Step-Rate Test in the Mississippian Reservoir in the Wellington Field

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Introduction

Step-rate and interference tests were performed in the Mississippian reservoir in the Wellington field (fig. 1). Water was injected at different rates in the injector well (2-32) and pressure responses were measured in well 2-32 and the observation wells (wells 55, 53, 62, and 61).

Step-rate test analysis can provide permeability, skin (s), reservoir pressure, fracture pressure, and closure pressure (minimum stress) and detection of any induced or natural fractures. Interference test analysis can provide inter-well permeability and detection of any fault, fracture, and discontinuity. This report contains the step-rate test analysis only. The interference test data could not be analyzed because the static bottomhole pressures of the observation wells were changing due to the surrounding production and injection wells, which were not shut-in during the test. Interpretation of the interference test would give inferior results.

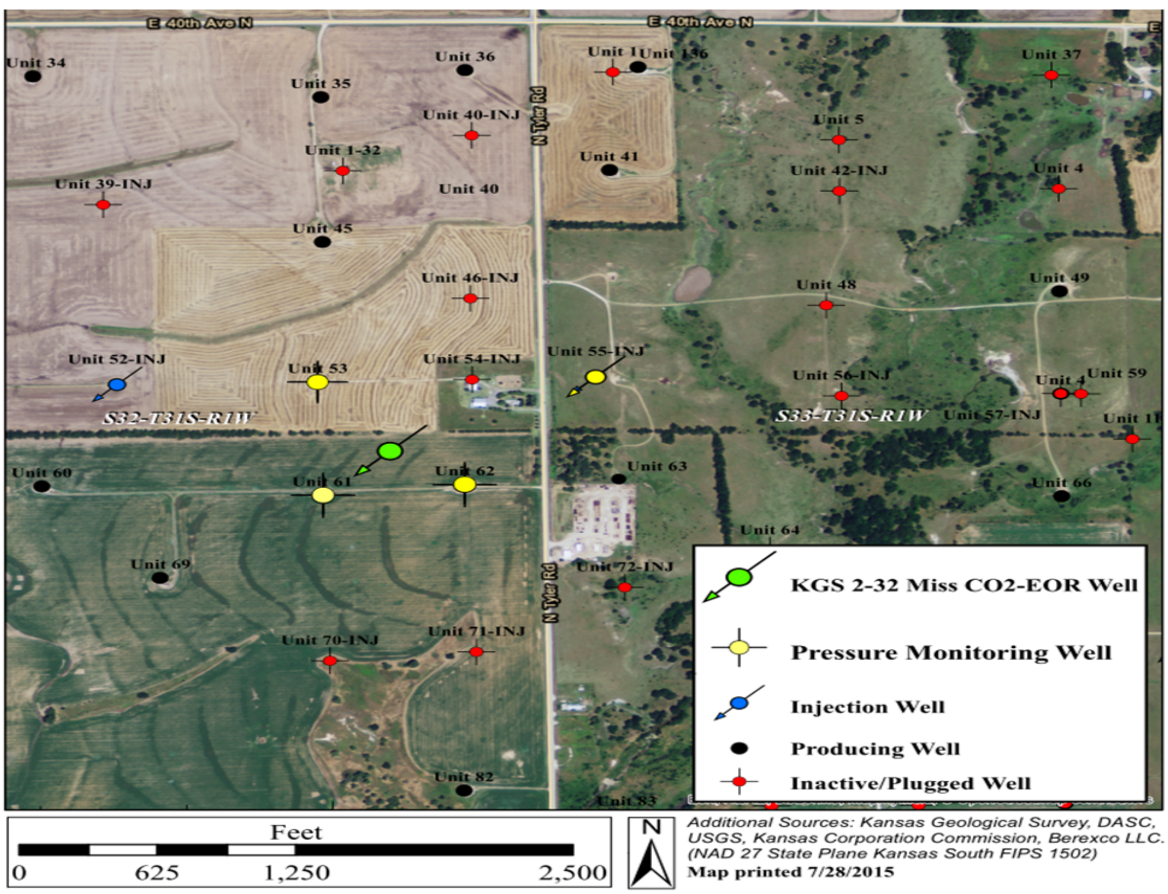

Figure 1: Location of step-rate and interference tests.

Step-Rate Test Analysis

Step-rate test data in Well 2-32 was analyzed by FEKETE Welltest using the “Fracture with Boundary” model. The step-rate test involved nine injection steps and nine fall-off periods. Each fall-off period was analyzed separately. There was an existing induced fracture at the wellbore, most certainly from the acid treatment that was performed before this test in which bottomhole injection pressure (BHIP) reached 3,035 psi, which exceeded the fracture pressure of the formation (table 1). The fracture was open during all injection steps and only closed during the last fall-off period, which was long (16 hrs). During the last fall-off period, bottomhole pressure (BHP) dropped below the closure pressure. The fracture length from the wellbore was extended as the final injection pressure in each step increased (table 2).

Table 1: Acid treatment bottomhole pressure.

Acid Treatment Data		
Rate	Wellhead Pressure	Bottomhole Pressure
BBL/min	psi	psi
3	1300	3035

Table 2: Results of all fall-off periods in Well 2-32.

Result from all Fall offs in Well 2-32						
Permeability, Fracture Half Length and skin						Summary of Results
Step No	**Cum Inj, BBL**	BHIP, psia	**K**	**Frac Xf, Ft**	**Sxf**	permeability to water5.8 md.
fall-off 9	50.6	1626	5.8	66.4	-4.7	Absolute permeability 17.8 md
fall-off 8	131	1517	5.8	22.7	-3.6	Frac closure press 1410 psia
fall-off 7	442	1544	5.8	29.5	-3.89	Frac closure press is reduced by cooling
fall-off 6	505	1575	5.8	35.8	-4.08	Press in all steps above closure press
fall-off 5	547	1681	5.8	71	-4.77	Fracture skin is negative
fall-off 3	573	1571	5.8	32	-3.98	Max frac half length 71 ft
fall-off 2	891	1529	5.8	0.7	-0.154	Reservoir press at 2-32 before test 964 psia
						Depth of pressure 3710 ft from 12' KB

BHIP = Bottomhole injection pressure (psia); K = Effective permeability to water (mD); Frac Xf = Fracture half length (ft); Sxf = Fracture skin

Quality of Data

The following limitations to the data should be considered in the analysis of the test data:

- Before the start of injection, there was a fill-up period with a misreported rate; the fill up was unnecessary.
- There was no shut-in period for 6 BBL/min; instead, the test skipped to 9 BBL/min injection.
- The shut-in period after each injection step was very short and bottomhole pressure did not reach the static reservoir pressure.
- Low injection rates, such as 0.5 bbl/min, were not included in the injection steps so that fracture opening could be identified.
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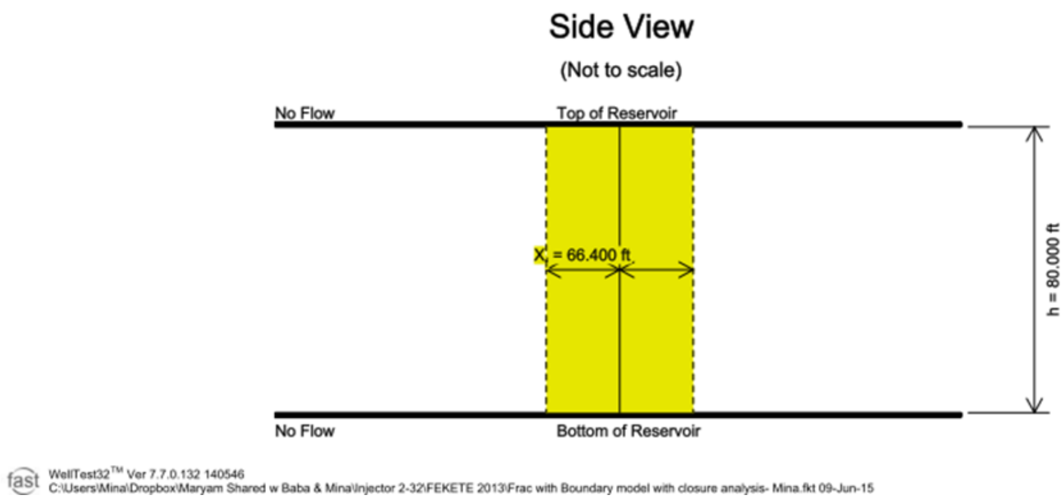
Results

