Additional Information

SRT for 30-025-45459 Tubing Upsize

IPI request for 30-025-45459 & f~~our~~ additional wells after tubing upsize

30-025-45479

30-025-45480

30-025-45481

30-025-45482

30-025-45483

7-17-2026

From: Vanessa Neal
To: Harris, Anthony, EMNRD
Cc: Goetze, Phillip, EMNRD; Sandoval, Stacy, EMNRD; Dougi, Delilah, EMNRD; Chavez, Carl, EMNRD; Huxley Song; Jessica LaMarro; Charles Hooper; Adam Holcomb; Joe Kent
Subject: [EXTERNAL] WEU Pilot 2 Package - Overview of Planned Work
Date: Thursday, March 5, 2026 3:49:57 PM
Attachments: image001.png
Pilot2_CrossSection_03052026.pdf

Good afternoon Tony,

FAE plans to recomplete all six (6) injectors within Pilot 2 of the WEST EUMONT UNIT (WEU) with the goal to expand the interval being waterflooded (within the approved unitized interval, EUMONT pool: Yates-Seven Rivers-Queen formations) and reduce surface injection pressure by installing larger tubing (3-1/2" IPC tbg). FAE does not intend to frac the reservoir and will perform a step rate test (SRT) to identify max surface injection pressure for the larger tubing size.

The attached cross-section shows the current open perfs in the Upr QUEEN formation (MAROON/PINK) and the proposed additional perfs in the Penrose Sand/Lwr QUEEN formation (GREEN). The proposed additional perfs are within the unitized interval of the WEST EUMONT UNIT.

Table 1 – Pilot 2 injectors with current and proposed perfs.

Well Name	API	Current Open Perfs	Proposed Additional Perfs
WEU 522	30-025-45479	3810 – 3932'	3980 – 4175'
WEU 523	30-025-45480	3714 – 3851'	3900 – 4100'
WEU 524	30-025-45481	3713 – 3825'	3875 – 4070'
WEU 525	30-025-45482	3789 – 3898'	3948 – 4160'
WEU 526	30-025-45483	3819 – 3929'	3982 – 4184'
WEU 527	30-025-45459	3715 – 3818'	3873 – 4055'

With the change of tubing size, FAE recognizes that the existing IPIs for these wells will no longer be valid. FAE intends to perform an SRT on the WEU 527 and apply for new IPIs for all six (6) injectors using the results of WEU 527's SRT. Until these new IPIs are approved, FAE understands that the maximum pressure of these well's original waterflood order (WFX-1036) will apply.

Table 2 – Current IPIs of Pilot 2 injectors that will become invalid upon recompletion & tubing upsize.

Order	Approval Date	Well No	API	Existing Tbg OD (in)	Initial New MSIP Limit (psi)	Injection Interval (ft)	Pressure Gradient (psi/ft)
IPI-530	8/24/2020	WEU 525	30-025-45482	2.375	1850	3789 - 3898	0.49
IPI-531	3/10/2021	WEU 527	30-025-45459	2.375	1814	3715 - 3818	0.49
IPI-532	3/10/2021	WEU 522	30-025-45479	2.375	1861	3812 - 3932	0.49
IPI-533	3/10/2021	WEU 523	30-025-45480	2.375	1813	3714 - 3851	0.49
IPI-534	3/10/2021	WEU 524	30-025-45481	2.375	1813	3713 - 3825	0.49
IPI-535	3/10/2021	WEU 526	30-025-45483	2.375	1865	3819 - 3929	0.49

All of the NOI sundries related to this work have been submitted via the NMOCD electronic system. Please let us know if you need any additional information.

Table 3 – Action IDs and description of C-103s submitted for the WEU Pilot 2 work package.

Action ID	Type	Well Name	API	Purpose
530712	C-103E	WEU 527	30-025-45459	Add Perfs, Acidize & Upsize Tbg
558414	C-103X	WEU 527	30-025-45459	Step Rate Test
560187	C-103E	WEU 526	30-025-45483	Add Perfs, Acidize & Upsize Tbg
560183	C-103E	WEU 525	30-025-45482	Add Perfs, Acidize & Upsize Tbg
560182	C-103E	WEU 524	30-025-45481	Add Perfs, Acidize & Upsize Tbg
560181	C-103E	WEU 523	30-025-45480	Add Perfs, Acidize & Upsize Tbg
560178	C-103E	WEU 522	30-025-45479	Add Perfs, Acidize & Upsize Tbg

Thank you,

Vanessa Neal |Sr Reservoir Engineer
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O 832.219.0990 (ext 165)
C 979.255.3476
E vanessa@faenergyus.com

Permian Basin - New Mexico and Texas

HS=139

PETRA 3/5/2026 11:35:48 AM

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https://www.emnrd.nm.gov/ocd/contact-us/

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO.
30-025-45459

5. Indicate Type of Lease
STATE ☐ FEE ☒

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name
WEST EUMONT UNIT

1. Type of Well: Oil Well ☐ Gas Well ☐ Other INJECTION-WATER

8. Well Number #527

2. Name of Operator
FORTY ACRES ENERGY LLC

9. OGRID Number
371416

3. Address of Operator
11757 KATY FREEWAY, SUITE 725, HOUSTON, TX 77079

10. Pool name or Wildcat
[22800] EUMONT; Y-7R-Q (OIL)

4. Well Location
Unit Letter K : 2365 feet from the SOUTH line and 2460 feet from the WEST line
Section 35 Township 20S Range 36E NMPM LEA County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*
3557' GL

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:
PERFORM REMEDIAL WORK ☐ PLUG AND ABANDON ☐
TEMPORARILY ABANDON ☐ CHANGE PLANS ☐
PULL OR ALTER CASING ☐ MULTIPLE COMPL ☐
DOWNHOLE COMMINGLE ☐
CLOSED-LOOP SYSTEM ☐
OTHER: ☐

SUBSEQUENT REPORT OF:
REMEDIAL WORK ☐ ALTERING CASING ☐
COMMENCE DRILLING OPNS. ☐ P AND A ☐
CASING/CEMENT JOB ☐
OTHER: **STEP RATE TEST** ☒

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

In Reference to:
WFX-1036
IPI-530, 531, 532, 533, 534, & 535

FAE requests an IPI for each injector in WEU pilot 2 (see table below) granting a MSIP for increased tubing size based on the SRTs performed on WEU 527 in 2026. Please see attached SRT data and analysis.

