

# Treatment Summary

# Birdum Creek-1

Stage 1  
Velkerri-B

McArthur/Beetaloo Basin, NT

**For: Steve Miller**

**Date Completed: October 4, 2015**

**Updated: November 13, 2015**

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**HALLIBURTON**

Steve Miller  
Pangaea Resources Pty Ltd  
Level 50, 1 Farrer Place  
Sydney, NSW 2000

Date:	October 4, 2015
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Dear Steve Miller,

The following treatment was completed on the 4th of October, 2015. The design fluid volume was 3,375 bbls and called for 42,000 lbs of 100 Mesh, 42,000 lbs of 40/70 sand and 30,000 pounds of 40/70 CarboLiteNRT proppant. The actual fluid volume was 3,393 bbls and 42,991 lbs of 100 Mesh, 42,991 lbs of 40/70 sand and 30,414 lbs of CarboLiteNRT were pumped. The amount of proppant placed in formation was 97% of design and 3 m of proppant was left in the wellbore.

Company:	Pangaea Resources Pty Ltd
Field:	Birdum Creek-1
Well #:	
Stage:	1
Frac Number:	1
Formation:	Velkerri-B
Top Perf MD:	1,802 m
Bottom Perf MD:	1,812 m
Midperf TVD:	1,805 m

Services SO#:	902766740
US Chem SO#:	902784226
AUS Chem SO#:	902784224
Fluid System:	FR Water
Gel Loading:	-
Water Source:	BC1 32620
Fluid Density:	8.33 lb/gal
Breaker:	DCA-13002
State:	NT

#### DFIT / Minifrac

	Surface (psi)	B.H. (psi)	B.H. Grad. (psi/ft)	Rate (bpm)		
Well Pressure:	0				Open Perfs:	51
ISIP:	4191	6784	1.15		Maximum Rate:	36.6 bpm
5 Minute:	3614	6202	1.05		TNWB Pressure Loss:	827 psi
Breakdown:	4661	7065	1.19	2.39	- Perf Friction:	349 psi
Closure Pressure:	-				- Tortuosity:	493 psi
					Leakoff Type:	PDL

#### Fracture Treatment

	Surface (psi)	B.H. (psi)	B.H. Grad. (psi/ft)	Rate (bpm)		Clean		Slurry	
						(gal)	(bbl)	(gal)	(bbl)
Well Pressure:	0				FR Water	140,878	3,354	143,800	3,424
Breakdown:	4,661	7,065	1.19	2.39	15% HCl	1,635	39	1,635	39
Initial ISIP:	4,191	6,784	1.15		<b>Total</b>	<b>142,513</b>	<b>3,393</b>	<b>145,435</b>	<b>3,463</b>
Average:	4,855	7,463	1.26	55.5					
Maximum:	6,028	8,878	1.50	61					
Final ISIP:	4,373	6,974	1.18						
ISIP +15 mins:	3,708	6,304	1.06						
Times					Proppant Weight				
Open Well:	11:54 AM					Densometer		Ticket Total	
Start Pumping:	11:54 AM				100 Mesh	42,266 lb	13 bags	42,991 lbs	
End Pumping:	2:13 PM				40/70 Sand	38,405 lb	13 bags	42,991 lbs	
Shut In Well:	2:30 PM				40/70 CarboLiteNRT	30,414 lb	11 bags	35,200 lbs	
Max Proppant Concentration:					Pressure Drop at Breakdown:	0 psi			
Max B.H. Proppant Concentration:					Pressure Drop when Acid at Perfs:	0 psi			
Proppant in Formation:					Minimum BHTP during Proppant:	7,322 psi			
% of Design Proppant Placed:					Flush Percent of Wellbore:	100%			
Proppant Left in Wellbore:					Net Pressure Rise (if applicable):	182			
Height of Proppant in Wellbore:									

Prior to the main fracture treatment on Birdum Creek-1, Coiled Tubing conducted a Nitrogen lift and pre-frac flow test to determine whether the presence of high density natural fractures allowed unstimulated flow of the Velkerri-B shale formation. After 1 day of testing, no flow of hydrocarbons to surface was observed. A 15,400 HHP frac spread was then rigged up to the well to perform fracture stimulation on the zone using a slickwater/waterfrac treatment. Prior to the main frac, a minifrac to determine near wellbore pressure loss was conducted, indicating 827 psi of pressure loss at 36.6 bpm. There were no changes to the design and the main treatment followed with a 1500 gal acid spearhead after some minor pump repairs. No major pressure drop was observed when the acid hit the perforations and the BH pressure remained stable until the 1.5 ppg hit the perforations and the pressure rose steeply. The screw was quickly turned off during the 2 ppg CarboLiteNRT stage and rate was dropped to 38 bpm. The wellbore was successfully cleared, placing 97% of the proppant into formation by flushing to the top perf. Contingent linear gel and crosslinked fluid was available for this treatment, however all of the proppant was on the belt before the pressure increase. There were some issues with pump failure during the treatment, reducing the slurry rate to 53.8 bpm during the 1.25 ppg 40/70 sand stage.

Please feel free to contact me at 08 8150 1200 if you have any questions or concerns.  
Thank you,

Troy Francis  
Technical Professional  
Halliburton Australia Pty Ltd, Adelaide, SA

**Well Bore Diagram**

\* Not to Scale \*

Perfs 1	1,802 m - 1,812 m
CBP/HUD	1,917 m
Casing 1	1,917 m

BHST	190 °F		
Res. Pres.	3,200 psi		
Latitude	15°	37'	49.81" S
Longitude	133°	8'	37.23" E

**Casing and Tubing Information**

	Top	Bottom	OD	Weight	ID	Vol. Factor		
	(m)	(m)	(in)	(lb/ft)	(in)	(bbl/ft)	Grade	Joint
Casing 1	0.0	1,916.8	7	35	6.004	0.03501	P110	Fox
Casing 2								
Casing 3								
Casing 4								
Tubing								

Underflush	0.0 bbl
Well Vol. to Top Perf	8,693 gal
Surface Line Volume	416 gal
Denso. To WH	50 gal
Flush from Denso.	8,743 gal

Wellbore Fluid	8.8 ppg Brine
Current Plug/HUD	1,917 m
Next Plug/HUD	
Top Perf to Next HUD	
- Volume	

**Perforation Information**

	Perforation Information											
		Top MD	Bottom MD				Perf Dia.	Gun Size			Charge Size	MD - TVD
	Formation	(m)	(m)	SPF	Holes	Phasing	(in)	(in)	Gun Type	Charge Type	(g)	(m)
Perfs 1	Velkerri-B	1,802	1,812	6	197	60°	0.36	3-3/8"	34JL UltraJet	HMX	21.6	2

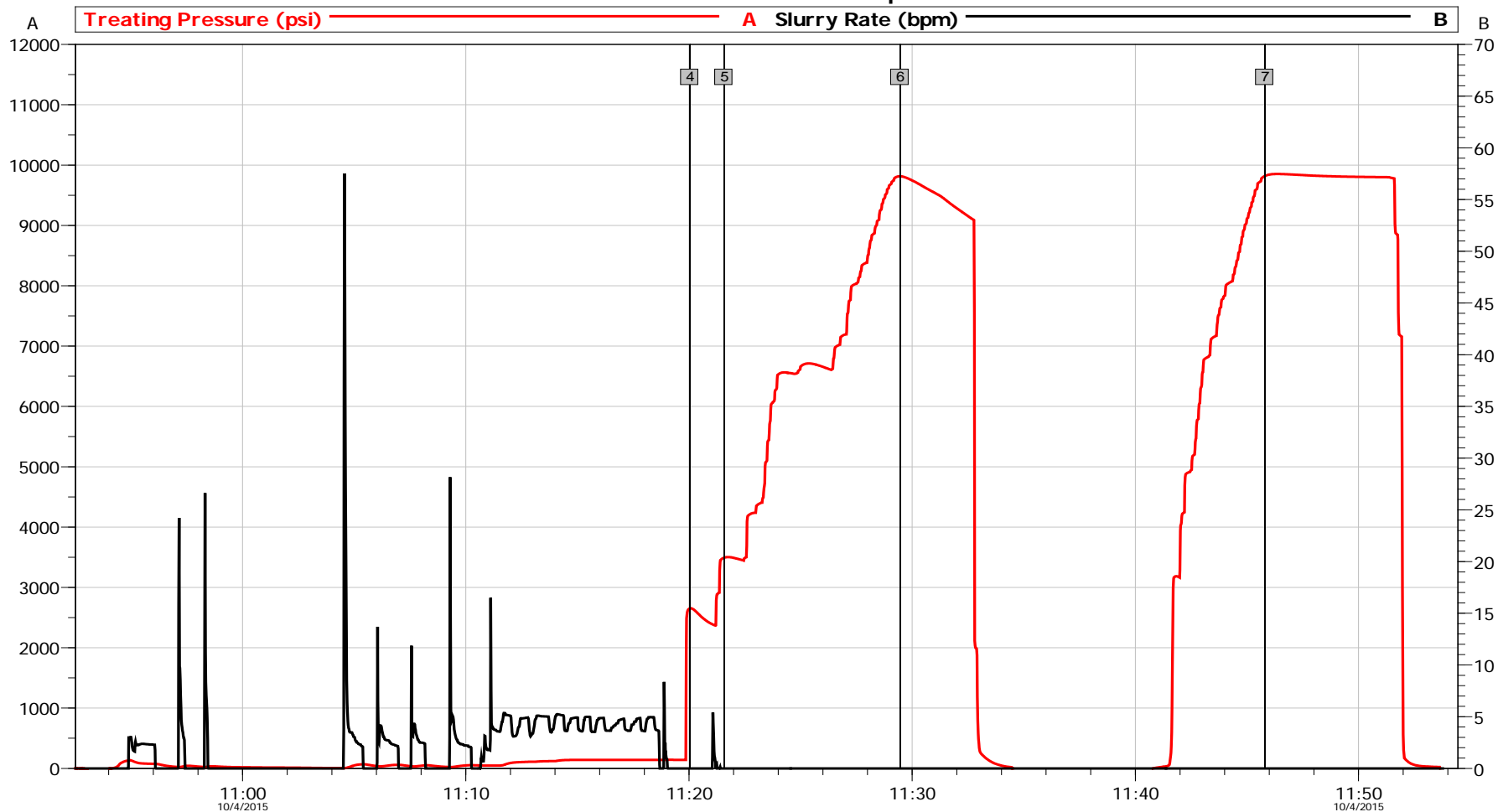
Stage	Stage Description	Pad or Slurry?	Fluid Type	Clean Vol. (gal)	Clean Left (bbl)	Prop Type	Prop AVF (gal/lb)	Prop Con		Stage Prop (lb)	Prop Sum (lb)	Slurry Vol (gal)	Slurry Rate (bpm)	Pump Time (min)	Stage	DCA-23001 Friction Reducer (lb/Mgal)	BE-9 Biocide (gal/Mgal)	DCA-16001 Clay Control (gal/Mgal)	DCA-32012 Surfactant (gal/Mgal)
								Start (lb/gal)	End (lb/gal)										
1	Fill hole and Breakdown		FR Water	9,109	3,375							9,109	2.5	86.75	1	2.2	0.6	1.5	0.5
2	Establish Rate		FR Water	1,000	3,158							1,000	60	0.40	2	2.2	0.6	1.5	0.5
3	Step Down Test		FR Water	1,000	3,134							1,000	60	0.40	3	2.2	0.6	1.5	0.5
4	Shut in				3,111										4				
5	Establish Rate		FR Water	200	3,111							200	2.5	1.90	5	2.2	0.6	1.5	0.5
6	Acid		15% HCl	1,500	3,106							1,500	2.5	14.29	6				
7	Flush Acid		FR Water	200	3,070							200	2.5	1.90	7	2.2	0.6	1.5	0.5
8	Pad	P	FR Water	8,000	3,065							8,000	60	3.17	8	2.2	0.6	1.5	0.5
9	0.25 ppg 100 mesh	P	FR Water	8,000	2,875	100 Mesh	0.0452	0.25	0.25	2,000	2,000	8,091	60	3.21	9	2.2	0.6	1.5	0.5
10	0.5 ppg 100 mesh	S	FR Water	8,000	2,684	100 Mesh	0.0452	0.50	0.50	4,000	6,000	8,181	60	3.25	10	2.2	0.6	1.5	0.5
11	0.75 ppg 100 mesh	S	FR Water	8,000	2,494	100 Mesh	0.0452	0.75	0.75	6,000	12,000	8,272	60	3.28	11	2.2	0.6	1.5	0.5
12	1.0 ppg 100 mesh	S	FR Water	8,000	2,303	100 Mesh	0.0452	1.00	1.00	8,000	20,000	8,362	60	3.32	12	2.2	0.6	1.5	0.5
13	1.25 ppg 100 mesh	S	FR Water	8,000	2,113	100 Mesh	0.0452	1.25	1.25	10,000	30,000	8,453	60	3.35	13	2.2	0.6	1.5	0.5
14	1.5 ppg 100 mesh	S	FR Water	8,000	1,922	100 Mesh	0.0452	1.50	1.50	12,000	42,000	8,544	60	3.39	14	2.2	0.6	1.5	0.5
15	0.25 ppg 40/70	S	FR Water	8,000	1,732	40/70 Sand	0.0452	0.25	0.25	2,000	44,000	8,091	60	3.21	15	2.2	0.6	1.5	0.5
16	0.5 ppg 40/70	S	FR Water	8,000	1,541	40/70 Sand	0.0452	0.50	0.50	4,000	48,000	8,181	60	3.25	16	2.2	0.6	1.5	0.5
17	0.75 ppg 40/70	S	FR Water	8,000	1,351	40/70 Sand	0.0452	0.75	0.75	6,000	54,000	8,272	60	3.28	17	2.2	0.6	1.5	0.5
18	1.0 ppg 40/70	S	FR Water	8,000	1,161	40/70 Sand	0.0452	1.00	1.00	8,000	62,000	8,362	60	3.32	18	2.2	0.6	1.5	0.5
19	1.25 ppg 40/70	S	FR Water	8,000	970	40/70 Sand	0.0452	1.25	1.25	10,000	72,000	8,453	60	3.35	19	2.2	0.6	1.5	0.5
20	1.5 ppg 40/70	S	FR Water	8,000	780	40/70 Sand	0.0452	1.50	1.50	12,000	84,000	8,544	60	3.39	20	2.2	0.6	1.5	0.5
21	1.75 ppg 40/70 CarboNRT	S	FR Water	8,000	589	40/70 CarboLiteNRT	0.0436	1.75	1.75	14,000	98,000	8,611	60	3.42	21	2.2	0.6	1.5	0.5
22	2.0 ppg 40/70 CarboNRT	S	FR Water	8,000	399	40/70 CarboLiteNRT	0.0436	2.00	2.00	16,000	114,000	8,698	60	3.45	22	2.2	0.6	1.5	0.5
23	Flush		FR Water	8,743	208							8,743	60	3.47	23	2.2	0.6	1.5	0.5
24	Shut in				0										24				
Totals				141,752						114,000		146,867		158.76		309	84	210	70