A. Brief Description of Analysis

Only fall-off periods could be analyzed by the "Fracture with Boundary" model. Each fall-off period was analyzed and modeled separately (figs. 2–9). The fall-off periods could not all be matched with a single model because each fall off has a different length of fracture and skin. First, the last fall-off period was analyzed and permeability, skin, and fracture half-length were calculated (fig. 2). Then, the estimated permeability was used in each of the other fall-off models to predict skin and fracture half-length in each period (figs. 4–9).



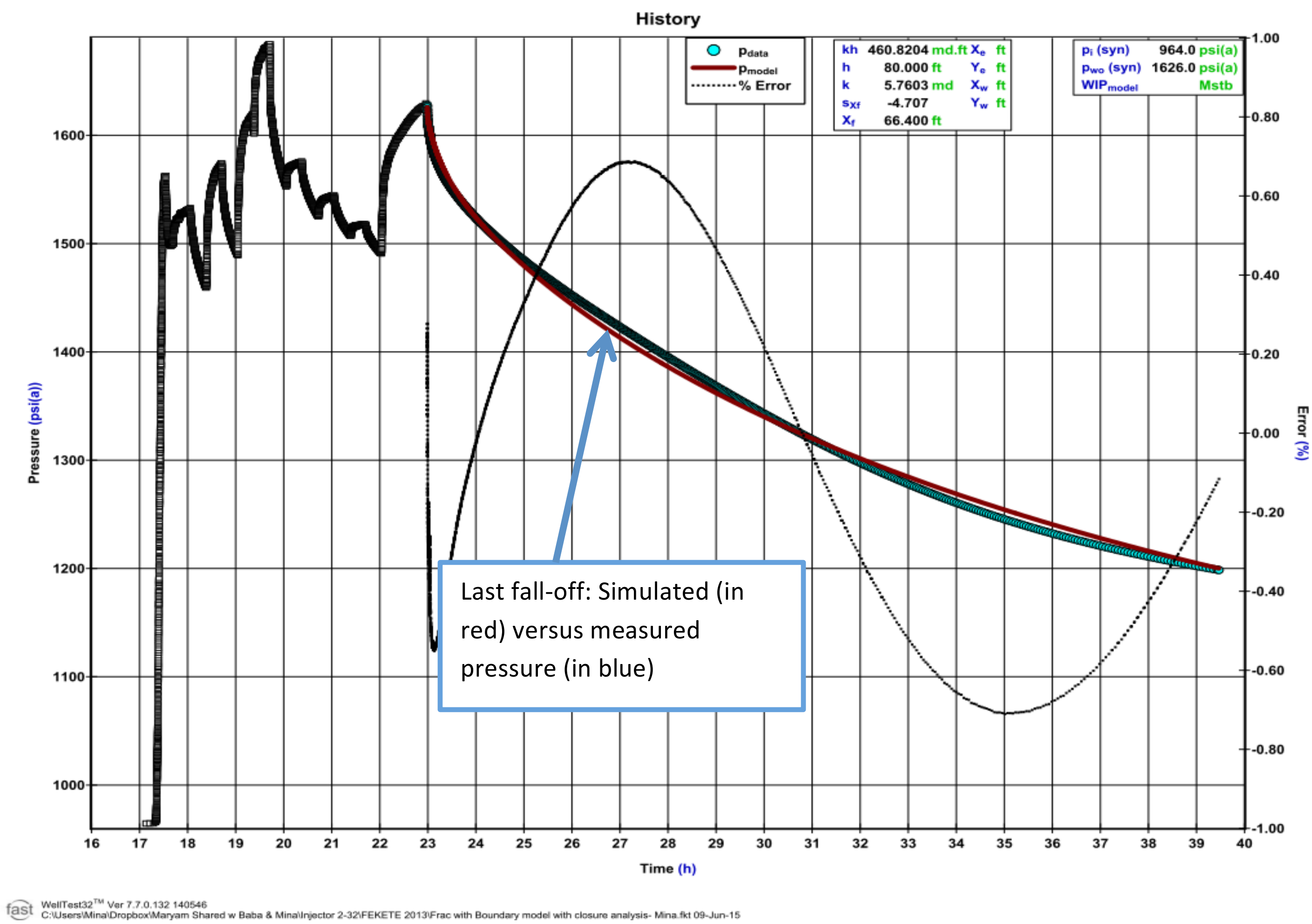


Figure 2: Last fall-off match between measured data (in blue) and simulated (in red).