Well Name	API	Injection Interval (ft)	New Tubing OD (in)	Requested New MSIP Limit (psi)
WEST EUMONT UNIT #527	30-025-45459	3715 - 4060	3.500	1,953
WEST EUMONT UNIT #522	30-025-45479	3810 - 4175	3.500	2,003
WEST EUMONT UNIT #523	30-025-45480	3714 - 4100	3.500	1,953
WEST EUMONT UNIT #524	30-025-45481	3713 - 4070	3.500	1,952
WEST EUMONT UNIT #525	30-025-45482	3789 - 4160	3.500	1,992
WEST EUMONT UNIT #526	30-025-45483	3819 - 4184	3.500	2,008

Spud Date: 6/18/2026 Rig Release Date: 6/18/2026

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE ____ TITLE SR RESERVOIR ENGINEER DATE 25 JUN 2026

Type or print name VANESSA NEAL E-mail address: vanessa@faenergyus.com PHONE: 832-219-0990
For State Use Only

APPROVED BY:____ TITLE____ DATE____
Conditions of Approval (if any):

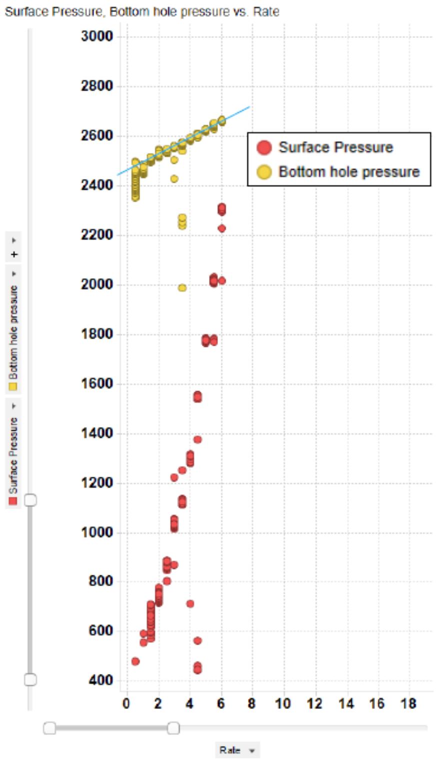
WEU 527 Step Rate Test Overview

- Pilot 2 Current IPI Order
- Waterflood Frac Pressure
- WEU 527 Step Rate Test
- Pilot 2 Injection Pressure for q=0 bwipd
- Address UIC’s May 8th questions

Existing Pilot 2 IPI Order from 2020

Original Pilot 2 Step Rate Test

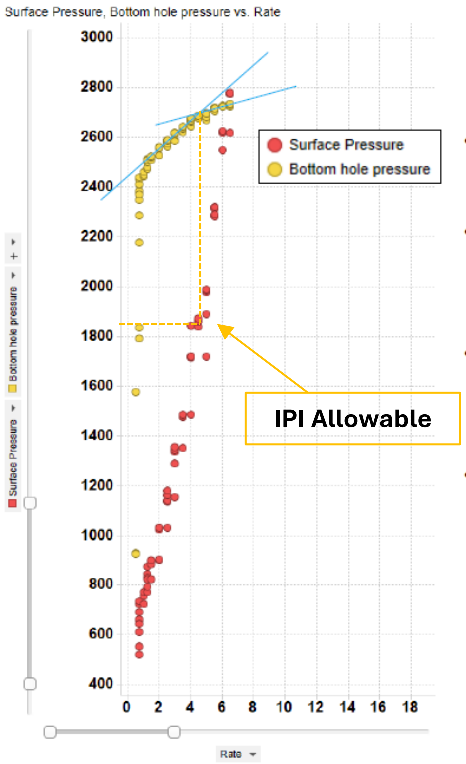
March SRT



March SRT Comments

- Max bottomhole pressure reached in March was 2,666 psi
- Max surface pressure was 2,316 psi
- We did not see the bottomhole pressure break over on the March step rate test (perfectly straight line)

June SRT



June SRT Comments

- Max bottomhole pressure reached in June was 2,734 psi
- Max surface pressure reached was 2,776 psi, ~460 psi greater than the March SRT
- We saw a breakover by pumping at the higher surface pressure
- The bottomhole breakover point is approximately 2,680 psi, which corresponds to a surface injection pressure of 1,850 psi

2

- We did two step rate tests in 2020
- The first step rate test did not see a slope change
- We increased the max pressure on the second test in an effort to see a slope change
- In our most recent step rate test, we knew we would not see a slope change, and offered that expectation ahead of the step rate test

IPI Order Summary

Well No.	API Number	UL-S-T-R	Injection Authority	Existing MSIP Limit (psi)	Existing Tubing OD (in)
West Eumont Unit No. 526	30-025-45483	E-35-20S-36E	WFX-1036	760	2.375

Well No.	Step Rate Test Date	Initial New MSIP Limit (psi)	While Injecting	Injection Interval (ft)	Pressure Gradient (psi/ft)
West Eumont Unit No. 526	6/26/2020	**1865**	Water	3819 – 3929	0.49

Waterflood Frac Pressure (Changes with Injection)

- Normal Fracture Pressure calc:

$$\textbf{Fracture Pressure} = \nu/(1-\nu)\left(S_v - P_p\right) + P_p$$

ν= Poisson's ratio

S_v= vertical overburden stress, psi

P_p = pore pressure, psi

***Key Points:**

1. **Pressure in the formation rises with injection and in turn the fracture pressure rises in proportion with increases in reservoir pressure**
2. **In waterfloods, operators should submit multiple step rate tests during the life of a waterflood to maintain injection rate as pressure rises in the formation**