Summary		Fluids		(gal)	(bbl)	Sand/Prop		(lb)	(bag)	Acid Mix	
Pad Percentage	13%	FR Water	140,252	3,339		100 Mesh	42,000	12.7		DCA-32009	3.0 gal
Pad Volume (gal)	16,000	15% HCl	1,500	36		40/70 Sand	42,000	12.7		DCA-17004	4.5 lb
Clean Volume (bbl)	3,375					40/70 CarboLiteNRT	30,000	9.4		FE-2	82.5 lb
										Acetic 60%	27.0 gal

Stage	Stage Description	Pad or Slurry?	Fluid Type	Clean Vol. (gal)	Clean Left (bbl)	Prop Type	Prop AVF (gal/lb)	Prop Con		Stage Prop (lb)	Prop Sum (lb)	Slurry Vol (gal)	Slurry Rate (bpm)	Pump Time (min)	Stage	DCA-23001	BE-9	DCA-16001	DCA-32012
								Start (lb/gal)	End (lb/gal)							Friction Reducer (lb/Mgal)	Biocide (gal/Mgal)	Clay Control (gal/Mgal)	Surfactant (gal/Mgal)
1	Fill hole and Breakdown		FR Water	8,225	3,393							8,225	26.28	7.45	1	2.2	0.6	1.5	0.5
2	Establish Rate		FR Water	2,690	3,197							2,690	29.45	2.17	2	2.2	0.6	1.5	0.5
3	Step Down Test		FR Water	1,058	3,133							1,058	23.1	1.09	3	2.2	0.6	1.5	0.5
4	Shut in				3,108										4				
5	Establish Rate		FR Water	282	3,108							282	2.04	3.29	5	2.2	0.6	1.5	0.5
6	Acid		15% HCl	1,635	3,101							1,635	2.8	13.90	6				
7	Flush Acid		FR Water	109	3,062							109	3.06	0.85	7	2.2	0.6	1.5	0.5
8	Pad	P	FR Water	8,189	3,060							8,189	47.05	4.14	8	2.2	0.6	1.5	0.5
9	0.25 ppg 100 mesh	P	FR Water	8,025	2,865	100 Mesh	0.0452	0.25	0.25	1,678	1,678	8,084	58.21	3.31	9	2.2	0.6	1.5	0.5
10	0.5 ppg 100 mesh	S	FR Water	8,011	2,674	100 Mesh	0.0452	0.50	0.50	3,783	5,461	8,125	60.29	3.21	10	2.2	0.6	1.5	0.5
11	0.75 ppg 100 mesh	S	FR Water	8,013	2,483	100 Mesh	0.0452	0.75	0.75	5,845	11,306	8,180	60.77	3.21	11	2.2	0.6	1.5	0.5
12	1.0 ppg 100 mesh	S	FR Water	8,030	2,292	100 Mesh	0.0452	1.00	1.00	7,754	19,060	8,249	60.85	3.23	12	2.2	0.6	1.5	0.5
13	1.25 ppg 100 mesh	S	FR Water	8,015	2,101	100 Mesh	0.0452	1.25	1.25	10,090	29,150	8,284	60.89	3.24	13	2.2	0.6	1.5	0.5
14	1.5 ppg 100 mesh	S	FR Water	9,880	1,910	100 Mesh	0.0452	1.50	1.50	13,116	42,266	10,271	60.92	4.01	14	2.2	0.6	1.5	0.5
15	0.25 ppg 40/70	S	FR Water	8,035	1,675	40/70 Sand	0.0452	0.25	0.25	2,210	44,476	8,088	60.92	3.16	15	2.2	0.6	1.5	0.5
16	0.5 ppg 40/70	S	FR Water	8,014	1,484	40/70 Sand	0.0452	0.50	0.50	4,236	48,712	8,119	60.79	3.18	16	2.2	0.6	1.5	0.5
17	0.75 ppg 40/70	S	FR Water	8,002	1,293	40/70 Sand	0.0452	0.75	0.75	6,502	55,214	8,157	60.83	3.19	17	2.2	0.6	1.5	0.5
18	1.0 ppg 40/70	S	FR Water	8,583	1,102	40/70 Sand	0.0452	1.00	1.00	8,983	64,197	8,802	58.18	3.60	18	2.2	0.6	1.5	0.5
19	1.25 ppg 40/70	S	FR Water	8,015	898	40/70 Sand	0.0452	1.25	1.25	10,544	74,741	8,268	53.69	3.67	19	2.2	0.6	1.5	0.5
20	1.5 ppg 40/70	S	FR Water	3,724	707	40/70 Sand	0.0452	1.50	1.50	5,930	80,671	3,864	53.89	1.71	20	2.2	0.6	1.5	0.5
21	1.75 ppg 40/70 CarboNRT	S	FR Water	8,012	619	40/70 CarboLiteNRT	0.0436	1.75	1.75	14,320	94,991	8,349	53.89	3.69	21	2.2	0.6	1.5	0.5
22	2.0 ppg 40/70 CarboNRT	S	FR Water	9,219	428	40/70 CarboLiteNRT	0.0436	2.00	2.00	16,094	111,085	9,658	52.04	4.42	22	2.2	0.6	1.5	0.5
23	Flush		FR Water	8,747	208							8,747	34.91	5.97	23	2.2	0.6	1.5	0.5
24	Shut in				0										24				
Totals				142,513						111,085		145,435		85.69		310	85	211	70

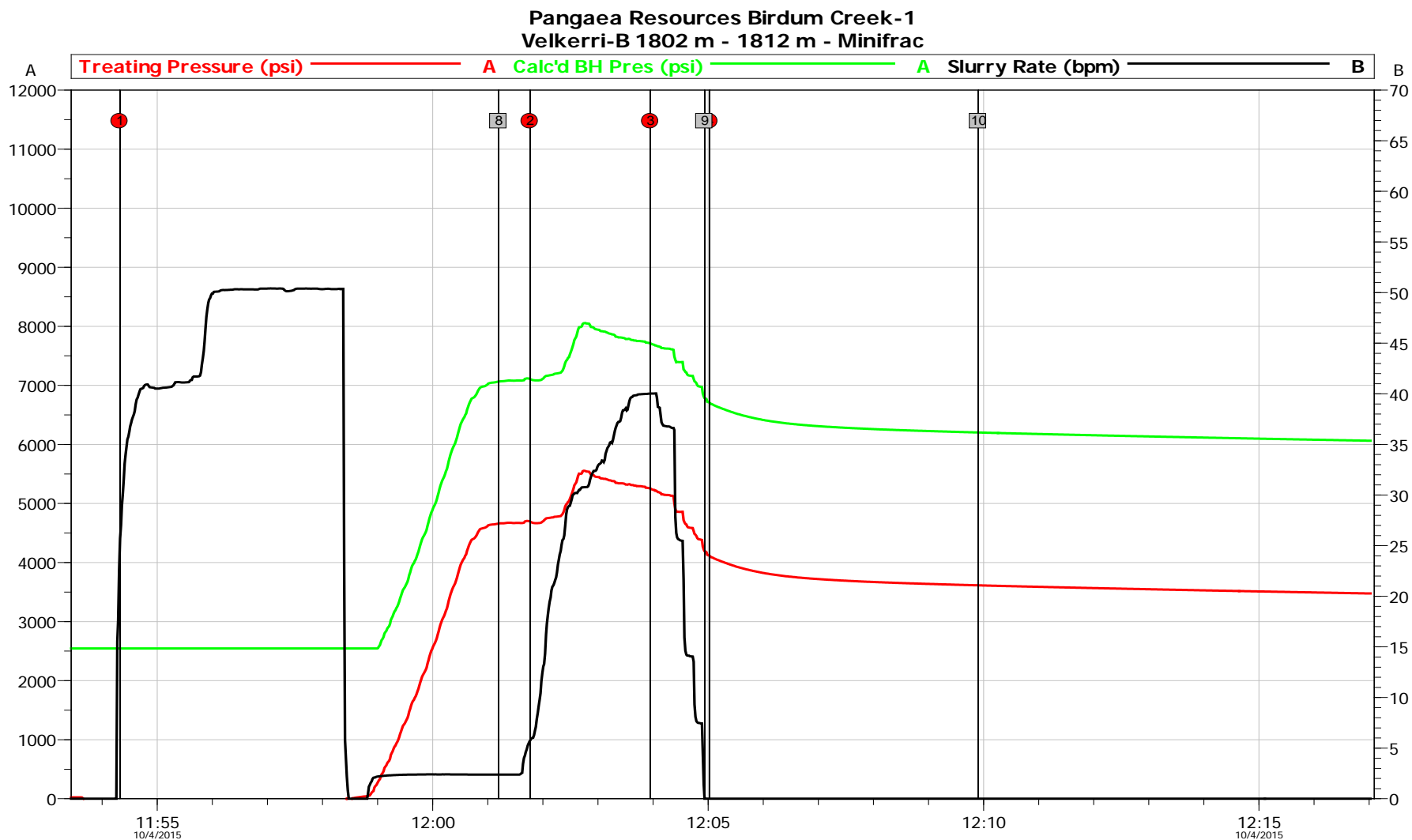
Summary		Fluids		(gal)	(bbl)	Sand/Prop		(lb)	(bag)	Acid Mix		Actual Use: Difference: Flowmeter:  Ticket Total:				
Pad Percentage	14%	FR Water	140,878	3,354	100 Mesh	42,266	12.8	DCA-32009	3.3 gal				419	85	200	65
Pad Volume (gal)	16,214	15% HCl	1,635	39	40/70 Sand	38,405	11.6	DCA-17004	5 lbs				35%		-5%	-7%
Clean Volume (bbl)	3,393				40/70 CarboLiteNRT	30,414	9.5						309	85	202	71
								FE-2	90 lb				DCA-23001	BE-9	DCA-16001	DCA-32012
								Acetic 60%	29 gal			419	85	200	65	