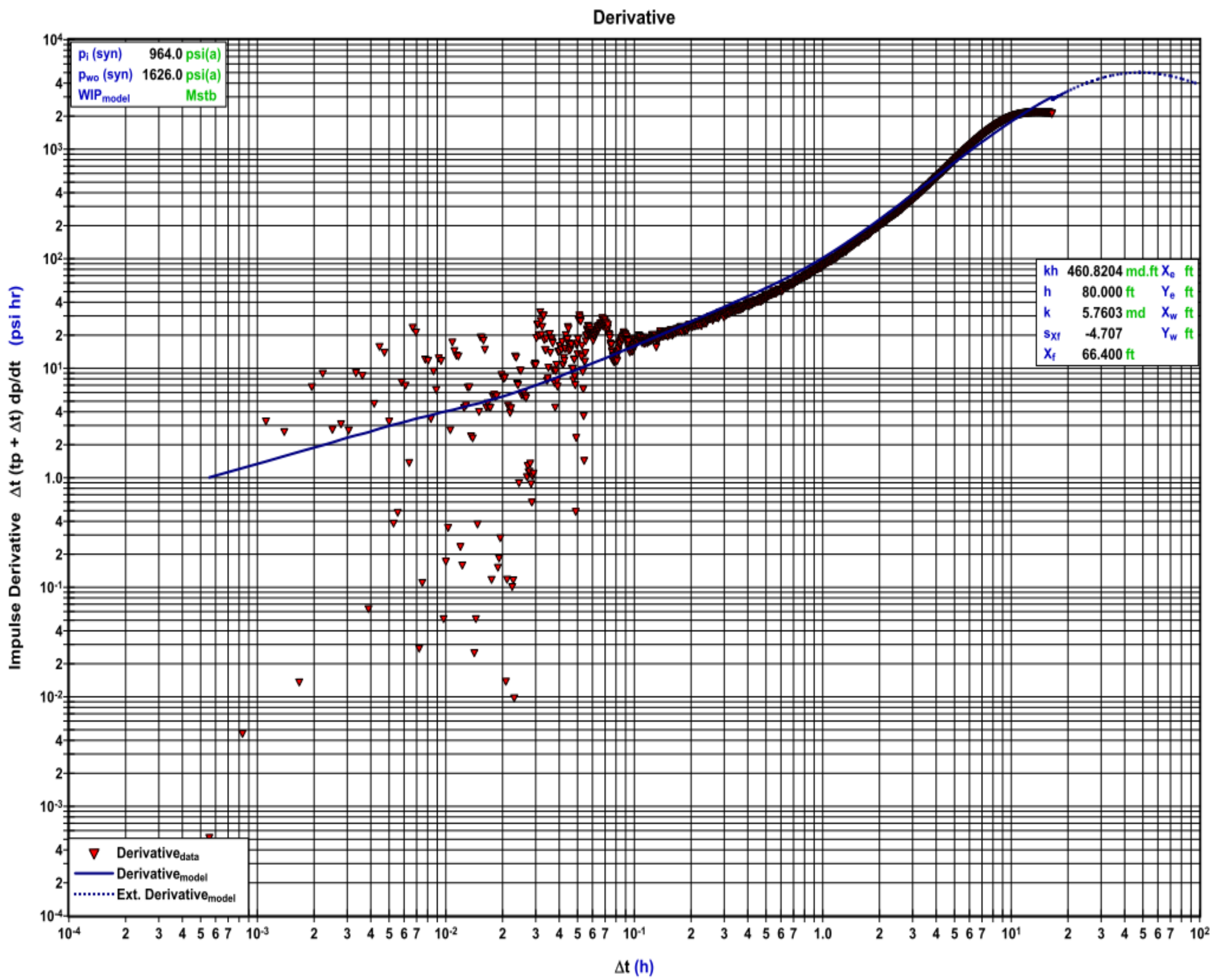


Figure 3: Derivative of last fall off: Measured (in red) versus simulated (in dark blue).

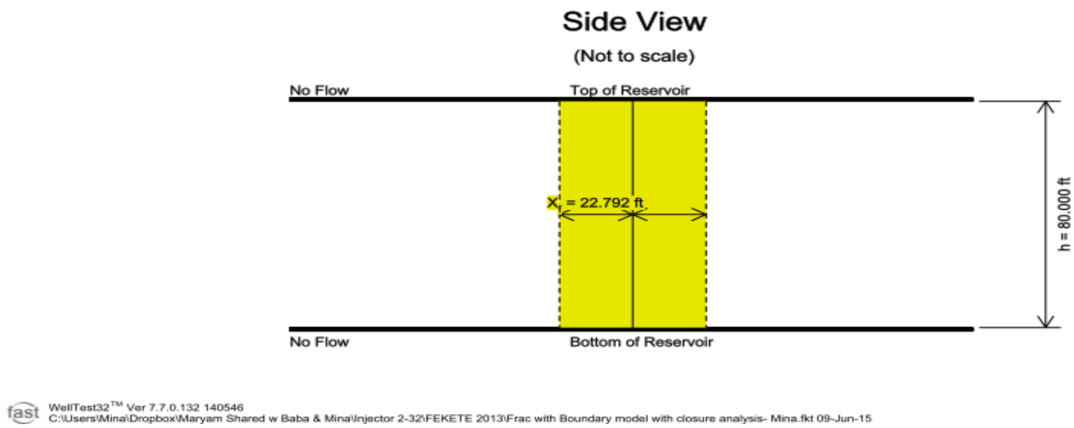
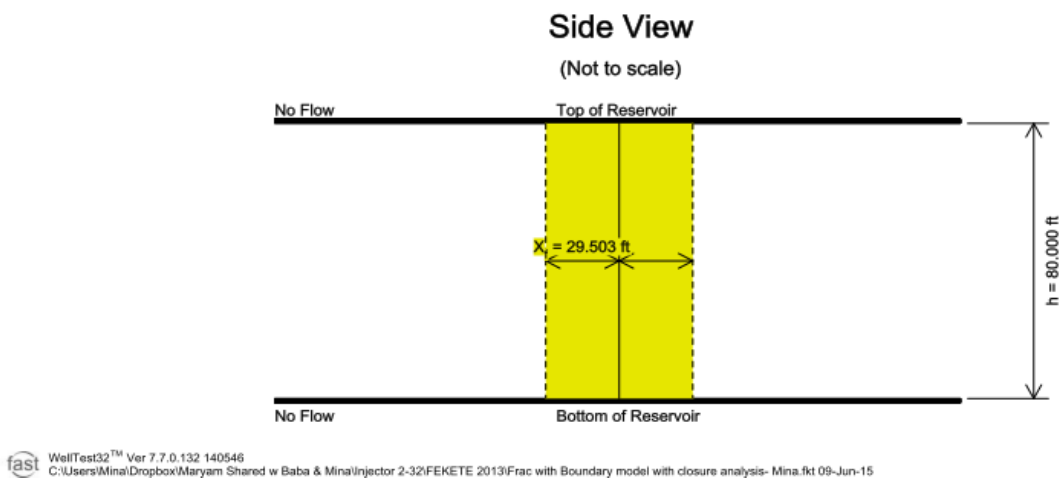


Figure 4: Fall-off 8: Measured (in blue) versus simulated (in red).