- Fracture Gradient after injection calc:

$$FG_{new} \approx FG_{initial} + \frac{A\Delta P_p}{TVD}$$

A= Stress path coefficient

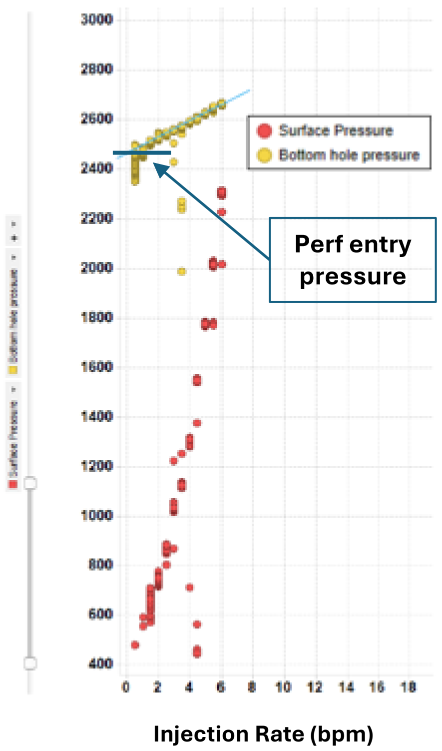
- It is field-specific and depends on reservoir geometry, boundary conditions, rock properties, depletion/injection history, faults, and pressure distribution. Literature commonly treats pore-pressure changes during production or injection as causing stress changes in and around the reservoir, described by a stress path.

Stress path coefficient (A)	Meaning
0.2–0.4	Weak stress coupling; pressure rises faster than frac pressure
0.4–0.7	Common practical range for many reservoirs
0.7–1.0	Strongly constrained / strong poroelastic coupling
>1.0	Possible locally in complex cases, but not a normal screening assumption