Stage Number	Time	Description	Stage Clean Volume	Stage Prop Mass	Max Treating Pressure	Max BH Treating Pressure	Max Slurry Rate	Max Slurry Prop Conc	Max BH Conc	Avg Treating Pressure	Avg BH Treating Pressure	Average Slurry Rate	Avg Slurry Prop Conc	Avg BH Conc
			gal	lb	psi	psi	bpm	lb/gal	lb/gal	psi	psi	bpm	lb/gal	lb/gal
Stage 1	4/10/2015 11:54	Fill hole and Breakdown	8225	0	4704	-15	50.4	0	0	1199	-15	27.6	0	0
Stage 2	12:01:46	Establish rate	2690	0	5554	-15	40	0	0	5174	-15	29.4	0	0
Stage 3	12:03:57	Step Down Test	1058	0	5241	8056	40	0	0	4858	8056	25.4	0	0
Stage 4	12:05:01	Shut-In	0	0	0	7512	0	0	0	0	7512	0	0	0
Stage 5	12:57:46	Establish rate	282	0	4434	7450	2.4	0	0	4108	7450	2.3	0	0
Stage 6	13:01:03	Acid	1635	0	4565	7452	3	0	0	4524	7452	2.8	0	0
Stage 7	13:14:58	Flush Acid	109	0	4562	7492	5.5	0	0	4512	7492	3.1	0	0
Stage 8	13:15:49	Pad	8189	0	5243	7486	59	0	0	5128	7486	47	0	0
Stage 9	13:19:58	0.25 ppg 100 mesh	8025	1678	5165	7482	59.4	0.39	0	5015	7482	58.2	0.21	0
Stage 10	13:23:17	0.5 ppg 100 mesh	8011	3783	4965	7428	60.8	0.63	0.4	4936	7428	60.3	0.47	0.21
Stage 11	13:26:31	0.75 ppg 100 mesh	8013	5845	4940	7434	60.8	0.91	0.63	4883	7434	60.8	0.73	0.48
Stage 12	13:29:46	1.0 ppg 100 mesh	8030	7754	4856	7400	60.9	1.18	0.91	4803	7400	60.8	0.97	0.73
Stage 13	13:33:02	1.25 ppg 100 mesh	8015	10090	4771	7378	61	1.46	1.19	4727	7378	60.9	1.26	0.97
Stage 14	13:36:21	1.5 ppg 100 mesh	9880	13116	4722	7411	61	1.56	1.47	4699	7411	60.9	1.33	1.27
Stage 15	13:40:27	0.25 ppg 40/70	8035	2210	5056	7499	61	0.32	1.57	4881	7499	60.9	0.28	1.34
Stage 16	13:43:38	0.5 ppg 40/70	8014	4236	5050	7455	60.9	0.8	0.32	4973	7455	60.8	0.53	0.28
Stage 17	13:46:50	0.75 ppg 40/70	8002	6502	4930	7473	60.9	1	0.81	4896	7473	60.8	0.81	0.53
Stage 18	13:50:05	1.0 ppg 40/70	8583	8983	4893	7496	60.9	1.27	1.01	4824	7496	58.2	1.05	0.82
Stage 19	13:53:46	1.25 ppg 40/70	8015	10544	4804	7450	56.2	1.48	1.28	4701	7450	53.7	1.32	1.05
Stage 20	13:57:32	1.5 ppg 40/70	3724	5930	4724	7512	53.9	1.75	1.49	4670	7512	53.9	1.59	1.33
Stage 21	13:59:19	1.75 ppg 40/70 NRT	8012	14320	4749	7493	53.9	1.89	1.76	4698	7493	53.9	1.79	1.6
Stage 22	14:03:07	2.0 ppg 40/70 NRT	9219	16094	6028	8878	54	2.08	1.91	5007	8878	52.1	1.7	1.8
Stage 23	14:07:40	Flush	8747	0	5112	8109	38.5	0.13	2.1	4959	8109	35.5	0.07	1.72
Stage 24	14:13:37	Shut-In	0	0	0		0	0		0		0	0	

Pangaea Resources Birdum Creek-1  
Velkerri-B 1802 m - 1812 m - Prime up/Pressure test

## Global Event Log

Intersection				CBP	SR	TP	Intersection				CBP	SR	TP
4	Test Globals	11:20:03	2545	0.000	2653		5	Test Locals	11:21:35	2545	0.000	3494	
6	Leak on Grizzly top cap	11:29:28	2545	0.000	9815		7	Pressure test main line	11:45:49	2545	0.000	9821	

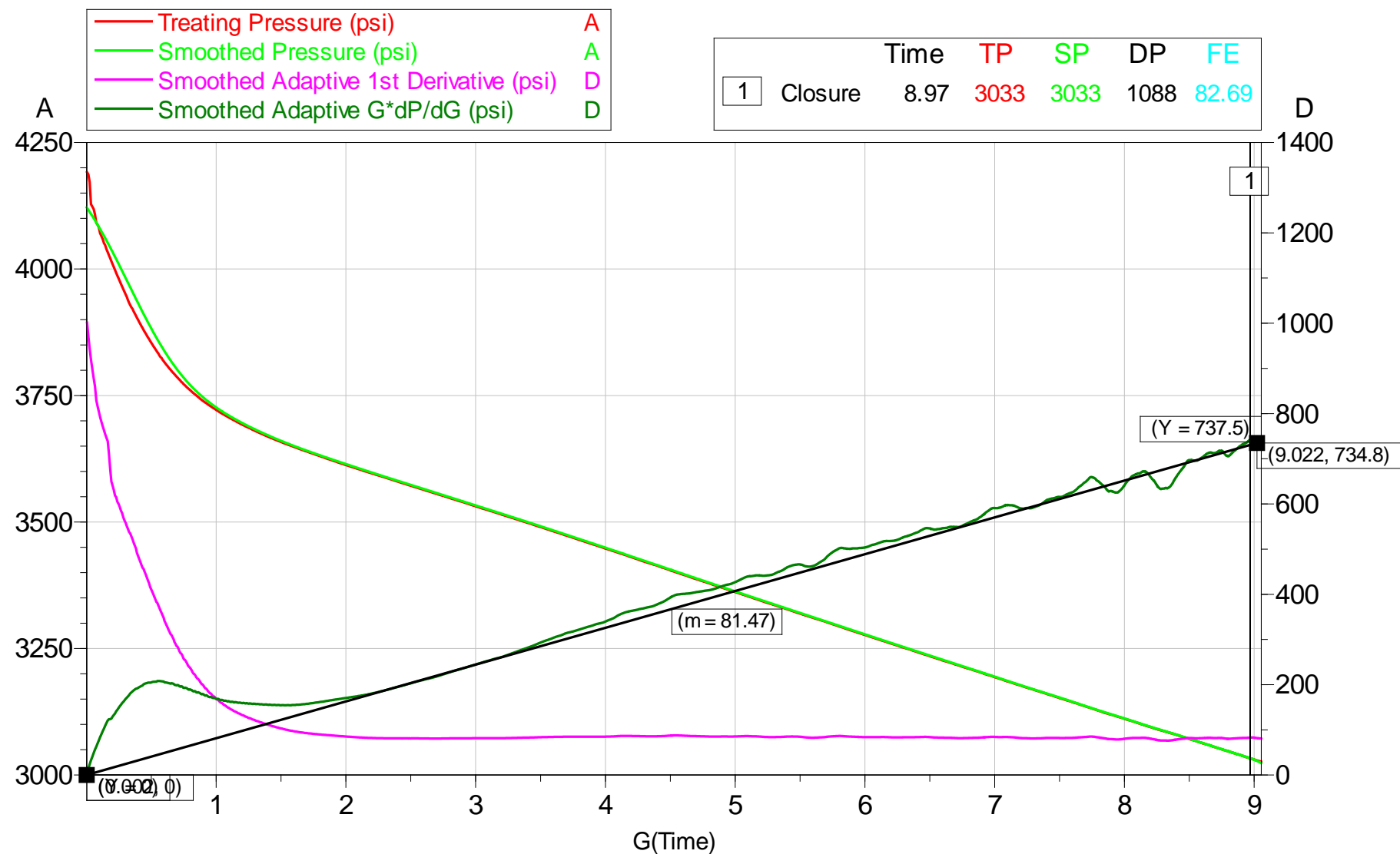
**Global Event Log**

Intersection				CBP	SR	TP	Intersection				CBP	SR	TP	Intersection				CBP	SR	TP
8	Break Formation	12:01:12	7065	2.390	4661	9	ISIP	12:04:56	6784	0.000	4191	10	ISIP + 5mins	12:09:54	6202	0.000	3614			



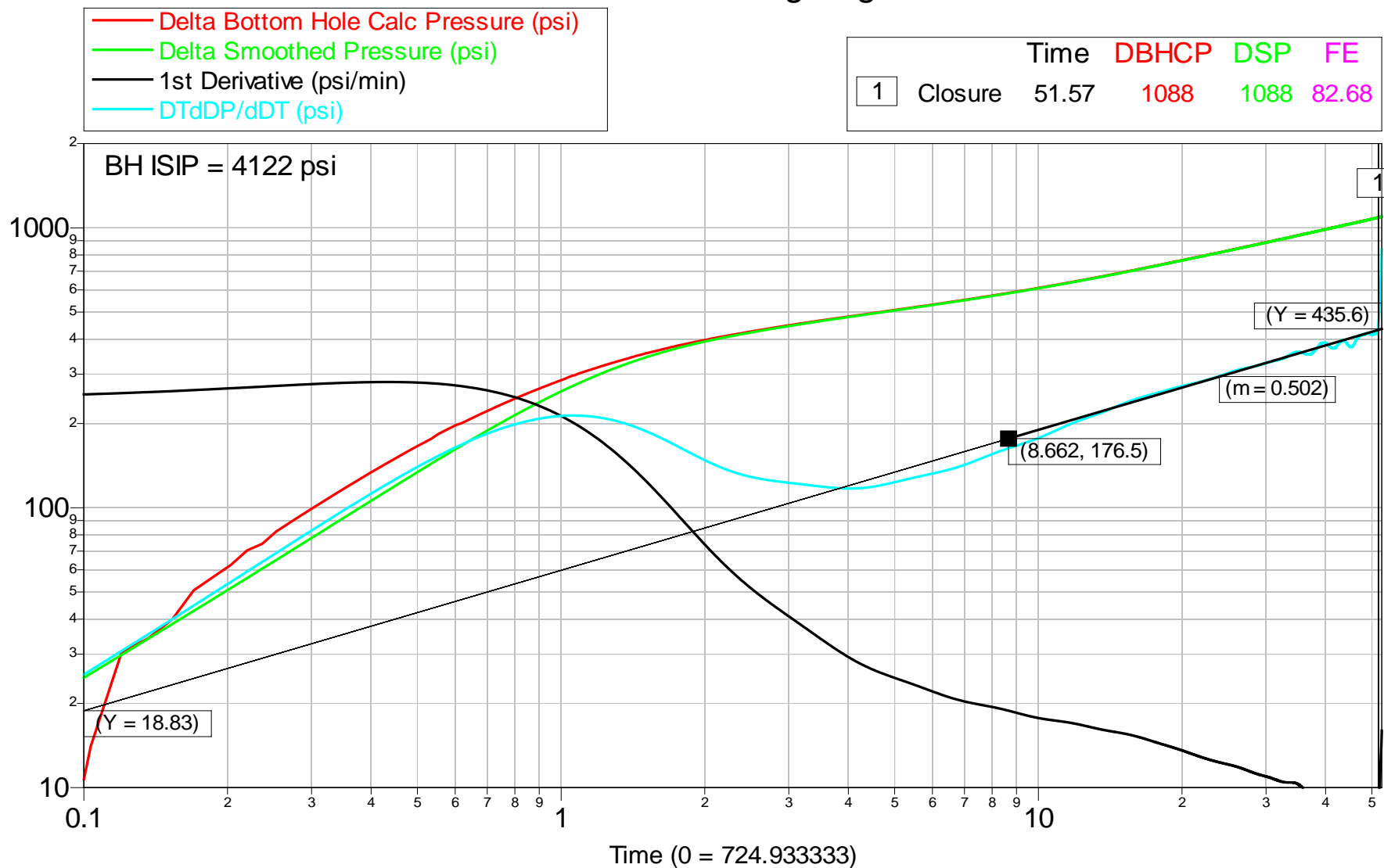
## Halliburton Pumping Diagnostic Analysis Toolkit

