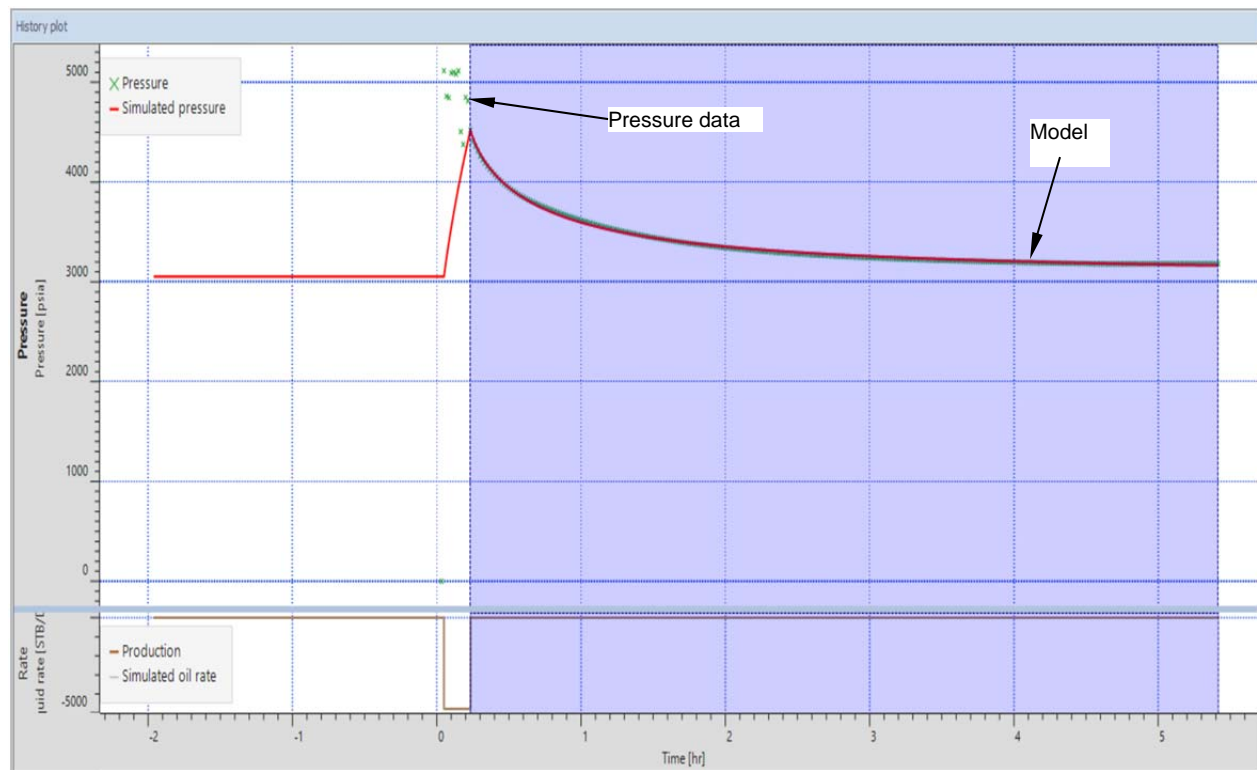


Figure 8: Model match of pressure history.