WEU 527 Step Rate Test Compared to Previous Step Rate Tests

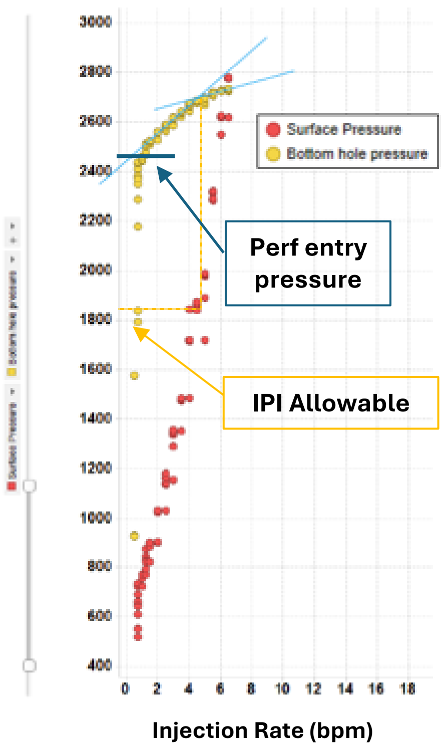
Step Rate Test Comparison

March 2020 SRT



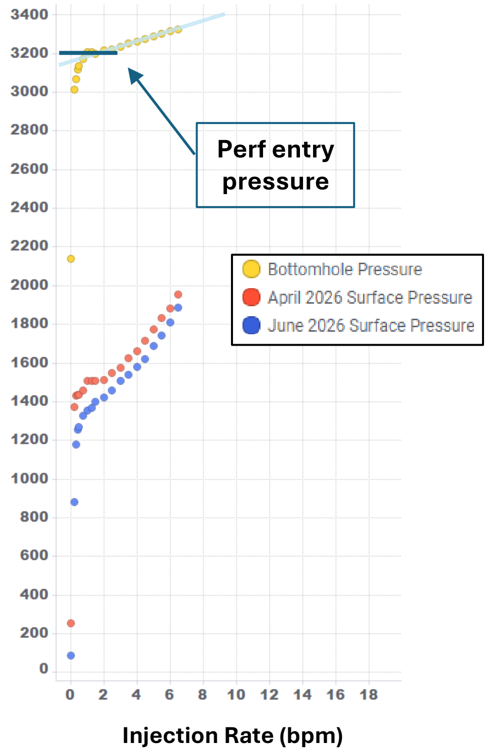
Result: No slope change

June 2020 SRT



Result:
Slope change at ~1,850 psi surface pressure

April and June 2026 SRT



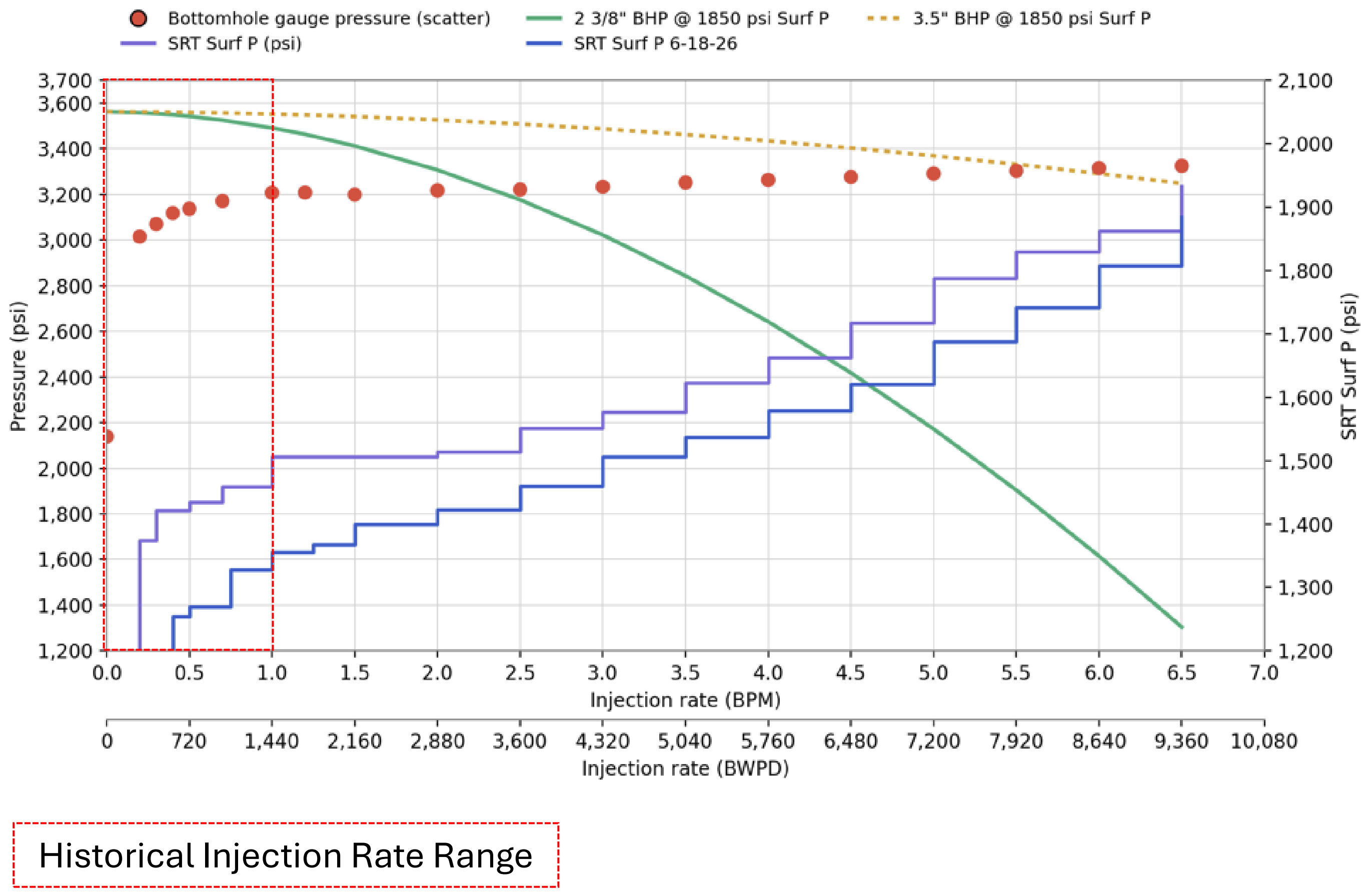
Result: No slope change

Key Points

- Reservoir pressure has increased dramatically due to the injection from the waterflood
  - Perf entry pressure rises with increased reservoir pressure
  - Perf entry pressure increased from ~2,450 psi to ~3,200 psi from 2020 to now
- FAE is seeing declining injection rates as we're limited by surface injection pressure as reservoir pressure increases
- FAE did not expect a slope change and did not see a slope change
- April 2026 SRT trend looks like March 2020 SRT trend
- The June and April 2026 step rate tests exhibit the exact same steady state slope.
- The June 2026 near wellbore reservoir pressure is lower vs April 2026 since we have not been able to inject due to the temporary lower allowable pressure being too low for us to inject water

WEU 527 Step Rate Test (May 2026)