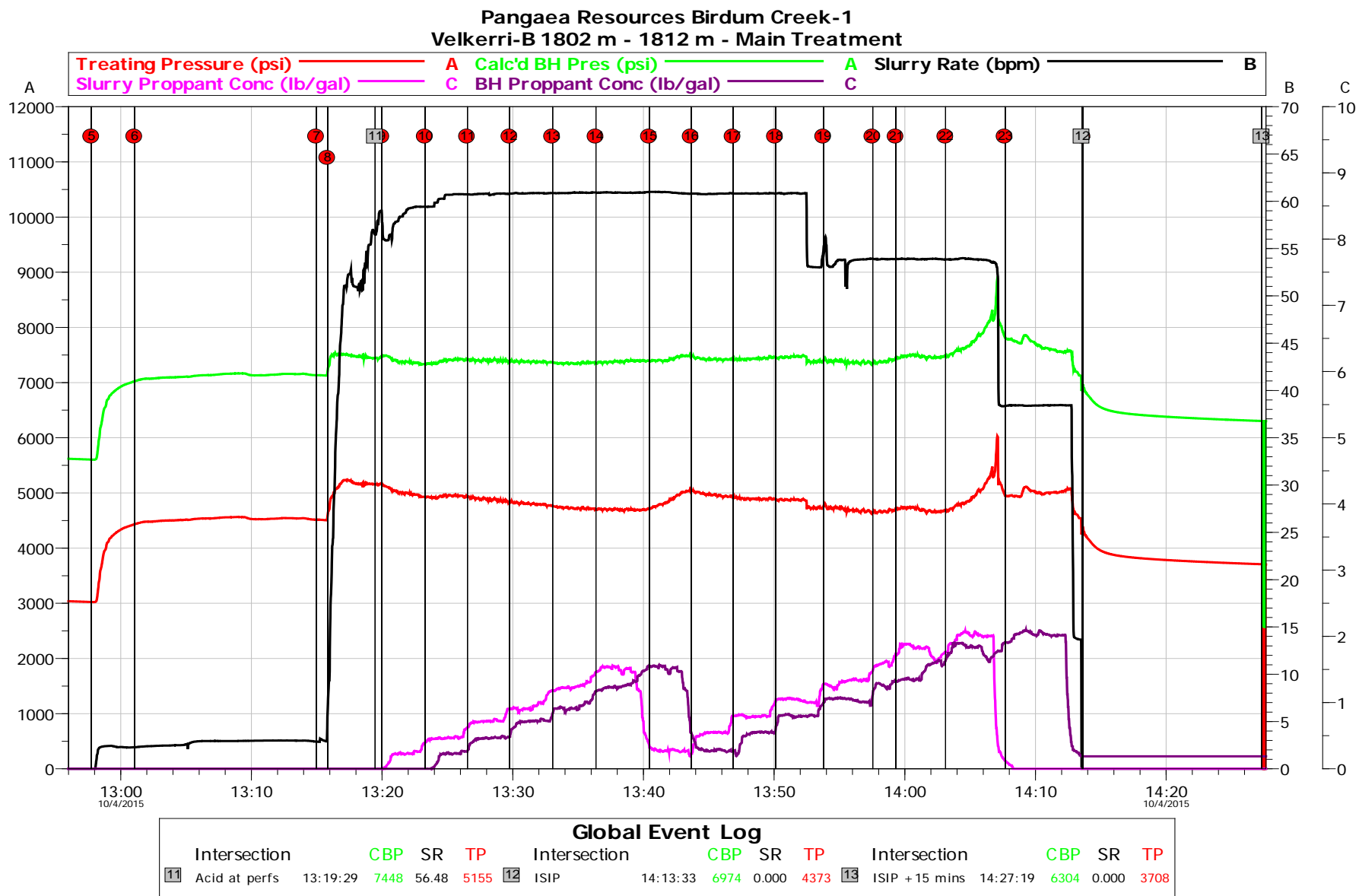
## Minifrac - G Function



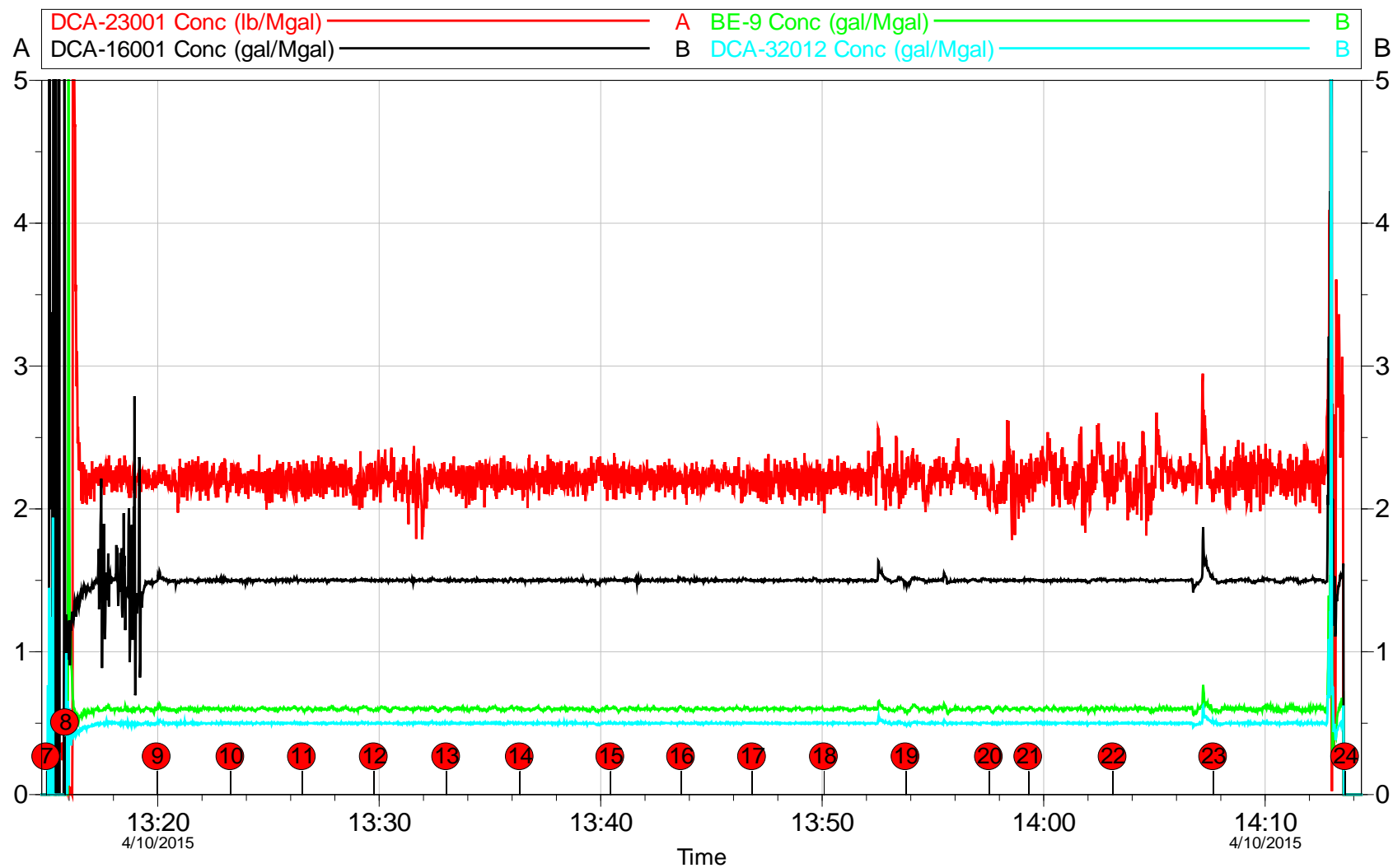
# Halliburton Pumping Diagnostic Analysis Toolkit

## Minifrac - Log Log





## FB4K Blender



INSITE for Stimulation v4.5.0  
04-Oct-15 17:02

# Near Wellbore Pressure Loss Evaluation

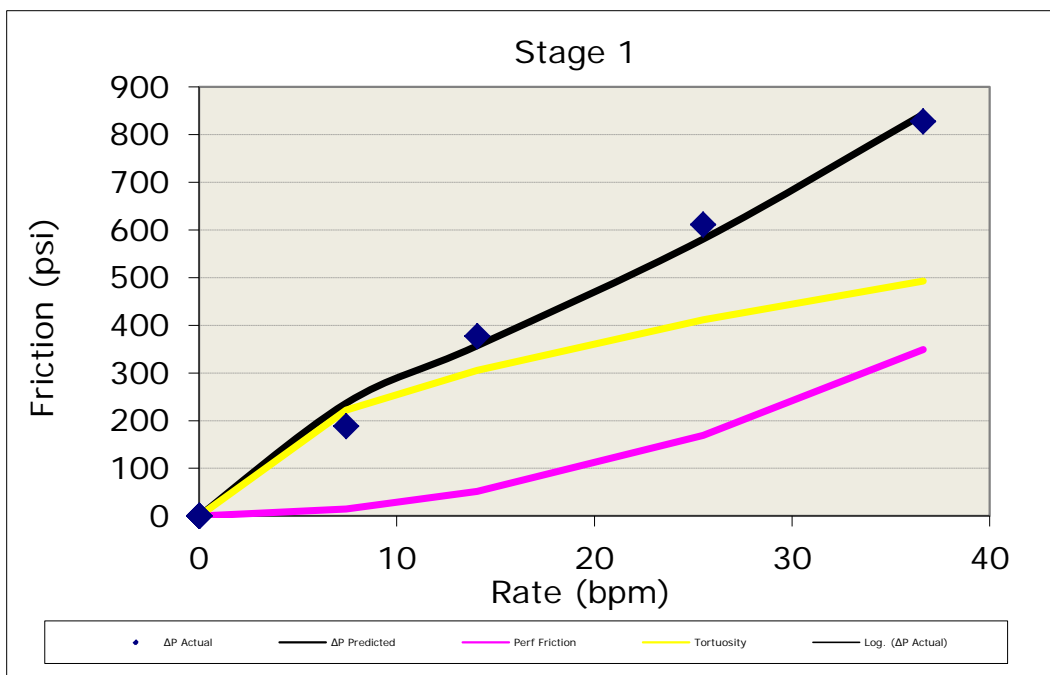
## Birdum Creek-1 - Stage 1


Tortuosity Power (x) **0.5**      Cd **0.6**  
 ISIP **6784**      psi      Perf Diam **0.3** in  
    Density **8.33** lb/gal

