Estimating Reservoir Pressure from Early Flowback Data

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Presented by Steve Jones at the Oil Capital Chapter of API
Tulsa, Oklahoma; June 30, 2016
Overview

• Frac and flowback operations
• Need for initial reservoir pressure, $p_R$
• Methods to estimate $p_R$
• Method using flowback data
• Examples and interpretation
• Validation and applicability
• Estimating $p_{wf}$ from surface data
Location

OKC 20 miles

Woodford Plays

Meramec Play

STACK

SCOOP

20 miles
Fracturing Operation
Frac Operation

Laterals 5000-10,000 ft long
Frac stages 150-400 ft
25-65 stages in a 10,000-ft lateral
4-12 days pumping the fracs

Pumping pressure 5000-9000 psi (80 BPM)
200-500k bbls water in a 10k’ well
12-24 MM lbs sand in a 10k’ well
2000-5000 psi ISIP after frac
Frac and Flowback
Frac and Flowback

$\rho_R$

$p_{frac}$

$p_{wf}$

Earth stress and rock compressibility

Water compressibility
Hydrocarbons begin to flow when pressure in the fracture falls below $p_R$. 

Frac and Flowback
Reservoir Pressure, $p_R$

Needed for:
• Oil in place – $B_o$ (rb/stb)
• Drawdown: $p_R - p_{wf}$
• Transient PI or PNR: $q_o / (p_i - p_{wf})$
• Rate Transient Analysis (RTA)
• Reservoir simulation

Reserves, forecasting, development planning
Methods to Estimate $p_R$

- Pressure buildup testing
- Formation test tools (DST, MDT, etc.)
- DFIT (Diagnostic Fracture Injection Test)
- Other methods
  - Relate $p_R$ to frac gradient
  - Infer $p_R$ from port opening pressure
  - Downhole gauge after toe prep

*Low permeability is an issue*
Flowback Example #1

Chart showing data for Days of Flowback with categories for Gas, Water, Oil, Casing Pressure, and Choke. The chart includes data points for MCFD, BOPD, BWPD, and PSI over time.
Flowback Example #2

Days of Flowback

Casing Pressure

Water

Gas

Oil

Choke, 64ths

MCFD, BOPD, BWPD, PSI
Method

• Calculate hourly $p_{wf}$ from surface data
• Plot $p_{wf}$ with rates vs. time.
• Identify flattening or minimum in $p_{wf}$ just prior to measurable oil or gas production
Woodford Gas Condensate Well

Example #1 with $p_{wf}$ calculated from surface data

$$p_{wf} = p_{surf} + p_{hyd} - p_{fric}$$
Woodford Gas Condensate Well

Estimated $p_{wf}$ mimics casing pressure up to this point
Woodford Gas Condensate Well

Estimated $p_{wf}$ drops when measured HC starts.
Flowback Operation

- Purpose is to handle water, sand, debris
- For gas wells, gas from tank is sent to flare
- Typically no 3-phase separator
Flowback Operation

Well is turned to production facilities when hydrocarbon rate is adequate. Oil is skimmed from flowback tank.
Woodford Gas Condensate Well

- **Est** $p_{wf}$
- Actual $p_{wf}$
- Water
- Gas
- Casing Pressure
- Oil

Turned to sales at this point
Woodford Gas Condensate Well

Est $p_{wf}$

This point is BELOW reservoir pressure. Well is making 2 mmcfd
Woodford Gas Condensate Well

Days of Flowback

MCFD, BOPD, BWPD, PSI

Casing Pressure

Water

Gas

Oil

Est $p_{wf}$

7860 psi

Choke, 64ths

Choke

0 1 2 3 4 5 6 7 8 9 10

0 1,000 2,000 3,000 4,000 5,000 6,000 7,000 8,000 9,000 10,000

0 10 20 30 40 50 60
Meramec Oil Well

![Graphical representation of flowback data with various indicators such as Est $p_{wf}$, water, casing pressure, gas, and oil. The graph shows data points and lines indicating flowback days, pressure, and flow rates for MCFD, BOPD, BWPD, and PSI.]

Est $p_{wf}$

Water

Casing Pressure

Gas

Oil

4400 psi

Choke
Validation Data

- Perf toe stage
- Break down perfs
- Hang BHP gauges
- Leave shut in until frac
- Gives min or max $p_R$
Woodford Gas Condensate Well

MCFD, BOPD, BWPD, PSI

Days of Flowback

Est $p_{wf}$

BHP Gauge:
7602 psi and rising

7720 psi

Woodford Gas Condensate Well

Water

Gas

Casing Pressure

Oil

7602 psi and rising
Issues

• Not theoretically rigorous
• Drawdown required for first HC production
• Supercharging of pore space by frac
• Pipe friction, flow-through plugs
• *Must validate* in new areas
DFIT Comparison Example

Average difference 4.3% or 144 psi higher than DFIT
Maximum difference 11.7% or 376 psi higher than DFIT

- DFIT subject to interpretation
- DFIT may be different for a reason
South Area, Woodford

Reservoir Pressure Gradient

- 0.58 psi/ft
- 0.46 psi/ft

- Focus on trends
- Compare PI values during assessment
Challenges

• Long shut-in after frac
• Normally or subnormally pressured
• Artificial lift from beginning
• Erratic choke management
• Gas or oil production starts immediately
• Severe skin damage on frac face
Estimating $p_{wf}$ - Gas Wells

Gray Correlation
- Calculated FBHP 1% high on average
- Average Absolute Error 6.4%, or 135 psi
Estimating $p_{wf}$ - Oil Wells

Hagedorn-Brown Correlation
Calculated FBHP 8% high on average
Average Absolute Error = 9%, or 73 psi
Estimating $p_{wf}$ Routinely

• Validate correlations
• Data quality
  – Hourly, daily, SCADA
  – Accurate input data
• Automate data flow
• Artificial lift
• Use static side where available
Benefits of Reliable $p_{wf}$

- Compare PI curves
- Establish allowable drawdowns
  - Avoid excessive condensate dropout
  - Avoid completion/formation damage
- Correlate performance with flowback practice
- Flowback analysis – methods developing
- Accuracy of RTA
- Feed reservoir simulator
Conclusions

• Provides $p_R$ estimate where buildup or DFIT are not applicable
• DFIT may be different for a reason
• **Must validate in new areas**
• Most accurate for flowing wells
• Easily applied on a routine basis
• Feeds all RE calculations
Questions?

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