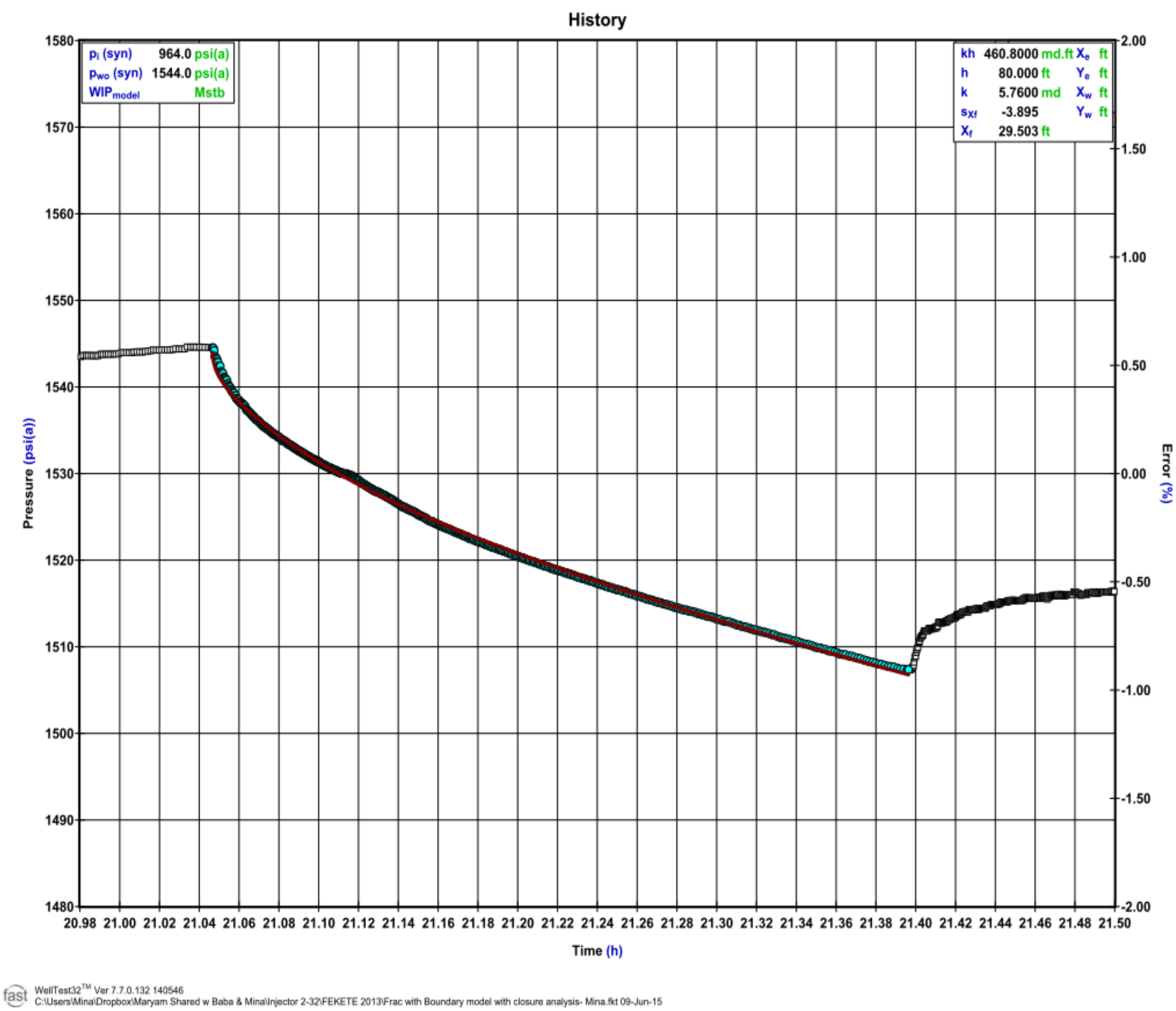
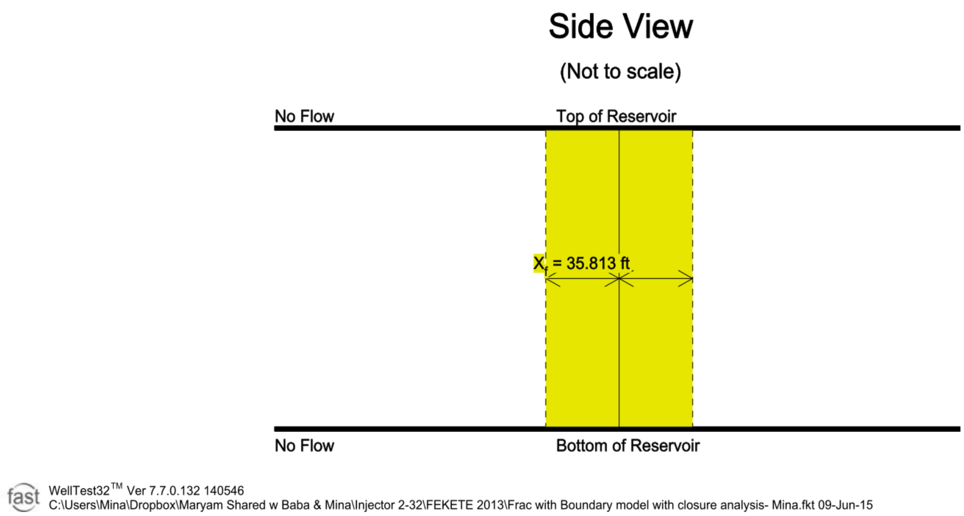


Figure 5: Fall-off 7: Measured (in blue) versus simulated (in red).



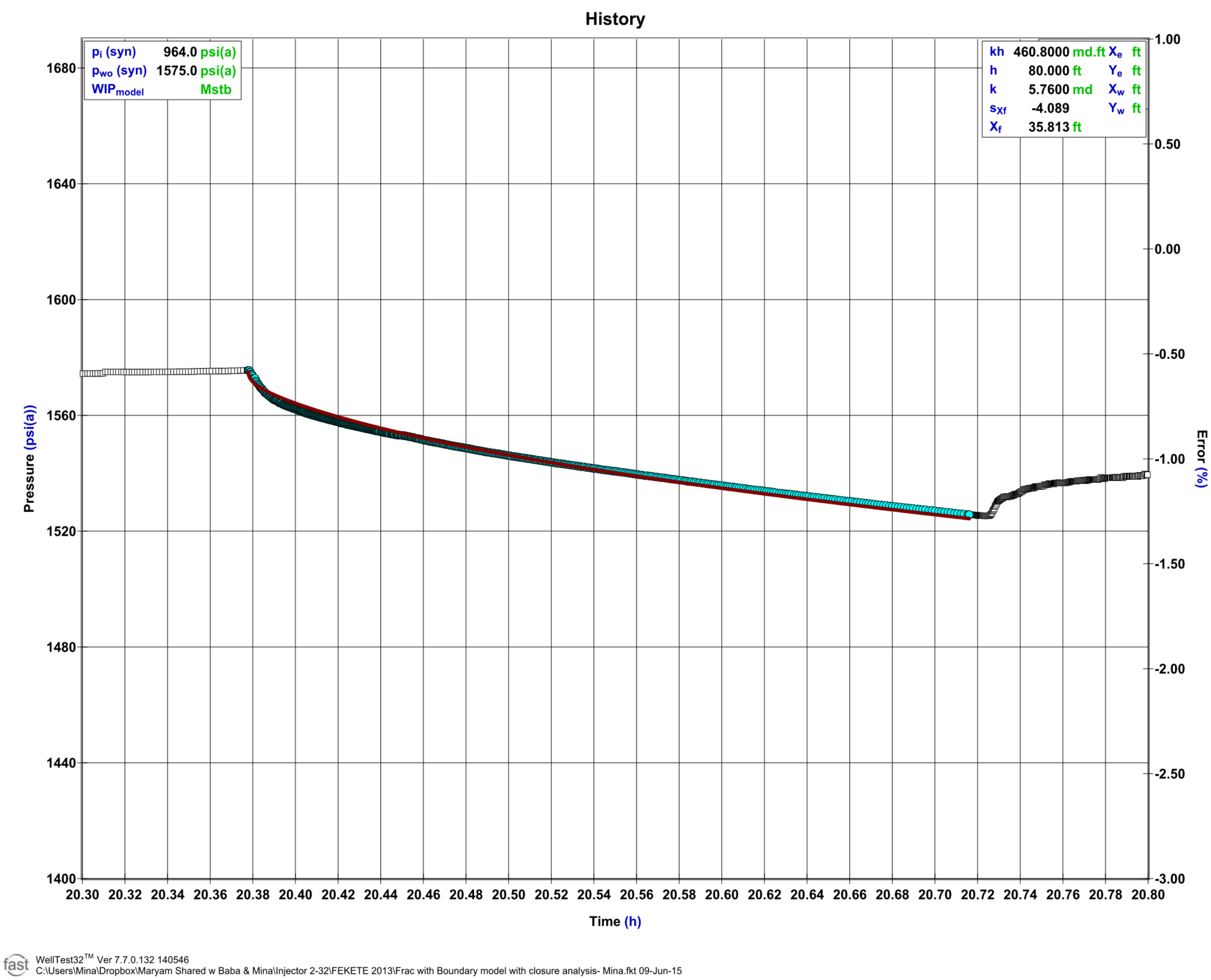
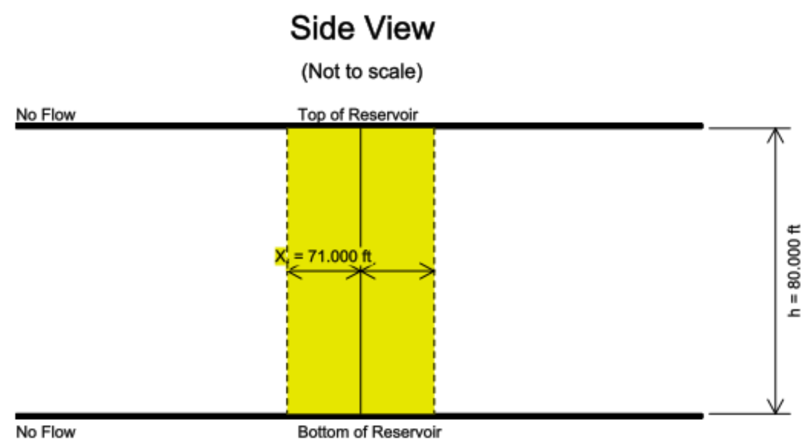


Figure 6: Fall-off 6: Measured (in blue) versus simulated (in red).