BHP	Rate
<b>7611</b>	<b>36.63</b>
<b>7395</b>	<b>25.5</b>
<b>7161</b>	<b>14.07</b>
<b>6972</b>	<b>7.44</b>

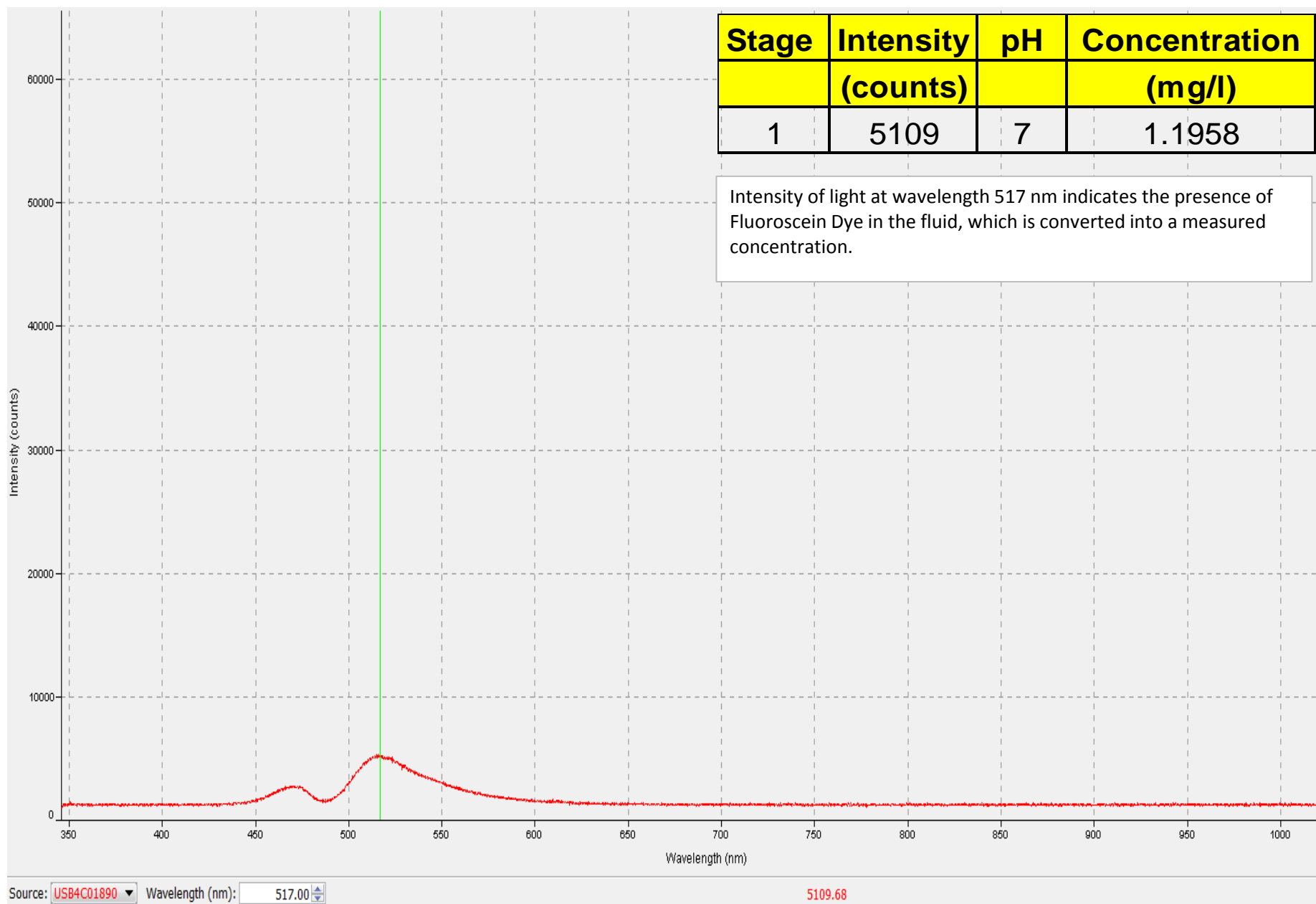
Perfs Open **51**

NWBPL @ 36.63 bpm **827** psi  
 Tortuosity @ 36.63 bpm **493** psi  
 Perf Friction @ 36.63 bpm **349** psi



Water Testing Report							
Date	Thursday, 1 October 2015					Overall Result	
Lab Technician	Troy Francis					Pass	
Water Source	BC1 32620						
Water Colour	Clear					Individual Results	
Sulphate Conc	200	ppm				Sulphate Conc	Pass
Iron Conc	0	ppm				Iron Conc	Pass
Phosphate Conc	0	ppm				Phosphate Conc	Pass
Hardness Conc	250	ppm	Other - Please specify below:			Hardness Conc	Pass
Temperature	30.0 °C	86.0 °F				Temperature	Pass
Specific Gravity	1.001					Specific Gravity	Pass
Sample Water Density	8.317	ppg	Pure water density at 30.0 °C = 8.309 ppg			Bicarbonates Conc	-
pH	6.74					pH	Pass
						Additional Comments:	
						Gold Medal Standards	
						Bacteria	
						pH	6 to 8
						Temperature	
						Bicarbonates	< 300 ppm
						Hardness	< 2000 ppm
						Iron	< 10 ppm
						Phosphates	< 5 ppm
						Reducing Agents	None
						Sulphates	< 500 ppm
						Specific Gravity	< 1.038
<p>If Sulphate reading is between 100-500 ppm, this passes the standard but consider using scale inhibitor. Some crosslinkers may be precipitated by sulphate ions in solution. Increasing the crosslinker concentration may prevent this problem. Acetic Acid will be used to lower the pH of gel for hydration, and the pH of hydration tank will be monitored and maintained on the fly.</p>							

<b>PILOT TEST*</b>					<b>Slurry Blender Chemicals</b>		<b>Final Recommended Concentration for Job</b>		<b>Amount for 500 ml</b>	
							gpt or ppt		ml or gm	
Date	4 October 2015				Sample Volume		500	ml		
Well Name	Birdum Creek-1	Test Volume		1.0L	BC-140C		1.50	gpt	0.75	ml
Gel System	Delta140	Polymer	WG-18		DCA-13002		1.00	ppt	0.06	gm
Water Source	BC1 32620	Pump Rate	60 bpm							
Lab Tech	Troy Francis									
Pipe Volume	8743 gal	Pipe Time	3. mins 47 secs							
Test Purpose	Pilot Test									
					<b>Notes:</b>					
<b>Dry Gel Blender Chemicals</b>										
	<b>Conc/Mgal</b>	<b>Amount for</b>		<b>1.0L</b>						
BE-9	0.60	gal	0.60	ml						
DCA-16001	1.5	gal	1.50	ml						
DCA-25005	15.00	lb	1.80	gm						
Acetic 60%	0.00	gal	0.00	ml						
DCA-32012	0.50	gal	0.50	ml	<b>X-Link Test</b>	<b>Test 1</b>	<b>Test 2</b>	<b>Test 3</b>	<b>Test 4</b>	<b>Test 5</b>
		lb		gm	BC-140C	1.50	1.500			
					DCA-13002	0.00	1.00			
	<b>pH</b>	<b>Temp</b>								
Initial Water	6.74	34.0 °C								
					Vortex Closure (sec)	23	23.00			
After Buffer/pH control	6.74	34.0 °C			Mushroom (sec)	30	39.00			
Final	6.98	34.0 °C			X-Link Time(min:sec)	30	39.00			
		°C			Cold pH	8.40	8.43			
		°C								
Hydration Time (min):	02:30				Temperature (°C)	30.00	31.00			
<b>Viscosity Test</b>					Description					
						Good Instant Xlink	Good Instant Xlink Broken in 7 mins			
600	300	200	100	Weight						
14.0cp	9.0cp	7.0cp	4.0cp	15#						



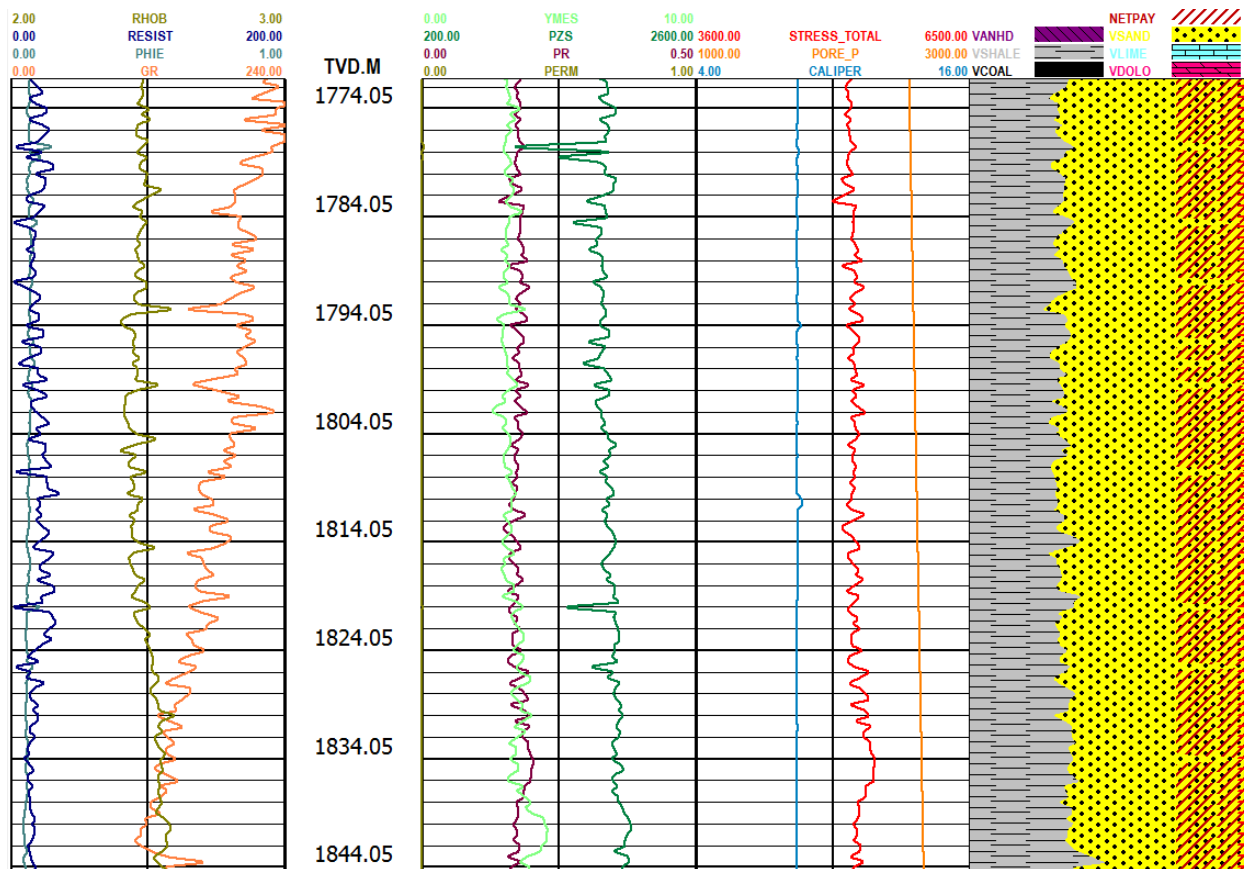


## Summary and Conclusions

Based on the Tarlee-1 DFIT injection analysis, surface microdeformation results and fracture treatment of the Birdum Creek-1 Velkerri-B shale formation, a pressure match analysis was conducted to model the possible fracture geometry and fracture characteristics based on principles of hydraulic fracturing. To better understand and further calibrate hydraulic fracture modeling, fracture diagnostics such as microseismic, microdeformation and near wellbore measurements of fracture height are required. These types of analysis teamed with production data can help best determine the optimal fracture treatment for the reservoir.