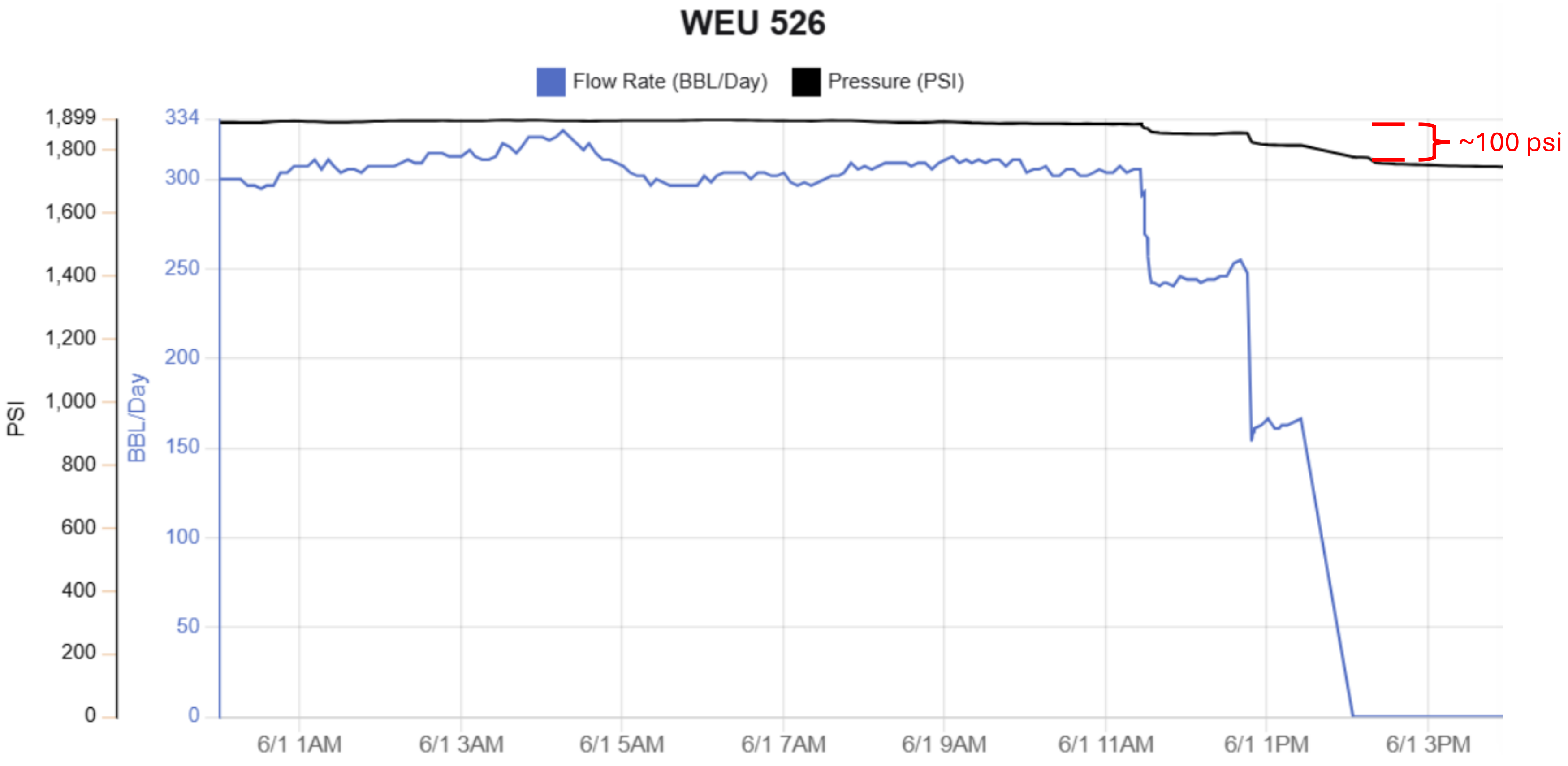
Step Rate Test Graph



Key Points

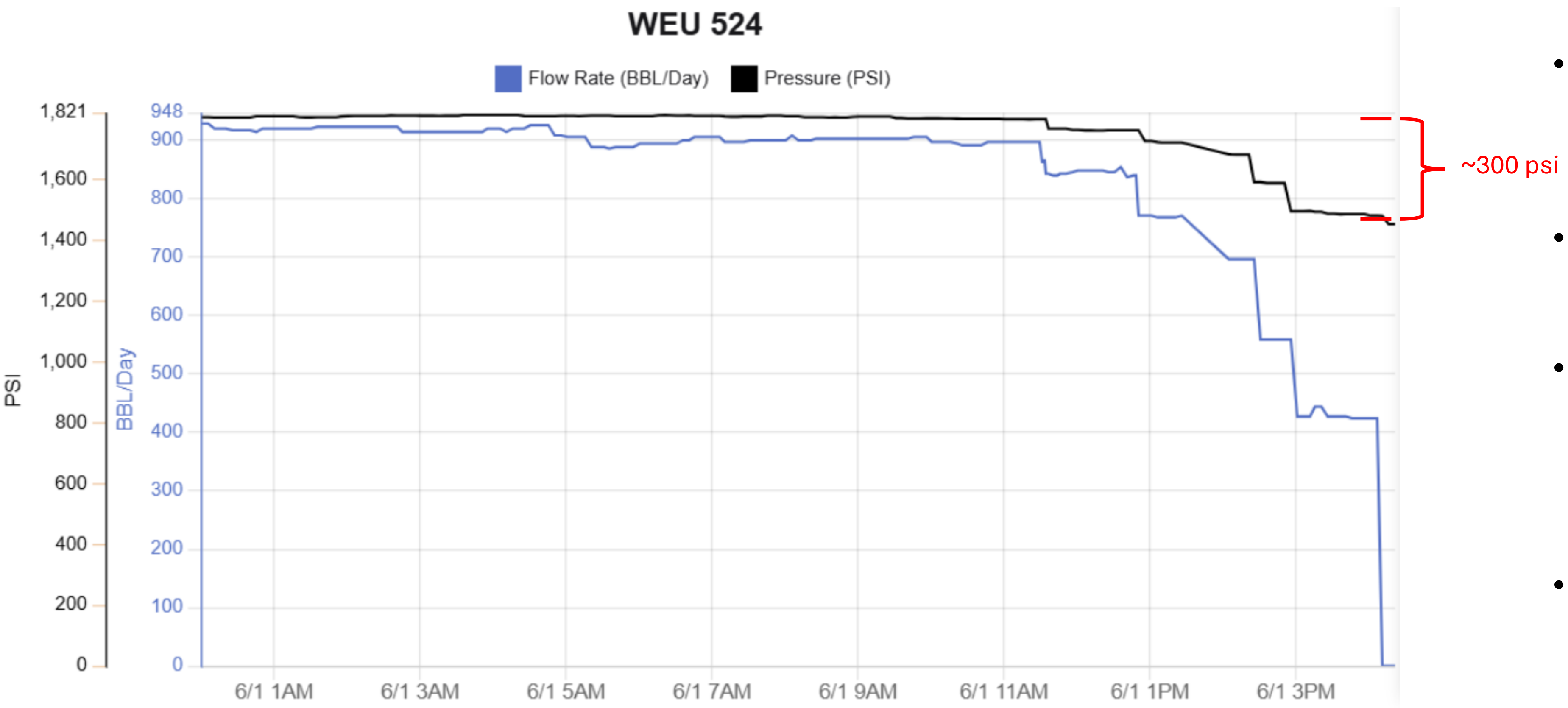
- Increased reservoir pressure from injection increases frac gradient proportionally
  - Current frac pressure is much higher than 2020 when we did our initial step rate test
- Difference in 2 3/8” and 3 ½” in the range of our actual historical injection rate is very small, ie the bottomhole pressure is very similar
- BHP will decrease even further as injection rate increases at any given allowable surface pressure as friction pressure increases
- If we get our surface injection pressure reduced from current levels, we will either not be able to inject at all or inject very little
- Our allowable pressure should increase over time so we can keep similar rates as fracture pressure increases with increasing reservoir pressure