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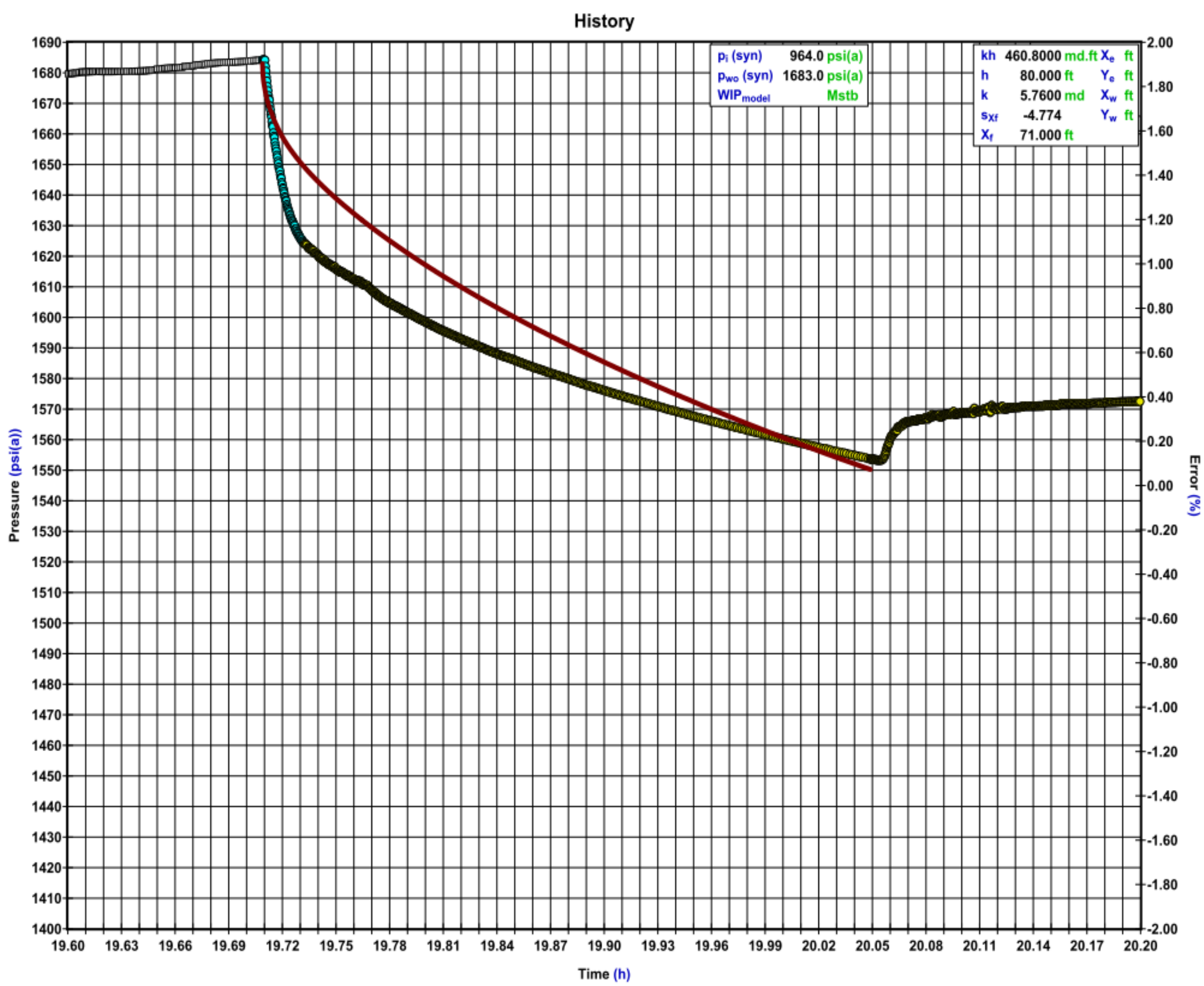

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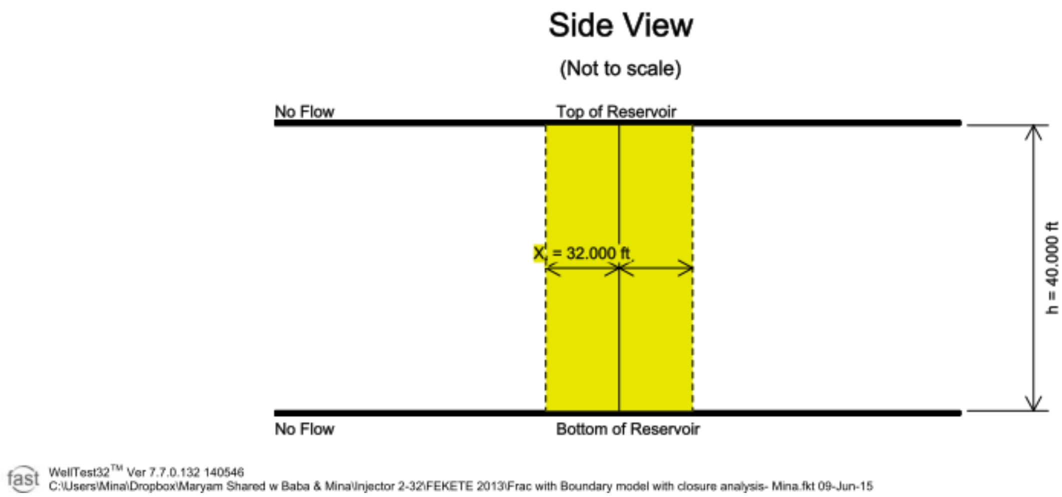
Figure 7: Fall-off 5: Measured (in blue) versus simulated (in red).