Prior to the main fracture treatment, a minifrac was performed with the pressure decline monitored for approximately 1 hour but closure was not observed. Therefore, the data obtained from the Tarlee-1 offset DFIT was used to calibrate the log analysis in Figure 1 within the hydraulic fracture simulation software GOHFER by adding tectonic strain to match the formation stress gradient to the closure pressure gradient of 0.89 psi/ft observed from the DFIT analysis.

Figure 1: GOHFER log analysis output

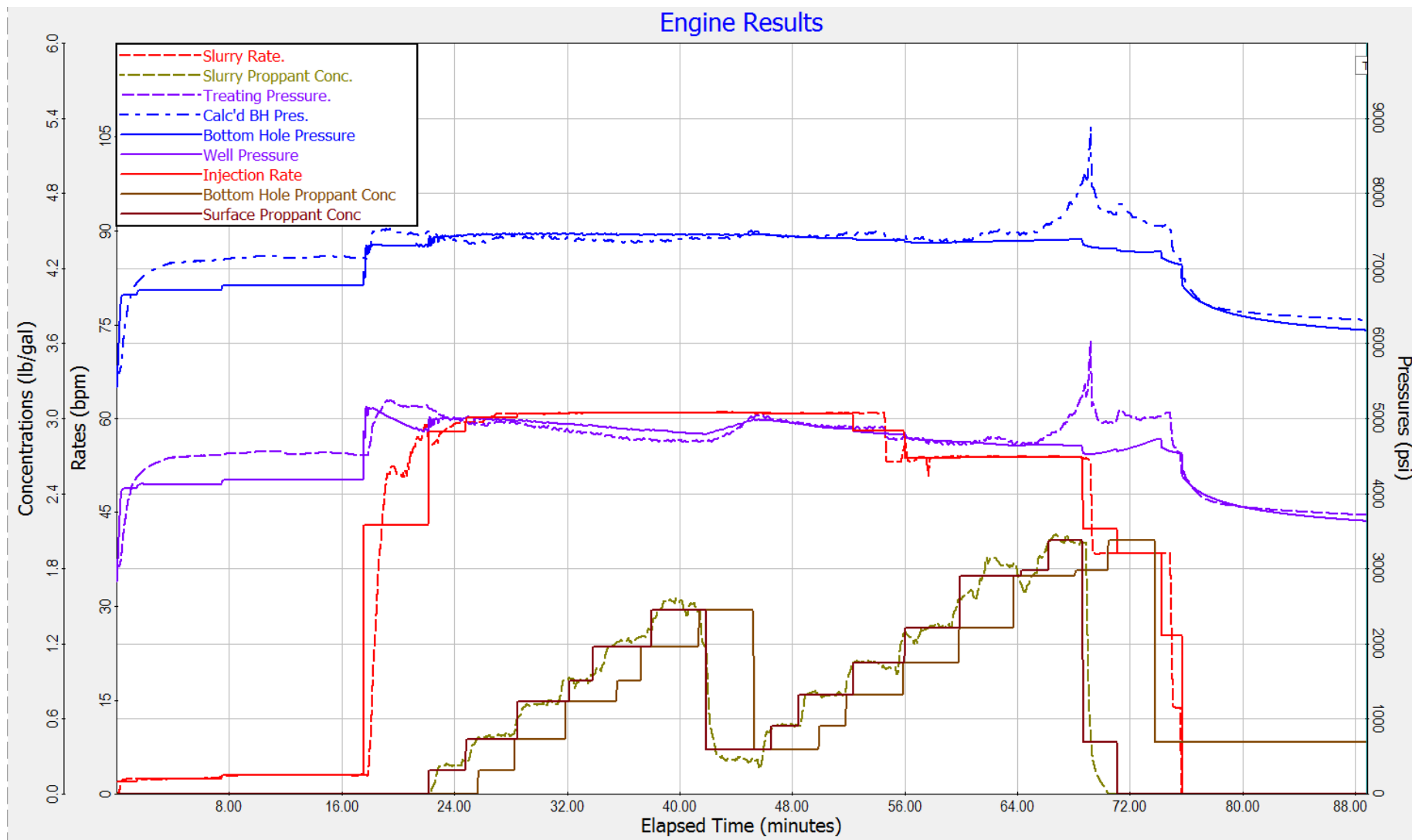


Results from the surface microdeformation will be presented at another time, however the preliminary results have been used to validate some of the GOHFER pressure matched simulation geometry and assumptions.

GOHFER (Grid Oriented Hydraulic Fracture Extension Replicator) is a planar 3D grid oriented hydraulic fracture simulator, that can present a theoretical representation of generated a two dimensional illustration fracture geometry based on principles of hydraulic fracturing, including integrated geomechanical and fluid/proppant transport models. This type of modelling is best suited to conventional planar fracture design and optimization; however for complex unconventional fracture design modelling, GOHFER is simply used as one tool to help determine possible primary fracture geometry in the dominant plane perpendicular to the minimum horizontal stress based on principles of hydraulic fracturing.

The GOHFER pressure matching based on the data available indicated a hydraulic fracture with a propped length of 320 m, maximum propped height of 11 m and maximum fracture width 0.58 in (14.7 mm). With results obtained from surface microdeformation analysis indicating a large horizontal fracture component of approximately 50%, the GOHFER pressure match fracture geometry is only possible for the vertical fracture component due to large amount of fluid and proppant moving into the transverse and horizontal components of a complex fracture network. GOHFER currently can calculate fluid and proppant moving into transverse, horizontal and natural fractures but mapping representative complex fracture networks with this type of software remains a challenge within the industry. Halliburton has recently developed complex fracture network geomechanical simulation software for shale and unconventional reservoirs to work in combination with software such as GOHFER, however this software requires further inputs from microseismic data.

Figure 2: GOHFER pressure matching graph



**Figure 3:** GOHFER pressure matched proppant concentration and NRT tracer output

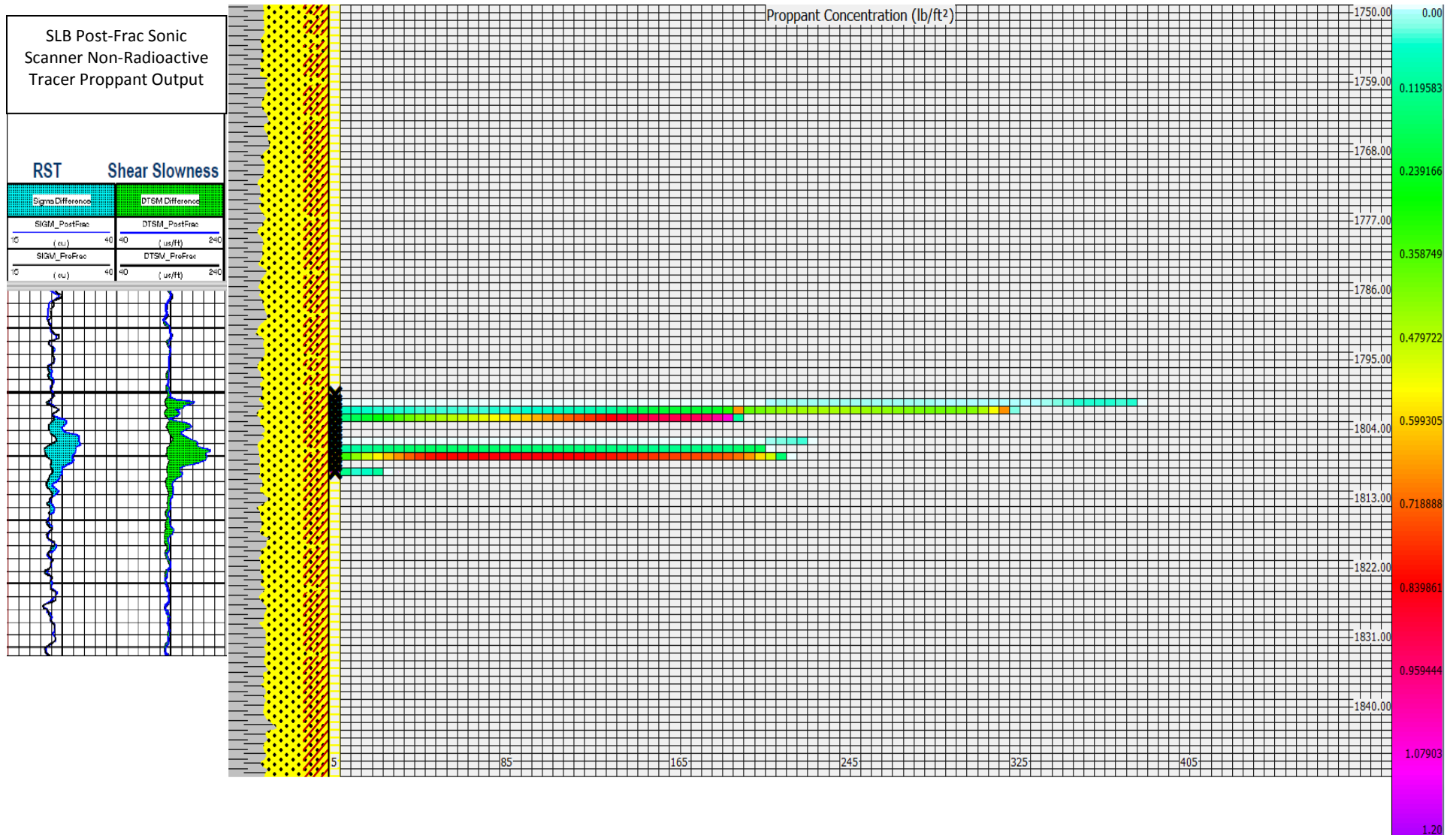
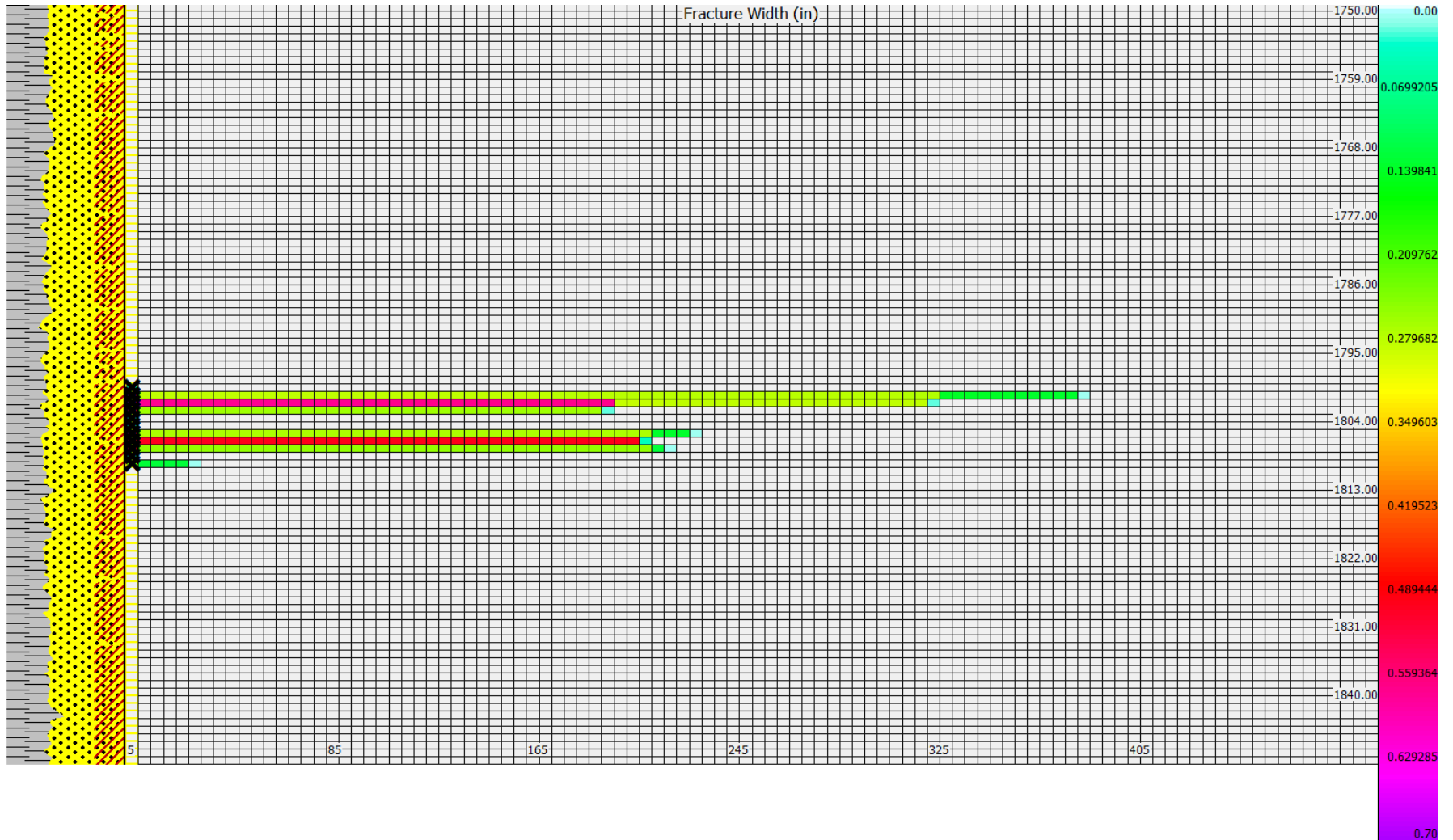