WEU 526 (Pilot 2 Well) Current Surface Pressure Where Inj Rate = 0 bwpd



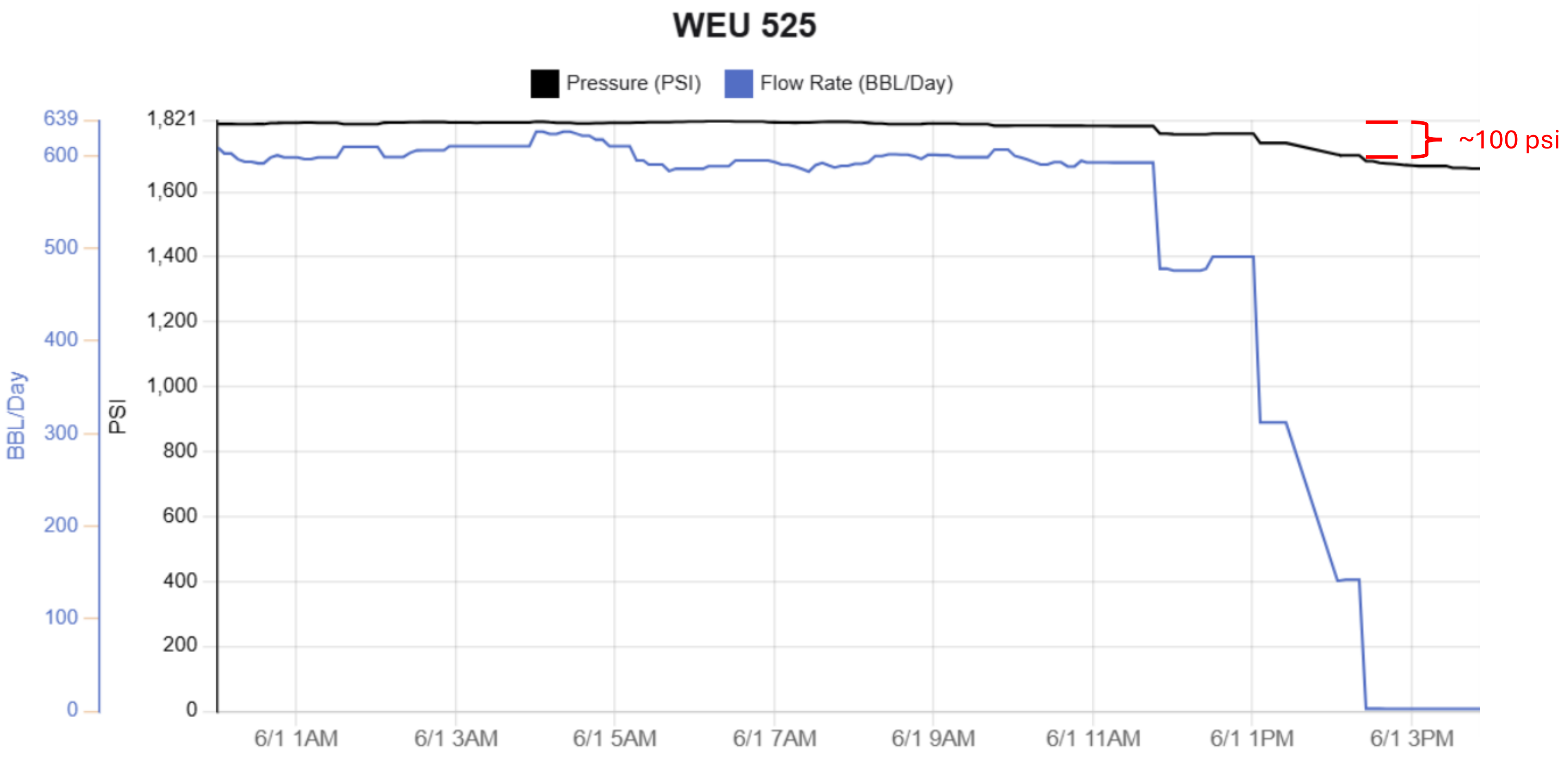
- Closest injector to the WEU 527 (step rate test well), ~1,240' from the WEU 527
- We currently inject at 1850 psi and 300 bpd
- At this rate, there is effectively no difference in friction pressure / BHP between 3 ½" and 2 3/8" tubing
- At ~1,750 psi surface pressure, or ~100 psi lower than our current injection pressure, we found this well will go to 0 bwpd rate

WEU 524 (Pilot 2 Well) Current Surface Pressure Where Inj Rate = 0 bwpd



- 2nd closest injector to the WEU 527 (step rate test well), ~1,590' from the WEU 527
- We currently inject at ~1,800 psi and 900 bpd
- At this rate, there is very little difference in friction pressure / BHP between 3 ½" and 2 3/8" tubing
- At ~1,500 psi surface pressure, or ~300 psi lower than our current injection pressure, we found this well will go to 0 bwpd rate

WEU 525 (Pilot 2 Well) Current Surface Pressure Where Inj Rate = 0 bwpd



- 3rd closest injector to the WEU 527 (step rate test well), ~1,770' from the WEU 527
- We currently inject at ~1800 psi and 600 bpd
- At this rate, there is effectively no difference in friction pressure / BHP between 3 ½" and 2 3/8" tubing
- At ~1,700 psi surface pressure, or ~100 psi lower than our current injection pressure, we found this well will go to 0 bwpd rate

WEU 527 — Waterflood History: No Indication of Fracture at Current Operating Pressure

Evidence the formation has not fractured

- **6 years continuous injection**

  Jun 2020 → present

- **Pressure stable since Q3 2023**

  3-yr median THP ~1781 psi, below MSIP 1,814 psi

- **Injectivity DEGRADED, not grew**

  Matrix flow + skin. Fracture extension would do the opposite.

- **Injection profile (4/30/26)**

  Injection contained within IPI-531 permitted interval (3,715-3,818 ft)

- **Offset producers 511 / 512 / 520**

  Gradual water-cut rise = normal pattern sweep, no channeling — no impact to correlative rights