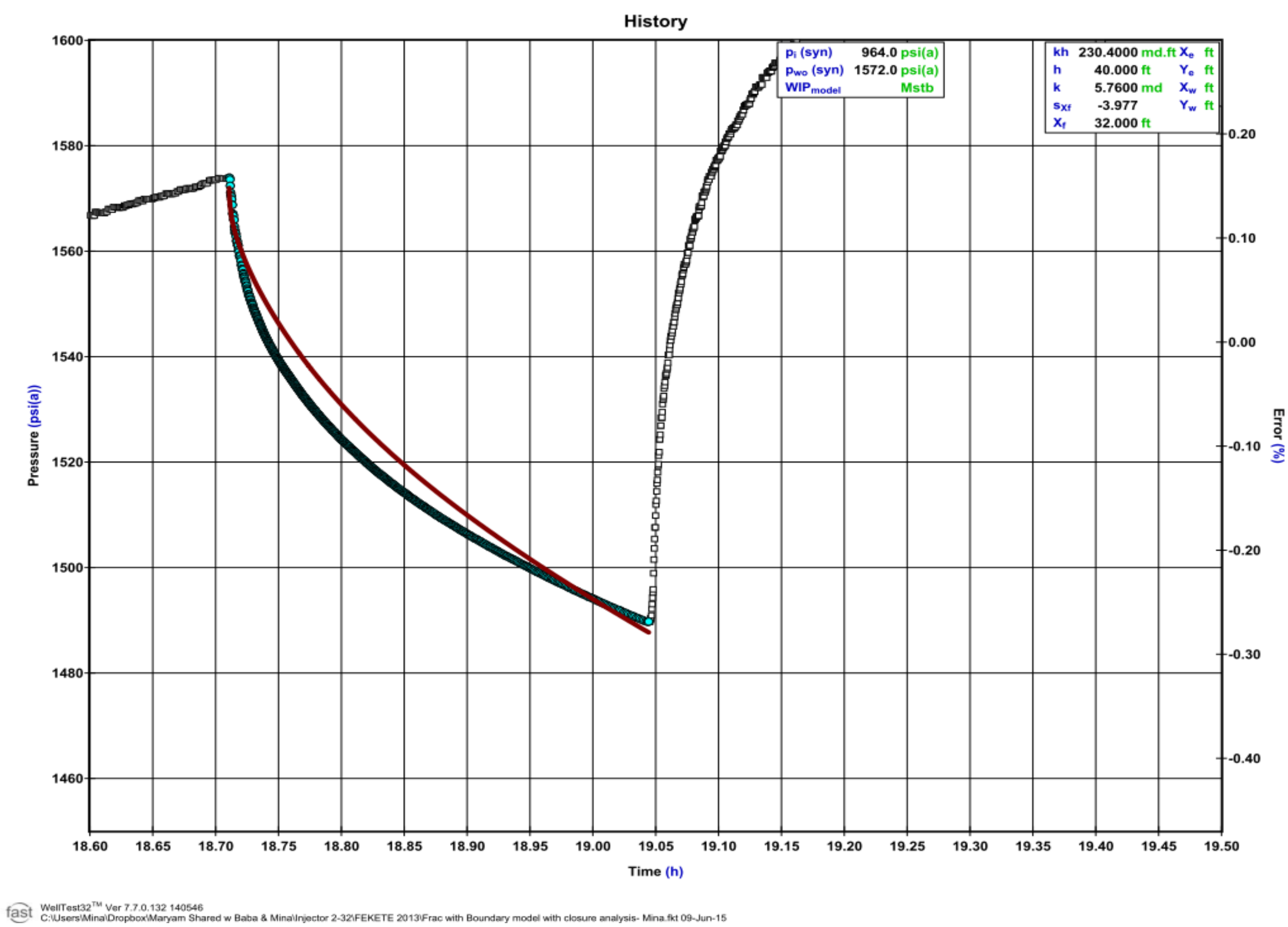
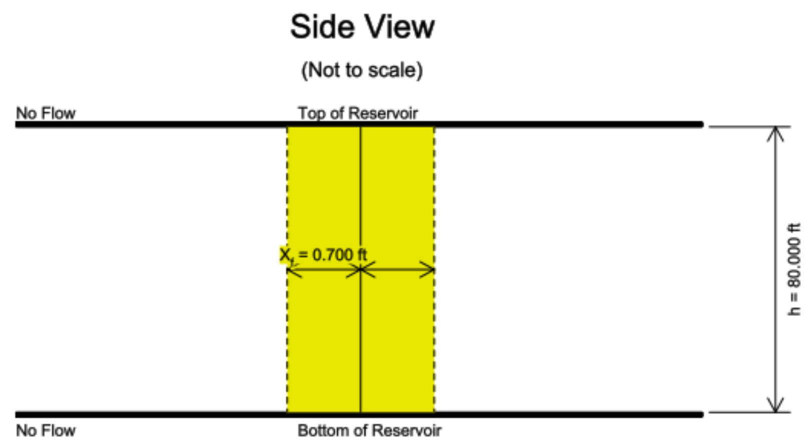


Figure 8: Fall-off 3: Measured (in blue) versus simulated (in red).



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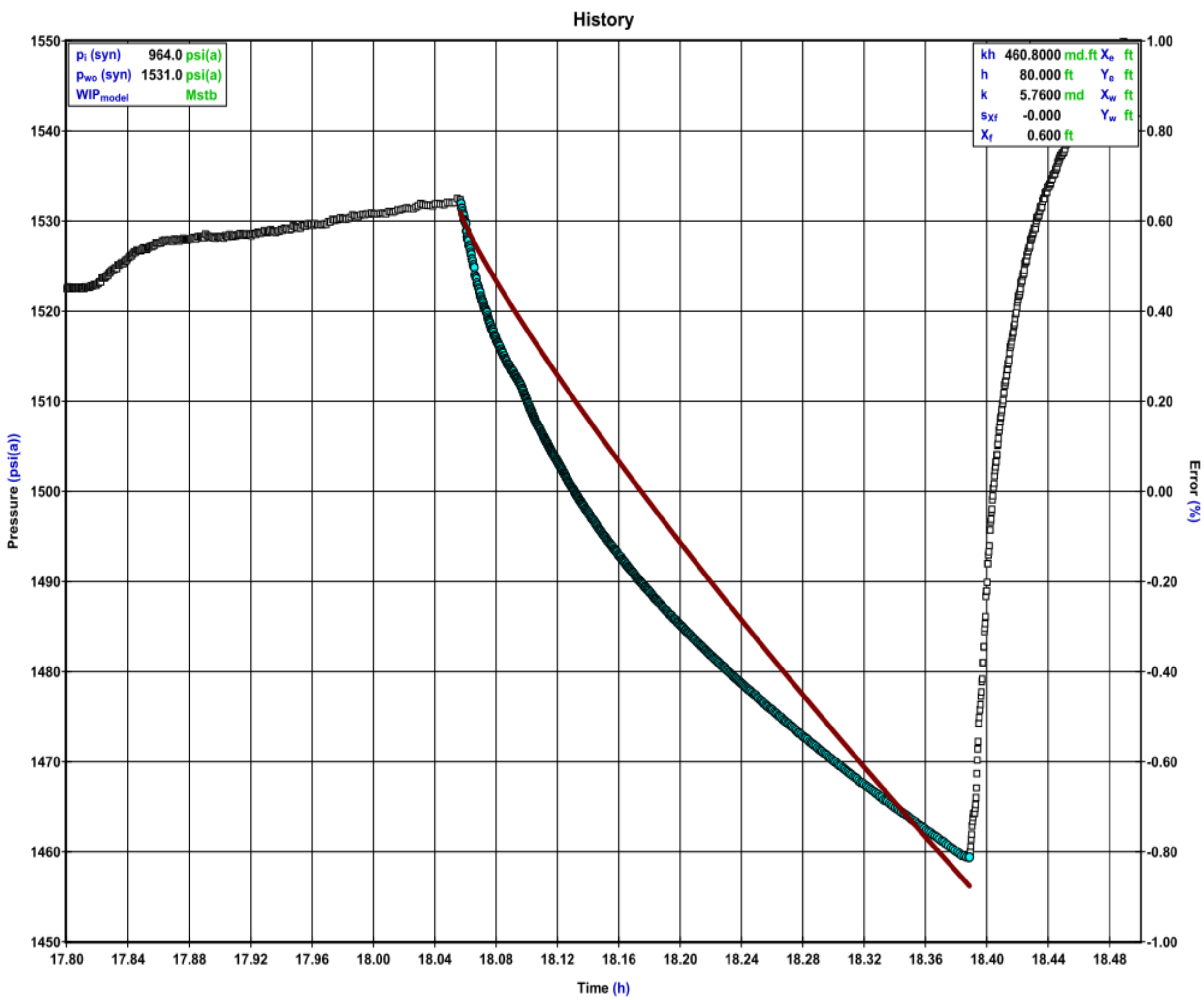

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Figure 9: Fall-off 2: Measured (in blue) versus simulated (in red).