Figure 4: GOHFER pressure matched fracture width

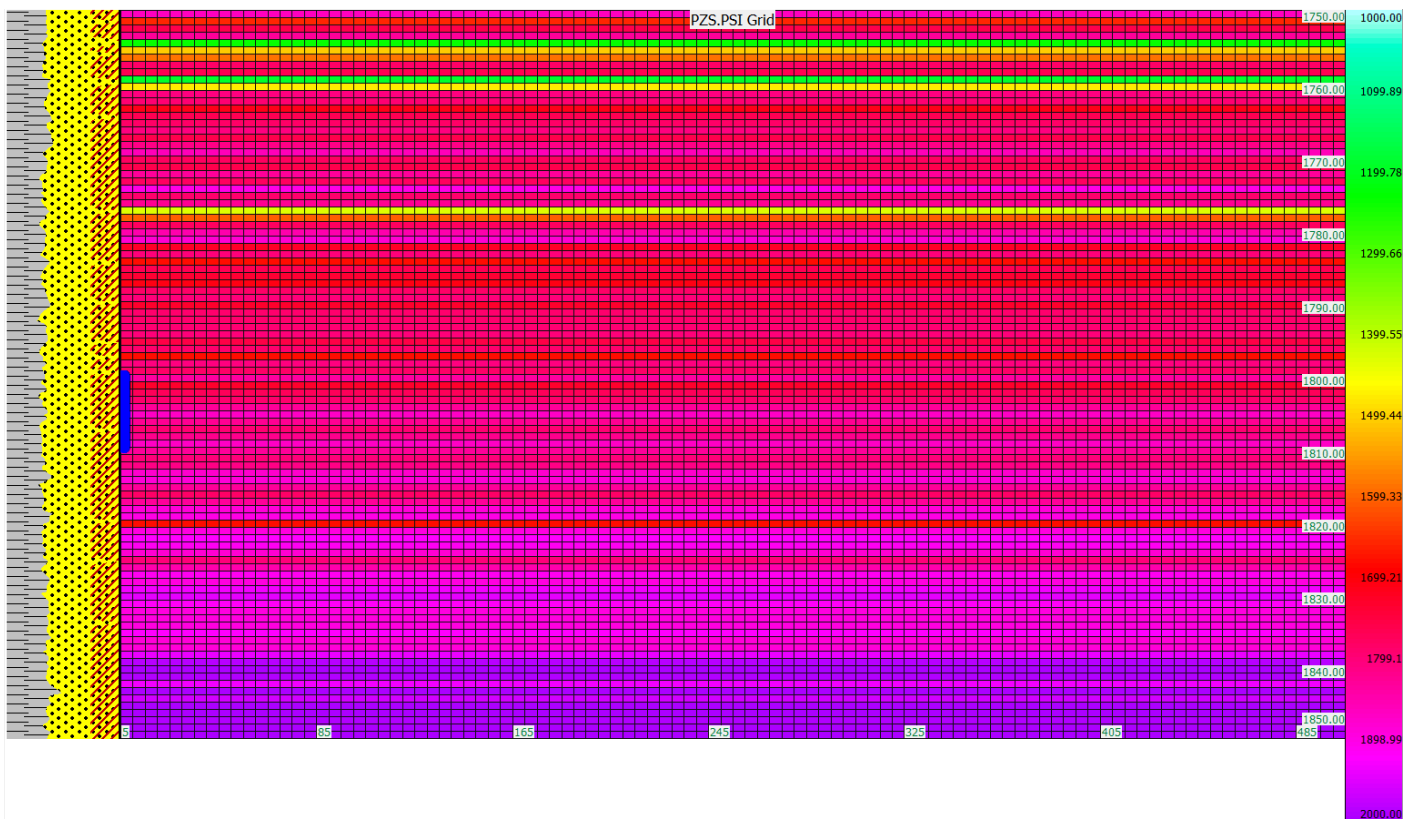


**GOHFER Pressure Matching Parameters**

In order to match the BH pressure in GOHFER, the parameters adjusted were:

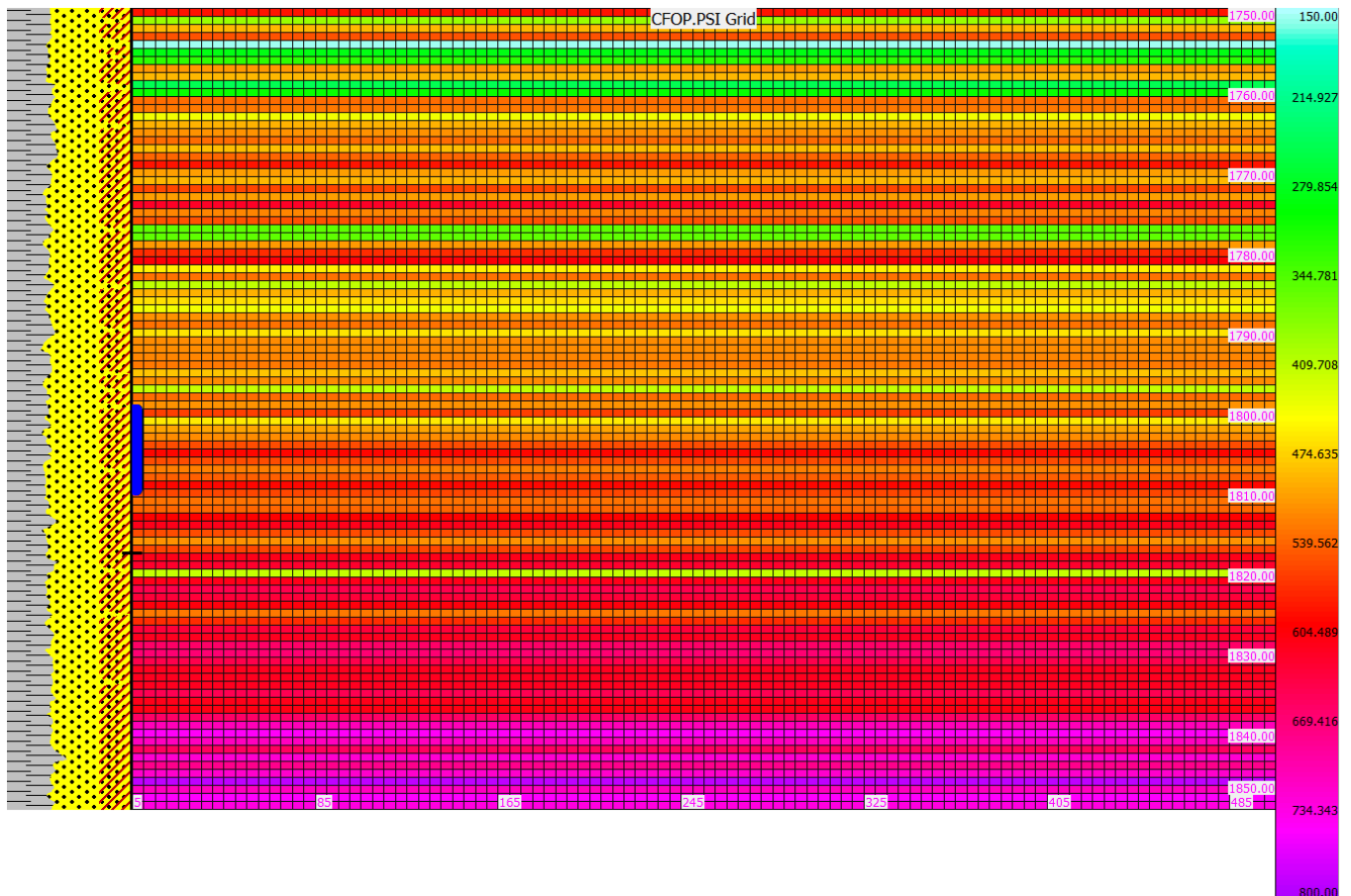
- Process zone stress (PZS) –is the combined effect of several mechanism such as fluid lag, rock tensile strength and non-linear stress dissipation around the fracture tip which restricts fracture growth. It is a directly measured parameter from the fracture extension pressure from an injection test minus the closure pressure or in-situ stress (ISIP-closure pressure). This parameter is a commonly used pressure matching input, which was adjusted to match the treatment data observed net pressure, assuming a stress gradient of 0.89 psi/ft (from Tarlee-1 DFIT closure stress). PZS used for matching was 1650 – 1850 psi at the perforations using formation porosity to differentiate between formation layers.