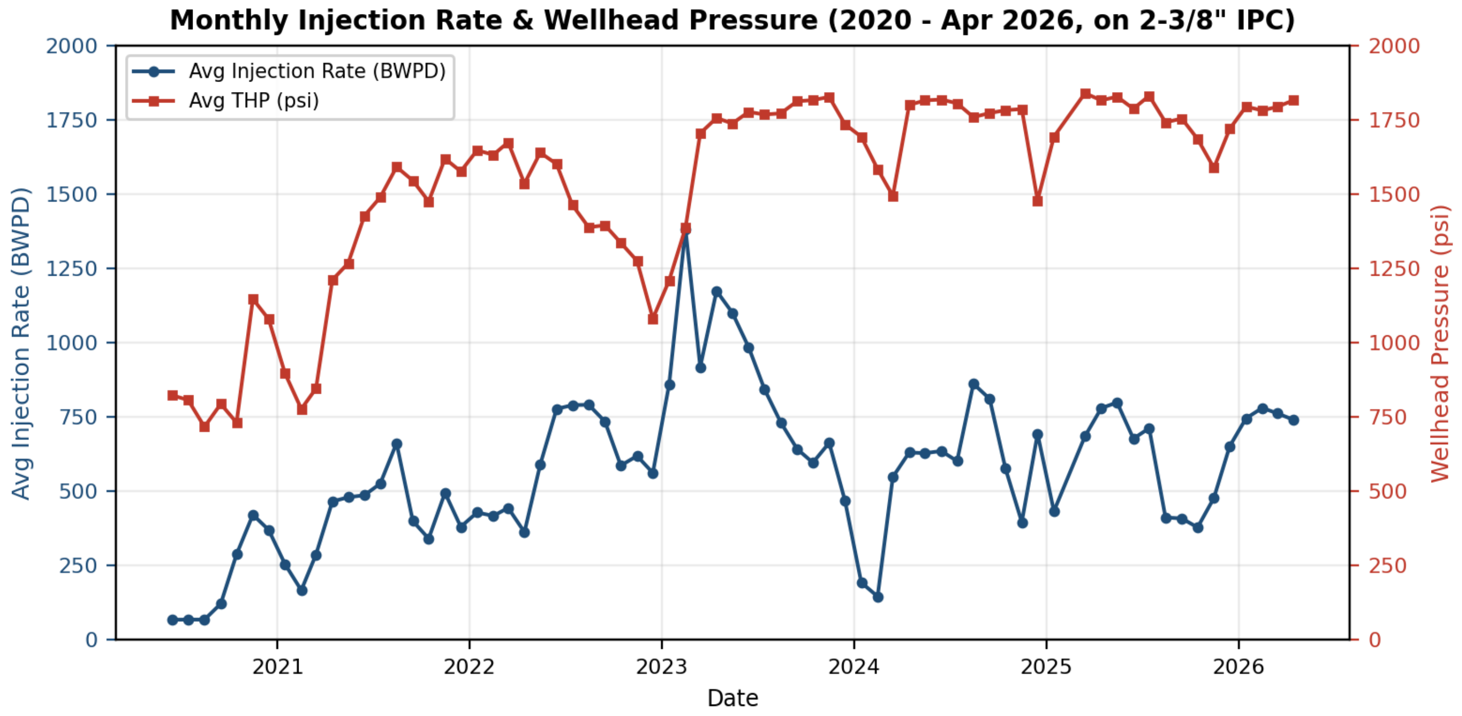
- **No MIT failures**

  Last MIT 12/26/2019; no offset injector pressure communication

- **Both IPI-531 safety conditions met**

  No fracture of permitted interval. No fracture of confining strata.

Key Points:
- No fracture from historical injection
- Minimal difference in friction pressure from 2 3/8” to 3 1/2“ tbg
- Keeping same surface pressure won’t fracture the formation



3-yr median operating (on 2-3/8" IPC): 647 BWPD @ 1781 psi THP → BHP at perfs

Tubing	Friction (psi)	BHP @ perfs (psi)	vs IPI-531 envelope
2-3/8" IPC (5-yr operating basis)	15	**3694**	(historical envelope)
3.5" IPC (new tubing)	2	**3707**	+13 psi at this rate
IPI-531 MSIP 1,814 on 2-3/8" (low Q)	~5	3736	permitted ceiling BHP

At the 3-yr average rate, BHP delivered on 3.5" IPC is essentially identical to 2-3/8" (+13 psi). The 5-year operating envelope translates 1-for-1 to the new tubing.

Source: Automation.dbo.vw_Injdata (Peloton + zdSCADA), Jun 2023 - May 2026 (34 months). BHP = THP + 1,927 psi hydrostatic (0.5188 psi/ft × 3,715 ft to top perf) - tubing friction (H-W C=150, 3,658 ft).

Response to UIC's Email

We are up against a very demanding workload at this time and , as a result, your request will require some additional time for consideration. My initial thoughts, and items to be clarified to support this request are as follows:

1. Can you please clarify how the bottomhole gauge was deployed / hung in tubing?
    1. Was it suspended from surface via wireline during the entire SRT (ie. with a wireline lubricator rigged-up onto the crown/swab valve)? OR
    2. Was the gauge set in a landing nipple in the tubing? OR
    3. Was the gauge set using a gauge hanger inside the tubing (Since it is internally coated tubing, I assume this option was not used to prevent damage to the internal coating)?

If option 1a or 1b was used, then the pressure recorded at the bottomhole gauge will not be truly representative of the pressure at the sandface since there would be a pressure drop due to the restriction associated with placement of the gauge inside the tubing.

1. Huxley's email referenced surface pressure of ~4000 psi (using 3.5" tubing) before formation parting is observed in offset wells. However, since surface pressure is strongly influenced by pump rate, fluid type, and proppant concentration (and the corresponding friction pressures associated with each of those parameters), we have to evaluate pressure relative to the pump rate, fluid type and proppant concentration to draw a proper conclusion.
    1. Can you please provide /summarize the data that Huxley is referencing to support the 4000 psi initiation pressure?
    2. Please provide bottomhole gauge data (if available) to confirm the bottomhole parting pressure to confirm the Frac Gradient.
    3. Please provide falloff data (if available) to characterize the frac closure pressure.

Covered earlier in this presentation

1. With reference to the SRT data from the WEU#527 well, the following is observed
    1. The interpreted inflection point was 3210 psi at the gauge depth of 3630 ft.
    2. This equates to a frac gradient of **0.88 psi/ft** which seems relatively high. However, as outlined in item 1 above, if the gauge was suspended in a landing nipple or using a gauge hanger, this may explain the relatively high frac gradient?
        i. Do you have any data from offset wells to support / validate this frac gradient?

Covered on next slide

1. Was a falloff period completed after the SRT?
    1. If yes, analysis of the falloff data could perhaps confirm whether a frac was initiated (ie. Frac Closure pressure analysis).
    2. Does sufficient mechanical properties data exist to estimate the frac gradient via Eaton's formula?