B. Permeability, Fracture Half-Length, and Skin

Based on the well test analysis, the matrix effective permeability in Well 2-32 is 5.8 mD (fig. 2). This permeability is a one phase effective permeability to water and not absolute permeability. There is about 25% residual oil saturation; therefore, absolute permeability can be calculated using the previously estimated relative permeability curves at 75% water saturation (fig. 10) and the predicted effective permeability from the step-rate test. At 75% water saturation, relative permeability to water is about 0.30; therefore, K= Kw/Krw, that is K=5.8/0.32= 17.8 mD.

The fracture length from the wellbore increased as final injection pressure increased. The maximum fracture half-length was 71 ft during fall-off period 5 when water was injected at 9 BBL/min. Fracture skin factor is negative in all steps (table 2).

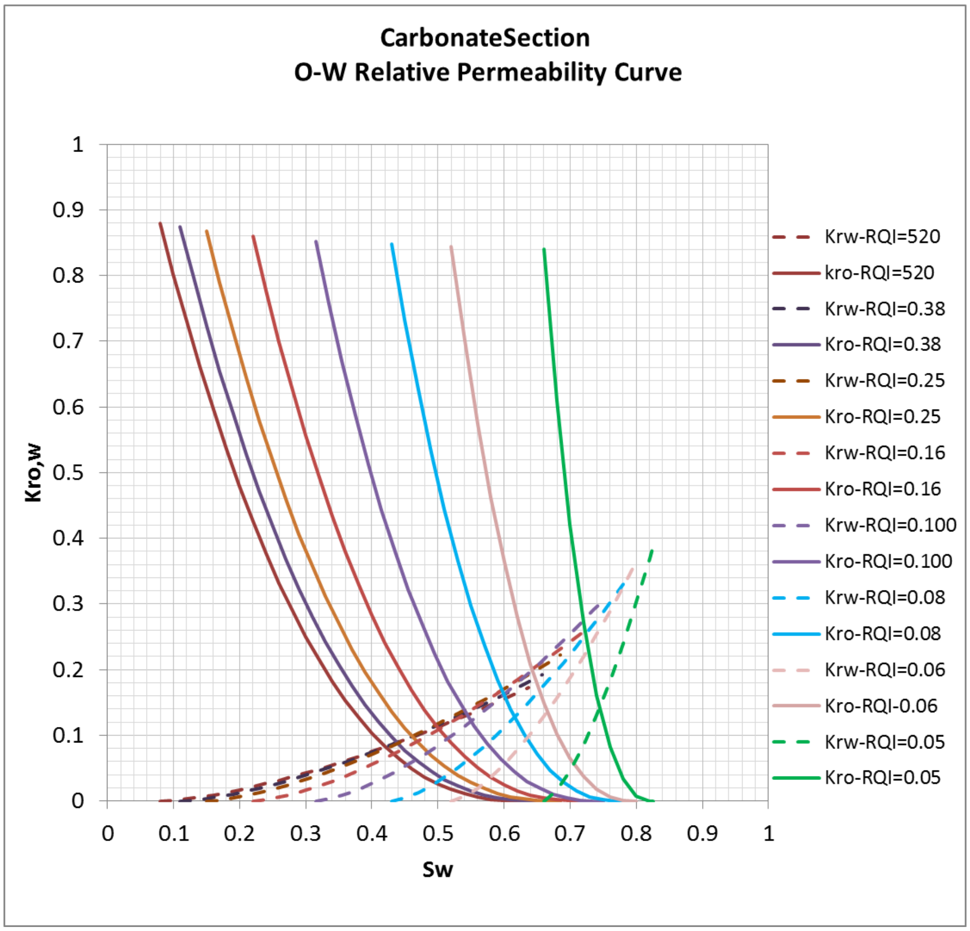

Figure 10: Relative permeability curves in the Mississippian.

Closure Pressure

Closure pressure (Pc) was calculated as follows:

- **G function and Sqrt(t) plot in FEKETE Welltest software**
  The slope on the G-function derivative (Gdp/dG) defines the closure pressure (Pc). Pc on the plot is identified when the G-function derivative departs from the slope (fig. 11). Sqrt(t) plot verifies/supports the Pc and closure time selected on the G-function plot. Pc corresponds to the peak of the first derivative (PPD) (dp/dt ½) (fig. 12). Pc from G-function and sqrt(t) plot is 1,334 psi, and the fracture closure pressure gradient is 0.36 psia/ft.
- **Plotting bottomhole injection pressure against half-length fracture.**
  Only pressures below 1,580 psia were used in this plot, and Pc was identified when the length of fracture becomes zero. The Pc from the plot is 1,410 psia, and its gradient is 0.38 psia/ft (fig. 13).

Closure pressures from both methods are low and below the initial closure pressure. Either method can result in a 5–6% margin of error, which is an acceptable error margin in analysis. The fracture pressure and closure pressure are reduced in the Mississippian due to pressure depletion and water injection, which is consistently colder in that formation. The cooling effect causes the formation to contract and thus the stresses are reduced below the initial fracture pressure.

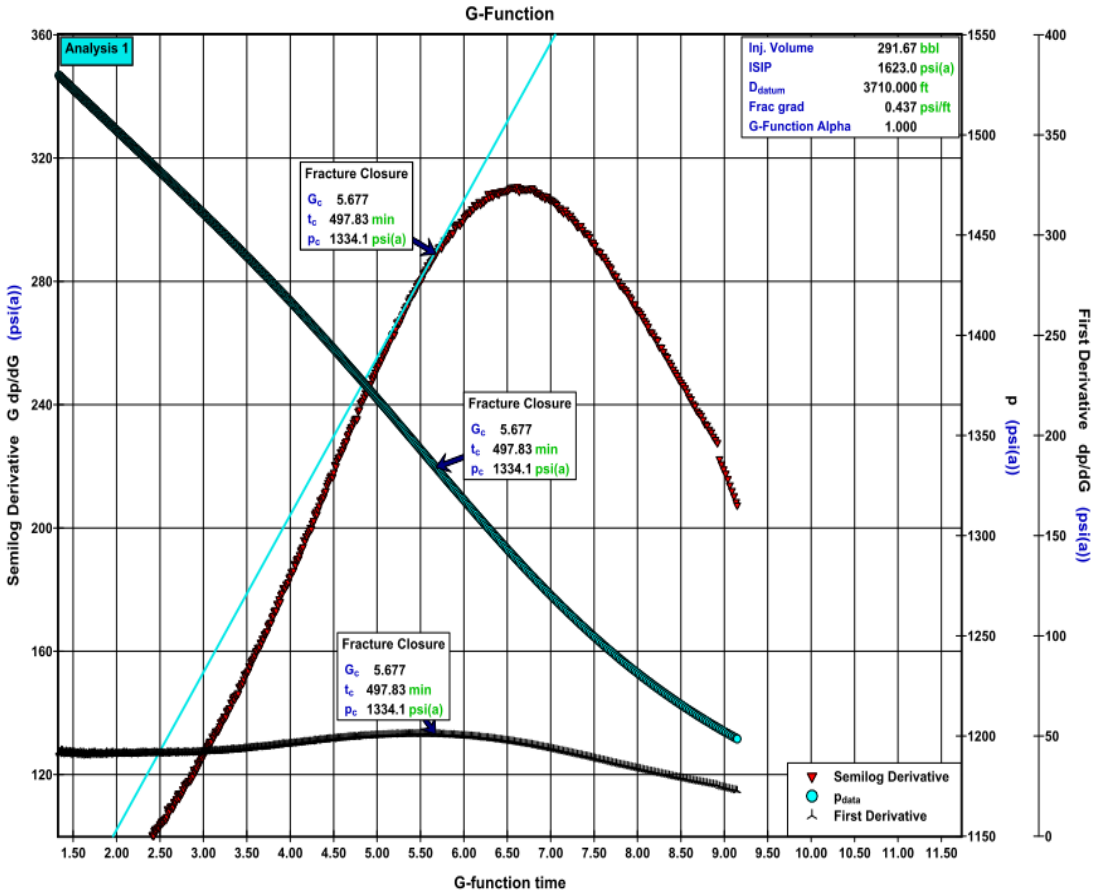

Figure 11: G-function showing closure pressure: Point of departure from the slope (in light blue) identifies closure pressure.