**Figure 5:** GOHFER process zone stress grid parameter



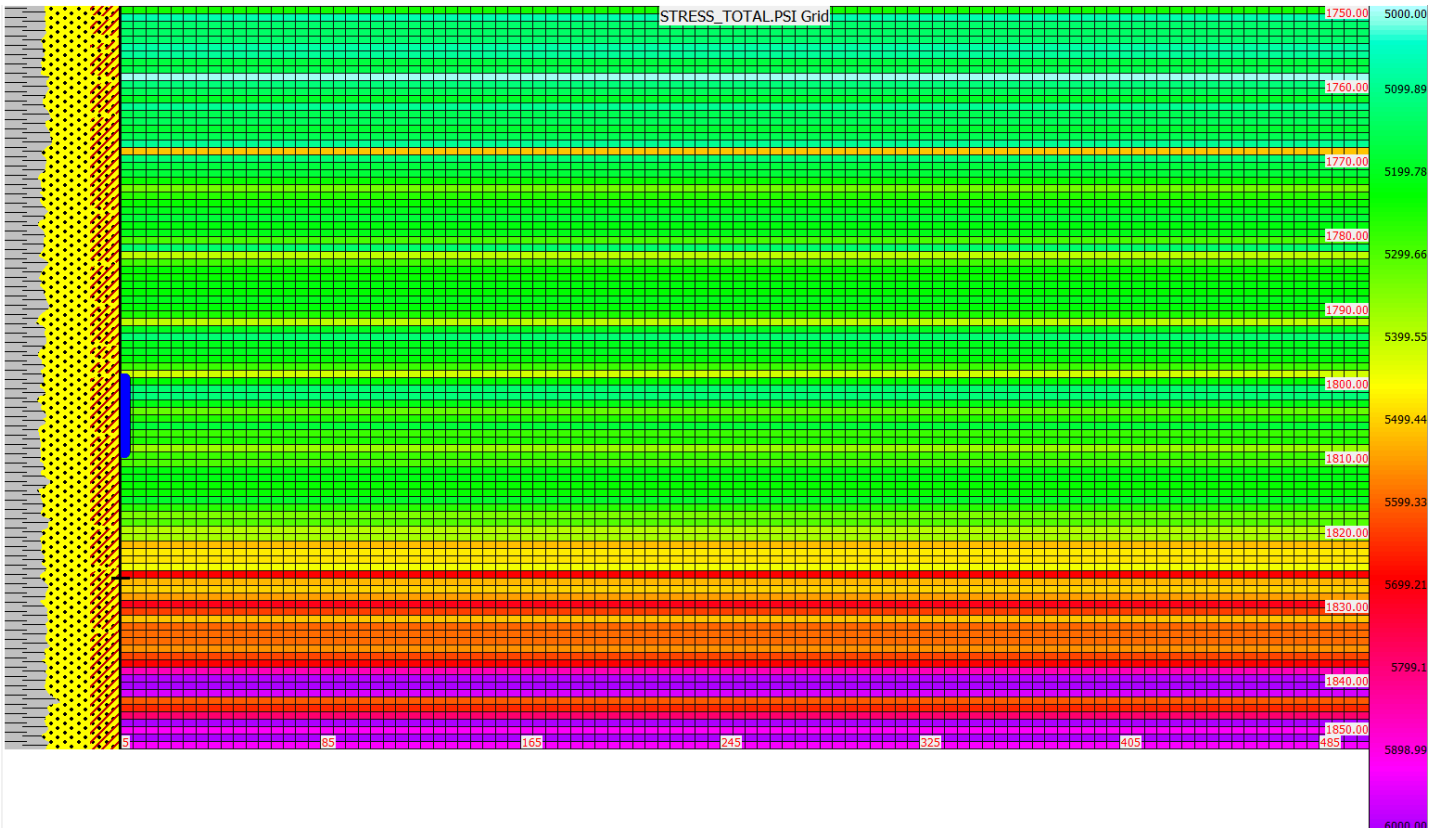
- Critical Fissure Opening Pressure (CFOP) – quantifies the amount of pressure above the total stress required to open natural fracture networks in the rock structure. The magnitude of the CFOP variable will affect the degree of pressure dependent leakoff and modulus stiffening caused by the opening of natural fractures. This parameter is a commonly used pressure matching input, which was adjusted based on the knowledge of high density natural fractures and BH pressure observations. CFOP used for the matching was 450-550 psi at the perforations using formation porosity to differentiate between layers.

**Figure 6:** GOHFER critical fissure opening pressure grid parameter



- Tectonic strain – is the amount of lateral tectonic movement that the reservoir is under. This is generally the preferred method to adjust log calculated total minimum horizontal stress to match observed closure stresses from injection tests. A value 515 microstrains was used in order to increase the total minimum horizontal stress to match the closure gradient of 0.89 psi/ft observed on Tarlee-1 DFIT.

**Figure 7:** GOHFER calibrated stress grid parameter adjusted by strain



- PDL coefficient, matrix permeability and relative permeability factor – The pressure dependent leakoff coefficient is used to determine the magnitude of leakoff change created by the opening of natural fractures. Matrix permeability is the estimated permeability of the reservoir based on log analysis. The relative perm ratio is the change in permeability from the reservoir fluid to the invading frac fluid. A combination of these factors were adjusted to match the leakoff signature at the end of the treatment. A PDL coefficient of  $1 \times 10^{-5}$  1/psi was used, scaling of the calculated matrix perm of by 0.5 and relative permeability factor of 5 (recommended for wet gas reservoirs).
- Transverse storage coefficient – defines how much fluid is moved from the main planar fracture to a network of fractures transverse to the main fracture. This parameter can be used to match modelled fracture geometry to microseismic lengths as well as pressure matching. This parameter was increased from a default of 0.0005 to 0.001 /psi due to the known presence of natural fractures in the structure and high horizontal component observed in the surface

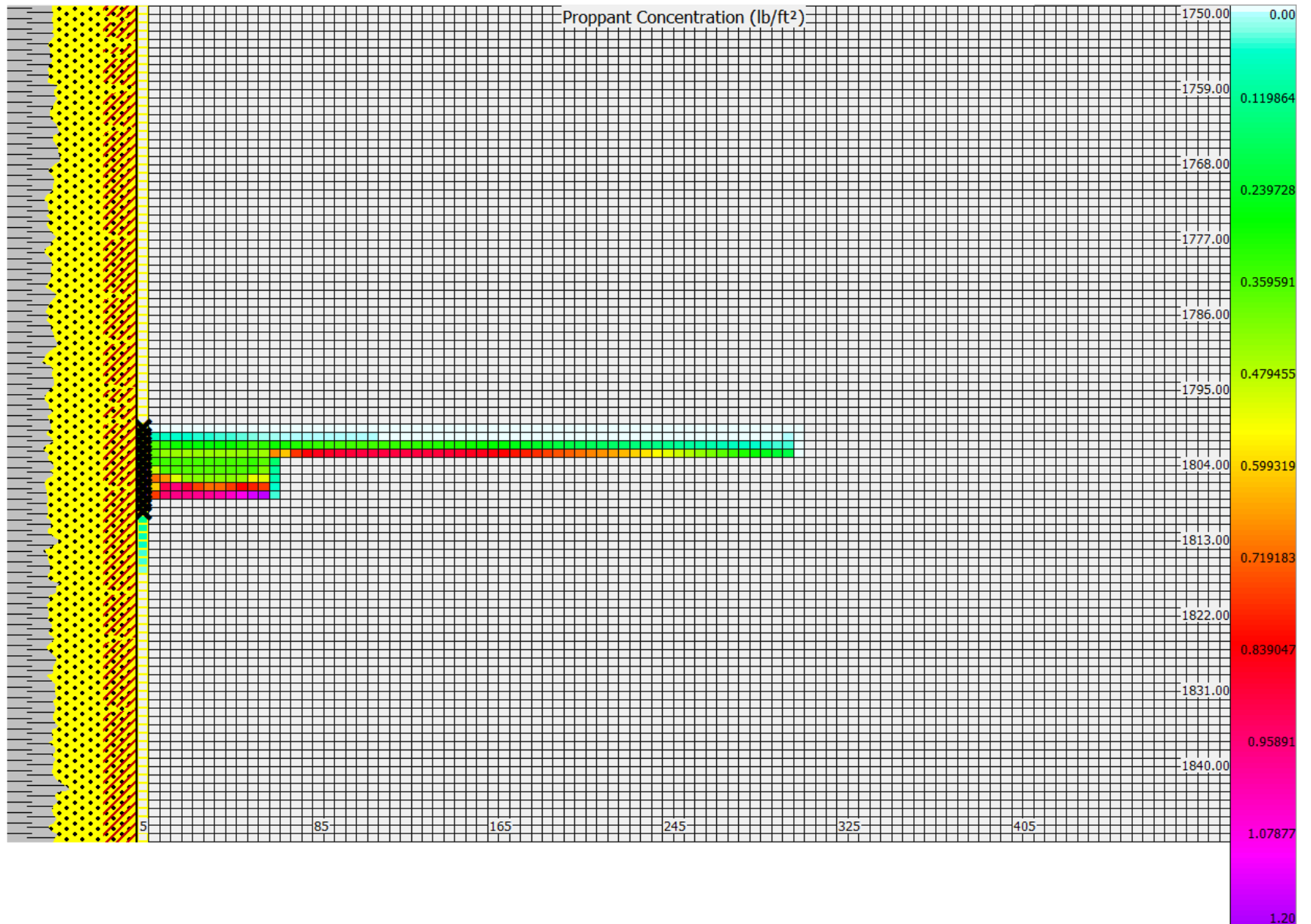


microdeformation results. Based on microdeformation results indicating that 47% of the fluid and proppant has moved from the vertical component planar fracture into the horizontal component. This is equivalent to reducing the rate into the modelled vertical fracture component by 53%. This was completed in GOHFER using the same parameters and output a similar resulting fracture as illustrated in Figure 8.

- Tortuosity factor and Tortuosity erosion factor – Tortuosity is a near wellbore pressure loss effect that results in excessive injection pressure due to an apparent restriction to fluid entry into the propagating fracture. The amount of tortuosity can be determined via a step down test, however as the total near wellbore pressure loss changes with volume, time and rate due to erosion of the near wellbore region it generally decreases during the treatment, which is controlled by the tortuosity erosion factor. These factors can be used to adjust the modelled BH pressure during pumping but will have no effect on fracture geometry or matching the end of job ISIP. A tortuosity factor of 50 psi/ bpm<sup>1/2</sup> and erosion factor of 0.01 were used to match the BH pressure shape while pumping.
- Transmissibility factor – In conjunction with the width exponent, the transmissibility factor affects the ability for the fluid to transmit pressure along the length of the fracture. As thin fluids cause very narrow fractures, the ability of the fluid to transmit pressure to the tip is lower than that of viscous fluids. In order to reduce the fracture length to a realistic length, the transmissibility factor was left at the default value of 1 for this treatment and the width exponent was primarily used to obtain a pressure match.
- Width exponent – is used for pressure matching the post frac ISIP and developing net pressure while pumping. It is used to determine the flow between fracture faces to determine the fluids ability to transmit pressure along the length of the fracture. For thin fracture apertures generated by low viscosity slickwater fluids, there may be additional wall roughness and tortuosity than larger width gelled treatment. The width exponent allows for a bigger variance between wide and narrow fracture apertures, with values of 3.2 to 3.4 (default=3) for slickwater treatments the additional effects of wall roughness and tortuosity can be modelled for thin fracture, increasing the fracture friction pressure and reducing the ability to transmit pressure along the fracture length. A value of 3.2 was used to match the BH ISIP.

Pangaea Resources Pty Ltd Birdum Creek-1 Stage 1  
Velkerri-B - 1,802m to 1,812m

Figure 8: GOHFER fracture proppant concentration with 53% of treatment rate



**Future Fracture Treatment Recommendations:**

1. **Perform further diagnostic fluid injection testing** in the area will allow further understanding of the stress regimes in the basin, which will allow further calibration of future frac model as well as indicate a tendency for the fractures to develop horizontally. Downhole gauges with higher sampling rates for DFITs can also assist with obtaining higher quality data for geomechanical model calibration.
2. **Further investigate the tendency for generating horizontal fractures (or pancake fracs).** Horizontal frac are generally undesirable due to typically low permeability in the vertical direction, however it may be possible that the horizontal component is the dominant frac connecting a large network of smaller vertical fractures. Fracture treatments that generate primarily horizontal fracture geometry can prove harder to pump to completion and will also affect the decisions with development of the field and completions in the future.
3. **Investigate the use of gelled fluid systems.** Slickwater fracture treatments are excellent at creating complexity which is desirable in very low permeable formations; however, in some formations low viscosity fluids tend to create large horizontal components and higher BHTP gradient due to its ability to open up natural horizontal fractures within laminated formations. Therefore, hybrid and/or higher viscosity gelled fracture designs may create more vertically dominated fracture networks.
4. **Investigate use of crosslinked gel for greater height coverage over the payzone.** The modelled height of the fracture does not extend much further above and below the perforations as observed with the tracer proppant. This indicates relatively poor coverage over the payzone. Crosslinked gel could also possibly assist with greater height growth to more efficiently prop the payzone. Figure 9 illustrates the same treatment but utilising crosslinked fluid for 0.5 ppg and higher 40/70 proppant concentration stages.
5. **Downhole Microseismic and Microdeformation fracture diagnostics** will help to further characterize the fracture geometry and how the fracture grows throughout the treatment by illustrating fracture length, fracture height away from the wellbore, out of zone growth and fracture complexity.
6. **Reservoir simulations from extended flow tests** can also be employed to further confirm fracture dimensions.

Figure 9: GOHFER proppant concentration demonstrating fracture geometry using 30# Hybor G crosslinked fluid in hybrid style treatment