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WEU 527 Downhole Pressure Gauge Pressure Drop

- Liquid Orifice Pressure Drop
  - The downhole gauge is 1.25” diameter while the tubing ID is 2.992”
  - Units
    - Q = 6.5 BPM = 273 GPM
    - Cd = 0.62 (sharp-edged, the gauge is actually rounded, so would be more like 0.7-0.8, but will assume sharp)
    - Dpipe = 2.992”
    - Dobstruction = 1.25”
    - SG = 1.0 water
  - Solve
    - d = sq rt (2.992^2 – 1.25^2) = 2.72”
    - Cv = 29.8 x 0.62 x 2.72^2 = 136.7
    - DP = (273/136.7)^2 x 1.0 = **3.99 psi**
  - Total pressure drop due to the downhole pressure gauge is 4 psi

Liquid Orifice Pressure Drop Formula

$$\Delta P = \left(\frac{Q}{29.8 \cdot C_d \cdot d^2}\right)^2 \cdot SG$$

Variable	Description	Units
ΔP	Pressure drop across the restriction	psi
Q	Volumetric flow rate	GPM (US gallons per minute)
29.8	Empirical constant for liquid flow at standard conditions	—
Cd	Discharge coefficient (0.62 for sharp-edged annular or orifice restrictions)	—
d	Equivalent diameter of the flow restriction	inches
SG	Specific gravity of the fluid (water = 1.0)	—

$$d_{eq} = \sqrt{D_{pipe}^2 - D_{obstruction}^2}$$

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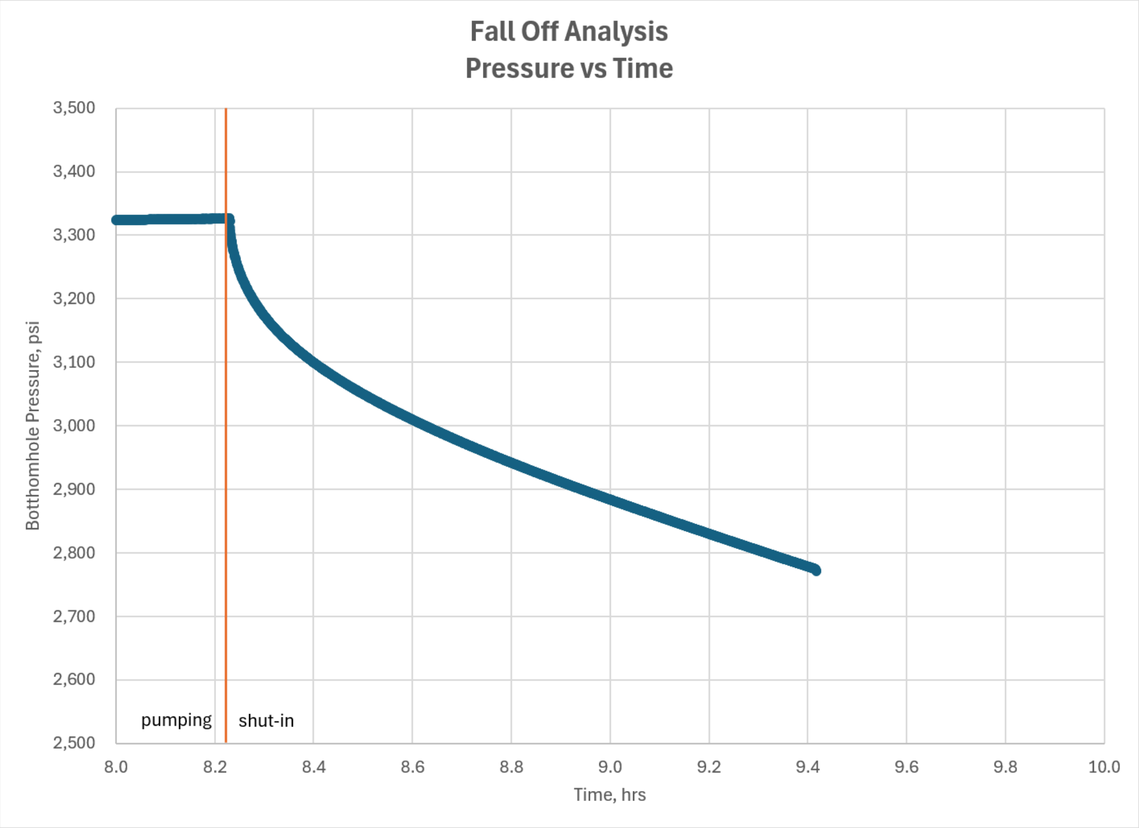
WEU 527 Eaton's Formula Summary



- The pressure response during a pressure fall off test is influenced by multiple coupled variables contained within Darcy's law and non-Darcy near-wellbore flow behavior, including:
  - Formation permeability
  - Fluid viscosity
  - Skin damage or stimulation
  - Perforation friction / perf entry pressure
  - Tubing friction
  - Reservoir pressure
  - Compressibility and storage effects
  - Near-wellbore turbulence
  - Layered interval contribution changes
- Without derivative diagnostics, G-function analysis, and friction-corrected sandface pressure, the fall off cannot uniquely distinguish between:
  - hydraulic fracture closure,
  - wellbore storage,
  - compressibility effects,
  - or transient radial leakoff behavior.
  - As a result, the data does not presently provide a clear, unambiguous fracture/no-fracture determination.
- Because several variables simultaneously affect the slope and curvature of the pressure-rate response, changes in slope alone are not definitive proof of fracture initiation. In particular, permeability-thickness variations, evolving skin, perforation efficiency changes, or non-Darcy flow effects can all produce apparent "breaks" in the step-rate trend that resemble fracture behavior.
- From an engineering standpoint, this is an important limitation of relying solely on Eaton-style fracture gradient concepts. Eaton's method is fundamentally a geomechanical estimation technique and does not fully account for the dynamic multi-variable flow behavior described by Darcy's law during active injection testing. In this case, the transient flow effects and completion-related friction components appear significant enough that they may obscure or mimic fracture-related signatures.

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State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 605845

CONDITIONS

Operator:	
FORTY ACRES ENERGY, LLC 11757 KATY FWY HOUSTON, TX 77079173	OGRID: 371416
	Action Number: 605845
	Action Type: [IM-SD] Admin Order Support Doc (ENG) (IM-AAO)

CONDITIONS

Created By	Condition	Condition Date
anthony.harris	None	7/17/2026