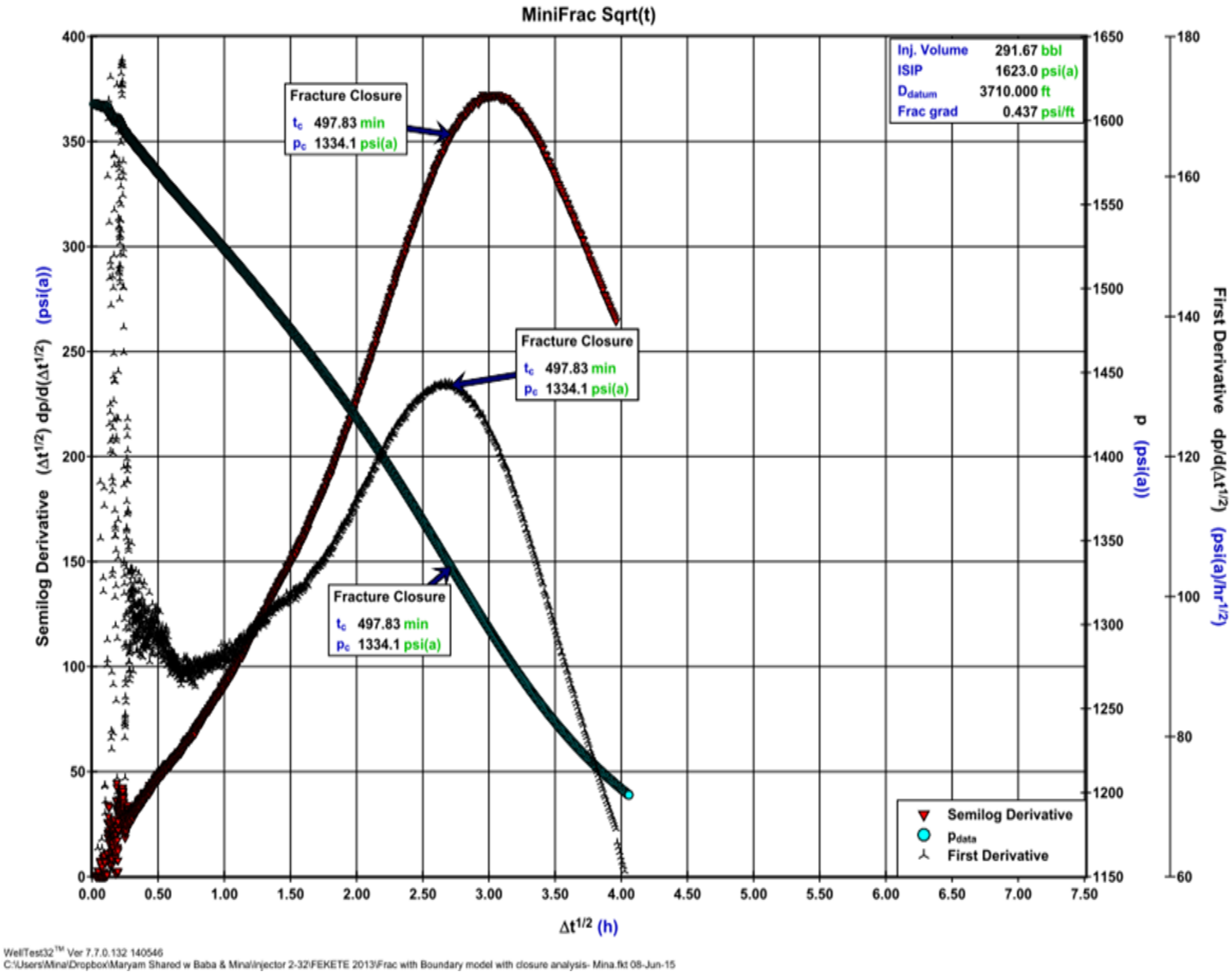

Figure 12: Sqrt(t) showing the closure pressure on the peak of first derivative.

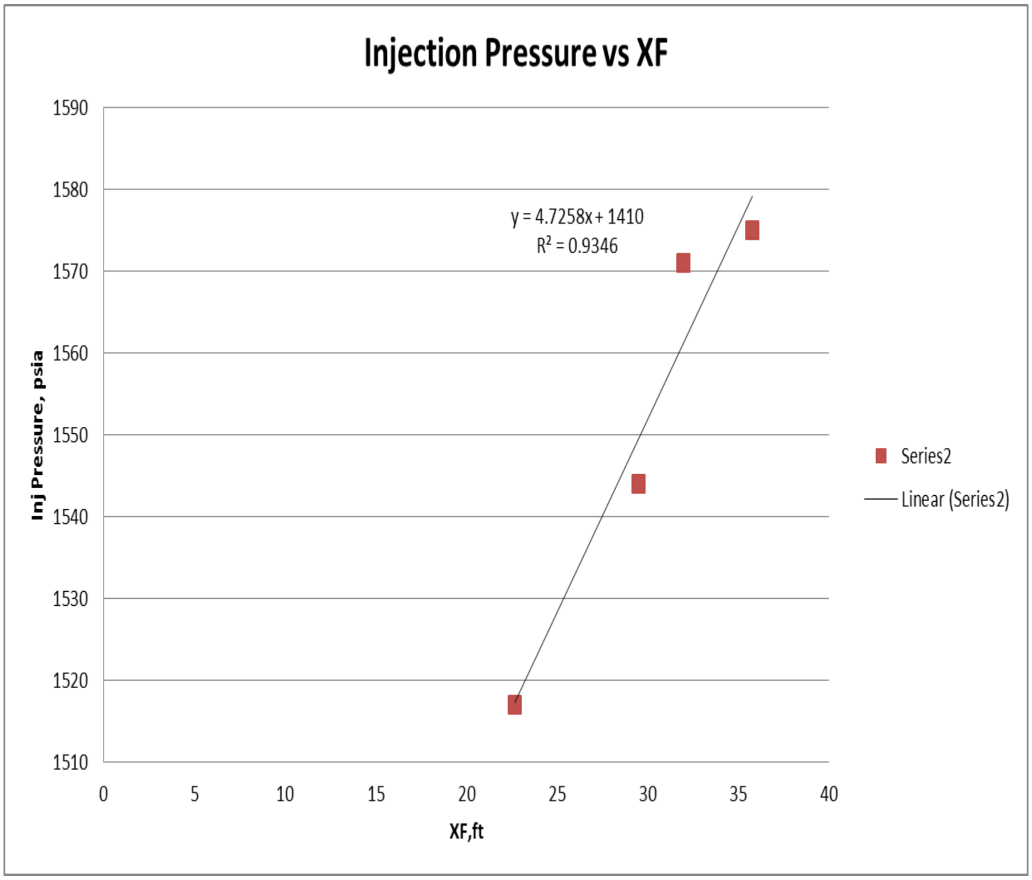

Figure 13: Bottomhole injection pressure versus half-length fracture.